November 16, 2015

Ms. Donna Mitchell, CPA
Controller/Treasurer
City of Dover
5 East Reed Street
Weyandt Hall, Suite 300
Dover, Delaware 19901

Re: 2015 Electric Cost-of-Service and Rate Design Study Update
Project Number 84122

Dear Ms. Mitchell:

Burns & McDonnell is pleased to present this report on the 2015 Electric Cost-of-Service and Rate Design Study Update (the Study) completed on behalf of the City of Dover (the City) and the Dover Municipal Electric Division (the Electric Division). This report was prepared and is submitted pursuant to the agreement between Burns & McDonnell and the City, executed March 24, 2015. This Study is an update to the rate study and analysis Burns & McDonnell prepared for the City and Electric Division in 2013.

BACKGROUND

In March 2015, the City retained Burns & McDonnell to develop recommended modifications to its electric rates. A primary driver behind this 2015 update was commercial and industrial rate competitiveness. Burns & McDonnell was tasked with balancing appropriate allocation of cost recovery while developing regionally competitive electric rates. This report describes the approach and assumptions used in the analyses completed for the 2015 Study and was initially provided in draft form in June. The report provides a review of the internally developed Electric Division five-year financial forecast, test period revenue requirement, and allocated, unbundled cost-of-service for each of the Electric Division's electric rate classifications. The report concludes with the presentation and a discussion of the proposed revisions to retail electric rates developed by Burns & McDonnell.

STUDY SCOPE

The Study addresses specific issues associated with allocating the cost of purchased power and developing rates designed to incorporate costs of providing service to various customer classes of the utility. Burns & McDonnell adhered to the following guidelines while completing the Study:

1. The rates to be developed must recover the Electric Division's revenue requirements.
2. The rates to be developed must be fair and equitable across customer classes.
3. The rates to be developed and the implementation schedule for those rates must be reasonable.

4. The rates to be developed will reflect the Electric Division's underlying power supply cost structure.

The major elements of the Scope of Work included the following:

- Review revenue requirements forecast and update as necessary
- Review cost-of-service functionalization, classification, and allocation
- Prepare necessary revisions to electric rates

METHOD OF ANALYSIS

Revenue Requirements Review

Burns & McDonnell reviewed the financial forecast model updated by the City in 2015 and incorporated updates into the model developed for the 2013 Study update. The financial forecast was developed to determine the adequacy of revenues for the five-year forecast period. The updated forecast includes projections of annual revenues under existing rates and the annual revenue requirement, including purchased power costs, all operating expenses, capital requirements, debt service requirements, and reserve requirements, by year from the Budget Year 2015 through FY 2020. The financial plan developed identifies the overall change in revenue required to provide adequate funding for capital improvement programs, to meet all operating expenditures, to cover all debt service requirements, to maintain sufficient cash balances and capital reserves, and to cover costs associated with purchased power supply. Information developed in previous electric rate studies and analyses was utilized in the revised forecast and financial plan. Prior to finalization of the financial plan, the City and Burns & McDonnell agreed on the revised financial forecast model results and the assessment of estimated impacts on the cash flow of the Electric Division.

Update Cost-of Service Analysis

The Study included an updated cost-of-service analysis to identify the relative responsibility of each rate classification for the recovery of the costs of service. The cost-of-service analysis provides for the classification of costs to specific utility functions. The analysis was completed using FY 2016 as the test year. The functionalization, classification, and allocation factors developed in the 2013 Study were utilized for this 2015 update.

Rate Revision

Burns & McDonnell developed proposed rate revisions for consideration by the City. This phase of the Study required particular attention in order to address specific objectives which must be met in the design of rates. Burns & McDonnell held discussions and maintained coordination with the City for this portion of the Study.

DATA SOURCES AND LIMITATIONS

The Finance, Administrative, and Electric Divisions of the City provided the information used in the preparation of the Study. This included various analyses, computer-generated information and reports, audited financial reports, and other financial and statistical information, as well as other documents such as operating budgets and current retail electric rate schedules. The Electric Division also provided input to key assumptions regarding expected future levels of revenue, sales, and expenditures.

Burns & McDonnell used the information provided by the City to make certain assumptions with respect to conditions that may exist in the future. While Burns & McDonnell believes the assumptions made are reasonable for the purposes of the Study, it makes no representation that the conditions assumed will occur. Burns & McDonnell has also relied on the information provided without independent verification and cannot guarantee its accuracy or completeness. Therefore, to the extent that actual future conditions differ from those assumed in the Study or from the information provided to Burns & McDonnell, the actual results may vary from those projected.

REVENUE REQUIREMENTS ANALYSIS

The first phase of the Study completed for the City was the review of the financial forecast and determination of the test period revenue requirement. Once completed, the test period revenue requirement was used as the basis for the subsequent phases of the Study; i.e. the cost-of-service analysis and the rate design. In order to determine the revenue requirement, City staff developed the initial 2015 financial forecast for the Electric Division utilizing a model previously prepared by Burns & McDonnell. Burns & McDonnell incorporated those updates into the model it developed during the 2013 Study, then checked and verified the forecast.

Financial Forecast Model

The financial forecast model provides for the estimation of financial results beginning in Budget Year FY 2015 and ending in FY 2020. The Study examines a forecast period of five years, from Budget Year 2015 through FY 2020. The City’s fiscal year begins on July 1, and ends on June 30.

The financial forecast includes projections of annual revenues, expenses and the resulting net income, as well as projections of cash flows. The forecast includes a projection of annual internally generated funds from operations and the Electric Division’s projected capital expenditure requirements. These estimates were used to forecast the Electric Division’s need for additional funds. The determination of whether required additional funds would be recovered through retail rate adjustments, external capital financing, and/or transfers from reserves was based on input from City staff, as well as the Utility Committee of the Dover City Council.

Projections developed in the financial forecast model were summarized in pro forma financial statements of projected net margins, cash flows, and revenue requirements within the model. The model includes spreadsheets that reflect the detailed projections of each element of the forecast. The test period revenue requirement is determined from these pro forma financial statements.

The bases and assumptions utilized in the evolution of the Electric Division financial forecast are explained herein. The projections included in the forecast are based on assumptions developed by the City and reviewed for reviewed reasonableness by Burns & McDonnell.

Projected Net Margins

The projection of annual net margins in the financial forecast was necessary to estimate the Electric Division's annual debt service coverage ratio. A coverage ratio of 125 percent is required by the City's bond resolution. In addition, the projection of net margins for each year provided the basis for determining the cash generated from operations, which affected estimates of cash flows for the forecast. Ultimately, the FY 2016 net margin was used to establish the Electric Division's test period base rate revenue requirement. The components that comprise the projected net margins are discussed below.

Energy Sales

Annual system energy sales were projected to decrease 1.2 percent from FY 2014 to FY 2015. The annual deviation of each customer class's energy sales was based on projections provided by the City. Estimated annual energy sales are forecast to total 712,216 megawatt-hours (MWh) in FY 2015 and increase to 722,595 in FY 2020.

Billing Demand

Annual billing demand for the system was projected to decrease 1.3 percent from the previous year in FY 2015. The annual deviation of each customer class's billing demand was tied to each respective class's energy sales projections for the analysis period. Estimated billing demand totals 1,266,916 kilowatts (kW) in FY 2015 and is expected to reach 1,277,347 kW in FY 2020.

Energy Analysis

Power supply projections were prepared by TEA and incorporated into the forecast model. The total projected power supply requirement is 741,522 MWh in FY 2015 and is projected to reach 751,825 MWh in FY 2020.

In addition to metered energy sales, unmetered usage and losses were projected for each year of the analysis as the difference between metered energy usage and TEA power supply projections. Unmetered usage and losses were projected to vary from a high of 4.1 percent to a low of 3.8 percent of power supply throughout the forecast.

Rate Revenues

Annual energy sales to each customer class were multiplied by the average revenue per kWh for each class from FY 2014 to calculate annual base rate revenue by class, by year. Annual base revenues estimated to be generated from current rates, assuming no rate adjustments are implemented, total $76.0 million in FY 2015; increasing to $77.2 million in FY 2020.

In addition to base rate revenues, the City collects state utility taxes from retail power sales. Utility tax was estimated by multiplying the projected annual total rate revenue for each year of the forecast by the ratio of utility tax to total rate revenue for the immediately preceding year.

The utility's purchased power costs have declined annually since FY 2009 mainly due to falling natural gas prices. This power cost decline has led to excess revenue generation for the City. In FY 2011 and 2012, the City utilized a Purchased Power Adjustment (PPA) to credit customers' accounts for the over recovery of purchased power costs generated with retail rates. To continue to curb the over accumulation of cash in FY 2013, the City implemented base rate reductions for each customer class. This Study was completed, in part, to formulate rates to recover revenue through base rate revenue adjustments based on a revised power supply forecast developed by TEA. Proposed adjustments are discussed later in this section.

Other Operating Revenue

Other types of electric operating revenues included in the forecast include green energy revenue, intra-fund service receipts, penalties, general service billing, miscellaneous revenue, reconnect fees, returned check fees, bad debt collections, new service fees, state reimbursements and grants, rent revenues, and other rebates/reimbursements. These revenues will constitute approximately 1.6 percent of the Electric Division's non-tax revenue in FY 2015. Each of the other types of non-rate revenues, except other reimbursements, were either held equal to their Budget Year estimates or escalated moderately for each year of the forecast. Other reimbursements were projected at $1.9 million for each year of the forecast. However, this income is directly offset by associated capital expenditures in projected years for new unplanned development projects.

Assuming no base rate adjustments are implemented in the Budget Year or during the forecast period, total annual operating revenues were projected to total $78.5 million in FY 2015 and increase to $81.4 million in FY 2020.

Power Supply Expense

The City retained the services of TEA to manage the procurement of its wholesale power supply. TEA also provides management support and hedging strategies for the purchasing and selling of energy in the PJM market. The purchased power expenses include various charges including wholesale power supply expense, Dover Sun Park energy, renewable energy credits, Delaware Regional Greenhouse Gas Initiative expense, power supply management expense, PJM load charges, PJM capacity charges, power generation fuel expense, PJM power generation credits, PJM capacity credits and renewable portfolio standard expense. The budgeted power supply expense for FY 2015 is $44.0 million. Power supply expense is projected to total $47.8 million in FY 2020.

Operation and Maintenance Expenses

In addition to the power supply costs discussed above, the Electric Division incurs other types of operating expenses associated with operating and maintaining the system. The operating and maintenance expenses associated with each of the three departments within the Electric Division which include Transmission and Distribution, Engineering, and Administration. Other operating expenses projected for the forecast include general administration, power plant operation and maintenance, non-capital expenses in Fund 487, utility tax, depreciation, interest on deposits, allowance for bad debts, retiree health care, post-retirement benefits, pension, green energy expense, inventory write-offs, compensated absences, and bank fees. Operating expenses, not including power supply expense, plant operations or depreciation, are estimated to total $14.2 million in FY 2015 and reach $16.5 million in FY 2020. Projections for these operation and maintenance expenses were developed by the City and reviewed for reasonableness by Burns & McDonnell.

Plant Investment

The Electric Division's projected net plant investment is based on the City's current plant in service and the projected capital improvements plan. The City's capital improvement budget for the Electric Division in FY 2015 is $7.3 million. The projected annual capital improvement budgets after FY 2015 range from a high of $6.4 million in FY 2017 to a low of $4.3 million in FY 2020.

Depreciation expense for each year was calculated based on the projected average annual adjusted gross plant in service as of the beginning and end of the year. The average gross plant in service balances of each plant category were multiplied by the corresponding depreciation rates, which were developed from assumed life years provided by the City for each type of property. Depreciation expense is projected to total $5.3 million in FY 2015; increasing to $6.2 million in FY 2020. Annual depreciation expense is included in the Electric Division's annual net revenue requirement.

Debt Service
Debt service expense for each year was calculated based on the existing debt service amortization schedules provided by the City. The City's existing debt service requirement is associated with the 2008 Revenue Bonds and the 2010 Revenue Bonds. The Electric Division's total Budget Year debt service principal and interest requirement is $3.3 million; $1.4 million of which is associated with 2008 Bonds and $1.9 million is associated with the 2010 Revenue Bonds, for which the last payment is due in FY 2016. Annual interest expense associated with debt is included in the Electric Division's annual net revenue requirement. As part of the bond covenants, the City is required to keep a minimum debt service coverage ratio of 125 percent.

Reserve Accounts
The City has various reserve accounts which support the ongoing operations of the Electric Division. These cash accounts include the Depreciation Reserve, Future Capacity Reserve, Insurance Stabilization Reserve, Rate Stabilization Reserve, Contingency Reserve, and Improvements and Extension Fund. These reserve accounts have various purposes and requirements as dictated in the existing bond covenants.

Other Non-Operating Income and Expense
Estimates for several categories of non-operating income and expenses are included in the forecast. The projections for these items include earned interest, operating and non-operating transfers, interest expense, and non-cash items.

Interest on operating and reserve accounts are included in the forecast. The FY 2015 estimated interest on operating funds of $36,800 was provided by the City and was projected to fluctuate throughout the analysis period. The estimated interest on reserve funds is based on the projected annual reserve fund beginning balances and an interest rate of 0.2 percent. Interest on reserve funds is estimated to be $63,900 in FY 2015; decreasing to $52,500 in FY 2020.

Projected operating transfers to the City's General Fund included in the City's Operating Budget are estimated to be $10.0 million in FY 2015 and each year thereafter.

Interest expense on long-term debt was forecasted based on the current debt amortization schedules for the bonds outstanding at the beginning of FY 2015. The bond interest expense is projected to total $1.0 million in FY 2015 and decrease to $815,700 in FY 2020.

The forecast includes projected depreciation expense for the plant in service. Non-cash expense items is forecast to total $5.3 million in FY 2015; increasing to 6.2 million in FY 2020.

Net Margins

Projected annual net margins for each year of the Forecast were determined by deducting the non-operating revenues and expenses estimates from the operating margins for the corresponding years. The annual net margins, without adjustments to retail rates, are presented in Table 1. Annual net margins are projected to total -$2.1 million in FY 2015 and drop to -$7.1 million in FY 2020.

Table 1

PROJECTED NET MARGINS - NO ADJUSTMENTS
Electric Division, City of Dover

	Revised 2015	Projected 2016	Projected 2017	Projected 2018	Projected 2019	Projected 2020
Revenue from Electric Sales - Current Rates	$ 76,020,100	$ 75,999,200	$ 76,524,000	$ 76,943,600	$ 77,205,000	$ 77,205,000
Operating Revenue - Purchased Power Adjustment	-	-	-	-	-	-
Operating Revenue - Utility Tax	1,244,100	1,243,800	1,252,400	1,309,600	1,334,200	1,332,500
Operating Revenue - Miscellaneous Receipts	1,202,000	2,827,800	2,832,600	2,837,600	2,842,600	2,847,600
Total Operating Revenue	$ 78,466,200	$ 80,070,800	$ 80,609,000	$ 81,090,800	$ 81,381,800	$ 81,385,100
Power Supply & Generation	$ (50,109,200)	$ (49,109,500)	$ (50,245,200)	$ (53,518,200)	$ (54,965,300)	$ (55,072,900)
Operating Expenses	(14,214,400)	(14,632,300)	(15,197,100)	(15,647,100)	(16,076,700)	(16,492,300)
Operating Transfers - Out (General Fund)	(10,000,000)	(10,000,000)	(10,000,000)	(10,000,000)	(10,000,000)	(10,000,000)
Operating Margin	$ 4,142,600	$ 6,329,000	$ 5,166,700	$ 1,925,500	$ 339,800	$ (180,100)
Non-Oper. Rev. - Interest on Operating	$ 36,800	$ 22,600	$ 18,400	$ 16,400	$ 14,300	$ 14,600
Non-Oper. Rev. - Interest on Reserves	63,900	58,200	52,200	52,200	52,400	52,500
Margins Available For Debt Service	$ 4,243,300	$ 6,409,800	$ 5,237,300	$ 1,994,100	$ 406,500	$ (113,000)
Interest for Long-Term Debt	(1,037,000)	(1,037,000)	(918,700)	(884,000)	(847,500)	(815,700)
Cash From Operations	$ 3,206,300	$ 5,372,800	$ 4,318,600	$ 1,110,100	$ (441,000)	$ (928,700)
Depreciation Expense	(5,336,658)	(5,533,600)	(5,744,400)	(5,961,700)	(6,120,800)	(6,245,700)
Net Margins	**$ (2,130,358)**	**$ (160,800)**	**$ (1,425,800)**	**$ (4,851,600)**	**$ (6,561,800)**	**$ (7,174,400)**
Debt Service Coverage						
Margins Available for Debt Service	$ 4,243,300	$ 6,409,800	$ 5,237,300	$ 1,994,100	$ 406,500	$ -
Total Debt Service	3,297,000	3,402,000	1,613,700	1,614,000	1,612,500	1,615,700
Debt Service Coverage Ratio	1.29	1.88	3.25	1.24	0.25	0.00

In order to maintain adequate net margins and maintain adequate operating fund cash balances, Burns & McDonnell proposes a base rate revenue increase of 3.0 percent effective July 1, 2015. In addition, the Electric Division will likely require increased revenue due to upward power supply cost pressure in FY 2018 through FY 2020. To continue to meet its financial requirements in those years, the City should consider the implementation of PPA charges. With the proposed base rate revenue increase and PPA charges in future years, the City will meet the 125 percent debt service coverage required by the bond covenant, and maintain adequate cash from operations for internal capital financing needs. The projected net margins resulting from the revenue adjustments are presented in Table 2.

Table 2

PROJECTED NET MARGINS - WITH BASE RATE REVENUE ADJUSTMENTS
Electric Division, City of Dover

	Revised 2015	Projected 2016	Projected 2017	Projected 2018	Projected 2019	Projected 2020
Revenue from Electric Sales - Current Rates	$ 76,020,100	$ 75,999,200	$ 76,524,000	$ 76,943,600	$ 77,205,000	$ 77,205,000
Proposed Adjustment in FY 2016 at 3.00%	-	2,280,000	2,295,700	2,308,300	2,316,200	2,316,200
Operating Revenue - Purchased Power Adjustment	-	-	-	3,074,200	4,316,500	4,213,200
Operating Revenue - Utility Tax	1,244,100	1,281,100	1,289,900	1,347,300	1,372,000	1,370,300
Operating Revenue - Miscellaneous Receipts	1,202,000	2,827,800	2,832,600	2,837,600	2,842,600	2,847,600
Total Operating Revenue	$ 78,466,200	$ 82,388,100	$ 82,942,200	$ 86,511,000	$ 88,052,300	$ 87,952,300
Power Supply & Generation	$ (50,109,200)	$ (49,109,500)	$ (50,245,200)	$ (53,518,200)	$ (54,965,300)	$ (55,072,900)
Operating Expenses	(14,214,400)	(14,669,600)	(15,234,600)	(15,684,800)	(16,114,500)	(16,530,100)
Operating Transfers - Out (General Fund)	(10,000,000)	(10,000,000)	(10,000,000)	(10,000,000)	(10,000,000)	(10,000,000)
Operating Margin	$ 4,142,600	$ 8,609,000	$ 7,462,400	$ 7,308,000	$ 6,972,500	$ 6,349,300
Non-Oper. Rev. - Interest on Operating	$ 36,800	$ 22,600	$ 18,400	$ 16,900	$ 15,000	$ 15,300
Non-Oper. Rev. - Interest on Reserves	63,900	58,200	52,200	52,200	52,400	52,500
Margins Available For Debt Service	$ 4,243,300	$ 8,689,800	$ 7,533,000	$ 7,377,100	$ 7,039,900	$ 6,417,100
Interest for Long-Term Debt	(1,037,000)	(1,037,000)	(918,700)	(884,000)	(847,500)	(815,700)
Cash From Operations	$ 3,206,300	$ 7,652,800	$ 6,614,300	$ 6,493,100	$ 6,192,400	$ 5,601,400
Depreciation Expense	(5,336,658)	(5,533,600)	(5,744,400)	(5,961,700)	(6,120,800)	(6,245,700)
Net Margins	**$ (2,130,358)**	**$ 2,119,200**	**$ 869,900**	**$ 531,400**	**$ 71,600**	**$ (644,300)**
Debt Service Coverage						
Margins Available for Debt Service	$ 4,243,300	$ 8,689,800	$ 7,533,000	$ 7,377,100	$ 7,039,900	$ 6,417,100
Total Debt Service	3,297,000	3,402,000	1,613,700	1,614,000	1,612,500	1,615,700
Debt Service Coverage Ratio	1.29	2.55	4.67	4.57	4.37	3.97

Test Period Net Revenue Requirement

The annual cost of service consists of total operating expenses, including depreciation, operating transfers, interest on debt, non-operating expenses, and net margins. The net base rate revenue requirement is equal to the annual cost-of-service minus other revenue. For the Study, the selected test period from which the cost-of-service analysis and rate design were based was FY 2016. The net base rate revenue requirement calculated for FY 2016 was $78.3 million. A summary of the projected annual net revenue requirements is presented as Table 3.

COST-OF-SERVICE ANALYSIS

The second phase of the Study completed for the City was the review of the cost-of-service analysis. The FY 2016 base rate revenue requirements served as the basis for the cost-of-service analysis. The functionalization, classification, and allocation factors developed in the 2013 Study were utilized for this 2015 update. The development of the cost-of-service analysis is described below.

Table 3

PROJECTED NET REVENUE REQUIREMENTS
Electric Division, City of Dover

	Revised 2015	**Test Period 2016**	Projected 2017	Projected 2018	Projected 2019	Projected 2020
Operating Expenses	$ 14,214,400	**$ 14,669,600**	$ 15,234,600	$ 15,684,800	$ 16,114,500	$ 16,530,100
Purchased Power Cost	50,109,200	**49,109,500**	50,245,200	53,518,200	54,965,300	55,072,900
Depreciation Expense	5,336,658	**5,533,600**	5,744,400	5,961,700	6,120,800	6,245,700
Interest on Long-Term Debt	1,037,000	**1,037,000**	918,700	884,000	847,500	815,700
Operating Transfers - Out (General Fund)	10,000,000	**10,000,000**	10,000,000	10,000,000	10,000,000	10,000,000
Net Margins	(2,130,358)	**2,119,200**	869,900	531,400	71,600	(644,300)
Total Cost of Service	$ 78,566,900	**$ 82,468,900**	$ 83,012,800	$ 86,580,100	$ 88,119,700	$ 88,020,100
Less						
Purchased Power Adjustment	-	**-**	-	3,074,200	4,316,500	4,213,200
Net Non-Operating Revenue and Expense	(100,700)	**(80,800)**	(70,600)	(69,100)	(67,400)	(67,800)
Other Non-Rate Revenues	(2,446,100)	**(4,108,900)**	(4,122,500)	(4,184,900)	(4,214,600)	(4,217,900)
Net Base Rate Revenue Requirement	$ 76,020,100	**$ 78,279,200**	$ 78,819,700	$ 85,400,300	$ 88,154,200	$ 87,947,600

Functionalization

The first step in the development of the cost-of-service analysis was unbundling the high-level functional services the utility provides to its customers. Recognizing these functional services as separate cost drivers facilitates the classification of the revenue requirement. This functional cost identification, and ultimately the classification and allocation of costs, allows the City to offer electric service rates that more accurately reflect the costs to serve. Identifying functional costs will aid the Electric Division in its overall management of costs and in communicating with its customers regarding the costs of providing service.

Functional Cost Categories

Five functional services in three cost categories were identified. These categories and services include the following:

- Power Supply
  - Demand, i.e. Capacity (kW)
  - Energy (kWh)
  - Transmission Delivery (TDEL)
- Distribution
  - Distribution Delivery (DIS)
- Customer
  - Customer Service (CUST)

Classification

The classification of the various components of the Electric Division's test period revenue requirement to each functional service is summarized on Table 4. The FY 2016 cost of each operating expense, net margin, net non-operating margin and other revenue component was categorized or classified as one or more of the unbundled functional services. The classification of the components was based on the utilization of specific data to estimate the portions of each cost attributable to the unbundled functional services. The classification ratio for each cost was developed using one of the following approaches:

- Direct Assignment: Costs were classified to one or more functional service categories due to the nature of the account/element. For example, purchased power expenses were assigned to Demand-kW and to Energy-kWh based on capacity and energy-related charges the utility is projected to incur during the test year.

- Assumed Percentage Assignment: Based on estimated level of activities within the account/element, costs were classified to multiple functional service categories. For example, retiree health care was allocated between TDEL, DIS, and CUST due to their assumed association with non-power supply costs the utility incurs. The assumed percentage classifications were reviewed with the City.

- Composite Ratio Assignment: Composite Ratio Assignment involves the classification of costs based on the ratio of costs by functional service, whose percentage allocations were already established, to the associated cost totals for the test period. For example, the ratio of the plant in service was applied to depreciation expense in order to proportionally distribute the cost of depreciation to electric utility assets in each functional service.

The manner in which each component was classified in a functional service category varied based on the nature of the component. Burns & McDonnell developed the unbundling of the components of the Electric Division's annual revenue requirement based on its understanding of the types of costs included in each component. The actual classification of each cost account/element is contained within the cost-of-service model prepared by Burns & McDonnell and reviewed by the City.

Table 4 presents a summary of the classification of the operating expenses, non-operating expenses, net margins and other revenues to each unbundled functional service. The table illustrates that 82.4 percent (29.9 percent-kW plus 52.5 percent-kWh) of the Electric Division's test period net revenue requirement is related to the power supply services.

Table 4

TEST PERIOD 2016 UNBUNDLED REVENUE REQUIREMENT ASSIGNMENT
Electric Division, City of Dover

	Total	kW	kWh	TDEL	DIS	CUST
General Administration	$ 3,795,100	$ 1,077,278	$ 1,986,644	$ 264,383	$ 350,117	$ 116,678
Power Plant Operations	6,434,600	6,434,600	-	-	-	-
Purchased Power	42,674,900	9,865,631	32,809,269	-	-	-
Other Misc. Items	100,000	-	-	-	-	100,000
Transmission/Distribution	4,050,800	-	-	1,709,498	2,341,302	-
Engineering	1,337,100	-	-	564,276	772,824	-
System Operators	687,200	-	-	290,009	397,191	-
Metering	357,300	-	-	-	-	357,300
Electric Administration	737,700	265,262	-	160,972	220,464	91,003
Non-Capital Expenses in Fund 487	150,000	-	-	63,302	86,698	-
Utility Tax	1,281,100	-	1,281,100	-	-	-
Depreciation	5,533,600	1,989,769	-	1,207,472	1,653,735	682,624
Interest on Deposits	20,500	-	-	-	-	20,500
Allowance for Bad Debts	200,000	-	-	-	-	200,000
Retiree Health Care	539,000	-	-	179,667	179,667	179,667
OPEB Trust - Full funding amtz pymt	1,030,000	-	-	343,333	343,333	343,333
Other Employment Expenses	55,800	-	-	18,600	18,600	18,600
Green Energy Expense	128,000	-	128,000	-	-	-
Comp Ab/OPEB/Pens NPO/NPA	50,000	-	-	16,667	16,667	16,667
Bank Fees	150,000	-	-	63,302	86,698	-
Other Expenses						
Interest on Long-Term Debt	1,037,000	372,884	-	226,281	309,911	127,924
Operating Transfers - Out	10,000,000	2,838,602	5,234,760	696,644	922,549	307,445
Net Margins	2,119,200	601,557	1,109,350	147,633	195,507	65,154
Total Cost of Service	$ 82,468,900	$ 23,445,582	$ 42,549,123	$ 5,952,038	$ 7,895,262	$ 2,626,894
Other Revenues	$ (4,189,700)	$ (22,936)	$ (1,451,397)	$ (879,211)	$ (1,232,339)	$ (603,817)
Net Revenue Requirement	$ 78,279,200	$ 23,422,646	$ 41,097,726	$ 5,072,828	$ 6,662,923	$ 2,023,077
	100.0%	29.9%	52.5%	6.5%	8.5%	2.6%

Allocation

Following classifying the various cost components of the test period revenue requirement to the functional utility service categories, the revenue requirement was allocated to the City's retail electric rate classifications. Cost allocation factors were developed to assign cost recovery responsibility of the revenue requirement to each rate class. Cost responsibility was determined for each of the current rate classifications:

- Residential
- Small Commercial
- Medium Commercial
- Large Commercial
- Primary
- Transmission
- Lighting

Cost Allocation Factors
Detailed FY 2014 billing history data and projections of future sales and loads provided by the City were utilized to develop a series of cost allocation factors. Based on statistical billing determinants, estimates of the contributions of each rate class to the Electric Division's test period energy requirements, coincident peak demand, and non-coincident class demands were developed. These ratios were used to allocate the costs of each unbundled revenue requirement component to each rate class. The basis for the development of the allocation factors is detailed below.

- <u>Energy Allocation Factors</u>
  Allocation factors were developed for use in the allocation of all energy-related expenses. Based on the updated forecast, test period energy sales for each class were factored up to the system level. System losses were assumed to occur evenly between three stages: from power supply transmission delivery to primary distribution voltage, and from primary distribution voltage to secondary distribution voltage. Therefore, the rate classes receiving service at transmission voltage or primary voltage were assumed not to share in secondary distribution system losses. Similarly, the rate classes receiving service at transmission voltage were assumed not to share in the primary distribution losses. The ratios of the resulting estimated contributions of each class to the total system energy requirements represented the energy allocation factors.

- <u>Demand Allocation Factors</u>: To develop demand cost factors, power supply demand-related costs were allocated using a coincident peak (CP) responsibility method. All other demand-related costs were allocated using a non-coincident (NCP) peak demand responsibility method.

  Demand determinants for each class except Transmission were based on estimated load factors due to the absence of actual load profile data for most classes. Load factor assumptions were determined with data from other Burns & McDonnell projects and through experience. To determine demand-related power supply costs to these various rate classes using the CP method, the estimated load factors at the time of the system peak were applied to the corresponding test period energy sales to estimate the coincident demand contributions for the classes. To determine demand related power delivery costs for each class except the Transmission class using the NCP method, estimated average annual load factors were applied to the corresponding test period energy sales to estimate the non-coincident peak demand for the classes.

  Estimates of the contributions the Transmission customers made to the power supply peak demand and power delivery non-coincident peak demand were developed based on actual coincident and non-coincident load factors, respectively. The load factors were applied to the corresponding total energy sales to estimate the demand contributions for these classes.

For the lighting classes, it was assumed that all lights were off and; therefore, did not contribute to the system peak demand since the FY 2014 system peak occurred on a summer afternoon.

Ratios of each class's contributions to the Electric Division's annual power supply peak demand and ratios of the maximum non-coincident demands for each class to the total for all classes were calculated. These ratios represented the factors to be used in allocating the transmission and distribution costs among the various rate classes.

- Customer Allocation Factors: Allocation factors were developed to allocate the costs of customer services among the various rate classifications. The factors were based on relative weighting factor of the number of customers in each rate class. Relative weights were estimated to reflect differences in the effort required and the cost incurred to provide customer services to individual customers in each rate class. With the relative weight of a Residential customer set equal to one, each of the other classes were assigned weighting factors. Any rate class, whose customers were assumed to incur more cost in individual meter reading, billing, collection, and providing other customer services relative to an individual in the Residential class, was assigned a weight greater than one. Conversely, any class whose customers were assumed to require less effort to serve was assigned a weight of less than one. The numbers of customers for each classification were multiplied by the relative weight factor to calculate the weighted number of customers in each class. The ratios of the weighted customer counts for each class to the total weighted number of customers represented the customer allocation factor.

A summary of the cost allocation factors and the resulting cost allocation is presented in Table 5. A brief discussion on cost allocation is provided below.

Cost Allocation
Each component item of the test period revenue requirement, which was classified to the various functional utility services summarized in Table 4, was allocated to the appropriate rate classifications using the corresponding cost allocation factors. As part of the cost allocations, distribution costs also split into primary and secondary distribution levels of service. The split was based on primary and secondary line miles. At year-end FY 2011, as most recently reported by Dover, there were 219 primary service line miles and 219 secondary line miles; therefore, distribution delivery demand costs were split equally between primary and secondary service

levels. This assignment was completed so that customers served directly off the primary loop did not share in the secondary loop distribution system costs.

Table 5 summarizes the total allocated cost for each functional service of the test period revenue requirement. The Electric Division's revenue requirement of $78.3 million and the total projected system sales of 712.0 million kWh, translate to an average cost of 10.99¢/kWh. The portion allocated to the Residential rate class totaled $26.2 million, or 33.5 percent of the test period net revenue requirement. Based on the estimated Residential portion of the system energy requirement of 203,250 MWh, the average cost per kWh is 12.89¢/kWh in FY 2016.

Table 5

TEST PERIOD 2016 REVENUE REQUIREMENT COST ALLOCATION SUMMARY
Electric Division, City of Dover

	Total System	Residential	Small Commercial	Medium Commercial	Large Commercial	Primary	Transmission	Lighting
Demand Cost Allocation Factors								
Contribution to Peak - kW	164,162	56,902	6,822	10,669	36,765	33,274	19,731	-
Peak Alloc. Factor	1.000	0.347	0.042	0.065	0.224	0.203	0.120	0.000
Non-Coincident Peak - kW	196,418	69,582	8,342	12,684	42,738	37,988	23,478	1,607
NCP Allocation Factor	1.000	0.354	0.042	0.065	0.218	0.193	0.120	0.008
NCP - Primary - kW	168,076	67,625	8,107	12,327	41,536	36,919	N/A	1,561
NCP - Primary Alloc. Factor	1.000	0.402	0.048	0.073	0.247	0.220	0.000	0.009
NCP - Secondary - kW	128,570	66,291	7,947	12,084	40,717	N/A	N/A	1,531
NCP - Second. Alloc. Factor	1.000	0.516	0.062	0.094	0.317	0.000	0.000	0.012
Energy Cost Allocation Factors								
Total Requirement - kWh	741,304,000	213,939,310	25,647,598	44,570,387	168,946,412	166,492,960	114,650,536	7,056,797
Energy Allocation Factor	1.000	0.289	0.035	0.060	0.228	0.225	0.155	0.010
Customer Cost Allocation Factors								
Number of Customers	32,849	19,847	2,189	590	444	35	5	9,739
Relative Weight		1	3	3	2	3	20	1
Weighted No. of Customers	29,380	19,847	2,716	934	888	105	20	4,870
Customer Allocation Factor	1.000	0.676	0.092	0.032	0.030	0.004	0.001	0.166
Cost Allocation by Unbundled Code								
KW	$23,422,646	$ 8,118,724	$ 973,294	$1,522,250	$ 5,245,610	$ 4,747,518	$ 2,815,252	$ -
KWH	41,097,726	11,860,747	1,421,897	2,470,972	9,366,351	9,230,332	6,356,200	391,227
TDEL	5,072,828	1,797,082	215,439	327,591	1,103,778	981,097	606,347	41,494
DIS								
PRIMARY	3,331,461	1,340,409	160,692	244,344	823,287	731,781	-	30,949
SECONDARY	3,331,461	1,717,719	205,925	313,124	1,055,033	-	-	39,661
CUST	2,023,077	1,366,668	187,024	64,315	61,148	7,230	1,377	335,315
Allocated Cost-of-Service	$78,279,200	$26,201,347	$3,164,270	$4,942,596	$17,655,206	$15,697,958	$ 9,779,176	$ 838,646
	100.0%	33.5%	4.0%	6.3%	22.6%	20.1%	12.5%	1.1%
Total Energy Sales - kWh	712,015,300	203,249,700	24,366,100	42,343,400	160,504,900	161,706,400	113,140,600	6,704,200
Total Cost - ¢/kWh	10.99	12.89	12.99	11.67	11.00	9.71	8.64	12.51

Cost-of-Service Summary

The results of the cost-of-service analysis and the allocation of the test period revenue requirement to the Electric Division's rate classes are presented on Table 6. The results are broken down into energy-related costs, expressed in dollars and ¢/kWh; demand-related costs, expressed in dollars and $/kW of system power supply billing demand per month; and customer-related costs, expressed in $/customer per month. Also, the total cost-of-service is expressed in dollars and ¢/kWh.

Table 6

TEST PERIOD 2016 COST-OF-SERVICE SUMMARY
Electric Division, City of Dover

	Total System	Residential	Small Commercial	Medium Commercial	Large Commercial	Primary	Transmission	Lighting
Power Supply Cost								
Capacity Cost	$ 23,422,646	$ 8,118,724	$ 973,294	$ 1,522,250	$ 5,245,610	$ 4,747,518	$ 2,815,252	$ -
Contribution to Peak - kW	157,676	54,194	6,497	10,161	35,015	32,338	19,471	-
$/kW-mo	$ 12.38	$ 12.48	$ 12.48	$ 12.48	$ 12.48	$ 12.23	$ 12.05	$ -
Energy Cost	$ 41,097,726	$ 11,860,747	$ 1,421,897	$ 2,470,972	$ 9,366,351	$ 9,230,332	$ 6,356,200	$ 391,227
Energy Sales - kWh	712,015,300	203,249,700	24,366,100	42,343,400	160,504,900	161,706,400	113,140,600	6,704,200
¢/kWh	5.77	5.84	5.84	5.84	5.84	5.71	5.62	5.84
Transmission Cost	$ 5,072,828	$ 1,797,082	$ 215,439	$ 327,591	$ 1,103,778	$ 981,097	$ 606,347	$ 41,494
Non-Coincident Peak - kW	188,658	66,291	7,947	12,084	40,717	36,919	23,168	1,531
$/kW-mo	$ 2.24	$ 2.26	$ 2.26	$ 2.26	$ 2.26	$ 2.21	$ 2.18	$ 2.26
Distribution Cost								
Primary Distribution Cost	$ 3,331,461	$ 1,340,409	$ 160,692	$ 244,344	$ 823,287	$ 731,781	$ -	$ 30,949
NCP Primary - kW	168,076	67,625	8,107	12,327	41,536	36,919	N/A	1,561
$/kW-mo	$ 1.65	$ 1.65	$ 1.65	$ 1.65	$ 1.65	$ 1.65	$ -	$ 1.65
Distribution Secondary Cost	$ 3,331,461	$ 1,717,719	$ 205,925	$ 313,124	$ 1,055,033	$ -	$ -	$ 39,661
NCP Secondary - kW	128,570	66,291	7,947	12,084	40,717	N/A	N/A	1,531
$/kW-mo	$ 2.16	$ 2.16	$ 2.16	$ 2.16	$ 2.16	$ -	$ -	$ 2.16
Customer Cost								
Customer Cost	$ 2,023,077	$ 1,366,668	$ 187,024	$ 64,315	$ 61,148	$ 7,230	$ 1,377	$ 335,315
Customer Accounts	32,849	19,847	2,189	590	444	35	5	9,739
$/Customer-mo	$ 5.13	$ 5.74	$ 7.12	$ 9.08	$ 11.48	$ 17.22	$ 22.95	$ 2.87
Net Revenue Requirement	$ 78,279,200	$ 26,201,347	$ 3,164,270	$ 4,942,596	$ 17,655,206	$ 15,697,958	$ 9,779,176	$ 838,646
¢/kWh	10.99	12.89	12.99	11.67	11.00	9.71	8.64	12.51
FY 2016 Lighting Adjustment	$ -	$ (17,253)	$ (334,163)	$ -	$ -	$ -	$ -	$ 351,416
Net Revenue Requirement - Adjusted	**$ 78,279,200**	**$ 26,184,094**	**$ 2,830,107**	**$ 4,942,596**	**$ 17,655,206**	**$ 15,697,958**	**$ 9,779,176**	**$ 1,190,062**
¢/kWh	**10.99**	**12.88**	**11.61**	**11.67**	**11.00**	**9.71**	**8.64**	**17.75**
Revenue/Cost Comparison								
Net Revenue Requirement	$ 78,279,200	$ 26,184,094	$ 2,830,107	$ 4,942,596	$ 17,655,206	$ 15,697,958	$ 9,779,176	$ 1,190,062
Revenue at Current Rates	75,999,200	25,628,900	2,726,900	4,845,600	17,135,500	15,043,900	9,463,000	1,155,400
(Over) Under Recovery	$ 2,280,000	$ 555,194	$ 103,207	$ 96,996	$ 519,706	$ 654,058	$ 316,176	$ 34,662
Cost of Service Adjustment	3.0%	2.2%	3.8%	2.0%	3.0%	4.3%	3.3%	3.0%

Table 6 provides a customer class comparison of the test period net revenue requirement to the projected total revenue that would be generated by the City's current retail electric rates. The difference in these totals was $2.3 million which reflects the amount of the proposed test period FY 2016 revenue adjustment. In addition, the same comparison by class indicates the extent to which the projected annual revenues generated from the current retail rates for each class would either exceed or fall short of the corresponding test period revenue requirement.

The cost-of-service analysis summarized in Table 6 served as input into the process of developing revised retail electric rates. These results, as well as other factors relating to the design of the City's electric rates, are discussed in the Rate Design Analysis section this report.

RATE DESIGN ANALYSIS

The final phase of the Study completed for the City was the design of revised retail electric rates. The cost-of-service analysis served as one input into the analysis and design of revised retail electric rates. Input from City staff was also taken into consideration in the development of the proposed rates. The Electric Division's objectives to be considered in the development of the proposed rate design included the following:

- Develop rates to recover the Electric Division's updated revenue requirements.
- Develop rates to be fair and equitable across the customer classes.
- Develop rates that are competitive with other nearby utilities.

Current and Proposed Electric Rates

As discussed in the previous sections of this report, the City bills its electric customers based on its current retail rate schedules which became effective July 1, 2014 (current rates). The current rate schedule classifications are listed below.

- Residential
- Small Commercial
- Medium Commercial
- Large Commercial
- Primary
- Transmission
- Outdoor Development Lighting
- Private Outdoor Lighting *(unmetered)*

Table 7 presents the current rates applicable to each of the rate classifications in the left column under each rate component, i.e. customer charge, energy charge, and demand charge. Table 7 also shows the proposed rates for each of the rate classes in the right column under each rate component. The proposed rate design was developed for implementation on July 1, 2015 to achieve a balance between the objectives of full cost recovery and reducing impacts on the customers. The development of the proposed rates is described in the subsequent sections of the report.

Table 7

MONTHLY ELECTRIC RATE SCHEDULES
Electric Division, City of Dover

	Customer Charge		Energy Charge		Demand Charge	
	Current - $/Month -	Proposed - $/Month -	Current - $/kWh -	Proposed - $/kWh -	Current - $/kW-mo. -	Proposed - $/kW-mo. -
Residential	$ 5.00	$ 7.50	$ 0.12040	$ 0.12030	$ -	$ -
Small Commercial						
Small Commercial-1 Phase	$ 5.00	$ 7.50	$ 0.10010	$ 0.10040	$ -	$ -
Small Commercial-3 Phase	$ 15.00	$ 22.50	$ 0.10010	$ 0.10040	$ -	$ -
Medium Commercial						
Medium Commercial-1 Phase	$ 5.00	$ 7.50	$ 0.06470	$ 0.06770	$ 13.95	$ 13.95
Medium Commercial-3 Phase	$ 15.00	$ 22.50	$ 0.06470	$ 0.06770	$ 13.95	$ 13.95
Large Commercial	$ 15.00	$ 22.50	$ 0.06470	$ 0.06770	$ 13.90	$ 13.90
Primary	$ 10.00	$ 15.00	$ 0.06450	$ 0.06760	$ 11.25	$ 11.25
Transmission	$ -	$ -	$ 0.06090	$ 0.06370	$ 10.50	$ 10.50
First State Power Mgmt. (NRG)	$ 3,680.00	$ 3,680.00	$ 0.06090	$ 0.06370	$ 10.50	$ 10.50

Residential Service

The current rates for the Residential customer class consist of a customer charge of $5.00 and a flat energy charge of 12.04¢/kWh for all kWh. The proposed rates include a customer charge of $7.50. The energy charge was reduced to 12.03¢/kWh. Based on average monthly consumption of 853 kWh, the proposed rate would generate a monthly bill of $110.27, compared to a bill of $107.85 calculated with the current rates. This is a difference of $2.41, or 2.2 percent. The sample bill calculation is provided in Table 8.

Table 8

SAMPLE MONTHLY BILL - RESIDENTIAL CUSTOMER
Electric Division, City of Dover

	Units	Current Billing	Proposed Billing	Adjustment	Adjustment
Residential					
Customer Charge	- $/mo. -	$ 5.00	$ 7.50	$ 2.50	50.00%
Energy Charge	- $/kWh -	$ 0.12040	$ 0.12030	$ (0.00010)	-0.08%
Purchased Power Adjustment	- $/kWh -	$ -	$ -	$ -	0.00%
Green Energy Fund Charge	- $/kWh -	$ 0.00018	$ 0.00018	$ -	0.00%
Average Monthly Energy [1]	- kWh -	853	853		
Customer Charge	- $ -	$ 5.00	$ 7.50	$ 2.50	50.00%
Energy Charges	- $ -	$ 102.70	$ 102.62	$ (0.09)	-0.08%
Subtotal - Base Rates		$ 107.70	$ 110.12	$ 2.41	2.24%
Purchased Power Adjustment	- $ -	$ -	$ -	$ -	0.00%
Green Energy Fund Charges	- $ -	$ 0.15	$ 0.15	$ -	0.00%
Total Bill		$ 107.85	$ 110.27	$ 2.41	2.24%

[1] Average customer monthly energy for the test period.

Small Commercial Service – Single Phase

The current rates for the Small Commercial 1-Phase customer class consist of a customer charge of $5.00 and a flat energy charge of 10.01¢/kWh for all kWh. The proposed rates include a $7.50 customer charge. The energy charge was raised to 10.04¢/kWh. Based on average monthly consumption of 825 kWh, the proposed rates would generate a monthly bill of $94.32, compared to a bill of $91.46 calculated with the current rates. This is a difference of $2.86, or 3.1 percent. The sample bill calculation is provided in Table 9.

Table 9

SAMPLE MONTHLY BILL - SMALL COMMERCIAL CUSTOMER
Electric Division, City of Dover

	Units	Current Billing	Proposed Billing	Adjustment	Adjustment
Small Commercial-1 Phase					
Customer Charge	- $/mo. -	$ 5.00	$ 7.50	$ 2.50	50.00%
Energy Charge	- $/kWh -	$ 0.10010	$ 0.10040	$ 0.00030	0.30%
Purchased Power Adjustment	- $/kWh -	$ -	$ -	$ -	0.00%
Green Energy Fund Charge	- $/kWh -	$ 0.00018	$ 0.00018	$ -	0.00%
Utility Tax Rate	- % -	4.25%	4.25%		
Average Monthly Energy [1]	- kWh -	825	825		
Customer Charge	- $ -	$ 5.00	$ 7.50	$ 2.50	50.00%
Energy Charges	- $ -	$ 82.58	$ 82.83	$ 0.25	0.30%
Subtotal - Base Rates		$ 87.58	$ 90.33	$ 2.75	3.14%
Purchased Power Adjustment	- $ -	$ -	$ -	$ -	0.00%
Green Energy Fund Charges	- $ -	$ 0.15	$ 0.15	$ -	0.00%
Utility Tax	- $ -	$ 3.73	$ 3.85	$ 0.12	3.13%
Total Bill		$ 91.46	$ 94.32	$ 2.86	3.13%

[1] Average customer monthly energy for the test period.

Medium Commercial Service – Single Phase

The current rates for the Medium Commercial customer class consist of a customer charge of $5.00, a flat energy charge of 6.47¢/kWh for all kWh, and a demand charge of $13.95/kW-mo. The proposed Medium Commercial rates include a customer charge of $7.50, a flat energy charge of 6.77¢/kWh for all kWh, and a demand charge of $13.95/kW-mo. Based on average monthly consumption of 4,708 kWh and demand of 18 kW, the proposed rates would generate a monthly bill of $602.74, compared to a bill of $585.41 based on the current rates. This is a difference of $17.33, or 3.0 percent, as shown on Table 10.

Table 10

SAMPLE MONTHLY BILL - MEDIUM COMMERCIAL CUSTOMER
Electric Division, City of Dover

	Units	Current Billing	Proposed Billing	Adjustment	Adjustment
Medium Commercial-1 Phase					
Customer Charge	- $/mo. -	$ 5.00	$ 7.50	$ 2.50	50.00%
Energy Charge	- $/kWh -	$ 0.06470	$ 0.06770	$ 0.00300	4.64%
Demand Charge	- $/kW-mo. -	$ 13.95	$ 13.95	$ -	0.00%
Purchased Power Adjustment	- $/kWh -	$ -	$ -	$ -	0.00%
Green Energy Fund Charge	- $/kWh -	$ 0.00018	$ 0.00018	$ -	0.00%
Utility Tax Rate	- % -	4.25%	4.25%		
Average Monthly Energy [1]	- kWh -	4,708	4,708		
Average Monthly Billing Demand [1]	- kW -	18	18		
Average Monthly Load Factor	- % -	36.33%	36.33%		
Customer Charge	- $ -	$ 5.00	$ 7.50	$ 2.50	50.00%
Energy Charges	- $ -	$ 304.61	$ 318.73	$ 14.12	4.64%
Demand Charges	- $ -	$ 251.10	$ 251.10	$ -	0.00%
Subtotal - Base Rates		$ 560.71	$ 577.33	$ 16.62	2.96%
Purchased Power Adjustment	- $ -	$ -	$ -	$ -	0.00%
Green Energy Fund Charges	- $ -	$ 0.84	$ 0.84	$ -	0.00%
Utility Tax	- $ -	$ 23.87	$ 24.57	$ 0.71	2.96%
Total Bill		$ 585.41	$ 602.74	$ 17.33	2.96%

[1] Average customer monthly energy and demand for the test period.

Large Commercial Service

The current rates for the Large Commercial customer class consist of a customer charge of $15.00, a flat energy charge of 6.47¢/kWh for all kWh, and a demand charge of $13.90/kW-mo. The proposed Large Commercial rates include a customer charge of $22.50, a flat energy charge of 6.77¢/kWh for all kWh, and a demand charge of $13.90/kW-mo. Based on an average monthly consumption of 30,125 kWh and demand of 89 kW, the proposed rates would generate a monthly bill of $3,445, compared to a bill of $3,343 calculated with the current rates. This is a difference of $102, or 3.1 percent, as shown in Table 11.

Table 11

SAMPLE MONTHLY BILL - LARGE COMMERCIAL CUSTOMER
Electric Division, City of Dover

	Units	Current Billing	Proposed Billing	Adjustment	Adjustment
Large Commercial					
Customer Charge	- $/mo. -	$ 15.00	$ 22.50	$ 7.50	50.00%
Energy Charge	- $/kWh -	$ 0.06470	$ 0.06770	$ 0.00300	4.64%
Demand Charge	- $/kW-mo. -	$ 13.90	$ 13.90	$ -	0.00%
Purchased Power Adjustment	- $/kWh -	$ -	$ -	$ -	0.00%
Green Energy Fund Charge	- $/kWh -	$ 0.00018	$ 0.00018	$ -	0.00%
Utility Tax Rate	- % -	4.25%	4.25%		
Average Monthly Energy [1]	- kWh -	30,125	30,125		
Average Monthly Billing Demand [1]	- kW -	89	89		
Average Monthly Load Factor	- % -	47.01%	47.01%		
Customer Charge	- $ -	$ 15.00	$ 22.50	$ 7.50	50.00%
Energy Charges	- $ -	$ 1,949.09	$ 2,039.46	$ 90.38	4.64%
Demand Charges	- $ -	$ 1,237.10	$ 1,237.10	$ -	0.00%
Subtotal - Base Rates		$ 3,201.19	$ 3,299.06	$ 97.87	3.06%
Purchased Power Adjustment	- $ -	$ -	$ -	$ -	0.00%
Green Energy Fund Charges	- $ -	$ 5.36	$ 5.36	$ -	0.00%
Utility Tax	- $ -	$ 136.28	$ 140.44	$ 4.16	3.05%
Total Bill		$ 3,342.83	$ 3,444.86	$ 102.03	3.05%

[1] Average customer monthly energy and demand for the test period.
[2] Power factor adjustment not included in calculations.

Primary Service

The current rates for the Primary customer class consist of a customer charge of $10.00, a flat energy charge of 6.45¢/kWh for all kWh, and a demand charge of $11.25/kW-mo. The proposed rates include an increased customer charge of $15.00, an energy charge of 6.76¢/kWh for all kWh, and a demand charge of $11.25/kW-mo. Based on average monthly consumption of 385,015 kWh and demand of 976 kW, the proposed rates would generate a monthly bill of $37,832, compared to a bill of $36,610 calculated with current rates. This is a difference of $1,223, or 3.3 percent, as shown in Table 12.

Table 12

SAMPLE MONTHLY BILL - PRIMARY CUSTOMER
Electric Division, City of Dover

	Units	Current Billing	Proposed Billing	Adjustment	Adjustment
Primary					
Customer Charge	- $/mo. -	$ 10.00	$ 15.00	$ 5.00	50.00%
Energy Charge	- $/kWh -	$ 0.06450	$ 0.06760	$ 0.00310	4.81%
Demand Charge	- $/kW-mo. -	$ 11.25	$ 11.25	$ -	0.00%
Purchased Power Adjustment	- $/kWh -	$ -	$ -	$ -	0.00%
Green Energy Fund Charge	- $/kWh -	$ 0.00018	$ 0.00018	$ -	0.00%
Utility Tax Rate	- % -	2.00%	2.00%		
Average Monthly Energy [1]	- kWh -	385,015	385,015		
Average Monthly Billing Demand [1]	- kW -	976	976		
Average Monthly Load Factor	- % -	54.79%	54.79%		
Customer Charge	- $ -	$ 10.00	$ 15.00	$ 5.00	50.00%
Energy Charges	- $ -	$ 24,833.47	$ 26,027.01	$ 1,193.55	4.81%
Demand Charges	- $ -	$ 10,980.00	$ 10,980.00	$ -	0.00%
Subtotal - Base Rates		$ 35,823.47	$ 37,022.01	$ 1,198.55	3.35%
Purchased Power Adjustment	- $ -	$ -	$ -	$ -	0.00%
Green Energy Fund Charges	- $ -	$ 68.53	$ 68.53	$ -	0.00%
Utility Tax	- $ -	$ 717.84	$ 741.81	$ 23.97	3.34%
Total Bill		$ 36,609.84	$ 37,832.36	$ 1,222.52	3.34%

[1] Average customer monthly energy and demand for the test period.
[2] Power factor adjustment not included in calculations.

Transmission Service

Transmission customers receive service from the Electric Division's 69-kV transmission system and include Dover Air Force Base, Kraft, Proctor & Gamble, White Oak Solar and First State Power Management. The current rates for Transmission customers, provided in Table 13, consist of a flat energy charge of 6.09¢/kWh for all kWh and a demand charge of 10.50/kW-mo. The proposed rates include an energy charge of 6.37¢/kWh for all kWh, and a demand charge of $10.50/kW-mo. Based on an average monthly consumption of 2,352,544 kWh and demand of 4,747 kW, the proposed rates would generate a monthly bill of $204,122, compared to a bill of $197,403 based on the current rates. This is a difference of $6,719, or 3.4 percent.

Table 13

SAMPLE MONTHLY BILL - TRANSMISSION CUSTOMER

Electric Division, City of Dover

	Units	Current Billing	Proposed Billing	Adjustment	Adjustment
Transmission					
Customer Charge	- $/mo. -	$ -	$ -	$ -	0.00%
Energy Charge	- $/kWh -	$ 0.06090	$ 0.06370	$ 0.00280	4.60%
Demand Charge	- $/kW-mo. -	$ 10.50	$ 10.50	$ -	0.00%
Purchased Power Adjustment	- $/kWh -	$ -	$ -	$ -	0.00%
Green Energy Fund Charge	- $/kWh -	$ 0.00018	$ 0.00018	$ -	0.00%
Utility Tax Rate	- % -	2.00%	2.00%		
Average Monthly Energy [1]	- kWh -	2,352,544	2,352,544		
Average Monthly Billing Demand [1]	- kW -	4,747	4,747		
Average Monthly Load Factor	- % -	68.83%	68.83%		
Customer Charge	- $ -	$ -	$ -	$ -	0.00%
Energy Charges	- $ -	$ 143,269.93	$ 149,857.05	$ 6,587.12	4.60%
Demand Charges	- $ -	$ 49,843.50	$ 49,843.50	$ -	0.00%
Subtotal - Base Rates		$ 193,113.43	$ 199,700.55	$ 6,587.12	3.41%
Purchased Power Adjustment	- $ -	$ -	$ -	$ -	0.00%
Green Energy Fund Charges	- $ -	$ 418.75	$ 418.75	$ -	0.00%
Utility Tax	- $ -	$ 3,870.64	$ 4,002.39	$ 131.74	3.40%
Total Bill		$ 197,402.83	$ 204,121.69	$ 6,718.87	3.40%

[1] Average customer monthly energy and demand for the test period.
[2] Power factor adjustment not included in calculations.

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Outdoor Lighting Service

The current rates for the Outdoor Development Lighting class consist of a customer charge and an energy charge. The current rates for the Private Outdoor Lighting class consist of a flat monthly charge varying by fixture type. The proposed rates for both lighting classes follow the same rate structures. A 3.0 percent increase was applied to all lighting rates. The charges are detailed on Table 14.

Table 14

MONTHLY ELECTRIC RATE SCHEDULES - OUTDOOR LIGHTING

Electric Division, City of Dover

	Customer Charge		Energy Charge	
	Current	Proposed	Current	Proposed
Outdoor Development Lighting	- $/Month -	- $/Month -	- $/kWh -	- $/kWh -
	$ 8.00	$ 8.25	$ 0.10900	$ 0.11230

		Unmetered Charge		Metered Charge	
	Units	Current	Proposed	Current	Proposed
Private Outdoor Lighting					
Security Lights					
110 watt HPS	- $/mo. -	$ 7.48	$ 7.70	$ 2.64	$ 2.72
175 watt HPS	- $/mo. -	$ 8.82	$ 9.08	$ 2.25	$ 2.32
70 watt HPS	- $/mo. -	$ 6.50	$ 6.70		
Decorative Lighting					
70 watt HPS w/o ladder rest	- $/mo. -	$ 11.31	$ 11.65	$ 6.22	$ 6.41
150 watt HPS w/o ladder rest	- $/mo. -	$ 14.09	$ 14.51	$ 6.39	$ 6.58
250 watt HPS w/o ladder rest	- $/mo. -	$ 19.72	$ 20.31	$ 8.18	$ 8.43
175 watt MV w/o ladder rest	- $/mo. -	$ 13.76	$ 14.17		
175 watt MV contemporary	- $/mo. -	$ 14.38	$ 14.81		
Roadway/Area Lighting					
100 wat HPS	- $/mo. -	$ 8.94	$ 9.21	$ 3.63	$ 3.74
175 watt MV	- $/mo. -	$ 10.00	$ 10.30	$ 3.11	$ 3.20
250 watt HPS	- $/mo. -	$ 13.87	$ 14.29	$ 3.91	$ 4.03
250 watt MV	- $/mo. -	$ 13.87	$ 14.29	$ 3.91	$ 4.03
400 watt MV	- $/mo. -	$ 18.60	$ 19.16	$ 4.09	$ 4.21
400 watt HPS	- $/mo. -	$ 18.69	$ 19.25	$ 4.15	$ 4.27
Pole Charges					
Poles installed through 2/28/1997	- $/mo. -	$ 2.03	$ 2.09	$ 2.03	$ 2.09
Poles installed/installed after 2/28/1997	- $/mo. -	$ 3.13	$ 3.22	$ 3.13	$ 3.22

Firm Standby and Supplemental Service
Prior to the completion of the 2015 Electric Cost-of-Service and Rate Design Study Update, Burns & McDonnell was engaged by the City to design a cost based Standby and Supplemental Service tariff coinciding with its newly established agreement with a large power customer.

The basis for establishing the standby rates was to recover cost for a service provider to stand ready to deliver power with short notice at the demand and voltage required by the customer and for the actual power itself. The standby rates developed and proposed feature three cost recovery components an energy charge, reservation charges, and a daily demand charge. Each of the components was developed from the 2013 cost-of-service analysis prepared by Burns & McDonnell for the City.

The proposed energy charge for standby service is 5.692¢/kWh, equal to the maximum allocated cost of energy amongst the customer classes. Congruent with theory of standby power, a customer may not consume energy each billing period. The energy charge should only be billed for energy delivered.

Since being able to deliver backup power expediently requires permanently installed delivery infrastructure, a monthly $1.78/kW transmission reservation charge is proposed; the average cost of transmission as developed in the cost-of-service analysis. Additional reservation charges should be billed to customers that take service at primary or secondary voltage at monthly rates of $1.48/kW and $3.44/kW, respectively. The reservation charge should be billed each month for theoretical reserve capacity in the wires, or the maximum demand Dover would provide to a customer during a backup power event. This reserve contract demand requirement should be defined in the standby power agreement.

The proposed daily demand charge of $0.14/kW is based on the average cost of forward capacity in the PJM market through 2017. The daily demand charge should be billed each billing period for actual demand required for that period. A customer may not require backup power each billing period. The daily demand charge should only be billed for power consumed by the customer.

The Firm Standby and Supplemental Service tariff development was completed under a separate authorization from this 2015 Study Update. Those rates were submitted to City Council for approval and became effective on July 1, 2015.

CONCLUSION
In March 2015, the City retained Burns & McDonnell to conduct the 2015 Electric Cost-of-Service and Rate Design Study Update completed on behalf of the City of Dover and the Dover

Municipal Electric Division. A primary driver behind this 2015 update was commercial and industrial rate competitiveness. Burns & McDonnell was tasked with balancing appropriate allocation of cost recovery while developing regionally competitive electric rates.

In order to maintain adequate net margins and maintain adequate operating fund cash balances, Burns & McDonnell proposes a base rate revenue increase of 3.0 percent effective July 1, 2015. A cost-of-service analysis was conducted to appropriately classify the revenue requirement to the appropriate functional services and to allocate the costs to the appropriate customer classes. The results of the cost-of-service analysis facilitated a thorough rate design which focused on raising revenue with strong consideration for regional retail rate competitiveness. The proposed rates will help the City meet the 125 percent debt service coverage required by the bond covenant, and maintain adequate cash from operations for internal capital financing needs.

As a result of PJM market changes, the City expects to retire McKee Run Units 1 and 2 sometime in 2017. The retirement of the units will reduce the capacity and energy credits received from the RTO, as residual credits will be earned by the remaining units, McKee Run Unit 3 and VanSant Unit 11. The revenue requirements analysis should be revisited once the timing of the retirements is clearly defined and a plan is developed for the utility to move forward.

We appreciate the opportunity to work with the City, the Electric Division, and its staff. We are grateful for the cooperation and assistance we received. Please contact us with any questions or comments you may have regarding this report.

Sincerely,
Burns & McDonnell

Ted J. Kelly
Principal & Senior Project Manager
Business & Technology Services

Gerron L. Blackwell
Project Analyst
Business & Technology Services

TJK/GLB

cc: Mr. Harry Maloney III, Electric Department Director