Petersburg Borough
Petersburg Municipal Power and Light
2013 Revenue Requirement Study

REPORT
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Prepared for

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by

Petersburg Municipal Power and Light

2013 Revenue Requirement Study

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Introduction and Summary

Background

The 2013 Revenue Requirement study was authorized by the Petersburg Borough (Borough), Municipal Power and Light (PMPL) to determine electric revenue requirements, review the cost of service to each customer class and develop a set of revised retail electric rate schedules. Revenue requirement projections were developed for a five year period, 2013 through 2017, based primarily on budgeted expenses for 2013, assumed rates of general inflation and other factors that are expected to affect the necessary expenditures of PMPL in the projection period. PMPL staff and management provided basic data and participated in the 2013 revenue requirement study throughout the study period.

The primary reason for the 2013 Revenue Requirement Study is to determine the magnitude of increase needed in PMPL's electric revenues to accommodate projected annual operating expenses as well as evaluate alternative electric rate options. PMPL last adjusted its electric rates in 2008 with an average rate decrease of 6%. Total annual energy sales have increased significantly in the past few years and it is expected that if sales continue to increase at a similar rate, new generating resources may be needed before long. Annual revenues from energy sales were \$4.9 million and \$5.2 million in fiscal years[1] 2011 and 2012, respectively. Annual operating expenses, which totaled \$5.1 million, excluding depreciation, in fiscal year 2012, continue to increase due to inflation and other factors and as a result, annual operating margins continue to decrease.

PMPL provides electric service to approximately 2,120 customers in the general vicinity of Petersburg. Total energy sales in fiscal year 2012 were 50,582 MWh and total energy requirements, including own use and energy losses, were 40,859 MWh. The system's peak demand in fiscal year 2012 was 8,010 kW. Total annual energy sales have increased about 22% over the past five years mostly due to increased electric space heating loads. PMPL's electric system is connected to the Wrangell and Ketchikan municipal electric systems by means of the Southeast Alaska Power Agency (SEAPA) transmission system. PMPL's primary source of power is the Borough-owned Blind Slough hydroelectric project and SEAPA's Tyee Lake and Swan Lake hydroelectric projects[2]. Supplemental power, as needed, is supplied from PMPL-owned diesel generators.

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[1] The Borough's fiscal year is July 1 through June 30.
[2] The 22.5-MW Tyee Lake and the 22.5-MW Swan Lake hydroelectric projects are owned by SEAPA, a joint-operating agency of which the Borough is a member. In 2009, SEAPA completed the Swan-Tyee Intertie that

Objectives

The primary objectives of the 2013 Electric Revenue Requirement Study were defined by PMPL as follows:

- Provide a projection of revenue requirements for a five-year period;
- Prepare a cost of service analysis (COSA);
- Provide suggested retail rate adjustments for all of PMPL's customer classes.

The objectives used in developing the proposed retail rates include:

- Adjust the rates as needed to provide revenues sufficient to meet the annual revenue requirement over the next three years;
- Simplify the rates, if possible, to include only two energy blocks for each rate class;
- Increase upper energy blocks to serve as a price signal to consumers to potentially reduce energy consumption;
- Adjust rates to move them towards cost of service;
- Provide rate adjustments over two consecutive years to limit the impact of the adjustments in any one year.

In addition to these objectives, consumer-owned electric utilities typically incorporate other general objectives in the development of rates. These objectives provide for rates that accomplish the following:

- Provide for continuity and stability of electric utility revenues.
- Provide practical rate structures that are understandable and acceptable to the public and relatively easy to administer.
- Reflect the cost of providing service, i.e. no significant subsidies between customer classes.
- Provide rates that are equitable and non-discriminatory.
- Encourage efficient consumption.
- Meet electric utility policy objectives such as bond covenants, budget targets and legal requirements.

connects the two hydroelectric projects to each other and interconnects the municipal electric systems of Wrangell, Petersburg and Ketchikan.

Summary of Results

A projection of total annual revenue requirements has been developed for each of the years 2013 through 2017. The basis for the projected expenses in 2013 was PMPL's 2013 budget. Inflation and other factors were used to forecast costs in subsequent years.

PMPL's major expenses include salaries, wages, and benefits of personnel, purchased power, fuel, materials and supplies, services, debt service and capital outlays. In 2012, the total revenue requirement of PMPL was $5,457,000, excluding depreciation[3]. Total revenues were $6,051,000, including the SEAPA rebate of $428,000, indicating a positive margin of $594,000. Without the SEAPA rebate, the net margin would have been $166,000. In fiscal year 2014, the total estimated revenue requirement is $5,881,000 which would exceed projected revenues in that year by $186,000. This means that additional revenues are needed to pay the annual revenue requirement beginning in 2014.

The results of the 2013 Revenue Requirement Study are summarized as follows:

1. By 2015 revenues will need to be increased by 3.7% over the level of revenue estimated to be received at existing rates. PMPL management has indicated that increases of 2% per year in both 2014 and 2015 would be an acceptable means to achieve this overall increase. In subsequent years the annual revenue requirement is projected to increase about 1.25 per year.

2. At the beginning of 2014, PMPL's operating reserve fund balance was approximately $5.8 million. Although the reserve fund has been used to partially fund capital improvement expenditures in recent years, it is not expected that further draws upon the reserve fund are to be used for this purpose through the remainder of the projection period.

3. The cost of service analysis conducted in this study indicates that the existing rate structure is reasonably close to the actual cost of service, however, residential and harbor rates appear to be somewhat below the allocated cost of service.

4. Proposed rates for 2014 and 2015 to achieve the estimated revenue requirement are provided in Table 9.

[3] Depreciation, which is not a cash expense, is not included among the expenses that comprise the annual revenue requirement in this report. For consumer-owned electric utilities, rates are generally established to achieve revenues to pay annual cash-based operating expenses, debt service (interest and principal) and all or a portion of annual costs of system improvements, replacements and additions.

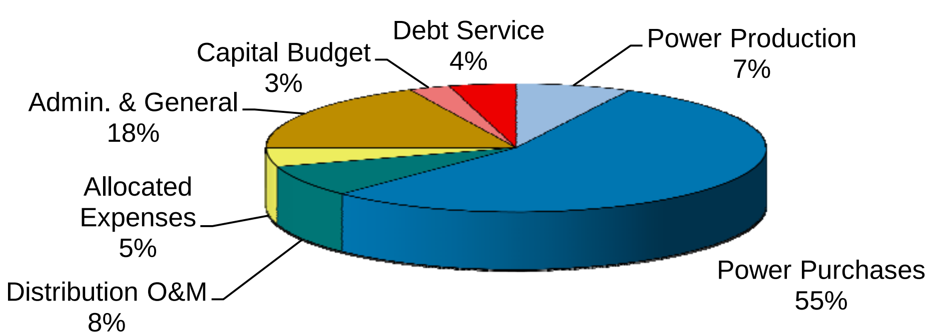
Section 2
Revenue Requirements

Projected Revenue Requirements

PMPL establishes its annual budget in conjunction with the Borough's annual budget process. PMPL's budgeted costs include staff salaries and benefits, purchased power, fuel, services, supplies, materials, and debt service, among other expenses. Since nearly all of PMPL's power requirement is supplied with Borough-owned hydroelectric generation and power purchases from the Lake Tyee hydroelectric project, fuel expenses are minor. For the purpose of the 2013 Revenue Requirement Study, the budget for fiscal year 2013 was used as the basis for determining the basis for projecting PMPL's annual revenue requirements.

PMPL's major expenses include salaries, wages, and benefits of personnel, purchased power, fuel, materials and supplies, services, debt service and capital outlays. These costs, based on more typical electric utility classifications[4] include: power production, power purchases, distribution operations and maintenance (O&M), allocated Borough services, administrative and general, debt service and capital projects. Allocated Borough services include much of the cost of customer accounting and other Borough administrative services that are provided and charged to the Borough's various utility operations, including PMPL, on an allocated basis. In 2012, the cost of purchased power represented 55% of the total expenses incurred by PMPL. Debt service represented 4% of the total expenses in 2012. No additional debt is projected to be incurred during the projection period. The percentages of PMPL's total expenses by classification in 2012 are shown in Figure 1.

FIGURE 1
Percentage of 2012 Annual Expenses by Classification



[4] Cost classifications for electric utilities are typically based on the business functional lines of power supply, transmission, distribution and customer service.

In 2012, the total revenue requirement of PMPL was $5,547,000, excluding depreciation. Total revenues were $6,051,000 including a $428,000 rebate from SEAPA. Although with the SEAPA rebate included net revenues were $594,000, without the SEAPA rebate, PMPL's net revenue would have been $166,000. The SEAPA rebate is not certain in the future.

A projection of total annual revenue requirements has been developed for each of the years 2013 through 2017 and is shown in Table 1. As previously indicated, the basis for the projected expenses in 2013 is PMPL's 2013 budget. Inflation and other factors were used to forecast costs in subsequent years. Principal assumptions used in developing the projected revenue requirements are as follows:

1. General inflation of 3.0% per year.
2. Purchased power cost of 6.8 cents per kWh. Although a rebate of $225,000 is included from SEAPA for 2013, no rebates are included in future years because of the uncertainty in SEAPA's ability to provide rebates to its members in the future.
3. Diesel fuel price of $4.00 per gallon in 2013, escalated at 3.5% per year thereafter.
4. Average annual energy generation of 12,000 MWh at the Borough's Blind Slough hydroelectric project.
5. Total annual diesel generation will be 700 MWh in 2013 and 600 MWh each year thereafter. Diesel generators will produce 13.5 kWh per gallon of fuel on an average annual basis.
6. Total expenditures for capital improvements, replacements and additions are as shown in Table A-1.2. These expenditures, with the exception of the diesel generator and 24.9-kV rebuild project, will be funded with current revenues.
7. Remaining costs of the new diesel generator and the 24.9-kV electric system rebuild projects in fiscal year 2013, estimated at $680,000 in total, will be funded with PMPL reserve funds.
8. Minimum debt service coverage of 1.25 times annual debt service payment requirement.

TABLE 1
Projected Revenue and Revenue Requirements
(Cash Based)

	2013	2014	2015	2016	2017
Energy Sales (MWh) [1]	51,780	52,200	52,620	53,060	53,480
Revenues					
Revenues at Existing Rates [2]	$5,374,000	$5,417,000	$5,459,800	$5,504,800	$5,547,800
Other Operating Revenues [3]	358,600	133,600	133,600	133,600	133,600
Other Income [4]	144,000	144,000	144,000	144,000	144,000
Total Revenues	$5,876,600	$5,694,600	$5,737,400	$5,782,400	$5,825,400
Expenses					
Power Production [5]	$ 391,000	$ 407,000	$ 385,000	$ 398,000	$ 411,000
Power Purchases [6]	3,083,600	3,123,700	3,156,300	3,190,900	3,223,500
Other Operating Costs	1,730,000	1,781,000	1,834,000	1,888,000	1,944,000
Debt Service [7]	237,000	239,000	236,000	238,000	239,000
Total Expenses	$5,441,600	$5,550,700	$5,611,300	$5,714,900	$5,817,500
Net Capital Budget from Revenues [8]	333,000	330,000	332,000	342,000	352,000
Total Revenue Requirement	$5,774,600	$5,880,700	$5,943,300	$6,056,900	$6,169,500
Necessary Revenue Increase	$ -	$ 186,100	$ 205,900	$ 274,500	$ 344,100
Percent of Existing Revenues [9]	-	3.4%	3.8%	5.0%	6.2%

[1] Based on actual energy sales for fiscal year 2012 with assumed annual load growth of 2.4% in 2013 and 0.8% per year thereafter.

[2] Estimated revenues with rates currently in effect.

[3] Budgeted amount for fiscal year 2013. Includes projected streetlight revenues.

[4] Budgeted amount for fiscal year 2013.

[5] Primarily hydroelectric and diesel generating facility operations and maintenance expense. Includes fuel cost for between 600 kWh and 800 kWh of annual diesel generation.

[6] Estimated cost of power purchases from SEAPA at current rate of 6.8 cents per kWh. Does not include potential rebate amounts after 2013.

[7] Includes interest and principal on existing loans.

[8] Estimated capital budget to be funded from annual revenues.

[9] Calculated as Necessary Revenue Increase divided by Revenues at Existing Rates. Note that the amount shown is cumulative over time and does not reflect any potential rate increases that may be implemented in prior years. Necessary increase percentage is not noted for 2013 since no action to increase revenues was needed in 2013.

As shown in Table 1, by 2015 revenues will need to be increased by 3.8% over the level of revenue estimated to be received at existing rates. PMPL management has indicated that achieving this increase over a two year period would be preferable to a one-time increase. Consequently, increases of 2% in each of 2014 and 2015 are proposed to reach the total increase amount.

It should be noted that the revenue requirement shown in Table 1 provides for "breakeven" operation in that revenues would be set to pay all operating expenses, debt service and estimated capital improvement expenditures but provide no contribution to reserves. Although some use of reserve funds to pay a portion of total capital expenditures is planned in 2013, additional draws upon the operating reserve are not projected to be needed. Typically, electric utilities will set rates to achieve a net margin after paying all expenses to allow for contingencies as well as to provide a contribution to reserves. Reserve funds are often used for long-term capital renewals and replacement expenditures.

A more detailed presentation of the projected revenue requirements is provided in Table A-1 in Appendix A.

Billing Determinants and Power Requirements

Table 2 shows the number of customers and annual energy sales by customer class used for the rate study based on actual customer counts and energy sales for fiscal year 2012. As can be seen in Table 2, energy sales to residential customers represent 40.7% of total sales. Energy sales to small commercial customers represent 14.2% and sales to large commercial customers represent 41.6% of total energy sales.

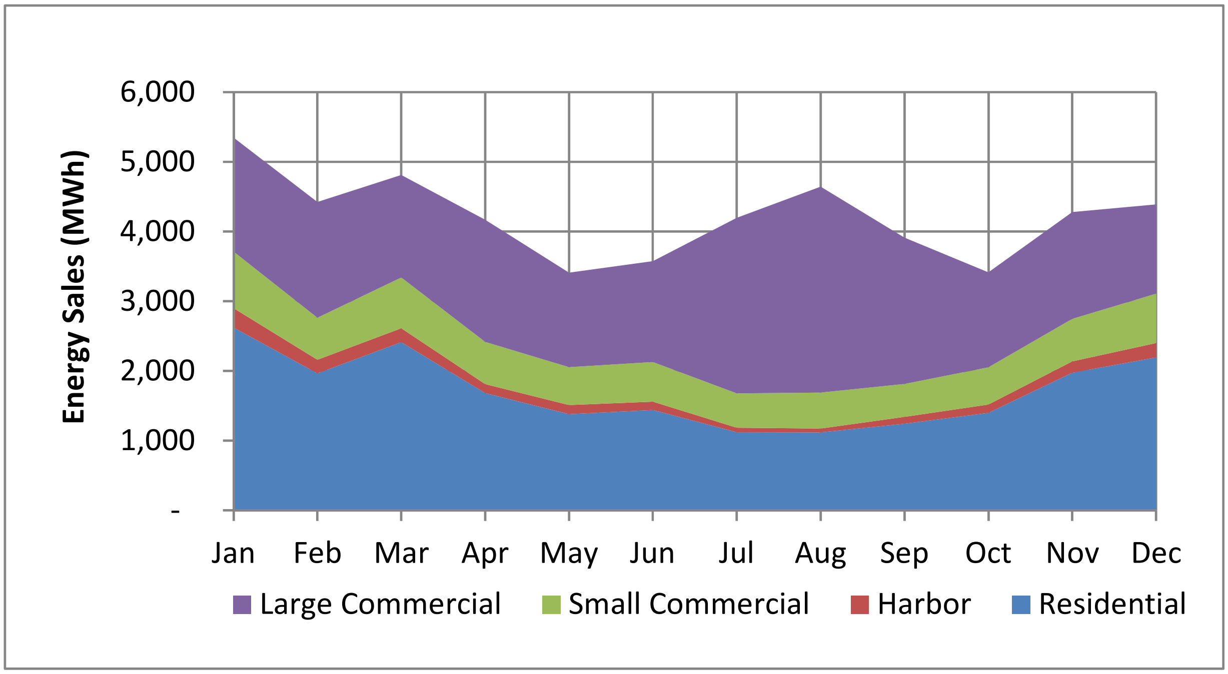
TABLE 2
Number of Customers and Annual Energy Sales
(Fiscal Year 2012 Actual)

	Number of Customers [1]	Energy Sales (MWh)	Percent of Total Sales
Residential	1,357	20,565	40.7%
Harbor	368	1,755	3.5%
Small Commercial	330	7,196	14.2%
Large Commercial	38	21,066	41.6%
Total Billed Sales	2,093	50,582	100.0%
Own Use		1,111	
Total Energy Accounted For		51,693	

[1] Annual average.

Energy sales to residential and small commercial customers are higher in the winter months than in other times of the year whereas energy sales to large commercial customers are much higher in the summer than in the winter. The energy load on a monthly basis is shown in Figure 2.

FIGURE 2
2012 Monthly Energy Sales
(Calendar Year Basis)



Based on recent experience, average system losses are estimated to be approximately 7.5% of total energy requirements. Combined with own-use energy requirements of 1,016 MWh, the total energy requirement was 55,759 MWh in fiscal year 2012. Although this is well within the total average annual energy generation capability of PMPL's available hydroelectric facilities, some diesel generation is expected to be needed each year when the Tyee Lake and Swan Lake projects are unavailable due to scheduled maintenance activities.

Total annual energy requirements of PMPL in fiscal year 2012 were 55,759 MWh. The system peak demand during fiscal year 2012 was 11,580 kW occurring in January 2012. Forecasted annual energy sales by customer class, total energy requirements and energy resources are shown in Appendix A, Table A-2.

Power Supply Costs

Power production costs, including purchased power, are typically the highest cost component of most electric utilities, often representing 50% or more of total annual expenses. PMPL relies upon its hydroelectric facility and power purchases from the SEAPA hydroelectric projects for its power supply with some supplemental generation from its diesel generators. The cost of operating and maintaining the Borough-owned Blind Slough hydroelectric facility per unit of generation is very low compared to the cost of diesel generation. Hydroelectric facilities have high initial capital requirements, however, and debt is often incurred to fund the construction costs. PMPL has no debt related to the Blind Slough facility.

The cost of power purchases from SEAPA is established in accordance with the SEAPA Power Sales Agreement. It is expected that the total rate of 6.8 cents per kWh will remain constant for at least the next few years. An annual “rebate” has been received in recent years but cannot be predicted in the future. The rebate is not factored in to the revenue requirements presented in this report for fiscal year 2014 and beyond. The estimated SEAPA rebate to PMPL in 2013 is $225,000.

TABLE 3
Projected Wholesale Power Supply Costs
($000)

	2013	2014	2015	2016	2017
Fuel Expense [1]	$ 207	$ 184	$ 190	$ 197	$ 204
Diesel & Hydro O&M	184	223	195	201	207
Subtotal - Production Costs	$ 391	$ 407	$ 385	$ 398	$ 411
Purchased Power [2]	3,084	3,124	3,156	3,191	3,224
Total Wholesale Cost of Power	$ 3,475	$ 3,531	$ 3,541	$ 3,589	$ 3,635
Total Energy Reqs. (MWh) [3]	57,121	57,581	58,031	58,511	58,961
Unit Cost (¢/kWh)	6.08	6.13	6.10	6.13	6.16
Fuel and Purch. Power (¢/kWh) [4]	7.29	7.26	7.27	7.28	7.30

[1] Assumes diesel fuel price of $4.00 per gallon in 2013 escalated at 3.5% per year thereafter.
[2] Includes estimated Thomas Bay Power Authority expense allocated to PMPL. Assumes no SEAPA rebates.
[3] Total energy requirements include total PMPL generation and total SEAPA energy purchases.
[4] Sum of Fuel and Purchased Power expense divided by total diesel energy generation and purchased energy.

The total net cost of power shown in Table 3 is representative of the total cost of power PMPL will incur in each year. The Fuel and Purchased Power cost is the portion of the total cost of power tied to diesel generation and purchased power. The power cost shown in Table 3 excludes all costs of distribution, transmission, and customer service.

Section 3

Cost of Service Analysis

The process to develop the cost of service analysis included the functionalization, classification and allocation of the PMPL's 2013 estimated revenue requirements. The various revenue requirements have been separated into the three main functions of electric service: power supply, transmission and distribution. Costs were then allocated to four main customer cost groups[5] (residential, harbor, small commercial and large commercial) using certain factors that represent the functional contribution of each group to the total. To the extent that costs can be classified specifically as demand, energy or customer-related costs, allocation factors based on these classifications were used. An example of this classification is the portion of power supply costs based on energy. These energy costs can be directly allocated to each unit of energy sold, on a one for one basis. System demand-related costs have been allocated to each customer cost group in proportion to each customer class's load at the time of the system peak.

Assignment of capacity or demand to the various cost groups was accomplished by direct meter readings where available and, for non-demand metered accounts, by loadfactors assumed to be reasonably representative of residential, harbor and small commercial loads. The computed demand was adjusted to match PMPL's monthly billed demand. Distribution operation and maintenance (O&M) costs have been allocated based on the proportion of class peak loads, regardless of time of occurrence (non-coincident peak allocator).

The costs of customer accounting, primarily related to meter reading and billing, have been allocated to each customer based on a weighted customer allocator. Administrative and general costs have been allocated to each cost group in proportion to the total other operating costs allocated to each group, excluding power supply costs. The fixed debt service costs of PMPL have been allocated to each cost group based on the percentage of utility plant allocated to the group.

Allocation Factors

The primary allocation factors developed for the cost of service analysis are shown in Appendix A, Table A-4, and are described below:

Average Coincident Peak (ACP) – The average coincident peak allocation factor represents the proportion of total system peak demand for each customer cost group, shown as an average over a twelve month period.

[5] Cost allocation is typically made to customer groupings with similar load and service characteristics. For most utilities, these groupings correspond to the customer classes, e.g. residential, commercial, industrial, irrigation, etc.

Average Non-Coincident Peak (ANCP) – The non-coincident peak allocation factor relates the peak demand for each customer cost group, not necessarily coincident with the system peak, to the summed total maximum peak demand for all customer cost groups, shown as an average over twelve months.

Energy (Sales) – This energy allocation factor reflects each group's share of the total energy sold.

Energy (Req) – The energy allocation factor reflects each group's share of the total energy generated.

Customers (Cust) – The customer allocation factor relates the number of customer accounts in each customer cost group to the total number of customers.

Weighted Customers (WtCust) – The weighted customer allocation factor adjusts the customer allocation factor by the relative service level for each customer cost group.

Revenue (Rev) – The revenue allocation factor reflects each group's share of the total revenue.

Utility Plant (Plt) – The utility plant allocation factor reflects the allocation of the Department's total utility plant to each customer cost group.

Distribution Plant (DPlt) – The distribution plant allocation factor reflects the allocation of the Department's total distribution plant to each customer cost group. This allocation factor is based on a combination of the number of customers in a class and the demand on the class.

Table 4 provides a summary of certain allocation factors used in the cost of service analysis. The allocation factors are also shown in Appendix A, Table A-4.

TABLE 4
Summary of Allocation Factors

	Average Coincident Peak (ACP)	Average Non-coincident Peak (ANCP)	Weighted Customers (WtCUST)	Energy (REQ)	Utility Plant (PLT)	Distribution Plant (DPLT)
Residential	35.595%	33.211%	48.760%	40.657%	38.569%	39.421%
Harbor	3.104%	3.163%	13.906%	3.470%	5.544%	6.197%
Small Commercial	12.025%	11.981%	23.715%	14.226%	12.562%	12.707%
Large Commercial	49.275%	51.645%	13.618%	41.647%	43.325%	41.675%
Total	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%

The allocation factors show the percentage that each customer group represents of the total for the PMPL system. These ratios are subject to change as a result of variations in energy and demand data for each customer group. Also, as one customer group becomes more or less dominant, its allocation will change.

Allocation of Expenses

Using these allocation factors, PMPL's operating costs and debt service are allocated to each customer cost group. Debt service will be a significant cost only if the powerplant relocation project requires new debt and is allocated in accordance with the percentage of utility plant allocated to each customer cost group. Production and transmission plant is allocated using the Average Coincident peak (ACP) allocator while distribution plant is allocated using the Distribution Plant (DPLT) allocator which combines the Average Non-coincident peak (ANCP) allocator and the Customer (CUST) allocator. Detailed results of the cost of service allocation analysis are provided in Appendix A, Table A-5.

The allocated costs shown in Table 5 represent the cost of service for each customer cost group.

TABLE 5
Allocation of Total 2013 Projected Costs Based on Cost of Service

	Power Supply Cost	Other Operating Costs	Debt Service and Capital Budget	Less: Other Revenue and Income	Total Cost of Service	Cost of Service (¢/kWh)
Residential	$ 1,311,880	$ 671,064	$ 268,053	$ (99,908)	$ 2,151,088	10.46
Harbor	112,077	98,843	38,531	(12,209)	237,243	13.52
Small Commercial	458,255	217,980	87,308	(34,097)	729,447	10.14
Large Commercial	1,367,415	742,113	301,107	(131,386)	2,279,250	10.82
Total	3,249,628	1,730,000	695,000	(277,600)	5,397,028	10.67

A detailed determination of revenues at existing rates using the billing determinants previously described, is summarized in Table 6, below. Table 6 also compares the estimated revenues at existing rates, to the allocated cost of service shown in Table 5.

TABLE 6
Revenue at Existing Rates Compared to Allocated Cost of Service

	Revenue at Existing Rates	Cost of Service	Necessary Increase	Necessary Increase (¢/kWh)	Necessary Increase (Percent)
Residential	$ 1,988,564	$ 2,151,088	$ 162,524	0.79	8.2%
Harbor	222,045	237,243	15,198	0.87	6.8%
Small Commercial	733,098	729,447	(3,651)	(0.05)	-0.5%
Large Commercial	2,297,748	2,279,250	(18,498)	(0.09)	-0.8%
Total	$ 5,241,454	$ 5,397,028	$ 155,574	0.31	3.0%

Based on the costs included in this analysis for the purpose of assessing the cost of service to each customer class, an overall increase of 3.0% is needed. To achieve cost of service based rates, certain customer groups would need to be increased more than others. Residential customers would require an 8.2% increase as opposed to a 0.8% decrease for large commercial customers. Overall, to move closer towards cost of service, residential and harbor rates would need to be increased more than commercial rates.

Section 4

Retail Rate Design

As shown in Table 1 in Section 2, PMPL will need to increase its revenues by about 4.0% over the next two years when compared to revenues that would be recovered with existing rates. To achieve this revenue increase, each existing customer class would see an increase in their respective rates. Table 7 provides the estimated increase in revenues for each customer class if allocated cost of service were to be used as the sole basis in adjusting the rates.

A number of issues were discussed with PMPL staff during the preparation of the 2005 Electric Revenue Requirement Study. The primary factors resulting from these discussions that affected the design of the rates are as follows:

- Rates should be adjusted over a two-year period to limit the magnitude of increase in any particular year.
- Reduce the number of energy blocks for each customer class from three to two, if practical.
- Increase the rate in the highest energy block relative to the lower energy block rate to provide a price signal to consumers that new generation when needed, will cost more than existing generation.
- Reduce the differential between Large Commercial and Small Commercial rates at the point of transfer between these two rate classes.
- Keep the monthly customer charge and the large commercial demand charge at the same rate as is currently charged.

TABLE 7
Proposed Revenue Increases by Customer Class

	System Total	Residential	Harbor	Small Commercial	Large Commercial
Estimated Sales (MWh)	50,582	20,565	1,755	7,196	21,066
Existing Rates					
Annual Revenues from Sales	$ 5,241,454	$ 1,988,564	$ 222,045	$ 733,098	$ 2,297,748
Unit Revenues (¢/kWh)	10.36	9.67	12.65	10.19	10.91
Year 1 - 2% Average Increase					
Annual Revenues from Sales	$ 5,347,935	$ 2,027,202	$ 225,397	$ 751,144	$ 2,344,193
Unit Revenues (¢/kWh)	10.57	9.86	12.84	10.44	11.13
Revenue Increase	$ 106,481	$ 38,637	$ 3,352	$ 18,046	$ 46,446
Increase (¢/kWh)	0.21	0.19	0.19	0.25	0.22
Percent Increase	2.0%	1.9%	1.5%	2.5%	2.0%
Year 2 - Additional 2% Increase					
Annual Revenues from Sales	$ 5,450,658	$ 2,075,070	$ 231,631	$ 765,223	$ 2,378,734
Unit Revenues (mills/kWh)	10.78	10.09	13.20	10.63	11.29
Revenue Increase	$ 209,203	$ 86,505	$ 9,586	$ 32,125	$ 80,986
Increase (¢/kWh)	0.41	0.42	0.55	0.45	0.38
Percent Increase	4.0%	4.4%	4.3%	4.4%	3.5%

Table 7 shows that on average, PMPL's revenues would be increased by 4% over the two year period. Residential, harbor and small commercial rates would increase slightly more than the average increase whereas large commercial rates would increase less than the average increase. As can be seen in the line labeled unit revenues, large commercial customers pay an average unit cost that is greater than the residential and small commercial customers. As previously mentioned, the results of the cost of service analysis indicated that large commercial rates should be reduced relative to the other customer classes to bring them closer to cost of service (see Table 6).

Another issue with regard to commercial rates is that small commercial unit revenues are less than large commercial unit revenues. The allocation of costs in the cost of service analysis indicates that this represents the cost of service to the two commercial classes. The existing rates, however, charge noticeably more for smaller large commercial customers than larger small commercial customers. This issue is particularly noticeable at the transition point between the small and large commercial customer classes. In order to address this issue, the lower relative increase in large commercial unit revenues shown in Table 7 is primarily due to a lower rate of increase for the smaller large commercial customers.

After the determination as to how much revenue each customer class will be responsible for, rates can be designed to achieve these revenues. Rates consist of components that relate to the measurable billing determinants for each customer class. The components typically are a customer or basic charge per month, a demand charge and an energy charge. Each of these components can be established in accordance with the allocation of the cost of service into demand, energy and customer related classifications. Much of an electric system's fixed costs would be classified as demand cost, however, demand charges can only be assessed of customers with demand meters, usually larger customers. Consequently, the demand charge assessed of smaller customers is generally applied through the energy charge.

Table 8 shows the existing electric rates for each of PMPL's customer classes.

TABLE 8
Existing Electric Rates

	Customer Charge ($/month)	Energy Charge (¢/kWh)	Demand Charge ($/kW)
Residential	$ 9.00		
0-325 kWh		11.80	-
326 - 650 kWh		11.40	-
over 650 kWh		7.00	-
Harbor	$ 9.00		
0-500 kWh		11.10	-
501 - 1,000 kWh		10.90	-
over 1,000 kWh		7.60	-
Small Commercial	$ 9.00		
0 - 1,500 kWh		11.10	-
1,501 - 3,000 kWh		10.90	-
over 3,000 kWh		7.60	-
Large Commercial	$ 28.00		3.10
0 - 30,000 kWh		10.80	-
30,001 - 60,000 kWh		10.60	-
over 60,000 kWh		8.10	-

The rate components shown in Table 8 can be adjusted a number of ways to accomplish different objectives. For example, a higher basic charge could lower the energy charge. Multiple energy charge blocks can be employed to encourage greater or lesser energy consumption on the part of customers. PMPL's existing rates recover a significant portion of the fixed costs of the system through the higher initial energy block charge. The significant issue, however, is that the total revenue received using the rate components needs to be the amount shown for each customer class in Table 7.

Table 9 presents the proposed rate structure based on the total revenue requirement shown in Table 7. The proposed rates also address the objectives defined earlier in this section. Among other things, the proposed rate structure has left the monthly customer charge and the demand charge the same as currently charged.

TABLE 9
Proposed Rate Design for 2014 and 2015

	Year 1			Year 2		
	Customer Charge ($/month)	Energy Charge (¢/kWh)	Demand Charge ($/kW)	Customer Charge ($/month)	Energy Charge (¢/kWh)	Demand Charge ($/kW)
Residential	$ 9.00			$ 9.00		
0-500 kWh		11.80	-		11.90	-
over 500 kWh		7.80	-		8.10	-
Harbor	$ 9.00			$ 9.00		
0-500 kWh		11.40	-		11.80	-
over 500 kWh		9.30	-		9.60	-
General Service	$ 9.00			$ 9.00		
0 - 3,000 kWh		11.00	-		11.00	-
over 3,000 kWh		8.30	-		8.80	-
Large Commercial	$ 28.00		3.10	$ 28.00		3.10
0 - 30,000 kWh		10.60	-		10.60	-
30,001 - 60,000 kWh		11.00	-		11.10	-
over 60,000 kWh		8.50	-		8.80	-

In addition to the changes in energy charges, the proposed rates incorporate a number of other changes as follows:

- The number of Residential energy blocks is changed from three to two: 0-500 kWh and 501 kWh and above.
- The number of Harbor energy blocks is changed from three to two: 0-500 kWh and 501 kWh and above.
- The Small Commercial class is changed to General Service. In the future, the smaller customers within the Large Commercial class may be separated into a new Small Commercial class.
- The number of General Service energy blocks is changed from three to two: 0-3,000 kWh and 3,001 kWh and above.
- The energy charge for the first Large Commercial energy block has been reduced to reduce the differential between General Service rates and Large Commercial rates.

Comparison of Monthly Charges for Electric Service

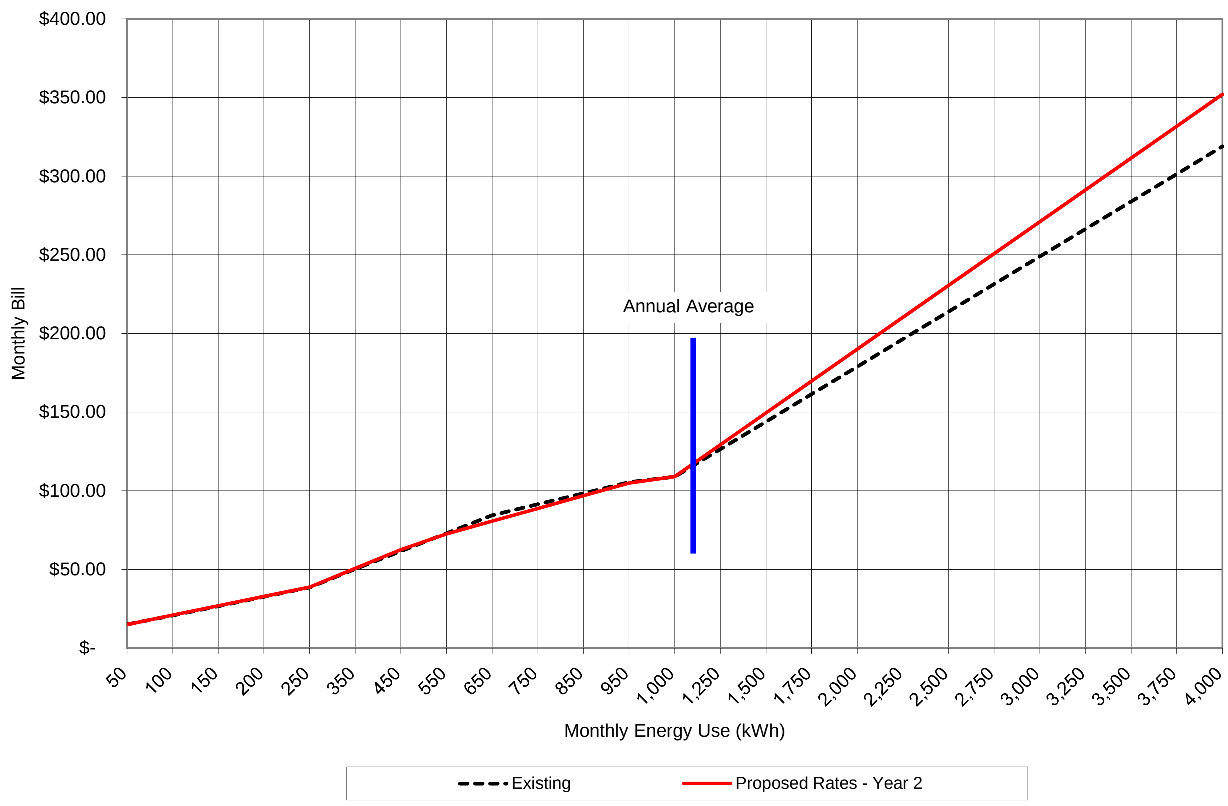
For the purpose of comparison, the monthly cost of electric service for residential customers has been calculated at alternative levels of service based on existing rates and the proposed rates shown in Table 9. The comparison for residential customers is shown in Table 10 and Figure 3. At PMPL's average monthly level of residential energy consumption of approximately 1,000 kWh, the increase in the monthly electric bill would be $0.10.

In Table 10, it can be seen that the percentage increase is higher for higher levels of consumption. Very little change will be seen by customers with 1,000 kWh of consumption or less whereas larger residential consumers would see noticeably higher monthly bills. It is important to keep in mind that the charges shown in Table 10 only include the proposed increases through 2015. Subsequent increases, if needed, would increase the differential between the existing and proposed rate monthly charges shown in Table 10.

TABLE 10
Comparison of Monthly Charges for Residential Service

		After Year 2 Adjustment		
Monthly kWh	Existing Rates	Proposed Rates	Increase	Increase %
50	$ 14.90	$ 14.95	$ 0.05	0.3%
100	20.80	20.90	0.10	0.5%
150	26.70	26.85	0.15	0.6%
200	32.60	32.80	0.20	0.6%
250	38.50	38.75	0.25	0.6%
350	50.20	50.65	0.45	0.9%
450	61.60	62.55	0.95	1.5%
550	73.00	72.55	(0.45)	-0.6%
650	84.40	80.65	(3.75)	-4.4%
750	91.40	88.75	(2.65)	-2.9%
850	98.40	96.85	(1.55)	-1.6%
950	105.40	104.95	(0.45)	-0.4%
1,000	108.90	109.00	0.10	0.1%
1,250	126.40	129.25	2.85	2.3%
1,500	143.90	149.50	5.60	3.9%
1,750	161.40	169.75	8.35	5.2%
2,000	178.90	190.00	11.10	6.2%
2,250	196.40	210.25	13.85	7.1%
2,500	213.90	230.50	16.60	7.8%
2,750	231.40	250.75	19.35	8.4%
3,000	248.90	271.00	22.10	8.9%
3,250	266.40	291.25	24.85	9.3%
3,500	283.90	311.50	27.60	9.7%
3,750	301.40	331.75	30.35	10.1%
4,000	318.90	352.00	33.10	10.4%

FIGURE 3
Comparison of Monthly Charges for Residential Service



A detailed analysis of the impact on commercial customer monthly bills was developed by PMPL. The change to commercial customer bills varies depending on consumption level and the relationship of average to peak demand during the month. A small commercial customer using 3,000 kWh per month would see no change in its monthly electricity bill.

APPENDIX A

Detailed Cost of Service and Rate Analysis Model Tables

TABLE A-1

Petersburg Municipal Power & Light

2013 Electric Revenue Requirement Study

Projected Revenues and Expenses

Cash Basis

($000)

CASE 1 - Base

		Actual		Projected				
		2011	2012	2013	2014	2015	2016	2017
	Operating Revenues							
1	Revenues at Existing Rates [1]							
2	Residential	$ 1,958	$ 1,995	$ 2,045	$ 2,065	$ 2,087	$ 2,108	$ 2,128
3	Harbor	212	212	217	220	221	223	226
4	Small Commercial	668	734	752	760	768	777	785
5	Large Commercial	2,085	2,309	2,360	2,372	2,384	2,396	2,408
6	Tyee Adjustment Charges [2]	-	-	-	-	-	-	-
7	Revenues from Energy Sales	$ 4,923	$ 5,250	$ 5,374	$ 5,417	$ 5,460	$ 5,505	$ 5,548
8	Street and Highway Lighting	68	72	72	72	72	72	72
9	Interruptible Sales	102	-	-	-	-	-	-
10	FDPPA/SEAPA Refund	185	428	225	-	-	-	-
11	Other Operating Revenues [3]	63	143	62	62	62	62	62
12	Total Operating Revenues	$ 5,341	$ 5,893	$ 5,733	$ 5,551	$ 5,593	$ 5,638	$ 5,681
13	Non-Operating Revenues [4]	190	158	144	144	144	144	144
14	Total Revenues at Existing Rates	$ 5,531	$ 6,051	$ 5,877	$ 5,695	$ 5,737	$ 5,782	$ 5,825
15	Revenues from Planned Increases	-	-	-	-	-	-	-
16	Additional Required Revenues [5]	-	-	-	186	206	275	344
17	Total Revenues	$ 5,531	$ 6,051	$ 5,877	$ 5,881	$ 5,943	$ 6,057	$ 6,170
18	Planned Increase	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
19	**Operating Expenses**							
20	Power Production							
21	Fuel [6]	$ 132	$ 227	$ 207	$ 184	$ 190	$ 197	$ 204
22	Diesel & Hydro O&M [7]	172	179	184	223	195	201	207
23	Subtotal - Production	$ 304	$ 406	$ 391	$ 407	$ 385	$ 398	$ 411
24	Purchased Power [8]	$ 2,863	$ 2,929	$ 3,021	$ 3,059	$ 3,089	$ 3,122	$ 3,153
25	TBPA Expense	45	61	63	65	67	69	71
26	Distribution O&M [9]	415	436	449	462	476	490	505
27	Customer Accounting [10]	-	-	-	-	-	-	-
28	Motor Pool Expenses [11]	130	128	132	136	140	144	148
29	Allocated Overhead [12]	113	129	133	137	141	145	149
30	General & Administrative [13]	911	986	1,016	1,046	1,077	1,109	1,142
31	Total Operating Expenses	$ 4,781	$ 5,075	$ 5,205	$ 5,312	$ 5,375	$ 5,477	$ 5,579
32	**Net Operating Income**	$ 750	$ 976	$ 672	$ 569	$ 568	$ 580	$ 591
33	Other Income	-	-	-	-	-	-	-
34	**Net Income Before Debt Service**	$ 750	$ 976	$ 672	$ 569	$ 568	$ 580	$ 591
35	Interest Expense [14]	$ 104	$ 136	$ 137	$ 134	$ 131	$ 128	$ 124
36	Principal Payment [14]	-	100	100	105	105	110	115
37	Subtotal - Bond Debt Service	$ 104	$ 236	$ 237	$ 239	$ 236	$ 238	$ 239
38	Debt Service Coverage [15]	7.21	4.14	2.84	2.38	2.41	2.44	2.47
39	Balance Available for Other Purposes	$ 646	$ 740	$ 435	$ 330	$ 332	$ 342	$ 352
40	Capital Imps. from Annual Revenues [16]	295	146	333	330	332	342	352
41	**Increase (Decr.) in Reserves from Ops.**	$ 351	$ 594	$ 102	$ -	$ -	$ -	$ -
42	Total System Energy Sales (MWh) [17]	46,965	50,582	51,780	52,200	52,620	53,060	53,480
43	Average Unit Revenue (¢/kWh) [18]	10.5	10.4	10.4	10.7	10.8	10.9	11.0
44	Increase (Decrease) Over Previous Year [19]	-0.5%	-1.0%	0.0%	3.4%	0.3%	1.2%	1.1%
45	Power Production Cost (¢/kWh Sold) [20]	6.7	6.6	6.6	6.6	6.6	6.6	6.7
46	Cap Imps. Funded from Reserves ($000)	385	1,314	678	-	-	-	-
47	Reserve Balance - End of Year	$ 8,106	$ 7,716	$ 5,880	$ 5,880	$ 5,880	$ 5,880	$ 5,880

TABLE A-1.2
Petersburg Municipal Power Light
2013 Electric Revenue Requirement Study

Budgeted and Projected Capital Improvement Expenditures

CASE 1 - Base	Actual	Fiscal Year Ending June 30				
	2012	2013	2014	2015	2016	2017
Normal Capital Additions						
Computer equipment	$ 990	$ 6,000	$ 6,000	$ 6,180	$ 6,370	$ 6,560
Poles, Towers, Fixtures	4,751	14,000	12,000	12,360	12,730	13,110
OH Conductor and devices	2,547	10,000	8,000	8,240	8,490	8,740
Underground conduit	7,935	8,000	6,000	6,180	6,370	6,560
Underground conductors	7,525	8,000	6,500	6,700	6,900	7,110
Line Transformers	-	45,000	40,000	41,200	42,440	43,710
Services	75,199	38,000	75,000	77,250	79,570	81,960
Meters	590	8,000	10,000	10,300	10,610	10,930
Streetlights & Signals	862	3,500	40,000	41,200	42,440	43,710
Raptor Protection	-	1,500	1,500	1,550	1,600	1,650
Office furniture & fixtures	2,316	2,500	2,500	2,580	2,660	2,740
Tools, shop and garage	2,384	12,000	12,000	12,360	12,730	13,110
Lab equipment	-	7,500	2,500	2,580	2,660	2,740
Communication equipment	269	14,000	3,000	3,090	3,180	3,280
Hydro generator auxiliary equipment	-	-	-	-	-	-
Subtotal - Normal Capital Additions	$ 105,368	$ 178,000	$ 225,000	$ 231,770	$ 238,750	$ 245,910
Capital Projects						
Auto Control System	$ 16,400	$ 10,000	$ 30,000	$ -	$ -	$ -
Scow Bay Turnaround	-	-	-	-	-	-
Hydro substation upgrade	19,038	60,500	-	-	-	-
Other	-	75,000	75,000	100,000	103,000	106,090
Subtotal - Capital Projects	$ 35,438	$ 145,500	$ 105,000	$ 100,000	$ 103,000	$ 106,090
Subtotal - Normal and Capital Projects	$ 140,806	$ 323,500	$ 330,000	$ 331,770	$ 341,750	$ 352,000
Special Projects						
Diesel Generator	$ 1,168,390	$ 460,350	$ -	$ -	$ -	$ -
24.9-kV Electric Rebuild	146,308	218,485	-	-	-	-
Blind Slough Gen. Rewind	-	-	-	-	-	-
Storage Yard Relocation	4,568	8,694	10	70	70	-
Subtotal - Special Projects	$ 1,319,266	$ 687,529	$ 10	$ 70	$ 70	$ -
Total - Capital Additions	$ 1,460,072	$ 1,011,029	$ 330,010	$ 331,840	$ 341,820	$ 352,000
Funding Sources						
Current Revenues	$ 146,072	$ 333,029	$ 330,010	$ 331,840	$ 341,820	$ 352,000
Customer Contributions	-	-	-	-	-	-
Reserves	1,314,000	678,000	-	-	-	-
Loans	-	-	-	-	-	-
Grants	-	-	-	-	-	-
Other	-	-	-	-	-	-
Total Funding Sources	$ 1,460,072	$ 1,011,029	$ 330,010	$ 331,840	$ 341,820	$ 352,000

TABLE A-2
Petersburg Municipal Power & Light
Loads, Resources and Diesel Generating Costs

		Actual			Projected				
		2010	2011	2012	2013	2014	2015	2016	2017
	Number of Customers [1]								
1	Residential	1,367	1,368	1,357	1,364	1,371	1,378	1,385	1,392
2	Harbor	396	398	387	389	391	393	395	397
3	Small Commercial	308	311	330	331	333	335	337	339
4	Large Commercial	35	36	38	38	38	38	38	38
5	**Annual Use per Cust. (kWh)** [2]								
6	Residential	13,919	14,631	15,150	15,453	15,530	15,608	15,686	15,764
7	Harbor	4,496	4,411	4,532	4,623	4,646	4,669	4,692	4,715
8	Small Commercial	20,646	21,022	21,829	22,265	22,376	22,488	22,600	22,713
9	Large Commercial	498,833	515,889	555,560	566,672	569,505	572,353	575,215	578,091
10	**Energy Sales (MWh)** [3]								
11	Residential	19,023	20,009	20,564	21,080	21,290	21,510	21,730	21,940
12	Harbor	1,780	1,755	1,755	1,800	1,820	1,830	1,850	1,870
13	Small Commercial	6,366	6,543	7,198	7,370	7,450	7,530	7,620	7,700
14	Large Commercial	17,667	18,658	21,065	21,530	21,640	21,750	21,860	21,970
15	Total Energy Sales	44,836	46,965	50,582	51,780	52,200	52,620	53,060	53,480
16	Increase over Previous Year	-3.5%	4.7%	7.7%	2.4%	0.8%	0.8%	0.8%	0.8%
17	Own Use	961	1,254	1,061	1,061	1,061	1,061	1,061	1,061
18	Interruptible Sales	1,549	1,956	-	-	-	-	-	-
19	Loss % of Total Reqs. [4]	7.4%	7.2%	7.4%	7.5%	7.5%	7.5%	7.5%	7.5%
20	System Losses	3,805	3,870	4,116	4,280	4,320	4,350	4,390	4,420
21	**Total Energy Requirements**	51,151	54,045	55,759	57,121	57,581	58,031	58,511	58,961
22	**Energy Resources (MWh)**								
23	Blind Slough Hydro	11,546	9,883	12,970	12,000	12,000	12,000	12,000	12,000
24	Lake Tyee Purchase	38,863	43,677	42,012	44,421	44,981	45,431	45,911	46,361
25	Diesel [5]	743	486	778	700	600	600	600	600
26	Total Energy Resources	51,152	54,046	55,760	57,121	57,581	58,031	58,511	58,961
27	**Diesel Energy Production Variable Cost**								
28	Fuel Use (gallons) [6]	47,710	46,656	61,779	51,852	44,444	44,444	44,444	44,444
29	Fuel Cost ($000) [7]	144	132	227	207	184	190	197	204
30	Fuel Price ($/gallon) [8]	3.01	2.83	3.67	4.00	4.14	4.28	4.43	4.59
31	**Power Purchase Cost ($000)**								
32	SEAPA Rate (¢/kWh) [9]			6.80	6.80	6.80	6.80	6.80	6.80
33	Purchased Power Cost [10]	$ 2,660	$ 2,908	$ 2,990	$ 3,021	$ 3,059	$ 3,089	$ 3,122	$ 3,153
34	Less: Estimated Rebate [11]	-	185	428	225	-	-	-	-
35	Net Cost	$ 2,660	$ 2,723	$ 2,562	$ 2,796	$ 3,059	$ 3,089	$ 3,122	$ 3,153
36	Net Rate (¢/kWh)	6.84	6.23	6.10	6.29	6.80	6.80	6.80	6.80

[1] Based on PMPL accounts for 2012 assumed to increase at rate of 0.5% per year thereater.
[2] Residential assumed to increase at 2.0% in 2013 and 0.5% per year thereafter.
[3] Number of accounts multipled by use per account.
[4] Projected losses assumed to remain constant.
[5] Projected diesel generation assumes limited interruption in Tyee Lake power deliveries.
[6] Projected fuel use based on estimated diesel generation at assumed usage rate of 13.5 kWh/gallon.
[7] Fuel Use multiplied by assumed fuel price.
[8] Based on assumed average price of $4.00/gallon in 2013 escalated at 3.5% per year.
[9] Assumed to remain constant.
[10] SEAPA Rate times Tyee Lake Purchase.
[11] No rebates are assumed to be provided in the future.

TABLE A-3
Petersburg Municipal Power & Light
2013 Electric Rate Study

Estimated Billing Determinants

		Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Total
	Hours in Period	744	744	720	744	720	744	744	696	744	720	744	720	8,784
	RESIDENTIAL													
1	Number of Customers	1,374	1,375	1,372	1,357	1,354	1,353	1,353	1,355	1,348	1,347	1,351	1,349	1,357
2	Energy Sold (MWh)	1,121	1,119	1,244	1,400	1,976	2,195	2,625	1,966	2,414	1,683	1,382	1,440	20,565
3	% Block 1 (<325)	36.6%	38.4%	35.8%	24.8%	17.5%	17.7%	15.4%	20.4%	17.8%	22.8%	26.6%	27.7%	23.1%
4	% Block 2 (326-650)	27.5%	28.0%	27.1%	20.6%	15.7%	15.8%	14.1%	17.6%	15.8%	19.4%	22.2%	23.2%	19.3%
5	% Block 3 (>650)	35.9%	33.6%	37.2%	54.6%	66.9%	66.6%	70.5%	62.0%	66.5%	57.9%	51.2%	49.2%	57.6%
6	Average Usage per Customer (kWh)	816	814	907	1,032	1,459	1,622	1,940	1,451	1,791	1,249	1,023	1,067	15,151
7	Losses	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	
8	MWh at Input	1,212	1,210	1,345	1,514	2,136	2,373	2,838	2,126	2,610	1,820	1,494	1,557	22,235
9	Demand Factor	2.12	2.11	2.32	2.60	3.53	3.87	4.53	3.51	4.22	3.08	2.58	2.68	
10	Calculated Demand (kW)	2,912	2,908	3,190	3,533	4,778	5,239	6,129	4,758	5,692	4,148	3,491	3,619	
11	Loadfactor	51.7%	51.7%	54.2%	53.3%	57.4%	56.3%	57.6%	59.4%	57.0%	56.3%	53.2%	55.3%	38.2%
12	Non-Coincident Peak (kW)	3,148	3,144	3,449	3,820	5,166	5,665	6,627	5,144	6,155	4,485	3,775	3,913	6,627
13	Coincidence Factor	93%	75%	75%	75%	60%	60%	60%	65%	54%	70%	70%	80%	
14	Coincident Peak (kW)	2,928	2,358	2,586	2,865	3,100	3,399	3,976	3,344	3,323	3,140	2,642	3,130	2,928
15														
16	**HARBOR**													
17	Number of Customers	424	414	400	376	369	372	370	365	361	373	409	414	387
18	Energy Sold (MWh)	65	56	99	119	162	207	276	194	199	130	129	119	1,755
19	% Block 1 (<501)	67.6%	73.6%	73.4%	60.1%	42.7%	49.0%	42.6%	55.4%	52.8%	65.3%	61.1%	63.6%	55.2%
20	% Block 2 (501-1000)	13.1%	11.0%	17.9%	22.4%	21.1%	24.7%	25.8%	25.5%	24.4%	21.9%	19.0%	20.7%	22.3%
21	% Block 3 (>1000)	19.3%	15.4%	8.7%	17.5%	36.2%	26.2%	31.7%	19.1%	22.7%	12.8%	19.9%	15.8%	22.5%
22	Average Usage per Customer (kWh)	153	135	248	316	439	556	746	532	551	349	315	287	4,532
23	Losses	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	
24	Energy at Input (MWh)	70	61	107	129	175	224	298	210	215	141	139	129	1,897
25	Loadfactor	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	26.9%
26	Non-Coincident Peak (kW)	189	163	297	346	487	602	802	603	578	390	375	357	802
27	Coincidence Factor	90%	75%	70%	70%	60%	60%	50%	50%	50%	70%	70%	80%	
28	Coincident Peak (kW)	170	122	208	242	292	361	401	301	289	273	262	286	170
29														

TABLE A-3

Petersburg Municipal Power & Light
2013 Electric Rate Study

Estimated Billing Determinants

		Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Total
	Hours in Period	744	744	720	744	720	744	744	696	744	720	744	720	8,784
30	**TOTAL COMMERCIAL**													
31	Number of Customers	353	353	353	371	379	380	373	373	371	367	369	370	368
32	Energy Sold (MWh)	3,011	3,470	2,570	1,896	2,142	1,988	2,448	2,265	2,200	2,356	1,899	2,017	28,262
33	Losses	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	
34	Energy at Input (MWh)	3,255	3,752	2,779	2,050	2,316	2,149	2,647	2,449	2,379	2,547	2,053	2,181	30,557
35	Loadfactor	45%	50%	41%	32%	35%	31%	36%	37%	33%	38%	31%	33%	35%
36	Non-Coincident Demand (kW)	9,043	9,256	8,623	8,054	8,494	8,710	9,248	8,805	8,898	8,514	8,289	8,459	9,256
37	Billed kW	7,794	8,094	7,535	6,847	7,023	6,925	7,276	7,175	7,102	7,050	7,047	7,100	
38	Coincidence Factor	94%	70%	70%	70%	52%	42%	35%	43%	37%	69%	69%	80%	
39	Coincident Peak (kW)	8,482	6,479	6,036	5,638	4,416	3,674	3,211	3,782	3,269	5,876	5,729	6,767	8,482
40														
41	**SMALL COMMERCIAL**													
42	Number of Customers	316	316	316	334	341	342	335	335	333	328	330	331	330
43	Energy Sold (MWh)	494	516	471	535	609	708	812	603	728	605	545	570	7,196
44	% Block 1 (<1501)	39.3%	45.5%	50.8%	47.2%	38.2%	37.4%	37.5%	45.0%	37.8%	44.0%	44.9%	42.6%	42.0%
45	% Block 2 (1501-3000)	16.5%	18.2%	17.5%	19.5%	19.6%	17.9%	19.1%	20.8%	18.8%	20.6%	18.9%	18.3%	18.9%
46	% Block 3 (>3000)	44.3%	36.3%	31.7%	33.4%	42.2%	44.7%	43.4%	34.2%	43.4%	35.4%	36.1%	39.1%	39.1%
47	Average usage per Customer (kWh)	1,563	1,633	1,491	1,602	1,786	2,070	2,424	1,800	2,186	1,845	1,652	1,722	
48	Losses	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	
49	Energy at Input (MWh)	534	558	509	578	658	765	878	652	787	654	589	616	7,780
50	Loadfactor	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	38%
51	Non-Coincident Demand (kW)	1,328	1,387	1,308	1,438	1,692	1,903	2,183	1,733	1,957	1,681	1,465	1,583	2,183
52	Coincidence Factor	93%	70%	70%	70%	60%	50%	50%	55%	50%	65%	65%	80%	
53	Coincident Peak (kW)	1,235	971	916	1,007	1,015	952	1,091	953	978	1,092	952	1,267	1,235
54														
55	**LARGE COMMERCIAL**													
56	Number of Customers	37	37	37	37	38	38	38	38	38	39	39	39	38
57	Energy Sold (MWh)	2,517	2,954	2,099	1,361	1,533	1,280	1,636	1,662	1,472	1,751	1,354	1,447	21,066
58	% Block 1 (<30001)	24.6%	21.9%	31.2%	46.0%	47.6%	55.0%	49.6%	46.3%	49.5%	42.3%	50.1%	44.6%	39.7%
59	% Block 2 (30001-60000)	11.4%	10.8%	16.2%	19.6%	16.6%	16.2%	18.0%	18.4%	17.5%	16.9%	18.9%	17.8%	15.8%
60	% Block 3 (>60000)	64.0%	67.2%	52.6%	34.5%	35.8%	28.8%	32.5%	35.3%	33.0%	40.8%	31.0%	37.6%	44.5%
61	Average usage per Customer (kWh)	68,027	79,838	56,730	36,784	40,342	33,684	43,053	43,737	38,737	44,897	34,718	37,103	
62	Losses	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	
63	Energy at Input (MWh)	2,721	3,194	2,269	1,471	1,657	1,384	1,769	1,797	1,592	1,893	1,464	1,564	22,776
64	Loadfactor	44%	50%	40%	28%	31%	25%	31%	34%	29%	36%	27%	29%	30%
65	Non-Coincident Demand (kW)	7,715	7,869	7,315	6,616	6,803	6,806	7,065	7,072	6,941	6,834	6,824	6,876	7,869
66	Coincidence Factor	94%	70%	70%	70%	50%	40%	30%	40%	33%	70%	70%	80%	
67	Coincident Peak (kW)	7,247	5,508	5,120	4,631	3,401	2,723	2,120	2,829	2,291	4,783	4,776	5,501	7,247
90														

TABLE A-3
Petersburg Municipal Power & Light
2013 Electric Rate Study

Estimated Billing Determinants

		Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Total
	Hours in Period	744	744	720	744	720	744	744	696	744	720	744	720	8,784
91	**TOTAL SYSTEM**													
92	**Number of Customers**	2,151	2,142	2,125	2,104	2,102	2,105	2,096	2,093	2,080	2,087	2,129	2,133	2,112
93	Energy Sold (MWh)	4,197	4,645	3,913	3,415	4,280	4,390	5,349	4,425	4,813	4,169	3,410	3,576	50,582
94	Energy at Input (MWh)	4,538	5,022	4,231	3,692	4,627	4,746	5,783	4,784	5,204	4,507	3,687	3,866	54,689
95	System LF (Based on est. peak)	46%	50%	44%	38%	42%	39%	43%	44%	41%	43%	37%	39%	50%
96	Sum Class NCP (kW)	12,380	12,562	12,369	12,220	14,147	14,976	16,677	14,551	15,631	13,390	12,438	12,729	16,685
97	Coincident Peak (kW) **	11,580	8,959	8,831	8,745	7,808	7,434	7,588	7,427	6,882	9,289	8,634	10,183	11,580
98														
99	Net Generation (MWh)	4,397	5,337	3,909	4,307	4,979	5,148	5,987	4,900	4,890	4,373	4,099	3,434	55,760
100	Losses and Own Use (MWh)	200	692	(4)	892	699	758	638	475	77	204	689	(142)	5,178
101	Losses and Own Use (%)	4.5%	13.0%	-0.1%	20.7%	14.0%	14.7%	10.7%	9.7%	1.6%	4.7%	16.8%	-4.1%	9.3%
102	Own Use (MWh)	49	58	61	99	113	117	137	108	101	84	82	62	1,071
103	Losses (MWh)	151	634	(65)	793	586	641	500	367	(24)	120	608	(204)	4,107
104	Losses (% of Generation)	3.4%	11.9%	-1.7%	18.4%	11.8%	12.5%	8.4%	7.5%	-0.5%	2.7%	14.8%	-5.9%	7.4%
105	Tyee - PMPL Peak (kW)	6,910	6,680	4,880	5,450	6,170	6,240	5,810	4,670	5,730	4,590	5,900	5,410	6,910
106	Total PMPL Peak (Net kW)	11,580	8,820	8,920	8,970	7,720	7,440	7,430	7,520	6,850	9,480	8,753	10,364	11,580

TABLE A-3.1

Petersburg Municipal Power & Light

2013 Electric Revenue Requirement Study

Electric Plant in Service and Accumulated Depreciation

		Gross Plant Balance 30-Jun-12	Acc. Depr. Balance 30-Jun-12	Net Plant Balance 30-Jun-12	Depreciation Expense FY 2012
	LAND				
130100	Mitkof HWY - Plant Relocation	$ 630,650.00	$ -	$ 630,650.00	
130101	Hydraulic production	2,933.63	-	2,933.63	
130102	Diesel production	23,719.06	-	23,719.06	
130103	Transmission production	340.51	-	340.51	
130104	Clearing lands and ROW	77,401.30	-	77,401.30	
	Total Land	$ 735,044.50	$ -	$ 735,044.50	
	BUILDINGS				
130120	Buildings	$ 44,757.60	$ 25,922.47	$ 18,835.13	$ 1,520.76
130121	Hydro - Structures & Improvements	198,404.12	198,404.12	-	$ -
130122	Diesel structures & imps	711,461.15	658,554.43	52,906.72	26,109.75
130123	Distribution plant - structures & imps	19,625.51	19,442.14	183.37	183.33
130124	General plant - structures & imps	93,012.55	84,648.55	8,364.00	1,045.50
	Total Buildings	$ 1,067,260.93	$ 986,971.71	$ 80,289.22	$ 28,859.34
	OTHER IMPROVEMENTS				
130125	Hydro plant - reservoirs, dams, waterways	$ 1,485,332.34	$ 988,773.53	$ 496,558.81	$ 28,867.36
130126	Diesel plant - fuel producers & resources	113,009.11	113,009.11	-	-
130127	Auto Load Control System	103,992.63	29,704.69	74,287.94	5,199.63
130128	24.9 kV Electric Upgrade	179,893.34	53,787.90	126,105.44	8,994.67
130129	Frederick Point Line Extension	266,761.12	26,676.11	240,085.01	13,338.06
130130	Structures & improvements	1,968,727.00	49,218.18	1,919,508.82	49,218.18
	Total Other Improvements	$ 4,117,715.54	$ 1,261,169.52	$ 2,856,546.02	$ 105,617.90
	MACHINERY & EQUIPMENT				
130161	Waterwheels, Turbines & generators	$ 280,109.14	$ 279,153.78	$ 955.36	$ 2,345.98
130162	Hydro - accessory electric equip switchboard	42,577.21	42,577.21	-	-
130163	Misc power plant equipment	160,726.29	160,726.29	-	-
130164	Diesel internal combustion engines	3,366,810.85	3,108,089.37	258,721.48	90,074.47
130165	Accessory electrical equipment	45,997.36	32,009.39	13,987.97	1,140.10
130166	Diesel - power plant equipment	8,985.83	8,985.83	-	-
130167	Station equipment - transmission	120,914.84	62,943.56	57,971.28	1,900.70
130168	Poles & fixtures	29,171.92	18,363.92	10,808.00	386.00
130169	Overhead conductors & devices	196,718.47	196,718.47	-	-
130170	Station equipment - distribution plant	224,034.43	175,306.48	48,727.95	6,330.00
130171	Storage battery equipment	35,196.23	35,196.23	-	492.23
130172	Poles, towers & fixtures	4,066,051.39	2,479,773.75	1,586,277.64	126,225.28
130173	Overhead conductors & devices	2,387,058.84	1,248,525.15	1,138,533.69	75,172.18
130174	Underground conduit - Distribution plant	959,737.57	708,219.40	251,518.17	31,132.73
130175	Underground conductors & devices	714,945.03	503,590.90	211,354.13	23,554.09
130176	Line transformers	1,592,163.12	1,081,897.64	510,265.48	49,534.77
130177	Services	956,756.69	662,771.03	293,985.66	27,955.48
130178	Meters	520,424.94	328,142.65	192,282.29	15,321.28
130179	Installations - customer premises	1,361.88	1,190.82	171.06	31.11
130180	Leased property on cust premises	18.21	18.21	-	-
130181	Street lighting & signal systems	105,126.33	63,788.53	41,337.80	2,665.19
130182	Unclassified distribution plant	52,279.63	52,279.63	-	-
130183	Office equipment	233,857.92	194,240.49	39,617.43	9,245.81

TABLE A-3.1

Petersburg Municipal Power & Light

2013 Electric Revenue Requirement Study

Electric Plant in Service and Accumulated Depreciation

		Gross Plant Balance 30-Jun-12	Acc. Depr. Balance 30-Jun-12	Net Plant Balance 30-Jun-12	Depreciation Expense FY 2012
130184	Transportation equipment	24,852.45	24,852.45	-	-
130185	Stores equipment	8,984.80	8,984.80	-	-
130186	Tools, shop & garage equipment	153,886.56	132,312.90	21,573.66	7,411.08
130187	Laboratory equipment	62,446.85	59,914.75	2,532.10	750.85
130188	Communication equipment	60,150.15	57,236.63	2,913.52	2,729.62
130189	Miscellaneous equipment	562,065.38	504,126.00	57,939.38	54,538.90
	Total Machinery & Equipment	$ 16,973,410.31	$ 12,231,936.26	$ 4,741,474.05	$ 528,937.85
	Subtotal	$ 22,893,431.28	$ 14,480,077.49	$ 8,413,353.79	$ 663,415.09
130140	Work in Progress	2,037,419.52			
362110	Contributed Capital	5,565,699.23	2,758,684.63	2,807,014.60	171,171.18
	Total	$ 30,496,550.03	$ 17,238,762.12	$ 11,220,368.39	$ 834,586.27
	SUMMARY				
	Land	$ 735,044.50	$ -	$ 735,044.50	$ -
	Production Plant				
	Hydroelectric	2,167,149.10	1,669,634.93	497,514.17	31,213.34
	Diesel	4,246,264.30	3,920,648.13	325,616.17	117,324.32
	Transmission Plant	346,805.23	278,025.95	68,779.28	2,286.70
	Distribution Plant	14,154,153.89	7,519,529.44	6,634,624.45	435,348.21
	General Plant				
	Buildings	137,770.15	110,571.02	27,199.13	2,566.26
	Machinery & Equipment	1,106,244.11	981,668.02	124,576.09	74,676.26
	Total	$ 22,893,431.28	$ 14,480,077.49	$ 8,413,353.79	$ 663,415.09

TABLE A-4
Petersburg Municipal Power & Light
2013
Electric Revenue Requirement Study

Independent Allocation Factors

		Factor Reference	Total System	Residential	Harbor	Small Commercial	Large Commercial
1	DEMAND ALLOCATORS						
2	Single CP Demand		11,580	2,928	170	1,235	7,247
3	Percent Responsibility	CP	100.0%	25.3%	1.5%	10.7%	62.6%
4	Average CP Demand - 12 month		8,613	3,066	267	1,036	4,244
5	Percent Responsibility	ACP	100.0%	35.6%	3.1%	12.0%	49.3%
6	NCP Demand		17,481	6,627	802	2,183	7,869
7	Percent Responsibility	NCP	100.0%	37.9%	4.6%	12.5%	45.0%
8	Average NCP Demand - 12 month		13,673	4,541	432	1,638	7,061
9	Percent Responsibility	ANCP	100.0%	33.2%	3.2%	12.0%	51.6%
10							
11	ENERGY ALLOCATOR						
12	Energy Sales (MWh)		50,582	20,565	1,755	7,196	21,066
13	Percent Responsibility	SALES	100.0%	40.7%	3.5%	14.2%	41.6%
14	Energy Usage		54,689	22,235	1,897	7,780	22,776
15	Percent Responsibility	REQ	100.0%	40.7%	3.5%	14.2%	41.6%
16							
17	CUSTOMER ALLOCATORS						
18	Number of Customers		2,112	1,357	387	330	38
19	Percent Responsibility	CUST	100.0%	64.3%	18.3%	15.6%	1.8%
20	Weighted No. of Customers		2,783	1,357	387	660	379
21	Percent Responsibility	WtCUST	100.0%	48.8%	13.9%	23.7%	13.6%
22							
23	REVENUES						
24	Present Base Revenues		5,241,454	1,988,564	222,045	733,098	2,297,748
25	Percent Responsibility	REV	100.0%	37.9%	4.2%	14.0%	43.8%
26							
27	DEPENDENT ALLOCATORS						
28	Plant Allocator	PLT	100.0%	38.6%	5.5%	12.6%	43.3%
29	Distribution Plant Allocator	DPLT	100.0%	39.4%	6.2%	12.7%	41.7%
30	Labor Allocator	LBR	100.0%	40.1%	3.9%	13.8%	42.1%

TABLE A-5
Petersburg Municipal Power & Light
2013 Electric Revenue Requirement Study

Allocation Analysis

Allocation of Plant in Service (Rate Base)

	Description	Weight Factor	Allocation Factor	Gross Utility Plant	Accum. Depr.	Net Utility Plant	Residential	Harbor	Small Commercial	Large Commercial
	PLANT IN SERVICE									
1	Intangible Plant (Land)		ACP	735,045	-	735,045	261,640	22,818	88,392	362,195
2	Production Plant									
3	Hydroelectric		ACP	2,167,149	1,669,635	497,514	177,091	15,444	59,828	245,151
4	Diesel		ACP	4,246,264	3,920,648	325,616	115,903	10,108	39,157	160,448
5	Transmission Plant		ACP	346,805	278,026	68,779	24,482	2,135	8,271	33,891
6	Distribution Plant									
7		20%	CUST	2,830,831	1,503,906	1,326,925	852,683	243,272	207,150	23,819
8		80%	ANCP	11,323,323	6,015,624	5,307,700	1,762,722	167,865	635,932	2,741,181
9	Subtotal - Distribution Plant			14,154,154	7,519,529	6,634,624	2,615,404	411,138	843,082	2,765,000
10	General Plant		ANCP			-	-	-	-	-
11	Buildings		ANCP	137,770	110,571	27,199	9,033	860	3,259	14,047
12	Equipment/Machinery		ANCP	1,106,244	981,668	124,576	41,373	3,940	14,926	64,338
13										
14	Grand Total - Plant in Service			22,893,431	14,480,077	8,413,354	3,244,926	466,443	1,056,915	3,645,070
15	% Responsibility						38.6%	5.5%	12.6%	43.3%

TABLE A-5
Petersburg Municipal Power & Light
2013 Electric Revenue Requirement Study

Allocation Analysis

Allocation of Total Costs

		Account	Allocation Factor	FY 2013 Total Cost	Residential	Harbor	Small Commercial	Large Commercial
	OPERATING EXPENSES							
16	Power Production							
17	Fuel		REQ	207,000	84,159	7,182	29,449	86,210
18	Hydro & Diesel O&M		ACP	184,000	65,495	5,712	22,127	90,666
19	Total - Power Production			391,000	149,655	12,894	51,575	176,876
20	Purchased Power		REQ	3,083,628	1,253,703	106,990	438,689	1,284,246
21	Distribution O&M		DPLT	449,000	176,998	27,824	57,056	187,122
22	Customer Accounting		CUST	-	-	-	-	-
23	Motor Pool Expenses		PLT	132,000	50,911	7,318	16,582	57,189
24	Allocated Overhead		PLT	133,000	51,296	7,374	16,708	57,622
25	Administrative & General		PLT	1,016,000	391,859	56,328	127,634	440,180
26	Total Operating Expenses			5,204,628	2,074,422	218,727	708,244	2,203,235
27								
28	Less: Interest income		PLT	(144,000)	(55,539)	(7,983)	(18,090)	(62,388)
29	Less: Other Op. Revenues		ANCP	(133,600)	(44,369)	(4,225)	(16,007)	(68,998)
30	Less: SEAPA Rebate		REQ	(225,000)	(91,478)	(7,807)	(32,009)	(93,706)
31	Debt Service on Existing Debt		PLT	237,000	91,408	13,139	29,773	102,680
32	Capital Improvements from Revenues		PLT	458,000	176,645	25,392	57,536	198,428
33	NET COST OF SERVICE			5,397,028	2,151,088	237,243	729,447	2,279,250
34								
35	Energy Sales (MWh)			50,582	20,565	1,755	7,196	21,066
36	Average Cost of Service (cents per kWh)			10.67	10.46	13.52	10.14	10.82
37								
38	Revenues from Existing Rates			5,241,454	1,988,564	222,045	733,098	2,297,748
39	Average Revenue (cents per kWh)			10.36	9.67	12.65	10.19	10.91
40								
41	Over (Under) Cost of Service			(155,574)	(162,524)	(15,198)	3,651	18,498
42	Over (Under) Cost of Service (cents per kWh)			(0.31)	(0.79)	(0.87)	0.05	0.09
43	Over (Under) Cost of Service (%)			-3.0%	-8.2%	-6.8%	0.5%	0.8%

TABLE A-9
Petersburg Municipal Power & Light
2013 Rate Study
Alternative Rate Design Options

CASE 4 - Two Years, No Sm Comm

	Existing Rates Effective 3/2006				Option I1 - Year 1, 2%				Option I2 - Year 2, 2% (~4% Total)			
	Block %	Billing Unit	Rate	Revenue ($000)	Block %	Billing Unit	Rate	Revenue ($000)	Block %	Billing Unit	Rate	Revenue ($000)
Residential	Block 1 <325, Block 2 <650, Block 3 >650				Block 1 ≤500, Block 2 >500				Block 1 ≤500, Block 2 >500			
Energy Charge (¢/kWh)												
Block 1	23.1%	4,750	11.80	$ 560	33.6%	6,913	11.80	$ 816	33.6%	6,913	11.90	$ 823
Block 2	19.3%	3,965	11.40	452	66.4%	13,652	7.80	1,065	66.4%	13,652	8.10	1,106
Block 3	57.6%	11,850	7.00	830	0.0%	-	-	-	0.0%	-	-	-
Subtotal	100.0%	20,565	8.96	$ 1,842	100.0%	20,565	9.14	$ 1,881	100.0%	20,565	9.38	$ 1,928
Demand Charge ($/kW)		-	-	-		-	-	-		-	-	-
Customer Charge ($/month)		1,357	9.00	147		1,357	9.00	147		1,357	9.00	147
Total ($000)				$ 1,989				$ 2,027				$ 2,075
Unit Revenue (¢/kWh)				9.67				9.86				10.09
Revenue Change								$ 39				$ 86
% Change								1.9%				4.3%
Harbor	Block 1 ≤500, Block 2 ≤1000, Block 3 >1000				Block 1 ≤500, Block 2 >500				Block 1 ≤500, Block 2 >500			
Energy Charge (¢/kWh)												
Block 1	55.2%	969	11.10	$ 108	55.2%	969	11.40	$ 111	55.2%	969	11.80	$ 114
Block 2	22.3%	391	10.90	43	44.8%	786	9.30	73	44.8%	786	9.60	75
Block 3	22.5%	394	7.60	30	0.0%	-	-	-	0.0%	-	-	-
Subtotal	100.0%	1,755		$ 180	100.0%	1,755		$ 184	100.0%	1,755		$ 190
Demand Charge ($/kW)		-	-	-		-	-	-		-	-	-
Customer Charge ($/month)		387	9.00	42		387	9.00	42		387	9.00	42
Total ($000)				$ 222				$ 225				$ 232
Unit Revenue (¢/kWh)				12.65				12.84				13.20
% Change								1.5%				4.3%
					General Service (Prev. Sm. Comm.)				**General Service (Prev. Sm. Comm.)**			
General Service (SmCom)	Block 1 ≤1500, Block 2 ≤3000, Block 3 >3000				Block 1 ≤3000, Block 2 >3000				Block 1 ≤3000, Block 2 >3000			
Energy Charge (¢/kWh)												
Block 1	0.0%	-	-	$ -	60.9%	4,380	11.00	$ 482	60.9%	4,380	11.00	$ 482
Block 2	0.0%	-	-	-	39.1%	2,816	8.30	234	39.1%	2,816	8.80	248
Block 3	0.0%	-	-	-	0.0%	-	-	-	0.0%	-	-	-
Subtotal	0.0%	-		$ -	100.0%	7,196		$ 716	100.0%	7,196		$ 730
Demand Charge ($/kW)		-	$ -	-		-	$ -	-		-	$ -	-
Customer Charge ($/month)		-	-	-		330	9.00	36		330	9.00	36
Total ($000)				$ -				$ 751				$ 765
Unit Revenue (¢/kWh)				-				10.44				10.63
% Change								2.5%				4.4%
					Small Commercial				**Small Commercial**			
Small Commercial	Block 1 ≤1500, Block 2 ≤3000, Block 3 >3000				Block 1 ≤15000, Block 2 >15000				Block 1 ≤15000, Block 2 >15000			
Energy Charge (¢/kWh)												
Block 1	42.0%	3,023	11.10	$ 336	61.2%	-	-	$ -	61.2%	-	-	$ -
Block 2	18.9%	1,357	10.90	148	38.8%	-	-	-	38.8%	-	-	-
Block 3	39.1%	2,816	7.60	214	0.0%	-	-	-	0.0%	-	-	-
Subtotal	100.0%	7,196		$ 697	100.0%	-		$ -	100.0%	-		$ -
Demand Charge ($/kW)		-	$ -	-		-	$ -	-		-	$ -	-
Customer Charge ($/month)		330	9.00	36		-	-	-		-	-	-
Total ($000)				$ 733				$ -				$ -
Unit Revenue (¢/kWh)				10.19				-				-
% Change								0.0%				0.0%
					Large Commercial (> 50 KW)				**Large Commercial (> 50 KW)**			
Large Commercial	Block 1 ≤30000, Block 2 ≤60000, Block 3 >60000				Block 1 ≤15000, Block 2 ≤60000, Block 3 >60000				Block 1 ≤15000, Block 2 ≤60000, Block 3 >60000			
Energy Charge (¢/kWh)												
Block 1	39.7%	8,355	10.80	$ 902	25.0%	5,271	10.60	$ 559	25.0%	5,271	10.60	$ 559
Block 2	15.8%	3,339	10.60	354	30.5%	6,422	11.00	706	30.5%	6,422	11.10	713
Block 3	44.5%	9,372	8.10	759	44.5%	9,373	8.50	797	44.5%	9,373	8.80	825
Subtotal	100.0%	21,066	9.57	$ 2,015	100.0%	21,066	9.79	$ 2,062	100.0%	21,066	9.95	$ 2,096
Demand Charge ($/kW)		86,968	$ 3.10	270		86,968	$ 3.10	270		86,968	$ 3.10	270
Customer Charge ($/month)		38	28.00	13		38	28.00	13		38	28.00	13
Total ($000)				$ 2,298				$ 2,344				$ 2,379
Unit Revenue (¢/kWh)				10.91				11.13				11.29
% Change								2.0%				3.5%
Total Revenue												
Energy Charge		50,582		$ 4,735		50,582		$ 4,842		50,582		$ 4,944
Demand Charge		86,968		270		86,968		270		86,968		270
Customer Charge		2,112		237		2,112		237		2,112		237
Total			10.36	$ 5,241			10.57	$ 5,348			10.78	$ 5,451
Unit Revenue (¢/kWh)				10.36				10.57				10.78
Increase over Previous								2.0%				4.0%