INCORPORATED COUNTY OF LOS ALAMOS
DEPARTMENT OF PUBLIC UTILITIES

Electric Utility Cost of Service Analysis and Rate Study

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Final Report

Cost of Service and Rate Design Study

Incorporated County of Los Alamos
Department of Public Utilities
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November 2014

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Introduction

The Incorporated County of Los Alamos, New Mexico ("LAC") owns, and the LAC Department of Public Utilities ("DPU" or "Utility") operates: electric, water, gas, and wastewater utility systems. In May 2014, LAC retained Leidos Engineering, LLC ("Leidos") to perform an Electric Utility Cost of Service Analysis and Rate Study (the "Study") for the LAC electric system (the "System"). This report provides a description of the analysis, methodology, and results of this Study ("Report"). Unless otherwise noted, DPU staff provided the system-specific data utilized for this Study. In certain cases where information was not available, Leidos developed estimates based on industry expertise, and publicly available information.

This Study was performed in accordance with generally accepted industry practices for municipal utilities and consisted of the following primary tasks:

- Reviewing electric system operational and financial characteristics;
- Conducting an Electric Cost of Service analysis ("COS"); and
- Designing Rates.

Leidos conducted the COS analysis by performing the following steps as illustrated in Figure 1-1, below:

1) Establish the Revenue Requirement—determine the total revenue the DPU must collect to serve its customers, maintain its debt service obligations, invest in its system, and provide additional funds required by governing bodies, as appropriate.
2) Perform Functional Unbundling—divide the DPU's revenue requirement between the four major business units or functions: Production, Transmission, Distribution, and Customer Costs. For the purposes of this Study, the Production and Transmission business units are combined as DPU's "Cost of Power."
3) Classify Costs within Functional Areas—classify costs based on the drivers within each functional area. Drivers of cost include system demand, energy consumption, and the number of customers being served, among other things. In some cases, costs can be allocated directly to the activity or class creating the cost as in the case of water production or lighting.
4) Allocate Costs across Customer Classes—based on the customer class usage characteristics, allocate the classified costs to customer classes and determine the costs of service.

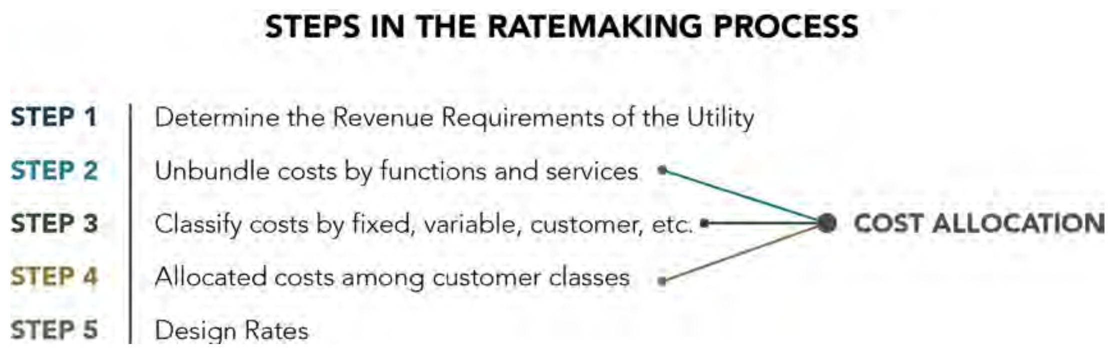

Figure 1-1 Study Approach

The cost of serving a utility's different customer classes can be used to assess the effectiveness of existing rates in adequately recovering the utility's costs from each of its customer classes. This Study provides a detailed evaluation of the extent to which existing rates adequately recover DPU's costs to serve by customer class.

A description of these efforts can be found in Section 2 through Section 4 of this Report. Section 5 provides a summary of the recommendations for this Study. Data and supporting analyses for this Report appear in an electronic spreadsheet model, the *"Los Alamos COS 2014 Model final.xls,"* provided to DPU under a separate cover. Appendices A through E to this Report provide a five-year revenue requirement projection, a capital improvement plan ("CIP"), a cost of power analysis, the detailed methodology for development of demand cost allocation factors, and a copy of DPU's municipal rate code and rules and regulations.

Overview

Leidos utilized historical data provided by the DPU for Fiscal Year ("FY") 2013 and FY 2014—for reference, the FY 2013 period began on July 1, 2012 and ended on June 30, 2013. A description of the existing system is provided in Section 2.

The FY 2015 budget was used as the Base Year revenue requirement for the COS analysis. Adjustments consisting of all "known and measurable" changes occurring after July 2014 were then applied to the Base Year to create the Test Year. "Known and Measurable" changes impact Utility costs or revenues and have either occurred or are expected to occur in the near future, i.e. during the Study period (FY 2015 through 2019). Test Year results are provided in Section 3 of this Report. For the purposes of this Study, the Test Year is determined to be limited to FY 2015 with the adjustments as noted herein. In addition to the Test Year, costs for the Utility were projected for FY 2016 through 2019, as provided in Appendix A.

Table 1-1 shows the FY 2015 budget and the adjustments that result in the total revenue requirement for the Test Year.

Table 1-1
Summary of Projected Revenue Requirements and Existing Rate Revenues

		Fiscal Year Ending June 30, 2015		
Ln. No.	Description	Proposed Budget 2015	Known and Measurable Adjustments	Test Year 2015 Revenue Requirement
	(a)	(b)	(c)	(d)
	Operating Expenses - Electric Distribution			
1	Cost of Power	8,298,265	982,851[1]	9,281,116
2	Supervision, Misc Direct Admin	768,556	0	768,556
3	Substation Maintenance	34,308	0	34,308
4	Switching Station Maintenance	28,308	0	28,308
5	Overhead Maintenance	385,674	0	385,674
6	Underground Maintenance	347,262	0	347,262
7	Meter Maintenance	62,616	0	62,616
8	Interdepartmental Charges	489,406	0	489,406
9	Administrative Division Allocation	819,165	0	819,165
10	In Lieu Taxes	379,236	0	379,236
11	*Total Operating Expenses*	*11,612,796*	*982,851*	*12,595,647*
	Other Revenue Requirements			
12	Existing Debt Service	1,426,595	(403,615)	1,022,980
13	Future Debt Service	0	0	0
14	Transfer to General Fund	564,222	0	564,222
15	Renewal and Replacement Fund	0	0	0
16	Restore Cash Reserves	0	450,000	450,000
17	Other Revenue Requirements	0	0	0
18	*Total Other Revenue Requirements*	*1,990,817*	*46,385*	*2,037,202*
19	*Total Expenditures*	*13,603,613*	*1,029,236*	*14,632,849*
	Less Transfers and Other Revenue			
20	Transfers	0	0	0
21	Smart House Lease Revenue	15,000	0	15,000
22	Bond Federal Subsidy	58,945	8,997	67,942
23	Revenue on Recoverable Work	183,750	0	183,750
24	Total Other Revenue	257,695	8,997	266,692
25	NET REVENUE REQUIREMENTS	13,345,918	1,020,239	14,366,157
	Projected Revenue From Sales			
26	Existing Base Rate Revenues	14,277,231	(1,653,055)[2]	12,624,176
27	Power Cost Adjustment Revenues	0	982,851	982,851
28	Other Revenue	0	0	0
29	TOTAL REVENUES FROM SALES	14,277,231	(670,204)	13,607,027
30	Revenue Surplus or (Deficiency)	$931,313	($1,690,444)	($759,131)
31	Surplus or (Deficiency) as a Percentage of Existing Base Rate Revenues			-6.0%

[1] Refer to Appendix C.
[2] Estimated Budget shortfall under current rates using FY 2014 billing determinants.

Overall, to achieve the projected revenue requirement for the system through June 30, 2016, increases to projected rate revenue under existing rates of approximately 6 percent as of January 1, 2015 and an additional 5 percent as of July 1, 2015 are required. Since DPU's FY 2015 budget included a 6 percent increase as of the beginning of the fiscal year, these increases account for the six-month lag in rate increase implementation from July 1 through December 31, 2015.

After determining the revenue requirement, Leidos categorized or "unbundled" Test Year data according to the three primary functional areas of: Cost of Power, Distribution, and Customer. Using principles of cost causation and LAC System characteristics, Leidos developed unbundling allocation factors. Within each of the functional areas, Leidos further allocated costs based on the four classifications of: Demand, Energy, Customer, and Direct Assignment. Leidos allocated classified costs to each customer class (i.e., tariff group, such as residential, small commercial, etc.) as described in Section 3 of this Report, to calculate DPU's estimated cost for serving each customer class.

Leidos used the COS as the basis for rate design by apportioning DPU's total cost for serving each customer class according to the rate mechanism for recovering the cost (i.e., demand charges, energy charges, customer charges, a Power Cost Adjustment ("PCA") charge, and specific rate riders). Using LAC System billing determinants (e.g., energy utilized by class, number of meters, etc.) and the proposed rates, Leidos performed a revenue adequacy test. By comparing forecasted electric system revenue under the proposed rate design to the Test Year COS, Leidos determined whether DPU would generate sufficient electric revenue to meet expenses and reserve requirements. Section 4 provides the recommended rate changes and a comparison of existing and proposed rate impacts with those of regional utilities.

Section 5 of this Report provides Leidos' recommendations.

Summary of Results

Several factors drive the rate design process for this Study. First, DPU desires to move towards cost-based rates. At this time, however, Study results indicate that subsidies exist between rate classes. Therefore, based on direction provided by DPU and to avoid undue rate shock, the rate design limits rate increases to 9 percent within each customer class.

Second, DPU wishes to implement a "pass through" mechanism to reflect changes between the budget and actual costs of power. This is typically referred to as a "Power Cost Adjustment" or PCA mechanism.

Third, DPU wishes to implement changes to Net Metering ("NEM") account charges to align with cost incurrence via a monthly wires charge. This charge is in addition to the proposed applicable customer service charge.

Fourth, DPU wishes to create a rate rider associated with the increased cost of serving both off-site and remote off-site loads, that is, loads that make use of external distribution infrastructure.

Fifth, DPU has developed an extensive long-term CIP to meet the long-term goals of the Board of Public Utilities ("Board") and LAC Council for continued, safe and reliable operation of the System. This aggressive capital plan includes approximately $2.5 million of annual infrastructure investment. At DPU's request, Leidos incorporated into this Study an analysis for funding the CIP. The Test Year includes debt service on the 2014 bonds that will be used to fund all capital improvements for

FY 2015 to 2017. DPU wishes to work towards creating a sustainable approach for maintaining its CIP comprised of cash reserves and future bond issues.

Sixth, DPU wishes to replenish cash reserves that have been depleted over the past several years in support of Board and Council recommendations for enhanced reliability and infrastructure improvements. An annual allowance for cash reserve replenishment has been included in the Test Year revenue requirement.

Ultimately, the most critical driver for rate design is revenue adequacy, i.e., that proposed rates generate adequate revenue to meet DPU's needs. The rates presented in this Report have been designed to recover revenues equal to the Test Year revenue requirement based the proposed rate plan.

The phased-in recommended approach recognizes the timing of the expected rate changes (midway through the fiscal year) as well as projected revenue shortfalls. This proposed increase can be attributed to increased capital investments in the system, shortfalls in both revenue recovery and cost of power recovery resulting from the level of existing rates and current rate design, and the need to replenish cash reserves. The Test Year revenue requirement also includes known and measurable changes to individual budget items included in the generation, transmission, distribution operations and maintenance ("O&M") expenses, as well as customer costs, and administrative and general cost categories.

The proposed DPU rates developed herein include, as applicable, the following mechanisms: demand charges, energy (consumption) charges, customer charges, PCA charges, rate riders, and wires charges. The proposed rate structure establishes DPU policy and methodology for administering the PCA. Rates were designed based on billing information provided by DPU. To the extent actual billing determinants vary from that provided by DPU, or future class usage characteristics vary from historical observations, actual revenues may vary from the expected revenues as presented herein.

Recommendations

Based on this analysis of the expenses and revenues associated with DPU, Leidos recommends the following:

- The Board should consider adopting the rates and recommendations as presented within this Study.
- DPU should consider moving towards cost-based rates to the extent possible within the constraint of limiting individual class rate increases to 9 percent.
- DPU should consider implementing a PCA charge, to reflect changes in expenses between the actual and budgeted cost of power, to stabilize revenues, and insulate against power cost volatility. The initial PCA for the Test Year based on historic data is estimated at $0.0077 per kilowatt hour ("kWh").
- DPU should consider aligning Net Metering account charges with cost incurrence by implementing a monthly wires charge.

- DPU should consider implementing a rate rider associated with the increased cost of serving both off-system and remote off-system loads.
- DPU should consider creating a sustainable approach for maintaining its CIP by replenishing cash reserves and issuing additional bonds in FY2018.[1]
- DPU should consider establishing an annual allowance for replenishing its cash reserve. The Test Year includes $450,000 for this purpose.
- DPU should continue to monitor revenues and expenses and update COS results regularly, at two- to three-year intervals, and adjust rates accordingly.

Table 1-2 summarizes recommended rate increases by customer tariff class. Importantly: Column (c) of this table *illustrates* the cost to serve customer classes; it *does not represent* the COS Study recommended rate changes by customer class. The recommended rate changes appear in Columns (d) and (e) and are discussed in Section 4 of this Study.

Table 1-2
Summary of Cost of Service Versus Proposed Rate Increases by Customer Class

Ln No	Service Class	Schedule	Cost of Service Based Change[1]	Proposed Blended Rate Change[2] January 2015	July 2015
	(a)	(b)	(c)	(d)	(e)
1	Residential Service	6-A[3]	5.2%	6.9%	5.8%
2	Small Commercial (< 50 kW)	6-G	2.1%	4.0%	3.3%
3	Large Commercial (> 50 kW)	6-K[4]	2.9%	4.6%	3.7%
4	Commercial Time-of-Use	6-T[5]	-5.9%	0.2%	0.2%
5	Small County	6-L	17.9%	9.0%	7.2%
6	Large County	6-M	18.4%	9.0%	7.5%
7	Small Public School	6-N	31.7%	6.0%	5.0%
8	Large Public School	6-R	26.6%	6.0%	5.0%
9	Private Area Lighting	6-Q	9.5%	6.0%	5.0%
10	TOTAL SYSTEM			6.0%	5.0%

[1] For illustrative purposes not proposed as actual rate increase.
[2] Amounts reflect changes to Base Rates and do not include the impact of the proposed PCA charge currently estimated to equal $0.0077/kWh. Blended rate change includes all components of the schedules as set forth in Table 4-2.
[3] DPU offers a Residential time-of-use ("TOU") rate (Schedule 6-U). No customers are currently on this schedule.
[4] Schedule 6-S, Special electric service, is included under this schedule.
[5] The rate changes result from increases to the monthly customer charge.

[1] CIP expenditures for FY 2015 through 2017 are funded from 2014 bond proceeds.

LAC is located at an elevation of 7,320 feet above sea level in a region of northern New Mexico known as the Pajarito Plateau and comprises the communities of Los Alamos and White Rock. According to the US Census Bureau, the 2010 population of Los Alamos and White Rock combined was 17,950. LAC is home to the Los Alamos National Laboratory ("LANL") and is surrounded by the San Ildefonso and Santa Clara Pueblos and the National Forest Service including Bandelier National Monument. LANL is the largest employer in LAC and northern New Mexico.

Overview

The DPU has served LAC for more than 45 years and was established under Article 5 of the 1968 Charter for the LAC. In accord with Resolution No. 97-07 the DPU provides payments to the County General Fund of 5 percent of total electric retail revenues excluding commodity sales to the schools and County.[2] In 2013, DPU served approximately 8,700 ratepayers including the communities of Los Alamos and White Rock. LAC is in a pooling arrangement (The Los Alamos Power Pool, "LAPP") with the National Nuclear Security Administration ("NNSA"), a division of the United States Department of Energy ("DOE"), to supply power for Los Alamos County and the LANL. LAC's approximately 1,500 businesses and commercial enterprises include retail, food services, limited manufacturing, and professional services. DPU's retail electric sales were approximately 127,000 megawatt hours ("MWh") or 127,000,000 kWh of electricity in FY 2013. The maximum System demand for FY 2013 was 86.663 MW on August 9, 2012 comprised of LAC's demand of 16.296 MW and 70.367 MW of LANL demand.

Figure 2-1 provides the number of customer bills and annual retail sales (MWh) for the period FY 2004 to 2013. Figure 2-2 provides DPU retail electric operating revenue by customer type (FY 2004 to 2013).

[2] LAC Resolution No. 97-07, *A Resolution Establishing a Methodology for Computing Electric and Gas Operating Profits for Transfer to the County General Fund*, 28 July 1997.

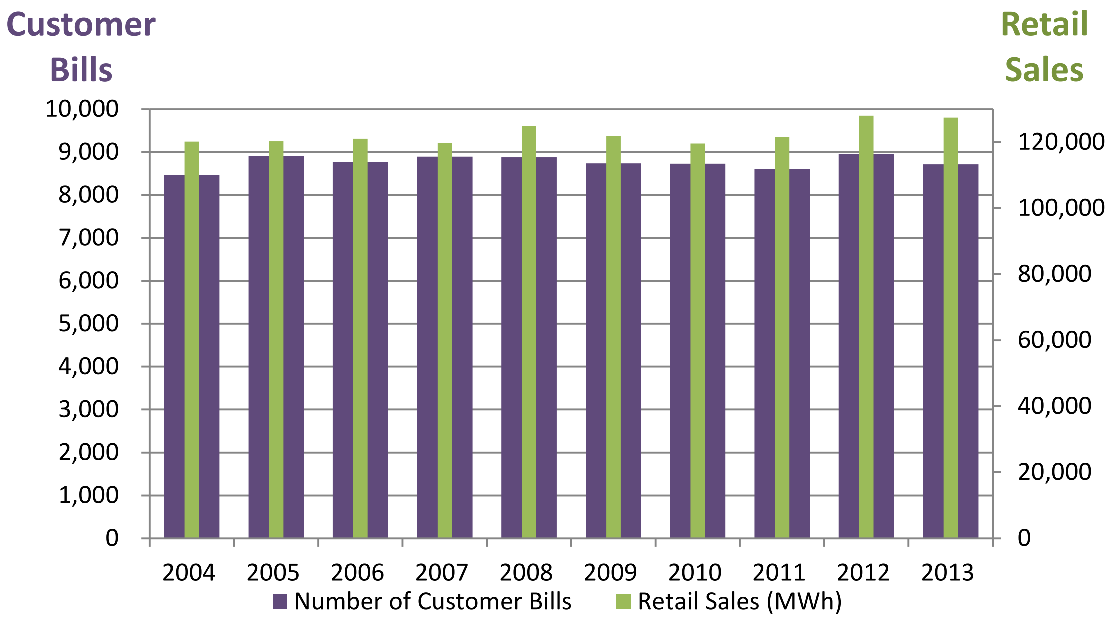

Figure 2-1 DPU Electric Customer Bills and Sales (FY 2004 to 2013)[3]

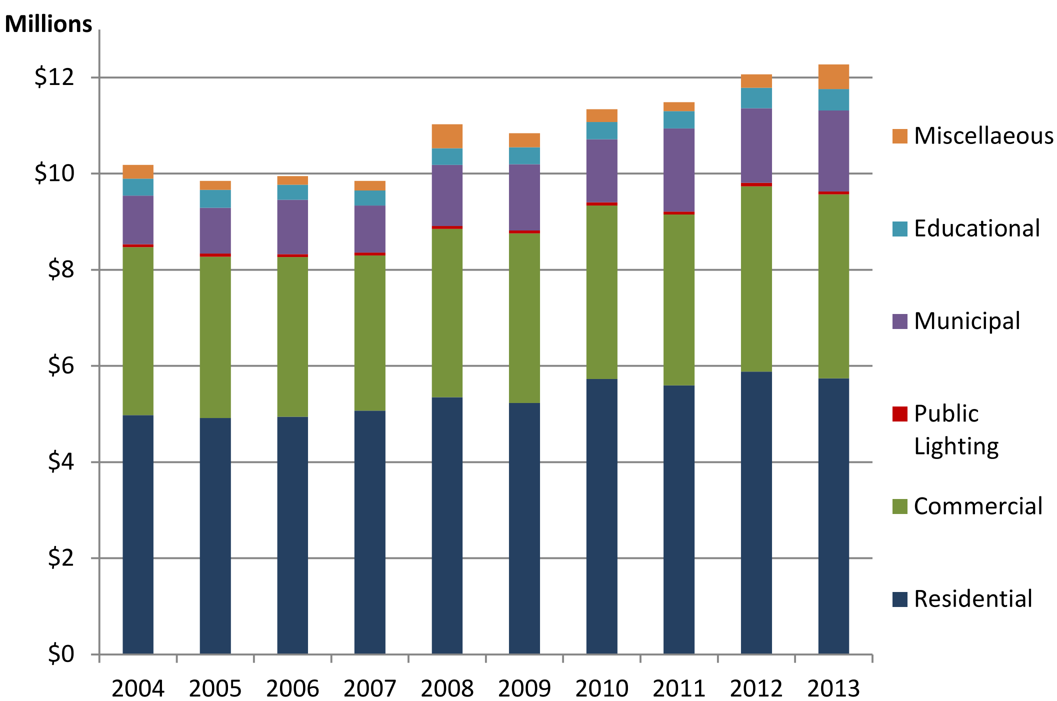

Figure 2-2 DPU Retail Electric Operating Revenue by Customer Type (FY 2004 to 2013)[4]

[3] Source: LAC Comprehensive Annual Financial Report FY Ended June 30, 2013. Number of Customer Bills varies based on cycle and schedule from 11 to 13 per customer account per annum.
[4] Source: LAC Comprehensive Annual Financial Report FY Ended June 30, 2013.

Power Supply

In 1985, LAC and the DOE entered into an electric coordination agreement to create a resource pool to which each party contributes the capacity and energy of individual electric supply and transmission resources to meet combined system requirements. LAPP owns up to 88.5 MW of generation resources and purchases up to 20 MW of power per year. LAC's contributions to the power pool include energy from its interest in San Juan Unit 4, the El Vado Hydroelectric Project, the Abiquiu Hydroelectric Project, its interest in the Laramie River Station, its Western Area Power Administration ("WAPA") entitlement, its Public Service of New Mexico ("PNM") Network Integration Transmission Service Agreement ("NITSA"), and various transmission services agreements. The contract between LAC and the DOE was renewed on April 8, 2014 and expires on June 30, 2020 with five one-year extension options. Table 2-1 illustrates the DPU's generation capacity by resource.

Table 2-1
DPU Generation Capacity

Unit / Plant	Fuel Type	MW
San Juan Unit #4	Coal	36.0
Laramie River Station	Coal	10.0
Abiquiu	Hydro	17.0
El Vado	Hydro	8.0
WAPA Allocation	Hydro	1.0
East Jemez Landfill	Solar	1.0
Total Generation Capacity		73.0

Transmission

PNM provides 115 kilovolt ("kV") transmission service into Los Alamos from two substations: the 115 mega volt ampere ("MVA") Norton line originating just west of Santa Fe; and the 130 MVA Reeves line originating just north of Albuquerque.[5] PNM provides primary and back-up relay protection to the DOE owned transmission lines within Los Alamos and is the "balancing authority" for LAPP. DPU dispatchers operate the DOE transmission system and manage LAPP resources. DPU's long-term plan is to develop additional substations to enhance reliability.

[5] LAC owns 16 miles of 69 kV transmission lines from El Vado that are operated and maintained by the Northern Rio Arriba Electric Cooperative.

Distribution

The LAC distribution system consists of two substations; Townsite, that serves the Los Alamos community, and White Rock, that serves its namesake. DPU owns and operates approximately 143 total miles of distribution lines, of which approximately 66 percent are underground.

Coincident and Non-Coincident Peak Demands

Based on Leidos' analysis of feeder data for portions of FY 2013 and 2014, average coincident peak ("CP") demands and non-coincident peak ("NCP") demands have been estimated for each customer class as shown in Table 2-2. Coincident peak demands by customer class reflect the maximum monthly and annual demands on the System. Non-coincident peak demands reflect the peak demand of customer classes whenever that may occur; customer class NCP may or may not coincide with the overall system peak. Appendix D provides additional information regarding development of the feeder data analysis.

Table 2-2
Coincident Peak and Non-Coincident Peak Demands
by Service Class and Schedule

Ln. No.	Service Class	Schedule	Average CP (MW)	Average CP %	Average NCP (MW)	Average NCP %
	(a)		(b)	(c)	(d)	(e)
1	Residential Service	6-A[1]	4.79	35.7%	10.12	50.5%
2	Small Commercial (<50kW)	6-G	2.20	16.4%	2.53	12.6%
3	Large Commercial (>50kW)	6-K[2]	3.41	25.5%	3.93	19.6%
4	Commercial Time-of-Use	6-T	0.02	0.2%	0.02	0.1%
5	Small County	6-L	0.26	1.9%	0.30	1.5%
6	Large County	6-M	1.59	11.9%	1.83	9.1%
7	Small Public School	6-N	0.08	0.6%	0.09	0.4%
8	Large Public School	6-R	1.06	7.9%	1.21	6.1%
10	Private Area Lighting	6-Q	-	-	0.01	0.0%
11	Municipal Water Production	6-W	*The rate for Municipal Water Production is based on the Cost of Power and is not included in the Cost of Service analysis.*			
12	TOTAL SYSTEM		13.40	100.0%	20.04	100.0%

[1] DPU offers a Residential time-of-use ("TOU") rate (Schedule 6-U). No customers are currently on this schedule.
[2] Schedule 6-S, Special electric service, is included under this schedule.

Usage Characteristics by Class

The COS examined detailed customer usage characteristics by rate class. Table 2-3 summarizes the number of customers and energy sales for the Test Year, based on FY 2014.

Table 2-3
Summary of Customers and Energy Sales
(FY 2015 Test Year)

Ln. No	Service Class	Schedule	Customer Bills[1]	Energy Sales (kWh)
	(a)	(b)	(c)	(d)
1	Residential Service	6-A	8,270	53,636,877
2	Small Commercial (<50kW)	6-G	674	16,190,065
3	Large Commercial (>50kW)	6-K[2]	39	25,145,900
4	Commercial Time-of-Use	6-T	1	143,360
5	Small County	6-L	103	1,363,127
6	Large County	6-M	48	8,319,331
7	Small Public School	6-N	19	334,501
8	Large Public School	6-R	36	4,662,820
10	Private Area Lighting	6-Q	-	37,416
11	Municipal Water Production	6-W	-	12,801,571
12	TOTAL SYSTEM		9,190	122,634,968

[1] Number of Customer Bills varies based on cycle and schedule from 11 to 13 per customer account per annum.
[2] Schedule 6-S, Special electric service, is included under this schedule.

Appendix E provides the proposed Ordinance amending Chapter 40, Article III, Sections 40-121, 40-122, and 40-123 relating to electric rate schedules, customer service charges, and electric energy charges, and adding new sections 40-126, off-system riders, and 40-127, power cost adjustment.

Introduction

A COS analysis is a detailed study that allocates the “Revenue Requirement” of the system to individual customer classes. This process involves four basic steps.

- Revenue Requirement—The revenue requirement determines the appropriate costs to be supported by rates. Utility rates are set equal to the overall system revenue requirement. The revenue requirement was developed based on a projection of expenses for FY 2015 through FY 2019. For the purposes of this Study, the Test Year includes known and measurable adjustments for FY 2015. A discussion of the impacts for these future years (pro forma financial projections for FY 2016-19) are provided in Appendix A. Sources for this data included DPU’s budgeted values for operations and capital improvements. Projections for customer load growth, operation and maintenance costs, and capital paid from current earnings were based on information provided by DPU.
- Functional Unbundling—The functional unbundling process categorizes the revenue requirement by basic utility function and service. In this particular case, DPU costs were unbundled into Production and Transmission, Distribution, and Customer functions. As indicated previously, DPU owns no significant transmission assets. For the purposes of this Study, costs for production and transmission are collectively referred to as the “Cost of Power.”
- Classification—Once unbundled, the costs are classified into the fundamental cost categories that directly influence the nature and type of cost. For DPU, costs are classified into demand-related (or fixed costs), energy-related (or variable costs), customer-related costs and costs that can be directly assigned to a particular class of customer.
- Allocation—Based on these cost classifications, costs are allocated to the individual customer classes based on their usage characteristics. For example, energy-related costs, such as fuel, are allocated to the various customer classes based on kWh sales.

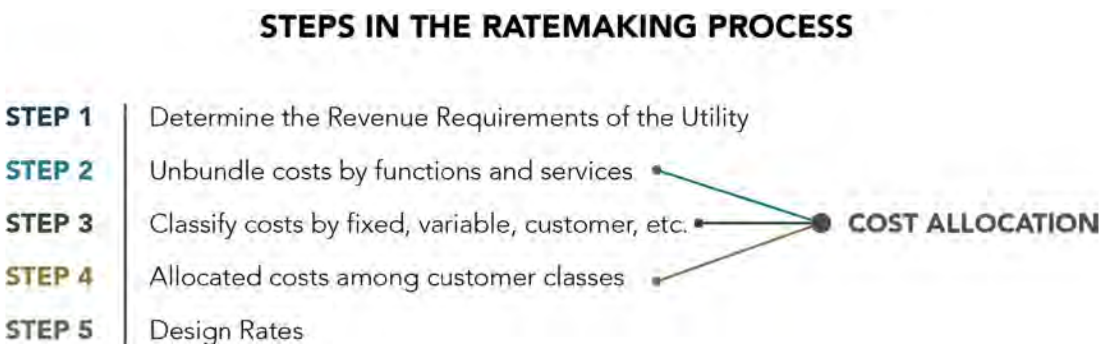

Figure 3-1 Study Approach

Projections for customer load growth, operation and maintenance costs, anticipated debt service, and capital paid from current earnings were based on examining historical trends and discussions with DPU staff. The Test Year includes estimated projections for these values.

Current DPU COS and Revenue

At present, DPU is in need of revenue increases to fund long term capital investments and ongoing operations and maintenance expenses. Additionally the DPU wishes to re-establish reserve funds for future projects and restore its cash balances. The proposed rates include funding additional reserves for an increased capital investment plan to allow DPU to continue to provide customers with safe, reliable electric service. Therefore, an overall revenue increase is needed to meet these goals.

COS Methodology

This Section describes the methodology utilized to develop the COS analysis. The actions taken to create the COS analysis are summarized as follows:

- Create a Test Year from FY 2015 costs projections.
- Unbundle the Test Year into Cost of Power, Distribution, , and Customer Related (functional areas).
- Allocate functions into classifications: Demand, Energy, Customer, and Directly Assignable.
- Assign classified costs to the customer classes.

Each of the steps is discussed in this Section.

While DPU currently offers time-of-use ("TOU") based rates for both Residential and Commercial customers, DPU currently has only one Commercial TOU customer. Therefore the COS Study did not analyze seasonal or daily rate differentials established for these rates.

Test Year Revenue Requirement

To determine DPU COS, a Test Year was based on the FY 2015 budget. A Test Year is a commonly used representation of a system's total estimated operating costs (revenue requirement) that must be recovered by rates over a defined period of time (e.g., FY). The term revenue requirement refers to the amount of rate proceeds necessary to meet the utility's financial obligations.

Leidos created the Test Year using a three-step process. The first step was to create a statement of expenses for the actual FY operations using the Federal Energy Regulatory Commission ("FERC") standard system of accounts. DPU provided this information based on FY 2013 data, which Leidos used to assign the FY 2015 budget to FERC accounts. The next step was to adjust the FY 2015 budget values for "known and measurable" changes that have occurred, or are expected to occur to the System. The last step was to combine the adjusted values to create the Test Year values. The following is a discussion of the known and measurable adjustments applied to the FY 2015 budget.

Cost of Power

The FY 2015 budgeted amount for the cost of power was $8,298,265. Based on an analysis of the cost of power for FY 2012 through 2014, an adjustment of $982,851 was made to reflect the estimated incurred cost for the Test Year. Additional information on the methodology for establishing the budgeted cost of power and historic and forecasted cost of power data appear in Appendix C. As indicated and more fully discussed herein, this adjustment is proposed to be collected using a PCA mechanism and is therefore not included in base rates.

Debt Service

Debt service expenses for FY 2015 were budgeted at $1,426,595. Based on the final debt service schedule for the August 2014 bond issue, an adjustment of ($403,615) was made to reflect the difference between the budgeted and projected debt service.

Capital Improvement Program

Rates reflect all CIP expenditures funded from 2014 bond proceeds for FY 2015 through FY 2017. In order to meet the long-term goals of the Board and LAC Council for continued, safe and reliable operation of the System, this aggressive capital plan includes approximately $2.5 million of annual infrastructure investment. The Test Year includes debt service on the 2014 bonds.

At DPU's request, Leidos incorporated into this Study an analysis for funding the CIP. Appendix B contains this analysis that recommends LAC issue bonds in FY 2018 to fund 80 percent of its CIP as of that year.

Cash Reserves

To assist in the effort to replenish the cash reserves of DPU, an allowance of $450,000 was made to the Test Year revenue requirement.

Other Revenue

Based on the final debt service schedule for the August 2014 bond issue, an adjustment of $8,997 was made to account for the Federal Bond Subsidy.

Fiscal Year, Adjustments, and Test Year

Table 3-1 provides a summary of the FY 2015 DPU total operations expenses, as well as the adjustments made to generate the Test Year revenue requirement for the electric utility. The Test Year revenue requirement is estimated to be $14,366,157.

Table 3-1
Test Year Revenue Requirement

		Fiscal Year Ending June 30, 2015		
Ln. No.	Description	Proposed Budget 2015	Known and Measurable Adjustments	Test Year 2015 Revenue Requirement
	(a)	(b)	(c)	(d)
	Operating Expenses - Electric Distribution			
1	Cost of Power	8,298,265	982,851	9,281,116
2	Supervision, Misc Direct Admin	768,556	0	768,556
3	Substation Maintenance	34,308	0	34,308
4	Switching Station Maintenance	28,308	0	28,308
5	Overhead Maintenance	385,674	0	385,674
6	Underground Maintenance	347,262	0	347,262
7	Meter Maintenance	62,616	0	62,616
8	Interdepartmental Charges	489,406	0	489,406
9	Administrative Division Allocation	819,165	0	819,165
10	In Lieu Taxes	379,236	0	379,236
11	*Total Operating Expenses*	*11,612,796*	*982,851*	*12,595,647*
	Other Revenue Requirements			
12	Existing Debt Service	1,426,595	(403,615)	1,022,980
13	Future Debt Service	0	0	0
14	Transfer to General Fund	564,222	0	564,222
15	Renewal and Replacement Fund	0	0	0
16	Restore Cash Reserves	0	450,000	450,000
17	Other Revenue Requirements	0	0	0
18	*Total Other Revenue Requirements*	*1,990,817*	*46,385*	*2,037,202*
19	Total Expenditures	13,603,613	1,029,236	14,632,849
	Less Transfers and Other Revenue			
20	Transfers	0	0	0
21	Smart House Lease Revenue	15,000	0	15,000
22	Bond Federal Subsidy	58,945	8,997	67,942
23	Revenue on Recoverable Work	183,750	0	183,750
24	Total Other Revenue	257,695	8,997	266,692
25	NET REVENUE REQUIREMENTS	13,345,918	1,020,239	14,366,157

Unbundling of Revenue Requirement

The revenue requirement determined for the Test Year was categorized or "unbundled" into the functional areas (or primary business units) of the Utility, including Cost of Power , Distribution, Customer, and Other. As indicated previously, given LAC's LAPP arrangement, all Production and Transmission related costs are included in the Cost of Power. The results are summarized in Table 3-2 below.

Table 3-2
Unbundled Revenue Requirement
(Test Year 2015)

Ln No	Unbundled by Functional Area	FY 2015 Test Year Amount
1	Production *(Cost of Power)*	$9,281,116
2	Transmission *(Included in Cost of Power)*	$ -
3	Total Distribution	$4,489,673
4	Customer *(Customer Related)*	$31,146
5	Other *(Transfer to General Fund - Revenue Related)*	$564,222
6	TOTAL REVENUE REQUIREMENTS	$14,366,157

Classification of Test Year Revenue Requirement

Utility costs can be classified into four generally accepted ratemaking cost classifications: (i) demand or fixed costs; (ii) energy or variable costs; (iii) customer-related costs; and (iv) directly assignable costs. In order to provide a reasonable basis for the assignment of total revenue requirements (costs) to each customer class, costs for each function in the System have been analyzed and classified into these four categories using the following parameters:

› Demand Costs—Capacity (fixed- or demand-related) costs are those costs incurred to maintain a utility system in a state of readiness to serve, enabling it to meet the total combined demands of its customers. Capacity costs include that portion of operating and maintenance expenses, debt service, capital expenditures, and other costs such as labor, which are generally fixed and do not vary materially with the quantity of usage or which cannot be designated specifically as a customer cost, a variable cost, or a directly assignable cost.

› Energy Costs—Energy or variable costs are costs that vary directly with energy usage, including such items as fuel, energy-related purchased power, and some maintenance expenses (those maintenance expenses not associated with fuel or labor).

› Customer Costs—Customer costs are those costs directly related to the number and type of customers, such as customer accounting and billing, and meter-related expenses.

- Direct Assignment Costs—Direct assignment costs are those costs that are readily identifiable and applicable to a particular customer or customer class.

See Table 3-3 for the types of demand, energy, customer and direct assignment costs within each function.

Table 3-3
Classified Revenue Requirement
(Test Year 2015)

Ln. No	Classification by Functional Area	FY 2015 Test Year Amount
	Production *(Cost of Power)*	
1	Demand Related	$3,646,267
2	Energy Related	5,076,860
3	Direct Assignment (Water Production)	557,989
4	Total Production	$9,281,116
5	Transmission *(Included in Cost of Power)*	$ -
	Distribution	
6	Demand Related	$2,307,196
7	Customer Related	2,169,478
8	Direct Assignment (Lighting)	13,000
9	Total Distribution	$4,489,673
10	Customer *(Customer Related)*	31,146
11	Other *(Transfer to General Fund - Revenue Related)*	564,222
12	TOTAL REVENUE REQUIREMENTS	$14,366,157

Once the costs within each function are assigned to each service category, the demand, energy, customer and direct assignment component of each service is calculated. As seen in Table 3-3, three major cost categories (demand, energy, and customer) cover the majority of all functional costs. This breakdown of demand, energy, customer and direct assignment costs is later applied to each customer class to create the Rate Design, as provided in Section 4.

Billing Determinants

The billing determinants for the Test Year are assumed to be equal to the billing determinants by class from the actual FY 2014 billing records. No load growth between FY 2014 and 2015 was assumed to occur.

Demand Allocation Factors

Demand allocation refers to the basis on which fixed or demand -related costs are distributed or assigned (allocated) among the various customer classes for the purpose of determining the COS for each class. The demand allocation factors that were developed reflect the cost responsibility of the various customer classes with respect to the revenue requirement components determined to be capacity-related or demand-related.

For customer class allocation purposes, average CP was used to allocate the demand-related cost of power. This method was used because the contribution to the System or CP is the primary driver of the demand related costs of power.

The average NCP was used to allocate the distribution primary demand costs to the customer classes. This method was used because distribution facilities are typically sized to meet the customer's localized demands as represented by each customer class's unique maximum demand or NCP.

Energy Allocation Factors

Energy allocation factors are the basis for allocating costs or expenses classified as variable or energy-related and are assumed to vary directly with the amount of kWh sales. The energy related costs of power are classified as variable. Typically, net energy for load ("NEFL"), or the kWh sales by customer class, is used to allocate these types of costs to individual customer rate classes. The use of NEFL recognizes that energy losses are inherent in the delivery of power. For this Study, DPU provided estimates of the power losses for their System.

Customer Allocation Factors

Customer costs are defined as those costs related to the number of customers and the type of service required. Included in the customer-related costs are the costs associated with transformers, customer connections or service drops, meter reading, customer service, sales, billing, collection, and other customer-related accounting activities. Additionally, a portion of the distribution system costs are related to the number of customers served by the utility. The customer allocation factors were based on the number of System customers in each class.

In allocating certain customer-related costs to the various customer classifications, weighted customer allocation factors were utilized. Weighting reflects that servicing certain types of customers requires more effort and expenses than other types of customers.

Cost of Service and Current Revenue

After the allocation factors are applied to the functional areas of the Utility and assigned to customers, the results are summed to create the COS for each class. Based on the allocation factors described previously, Table 3-4 summarizes the results of the COS analysis, compared to current revenue (based on adjustments made to rate classes above and using updated and revised billing determinants). An adjustment for the proposed PCA has been included to demonstrate that revenue from the PCA is included in neither the projected base rates nor in the current revenue.

As seen in Table 3-4, the estimated total Test Year rate revenue using the existing rate structure collects approximately $759,131 less than indicated by the COS analysis ($14,366,157 less $13,607,027). This table illustrates the cost to serve DPU's customer classes and ***does not*** represent the recommended rate changes by customer class. The recommended rate changes appear in Section 4.

Table 3-4
Comparison of Revenues by Class Versus Cost of Service[1]

Ln No	Service Class	Test Year Existing Revenue Base Rate[2]	PCA	Total	Cost of Service Requirement Base Rate	PCA	Total	Base Rate Difference ($)	%
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Residential Service	$6,341,159	$479,973	$6,821,132	$6,669,563	$479,973	$7,149,536	$(328,404)	-5.2%
2	Small Commercial (< 50 kW)	1,776,640	144,878	1,921,518	1,814,021	144,878	1,958,898	(37,381)	-2.1%
3	Large Commercial[3] (> 50 kW)	2,403,425	225,020	2,628,445	2,472,979	225,020	2,697,998	(69,554)	-2.9%
4	Commercial Time-of-Use	16,029	1,283	17,312	15,085	1,283	16,368	944	5.9%
5	Small County	152,107	12,198	164,305	179,358	12,198	191,556	(27,250)	-17.9%
6	Large County	831,862	74,446	906,308	985,189	74,446	1,059,635	(153,328)	-18.4%
7	Small Public School	36,015	2,993	39,008	47,416	2,993	50,409	(11,401)	-31.7%
8	Large Public School	493,662	41,726	535,387	624,968	41,726	666,694	(131,307)	-26.6%
9	Private Area Lighting	15,288	335	15,622	16,738	335	17,073	(1,450)	-9.5%
10	Municipal Water Production	557,989	0	557,989	557,989	0	557,989	0	0.0%
11	TOTAL SYSTEM	$12,624,176	$982,851	$13,607,027	$13,383,306	$982,851	$14,366,157	$(759,131)	-6.0%

[1] For illustrative purposes only. The actual recommended rate changes by class appear in Section 4.
[2] Includes allocation of pole rental and miscellaneous revenues.
[3] Includes Schedule 6-S Special electric service; refer to Appendix F for the associated cost of service analysis.

Five Year Projection and Future Rate Increases

As shown in Appendix A, in addition to the Test Year revenue requirements, a projection of revenue requirements was made for the FY 2016 through 2019. This projection included an analysis of future capital expenditures and an estimated bond issuance in FY 2018 (Appendix B). As recommended herein, the overall projected rate increase of 6 percent is to become effective in January 2015. To recover the total revenue requirements through June 30, 2016, it is projected that an additional rate increase of 5 percent to be effective July 2015 would be necessary.

Introduction

This Section discusses the proposed rate changes to each of DPU's rate classes. Several factors drive the rate design process. One factor is the COS results that determines the specific cost to serve each customer class. The existing rate structure and implementation schedule are also factors that impact rate design. The existing rate structure comprises what customers are used to paying. Sudden and unexpected rate increases from the current rate structure can negatively impact customers. Public policy issues can also influence the rate design and can often dictate whether one class subsidizes another, or how much emphasis is placed on fixed charges (such as the customer charge) versus variable or consumption based charges (such as the energy charge), as well as the time period over which new rates are implemented.

DPU has indicated that to the extent feasible, it would prefer to have each of the customer classes support their own costs (i.e., no subsidies between classes). However, based on direction provided by DPU and to avoid undue rate shock, the rate design limits rate increases to 9 percent within each customer class. Additionally, rate design consideration must be given to the appropriate mix between fixed and variable rate components and the period over which adjustments are phased. Rates should be designed to send proper "pricing signals" to consumers. Rate designs should take into account the degree of consumer influence over consumption behavior. However, the most critical driver for rate design is revenue adequacy: the proposed rates must result in adequate revenue to meet the financial needs of the Utility.

The proposed rates include an overall rate increase to each customer class as calculated by the COS results. The COS results indicate that more than a 9 percent increase would be required to move the County, Schools and Private Area Lighting rate classes to actual COS-based rates. Therefore, it is proposed that the rates for these customer classes move towards, but do not achieve, COS-based rates for the period of recommended rate changes in this Study. The proposed rate changes and associated analyses are measured against "base rates;" the proposed PCA (and other rate riders described herein) are not included in the percentage rate increase analysis.

Revenue Adequacy of Proposed Rates

The rates presented in this Section have been designed to recover revenues equal to the Test Year revenue requirement presented in Section 3.

Rates were designed based on billing information provided by DPU. To the extent actual billing determinants vary from that provided by DPU, or future class usage characteristics vary from historical observations, actual revenues may vary from the expected revenues as presented herein. In addition to the revenue requirements for the Test Year, a projection of the revenue requirements for FY 2016 through 2019 was made. Overall, to achieve the projected revenue requirement for the system through June 30, 2016, increases to projected rate revenue under existing rates of approximately 6 percent as of January 1, 2015 and an additional 5 percent as of July 1, 2015 are required. This phased-in approach recognizes the timing of the expected rate changes as well as projected revenue shortfalls under the current rate structure.

Rate Structure

The proposed DPU rates include a demand charge (where applicable), energy charge, and customer charge.

Table 4-1 summarizes the proposed rate increases by class effective January 2015 and July 2015. Column (c) of this table *illustrates* the cost to serve customer classes; it *does not represent* the recommended rate changes by customer class. The recommended rate changes appear in Columns (d) and (e).

Table 4-1
Summary of Cost of Service Versus Proposed Rate Increases by Customer Class

				Proposed Blended Rate Change[2]	
Ln No	Service Class	Schedule	Cost of Service Based Change[1]	January 2015	July 2015
	(a)	(b)	(c)	(d)	(e)
1	Residential Service	6-A[3]	5.2%	6.9%	5.8%
2	Small Commercial (< 50 kW)	6-G	2.1%	4.0%	3.3%
3	Large Commercial (> 50 kW)	6-K[4]	2.9%	4.6%	3.7%
4	Commercial Time-of-Use	6-T	-5.9%	0.2%	0.2%
5	Small County	6-L	17.9%	9.0%	7.2%
6	Large County	6-M	18.4%	9.0%	7.5%
7	Small Public School	6-N	31.7%	6.0%	5.0%
8	Large Public School	6-R	26.6%	6.0%	5.0%
9	Private Area Lighting	6-Q	9.5%	6.0%	5.0%
10	TOTAL SYSTEM			6.0%	5.0%

[1] For illustrative purposes not proposed as actual rate increase.
[2] Amounts reflect changes to Base Rates and do not include the impact of the proposed PCA charge currently estimated to equal $0.0077/kWh. Blended rate change includes all components of the schedules as set forth in Table 4 2.
[3] DPU offers a Residential time-of-use ("TOU") rate (Schedule 6-U). No customers are currently on this schedule.
[4] Schedule 6-S, Special electric service, is included under this schedule.

Table 4-2 shows the proposed rates for each class effective January 2015 and July 2015.

Table 4-2
Existing and Proposed Rates
by Schedule and Class

Class (a)	Schedule (b)			Unit (c)	Existing Rates (d)	Proposed Rates[1] January 2015 (e)	Proposed Rates[1] July 2015 (f)
Residential	6-A	Service Charge		($/month)	$6.43	$10.00	$12.00
		Commodity Charge		($/kWh)	$0.1028	$0.1041	$0.1075
Residential Time-of-Use	6-U	Service Charge		($/month)	$10.04	$15.00	$17.00
		Commodity Charge	Winter On-Peak	($/kWh)	$0.1269	$0.1357	$0.1424
			Winter Off-Peak	($/kWh)	$0.0891	$0.0952	$0.1000
			Summer On-Peak	($/kWh)	$0.1232	$0.1317	$0.1383
			Summer Off-Peak	($/kWh)	$0.0808	$0.0864	$0.0907
Small Commercial (< 50 kW)	6-G	Service Charge		($/month)	$18.14	$20.00	$22.00
		Commodity Charge		($/kWh)	$0.0974	$0.1007	$0.1034
Large Commercial (> 50 kW)	6-K	Service Charge		($/month)	N/A	$60.00	$65.00
		Demand Charge		($/kW)	$10.10	$10.50	$11.00
		Commodity Charge		($/kWh)	$0.06980	$0.0720	$0.0744
Commercial Time-of-Use	6-T	Service Charge		($/month)	$28.35	$30.00	$32.00
		Commodity Charge	Winter On-Peak	($/kWh)	$0.1269	$0.1269	$0.1269
			Winter Off-Peak	($/kWh)	$0.0891	$0.0891	$0.0891
			Summer On-Peak	($/kWh)	$0.1232	$0.1232	$0.1232
			Summer Off-Peak	($/kWh)	$0.0808	$0.0808	$0.0808
Small County	6-L	Service Charge		($/month)	$17.24	$20.00	$22.00
		Commodity Charge		($/kWh)	$0.0926	$0.0998	$0.1065
Large County	6-M	Service Charge		($/month)	N/A	$60.00	$65.00
		Demand Charge		($/kW)	$9.64	$10.00	$10.50
		Commodity Charge		($/kWh)	$0.0662	$0.0697	$0.0757
Small Public School	6-N	Service Charge		($/month)	$17.24	$20.00	$22.00
		Commodity Charge		($/kWh)	$0.0926	$0.0970	$0.1012
Large Public School	6-R	Service Charge		($/month)	N/A	$60.00	$65.00
		Demand Charge		($/kW)	$9.64	$10.00	$10.50
		Commodity Charge		($/kWh)	$0.0662	$0.0655	$0.0686

Class	Schedule			Unit	Existing Rates	Proposed Rates[1] January 2015	July 2015
(a)	(b)			(c)	(d)	(e)	(f)
Special Electric Service[2]	6-S	Service Charge		($/month)	$18.14	$60.00	$65.00
		Demand Charge		($/kW)	N/A	$10.50	$11.00
		Commodity Charge		($/kWh)	$0.0974	$0.0720	$0.0744
County Time-of-Use	6-V	Service Charge		($/month)	$27.00	$30.00	$32.00
		Commodity Charge	Winter On-Peak	($/kWh)	$0.1209	$0.1209	$0.1209
			Winter Off-Peak	($/kWh)	$0.0849	$0.0849	$0.0849
			Summer On-Peak	($/kWh)	$0.1174	$0.1174	$0.1174
			Summer Off-Peak	($/kWh)	$0.0770	$0.0770	$0.0770
Public School Time-of-Use	6-Y	Service Charge		($/month)	$27.00	$30.00	$32.00
		Commodity Charge	Winter On-Peak	($/kWh)	$0.1209	$0.1209	$0.1209
			Winter Off-Peak	($/kWh)	$0.0849	$0.0849	$0.0849
			Summer On-Peak	($/kWh)	$0.1174	$0.1174	$0.1174
			Summer Off-Peak	($/kWh)	$0.0770	$0.0770	$0.0770
Municipal Water Production	6-W	Service Charge		($/month)	$170.10	$180.00	$190.00
		Commodity Charge		($/kWh)	*Based on Cost of Power*		
Street and Traffic Lighting	6-P	Service Charge		($/month)	$17.24	$18.27	$19.18
		Commodity Charge		($/kWh)	$0.09260	$0.09816	$0.10307
Private Area Lighting	6-Q	Private Area Lighting - Metered			$1.08	$1.14	$1.20
		High Pressure Sodium Vapor ($ per fixture per mo.)	70 Watt Fixture – Private		$3.09	$3.28	$3.44
			70 Watt Fixture - County"		$4.01	$4.25	$4.46
			70 Watt Fixture - Res or Comm		$4.13	$4.38	$4.50
			100 Watt Fixture - Private"		$4.35	$4.61	$4.84
			100 Watt Fixture - County"		$5.21	$5.52	$5.80
			100 Watt Fixture - Res or Comm"		$5.44	$5.77	$6.06
			175 Watt Fixture - Private"		$7.27	$7.71	$8.10
			175 Watt Fixture - County"		$7.96	$8.44	$8.86
			175 Watt Fixture - Res or Comm"		$8.36	$8.86	$9.30
			400 Watt Fixture - Private"		$15.40	$16.32	$17.14
			400 Watt Fixture - County"		$15.68	$16.62	$17.45
			400 Watt Fixture - Res or Comm"		$16.48	$17.47	$18.34
Power Cost Adjustment	Rider PCA	PCA Charge		($/kWh)	N/A	$0.0077	TBD

Class	Schedule		Unit	Existing Rates	Proposed Rates[1] January 2015	July 2015
(a)	(b)		(c)	(d)	(e)	(f)
Off-System Charges	Rider OS	Off-System Charge	($/kWh)	N/A	$0.0030	$0.0032
	Rider ROS	Remote Off-System Charge	($/kWh)	N/A	$0.0080	$0.0084
Net Metering Charge[3]	Rider NEM	Residential NEM Customer Charge	($/month)	N/A	$10.00	$12.00
		Non-residential NEM Customer Charge	($/kW)	N/A	$2.88	$3.00

[1] Amounts reflect Base Rates and do not include the impact of the proposed PCA Charge currently estimated to equal $0.0077/kWh appearing under Rider PCA of this schedule.
[2] Refer to Appendix F for the associated cost of service analysis.
[3] This proposed monthly wires charge is in addition to the monthly customer charge or demand charge based on the applicable customer Schedule and does not affect the current tariff arrangement for NEM customers. Refer to Appendix E.

Cost-Based Rates

As indicated herein, DPU desires to move towards cost-based rates. At this time, however, Study results indicate that subsidies exists between rate classes. Therefore, to avoid undue rate shock and in accord with DPU policy direction, this Study has limited rate increases to 9 percent while recommending a phased approach for transitioning to full cost-based rates.

PCA Charge

The PCA mechanism is proposed to recover costs associated with the DPU cost of power purchases. The PCA is designed to be a “pass through” mechanism to allow DPU to recover changes in the cost of power without the need for a base rate increase. This type of pass through rate mechanism is widely used by municipal and investor owned utilities alike. The PCA insulates DPU from the risk of under-recovering its power costs due to variances between its budgeted forecast and the actual cost incurred.

Under this approach, the cost of power is recovered by two rate structures. The first consists of the budgeted cost of power and is included in energy portion of the base rates, and is currently set at $0.06535 per kWh. The second rate structure typically is charged as a line item on a customer’s bill. The PCA charge for this Study was estimated at $0.0077 per kWh based on the difference between the estimated and budgeted cost of power for FY 2015. As currently proposed, this PCA will be reviewed at six month intervals and reset as appropriate.

Net Metering Charge

The Net Metering account charges are meant to align with cost of service by implementing a monthly wires charge. For the purposes of this Study, a monthly wires charge of $10.00 (for January 2015) increasing to $12.00 (for July 2015) is proposed based on the COS analysis. This charge would be in addition to the monthly customer charge. The proposed monthly customer charge does not fully recover the fixed portion of the cost of distribution service. Since residential and small commercial customers do not pay a demand charge, a portion of the fixed cost to serve is recovered through the consumption-based energy charge. Net Metering customers have low and sometimes negative energy consumption. Therefore, the proposed Net Metering Charge seeks to move towards recovering the true cost of service from these customers.

This proposed Net Metering charge does not alter the current tariff arrangements governing energy-based consumption for NEM customers.[6] Refer to Appendix E.

Off-System Charges

A portion of DPU's customers are located within the LANL distribution system. LAC incurs additional costs including power losses for serving these off-system customers. A rate rider associated with the increased cost of serving off-system loads has been proposed to ensure cost recovery for serving these customers.

A portion of DPU's customers are not directly connected to the main LAC distribution system (i.e., they are not fed from LAC feeders). LAC incurs additional costs including power losses for serving these remote off-system customers. A rate rider associated with the increased cost of serving remote off-system loads has been proposed to ensure cost recovery for serving these customers.

Green Power Charges

No change is proposed.

Pro-Forma Financial Analysis

As shown in Appendix A, in addition to the Test Year revenue requirements, a projection of revenue requirements was made for the FY 2016 through 2019. This projection included an analysis of future capital expenditures and an estimated bond issuance in FY 2018 (Appendix B). The rate design considered various options for achieving DPU revenue requirements to cover projected revenue requirements from FY 2015 through 2019, including:

- One overall rate increase;
- A series of equal annual rate increases; and
- A two-phased increase effective January and July 2015.

Ultimately the two-phased rate increase consisting of 6 percent and 5 percent in January 2015 and July 2015, respectively, was recommended. This recommendation was based on the inherent uncertainties in forecasting long-term revenue requirements,

[6] Refer to DPU Rules and Regulations, Electric Rule E-5, Section E-5.03, concerning purchases of energy from Customer-Owned Qualifying Facilities.

in combination with the expectation that the recommended PCA mechanism will mitigate one of DPU's main budget risks. This proposed rate design is expected to recover projected revenue requirements through FY 2016, after which current projections for rate increases are modest (slightly over 1 percent annually).

Based on industry best practices, COS Study results should be updated on a two- to three-year basis or when known changes to operations occur. In preparation for the planned FY 2018 bond issuance, it is expected that the projected revenue requirements will be updated.

Comparisons with Neighboring Utilities

DPU's existing and proposed residential, small commercial and large commercial rates have been compared with those of neighboring utilities, including investor owned, municipal, and cooperative utilities, based on reported rates effective July 2014. In the comparison, it was found that many of the neighboring utilities' rates included a fuel adjustment or power cost adjustment similar to that proposed for DPU. The average such adjustment was approximately $0.01 per kWh. Also, most of the neighboring utilities' rates contained customer charges or service charges significantly higher than DPU's existing service charges. For example, the average residential service charge was approximately $10 per month, the average small commercial service charge was approximately $20 per month, and the average large commercial customer charge was approximately $100. It should also be noted that some utilities rates contain franchise fees and other rate riders or adders, which are not included in the comparison.

The following graphs show the comparison of DPU's existing and proposed rates with those of neighboring utilities for residential, small commercial and large commercial customers. Figure 4-1 presents a comparison of average monthly residential bills at 500 kWh. Figure 4-2 presents a comparison of average monthly small commercial bills at 1,200 kWh. Figure 4-3 presents a comparison of average monthly large commercial bills at 50kW demand and 15,000 kWh.

As shown in these comparisons, even with the proposed rate increases, DPU's estimated bills are competitive with or lower than those of neighboring utilities. Furthermore, several of neighboring utilities are in the process of seeking rate increases. In particular, Public Service of New Mexico, Inc. ("PNM") is expected to increase rates by December 2014.[7]

[7] Kevin Robinson-Avila, *PNM to File For a Rate Hike by December*, Albuquerque Journal, September 2, 2014, www.abqjournal.com/455367/news//new-costs-lower-revenue-behind-pnm-rate-hike-bid.html.

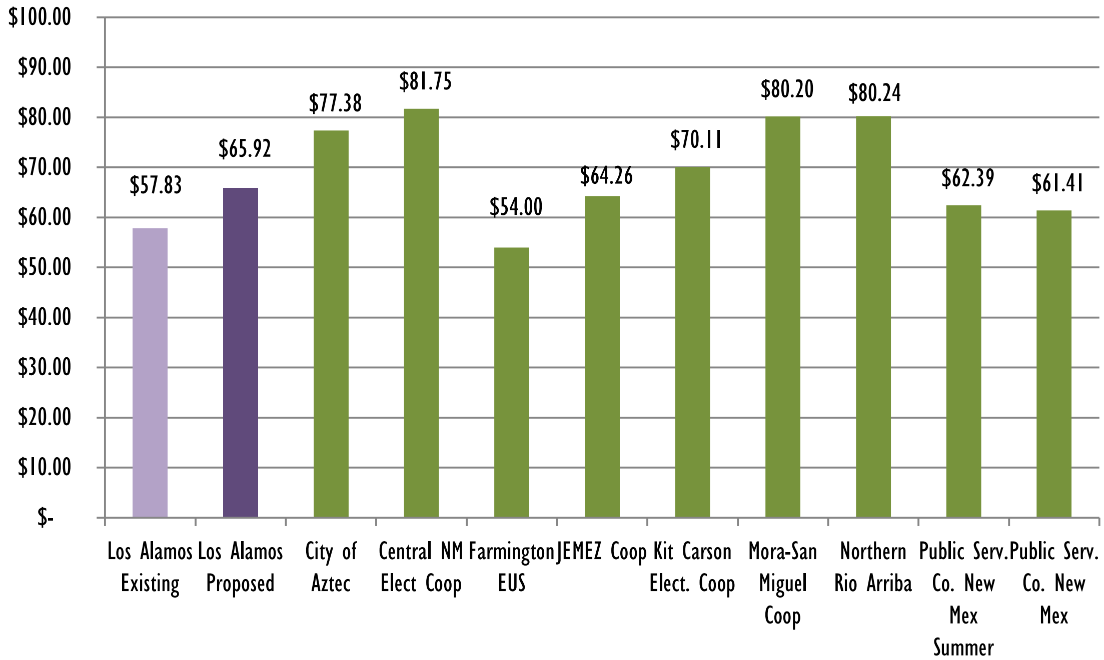

Figure 4-1 Neighboring Utility Monthly Bill Comparison Residential Bills (500 kWh)[8]

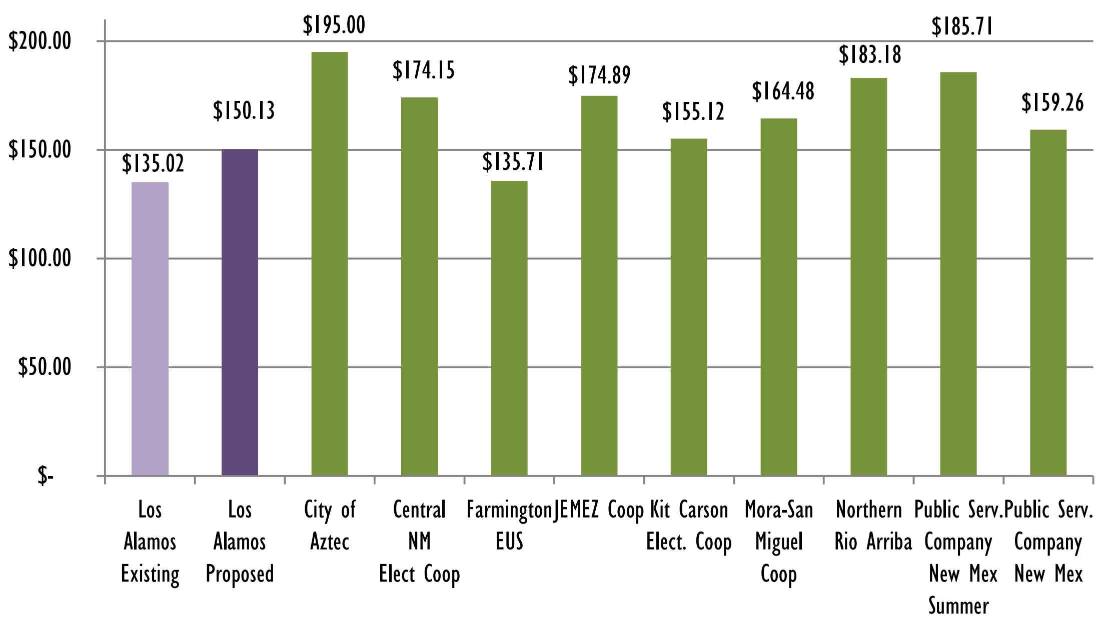

Figure 4-2 Neighboring Utility Monthly Bill Comparison Small Commercial Bills (1,200 kWh)[9]

[8] Rates for neighboring utilities effective July 2014. LAC proposed rates effective January 2015.
[9] Rates for neighboring utilities effective July 2014. LAC proposed rates effective January 2015.

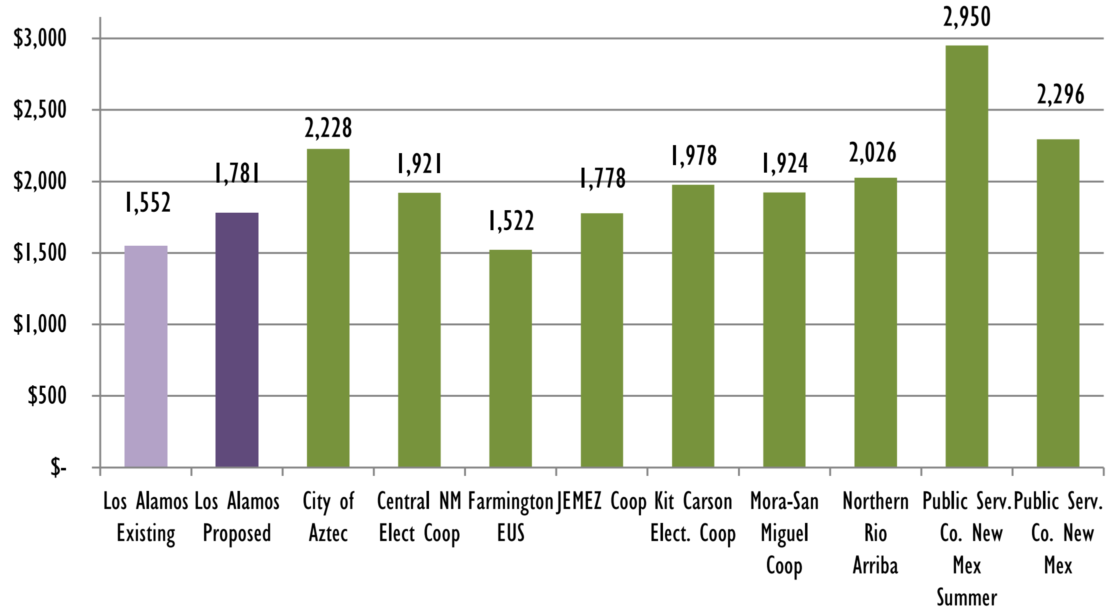

Figure 4-3 Neighboring Utility Monthly Bill Comparison Commercial Demand Bill (50 kW &15,000 kWh)[10]

[10] Rates for neighboring utilities effective July 2014. LAC proposed rates effective January 2015. City of Aztec does not have a Demand Charge until demand reaches 150 kW.

Recommendations

Based on our analysis of the expenses and revenues associated with DPU, we recommend the following:

- The Board should consider adopting the rates and recommendations as presented within this Study.
- DPU should consider moving towards cost-based rates to the extent possible within the constraint of limiting individual class rate increases to 9 percent.
- DPU should consider implementing a PCA charge to reflect changes in expenses between the actual and budgeted cost of power, to stabilize revenues, and insulate against power cost volatility. The initial PCA for the Test Year based on historic data is estimated at $0.0077 per kilowatt hour ("kWh").
- DPU should consider aligning Net Metering account charges with cost incurrence by implementing a monthly wires charge.
- DPU should consider implementing a rate rider associated with the increased cost of serving both off-system and remote off-system loads.
- DPU should consider creating a sustainable approach for maintaining its CIP by establishing cash reserves and issuing additional bonds in FY2018.[11]
- DPU should consider establishing an annual allowance replenishing its cash reserve. The Test Year includes $450,000 for this purpose.
- DPU should continue to monitor revenues and expenses and update COS results regularly, at two- to three-year intervals, and adjust rates accordingly.

Table 5-1 summarizes recommended rate increases by tariff class. Column (c) of this table *illustrates* the cost to serve customer classes; it *does not represent* the recommended rate changes by customer class. The recommended rate changes appear in Columns (d) and (e).

[11] CIP expenditures for FY 2015 through 2017 are funded from 2014 bond proceeds.

Table 5-1
Summary of Cost of Service Versus Proposed Rate Increases by Customer Class

Ln No	Service Class	Schedule	Cost of Service Based Change[1]	Proposed Blended Rate Change[2] January 2015	July 2015
	(a)	(b)	(c)	(d)	(e)
1	Residential Service	6-A[3]	5.2%	6.9%	5.8%
2	Small Commercial (< 50 kW)	6-G	2.1%	4.0%	3.3%
3	Large Commercial (> 50 kW)	6-K[4]	2.9%	4.6%	3.7%
4	Commercial Time-of-Use	6-T	-5.9%	0.2%	0.2%
5	Small County	6-L	17.9%	9.0%	7.2%
6	Large County	6-M	18.4%	9.0%	7.5%
7	Small Public School	6-N	31.7%	6.0%	5.0%
8	Large Public School	6-R	26.6%	6.0%	5.0%
9	Private Area Lighting	6-Q	9.5%	6.0%	5.0%
10	TOTAL SYSTEM			6.0%	5.0%

[1] For illustrative purposes not proposed as actual rate increase.
[2] Amounts reflect changes to Base Rates and do not include the impact of the proposed PCA charge currently estimated to equal $0.0077/kWh. Blended rate change includes all components of the schedules as set forth in Table 4-2.
[3] DPU offers a Residential time-of-use (“TOU”) rate (Schedule 6-U). No customers are currently on this schedule.
[4] Schedule 6-S, Special electric service, is included under this schedule.

Summary of Projected Revenue Requirements and Existing Rate Revenues

Fiscal Year Ending June 30

Ln. No.	Description	Proposed Budget 2015	Known and Measurable Adjustments	2015 Test Year	2016	2017	2018	2019
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Operating Expenses - Electric Distribution							
1	Cost of Power	$8,298,265	$982,851	$9,281,116	$9,551,450	$8,542,960	$8,980,231	$9,436,257
2	Supervision, Misc Direct Admin	768,556	0	768,556	774,152	785,764	797,551	809,514
3	Substation Maintenance	34,308	0	34,308	34,885	35,408	35,939	36,478
4	Switching Station Maintenance	28,308	0	28,308	28,885	29,318	29,758	30,204
5	Overhead Maintenance	385,674	0	385,674	392,003	397,883	403,851	409,909
6	Underground Maintenance	347,262	0	347,262	346,803	352,005	357,285	362,644
7	Meter Maintenance	62,616	0	62,616	63,769	64,726	65,696	66,682
8	Interdepartmental Charges	489,406	0	489,406	489,406	496,747	504,198	511,761
9	Administrative Division Allocation	819,165	0	819,165	809,376	819,358	829,489	839,773
10	In Lieu Taxes	379,236	0	379,236	379,236	416,202	432,843	440,821
11	*Total Operating Expenses*	11,612,796	982,851	12,595,647	12,869,965	11,940,371	12,436,843	12,944,045
	Other Revenue Requirements							
12	Existing Debt Service	1,426,595	(403,615)	1,022,980	1,247,405	1,244,661	1,237,793	1,239,595
13	Future Debt Service	0	0	0	0	0	367,909	367,909
14	Transfer to General Fund	564,222	0	564,222	601,433	647,584	683,363	700,516
15	Renewal and Replace Fund	0	0	0	0	0	482,600	480,000
16	Restore Cash Reserves	0	450,000	450,000	450,000	450,000	450,000	450,000
17	Other Revenue Requirements	0	0	0	0	0	0	0
18	*Total Other Revenue Requirements*	1,990,817	46,385	2,037,202	2,298,838	2,342,246	3,221,665	3,238,020
19	*Total Expenditures*	*13,603,613*	*1,029,236*	*14,632,849*	*15,168,803*	*14,282,617*	*15,658,508*	*16,182,065*
	Less Transfers and Other Revenue							
20	Transfers	0	0	0	0	0	0	0
21	Smart House Lease Revenue	15,000	0	15,000	15,000	15,000	15,000	15,000
22	Bond Federal Subsidy	58,945	8,997	67,942	67,942	67,942	67,942	67,942
23	Revenue on Recoverable Work	183,750	0	183,750	183,750	183,750	183,750	183,750
24	Total Other Revenue	257,695	8,997	266,692	266,692	266,692	266,692	266,692

Summary of Projected Revenue Requirements and Existing Rate Revenues

Fiscal Year Ending June 30

Ln. No.	Description	Proposed Budget 2015	Known and Measurable Adjustments	2015 Test Year	2016	2017	2018	2019
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
25	NET REVENUE REQUIREMENTS	13,345,918	1,020,239	14,366,157	14,902,111	14,015,925	15,391,816	15,915,372
	Projected Revenue From Sales							
26	Existing Base Rate Revenues	14,277,231	(1,653,055)	12,624,176	12,624,176	12,687,297	12,750,733	12,814,487
27	Power Cost Adjustment Revenues	0	982,851	982,851	1,253,185	203,204	598,776	1,012,895
28	Other Revenue	0	0	0	0	0	0	0
29	TOTAL REVENUES FROM SALES	14,277,231	(670,204)	13,607,027	13,877,361	12,890,500	13,349,509	13,827,381
30	Revenue Surplus or (Deficiency)	$931,313	($1,690,444)	($759,131)	($1,024,750)	($1,125,425)	($2,042,307)	($2,087,991)
31	Surplus or (Deficiency) as a Percentage of Existing Base Rate Revenues			-6.0%	-8.1%	-8.9%	-16.0%	-16.3%

Summary of Capital Improvement Plan - Expenditures and Funding Sources

Ln. No.	Projects (a)	Fiscal Year Ending June 30 2015 (b)	2016 (c)	2017 (d)	2018 (e)	2019 (f)	Total (g)
1	ELECTRIC DISTRIBUTION						
	OH REPLACEMENTS						
2	Pole and Xarm replacement (system wide); Feeders WR1,WR2, 13, 15, 16	$175,000	$175,000	$0	$0	$0	$350,000
3	PCB OH Transformer replacement (system wide);	100,000	100,000	-	-	-	200,000
4	EA4 Feeder Replacement Design (2 miles, 40 structures)	125,000	-	-	-	-	125,000
5	New TC-1-TC-2 to LASS Substation (LANL work)	-	-	500,000	-	-	500,000
6	New Feeders 13T, 15T, 16T, LAMC	-	-	500,000	-	-	500,000
7	Overhead System Replacement (poles, xarms, transformers)	-	-	300,000	-	-	300,000
8	WR1/WR2 3 PH Rebuild Phase 1	-	-	-	1,313,000	-	1,313,000
9	Circuit 15 3 PH Rebuild	-	-	-	-	750,000	750,000
10	Circuit 13 3 PH Ski Hill Rebuild	-	-	-	-	750,000	750,000
	UG REPLACEMENTS						
11	PCB UG Transformer replacement (system wide);	100,000	100,000	-	-	-	200,000
12	Replace 1400 ft. 500mcm from Chili Works to 901 Trinity	75,000	-	-	-	-	75,000
13	N. Mesa, San I Loop (3200 ft. conduit in place)	25,000	-	-	-	-	25,000
14	Install 1-6"C, 2-4"C, Meadow Lane (Overlook to Grand Canyon)	300,000	-	-	-	-	300,000
15	Replace 1200 ft. of 1/0 AL from Tsankawi to Cheyenne	-	150,000	-	-	-	150,000
16	Duct bank for Future LASS substation	-	450,000	-	-	-	450,000
17	Miscellaneous URD Replacements (replacements after power	200,000	200,000	-	-	-	400,000

Summary of Capital Improvement Plan - Expenditures and Funding Sources

Ln. No.	Projects (a)	*Fiscal Year Ending June 30* 2015 (b)	2016 (c)	2017 (d)	2018 (e)	2019 (f)	Total (g)
	outages)						
18	Los Alamos URD Replacement (cables, jboxes, pedestals)	-	-	200,000	300,000	300,000	800,000
19	White Rock URD Replacement (cables, jboxes, pedestals)	-	-	200,000	300,000	300,000	800,000
20	NM 502 Project (Equipment & Labor)	300,000	-		-	-	300,000
21	502 (DP to Tewa Loop)	190,678	-	-	-	-	190,678
22	Meadow Lane URD Replacement	-	-	-	300,000	-	300,000
23	Tsikumu Village URD Replacement	-	-	-	-	300,000	300,000
24	County Labor and Benefits	326,042	337,763	-	-	-	663,804
25	New LASS Substation	-	-	1,000,000	-	-	1,000,000
26	WR Substation Oil Retention	-	-	-	200,000	-	200,000
27	Other Capital Projects to be Identified	-	-	-	-	-	-
28	Total Proposed Expenditures	$1,916,720	$1,512,763	$2,700,000	$2,413,000	$2,400,000	$10,942,482
	Funding Sources						
29	Bond Proceeds	1,916,720	1,512,763	2,700,000	1,930,400	1,920,000	9,979,883
30	Transfers	-	-	-	-	-	-
31	Operating Revenues	-	-	-	482,600	480,000	962,600
32	Total Funding Sources	$1,916,720	$1,512,763	$2,700,000	$2,413,000	$2,400,000	$10,942,483
	Assume Bond Issue in 2018:						
33	Principal Amount					$5,000,000	
36	Future Debt Service[1]					367,909	367,909

[1] Assumes 20 year life at 4 percent.

Appendix C
Cost of Power

	kwh sold		Cost of Power		Cost of Power per FYxx 10-Year Forecast					
Fiscal Year	Actual	Approved Budget	Actual	Approved Budget	FY15	FY14	FY13	FY12	FY11	FY10
FY24					$ 9,781,269					
FY23					$ 9,377,201	$ 7,493,243				
FY22					$ 9,136,796	$ 8,729,442	$ 4,244,380			
FY21					$ 8,758,166	$ 7,499,857	$ 4,244,380	$ 8,639,315		
FY20					$ 8,989,650	$ 7,748,857	$ 4,244,380	$ 5,997,081	$ 9,877,415	
FY19					$ 8,453,406	$ 7,247,704	$ 5,001,974	$ 5,776,987	$ 9,408,193	$ 7,951,782
FY18					$ 7,997,380	$ 7,250,830	$ 5,059,415	$ 5,410,302	$ 8,930,324	$ 7,834,268
FY17					$ 7,560,109	$ 7,643,600	$ 4,726,892	$ 5,338,451	$ 8,418,678	$ 7,718,491
FY16		126,971,500			$ 8,568,599	$ 7,297,229	$ 4,622,667	$ 5,270,876	$ 8,143,228	$ 7,519,882
FY15		126,971,500		$ 8,298,265	$ 8,298,265	$ 7,299,923	$ 6,009,579	$ 5,002,325	$ 7,691,901	$ 7,237,857
FY14	121,929,697	126,971,500	$ 9,220,498	$ 9,558,523		$ 9,558,523	$ 8,131,000	$ 7,900,896	$ 8,415,381	$ 8,858,438
FY13	127,439,741	124,496,230	$ 9,374,681	$ 8,131,000			$ 8,131,000	$ 9,000,408	$ 7,927,896	$ 8,652,252
FY12	128,035,367	125,229,706	$ 9,248,169	$ 9,107,556				$ 9,107,556	$ 7,689,894	$ 8,590,307
FY11	121,486,036	123,379,021	$ 8,292,465	$ 7,576,250					$ 7,576,250	$ 8,445,767
FY10	119,587,075	125,523,416	$ 9,048,933	$ 7,997,510						$ 7,497,510
Average Cost of Power FY 12 - FY 14:				*$9,281,116*						
Budget FY 15:				*$8,298,265*						
Difference (FY 15 Test Year Adjustment)				*$982,851*						

Class Contribution to Coincident Peak

Leidos completed an analysis of DPU feeder SCADA data to develop assumptions regarding the class contribution of Residential and Commercial customers to DPU's system coincident peak (CP). The class contributions were utilized in the COS analysis to allocate demand related costs to the DPU customer classes. For the purposes of this feeder analysis, Commercial customers were assumed to represent the entirety of the non-Residential customers served by DPU. This was assumed because data for the individual Commercial classes (i.e. Small Commercial, County, etc.) was not available for review.

To complete this analysis, Leidos analyzed hourly feeder demand data for six feeders: 13, 14, 15, 16, 17, and 18. To make assumptions about the magnitude of Residential and Commercial customer class demand at CP, Leidos assumed each feeder to represent the customer class that was most prevalent in the makeup of the customers served by each feeder. For example, because the vast majority of customers on feeders 13-16, and 18 are Residential, the hourly load profiles for those feeders are assumed to represent the load profile of the entire Residential class; likewise, Feeder 17 is assumed to represent the Commercial class. The breakdown of customers by type for each feeder is provided in Table D-1 below.

Data was summed for feeders 13-15 and feeders 16-18 (the summed datasets are named TC1 and TC2, respectively) to create an aggregated feeder dataset (and customer set) that was also assumed to be indicative of the Residential class. This step was taken to smooth individual feeder data during the periodic times during which an individual feeder was shut down for maintenance and its load reduced to zero. During such times, another feeder would be used as backup and that feeder's load would spike as it was now serving customers on two feeders. Including TC1 and TC2 in the calculation of Residential demand developed additional data sets from which to determine demand contribution of the Residential and Commercial classes to the system peak.

Table D-1
Customer Breakdown by Feeder

Feeder	APT	CHRCH	CNTY	COMM	RES	SCHOO	
13	10 (0.6%)	7 (0.42%)	15 (0.89%)	122 (7.27%)	1508 (89.92%)	15 (0.89%)	Residential Feeders
14	20 (3.72%)	6 (1.12%)	16 (2.97%)	40 (7.43%)	454 (84.39%)	2 (0.37%)	
15	11 (0.59%)	5 (0.27%)	24 (1.28%)	58 (3.1%)	1758 (94.06%)	13 (0.7%)	
16	8 (0.44%)	0 (0%)	22 (1.2%)	33 (1.8%)	1770 (96.3%)	5 (0.27%)	
18	0 (0%)	0 (0%)	3 (2.27%)	29 (21.97%)	100 (75.76%)	0 (0%)	
TC1 (13-15)	41 (1%)	18 (0.44%)	55 (1.35%)	220 (5.39%)	3720 (91.09%)	30 (0.73%)	
TC2 (16-18)	8 (0.37%)	0 (0%)	39 (1.8%)	237 (10.95%)	1875 (86.65%)	5 (0.23%)	
17	0 (0%)	0 (0%)	14 (7.22%)	175 (90.21%)	5 (2.58%)	0 (0%)	Comm Feeder

Feeder 17 was selected to represent the Commercial class because of the greater proportion of Commercial customers served by that feeder. As a method to check the feeders chosen represented a given customer class' demonstrated expected behavior, Leidos sampled daily load profiles to assess the timing of peak load. For Residential feeders, daily peak demand would be expected to occur in the evening hours, and for Commercial feeders, daily peak demand would be expected to occur in the middle of the day. Figure D-1 below demonstrates an example of a Residential feeder (13) and a Commercial feeder (17) on January 14, 2013, which was the date of the monthly CP (for the System).

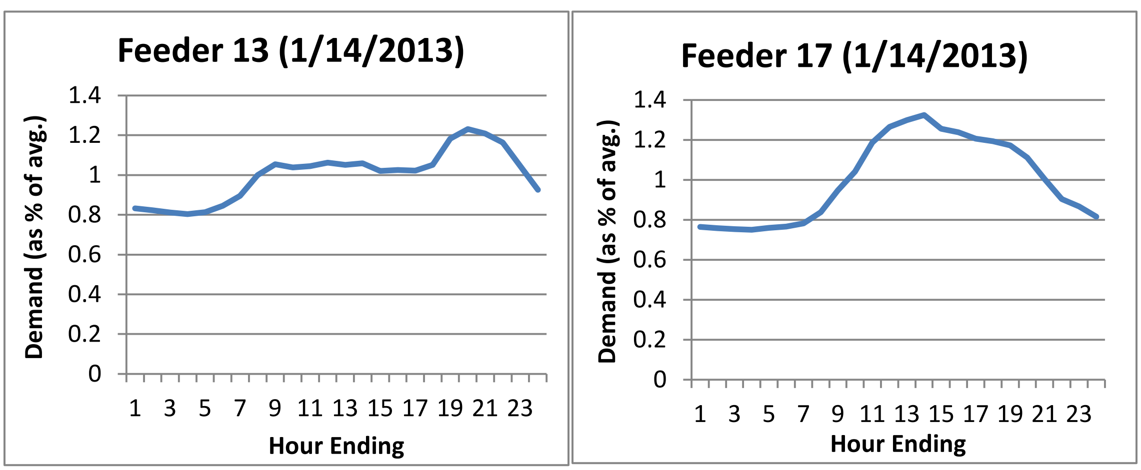

Figure D-1 Residential and Commercial Feeder Hourly Load Profile on CP Day

Feeder 13 demonstrates an evening peak (approximately hour 19 or 7:00 PM), and Feeder 17 demonstrates an afternoon peak (approximately hour 13 or 1:00 PM). The y-axis of the figures above have been adjusted on a relative scale to provide a better comparison of the shape of the Residential feeder to the shape of the Commercial feeder.

DPU supplied the date, hour, and peak demand of the system for each month's CP. This data was obtained from the Power Pool and includes the impact of LANL operations. That CP data is contained in the Table D-2 below.

Table D-2
Los Alamos Monthly CP Timing and Load[1]

System CP Time	Peak Load (MW)
1/14/13 12:00	85.36
2/27/13 12:00	81.26
3/1/13 7:00	77.22
4/30/13 13:00	73.24
5/23/13 15:00	73.01
6/27/13 17:00	79.25
7/10/2013 14:00	81.25
8/22/2013 15:00	84.63
9/3/2013 14:00	78.22
10/2/2013 15:00	76.63
11/25/2013 9:00	75.80
12/5/2013 12:00	79.81
1/23/2014 13:00	79.68
2/3/2014 10:00	77.14
3/19/2014 6:00	70.24
4/14/2014 9:00	60.51
5/28/2014 14:00	61.76
6/30/2014 14:00	68.11

[1] Peak Load includes demand contribution of LANL operation.

To estimate Residential and Commercial contribution to system CP, feeder demand at the time of each month's CP was noted. For Residential feeders, commercial load during CP was assumed to equal 11 kilowatts (kW)/customer, based on an analysis of billed demand data and the feeder analysis. This value was multiplied by the number of non-residential customers[1] on each Residential feeder, and the resulting load was subtracted from the feeder load at each month's CP. The resulting load was assumed

[1] This includes COMM, APT, CHRCH, CNTY, and SCHOO customers, as indicated in Table D-1.

to represent the total Residential load on the feeder at CP, and was divided by the number of Residential customers on the feeder to calculate the demand per Residential per month customer at CP (kW/customer). These values calculated for each Residential feeder for each month of the analysis are provided in Table D-3 below.

Table D-3
Residential Monthly Demand per Customer

	Demand per Residential Customer (kW/customer)							Weighted Average kW/Cust
	Feeder 13	Feeder 14	Feeder 15	Feeder 16	Feeder 18	TC1	TC2	
Jan-13	0.74	1.90	0.64	0.92	2.69	0.74	1.27	0.90
Feb-13	0.57	1.59	0.44	0.62	2.53	0.55	1.00	0.68
Mar-13	0.73	1.87	0.70	0.94	2.47	0.78	1.14	0.91
Apr-13	0.16	1.24	0.23	0.37	2.37	0.21	0.80	0.39
May-13	0.04	1.23	0.20	0.44	1.97	0.12	0.78	0.34
Jun-13	0.40	1.90	0.53	0.90	2.12	0.52	1.26	0.76
Jul-13	0.10	1.49	0.26	0.47	2.24	0.20	0.87	0.42
Aug-13	0.15	1.63	0.30	0.58	2.69	0.28	1.04	0.52
Sep-13	0.26	1.41	0.27	0.58	2.62	0.30	1.03	0.52
Oct-13	0.10	1.44	0.21	0.45	(0.02)	0.20	0.59	0.34
Nov-13	0.50	1.78	0.53	0.75	1.97	0.59	0.97	0.72
Dec-13	0.60	1.78	0.54	0.81	2.19	0.61	1.09	0.77
Jan-14	0.64	1.94	0.57	0.82	2.39	0.68	1.18	0.83
Feb-14	0.55	1.62	0.39	0.61	2.24	0.57	1.03	0.68
Mar-14	0.54	1.73	0.71	0.89	1.87	0.64	0.95	0.79
Apr-14	0.26	1.35	0.41	0.67	2.08	0.34	0.76	0.52
May-14	0.10	1.16	0.14	0.44	2.57	0.12	0.70	0.33
Jun-14	0.18	1.88	0.42	0.66	6.05	0.36	1.39	0.68

The weighted average of Residential demand per customer was multiplied by the total number of Residential meters across the entire system for that same month to produce the Residential class contribution to CP.

To calculate Commercial contribution to CP, the weighted average Residential kW/customer for each month was multiplied by the number of Residential customers on Feeder 17. This load was subtracted from the feeder's load at each month's CP to estimate Commercial load on the feeder at CP.[2] The feeder's Commercial load at each month's CP was divided by the number of non-Residential customers on the feeder to produce the demand per Commercial customer per month at CP (kW/Customer). This amount was multiplied by the total number of Commercial meters on DPU System each month to estimate the total demand of the Commercial class at CP.

The final results of the CP analysis are contained in the Table below.

Table D-4
Results of Feeder CP Analysis

	Class Demand at CP (MW)				*Class Contribution to CP (%)*		
	COMM	RES	SYSTEM CP[1]		COMM	RES	SUM
Jan-13	8.10	7.20	85.36		9.5%	8.4%	17.9%
Feb-13	8.00	4.96	81.26		9.8%	6.1%	16.0%
Mar-13	6.07	7.30	77.22		7.9%	9.4%	17.3%
Apr-13	9.24	3.11	73.24		12.6%	4.2%	16.9%
May-13	10.18	2.79	73.01		13.9%	3.8%	17.8%
Jun-13	7.96	6.16	79.25		10.0%	7.8%	17.8%
Jul-13	11.32	3.91	81.25		13.9%	4.8%	18.8%
Aug-13	9.79	4.28	84.63		11.6%	5.1%	16.6%
Sep-13	9.10	4.02	78.22		11.6%	5.1%	16.8%
Oct-13	9.27	2.76	76.63		12.1%	3.6%	15.7%
Nov-13	7.67	5.24	75.80		10.1%	6.9%	17.0%
Dec-13	8.49	6.19	79.81		10.6%	7.7%	18.4%
Jan-14	8.91	6.68	79.68		11.2%	8.4%	19.6%
Feb-14	7.27	5.27	77.14		9.4%	6.8%	16.2%
Mar-14	6.52	6.34	70.24		9.3%	9.0%	18.3%
Apr-14	7.36	3.94	60.51		12.2%	6.5%	18.7%
May-14	9.70	2.68	61.76		15.7%	4.3%	20.0%
				Avg.	10.6%	6.0%	16.7%

[1] System CP includes demand contribution of LANL operations.

[2] There are 14 CNTY customers on Feeder 17 which were assumed to be commercial for the purposes of calculating the Commercial contribution to CP.

Class Contribution to Non-Coincident Peak

To calculate Residential and Commercial class contribution to NCP, the Residential and Commercial feeders from the CP analysis above were analyzed. It was assumed that that feeder's demand profile was representative of the selected class' hourly load profile across the system.

Once representative feeders were selected to define the load profile of the Residential and Commercial customer classes, each feeder's peak for each month was determined to be the class NCP for that month. Coincidence factors for the non-selected customer classes were determined and use to subtract the non-selected class load from the feeder peak at the NCP for the month. Residential coincidence factors were calculated based on the average load shape of the Residential feeders. Commercial coincidence factors were calculated based on the average load shape of the Commercial feeders.

As an example, for Feeder 13, which was assumed to be a Residential feeder, the feeder's peak for a given month was calculated, but the Commercial load was removed from this load data to result in Residential load at NCP for the month. Based on the feeder CP analysis, an assumption of how Commercial load on the CP time and day related to Commercial load at the feeder's NCP time and day. A coincidence factor was calculated to compare Feeder 17 (a Commercial feeder) load at CP time on Feeder 13's NCP day to Feeder 17's load at Feeder 13's NCP time and NCP day. This coincidence factor was multiplied by the Commercial load on Feeder 13 at CP time to yield Commercial load on Feeder 13 at Feeder 13 NCP. This amount was subtracted from the feeder load at NCP time and day to yield Residential demand at NCP. This amount was divided by the number of Residential customers on the feeder to produce Residential load per customer at NCP. This process was repeated for all other analyzed feeders to produce the demand per customer at class NCP.

The results of this NCP analysis are contained in the Table below.

Table D-5
Results of Feeder NCP Analysis

	NCP by Class (MW)				*NCP by Class (%)*		
	COMM	RES	OTHER	Sum NCP (MW)	COMM	RES	SUM
Jan-13	8.54	11.48	-	20.02	42.7%	57.3%	100.0%
Feb-13	8.30	9.51	-	17.82	46.6%	53.4%	100.0%
Mar-13	8.49	7.82	-	16.31	52.1%	47.9%	100.0%
Apr-13	9.24	7.23	-	16.47	56.1%	43.9%	100.0%
May-13	10.38	10.89	-	21.26	48.8%	51.2%	100.0%
Jun-13	11.58	7.10	-	18.68	62.0%	38.0%	100.0%
Jul-13	12.14	13.90	-	26.04	46.6%	53.4%	100.0%
Aug-13	14.33	12.11	-	26.44	54.2%	45.8%	100.0%
Sep-13	10.12	7.43	-	17.56	57.7%	42.3%	100.0%

	NCP by Class (MW)					*NCP by Class (%)*		
	COMM	RES	OTHER	Sum NCP (MW)		COMM	RES	SUM
Oct-13	9.81	7.36	-	17.17		57.1%	42.9%	100.0%
Nov-13	7.94	9.34	-	17.28		46.0%	54.0%	100.0%
Dec-13	8.62	11.58	-	20.20		42.7%	57.3%	100.0%
Jan-14	9.25	21.04	-	30.28		30.5%	69.5%	100.0%
Feb-14	8.56	10.76	-	19.32		44.3%	55.7%	100.0%
Mar-14	8.42	7.86	-	16.28		51.7%	48.3%	100.0%
Apr-14	8.16	6.67	-	14.83		55.0%	45.0%	100.0%
May-14	10.06	6.31	-	16.37		61.4%	38.6%	100.0%
					Avg.	50.3%	49.7%	

LAC Code Ordinance No. 02-252

INCORPORATED COUNTY OF LOS ALAMOS CODE ORDINANCE NO. 02-252

AN ORDINANCE AMENDING CHAPTER 40, ARTICLE III, SECTIONS 40-121, 40-122, AND 40-123 RELATING TO ELECTRIC RATE SCHEDULES, CUSTOMER SERVICE CHARGES, AND ELECTRIC ENERGY CHARGES, AND ADDING NEW SECTIONS 40-126, OFF-SYSTEM RIDERS, AND 40-127, POWER COST ADJUSTMENT

THE INCORPORATED COUNTY OF LOS ALAMOS HEREBY ORDAINS:

Section 1. Sections 40-121, 40-122 and 40-123 of the Code of the Incorporated County of Los Alamos are amended to read as follows:

Sec. 40-121. Schedules.

(a) Residential rate service schedule 6-A is applicable only for normal domestic light and power use in individual residences, dwelling units, and individual apartments, where each unit is separately metered. All service shall be delivered through a single set of service wires at a single service location and measured by one meter.

(b) Small commercial (less than 50 kilowatts per month) rate service schedule 6-G is applicable for commercial lighting, small power and other commercial, business, professional and small industrial loads. All service shall be delivered through a single set of service wires at a single service location and measured by one meter. The customer's monthly demand shall be less than 50 kilowatts (kW), but excludes customers to whom service is applicable under another rate service schedule. When a customer under this schedule establishes a demand of 50 kilowatts or greater for two consecutive months, the large commercial (50 kilowatts per month or greater) rate schedule 6-K will be charged for the current billing month plus a minimum of 11 succeeding billing months.

(c) Large commercial (50 kilowatts per month or greater) rate service schedule 6-K is applicable to all customers with a demand over 50 kilowatts per month or greater. All service shall be delivered through a single set of service wires at a single service location and measured by one meter, but excludes those customers to whom service is applicable under another rate schedule.

(d) Small county (less than 50 kilowatts per month), schedule 6-L, and small public schools (less than 50 kilowatts per month), schedule 6-N, are applicable, respectively, to power used by the incorporated county and the public schools. All service shall be provided by single set of service wires at a single service location at one point of delivery, measured by one meter. The customer's demand for the month shall be less than 50 kilowatts, but excludes those customers to whom service is applicable under another rate schedule. When a customer under this schedule establishes a demand of 50 kilowatts or greater for two consecutive months, the large county (50 kilowatts per months or greater) schedule 6-M, or the large public schools (50 kilowatts per month or greater) schedule 6-R, rate schedule will be charged for the current billing month plus a minimum of 11 succeeding billing months.

(e) Large county (50 kilowatts per month or greater), schedule 6-M, and large public schools (50 kilowatts per month or greater) schedule 6-R, are applicable, respectively, to the incorporated county of Los Alamos and the public schools. All service shall be provided by a single set of service wires at a single service location supplied at one point of delivery, measured by one meter, and the customer's demand for the month shall be 50 kilowatts or greater, but excludes those customers to whom service is applicable under another rate schedule.

(f) Municipal street and traffic light service rate schedule 6-P is applicable to electric service provided to the incorporated county for street and traffic lights.

(g) Area lighting service schedule 6-Q is applicable to all customers for private area lighting service.

(h) ~~Seasonal electric service schedule 6-S is applicable to winter recreational facilities whose business operations occur during the months of October through April (season) where the entire requirements for service for the facility are supplied at one point of delivery and measured by one meter, but excludes those customers to whom service is applicable under another rate schedule.~~ Special electric service schedule 6-S is applicable to large power user with an annual load factor less than 20 percent and a connected load greater than 50 kilowatt. Annual load factor is calculated as average demand divided by peak demand to be calculated in January for the prior twelve months.

(i) Municipal water production system rate schedule 6-W is applicable to electric service provided to the incorporated county for metered bulk water pumping.

(j) Commercial time-of-use rate schedule 6-T is applicable to each commercial customer otherwise subject to rate service schedules 6-G or 6-K who has given at least 15-days' notice to the utilities department that it wishes to obtain electric service under this rate service schedule. Any customer requesting service under this schedule shall be required to remain on this schedule for no less than 12 consecutive months before notice is given to return to rate service schedule 6-G or 6-K.

(k) Residential time-of-use rate schedule 6-U is applicable to each residential customer otherwise subject to rate service schedules 6-A who has given at least 15-days' notice to the utilities department that it wishes to obtain electric service under this rate service schedule. Any customer requesting service under this schedule shall be required to remain on this schedule for no less than 12 consecutive months before notice is given to return to rate service schedule 6-A.

(l) County time-of-use rate schedule 6-V is applicable to each county customer otherwise subject to rate service schedules 6-L or 6-M; public schools time-of-use rate schedule 6-Y is applicable to each public school customer otherwise subject to rate service schedules 6-N or 6-R, who has given at least 15-days' notice to the utilities department that it wishes to obtain electric service under this rate service schedule. Any customer requesting service under schedule 6-V or 6-Y shall be required to remain on this schedule for no less than 12 consecutive months before notice is given to return to rate service schedule 6-L, 6-M, 6-N, 6-R.

Sec. 40-122. Electric customer service charges.

Customer service charges are to be applied as follows:

(1) To each customer billed under rate service schedule 6-A, ~~$6.43~~$10.00 per month per meter for billings processed after January 1, 2015 and $12.00 per month per meter for billings processed after July 1, 2015.

(2) To each customer billed under rate service schedules 6-G ~~and 6-S,~~ ~~$18.14~~ $20.00 per month per meter for billings processed after January 1, 2015 and $22.00 per month per meter for billings processed after July 1, 2015.

(3) To each customer billed under rate service schedules 6-L~~,~~ and 6-N ~~and 6-P, $17.24~~ $20.00 per month per meter for billings processed after January 1, 2015 and $22.00 per month per meter for billings processed after July 1, 2015.

(4) To each customer billed under rate service schedule 6-W, ~~$170.10~~ $180.00 per month plus charges for energy and demand for billings processed after January 1, 2015 and $190.00 per month plus charges for energy and demand for billings processed after July 1, 2015.

(5) To each customer billed under rate service schedule 6-T, ~~$28.35~~$30.00~~,~~; service schedule 6-U, ~~$10.04~~$15.00~~,~~; service schedules 6-V and 6-Y, ~~$27.00~~$30.00 per month per meter for billings processed after January 1, 2015. To each customer billed under rate service schedule 6-T, $32.00 service schedule 6-U, $17.00 service schedules 6-V and 6-Y, $32.00 per month per meter for billings processed after July 1, 2015.

(6) To each customer billed under rate service schedule 6-P, $18.27 per month per meter for billings processed after January 1, 2015 and $19.18 per month per meter for billings processed after July 1, 2015.

(7) To each customer billed under rate service schedule 6-S, $60.00 per month per meter for billings processed after January 1, 2015 and $65.00 per month per meter for billings processed after July 1, 2015.

(8) To each customer billed under rate service 6-K, 6-M and 6-R, $60.00 per month per meter for billings processed after January 1, 2015 and $65.00 per month per meter for billings processed after July 1, 2015.

(9) Net Metering Facilities Charge.

a. Net metering is defined as a system in which solar panels or other distributed generation are connected to Los Alamos County's power grid and is capable of transferring surplus power onto the grid, allowing customers to offset the cost of power drawn from the utility.

b. In addition to customer services charges applicable to the appropriate rate class each net metering residential customer shall be charged $10.00 per month per meter for billings processed after January 1, 2015 and $12.00 per month per meter for billings processed after July 1, 2015. In addition to customer services charges applicable to the appropriate rate class to each net metering non-residential customer shall be charged $2.88 per month per connected kw of distributed generation for billings processed after January 1, 2015 and $3.00 per month per connected kw of distributed generation for billings processed after July 1, 2015.

Sec. 40-123. Electric energy charges.

In addition to applicable customer service charges, electric energy charges and demand charges are to be applied as follows:

(1) *Schedule 6-A.* Each customer billed under rate service schedule 6-A shall be charged ~~$0.1028~~$0.1041 per kilowatt hour for billings processed after January 1, 2015 and $0.1075 per kilowatt hour for billings processed after July 1, 2015. In addition to the charge authorized by this subsection, the following optional charges are authorized subject to rules promulgated by the department necessary to carry out its provisions:

a. *Fixed option.* Customers billed under rate service schedule 6-A may choose to subscribe monthly to 100 kWh blocks of green power at a rate of $0.5000 per block. The total of the subscribed blocks shall not exceed 90 percent of that customer's minimum monthly electric consumption during the previous 12 months.

b. *Variable option.* Customers billed under rate service schedule 6-A may choose to subscribe to green power for 90 percent of their monthly electric consumption. Such consumption shall be billed at the additional rate of $0.0050 per kilowatt hour.

(2) *~~Schedules~~Schedule 6-G~~ and 6-S~~.* Each customer billed under rate service ~~schedules~~schedule 6-G~~ or 6-S~~ shall be charged ~~$0.0974~~$0.1007 per kilowatt hour for billings processed after January 1, 2015 and $0.1034 per kilowatt hour for billings processed after July 1, 2015. In addition to the charge authorized by this subsection, the following optional charges are authorized subject to rules promulgated by the department necessary to carry out its provisions:

a. *Fixed option.* Customers billed under rate service schedule 6-G only, may choose to subscribe monthly to 100 kWh blocks of green power at a rate of $0.5000 per block. The total of the subscribed blocks shall not exceed 90 percent of that customer's minimum monthly electric consumption during the previous 12 months.

b. *Variable option.* Customers billed under rate service schedule 6-G~~ or 6-S~~ may choose to subscribe to green power for 90 percent of their monthly electric consumption. Such consumption shall be billed at the additional rate of $0.0050 per kilowatt hour.

(3) *~~Schedules~~Schedule 6-L~~, 6-N and 6-P~~.* Each customer billed under rate service ~~schedules~~schedule 6-L~~, 6-N and 6-P~~ shall be charged ~~$0.0926~~$0.0998 per kilowatt hour for billings processed after January 1, 2015 and $0.1065 per kilowatt hour for billings processed after July 1, 2015. In addition to the charge authorized by this

subsection, the following optional charges for rate service ~~schedules~~schedule 6-L ~~and 6-N~~ are authorized subject to rules promulgated by the department necessary to carry out its provisions:

a. *Fixed option.* Customers billed under rate service schedule 6L ~~or 6N~~ may choose to subscribe monthly to 100 kWh blocks of green power at a rate of $0.5000 per block. The total of subscribed blocks shall not exceed 90 percent of that customer's minimum monthly electric consumption during the previous 12 months.

b. *Variable option.* Customers billed under rate service schedule 6L ~~or 6N~~ may choose to subscribe to green power for 90 percent of their monthly electric consumption. Such consumption shall be billed at the additional rate of $0.0050 per kilowatt hour.

(4) *Schedule 6-N.* Each customer billed under rate service schedule 6-N shall be charged $0.0970 per kilowatt hour for billings processed after January 1, 2015 and $0.1012 per kilowatt hour for billings processed after July 1, 2015. In addition to the charge authorized by this subsection, the following optional charges for rate service schedules 6-L and 6-N are authorized subject to rules promulgated by the department necessary to carry out its provisions:

a. *Fixed option.* Customers billed under rate service schedule 6N may choose to subscribe monthly to 100 kWh blocks of green power at a rate of $0.5000 per block. The total of subscribed blocks shall not exceed 90 percent of that customer's minimum monthly electric consumption during the previous 12 months.

b. *Variable option.* Customers billed under rate service schedule 6N may choose to subscribe to green power for 90 percent of their monthly electric consumption. Such consumption shall be billed at the additional rate of $0.0050 per kilowatt hour.

(5) *Schedule 6-P.* Each customer billed under rate service schedule 6-P shall be charged $0.09816 per kilowatt hour for billings processed after January 1, 2015 and $0.10307 per kilowatt hour for billings processed after July 1, 2015.

~~(4)~~(6) *Schedule 6-K.* Each customer under rate service schedule 6-K shall be charged ~~$10.0980~~$10.50 per kW of peak demand plus ~~$0.0698~~$0.0720 per kilowatt hour for billings processed after January 1, 2015 and $11.00 per kW of peak demand plus $0.0744 per kilowatt hour for billings processed after July 1, 2015. In addition to the charge authorized by this subsection, the following optional charges are authorized subject to rules promulgated by the department necessary to carry out its provisions:

Customers billed under rate service schedule 6-K may choose to subscribe to green power for one percent, two percent, three percent, five percent, ten percent, 50 percent or 90 percent of their monthly energy electric consumption. Such consumption shall be billed at the additional rate of $0.0050 per kilowatt hour.

~~(5)~~(7) ~~*Schedules*~~*Schedule 6-M~~ and 6-R~~.* Each customer under rate service ~~schedules~~schedule 6-M~~ or 6-R~~ shall be charged ~~$9.6444~~$10.00 per kW of peak demand plus ~~$0.0662~~$0.0697 per kilowatt hour for billings processed after January 1, 2015 and $10.50 per kW of peak demand plus $0.0757 for billings processed after July 1, 2015. In addition to the charge authorized by this subsection, the following optional charges for rate service ~~schedules~~schedule 6-M~~ and 6-R~~ are authorized subject to rules promulgated by the department necessary to carry out its provisions:

Customers billed under rate service schedule 6-M~~ or 6-R~~ may choose to subscribe to green power for one percent, two percent, three percent, five percent, ten percent, 50 percent or 90 percent of their monthly energy electric consumption. Such consumption shall be billed at the additional rate of $0.0050 per kilowatt hour.

(8) *Schedule 6-R.* Each customer under rate service schedule 6-R shall be charged $10.00 per kW of peak demand plus $0.0655 per kilowatt hour for billings processed after January 1, 2015 and $10.50 per kW of peak demand plus $0.0686 per kilowatt hour for billings processed after July 1, 2015. In addition to the charge authorized by this subsection, the following optional charges for rate service schedule 6-R are authorized subject to rules promulgated by the department necessary to carry out its provisions:

Customers billed under rate service schedule 6-R may choose to subscribe to green power for one percent, two percent, three percent, five percent, ten percent, 50 percent or 90 percent of their monthly energy electric consumption. Such consumption shall be billed at the additional rate of $0.0050 per kilowatt hour.

~~(6)~~(9) *Schedule 6-Q.*

a. All metered customers under rate service schedule 6-Q shall be billed ~~$1.0800~~$1.14 per light per month in addition to metered charges for billings processed after January 1, 2015 and $1.20 per light per month in addition to metered charges for billings processed after July 1, 2015.

b. Unmetered customers under rate service schedule 6-Q shall be billed:

1. For each 70-watt high pressure sodium lamp which is privately owned and maintained, ~~$3.09~~$3.28 per month for billings processed after January 1, 2015 and $3.44 per month for billings processed after July 1, 2015.

2. For each 70-watt high pressure sodium lamp for county or public school use, ~~$4.01~~$4.25 per month for billings processed after January 1, 2015 and $4.46 per month for billings processed after July 1, 2015.

3. For each 70-watt high pressure sodium lamp for residential or commercial use, ~~$4.13~~$4.38 per month for billings processed after January 1, 2015 and $4.50 per month for billings processed after July 1, 2015.

4. For each 100-watt high pressure sodium lamp which is privately owned and maintained, ~~$4.35~~$4.61 per month for billings processed after January 1, 2015 and $4.84 per month for billings processed after July 1, 2015.

5. For each 100-watt high pressure sodium lamp for county or public school use, ~~$5.21~~$5.52 per month for billings processed after January 1, 2015 and $5.80 per month for billings processed after July 1, 2015.

6. For each 100-watt high pressure sodium lamp for residential or commercial use, ~~$5.44~~$5.77 per month for billings processed after January 1, 2015 and $6.06 per month for billings processed after July 1, 2015.

7. For each 175-watt mercury vapor lamp which is privately owned and maintained, ~~$7.27~~$7.71 per month for billings processed after January 1, 2015 and $8.10 per month for billings processed after July 1, 2015.

8. For each 175-watt mercury vapor lamp for county or public school use, ~~$7.96~~$8.44 per month for billings processed after January 1, 2015 and $8.86 per month for billings processed after July 1, 2015.

9. For each 175-watt mercury vapor lamp for residential or commercial use, ~~$8.36~~$8.86 per month for billings processed after January 1, 2015 and $9.30 per month for billings processed after July 1, 2015.

10. For each 400-watt mercury vapor lamp which is privately owned and maintained, ~~$15.40~~$16.32 per month for billings processed after January 1, 2015 and $17.14 per month for billings processed after July 1, 2015.

11. For each 400-watt mercury vapor lamp for county or public school use, ~~$15.68~~$16.62 per month for billings processed after January 1, 2015 and $17.45 per month for billings processed after July 1, 2015.

12. For each 400-watt mercury vapor lamp for residential or commercial use, ~~$16.48~~$17.47 per month for billings processed after January 1, 2015 and $18.34 per month for billings processed after July 1, 2015.

~~(7)~~(10) *Schedule 6-W.* Customers under rate service schedule 6-W shall be billed:

a. A monthly energy charge equal to the sum of the actual LAC/DOE electric resource pool unit cost for the applicable month plus ~~$0.16~~$.016 per ~~times the kWh~~ ~~consumption~~ kilowatt hour for the water production system; and

b. A monthly demand charge equal to the actual LAC/DOE electric resource pool demand cost per kW times the water production system kW demand coincident with the LAC/DOE electric resource pool demand for the applicable month.

~~(8)~~(11) *Schedule 6-T ~~and 6-U~~.*

a. Customers under rate service schedule 6-T ~~and 6-U~~ shall be billed:

1. During the winter season beginning at 12:00 midnight on October 1 through 11:59 p.m. on April 30 of each year at an on-peak rate of $0.1269 per kWh and an off-peak rate of $0.0891 per kWh; and

2. During the summer season beginning at 12:00 midnight on May 1 through 11:59 p.m. on September 30 of each year at an on-peak rate of $0.1232 per kWh and an off-peak rate of $0.0808 per kWh.

b. For purposes of this rate service schedule 6-T ~~and 6-U~~, on-peak hours are defined for the winter season as beginning at 9:00 a.m. and ending at 10:00 p.m. each weekday. On-peak hours are defined for the summer season as beginning at 9:00 a.m. and ending at 8:00 p.m. each weekday. Off-peak hours for winter and summer seasons are defined as any hours not otherwise defined as on-peak.

(12) *Schedule 6-U.*

a. Customers under rate service schedule 6-U shall be billed:

1. During the winter season beginning at 12:00 midnight on October 1 through 11:59 p.m. on April 30 of each year at an on-peak rate of $0.1357 per kWh and an off-peak rate of $0.0952 per kWh for billings processed after January 1, 2015 and during the winter season beginning at 12:00 midnight on October 1 through 11:59 p.m. on April 30 of each year at an on-peak rate of $0.1424 per kWh and an off-peak rate of $0.10 per kWh for billings processed after July 1, 2015; and

2. During the summer season beginning at 12:00 midnight on May 1 through 11:59 p.m. on September 30 of each year at an on-peak rate of $0.1317 per kWh and an off-peak rate of $0.0864 per kWh for billings processed after January 1, 2015 and during the winter season beginning at 12:00 midnight on October 1 through 11:59 p.m. on April 30 of each year at an on-peak rate of $0.1383 per kWh and an off-peak rate of $0.0907 per kWh for billings processed after July 1, 2015; and

b. For purposes of this rate service schedule 6-U, on-peak hours are defined for the winter season as beginning at 9:00 a.m. and ending at 10:00 p.m. each weekday. On-peak hours are defined for the summer season as beginning at 9:00 a.m. and ending at 8:00 p.m. each weekday. Off-peak hours for winter and summer seasons are defined as any hours not otherwise defined as on-peak.

~~(9)~~(13) *Schedule 6-V and 6-Y.*

a. Customers under rate service schedule 6-V and 6-Y shall be billed:

1. During the winter season beginning at 12:00 midnight on October 1 through 11:59 p.m. on April 30 of each year at an on-peak rate of $0.1209 per kWh and an off-peak rate of $0.0849 per kWh; and

2. During the summer season beginning at 12:00 midnight on May 1 through 11:59 p.m. on September 30 of each year at an on-peak rate of $0.1174 per kWh and an off-peak rate of $0.0770 per kWh.

b. For purposes of this rate service schedule 6-V and 6-Y, on-peak hours are defined for the winter season as beginning at 9:00 a.m. and ending at 10:00 p.m. each weekday. On-peak hours are defined for the summer season as beginning at 9:00 a.m. and ending at 8:00 p.m. each weekday. Off-peak hours for winter and summer seasons are defined as any hours not otherwise defined as on-peak.

(14) *Schedule 6-S.* Each customer under rate service schedule 6-S shall be charged $10.50 per kW of peak demand plus $0.0720 per kilowatt hour for billings processed after January 1, 2015 and $11.00 per kW of peak demand plus $0.0744 per kilowatt hour for billings processed after July 1, 2015.

Section 2. The Los Alamos County Code of Ordinances is amended by adding a new section to be numbered 40-126, which section reads as follows:

Sec. 40-126. Off-System riders.

In addition to applicable electric energy and demand charges, off-system rider charges are applied as follows:

(a) Off-System Charge. Each nonresidential customer of the county served directly through the Los Alamos National Laboratory distribution system, $0.0030 per kilowatt hour shall be charged for billings processed after January 1, 2015 and $0.0032 per kilowatt hour for billings processed after July 1, 2015.

(b) Remote Off-System Charge. For each customer located more than three (3) miles from the County's contiguous distribution systems in Los Alamos Townsite or White Rock and served by Los Alamos County, $0.0080 per kilowatt hour shall be charged for billings processed after January 1, 2015 and $0.0084 per kilowatt hour for billings processed after July 1, 2015.

Section 3. The Los Alamos County Code of Ordinances is amended by adding a new section to be numbered 40-127, which section reads as follows:

Sec. 40-127. Power cost adjustment.

(a) In addition to applicable customer service charges, electric energy charges and demand charges (if applicable), customers billed under rate service schedules 6-A, 6-G, 6-K, 6-L, 6-M, 6-N, 6-R, 6-S, 6-T, 6-U, 6-V and 6-Y will also be subject to a Power Cost Adjustment of $0.0077 per kilowatt hour for billings processed after January 1, 2015.

(b) The cost of power will be reviewed in January and July for the prior six months and the associated Power Cost Adjustment will be recalculated. The resulting increase or decrease in the Power Cost Adjustment will be effective on the billing processed after January 1 and July 1 of each year.

(c) Should the Power Cost Adjustment exceed $0.99 per kilowatt hour, the billed Power Cost Adjustment will not change until the Power Cost Adjustment rate is approved by an ordinance of the council.

(d) The provisions of section 40-126 expire on December 31, 2017 unless reenacted through an ordinance approved by the county council.

Section 3. Effective Date. This ordinance shall become effective January 1, 2015.

Section 4. Severability. Should any section, paragraph, clause or provision of this ordinance, for any reason, be held to be invalid or unenforceable, the invalidity or unenforceability of such section, paragraph, clause or provision shall not affect any of the remaining provisions of this ordinance.

Section 5. Repealer. All ordinances or resolutions, or parts thereof, inconsistent herewith are hereby repealed only to the extent of such inconsistency. This repealer shall not be construed to revive any ordinance or resolution, or part thereof, heretofore repealed.

ADOPTED this ____ day of ______________, 2014.

COUNCIL OF THE INCORPORATED COUNTY OF LOS ALAMOS

____

Geoff Rodgers
Council Chair

ATTEST: (SEAL)

____

Sharon Stover
Los Alamos County Clerk

DPU Rules and Regulations, Electric, Rule E-5

RULES AND REGULATIONS
ELECTRIC (E)
RULE E-5
INTERCONNECTION - CONNECTION WITH COGENERATION AND SMALL POWER PRODUCERS

E-5.01 GENERAL

The purpose of this rule is to provide for the purchase of energy from customers of the Utility meeting the interconnection requirements for Qualifying Facilities.

All interconnections with the electric distribution system require prior written approval by the Utility department of Engineering, the completion of the Interconnection Agreement (see Appendix I) and the payment of all applicable fees.

E-5.02 DEFINITIONS

As used in this rule, unless otherwise specified:

A. "Qualifying Facility" means a cogeneration or a small power production facility which has a design capacity of 10 kW or less and meets the criteria for qualification contained in 18 C.F.R. Section 292.203, or such other criteria as may be reasonably prescribed by rule by the Utility.
B. "Customer" means a customer of Utility who owns or operates a Qualifying Facility.

E-5.03 PURCHASES OF ENERGY FROM CUSTOMER-OWNED QUALIFYING FACILITIES

Utility may purchase up to 2000 kW of capacity, in the aggregate, of solar, wind, or other renewable energy from customer-owned Qualifying Facilities within the service area of Utility. The maximum purchase from any residential customer is limited to the lesser of 10 kW or the capacity available on the transformer serving the customer. The maximum purchase from all other customers is limited to a lesser of 100KW or the capacity of the transformer serving that customer.

E-5.04 PROCEDURE FOR INTERCONNECTION

A. General. Unless otherwise specifically provided for in a special interconnection agreement negotiated with the Utility, the procedures for standard interconnection agreements and interconnections set forth in this rule shall be followed.
B. Conditions of interconnection. Utility shall interconnect with any Qualifying Facility which:

   1) is covered by a signed standard or special interconnection agreement between the customer and Utility, which is consistent with the approved form of agreement set forth in this rule;
   2) is capable of operating safely and commencing the delivery of power into the Electric Utility's system, including but not limited to protection from over currents, fault currents, frequency disturbances, and voltage differentials;
   3) has met all applicable safety and performance standards established by local and national electrical codes, including the most recent National Electrical Code (NEC), the most recent National Electrical Safety Code (NESC), the Institute of Electrical and Electronics Engineers (IEEE), and Underwriters Laboratories, as well as all applicable safety and performance standards adopted by rule of the Utility that are necessary to protect public safety and system reliability;
   4) was constructed in accordance with a design that has been submitted to and approved by the Utility;
   5) has been installed by a licensed electrician who has obtained all required permits and inspections.

Revised May 17, 2006

C. Isolation transformers and disconnection switches. Utility shall not require an isolation transformer for interconnection of single phase photovoltaic Facilities meeting the requirements of Subsection B of this section. If Utility determines that an isolation transformer is required for other types of Qualifying Facilities, the Utility may require the transformer by providing written notice to the Customer at the time of application. The customer shall have installed and maintained in proper operating condition, at Customer's sole expense, a separate load break disconnect switch as a visible means of disconnection, unless the customer and Utility shall agree in writing to the use of the meter as a visible means of disconnecting single-phase photovoltaic facilities.

D. Meters. A single reversible meter shall be used unless an alternate metering arrangement is agreed to by the customer and Utility. The register shall be used to measure the amount of energy delivered by the Utility to the customer and will reverse enabling measurement of the amount of energy which is produced by the Qualifying Facility and delivered to Utility. The customer shall be required to pay the cost of the required metering equipment with the exception of the meter. Within twenty (20) days of receiving notification from the customer of the intent to interconnect, the Utility will notify the customer of any metering costs. Charges for special metering costs shall be paid by the customer, or arrangements for payment agreed to between the customer and Utility, prior to the Utility authorizing interconnected operation.

E. Liability insurance. Customers are urged to obtain adequate liability insurance to cover risks, liabilities, and consequences, which may arise as a result of interconnection with a utility system. For good cause shown, the Utility may require a customer to obtain general liability insurance.

F. Provision of interconnection agreement. The Utility shall provide a standard interconnection agreement within ten (10) days of a request for such form. When a customer enters into an interconnection agreement pursuant to this rule, the Utility shall provide the customer with a copy of that interconnection agreement. Utility shall provide a blank form of application for interconnection within ten (10) days of a written request for such form. The Utility shall maintain a file of each interconnection agreement entered into by the Utility.

E-5.05 METERING CALCULATION

Utility shall calculate each customer's bill for the billing period using the standards and conditions stated in this section.

A. Applicable rate. Customers shall be billed for service in accordance with the rate structure and monthly charges that the customer would be assigned if the customer had not interconnected a Facility with Utility's system, plus any incremental cost of required metering equipment. Energy produced or consumed on a monthly basis shall be measured in accordance with standard net metering practice. Power supplied to the customer will be billed at the customer's applicable rate under Utility's current rate schedule.

B. Credit for excess energy. If electricity generated by the customer exceeds the electricity supplied by the Utility during a billing period, the Utility shall credit the customer through a balancing account for the excess kilowatt-hours generated, by crediting the customer for the net energy supplied to the Utility. The rate paid or credited to the Customer will be the Utility's average cost for capacity and energy from the Los Alamos County Resource Pool for the previous year. The Customers balancing account shall be closed out annually and any funds owing to the Customer will be paid within 30 days.

E-5.06 COMPLAINTS AND INVESTIGATIONS

Any disputes over the implementation of this rule shall be addressed in accordance with dispute resolution procedures set forth in the rules governing service from Utility.

E-5.07 SEVERABILITY

If any part of this rule or any application thereof is held invalid, the remainder of this rule or its application to other situations or persons shall not be affected.

E-5.08 EXEMPTION OR VARIANCE

A. Any interested person may file an application for an exemption or a variance from the requirements of this rule. Such application shall:

1) describe the situation which necessitates the exemption or variance;
2) set forth the effect of complying with this rule on the utility and its customers if the exemption or variance is not granted;
3) identify the Section of this rule for which the exemption or variance is requested;
4) describe the result which the request will have if granted;
5) state how the exemption or variance will promote the achievement of the purposes of this rule; and,
6) state why no other reasonable alternative is available.

B. If the Utility determines that the exemption or variance is consistent with the purposes of this rule, the exemption or variance may be granted. The Utility may, at its option, require an informal conference or formal evidentiary hearing prior to the granting of the variance.

E-5.09 REQUEST FOR STAY PENDING AMENDMENT, EXEMPTION, OR VARIANCE

A request for an amendment, exemption, or a variance from the requirements of this rule may include a request that the Utility stay the application of the affected portion of this rule for the transaction specified in the motion. Utility has the sole discretion to determine whether to grant a request for an amendment, exemption or variance or an accompanying request for a stay. In reviewing such request, Utility will not act unreasonably.

E-5.10 CUSTOMER INFORMATION

Utility will provide information to all customers regarding this rule, including, but not limited to, contact persons and a description of terms and conditions for purchases from Qualifying Facilities.

Rule Revised: 11/18/09

Los Alamos
2014 Cost of Service Study
Schedule 6-S

		Rate	Units	Revenue
	Existing Revenue			
1	Customer Charge	$18.14	96	$1,741.44
2	Energy Charge	0.09740	290,486	$28,293.34
3	Total Revenue			$30,034.78
	Cost of Service			
4	Customer Charge	$56.26	96	$5,400.96
5	Demand Charge	$26.44	2,325	$61,473.00
6	Energy Charge	0.03727	290,486	$10,826.41
7	PCA	0.00770	290,486	$2,236.74
8	Total Revenue			$79,937.12
	Proposed Rate			
9	Customer Charge	$60.00	96	$5,760.00
10	Demand Charge	$10.50	2,325	$24,412.50
11	Energy Charge	0.07200	290,486	$20,914.99
12	PCA	0.00770	290,486	$2,236.74
13	Total Revenue			$53,324.23