EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1. 1. OEB STAFF 1

Updated RRWF

Upon completing all interrogatories from Board staff and interveners, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the previous version of the RRWF included in the middle column. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

Response:

The updated RRWF in working Microsoft Excel format has been uploaded to Festival's 2015 COS web drawer. Changes arising from interrogatories have been noted in the middle column. The following is a list of the adjustments made as a result of the interrogatory process:

1. Average capital has been adjusted by $2,185 and controllable expenses increased by $27,155 due to changes to compensation as related to interrogatory 4 Staff 39.
2. Cost of Power has been adjusted to correct pricing as identified in interrogatory per 3 EP 22.
3. Distribution Revenue at Current Rates and Proposed Rates have changes as a result of changing the load forecast due to impact of CDM impacts as per interrogatory 3 EP 19.
4. PILs have been updated to reflect the above noted changes.

Please refer to attached Appendix: Festival_2015 COS_Rev_Reqt_Work_Form_V4_20140827 Final.

As a result of the changes above a number of other models have been updated which include:

1. Cost Allocation model
2. EDVARR model

2. 1. OEB STAFF 2

Updated Appendix 2-W, Bill Impacts

Upon completing all interrogatories from Board staff and intervenors, please provide an updated Appendix 2-W for all classes at the typical consumption / demand levels (e.g. 800 kWh for residential, 2,000 kWh for GS<50, etc.).

Response:

Provided below is a summary table of the Bill Impacts upon completion of all interrogatories. Residential and G.S. < 50 kW see a reduction primarily due to the removal of the ICM and smart meter rater riders. G.S > 50 kW and Large Use see an increase primarily as a result of a new Global Adjustment rater rider. USL and streetlights have a reduction primarily due to Revenue to Cost Adjustments. An excel file containing 2 W for all classes has been submitted through RESS and can be found in festival 2015 COS web drawer.

Table 1 staff 2 bill impacts:

2015 COS - Bill Impact for Typical Festival Hydro Customers (Revised August 27, 2014)

Customer Class	2014 Distribution Charge	2015 Proposed Distribution Charge	Dollar Change	%Change	2014 Total Bill	2015 Total Bill	Dollar Change	%Change
Residential, 250 kWh	24.16	22.43	(1.73)	-7.2%	49.59	46.99	(2.60)	-5.2%
Residential, 800 kWh	33.84	32.83	(1.01)	-3.0%	114.79	111.19	(3.60)	-3.1%
GS < 50 kW, 2,000 kWh	67.29	67.83	0.54	0.8%	291.07	285.91	(5.16)	-1.8%
GS < 50 kW, 10,000 kWh	192.09	203.03	10.94	5.7%	1,336.02	1,318.61	(17.41)	-1.3%
GS >50 to 4,999 kW, 100 kW, 51,100 kWh	487.59	513.90	26.31	5.4%	6,546.03	6,560.51	14.48	0.2%
GS >50 to 4,999 kW, Interval, 600 kW, 306,600 kWh	1,713.24	1,945.55	232.31	13.6%	40,131.68	40,290.91	159.23	0.4%
Large Use, 5000 kW, 2,555,000 kWh	16,805.62	19,854.89	3,049.27	18.1%	338,731.81	343,558.12	4,826.31	1.4%
Unmettered Scatterd Load SL, 340 kWh	18.34	11.19	(7.15)	-39.0%	53.43	44.95	(8.48)	-15.9%
Sentinel Lights, 131 kWh, 0.36 kW	6.28	6.65	0.37	5.9%	19.65	19.39	(0.26)	-1.3%
Street Lights, 657 kW, 239,805 kWh	6,932.12	5,960.78	(971.34)	-14.0%	37,730.75	35,735.07	(1,995.68)	-5.3%

3. 1. OEB STAFF 3

Ref: E1/T4/S1/p.1

Please provide the finalized 2013 audited financial statements and indicate the changes from the draft version provided in the application.

Response:

While page one of E1/T4/S1 was not updated to indicate that final 2013 statements had been attached to the application – the statements included in E1/T4/S1/A3 are in fact the final copy signed by Festival Board members and KPMG.

4. 1. OEB STAFF 4

Ref: E1/T6/S17/p.1 and E4/T4/T1/p.1

In Exhibit 1, Festival indicated that pro-forma for 2015 were prepared in accordance with its usual processes except amortization that reflects the half-year rule. In Exhibit 4, Festival indicated that the half year rule is applied in the year of the addition.

a) Please clarify whether Festival's usual process does not apply the half year rule.

b) Please indicate whether the half year rule was applied in the rate application for each year from 2010 to 2015, including the Appendix 2-C depreciation schedules which are templated to apply the half year rule.

Response:

a) Festival's usual process is to apply the half year rule in the year of capital addition. This item should not be included as an exception to our usual process in E1/T6/S17.

b) The half year rule was applied in the rate application for each year from 2010 to 2015, including the depreciation schedules in appendix 2-C.

5. 1. AMPCO 1

Ref: Exhibit 1, Tab 2, Schedule 6, Page 2

a) Please confirm the other costs in the application impacted by inflation projected at 2%.

Response:

Festival notes that E4/T1/S1/page 2 incorrectly stated that other costs were included in our application at an inflation rate of 2%. Festival's figures for costs other than labour were actually increased by an inflationary factor of 1.6%. Festival notes that costs where this inflationary amount applies were items such as material costs, subcontractor costs (not included in a long term contract at a fixed price), and other miscellaneous costs such as supplies.

6. 1. AMPCO 2

Ref: Exhibit 1, Tab 2, Schedule 8

a) *Page 1 - Please explain why no direct allocations have been made in the cost allocation model.*

b) Page 2 – Please explain the added complexities with smart meters and TOU pricing that make the meter reading and billing costs more reflective of the GS>50 kW and Large Use classes.

Response:

a) The 2010 COS cost allocation model completed by Festival Hydro allocated cost based on billing data, customer data, meter capital and meter reads. For the 2010 COS, Festival had no direct allocations. With the introduction of the weighing factor methodology in the 2014 model, it is Festival's belief that the use of these weighting factors is a further step in ensuring costs are equitably allocated to the various rate classes and the need for direct allocations in Festival's 2015 COS model is not necessary.

b) Previously for conventional residential and G.S. < 50 kW meters, meter reads were manually read and entered into a handheld device. The data from the handheld device was downloaded to the billing system. A variance report was run to identify unusual reads. This would sometimes result in manually verifying a read or doing an estimate if a true read was not available. Customers were then billed using a 2 tiered system. There was no on-line access to view their electrical usage data.

With smart meters and TOU piecing there are greater similarities in processing as described below:

Data retrieval - With the introduction of smart meters and TOU pricing, similar to interval meters, reads are retrieved for hourly intervals (for interval accounts in 5 or 15 minute intervals). For both situations, the data is backhauled through an electronic means, such as WI-FI, cellular or smart synch.

Pricing of intervals for billing - For interval accounts, Festival contracts a third party to provide the interval readings and hourly pricing for billing purposes. The data is download from the settlement provider's website into Festival's billing system. For smart meters on TOU pricing, the data received is processed through the ODS for completeness and sent to the MDR whereby the quantities and pricing is returned back to the LDC for billing.

On-line Access for Energy Management - Interval customers have access to their meter and billing data through a website for energy management purposes; TOU customers also have access to a website to monitor their electrical use.

In particular, the new IT systems and software required to support smart meter data processing and TOU pricing has resulted in cost to the customer more in line for costs associated with an interval customer's account.

7. 1. AMPCO 3

Ref: Exhibit 1, Tab 2, Schedule 8, Pages 3-4

Preamble: Festival Hydro is proposing to realign its revenue to cost ratios in this application. The rebalancing R/C Rations Table on Page 4 appear to differ from the explanation of the realignment proposal on Page 3.

Please reconcile.

Response:

Exhibit 7 Cost Allocation filing and the table on E1/T2/S8 page 4 have the correct amounts. The narrative on E1/T2/S8 page 3 is incorrect. Thank you for bringing to our attention. A detailed calculation showing how Festival derived the final revenue requirement by rate class , the proposed final ratios and the dollars required to rebalance the revenue requirement can be found in Festival's 2015 Cost Allocation model v3.1 excel model, on Tab 01 Revenue to Cost RR, on the bottom of the page, starting at line 87 of the excel spreadsheet.

Festival Hydro is proposing in this application to re-align its revenue to cost ratios by adjusting the allocations of revenue among rate classes in order to reduce some of the cross-subsidization that is occurring and to bring all ratios within the target ranges. The following re-alignments are proposed for each rate class in order to bring all classes within the target ranges, which have been updated for interrogatory responses:

- Residential class in well within the range at 104.18, so no adjustments are proposed.
- Residential Hensall is being adjusted from 103.13 to 104.18 in order to harmonize Residential Hensall with the regular Residential class.
- General Service <50 kW is within the range so no adjustments have been made It continues to have the highest ratio at 118.62.
- General Service > 50 kW has been raised by 1.44 from the current ratio of 81.29 to 82.73, and is being used as the offset account to be increased as result of reduction to USL and sentinel lights.
- Large Use is at 100.62 so no adjustment required.
- Sentinel lights is within the range at 85.27 so no adjustment required.
- Street Lighting is beyond the range at 147.54 so Festival proposes a 27.54 adjustment in test year 2015 to bring this class to the 120 maximum target immediately.
- Unmetered Scattered Load is at 202.50. Festival is proposing to reduce by 82.50 to bring this class to the 120 maximum target immediately.

8. 1. AMPCO 4

Ref: Exhibit 1, Tab 3, Schedule 1, Page 4

Preamble: Festival Hydro indicates it plans to issue another survey in 2014.

a) When does Festival Hydro plan to issue the survey in 2014?

b) Please discuss the proposed frequency of future surveys and the customer classes to be included.

c) Please discuss how frequently and by what means Festival Hydro has communicated with its Large Use and larger commercial customers between 2006 and 2012.

Response:

a) Festival is planning to issue the survey in Q3/Q4 of 2014.

b) Festival plans to issue a survey every year or every two years. All classes of customers will be included although the survey questions may be unique to specific customer classes (eg commercial and industrial customers will not be included in questions relating to using the FHI “time of use” website as it does not apply to them).

c) Festival communicates directly with all large commercial and industrial customers at least once per year by phone call. Our Energy Conservation Officer acts as our key account executive and initiates this contact to ensure these customers are aware of conservation opportunities, but she also inquires if they have any other concerns. All concerns not related to conservation are forwarded to the appropriate department for follow up. In addition to a phone call, these customers are given the opportunity for a site visit by the Energy Conservation Officer and additional Festival staff may attend these site visits if there has been concerns expressed about billing, metering, power quality, or reliability. This group of customers is invited to attend a breakfast meeting once a year, during which conservation success stories are shared and a senior executive from Festival is on hand to speak with customers one-on-one or to set up additional meetings to address concerns. These customers are invited to sign up to an email list to receive messages regarding the analysis of outages that affect them, and they have a separate phone number to call during an outage for a recording of the current status of an outage and a projected restoration time (once known by Festival crews).

9. 1. AMPCO 5

Ref: Exhibit 1, Tab 6, Schedule 12

a) Page 3 – The evidence states the President/CEO became two positions and a VP position and COO position were eliminated. The organizational Chart reflects this as well as a CFO position. Is the CFO a new position? If yes, when was this position hired.

Response:

a) Festival confirms that the CFO is not a new position – the position was previously titled secretary treasurer and was updated to CFO in 2012.

10. 1. AMPCO 6

Ref: Exhibit 1, Tab 6, Schedule 13

a) Attachment 1.1 – Please provide a listing of Festival Hydro's Board of Directors and discuss any changes in membership since 2010.

b) Attachment 1.7 - Please advise if any of the five HR subcommittee members have H/R designations.

Response:

a) Festival has the following Board of Directors:

   a. Board Chair – Walter Malcolm
   b. Vice Chair - Darcy Delamere
   c. Director Ron Charie
   d. Director Ron Kurtz
   e. Director David Scott
   f. Director Dan Mathieson
   g. Director Frank Mark
   h. Director Tom Clifford

Festival notes that Darcy and David are new Board members since 2010.

b) The Chair of Festival's HR subcommittee has a Certified HR professional's designation (CHRP).

11. 1. ENERGY PROBE 1

Ref: Exhibit 1, Tab 2, Schedule 3

a) What is the current status of the union negotiations that began in Q1 of 2014?

b) What is the total increase in each of 2014 and 2015 associated with the assumed cost of living adjustments of 2.5%?

c) What is the source of the 2.0% increase in costs other than labour costs?

d) What is the impact in each of 2014 and 2015 of the assumed increase of 2.0% per year increase in costs other than labour costs?

Response:

a) Refer to responses to 4-Staff-34 and 4-AMPCO-9a.

b) Festival estimates the impact of the inflationary increase on labour and benefits of 2.5% at $84K in 2014 and $88K in 2015.

c) Refer to response to 1.0-VECC-1.

d) As noted in 1.0-VECC-1, the inflationary increase for costs other than labour was actually 1.6% in Festival's application and not the 2% quoted in E1/T2/S3/page 2. Festival notes that the impact of the 1.6% increase on costs other than labour is projected at $21K in 2014 and $22K in 2015.

12. 1. ENERGY PROBE 2

Ref: Exhibit 1, Tab 2, Schedule 5

Appendix 2-AB does not have figures shown for system O&M for 2013 (plan or actual) 2014 (forecast) or 2019 (forecast). Please provide these figures.

Response:

Appendix 2-AB has been updated in OEB Staff response 2 –Staff-17

13. 1. ENERGY PROBE 3

Ref: Exhibit 1, Tab 2, Schedule 6

Please provide the two components of the 2 factor inflation measure used by the OEB to calculate the inflation factor to be used for IRM applications based on the most recent year (2013) of data available from Statistics Canada (i.e. GDPIPIFDD and AWE-All Employees-Ontario (including overtime)).

Response:

Festival notes that in our 2014 IRM decision (EB-2013-0129) the inflation factor for 2014 rates used by the OEB is 1.7%. A productivity factor of 0% and a stretch factor of 0.45% is then applied. This resulted in an approved OEB inflationary percentage for rates of 1.25%. As per the Stats Canada site for 2013 the GDP IPI (FDD) is 1.7% and the AWE – All Employees – Ontario (including overtime) is 1.55%.

14. 1. ENERGY PROBE 4

Ref: Exhibit 1, Tab 4, Schedule 1

a) Please confirm that Festival will convert to MIFRS effective January 1, 2015? If this cannot be confirmed, please explain and provide details.

b) Please confirm that Festival changed its depreciation rates and capitalization policy to be consistent with MIFRS effective January 1, 2013. If this cannot be confirmed, please explain and provide details.

Response:

a) Confirmed.

b) Confirmed.

15. 1. ENERGY PROBE 5

Ref: Exhibit 1, Tab 6, Schedule 12

Please confirm that there are no costs associated with the Board of Directors of Festival Hydro Services Inc. included in the historical, bridge and test year OM&A figures for Festival Hydro Inc. If this cannot be confirmed, please provide a table showing the amount included in OM&A for each of 2010 through 2015.

Response:

Confirmed

16. 1. ENERGY PROBE 6

Ref: Exhibit 1, Tab 6, Schedule 12

The heading on this schedule indicates that it was filed on August 15, 2013. The evidence also indicates that there are no known costs associated with the structure change at this time as additional roles were not added and salaries are still being negotiated.

Please update the evidence to reflect any costs that are now known of this change in structure.

Response:

The date on the filing was incorrect and should have read May 29, 2014. Please refer to 4-Staff-39 for additional information obtained since filing on May 29, 2014 regarding costs associated with the structure change and negotiated salaries. The evidence has been updated to reflect the information obtained regarding newly negotiated salaries.

17. 1. ENERGY PROBE 7

Ref: Exhibit 1, Tab 6, Schedule 13

What is the current status of the document in E1/T6/S13/A8? If revised, please file the revised document.

b) Please provide the total cost of the Board of Directors for each of 2010 through 2013 and the forecast for 2014 and 2015. Please explain any significant changes due to the number of directors, or changes in their remuneration.

Response:

a) The document has been finalized and was approved by the Board of Directors. A revised copy is attached.

b) The following table details the total costs of the Board of Directors for 2010 – 2015. There are no significant changes however the table shows that costs are gradually increasing based on approved remuneration and per diem increases effective in 2013. Festival also notes that there was an anniversary EDA event in 2012 attended by many Board members that increased the overall cost of the directors in that year.

Board of Director's expenses	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
	39,288	38,304	42,357	41,267	44,003	48,672

18. 1. SEC 1

Ref: [Ex.1/2/1, p. 1]

Please provide a copy of the strategy document that arose out of the "planning meetings in order to set the strategy for the organization", i.e. the document setting out the strategy that was implemented by the Applicant. Please provide details of any approval of that strategy by the Applicant's Board of Directors, and a copy of any presentations or other documents provided to the directors as part of obtaining that approval.

Response:

The strategy document referred to in E1/T2/S1 was provided at E1/T6/S13/A8. No other strategy document or presentations were made to the Board of Directors in respect of this document. The Board of Directors were involved in the development of the Mission, Vision and Strategic Planning document. In pursuing FHI's strategy, senior management will identify and bring to the Board specific items that require Board consideration.

19. 1. SEC 2

Ref: [Ex.1/2/2]

Please confirm that the weighted average rate increase being requested, adjusting for the $808,913 reduction in revenue requirement due to accounting changes, is 17.3% (calculated as $1,758,528 ($949,615+$808,913) adjusted deficiency, divided by $10,165,694 revenue at existing rates).

Response:

Confirmed

20. 1. SEC 3

Ref: [Ex.1/3/1, p. 1]

Please provide details of the storefront, including a description of its location and function, and an estimate of its costs of operation.

Response:

Festival has a storefront in the main administration building located at 187 Erie Street, Stratford. It is open 830am to 430pm on regular workdays. Customers can pay bills, make payment arrangements, sign up for a new service, and meet with a customer service representative to review billing etc. The area also serves as a reception area for people meeting with other departments.

As the reception area is part of the administration building and is staffed by the same customer service representatives who answer telephone queries, it is difficult to provide an estimate of its cost of operation. If the storefront was eliminated, there would be no reduction in staff as the work would simply shift to telephone queries instead of in-person visits.

21. 1 SEC 4

Ref: [Ex.1/3/1, p. 3 and 2/2/1, p. 7]

Please provide a list of the "larger commercial and industrial customers" that were interviewed. If any were contacted but refused to be interviewed, please provide a list. If any presentations or other documents were provided to those customers interviewed, please provide copies. If a script or other interview outline was used in those interviews, please provide a copy.

Response:

Due to privacy concerns, Festival will not be providing a list of specific customers that were interviewed. There were no presentations or other documents provided to these customers. The script of the interview is provided in Appendix 2c of the Distribution System Plan, located at Exhibit 2, Tab 2, Schedule 1 (page 526 of 631 in the pdf document for Exhibit 2, last page just before Appendix 3 – OPA REG Letter).

22. 1 SEC 5

Ref: [Ex. 1/4/1, Attach 3, Note 4]

Please advise whether the 2013 and 2012 labels in the table are correct. If they are, please advise why the Transformer Station is listed in 2012 but not 2013.

Response:

The 2013 and 2012 labels in the table are correct. Festival moved the transformer station assets into a variance account in 2013 after approval was received for our incremental capital module included in our 2013 IRM filing (EB-2012-0124) received in April of 2013.

23. 1 SEC 6

Ref: [Ex.1/4/1, Attach 3, Note 17]

Please provide a copy of the May 27, 2013 intercompany loan agreement. Please explain the reason the interest rate charged to FHSI was changed.

Response:

The loan agreement between FHI and FHSI has been attached to these responses in the appendices. The loan agreement contemplates a variable loan rate which will periodically change depending upon reference rate. The terms of the loan agreement are the result of a process whereby, FHSI received a competitive quote from a third party bank. The loan agreement provides revenue to FHI in excess of the

Board approved rate for such monies thereby lowering FHI's revenue requirement. As FHI had the capacity to meet this competitive rate without negative impact to the rate payer, FHI provided the loan to FHSI.

24. 1 SEC 7

Ref: [Ex.1/4/1, Attach 3, Note 21]

Please provide a copy of the most recent financial statements of FHSI. If an audit was performed on those financial statements, please provide the audited statements including the audit opinion.

Response:

FHSI operates in a competitive market as an internet service provider, and as such the audited financial statements of this corporation will not be disclosed publicly. All information relating to intercompany transactions between Festival and FHSI are as disclosed in the audited financial statements of Festival in note #21.

25. 1 SEC 22

Ref: [Ex.1/2/1]

Please review the attached table, showing efficiency assessments of all Ontario I utilities, from the PEG Update report published today. The table shows that the Applicant's costs have been above the benchmark costs applicable for each of the last four years, and in 2013 were above benchmark costs by $2,258,333. With respect to the benchmarking data:

a) Please provide details, with specific reference to the PEG Benchmarking Update Calculations model filed with the Board, of any anomalies in the benchmarking data or model structure that cause the information with respect to the Applicant to be unrepresentative of a reasonable cost comparison.

b) Please describe the Applicant's strategy, if any to cause its actual costs to reduce to the level of the benchmark costs, including details of all material drivers that will allow the Applicant to achieve that result.

Response:

a) Festival has not completed a full review of the PEG benchmarking analysis. Festival has identified capital costs in 2013 and 2008 that relate to a permanent transformer station bypass and a reclassification of capital that we believe warrant further discussion. An email has been sent to the OEB regarding the process of this review. Festival will continue to review the PEG benchmarking analysis.

Festival would note there are many ways in which efficiency or utilities can be measured. For example, under the prior version of the benchmarking, the emphasis was on OM&A spending which consistently ranked Festival very favourably.

b) One of the drivers of Festival Hydro's overall cost has been the emphasis on capital project to replace end of life assets and to ensure a safe and reliable distribution system. FHI's DSP for 2014 – 2019 identifies a 16% reduction in capital spending over the forecast period. This single reduction in spending is expected to decrease Festival's overall costs by roughly $240,000 per year (based on the 2013 PEG model), which should reduce Festival's actual costs to benchmark levels over a 10 year period. Festival will continue to evaluate the PEG model and, where appropriate, incorporate the findings into its decision making.

Festival would note that it has provided its capital spending plan and its methodology for assessing capital projects in its evidence. Festival believes its expenditures have been and will continue to be prudent.

26. 1 VECC 1

Ref: E1/T2/S6/pg.2 & E4/T1/S1

a) Please provide the CPI and GDPI assumptions used by Festival for the years 2010 through 2015. Please provide the source of these assumptions.

Response:

The table below highlights Festival's inflationary assumptions used for budgeting purposes for labour costs and other costs for 2010 through to 2015.

Inflation Assumptions for Budgeting Purposes				
	Labour	**Other Costs**		
2010	3.00%	3.00%		
2011	2.50%	2.00%		
2012	3.00%	2.00%		
2013	2.25%	2.25%		
2014	2.50%	1.60%		
2015	2.50%	1.60%		

The inflationary assumption for labour in 2014 and 2015 was made based on the anticipated increase to union labour costs under a new collective agreement which was finalized in May of 2014 (application budgets were started in July 2013 and finalized in November of 2013). Historically, the union labour increase has been approved for all Festival labour and this assumption was used to calculate 2015 labour in Festival's cost of service application. Festival reviewed recently renewed collective agreements to decide that 2.5% was a reasonable factor to apply.

For historical years inflationary factor for other costs, Festival typically referenced CPI, utility distribution index, GDP-IPI etc. when coming up with our inflationary estimate. For 2014 and 2015, Festival utilized the reported consumer price index for July and August of 2013 as that was the time in which we were drafting our 2015 cost of service budgets. In support of our 1.6% assumption, Festival received approval on our 2014 IRM application (EB-2013-0129) in March of 2014 approving a 1.7% inflationary increase less a productivity factor.

27. 1 VECC 2

Ref: E1/T3/S1/Attachment 1

a) Please confirm the 2013 customer survey is the one that begins on page marked 1 of 10 (PDF pg.59).

b) Did Festival ask the same questions as it had in the 2005 customer survey? If not, why not and specifically how does Festival gauge the change in consumer opinion over time?

c) How frequently does Festival survey its customers?

Response:

a) Confirmed

b) No. The 2005 survey was issued to large commercial and industrial customers (82 total) to obtain their opinion on system reliability. The 2013 survey was issued to all customer classes to gather input used in formulating the five year plan. Festival has historically used informal methods for gauging change in customer opinion over time - direct feedback from customers via email, phone calls, in-person contact at office or at community events. Starting in 2014, surveys will be used to formalize this process.

c) Festival has only issued formal surveys in 2005, and 2013. Plans are in place to issue surveys more frequently – possibly every year or every two years.

EXHIBIT 2 – RATE BASE

28. 2. OEB STAFF 5

Ref: E2/T1/S1/Att. 1, Appendix-2BA and Accounting Procedures Handbook, effective January 1, 2012

For Appendix 2-BA Fixed Asset Continuity schedule,

a) The gross cost in the 2014-New Policies schedule is different from the gross cost in the 2014-MIFRS schedule by $15,722,884 in disposals. Please explain the causes of the disposals and the nature of the disposals. Please also explain why the quantum of the disposals is so significant.

b) In the 2015-MIFRS schedule, there are disposals of $16,193,383, please explain the causes of the disposals and the nature of the disposals. Please also explain why the quantum of the disposals is so significant.

c) Please explain whether the disposals in 2014-MIFRS and 2015-MIFRS are related to the change in useful lives of capital assets that Festival implemented January 1, 2013. If yes, please explain why these disposals were not included in 2013 instead of when Festival transitioned/adopted MIFRS

d) Per page 15 of Article 410 of the APH, gains or losses on the retirement of assets in a pool of like assets are reclassified as depreciation expense. No such balance is shown for this reclassification in Appendices 2-BA for 2014 MIFRS or 2015 MIFRS. Please confirm that APH guidance has been followed. If not, please revise the evidence as necessary and quantify the amount to be reclassified.

e) Per page 16 of Article 410 of the APH, gains and losses on de-recognition, disposal, retirement or impairment of readily identifiable assets are to be recorded in Other Income accounts (4355, 4357,4360, 4362). Please quantify the net gains and the net losses. Please also indicate where the gains and losses have been recorded in the application.

Response:

a) The disposals included in the 2014 MIFRS table largely represent the removal of capital items with a net book value of zero. This represents $14,976,587 of the disposals. The remaining $746,297 book value disposed of in this table represents assets no longer in use by Festival, but not fully amortized at December 31, 2014. The quantum of total disposal cost of $15M is so significant because in prior years Festival never removed from either asset cost or accumulated depreciation fully depreciated assets as will be required under MIFRS.

b) The 2015 MIFRS schedule is a continuity from the 2014 new policy schedule and was meant to reflect what the fixed asset continuity would look like in 2015 should MIFRS be reflected in that year only. As such, assets with a net book value of zero have been included in the disposal column of both the cost and accumulated depreciation for each applicable asset class. This represents $15,560,633 of the $16,193,383 disposal cost. The difference of $632,750 represents the assets that would be disposed in 2015 under MIFRS rules that have net book value remaining. The disposals reflected in the 2015 MIFRS schedule are the same as those shown as disposals in the 2014 MIFRS schedule, but have had one additional year of depreciation expense taken (in 2014) to come up with a lower NBV of disposal items in 2015.

c) The disposals reflected in the two MIFRS tables represent for the most part the removal of assets with a net book value of zero, which have not historically been removed from Festival's capital cost and accumulated depreciation. The remaining disposals above and beyond this as indicated in 5a & 5b represent items that are no longer in use at Festival but have not been fully amortized. These disposals do not relate to the changing amortization periods selected by Festival upon implementation of the new accounting policies effective January 1, 2013. Items not readily identifiable in nature in prior years were not disposed of for accounting purposes, but remained in net book value and continued to be annually amortized until fully amortized. Festival has always recorded the disposal of readily identifiable assets through the fixed asset general ledger such as land, buildings, and vehicles. The 2015 remaining net book value of $632K appearing as a disposal is the accumulation of items no longer in use by Festival in 2015 but with remaining useful lives.

d) As indicated in 5c – in prior years an item of immaterial amount that was taken out of use in a particular year was not recorded through the fixed asset general ledger and as such the amount continued to be amortized and recorded through depreciation expense. Upon transition to MIFRS at January 1, 2015 Festival is required to dispose of these items. Festival has updated Appendix 2-BA table 2015 MIFRS to record the amount of the loss on transition in the row in the continuity titled Depreciation expense adj. from gain or loss on the retirement of assets (pool of like assets). Please refer to revised appendix 2-BA attached.

e) Festival has shown the 2014 MIFRS schedule for comparative purposes – but proposes to dispose of the accumulation of prior year's net book value of non-readily identifiable items (identified through the detailed fixed asset analysis undergone for asset policy changes in 2013) totalling $632,750 in 2015. This disposal would be considered a loss and the $632,750 and has been included in revised appendix 2-BA as an adjustment to depreciation expense in 2014. The loss has been included as a MIFRS transitional item in account 1575. Appendices 2 EA can be found under 9 STAFF 61. The EDVARR model has been updated to reflect the impact of the $632,750 loss and the rate rider amounts have been updated accordingly.

29. 2. OEB STAFF 6

Ref: E2/T1/S1/Att. 1, Appendix-2BA

In the opening balance of 2015 PP&E, Festival has used the closing 2014 Revised CGAAP PP&E balance instead of the 2014 MIFRS PP&E balance. While this is consistent with the APH, Board staff observes that there may be impacts arising from disposals in 2014 under MIFRS that are not reflected in 2014 Revised CGAAP. Please indicate and quantify the impact to 2015 rate base and revenue requirement if Festival uses the 2014 MIFRS PP&E closing balance instead of the 2014 Revised CGAAP PP&E closing balance as the opening balance of 2015 PP&E.

Response:

Rate base as calculated in the application was $63,100,999. If average net book value was calculated assuming disposals of prior year's non-readily identifiable assets were taken in 2014 – rate base would decrease to $62,761, 324 as calculated in the table below.

2014 MIFRS	2015 MIFRS
77,102,324	94,415,106
- 38,840,162	- 41,002,344
14,946,801	0
53,208,963	53,412,762
	53,310,863
	72,695,856
	13%
	9,450,461.28
	63,245,39

Revenue requirement as calculated in the original application was $11,871,010. If disposals were considered in 2014, this amount would decrease to $11,845,258. The calculation incorporates a change in PILS due to the change in rate base. The revised form from RRWF incorporating this change is as copied below.

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	At Current Approved Rates	At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$923,865		($2,931,235)		$7,666,540
2	Distribution Revenue	$10,165,694	$10,165,694	$10,165,694	$14,020,794	$ -	($7,666,540)
3	Other Operating Revenue Offsets - net	$755,699	$755,699	$ -	$ -	$ -	$ -
4	**Total Revenue**	$10,921,393	$11,845,258	$10,165,694	$11,089,559	$ -	$ -
5	Operating Expenses	$7,666,540	$7,666,540	$7,666,540	$7,666,540	$7,666,540	$7,666,540
6	Deemed Interest Expense	$1,570,625	$1,570,625	$ -	$ -	$ -	$ -
8	**Total Cost and Expenses**	$9,237,165	$9,237,165	$7,666,540	$7,666,540	$7,666,540	$7,666,540
9	**Utility Income Before Income Taxes**	$1,684,228	$2,608,093	$2,499,154	$3,423,019	($7,666,540)	($7,666,540)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($1,426,578)	($1,426,578)	($1,426,578)	($1,426,578)	$ -	$ -
11	**Taxable Income**	$257,650	$1,181,515	$1,072,576	$1,996,441	($7,666,540)	($7,666,540)
12	Income Tax Rate	22.71%	22.71%	22.71%	22.71%	22.71%	22.71%
13	**Income Tax on Taxable Income**	$58,510	$268,309	$243,570	$453,370	($1,740,987)	($1,740,987)
14	**Income Tax Credits**	($10,000)	($10,000)	($10,000)	($10,000)	$ -	$ -
15	**Utility Net Income**	$1,635,719	$2,349,784	$2,265,584	($7,924,849)	($5,925,553)	($7,924,849)
16	**Utility Rate Base**	$62,761,324	$62,761,324	$62,761,324	$62,761,324	$62,761,324	$62,761,324
17	Deemed Equity Portion of Rate Base	$25,104,530	$25,104,530	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	6.52%	9.36%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	9.36%	9.36%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-2.84%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	5.11%	6.25%	3.61%	0.00%	-9.44%	0.00%
22	Requested Rate of Return on Rate Base	6.25%	6.25%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-1.14%	0.00%	3.61%	0.00%	-9.44%	0.00%
24	Target Return on Equity	$2,349,784	$2,349,784	$ -	$ -	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$714,065	$0	($2,265,584)	$ -	$5,925,553	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$923,865 (1)		($2,931,235) (1)		$7,666,540 (1)	

30. 2. OEB STAFF 7

Ref: E2/T2/S3/Att. 1, Appendix 2-DA/DB

Regarding truck allocations in the two tables:

a) Please explain why the capitalized trucking allocation is consistently $222,429 for all years in the top table.
b) Please explain why the trucking allocation amounts no longer capitalized in the bottom table are all negative amounts.

Response:

a) As the trucking allocation is made based on an average cost per hour of use for varying types of trucks – it was assumed that this allocation would remain relatively consistent year over year. While it will not be exactly the same cost that is allocated each year – it will not be materially different year over year.

b) The trucking allocation overhead rates were reduced slightly when reviewed for overhead policy changes in 2013. The negative amounts reflect the overhead rate reduction.

31. 2. OEB STAFF 8

Ref: E2/T1/S1 p. 2, Appendix 2-BA and E9/T3/S12 p. 3 – Net Book Value 62 MVA Transformer Station

a) Please confirm the net book value of the new 62 MVA transformer station transferred to rate base as of January 1, 2015.

Response:

The net book value of the new 62 MVA transformer station transferred to rate base as of January 1, 2015 was $14,946,801.

ICM Rate Rider ACCOUNT # 1508 - Continuity Schedule (REVISED to agree to 2 staff 8)				
		2013	**2014**	**Jan 1, 2015 transfer**
Opening, Jan 1		0	15,058,931	14,710,516
TS O & M Expenses		104,816	140,000	-244,816
Interest		17,623	217,469	-235,093
Transfer in from CWIP		15,311,782	0	-15,311,782
Depreciation & Amortization		28,137	337,647	-365,784
Accumulated Depreciation & Amort		-28,137	-337,647	365,784
Less ICM Rate Rider Recovery		-375,291	-705,884	1,081,174
Ending Bal, Dec 31		**15,058,931**	**14,710,516**	**-0**

Entry required for Jan 1, 2015 disposition:				
		USOA		
TS Land	DR	1805	913,474.39	
TS capital	DR	1815	13,961,839.83	
CCRA agreement	DR	1609	436,468.00	
Interest Income	DR	4405	235,092.89	
Distribution Revenue	CR	4080		1,081,174.36
Depn Exp	DR	5705	346,870.00	
Amort Exp	DR	5715	18,914.00	
Accum Depn	CR	2105		346,870.00
Accum Amort	CR	2120		18,914.00
TS O & M Expenses	DR	5015	244,815.74	
ICM Variance Acct	CR	1508		14,710,516.49
			16,157,474.85	16,157,474.85
Transfer back to fixed asssets1805,1815,1609 (gross)			15,311,782.22	
Less Accuimulated Depreciation/Amortization			-365,784.00	
Net book value upon transfer , Jan 1, 2015			14,945,998.22	

32. 2. OEB STAFF 9

Ref: E2/T2/S1, p. 14 – Stratford Transformer Station – Permanent Bypass Agreement

On page 14, Festival Hydro states that:

As a result of Festival constructing a new transformer station, Festival entered into a Permanent Bypass Compensation Agreement with Hydro One for the purpose of addressing the bypass compensation payable by Festival in accordance with Section 6.7.7 of the Transmission System Code. The agreement allows for a Bypass Capacity from the existing Hydro One station at an estimate 20 MW with a Bypass Compensation Estimate amount of $1,230,026.

The cost of this Bypass agreement was not part of the original construction budget used for the ICM rate rider. However, the cost is a component of the overall cost of the transformer station. Festival commenced the bypass on December 1, 2013 upon energizing its first customer for the new TS. Currently (Feb 2014), there is about 12 MW being bypassed with a plan to migrate close to the 20 MW during 2014.

a) Please confirm that Festival is including an incremental $1.23M in rate base for a permanent Bypass Agreement with HONI.

b) Please explain why the cost of the Bypass agreement was not part of the ICM application for the 2013 rate year.

c) Please provide a revised assessment that shows that the cost of the new transformer station, including the cost of the bypass agreement, was still the best option.

d) Has the amount of $1.23M been paid in full to HONI as a one-time cost?

i. If so, provide the date the transaction.

ii. If not, please provide a payment schedule and describe the accounting treatment of the off-setting entry to intangible assets.

iii. Does Festival Hydro expect to incur future costs related to the bypass agreement?

e) Please explain how Festival believes the Stratford Transformer Station Permanent Bypass meets the definition of an intangible asset under IAS 38.

f) Please indicate if Festival has discussed this with its external auditor and provide any documents received by Festival that express the views and opinions of its external auditor.

Response:

a) Confirmed. $1.23M has been added to the rate base for the Permanent Bypass Agreement with HONI.

b) At the time of creating the Transformer Station (TS) budget, it was not envisage that a Permanent Bypass arrangement was going to be required.

c) Below is the table presented in Festival's 2013 IRM Application (EB-2012-0124) comparing the various options available to Festival Hydro for construction of the TS. The decision to build was not solely based on the Net present value of the best option, but also on how the option would best address other critical factors such as capacity requirements, voltage issues and reliability performance. The preferred option which addressed all issues and was also the lowest cost was the 4th option - Festival Hydro to construct the TS.

Scenario	NPV[1]	Address Capacity Issue?	Address Voltage Issue?	Address Reliability Issue?
Hydro One Replaces One Transformer at Devon TS in 2010, Festival Builds New Feeder in 2010, Hydro One Builds Second TS in 2015	$16.8M	yes	Not until 2015	Minimal until 2015
Hydro One Replaces One Transformer at Devon TS in 2010, Festival Builds New Feeder in 2010, Festival Hydro Builds Second TS in 2015	$14.7M	yes	Not until 2015	Minimal until 2015
Hydro One Builds Second TS in 2010	$13.3M	yes	yes	Yes
Festival Hydro Builds Second TS in 2010	$10.5M	yes	yes	Yes

Festival is of the opinion that with the addition of the cost of the Permanent Bypass the decision for Festival to construct was still the best option. The TS has been successfully up and operational since December 2013 with minimal problems encountered. With the TS build completed by Festival, Festival has been able to successfully achieve the requirements of the other major criteria identified as critical to the project, that being the issues of capacity, voltage and reliability.

Outlined below is the financial analysis of the actual TS expenditure compared to budget if Permanent Bypass is considered :

Original TS Budget	$15,863,114 (on page 15 of 2013 IRM)	
Actual Expenditures:		
Capital spend	$15,311,782 (capital transferred to 1508)	
Permanent Bypass	1,025,481	($1,230,026 in 2010 dollars)
Total Capital Spend	$16,337,263	
Amount over original budget	$ 474,149	

If the over budget amount of $474K is added to the original projected NPV of $10.5 the amount of $11.0M is still less than the $13.3M for the second lowest cost option, and this is without even taking into account the $475K being saved annually on transmission connection charges.

d) The $1.23M bypass agreement was set up as an Accounts Payable at December 31, 2013. The transformer station went into service on December 2, 2013 and Festival's customers have been receiving the benefits of reduced transmission charges since that date through reductions in transmission charges form the IESO. However, the bypass assessment date is not being completed until in or around June 1, 2014, and the payment due date is 180 days following that, so Festival

[1] A discount rate of 5.5% was used. Adjusting the discount rate from a low of 2.5% to a high of 7.5% made no difference in the relative ranking of the scenarios.

Hydro expects to make the payment in December 2014. The accounting entry to set up the bypass agreement as an asset was Debit 1609 Capital Contributions Paid and Credit # 2205 Accounts Payable. Upon settlement, the entry will be to Debit #2205 Accounts Payable and Credit #1005 Cash. At this time, Festival does not expected to incur any additional costs related to the Permanent Bypass. Excerpts from the Permanent Bypass agreement are copied below:

in or around June 1, 2014, the Customer intends to by-pass Hydro One's Stratford TS (the "**Station & Line Assets**") in respect of a portion of the Existing Load; and

Bypass Compensation – Estimate:

$\underline{\textbf{\$1,230,026}} = [NBV_T + DC_T - SC_T] \text{ x } [BC/TNSC_T] + [NBV_L + DC_L - SC_L] \text{ x } [BC/TNSC_L]$

e) Article 410 of the OEB Handbook is fairly specific that intangible assets include capital contributions paid by the distributor to other distributors for capital projects. While the payment was not directly attributed to a capital project of another distributor, it was a payment to HONI to facilitate the full operation of the asset Festival constructed. The account definition of USOA # 1609 states "This account shall include capital contributions paid by a distributor to a host distributor, a transmitter or a generator for capital expenditures (e.g., under a Connection and Cost Recovery Agreement) that meet the IAS 38 Intangible Assets requirements for classification as an intangible asset. "The nature of the agreement fits the description of Acct # 1609
From an IAS 38 standpoint:
   a) The payment meets the definition of an asset - it is an identifiable non-monetary asset without physical substance that was/is controlled by Festival as a result of past events; and will derive future economic benefit from making the payment.
   b) The payment is identifiable because it meets both criteria in IAS 38, paragraph 12.
   c) Festival controls the asset – as Festival has the power to obtain future economic benefit from it – i.e. the ability to distribute power through the TS and bill customers for it
   d) Can be recognized as an intangible according to IAS 38, paragraphs 21 and 22, because the payment meets the criteria required for recognition as an intangible.

f) The accounting treatment was discussed in advance of the 2013 yearend audit with our external auditors to ensure proper accounting treatment was met. Being it was a material dollar value, the agreement was subject to external audit review. In the Notes to the 2013 audited financial statements, Section 1 Significant Accounting Policies – section f) provides the policy related to Intangible Assets. Under Note 5 is provided the details of the agreements associated with the balance in the Intangible Asset account.

The auditors issued an unqualified auditors' report on Festival's 2013 financial statements which include this amount being included as an intangible asset.

33. 2. OEB STAFF 10

Ref: Appendix 2-AA – Capital Expenditures – System Renewal

Under the category system renewals, Board staff notes that the category miscellaneous in the years 2012 ($802,002) and 2013 ($1,014,652) represents 46% and 49% of the overall budget for this category, respectively.

a) Please provide a break-down of miscellaneous material capital expenditures.
b) Please explain the reduction of 69.1% or $701K in the 2014 bridge year and 77% or $784K in the test year.
c) Please describe and quantify where possible the benefits that the applicant's customers will realize from these investments.
d) Please describe the alternatives to capital investment that were assessed and rejected in favour of the proposed capital investments.

Response:

a)

2012 miscellaneous material projects

- Glass Street Rebuild - $105,718 (unbudgeted replacement of end-of-life assets)
- St. David Rebuild - $70,632 (completion of 2011 planned capital project carried over yearend)
- Numerous non-material unbudgeted system renewal projects categorized under capital additions - $474,609 – includes like-for-like replacements of poles, conductors, insulators and other unbudgeted system renewal projects.
- Numerous non-material Customer initiated projects categorized under capital additions - $135,012

2013 miscellaneous material projects

- Numerous non-material unbudgeted system renewal projects categorized under capital additions - $143,733 – includes like-for-like replacements of poles, conductors, insulators and other unbudgeted system renewal projects.
- Numerous non-material Customer initiated projects categorized under capital additions - $201,100
- One Material Customer initiated workMarket Rebuild - $135,986

b) Starting in 2014, only un-forecasted replacement; such as emergency replacements and miscellaneous system renewal projects have been included in the Miscellaneous System Renewal category. Previously unbudgeted capital additions including emergency repairs, unbudgeted additions and customer driven additions were included in this category. This change in forecasting capital additions accounts for reduction of miscellaneous projects going forward.

c) Miscellaneous projects within system renewals are simply smaller infrastructure replacement projects. These projects make up part of the overall requirements of the DSP and they contribute directly to maintain system reliability and safety.

d) The alternatives that are considered for infrastructure renewal projects were described in section 5.4.5.2 of the DSP. Festival Hydro evaluates the need of the infrastructure being considered for replacement and assess if a change in design could make the rebuild redundant. This process ensures the pace of replacement is maintained overtime while increasing system efficiency.

34. 2. OEB STAFF 11

Ref: Appendix 2-AA – Capital Expenditures – New 62 MVA Transformer station

a) Please confirm that the capital expenditures for the new 62 MVA Transformer station, funded through the ICM mechanism, is incorporated into the historical capital expenditures for comparison? If not, please provide table showing Festival Hydro capital expenditures from 2010 Board-approved to 2015 test year forecast inclusive of the new Transformer station.

Response:

TS capital expenditures are not included in Table 2AA, but are reflected in table 2AB under the total expenditures section.

35. 2. OEB STAFF 12

Ref: Appendix 2-AA – Capital Expenditures – Capital Additions and E2/T2/S1, Appendix 4, p.14

Under the category of System Access, Festival Hydro forecasted $200,000 of capital additions in 2014 and $204,000 in 2015. On page 14 Festival Hydro notes that this investment category is unbudgeted, miscellaneous projects, which are completely customer driven.

a) Please provide further explanation as to the capital additions planned for the 2014 and 2015 rate years under this category and provide a historic comparison.

b) Please provide the up-to-date capital expenditure for the 2014 rate year under this category and compare to the equivalent time period in the previous year.

Response:

a) Capital additions are not planned in advance, but planned as requested by customers. This type of work could include pole line extensions, transformer installations or subdivision work. Some of this type of work is known in advance while other work becomes identified as needed. The $200,000 per year spending is based on a 4 year historical average 2009 – 2012 (numbers provided below). Please note as mentioned in 2 – Staff – 10 pre 2014 capital additions were based on a combination of FHI and customer requested capital additions. The values presented below contain the customer requested additions.

2009 – $305,529
2010 – $256,445
2011 - $72,708
2012 – $133,615

4 year average = $192,704

b) 2014 capital additions spending up to June 30th is at $0. There are currently 4 identified projects for the 2014 year and an additional 4 potential projects identified. The 2013 spend in capital additions for this point in the year was $168,543.

36. 2. OEB STAFF 13

Ref: E2/T2/S1, Attachment 1, p. 25 – Variance Analysis

In section 5.2.3, p. 25 of the DSP, Festival Hydro provided the following table as a variance analysis over its historic capital expenditure.

On p. 26, Festival Hydro provides a brief variance analysis for capital expenditures in the 2009, 2010 and 2013 rate years. Board staff notes that Festival Hydro did not provide any variance analysis for the 2011 and 2012 rate years.

Actual spend vs budget (per year and over system planning forecast)

Year		Budget	Actual		Spending overage to Budget
2009		$3,352,000	$3,823,284		14%
2010		$2,992,000	$2,989,043		0%
2011		$3,350,400	$3,010,362		-10%
2012		$3,370,800	$3,021,956		-10%
2013		$3,388,400	$2,953,866		-12%
Average		$3,290,720	$3,159,702		-4%

Appendix 2-AA shown the following capital expenditures from 2010 – 2015 in the excerpt below.

Projects	2010	2011	2012	2013	2014 Bridge Year	2015 Test Year

Total	3,139,803	3,058,814	3,291,413	3,387,787	2,773,000	2,621,500
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*						
Total	3,139,803	3,058,814	3,291,413	3,387,787	2,773,000	2,621,500

a) Please reconcile the actual capital expenditures provided in Appendix 2-AA with the table above.
b) Please provide a variance analysis for the missing years
c) Please explain in detail why Festival Hydro's actual capital expenditure from 2011 – 2013 was 10%, 10% and 12 % below its budget, respectively.
d) Please explain to what extent deferred investments have resulted in any backlog of work.
e) Please explain if and how Festival Hydro's lower actual capital expenditures impacts system reliability at its current levels, given that the customer survey shows that reliability is the major concern for customers.
f) Please state how this trend has been incorporated into the 5 year capital plan laid out in the DSP.

Response:

a) Actual capital expenditures (as provided in 2-AA) vary with respect to the variance analysis presented in section 5.2.3 because of timing and the projects which represent the capital. The variance analysis uses the capital spending as identified in FHI work order system. The work order system closes in mid-January and isn't reconciled with accruals or subdivision. It also may not include certain projects outside the scope of Engineering and Operations including elements of the TS build, smart meters or generation projects. Table 2AA uses capital values from the GL and captures the total capital spend of the corporation including activities outside of Engineering and Operations. The work order system provides FHI staff an opportunity to access spending on a project by project basis. Although the final numbers aren't exact they are close enough to perform a variance analysis to identifying major trends.

2010, Appendix 2-AA shows an amount $150,760 higher – this can be reconciled as follows:

Additional costs in the GL inputted after WO close or charged directly to a GL
OH and UG projects - $44,522
New and Upgrades Services - $54,311
Distribution Meters -$17,726
Buildings - $1720
Vehicles - $145
Computer Equipment - $32,333

2011, Appendix 2-AA shows an amount $48,452 higher – this can be reconciled as follows:
Additional costs in the GL inputted after WO close or charged directly to a GL
OH and UG projects - $50,202
New and Upgrades Services - $4,068
Buildings - $11,986
Vehicles - $4,448

Work orders with costs over accrued at year end
Distribution Meters -$(254)
Computer Equipment - $(21,997)

2012, Appendix 2-AA shows an amount $269,457 higher – this can be reconciled as follows:
Additional costs in the GL inputted after WO close or charged directly to a GL
OH and UG projects - $191,097 of which $100,000 is from subdivision entries to the GL
New and Upgrades Services - $90,952
Tools and Equipment - $6015
Vehicles - $819

Work orders with costs over accrued at year end
Buildings - $(12,756)
Computer Equipment - $(6,670)

2013, Appendix 2-AA shows an amount $433,921 higher – this can be reconciled as follows:
Additional costs in the GL inputted after WO close or charged directly to a GL
OH and UG projects - $427,200 of which $418,459 was UG conductor charged directly to the GL
Distribution Meters -$136
Vehicles - $3,000
Computer Equipment - $9,154
Work orders with costs over accrued at year end
New and Upgrades Services - $(5528)
Buildings - $(41)

b) Festival Hydro only conducts variance analysis on years that are outside 10% variance. In the 2011 year $140,000 was attributed to smart grid projects including SCADA upgrades and an ODS system for smart meters. FHI did not end up purchasing an ODS system, instead FHI went to a service provider for ODS services (OM&A versus Capital). Also overhead and underground projects came to $100,000 under budget although all the work was completed as designed.

   In 2012 the variance was attributed to 2 main areas: first, UG conductor for the TS was deferred to 2013 ($580,000 mostly material cost) and capital additions were $300,000 more than budget, this lead to an under spend of roughly $280,000 in these two line items alone.

c) Please refer to the response above for years 2011 and 2012. The 2013 year was explained within the DSP "The largest single contribution to this deviation was that $200,000 of proposed SCADA work planned for 2013 was charged to the completion of the transformer station. This work was initially budgeted as part of the 2013 budget but ultimately was required as part of the TS."

d) As can be seen from the response of b and c, the work identified in the 2011 – 2013 budgets has been completed. The variances identified mainly dealt with budgeted Engineering and Operations capital work being carried out under OM&A or TS capital. This hasn't led to any backlog of work.

e) No impact, as required system renewal work has been completed.

f) Festival Hydro DSP has seen reduced capital spending by 16% versus the historical time frame.

37. 2. OEB STAFF 14

Ref: E2/T2/S1, Appendix 4, p. 2 – 2015 Capital Budget

In Appendix 4, p. 2, Festival Hydro provided the following table to show actual capital spending and forecast capital expenditures for 2014 and 2015.

Capital Budget	2011	2012	2013	2014	2015
	Actual	Actual	Budget	Budget	Budget
Total Capital	$3,063,507	$3,021,956	$3,388,400	$2,773,000	$2,621,500
Customer Base	19,995	20,200	20,210	20,400	20,600
Capital $/customer	$153.21	$149.60	$167.66	$135.93	$127.26

Below is an excerpt of Appendix 2-AA.

Projects	2010	2011	2012	2013	2014 Bridge Year	2015 Test Year
Total	3,139,803	3,058,814	3,291,413	3,387,787	2,773,000	2,621,500
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*						
Total	3,139,803	3,058,814	3,291,413	3,387,787	2,773,000	2,621,500

a) Please reconcile the capital expenditure amount for the 2012 rate year and recalculate capital$/customer if necessary.

Response:

a) Please see response to 2-Staff-13 (a). The updated capital cost per customer using Appendix 2-AA is as follows:

2011- $152.98 per customer
2012- $162.94 per customer
2013- $167.62 per customer

38. 2. OEB STAFF 15

Ref: Appendix 2-AA and E2/T2/S1, DSP – Attachment 1, Section 5.4.1, p. 36; Asset Management Plan, Appendix 11

In section 5.4.1 d), Festival Hydro lists a description of material projects, including the replacement of 100 poles for a total capital expenditure of $650,000 over a ten-year period.

a) Please identify capital spending amount for pole replacement included in the 2015 test year capital budget and compare that amount to the historical, annual capital expenditure for pole replacement.

b) Appendix 11, Pole Inspection Report 2013, p. 9 states that based on the relatively low rate of decay found during the 2013 pole inspection program, "Festival Hydro is justified in proceeding with a treat based on condition approach".

i. Please provide further detail regarding Festival Hydro's pole replacement program, including number of poles to be replaced in the test year and percentage of total number of poles.

ii. Does Festival Hydro track interruptions caused by pole failure? If not, why not? If so, why aren't interruptions caused by pole failure a proposed performance metric?

iii. What is the average cost per replaced pole? Is Festival Hydro realizing any efficiency on a unit cost basis?

Response:

a) The 2015 capital spending on pole replacements is $650,000 for 100 poles. The annual historical spending is as follows:

   2011 - $1,226,278 for 191 poles = $6420/pole
   2012 - $829,178 for 116 poles = $7148/pole
   2013 - $787,021 for 146 poles = $5390/pole
   2014 - $840,000 for 130 poles = $6461/pole

b) Festival Hydro has established a replacement program that would keep the number of wood poles over 40 years old kept to the same level in 10 years as today. This would require a replacement of 100 wood poles per year to maintain current system conditions (1.6% of the total pole inventory on a year over year basis). A pole inspection program (third party contract) identifies individual poles or areas that are a priority for replacement or treatment. The data on pole condition is used to establish the current years capital expenditures and also identifies areas were pole treatment can be used to increase the useful life of assets.

   i. Festival Hydro has established a replacement program that would keep the number of wood poles over 40 years old kept to the same level in 10 years as today. This would require a replacement of 100 wood poles per year to maintain current system conditions (1.6% of the total pole inventory on a year over year basis). A pole inspection program (third party contract) identifies individual poles or areas that are a priority for replacement or treatment. The data on pole condition is used to establish the current years capital expenditures and also identifies areas were pole treatment can be used to increase the useful life of assets.

ii. Festival Hydro tracks equipment failure in the outage database. The type of equipment failure that led to an outage is noted in the Details section of the outage record. When equipment failure related outages are reviewed to determine if any trends exist, the details are then used to group the failures by equipment type. In the past ten years, the numbers of pole failures, resulting in an outage, have been too few to trigger a change in the pole replacement program.

iii. The average cost per pole replaced as part of the 2015 budget is $6500 per pole. The cost per pole replacement is in line with actual costs over the last 3 years.

39. 2. OEB STAFF 16

Ref: E2/T2/S1/Att. 1/p. 5 – 5.2.1 Distribution System Plan Overview

At page 5 of the reference, under the title "4 kV system conversions", it is indicated that conversion of the 4 kV system to a 27.6 kV system in the City of Stratford will standardize the voltage and reduce system losses.

a) Please provide a copy of the original business case study justifying the conversion project investment and any updates to that study that includes justification for the continued conversion investment in this DSP period.

b) Please identify the steps that were taken to elicit the views of customers on this project, its merits, and the willingness of customers to abide the associated rate increases

c) Please indicate how customers' views were factored into the plan and its timing.

Response:

a) The "4kV System Conversions" is a multi-year project initiated over 10 years ago when the municipal substations began to reach end of life. A "business case" for the conversion program was not created as the evaluation process results in an obvious conclusion and is comparable to conversion programs done at other municipal LDCs in Ontario. Each municipal substation and the area supplied by it are evaluated as they approach end of life to determine the best option for replacement. In many cases, the distribution circuits supplied by the municipal substation (poles, crossarms, insulators) require replacement before the station reaches end of life. Rather than simply replace the components "like-for-like", upgrading to a higher voltage class through a voltage conversion provides a better long term solution. In most cases, the higher voltage circuit is on the same pole line (or within the same duct bank) as the 4 kV circuit, so upgrades generally consist of replacing the end-of-life 4 kV transformers with higher voltage transformers (replacing the pole if at end-of-life) and removing the 4 kV circuit. On side streets with only 4 kV, the upgrades are incremental (higher voltage class insulators, marginally taller poles). As these distribution circuits are converted, the remaining load on the municipal substations decreases to the point where replacement of the municipal substation equipment (switchgear and transformer) is not warranted nor needed. The savings associated with the elimination of the substation and reduced line losses are intuitively greater than the incremental costs associated with voltage upgrades.

b) Customer views for the conversion program were not elicited. The incremental costs associated with voltage conversion are more than offset by the savings related to the substation elimination and lower line losses, so any rate increase would be less than if a like-for-like replacement program was used.

c) Customer views were not elicited.

40. 2. OEB STAFF 17

Ref: E2/T2/S1/Att. 1/p. 27 and E2/T2/S1/Att. 2, Appendix 2-AB – 5.2.3 Performance measurement for continuous improvement

At page 27 of the first reference, under "d) How has this information affected the DS Plan and how has it been used to continually….." it is stated that:

KPI's (as defined in the above section) ensure we are executing on our asset management plan within our capital expenditure process. This is identified by the following indicators: year to year budget comparison and actual to budget spend comparison. Since Festival Hydro's infrastructure is in good condition the expectation is to keep spending levels flat in relation to year over year spending. Deviations in budgeting or spending in a given year provide feedback to be considered in future years. [emphasis added]

a) Please provide a definition of the noted "KPI" as it is was not defined in the section above section d) as stated.

b) Please provide a revised table "OEB Appendix 2-AB", provided in the second reference, by adding another "row" listing the "Annual Depreciation Amounts" for:

- the historical years 2010, 2011, 2012 and 2013;
- the "Bridge 2014 Year", the Test Year; and
- if possible, a forecast for each of the years 2016 – 2019.

Response:

a) The KPI's were defined in section b.

b) Refer to revised OEB Appendix 2-AB below.

File Number:	EB 2014 0073
Exhibit:	2
Tab:	2
Schedule:	1
Attachment:	2
Date:	25-Apr-14

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2015*

CATEGORY	**Historical Period** (previous plan[1] & actual)															**Forecast Period** (planned)				
	2010			**2011**			**2012**			**2013**			**2014**			**2015**	**2016**	**2017**	**2018**	**2019**
	Plan	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual[2]**	**Var**					
	$ '000		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*				
System Access	295,600	285,868	-3.3%	609,000	439,986	-27.8%	364,000	503,122	38.2%	452,000	272,227	-39.8%	315,000		-100.0%	321,500	328,000	334,500	341,000	347,500
System Renewal	2,468,400	2,116,936	-14.2%	2,111,000	2,306,268	9.3%	2,146,000	1,759,913	-18.0%	1,706,500	2,036,400	19.3%	1,688,000		-100.0%	1,490,000	1,513,000	1,539,000	1,565,000	1,592,000
System Service	498,000	377,833	-24.1%	200,000	93,154	-53.4%	465,000	523,091	12.5%	881,500	673,952	-23.5%	310,000		-100.0%	310,000	314,000	316,000	318,000	320,000
General Plant	485,000	359,166	-25.9%	471,500	219,406	-53.5%	434,000	505,287	16.4%	403,000	405,208	0.5%	460,000		-100.0%	500,000	427,000	826,000	445,000	415,000
TOTAL EXPENDITURE	3,747,000	3,139,803	-16.2%	3,391,500	3,058,814	-9.8%	3,409,000	3,291,413	-3.4%	3,443,000	3,387,787	-1.6%	2,773,000	-	-100.0%	2,621,500	2,582,000	3,015,500	2,669,000	2,674,500
Increase in major spare parts		41,549			-			66,863			-									
smart meters and related computer equipment reclassified from USOA 1555								3,694,577												
contributed capital USOA 1995	- 390,000	- 474,049			- 106,480			- 342,654			- 154,030		- 150,000			- 120,000	- 120,000	- 120,000	- 120,000	- 120,000
TS CWIP USOA 2205		879,452			312,730			7,830,663			5,860,659									
Non Rate-Regulated Utility Property USOA 2017 (solar)		44,951			249,738			-			-									
TOTAL EXPENDITURE		3,631,705			3,514,802			14,540,863			9,094,416		2,623,000			2,501,500	2,462,000	2,895,500	2,549,000	2,554,500
System O&M	$1,472,730	$ 1,446,517	-1.8%	$1,509,548	$ 1,539,820	2.0%	$ 1,539,739	$ 2,202,237	43.0%		$ 2,028,047	--	$ 1,988,810		-100.0%	$ 2,142,787	$2,084,956	$2,123,978	$2,171,021	
PER EXB 4 DATA		1,446,518			1,539,820			2,202,238												
Annual Depreciation Amounts:		2,785,908			2,790,514			3,442,289			2,114,336		$ 1,900,978			$ 2,679,286				

Notes to the Table:
1. Historical "previous plan" data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. histrical budgets by category

System Access - historical budget vs forecast is stable over the planning horizon. System access is mostly driven by 3rd party work and no major changes are expected. The forecast period budget is 10% below historical actual to date.
System Renewal - forecasted budget for SR projects decreases compared to historical budget due to the age and system condition of assets as defined in the asset management report. spending stays stable over the forecast budget
System service - forecasted budget for SS decreases slightly from the historical to forecast period, but spending remains stable.

Notes on year over year Plan vs. Actual variances for Total Expenditures

There is one historical year the variance exceeds +-10 percent of spending, 2010. As was described in the DSP, $515,000 was removed from the 2010 budget do to additonal spending required in the smart meter roll out.

Notes on Plan vs. Actual variance trends for individual expenditure categories

System Access - The variance for this category is attributed to the amount of actual work required to be completed by customers. All work in this category is customer driven for which FHI has no control.
System Renewal - Although system renewal had year to year variances the total variance over the 4 year reported period is less than 1%. this can be attributed to timing.
System Service - The 2010 variance can be attributed to the removal of projects described above. the 2011 variance can be attributed to a distribution automation project being contracted as a service as opposed to capitalized.The 2012 variance can be attritubed to unforseen costs of replacing live front with dead front switchgear (1st time project). The 2013 can be attritubed to automation work being charge to the TS project as opposed to the capital budget.
General Plant - The variation of GP spending can be attributed to the reduced replacement of large fleet vehicles from the original plan.

41. 2. OEB STAFF 18

Ref: E2/T2/S1/Att. 1/pp. 31 – 33 and E2/T2/S1/Att. 1/pp. 15 – 24 – 5.2.3 Performance measurement for continuous improvement & 5.3.2 Overview of Assets Managed

At the second reference (re 5.3.2 Overview of Assets Managed) on pages 31 -33, it is shown that FHI has a total of 22 feeders as follows:

- *5 feeders at 4 kV;*
- *2 feeders at 8.32;*
- *4 feeders at 13.8 kV; and*
- *11 feeders at 27.6 kV*

At the first reference (re 5.2.3 Performance measurement for continuous improvement), at pages 15-24, the 10 tables provided on system performance (SAIDI, SAIFI…etc.) cover only 9 of the 22 feeders owned by Festival Hydro.

a) Please provide system performance tables for the 13 feeders to provide the same results as those provided for the 9 feeders as outlined in the second reference.

Response:

a) 4 of the 27.6kV feeders are new as of December 2013 and don't have historical performance metrics. Those feeders are part of the new Stratford TS and were included with the existing Stratford performance measurements. The 9 feeders identified (5 – 27.6 kV feeders in Stratford and 4- 13.8 kV feeders in St Marys) account for over 87% of FHI customer count. Three of the 4 kV feeders are supplied by the 27.6 kV feeders in Stratford and their reliability performance is included in the results of the 27.6 kV feeders. The number of customers directly supplied by these 4 kV feeders are few and their reliability is almost exclusively impacted by the reliability of the 27.6 kV supply (i.e. very few outages impact only the 4 kV feeder). The remaining feeders are located in smaller municipalities of Seaforth, Brussels, Dashwood, Hensall and Zurich. Most of the feeders in these towns are embedded Hydro One feeders, with the vast majority of outages caused by loss of supply. The performance metrics highlighted in pages 15 – 24 are meant to identify the areas that both impact FHI outage statistics and those feeders which FHI has ability to improve reliability. Based on the above, FHI does not track SAIDI and SAIFI values for the remaining towns as part of our KPI's.

42. 2. OEB STAFF 19

Ref: E2/T2/S1/Att. 1/pp. 28 – 29 and E2/T2/S1/Att. 1/Appendix 4 – 2015 Board Capital Plan 5.3.1 Asset Management Process

At the first reference, on pages 28 and 29 under "b) Information regarding the components of the asset management process used to prepare a capital expenditure plan, it is stated in part that "the Asset Management Plan becomes one of the inputs of the Capital Expenditure Plan with the other inputs being regulatory requirements (i.e., smart meter, or smart grid), customer driven (as identified in the surveys, or customer initiated work) and system optimization and efficiencies (eg. voltage conversions). These projects are then prioritized by considering the results of the Asset Management plan, safety, reliability, customer inputs, system efficiency and financial constraint to develop specific year budgets. All the projects identified in a specific year are deemed to be non-discretionary in nature as their deferral would lead to negative system impacts".

At the second reference on page 5 under the project "Stratford – Reinsulate Poles" it is indicated that it will cost $150,000 and on the second reference, page 7 under "Stratford – MS # 9 Ph1 Conversion…" it is indicated that it will cost $230,000.

a) Please elaborate on how the prioritization and selection of projects are implemented between unavoidable projects such as those related to "System Access" and projects described above that are related to system optimization (e.g., voltage conversions) in situations where the total capital approved by the Board would not allow for all of them to be implemented.

b) If the situation outlined in a) above were to occur, please describe the criteria that would be used to prioritize and select amongst projects that are viewed as discretionary such as the "Stratford – Reinsulate Poles " costing $150,000 and the "Stratford – MS # 9 Ph1 Conversion…" costing $230,000.

Response:

a) As was mentioned in the DSP Festival Hydro has not defined a process to prioritize projects that are deemed non-discretionary in nature. If in the future this becomes a requirement, FHI would apply a weighting to all the elements that make up the capital expenditure plan (safety, reliability, financial, regulatory, customer initiated and efficiency) which would aid in scoring each of the identified capital projects for that year.

b) The same methodology would be applied as in section A

43. 2. OEB STAFF 20

Ref: E2/T2/S1/Att. 1/p. 36 and E2/T2/S1/Att. 1/Appendix 4 (5.4.1 Summary) – 2015 Board Capital Plan

At the first reference on page 36, one of the System Renewal "SR" projects is described as "Underground Feeder – SR, Replacement (2500-4500m)" costing $230,000, and under the "Description" in that table, it refers to Appendix 4 for a list of proposed work.

At the second reference (Appendix 4) there are no reference or details for the "Underground Feeder – SR Replacement (2500 -4500m)" project described in the first reference. At page 15 of Appendix 4, there is a listing titled "Miscellaneous Projects & Capital Additions", where it is reported that $200,000 are for "Miscellaneous Projects".

a) Please clarify, and provide details regarding the location of the projects that totals $230,000 as listed in the first reference

Response:

a) The SR replacement (2500 – 4500m) is located on Page 7 of Appendix 4.

44. 2. OEB STAFF 21

Ref: E2/T2/S1/Att. 1/p. 46 and E2/T2/S1/Att. 1/Appendix 3 – OPA REG Letter, December 23, 2013 - 5.4.3 System capability assessment for renewable energy generation

At the first reference, it is reported that Festival Hydro has connected 34 MicroFIT customers for a total generation output of 318 kW, and there are an additional 13 MicroFIT applications at various steps along the process.

At the second reference, the OPA letter indicated that it offered contracts to 48 Micro FIT projects totalling 1,119 kW.

Comparison of the two sources reveal close results in terms of the total number of MicroFIT projects (47 reported by FHI and 48 reported by the OPA), but the total kW difference between the two sources corresponding to the remaining to be connected is large:

- *[1,119 kW (48 Projects) per the OPA] minus [318 kW (34 projects) per FHI] = 801 kW for the remaining 14 projects.*
- *the above indicate that assuming a maximum size of 10 kW per MicroFit project, the number of outstanding projects is about 80 projects.*

a) Please clarify and explain the apparent discrepancy outlined above.

Response:

a) The OPA has sent an email clarifying that the 34 MicroFIT Customers connected as of December 2013 had a generation totalling 315.2 kW, not the 1119kW highlighted in the report. The 1119kW was entered in error.

45. 2. OEB STAFF 22

Ref: E2/T2/S1/Att. 1/Appendix 1/p. 8 – Asset Management Plan – Transformer Station

At the reference it is stated that:

Festival Hydro constructed a Municipal Transformer Station (MTS#1) in 2012/2013. It was put into service on December 2, 2013. It was designed and built to provide long term, reliable supply for the City of Stratford. The switchgear is gas insulated with vacuum breakers and the on-load tap changers are low maintenance vacuum breaker design. As it is a new facility, there should be minimal capital expenditures during the first ten years, and all major components have a warranty of at least five years. Annual preventative maintenance will be contracted out to qualified vendors. For the next 25 years, the only foreseeable capital expenditures include replacement of batteries within the battery banks (every 5 to 8 years), and upgrades to intelligent electronic devices (IEDs such as relays, routers, telecom equipment – every 8 to 10 years).

a) How has Festival Hydro mitigated any risk through its insurance coverage?

b) Please describe FHI plans to maintain electricity service to its customers for the period between an event involving damage to its power transformers and when replacement is in service. Please cover a single contingency where one power transformer is damaged and a double contingency when both power transformers are damaged.

Response:

a) FHI has full replacement coverage for the major components of the transformer station if damaged due to catastrophic failure or other emergencies (fire, weather, etc).

b) The station design is such that during a single contingency (eg the loss of one power transformer), all load can be supplied by the remaining element for an indefinite period of time. During a double contingency (eg loss of both power transformers), load would be transferred to the Hydro One Transformer Station in Stratford via existing tie switches on the feeders. This would likely place the overall load on the Hydro One TS above its rated LTR but within its emergency capacity rating. Hydro One permits exceeding the LTR rating for 10 days, which should be sufficient time to repair at least one of the damaged transformers, or arrange for the installation of a mobile TS. FHI has obtained spare parts for the transformer components most likely to fail (high voltage and low voltage bushings), and the overall design of the station has made the simultaneous failure of both transformers highly unlikely (fire separation, blast wall, separate containment pits, separate controls, separate service transformers, etc).

46. 2. OEB STAFF 23

Ref: E2/T2/S1/Att. 1/Appendix 4/p. 15 and Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, March 28, 2013/pp. 16 -17 – 5.4.5.2 Material Investments – Distribution Transformers

At the first reference the "2015 Board Capital Plan" under "Transformers", it is indicated that $205,000 is needed to meet load growth, replacements, conversions and new development. This indicates that the "Transformer" investment can be split between the three main categories namely: System Access; System Renewal; and System Service.

At the second reference it is stated that:

Despite the 'multi-purpose' character of a project or activity, for 'summary' purposes the entire costs of individual projects or activities are to be allocated to one of the four investment categories on the basis of the primary (i.e. initial or 'trigger') driver of the investment. Note, however, that for material projects, a distributor must estimate and allocate costs to the relevant investment categories when providing information to justify the investment, as this assists in understanding the relationship between the costs and benefits attributable to each driver underlying the investment. [emphasis added]

a) Please allocate the $205,000 cost of transformers among the various projects included for the 2015 Test Year as outlined in Appendix 4 as well as the sum total for each of the three noted categories - namely System Access; System Renewal; and System Service.

Response:

a) For the $205,000 identified in transformer purchases for the 2015 Test year it is expected that $56,500 will be for System Access, $60,750 will be for System Service and $87,750 for System Renewal based on known work and historical forecasts.

47. 2. OEB STAFF 24

Ref: E2/T2/S1/Att. 3, Appendix 2-AA and E2/T2/S1/Att. 1/p. 65 – 5.4.5.2 Material Investments – Smart Meters

At the first reference for Distribution Meters, it shows historical capital expenditures for 2010 to 2013, and forecast for the bridge year (2014) and the 2015 Test Year. For convenience the relevant portion covering Distribution Meters from Appendix 2-AA, is shown below:

	2010	2011	2012	2013	2014 Bridge Year	2015 Test Year
Distribution Meters	$198,000	$147,080	$152,023	$91,138	$190,000	$175,000

At the second reference it is stated in part that:

The main drivers for distribution meters are failure and mandated service obligations. This value takes into account historical growth rates and potential meter replacements as part of non-warranty smart meter failures. Festival Hydro smart meters have experienced a failure rate of 7.5% per year since their installation in 2011. These failures are for the most part still being covered by Trilliant outside of the warranty period, but it is unclear how long this may continue. Given the uncertainty of warranty coverage FHI is budgeting 26% of its metering budget to the replacement of failed smart meters.

a) Please indicate whether or not FHI received any warranty from Trilliant for the Smart Meters? If not, please elaborate as the reasons for not receiving such a warranty.
b) Is the failure rate of 7.5% per year in the range experienced by other Distributors?
c) Please provide the number of Smart Meter failures from January 1, 2014 to present date? Please indicate whether or not Trilliant charged FHI for the cost of replacing these Smart Meters.
d) What is the total number of smart meters installed by FHI in 2011, and what is the installed cost per meter, broken to (Meter & Material) and labour.

Response:

a) Trilliant provided a one year warranty on defective meters. The warranty only covers the replacement of the meter and does not cover the labour or shipping costs associated with a warranty exchange.

b) FHI cannot speak to the failure rates for all other distributors, but based on some discussions had with some distributors the current Trilliant failure rate seems to exceed the expected industry failure rate.

c) From Jan 1 2014 to present there have been 600 meter failures. Trilliant has covered the cost of repair of all but 19 meters. (again Trilliant only covers the meter costs)

d) There were 104 meters installed by FHI in 2011. Meter costs were $40,275 and labour costs were $7,226. The equals a per meter cost of $387 and an installation cost of $69.

48. 2. OEB STAFF 25

Ref: E2/T2/S1/Att. 1/p. 68 & Appendix 4/p. 15; E2/T2/S1/Att. 1/Appendix 2 “Customer Consultation Results”/Question 4 and Report of the Board, Supplementary Report on Smart Grid, February 11, 2013 (EB-2011-0004) – 5.4.5.2 Material Investments – Electric Vehicle

At the first reference under “Vehicles and Trailers”, it is indicated that introducing an electric vehicle, within FHI’s fleet would allow for assessment of the impact on the electrical system; and potential operational efficiencies gained through hybrid technology. On page 15 of Appendix 4, Festival Hydro shows that the cost of the electric vehicle is $70,000.

In the second reference, at Appendix 2, respondents to Question 4 in regard to their intentions to purchase either a fully electric or plug-in hybrid in the next five years indicated that: 90.79% do not intend to purchase an electric vehicle in the next 5 years; 7.02% would purchase in the next five years if the price difference decreases to less than $3,000; 1.75% would buy within the next five years; and 0.44% currently own an electric vehicle.

At page 14 of the third reference, it is indicated that:

- *Following Board approval, some distributors have already undertaken pilot and demonstration projects related to adaptive infrastructure, including electric vehicle charging. `*
- *The Board expects that distributors will report on the outcomes and learning from these pilots for the benefit all regulated entities. This expectation is consistent with the Board's policies (e.g., Filing Requirements: Distribution System Plans), which emphasize the need to avoid duplication of efforts in testing out and learning about new technologies.*

a) Please provide the analysis used in support of the decision to purchase the $70,000 electric vehicle. In providing the analysis, please include the original cost of the vehicle, the estimated energy cost (gas and electricity as appropriate), maintenance cost over the expected useful life of the vehicles, insurance cost including contingencies for the electric vehicle's battery in case of failure past the warranty period.

b) Given the low response of the respondents in regard to their intent to purchase electric vehicles outlined in the second reference, please indicate whether FHI communicated with other distributors in Ontario regarding any projects in progress that may be similar to what it plans to learn from its electric vehicle purchase, so duplications can be averted? If so, please provide description of such projects.

c) If FHI did not communicate with other distributors in Ontario as outlined in 2) above, please indicate what steps FHI would take to address the potential duplication of its project.

d) Does Festival plan to put any corporate branding on the vehicle and to promote it as a clean/zero tailpipe emissions vehicle? If so, please explain whether the shareholder will bear a portion of the vehicle's costs given its marketing benefits.

Response:

a) An analysis has not yet been completed for the purchase of an electric vehicle. This analysis will be completed before the purchase (2015). The main reason for the purchase of the electric vehicle is to see the impact within FHI distribution system. Its ability to act as a fleet vehicle provides a secondary benefit. The total cost of the vehicle has been estimated based on costs determined online. When FHI goes out for competitive quote it is quite possible that the total cost of the electric vehicle may not be material.

b) Before the purchase of an electric vehicle, FHI will speak with some other distributors to gain insight on their programs to ensure our efforts are not being duplicated. Although Stratford residents have responded that only a few plan to purchase an electric vehicle, the City of Stratford is unique in that over 600,000 tourists per year visit Stratford's Shakespearean Festival. It's this influx in population with the potential of electric vehicles that FHI is trying to understand. The impact of charging electric vehicles in commercial locations (hotels, restaurants, shopping areas, bed & breakfasts) will be of primary concern, rather than customers charging electric vehicles at home.

c) Refer to B

d) Unknown at this time, but it's not expected for the shareholder to share in any costs.

49. 2. OEB STAFF 26

Ref: E2/T2/S1/Att. 3 – OEB Appendix 2-AA; E2/T2/S1/Att. 1/p. 69 and E2/T2/S1/Att. 1, Appendix 1; Asset Management Plan/Appendix 14/p. 6 – 5.4.5.2 Material Investments – GIS Development Plans

At the first reference, the "Capital Projects Table" shows an investment in 2015 of $245,000 against Computer Equipment.

At page 69 of the second reference, it indicates that in Appendix 14 of the Asset Management Plan "Computer Equipment" is made of a number of small projects – none of which exceed materiality threshold.

At page 6 of the third reference, under "GIS system phase 1" it is indicates that:

- *Festival Hydro does not currently have a GIS to track assets and their status in the field*
- *This phase 1 would Cost: $30,000 (For the RFP phase of this project)*
- *Risks if not completed is Loss of GIS data, work planned based on inconsistent information, prevention of intelligent OMS system build.*

a) Please clarify the full name for the abbreviated "OMS system", and also provide:
   i.) description of its current status, what functions that OMS system currently performs,
   ii.) description of any future enhancements, costs of such enhancements and year of expected implementation.

b) As a Geographic Information System (GIS) system is one of the important tools for a Distributor's Asset Management System, please provide details of all the phases for the proposed GIS outlining for each phase its cost, year of completion and expected achievements

c) Please also indicate whether FHI intends to include in its proposed GIS, all asset groups such as Poles, Distribution Transformers (Overhead, Underground and Pad Mounted Transformers), Switchgear (Overhead Line Switches and Pad-Mounted), and Underground Cables.

Response:

a)

i. OMS stands for "Outage Management System". At its core an OMS system helps utilities identify the cause of outages. This would allow for quicker response and restoration in outage situation. An OMS can also help communicate outage conditions to customers in an automated fashion.

ii. Currently FHI does not have and has not priced out an OMS solution (which is usually dependent on the GIS system).

b) The phases in the GIS implementation have yet to be planned out. Much of this work will be completed based on the system chosen from the RFP process. FHI will look to reduce costs and timelines through shared services with the municipality or other utilities were possible.
c) FHI plans to include all asset groups within the GIS system, including: poles, transformers, switchgear and underground cable.

50. 2. AMPCO 7

Ref: Exhibit 2, Tab 1, Schedule 11, Page 9

a) Please discuss if the focus during spring, summer and fall months on capital will have any impact on maintenance spending in 2014.

b) Please provide the actual capital in-service additions to date and the forecast to year end for 2014.

Response:

a) It's customary that FHI has a heavier O&M focus on the first two quarters of the year with a shift to capital spending in the summer and fall months. This should cause no issues in the overall 2014 maintenance spending

b) The following projects have already been completed

Brunswick Street
CN Road
Dunedin
Queen and Albert Street

Projects to be completed in Q3
Mornington St
Remove M5 Feeder
Elgin Street
Underground Drill – Britannia at Fairgrounds

Projects to be completed in Q4
Re-insulate
Church St. N & Egan
Center Street (OH and UG)
MS#8
Switchgear
Vault Repair

51. 2. AMPCO 8

Ref: Exhibit 2, Tab 2, Schedule 1

a) Page 11 – SAIDI – Please provide the source of the Ontario average for SAIDI.

b) Page 23 – Please provide a breakdown of the cause of defective equipment for momentary outages.

c) Page 23 - Please provide a similar table for SAIDI and SAIFI causes for the years 2019 to 2013 including a further breakdown of the cause of defective equipment.

d) Page 25 – How did Festival make the determination that 1 unit = 3 staff for 1 week.

e) Page 36 – Please provide the unit costs in 2015 compared to 2010 and 2013 for the replacement of poles, underground feeders, and switchgear and the reinsulate project and show the calculations.

Response:

a) OEB Yearbook

b)

	2009	2010	2011	2012	2013
Junction Point		12.5%			20.0%
Cable	12.5%				40.0%
Transformer				50.0%	20.0%
Elbow	37.5%	12.5%	22.2%		20.0%
Switch	25.0%			50.0%	
Arrester	25.0%	50.0%	44.4%		
Switchgear			33.3%		
Insulator		12.5%			
Terminator		12.5%			

Please note as per the DSP defective equipment is the second lowest cause of momentary outages within FHI's system. Also note that a trend does not exist in the type of equipment causing momentary outages on a year over year basis

c)

Outages by Cause (excluding planned and loss of supply)

	2009	2010	2011	2012	2013
Adverse Environment					2.2%
Adverse Weather	7.9%	15.8%	14.8%	16.7%	19.8%
Defective Equipment	22.4%	44.7%	35.2%	15.3%	33.0%

Foreign Interference	31.6%	25.0%	38.6%	47.2%	36.3%
Human	3.9%	1.3%		1.4%	1.1%
Trees	22.4%	7.9%	10.2%	2.8%	2.2%
Unknown	11.8%	5.3%	1.1%	16.7%	5.5%

Prolonged DE Causes

	2009	**2010**	**2011**	**2012**	**2013**
Arrester	5.9%	8.8%	19.4%		10.0%
Cable	11.8%		6.5%	9.1%	3.3%
Connection	17.6%	14.7%	22.6%	18.2%	10.0%
Customer	5.9%	14.7%	6.5%		13.3%
Elbow	23.5%	8.8%	12.9%	9.1%	16.7%
Splice					6.7%
Switch		8.8%	9.7%	18.2%	3.3%
Transformer	11.8%	14.7%	12.9%	27.3%	26.7%
Terminator	5.9%	2.9%			10.0%
Insulator	11.8%	20.6%	6.5%	18.2%	
Switchgear		2.9%	3.2%		
Pole	5.9%	2.9%			

d) This unit was selected to represent 1 week of work for a full crew (3 staff). The actual unit of measure is immaterial as the end result is to determine the number of hours required to complete a project.

e)

Pole replacement
2010 - $1,182,070 for 208 Poles replaced = $5683 per pole
2013 - $787,021 for 146 Poles replaced = $5390 per pole
2015 - $650,000 for 100 Poles replaced = $6500 per pole

note that since 2010 – 2015 the average cost per pole replaced has been $6300 per pole – refer to 2 – Staff – 15 (a)

Switchgear
2010 - $66,731 for 1 unit = $66,731 per unit installed
2013 - $112,695 for 2 units = $56,347 per unit installed
2015 - $110,000 for 2 unit = $55,000 per unit installed

Reinsulate Project

2010 - $45,795 for 39 poles reinsulated = $1174/pole
2013 - $98,812 for 82 poles reinsulated = $1205/pole
2015 – no set number of poles have been identified but based on historical figures we would estimate 125 poles reinsulated for $150,000 = $1200/pole
UG Feeder project
2010 – no material UG projects were completed
2013 – only 500 MCM main feeder work was completed
2015 – 1/0 conversion work is being estimated.
Based on the fact that no common UG work has been carried out in 2010,2013 and 2015 we are unable to provide a year over year comparison.

52. 2. ENERGY PROBE 8

Ref: Exhibit 2, Tab 1, Schedule 1

Please explain why depreciation rates were slightly different than were included and approved in the 2010 application (page 4).

b) Please provide the level of capital spending to date in 2014 as compared to plan. Has Festival caught up from the lower capital spend to March 31, 2014 noted on page 9?

Response:

a) Festival noted on page 4 of E2/T1/S1 that the average of actual net fixed assets in 2010 was $158K less than Board Approved, as a result of capital spending and depreciation rates being slightly different than were included and approved in the 2010 application. Festival would like to clarify that depreciation rates applied to the asset classes did not change in 2010 as were included in 2010 Board approved figures, however, total additions and the asset classes where additions were categorized were slightly different than projected in the 2010 application causing the depreciation expense calculated on actual figures to be slightly different than projected in the application.

b) Please refer to 2.0-VECC – 6a for updated capital spending to June 30, 2014. Also, please refer to AMPCO #7a and #7b for reference to the typical timing of maintenance work versus capital work due to weather. Festival notes that we anticipate completing all of our planned capital work in 2014.

53. 2. ENERGY PROBE 9

Ref: Exhibit 2, Tab 1, Schedule 1, Attachment 1 & Exhibit 1, Tab 2, Schedule 5

Please reconcile the capital expenditures of $2.5 million for 2015 in the second reference (Appendix 1-AB) and the $17.783 million shown in Appendix 2-BA in the second reference, after taking into account the $13.961 million for the TS station in account 1815.

Response:

The table below provides the reconciliation requested. Festival notes that the total cost moved from the transformer station variance account included land and CCRA agreements which were categorized in general ledger accounts other than GL 1815. Festival also notes that appendix 2-AB incorrectly includes contributed capital at $120,000 versus the $150,000 included in 2-BA.

Reconciliation 2015 Additions in 2-AB vs. 2-BA		
Total capital additions per 2-AB		2,501,500
Moved from transformer station VR acct		15,311,782
Difference on contributed capital	-	30,000
Additions per 2-BA		17,783,282

54. 2. ENERGY PROBE 10

Ref: Exhibit 2, Tab 1, Schedule 1, Attachment 1

a) *Please explain why the TS station is not included in the closing balance for 2014 and the opening balance of 2015.*

b) *The test year continuity schedules show an amount of fully allocated depreciation of $156,997. Please indicate how much of this is expensed in OM&A and how much is capitalized.*

c) *Please provided updated continuity schedules for 2014 (all three versions shown in Appendix 2-BA) to reflect actual capital additions closed to rate base in 2014 for the most recent actual period available, along with the forecast for the remainder of the year.*

Response:

a) Festival notes that given rates are being requested for January 1, 2015, and moving the transformer station assets out of the variance account and into general capital is based on this rate approval, we felt it was most correct to show the assets coming into our general capital asset pool in the 2015 continuity schedule versus 2014.

b) Festival allocated depreciation from account 5705 up into operating and maintenance expenses for presentation purposes in our income statement. Based on historical trends, Festival estimates $68K of these costs will be allocated to capital in 2015.

c) As noted in 2-EP-8b, Festival intends to complete all capital work as planned and as such 2014 continuity schedules were not revised.

55. 2. ENERGY PROBE 11

Ref: Exhibit 2, Tab 1, Schedule 1, Attachment 1 & Exhibit 2, Tab 1, Schedule 2

Please show the derivation of the 2013 and 2014 figures on the table on the first page of the second reference above.

b) Please reconcile the 2014 figure of $14,946,801 shown in the second reference with the additions of gross assets of $13,961,840 and accumulated depreciation of -$667,059 shown in Appendix 2-BA in the first reference.

Response:

a) In the table referenced in E2/T1/S2/page 1, the 2013 and 2014 gross assets and accumulated depreciation agree to Appendix 2-BA continuity schedules for 2013 new policies and 2014 new policies under CGAAP. The transformer station net book values for 2013 and 2014 agree to the balance included in the ICM variance account at the end of 2013 and 2014 (refer to E2/T2/S5 for more information on the transformer station variance account and specifically page 6 for a breakdown of the amounts included in the table referenced in this question).

b) The table below provides the reconciliation requested. Festival notes that the variance account that accumulated the transformer station assets was not all classed as general ledger 1815 assets as land and a CCRA agreement were included in the variance account as well. Festival also notes that the $667,059 is depreciation expense accumulated to the end of 2014 plus new depreciation on the transformer station assets in account 1815 for 2015.

Transformer Station Assets moved to Capital Jan 1, 2015		
Land		913,474
Transformer Capital		13,961,840
CCRA agreement		436,468
Depreciation to Dec 31/14	-	365,781
NBV of TS assets at Jan 1/15		14,946,001
New Depreciation in 2015		
TS capital	-	301,278
CCRA agreement	-	95,704
NBV of TS assets at Dec 31/15		14,549,019

56. 2. ENERGY PROBE 12

Ref: Exhibit 2, Tab 1, Schedule 3

a) Which rate classes does Festival bill monthly? What rate classes are billed bi-monthly?

b) Has Festival changed the billing frequency for any rate classes since the 2010 application? If yes, please provide details.

Response:

a) Festival bills all customers monthly.

b) Festival has not changed the billing frequency for any rate classes since the 2010 rate application.

57. 2. ENERGY PROBE 13

Ref: Exhibit 2, Tab 1, Schedule 1, Attachment 1 & Exhibit 2, Tab 1, Schedule 4

a) Please confirm that Festival did not remove the stranded meter assets from the continuity schedules in the first reference at the end of 2014.

b) Please confirm that the stranded meters were removed in the 2015 continuity schedule.

Response:

a) Confirmed.

b) Confirmed. Stranded meters were shown on the 2015 continuity as disposals effective January 1, 2015.

58. 2. ENERGY PROBE 14

Ref: Exhibit 2, Tab 1, Schedule 1, Attachment 1 & Exhibit 2, Tab 2, Schedule 1, Attachment 1

On page 5 of the second reference, Festival indicates that it has current properties that are not being fully utilized by the utility, including a property next to the main administration building.

a) Please confirm that Festival has reduced the OM&A forecast for 2015 by the $8,000 to $10,000 noted on page 5 of the second exhibit. If this cannot be confirmed, please explain.

b) While there is disposal of buildings shown for 2015 in Appendix 2-BA in the first reference, there does not appear to be any disposal of land. Please explain if the property to be disposed of in 2015 has been reflected in the continuity schedule for 2015.

c) What is the net book value of the properties that may be disposed of in 2015?

d) What are the expected remediation costs for each property that may be disposed of in 2015?

e) What is the estimated value of each of the properties that may be disposed of in 2015?

f) How has the potential disposition of the properties in 2015 been reflected in the revenue requirement calculation?

g) Has or will Festival be disposing of any properties in 2014? If yes, please provide full details, including the net book values, remediation costs and selling prices.

Response:

a) Festival confirms that the $8,000 reduction was included in GL 5012 and 5675, and Festival has shown this $8K as a negative cost driver in OEB appendix 2-JB.

b) Festival notes that the building disposals included in appendix 2-BA in 2015 were for a substation property where the land was purchased from the City of Stratford in 1962 for $1. The other disposals are disposals of components of buildings that have since been replaced or are scheduled to be replaced in 2015. As such – it is correct that there is no corresponding land disposal recorded in 2015.

c) There is no book value to the substation being removed from fixed assets in 2015.

d) Festival estimated the cost for demolition of the property and environmental cleanup to return the property to green space at $60K which is being incurred in 2014.

e) There are no properties with value anticipated to be sold in 2015.

f) The remediation expense is expected in 2014 and has been added back in the PILS calculation in that year as it was anticipated that the property would be sold in 2014. As per OEB #47 – Festival no longer anticipates selling this property as the size and location of it make it unmarketable. There were no anticipated impacts to revenue requirement based on the sale of this property as it had not net book value.

g) Festival has not and does not plan to sell any properties in 2014.

59. 2. SEC 8

Ref: [Ex. 2/2/1, p. 2]

Please confirm that the 16% reduction in capital expenditures excludes the impact of the transformer station.

Response: Confirmed

60. 2. SEC 9

Ref: [Ex.2/2/1, p. 53]

Please provide more information on Utilities Standards Forum (USF), including the Applicant's annual costs to be a member, and the Applicant's actual and forecast activities in the current and test years in support of USF.

Response:

The activities that FHI participates in to help USF are as follows: CEO sits on USF Board which meets 4 times per year, Distribution Engineer attends user group meetings 3 times per year and answers technical questions put forth by USF members, FHI has volunteered to give USF presentations on topics such as the DSP. Annual membership cost is $8750.

61. 2. SEC 10

Ref: [Ex.2/2/1, App. 1]

Please provide the date the Asset Management Plan was completed. If it was approved by the Board of Directors, please provide the date of approval. If any external assistance was used in the preparation of the Asset Management Plan (other than the reports attached as Appendices 6, 7, 9, 10 and 11), please provide particulars. Please provide a high level summary of the major changes in the 2013 Edition of the Asset Management Plan relative to the Applicant's pre-existing practices.

Response:

a) The Asset Management Plan was completed in October of 2013 and approved by the Board of Directors at the November 28, 2013 meeting. No external assistance was used in the preparation of the report. The only changes from the previous version of the report at a high level were as follows:

- The addition of age distribution graphs for Poles, Conductors and Transformers)
- The addition of the following sections for major equipment
- Padmount Switchgear
- Manholes
- Transformer Station

62. 2. SEC 11

Ref: [Ex.2/2/1, App. 5a] With respect to the 2013 Board Capital Plan:

a. Please explain why the memorandum accompanying the plan is dated November 12, 2013, when the plan is for the year commencing January 1, 2013.

b. Please explain why the 2013 plan does not contain a 5 year operating budget, as do the 2014 and 2015 plans.

Response:

a) The date was auto changed by software when included in the package. The 2013 board capital plan was provided to the board on November 29, 2012.

b) The 2013 plan was meant to highlight the scope and cost of the capital work presented and didn't pertain to O&M. The 2013 capital appendix attached was the version without O&M.

63. 2. SEC 12

Ref: [Ex.2/2/1, App. 5b] With respect to the 2014 Board Capital Plan:

a. Please confirm that the 2014 and 2015 capital plans were submitted to the Board of Directors together, with the first dated November 21 and the second dated November 22.

b. Please explain why the financial statements attached to the 2014 plan are dated November 22, the day after the date of submission.

Response:

a) Yes, both the 2014 and 2015 plans were submitted together and approved at the November 28, 2013 Board of Directors meeting.
b) Please refer to a)

64. 2. SEC 13

Ref: [Ex.2 generally]

Please provide a list of asset categories that the Applicant runs to failure. Has the Applicant changed which asset categories it runs to failure since its last cost of service application? If so, please provide details.

Response:

The only asset that FHI runs to failure is secondary cable. This has not changed since the last application.

65. 2.0 - VECC 3

Reference: E2/T1/S3

a) Does Festival monthly or bi-monthly bill its customers? If the former has the Utility reviewed the result of lead/lag studies undertaken by Utilities in Ontario that do monthly billing?

Response:

a) Festival bills all customer classes monthly. Festival is aware some LDCs have undertaken lead/lag studies but Festival has not reviewed the results of their lead/lag studies in detail.

66. 2.0 - VECC 4

Reference: E2/T1/S1& S2/pg.3 & E4/T2/S1/pg.7

a) Please show how the $475k in annual savings for network connection costs is calculated. The evidence at E4 suggests there are further savings from the new transformer station. Please provide an estimate of these other savings (specify if one-time or annual).

b) Please explain the rationale for a 25 year amortization of the bypass compensation amount of $1,230,026.

c) Was the by-pass agreement and its estimated cost discussed in the evidence of EB-2013-0214? If yes please provide the extract of that evidence.

Response:

a) The monthly reduction of 20,000 kW arising from the Permanent Bypass Agreement with Hydro One results in annual savings of $475,200 in transformation connection charges. The kW reduction has been reflected monthly in the RTSR Model on Tab # 8 Forecasted Wholesale. In summary:

Tab 7 Current Wholesale (2013)	1,042,640 kW @ $1.98	$2,064,427
Tab 8 Forecast Wholesale (2015)	802,640 kW @ $1.98	$1,589,227
Reduction	240,000 kW	$ 475,200

In addition, customers will save the 13% HST, which is another $61,776 (slightly less for those eligible for OCEB). The 2013 IRM submission (EB 2012-0124) provides, in detail, the expected costs associated with the TS construction compared to the many benefits to be achieved such as addressing of capacity requirements, feeder loading issues, voltage issues and reliability improvements.

b) The Permanent Bypass is subject to a 45 amortization period, which is equal to the depreciation period for the major component of the transformer station, namely the transformers and the switch gear. The 25 year period as stated is not correct. Note that all our calculations have been based on this cost being amortized over a 45 year period.

c) It was not discussed as part of evidence in EB 2013-0124 as the need for a Permanent Bypass Agreement was not envisaged at that time.

67. 2.0 - VECC 5

Reference: E2/T2/S1/pg.35 & E2/T2/S1/pg.14

a) The average capital budget between 2009 and 2013 (not including smart meters and subdivisions) was $3.3 million. The average for 2014 through 2016 is approximately $1.0 million less (if one excludes System Access as a proxy for subdivisions). Yet the Distribution System Plan supports a 10 year refurbishment of the distribution system. Please explain the reasons for the significant decline in spending over time and how the proposed budgets are congruent with the plan for a 10 year refurbishment of the distribution system.

Response:

a) The 10 year reference in the DSP referred to a planning horizon. FHI bases capital spending requirements on a 10 year planning horizon not a 10 year refurbishment cycle. Based on the current age and condition of assets the reduced capital spend is expected to maintain asset condition over a 10 year period.

68. 2.0 - VECC 6

Reference: E2/T2/S1/Attachment 3

a) Please update Appendix 2-AA to show the actual amounts spent to date on capital projects and separately any revision to the forecast for 2014.

b) Please provide the current estimated in-service dates for the following projects:

i. Brunswick Street
ii. Elgin Street
iii. Church St N. & Egan St. (M2 Rebuild)
iv. M.S. #8 Ph 2
v. Brussels-CN Road

Response:

a) Please refer to updated 2.0 VECC 6 2AA appendix. We do not expect any revisions to the capital budget at this time.

b) Please refer to AMPCO response 7b.

69. 2.0 - VECC 7

Reference: E2/T2/S1/Attachment 3

Festival notes that System Access costs are based on past experience. However, Appendix 2-AA shows no costs prior to 2014 for new upgraded services or capital additions.

a) Please provide the number of new home or subdivision connections made in each of 2010 through 2013.

b) Please provide any information Festival has on new development activity in its service territory for 2014 and 2015.

c) Please explain the $305k for "Customer Connection/Extension" in 2013.

Response:

a) Net new home connections for each year are as follows:
2010 – 60
2011 – 283
2012 – 165
2013 – 120

b) Please refer to 2 – Staff – 12b

c) Assuming the question is referring to 2011. This cost was for an UG feeder extension to pick up a larger commercial customer.

70. 2.0 - VECC 8

Reference: E2/T2/S2/pg.5

a) Please provide the capital contributions (actual and forecast) in each of the years 2010 through 2015.

b) Please also provide the total capital expenditures related to the above capital contributions for each of those years.

Response:

a) As per E2/T2/S1 Attachment 2 Capital contributions received 2010 to 2013 and 2014/15 forecast:

2010	$474,049
2011	$106,480
2012	$342,654
2013	$154,030
2014	$150,000
2015	$120,000

b) The capital expenditures associated with capital contributions are for System access and system service related projects. As per E2/T2/S1 Attachment 2 the amounts spent on system access and system services in 2010 to 2013 and 2014/15 forecast:

2010	$ 663,701
2011	$ 533,140
2012	$1,026,213
2013	$ 946,579
2014	$ 625,000
2015	$ 631,500

EXHIBIT 3 – OPERATING REVENUE

71. 3. OEB STAFF 27

Ref: E3/T1/S2 and Attachments – Load Forecast

Board staff would like some clarification and additional information concerning Festivals Load forecast.

a) Please state the difference between the two weather stations London International Airport and London CS. Please state the reasons for selecting London CS.

b) Festival Hydro has provided some parametric statistics for each of its models. Board staff would like Festival to also provide:

i.) The standard error of each estimated parameter, including the intercept;

ii.) A review and comment on the plot of the residuals; and

iii.) One would assume that an energy consumption model would have an intercept at or near zero. Please comment on the large negative intercept.

Response:

a) There are 3 weather stations located at the London International Airport, London International Airport, London CS, and London A. The weather station London International Airport does not have recorded temperature data. London CS has temperature data for all except 9 days from 2005-2013. London A is missing temperature recordings for 10 days in 2013 alone.

i. Please see the tables below

Table 2.2 (restated with std. error)
Model 1: OLS, using observations 2005:01-2013:12 (T = 108)
Dependent variable: NSLS

	coefficient	std. error	t-ratio	p-value
const	- 83,978.61	3,441,923.85	- 0.0244	0.980582693
LondonHDD	11,410.71	534.30	21.3562	3.09226E-39
LondonCDD	44,488.86	3,628.96	12.2594	1.03919E-21
LONFTE	53,918.43	11,205.15	4.8119	5.24408E-06
PeakDays	215,834.14	70,875.68	3.0452	0.002965286
Shoulder1	- 832,374.56	214,083.31	- 3.8881	0.000181002
Increment	- 6,942.73	2,959.68	- 2.3458	0.020941661

R-squared	0.905438299	Adjusted R-squared	0.899821
F(6, 101)	161.1809484	P-value(F)	2.09E-49
Theil's U	0.29965	Durbin-Watson	1.575643

Table 3.1 (restated with std. error)

Model 1: OLS, using observations 2005:01-2013:12 (T = 108)
Dependent variable: Interval

	coefficient	std. error	t-ratio	p-value
const	- 4,534,224.59	10,679,031.86	- 0.4246	0.672056
LondonHDD	2,794.86	1,109.35	2.5194	0.013357
LondonCDD	17,955.85	7,140.24	2.5147	0.013523
LONFTE	89,837.66	37,930.01	2.3685	0.019802
PeakDays	1,064,821.28	237,480.03	4.4838	1.98E-05
WorkDays	- 437,915.33	272,089.83	- 1.6095	0.110702
Shoulder1	1,009,449.64	419,783.89	2.4047	0.018045
Increment	- 21,427.74	10,880.82	- 1.9693	0.051712
Recession	- 655,118.49	1,010,305.74	- 0.6484	0.518204
R-squared	0.62851769	Adjusted R-squared		0.598499
F(8, 99)	20.93748802	P-value(F)		3.02E-18
Theil's U	0.67534	Durbin-Watson		1.062991

ii. It is assumed that by plot of residuals, this question is asking about the Chart 2.1 and Chart 3.1 at Exhibit 3, Tab 1, Schedule 2, Attachment 1.

Chart 2.1 indicates that the NSLS model has predicted the summer and winter peaks as well as overall consumption reasonably well. In addition, the overall decreasing trend is captured. One would expect a good fit given that the R-squared of the model is over 90%

In Chart 3.1, the difficulty of forecasting interval metered customers with a regression model is more apparent. Despite an employment parameter, and a recession indicator, the model has failed to capture the severity of the recession of 2008. In addition, there is more variability in the Actual observations than the model has predicted. The model is however close to the actual demand in 2007, 2010, and 2013, and reasonably captures the long-term decreasing trend. At table 3.2, if the outlier years 2008 and 2009 were removed, the model would have an annual absolute error of 1.5% over the remaining 7 years, which is nearly as good as the NSLS forecast error of 1.1% per year.

iii. The NSLS model shown in Table 2.2 has an intercept of -83,979 kWh / month. Given that this model predicts average monthly consumption in excess of 22,000,000 kWh, the intercept represents less than half a percent of the forecast, and is indeed near zero.

In the case of the Interval model at Table 3.1, the intercept is -4,534,225 kWh / month for a model which predicts average monthly consumption of nearly 31,900,000 kWh. The intercept represents approximately 14.2% of the forecast. The Interval model includes parameters for LONFTE, an employment metric, as well as Peak Days which represents the number of weekdays excluding holidays in each month. Both metrics are statistically significant and strengthen the model. Since the energy being modelled consists primarily of GS > 50 and Large Use customers however, it is reasonable that demand could scale as much as linearly in both of those parameters. Indeed, these metrics combined account for more than the total demand of the model, hence the resulting negative intercept.

72. 3. OEB STAFF 28

Ref: E3/T1/S2, Attachment 1, Schedule 2, p. 2 and Schedule 3, p. 2 – Trend variable

Festival Hydro states that it has included a trend variable in the regression analysis for the Net System Load Shape profile and the Interval load profile.

a) Please explain in detail how this variable was developed for either of the two load profiles. Elaborate on the value and interpretation of the Trend variable as an explanatory variable.

i.) Please confirm that the trend variable is represented by the Increment variable in the model; and

ii.) Please explain the negative trend variable, and if Festival suspects that some conservation measures, not captured by the OPA analysis, is responsible please give examples of the measures.

b) Please describe what alternative variables were examined by Festival Hydro to capture the impact captured by the trend variable.

Response:

a) In both the Net System Load Shape and Interval load profiles, the trend variable was assigned a value of 1 in January 2005, and was incremented by 1 in each successive month. I.e. the trend variable had a value of 2 in February 2005 increasing to 108 in December 2013, and 132 in December 2015.

   i. The trend variable is represented by the Increment variable in the model.
   ii. For the rate classes captured in the NSLS model, the trend variable captures a reduction of 6,943 kWh / month, or 83,313 kWh/year. For the rate classes captured in the Interval model, the trend variable captures a further reduction of 21,428kWh / month or 257,133 kWh / year. The total trend for Festival is therefore a reduction of 340,446 kWh per year.

b) This trend is observed over the entire period from 2005 to 2013 and therefore pre-dates the OPA conservation targets. The cause of this reduction is not apparent to Festival, but it could be for many reasons. It could be due to natural conservation, or due to changes in economic activity or demographics.

c) A recession variable was included to attempt to capture the lasting impact of the 2008 recession, and permanent loss of energy intensive manufacturing customers.

73. 3. OEB STAFF 29

Ref: E3/T1/S2, Attachment 1, Schedule 3, p. 2 – Number of Workdays, London FTE and Recession variable

On page 2, Festival Hydro states:
"Elenchus has also included a trend variable that starts with a variable of 1 in January 2005 and increments by 1 in each subsequent month. Also included is the number of workdays and a recession variable with a binary value of 0 for the period January 1, 2005 to December 31, 2008 and a binary value of 1 for the period January 1, 2009 to December 31, 2013 to build up the robustness of the model."

Festival Hydro, on page 1, also notes that it includes monthly full-time employment levels for London in its regression analysis in order to measure the change in economic activity.

a) Board staff notes the Festival Hydro has peak days as well as number of workdays in its regression analysis. Please explain how these variables differ and explain why the regression analysis uses both variables, given that the number of workdays variable shows a negative co-efficient, which is counter-intuitive.
b) Festival has employed two economic variables, FTE and Recession. Please review for any auto-correlation, and explain how Festival thinks that these two variables are independent or alternatively should not be independent.
c) Please explain how the recession variable was developed and elaborate on the value of this variable, given its statically insignificance and the inclusion of a trend variable.
d) Please describe what alternative modelling efforts, such as alternative variables, were examined by Festival Hydro to improve the system load regression model.

Response:

a) The workdays variable and peak days variable attempt to address the same causation. Peak Days consists of a count of week days excluding statutory holidays in each month, whereas the workdays variable consists of a count of week days in each month. The work days should have been removed prior to use in the final application. Please see part c) for a revised model which eliminates this variable.

b) The FTE variable tracks full-time employment in the London economic region. The recession variable is intended to track the impact of the 2008/2009 recession and permanent loss of energy intensive manufacturing industry in particular. The intent is that we could have a recovery in employment without ever achieving a recovery in energy usage. However, for the reason in part c), the Recession variable should not have been included.

c) The recession variable is an indicator, having a value of 0 up to and including December 2008, and a value of 1 starting in January 2009. It is intended to capture the lasting manufacturing impact of the 2008/2009 recession. Given that it is not statistically significant, it should not have been included. Below is an improved model which excludes the Work Days variable as explained in part a) and the Recession variable.

Model 2: OLS, using observations 2005:01-2013:12 (T = 108)
Dependent variable: Interval

	Coefficient	*Std. Error*	*t-ratio*	*p-value*	
const	-1.18393e+07	6.72462e+06	-1.7606	0.08134	*
LondonHDD	2939.11	1043.89	2.8155	0.00586	***
LondonCDD	17409.2	7090.05	2.4554	0.01578	**
LONFTE	105603	21891.9	4.8238	<0.00001	***
PeakDays	759967	138473	5.4882	<0.00001	***
Shoulder1	1.05824e+06	418263	2.5301	0.01295	**
Increment	-28626.3	5782.44	-4.9506	<0.00001	***

R-squared	0.616363	Adjusted R-squared	0.593573
F(6, 101)	27.04497	P-value(F)	5.12e-19
Theil's U	0.68795	Durbin-Watson	1.070671

d) As explained in response to 3-Staff-27, it is difficult to forecast energy using a regression model for interval metered customers. An alternative approach would be to assume that large customers would maintain status quo usage. In this case, use of a regression model, though challenging was considered to be superior.

74. 3. OEB STAFF 30

Ref: E3/T1/S2, Attachment 1, Schedule 5, p. 3-5 – CDM Adjustment

On page 2 of E3/T1/S2, Attachment 1, Schedule 5, Festival Hydro notes that "in order to calculate the CDM impact for the 2015 load forecast Elenchus includes persistence for 2013 and 2014 programs plus an estimate for 2015 programs" of 1,500,000 kWh at a half-year value of 750,000 kWh.

a) Please provide the basis for the 2015 estimated CDM savings elaborate on how this amount was arrived at.

b) Please provide the kW CDM savings built into the 2015 forecast.

c) Please update Appendix 2-I, the Load Forecast CDM Adjustment Work Form, for the 2015 edition, available on the Board's 2015 EDR [2015 EDR webpage].

Response:

a) At the time Festival's COS application was filed, there was uncertainty as to the nature of post 2014 CDM programs and the related targets. The expectation was there would be some form of continuation into 2015, so the numbers entered were an estimate of that extension. Since our original filing, the OPA has established new programs for the 2015 to 2020 time period with specific kWh only targets to be met.

b) The kW CDM savings built into the 2015 forecast can be found on E3/T1/S5 Page 4 of 5. Festival recently received its targets, which are almost double the existing target at 36.5 GWh over the 5 year period. Festival has updated its 2015 CDM impact in the load forecast to reflect what it realistically feels it can achieve in the 2015 year. Since the program is a 5 year program, that works to an average of 16.6% to be achieved each year. According to the OPA's LDCs toolkit, a minimum of 8.3% must be met in each year. Festival expects it can achieve the midpoint of these two ranges in the first year, that being 12.45% of the 36.5 GWh target which equals 4,544,250. At a half year value, the amount is 2,272,125 kWh. The load forecast has been updated to reflect these greater impacts, as noted below:

Adjustments to kWh for CDM Impact:							
Original CDM Forecast:							
			Est 2015				
	2013Programs						
	2014		324,574				
	2015 Est		750,000	(.5 * 1,500,000)			
	Total		1,074,574	**Weather Norm**	**Weather Norm**	**Revised**	**Weather Norm**
				2015 before CDM	**2015 after CDM**	**CDM**	**15 after revised CDM**
	Allocated as:						
	Residential		247,905	137,393,847	137,145,942	438,533	136,955,314
	Res Hensall		6,787	3,761,644	3,754,857	11,244	3,750,400
	G.S. <50 kW		116,011	64,295,632	64,179,621	257,858	64,037,774
	G.S. >50 kW		654,047	362,486,529	361,832,482	1,453,753	361,032,776
	Large Use		40,113	22,231,439	22,191,326	89,159	22,142,280
	Streetlights		8,241	4,567,584	4,559,343	18,318	4,549,266
	Sentinel Lights		271	150,427	150,156	603	149,824
	USL		1,195	662,162	660,967	2,656	659,506
			1,074,570	595,549,264	594,474,694	2,272,125	593,277,139
					453,573,895		593,277,139
	New OPA Targets:						1,197,555
	2015 to 2020 Budget		kWh	36,500,000			
	Minimum per year		8.30%	3,029,500			
	5 year avge		16.67%	6,083,455			
	Mid point		12.45%	4,544,250			
	Half year rule			2,272,125			
	Allocated target FOR 2015:						
	Residential		1,084	19.8%	449,778		
	NonRes		4,392	80.2%	1,822,347		
			5,476	100.0%	2,272,125		
Adjustments to kW for CDM Impact:							
				kW	**kW**	**kW**	**kW**
				Weather Norm	**Weather Norm**	**Revised**	**Weather Norm**
				2015 before CDM	**2015 after CDM**	**CDM**	**15 after revised CDM**
	Allocated as:						
	Residential						
	Res Hensall						
	G.S. <50 kW						
	G.S. >50 kW		946,164	1,707	944,457	3,609	942,555
	Large Use		34,422	62	34,360	131	34,291
	Streetlights		12,017	22	11,995	47	11,970
	Sentinel Lights		356	1	355	2	354
	USL		0	0	0	0	0
			992,959	1,792	991,167	3,789	989,170
		kWh	kW				
Original CDM		1,074,570	1,792				
Revised CDM		2,272,125	3,789	2.11			

c) Appendix 2-1 has been populated within the Appendices excel model. It includes the changes noted in a) to c) above.

75. 3. OEB STAFF 31

Ref: E3/T2/S1, Attachment 1 – Load Data and Forecast

Please update Festival Hydro's summary and variance of actual and forecasted data by completing Appendix 2-IA, available on the Board's 2015 EDR [2015 EDR webpage].

Response

a) Appendix 2-1A has been populated within the Appendices excel model and includes the changes noted in the response to a) to c) of 3-Staff-30.

76. 3. ENERGY PROBE 15

Ref: Exhibit 3, Tab 1, Schedule 1, Attachment 1

a) Do the wholesale data included in Table 2.1 (Schedule 2) include losses? If yes, please explain whether or not the interval and street light column also includes losses, or are all the losses included in the NSLS column?

b) If the wholesale data shown in Table 2.1 (Schedule 2) does not include losses, please explain the difference in these figures from those shown in the table on page 2 of Schedule 1.

c) Please explain why the interval and street light figures shown in Table 2.1 (Schedule 2) do not correspond to the figures shown in the table on page 2 of Schedule 1. Please show how the figures in this column are arrived at.

d) What other rate classes or figures are included in NSLS class in Table 2.1 (Schedule 2) other than Residential, GS<50 and USL?)

e) Please provide versions of Tables 2.2, 2.3, and 2.7 through 2.11 (Schedule 2) based on each of the regression equations below. Please provide a live Excel spreadsheet with each of the requested equations, with all links still in place:

i) replacing the shoulder variable with a spring variable and a fall variable, and changing the trend variable to be 1 in each month in 2005, 2 in each month of 2006 and so on;

ii) in addition to the above, adding the number of days in the month as an explanatory variable.

Response

a) The wholesale data includes losses. The interval and streetlight columns include their own losses and NSLS includes only NSLS losses.

b) Losses included.

c) The kWh on Schedule 1 page 2 represent our distribution revenue billed kWh (before losses). The kWh in Table 2.1 represent the kWh wholesale purchases from the IESO, MicroFITs and FITs and net HONI load transfers.

d) NSLS also includes G.S < 50 kW with demand meters and sentinel lights.

e)
   i. Please see the attached live model, and tables below:

Table 2.2

Model 1: OLS, using observations 2005:01-2013:12 (T = 108)
Dependent variable: NSLS

	Coefficient	*Std. Error*	*t-ratio*	*p-value*	
const	1.93553e+06	3.62909e+06	0.5333	0.59498	
LondonHDD	11411.8	528.185	21.6056	<0.00001	***
LondonCDD	45124.1	3641.56	12.3914	<0.00001	***
LONFTE	46801.3	11994.4	3.9019	0.00017	***
PeakDays	215027	70180.9	3.0639	0.00281	***
Spring	-920536	234811	-3.9203	0.00016	***
Fall	-746256	247163	-3.0193	0.00322	***
trend	-107848	36826.6	-2.9285	0.00422	***

R-squared	0.908196	Adjusted R-squared	0.901770
F(7, 100)	141.3252	P-value(F)	6.37e-49
Theil's U	0.2941	Durbin-Watson	1.681310

Table 2.3

Annual Predicted vs. Actual NSLS

	NSLS	Predicted Value	Absolute % Error
2005	283,289,663	284,898,293	0.6%
2006	269,037,634	271,161,261	0.8%
2007	277,453,830	277,344,665	0.0%
2008	277,015,109	274,747,684	0.8%
2009	266,610,077	258,173,913	3.2%

2010	261,466,185	264,007,755	1.0%
2011	262,568,154	264,789,299	0.8%
2012	255,429,249	261,364,594	2.3%
2013	265,429,952	261,812,389	1.4%
		Mean Absolute Percentage Error (Annual)	**1.2%**
		Mean Absolute Percentage Error (Monthly)	**2.7%**

Table 2.7

Annual Actual vs. Normalized NSLS

	NSLS	% Change	Normalized Value	% Change
2005	283,289,663		277,538,757	
2006	269,037,634	-5.0%	275,149,426	-0.9%
2007	277,453,830	3.1%	275,839,361	0.3%
2008	277,015,109	-0.2%	274,928,951	-0.3%
2009	266,610,077	-3.8%	262,496,320	-4.5%
2010	261,466,185	-1.9%	261,754,394	-0.3%
2011	262,568,154	0.4%	263,109,425	0.5%
2012	255,429,249	-2.7%	262,690,170	-0.2%
2013	265,429,952	3.9%	261,143,262	-0.6%
2014			261,729,515	0.2%
2015			262,486,743	0.3%

Table 2.8

Residential - Festival

Year	Actual kWh	Share	Normalized kWh	% Change
2005	143,411,804	0.50624	140,500,481	
2006	138,207,589	0.51371	141,347,284	0.6%
2007	139,603,876	0.50316	138,791,539	-1.8%
2008	136,970,688	0.49445	135,939,183	-2.1%
2009	135,328,095	0.50759	133,240,001	-2.0%
2010	137,431,624	0.52562	137,583,112	3.3%
2011	137,110,454	0.52219	137,393,101	-0.1%
2012	135,123,779	0.52901	138,964,855	1.1%
2013	137,844,076	0.51932	135,617,896	-2.4%
2014			135,922,351	0.2%
2015			136,315,598	0.3%

Table 2.9

Residential - Hensall

Year	Actual kWh	Share	Normalized kWh	% Change
2005	4,255,224	0.01502	4,168,841	
2006	3,852,878	0.01432	3,940,405	-5.5%
2007	4,054,439	0.01461	4,030,847	2.3%
2008	4,016,517	0.01450	3,986,269	-1.1%
2009	3,926,619	0.01473	3,866,032	-3.0%
2010	3,885,021	0.01486	3,889,303	0.6%
2011	3,814,545	0.01453	3,822,408	-1.7%
2012	3,709,946	0.01452	3,815,406	-0.2%
2013	3,773,971	0.01422	3,713,021	-2.7%
2014			3,721,357	0.2%
2015			3,732,123	0.3%

Table 2.10

GS < 50

Year	Actual kWh	Share	Normalized kWh	% Change
2005	71,281,495	0.25162	69,834,449	
2006	68,326,693	0.25397	69,878,887	0.1%
2007	69,632,805	0.25097	69,227,621	-0.9%
2008	67,284,782	0.24289	66,778,071	-3.5%
2009	64,699,032	0.24267	63,700,735	-4.6%
2010	65,179,456	0.24928	65,251,302	2.4%
2011	63,567,429	0.24210	63,698,470	-2.4%
2012	62,255,637	0.24373	64,025,338	0.5%
2013	64,506,324	0.24303	63,464,548	-0.9%
2014			63,607,022	0.2%
2015			63,791,048	0.3%

Table 2.11

USL

Year	Actual kWh	Share	Normalized kWh	% Change
2005	914,396	0.00323	895,833	
2006	776,820	0.00289	794,467	-11.3%
2007	732,005	0.00264	727,746	-8.4%

2008	681,719	0.00246	676,585	-7.0%
2009	663,570	0.00249	653,331	-3.4%
2010	673,251	0.00257	673,993	3.2%
2011	666,441	0.00254	667,815	-0.9%
2012	667,380	0.00261	686,351	2.8%
2013	664,332	0.00250	653,603	-4.8%
2014			655,070	0.2%
2015			656,966	0.3%

ii. Please see the attached live model, and tables below, but please note that the addition of MonthDays has resulted in the PeakDays variable having a Std. Error greater than the Coefficient.

Table 2.2

Model 2: OLS, using observations 2005:01-2013:12 (T = 108)
Dependent variable: NSLS

	Coefficient	*Std. Error*	*t-ratio*	*p-value*	
const	-1.22847e+07	3.00102e+06	-4.0935	0.00009	***
LondonHDD	11059.8	382.454	28.9180	<0.00001	***
LondonCDD	41292.4	2654.6	15.5551	<0.00001	***
LONFTE	32286.6	8774.96	3.6794	0.00038	***
PeakDays	48521.9	53437.8	0.9080	0.36608	
Spring	-1.33151e+06	174508	-7.6300	<0.00001	***
Fall	-816675	178305	-4.5802	0.00001	***
trend	-138937	26738.8	-5.1961	<0.00001	***
MonthDays	721621	74639.5	9.6681	<0.00001	***

R-squared	0.952780	Adjusted R-squared	0.948964
F(8, 99)	249.6938	P-value(F)	4.62e-62
Theil's U	0.22183	Durbin-Watson	1.093507

Table 2.3

Annual Predicted vs. Actual NSLS

	NSLS	Predicted Value	Absolute % Error
2005	283,289,663	284,513,566	0.4%
2006	269,037,634	271,418,575	0.9%
2007	277,453,830	276,258,445	0.4%
2008	277,015,109	274,113,814	1.0%
2009	266,610,077	260,325,201	2.4%

2010	261,466,185	264,902,187	1.3%
2011	262,568,154	264,699,519	0.8%
2012	255,429,249	261,218,989	2.3%
2013	265,429,952	260,849,556	1.7%
		Mean Absolute Percentage Error (Annual)	**1.3%**
		Mean Absolute Percentage Error (Monthly)	**1.9%**

Table 2.7

Annual Actual vs. Normalized NSLS

	NSLS	% Change	Normalized Value	% Change
2005	283,289,663		277,665,432	
2006	269,037,634	-5.0%	275,242,680	-0.9%
2007	277,453,830	3.1%	274,844,388	-0.1%
2008	277,015,109	-0.2%	274,163,512	-0.2%
2009	266,610,077	-3.8%	264,190,440	-3.6%
2010	261,466,185	-1.9%	262,904,176	-0.5%
2011	262,568,154	0.4%	263,164,345	0.1%
2012	255,429,249	-2.7%	262,722,482	-0.2%
2013	265,429,952	3.9%	260,159,267	-1.0%
2014			268,448,713	3.2%
2015			276,856,109	3.1%

Table 2.8

Residential - Festival

Year	Actual kWh	Share	Normalized kWh	% Change
2005	143,411,804	0.50624	140,564,608	
2006	138,207,589	0.51371	141,395,189	0.6%
2007	139,603,876	0.50316	138,290,907	-2.2%
2008	136,970,688	0.49445	135,560,710	-2.0%
2009	135,328,095	0.50759	134,099,916	-1.1%
2010	137,431,624	0.52562	138,187,459	3.0%
2011	137,110,454	0.52219	137,421,779	-0.6%
2012	135,123,779	0.52901	138,981,948	1.1%
2013	137,844,076	0.51932	135,106,884	-2.8%
2014			139,411,791	3.2%
2015			143,777,951	3.1%

Table 2.9

Residential - Hensall

Year	Actual kWh	Share	Normalized kWh	% Change
2005	4,255,224	0.01502	4,170,744	
2006	3,852,878	0.01432	3,941,740	-5.5%
2007	4,054,439	0.01461	4,016,307	1.9%
2008	4,016,517	0.01450	3,975,171	-1.0%
2009	3,926,619	0.01473	3,890,983	-2.1%
2010	3,885,021	0.01486	3,906,388	0.4%
2011	3,814,545	0.01453	3,823,206	-2.1%
2012	3,709,946	0.01452	3,815,876	-0.2%
2013	3,773,971	0.01422	3,699,031	-3.1%
2014			3,816,893	3.2%
2015			3,936,432	3.1%

Table 2.10

GS < 50

Year	Actual kWh	Share	Normalized kWh	% Change
2005	71,281,495	0.25162	69,866,323	
2006	68,326,693	0.25397	69,902,570	0.1%
2007	69,632,805	0.25097	68,977,911	-1.3%
2008	67,284,782	0.24289	66,592,152	-3.5%
2009	64,699,032	0.24267	64,111,852	-3.7%
2010	65,179,456	0.24928	65,537,925	2.2%
2011	63,567,429	0.24210	63,711,766	-2.8%
2012	62,255,637	0.24373	64,033,213	0.5%
2013	64,506,324	0.24303	63,225,412	-1.3%
2014			65,239,961	3.2%
2015			67,283,175	3.1%

Table 2.11

USL

Year	Actual kWh	Share	Normalized kWh	% Change
2005	914,396	0.00323	896,242	
2006	776,820	0.00289	794,736	-11.3%
2007	732,005	0.00264	725,121	-8.8%
2008	681,719	0.00246	674,701	-7.0%

2009	663,570	0.00249	657,548	-2.5%
2010	673,251	0.00257	676,954	3.0%
2011	666,441	0.00254	667,954	-1.3%
2012	667,380	0.00261	686,436	2.8%
2013	664,332	0.00250	651,140	-5.1%
2014			671,888	3.2%
2015			692,930	3.1%

77. 3. ENERGY PROBE 16

Ref: Exhibit 3, Tab 1, Schedule 1, Attachment 1

Please provide a live Excel spreadsheet with all the historical data and the trend equation used to estimate the 20 year trend data shown in Table 2.5 (Schedule 2). If an equation was not estimated, please explain how the 20 year trend figures were calculated and provide the 20 years of historical data used.

Response:

Table 2.5 was labelled as London CS, the source for all current readings. There are actually 3 weather stations located in the immediate area of the London International Airport, and no one of them has a recent 20 years of history. However, given the close physical proximity, the weather at any one of the stations can reasonably be expected to be the same as at the others. London CS was selected as the source for all readings since its first full month of operation in 2002. The earlier readings were sourced from the London International Airport station which no longer records temperature readings. Please see the attached table with 20 years of monthly HDD and CDD values, and indicates which readings were taken from each station.

78. 3. ENERGY PROBE 17

Ref: Exhibit 3, Tab 1, Schedule 1, Attachment 1

a) Why has Elenchus included the recession variable in Table 3.1 (Schedule 3) even though it is not statistically significant at a 50% level of confidence?

b) Please provide versions of Tables 3.1, 3.2, and 3.7 through 3.10 (Schedule 3) based on each of the regression equation used, but excluding the recession variable. Please provide a live Excel spreadsheet for the requested equation, with all links still in place.

c) In addition to the equation requested in part (b) above, please replace the work day variable with the number of days in the month and replace the shoulder variable with spring and fall variables and changing the trend variable to be 1 in each month in 2005, 2 in each month of 2006 and so on replace the trend variable used. Please provide the same information requested in part (b) above, including the live Excel spreadsheet.

Response:

a) The Recession variable was intended to capture the impact of the permanent loss of manufacturing load as several GS > 50 customers ceased operations following the 2008 recession. Since it is not statistically significant, it should not have been included.
b) Please see the attached model, and tables below:

Table 3.1

Model 2: OLS, using observations 2005:01-2013:12 (T = 108)
Dependent variable: Interval

	Coefficient	*Std. Error*	*t-ratio*	*p-value*	
const	-9.88175e+06	6.76499e+06	-1.4607	0.14723	
LondonHDD	3046.08	1036.48	2.9389	0.00409	***
LondonCDD	17213.7	7027.46	2.4495	0.01604	**
LONFTE	109915	21846.3	5.0313	<0.00001	***
PeakDays	1.08187e+06	235335	4.5972	0.00001	***
WorkDays	-454732	270065	-1.6838	0.09534	*
Shoulder1	1.04698e+06	414568	2.5255	0.01312	**
Increment	-27399.9	5776.71	-4.7432	<0.00001	***

R-squared	0.626940	Adjusted R-squared	0.600826
F(7, 100)	24.00762	P-value(F)	7.21e-19
Theil's U	0.67851	Durbin-Watson	1.054793

Table 3.2

Annual Predicted vs. Actual Interval

	Interval	Predicted Value	Absolute % Error
2005	415,128,037	410,769,716	1.0%
2006	409,556,912	400,533,602	2.2%
2007	404,758,925	403,018,210	0.4%
2008	385,087,341	398,707,171	3.5%
2009	344,781,983	366,955,817	6.4%
2010	368,453,232	367,142,247	0.4%
2011	379,222,059	368,946,265	2.7%
2012	377,856,480	366,642,098	3.0%
2013	359,953,516	362,083,359	0.6%

Mean Absolute Percentage Error (Annual)	**2.3%**
Mean Absolute Percentage Error (Monthly)	**3.6%**

Table 3.7

GS > 50

Year	Actual kWh	Normalized kWh	% Change
2005	408,742,729	401,923,941	
2006	402,804,822	395,062,822	-1.7%
2007	397,763,768	395,564,965	0.1%
2008	380,372,511	394,136,984	-0.4%
2009	341,075,319	364,830,822	-7.4%
2010	360,896,551	358,637,666	-1.7%
2011	370,522,725	359,852,275	0.3%
2012	370,402,101	359,301,450	-0.2%
2013	358,315,518	360,346,016	0.3%
2014		360,814,548	0.1%
2015		361,682,793	0.2%

Table 3.8

Large Use

Year	Actual kWh	Normalized kWh	% Change
2005		0	
2006		0	
2007		0	
2008		0	
2009		0	
2010		0	
2011	2,464,261	2,393,294	
2012	18,846,858	18,282,033	
2013	21,975,629	22,100,160	20.9%
2014		22,128,896	0.1%
2015		22,182,145	0.2%

Table 3.9

GS > 50

Year	Actual kW	kW/kWh	Normalized kW	% Change
2005	964,785	0.00236	948,690	
2006	985,468	0.00245	966,527	1.9%

2007	996,918	0.00251	991,407	2.6%
2008	981,947	0.00258	1,017,481	2.6%
2009	938,301	0.00275	1,003,652	-1.4%
2010	922,410	0.00256	916,637	-8.7%
2011	948,363	0.00256	921,051	0.5%
2012	959,778	0.00259	931,015	1.1%
2013	935,277	0.00261	940,577	1.0%
2014			941,800	0.1%
2015			944,066	0.2%

Table 3.10

		Large Use		
Year	Actual kW	kW/kWh	Normalized kW	% Change
2005				
2006				
2007				
2008				
2009				
2010				
2011	3,992	0.00162	3,877	
2012	31,447	0.00167	30,505	
2013	34,026	0.00155	34,219	12.2%
2014			34,263	0.1%
2015			34,346	0.2%

c) Please see the attached model, and tables below:

Table 3.1

Model 1: OLS, using observations 2005:01-2013:12 (T = 108)
Dependent variable: Interval

	Coefficient	*Std. Error*	*t-ratio*	*p-value*	
const	-9.44187e+06	8.34953e+06	-1.1308	0.26086	
LondonHDD	3181.02	1071.35	2.9692	0.00375	***
LondonCDD	18315	7451.32	2.4580	0.01571	**
LONFTE	115187	24517.2	4.6982	<0.00001	***

PeakDays	811460	149507	5.4276	<0.00001	***
Month_Days	-201632	198724	-1.0146	0.31276	
Spring	1.28222e+06	490006	2.6167	0.01027	**
Fall	952606	500526	1.9032	0.05992	*
trend	-305537	74807.7	-4.0843	0.00009	***

R-squared	0.605204	Adjusted R-squared	0.573301
F(8, 99)	18.97028	P-value(F)	5.50e-17
Theil's U	0.69401	Durbin-Watson	1.153738

Table 3.2

Annual Predicted vs. Actual Interval

	Interval	Predicted Value	Absolute % Error
2005	415,128,037	409,931,191	1.3%
2006	409,556,912	399,640,940	2.4%
2007	404,758,925	402,873,249	0.5%
2008	385,087,341	399,078,008	3.6%
2009	344,781,983	366,297,578	6.2%
2010	368,453,232	367,021,727	0.4%
2011	379,222,059	369,214,824	2.6%
2012	377,856,480	367,240,589	2.8%
2013	359,953,516	363,097,116	0.9%
		Mean Absolute Percentage Error (Annual)	**2.3%**
		Mean Absolute Percentage Error (Monthly)	**3.7%**

Table 3.7

GS > 50

Year	Actual kWh	Normalized kWh	% Change
2005	408,742,729	400,947,465	
2006	402,804,822	394,240,656	-1.7%
2007	397,763,768	395,394,768	0.3%
2008	380,372,511	394,534,351	-0.2%
2009	341,075,319	364,304,766	-7.7%
2010	360,896,551	358,451,162	-1.6%
2011	370,522,725	360,074,148	0.5%
2012	370,402,101	359,853,595	-0.1%
2013	358,315,518	361,356,964	0.4%
2014		362,314,245	0.3%
2015		363,690,411	0.4%

Table 3.8

		Large Use	
Year	Actual kWh	Normalized kWh	% Change
2005		0	
2006		0	
2007		0	
2008		0	
2009		0	
2010		0	
2011	2,464,261	2,394,770	
2012	18,846,858	18,310,127	
2013	21,975,629	22,162,162	21.0%
2014		22,220,873	0.3%
2015		22,305,273	0.4%

Table 3.9

		GS > 50		
Year	Actual kW	kW/kWh	Normalized kW	% Change
2005	964,785	0.00236	946,385	
2006	985,468	0.00245	964,516	1.9%
2007	996,918	0.00251	990,981	2.7%
2008	981,947	0.00258	1,018,507	2.8%
2009	938,301	0.00275	1,002,205	-1.6%
2010	922,410	0.00256	916,160	-8.6%
2011	948,363	0.00256	921,619	0.6%
2012	959,778	0.00259	932,445	1.2%
2013	935,277	0.00261	943,216	1.2%
2014			945,714	0.3%
2015			949,307	0.4%

Table 3.10

		Large Use		
Year	Actual kW	kW/kWh	Normalized kW	% Change
2005				
2006				
2007				

2008				
2009				
2010				
2011	3,992	0.00162	3,879	
2012	31,447	0.00167	30,551	
2013	34,026	0.00155	34,315	12.3%
2014			34,406	0.3%
2015			34,536	0.4%

79. 3. ENERGY PROBE 18

Ref: Exhibit 3, Tab 1, Schedule 1, Attachment 1

Please provide a table that shows the historical share of interval kWh for each of the rate classes (page 2 of Schedule 3).

b) Please explain why the sum of the GS<50 and Large Use classes in Tables 3.7 and 3.8 is less than that shown in Table 3.6 for 2005 through 2011, but higher in 2012 and 2013 and higher for the forecasts shown for 2014 and 2015.

c) Please provide the most recent year-to-date figures for 2014 associated with kW's for each of the GS>50 and Large User classes, along with the corresponding figures for the same period in 2013.

Response:

a) The excel file showing the historical share of interval kWh is filed in Festival's 2015 COS web drawer named Festival_2015 COS_3 EP -18_20140827

b) The GS > 50 data in table in 3.7 contains the data for both G.S. > 50kW interval customers and G.S> 50 kW demand metered customers.

c) kW billed for first 6 months of year (2014-0.5% decrease from 2013):

	2013	**2014**
G.S. > 50 kW	457,747	454,032
Large Use	17,207	18,471
Total	474,954 kW	472,503 kW

80. 3. ENERGY PROBE 19

Ref: Exhibit 3, Tab 1, Schedule 1, Attachment 1

a) Please update all the tables in Schedule 5 if the 2013 OPA final report is now available.

b) How has the incremental 1,500,000 of kWh reductions forecast for 2015 been determined?

Response:

a) The draft final report is available but the OPA's final report will not be available until September 1, 2014. As noted under 9 Staff 67, Festival will update based on the final report by no later than September 30, 2014.

b) At the time Festival's COS application was filed, there was uncertainty as to the nature of post 2014 CDM programs and the related targets. The expectation was there would be some form of continuation into 2015, so the numbers entered were an estimate of that extension. The 1,500,000 was an estimate at that time. Since our original filing, the OPA has established new programs for the 2015 to 2020 time period with specific kWh only targets to be met. Festival recently received its targets, which are almost double the existing target at 36.5 GWh over the 5 year period. Festival has updated its 2015 CDM impact in the load forecast to reflect what it realistically feels it can achieve in the 2015 year. Since the program is a 5 year program, that works to an average of 16.6% to be achieved each year. According to the OPA's LDCs toolkit, a minimum of 8.3% must be met in each year. Festival expects it can achieve the midpoint of these two ranges in the first year, that being 12.45% of the 36.5 GWh target which equals 4,544,250. At a half year value, the amount is 2,272,125 kWh. The load forecast has been updated to reflect these greater impacts, as noted below:

3 EP 19							
Adjustments to kWh for CDM Impact:							
Original CDM Forecast:							
			Est 2015				
	2013Programs						
	2014		324,574				
	2015 Est		750,000	(.5 * 1,500,000)			
	Total		1,074,574	**Weather Norm**	**Weather Norm**	**Revised**	**Weather Norm**
				2015 before CDM	**2015 after CDM**	**CDM**	**15 after revised CDM**
	Allocated as:						
	Residential		247,905	137,393,847	137,145,942	438,533	136,955,314
	Res Hensall		6,787	3,761,644	3,754,857	11,244	3,750,400
	G.S. <50 kW		116,011	64,295,632	64,179,621	257,858	64,037,774
	G.S. >50 kW		654,047	362,486,529	361,832,482	1,453,753	361,032,776
	Large Use		40,113	22,231,439	22,191,326	89,159	22,142,280
	Streetlights		8,241	4,567,584	4,559,343	18,318	4,549,266
	Sentinel Lights		271	150,427	150,156	603	149,824
	USL		1,195	662,162	660,967	2,656	659,506
			1,074,570	595,549,264	594,474,694	2,272,125	593,277,139
					453,573,895		593,277,139
	New OPA Targets:						1,197,555
	2015 to 2020 Budget		kWh	36,500,000			
	Minimum per year		8.30%	3,029,500			
	5 year avge		16.67%	6,083,455			
	Mid point		12.45%	4,544,250			
	Half year rule			2,272,125			
	Allocated target FOR 2015:						
	Residential		1,084	19.8%	449,778		
	NonRes		4,392	80.2%	1,822,347		
			5,476	100.0%	2,272,125		
Adjustments to kW for CDM Impact:							
				kW	**kW**	**kW**	**kW**
				Weather Norm	**Weather Norm**	**Revised**	**Weather Norm**
				2015 before CDM	**2015 after CDM**	**CDM**	**15 after revised CDM**
	Allocated as:						
	Residential						
	Res Hensall						
	G.S. <50 kW						
	G.S. >50 kW		946,164	1,707	944,457	3,609	942,555
	Large Use		34,422	62	34,360	131	34,291
	Streetlights		12,017	22	11,995	47	11,970
	Sentinel Lights		356	1	355	2	354
	USL		0	0	0	0	0
			992,959	1,792	991,167	3,789	989,170
		kWh	kW				
Original CDM		1,074,570	1,792				
Revised CDM		2,272,125	3,789	2.11			

81. 3. ENERGY PROBE 20

Ref: Exhibit 3, Tab 3, Schedule 1, Attachment 1

a) Please provide the most recent year-to-date figures available for 2014 in the same level of detail as found in Appendix 2-H, along with the figures for the corresponding period in 2013.

b) Please provide the interest and dividend income excluding interest on variance accounts for 2010 through 2015.

c) Where is the revenue associated with the MicroFIT charge shown in Appendix 2-H? Please provide the actual and forecasted number of MicroFIT customers for 2010 through 2015.

Response:

a) Updated appendix 2 – H comparing 6 months June 30, 2014 to June 30, 2013 is noted below.

Other Operating Revenue for six months 2014 & 2013						
USoA #	**USoA Description**	**2013 Actual[2]**	**Bridge Year[3]**	**Test Year**	**2014**	**2013**
		2013	**2014**	**2015**	**Six months to Jun 30th**	**Six months to Jun 30th**
	Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**CGAAP**	**CGAAP**
4235	**Specific Service Charges**	$ 128,869	$ 130,870	$ 132,833	$ 57,465	$ 59,265
4225	**Late Payment Charges**	$ 109,466	$ 116,345	$ 118,090	$ 69,719	$ 52,229
4082	**Retail Services Revenues**	$ 25,380	$ 23,280	$ 21,280	$ 11,996	$ 13,056
4084	**Retail Services Revenues**	$ 296	$ 296	$ 296	$ 146	$ 149
4086	SSS Admin Fee	$ 54,005	$ 55,505	$ 57,005	$ 27,415	$ 26,885
4210	Rent from Elec Property	$ 193,826	$ 196,733	$ 189,160	$ 95,357	$ 110,769
4220	Other Electric Revenue	$ 6,188	$ 9,237	$ 9,375	$ 1,190	$ 2,674
4324	Special Purpose Charge	$ -	$ -	$ -	$ -	$ -
4355	Gain on Disposal of Elec	$ 3,210	$ 3,210	$ 3,210	$ 4,500	$ -
4360	Loss on Disposal Elec	$ -	-$ 60,000	$ -	$ -	$ -
4367	Gain on Retirement of Elec			$ 52,000	$ -	$ -
4375	Revenue Non-Electric	$ 761,227	$ 789,300	$ 777,533	$ 388,034	$ 374,595
4380	Expenses Non-Electric	-$ 612,589	-$ 649,828	-$ 646,381	-$ 295,298	-$ 297,812
4390	Misc Non-operating Income	$ 29,891	$ 55,339	$ 1,000	$ 30,150	$ 24,857
4405	Interest and Div Income	$ 100,366	$ 293,275	$ 75,534	$ 122,110	$ 37,767
4305	Reg Debits - Depn & Alloc	-$ 696,846	-$ 737,851		-$ 401,184	-$ 368,926
4335	Pension Actuarial gains/loss	$ 91,659	$ -	$ -	$ -	$ -
	Total	$ 194,948	$ 225,711	$ 790,936	$ 111,600	$ 35,509
4405	Interest on Variance Accounts:					
	Other Interest				$ 118,282	$ 14,197
	Total interest income				$ 3,828	$ 23,570
	Total				$ 122,110	$ 37,767

b) Interest and dividend income excluding variance accounts: Actual and 2014/15 projected amounts: Interest and Dividend excluding variance accounts

2010- $ 48,176
2011- $51,672
2012- $52,340
2013- $51,918
2014- $46,402 Bridge
2015- $58,423 Test

c) MicroFIT charges are recorded in Acct # 4235 Specific Service charges ($5.25/$5.40). Actual and 2014/15 projected fees and numbers:

Fees		Customers (as at Dec 31st)
2010-	$ 148	10
2011-	$1,178	28
2012-	$1,923	34

2013-	$2,232	39
2014-	$2,319 Bridge	41
2015-	$2,353 Test	42

82. 3. ENERBY PROBE 21

Ref: Exhibit 3, Tab 3, Schedule 1, Attachment 1

a) Please provide a version of the table for account 4375/4380 that excludes both OPA incentives and solar generation (net).

b) Please explain how the 2015 forecast for streetlight capital work & maintenance was derived and why it is less than the 2014 forecast.

c) Please explain the reduction in the forecast for 2015 for affiliate management fees.

d) What are the costs associated with providing the affiliate management services? Are these costs included in OM&A?

Response:

a)

3 EP 21

Accounts 4375/4380 net of OPA and Solar

Account 4375 - Revenues Non-Electric

	2010 Approved	2010 Actual	2011 Actual	2012 Actual²	2013 Actual²	2014 Bridge Year³	2015 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**
Water and Sewage Bi		$ 409,014	$ 410,721	$ 420,015	$ 437,209	$ 442,674	$ 448,207
Streetlight Capital Work & Maintenan		$ 204,198	$ 203,586	$ 266,662	$ 231,645	$ 264,500	$ 258,400
Affiliate Management Fees		$ 32,793	$ 41,711	$ 75,032	$ 74,247	$ 64,000	$ 52,800
Solar Generation (net)	$ -	$ -	$ 24,107	$ 24,970	$ 18,126	$ 18,126	$ 18,126
OPA incentives		$ 44,072	$ 19,569	$ 176,389	$ -	$ -	$ -
Total	$ 696,328	$ 690,077	$ 699,694	$ 963,068	$ 761,227	$ 789,300	$ 777,533
With OPA incentives and Solar removed	$ 696,328	$ 646,005	$ 656,018	$ 761,709	$ 743,101	$ 771,174	$ 759,407

Account 4380 - Expenses Non-Electric

	2010 Approved	2010 Actual	2011 Actual	2012 Actual²	2013 Actual²	2014 Bridge Year³	2015 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**
Water and Sewage Bi		-$ 327,776	-$ 366,161	-$ 367,909	-$ 405,142	-$ 407,168	-$ 409,317
Streetlight Capital Work & Maintenan		-$ 195,389	-$ 192,017	-$ 249,735	-$ 207,447	-$ 242,661	-$ 237,064
Total	-$ 631,478	-$ 523,165	-$ 558,178	-$ 617,644	-$ 612,589	-$ 649,828	-$ 646,381

Account 437/4380 - Net Revenues Non-Electric

	2010 Approved	2010 Actual	2011 Actual	2012 Actual²	2013 Actual²	2014 Bridge Year³	2015 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**
Water and Sewage Bi		$ 81,238	$ 44,560	$ 52,106	$ 32,067	$ 35,506	$ 38,891
Streetlight Capital Work & Maintenan		$ 8,809	$ 11,569	$ 16,927	$ 24,198	$ 21,839	$ 21,336
Affiliate Management Fees		$ 32,793	$ 41,711	$ 75,032	$ 74,247	$ 64,000	$ 52,800
Solar Generation (net)	$ -	$ -	$ 24,107	$ 24,970	$ 18,126	$ 18,126	$ 18,126
OPA incentives		$ 44,072	$ 19,569	$ 176,389	$ -	$ -	$ -
Total	$ 64,850	$ 166,912	$ 141,516	$ 345,424	$ 148,638	$ 139,472	$ 131,153
With OPA incentives and Solar removed	$ 64,850	$ 122,840	$ 121,947	$ 169,035	$ 148,638	$ 139,472	$ 131,153

b) The streetlight capital and maintenance is based on streetlight planning meetings held with the City of Stratford's engineering department. In 2014 there are a number of new streetlights planned for an area in Stratford. There is projected to be less capital (i.e. new streetlights added) in 2015 as existing subdivisions under development already have streetlights in place. For the small towns where Festival Hydro does capital and maintenance, there is expected to be no new capital in 2014 or 2015 and status quo on maintenance. On street lighting Festival applies a mark up equal to the Board approved ROE (currently 9.85%).

c) FHSI is planning to bring on more resources requiring less commitment by Festival Hydro management.

d) The costs represent labour and overhead for services provided to FHSI for management service, accounting and other administrative services. These costs are part of Festival's OM& A.

83. 3. ENERGY PROBE 22

Ref: Exhibit 3, Tab 3, Schedule 2

Please explain why Festival is using the load-weighted price for RPP consumers ($28.70 per MWh) in the calculation of the price for non-RPP consumers rather than the forecast wholesale electricity price of $26.28 per MWh.

Response:

The wrong figure was picked up. Festival has reduced the commodity pricing in the model for 2014 and 2015 and has updated the working capital allowance, the RRWF, and the cost allocation model accordingly.

84. 3.0 –VECC – 9

Reference: E3/T1/S1/pg.1&2 E3/T1/S2, Attachment 1/S2, pg.1

a) Please provide a schedule that sets out the derivation of the Monthly Wholesale kWh values in Table 2.1 by source (i.e. IESO, Hydro One and MicroFIT/FIT).

b) With respect to Attachment 1, Schedule 2, page 1, please clarify the derivation the NSLS kWh values:

- *Lines 3-6 suggest that they represent wholesale meter deliveries less large commercial customer interval meter customer data*
- *Table 2.1 suggests that they represent wholesale meter deliveries less Interval meter and Street Lighting data*
- *E3/T1/S2, page 2 suggests that they represent the load for Residential, GS<50 and USL (i.e., wholesale deliveries less large commercial interval data {GS>50 & Large Use}, Street Lighting and Sentinel Lighting data)*

c) If the derivation of the NSLS kWh is not based on the approach set out in the third bullet, please explain why the derivation approach used is appropriate.

d) With respect to Attachment 1, please explain why the values shown in Table 2.1 for Interval plus Street Light kWh are less than the values shown in Table 3.7 for just the GS>50 class.

Response:

a) Enclosed is provided an excel spreadsheet with the Monthly wholesale kWh values by source. There are three sources: IESO, MIcroFIT/FIT and the net value of Hydro One long term load transfers.

b) The NSLS load is equal to the total load less the load used by interval customers less the streetlight load. The NSLS load is made up of residential customers, G.S< 50 kW , G.S. > 50 kW not on interval meters, USL and sentinel lights.

c) The approach taken of splitting our total purchased wholesale load into three components is based on the information from our settlement software. The splitting of the load into more logical segments was done to improve the outcome of the forecast. For example, the interval customers' usage patterns may differ from that of NSLS as it reflects the impact of the economy to a great extent than the NSLS load which is more driven by weather.

d) The G.S. > 50 kW data in table 3.7 contains the data for both G.S> > 50 kW interval customers and G.S > 50 kW customers on demand meters.

85. 3.0 – VECC -10

Reference: E3/T1/S1, Attachment 1, Table 2.8, 2.9, 2.10 and 2.11 E3/T2/S1, page 7

a) Please explain why the 2015 kWh values for Residential-Festival, Residential-Hensall, GS<50 and USL in Tables 2.8 through 2.11 differ from those set out in E3/T2/S1. Page 7.

Response:

The 2015 values reflect the offset of the 2015 CDM Load forecast adjustment which is provided in the E3/S5 Elenchus Report on Page 4.

86. 3.0 – VECC – 11

Reference: E3/T1/S1, Attachment 1, Table 3.7, 3.8 and Table 4.1 E3/T2/S1, page 7

a) Please explain why the historical kWh values for GS>50 shown in Table 3.7 differ from those set out in E3/T2/S1, page 7.

b) Please explain why the 2015 kWh value for GS>50 in Table 3.7 differs from that set out in E3/T2/S1, Page 7.

c) Please explain why the historical kWh values for Large Use shown in Table 3.8 differ from those set out in E3/T2/S1, page 7.

d) Please explain why the 2015 kWh value for Large Use set out in Table 3.18 differs from that shown in E3/T2/S1, page 7.

e) Please explain why the historical kWh values for Sentinel and Street Lights shown in Table 4.1 differ from those set out in E3/T2/S1, page 7.

f) Please explain why the 2015 kWh values for Street and Sentinel Lights shown in Table 4.1 differ from the values shown in E3/T2/S1, page 7.

Response:

a) E3/T2/S1, page 7 shows the kWh sales by rate class for each of the years as reported to the OEB in our RRR filing. For load forecast purposes, the historic kWh for two customers who were Large Use at time of 2010 COS and reclassified to G.S. > 50 kW class in 2010 and 2011 has been reclassified to be included in the G.S. > 50 KW data for all years so that the 2014 and 2015 forecasts reflect as if these customers were within the G.S. > 50 class the entire period. The addition of the kWh quantities on Tables 3.7 and 3.8 add up to the G.S> 50 kW and Large Use quantities as shown on E3/T2/S1. This is further described in the report on Schedule 3 Page 1 of 10.

b) The 2015 forecasted kWh value for GS > 50 kW on E3/T2/S1, page 7 is after adjusting for the impact of CDM as found at Table 5.4.

c) As described in a) above, For load forecasting purposes on Table 3.8, Festival currently has only one large use customer who was connected to the electrical system in 2011. For forecasting purposes we included only the historical data for that one customer.

d) The 2015 forecasted kWh value for Large Use on E3/T2/S1, page 7 is after adjusting for the impact of CDM as found at Table 5.4.

e) I have went back and checked the streetlight and sentinel light kWh data from 2007 to 2014 from Table 4.1 to E3/T2/S1, page 7 and the numbers are in agreement.

f) The 2015 forecasted kWh values for Street lighting and Sentinel lights on E3/T2/S1, page 7 are after adjusting for the impact of CDM as found at Table 5.4.

87. 3.0 –VECC - 12

Reference: E3/T1/S1, Attachment 1, Table 3.9, 3.10 and Table 4.2 E3/T2/S1, page 13

a) Please explain why the historical kW values for GS>50 shown in Table 3.9 differ from those set out in E3/T2/S1, page 13.

b) Please explain why the 2015 kW value for GS>50 in Table 3.9 differs from those set out in E3/T2/S1. Page 13.

c) Please explain why the historical kW values for Large Use shown in Table 3.10 differ from those set out in E3/T2/S1, page 13.

d) Please explain why the 2015 kW value for Large Use set out in Table 3.10 differs from that shown in E3/T2/S1, page 13

e) Please explain why the historical kW values for Sentinel and Street Lights shown in Table 4.2 differ from those set out in E3/T2/S1, page 7.

f) Please explain why the 2015 kW value for Street Light set out in Table 4.2 differs from that shown in E3/T2/S1, page 13

Response:

a) E3/T2/S1, page 13 shows the kW sales by rate class for each of the years as reported to the OEB in our RRR filing. For load forecast purposes, the historic kW for two customers who were Large Use at time of 2010 COS and reclassified to G.S. > 50 kW class in 2011 has been reclassified to be included in the G.S. > 50 KW data for all years so that the 2014 and 2015 forecasts reflect as if these customers were within the G.S. > 50 class the entire period. The addition of the kW quantities on Tables 3.9 and 3.10 add up to the G.S> > 50 kW and Large Use quantities as shown on E3/T2/S1 page 13.

b) The 2015 forecasted kWh value for GS > 50 kW on E3/T2/S1, page 13 is after adjusting for the impact of CDM as found at Table 5.5.

c) As described in a) above, for load forecasting purposes on Table 3.10, Festival currently has only one large use customer who connected to the electrical system in 2011. For forecasting purposes we included only the historical kW data for that one customer.

d) The 2015 forecasted kWh value for Large Use on E3/T2/S1, page 13 is after adjusting for the impact of CDM as found at Table 5.5.

e) I have went back and checked the streetlight and sentinel light kW data from 2007 to 2014 from Table 4.1 to E3/T2/S1, page 13 and the numbers are in agreement.

f) The 2015 forecasted kW values for Street lighting and Sentinel lights on E3/T2/S1, page 13 are after adjusting for the impact of CDM as found at Table 5.5.

88. 3.0 –VECC - 13

Reference: E3/T1/S1, Attachment 1, Schedule 2, pg.3

a) To what factors does Festival (and/or Elenchus) attribute the negative coefficient derived for the Trend Variable?

b) Is it possible that CDM is contributing to the negative value?

c) If so, does continuing to increase this variable through 2014 and 2015 as well as making a manual adjustment for CDM potentially double-count the impact of CDM? If not, why not?

d) Please re-estimate the equation without the Trend Variable, provide the results similar to Table 2.2 and provide the forecast NSLS values for 2014 and 2015 using the results (prior to any CDM adjustment).

Response

a) This trend is observed over the entire period from 2005 to 2013 and therefore pre-dates the OPA conservation targets. The cause of this reduction is not apparent to Festival, but it could be for many reasons. It could be due to natural conservation, or due to changes in economic activity or demographics.

b) It is possible that CDM has contributed to the negative value in recent years.

c) Given the durability of the trend, and the existence prior to the current OPA targets, it is likely that factors other than CDM are largely responsible for the decreasing energy.

d) Please see the model below:

Model 1: OLS, using observations 2005:01-2013:12 (T = 108)
Dependent variable: NSLS

	Coefficient	*Std. Error*	*t-ratio*	*p-value*	
const	-4.53773e+06	2.93358e+06	-1.5468	0.12500	
LondonHDD	11681.5	533.071	21.9137	<0.00001	***
LondonCDD	44221.1	3706.36	11.9311	<0.00001	***
LONFTE	68825	9430.46	7.2982	<0.00001	***
PeakDays	220197	72398.2	3.0415	0.00299	***
Shoulder1	-801341	218339	-3.6702	0.00039	***

R-squared	0.900286	Adjusted R-squared	0.895398
F(5, 102)	184.1860	P-value(F)	2.10e-49
Theil's U	0.30812	Durbin-Watson	1.484381

The resulting NSLS forecast would be:

Annual Actual vs. Normalized NSLS

	NSLS	% Change	Normalized Value	% Change
2005	283,289,663		274,303,615	
2006	269,037,634	-5.0%	272,693,109	-0.6%
2007	277,453,830	3.1%	275,514,893	1.0%
2008	277,015,109	-0.2%	276,079,258	0.2%
2009	266,610,077	-3.8%	259,795,299	-5.9%
2010	261,466,185	-1.9%	260,607,434	0.3%
2011	262,568,154	0.4%	264,599,329	1.5%
2012	255,429,249	-2.7%	265,789,959	0.4%
2013	265,429,952	3.9%	265,418,304	-0.1%
2014			268,183,632	1.0%
2015			271,200,391	1.1%

89. 3.0 –VECC - 14

Reference: E3/T1/S1, Attachment 1, Schedule 2, pg.5

a) The filing guidelines require that a load forecast be provided based on 20-year trend HDD and CDD values. Please provide a 2015 forecast for both the NSLS kWh and the Interval kWh using these values and contrast with Festival's proposed forecast (prior to CDM adjustments).

Response:

a) Please see the models below based on 20-year weather normal heating degree and cooling degree days below.

The NSLS model:

Annual Actual vs. Normalized NSLS

	NSLS	% Change	Normalized Value	% Change
2005	283,289,663		277,265,264	
2006	269,037,634	-5.0%	275,003,819	-0.8%
2007	277,453,830	3.1%	276,258,016	0.5%
2008	277,015,109	-0.2%	275,700,394	-0.2%
2009	266,610,077	-3.8%	261,900,244	-5.0%
2010	261,466,185	-1.9%	261,536,727	-0.1%
2011	262,568,154	0.4%	263,620,948	0.8%
2012	255,429,249	-2.7%	263,597,278	0.0%
2013	265,429,952	3.9%	262,306,364	-0.5%
2014			263,473,005	0.4%
2015			264,836,620	0.5%

The Interval Model:

Annual Actual vs. Normalized Interval

	Interval	% Change	Normalized Value	% Change
2005	415,128,037		407,534,999	
2006	409,556,912	-1.3%	402,347,203	-1.3%
2007	404,758,925	-1.2%	403,284,378	0.2%
2008	385,087,341	-4.9%	400,497,537	-0.7%
2009	344,781,983	-10.5%	367,955,504	-8.1%
2010	368,453,232	6.9%	365,929,994	-0.6%
2011	379,222,059	2.9%	367,715,558	0.5%
2012	377,856,480	-0.4%	366,523,581	-0.3%
2013	359,953,516	-4.7%	362,952,863	-1.0%
2014			363,476,864	0.1%
2015			364,329,062	0.2%

90. 3.0 –VECC - 15

Reference: E3/T1/S1, Attachment 1, Schedule 2, pg.7-8

a) Please re-do the forecast for 2015 set out in Tables 2.8 through 2.11 using the average shares for each class over the 2005-2013 period.

Response:

a) Please see the following tables:

Table 2.8 (restated)

Residential - Festival

Year	Actual kWh	Share	Normalized kWh	% Change
2005	143,411,804	0.50624	140,223,511	
2006	138,207,589	0.51371	141,131,922	0.6%
2007	139,603,876	0.50316	138,864,515	-1.6%
2008	136,970,688	0.49445	136,185,332	-1.9%
2009	135,328,095	0.50759	132,798,553	-2.5%
2010	137,431,624	0.52562	137,324,882	3.4%

2011	137,110,454	0.52219	137,517,330	0.1%
2012	135,123,779	0.52901	139,299,974	1.3%
2013	137,844,076	0.51932	136,079,825	-2.3%
2014		0.51348	135,146,704	-0.7%
2015		0.51348	135,846,888	0.5%

Table 2.9 (restated)

Residential - Hensall

Year	Actual kWh	Share	Normalized kWh	% Change
2005	4,255,224	0.01502	4,160,623	
2006	3,852,878	0.01432	3,934,401	-5.4%
2007	4,054,439	0.01461	4,032,966	2.5%
2008	4,016,517	0.01450	3,993,487	-1.0%
2009	3,926,619	0.01473	3,853,223	-3.5%
2010	3,885,021	0.01486	3,882,004	0.7%
2011	3,814,545	0.01453	3,825,865	-1.4%
2012	3,709,946	0.01452	3,824,607	0.0%
2013	3,773,971	0.01422	3,725,668	-2.6%
2014		0.01459	3,840,110	3.1%
2015		0.01459	3,860,006	0.5%

Table 2.10 (restated)

GS < 50

Year	Actual kWh	Share	Normalized kWh	% Change
2005	71,281,495	0.25162	69,696,784	
2006	68,326,693	0.25397	69,772,417	0.1%
2007	69,632,805	0.25097	69,264,020	-0.7%
2008	67,284,782	0.24289	66,898,988	-3.4%
2009	64,699,032	0.24267	63,489,683	-5.1%
2010	65,179,456	0.24928	65,128,832	2.6%
2011	63,567,429	0.24210	63,756,066	-2.1%
2012	62,255,637	0.24373	64,179,737	0.7%
2013	64,506,324	0.24303	63,680,715	-0.8%
2014		0.24670	64,930,172	2.0%
2015		0.24670	65,266,570	0.5%

Table 2.11 (restated)

USL

Year	Actual kWh	Share	Normalized kWh	% Change
2005	914,396	0.00323	894,067	
2006	776,820	0.00289	793,257	-11.3%
2007	732,005	0.00264	728,128	-8.2%
2008	681,719	0.00246	677,810	-6.9%
2009	663,570	0.00249	651,167	-3.9%
2010	673,251	0.00257	672,728	3.3%
2011	666,441	0.00254	668,419	-0.6%
2012	667,380	0.00261	688,006	2.9%
2013	664,332	0.00250	655,829	-4.7%
2014		0.00266	699,877	6.7%
2015		0.00266	703,504	0.5%

91. 3.0 –VECC - 16

Reference: E3/T2/S1, pg.15

a) Are the customer counts for each class year-end or average annual values?

b) Please provide a schedule that sets out the customer count for each of the four classes as of June 30, 2013 and June 30, 2014.

Response:

a) Customer counts are based on average annual values.

b) Customer counts as at June 30, 2013 and June 30, 2104 are as follows:

Rate Class	Jun 30, 2013	Jun 30, 2014	Increase	2014 Avge used in Forecast
Residential (all)	17,854	17,987	133	18,050
G.S < 50 KW	2,028	2,030	2	2,025
G.S> > 50 kW	222	221	-1	225
Large Use	1	1	0	1

Based on the June 2013 to June 2014 results, Residential with an increase of 133 customers over the past year falls behind our predicted increase of 172 for 2014. G.S. < 50 kW customer counts are 5 customers ahead of the 2014 average forecasted. G.S.> 50kW has in fact seen a reduction of one customer, 4 behind our 2014 Average forecast.

92. 3.0 –VECC - 17

Reference: E3/T1/S1, Attachment 1, Schedule 3, pg.2-3

a) Please confirm that the coefficient for the "Recession" variable is not statistically significant.
b) Please re-estimate the equation without the Recession variable or the WorkDay variable, provide the results similar to Table 3.1 and provide the forecast Interval kWh for 2014 and 2015 using the results (prior to any CDM adjustment).
c) Please re-estimate the equation without the Recession variable, the Trend variable or the WorkDay variable, provide the results similar to Table 3.1 and provide the forecast NSLS Interval values for 2014 and 2015 using these results (prior to any CDM adjustment).

Response:

a) Confirmed, the coefficient for the Recession variable is not statistically significant.

b) Please see the response to Staff-29 for the updated Interval model without the Recession and WorkDay variables. Please see below for the revised kWh forecast.

Annual Actual vs. Normalized Interval

	Interval	% Change	Normalized Value	% Change
2005	415,128,037		408,209,786	
2006	409,556,912	-1.3%	401,616,490	-1.6%
2007	404,758,925	-1.2%	402,246,062	0.2%
2008	385,087,341	-4.9%	398,989,820	-0.8%
2009	344,781,983	-10.5%	369,459,936	-7.4%
2010	368,453,232	6.9%	366,583,864	-0.8%
2011	379,222,059	2.9%	368,164,613	0.4%
2012	377,856,480	-0.4%	366,291,395	-0.5%
2013	359,953,516	-4.7%	361,598,952	-1.3%
2014			361,719,798	0.0%
2015			362,226,433	0.1%

c) Please see below for the requested Interval model:

Model 2: OLS, using observations 2005:01-2013:12 (T = 108)
Dependent variable: Interval

	Coefficient	*Std. Error*	*t-ratio*	*p-value*	
const	-3.0203e+07	6.22185e+06	-4.8543	<0.00001	***
LondonHDD	4055.79	1130.59	3.5873	0.00051	***
LondonCDD	16305.2	7860.85	2.0742	0.04058	**

LONFTE	167066	20001.1	8.3528	<0.00001	***
PeakDays	777956	153550	5.0665	<0.00001	***
Shoulder1	1.1862e+06	463078	2.5616	0.01188	**

Mean dependent var	31896282	S.D. dependent var	2414677
Sum squared resid	2.97e+14	S.E. of regression	1707600
R-squared	0.523272	Adjusted R-squared	0.499903
F(5, 102)	22.39173	P-value(F)	4.31e-15
Log-likelihood	-1700.024	Akaike criterion	3412.047
Schwarz criterion	3428.140	Hannan-Quinn	3418.572
rho	0.528969	Durbin-Watson	0.906764

Please see below for the resulting Normalized Interval Forecast.

Annual Actual vs. Normalized Interval

	Interval	% Change	Normalized Value	% Change
2005	415,128,037		397,126,503	
2006	409,556,912	-1.3%	393,217,161	-1.0%
2007	404,758,925	-1.2%	400,310,207	1.8%
2008	385,087,341	-4.9%	401,680,148	0.3%
2009	344,781,983	-10.5%	361,909,016	-9.9%
2010	368,453,232	6.9%	363,880,394	0.5%
2011	379,222,059	2.9%	373,326,869	2.6%
2012	377,856,480	-0.4%	376,460,454	0.8%
2013	359,953,516	-4.7%	375,558,298	-0.2%
2014			382,270,855	1.8%
2015			389,593,738	1.9%

93. 3.0 –VECC -18

Reference: E3/T1/S1, Attachment 1, Schedule 3, pg.4-8

a) Please reconcile the total Interval kWh for the years 2005-2013 as shown in Tables 3.2 and 3.6 with the historical values for GS>50 and LU shown in Tables 3.7 and 3.8. The individual class values do not sum to the value shown for Interval overall.

b) Contrary to the text on page 7 there are no tables setting out the historic GS>50 and LU shares of the total Interval kWh. Please provide.

c) Please provide a schedule that sets out how the 2015 forecast kWh values for GS>50 and LU were derived from the 2015 Interval forecast in Table 3.6.

Response:

a) Tables 3.2 and 3.6 are based on kWh billed (metered consumption) whereas Tables 3.7 and 3.8 are based on kWh purchases. The differences represent losses.

b) Table3.7 and 3.8 break out the G.S. > 50 from the large use actual kWh. As described in the response to 3.0-VECC -9 a), only the KWh of the current Large use customer is provided separate in table 3.8. The kWh quantities related to the two large use customers at time of last COS have been included with the GS > 50 kW quantities as these 2 accounts were reclassified in 2010 and 2011.

c) Festival has submitted an excel file of the interval data which splits out the G.s> 50 kW from the on large use customer. It is in Festival's 2015 COS web drawer labelled Festival_2015_COS_3 EP 8_Interval Data_20140827.

94. 3.0 –VECC -19

Reference: E3/T1/S1, Attachment 1, Schedule 5, pg.2-5

a) Please provide any reports available from the OPA regarding Festival's 2013 CDM results.
b) Please provide a copy of the 2012 OPA Final CDM Report for Festival.
c) What is the basis for the 1,500,000 kWh of CDM forecast for 2015 from 2015 programs?

Response:

a) Attached is the draft 2013 Final OPA results. The final report won't be available until September 1, 2014. The 2013 final CDM report will be forwarded under separate cover as soon as it is received.

b) The 2012 OPA Final CDM Report can be found under E9/T3/S10 Attachment 1 of 1 (starts on page 106 to 131 of the Exhibit 9 pdf filing on the Board's website).

c) At the time Festival's COS application was filed, there was uncertainty as to the nature of post 2014 CDM programs and the related targets. The expectation was there would be some form of continuation into 2015, so the numbers entered were an estimate of that extension. The 1,500,000 kWh was an estimate at that time. Since our original filing, the OPA has established new programs for the 2015 to 2020 time period with specific kWh only targets to be met. Festival recently received its targets, which are almost double the existing target at 36.5 GWh over the 5 year period. Festival has updated its 2015 CDM impact in the load forecast to reflect what it realistically feels it can achieve in the 2015 year. Since the program is a 5 year program, that works to an average of 16.6% to be achieved each year. According to the OPA's LDCs toolkit, a minimum of 8.3% must be met in each year. Festival expects it can achieve the midpoint of these two ranges in the first year, that being 12.45% of the 36.5 GWh target which equals 4,544,250. At a half year value, the amount is 2,272,125 kWh. The load forecast has been updated to reflect these greater impacts, as noted below:

Adjustments to kWh for CDM Impact:								
Original CDM Forecast:								
			Est 2015					
	2013Programs							
	2014		324,574					
	2015 Est		750,000	(.5 * 1,500,000)				
	Total		1,074,574	**Weather Norm**	**Weather Norm**	**Revised**	**Weather Norm**	
				2015 before CDM	**2015 after CDM**	**CDM**	**15 after revised CDM**	
	Allocated as:							
	Residential		247,905	137,393,847	137,145,942	438,533	136,955,314	
	Res Hensall		6,787	3,761,644	3,754,857	11,244	3,750,400	
	G.S. <50 kW		116,011	64,295,632	64,179,621	257,858	64,037,774	
	G.S. >50 kW		654,047	362,486,529	361,832,482	1,453,753	361,032,776	
	Large Use		40,113	22,231,439	22,191,326	89,159	22,142,280	
	Streetlights		8,241	4,567,584	4,559,343	18,318	4,549,266	
	Sentinel Lights		271	150,427	150,156	603	149,824	
	USL		1,195	662,162	660,967	2,656	659,506	
			1,074,570	595,549,264	594,474,694	2,272,125	593,277,139	
					453,573,895		593,277,139	
	New OPA Targets:						1,197,555	
	2015 to 2020 Budget		kWh	36,500,000				
	Minimum per year		8.30%	3,029,500				
	5 year avge		16.67%	6,083,455				
	Mid point		12.45%	4,544,250				
	Half year rule			2,272,125				
	Allocated target FOR 2015:							
	Residential		1,084	19.8%	449,778			
	NonRes		4,392	80.2%	1,822,347			
			5,476	100.0%	2,272,125			
Adjustments to kW for CDM Impact:								
				kW	**kW**	**kW**	**kW**	
				Weather Norm	**Weather Norm**	**Revised**	**Weather Norm**	
				2015 before CDM	**2015 after CDM**	**CDM**	**15 after revised CDM**	
	Allocated as:							
	Residential							
	Res Hensall							
	G.S. <50 kW							
	G.S. >50 kW		946,164	1,707	944,457	3,609	942,555	
	Large Use		34,422	62	34,360	131	34,291	
	Streetlights		12,017	22	11,995	47	11,970	
	Sentinel Lights		356	1	355	2	354	
	USL		0	0	0	0	0	
			992,959	1,792	991,167	3,789	989,170	
		kWh	kW					
Original CDM		1,074,570	1,792					
Revised CDM		2,272,125	3,789	2.11				

95. 3.0 –VECC -20

Reference: E3/T2/S1, Attachment 1, pg.1

a) Please confirm that, contrary to the footnotes, Columns A and E represent the variable charge revenues at existing and proposed rates respectively.

Response:

a) Agreed- Columns A and E represent the variable charge revenues at existing and proposed rates, respectively.

96. 3.0 –VECC -21

Reference: E3/T3/S1/pg.6-7 E3/T3/S1, Attachment 1, Appendix 2-H

a) With respect to Water and Sewage Billing, please provide a schedule that sets out the derivation of the annual returns for 2010 through 2015 as discussed at page 6, lines 24-29.

b) With respect to Streetlight Maintenance and Capital, do the time and material charges include an allowance for cost of Festival equipment and vehicles used?

c) With respect to Solar Installations, do the revenues include the revenue from the microFIT charges discussed I E8/T9/S1? If not, where are the revenues from these charges accounted for? If yes, please explain more fully, why these revenues are excluded from the Revenue Offsets.

Response:

a) The table below shows the derivation of the annual returns related to water and sewage billings form 2010 to 2015:

Year	Revenue	Expense	Net	Mark up
2010	409,014	327,776	81,238	24.8%
2011	410,721	366,161	44,560	12.2%
2012	420,015	367,909	52,106	14.2%
2013	437,209	405,142	32,067	7.9%
2014	442,674	407,168	35,506	8.7%
2015	448,207	409,317	38,891	9.5%

b) Time and material charges includes direct labour and overhead costs , costs of materials, allowance for equipment/ transportation equipment costs plus a mark-up currently equal to the deemed ROE of 9.85% added to each bill.

c) MicroFIT charges are included in Specific Service Charges account # 4235 and treated as Revenue Offsets. The breakdown for Specific service charges # 4235 can be found on E3/T3/S1 Attachment 1 – Appendix 2-H Other Operating Revenue. The revenue charges at the standard rates of $5.40 (previously $5.25) are as follows: 2010- $148; 2011 - $1,178; 2012 - $1.923; 2013-$2,232; 2014 - $2,319; 2014- $2,353.

EXHIBIT 4 – OPERATING COSTS

97. 4. OEB STAFF 32

Ref: Appendix 2-JA and Appendix 2-JC – Summary of Recoverable OM&A Expenses

Appendix 2-JA shows a 48.1% increase in Operations and Maintenance costs over the 2010 actual, comprised of a respective increase of 60.98% and 39.66%.

a) Please provide further detail of the individual cost drivers for each of these two categories.

b) Please explain the overall increase in maintenance cost, given that Appendix 2-JC shows overhead and underground maintenance programs declining by 28% and 40% respectively since Festival Hydro 2010 actual costs.

Response:

a) A modified appendix 2-JC is attached below with details of the cost drivers included in operations and maintenance only.

Modified Appendix 2-JC for O&M Cost Drivers Only

Programs	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Draft Actuals	2014 Bridge Year	2015 Test Year
Reporting Basis							
Distribution Stations							
Labour		12,257	8,326	5,817	6,656		
Materials		4,946	4,914	1,873	2,397		
Outside Services		9,977	14,195	7,069	2,835		
Other costs		1,914	1,137	994	564		
Sub-Total	41,793	29,094	28,572	15,753	12,452	15,306	13,622
Transformer Station							
Sub-Total						0	140,000
Overhead Maintenance							
Labour		267,783	242,771	266,011	255,457		
Materials		102,435	57,597	39,346	79,595		
Outside Services		2,390	4,887	15,498	20,104		
Other costs		87,196	50,062	68,998	50,667		
Sub-Total	402,008	459,804	355,317	389,853	405,823	328,877	330,619
Tree Trimming							
Labour		51,036	100,673	70,375	53,777		
Materials		923	590	506	1,247		
Outside Services		53,003	39,950	44,800	78,252		
Other costs		12,892	21,071	18,464	9,477		
Sub-Total	170,517	117,854	162,284	134,145	142,753	159,371	162,743
Load Dispatching							
Labour		5,115	6,673	3,887	2,747		
Materials			-356	0	20		
Outside Services		715	5,808	24,679	530		
Other costs		20,132	28,567	29,405	14,782		
Sub-Total	37,575	25,962	40,692	57,971	18,079	28,207	28,681
Underground Maintenance							
Labour		195,706	143,940	174,948	108,636		
Materials		39,681	39,760	31,534	23,250		
Outside Services		11,545	11,818	10,982	14,357		
Other costs		39,776	31,210	29,183	19,648		
Sub-Total	246,702	286,708	226,728	246,647	165,891	168,426	172,078
Distribution Transformer Operation							
Labour		24,703	31,623	31,254	30,338		
Materials		7,353	16,622	7,119	9,340		
Outside Services		820	3,548	756	3,986		
Other costs		5,924	7,169	8,102	5,168		
Sub-Total	52,908	38,800	58,962	47,231	48,832	58,840	60,161
Meter Expense							
Labour		232,202	245,504	262,292	282,908		
Materials		15,369	12,705	12,890	11,029		
Outside Services		68,575	53,361	54,455	56,744		
Other costs		25,165	33,708	580,795	36,611		
Sub-Total	280,911	341,311	345,278	910,432	387,292	381,504	382,556
Customer Premises							
Labour		129,145	127,623	142,341	169,613		
Materials		3,410	2,333	3,143	2,166		
Outside Services		420	212	6,591	6,316		
Other costs		12,209	11,612	12,202	12,544		
Sub-Total	213,584	145,184	141,780	164,277	190,639	182,703	181,297
Unallocated Engineering, Operations Supervision, Trucks, Stores							
Sub-Total	0	-38,636	104,375	169,868	395,220	444,580	450,650
Training/Health & Safety							
Sub-Total	0	20,621	47,016	44,382	246,218	222,525	222,642
Total	**1,445,998**	**1,426,702**	**1,511,004**	**2,180,559**	**2,013,199**	**1,990,339**	**2,145,049**
O&M Per 2-JA	1,445,997	1,446,518	1,539,820	2,202,238	2,028,047	1,988,810	2,142,787
Difference	1	- 19,816	- 28,816	- 21,679	- 14,848	1,529	2,262

Notes: Differences are immaterial.

b) USOA GL 5130 Maintenance of Overhead Services averaged $304K in 2009 – 2012. In 2013 when new overhead capitalization policies took effect – this USOA GL increased to $636K and is projected to average this amount in 2014 and 2015. This is the result of the cost drivers identified in table 2JC for unallocated overhead costs and training expenses. Both of these drivers are now fully impacting operations and maintenance expense, but were allocated partially to capital in prior years. A large portion of the training driver identified in 2JC is coded to USOA GL 5130 and therefore this policy change impacts the maintenance total greater than it impacts the operations total.

98. 4. OEB STAFF 33

Ref: Appendix 2-JA – Benefits from OM&A Increases

Appendix 2-L shows a 21.7% increase in the OM&A cost per customer 32.9% increase in OM&A cost per FTE.

a) Please explain what measures Festival has adopted to ensure that its proposed OM&A spending is appropriate and adequately planned. What consideration was given to overall bill impacts when setting O&M program budgets?

b) Please identify what improvements in services and outcomes the applicant's customers will experience in 2014 and during the subsequent IRM term as a result of increasing the provision for OM&A in 2014.

c) How has the applicant communicated these benefits and related costs to its customers, and how did customers respond? Please provide some examples, including any customer feedback. If no communications took place, please explain why not.

Response:

Festival would note that the much of the increase in OM&A has corresponding decreases in other areas and so the 21.7% increase is not an appropriate comparison. Festival would note that costs per FTE have increased as the result of inflation and the progression of the classification of several employees through gaining experience. See also, the response to 4-Board Staff-34 and 4-Board Staff-40.

a) Festival was guided by several factors including the overall bill impact, whether costs were truly incremental or the result of shifting from rate riders to the OM&A, inflation other drivers of the OM&A factors discussed in Exhibit 4 such as compliance activities. In addition, Festival was guided by the customer feedback which identified reliability as a priority. In addition, the new Transformer Station created new OM&A costs but the benefits of the new TS have been demonstrated in the ICM proceeding and in response to interrogatories 8-SEC-21. As noted, much of the cost increase in the OM&A was related to work already being performed but being categorized differently.

b) Festival would note that customers will see improved reliability as a result of the new TS, and lower costs, the ability to expand the customer base without the installation of a new circuit from the existing TS across the City of Stratford. Festival would note the overall bill impact provides for a reduction in the total bill for many customers.

c) Festival is in constant contact with customers through meeting, billing inquiries, the customer survey and through community events. In addition, Festival has a website which customers may visit to learn more about Festival and its activities. Festival would note that customers have identified reliability as a priority in the customer survey. As noted, some of the costs were the result of activities considered in prior approvals such as the costs related to Smart Meters and the new TS. Customers would have been aware of those costs from the application, notice and decisions in such proceedings.

99. 4. OEB STAFF 34

Ref: E4/T1/S1, p. 2 – Labor Costs

On page 2, Festival Hydro notes that its Collective Agreement was in the process of being renegotiated at the time of filing this application. Festival Hydro further notes that the agreement will have an effective date of May 1, 2014.

a) Please confirm that an agreement has been reached.

b) Please provide the overall wage increase for all union and non-union employees and provide a copy of the Collective Agreement.

Response:

a) Confirmed.

b) The overall wage increase for all union and non-union employees was 2.02%. Festival declines to provide a copy of the Collective Agreement but will respond to specific questions from the Board and intervenors regarding the Collective Agreement. If so ordered by the Board, Festival will provide a copy of the Collective Agreement to the Board in confidence in accordance with the Board's Practice Direction on Confidential Filings.

100. 4. OEB STAFF 35

Ref: E4/T3/S1, Appendix 2-JC – OM&A Programs Table

Please provide an updated Appendix 2-JC by showing 2014 up-to-date costs as well as the comparable costs during the same period in the 2013 rate year.

Response:

Festival notes that compiling appendix 2JC for any time period is an extensive manual process due to system limitations. In order to provide a granular trend analysis for 2014 year to date data with 2013 comparatives for OM&A expenses – Festival has prepared the table attached below. Festival notes that the overall increase in 2014 as compared to the same time period in 2013 is 2%.

	2013 6mo Actuals	2014 6mo Actuals
3500-Distribution Expenses - Operation		
5005-Operation Supervision and Engineering	73,037	141,642
5010-Load Dispatching	8,210	13,573
5012-Station Buildings and Fixtures Expense	6,607	5,385
5015-Transformer Station Equipment - Operation Supplies and Expenses		10
5020-Overhead Distribution Lines and Feeders - Operation Labour	14,197	14,917
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	11,243	11,030
5035-Overhead Distribution Transformers- Operation	4,802	1,387
5040-Underground Distribution Lines and Feeders - Operation Labour	- 1,290	281
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	136	131
5055-Underground Distribution Transformers - Operation	13,960	3,038
5065-Meter Expense	176,350	127,485
5070-Customer Premises - Operation Labour	101,930	93,968
5075-Customer Premises - Materials and Expenses	967	2,429
5085-Miscellaneous Distribution Expense	1,279	932
5095-Overhead Distribution Lines and Feeders - Rental Paid	4,286	3,218
3500-Distribution Expenses - Operation Total	415,714	419,426
3550-Distribution Expenses - Maintenance		
5105-Maintenance Supervision and Engineering		
5110-Maintenance of Buildings and Fixtures - Distribution Stations	23	180
5120-Maintenance of Poles, Towers and Fixtures	55,875	19,272
5125-Maintenance of Overhead Conductors and Devices	129,200	87,840
5130-Maintenance of Overhead Services	345,541	305,601
5135-Overhead Distribution Lines and Feeders - Right of Way	112,612	97,863
5145-Maintenance of Underground Conduit	8,392	11,404
5150-Maintenance of Underground Conductors and Devices	36,936	63,334
5155-Maintenance of Underground Services	35,672	35,299
5160-Maintenance of Line Transformers	13,027	28,756
5175-Maintenance of Meters	29,837	41,416
3550-Distribution Expenses - Maintenance Total	767,115	690,965
3650-Billing and Collecting		
5305-Supervision	13,886	14,538
5310-Meter Reading Expense	93,231	120,779
5315-Customer Billing	282,532	289,720
5320-Collecting	112,311	99,631
5330-Collection Charges	- 23,803	- 21,870
5335-Bad Debt Expense	37,500	40,200
5340-Miscellaneous Customer Accounts Expenses	78,293	79,434
3650-Billing and Collecting Total	593,950	622,432
3700-Community Relations		
5410-Community Relations - Sundry	375	-
5420-Community Safety Program	6,626	9,242
3700-Community Relations Total	7,001	9,242
3800-Administrative and General Expenses		
5605-Executive Salaries and Expenses	133,012	167,441
5610-Management Salaries and Expenses	181,733	175,198
5615-General Administrative Salaries and Expenses	171,701	225,340
5620-Office Supplies and Expenses	78,238	85,990
5630-Outside Services Employed	21,261	44,779
5635-Property Insurance	14,639	13,147
5640-Injuries and Damages	21,284	23,916
5645-Employee Pensions and Benefits	47,862	13,415
5655-Regulatory Expenses	53,387	51,425
5665-Miscellaneous General Expenses	18,432	19,069
5675-Maintenance of General Plant	64,559	73,819
5680-Electrical Safety Authority Fees	4,814	5,246
3800-Administrative and General Expenses Total	810,922	898,785
Total OM&A	**2,594,702**	**2,640,850**

101. 4. OEB STAFF 36

Ref: E4/T3/S1, Appendix 2-JC – Tree Trimming

In its last rebasing application, Festival Hydro was approved for a tree trimming budget of $170,517. During the intervening IRM period of 4 years, Festival Hydro's actual spending has not reached this approved budget. Board staff notes that Festival Hydro is requesting an increase of 14% over 2013 actual costs of $142,753.

a) Please explain why Festival Hydro has not used its approved tree trimming budget during the IRM period. Please explain what expenditures were incurred rather than tree trimming.

b) Please explain the increase in tree trimming expenses in the 2015 test year with reference to the overall multi-year tree trimming program or strategy.

c) Please provide the actual tree trimming expenses year-to-date.

d) Please provide annual detail on the number of outages in FHI's system, by cause (e.g. by equipment failure, tree contact, etc), since its last rebasing application. Discuss any trends relevant to vegetation management spending.

Response:

a) Festival's 2010 approved budget for tree trimming was based on Festival's estimate of the need for tree trimming services within our distribution territory. Festival notes that it completes tree trimming maintenance as required and in some instances other maintenance projects may take priority and shift costs into other areas such as overhead maintenance, underground maintenance or meter maintenance.

b) Historically, tree trimming has been focused on the main feeders to ensure outages due to tree contacts with bare overhead wires is minimized and to reduce the frequency of animal (squirrel) contacts by increasing the space between the overhead feeders and tree branches. The amount spent per year fluctuates with the actual amount of trimming needed due to varying tree growth rates and the amount removed during the previous tree trimming cycle. The two ice storms in 2013 resulted in very few tree-related problems along the main feeder routes providing us with confirmation that our tree trimming program along the main feeders is effective. There was significant damage to overhead secondary services as a result of ice laden tree branches. As a result, FHI will be expanding the scope of the tree trimming program to include trees on municipal right of ways that could impact secondary services. The budget for tree trimming for the 2015 test year has been increased to account for inflation and additional trimming near secondary services.

c) Actual tree trimming costs to June 30, 2014 are $97,863.

d) The number of prolonged system outages (not including loss of supply or scheduled work) was as follows:

2009 - 76	2010 - 76	2011 - 88	2012 - 72	2013 – 91

A breakdown of outages by cause is presented in AMPCO Interrogatory #8c. It can be seen from this analysis that tree contact outages are in line with outages in the last rate rebasing.

102. 4. OEB STAFF 37

Ref: E4/T3/S1, Appendix 2-JC; E4/T3/S1, p. 4 and E2/T2/S3, Attachment 1, Appendix 2-DA – Training/Health and Safety costs

In the first two references, Festival Hydro notes an increase of approx. $180K or 418% in its Training/Health and Safety cost category. In E4/T3/S1, page 4, Festival Hydro states that this increase is the result of overhead capitalization policy changes, which specifically prohibit all training costs from being capitalized.

In Appendix 2-DA (E2/T2/S3, Attachment 1), Overhead Expense, Festival Hydro is showing "miscellaneous lineman costs including training" of $52,235.

a) Please provide a breakdown of the Training/Health and Safety Costs and explain the increase in greater detail.

b) Please reconcile the increase due to overhead capitalization with Appendix 2-DA.

c) Please provide a detailed description and the cost component of Festival Hydro's Health and Safety Costs.

Response:

a) Refer to the table below for a breakdown of balances included in appendix 2-JC training/health & safety category. Festival notes prior to 2013 – linemen overhead costs were allocated to capital and other O&M categories. In 2013 the items included in this account were determined to be non-directly attributable items and were therefore no longer to be capitalized. At that time, Festival discontinued allocating these costs to other O&M categories as well and all costs remained in this general ledger account. A further detailed breakdown of the types of costs included in linemen overhead costs is included in the second table below using 2013 actual costs as an example. Festival notes that the community safety program costs and EDA membership dues were also included in this program cost in appendix 2-JC. The EDA membership dues are not training or health and safety related and as such the program title likely should've encompassed membership dues to be more straightforward.

Summary of Appendix 2JC - Training/Health & Safety						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**
Linemen overhead costs	- 18,788	4,880	1,410	208,093	179,516	178,834
Community Safety program	9,344	10,828	11,340	6,402	10,203	10,475
General Expenses (EDA membership)	30,065	31,308	31,632	31,723	32,806	33,333
	20,621	47,016	44,382	246,218	222,525	222,642

Linemen Overhead Cost Summary - 2013	
Standby & Union Business Labour	23,494
Safety Meeting Labour	13,507
Supplies & Phone Expense for service centre	16,898
Boot/Uniform Purchases	15,351
Training Labour	40,728
Subcontractor labour to teach trainings	22,788
Travel, Hotel, Meals & training registrations	10,323
Labour overhead for benefits & supervision	59,792
Safety Equipment	5,212
	208,093

b) The costs included in linemen overhead prior to January 1, 2013 were allocated at a rate of 20% per labour dollar of linemen accumulated in capital or operations & maintenance general ledgers. The true P&L impact however is only the portion of costs that would've been allocated to capital via this overhead rate. The fact that the costs no longer follow labour dollars in other operating and maintenance accounts has no bottom line impact. As highlighted in the first table for 37a) above – in the years prior to 2013, the intention was to zero out linemen overhead costs from this account and fully allocate them to capital and OM&A accounts – and the 20% allocation/labour dollar did this leaving immaterial balances unallocated. The appendix 2DA is meant to represent the portion of this account that can no longer be capitalized only. As such – Festival cannot reconcile the change in this project cost category to appendix 2-DA – but expects that the information included above will provide sufficient detail of what makes up this project cost category included in appendix 2-JC.

c) As noted in the detail provided above, Festival incurs approximately $10K on average each year to provide a community safety program whereby representatives from our line professional team go into various classrooms throughout our distribution territory to teach children about electrical safety. The program costs include the time and supplies utilized in the program. The line crew also attend various safety meetings and courses each year and their labour as well as the cost of course registration or hiring an instructor to teach the course is incurred. These costs are as detailed in the linemen overhead cost summary provided above using 2013 actual figures as an example.

103. 4. OEB STAFF 38

Ref: E4/T3/S1, Appendix 2-JC; E4/T3/S1, p. 3

Festival Hydro shows an increase in Billing and Settlement costs of approx. $296K or 75%. Festival Hydro noted that this increase began in 2013 as the result of new operating cots required with the implementation of smart meters.

a) Please provide a breakdown of this cost category.

b) Please state how much of this increase is due to smart meters.
c) Please explain the ongoing nature of these costs.
d) Board staff notes that meter reading expenses have also increased by approx. 24%. Please explain if and where Festival Hydro was able to realize some efficiency gains due to implementing the smart meter program.
e) If not, please provide more detailed explanation as to these costs.

Response:

a) A breakdown of this cost category is included in the table below.

Billing & Settlement Summary						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**
Supervision - Billing	11,870	13,103	12,617	14,591	14,182	14,534
Smart Meter Billing Costs			17,917	92,977	118,049	119,938
Customer Billing	293,129	362,423	337,941	469,083	498,917	512,543
Billing - STR Processing	1,547	350	290	296	249	246
Billing - Other Retailer Services	40,859	32,500	29,052	25,380	26,391	-
SSS Admin Charge	40,912	40,912	40,912	40,913	41,567	42,232
Reconnection Charge Offset	- 32,243	- 35,084	- 30,523	- 30,048	-	-
	356,074	414,204	408,206	613,192	699,355	689,493

b) Based on the table above – smart meter billing costs are estimated at $120K in 2015 and were zero in our last rebasing year.

c) The smart meter billing costs include costs relating to Festival's ODS service provider, Web presentment provider, head end system software support, and verification, editing, and estimation service provider. All of these costs are considered to be ongoing in nature.

d) The meter reading cost driver includes costs for smart meter data backhaul averaging around $100K/year which is a new cost as a result of smart meters. Festival continues to pay approximately $30K/year for manual meter reads for meters that are not a part of the smart meter program. Festival notes that we have reduced our meter reading costs by approximately $84K/year as a result of the implementation of smart meters.

e) Refer to efficiency response in 38d.

104. 4. OEB STAFF 39

Benchmarking

Board staff notes that Festival Hydro seemingly did not undertake any studies of its proposed increases in compensation/headcount on the basis of compensation benchmarking, or any other external comparators, and appears to have justified its proposed increases solely on the basis of its anticipated needs without any specific reference to any external comparators.

a) Please confirm whether or not Festival Hydro took into account any external comparators when determining these increases. If yes, please state what they were and how they impacted on what is proposed in the application. If not, please state why not, and explain the justification for the spending level in the absence of such information.

Response:

a) Yes, Festival Hydro did consider external comparators when determining compensation increases. Festival Hydro obtained 2013 contract settlement information from neighbouring utilities to determine market condition. A rate of 2.5% was estimated based on the information available. Festival Hydro's final contract negotiation resulted in a 2.02% increase which was amongst the lowest increases of neighbouring utilities.

105. 4. OEB STAFF 40

Ref: E4/T3/S2, Appendix 2-K – Compensation Strategy

With respect to Appendix 2-K, please explain the applicant's compensation strategy and its core HR objectives. Please explain how this strategy has resulted in a 13.4% increase in non-management compensation, while compensation for management has remained flat.

Response:

Festival Hydro compensation strategy is to pay competitively to ensure that Festival is able to attract and retain qualified employees. Employee continuity adds to institutional knowledge and avoids costs to find, hire and, and train new employees. Further, the strategy incorporates an employee's development and progression within the succession planning requirements of the organization. Specifically, as it relates to Appendix 2-K Festival's compensation strategy is to keep year over year increases (excluding overtime) in line with contract settlements of neighbouring utilities (as stated in 4-Staff-39) and to also keep increases between management and non-management equal.
The inequality that can been seen between management and non-management as it relates to increases since the last rebasing period can be attributed to changes in overtime worked (management is salary) and the fact that management employees were for the most part at the top of pay progression in 2010. Therefore all increase for management employees were as a result of cost of living increases where as many employees in the non-management group have moved from apprenticeship or step 1 category to the top of their grids over the last 5 years.

File Number:	EB 2014 0073
Exhibit:	4
Tab:	3
Schedule:	2
Attachment:	2
Date:	25-Apr-14

Appendix 2-K
Employee Costs

	Last Rebasing Year - 2010- Board Approved	Last Rebasing Year - 2010- Actual	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Test Year
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)	11	11	12	12	12	11	11
Non-Management (union and non-union)	34	36	33	35	35	34	34
Total	45	47	45	47	47	45	45
Total Salary and Wages including ovetime and incentive pay							
Management (including executive)	$ 872,182	$ 1,095,323	$ 1,206,051	$ 1,251,645	$ 1,299,464	$ 1,170,301	$ 1,135,863
Non-Management (union and non-union)	$ 2,217,898	$ 2,203,848	$ 2,335,579	$ 2,350,858	$ 2,500,330	$ 2,456,962	$ 2,489,336
Total	$ 3,090,080	$ 3,299,171	$ 3,541,630	$ 3,602,503	$ 3,799,794	$ 3,627,263	$ 3,625,199
Total Benefits (Current + Accrued)							
Management (including executive)	$ 153,857	$ 209,762	$ 242,437	$ 281,993	$ 302,820	$ 264,811	$ 263,139
Non-Management (union and non-union)	$ 313,638	$ 477,560	$ 521,265	$ 550,963	$ 586,369	$ 580,559	$ 599,136
Total	$ 467,495	$ 687,322	$ 763,702	$ 832,956	$ 889,189	$ 845,370	$ 862,275
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ 1,026,039	$ 1,305,085	$ 1,448,488	$ 1,533,638	$ 1,602,284	$ 1,435,112	$ 1,399,002
Non-Management (union and non-union)	$ 2,531,536	$ 2,681,408	$ 2,856,844	$ 2,901,821	$ 3,086,699	$ 3,037,521	$ 3,088,472
Total	$ 3,557,575	$ 3,986,493	$ 4,305,332	$ 4,435,459	$ 4,688,983	$ 4,472,633	$ 4,487,474
Total Compensation Allocated to OM&A		3,088,858	3,334,551	3,345,148	3,710,598	3,800,695	3,895,712
Total Compensation Allocated to Capital		897,635	970,781	1,090,311	978,385	671,938	591,762
						$ 3,263	$ 24,895

106. 4. OEB STAFF 41

Ref: E3/T3/S1/p. 9; E4/T3/S1; and Accounting Procedures Handbook, effective January 1, 2012

Festival indicated that it has recorded gains or losses related to the change in the discount rate for the Employee Future Benefit cost determination in Account 4335 Pension Actuarial Gains and Losses. It has also not recorded any amounts for gains and losses for 2014 and 2015 and is of the opinion that it should not be considered in its revenue requirement.

a) Per APH effective January 1, 2014, Account 4335 is for Profits and Losses from Financial Instrument Hedges that is be used to record profits and losses from financial instruments used as hedges against financial risks such as price risk credit risk, liquidity risk and cash flow risk. Please explain why Festival is not adhering to the APH's definition of Account 4335.

b) As Festival is proposing that actuarial gains and losses be excluded from its revenue requirement,

i. Please explain if Festival will be requesting any refund or recovery in the future when Festival actually incurs the actuarial gain or loss.

ii. From 2000 to 2005, please confirm that Festival recovered OPEB costs in rates on a cash basis.

iii. Please provide a table comparing the actuarial gain/loss included in Festival's revenue requirement to the actual actuarial gain/loss incurred from the year Festival first included the gain/loss in its revenue requirement to 2015.

iv. Please provide a table similar to the one below for each year from the first year Festival included Other Post-Employment Benefits ("OPEB") in rates on an accrual basis of accounting to 2015, comparing to amounts Festival actually paid.

	…2006	2011	2012	2013	2014	2015
Amounts included in rates						
OM&A						
Capital expenditures						
Sub-total						
Paid amounts						
Net excess amount included in rates greater than amounts actually paid						

c) Festival indicated that it used to record actuarial gains and losses in Account 5645.

i. Please explain how the amounts pertaining to actuarial gains and losses included in rates under Account 5655 per part biii) above relate to the Benefits variance analysis provided in Exhibit 4, Tab 3, Schedule 1, Employee Compensation Breakdown section.

ii. Please explain what portion of actuarial gains and losses have been included or excluded in the Benefit Expense table from 2010 to 2015 in the Employee Compensation Breakdown section in Exhibit 4, Tab 3, Schedule 1.

d) Please explain what Festival has done with the excess amounts greater than the actual benefit payments recovered from ratepayers, if any, as shown in the previous table above in (b).

Response:

a) Festival had found that charging the annual gain/loss arising from the update of the discount rate to acct 5645 resulted in a large variation in the account year over year. It was Festival's opinion that the gain/loss did not represent normal operating costs and the gain/loss portion arising from the change in the discount rate was better included in Other Operating Revenue where other gains and losses are recorded. Festival selected Acct # 4335 as there did not appear to be another account with a proper description to be used (# 4390 probably more suitable). The remainder of the change in the Future employee benefit accrual (i.e. expense) arising on the employee future benefit evaluation was then charged to 5645. Based on the attached Note IAS 19 Disclosures note prepared by Collins Barrow, it would appear this is the approach to be taken under IFRS with the benefit costs and interest component going to the income statement and the gain/loss arising from a change in the financial assumptions going to Other Comprehensive Income.

b) Festival did not mean to imply that it was not taking the gain/loss on the discount rate into consideration. What was intended to be said was that Festival assumed there was no change in the discount rate in 2014 or 2015 so there is no gain or loss arising from the change in financial assumptions to be recognized.
   i. In 2014, Festival will book the entire charge, including the gain and loss to 5645. For 2015, Festival will follow the IFRS accounting presentation as directed in IAS 19. Currently, the Cost of Service followed by the annual IRM process does not allow for future recovery of a gains/losses that deviates from the amount approved from the COS year. For example, if a gain of $100,000 is reflected in the cost of service year (i.e. reducing your revenue

requirement by $100K), the IRM process then allows for a change annually by the annual inflation factor. If the next year after COS the LDC suffers a $50,000 loss on the discount rate, there is no mechanism to true up for in thy difference on the $100,000 gain built into COS versus the $50,000 loss in the current year. So to the extent the gain/loss varies in the IRM years to the COS year, it is Festival's belief that there is no mechanism in place to compensate the LDC or reimburse the customer when these variations occur related to the discount rate.

ii. From years 2000 to 2005, the change in the Employee Benefit accrual, were charged to Acct # 5645. The balances were never amortized over a period of time.

iii. The gains/losses have always been included in revenue requirement. Since our 2010 COS was based on 2008 actual plus projections for 2009 and 2010, 2009 and 2010 would have been a recovery. In 2009, Festival had a huge gain so in that year Festival booked the gain to 4390, for the same reasons given in a). above. Again in 2013 Festival Hydro questioned the validity of charging the gain and loss the Acct # 5645 and split the gain portion out to a separate account. Either way, the total costs have always been part of revenue requirement. See table below:

iv. Below is a table of the charges annually and the accounts these were posted. According to the table, the accrual basis has been used no later than in 2008.

4 Staff 41												Actuarial	Actuarial		Actuarial
Other Post Employment Benefits												Report	Report		Report
Employee Future Benefit Accrual												2014 Projection	2014 Projection		2015 Projection
	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014 Bridge**	**2015 Test**	CICA	IAS 19	Difference	IAS 19
Beginning Accrual balance	1,152,145	1,240,577	1,275,094	1,314,681	1,286,629	1,234,998	1,342,826	1,346,328	1,458,962	1,397,008	1,427,307	1,397,008	1,219,179	- 177,829	1,357,108
Service and Interest costs	139,594	89,283	92,487	89,623	90,735	94,887	85,093	87,293	89,335	91,122	92,580	81,306	80,149	- 1,157	81774
Actuarial loss (gain)	-	-	-	- 54,301	- 73,529	75,139	- 16,331	86,683	- 91,659	-	-	- 22,090	112,046	134,136	-
Benefits paid	- 51,162	- 54,766	- 52,900	- 63,374	- 68,837	- 62,198	- 65,260	- 61,342	- 59,630	- 60,823	- 61,796	- 54,266	- 54,266	-	-59548
	1,240,577	1,275,094	1,314,681	1,286,629	1,234,998	1,342,826	1,346,328	1,458,962	1,397,008	1,427,307	1,458,091	1,401,958	1,357,108	- 44,850	1,379,334
	88,432	34,517	39,587	- 28,052	- 51,631	107,828	3,502	112,634	- 61,954	30,299	30,784	4,950		- 44,850	22,226
														To DVA Account	
Account charged to :	**5645**	**5645**	**5645**	**5645**	**5645- $21,898**	**5645**	**5645**	**5645**	**5645- $29,705**	**5645**	**5645**			difference arising	
					4390 - $73529				**4390 - $91,659**						
Summary of costs:															
Service,interst net of benefit paid	88,432	34,517	39,587	26,249	21,898	32,689	19,833	25,951	29,705	30,299	30,784	27,040			
Actuarial loss (gain)	-	-	-	- 54,301	- 73,529	75,139	- 16,331	86,683	- 91,659	-	-	- 22,090			
Total	88,432	34,517	39,587	- 28,052	- 51,631	107,828	3,502	112,634	- 61,954	30,299	30,784	4,950			
Change						AnnualChange excluding gain(loss)			3,754	594	485				

Summary of Expensed amounts:	**2014 Bridge**	**2015 Test**
Total Expense at 2.0%	30,299	
Total Expense at 1.6%		30,784
Actuarial Report:		
Expense	27,040	22,226
Gain	- 22,090	-
Net expense	4,950	22,226
Difference - excess expense	25,349	8,558

Note: Actual expense will vary based on year end discount rate
so 2015 test expense appears to be in line.

c) With the exception of 2009 and 2013, in all other years the full impact of the cost of future employee benefits, including gains and losses, have been charge to acct # 5645.

d) As noted in b). i. above, while the annual amount of service costs, interest less payments made is fairly constant one year to the next, the gains or losses on the financial assumptions can be great. There is no mechanism to adjust for the impact of these varying amounts.

A copy of the most recent actuarial report it attached as an Attachment.

107. 4. OEB STAFF 42

Ref: E4/T4/S1/p. 1-4; E4/T4/S1/Att. 2-3, Appendix 2-C; and Accounting Procedures Handbook, effective January 1, 2012

Regarding depreciation expense,

a) In the depreciation expense summary table on page 4, the 2014 depreciation expense under new policies and 2014 MIFRS depreciation expense are different.

b) i. Please confirm that one of the reasons for the difference is due to the amortization of the assets over average remaining useful life recalculated as at January 1, 2014.

ii. Please explain any other reasons for the difference in depreciation, including any impact from disposals of assets in 2014 under MIFRS.

c) As indicated on page 2, Festival has recalculated the average remaining useful life of opening balance of assets on January 1, 2013. The change in useful lives was implemented January 1, 2013. On page 1, Festival also indicated that due to transition to MIFRS, it will amortize the opening net book value of assets over their average remaining life in 2015. In Appendix 2-C, the 2014 MIFRS (2-CL) and 2015 MIFRS (2-CM) depreciation schedules also show the recalculated average remaining life of opening NBV as at the beginning of that year.

i. Please confirm that in the calculating depreciation expense, Festival has recalculated the useful lives again in each of 2014 and 2015 as the average remaining life of the opening NBV as at January 1, 2014 and January 1, 2015 respectively.

ii. If the response to part i) above is no, please explain how Festival has calculated the depreciation under MIFRS in 2014 and 2015.

iii. Per pages 4 and 5 of Article 320 of the APH, a change in estimate of useful lives is accounted for prospectively, with a recalculation of the average remaining useful life of the opening net book value. Please indicate if Festival has made further changes to useful lives in 2014 and 2015. If yes, please identify and explain what further changes to useful lives Festival has made in 2014 and 2015, why the changes were made and the nature of the changes.

iv. If no further changes in useful lives were made in 2014 or 2015, please explain why Festival has amortized the opening net book value of assets over their recalculated average remaining life in 2014 and 2015 in the calculation of depreciation expense.

v. Please revise the depreciation schedules for 2014 and 2015 as necessary. Please update the evidence, including rate base, Appendix 2-BA, Accounts 1575 and 1576 for the revisions.

Response:

a) Confirmed

b)

i. Confirmed
ii. The 2014 MIFRS table includes disposals with net book value of $746K which impacts the depreciation calc. in the schedule. The 2014 new policy table assumes these assets continue to be amortized under the pooled depreciation method.

c)

i. Festival confirms that we recalculated the average remaining useful life for 2013 when policy changes were implemented. The 2014 MIFRS and 2015 MIFRS schedules also show recalculated average remaining useful lives assuming disposals are made in each of these years.
ii. N/A
iii. Festival has not made any further changes to useful lives in 2014 or 2015 than those that were determined when new depreciation policies were implemented in 2013.
iv. Festival notes that the 2014 MIFRS schedule was prepared for additional information only, and shows what depreciation expense would be under MIFRS in 2014 should disposals be made in that year. Festival plans to continue with pooled depreciation in 2014 and record disposals upon transition to MIFRS January 1, 2015. At that point in time – the average remaining useful life of each asset pool will need to be recalculated reflecting the removal of useful lives of assets disposed at January 1, 2015. The 2015 depreciation schedule was prepared to reflect this.
v. Based on responses to #42 above, Festival has not provided any updated schedules or evidence.

108. 4. OEB STAFF 43

Ref: E4/T5/S1/Att. 1, PILS model and E2/T1/S1/Att. 1, Appendix 2-BA

On Schedule 8 CCA of the test year, additions of $14,398,308 are listed with a description of "additions on 2015 continuity but added to CCA purposes in prior year".

a) Please indicate where this addition and the corresponding CCA is shown on the Schedule 8 CCA of the bridge year.

b) On the Schedule 8 CCA of the test year, please explain why $0 of CCA is included for these assets in the test year.

c) The $14,398,308 additions are for the ICM assets. Please explain why Festival is proposing to include the CCA starting in the bridge year and not the test year or historic 2013.

d) In Appendix 2-BA 2015 MIFRS, $436,468 of additions is included in Account 1609 Intangible assets. This amount is part of the $14,398,308 ICM assets on Schedule 8 CCA of the test year. This amount is not added to Schedule 10 CEC of the test year. Please explain why this amount was included in the CCA schedule and not the CEC schedule.

e) Please update the PILS model as appropriate.

Response:

a) The addition was included in Festival's 2013 tax return (historical year) as the transformer station was brought into use in 2013 and therefore could be depreciated for tax purposes at that time despite the asset being included in a variance account for regulatory purposes. Festival has therefore accounted for this asset on the historical s(8) tab of the PILS model.

b) As these assets are already included in the opening UCC of the test year, the row where they are identified to reconcile to additions on the fixed asset continuity schedule was added with no CCA rate so that CCA was not taken twice on these assets.

c) As indicated in (a) above, Festival has included these assets in CCA of the historic year as the year the asset was put into use, and therefore depreciable for tax purposes.

d) The $436,468 is a limited life intangible asset and therefore was included in class 14 for CCA purposes when the CCRA agreement resulting in the cost was put in place in 2013. This is a 25 year agreement and will therefore be expensed for tax purposes over 25 years.

e) Based on Festival's clarifications above, no updates are required to the PILS model.

109. 4. OEB STAFF 44

Ref: E4/T5/S1/Att. 1, PILS model and E4/T3/S8/p. 1

Please confirm that Festival has made the appropriate adjustments for charitable donations in the PILS model for the bridge and test year.

Response:

Festival confirms that we have made the appropriate adjustments for charitable donations in the PILS model for the bridge year by reducing the net income for the donation prior to calculating taxable income. In 2015, the planned donations of $52K were neither added back or deducted – and therefore Festival confirms our taxable income as reported is correct.

110. 4. OEB STAFF 45

Ref: E4/T5/S2/Att. 1

Please indicate if there have been any reassessments on Festival's 2013 tax return. If yes and the reassessment is material, please provide the 2013 Notice of Assessment.

Response:

There were no reassessments on Festival's 2013 tax return.

111. 4. OEB STAFF 46

Ref: E4/T5/S7 and RRWF

In Exhibit 4, Festival indicated that the property taxes for 2015 are $188,000. In the RRWF, property tax of $19,225 is included. Please explain the difference and update the evidence as necessary.

Response:

The $19,225 reported in the RRWF relates to property tax PIL payments to the ministry of finance only. The $188K reported in exhibit 4 represents all municipal property taxes paid.

112. 4. OEB STAFF 47

Ref: E4/T5/S2, p. 1 and Attachment 1, PILs model – PILs

On page 1 of the first reference, Festival Hydro notes that a loss of $60K has been projected and added back in the PILs calculation of the bridge year. This projected loss represents the cost of preparing a municipal substation for disposal.

a) Please explain why Festival Hydro has included a projected loss on the property prior to the sale of the substation in its PILs calculation.

b) Please discuss the expected time of sales of the property and the expected total gain or loss upon sale and how this gain or loss will be shared with customers.

Response:

a) Festival has assumed that the substation not only would be prepared for sale, but would also be sold in 2014, and as such has recorded the $60K loss on the sale in our PILS calculation. Festival has since determined the property likely is not saleable given the size and location of the property making it unmarketable. Note that the asset cost and accumulated depreciation for the building (net book value of 0) was included in disposals of the 2015 MIFRS table in appendix 2-BA. As an identifiable asset – it should have been recorded in the 2014 continuity. However, given that it has net book value of zero, there was not impact on rate base.
b) As noted above, the sale was expected in 2014 and the loss was expected to be $60K. The $60K expenses incurred to demolish the building and return the property to green space is considered a cost of the utility and will be included as an expense for accounting purposes.

113. 4. OEB STAFF 48

Ref: E4/T4/S1/Att. 2-3, Appendix 2-C and E9/T3/S12/p.3

In Appendix 2-CM, 2015 MIFRS depreciation schedule, variances are noted in the depreciation schedule between the depreciation expense calculated in the appendix and depreciation expense per Appendix 2-BA as the half year rule was not being applied to the transformer station assets transferred into capital. The total depreciation from the variance account for 2013 and 2014 as per the note in the 2015 Appendix 2-CM is $365,784 ($346,871+$18,914). The total depreciation expense to be transferred into capital per Exhibit 9 is $253,235. There is a difference of $112,549.

a) Please explain the difference and revise the evidence as necessary.
b) Please provide a true-up calculation applying the half-year rule as originally applied for, adjusting only for the capital expenditure reduction of $551,330 and final TS asset values.
c) Please provide the resulting net book value for the TS station as of January 1, 2015.

Response:

a) The information in Appendix 9 was incorrect. Please refer to 2 staff 8 and 9 staff 63 for the correct values. Both tables have been revised to reflect depreciation/amortization in the amount of $365,784 being transferred from the ICM Rate Rider Account # 1508 to the respective asset classes.

b) Under 9 staff 64 Festival has recalculated the ICM true up using the half year rule as originally applied for, and the reduction of $551,330 to reflect the final TS asset value. If the half year rule is used for 2013, then it is only fair that for the 8 months of 2014 the ICM model be calculated with an 8/12ths of a full year's depreciation, as originally filed by Festival hydro under E9/T3/S12 pp 1-9.

c) The net book value, with a half year of depreciation and amortization taken in 2013 results in a January 1, 2015 net book value of $14,805,313 as per the table below:

4 Staff 48 table				
ICM Rate Rider ACCOUNT # 1508 - Continuity Schedule				
with half year rule depreciaiotn in 2013; ull depn in 2014				
		2013	**2014**	**Jan 1, 2015 transfer**
Opening, Jan 1		0	15,058,931	14,710,516
TS O & M Expenses		104,816	140,000	-244,816
Interest		17,623	217,469	-235,093
Transfer in from CWIP		15,311,782	0	-15,311,782
Depreciation & Amortization		168,822	337,647	-506,469
Accumulated Depreciation & Amort		-168,822	-337,647	506,469
Less ICM Rate Rider Recovery		-375,291	-705,884	1,081,174
Ending Bal, Dec 31		**15,058,931**	**14,710,516**	**-0**

Entry required for Jan 1, 2015 disposition:				
		USOA		
TS Land	DR	1805	913,474.39	
TS capital	DR	1815	13,961,839.83	
CCRA agreement	DR	1609	436,468.00	
Interest Income	DR	4405	235,092.89	
Distribution Revenue	CR	4080		1,081,174.36
Depn Exp	DR	5705	480,280.00	
Amort Exp	DR	5715	26,189.00	
Accum Depn	CR	2105		480,280.00
Accum Amort	CR	2120		26,189.00
TS O & M Expenses	DR	5015	244,815.74	
ICM Variance Acct	CR	1508		14,710,516.49
			16,298,159.85	16,298,159.85
Transfer back to fixed asssets1805,1815,1609 (gross)				15,311,782.22
Less Accuimulated Depreciation/Amortization				-506,469.00
Net book value upon transfer , Jan 1, 2015 with 2013 half year rule				14,805,313.22
With only one month depn in 2013:				
Net book value upon transfer , Jan 1, 2015				14,945,998.00
Reduction in NBV bt taking half year rule				-140,684.78
rather than one month depn for 2013				

114. 4. AMPCO 9

Ref: Exhibit 4, Tab 1, Schedule 1

a) Page 2 – Please confirm the effective date of Festival's latest collective agreement, the length of the agreement, and the annual increases.

Response:

The effective date of Festival's latest collective agreement is May 1, 2014 and it expires on April 30, 2017. A 1.75% increase was agreed to in each of the four years of the agreement. In addition, wage increases to the trades and semi-skilled workers categories were also agreed to. Festival's total cost increase considering the benefits impact of the wage increases and that Festival's Board of Directors approved a similar increase in 2014 for non-union staff, is 2.02%.

b) Page 4 – Please provide the $ amounts for the extraordinary cost items listed.

Response:

A summary table of these extraordinary cost drivers comparing 2015 to 2010 is included in E1/T2/S6/page 2 as well as their percentage impact of the total impact.

115. 4. AMPCO 10

Ref: Exhibit 4, Tab 2, Schedule 1

a) Page 3 – Please confirm when the Chief Operating Officer position was created and filled.

Response:

The COO position was created effective May 2011 and was filled by an internal resource in May 2011.

b) Page 4 – Please explain then increase need to hire an accounting clerk to aid in the volume of work performed by the accounting department.

Response:

The utility has taken on many new initiatives in recent years such as smart meters and conservation to name a few. In addition, there has been one significant legislative changes in this timeframe (the implementation of HST in Ontario) that has impacted the work in the accounting department, particularly given that Festival tracks restricted ITC's as a large corporation, and given the regulatory tracking to record PST recoverable that had previously been approved as an expense or capital item in our 2010 rate application. Each new initiative taken on by the utility generally impacts the accounting department in some way either through increased volume of payables, record keeping or increased retrofit payments as examples. Early in 2012 it was determined that the processes in the accounting department were taking too long to complete or were being completed inconsistently due mainly to work overload. Festival did consider overall headcount of the organization, as well as succession planning within the accounting department prior to making a decision to have a third resource hired. This resource was also trained in multiple jobs such as the cashier's position as well as on regulatory duties in order to gain efficiencies and balance workload. Also – as per response to 10d below – the receptionist position was not filled when it became vacant due to a retirement in customer service – and as such this new accounting position picked up various duties from that role including timesheet entry and balancing for payroll.

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c) Page 5 – Please explain the need to hire an engineering technician to aid in the volume of engineering work.

Response:

An Engineering technician was hired in 2013 to address the backlog of design work arising from an increase in the number of projects initiated by customers and additional record keeping required through the implementation of ESA Reg 22/04. This position will be a key resource for the future implementation of GIS and OMS, and is part of the succession planning for the Engineering & Operations Department as two managers are expected to retire in the next two years and another manager could retire within five years.

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d) Please discuss if any retirements over the 2011 to 2015 period are not backfilled and why.

Response:

A customer service representative retired in 2011 and was replaced internally. The receptionist position that became vacant due to this retirement and was not was not filled. As such that FTE was replaced by an accounting clerk in 2012 due to the reasons documented in 10b above. In 2013 a lineman retired and the lineman position was filled internally with a mechanic that began his lineman/journeyman apprenticeship in 2012. The mechanic position was not filled and that FTE position was replaced in 2013 with the hire of the engineering technician. In 2014 there has been one lineman position move into a management position due to a retirement. This lineman position was not filled. There was another retirement from the line crew in Q2 of 2014 that is not expected to be replaced. The reason these two line positions have not been backfilled in our projections is given the reduction in planned capital spend.

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e) Please provide a summary of vacant positions over the period 2010 to 2015.

Response:

There were no vacant positions and are no projected vacant positions in our 2015 application.

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f) Page 6 – The evidence indicates that 2014 includes the OM&A of labour costs of time the existing chief operating officer and VP of engineering and operations had been spending in prior years on transformer station capital work as well as conservation initiatives. Please explain further why prior year costs are included in 2014.

Response:

To clarify, prior year costs have not been included in Festival's 2014 OM&A projections. This statement was meant to indicate that in 2013 and prior, the COO charged much of his labour cost to the transformer station project. The VP of Engineering and Operations was also highly involved in the conservation strategy from 2011 – 2013 and as such some of his labour costs flowed through the OPA budget versus Festival's OM&A budget. The fact that both of these positions were logging more time outside of these projects in 2014 created a cost driver in Festival's 2014 OM&A.

g) Page 7 – Please confirm if the lineman that retired in 2014 will be replaced in 2014 or 2015.

Response:

Please refer to Festival's response and strategy as documented in 10d.

h) Page 8 – Please confirm if headcount has the same meaning as FTE

Response:

Festival confirms that on page 8 of E4/T2/S1 the reference to headcount has the same meaning as FTE.

i) Appendix 2-JA – Please provide 2013 audited actuals.

Response:

Festival confirms that while appendix 2-JA column heading still indicates 2013 draft actual figures – Festival's draft figures did agree to the final audited figures included in our final audited statements in E1/T4/S1/A3.

j) Appendix 2-JB – Please provide the overtime amounts plan vs. actual for 2011 to 2013 and 2014 and 2015 plan.

Response:

Festival does not plan overtime, but expects there will be circumstances every year (unplanned outages, scheduled outages during off peak hours to accommodate specific capital and maintenance projects, after hours re-connects, etc.) that will require the use of overtime and our annual budgets reflect a typical amount of overtime will be required during the year. There are circumstances outside of Festival's control (such as the two ice storms that Festival experienced in 2013) that can cause unplanned OT to be significant.

k) Appendix 2-JB – Please confirm the increase in overtime in 2013.

Response:

Appendix 2-JB indicated that overtime was a cost driver of OM&A in 2013 by $49K in error. Overtime worked as a result of the storms in April and December of 2013 was erroneously included in the overtime cost driver as well as the cost driver for labour-storm damage. As such – the cost driver for overtime in 2013 would be approximately $18K, most of which is the result of overtime paid to IT staff resulting from work performed in relation to smart meter verification, estimation, and editing processes with the MDMR. This work has since been subcontracted out to a third party and IT overtime has fallen back in line with prior years.

l) Please discuss the circumstances where double time is applicable.

Response:

Staff are paid double time when they work greater than 8 hours in a day, or greater than 40 hours in a week.

m) Please provide the number of apprentices hired each year for the years 2011 to 2015.

Response:

One apprentice was hired in 2012. There were no apprentices hired in any of the other historical years and no apprentices have been projected to be hired in 2014 or 2015.

116. 4. AMPCO 11

Ref: Exhibit 4, Tab 3, Schedule 1, Attachment 1 Employee Compensation Breakdown

a) FTE Definition: Please explain the significance of 2080 base hours and the calculation of an FTE.

Response:

Festival has some full time staff that work 40 hours in a week (40hours x 52 weeks = 2,080 hours), and some that work 35 hours in a week (35hours x 52 weeks = 1,820 hours). Therefore, in our calculation of FTE – we took into considering the category the employee fell into as each is considered an FTE for our purposes.

b) Please confirm the number of permanent and temporary employees hired to work on the smart meter program by year and confirm the status of these positions in 2015.

Response:

There were no permanent employees hired to work on the smart meter program. 6 temporary employees were hired in 2010 to work on smart meter program installing meters (two from March – September and four from May – September). In 2011, one temporary employee was hired for June – October for the smart meter program.

c) Please confirm when the President position is to be filled.

Response:

As documented in E1/T6/S12/page 3 – effective May 12, 2014 Festival created and filled the position of CEO and also filled the position of President.

d) Please confirm the operations manager retired in June 2014.

Response:

Festival confirms the Operation Manager retired in June of 2014.

e) Please confirm the overlap period between the manager and the lineman transitioning to the manager position.

Response:

Festival confirms that the new Operations Manager began his training in his new position in January 2014. Festival notes that while the previous Operations Manager did not officially retire until June of 2014, he took his vacation allotment prior to his retirement and was effectively finished his role as Operations Manager April 11 2014 – making the overlap/training period approximately 3.5 months.

117. 4. ENERGY PROBE 23

Ref: Exhibit 4, Tab 2, Schedule 1

a) The evidence (page 4) indicates that Festival expensed the smart meter expenses that were accumulated in the variance account in 2012. Please provide a breakdown of the amount of $546,293 expensed in 2012 by the years in which the expenses were incurred.

b) The evidence (page 6) indicates that Festival expensed $79,393 in 2013 related to PST costs incurred in previous years. Please provide a breakdown of the $79,393 by the years in which the costs were actually incurred.

Response:

a) The table below details the years the smart meter operating expenses were incurred that were included in 2012 OM&A expenses.

Smart Meter Operating Cost Disposition included in 2012:					
2010 Costs		115,494			
2011 Costs		189,001			
2012 Costs		241,798			
		546,293			

b) The table below provides the breakdown of years the expenses were incurred that were disposed of in 2013. Festival notes that a disposal of cost was made in 2011 for 2010 and part of 2011, but another entry was not booked until 2013.

PST Costs by Year	
2011	11,593
2012	32,627
2013	35,173
	79,393

118. 4. ENERGY PROBE 24

Ref: Exhibit 4, Tab 2, Schedule 1

Please show where in the evidence the savings of $475,000 in annual network connection costs has been reflected.

Response:

The monthly reduction of 20,000 kW arising from the Permanent Bypass Agreement with Hydro One results in annual savings of $475,200 in transformation connection charges. The kW reduction has been reflected monthly in the RTSR Model on Tab # 8 Forecasted Wholesale. In summary:

Tab 7 Current Wholesale (2013)	1,042,640 kW @ $1.98	$2,064,427
Tab 8 Forecast Wholesale (2015)	802,640 kW @ $1.98	$1,589,227
Reduction	240,000 kW	$ 475,200

119. 4. ENERGY PROBE 25

Ref: Exhibit 4, Tab 2, Schedule 1, Attachment 1

Please provide a table in the same level of detail as shown in Appendix 2-JA that shows the most recent year-to-date actual expenses for 2014. Please also provide a column that shows the figures for the corresponding period in 2013.

Response

The following table details the information requested.

	2013 6mo. Actuals	2014 6mo. Actuals
Reporting Basis	CGAAP	CGAAP
Operations	$ 415,714	$ 419,426
Maintenance	$ 767,115	$ 690,965
SubTotal	**$ 1,182,829**	**$ 1,110,391**
%Change (year over year)		-6.1%
%Change (Test Year vs Last Rebasing Year - Actual)		
Billing and Collecting	$ 593,950	$ 622,432
Community Relations	$ 7,001	$ 9,242
Administrative and General	$ 810,922	$ 898,785
SubTotal	**$ 1,411,873**	**$ 1,530,459**
%Change (year over year)		8.4%
%Change (Test Year vs Last Rebasing Year - Actual)		
Total	**$ 2,594,702**	**$ 2,640,850**
%Change (year over year)		1.8%

	2013 6mo. Actuals	2014 6mo. Actuals	Variance 2014 6 Mo. Actuals vs. 2013 6 Mo. Actuals
Operations	$ 415,714	$ 419,426	-$ 3,712
Maintenance	$ 767,115	$ 690,965	$ 76,150
Billing and Collecting	$ 593,950	$ 622,432	-$ 28,482
Community Relations	$ 7,001	$ 9,242	-$ 2,241
Administrative and General	$ 810,922	$ 898,785	-$ 87,863
Total	**$ 2,594,702**	**$ 2,640,850**	**-$ 46,148**
%Change (year over year)		1.8%	

120. 4. ENERGY PROBE 26

Ref: Exhibit 4, Tab 2, Schedule 1, Attachment 2 & Attachment 4 & Exhibit 6, Tab 1, Schedule 1

a) Please provide a reconciliation of the figures for 2013 with respect to the $298,746 related to overhead policy changes and ($133,302) related allocated depreciation costs on trucks in Appendix 2-JB with the figure of $254,313 shown in Appendix 2-DA for the historic year.

b) Do the OM&A figures shown in Appendix 2-DA for the bridge and test years ($167,816 and $148,417, respectively) mean that Festival estimates that overall OM&A costs in 2014 and 2015 are higher by these amounts because of the accounting change that was made in 2013?

c) On page 3 of Exhibit 6, Tab 1, Schedule 1, the evidence states that the 2015 test year OM&A is higher due to the accounting changes by $267,660. Please reconcile this figure with the two figures noted in Attachments 2 and 4 in Exhibit 4, Tab 2, Schedule 1.

d) Based on any changes or updates, please provide the estimated increase in OM&A for each of 2013, 2014 and 2015 as a result of the change in accounting policies adopted in 2013.

Response:

a) The $133,302 cost driver reported in Appendix 2-JB is the total depreciation difference for trucks when comparing old depreciation policies to new depreciation polices. As per appendix 2-BA the 2013 continuity schedule under old policies shows a depreciation amount for trucks of $245,533 as compared to $112,230 shown in the 2013 fixed asset continuity under new accounting policies. Appendix 2-DA was used to highlight impacts to overhead capitalized versus overhead expensed. As such – the $133,302 is not something that should be reconciled with the total of the historical column in appendix 2-DA.

b) Festival agrees that we have estimated the OM&A impact of overhead capitalization policy changes in 2014 and 2015 to increase OM&A by $167,816 and $148,417 respectively.

c) Festival notes that the $267K quoted in E6/T1/S1 and referenced to appendix 2-DA in E4/T2/S1/A4 is an outdated figure and was meant to reference $254,313 documented in appendix 2-DA for the historical year. Festival notes that the figure included in appendix 2-JB (E4/T2/S1/A2) as a cost driver relating to the policy change in the historical year of $298,746 includes not only the capital impact of $254,313 – but also the impact of not allocating any additional linemen charges after the policy changes in 2013 to items such as billable work, and work on revenue offsets like street-lighting projects. For more detail on the types of additional linemen charges that are no longer allocated and all remain in OM&A under the new policies refer to 4-Staff-37b. In exhibit 6 this impacts two drivers of test year deficiency. A revised table has been included below.

Drivers of Revenue Deficiency			
Description		Impact on Revenue Deficiency	Reference
OM&A (excluding impact of change in accounting policy under CGAAP)		990,160	
Impact of Change in Accounting Policy under CGAAP (Rate base, OM&A, Depreciation)	-	903,156	
PILS	-	585,524	
Return on Incremental Rate Base (Excluding Impact of Change in Accounting Policy under CGAAP)		1,003,567	
Depreciation expense		1,077,868	
Distribution revenue increase due to IRM rate increases and volume fluctuations	-	555,446	
Increase in Other Revenue Offset	-	77,783	
Other	-	71	
		949,615	

d) Festival does not believe total OM&A for 2013, 2014, or 2015 should change based on the responses above. Festival has noted in the above table that the driver of revenue deficiency in the test year should be updated to reflect more OM&A impact on revenue deficiency due to a correction in the amount of impact due to overhead capitalization policy changes.

121. 4. ENERGY PROBE 27

Ref: Exhibit 4, Tab 3, Schedule 1, Attachment 1

a) Please show the historical amount for each of 2010 through 2013 and the forecast for 2014 through 2015 associated with emergency repairs (storms).

b) Festival has spent less in tree trimming in each of 2010 through 2013 than was approved in the 2010 application. Please explain why the actual level of tree trimming has been below that forecast in 2010.

c) Please explain why there are sub-totals for meter reading expenses in 2014 and 2015, despite no individual line items being shown.

Response:

a) The following table details emergency repair costs historically and projections.

Emergency Repair Costs		
2010	13,130	
2011	-	
2012	-	
2013	84,793	
2014	-	
2015	-	
	97,923	

b) Please refer to the response to 4-Staff-26.

c) Appendix 2-JC was prepared this way for all program categories and Festival notes that the breakdown within each category between labour, material, and outside services would be similar to the previous year.

122. 4. ENERGY PROBE 28

Ref: Exhibit 4, Tab 4, Schedule 4

a) Please confirm that, with the exception of the transformer station in the ICM model, Festival uses the half year depreciation methodology for all capital additions placed into service in the current year for both regulatory accounting purposes and for financial accounting purposes. If this cannot be confirmed, please explain.

b) Has Festival made any changes in the regulatory or financial accounting with respect to depreciation expense since the last cost of service application for 2010 rates was approved? If yes, please provide details.

Response:

a) Confirmed.

b) The only changes made to financial accounting for depreciation expense that Festival has made since the last rebasing in 2010 was to implement new useful lives for new components of assets as required by the OEB effective January 1, 2013. For documentation on these changes please refer to the depreciation section of exhibit 4 of our application.

123. 4. ENERGY PROBE 29

Ref: Exhibit 4, Tab 5, Schedule 3

Does Festival have any positions that qualify for the Ontario co-operative education tax credits? If yes, please provide details.

Response:

Festival confirms that we have one position within the IT department currently in 2014 that qualifies for the Ontario co-operative education tax credits. The individual is a computer science student at the University of Waterloo and his work term with Festival started in May of 2014 and ends in August 2014.

124. 4. ENERGY PROBE 30

Ref: Exhibit 4, Tab 5, Schedule 6

The 2014 provincial budget has eliminated the small business deduction for Canadian controlled private corporations with taxable capital in excess of $15 million. Please show the impact on PILs of this elimination.

Response:

Festival notes that the budget passed legislature July 24, 2014 – and as such phasing out of the small business deduction would be prorated in the bridge year (2014), and fully eliminated in 2015. As Festival was claiming the full benefit of the small business deduction – this would impact the PILS calculation in our 2015 test year by approximately $35,000 on tax payable, and $61,010 on grossed up PILS. Festival will include with the IR responses and updated PILS model to reflect this change.

125. 4. ENERGY PROBE 31

Ref: Exhibit 4, Tab 5, Schedule 7

a) Please show the actual amount of property taxes paid in each of 2010 through 2013.

b) Please show the amount of property taxes paid or forecast to be paid for 2014. Please also provide the amount that is based on bills received at this point in time for 2014.

c) What is the actual amount of property taxes in 2014 associated with the transformer station property?

d) Please explain the difference in the $188,000 noted in the evidence and the amount of $19,225 shown in the RRWF for property taxes in the test year.

Response:

a) The following table shows the actual property tax paid for 2010 – 2013.

Property Tax Paid	2010	2011	2012	2013
	110,054.67	100,964.72	104,424.50	105,692.34

b) Provided in the table below are 2014 taxes paid to date as well as the 2014 assessment value.

TOTAL INTERIM BILLING FOR 2014	TOTAL PROJECTED BILLING FOR 2014
$52,611.40	$107,339.55

c) The total property taxes paid in 2014 to date for the transformer station property is $4,963. The total projected expense for this property in 2014 based on the interim tax bills is $12,280. In the $140,000 operating costs of the transformer station for the test year, $78K is included for property taxes, which was based on discussions with the City tax department and MPAC. The tax bills for 2014 are only interim bills and at some point in time, once MPAC has completed their assessment, we expect to be assessed back to the date in which the TS was energized (December 2013).

d) Please refer to response 4-Staff-46.

126. 4. SEC 14

Ref: [Ex.4/1/1, p. 4]

Please provide details of the issue of "parity of wages and benefits with neighbouring utilities". Please provide details of the extent, if any, to which wages and benefits payable to employees of Hydro One Networks exert any influence, or have any impact, on the compensation costs of the Applicant.

Response:

Festival has not hired a Hydro One employee for several years but has hired staff from other utilities. As such, Festival is not aware of any direct influence that the wages and benefits payable to employees of Hydro One Networks have on Festival's wages and benefits. Festival notes however that there are several utilities within commuting distance of Festival and its compensation is influenced by the wages and benefits offered by these utilities which may be influenced by the wages and benefits payable to Hydro One but the extent of influence, if any, is not known to Festival. Festival is aware that it must provide a competitive compensation package to maintain its employees and attract new employees to fill job vacancies.

127. 4. SEC 15

Ref: [Ex.4/2/1, Attach. 3]

Please confirm that, excluding the impacts of accounting changes, and the additional OM&A associated with the transformer station, OM&A per customer in 2015 is expected to be approximately 11% higher than actual OM&A per customer in 2010.

Response:

Festival notes that as per 4-EP-26c, the impact of policy changes of $267,660 is incorrect. The correct figure for policy changes impacting capital and OM&A in 2015 is $148,417. Festival also notes that in 2013 – there was an impact of approximately $44K of cost that would have been allocated to billable work and revenue offsetting work under old policies. As all of this cost is now remaining in the OM&A expenses, it should also be considered in the analysis below. Festival estimates these costs for 2015 are approximately $25K. After making these changes, the % increase per customer of OM&A costs since 2010 is 14%.

OM&A Increase Per Customer	
2015 Projected OM&A	5,114,251
Less: TS Operating costs	- 140,000
Less: Impact of accounting policy changes between capital & OM&A	- 148,417
Less: Impact of policy changes outside of capital on OM&A	- 25,000
Net OM&A projected for 2015	4,800,834
2015 projected customers	20,554
Net 2015 OM&A cost per customer	233.57
2010 Actual OM&A cost per customer	205.62
% Increase in cost per customer from 2010	14%
% Increase per year since 2010	3%

128. 4. SEC 16

Ref: [Ex.4/3/2, Attach. 2]

Please provide this table with two additional rows on the bottom, dividing the total amount of compensation costs in each column into the amounts allocated to OM&A and to capital.

Response:

See table with additions requested below.

Appendix 2-K
Employee Costs

	Last Rebasing Year - 2010- Board Approved	Last Rebasing Year - 2010- Actual	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Test Year
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)	11	11	12	12	12	11	11
Non-Management (union and non-union)	34	36	33	35	35	34	34
Total	45	47	45	47	47	45	45
Total Salary and Wages including ovetime and incentive pay							
Management (including executive)	$ 872,182	$ 1,095,323	$ 1,206,051	$ 1,251,645	$ 1,299,464	$ 1,158,726	$ 1,106,724
Non-Management (union and non-union)	$ 2,217,898	$ 2,203,848	$ 2,335,579	$ 2,350,858	$ 2,500,330	$ 2,466,931	$ 2,499,984
Total	$ 3,090,080	$ 3,299,171	$ 3,541,630	$ 3,602,503	$ 3,799,794	$ 3,625,657	$ 3,606,708
Total Benefits (Current + Accrued)							
Management (including executive)	$ 153,857	$ 209,762	$ 242,437	$ 281,993	$ 302,820	$ 260,715	$ 254,085
Non-Management (union and non-union)	$ 313,638	$ 477,560	$ 521,265	$ 550,963	$ 586,369	$ 582,999	$ 601,786
Total	$ 467,495	$ 687,322	$ 763,702	$ 832,956	$ 889,189	$ 843,713	$ 855,871
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ 1,026,039	$ 1,305,085	$ 1,448,488	$ 1,533,638	$ 1,602,284	$ 1,419,441	$ 1,360,809
Non-Management (union and non-union)	$ 2,531,536	$ 2,681,408	$ 2,856,844	$ 2,901,821	$ 3,086,699	$ 3,049,929	$ 3,101,770
Total	$ 3,557,575	$ 3,986,493	$ 4,305,332	$ 4,435,459	$ 4,688,983	$ 4,469,370	$ 4,462,579
Total Compensation Allocated to OM&A		3,088,858	3,334,551	3,345,148	3,710,598	3,800,695	3,895,712
Total Compensation Allocated to Capital		897,635	970,781	1,090,311	978,385	668,675	566,867

129. 4. SEC 17

Ref: [Ex.4/3/3, p.3]

Please confirm that the costs in the table on this page are included in the OM&A costs of the Applicant in this Application. If confirmed, please confirm that the $121,016 increase from 2010 to 2015 to deliver shared services is one of the drivers of the increase in OM&A cost, but is offset by a slightly larger increase in Other Revenues. If not confirmed, please advise where the impacts of the costs and revenues from shared services are reflected in the OM&A budget.

Response:

Festival notes that the costs included in this table are part of revenue offsets and not OM&A in Festival's application.

130. 4. SEC 18

Ref: [Ex.4/3/6, p. 1 and Attach. 1]

Please confirm that the figures for this cost-of-service Application are one-fifth of the forecast cost, and that the total cost is budgeted at $201,000. Whether or not confirmed, please provide the basis for the forecast of costs for this Application.

Response:

Festival has attached a revised appendix 2M in the appendices of these responses. Festival had incorrectly completed the schedule detailing the application costs – and Festival also notes that it had erroneously included S30 costs as one time versus on-going. Festival confirms that our total test year regulatory costs of $103,100 are correct and therefore no changes have been made to revenue requirement. In the revised appendix 2M Festival has shown both the gross application costs as well as the amortized amount (1/5 of the gross) for clarity purposes.

131. 4. VECC 22

Reference: E4/T3/S1/pg.3

a) Please provide a breakdown of the incremental smart meter costs which shows all offsetting cost reductions (meter reading etc.).

b) Please provide a comparison of USoA Accounts: 5305 (Supervision); 5310 (Meter Reading Expenses); 5315 (Customer Billing); 5320 (Collecting); 5325 (Collecting – Cash/Over and Short); 5330 (Collection Charges); 5335 (Bad Debt Expense); and 5340 (Miscellaneous Customer Accounts Expenses) for the years 2010 and 2015.

c) Please explain why meter reading costs have increased from $108k in 2010 to $131k in 2015 and notwithstanding the introduction of smart meters.

d) How many electricity meters are currently manually read? How many water meters are read?

e) Does Festival provide a single utility bill (water and electricity) for the City of Stratford? Is the Stratford electricity bill a different format from those sent to non-Stratford customers?

Response:

a) The table below provides a breakdown of the incremental smart meter costs, including the offsetting reduction identified.

Summary of Incremental Smart Meter Costs	**2013**	**2014**	**2015**
ODS service provider Costs	39,311	37,499	39,388
Web presentment service provider	7,914	7,900	7,900
Smart meter data backhaul	100,000	100,000	100,000
Head End system software support	17,177	15,500	15,500
Verification, editing & estimating service provider	28,575	57,150	57,150
	192,977	218,049	219,938
Reduction in Meter Reading Cost	- 84,000	- 84,000	- 84,000
	108,977	**134,049**	**135,938**

b) The table below provides the comparison USOA data requested.

	2010 Bd Approved	2010 Actual	2011 Actual	2012 Actual	2013 Draft	2014 Projected	2015 Projected
3650-Billing and Collecting							
5305-Supervision	24,371	23,909	26,628	25,410	29,247	28,462	29,168
5310-Meter Reading Expense	105,899	107,958	106,716	81,234	223,379	246,940	251,400
5315-Customer Billing	393,491	376,448	436,185	408,195	535,670	567,125	555,021
5320-Collecting	162,038	184,101	195,855	192,847	228,259	169,552	176,103
5325-Collecting - cash over and short	17	- 100	-	-			
5330-Collection Charges	-	- 54,921	- 57,812	- 47,964	- 48,007	- 50,512	- 51,365
5335-Bad Debt Expense	106,137	74,628	55,000	57,800	82,000	76,200	90,564
5340-Miscellaneous Customer Accounts Expenses	213,059	154,975	173,955	176,474	160,017	158,025	161,926
3650-Billing and Collecting Total	1,005,013	866,998	936,527	893,996	1,210,565	1,195,792	1,212,817

c) The figures quoted in the question are from appendix 2-JC. Festival notes that the table provided above has a USOA account called meter reading costs which includes more cost than included in the meter reading program per appendix 2-JC. The increase in meter reading costs per appendix 2-JC is as documented in 4-Staff-38d.

d) 142 GS > 50kW electric meters are currently manually read and 11,686 water meters are read.

e) Festival confirms it does provide a single utility bill for the City of Stratford. The only difference from a Stratford bill and a non-Stratford bill is that water and waste water charges are not included on non-Stratford bills.

132. 4. VECC 23

Reference: E4/T1/S1/Appendix A

a) Please confirm adjustment to 2015OM&A due to changes in capitalization policy costs is 426k.

Response:

Festival notes that we believe you are referring to $426K variance that is highlighted in Appendix 2-JC for the program category for unallocated engineering, operations supervision, trucks, stores. The entire $426K variance is not the result of overhead policy changes given there were unallocated expenses in this program category prior to 2013. In addition, the overhead capitalization policy changes have also impacted the training/health & safety program category where linemen overhead costs are no longer allocated to capital. Please refer to 4-Staff-37b for further detail on the impact of the policy changes on the linemen overhead expense allocation.

133. 4. VECC 24

Reference E4/T1/S1/Appendix 2-JA

Pre-amble The OEB requires distributors adopting IFRS to present one year of comparative information in its first IFRS financial statements for financial reporting purposes

a) Please provide the 2015 Test Year OM&A shown in Appendix 2-JA and Appendix 2-JC for 2015 in CGAAP.

Response:

a) Appendices 2-JA, JB, & JC all indicate total test year OM&A is $5,144,251. Festival notes that policy changes made in 2013 that impact OM&A were made under Canadian GAAP, but are in line with the requirements of IFRS. As such, there is no difference in 2015 OM&A as reported in our cost of service application and what OM&A under CGAAP would have been.

134. 4. VECC 25

Reference E4/T3/S1/

a) Please provide the actual bad debt in 2009 through 2013 and 2014 to-date. Please provide the forecast bad debt in 2014 and 2015.

b) Please explain how the forecast for bad debt is calculated.

Response:

a) Actual bad debts acct # 5335 from 2009 to 2013, forecasted 2014 and 2015:

Year	Amount
2009	$42,000
2010	$74,628
2011	$55,000
2012	$57,800
2013	$82,000
2014 Bridge	$76,200
2015 Test year	$77,419

Note: In 2006 and 2007 had bad debts of $152,889 and $111,956 respectively due to Chapter 11 filing for a larger manufacturing facility. In recent years it has been primarily residential and G.S. < 50 kW write offs. 2013 actual of $82,000 was higher than 2013 budget of $75,000 due to more write-offs occurring than was anticipated.

b) Festival uses a formula that looks at the arrears categories (30 to 60 days, 60 to 90 days, over 90 days) and applies a % to come up with an allowance amount. Festival also identifies any specific larger accounts which need allowed for beyond what is covered through the formula basis. This calculation is reviewed annually by our external auditors.

135. 4. VECC 26

Reference: E4/T3/S1/Attachment 1

a) The table at PDF page 41 is entitled “Summary of Inflationary Increases”. Please provide the actual CPI annual inflation (Stats Canada) for 2010 through 2013.

b) Please provide Festival's forecast for inflation for 2014 and 2015.

Response:

a) As per stats Canada's historical summary – the annual change in consumer price index for the period requested is as follows:
2010 – 1.8%
2011 – 2.9%
2012 – 1.5%
2013 – 0.9%

b) Please refer to the table provided at 1.0-VECC-1 for Festival's forecast for inflation for 2014 and 2015.

136. 4. VECC 27

Reference: E4/

For each of the years 2011 through 2015 please provide:

a) EDA membership fees

b) All other corporate membership fees

Response:

a) & b) Please refer to data provided in table below as response to these questions.

	2011	2012	2013	2014	2015
EDA Membership Fees	26,950	28,450	29,800	30,277	30,761
Other Corporate Membership Fees	12,668	14,858	14,218	14,445	14,677

137. 4. VECC 28

Reference: E4/T3/S1

a) Please provide all training and conference costs for the 2011-2015 period broken down into the following categories

i. Training – for operations/maintenance staff
ii. Training – executive and other
iii. Conferences (all)
iv. Travel (all)

Response:

Please refer to data provided in the table below as response to this question.

	2011	2012	2013	2014	2015
Training for Operations & Maintenance Staff (labour)	31,309	54,596	58,296	59,753	61,247
Training for Executive & Other (labour)	25,041	18,794	15,746	16,140	16,559
Conferences (registrations all staff)	37,880	47,271	32,030	32,542	33,063
Travel (to and from conferences all staff)	20,904	35,678	23,996	24,380	24,770

138. 4. VECC 29

Reference: E4/T4/S3

a) Please show a breakdown of the cost of providing Water/Sewage Billing and Collection services to the City of Stratford for 2010 as compared to 2015. Please show separately the mailing costs and meter reading costs and collection costs for these years.

b) Who does the Water/Sewage Billing & Collecting Services for the other towns served by Festival Hydro? Is Festival aware of the cost per bill for Billing and Collection services in any of these towns?

Response:

a) As provided in OEB appendix 2-N Shared services, the cost to provide water/sewage billing and collecting for the City of Stratford in 2010 was $327,776. The projected cost for 2015 is $409,317. As per question 4.0-VECC-22e Festival provides a single electric and water/sewage bill to City of Stratford customers and as such mailing costs cannot be separated as a cost specifically of the water/sewage service we provide to the City. Similarly – collection costs are performed by Festival's customer service staff and meter reading costs are billed to Festival by Festival's meter reading subcontractor. To calculate the cost of providing such services to the City of Stratford an allocation of these total costs incurred by Festival is performed. A breakdown of the City's allocation of these costs is provided in the table below.

Water Billing Costs Charged to City of Stratford	
Billing	113,747
Collecting	129,925
Meter Reading	76,294
Misc. Customer Services	89,351
	409,317

b) Festival is not aware of who does the water/sewage billing & collecting services for the other towns in Festival's distribution territory and is not aware of the cost per bill for such services in any of these towns.

139. 4. VECC 30

Reference: E4/T3/S4

a) Does Festival purchase insurance from the MEARIE Group?
b) Please provide the 2010 and 2015 insurance costs.

Response:

a) Festival does purchase insurance from the MEARIE group.

b) The table below provides the data requested and includes insurance for property, liability, enhanced directors, cyber security, fleet and vehicle.

	2010	2011	2012	2013	2014	2015
Insurance Costs	94,585	109,169	94,991	128,532	129,488	130,000

140. 4. VECC 31

Reference: E4/T3/S1

a) Who provides vegetation management services for Festival Hydro?

Response:

a) A subcontractor of the City of Stratford provides vegetation management services for Festival within the City of Stratford. Outside of the City of Stratford, Festival staff perform our vegetation management.

141. 4-VECC 32

Reference: E4/T3/S6

a) Please reconcile the $39.2k /year in regulatory costs related to the application (page 1) with the amount for 2015 shown in Appendix 2-M (2nd box) of $40,200.

Response:

a) The table at the bottom of appendix 2-M that breaks down the cost of service application costs has been prepared incorrectly. Please refer to response 4-SEC-18 as well as the revised appendix 2-M submitted in the appendices to the responses.

142. 4. VECC 33

Reference E4/T4/S1

a) Please identify any proposed asset depreciation lives which deviate from the range(s) provided in the Kinetics Report.
b) Please provide the financial impact (if any) of these deviations on the proposed revenue requirement.

Response:

a) As documented in E4/T4/S1/p1 – Festival confirms that the useful lives for its asset groups fall within the range allowed in the Board sponsored Kinetics study.

b) N/A

EXHIBIT 5 - COST OF CAPITAL AND RATE OF RETURN

143. 5. ENERGY PROBE 32

Ref: Exhibit 5, Tab 2, Schedule 1

a) Please explain why the Board's deemed rate should apply to the deemed debt in excess of the actual long term debt obligations.

b) Has Festival issued any long term debt in 2014, or does it plan to do so?

c) Is Festival forecasting the need for any long term debt in 2015? If so, please provide details.

d) Given the competitive RFP process noted on page 3 in securing the $14 million required for the TS, has Festival considered replacing any of its affiliate debt with debt at lower rates? If not, why not?

Response:

a) For Festival's 2010 COS approved capital structure, the excess debt over long term debt obligations was subject to the deemed debt rate. Festival anticipates consistent treatment for its 2015 COS as there has been no directive issued by the Board indicating otherwise.

b) No long term debt has been issued in 2014. Festival is considering adding $1.2 million in debt to cover the payment of the Permanent Bypass Agreement which is due in December 2014.

c) There are no plans for additional long term debt in 2015.

d) Festival is not considering replacing any of its affiliate debt at this time. As in the 2010 COS application, Festival has applied for the deemed interest rate to be applied to the affiliate debt, so we are requesting consistent treatment for the 2015 COS application. This mechanism of applying the deemed interest rate to affiliate debt is well established in COS approvals as a means to limit the cost incurred by the rate payer as it relates to the affiliate debt.

144. 5. SEC 19

Ref: [Ex.5/2/1, p.3]

Please confirm that the weighted average cost of the $30,380,081 of actual long term debt, at regulatory rates, is 4.23179%. Please confirm that if that rate is applied to the deemed long term debt of $35,336,560, the total cost of long term debt in the test year would be $1,495,369, a reduction of $30,499 in revenue requirement.

Response:

This is to confirm that the weighted average cost of the $30,380,081 of actual long term debt, at regulatory rates, is 4.23179%. Also to confirm that if the rate of 4.23179% was applied to the $35,336,560 long term debt it would result in a difference of approximately 30,499. In Festival's 2010 COS application the deemed rate was applied on the remaining deemed debt amount and it is Festival's expectation that the same methodology should apply for the 2015 COS application.

EXHIBIT 7 – COST ALLOCATION

145. 7. OEB STAFF 49

Ref: E7/T1/S1 – Weighting Factor

On page 4, Festival states that in developing weighting factors for Billing and Collection there are no major differences in rate class billing costs with TOU billing now in place. However, there is not equality for Collection costs. Festival states that less time is spent on the higher value customer such as GS>50 kW, and that greater time is spent with residential customers explaining bills, taking care of retailer questions, making payment arrangements, LEAP and AMP provisions, and collection and disconnection activities. However, the weighting factors seem to not reflect these points, with GS>50 weighted higher at only 1.5 relative to 1.0 for the residential. Given the explanation that there are limited collection activities and the volume of bills is low, Board staff think that a weighting factor that is 80% of the more demanding residential class for Street lighting and Unmetered Scattered Load might be high.

a) Please explain any other factors that that contributed to the weighting factors.

b) If any or all of the weighting factors need to be adjusted:

i.) Please submit new factors and explain the new factors; and

ii.) Please update the cost allocation model, and provides a live excel version of that model.

Response:

a) My statement was not correct. The higher factors for billing and collecting of G.S. > 50 kW are reflective of the fact that the G.S. > 50 kW and Large use billing is more complicated in terms of billing of demand charges and other charges such as transformer allowance and primary metering discounts. A billing correction is more complicated for a kW demand billed customer than billings based on kWh. In terms of collection activities, there is much fewer collection issues with G.S. > 50 kW and large use customers but when they do arise they are more complicated given the high dollar values involved and the creditor arrangement involved in settling those accounts. As such a factor of 1.5 to 1.0 does reflect the more complicated billing and collection related activities for these accounts. G.S. < 50 kW is now very similar to billing of residential customer but again more complicated collection activity when problems occur. The ratio has been decreased between residential and G.S. > 50kW at 1.25.

b) With respect to Streetlighting and USL, these accounts do require ongoing maintenance to their accounts to reflect additions/deletions of fixtures and periodic reconciliation of accounts with the municipalities. Under the recently issued OEB directive regarding unmetered loads, there is going to be increased dialogue required between LDCs and municipalities regarding streetlight and USL distribution rates.

c) For the reasons noted above, the factors used in the Cost Allocation model have been left as presented except for a change to G.S < 50 kW to 1.25. An updated version of the Cost Allocation model has been submitted.

146. 7. OEB STAFF 50

Ref: E8/T1/S1 – Cost Allocation Model - Sheet O2, Monthly Fixed Charge

On page 2, Festival has provided two tables.

a) In the first table please confirm that the Cost Allocation – Maximum Fixed Rate (b), sub column Rate should contain the Customer Unit Cost per month – Minimum System with PLCC Adjustment form Sheet O2 in the Cost Allocation Model. If so, please update.

The second table lacks the superior column headings.

b) Please confirm that the first green shaded column in the second table contains the proposed fixed charges.

Board staff has developed the following table from the above two references.

Rate Classes above the Maximum				
	(Col. 1)	(Col. 2)		(Col. 3)
	Fixed Rate			Sheet O1
	Current	Proposed		Maximum
General Service 50 - 4,999 kW	$227.57	$253.49		$66.33
Large Use	$10,883.89	$11,900.62		$874.44
Unmetered Scattered Load	$13.04	$8.17		$8.12

c) Please confirm the values in the table.

Response:

a) Agreed. The Cost Allocation – Maximum Fixed Rate (b), sub column Rate should contain the Customer Unit Cost per month – Minimum System with PLCC Adjustment form Sheet O2 in the Cost Allocation Model.

b) Agreed. The first green shaded column in the second table contains the proposed fixed charges.

c) The values as displayed in the table above are the correct values. In the original 2015 COS filing Festival established rates based on existing fixed variable splits, however, the maximum fixed rate should be the greater of the Directly Related, Minimum System with PLCC Adjustment or Existing Rate. So for the G.S. >50 kW and Large Use the proposed fixed rate can be no greater that the current rates. For USL, Festival will adjust the fixed further down so as to agree to the maximum. The Cost allocation model has been updated and submitted on RESS to reflect these changes.

147. 7. ENERGY PROBE 33

Ref: Exhibit 7, Tab 1, Schedule 1

a) Please confirm that the services (account 1855) weighting factors should be based on relative cost by rate class. If this cannot be confirmed, please explain fully.

b) Please provide the average service cost for a residential customer and the average service customer for a GS <50 customer.

c) What is the impact on the revenue to cost ratios if the services weighting for the GS<50 class is changed to the ratio of the GS<50 to residential figures provided in part (b) above? In particular, please provide a table that shows the status quo and proposed ratios, comparable to that shown in Exhibit 7, Tab 1, Schedule 4, and Attachment 1.

Response:

a) Confirmed. The weighting factors for services Acct # 1855 should be based on relative costs by rate class.

b) The cost to install a G.S. < 50 kW service and a residential service is relatively the same. Note that within the classes themselves there can be a variation of cost from one customer to the next for which no differentiation is made. Festival believes there is no notable difference in the cost between the two classes and as such have assigned the same weighting factor.

c) Weightings have not been changed.

148. 7. VECC 34

Reference: E7/T1/S1/ pg.4

a) With respect to Services, under what circumstances are GS<50 customers responsible for providing and maintaining their own services?
b) With respect to Services, under what circumstances would a GS>50 customer not be responsible for providing (and maintaining) their own Service assets?
c) With respect to Services, please explain why "infrequency" of service connections for Streetlight, USL and Sentinel Lights is relevant in the determination of the weights to applied per customer.

Response:

a) GS<50 customers would be responsible for providing and maintaining their own services if they requested a service at a voltage that was not standard to Festival (eg 480 V three phase).

b) GS>50 customers are not responsible for providing and maintaining their own service assets under the following circumstances:

i. Primary voltage (>600V) connection via overhead distribution line to customer owned substation.
ii. Secondary voltage (600 V or less) connection that does not require on-site transformation, or a municipal road crossing, or easement crossing.

c) The low frequency of service connections for Streetlight, USL and Sentinel Lights allows for essentially all of these connections to be made on existing secondary circuits. If the frequency were to increase significantly (eg a street light on every distribution pole), it would eventually become necessary to upgrade the secondary circuits (or provide separate circuits) to accommodate the number of connections, which would drive up the cost per connection.

149. 7. VECC 35

Reference: E7/T1/S1/ pg.4

a) Lines 19-21 outline a number of interactions that are related to residential customers. Please confirm that the staff costs associated with these activities are all included in Accounts #5315 and #5320. If not, where are the costs recorded?

b) What proportion of the Festival customers that are serviced by Retailers are Residential?

c) Why isn't the cost of addressing questions from Retailers assigned to the Retail Services RSVA accounts?

Response:

a) Yes, these costs are included in Accounts 5315, 5320 and also 5340.

b) About 1,640 of Festival's 17,965 residential customers, or 9.1%, are serviced by a retailer (based on data as at March 31, 2014).

c) At the time of market opening, Festival Hydro did add any new FTE or part FTE to its customer service staffing levels. The retailer accounts were added to their existing work load. So being there was no incremental staffing added to customer service none of this cost could be charged to Retailer Services RSVA accounts. Only incremental charges are allowed to be recorded into these accounts.

150. 7. VECC 36

Reference: E7/T1/S1/ pg.4-5

a) How is fact that the IESO undertakes meter data verification for those customer with smart meters whereas for larger customers this function must be performed by Festival taken into account in the weighting factors?

Response:

a) The verification of the data for smart meters is performed through the MDMR. For interval accounts, the data is verified as well by a third party. Please refer to 1 AMPCO 2 where there is a detailed explanation comparing the metering and bill activities for smart meter/TOU billed customers to interval customer billed customers. The complexities of each have been taken into the weighting factors.

151. 7. VECC 37

Reference: E7/T1/S3, Attachment 1 E7/T1/S4, pg.3

a) Please confirm that for 2015 Festival is proposing to collapse the existing Residential-Festival and Residential-Hensall classes into one single Residential customer class.

b) Please provide a revised Cost Allocation model where there is only one Residential customer class, consisting of the total of the existing two residential classes.

Response:

a) Agreed. The two existing residential classes will be combined into one single residential class.

b) Refer to results under 7 VECC 38 for combined residential class Cost allocation model.

152. 7. VECC 38

Reference: E7/T1/S4, pg.1-2

a) What would be the aggregate status quo revenue to cost ratio if the revenues for Residential-Festival and –Hensall were combined and similarly the allocated costs for the two were combined.

b) Please provide a schedule that sets out the aggregate fixed/variable split for the Residential-Festival and –Hensall classes combined based on the 2015 load forecast and existing (2014) rates?

c) What would be the resulting 2015 Residential rates if the results from parts (a) and (b) were used to establish Festival's Residential rates?

Response:

a) The aggregated status quo revenue to cost ratio combining all residential is 103.85%.

b) The fixed/variable splits of the combined residential would be basically the same as determined using Festival Hydro's approach at 41.63% to 58.37%.

c) Comparison of results:

Comparison of results:	Festival Hydro approach to	Combined approach:
Allocated Revenue Req	$6,280,010	$6,277,823
Fixed Rate	$16.75	$16.74
Variable Rate	$.0186	$.0186

The Combined residential costs allocation model has been filed in Festivals 2015 COS web drawer.

EXHIBIT 8 – RATE DESIGN

153. 8. OEB STAFF 51

Ref: E8/T7/S1 – Low Voltage Service Rates

Festival states that in order to determine new rates for 2014 and 2015, it took the Low Voltage kW demands for 2013, and applied the new January 2014 rates to determine the bridge year 2014 costs. Festival states that it then applied an estimated 2.0 % increase for the 2015 test year. However, the table illustrating the calculation uses 2013 actual costs and 2014 projected demand.

a) Please provide a table that illustrates what Festival proposes and explain the calculations and reasons why the approach Festival is proposing is appropriate.

b) Please explain why Festival did not apply the new Hydro One rates to the forecast demand for 2014 and then, if necessary, adjust with an estimated inflator such as 2% for the fact that Hydro One has applied for new higher rates.

c) If Festival's response to a) is not the approach stated in b), please proved the results from the approach described in b).

Response:

a) The Hydro One low voltage charges arise from the connection of the metering points at the smaller towns (Brussels, Dashwood, Hensall, Seaforth, and Zurich). Stratford and St. Mary are directly connected to the IESO. There is expected to be marginal to no growth in these smaller rural Ontario communities. As such, in the table on E8/T7/S1, Festivals calculation took the 2013 kW demands times the Jan 1, 2014 rates. Then for 2015 applied a 2% increase factor. The 2013 Actual cost in the first line is just provided for comparative purposes.

b) Festival did in fact use the 2013 kW quantity times HONI's January 1, 2014 approved sub transmission charges and then applied 2.0% for 2015.

c) Festival has not revised the filing as we believe the methodology as recommended above has been followed

154. 8. OEB STAFF 52

Ref: E8/T6/S1 and E3/T3/S1, p. 10 and Appendix 2-H – Specific Service Charge

In its application Festival Hydro requested to remove three of its temporary service – specific service charges from the Tariff of Rates and Charges and consequently change its Conditions of Service to adjust for these charges.

a) Please elaborate on how Festival Hydro's approach is in compliance with section 78(2) of the OEB Act?

b) Please provide a methodology that could be listed on the Tariff of Rates and Charges that would allow for a case-by-case calculation of these three charges, e.g. Temporary service – install & remove overhead – no transformer …time and material.

Response:

a) Festival intent is not to be in contravention of any section of the OEB Act. The intent is to establish a method whereby each customer pays their fair share of the cost of a temporary service because the time and material needed can vary somewhat significantly from one installation to the next.

b) The preference would be to include it on the Tariff of Rates and Charges with a description of "Time and Material" charge, and to spell out in the Conditions of Service what time and material on the Tariff of Rates and Charges consists of – i.e. wages and associated overheads, equipment and transportation, materials and contracted third party costs."

   If this is not an acceptable solution, Festival is then prepared to maintain status quo with temporary services as currently defined on the Tariff of Rates and Charges at the existing standard rates.

155. 8. OEB STAFF 53

Ref: E8/T10 – Tariff of Rates and Charges

The 3rd paragraph in the "Application" section of the tariff sheet for each rate class reads as follows:

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

Based on recent Tariff of Rates and Charges approved by the Board in 2013 and 2014 rate applications, the above paragraph should be amended as follows:

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

Please confirm whether the applicant has any concerns with the noted change to be applied to those classes for which the regulatory component applies, and if so, why.

Response:

Thank you for bringing this to our attention. The intent is to use the wording as presented on the recent Tariff of Rates and Charges approved by the Board for the 2013 and 2014 rate applications.

156. 8. OEB STAFF 54

Monthly Billing Impacts

a) Please identify the billing frequency that the applicant is planning on using for the test period and beyond.

b) If the applicant is planning to implement monthly billing, please refer to parts c) through g) below. If not, please explain why not.

c) Please identify any impacts that the implementation of monthly billing has had on billing and collection expenses or any other OM&A category.

d) Please identify the percentage of customers on e-billing as of December 31, 2013.

e) Please describe the Applicant's efforts to promote e-billing to its customers.

f) Please describe other initiatives that the Applicant has undertaken, or intends to undertake, to manage the costs of monthly billing for all customers.

g) As part of the decision making process, has the applicant determined the impact of the change to monthly billing on its working capital? If so, how is the working capital impacted by this change? If not, why not?

Response:

a) Festival has always billed customers on a monthly basis and plan to continue to do so.

b) N.A.

c) N.A.

d) There are 1,397 (as at Aug 8, 2014) or 6.9% of our customers on e-billing.

e) Festival has promoted e-billing on its website and billing inserts

f) Continue to encourage e-billing in order to reduce cost associate with billing forms and to offset the impact of increasing postage costs.

g) N.A.

157. 8. AMPCO 12

Ref: Exhibit 8, Tab 1, Schedule 1

a) Please provide the proposed fixed and variable rates for each customer class if the added constraint of not decreasing the monthly fixed charge was removed and the monthly fixed charge was the customer unit cost per month based on minimum system with PLCC adjustment as per the cost allocation model. Please confirm the fixed/variable splits under this scenario.

Response:

Attached are two tables – 1. Festival's proposed fixed/variable rates as filed and 2. Fixed/variable rates with the fixed rate based on customer unit cost per month based on minimum system with PLCC adjustment as per the cost allocation model, as requested.

Response to -AMPCO - 12
Distribution Revenue at Propsed Rates

	Fixed Charge			Variable Charge			Gross Revenue from Distribution Charges					
	Rate [1]	Volume [2]	Revenue [3]	Rate [1]	Volume [2]	Revenue [3]	Calculated *	Per 01 Dist Rev Eqmt	Difference	Fixed %	Variable %	
Residential - All	$16.59	218,688	3,628,034	$0.0185	140,900,799	2,606,665	6,234,699	6,233,759	-940	58.2%	41.8%	100.0%
General Service < 50 kW	$32.16	24,348	783,032	$0.0163	64,179,620	1,046,128	1,829,159	1,829,370	211	42.8%	57.2%	100.0%
General Service > 50 to 4999 kW	$253.49	2,724	690,507	$2.5557	944,456	2,413,746	3,104,253	2,731,647	-372,606	22.2%	77.8%	100.0%
Large Use	$11,900.62	12	142,807	$1.0482	34,360	36,016	178,824	158,170	-20,654	79.9%	20.1%	100.0%
USL (per connection)	$8.17	2,724	22,255	$0.0081	660,967	5,354	27,609	27,601	-8	80.6%	19.4%	100.0%
Sentinel Light (per connection)	$2.25	492	1,107	$11.8333	356	4,213	5,320	5,320	0	20.8%	79.2%	100.0%
Street Lighting (per light)	$0.96	79,512	76,332	$4.3975	11,995	52,748	129,080	129,442	362	59.1%	40.9%	100.0%
		328,500	5,344,073		206,732,553	6,164,869	11,508,943	11,115,309	-393,634			
					Transformer Allowances		-393290		393290			
							11,115,653	11,115,309	-344			

Distribution Revenue at Cusotmer Unit Cost per month based on minimum system with PLCC adjustment

	Fixed Charge			Variable Charge			Gross Revenue from Distribution Charges					
	Rate [1]	Volume [2]	Revenue [3]	Rate [1]	Volume [2]	Revenue [3]	Calculated *	Per 01 Dist Rev Eqmt	Difference	Fixed %	Variable %	
Residential - All	$20.14	218,688	4,404,376	$0.4154	140,900,799	1,829,383	6,233,759	6,233,759	0	70.7%	29.3%	100.0%
General Service < 50 kW	$34.38	24,348	837,084	$1.1854	64,179,620	992,286	1,829,370	1,829,370	0	45.8%	54.2%	100.0%
General Service > 50 to 4999 kW	$66.41	2,724	180,901	$14.1002	944,456	2,550,746	3,104,283	2,731,647	-372,636	5.8%	82.2%	88.0%
Large Use	$875.50	12	10,506	$14.0552	34,360	147,664	178,824	158,170	-20,654	5.9%	82.6%	88.5%
USL (per connection)	$8.13	2,724	22,146	$0.2463	660,967	5,455	27,601	27,601	0	80.2%	19.8%	100.0%
Sentinel Light (per connection)	$10.11	492	4,974	$0.0695	356	346	5,320	5,320	0	93.5%	6.5%	100.0%
Street Lighting (per light)	$6.42	79,512	510,467	($0.7464)	11,995	-381,025	129,442	129,442	0	394.4%	-294.4%	100.0%
		328,500	5,970,455		206,732,553	5,144,854	11,508,599	11,115,309	-393,290			
					Transformer Allowances		-393290		393290			
							11,115,309	11,115,309	0			

158. 8. AMPCO 13

Ref: Exhibit 8, Tab 1, Schedule 1 (Page 4 of 1)

Preamble: The evidence indicates Festival has three rate classes with fixed and variable rates outside of the ranges suggested by the cost allocation model (GS>50 kW and Large User are over; sentinel lighting is under), however the 2015 proposed fixed/variable splits are consistent with prior year.

a) AMPCO is not fully clear on the meaning of this statement. Please provide the fixed and variable information to support this statement.

Response:

Festival is proposing to maintain fixed/variable splits similar to the existing 2014 variable/fixed splits for most rate classes so as to minimize any bill impact which arise from modifying these splits. However, Festival has made a change as a result of the interrogatory process whereby the maximum fixed rate being charged will be the higher of the existing 2014 fixed rate charge or the minimum system with PLCC adjustment as per the cost allocation model. As such, Festival is proposing that for G.S. > 50 kW and Large Use proposed fixed rates will be their current fixed rate charge of $227.57 and $10,833.89, respectively. In addition, unmetered scattered load will be moved down to the minimum system with PLCC adjustment of $8.19 as per the cost allocation model. All other rates are below the minimum system with PLCC adjustment.
As noted in Festival original filing (E8/T1/S1 page 4), Festival is awaiting the final outcome of the OEB's initiative on Rate Design under EB-2012-0410, and will at that time consider undertaken any additional rate design changes as required.

159. 8. ENERGY PROBE 34

Ref: Exhibit 8, Tab 1, Schedule 1

What is the current status of the EB-2012-0410 OEB initiative noted on page 4?

b) Is Festival proposing any changes to the fixed/variable splits as a result of the OEB's initiative in this proceeding?

Response:

a) The Board issued a letter on April 30, 2014 along with its draft report on Rate Design. The letter also invited participants to take part in a stakeholder meeting, which have been held, and notes were posted on the Board website on June 3, 2014. The original letter also required written comments to be back by May 16, 2014 which was later changed to June 6, 2014. As of today, numerous written comments have been received by various stakeholders and posted on the website but no further reports or final decision has been released by the OEB.

b) In light of the fact this initiative is in progress with no final decision, Festival in the 2015 COS application is proposing fixed/variable splits for the 2015 test year which are very similar to fixed/variable splits in place for the 2014 rate year.

160. 8. SEC 20

Ref: [Ex. 8/1/1, p. 2]

Please confirm that the maximum fixed rate for GS>50, per the cost allocation study, is $66.41 per month, not $227.57. Please confirm that, if the fixed monthly charge for GS>50 in the Test Year is set at the maximum, $66.41, the variable charge would be $3.1937 per KW.

Response:

The Customer unit cost per month – Minimum System with PLCC Adjustment Rate as calculated in the Cost Allocation Model V 3.1 on the O2 Fixed Charge – Floor- Ceiling tab for G.S. > 50 kW is $66.41 per month.

The table below provides the calculation of the variable rate required in order to produce the total revenue requirement through distribution rates for the G.S. > 50 kW rate class under four scenarios: 1. using the proposed 2015 COS fixed rate 2. using the 2014 existing fixed rate (including the IRM Rate rider) (provided for comparative purposes) 3. using the Customer unit cost per month – Minimum System with PLCC Adjustment and 4. a calculation using the SEC reported amounts of $66.41 fixed and variable of $3.1937.

Total Distribution Revenue required through rates from G.S. >50 kW: $3,104,253
Total Forecasted Number of G.S. > 50 kW Customers: 227
Total Forecasted kW sold: 944,456 Kw

		Proposed 2015 COS Fixed of $253.49	**Existing 2014 Fixed Rate with ICM Rate Rider $242.26**	**Customer unit cost per month – Minimum System with PLCC Adjustment Rate $66.41**	**SEC calculation at $66.41 fixed and 3.1937 variable**
(A)	**Monthly Fixed Rate**	$253.49	$242.26	$66.41	66.41
(B)	**Fixed Rate Revenue (i.e. 227*12*(A)**	$690,507	$659,916	$180,901	$180,901
(C)	**Amount required through variable rates ($3,104,253-(B)**	$2,413,746	$2,444,347	$2,923,352	$3,016,309
(D)	**Required kW Distribution Rate (i.e. (C)/944,546 kW**	$2.5557	$2.5881	$3.0953	$3.1937
	Total Distribution Revenue Required through rates	$3,104,253***	$3,104,253***	$3,104,253***	$3,197,210

*** Total distribution revenue requirement through rates - this amount is after adjustments are made to revenue to costs ratios to bring outliers into acceptable ranges – See tab 01 Revenue to Cost RR cell G100.

Festival cannot confirm that at a fixed rate of $66.41 the variable rate would be $3.1937 as Festival arrives at a different total distribution revenue amount being generated through distribution rates.

161. 8. SEC 21

Ref: [Ex. 8/2/1, p. 2]

Please confirm that, as a result of the commissioning of the new transformer station in 2013, the transmission connection charges for the Applicant's customers are forecast to be reduced by about $350,000 in the Test Year. Please provide a cost-benefit analysis, from the customers' point of view, *showing the incremental costs they are bearing as a result of the transformer station (cost of capital, depreciation, PILs, OM&A, and any other costs), and the savings they are expected to enjoy as a result of the station (reduced transmission connection charges, line losses, station maintenance and other OM&A costs, and any other benefits). Please provide the cost-benefit analysis at least for the Test Year, and if possible also on a lifecycle basis.*

Response:

The monthly reduction of 20,000 kW arising from the Permanent Bypass Agreement with Hydro One results in annual savings of $475,200 in transformation connection charges. The kW reduction has been reflected monthly in the RTSR Model on Tab # 8 Forecasted Wholesale. In summary:

Tab 7 Current Wholesale (2013)	1,042,640 kW @ $1.98	$2,064,427
Tab 8 Forecast Wholesale (2015)	802,640 kW @ $1.98	$1,589,227
Reduction	240,000 kW	$ 475,200

In the table below, Table 8-SEC-21, the projected costs associated with the construction and operation of the Transformer Station (i.e. annual and periodic maintenance, costs of capital, depreciation and PILs) compared to the projected revenues/savings to customers arising from the Permanent Bypass agreement and the projected incremental distribution revenues (due to load growth) associated with the TS operations. The spreadsheet shows a net positive return occurring in 2037. This trend is expected to continue beyond the 25 years shown in the table as the TS assets are expected to have a useful life in excess of 40 years.

Festival would note that the status quo that existed prior to the construction of the Transformer Station was not sustainable and the comparison provided in this response does not include the inevitable additional costs that would have been incurred or other incremental impacts that would have resulted if any of the other options were chosen. Further, the savings due to reduced losses has not been factored in this calculation as they are expected to be marginal and were not a significant factor in the decision to construct the TS.

In terms of cost/benefit analysis, Festival's detailed justification for the construction of the transformer station can be found in Festival's 2013 IRM Application (EB-2012-0124) starting on page 12. The 2013 IRM submission provides, in detail, the expected costs associated with the TS construction compared to the many benefits to be achieved such as addressing of capacity requirements, feeder loading issues, voltage issues and reliability improvements. The decision for Festival to proceed with the construction of the Transformer Station was reviewed by the Board and was not based only on a cost/benefit analysis.

New TS Operating & Maintenance Costs - All Third Party (not indexed for inflation, does not include property tax														
	COSTS							Revenue (& Offsets)			NET			
	Annual Monitoring, Operating, Reporting	Periodic Extensive Maintenance	Weighted Cost of Capital - TS	Weighted Cost of Capital - Permanent Bypass	PILS	Depreciation	Total Costs	Distribution Revenue	Transmission Connection Savings	Total Revenue Offsets	Net Revenue	Average Capital	Average Permanent Bypass	Average Balance of Additional Capital
2015	$140,000		$923,574	$80,293	$266,025	$364,981	$1,774,873	$508,490	$475,200	$983,690	-$791,183	$14,777,178	$1,175,358	$0
2016	$142,800		$902,471	$80,293	$260,432	$364,981	$1,750,978	$533,109	$475,200	$1,008,309	-$742,669	$14,439,531	$1,148,024	$0
2017	$145,656		$881,368	$80,293	$254,840	$364,981	$1,727,138	$555,579	$475,200	$1,030,779	-$696,359	$14,101,884	$1,120,690	$0
2018	$148,569		$860,265	$80,293	$249,248	$364,981	$1,703,356	$575,406	$475,200	$1,050,606	-$652,750	$13,764,237	$1,093,356	$0
2019	$151,541		$839,162	$80,293	$243,656	$364,981	$1,679,632	$597,875	$475,200	$1,073,075	-$606,557	$13,426,590	$1,066,022	$0
2020	$154,571	$50,000	$818,059	$80,293	$238,063	$364,981	$1,705,968	$612,477	$475,200	$1,087,677	-$618,291	$13,088,943	$1,038,688	$0
2021	$157,663		$796,956	$80,293	$232,471	$364,981	$1,632,364	$626,804	$475,200	$1,102,004	-$530,360	$12,751,296	$1,011,354	$0
2022	$160,816		$775,853	$80,293	$226,879	$364,981	$1,608,822	$638,697	$475,200	$1,113,897	-$494,925	$12,413,649	$984,020	$0
2023	$164,032		$754,750	$80,293	$221,287	$364,981	$1,585,343	$653,024	$475,200	$1,128,224	-$457,119	$12,076,002	$956,686	$0
2024	$167,313		$746,147	$80,293	$219,007	$364,981	$1,577,741	$664,917	$475,200	$1,140,117	-$437,624	$11,738,355	$929,352	$200,000
2025	$170,659	$50,000	$724,544	$80,293	$213,282	$372,981	$1,611,760	$679,244	$475,200	$1,154,444	-$457,316	$11,400,708	$902,018	$192,000
2026	$174,072		$702,961	$80,293	$207,562	$372,661	$1,537,551	$691,136	$475,200	$1,166,336	-$371,215	$11,063,061	$874,684	$184,320
2027	$177,554		$681,398	$80,293	$201,848	$372,354	$1,513,447	$705,463	$475,200	$1,180,663	-$332,784	$10,725,414	$847,350	$176,947
2028	$181,105		$659,852	$80,293	$196,139	$372,059	$1,489,448	$717,356	$475,200	$1,192,556	-$296,892	$10,387,767	$820,016	$169,869
2029	$184,727		$638,325	$80,293	$190,434	$371,776	$1,465,555	$731,683	$475,200	$1,206,883	-$258,672	$10,050,120	$792,682	$163,075
2030	$188,422	$50,000	$616,814	$80,293	$184,733	$371,504	$1,491,766	$743,576	$475,200	$1,218,776	-$272,990	$9,712,473	$765,348	$156,552
2031	$192,190		$595,320	$80,293	$179,037	$371,243	$1,418,084	$757,903	$475,200	$1,233,103	-$184,981	$9,374,826	$738,014	$150,289
2032	$196,034		$573,841	$80,293	$173,346	$370,993	$1,394,506	$769,796	$475,200	$1,244,996	-$149,510	$9,037,179	$710,680	$144,278
2033	$199,954		$552,377	$80,293	$167,658	$370,752	$1,371,035	$784,123	$475,200	$1,259,323	-$111,712	$8,699,532	$683,346	$138,507
2034	$203,954		$543,351	$80,293	$165,266	$371,751	$1,364,615	$796,016	$475,200	$1,271,216	-$93,399	$8,361,885	$656,012	$331,737
2035	$208,033	$50,000	$521,419	$80,293	$159,454	$371,751	$1,390,950	$808,868	$475,200	$1,284,068	-$106,882	$8,024,238	$628,678	$318,468
2036	$212,193		$499,893	$80,293	$153,749	$371,751	$1,317,880	$819,286	$475,200	$1,294,486	-$23,394	$7,686,591	$601,344	$311,698
2037	$216,437		$478,367	$80,293	$148,045	$371,751	$1,294,894	$832,138	$475,200	$1,307,338	$12,444	$7,348,944	$574,010	$304,928
2038	$220,766		$456,841	$80,293	$142,341	$371,751	$1,271,992	$842,556	$475,200	$1,317,756	$45,764	$7,011,297	$546,676	$298,158
2039	$225,181		$435,315	$80,293	$136,636	$371,751	$1,249,177	$842,556	$475,200	$1,317,756	$68,579	$6,673,650	$519,342	$291,388
2040	$229,685	$50,000	$413,789	$80,293	$130,932	$371,751	$1,276,450	$842,556	$475,200	$1,317,756	$41,306	$6,336,003	$492,008	$284,618

162. 8. VECC 39

Reference: E8/T2/S1/pg.1

a) Please provide a copy of the Permanent Bypass Agreement with Hydro One.

b) Please describe more fully precisely how the 20,000 kW demand per month was accounted for the RTSR model.

Response:

a) A copy of the Permanent Bypass Agreement has been filed in the Festival Hydro 2015 COS web drawer.

b) The monthly reduction of 20,000 kW arising from the Permanent Bypass Agreement with Hydro One results in annual savings of $475,200 in transformation connection charges. The kW reduction has been reflected monthly in the RTSR Model on Tab # 8 Forecasted Wholesale. In summary:

Tab 7 Current Wholesale (2013)	1,042,640 kW @ $1.98	$2,064,427
Tab 8 Forecast Wholesale (2015)	802,640 kW @ $1.98	$1,589,227
Reduction	240,000 kW	$ 475,200

163. 8. VECC 40

Reference: E8/T8/S1, Attachment 1

a) Please reconcile the Large Use kWh shown in Row B with the values reported in Exhibit 3 at:
- *E3/T2/S1, page 7*
- *E3/T1/S2, Attachment 1, Schedule 3, page 8 (Table 3.8)*

b) Please indicate how the Supply Facilities Loss Factor (row H) was determined for each year.

c) Please indicate how the determination of the Supply Facilities Loss Factor accounts for the fact that a portion of Festival's power comes from microFIT and FIT installations.

Response:

a) Row B of Appendix 2-R includes all kWh which were sold at the large use class rates subject to the approved loss factor for Primary metered customers > 5000 kW. For load forecasting under Exhibit 3, the kWh of the former large use customers (that are now in G.S> 50 kW class) has been reclassified to G.S. > 50 kW in order to properly forecast the load for each of these classes. So the Large Use kWh on Appendix 2-R for 2009 to 2011 will not agree to the load forecast historical quantities. For 2012 and 2013, being there is just the single customer, the large use quantities on Appendix 2-R agree to the load forecast data as presented on E3/T1/S2 Attachment 1 Schedule 1 page 2 and Schedule 3 page 8 (3.8). The page with discrepancies is actually found on E3/T2/S1 page 7. The total kWh sold in the year is correct but there is a slight overage/underage in Large Use which is equally offset in the G.S. > 50 kW category.

b) Festival is directly connected to the IESO controlled grid. Even though some metering points are embedded, all metering points are connected to the IESO control grid and Festival is billed by the IESO for all energy purchased. Festival's settlement software provides the consolidated values for all of Festival's metering points to be able to perform this calculation.

c) On the generator's bill, a loss factor is applied to the generation kWh being fed into the grid equal to Festival's supply loss factor.

EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNT

164. 9. OEB STAFF 55

Ref: E9/T1/S1/p.2 and Accounting Procedures Handbook, effective January 1, 2012

In the DVA table for Account 1590 Recovery of Regulatory Asset Balances, Festival has indicated that the account will be continued. If Account 1590 is approved for disposal, this account will be cleared to $0. Account 1590 has been discontinued in the Accounting Procedures Handbook, effective January 1, 2012. The Board approved Account 1595 Disposition and Recovery/Refund of Regulatory Balances in 2008. Please explain why Festival is proposing the continuation of Account 1590.

a) Please revise the evidence as appropriate.

Response:

a) Festival reported "Yes" to the continuation of Acct # 1590 in error. The schedule has been updated to state "No". Likewise for 1508-IFRS.

Summary of Deferral and Variance Accounts for 2015 COS Applicat		Principal & Int Dec 31, 2013	2014 Dispositions	2014 Projected Interest	2015 COS Claim	Continuation of Account
LV Variance Account	1550	127,887	-	1,885	129,772	Yes
RSVA - Wholesale Market Service Charge	1580	- 2,360,459	-	- 33,667	- 2,394,126	Yes
RSVA - Retail Transmission Network Charge	1584	283,491	-	4,128	287,619	Yes
RSVA - Retail Transmission Connection Charge	1586	404,329	-	5,704	410,033	Yes
RSVA - Power (excluding Global Adjustment)	1588	213,293	-	3,245	216,538	Yes
RSVA - Global Adjustment	1589	1,056,009	-	14,762	1,070,771	Yes
Recovery of Regulatory Asset Balances	1590	48,266	-	1,394	49,659	No
Smart Meter Entity Charge Variance Account	1551	15,670	-	228	15,898	Yes
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	-		-	-	
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	- 312,135	254,512	-	- 57,623	No
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	1,640	-	-	1,640	No
Total of Group 1 Accounts (excluding 1589)		**-$522,009**		**-$2,322**	**- 269,819**	
Other Regulatory Assets - Sub-Account - Deferred IFRS Transitior	1508	113,398	-	1,612	115,010	No
Other Regulatory Assets - Sub-Account - Incremental Capital Cha	1508	2,269	-	32	2,301	No
Other Regulatory Assets - Sub-Account - Other - ICM Rate Rider	1508	15,053,811	- 15,053,811	-	0	Yes
Retail Cost Variance Account - Retail	1518	- 53,429	-	- 751	- 54,180	Yes
Misc. Deferred Debits - 2010 Rate Application Costs	1525	15,725	- 12,000	-	3,725	No
Retail Cost Variance Account - STR	1548	- 1,413	-	- 20	- 1,433	Yes
Other Deferred Credits	2405	45,209	-	-	45,209	No
Total of Group 2 Accounts		**$15,175,571**	**-$15,065,811**	**$872**	**110,632**	
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592					
Total of Account 1562 and Account 1592		**-$164,589**	**-$37,211**	**$0**	**-$164,589**	No
LRAM Variance Account	1568	**$175,826**	**$54,271**	**$2,484**	**$178,310**	Yes
IFRS-CGAAP Transition PP&E Amounts Balance + Return Compo	1575	- 696,846	- 826,853	- 190,462	- 1,714,161	Yes
Accounting Changes Under CGAAP Balance + Return Componer	1576	-	-	-	-	
Total Balance Allocated to each class for Accounts 1575 and 1576		**- 696,846**	**- 826,853**	**- 190,462**	**- 1,714,161**	
Smart Meter Capital and Recovery Offset Variance - Sub-Account	1555	**$0**	**$234,537**	**$0**	**$234,537**	No
			ICM Rate Rider Claim		326,336.00	
			Total Claim		**- 1,298,753.69**	

165. 9. OEB STAFF 56

Ref: E9/T2/S4/p. 1; EDDVAR Continuity Schedule; and Report of the Board on Electricity Distributor's Deferral and Variance Account Review Initiative ("EDDVAR Report")

Per Exhibit 9, Account 1595-2010 balance was to be disposed over a four year period ending April 30, 2014 as per Festival's 2010 cost of service application. As at April 30, 2014, Festival projects that the principal and original interest will have been fully repaid and $57,623 of new interest will remain at December 31, 2014. No new interest has been added to the account after April 30, 2014. Festival is requesting the disposition of this remaining balance and the account to be closed.

a) The 2015 claim amount for Account 1595-2010 in the EDDVAR continuity schedule is for principal and interest balances as at December 31, 2013. For the claim amount of ($57,623), please clarify:

i.) The date in which the principal and "original" interest pertains to (i.e. as at December 31, 2013 per EDDVAR continuity schedule or December 31, 2014 per Exhibit 9)

ii.) The date in which the "new" interest pertains to as Festival indicated $57,623 of new interest will remain as at December 31, 2014, but no new interest has been added to the account after April 30, 2014.

iii.) Whether the claim amount includes all rate riders refunded up to and only up to April 30, 2014. If not, please provide further details.

iv.) Why the claim amount of ($57,623) is exactly equal to the "new" interest (i.e. was there no under or over collection of rate riders as at April 30, 2014?).

v.) What the $254,512 in the 2014 Disposition column of the EDDVAR continuity schedule represents.

b) Per page 12 of the EDDVAR Report, the balances to be reviewed in the distributor's application will be for the most recent period ending December 31 as reported to the Board as of April 30 through the RRR. In Festival's case, this will be balances as at December 31, 2013. It appears that Festival is proposing to dispose of Account 1595-2010 as at April 30, 2014 or December 30, 2014. Please clarify which date Festival is proposing to dispose the account as at and explain why Festival is proposing to deviate from the EDDVAR Report and dispose of a future unaudited balance.

Response:

a)

i. This is the balance projected to remain in the account after the existing rate rider had come to an end as at April 30, 2014 and hence the December 31, 2014 balance.
ii. It is Festival's understanding that new interest could only be calculated on the declining original principal balance, so when the principal was fully paid in April 2014 Festival ceased accruing any new interest.
iii. It includes all rate rider amounts paid until the rate rider ceased effective April 30, 2014.
iv. The original principal and original interest has been fully paid. In addition, there was $1,404 paid that was applied against the new interest balance.
v. The $254,512 was the rate rider amount projected to be paid from January 1, 2014 to April 30, 2014. Festival was working with an unlocked version of the 2014 EDVAR spreadsheet and did not add any new columns so entered the 2014 rate rider amount as such.

b) Festival is requesting the disposal of the balance in #1595-2010 as part of the COS application contrary to page 12 of the EDDVAR report. When completing the COS application Festival knew that by the time the interrogatories were filed that the payout of the rate rider would be complete and the remaining balance of the account would be known. The current balance in the account is a credit owing of $56,321, which is $1,302 difference from what was reported. Festival would prefer if this balance could be cleared so Account 1595-2010 can be removed from the books effective January 1, 2015.

166. 9. OEB STAFF 57

Ref: E9/T3/S2/p.1-2; E9/T3/S3/p. 1; Festival 2010 Cost of Service Decision EB-2009-0263 and Accounting Procedures Handbook ("APH") FAQ December 2010

Per Schedule 2, Festival indicated that it was directed by the Board to record incremental savings on HST in its 2010 cost of service application. Festival has recorded this under Account 1592, PIL's and Tax Variances for 2006 and Subsequent Years. Per Schedule 3, Festival indicated that Account 1592 Harmonized Sales Tax deferral account is not used. Per page 19 of the Board decision for Festival's 2010 cost of service application, Festival was directed to use deferral account 1592 PILS and Tax Variances, sub-account HST/OVAT Input Tax Credits.

a) Please explain why Festival is not using the Board directed sub-account. Please revise the evidence as necessary, specifically indicating which account Festival is using and the continuation and discontinuation of the sub-accounts.

b) Please confirm that the balance of $164,589 requested for disposition is 50% of the total ITCs tracked from July 1, 2010 to December 31, 2013 and ITCs forecasted from January 1, 2014 to December 31, 2014. If not, please explain what portion of the ITCs the 50% was applied to.

Festival indicated that it has not included any of the savings related to capital purchases. APH FAQ dated December 2010, FAQ #4 states that "For any period before the rebasing that occurs after July 1, 2010 these PST savings would be included in the annual depreciation of the capital items. These depreciation saving amounts would need to be identified, calculated and summarized." Festival last rebased in 2010, per page 18 of the Board Decision for Festival's 2010 cost of service rate application, Festival stated that it has not made any adjustments to its 2010 OM&A and capital expenditure forecasts. Therefore, Festival should include capital related savings in the account.

c) Please explain why Festival did not include savings related to capital purchases in the account.

d) Please provide an analysis on the capital savings from July 1, 2010 to December 31, 2014 in accordance with APH FAQ December 2010, FAQ #4 and update the evidence as necessary.

Response:

a) Festival is in fact using deferral account 1592 PILS and Tax Variances, sub-account HST/OVAT Input Tax Credits. E9/T3/S3 has been updated correctly.

Account 1592 Harmonized Sales Tax Deferred Credit E9/TS/S3/Pg 1

As part of Festivals 2010 COS application, the Board directed Festival to use Deferral account 1595 PILS and Tax Variances, Subaccount HST/OVAT Input Tax Credits to record the incremental savings resulting from the replacement of the Provincial Sales tax with the Harmonized Sales Tax (HST) effective July 1, 2010.

The Board provided further direction on a proxy method to record incremental tax savings amounts into account 1592 in the OEB APH – FAQ dated December 2010. However, Festival had already put processes and procedures in place in order to record the incremental savings on a transaction by transaction basis starting July 1, 2010. This procedure will be kept in place until December 31, 2014.

On the EDVARR continuity schedule, the actual incremental savings have been included annually up to December 31, 2013. For fiscal 2014, an estimate of savings was used based on the actual savings incurred in fiscal 2013. On the EDVARR continuity, the amount for 2014 has been entered into the 2014 Board approved disposition column in order to get the 2014 amount into the Total Claim. The amount being reported in this application of $164,589 ($159,506 principal and $5,083 interest) in account # 1592 represents a refund owing to customers. The amount is 50% of the estimated gross savings, which is based on the methodology that is consistent with the approach taken by Powerstream (EB-2012-0161) and consistent with Board's guidance.

In addition, under FAQ #4 it is noted that capital purchases made on or after July 1, 2010 will be reflected in the reduced values of the assets included in the rate base at time of next cost of service application. The savings in costs will flow to ratepayers at that time. Accordingly, Festival has not included any of the savings related to capital purchases as the ratepayers will benefit as a result of the lower rate base.

Appendix 2-TB below provides the balances for each of the years 2010 through to December 31, 2014, including carrying charges. Festivals request disposition of this account over a one year period based on Distribution Revenue. Festival request discontinuation of the 1592 HST sub account as it is no longer needed after December 1, 2014.

b) Confirmed. The balance of $164,589 requested for disposition is 50% of the total ITCs tracked from July 1, 2010 to December 31, 2013 and ITCs forecasted from January 1, 2014 to December 31, 2014. However, there has been no HST impact calculated on either Smart meters or Transformer station assets and expenses because these assets and expenses were never part of Festival's 2010 COS so therefore there no HST savings.

c) Festival's has revised Appendix 2- TA and 2-TB to reflect the HST related to the depreciation savings amounts. An amount of $17,524 has been added. The EDVARR continuity schedule and the Rate rider determination shown on E9/T1/T1 has been updated to reflect this change.
Impact of HST capital savings is noted below:

9 Staff 57

HST on Capital Additions					Estimate	
	2010 - 6 mths	**2011**	**2012**	**2013**	**2014**	**Total**
Total HST on Capital	59,549	130,034	72,808	117,521	74,947	454,859
Depn	25 yrs	25 yrs	25 yrs	40 yrs	40 yrs	
half year rule	1,191	2,601	1,456	1,469	937	
Full year	2,382	5,201	2,912	2,938	1,874	
Change to 40 year avge	1,489	3,251	1,820	2,938	1,874	
Annual Depn:						
2010	1,191	2,382	2,382	1,489	1,489	
2011		2,601	5,201	3,251	3,251	
2012			1,456	1,820	1,820	
2013				1,469	2,938	
2014					1,874	
	1,191	4,983	9,039	8,029	11,371	
Half Rule	595	2,491	4,520	4,014	5,686	17,307
Interest 1.47%	9	23	52	63	71	217
Total	604	2,514	4,571	4,077	5,757	17,524

Appendix 2-TA
Account 1592, PILs and Tax Variances for 2006 and

accordance with the notes following the table. An explanation should be provided for any

Tax Item		Principal as of December 31, 20XX
application PILs model for the period from May 1, 2006 to April 30,		
application PILs model for the period from January 1, 2006 to April		
for 2007		
for 2008		
for 2009		
for 2010		
for 2011		
for 2012		
for 2013		
for 2006		
for 2007		
for 2008		
for 2009		
for 2010		
for 2011		
for 2012		
for 2013		
not recorded above. Please provide details and explanation		
Sub Account HST OVAT Input Tax Credits		$ 182,031
Total		$ 182,031

File Number:	0
Exhibit:	9
Tab:	3
Schedule:	2
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Appendix 2-TB
Account 1592, PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST/OVAT Input Tax Credits (ITCs)

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries.

100% of the balance in Account 1592, PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST/OVAT Input Tax Credits (ITCs), should be recorded in this table.

Summary of PST Savings from 2009 Historic Year Analysis

	Principal 2010	Principal 2011	Principal 2012	Principal 2013	Principal 2014	Principal Jan-April 2015 [1]	Carrying Charges to Dec 31, 2014	Total Account 1592, sub-account HST/OVAT Balance
OM&A Expenses PST Savings	$ 19,698	$ 36,835	$ 32,627	$ 35,173	$ 35,173	$ -	$ 5,001	$ 164,507
Capital Items PST Savings	$ 596	$ 2,491	$ 4,520	$ 4,014	$ 5,686	$ -	$ 217	$ 17,524
Total Annual PST Savings [2]	$ 20,294	$ 39,326	$ 37,147	$ 39,187	$ 40,859	$ -	$ 5,218	$ 182,031

[1] Include January to April 30, 2015 PST savings if the rate year begins May 1, 2015. If the rate year begins Jan 1, 2015, include PST savings to December 31, 2014.

[2] Derived PST savings proxy for each year per 2009 historic year analysis

Note: Assumes level OM&A and Capital Spending year over year. An alternative detailed transactional analysis may also be performed using actual expenditures from 2010 to the start of the rate year.

167. 9. OEB STAFF 58

Ref: E9/T3/S4/p. 1 and E9/T3/S6/Att. 1, Appendix 2-U; and Filing Requirements

Electricity Distribution Rate Applications for 2015 Rate Applications, dated July 18, 2014

In Exhibit 9, Festival indicated that the balance in Account 1508 Deferred IFRS Transition Costs is $115,398, including $109,628 in costs and carrying charges of $5,770 as at December 3, 2014.

In Appendix 2-U, please clarify whether the $9,525 in the Audited Carrying Charges to Dec. 31, 2013 column are actually costs incurred in 2013 or are carrying charges. If it is for carrying charges, please explain the nature of these carrying charges.

Per chapter 2, page 61 of the Filing Requirements, an applicant should request for review and disposal of the account for the balance including the unaudited actuals for the bridge year and a forecast of any remaining costs to be incurred for the test year.

a) Please quantify these costs and the related carrying charges to December 31, 2014 and update the evidence.

Response:

a) The 6th column consists of $9,525 in expenditures and $1,591 in carrying charges, as Festival was using the 2014 version of the model. With an updated version of Appendix 2 – U available, Festival has filed the revised 2 - U to place the 2013 balance in the correct columns and also added $20,000 of costs expected to be incurred in 2014 related to final accounting advisory services, assistance on financial statement notes, and the cost of auditing the opening IFRS balances for a revised total of $135,083. The EDVARR continuity schedule and the Rate rider determination shown on E9/T1/T1 have been updated to reflect this change. In addition, this account can be closed as part of the 2015 COS application and no continuation are necessary.

Exhibit: 9
Tab: 3
Schedule: 8
Page: 1

Date: 27-Aug-14

Appendix 2 U

One time Incremental IFRS

Regulatory Assets, sub-account Deferred IFRS Transition Costs Account, or Account 1508, Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account.

Nature of One-Time Incremental IFRS Transition Costs [1]	Audited Actual Costs Incurred 2009	Audited Actual Costs Incurred 2010	Audited Actual Costs Incurred 2011	Audited Actual Costs Incurred 2012	Audited Actual Costs Incurred 2013	Audited Carrying Charges to Dec 31, 2013	Forecasted Costs 2014	Forecasted Costs 2015	Total Costs Excluding Carrying Charges	Carrying Charges January 1, 2014 to April 30, 2015	Total Costs and Carrying Charges	Reasons why the costs recorded meet the criteria of one-time IFRS administrative incremental costs
professional accounting fees	$ 33,000	$ 14,250		$ 9,010			$ 20,000		$ 76,260		$ 76,260	Guidance on policies; advisory services, auditing
professional legal fees									$ -		$ -	opening balances
salaries, wages and benefits of staff added to support the transition to IFRS				$ 41,729	$ 9,525				$ 51,254		$ 51,254	3rd part contractor working on conversion
associated staff training and development costs	$ 1,084		$ 598	$ 432					$ 2,114		$ 2,114	IFRS training for existing staff
costs related to system upgrades, or replacements or changes where IFRS was the major reason for conversion									$ -		$ -	
									$ -		$ -	
Carrying charges at prescribed rates						$ 3,770			$ -	$ 1,685	$ 5,455	Carrying charges at prescribed rates
									$ -		$ -	
									$ -		$ -	
previous Board approved rates									$ -		$ -	
									$ -		$ -	
Insert description of additional item(s) and new rows if needed.									$ -		$ -	
Total	$ 34,084	$ 14,250	$ 598	$ 51,171	$ 9,525	$ 3,770	$ 20,000	$ -	$ 129,628		$ 135,083	

Note:
1 changes that reflect changes in the timing of the recognition of income. The incremental costs in these accounts shall not include costs related to system upgrades, or replacements or changes where IFRS was not the major reason for conversion. In addition,
2 Board approved rates, please state the EB #: nil

168. 9. OEB STAFF 59

Ref: E9/T3/S7/p.1-3 and Accounting Procedures Handbook ("APH"), effective January 1, 2012

Festival stated that it is awaiting its 2015 future employee benefit actuarial report. Festival requested that as part of this proceeding, Festival be allowed to update Account 1575 for the projected change in liability arising due to the adoption of MIFRS. Per the APH, Account 1575 pertains only to differences in PP&E accounts that will be included in rate base.

a) Please explain why Festival is proposing to include future employee benefit obligations in Account 1575.

b) Please provide any updates to future employee benefits in the relevant sections of the application.

Response:

a) Festival in error thought all changes related to IFRS conversion were to go into Account # 1575. We now understand # 1575 and # 1576 relates only to PP & E. A request for a new deferral and variance account is proposed under 9 staff 60.

b) Section 4 staff 41 provides an update on Festival's projected 2014 and 2015 Employee Future Benefit Accruals along with a copy of the Actuarial report. Note that the discount rates used are estimates based on current discount rates and are subject to change when revalued at year end using the discount rates in place at that time.

169. 9. OEB STAFF 60

Ref: E9/T3/S7/p.1-3

With regards to Account 1575, Festival requests the ability to true up 2014 bridge year forecasted amounts used in determining Account 1575 balances and other transitional amounts not identified in the application.

a) Please explain what the "other transitional amounts" not identified in the application could include.

b) In response to part (a), please explain why these other transitional amounts have not been incorporated into the application even though Festival is filing a 2015 cost of service application based on MIFRS.

c) In the past, the Board has typically approved the disposition of Account 1575 with no true-up to actuals. Please explain why Festival is requesting that the Board deviate from this practice.

Response:

a) As Accounts # 1575 and # 1576 relate strictly to PP & E, there are no other transition amounts to include in these accounts. Festival in error thought all changes related to IFRS conversion were to go into Account # 1575.

b) The only other transitional amount Festival has identified is the difference arising upon converting the Employee Future Benefit Accrual from CGAAP to IAS 19. As noted in 4 staff 41, based on recent Actuarial estimates, an amount of $44,850 is owing to Festival Hydro arises as a result of transitioning to IAS 19. As a result, Festival is requesting a new variance account related to IFRS conversion for the impact of the change in the Future Employee Benefit Accrual arising from conversion to IAS 19. Festival will request to disposed of this amount as part of a future IRM proceeding.

2015 DVA Account Required:

Closing Accrual under CICA, Dec 31, 2014	1,401,958	(Festival accrued/expensed)
Closing Accrual under IAS19, Dec 31, 2014	1,357,108	(Accrual needed under IAS 19)
Difference arising on converting to IFRS	44,850	(owing to Festival Hydro)

c) Correction. No true up to actual is requested for Account # 1575.

170. 9. OEB STAFF 61

Ref: E9/T3/S8; E9/T3/S7/Att. 1, Appendix 2-EE; E2/T1/S1/Att. 1, Appendix 2-BA; E3/T3/S1/p.9; E1/T4/S1/Att. 3, 2013 Financial Statements; and Accounting Procedures Handbook, FAQ, July 2012

Per Schedule 7, Festival made accounting policy changes effective January 1, 2013, when Festival was still under CGAAP. The balance related to this was recorded in Account 1575. Per Schedule 8, Account 1576 has a zero balance. However, the balance pertaining to the capitalization and depreciation policy changes should be recorded in Account 1576 as per the definition of the account in the APH. Per APH FAQ July 2012 Q2, Appendix A, Account 1575 and Account 1576 cannot be used interchangeably.

a) Please separate out the total change in PP&E between Accounts 1575 and 1576, subject to the interrogatories below, since the difference between Revised CGAAP and MIFRS in the bridge year is material, as can be seen in the Appendix 2-BA 2014 schedules.

Differences were noted regarding the total difference in PP&E balance Festival recorded in Account 1575. In Appendix 2-EE, the 2014 net closing PP&E under Revised CGAAP is $38,621,332. This balance does not correspond to the Appendix 2-BA 2014 New Policies net closing PP&E balance of $38,941,519 or MIFRS net closing PP&E balance of $38,262,163.

b) Please explain how the balance in Appendix 2-EE was derived and why it does not correspond to the balances from Appendix 2-BA.

c) Please update the evidence as appropriate to separate out the total PP&E difference between Accounts 1575 and 1576 as requested in part a) above, ensuring that the 2014 net closing PP&E balances agree to the balances in Appendix 2-BA Revised CGAAP for Account 1576 and MIFRS for Account 1575.

Differences were noted between the amounts recorded in Account 4305 (which agrees to the amount in Festival's 2013 financial statements) and the amounts recorded in Account 1575 from Appendix 2-EE as shown below.

	2013 FS Note 8	Exhibit 3, Tab 3, Schedule 1, Page 9	Appendix 2-EE

2013	696,846	696,846	737,036
2014	N/A	737,851	786,346
		1,434,697	1,523,382

d) Please explain and reconcile the differences between the amounts recorded in Account 4305/2013 financial statements and the amounts recorded in Account 1575. Please update the evidence as appropriate, subject to the interrogatories above.

Response:

a) Based on the fact that the balance pertaining to the capitalization and depreciation policy changes should be reported in account 1576, Festival has updated our E9/T3/S8 to reflect this.

b) The depreciation expense in appendix 2EE (in Festival's application filing) under new 2014 policies was overstated by $320K causing the difference noted. Festival has corrected this and has submitted a revised appendix 2EA and 2EC (templates from the new 2015 appendices released in August 2014) as noted in 61c below. Festival has also updated the relevant variance account schedules in exhibit 9.

c) To prepare the data requested for this question Festival used the newly released OEB appendices for 2015 filers and updated appendix 2-EA for account 1575 and appendix 2-EC for account 1576. Appendix 2-EC shows a difference in net PP&E under CGAAP and MIFRS in 2014 as a result of disposals being reflected under 2014 MIFRS and the resulting impact on depreciation expense due to these disposals as well. In preparing this analysis – Festival also noted that appendix 2BA table 2014 MIFRS had a formula error and has corrected the table. As indicated in Staff IR#5e – Festival plans to dispose of assets on conversion at January 1, 2015 and the 2014 MIFRS continuity schedule was created for comparative purposes only. The EDVORR Schedule and rate rider calculations have been updated to reflect the revised balance in 1576, a balance in 1575 previously no reported in error, and a change in payback period over 4 years rather than 2 years due to cash flow impacts.

d) During the process of preparing our cost of service application, Festival revised calculations of the impacts of the capitalization and depreciation changes on fixed assets. As such – our 2013 audited figure of $697K was immaterially different from what was reported in appendix 2. Festival also notes that Appendix 2 has been revised for 2014 anticipated variances and as such the figures included in exhibit 3 should be revised to agree to Appendix 2-EA.

File Number:	EB 2014 0073
Exhibit:	
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Appendix 2-EA
Account 1575 - IFRS-CGAAP Transitional PP&E Amounts
2015 Adopters of IFRS for Financial Reporting Purposes

For applicants that will adopt IFRS on January 1, 2015 for financial reporting purposes

	Rebasing	2011	2012	2013	2014	Rebasing
Reporting Basis	CGAAP	IRM	IRM	IRM	IRM	MIFRS
	Forecast	Actual	Actual	Actual	Forecast	Forecast
					$	$
PP&E Values under CGAAP						
Opening net PP&E - Note 1					38,941,516	
Net Additions - Note 4					2,222,648	
Net Depreciation (amounts should be negative) - Note 4					-2,679,286	
Closing net PP&E (1)					38,484,878	
PP&E Values under MIFRS (Starts from 2014, the transition year)						
Opening net PP&E - Note 1					38,941,516	
Net Additions - Note 4					1,589,898	
Net Depreciation (amounts should be negative) - Note 4					-2,679,285	
Closing net PP&E (2)					37,852,129	
Difference in Closing net PP&E, CGAAP vs. MIFRS					632,749	

Effect on Deferral and Variance Account Rate Riders			
Closing balance in deferral account	632,749	**WACC**	6.25%
balance at WACC - Note 2	158,187	**# of years of rate rider disposition period**	4
Amount included in Deferral and Variance Account Rate Rider Calculation	790,936		

Notes:
1 For an applicant that adopts IFRS on January 1, 2015, the PP&E values as of January 1, 2014 under both CGAAP and MIFRS should be the same.
2 Return on rate base associated with deferred balance is calculated as:
the deferral account opening balance as of 2015 rebasing year x WACC X # of years of rate rider disposition period
* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.
3 The PP&E deferral account is cleared by including the total balance in the deferral and variance account rate rider calculation.
4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

File Number:	EB 2014 0073
Exhibit:	
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Appendix 2-EC
Account 1576 - Accounting Changes under CGAAP
2013 Changes in Accounting Policies under CGAAP

For applicants that made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

	2010 Rebasing Year	2011	2012	2013	2014	2015 Rebasing Year
Reporting Basis	CGAAP	IRM	IRM	IRM	IRM	MIFRS
	Forecast	Actual	Actual	Actual	Forecast	Forecast
					$	$
PP&E Values under former CGAAP						
Opening net PP&E - Note 1				35,396,846	37,482,461	
Net Additions - Note 4				5,157,572	2,790,817	
Net Depreciation (amounts should be negative) - Note 4				-3,071,957	-3,175,328	
Closing net PP&E (1)				37,482,461	37,097,950	
PP&E Values under revised CGAAP (Starts from 2013)						
Opening net PP&E - Note 1				35,396,846	38,219,494	
Net Additions - Note 4				4,906,054	2,623,001	
Net Depreciation (amounts should be negative) - Note 4				-2,083,406	-1,900,978	
Closing net PP&E (2)				38,219,494	38,941,517	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				-737,033	-1,843,567	

Effect on Deferral and Variance Account Rate Riders			
Closing balance in Account 1576	- 1,843,567	**WACC**	6.25%
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	- 460,892		
Amount included in Deferral and Variance Account Rate Rider Calculation	- 2,304,459	**# of years of rate rider disposition period**	4

Notes:
revised CGAAP should be the same.
2 Return on rate base associated with Account 1576 balance is calculated as:
the variance account opening balance as of 2015 rebasing year x WACC X # of years of rate rider disposition period
* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.
3 Account 1576 is cleared by including the total balance in the deferral and variance account rate rider calculation.
4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

171. 9. OEB STAFF 62

Ref: E9/T3/S12 and Filing Requirements for Electricity Distribution Rate Applications 2015 Rate Applications, dated July 18, 2014

a) Per Chapter 2, Section 2.5.2.7 of the Filing Requirements, please provide the account balances recorded under:

- *Account 1508 Other Regulatory Asset, Sub-account, Incremental Capital Expenditures, including a breakdown of the carrying charges*
- *Account 1508 Other Regulatory Asset, Sub-account, Depreciation Expense*

- *Account 1508 Other Regulatory Asset, Sub-account Accumulated Depreciation and*
- *Account 1508 Other Regulatory Asset, Sub-account Incremental Capital Expenditures Rate Rider, including a breakdown of the carrying charges*

Response:

The following is the breakdown of the account balances under Acct # 1508 ICM Rate Rider account as at December 31, 2004:

Account # 1508 ICM Account	**December 31, 2014**
ICM Capital Expenditures – Capital	$15,311,782
ICM Capital Expenditure–Carrying charges @1.47%	243,465
Total Capital	15,555,247
ICM Depreciation & Amort Expense	365,784
ICM Accumulated Depreciation & Amort	-365,784
ICM Rate Rider- Recoveries	-1,081,174
ICM Rate Rider – Interest on Recoveries @ 1.47%	-11,423
Total ICM Recoveries	-1,081,174
Balance prior to O & M Expenditures	14,461,325
TS O & M Expenditures (cost not in 2010 COS)	244,816
TS O & M Expenditures -Carrying charges @ 1.47%	3,051
Total Balance at December 31, 2014	**14,710,517**

172. 9. OEB STAFF 63

Ref: E9/T3/S12/p.2-3 and Supplemental Report of the Board on 3rd Generation Incentive Regulation, September 17, 2008 ("Supplemental Report")

For the ICM Rate Rider Account #1522 table,

a) Please confirm that the ICM Rate Rider Account #1522 should be Account 1508. If not, please explain what Account 1522 is.

b) On p. 30 of the Supplemental Report of the Board, the Board stated that the capital module is intended to be reserved for unusual circumstances…and where the distributor has no other options for meeting its capital requirements within the context of its financial capacity underpinned by existing rates. Festival Hydro is showing OM&A of $244,816 related to the TS.

vi.) Please explain what is included in this amount and why Festival Hydro is recording out-of-period OM&A expenses in account 1522.

vii.) Please state if these OM&A expenses where approved as part of Festival Hydro 2013 IRM-ICM application.

viii.) Please revise the evidence as necessary.

c) Please confirm whether or not the Interest line of $235,093 represents the carrying charges for Incremental Capital Expenditures and Incremental Capital Expenditures rate rider. If not, please clarify what the interest amount is for.

d) Festival is proposing to transfer all accumulated depreciation to Account 2218 and depreciation expense to Account 5705. Please explain what Account 2218 is.

e) Please revise the evidence to reflect the accumulated amortization in Account 2105 Accumulated Depreciation of Electric Utility Plant - Property, Plant and Equipment and Account 2120 Accumulated Amortization of Electric Utility Plant – Intangibles and the depreciation expense in Account 5705 and Account 5715 Amortization of Limited Term Electric Plant.

Response:

a) Agreed. The account for the ICM Rate Rider is USOA # 1508. Account # 1522 as noted is used for internal record keeping purposes only.

b)

i. Festival has adopted accounting practices for its ICM account similar to what was followed for Smart meter, whereby O & M costs were recorded into the smart meter variance account until time of disposition. As was the case for smart meters, for the TS there were no O & M expenses approved as part of 2010 Rate application for operation and maintenance. It is Festival's belief that these costs would be recorded into Account # 1508 and disposed of as part of the overall disposition of the ICM Variance account. The amount represents the December 2013 and 2014 operating costs actually incurred including such items as property taxes, insurance maintenance, monitoring costs (excluding depreciation), of which none of these costs were part of the 2010 O & M expense. As the ICM is intended for extraordinary capital expenses the resulting OM&A from such capital expenses should also be considered extraordinary and such costs should be considered in the same manner and recoverable.

ii. In terms of approval of the expense, the 2013 IRM Decision and Order (EB-2012-0124) does not specifically state whether or not OM & A may be added to the ICM account # 1508.

iii. Under 9 Staff 62 the table breaking down the contents of Acct # 1508 is shown before adding in the O & M expenses (and related interest) and the total including O & M expenses.

c) The $235,093 is the net carrying charges related to the Incremental Capital Expenditures, O & M expenses and Incremental Capital Expenditures rate rider. as broken down for 9 staff 62.

d) The accounts which Festival Hydro uses for recording are: 2105 Accumulated Depreciation of Electric Utility Plant - Property, Account 2120 Accumulated Amortization of Electric Utility Plant – Intangibles: Transformer station > 50 KV depreciation expense in Account 5705 and Account 5715 Amortization of Limited Term Electric Plant.

e) Evidence has been revised accordingly.

9 Staff 63 table				
ICM Rate Rider ACCOUNT # 1508 - Continuity Schedule (REVISED -agrees to 2 staff 8)				
		2013	**2014**	**Jan 1, 2015 transfer**
Opening, Jan 1		0	15,058,931	14,710,516
TS O & M Expenses		104,816	140,000	-244,816
Interest		17,623	217,469	-235,093
Transfer in from CWIP		15,311,782	0	-15,311,782
Depreciation & Amortization		28,137	337,647	-365,784
Accumulated Depreciation & Amort		-28,137	-337,647	365,784
Less ICM Rate Rider Recovery		-375,291	-705,884	1,081,174
Ending Bal, Dec 31		**15,058,931**	**14,710,516**	**-0**
(with one mth depn in 2013)				

Entry required for Jan 1, 2015 disposition:				
		USOA		
TS Land	DR	1805	913,474.39	
TS capital	DR	1815	13,961,839.83	
CCRA agreement	DR	1609	436,468.00	
Interest Income	DR	4405	235,092.89	
Distribution Revenue	CR	4080		1,081,174.36
Depn Exp	DR	5705	346,870.00	
Amort Exp	DR	5715	18,914.00	
Accum Depn	CR	2105		346,870.00
Accum Amort	CR	2120		18,914.00
TS O & M Expenses	DR	5015	244,815.74	
ICM Variance Acct	CR	1508		14,710,516.49
			16,157,474.85	16,157,474.85
Transfer back to fixed asssets1805,1815,1609 (gross)			15,311,782.22	
Less Accuimulated Depreciation/Amortization			-365,784.00	
Net book value upon transfer , Jan 1, 2015			14,945,998.22	

173. 9. OEB STAFF 64

Ref: E9/T3/S12, pp. 1-9 – Incremental Capital Module True-up

Festival Hydro has provided a true-up of its new 62 MVA Transformer station, which was funded through an incremental capital module as part of its 2013 IRM application. As part of its current application Festival Hydro is requesting additional ICM rate riders to recover incremental revenue requirement as follows:

Description	2013	2014 (8 months)	Total
Inc. Revenue Requirement – as originally filed EB-2001-0124) (2014=2013/12*8)	$672,412	$448,275	$1,120,687
Inc. Revenue Requirement – true up of costs, depreciation and CCA)	$508,652	$938,371	$1,447,023
Variance arising on true up – additional inc capital requirement	**$(163,760)**	**$490,096**	**$326,336**

Proposed Incremental Capital Volumetric Rate Rider effective Jan 1, 2015 to Dec 31, 2015 (1 year)					$ 326,336.00	
Rate Class	2015 Test Year kWh	2015 Test Year kW	Allocatoin based on 2015 TY kWh	Allocated Balance	Volumetric Rate Rider	Unit
Residential	140,900,798	-	23.7%	77,347	$ 0.0005	kWh
GS < 50 kW	64,179,621	-	10.8%	35,231	$ 0.0005	kWh
GS >50 kW to 4,999 kW	361,832,480	946,164	60.9%	198,627	$ 0.2099	kW
Large Use	22,191,326	34,422	3.7%	12,182	$ 0.3539	kW
USL	660,967	-	0.1%	363	$ 0.0005	kWh
Sentinel Lights	150,156	356	0.0%	82	$ 0.2315	kW
Street Lighting	4,559,343	12,017	0.8%	2,503	$ 0.2083	kW
Total	594,474,691	992,959	1	326,336		

a) Please provide a true-up calculation applying the half-year rule as originally applied for, adjusting only for the capital expenditure reduction of $551,330 and final TS asset values.

b) Please provide the resulting net book value for the TS station as of January 1, 2015.

Response:

a) Festival has recalculated the Incremental capital module as requested using the Final TS balances (net of the $551,330) and applying the half year rule. The attached models are called:

9 staff 64 Festival_2013_Incremental_Capital_Project_V1.0_20140827_
9 staff 64 FESTIVAL_2013_IRM3_Incremental_Capital_Wrkfrm_V1.0_20140827
9 staff 64 with Bypass Festival_2013_Incremental_Capital_Project_V1.0_20140827_
9 staff 64 with bypass FESTIVAL_2013_IRM3_Incremental_Capital_Wrkfrm_V1.0_20140827

With the revised model, the 2013 amount is $631,181 plus 8 months of $420,787 for a total of $1,051,968 or $68,719 less than the original filed request.

Festival has also calculated the incremental revenue requirement including the $1.2 M Permanent Bypass arrangement. Even though it was not in the original budget, the spending would never have occurred without the existence of the TS station. As such, given the nature of this expenditure this should also be part of the project. When Festival recalculates the Incremental Capital Modules including the Bypass agreement it results in an amount of $682,746 plus 8 months at $455,164 for a total of $1,137,910 or $17,223 higher than the original filed request.

Festival is still of the belief the half year rule should only apply to the 2013 period and the 8 months for 2014 should be compensated at the full asset value, as outlined in E9/T3/S12 of the original filing.

b) *The resulting net book value would be $14,945,998. The change in the values in the ICM model impacts the distribution revenue earned as opposed to the net book value of the asset being transferred.*

174. 9. OEB STAFF 65

Ref: E9/T3/S11 – Stranded Meter Costs

Festival Hydro provided a cost allocation for stranded meter costs based on number of customers.

a) Please provide sheet I 7.1 from Festival Hydro last rebasing cost allocation study.

b) Please provide a cost allocation of stranded meters by rate class based on the breakdown of conventional meter costs found on sheet I7.1 as shown in Festival Hydro's 2010 cost of service application.

Response:

a) Sheet I7.1 from Festival's final 2010 COS Cost Allocation Model attached below.

b) The following is the determination of the stranded meter rate rider based on the 2010 COS Sheet I7.1:

	Residential	**G.S> < 50 kW**	**Total**
Number of Customers/meters per Sheet I7.1	17,115	1,968	19,083
Total weighted metering costs per Sheet I7.1	$1,097,812	$413,280	$1,511,092
% of total costs	72.65%	27.35%	100.00%
Total stranded SM costs per EDVAR continuity Tab 6 Rate Rider Calculation	$170,391	64,146	$234,537
# customers per EDVAR	18,224	2,029	20,363
Monthly per customer fixed Stranded meter RR charge	$0.78 per month fixed charge	$2.63 per month fixed charge	

2006 Cost Allocation Information Filing
FESTIVAL HYDRO INC.
EB-2005-0364 EB-2007-0002
Friday August 28, 2009
Sheet 17.1 Meter Capital Worksheet - Second Run 2010 - Run 2 Model

		Residential			GS <50			
		1	2	3	1	2	3	1
		Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters
	Allocation Percentage Weighted Factor			45.17%			17%	
	Cost Relative to Residential Average Cost			1.00			3.27	
	Total	17115.00	1097811.95	64.14	1968.00	413280.00	210.00	221.00
Meter Types	Cost per Meter (Installed)							
Single Phase 200 Amp - Urban	50	15734.53	786726.50			0.00		
Single Phase 200 Amp - Rural	150		0.00			0.00		
Central Meter	250	19.19	4797.00			0.00		
Network Meter (Costs to be updated)	225	1361.28	306288.45			0.00		
Three-phase - No demand	210		0.00		1968.00	413280.00		
Smart Meters	300		0.00			0.00		
Demand without IT (usually three-phase)	500		0.00			0.00		122.00
Demand with IT	2,100		0.00			0.00		0.0
Demand with IT and Interval Capability - Secondary	2,300		0.00			0.00		66.0
Demand with IT and interval Capability - Primary	10,000		0.00			0.00		22.0
Demand with IT and Interval Capability -Special (WMP)	40,000		0.00			0.00		11.0
LDC Specific 1			0.00			0.00		
LDC Specific 2			0.00			0.00		
LDC Specific 3			0.00			0.00		

175. 9. OEB STAFF 66

Ref: E9, Attachment 1 of 1, LRAM & CDM Reports, Page 1 of 19, Table

Festival shows its 2011 program savings and lost revenues in the table at the reference above. Staff has copied a portion of the table below. Festival has included a kW savings amount related to its Energy Audit initiative for GS>50kW to 4,999 kW customers.

2011 adjustments			5.00	11,580
GENERAL SERVICE <50kW TOTAL				
General Service >50kW to 4,999kW				
Efficiency: Equipment Replacement	2011	Final	107.38	583,061
New Construction	2011	Final	0.00	0
2011 adjustments			238.69	1,341,638
Energy Audit	2011	Final	0.00	0
2011 adjustments			5.00	25,176
Demand Response 3	2011	Final	68.00	2,665
GENERAL SERVICE >50kW to 4,999kW TOTAL				
Large Use				
New Construction	2011	Final	0.00	0
2011 adjustments			549.31	2,079,477
LARGE USE TOTAL				
TOTAL LRAMVA - 2011 OPA PROGRAM RESULTS				

a) Please provide the reference in the OPA Final Results report for the savings amount of 238.69 kW for the Energy Audit initiative.

Response:

a) On page 6 is provided the Detailed Verified Results Due to Errors and Omissions for 2011. On page 1, the New Construction totals have been split between G.S. > 50 kW and Large Use as follows:

	kW	kWh
Page 6:		
New Construction	788.0	3,421,115
Page 1:		
G.S. > 50 – New construction	238.69	1,341,638
Large Use-New construction	549.31	2.079.477
Total 2011 Adjustments	788.00	3,421,115

176. 9. OEB STAFF 67

Ref: 2015 COS Application, Exhibit 9, Tab 3, Schedule 10, Page 2 of 3

Festival notes that it has relied on 2013 preliminary results and will update these amounts once the OPA provides it with the final results.

a) Please confirm that Festival expects to be able to update its 2013 LRAMVA amount and total request with the final 2013 results on or before September 30, 2014.

Response:

a) Festival has received its draft final OPA results, which is subject to change. The final report will not be available until September 1, 2014, after responses to interrogatories are complete. Festival requests that the Board allow an update to its LRAMVA amount to be filed on or before September 30, 2014 based on the final report.

177. 9. ENERGY PROBE 35

Ref: Exhibit 9, Tab 2, Schedule 4

Please update the balance in account 1595 to reflect actual amounts collected through the rider through to the end of April, 2014.

Response:

(Acct # 1595- 2010 year) This was a credit rate rider where payments were being made back to the customers, not collected from customers. The full original principal and interest transferred into #1595 (2010) has been repaid in full. The only portion owing is the new interest portion in amount of $56,321 (as of June 30, 2014). In EDVARR disposition schedule, Festival is showing a projected balance owing of $57,623.

Original OEB Approved transfer	$2,149,257
Actual balance owing transferred	$2,149,397
Difference	$ 40

Residual difference was transferred in to clear out the accounts.

Payments made to end of Rate rider effective April 30, 2014:

	Owing	Paid	Balance
Original Principal	$2,086,274	$2,086,274	Nil
Original interest owing	$ 63,123	$ 63,123	Nil
New Interest owing	$ 57,725	$ 1,404	$56,321

(Acct #1595- 2012) This was a debit rate rider being collected from customers. The full original principal and all interest transferred into #1595 (2012) has been collected except for $888 of old interest. The new interest portion due totals $752 for a combined amount due to Festival of $1,640. In EDVARR disposition schedule, Festival is showing a balance due of $1,640.

Original OEB Approved transfer	$279,206
Actual balance owing transferred	$279,206
Difference	$ 0

Payments received to end of Rate rider:

	Owing	Received	Balance
Original Principal	$131,718	$131,718	Nil
Original interest	$147,490	$146,602	$ 888
New Interest	$ 752	$ 752	$ 752
Amount due			$1,640

178. 9. ENERGY PROBE 36

Ref: Exhibit 9, Tab 3, Schedule 7

a) Does Festival have any updates related to the 2015 future employee benefit actuarial report for 2015?
b) Please explain why Festival believes that account 1575 should be updated for the projected liability arising due to the adoption of MIFRS. In particular, please explain the change in PP&E as a result of this change in the liability.

Response

a) Yes, Festival has received a 2015 future employee benefit actuarial report. Please refer to 4 Staff 41 which has a detailed explanation of the Future employee benefit accrual and its impact on test year 2015.

b) Please refer to 9 Staff 59 for detailed explanation. Festival in error believed all IFRS transitional amounts were to be posted to Acct# 1575 but have since realized only PP & E related charges are to go to Acct # 1575. In 4 staff 41, Festival is requesting a new Deferral and variance account to record the difference arising on the conversion from CGAAP to IAS 19 for future employee benefits.

179. 9. ENERGY PROBE 37

Ref: Exhibit 9, Tab 3, Schedule 8, Attachment 2 & Exhibit 2, Tab 1, Schedule 1, Attachment 1

a) Please explain why the 2014 closing net PP&E shown in Appendix 2-EE under the revised CGAAP of $38,621,332 does not match the figure in the 2014 (new policies) continuity schedule shown in Appendix 2-BA of $38,941,519 when all of the other figures under the new CGAAP and former CGAAP match.

b) Please show the reconciliation of the two figures noted above in part (a).

Response:

a) Please refer to response for 9-Staff-61b.

b) A revised appendix 2-EC has been prepared as per 9-Staff-61b to correct the error.

180. 9. ENERGY PROBE 38

Ref: Exhibit 9, Tab 3, Schedule 11

a) Please explain why Festival believes that the number of customers is an appropriate allocator of the stranded meter assets.

b) Did Festival record and track meter costs by rate class? If so, please provide a breakdown of the residual net book value based on this information.

c) If Festival did not track meter costs by rate class, please use the relative cost of residential and GS<50 meters used in the approved 2010 cost allocation model, along with the number of customers to derive an allocation between these two classes.

d) Given that residential and GS<50 meter costs were not the same for the stranded meters, does Festival agree that an allocation based on costs as estimated in part (c) above is more appropriate? If not, please explain fully.

e) Please calculate the rate riders based on the responses to part (b), or part (c), whichever is applicable.

Response:

a) A fixed monthly charge per customer was the means used to collect the Rate Rider for Smart Meter Incremental Revenue Requirement (SMIRR) so the same methodology is being used for the Rate Rater related to Stranded Meters.

b) Festival does not have detailed records on costs by rate class as it related to the remaining net book value of stranded meters.

c) To arrive at the monthly rate rider as reported in the EDVAR Schedule Tab 6. Rate Rider Calculations, Festival did use the relative costs for the two rate classes based on their existing SMIRR rate rider, as calculated below:

	Residential	G.S. < 50 kW	Total
Existing Rate Rider for Recovery of SMIRR (Nov 1, 2012 approved rate) (fixed monthly rate per customer)	$2.79	$4.72	
Total # of customers	18,224	2,029	20,253
Annual rate rider revenue	$ 610,140	$ 114,923	$725,063
Percentage ratio	84.14%	15.85%	
Portion of stranded S.M. costs	$197,246	$ 37,291	$234,537
Monthly per customer Charge	$ 0.90	$ 1.53	

d) Festival is of the opinion this calculation does achieve the goal of proportionate costs to each rate class.

e) As calculated above and as reported in the EDVARR model Tab 6 Rate Rider Calculations.

181. 9. ENERGY PROBE 39

Ref: Exhibit 9, Tab 3, Schedule 12

a) Please explain what each of the three Incremental Capital Adjustment tables represent (pgs 6-8).

b) Please show the derivation of the Incremental Capital CAPEX figure in each of the three tables.

c) Please show the calculation of the CCA deduction in each of the three tables.

Response:

a) The three tables are as follows along with (b) the derivation of CAPEX :

i. ICM Requirement as filed with the Board – Page 8 - this was the original ICM model filed and approved as part of Festival's 2013 IRM application (EB-2012-0124) using the budget capital of $15,863,114 and applying the half year rule for the capital expenditure and related depreciation and amortization. The amount calculated for 2013 is $672,412. Applying this to the 8 months of 2014 represents $448,275 for a total of $1,120,687 expected to be collected through the existing rate rider effective top December 31, 2014.

Incremental Capex: $15,863,113/2+$3,489,000-$3,642,654
(for 2013 & 2014) (Original budget/half year rule add normal capital less threshold)

ii. Revised ICM Requirement for 2013 based on actual results – Page 6 - this is an update to the ICM model reflecting actual results: i.e. applying the half year rule to the capital spend of $15,311,784 and reflecting only one month's deprecation to be consistent with the financial statement presentation as the TS was not energized until December 2013. The amount calculated based on actual for 2013 is $508,652.

Incremental Capex: $15,311,782/2+$3,489,000-$3,642,654
(for revised 2013) (Actual spend/half year rule add normal capital less threshold)

iii. Revised ICM Requirement for 2014 based on actual results – Page 7 - this is an update to the ICM model reflecting actual results for the 8 months of 2014: i.e. using the full value of the capital spend of $15,311,784 and reflecting a full year's depreciation. Since the half year rule for capital additions and depreciation applied to 2013, Festival has calculated the 2014 requirement based on a full year's value for 2014. The amount calculated based on actual for 2013 is $938,371.

**Incremental Capex: $15,311,782-28137+$3,489,000-$3,642,654)/12*8
(for revised 2014) (Actual spend less 2013 depn exp add normal capital less threshold/12mths x 8 mths)**

b) CAPEX noted above.

c) Attached are the ICM Project Workforms which contain the CCA deductions for each of the above three noted models (filed in Festival's 2015 COS web drawer called:
FESTIVAL_2013_IRM3_Incremental_Capital_Wrkfrm_Updated for 2015 COS
9 staff 64 FESTIVAL_2013_IRM3_Incremental_Capital_Wrkfrm_V1.0_20140827
FESTIVAL_2014_IRM3_Incremental_Capital_Wrkfrm_ for 2014 year Updated for 2015 COS

182. 9. VECC 41

Reference: E9/T3/S4

a) Please provide an estimate of the remaining costs related to implementation of IFRS that are expected to be incurred after 2014.

Response:

Please refer to 9 Board 58 as it relates to further IFRS conversion expenses estimated at $20,000 and added to the EDVARR schedule as noted below:

a) With an updated version of Appendix 2 – U available, Festival has filed the revised 2 - U to place the 2013 balance in the correct columns and has also added $20,000 of costs expected to be incurred in 2014 related to final accounting advisory services, assistance on financial statement notes, and the cost of auditing the opening IFRS balances for a revised total of $135,083. The EDVARR continuity schedule and the Rate rider determination shown on E9/T1/T1 have been updated to reflect this change. In addition, this account can be closed as part of the 2015 COS application and no continuation is necessary.

183. 9. VECC 42

Reference: E9/T3/S12

a) Please explain the rationale for continuation of the ICM rate rider, specifically why does Festival believe that that it should recover the variance (shortfall) as between the calculated ICM rate rider and the actual costs if actual costs are incorporated into rate base for 2015?

b) Please show the derivation of the $326k Festival is seeking to recover specifically showing the cost impact of:

i. adjustment due to under budget of project of 551k
ii. adjustment due to forecast vs. actual in-service date
iii. adjustment due to IFRS depreciation rate changes

Response:

a) Please refer to 9 Staff 64 and 9 EP 39 for supporting documents related to the additional $326 K being identified to be recovered by Festival Hydro. The Board approved the ICM rate rider recovery based on the original budget amount to be in effect until the effective date of the next cost of service based rate order. Under this model the half year rule applied to 2013 and to the 8 months of the 2014 rate year. i.e. whereby only one half the value of the asset is allowed. Being the half rule was applied to the 2013 rate year, Festival is making a claim for the 8 months in 2014 based on the full value of the asset and related depreciation as the half year rule had been met in the 2013 rate year. Festival has recalculated 2013 based on the actual costs (i.e. 551K lower than budget for 2013) and applying the half year rule to the capital asset amount. Festival has then for the 8 month period of 2014 calculated the 2014 recovery based on the full net book value of the asset (and full depreciation). The rationale for the continuation of the ICM rate rider is to recover this shortfall arising due to applying the half year rule for both 2013 and 2014.

b)

I. 9 EP 39 shows the CAPEX calculation completed by Festival. In Festival's true up calculations for 2013 and 2014 the actual capital expenditure is used; not the original budget amount.

II. The TS was originally expected to be energized sometime in the summer of 2013 but did not get energized until December 2, 2013. There were vendor related issues that prevented the TS from becoming operational at the earlier date. However, the bulk of the funds were paid out before May 30, 2013, that being the date in which the $14 million CWIP loan was converted to a fixed rate loan. So even though it was no energized until a later date, the funding had for the most part been spent by mid 2013 (other than holdbacks).

III. Festival adopted new depreciation and overhead allocation polices effective January 1, 23013, so the depreciation rates for the TS are the identical under both CGAPP and IFRS with no adjustments required.

184. **NEW** FESTIVAL HYDRO REQUEST for Deferral Account

Request for New Deferral Accounts re: Board Staff Proposal for New Policy Options for the Funding of Capital Investments Board File Number EB-2014-0219

Board staff issued a proposal dated June 20, 2014 which considers revised approaches to the funding of capital. Board staff proposed the following possible D1 factor process:

"1. Eliminate the effect of the half year rule on test year capital additions for the intervening years between rebasing applications (i.e. during the subsequent IR plan) by adjusting for the incremental revenue requirement (depreciation expense plus return on capital and associated taxes/PILs) of the test year capital additions. This is proposed to be accomplished through an adjustment (to be referred to as

the D1-factor) to the price cap formula in the first IR application subsequent to the cost of service application that resulted in rebased rates. The half year rule would still apply for the test year."
In the event that the Board adopts the D1-factor mechanism or a similar mechanism, Festival hereby request the granting of deferral accounts to record depreciation expenses plus return on capital and associated taxes/PILs from our 2015 test year capital additions, during the forthcoming IRM period (i.e. 2016 - 2019).

With Festival's application in progress, we anticipate Festival will not be able to incorporate any of the Board approved changes to the funding of capital that may come out of this proceeding until after our second rebasing under the RRFE (i.e. in 2020). We submit that it would be unfair to treat the 2014 and January 1, 2105 COS filers differently and as such request the establishment of the deferral account to record the differences, to be put forward to the Board for future disposition.