1.0 ADMINISTRATION (EXHIBIT 1)

1.0-VECC-1

Reference: Exhibit 1, page 4

a) For the residential class what are the percentage of customers receiving e-bill and paper bills.

As of November 30, 2021, there is approximately 29% of residential customers receiving e-bills.

b) What are the payment methods provided by the Utility (e.g. : credit card, debit card, cash, cheque, online bank, online direct to utility, etc.)?

The utility provides payment by debit card, cash, cheque, online banking, EFT (for large customers), pre-authorized payment and credit card via the website. The company is currently re-arranging its banking and is introducing the ability to pay by credit card in office or over the phone and certain customers may also be eligible to pay by e-transfer.

c) If ORPC tracks the number of bill payments by payment type please provide this for the last complete year (i.e., 2020). If not, please provide the Utility's best estimate as to the most common payment methods.

The utility does not track the number of bill payments by payment type. The utility estimates that 25% of customers pay by pre-authorized payment, 0% by credit card, >1% by debit card, >1% by cash, >1% by EFT, 5% by cheque and 65% to 70% by online banking.

d) Have customers inquired (via survey or otherwise) to pay by a method not currently offered by ORPC?

Customers have inquired about the ability to pay by credit card in office and over the phone and the ability to pay by e-transfer. As noted above, the utility is currently introducing these payment methods. E-transfers will be limited to certain customers due to the inefficiency in the time requirement to manually enter all e-transfers received.

1.0-VECC-2

Reference: Exhibit 1, Appendix 1E

a) Please provide the cost of the METSCO Survey.

The cost of the METSCO survey billed to ORPC was $15,000 plus HST.

b) Is this cost included in the one-time costs of this application being sought for recovery?

Ottawa River Power Corporation confirms that the cost of the survey is included in the one-time costs being sought for recovery.

1.0-VECC-3

Reference: Exhibit 1,

a) Please confirm (or correct) that the last cost of service filing by OPRUC was EB-2014-0105 for rates beginning May 1, 2016.

Ottawa River Power Corporation confirms that the last cost of service filing by ORPC was EB-2014-0105 for rates beginning May 1, 2016.

b) How many rate rebasing (cost of service) deferrals did ORPC seek since its last rebasing?

ORPC sought 1 rate rebasing deferral since its last rebasing.

c) Please provide the letter(s) seeking rebasing deferral and the Board response(s).

All communications regarding the deferral can be found on the OEB website at the following location:

https://www.oeb.ca/applications/applications-oeb/electricity-distribution-rates/2021-electricity-distribution-rate

2.0 RATE BASE (EXHIBIT 2)

2.0-VECC -4

Reference: Exhibit 2, Appendix 2-AA

a) Please update Appendix 2-AA to show 2021 year-end forecast close.

Please see the Excel appendices response to 2-Staff-10.

b) Please add the capital contributions and net capital to the revised Appendix 2-AA

Please see the Excel appendices response to 2-Staff-10.

c) Please update the 2022 capital projects column for any adjustments required due to changes in 2021.

ORPC does not currently forecast any material changes to its 2022 capital projects due to changes in 2021.

2.0-VECC -5

Reference: Exhibit 2, Appendix 2-A 2022 Distribution System Plan, pages 48 Appendix A Reliability Assessment Report 2021

"*Overall, the success that ORPC has had over the previous 6 years indicates that current levels of spending on reliability initiatives should be maintained. However, one area of concern would be defective equipment, as this is a high contributor to ORPC's SAID and SAIFI scores. Equipment failures should be investigated for trends and may indicate a need for Renewal Investment or Targeted Maintenance*." Reliability Report 4.Conclusions

a) Tables 2-13 through 2-15 show a trend of increasing number of outages due to defective equipment since 2015. Please provide the number of outages due to defective equipment by type of equipment type since 2015. If that is not available provide ORPC's assessment of equipment most likely to fail.

Ottawa River Power Corporation confirms that it did not track the number of outages due to equipment by type of equipment. The utility will begin tracking by type of equipment immediately with the introduction of new reporting tools and standardization which is further discussed below. To determine the equipment most likely to fail, ORPC performed an Asset Condition Assessment ("ACA") through Metsco Energy Solutions. The ACA identified assets that are in poor or very poor condition which aided in the development of projects through the distribution system plan. It identified that overhead equipment require the largest renewal investment. This was also confirmed by a recent pole condition assessment performed by ORPC that has indicated that 10.8% of overhead poles are in very poor condition (reference Exhibit 2 DSP section 6.2).

b) Please explain what capital projects over the new DSP period are focused on addressing outages due to defective equipment.

Underground projects targeted at replacing deteriorating and aging assets (exceeding their TUL in the 5-year DSP planning period) include the following projects in Pembroke:

• Boundary Road: Install 2 – Four-Position Switch Cubicles, 2 Cement Pad mount Transformer bases and Transformers, 1800m of direct-buried conduit. Replace existing underground XLPE cables with new 15kV 1/0 CU Primary TRXLPE cables.

• O'Brien St: Replace 800m of 15kV Primary XLPE cables, 4 pad-mounted distribution transformers, and 2 - 4 position switch cubicles

Deteriorating and aging overhead plant assets are also planned for replacement. ORPC has identified projects that will address overhead assets over the new DSP period. This includes the following projects in Pembroke:

• Esther St: Replace 7 spans of 3-phase, #2 solid copper conductor on Esther St. between MacKay St. and Maple Ave. Install 4 - 45'/3 poles and 2 - 40'/3 poles between Maple Ave. and Cecilia St. Replace 2 OH transformers between Maple Ave. and Cecilia

• John St: Replace 6 poles located between Pembroke St. E. and Sussex St., crossing John St

• McKenzie St: Replace 4 poles and 1 OH transformer

• Third Ave: Replace 5 poles

• Thompson St: Replace 1 - 35' end of life wood pole with a 45' class 3 pole. Replace 4 end of life 35' secondary poles with 4 - 40' class 3 wood poles. 152

As well as the following projects in Almonte:

• Larose St: Upgrade 3 existing poles behind Larose St. adding 1 pole to relocate transformer from backyard and upgrade 1 pole behind. Johanna St. transfer existing conductor and services

• Naismith Drive: Upgrade 4 poles and secondary conductor in the rear lot

• Evelyn St: Upgrade 3 poles and secondary conductor in rear lot

• Florence St: Upgrade 3 poles on Florence St. and 1 on Maude St.

As part of this program, legacy assets will be replaced with polymeric insulators and switches, which do not possess the same brittle construction and therefore do not introduce risks into the system. Some transformers are also scheduled for replacement as part of this work.

c) Please explain how ORPC is responding during the rate plan period to the recommendation of the Reliability Report (section 5) and specifically the recommendations on reporting tools and standardization.

Reporting Tool:

OPRC is planning to develop and utilize a standardized reporting tool within the rate plan period that can be used on tablets and phones for staff. Third party platforms such as Fulcrum, or ESRI GIS will allow for form creation and more streamlined controls for consistent and standardized data input which is then stored in a database. The platforms are cost effective, ranging from products currently under license to ORPC, or small monthly fees ($24/month). ORPC has utilized online platforms on projects in the past, as well as some other internal processes, to carry out testing of these tools.

Standardization:

As part of the development of a standardized reporting tool, predefined granular options (sub-events) will be a built-in requirement as part of the reporting process. This can be applied as a "mandatory field" when filling out the report. Standard Cause-Codes will be required as part of the reporting process.

2.0-VECC -6

Reference: Exhibit 2, Appendix 2-A 2022 Distribution System Plan, page 117

Table 4-3: 2022 – 2026 Capital Expenditure Plan by Investment Program (Net Costs - $K)

DSP Category	Proposed DSP Program	2022	2023	2024	2025	2026
System Access	Customer Connections	$ 120.70	$ 40.75	$ 67.91	$ 81.49	$ 81.49
	Metering	$ 95.40	$ 86.06	$ 68.80	$ 88.84	$ 56.55
	Externally Initiated Plant Relocation	$ 193.60	$ 85.73	$ 98.65	$ 35.47	$ 41.38
System Renewal	UG Renewal	$ 43.56	$ 48.11	$ 60.14	$ 64.95	$ 67.36
	OH Renewal	$ 454.22	$ 463.49	$ 483.64	$ 523.94	$ 544.09
	Stations	$ 750.00	$ 227.01	$ 227.01	$ 272.41	$ 181.61
System Service	System Enhancement	$ -	$ 51.91	$ 62.30	$ 70.08	$ 75.27
	Station Expansion	$ 105.00	$ 110.00	$ -	$ -	$ -
General Plant	Information Technology	$ 66.00	$ 1.40	$ 12.40	$ 1.40	$ 11.40
	Fleet	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 412.00
	Operational Technology	$ 19.21	0	$ -	$ -	$ -
	Facilities	$ 49.00	$ 13.00	$ 12.50	$ 1.00	$ 5.00
Total		$ 1,901.69	$ 1,132.47	$ 1,098.34	$ 1,144.59	$ 1,476.16

a) Using the table format above please provide the capital expenditures for the 2016 through 2021 period.

Please refer to the Excel Appendices for the response. The data contained in 2021 is based on the projections outlined in the Excel appendices response to 2-Staff-10.

2.0-VECC -7

Reference: EB-2014-0105 Ex/2/Tab5/Sch.2/Section 5.4.4, page 121
Distribution Plan/ Appendices 2-AA and 2-AB Tab

Capital Project Name	2014	2015	2016	2017	2018	2019	Total
Fully Dressed Wood Pole Replacement Program	$34,000	$64,500	$64,500	$64,500	$64,500	$64,500	$322,500
Overhead & Pad-Mounted Transformer Replacement Program	$59,600	$59,500	$103,300	$103,300	$103,300	$103,300	$472,700
Conductors	$220,359	$60,200	$44,500	$14,000	$14,000	$14,000	$146,700
Fleet Vehicle Replacement Program	$49,066	$61,000	$300,000	$60,000	$60,000	-	$481,000
Scada		$18,000	$45,000	$45,000		$45,000	$153,000

Transformer “station – Power Transformer Fire Barrier				$65,000			$65,000
Information System	$35,425	$10,000			$26,000	$47,000	$83,000
Transformer Station - 44kV Breaker Replacement				$108,000		$108,000	$216,000
Engineering Studies			$86,000				$86,000
Outage Management System			$78,000				$78,000
44 KV tie Line Almonte				$100,000			$100,000
Substation upgrades	$84,000				$228,000		$228,000
Almonte Substation					$280,000		$280,000
Substation Design	$74,600				$73,000	$115,000	$188,000
Scattered Residential and Subdivisions	$203,500	$400,850	$400,850	$290,700	$290,700	$290,700	$1,673,800
Commercial	$108,370	$100,500	$100,500	$161,500	$91,500	$91,500	$545,500
2015 Misc. Small Capital Projects		$285,250					$285,250
2016 Misc. Small Capital Projects			$424,100				$424,100
2017 Misc. Small Capital Projects				$219,700			$219,700
2018 Misc. Small Capital Projects					$226,550		$226,550
2019 Misc. Small Capital Projects						$222,900	$222,900

a) The table shown was provided in ORPC’s last DSP. Please provide a variance analysis of the material projects (total sums) proposed for the 2016 to 2019 period in the last DSP and what had been achieved by year end 2019, and that completed by year end 2021.

ORPC cannot provide a response with the time and resources available.

b) Please reconcile the annual sums shown in this table for the periods 2016 through 2019 with the total capital budgets shown in Appendix 2-AA.

ORPC cannot definitively reconcile the differences between the annual spending forecast on page 121 of the DSP filed in EB-2014-0105 and the Appendix 2-AB filed in EB-2014-0105. At a high level ORPC expects that the difference between the two forecasts is related to the fact that the DSP was originally prepared in November 2014 covering the period from 2014 to 2019 at a time when ORPC intended to file a cost of service application in 2014 for 2015 rates, whereas ORPC did not file an application until August 2015 for 2016 rates, such that the Appendix 2-AB filed in EB-2014-0105 would have contained updated budgeting information for the 2016-2019 period relative to the November 2104 DSP.

c) We are unable to locate a similar table in the new DSP showing material projects expected over the life of the plan. Please provide a table similar to the one above for the 2022-2026 DSP.

Please refer to the Excel appendices answer provided to 2-Staff-15.

3.0 OPERATING REVENUE (EXHIBIT 3)

3.0-VECC -8

Reference: Exhibit 3, page 7

Preamble: The Application states: "*The methodology proposed in this application predicts wholesale consumption (Predicted) using a multiple regression analysis that relates historical monthly wholesale kWh usage (normally January 2011 to December 2020 however 2014-2020 were used in this case) to carefully selected variables.*"

a) Please explain why the years 2014-2020 were used as opposed to the years 2011-2020.

Ottawa River Power Corporation, with the assistance of Metsco, reviewed its purchase and sale data kWh for previous years in order to investigate line loss percentages. The utility had sufficient historical data dating back to 2014 to confirm the accuracy of the sale data presented. However, a mixture of off-calendar month billing and limited historical reporting capabilities within the Customer Information System have not made it possible to review 2011 to 2013 data. The whole purchase data could not be revised due to metering software retention policies. ORPC does believe that the difference in wholesale purchase data would not be materially different if revised for the purpose of load forecasting but may be materially different for the purpose of calculating line loss percentages. The report from Metsco outlining the revised methodology is found at Appendix 3A in Exhibit 3.

3.0-VECC -9

Reference: Exhibit 3, page 10

Preamble: The Application states: "*Additional subdivisions are beginning construction in both Almonte and Pembroke which include Orchardview and Carss Street in Almonte and Golfview, Blakely Crescent and Boundary Road West subdivisions in Pembroke. Little to no growth is anticipated in Beachburg or Killaloe*."

a) When are each of the referenced new subdivisions expected to be completed (i.e., available for occupancy) and how many housing units are in each?

Please refer to the table below for the information requested:

Subdivision	**Anticipated Occupancy Year**	**Number New Connections** (estimated)
Orchardview	2022	92
Carss Street	2023	50 to 100
Golfview	2022 and 2023	96
Blakely Crescent	2023 and 2024	140
Boundary Road West	2022	46

3.0-VECC -10

Reference: Exhibit 3, pages 7, 11 & 12

a) At page 7 the Application states that the years 2014-2020 were used in the multiple regression analysis. However, at page 11 the Application states "that monthly invoice data from suppliers was collected for the years 2016-2020". Please reconcile and explain the source of the 2014 and 2015 purchase data.

Ottawa River Power Corporation confirms that the 2014 and 2015 purchase was collected in the same manner. However, the statement on page 11 only addresses 2016 to 2020 as previous usage data was collected and presented in the previous Cost of Service application.

b) At page 12 the Application states "Following receipt of the report, ORPC followed the methodology in the report to revise its 2016 to 2019 usage data." Was the 2014 and 2015 purchase data also adjusted using the METSCO methodology? If not, why not?

Ottawa River Power Corporation did not revise its 2014 and 2015 data due to the metering software only retaining data for 6 years. Metering data 7 and 8 years in the past would have been required to review and analyze 2014 and 2015 data.

3.0-VECC -11

Reference: Exhibit 3, pages 14 & 16

Preamble: The Application states: "*During the process of testing the regression analysis, many different variables and time periods are tested to arrive at the best R-Squared. The utility's rationale behind selecting or dropping certain variables involves a "no-worse" rationale.*"

a) What were the other different variables and time periods tested? In each case, please indicate why they there were not selected as the basis for the final model.

ORPC did test the period of 2011-2020 which yielded a lower R-Square. In analysing the data, ORPC found anomalies in 2011-2013 as explained in the response to 3.0 VECC-8 and opted to leave them out after removing each year and rerunning the regression without the years in question. Other variables that were tested and ultimately dropped were, “Daylight hours” which was dropped as it didn’t improve the R-Square and was found to be redundant to the HDD and CDD. Although OPRC did not record the results, “Customer Count” and Electricity Costs did not improve the R-Square. Adding all three of the above variables yielded a lower R-Square.

b) Page 14 makes specific reference to CDM impacting monthly energy use but it is not included in the final regression analysis. Was a CDM variable tested and, if so, what were the results (i.e., please provide the model with the historic data used and the regression results)?

The results using the HDD, CDD, Days in Month and Spring and Fall flag yielded good results in ORPC’s view. It is ORPC’s opinion that that the CDM embedded in its historical load need not be isolated as an explanatory variable within the regression. As such, a CDM variable was not tested.

3.0-VECC -12

Reference: Exhibit 3, page 18

a) For each of the years 2014-2020 please calculate the “weather normal” for each year by using the HDD and CDD coefficients and the difference between the actual HDD & CDD values and the weather normal HDD & CDD values to adjust the actual purchases so as to remove the impact of weather variations.

The table below shows the information requested. Details and calculations are provided in the Excel Appendices filed along with these responses.

Year	Actual	Predicted Incl. HDD&CDD	Predicted W/O HDD	Predicted W/O CDD	Impact of HDD on load	Impact of CDD on load
Dec-14	191,637,146	189,063,542	154,949,102	185,240,710	- 24,858,552	- 3,570,745
Dec-15	190,465,329	188,460,831	156,530,475	183,424,665	- 23,339,922	- 4,583,444

Dec-16	190,198,454	191,686,295	164,718,562	178,094,002	- 20,771,131	- 11,160,915
Dec-17	184,181,850	187,486,875	155,235,352	183,377,792	- 23,920,840	- 3,832,928
Dec-18	192,794,491	191,531,130	158,040,609	184,616,790	- 24,725,115	- 6,005,795
Dec-19	190,916,363	190,586,281	155,723,433	186,357,157	- 25,595,768	- 3,749,416
Dec-20	187,587,218	188,965,897	157,798,681	182,293,485	- 23,758,939	- 5,724,703
Dec-21		189,972,510	157,860,419	183,238,360	- 24,187,405	- 6,490,387
Dec-22		189,627,160	157,515,069	183,238,360	- 23,970,670	- 5,809,260

3.0-VECC -13

Reference: Exhibit 3, page 21

a) For the USL and Sentinel Classes what would be the 2022 forecast kWh if the calculation was based on the average use for all seven years (i.e., the same period as used for Residential, GS<50 and GS>50)?

Please refer to the table below:

	Year	2022 As Filed	2022 Using 7yr average for non weather sensitive classes
Residential	Cust/Conn	10,191	10,191
	kWh	80,356,209	80,356,209
	kW		
General Service < 50 kW	Cust/Conn	1,264	1,264
	kWh	29,645,117	29,645,117
	kW		
General Service > 50 to 4999 kW	Cust/Conn	151	151
	kWh	70,993,966	70,993,966
	kW	219,807	219,807
Sentinel	Cust/Conn	166	166
	kWh	194,767	201,549
	kW	495	461
Street Lighting	Cust/Conn	2,949	2,949
	kWh	1,080,789	1,550,510
	kW	3,027	4,505
USL	Cust/Conn	19	19
	kWh	606,879	570,371
	kW	-	-

b) The Application states “Allocation to specific non-weather sensitive rate classes (GS>50, USL, Sentinel and Streetlights) is based on an average of 3-years of demand/customer which is a more appropriate historical average to determine the demand per customer.” Please confirm that the GS>50 forecast is not based on a three-year historic average of the demand/customer.

ORPC confirms the above. With respect to the GS>50 class, the utility felt that it should use the same historical average for the determination for the determination of the demand than it used for the energy hence the 7-year average.

3.0-VECC -14

Reference: Exhibit 3, page 24

Preamble: The Application states: “*As noted in the table above, this caused a decrease of 41% in (Street Light) usage from 2015 to 2016 with an overall decrease of 58% from 2014 to 2020. The project began in December 2015 and was completed in early 2016*.”

a) Please confirm that the higher Street Light usage per “lamp” in 2014 and 2015 will affect the Residential, GS<50 and GS>50 percentages of wholesale purchases for those years and therefore impact the forecast 2022 for these classes.

ORPC does not confirm this. The load forecast predicts the load of each class independently from one another therefore including 2014-2016 in the determination of the load for the non-weather sensitive classes did not affect the forecast for the weather sensitive classes.

3.0-VECC -15

Reference: Exhibit 3, page 25

a) Please provide the customer/connection counts for each class as of the end of June 2020 and the end of June 2021.

Customer connection counts at the end of June 2020 and June 2021 are provided in the Excel Appendices response to 3-Staff-26.

b) Do any of the new subdivisions discussed on page 10 impact the June 2021 customer/connections counts? If so, what is their impact?

The new subdivisions discussed on Page 10 do not impact the June 2021 customer/connections counts.

c) Please provide the customer/connection counts for the most recent month available.

The most recent available data is presented in the Excel Appendices response to 3-Staff-26.

3.0-VECC -16

Reference: Exhibit 3, pages 22-23, 26 and pages 29-31

a) Does ORPC expect the pandemic to have an impact on its kWh sales for 2022? If yes, what are the anticipated impacts?

ORPC did not anticipate any impact as a result of the pandemic on its kWh sales for 2022.

b) In Tables 12, 13 and 14, the year 2020 is the year with the highest Residential sales and the lowest GS<50 & GS>50 sales. Please confirm that, based on the discussion per pages 29-31, ORPC attributes these results to the pandemic?

ORPC confirms the 2020 usage would be attributed to the pandemic.

c) Please provide a schedule which sets out for the Residential, GS<50 and GS>50 year to date (2021) sales and the sales to each class for the comparable period in 2020.

Please see the Excel appendices response to 3-Staff-26 for monthly usage from January 2020 to October 2021 sales. Please note that November and December 2019 usage data could not be obtained as ORPC was not billing customers on a calendar month basis until the beginning of 2020 and metering reporting limitations due to the off-calendar month billing cycles.

d) Please provide a revised version of the load forecast model where the percentages used for the Residential, GS<50 and GS>50 classes are based on the average of 2014-2019 (as opposed to 2014-2020).

The requested scenario has been filed along with these response. The filename is OPRC 2022 TESI Load Forecasting Model VECC 3-16d 20211222.

4.0 OPERATING COSTS (EXHIBIT 4)

4.0 -VECC -17
Reference: Exhibit 4, page 19

Preamble: "*Specifically, this resulted in personal protective equipment of $30,842, inventory maintenance of $34,286.39 and $129,738.73 of standby labour now included in 5085*"

a) The above statement was made in respect to explaining variances in account 5085. Please explain the meaning of "*standby labour*".

Please refer to the answer provided in 4-SEC-23.

4.0-VECC -18
Reference: Exhibit 2, Section 4.6, page 49

a) If ORPC is a member of the EDA please provide the annual dues for the 2016 through 2022 (forecast) period.

Please find the annual EDA membership dues listed below:

Year	Annual Fee Excl. HST
2016	$32,500.00
2017	$32,800.00
2018	$33,500.00
2019	$34,200.00
2020	$34,900.00
2021	$35,200.00
2022	$35,200.00

4.0 -VECC -19

Reference: Exhibit 4, page 23

a) In explaining the increase in account 5610 (management salaries) ORPC explains that in 2020 the Utility modified its accounting such that previous burdens shown in account 5645 (Pensions and Benefits) were included in 5610. Yet for the period 2019 through 2022 account 5645 has continually increased. No amounts were recorded in account 5645 in 2016 and 2017. ORPC further explains later in the evidence (page 23) that account 5645 increased due to less pension costs being allocated to other categories. Please explain the apparent contradiction in these explanations of variances.

There is no contradiction in the statements. Account 5610 originally only included the hourly rates of employees without burdens and was modified in 2020 to include a burden of 44.23% on management salaries. Elsewhere, it is explained that ORPC utilized a burden of 57% at the beginning of 2019 and then decreased the burden to 44.23% for all of 2020. Account 5610 increased because the burden was added whereas 5645 also increased because there was 12.77% less (57% minus 44.23%) salaries allocated to other areas resulting in the account retaining the extra 12.77% on salaries. This extra retention outweighs the dollar value of the extra management salaries burden allocated to 5610. All 5645 costs for 2016 and 2017 were previously included in account 5615.

b) For the period 2016 to 2022 please show the total pension and benefit costs incurred and included in OM&A costs or confirm these costs are the same as that shown in Table 17 at page 37.

Table 17 at page 37 demonstrates the total pension and benefit costs incurred by the corporation. Of the costs incurred, the revised Appendix 2-D filed on November 12, 2021 demonstrated the amount of pension and benefit costs allocated to capital. The allocations can be summarized as follows where 2016 and 2017 capitalized amounts have been added as they were not included in Appendix 2-D. Please note that the amounts included in OM&A also include any amounts allocated to the affiliate:

	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2020**
Total Benefit Costs	$449,231	$476,107	$541,026	$538,345	$557,751	$570,454	$603,970
Amount Capitalized per Appendix 2-D	$116,784	$148,109	$178,976	$105,878	$74,754	$111,912	$114,873
Amount Included in OM&A	$332,447	$327,998	$362,050	$432,467	$482,997	$458,542	$489,097

4.0 -VECC -20

Reference: Exhibit 4, page 23

a) Are any amounts of the one-time costs for this application recorded as part of the $183,062 in regulatory costs in account 5655 in 2022?

The utility has included an estimated $74,700 (1/5th of total one-time costs) in costs pertaining to this application in 2022.

b) Are any of the costs of preparing this application recorded as part of the $117,730 in 2021?

No costs for preparing this application were recorded as part of the $117,730 in 2021.

4.0 -VECC -21

Reference: Exhibit 4, page 28

a) Billing and collation costs increase by 114k as between 2020 and 2021. ORPC explains this increase as a transfer of a portion of salary from the Administrative and General category to Billing and Collection. The latter category was only reduced 45k in the same period leaving some 67k unexplained. Since 2016 these costs have increased by more than $200k from $408k in 2016 rising to a proposed $612k in 2021. Please provide more details on the reasons for the increase in Billing and Collecting costs since the last rebasing.

Additional details on billing and collecting are provided on Page 17 and 21 of Exhibit 4. Page 16 demonstrates the composition of the variances over time. From 2016 to 2021, the increases arise from the following accounts:

USofA Account	2016 to 2021 Change ($)
5305	$59,554
5310	$20,649
5315	$201,826
5320	$(57,233)
5325	$0
5330	$0
5335	$(20,624)
5340	$80
Total	$204,252

Based on the table above, material variances from 2016 to 2021 are arising from 5305, 5315 and 5320.

As stated on Exhibit 4 Page 21, the variance in 5305 was caused as a portion of the salary for the Office Manager, who is in charge of supervising billing activities, was previously included in administrative and general expenses in 2020 but was reallocated to 5315 in 2020 and then moved to 5305 in 2021.

The variance within 5315 was comprised of multiple aspects. Notably, $42,000 is composed of salaries and wages pertaining to the IT/Network

Administrator as 2021 includes a full year of wages compared to partial year wages in 2016. Please see the response to 4-VECC-22 below for more details on the IT/Network Administrator position. Elsewhere, there was a $29,000 increase in annual support and maintenance fees for the Customer Information System as the reporting needs and capabilities of the system became more complex and a $32,000 or 19% increase in customer billing wages due to the Collective Bargaining Agreement increases and the commencement of burdening on the accounts in 2020. ORPC also previously included $20,800 in internet costs, $8,000 in training costs and $10,000 in utilities costs in general and administration expenses but began allocation them to 5315 in 2020.

The variance is 5320 was caused due to staff rotation and leaves of absence within the collections position which has excluded the impact of full salaries. There were also less collection labour hours required leading to decreases in subsequent years with the introduction of disconnection bans and extended disconnection bans throughout the pandemic which limited collection activities.

4.0 -VECC -22

Reference: Exhibit 4, page 39

a) ORPC hired an IT/Networker Administrator in 2019 after not having that position for the 3 years prior. Why was this position added?

The position was not added but was vacant. An IT/Network Administrator was employed until the middle of 2016 at which point the position remained vacant until 2018 due to hiring difficulties. The position then experienced 3 subsequent staff rotations in 2018, 2019 and 2020. From 2016 to 2019, the position was vacant at the end of each year and was not included in the year-end headcount.

b) Is this position incremental since the last cost of service application?

The position is not incremental since the last Cost of Service application.

4.0 -VECC -23

Reference: Exhibit 4, Appendix 2-k

a) Please modify Appendix 2-K to show the amount for each year the amount of compensation capitalized and expensed.

Please see the response provided within the Excel Appendices. Please note that in order to provide the amounts capitalized and expensed by ORPC, the utility has also included the amount allocated to ORPC's affiliate in each year.

4.0 -VECC -24

Reference: Exhibit 4, page 38

a) The average total compensation rate in 2022 ($103,712) as compared to the average rate in 2016 ($87,046) exceeds the CPI inflation rate for the same period (we use the Bank of Canada inflation calculator). Please explain why ratepayers should pay for compensation rates above the inflation rate.

The Collective Bargaining Agreement included annual increases of 2.80% up to 2019 and 2.65% thereafter. This increase beyond inflation was necessary for experienced and educated talent and to ensure staff retention while attempting to stay reasonable compared to large utilities in the area. Staff retention minimizes training costs and ensures expertize on ORPC system knowledge is retained which increases efficiency of operations. The cost of benefits also increased beyond inflation and the cost of CPP increased recently which were not planned in the previous application.

5.0 COST OF CAPITAL AND RATE OF RETURN (EXHIBIT 5)

5.0 -VECC -25

Reference: Exhibit 5

a) Please provide the rates of return for ORPC for each year 2015 through 2021 (estimate).

	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Regulatory Return on Equity (%)	6.32	11.82	18.01	14.48	9.61	9.19

6.0 CALCULATION OF REVENUE DEFICIENCY/SURPLUS (EXHIBIT 6)

6.0-VECC-26

Reference: Exhibit 6, pages 18 and 24

Preamble: The Application states (page 18): "*The increase in Interest Income was caused by the auditors reclassifying $19,904.69 of depreciation on capital contributions into other income for financial statement presentation purposes*."

The Application states (page 24): "*whereas the external auditors ceased reclassifying depreciation on capital contributions into other income for financial statement presentation purposes. In 2018, the auditors had included $18,076.55 of this depreciation in interest income*."

a) For the years 2019 and after how was/is depreciation on capital contributions classified? As part of the response, please explain where/how this amount in included in the determination of the 2022 revenue requirement.

For the years 2019 and after, depreciation on capital contributions was classified as a credit to account 5705. In the determination of the 2022 revenue requirement, depreciation on capital contributions was classified as a credit to calculated amortization and was included on the depreciation and capital asset continuity schedules.

7.0 COST ALLOCATION (EXHIBIT 7)

7.0-VECC-27

Reference: Exhibit 7, pages 13 and 15

a) With respect to the GS>50 class, page 13 shows a Line Transformer Customer base of 8 and a Secondary Customer base of 143. This suggests that there are 135 GS>50 customers who own the transformer but do not own the secondary lines on the low side of the transformer. Is this the case or do customers who own the transformer also own the line facilities on the low side of the transformer? Please explain and indicate if any changes are required to Worksheet I6.2 – Customer Data.

   Please refer to the response provided to 7-Staff-52.

b) With respect the GS>50 class, page 15 shows values of zero for the LTNCP4 and SNCP4 allocators, while page 13 indicates there are customers using Line Transformers and Secondary Lines owned by ORPC. Please reconcile.

   Please refer to the response provided to 7-Staff-52.

c) With respect to the Street Lighting class, page 13 shows a Devices value of zero which results in no customer-related Line Transformer (USOA 1850) or Primary facilities (USOA 1830-4, 1835-4, 1840-4 and 1845-4) being allocated to Street Lighting (see CA Model – Tab O6). How many Street Lighting devices associated with the forecasted 2949 connections in 2022? Please a revised version of the CA Model that incorporates this value.
   A revised Cost Allocation Model has been filed to incorporate these values.

7.0-VECC-28

Reference: Exhibit 7, page 6

a) Please provide a schedule that compares the break-out of assets percentages as between primary and secondary as used in the current Allocation as compared to ORPC's last cost of service. Please explain any material changes.

Ottawa River Power Corporation notes that the breakout included in the Cost Allocation for 1830 and 1835 and has filed a revised model containing the break-out percentages presented below.

The breakout of asset percentage comparison (with revised breakout percentages noted below) between primary and secondary has been provided in the Excel appendices response. Material changes can be noted in categories 1830, 1835, 1840 and 1845. Current management was not involved in the prior Cost of Service application performed by ORPC and therefore it recalculated the asset breakout percentages based on available data. It cannot confirm the source of the previous breakout percentages. The new splits between primary and secondary were calculated based on the following data:

Line Type	**Length (meters) Installed in System**	**Breakout (%)**
Underground Conduit – Primary	30,012	41.27%
Underground Conduit - Secondary	42,714	58.73%
Total	72,726	100%
Line Type	**Length (meters) Installed in System**	**Breakout (%)**
Overhead – Primary	155,002	53.53%
Overhead - Secondary	134,541	46.47%
Total	289,543	100%

7.0-VECC-29

Reference: Exhibit 7, pages 8-10

a) With respect to Table 3, for each of the rows in the Table please explain the basis for the allocation to customer classes (e.g., number of bills, number of customer or weighted variation of either).

Category	**Basis**
5315 - Customer Billing - Labor & overheads	Number of Bills
5315 - Customer Billing - IT - Labor & overheads	Number of Bills
5315 - Customer Billing expenses (ERTH Holdings)	Number of Customers Enrolled with Retailers
5315 - Customer Billing expenses (ESRI)	Number of Bills
5315 - Customer Billing expenses (E-Billing Hosting)	Number of Customer Enrolled in E-Billing
5315 - Customer Billing expenses (Internet and Utilities)	Number of Bills
5315 - Customer Billing expenses (Postage and Folding Machine Leases)	Number of Bills
5315 - Customer Billing expenses (Canada Post)	Number of Bills
5315 - Customer Billing expenses (Letterhead)	Number of Bills
5315 - Customer Billing expenses (Supplies)	Number of Bills
5315 - Customer Billing expenses (NorthStar)	Number of Bills
5315 - Customer Billing expenses (Utilismart - Settlements)	Number of Bills
5320 - Collecting - Labour	Number of Customers in Arrears
5320 - Collecting - Credit Bureau Fees	Number of Customers in Arrears
5325 - Collecting - Cash Over and Short	Number of Customers in Arrears
5330 - Returned Cheques and Reconnection Charges	Number of Bills Excluding Sentinel and Street Lights
5340 - Misc. Cust Account Exp. - Lawyer Requisitions	Number of Bills Excluding Sentinel and Street Lights
5340 - Misc. Cust Account Exp. - Supplies	Number of Bills Excluding Sentinel and Street Lights

b) Have the allocation factors associated with cost of sending "paper bills" been adjusted to reflect the fact customers in some classes received e-bills? If yes, how? If not, what would be an appropriate adjustment?

The cost of sending "paper bills" has not been adjusted to reflect the impact of e-billing. A comparison of the current allocations pertaining to paper bills appear versus one adjusted for e-billing has been presented within the Excel Appendices.

c) At page 8 the Application states that for the GS>50 class "there is additional staff time required to prepare and validate each bill to ensure monthly consumption data aligns to the settlement data for the period."

Where and how is the extra effort reflected in Table 3?

The impact of the additional time requirement for the GS>50 class is not reflected in Table 3.

d) The Application states that the billing and collecting factors used for GS<50 and GS>50 reflect the fact that ORPC receives fewer calls from customers in these rate class as compared to the Residential Class. However, these classes also have fewer customers and weighting factors are on a per bill basis. When adjusted for the number of customers in each class, does ORPC receive fewer calls from customers these classes as compared to the Residential class?

ORPC can confirm that when adjusted for the number of customers in each class, the utility receives fewer calls from other classes as compared to the residential class. The residential class sees increased call volumes with more move-ins and move-outs as the remaining classes remain relatively unchanged month to month.

e) Please explain how the low number of bills issued to the Street Lighting, Sentinel and USL classes impact the <u>per bill</u> weighting factor as suggested on page 8.

Upon review, ORPC wishes to remove those statements as the low number of bills issued do not impact the weighting factors. The low weighting factors for street lighting and sentinel lighting are driven by decreased costs pertaining to collections activity as these classes typically do not see any arrears and collections. The USL weighting factor is almost identical to residential.

7.0-VECC-30

Reference: Exhibit 7, page 25 /Cost Allocation Model, Tab O1 /RRWF, Tab 11

a) The Status Quo ratios in RRWF, Tab 11 don't match those in Exhibit 7 or the Cost Allocation Model, Tab O1. Please reconcile.

OPRC acknowledges that there was an error in populating tab 11 of the RRWF. The allocation proposed in table 16 of the application was the intended revenue to cost ratios.

b) The 2022 proposed R/C ratios in the RRWF, Tab 11 don't match those in Exhibit 7, Table 16. Please reconcile and clarify ORPC's proposal. Also, all of the proposed ratios for 2022 are not within the Board's policy ranges, please set out ORPC's proposals for the years 2023-2025.

OPRC acknowledges that there was an error in populating tab 11 of the RRWF. The allocation proposed in table 16 of the application was the intended revenue to cost ratios. The GS 50 to 4999 class which fell outside of the range is proposed to be moved to the ceiling of 1.20 in 2023 as indicated in Table 16.

c) What would be the resulting R/C ratios if the ratios for GS>50 and Street Lighting were set at the upper end of the Board's policy ranges and the ratios for all the other classes (which are all currently less than 100%) were set at the same value so as to maintain revenue neutrality?

Please find below the requested scenario:

Revenue to Cost Ratio Allocation

Customer Class Name	**Calculated R/C Ratio**	**Proposed R/C Ratio**	**Variance**	**Revenue Reallocation**
Residential	0.8915	0.9708	-0.08	-295,638.4
GS<50 kW	0.9371	0.9700	-0.03	-29,193.0
GS 50 to 4999 kW	1.7566	1.2000	0.56	319,797.7
Sentinel Lighting	0.7890	0.9700	-0.18	-2,786.3
Street Lighting	1.3031	1.2000	0.10	11,026.9
Unmetered Scattered Load	0.6089	0.9700	-0.36	-3,172.8

8.0 RATE DESIGN (EXHIBIT 8)

8.0-VECC-31

Reference: Exhibit 8, pages 13-14 / RTSR Workform, Tabs 3 and 5

a) Tables 6 and 7 do not set out the current and proposed RTSRs for Network and Line & Transformation respectively as titled. Please provide revised tables.

The revised tables have been provided within the Excel Appendices.

b) Please confirm that the RRR data in Tab 3 and the billing unit data in Tab 5 are both based on 2020 actual values.

Ottawa River Power Corporation confirms that the RRR data in Tab 3 and the billing unit data in Tab 5 are both based on 2020 actual values.

8.0-VECC-32

Reference: Exhibit 8, page 17

a) For purpose of determining the Other Revenues in Exhibit 6 were the revenues from Retail Service Charges based on 2021 rates or were the 2021 rates escalated by an "assumed" inflation factor? If the latter, what was the inflation factor used?

The 2022 Retailer Services Revenues included in account 4082 were $14,635 which was based on 2021 projected revenues. An inflation factor was not used.

8.0-VECC-33

Reference: Exhibit 8, page 28

a) Please explain why there is a difference between the LV costs used to determine the 2022 LV rates ($487,559) and the LV costs included in the power supply expense ($488,695).

The $487,559 represents the average of actual low voltage charges incurred over the previous five years. The difference of $1,136 arises as a result of rounding of the rates to the 4th decimal place in the second chart of Exhibit 8 page 28. For example, in the first chart the residential low voltage rate is calculated as $214,374 divided by 80,356,209 kWh which equals $0.002667796/kWh. For rate design purposes, the rate charged would be rounded at the 4th decimal to $0.0027/kWh which, when rounded, would create a charge of $216,962 ($0.0027/kWh x 80,356,209kWh) therefore creating a rounding difference of $2,588.