BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF NEW MEXICO FOR REVISION OF ITS RETAIL ELECTRIC RATES PURSUANT TO ADVICE NOTICE NO. 533	)	**Case No. 16-00276-UT**
PUBLIC SERVICE COMPANY OF NEW MEXICO,	)	
Applicant	)	

DIRECT TESTIMONY

OF

STELLA CHAN

December 7, 2016

NMPRC CASE NO. 16-00276-UT
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WITNESS FOR
PUBLIC SERVICE COMPANY OF NEW MEXICO

DIRECT TESTIMONY OF
STELLA CHAN
NMPRC CASE NO. 16-00276-UT

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Stella Chan. I am the Executive Director, Strategic Marketing and Product Management at Public Service Company of New Mexico ("PNM" or the "Company"), where I am responsible for Pricing, Load Research, Strategic Account Management, Marketing and Product Development. My address is 414 Silver Avenue, SW, Albuquerque, New Mexico 87102.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I have been in my current position at PNM since 2015. I have worked in the energy industry for over 25 years in a variety of management, pricing, rate design and analytic positions. I received a BBA in Finance as well as an MBA with a concentration in Finance from the University of Houston. PNM Exhibit SC-1 provides a description of my experience and educational background and the proceedings before the New Mexico Public Regulation Commission ("NMPRC" or the "Commission")[1] in which I have filed testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to set a framework for PNM's rate design objectives in this case. My testimony also provides a high-level overview of the

[1] All the acronyms used in this testimony are included in PNM Exhibit SC-2.

process the Company undertakes to develop rates. This high-level overview includes a discussion of the steps taken to arrive at proposed rates that are supported by me, as well as by PNM Witnesses Aguirre and Vogt. I support some of the initial steps necessary to develop new rates based upon the Company's proposed revenue requirement, including the development of new energy and peak demand forecasts for the Test Period.[2] In accordance with the requirements of NMPRC Case No. 15-00261-UT ("2015 Rate Case"), I support the Company's determination that it should gradually transition its Rider 8 – Incremental Interruptible Power Rate ("Rider 8 – IIPR" or "Rider 8") customers off of Rider 8. To accomplish the transition, PNM is proposing a modified discount under a new "Transitional Rider 8 – Incremental Interruptible Power Rate ("Transitional Rider 8 – IIPR" or "Transitional IIPR"), with the goal of the Transitional IIPR expiring in four years or on the effective date of new rates approved for implementation after December 31, 2021, whichever is later. I also address PNM's current position regarding its Time-of-Use ("TOU") rates.

Q. PLEASE LIST THE RULE 530 SCHEDULES YOU ARE SPONSORING.

A. The Rule 530 Schedules I am sponsoring are:

- M-3, Demand and energy loss factors for the Base Period and Test Period.[3]
- P-1, Peak demand information.
- P-5, Customer information.

[2] The Test Period for this rate case spans the calendar year of 2018.
[3] I co-sponsor this Rule 530 Schedule with PNM Witness Mechenbier.

- P-6, Weather data.
- P-9, Line loss information.[4]
- P-11, Reserve margin information.
- Q-1, Load research program.

All of the Rule 530 Schedules listed above with the exception of Rule 530 Schedule Q-1 are being provided in executable electronic format. Rule 530 Schedule Q-1 will be provided electronically in PDF format.

Q. ARE ANY OF YOUR EXHIBITS OR THE RULE 530 SCHEDULES THAT YOU SPONSOR BEING PROVIDED ELECTRONICALLY?

A. Yes. PNM Exhibit SC-5, the Test Period Billing Determinants, is being provided in an executable electronic format and is functionally linked to the Rate Design Model (PNM Exhibit JCA-4). This exhibit will be provided on the DVD-ROM labeled "2016 Electric Rate Case Filing Case No. 16-00276-UT Cost of Service Model, Embedded Class Cost of Service and Rate Design including Workpapers."

Q. ARE YOU ADDRESSING ANY OF THE COMPLIANCE REQUIREMENTS FROM THE 2015 RATE CASE?

A. Yes. In accordance with the Final Order in the 2015 Rate Case, PNM was required to file direct testimony justifying Rider 8 – IIPR if PNM supported continuation of this rider. My testimony details PNM's proposal for a Transitional IIPR.

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[4] I co-sponsor this Rule 530 Schedule with PNM Witness Mechenbier.

I also explain below the mediated process PNM is engaging in with stakeholders regarding its TOU rates, as required by the Final Order from the 2015 Rate Case.

II. OVERVIEW OF RATE DESIGN OBJECTIVES FOR COST RECOVERY

Q. WHAT ARE THE COMPANY'S PRIMARY OBJECTIVES WHEN DEVELOPING ITS RATE DESIGN PROPOSALS?

A. PNM is continuing with its efforts that began in the 2015 Rate Case to improve on the Company's outdated rate design so that rates will more accurately reflect the costs the Company incurs to serve its customers by rate class. While the rate design approved by the Commission in the 2015 Rate Case made significant improvements in terms of reflecting each customer class' true cost of service, PNM is seeking additional modifications to its rates to not only more accurately reflect the cost of service, but also to balance the ultimate rate class impacts in recognition of the long-accepted principle of gradualism.

Q. WHAT APPROVALS FROM THE 2015 RATE CASE PROMOTE MOVEMENT TOWARD MORE COST-BASED RATES AND RESULT IN A MORE UPDATED RATE DESIGN?

A. The approval of PNM's 3-Summer/1-Winter Coincident Peak ("3S1WCP") allocator for generation-demand costs results in a revenue requirement by class that more closely reflects how the Company incurs costs during its summer and winter peaks. The Commission also approved banding that moved most rate classes closer to their allocated cost of service.

The approval of the increased customer charge for the residential and small power rate classes also results in a charge that more closely reflects the fixed customer-related costs PNM incurs to serve each of these customer classes. Furthermore, the approved increase to demand charges consistent with each rate class' demand-related costs has similarly improved price signals to customers. These approvals collectively have promoted rates that are more closely aligned with class cost of service principles.

PNM also sought and was granted approval for a new rate class and a new rider that accomplished important economic development initiatives, namely Rate 35B – Large Power Service >=3,000 kW ("Rate 35B") and the Economic Development Rider No. 45 ("EDR"). The changes approved by the Commission for Rate 35B have made it a more attractive rate for higher usage customers, such as data centers and other high-load manufacturing customers. The EDR facilitates demand charge discounts for qualified new and existing customers to incentivize further investment in the State of New Mexico.

Finally, the approved changes to Rate No. 20 – Integrated System Streetlighting and Floodlighting Service New Installation ("Streetlighting" or "Rate 20 – Streetlighting") also reflects a more updated rate design, as the tariff promotes the use of energy efficient lighting and provides more flexibility to Streetlighting customers.

Q. ARE THERE UNIQUE CIRCUMSTANCES IN THIS CASE THAT INFLUENCE PNM'S PROPOSED COST-BASED RECOVERY?

A. Yes. As detailed in the testimony of PNM Witness Ortiz, the timing of this rate case is directly tied to cost recovery in accordance with the Commission's Final Order in NMPRC Case No. 13-00390-UT (referred to as the "BART Case"). While the timing of this rate case is driven by the unavoidable changes resulting from the BART Case, PNM is sensitive to the proximity in time between this rate case and the 2015 Rate Case and the impact that successive rate increase will have on its customers, particularly its residential customers. As such, PNM has proposed two principal efforts to mitigate the full rate impact on customers.

First, as detailed by PNM Witness Ortiz and further supported by PNM Witness Aguirre, PNM is proposing to phase-in the rate increase that would result from the Commission's approval of the full revenue requirement as requested. Second, PNM's proposed banding in this rate case, as detailed by PNM Witness Aguirre, will cap the total rate increase for all customers at 110% of the system average increase. The system average increase, as supported by PNM Witness Aguirre, is 14.33%; therefore the maximum percentage increase to any customer class upon full implementation of the total rate increase will be capped at 15.76%, which is 110% of the 14.33% system average increase.

Q. WHAT IS THE IMPLICATION OF CAPPING THE RATE INCREASE AT 110% OF THE SYSTEM AVERAGE INCREASE?

A. Capping the rate class increase at 110% of the system average increase helps to stabilize rate impacts and to achieve improved class cost recovery for five of PNM's customer classes as compared to the final approved rates from the 2015 Rate Case. In addition, two classes are set at unity of return, which means that these rate classes are paying no more and no less than their cost of service. While some rate classes do not demonstrate improved cost recovery, the following two customer classes moved only 0.01% further away from their true cost of service as compared to the 2015 Rate Case: the combined Rates 2A – Small Power Service ("Rate 2A – Small Power") and 2B – Small Power Service Time-of-Use ("Rate 2B – Small Power TOU", combined "Rates 2A/2B – Small Power"); and Rate 30B – Large Service for Manufacturing >=30,000 kW ("Rate 30B – Manufacturing" or "Rate 30B"). PNM Witness Aguirre provides further detail on each rate class' cost of service recovery.

PNM's stated intent in the 2015 Rate Case was to take steps in each subsequent rate case to improve its rate design. PNM's proposed rate design for this rate case demonstrates an improved outcome for seven of its 15 customer classes. Ultimately, however, balancing customer impacts has been given some precedence in this case as compared to other important rate design objectives.

Q. DOES BALANCING CUSTOMER IMPACTS STILL ALLOW FOR PROGRESS IN SETTING CUSTOMER CHARGES THAT REFLECT THE UNDERLYING FIXED CUSTOMER COSTS?

A. Yes. PNM is still proposing to send more accurate price signals to its customers by requesting an increased customer charge for its residential and small power customers to fully reflect the fixed, customer-related costs required to serve these rate classes. The customer charge reflects the costs that the Company incurs to connect each customer to the system and includes all customer-related costs, including meter reading, billing and customer service costs. A customer charge that accurately reflects the Company's costs for these fixed charges sends a more accurate price signal.

Q. WHAT IS PNM'S PROPOSAL FOR ITS RESIDENTIAL CUSTOMER CHARGE IN THIS RATE CASE AS COMPARED TO THE APPROVED CUSTOMER CHARGE FROM THE 2015 RATE CASE?

A. Based upon the Commission's approved revenue requirement in the 2015 Rate Case, a cost-based customer charge would have been $12.63 per month in order to collect the fixed, customer-related costs for each residential customer. However, relying on the principle of gradualism, the Commission approved an increase to PNM's residential customer charge of just $7.00 per month.

In this rate case, PNM has determined that it incurs $13.77 in customer-related costs for each residential customer per month. In recognition of the

Commission's gradual approach to increasing the residential class' customer charge, PNM is seeking an increase of its Rate 1A – Residential Service ("Rate 1A – Residential") customer charge in two steps consistent with the proposal to phase-in the rate increase if the full revenue requirement is approved. PNM Aguirre supports and details the customer charge phase-in proposal.

Q. HAS PNM CONDUCTED ANY SPECIFIC ANALYSIS TO DETERMINE WHETHER ITS PROPOSALS TO INCREASE THE RESIDENTIAL CUSTOMER CHARGE WILL ADVERSELY AFFECT LOW-INCOME CUSTOMERS?

A. Yes. In response to concerns expressed by certain parties in the 2015 Rate Case, PNM conducted an analysis of 2013, 2014, and 2015 customer usage data, utilizing the U.S. Census Block Groups and Median Household Income as reported by the U.S. Census Bureau to determine whether there is a relationship between energy usage and income levels. PNM Exhibit SC-3 provides an explanation of the method of analysis conducted and presents graphs outlining the relationship between income and residential electric energy consumption for each year analyzed. The analysis indicates no statistically significant correlation between energy usage and income levels in each year analyzed. In particular, the graphs show no pattern consistent with the best fit that would indicate a relationship between energy usage by Census Block Group and the Median Household Income within each Census Block Group.

Q. WHAT OTHER COST-BASED RATE DESIGN MODIFICATIONS IS PNM PROPOSING IN THIS RATE CASE?

A. PNM also is proposing to modify its inclining block rate pricing for residential customers as the first step to transition into a more effective TOU rate offering in the future and a more cost-based commodity rate for residential customers. PNM Witness Aguirre supports this proposal.

For customer classes with a three-part tariff, PNM is proposing to set demand rates as close to 100% as possible, while balancing the rate impacts within a particular class. PNM Witness Aguirre also supports this proposal.

Q. ARE ANY OF PNM'S RATE PROPOSALS IN THIS RATE CASE AIMED AT SUPPORTING ITS COMMERCIAL AND INDUSTRIAL CUSTOMERS?

A. Yes. PNM is proposing a Transitional IIPR to maintain a portion of the discount these customers received in the past pursuant to Rider 8 for at least four years in order to mitigate significant bill impacts. Specifically, two Rider 8 – IIPR customers that are served under Rate 35B could see nearly a 30% increase even after banding if the Transitional IIPR is not approved by the Commission.[5] Therefore, consistent with the principle of gradualism, the Company proposes to decrease the discounts the Rider 8 customers currently receive under Rider 8, and

[5] Prior to banding and without the Transitional IIPR discount, the increase to these customers would be above 70%.

pursuant to the terms of the Transitional IIPR, continue the decreased discount for a period of time.

III. PNM'S RATE DESIGN PROCESS AND THE KEY DATA INPUTS USED IN THE RATE DESIGN PROCESS

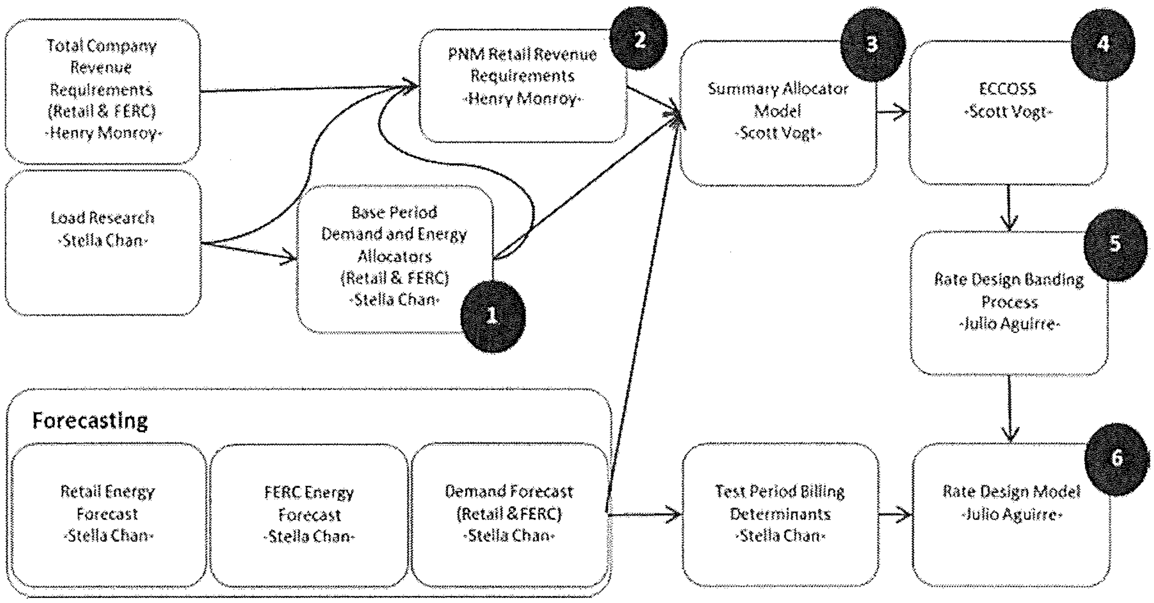
Q. WHAT IS THE PROCESS PNM UNDERTAKES TO DEVELOP RATES?

A. To develop rates, PNM must convert the system level revenue requirements, as developed by PNM Witness Monroy, into the individual retail rates. This conversion process involves a series of steps that include: (1) developing generation demand and energy allocators using historical load research and forecast data; (2) where applicable, splitting the system revenue requirement into Federal Energy Regulatory Commission ("FERC") wholesale and retail revenue requirements using the generation demand, transmission demand and energy allocators; (3) developing the Base Period[6] and Test Period production, transmission, distribution and other allocators used to allocate costs among PNM's rate classes; (4) applying the Embedded Class Cost of Service Study ("ECCOSS") Model using the demand, energy and other allocators to allocate production, transmission, distribution and other costs to determine the revenue requirements by rate class; (5) designing and applying banding to the class revenue requirement outputs from the ECCOSS Model to take into account gradualism in assigning full cost responsibility among rate classes; and (6) using the Rate Design Model to determine the individual rate components by applying

[6] "Base Period" is July 1, 2015 through June 30, 2016.

the Test Period Billing Determinants to the class-level revenue requirements after banding. Figure SC-1 below depicts the steps described above. As can be seen in Figure SC-1, I sponsor step 1, PNM Witness Monroy sponsors step 2, PNM Witness Vogt sponsors steps 3 and 4, and PNM Witness Aguirre sponsors steps 5 and 6.

Figure SC-1
Rate Design Process



Q. STARTING WITH STEP 1 IN FIGURE SC-1 ABOVE, HOW ARE THE GENERATION DEMAND AND ENERGY ALLOCATORS USED DURING THE RATE DESIGN PROCESS?

A. PNM uses the Base Period and Test Period demand and energy allocators to allocate total Company revenue requirements between the FERC wholesale jurisdiction and the Company's retail jurisdiction.

Q. HOW DOES PNM CALCULATE THE BASE PERIOD GENERATION DEMAND AND ENERGY ALLOCATORS, WHICH ARE USED BY PNM WITNESS MONROY TO SPLIT THE SYSTEM REVENUE REQUIREMENT INTO FERC WHOLESALE AND RETAIL REVENUE REQUIREMENTS?

A. The Base Period monthly generation demand allocators are calculated by first gathering load research data on customer class peak demands at the distribution level.[7] To convert these distribution-level demand allocators to demand allocators at the generation level, PNM must factor in losses that occur between the generation of electricity and the metered electricity for each individual customer class.[8] Additional adjustments are made to account for differences due to sample error and/or unaccounted for energy. After making these adjustments, PNM uses 12 months of coincident peak ("CP") data to determine each class' contribution to peak at the peak hour. I support the underlying 12 CP data and the adjusted generation-related demand allocators; PNM Witness Monroy utilizes the 12 CP method for allocating the adjusted generation-related demand costs between FERC wholesale and PNM retail customers.[9]

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[7] Rule 530 Schedule Q-1, which I am sponsoring, describes PNM's Load Research Department and the load research program undertaken by the Company.

[8] I co-sponsor Rule 530 Schedule M-3 with PNM Witness Mechenbier. This schedule shows the cumulative demand loss factors for each retail rate class. Additionally, I jointly sponsor Rule 530 Schedule P-9 with PNM Witness Mechenbier, which describes the data used to calculate PNM's demand and energy losses.

[9] Rule 530 Schedule P-1, which I am sponsoring, details PNM's total system peak demand, as well as PNM's retail peak demand for the Test Period. The difference between the total system peak demand and the retail peak demand equals PNM's peak demands for its FERC wholesale customers.

To calculate PNM's Base Period monthly energy allocators, the meter-to-generation losses are applied to the General Ledger metered energy for the Base Period for each retail customer class, which results in the amount of total energy produced at generation for the Base Period.[10] This total energy at generation by customer class is used to determine the Base Period energy allocator, which reflects a 12-month average of energy.[11] As with the demand allocators, I support the underlying data used by PNM Witness Monroy.

The underlying data used to support the Base Period generation demand and energy allocators is included in PNM Exhibit SC-4.

Q. IS IT NECESSARY TO APPLY THE DEMAND AND ENERGY ALLOCATORS IN THE TEST PERIOD TO ALLOCATE COSTS BETWEEN FERC WHOLESALE AND RETAIL CUSTOMERS?

A. No. PNM has no FERC wholesale customers in the Test Period, and thus, no allocation process is needed. PNM Exhibit SC-4 reflects the 100% allocation of generation demand and energy to retail customers in the Test Period.

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[10] As with the calculation of the demand energy allocators, adjustments are made to account for differences due to sample error and/or unaccounted for energy, in addition to meter-to-generation losses.

[11] I co-sponsor Rule 530 Schedule M-3 with PNM Witness Mechenbier, which shows the cumulative energy loss factor for each retail rate class.

Q. FOR STEP 2 IN FIGURE SC-1, WHO SPONSORS THE DETERMINATION OF PNM'S RETAIL REVENUE REQUIREMENTS?

A. PNM Witness Monroy provides PNM retail revenue requirements for the Test Period.

Q. REGARDING STEP 3 IN FIGURE SC-1, HOW DOES PNM DERIVE THE PRODUCTION, TRANSMISSION AND DISTRIBUTION ALLOCATORS?

A. PNM uses the Base Period actual energy sales adjusted for losses and various forecasts referenced in Figure SC-1, along with other load research (*i.e.*, coincident and non-coincident peak demands), to derive the Base Period and Test Period production, transmission, distribution and other allocators. PNM Witness Vogt sponsors the Summary Allocators Model (PNM Exhibit SAV-3), which develops these production, transmission, distribution and other allocators. The Summary Allocators Model also shows the relevant data that is used to calculate the allocators used in the ECCOSS Model.[12]

Q. ONCE CALCULATED, HOW ARE THE SUMMARY ALLOCATORS INCLUDED IN PNM EXHIBIT SAV-3 USED?

A. These allocators are used to allocate production, transmission and distribution revenue requirements to various rate schedules in the ECCOSS Model.

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[12] *See also* Rule 530 Schedule P-5, which I am sponsoring. This schedule sets forth PNM's customer count, kWh sales and revenue for the Base Period, as well as the forecasted customer count, kWh sales and revenue for the Test Period. The forecasted customer count and kWh sales for the Test Period are an output from the energy forecast; the forecasted revenue is an output from ECCOSS modeling after the energy forecast is utilized to create the allocators applied in the ECCOSS Model.

Q. PLEASE DESCRIBE STEP 4 IN FIGURE SC-1 REGARDING APPLICATION OF THE ECCOSS MODEL.

A. The costs associated with PNM's revenue requirement are input into the ECCOSS Model. Within the ECCOSS Model, costs are functionalized, classified and allocated to the different rate classes. The final output from the ECCOSS Model is the Test Period revenue requirement for each rate class. PNM Witness Vogt sponsors the ECCOSS Model.

Q. PLEASE BRIEFLY DESCRIBE THE BANDING PROCESS, WHICH IS STEP 5 OF THE RATE DESIGN PROCESS SHOWN IN FIGURE SC-1.

A. The non-fuel revenue requirement for the Test Period, an output of the ECCOSS Model, is banded to ensure the Company's resulting rate design supports a reasonable and moderate step toward full cost recovery by class. Banding, which is a method of limiting the customer class revenue requirement increase to a given percentage above or below the average system impact, puts into effect the principle of rate gradualism discussed earlier. PNM Witness Aguirre supports PNM's proposed banding process.

Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE TEST PERIOD BILLING DETERMINANTS THAT ARE USED IN THE RATE DESIGN MODEL.

A. To derive the Test Period Billing Determinants, the Company starts with the outputs from the energy forecast that I am sponsoring. In particular, the energy forecast shows PNM's forecasted number of customers and energy by rate class. This information must be separated into the rate components that PNM uses to bill its customers. For example, the residential customer and energy forecast must be divided such that rates for Rate 1A – Residential and Rate 1B – Residential Service Time-of-Use ("Rate 1B – Residential TOU") can be developed, as well as for each inclining block 1, 2 or 3, and for the summer and non-summer periods. To transform the higher-level energy forecast into these individual rate components, PNM calculates ratios based upon historical data that replicate the proportionality of these different rate components as compared to the rate class as a whole. The result is PNM Exhibit SC-5, which is the Test Period Billing Determinants.

Q. HOW DOES PNM DEVELOP ITS ACTUAL RATES USING THE RATE DESIGN MODEL, REPRESENTED BY STEP 6 IN THE RATE DESIGN PROCESS SHOWN IN FIGURE SC-1?

A. The Rate Design Model's key function is to convert the Test Period revenue requirement for each rate class after banding into the individual rate elements (e.g., customer, demand, and energy charges) found in PNM's tariffs. The Rate Design Model (PNM Exhibit JCA-4) derives each of these rate elements using the Test Period Billing Determinants (PNM Exhibit SC-5), such that these rate elements total an amount that recovers the Company's proposed revenue requirement for the Test Period for each rate class. PNM Witness Aguirre is the sponsor of the Company's Rate Design Model, and the proof of revenue (Rule 530 Schedule O-2) that results from the proposed rates.

IV. THE APPLICABILITY OF ENERGY AND PEAK DEMAND FORECASTS IN RATE CASES

Q. HOW ARE THE ENERGY AND PEAK DEMAND FORECASTS USED IN THE RATE CASE?

A. The application of the energy and peak demand forecast data presented in a rate case is narrowly focused on the allocation of costs among rate schedules and the development of billing determinants for rate design in the Test Period.

Q. DO THE ENERGY AND PEAK DEMAND FORECASTS THAT YOU SUPPORT PROVIDE ADDITIONAL DATA BEYOND THE TEST PERIOD?

A. Yes. Although the energy and peak demand forecasts are presented to develop the Test Period Billing Determinants for calendar year 2018 (PNM Exhibit SC-5), my presentation of these forecasts below include the Company's forecast data through 2023, consistent with the data requirements in the Rule 530 Schedule P Series. While Rule 530 requires energy and demand forecast data over a longer time horizon for informational purposes,[13] PNM uses only the Test Period peak demand and energy forecast data to derive its proposed rates.

[13] The 530 rules governing Rule 530 Schedule P-5 require annual kWh sales and revenues, as well as certain customer data, for the four years prior to the Test Period and for five years after the Base Period. 17.9.530.14(P)(5)(c) and (d) NMAC; 17.1.3.8(A) NMAC.

V. ENERGY FORECAST

Q. PLEASE PROVIDE A SUMMARY OF THE PROCESS FOR DEVELOPING PNM'S ENERGY FORECAST IN THIS RATE CASE.

A. PNM's energy forecast is the sum of total energy sales across all rate classes. PNM uses four different forecasting methods to forecast energy for all of its customer classes. The first method, which is used for select rate classes, derives total energy sales as the product of usage per customer ("UPC") and the number of customers minus adjustments.[14] For other rate classes (the second method), PNM reviews a combination of factors to determine total energy sales, including historical data and specific information from individual customers, including data gathered from account managers for individually managed customer accounts. The third method forecasts energy on an aggregate customer class basis, using historical trends for the rate class as a whole. The final method is specific to Streetlighting customers, which is described below.

Q. PLEASE DESCRIBE THE FIRST FORECAST METHOD OF USING UPC AND THE NUMBER OF CUSTOMERS TO FORECAST ENERGY SALES FOR SELECT CUSTOMER CLASSES.

A. In the first method, PNM estimates UPC and the number of customers using its own customer data, with particular reliance on historical data and a trend analysis derived from this historical data. To a lesser extent, PNM uses economic data

[14] Throughout my testimony, I will refer to the product of UPC and the number of customers without adjustments (i.e., energy efficiency, distributed generation and Codes & Standards) as "unadjusted" sales or energy.

from the quarterly economic forecast produced by the Bureau of Business and Economic Research ("BBER") at the University of New Mexico.

PNM also includes weather as an input to this forecast process. Specifically, Heating Degree Days ("HDDs")[15] and Cooling Degree Days ("CDDs") by month are calculated based on weather data from the National Oceanic and Atmospheric Administration ("NOAA"). To construct PNM's energy forecast, the 10-year average for HDDs or for CDDs, weighted by the days in the billing cycle, serves as a reasonable approximation of future weather patterns.

Q. FOR WHICH CUSTOMER CLASSES DOES PNM APPLY THIS FIRST FORECAST METHOD TO DETERMINE THEIR ENERGY FORECAST?

A. PNM applies the first method to derive the energy forecast for the following rate classes:

- Rate 1A – Residential;
- Rate 1B – Residential TOU;
- Rate 2A – Small Power;
- Rate 2B – Small Power TOU;
- Rate 3B – General Power TOU;
- Rate 3C –General Power Low Load Factor;
- Rate 10A – Irrigation Service ("Rate 10A – Irrigation"); and

[15] The temperature cutoffs are 58°F and 70°F for HDDs and CDDs, respectively, among residential customers and 60°F for both HDDs and CDDs among commercial customers.

- Rate 10B – Irrigation Service Time-of-Use ("Rate 10B – Irrigation TOU").

Q. AS PART OF THE FIRST METHOD FOR FORECASTING ENERGY, ARE THERE ANY SPECIAL PRACTICES USED FOR SOME OF THE CLASSES LISTED ABOVE?

A. Yes. For Rates 2A/2B – Small Power, PNM forecasts the UPC on a combined basis, but uses the individual rate class' customer count to determine an energy forecast for each separate rate schedule. In other words, for Rates 2A/2B – Small Power, PNM forecasts the UPC for these rate classes on a combined basis. That combined UPC is multiplied by the specific Rate 2A – Small Power customer count to derive a Rate 2A – Small Power energy forecast. Likewise, the combined Small Power UPC is multiplied by the specific Rate 2B – Small Power TOU customer count to derive a Rate 2B – Small Power TOU energy forecast.

For Rates 3B and 3C – General Power, the energy forecast for UPC, as well as customer count, are derived on a combined class. Then this combined energy forecast is divided into separate energy forecasts for Rate 3B and Rate 3C using historical data.

Q. PLEASE DESCRIBE THE SECOND FORECASTING METHOD THAT RELIES UPON HISTORICAL DATA AND SPECIFIC INFORMATION FROM INDIVIDUAL CUSTOMERS.

A. For this method, PNM reviews a combination of factors to determine total energy sales, including: (1) historical data from individual customers that might reflect known information about expansion or contraction of business operations; (2) where applicable, information from account managers for individually managed customer accounts; and (3) when available, known future distributed generation and energy efficiency projects that will affect usage for large customers on a going-forward basis.

Q. WHICH RATE CLASSES ARE FORECASTED IN THIS MANNER?

A. The second method of forecasting using historical data and customer-specific information as described above is used to derive the energy forecast for the following rate classes:

- Those Rate 4B – Large Power Service Time-of-Use ("Rate 4B – Larger Power" or "Rate 4B") customers that have account managers;
- Rate 5B – Large Service for Customers >= 8,000 kW ("Rate 5B – Large Service");
- Those Rate 11B – Water and Sewage Pumping Time-of-Use ("Rate 11B – Water and Sewage" or "Rate 11B") customers that have account mangers;
- Rate 15B – Large Service for Public Universities > 8,000 kW ("Rate 15B – Universities");
- Rate 30B – Manufacturing;

- Rate 33B – Large Service for Station Power ("Rate 33B – Station Power");
- Rate 35B; and
- Rate 36B –Special Service Rate – Renewable Energy Resource ("Rate 36B").

Q. PLEASE DESCRIBE THE THIRD FORECASTING METHOD THAT RELIES UPON AGGREGATE CUSTOMER CLASS TRENDS.

A. The third forecasting method uses aggregate customer class data, specifically historical trends for the rate class as a whole, to forecast energy. PNM uses this energy forecasting method for customers of Rate 4B – Large Power and Rate 11B – Water and Sewage that are not individually managed by PNM account managers.

Q. HOW DOES PNM DETERMINE THE TOTAL FORECASTED ENERGY FOR RATES 4B AND 11B GIVEN THAT TWO DIFFERENT FORECASTING METHODS ARE USED FOR CUSTOMERS WITHIN THESE RATE SCHEDULES?

A. For Rate 4B – Large Power and Rate 11B – Water and Sewage, total forecasted energy for each of these rate classes will be the sum of the aggregate customer class trends (the third forecasting method) and customer-specific information (the second forecasting method), as described above.

Q. WHAT ENERGY FORECASTING METHOD DOES PNM USE FOR ITS STREETLIGHTING CUSTOMERS?

A. For Rate 20 –Streetlighting and Rate 6 – Private Area Lighting Service ("Rate 6 – Private Lighting"), PNM applies the fourth method to develop the energy forecast, which uses recent actual historical data to forecast energy usage on a going-forward basis.

Q. DOES THE RATE 20 – STREETLIGHTING ENERGY FORECAST ACCOUNT FOR ANY LED CONVERSIONS?

A. No. At the time of filing, no Streetlighting customers had yet developed sufficient data for PNM to be able to accurately forecast the changes to usage that will result from the adoption of LED streetlights during the Test Period.

Q. ARE PNM'S FORECAST MODEL AND PROCESS SIMILAR TO THE ENERGY FORECAST MODEL PRESENTED IN THE 2015 RATE CASE?

A. Yes. The starting point for the forecasting model that I sponsor in this case is the energy forecast model supported by PNM Witness Faruqui in the 2015 Rate Case. The 2015 Rate Case model was updated and modified to ensure that a robust and statistically significant relationship exists between each explanatory variable in the model and the resulting forecast outputs. The revised model relies more heavily on history and trend analysis as compared to economic data, to the extent that the economic data shows weakening correlation with energy consumption.

PNM also updates the values (or inputs) into the forecast to reflect the most recent historical period used to develop the new energy forecast.

Q. WHAT SPECIFIC VALUES OR INPUTS WERE UPDATED AS FROM THE ENERGY FORECAST FILED IN THE 2015 RATE CASE?

A. The historical data used to determine Test Period energy sales was updated through April 2016. Additionally, the energy forecast incorporates 10 years of normal CDDs and HDDs, from 2006 through 2015. Certain data inputs from BBER also were updated to reflect values in BBER's spring 2016 database, which was the most recent data available to PNM when it was preparing its forecast. BBER's spring 2016 database reflects updated historical and forecasted economic variables.

Q. WHAT ARE THE RESULTS OF PNM'S CURRENT ENERGY FORECAST?

A. The Test Period energy unadjusted sales is 8,439 GWh, which represents a 1.76% increase from the 2017 energy forecast.[16] After the adjustments, as I describe below, the Test Period adjusted energy sales is 8,102 GWh which represents a slight growth, 0.41%, from the 2017 adjusted energy forecast.

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[16] The 2017 energy forecast referenced above is a new forecast presented in this rate case.

Q. WHAT ARE THE OFFSETTING FACTORS OR ADJUSTMENTS THAT AFFECT PNM'S ENERGY FORECAST?

A. After the energy forecast is derived, PNM makes adjustments using forecasted distributed generation ("DG"), energy efficiency ("EE") savings from PNM's programs and mandated Codes & Standards, all of which decrease the energy forecast. The adjusted energy forecast is then used to develop the Test Period Energy Billing Determinants (PNM Exhibit SC-5).

I discuss in more detail below each of the adjustments. I also provide a figure below that demonstrates how each of these adjustments affects the overall energy forecast.

Q. PLEASE EXPLAIN HOW PNM DETERMINES ITS ADJUSTMENT TO THE ENERGY FORECAST AS A RESULT OF DG.

A. The adjustment for DG on PNM's system is determined by multiplying the historical capacity of the system across photovoltaic customers with the total sun hours of a fixed tilt, south facing solar panel in Albuquerque during the month. Solar resource information is provided by the National Renewable Energy Laboratory ("NREL"). Historical capacity of the system (prior to 2016) is determined by total kW_{AC} of all the interconnected customers. For 2016, the capacity is determined by the total kW_{AC} for customers who are expected to be interconnected. Specifically, the energy forecast predicts 2,500 new DG interconnections in 2016. For 2017 and 2018, the energy forecasts assumes the new interconnections expected in 2016 (approximately 2,500 per year) will remain constant. Based on the number of DG applications and interconnections to PNM's system through the third quarter of 2016, these DG assumptions are conservative.

Q. HOW DOES PNM DERIVE ITS ADJUSTMENT RELATED TO ENERGY EFFICIENCY?

A. New Mexico's Efficient Use of Energy Act ("EUEA") requires that public utilities acquire cost-effective and achievable energy efficiency and load management resources available in their service territories. This requirement mandates that the savings be five percent of 2005 total retail kilowatt-hour sales to New Mexico customers in calendar year 2014 and eight percent of 2005 total retail kilowatt-hour sales to New Mexico customers in 2020 as a result of energy efficiency and load management programs. NMSA 1978, § 62-17-5(G).

Savings associated with existing energy efficiency and load management programs can be calculated as the product of customer participation and savings per participant, which is measured and verified by an independent third party in accordance with NMSA 1978, § 62-17-8(B). Total historical savings is the sum across these existing programs. Actual energy sales reflect energy usage after energy efficiency savings are realized. In other words, when PNM updates historical energy sales for the forecast, the historical savings from energy efficiency is captured.

PNM also forecasts its future energy efficiency savings for the Test Period because historical data do not capture the effect of additional customer participation in new programs on energy sales in the Test Period. The forecasted energy efficiency savings for the Test Period is derived in conjunction with PNM's energy efficiency department. For the forecasts, PNM assumes that the EUEA threshold (eight percent of 2005 total retail kilowatt-hour sales to New Mexico customers in 2020) is met in all future periods. Other factors that the energy efficiency department takes into consideration to forecast energy efficiency savings, include: (1) the amount of energy efficiency spending as required by statute;[17] and (2) the average cost per kWh of energy efficiency savings projected for the Test Period. PNM forecasted approximately 71,173 MWh of total incremental energy efficiency savings for the Test Period, including approximately 31,090 MWh of savings for the residential class and 7,085 MWh of savings for the small power class.

Q. WHY MUST PNM MAKE A CODES AND STANDARDS ADJUSTMENT TO ITS ENERGY FORECAST?

A. While the adjustment for energy efficiency captures the projected savings from PNM sponsored programs, there are federally mandated Codes and Standards for appliances and lighting that result in energy savings apart from PNM's energy efficiency programs.

[17] *See* NMSA 1978, § 62-17-6(A).

Q. WHAT IS THE METHODOLOGY TO DETERMINE THE CODES AND STANDARDS ADJUSTMENT?

A. PNM's Codes and Standards adjustment is calculated using LoadMAP™, an end-use model developed and maintained by the Applied Energy Group ("AEG"). In particular, LoadMAP™ addresses a variety of forecast drivers, including appliance standards, by computing electricity consumption for each major appliance category for residential and commercial customers. As an end-use or "bottom-up" model, LoadMAP™ gathers information on how many appliances of each efficiency level are in the "existing" stock of homes and how many appliances of each efficiency level are in the "new" market, consisting of replacements and new construction. It then computes the energy used by all the existing and new appliances, assuming that the appliances run for a specified number of hours per year under designated weather conditions.

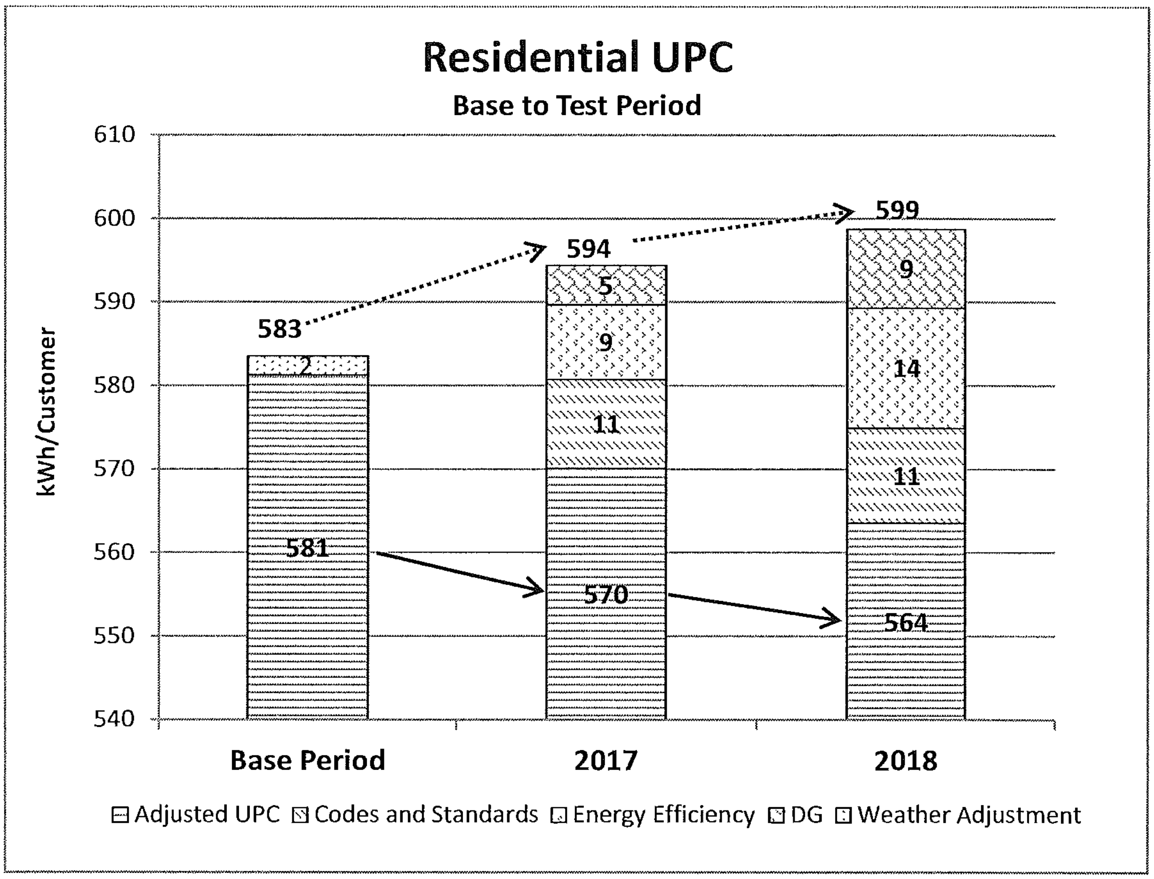
The appliance standards set minimum levels by appliance and building type. LoadMAP™ is able to run simulations in a base case without the standards and come up with an aggregate electricity consumption estimate by appliance. Then the model is re-run with the provision that none of the appliances that fall below the efficiency levels specified by the standards will be purchased. The difference between the two cases is the impact of the appliance standards.

PNM Exhibit SC-6 provides a more detailed discussion the Codes and Standards adjustment for residential and commercial sales.

Q. HOW DO ALL THESE ADJUSTMENTS AFFECT THE UPC FOR THE RESIDENTIAL CUSTOMER CLASS?

A. As demonstrated by Figure SC-2 below, the weather normalized residential UPC, after adjustments for EE, DG and Codes and Standards, decreases between the Base Period and the Test Period.

Figure SC-2



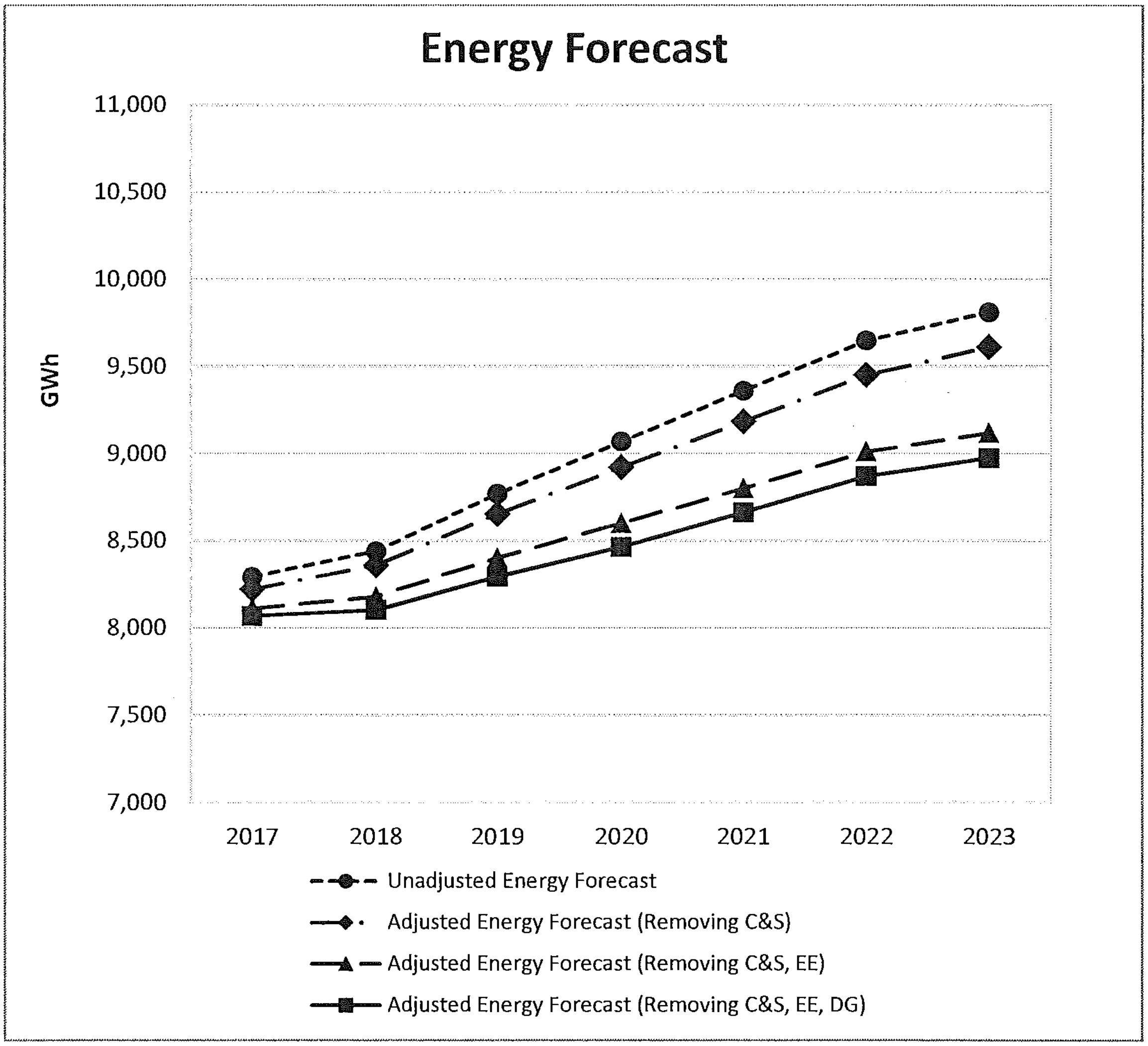
Q. HOW DOES THIS REDUCED UPC IMPACT THE ENERGY FORECAST?

A. As noted above, the energy forecast for the residential class is derived by multiplying the UPC by the number of customers. Figure SC-2 shows that the Test Period adjusted UPC is 3.26% lower than the weather-normalized UPC in the Base Period. As a result, the Test Period residential energy forecast, which is the product of adjusted UPC multiplied by the number of customers, also decreases as demonstrated by Figure SC-4 below.

Q. WHAT IS THE RESULTING ENERGY FORECAST TAKING INTO CONSIDERATION THE ADJUSTMENTS FOR EE, DG AND CODES AND STANDARDS?

A. Figure SC-3 shows the unadjusted energy forecast, how each of the adjustments discussed above affects the forecast, and ultimately, the final, adjusted energy forecast.

Figure SC-3



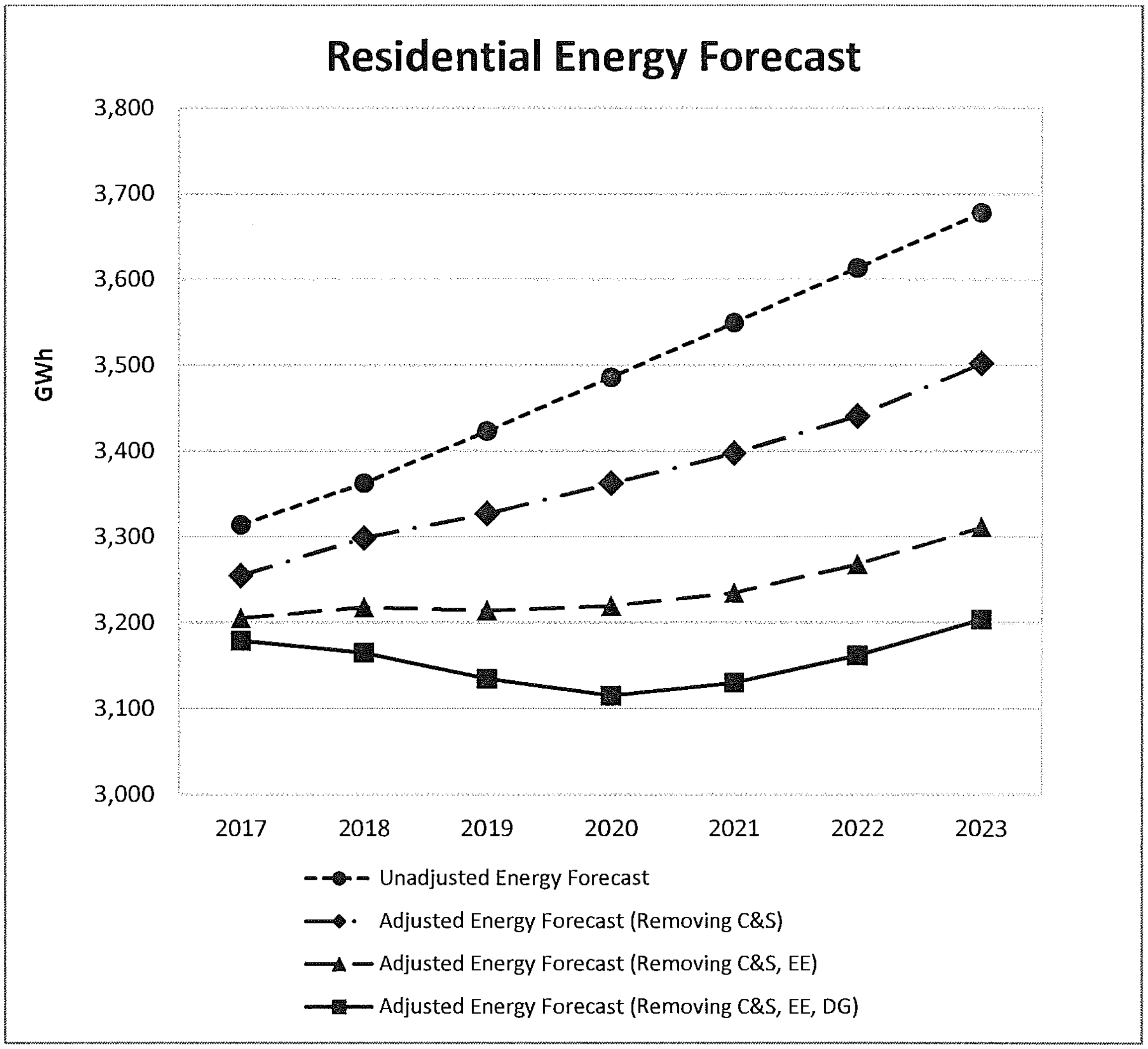
Q. WHAT DOES FIGURE SC-3 SHOW IN TERMS OF IMPACT FROM EACH ADJUSTMENT?

A. As Figure SC-3 shows, the adjustment that has the most significant downward impact on the overall energy forecast is energy efficiency.

Q. HOW DO THE VARIOUS ADJUSTMENTS IMPACT THE RESIDENTIAL ENERGY FORECAST?

A. The downward pressure on the energy forecast from DG, EE and Codes and Standards can be seen in the Test Period. Figure SC-4 below shows that the unadjusted forecast increases each year; however, DG, EE and Codes and Standards turn an increasing energy forecast to a declining forecast during the Test Period. As also can be seen from Figure SC-4 below, while PNM's EE programs have the most significant impact on lowering the energy forecast for the residential rate class, the negative effect of DG on the energy forecast is increasing through 2020.

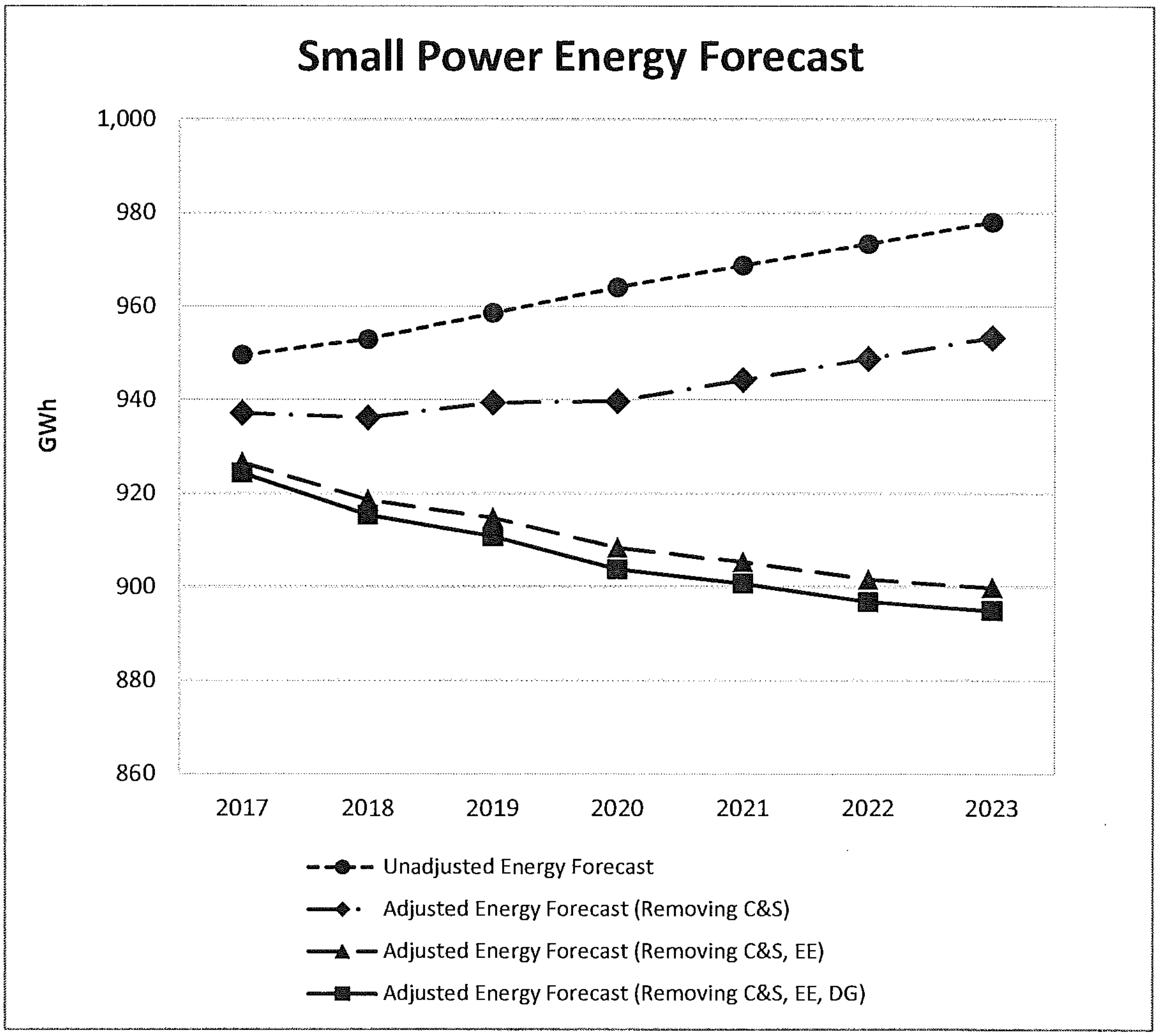
Figure SC-4



Q. BESIDES THE RESIDENTIAL RATE CLASS, WHAT OTHER RATE CLASSES NEGATIVELY IMPACT THE TOTAL RETAIL SYSTEM ENERGY FORECAST?

A. Rate 2A/2B – Small Power is another rate class that drives down the overall energy forecast when DG, EE and Codes and Standards are taken into account. Figure SC-5 below shows that when the various adjustments are made to the energy forecast for Small Power, particularly the EE adjustment, the energy forecast in the Test Period significantly declines.

Figure SC-5



Q. WHAT ABOUT THE OTHER RATE CLASSES?

A. PNM Exhibit SC-7 presents a compilation of tables for each rate class that includes the unadjusted energy forecast, the effect of the adjustments on the energy forecast, and the final, adjusted forecast.[18]

Q. HOW DO THE ADJUSTMENTS TO THE ENERGY FORECAST ULTIMATELY AFFECT RATES?

A. As described above, the energy and peak demand forecast are used to derive the Test Period Billing Determinants (PNM Exhibit SC-5). These Test Period Billing Determinants are used to derive the Company's rates. Ultimately, lowered billing determinants will affect the revenue that PNM can collect from each customer class, driving a higher revenue deficiency that must be accounted for in new rates. Figure SC-6 illustrates the result after the DG, EE and Codes and Standards adjustments, as well as other factors such as changes in customer load, have on total energy-related billing determinants for this rate case as compared to the 2015 Rate Case. As noted above, billing determinants are also calculated for other rate design purposes.

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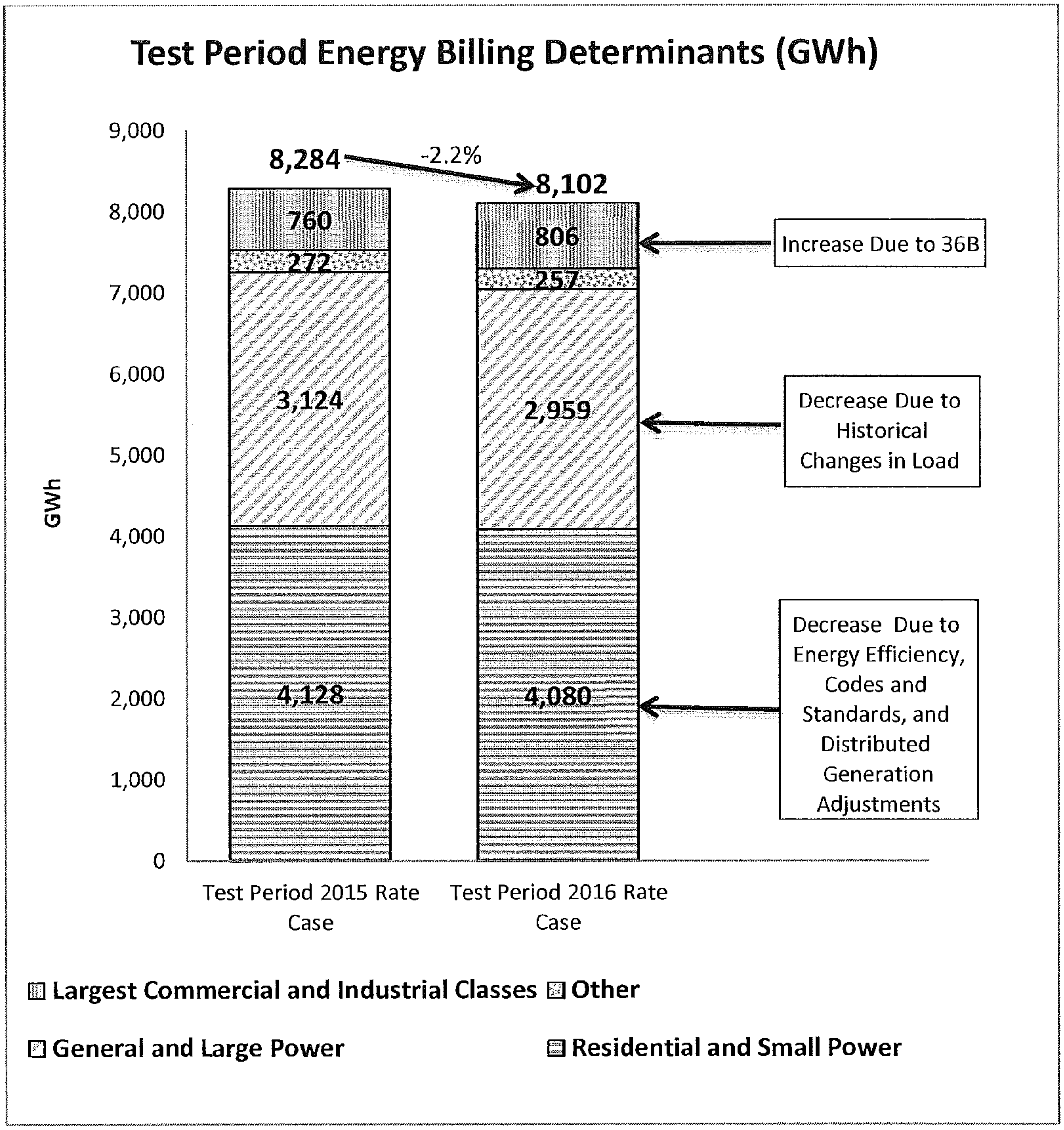
[18] Given that the new Rate 36B customer will start taking service from PNM in the Test Period, the Company has incorporated the impact of this customer into the energy forecast. The forecast incorporates the assumptions as set forth in Case No. 16-00191-UT, as updated.

Figure SC-6


Test Period Energy Billing Determinants (GWh)
GWh
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
8,284
-2.2%
8,102
760
272
3,124
4,128
806
257
2,959
4,080
Increase Due to 36B
Decrease Due to Historical Changes in Load
Decrease Due to Energy Efficiency, Codes and Standards, and Distributed Generation Adjustments
Test Period 2015 Rate Case
Test Period 2016 Rate Case
Largest Commercial and Industrial Classes
Other
General and Large Power
Residential and Small Power

Q. ARE CHANGES TO BILLING DETERMINANTS A DRIVER TO PNM'S REVENUE DEFICIENCY IN THIS CASE?

A. Yes. The changes to all of PNM's billing determinants, including but not limited to the energy billing determinants discussed above, are contributing approximately $11 million to the revenue deficiency in this rate case.

VI. PEAK DEMAND FORECAST

Q. PLEASE PROVIDE A SUMMARY OF THE PROCESS FOR DEVELOPING PNM'S PEAK DEMAND FORECAST.

A. PNM's retail peak demand forecast is conducted on the aggregate retail system level, inclusive of losses.[19] Both historical and forecasted energy and historical peak demand data are used to determine the peak demand forecast.

Q. WHAT HISTORICAL DATA IS USED IN DETERMINING THE PEAK DEMAND FORECAST?

A. A model is developed that uses historical retail peak demands adjusted for demand response. This model also factors in the historical average of the maximum and minimum temperatures on the peak day for each month. Finally, the model also incorporates historical retail energy.

[19] As noted above, PNM Witness Mechenbier supports the demand and energy losses.

Q. HOW IS THE RETAIL PEAK DEMAND FORECAST DERIVED FROM THIS HISTORICAL MODEL?

A. Once this historical model is created, the retail peak demand forecast is determined by running this model with forecasted energy from PNM's energy forecast, along with certain weather assumptions. The weather assumptions are derived using either five-year or 10-year averages. Specifically, for the summer months, the Company uses a five-year average of the maximum and minimum summer system peak day temperature to better capture any recent warming trends during the summer season. For every other month, the Company uses a 10-year average of the maximum and minimum temperature.

Q. HOW IS THE SYSTEM PEAK DEMAND FORECAST DETERMINED?

A. After the retail peak demand forecast is created, separate peak demand forecasts for wholesale (or FERC) customers are prepared, if applicable.[20] In addition, separate forecasts to determine the effect of EE, DG and Codes and Standards on demand also are prepared to adjust the overall peak demand forecast. The sum of these forecasts – the retail peak demand forecast, the adjustments to the retail forecast given EE, DG and Codes and Standards, and the peak demand forecast for wholesale customers, if any – results in a final system peak demand forecast.

[20] As noted above, PNM has no FERC wholesale power customers in the Test Period.

Q. IS PNM'S FORECAST METHODOLOGY SIMILAR TO THE PEAK DEMAND FORECAST USED IN ITS 2015 RATE CASE?

A. Yes. The peak demand forecast methodology is similar to the process used in the 2015 Rate Case. PNM, however, has updated inputs into the forecast, including historical retail peak demands, historical retail energy and the weather on peak days.

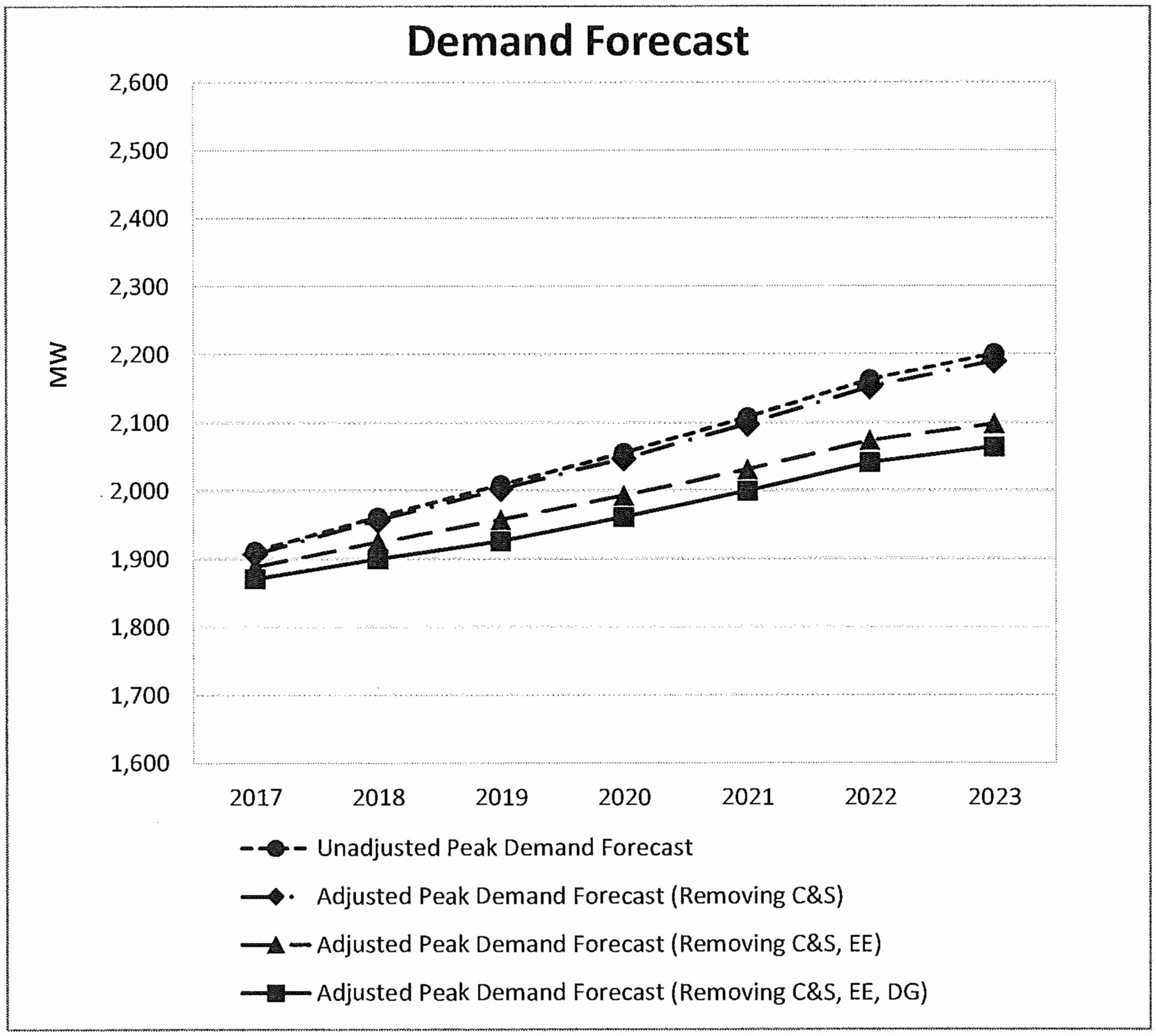
Q. HOW DOES THE CURRENT FORECAST FOR PEAK DEMAND COMPARE TO THE FORECAST USED IN THE 2015 RATE CASE?

A. The updated inputs, including the addition of a new Rate 36B customer who will start taking service on PNM's system during the Test Period, have resulted in a lower overall peak demand forecast when compared to the 2015 Rate Case. First, PNM no longer has any wholesale customers in the Test Period, and this is reflected in the system-wide peak demand forecast. Second, the overall trend has changed to reflect a lower rate of demand growth compared to the 2015 Rate Case. In particular, PNM has experienced increased DG penetration and decreased forecasted energy sales as compared to the 2015 Rate Case forecast. These decreased energy sales are an input to the peak demand forecast, resulting in a trend of lower demand growth.

Q. WHAT DOES PNM'S PEAK DEMAND FORECAST INDICATE?

A. Figure SC-7 below shows that, much like the energy forecast, the peak demand forecast reflects the same upward trend before any adjustments for DG, EE and Codes and Standards are made.

Figure SC-7



Q. WHAT ARE THE ADJUSTMENTS PNM MAKES TO THE DEMAND FORECAST PRESENTED ABOVE?

A. As noted above, the peak demand forecast is adjusted for anticipated changes in DG, EE savings from PNM's programs and mandated Codes and Standards, all of which decrease the peak demand that ultimately goes into development of Test Period allocators and billing determinants.

Q. PLEASE EXPLAIN HOW PNM CALCULATES THE DG, EE AND CODES AND STANDARDS ADJUSTMENTS TO THE PEAK DEMAND FORECAST.

A. A forecast is prepared that determines energy savings by month for DG, EE and Codes and Standards separately. Each of these forecasts is then applied to various hourly shapes representative of the relevant adjustment to create an hourly forecast. For example, the monthly EE forecast is applied to a series of hourly shapes representative of the effect that PNM's EE programs have on the system to create an hourly EE forecast. A representative, specific hour for each month is then selected from this hourly forecast based on the average historical peak hour for the month. This process converts the hourly DG, EE or Codes and Standards forecast to a monthly peak demand forecast.

Q. WHAT IS THE FINAL PEAK DEMAND FORECAST?

A. The peak demand forecast indicates a retail peak of 1,900 MW in the Test Period with all adjustments included.[21] Figure SC-7 shows PNM's peak demand forecast over a six-year period (2017-2023) before and after adjustments. As can be seen, growth in the demand forecast is significantly slowed by the adjustments for DG, EE and Codes and Standards. The EE adjustment is the largest of the three adjustments to the peak demand forecast.

Q. DO THE ADJUSTMENTS FOR DG, EE AND CODES AND STANDARDS HAVE THE SAME IMPACT ON THE PEAK DEMAND FORECAST AS ON ENERGY FORECAST?

A. No. For example, lighting standards do not impact peaks in the summer months since the summer peaks occur during daylight hours. Similarly, DG does not affect the winter peaks, as those peaks happen later in the evening after the sun has gone down and there is no DG production.

[21] Given that the new Rate 36B customer will start taking service from PNM in the Test Period, the Company has incorporated the impact of this customer into the peak demand forecast. The forecast incorporates the assumptions as set forth in Case No. 16-00191-UT with some updated information from the customer.

VII. TRANSITIONAL RIDER 8 – IIPR

Q. IS PNM PROPOSING TO CONTINUE OFFERING RIDER 8 – IIPR IN THIS RATE CASE UNDER ITS CURRENT TERMS?

A. No. PNM is proposing to modify the terms and conditions of the current Rider 8 to a Transitional IIPR, because the current Rider 8 no longer serves the original purposes contemplated at its inception as an interruptible rate, as described below. Current Rider 8 customers will receive a smaller discount for incremental load served pursuant to the revised rider, but will no longer be subject to interruption. The new proposed Transitional Rider 8 – IIPR is attached as PNM Exhibit SC-8, which is a redline of the current Rider 8.

Q. WHAT PURPOSE DOES THE TRANSITIONAL IIPR SERVE?

A. The purpose of the proposed Transitional IIPR is to prevent the rate shock that results from increases as high as 72% (before banding) for some of the Rider 8 customers. Without the Transitional IIPR, PNM's current Rider 8 customers would experience an approximately 30% rate impact even after banding. Given these rate impacts, PNM's proposal is aimed at transitioning the current Rider 8 customers off of their current IIPR discounts, but maintains some discount level for at least four years to mitigate extreme rate impacts.[22]

[22] As noted above, PNM's Transitional IIPR is proposed to expire after four years or the effective date of new rates approved for implementation after December 31, 2021, whichever is later.

Q. WHAT WAS THE ORIGINAL PURPOSE OF IIPR?

A. The original purpose in offering Rider 8 was to promote efficient and flexible utilization of the Company's generation and transmission capacity, while providing opportunities for customers to expand their operations. For qualifying customers in particular, Rider 8 was originally intended to provide a discount in return for PNM's ability to call for an interruption of incremental billed demand as result of an emergency during the Company's on-peak period. The loads subject to the Rider 8 were incremental to the customers' existing loads at the time they were offered the discount. In fact, these additional loads were developed in large part as a response to the economic benefit these customers received from the discount given each customer's agreement to take provisional or flexible service that could be interrupted in an emergency.

Q. WHAT DO YOU MEAN BY INCREMENTAL BILLED DEMAND?

A. The demand was incremental in that the Rider 8 customers received discounts only for the expanded demands on the system as defined in their contracts.

Q. IS THE ORIGINAL PURPOSE OF RIDER 8 – IIPR STILL BEING FULFILLED?

A. No, it is not. The Rider 8's provisions for interrupting on-peak demand have limited value to PNM's operating system for a variety of reasons, one being the lack of control over the interruptions. For example, since Rider 8 was originally implemented, PNM has developed a load management program that utilizes automatic control equipment to facilitate interruptions for participating customers. Under the original terms of Rider 8, customers are notified to curtail demand within thirty minutes, after which the customer takes the necessary steps onsite to interrupt its load.

The notification time period for interruption, which is 30 minutes under the current rider, is too long to meet operational requirements. While some of the customers could move their interruption time down to 10 minutes, which is consistent with PNM's demand response programs, others on the current Rider 8 could not. The use of mandatory 10 minute interruptions by PNM may be operationally infeasible for certain Rider 8 customers to remain on this rate. Additionally, PNM has upgraded its system to maintain compliance with regional and national operating requirements, which lessen the need to rely on Rider 8 customers for emergency interruptions.

Q. HOW MANY RIDER 8 – IIPR CUSTOMERS ARE THERE AND FROM WHICH RATE CLASS ARE THEY SERVED?

A. Rider 8 – IIPR is a closed tariff with eight customers currently receiving discounts pursuant to the rider. Five customers take service under Rate 3C – General Power Low Load Factor, one customer takes service under Rate 4B – Large Power and two customers are on Rate 35B.

Q. WHY IS PNM PROPOSING TO MAINTAIN THE TRANSITIONAL IIPR FOR THE LONGER OF A FOUR-YEAR PERIOD OR UPON THE EFFECTIVE DATE OF NEW RATES APPROVED FOR IMPLEMENTATION AFTER DECEMBER 31, 2021?

A. PNM reached out to all of its current Rider 8 – IIPR customers prior to this filing to understand how integral the current Rider 8 discount is to their business operations. PNM communicated with seven of its eight current IIPR customers by the time of filing. Those customers were overwhelmingly concerned about the potential elimination of the current Rider 8 – IIPR discount given that more affordable electricity prices were built into their business models. For many of these customers, the Rider 8 discounts have been in place and depended upon since the 1990s. Furthermore, these customers made business decisions to incrementally expand operations in the state as a result of the Rider 8 discounts. Some of the customers said they might leave PNM's service territory, reduce their operations and/or seek other opportunities for alternative fuels or generation supply if Rider 8 were eliminated. PNM's proposal in this case took into consideration the concerns raised by these customers. Because of this significant change to rates, PNM determined that it was reasonable to permit at least four years for the customers to adjust and/or modify business operations and budgets before the discount is completely removed.

PNM's proposal to extend the discount for four years or the effective date of new rates approved for implementation after December 31, 2021, whichever is later, will permit PNM to continue communicating with these customers about the impacts of the reduced discounts. PNM will work with its customers during the remaining period of the Transitional IIPR to evaluate alternatives to the expiration of the Transitional IIPR, including the reasonableness of continuing the Transitional IIPR discounts, or proposing a new load retention tariff or a new interruptible offering. PNM's next steps are dependent upon the customers' specific circumstances.

Q. DOES PNM'S PROPOSAL TO MAINTAIN SOME DISCOUNT FOR RIDER 8 – IIPR CUSTOMERS BENEFIT THE COMPANY'S OTHER CUSTOMERS? ?

A. Yes. As noted above, if PNM does not provide any discount to these eight customers, most will experience rate shock. For example, even after banding, the two largest Rider 8 customers served under Rate 35B will experience a rate increase of nearly 30%. Without banding, these Rate 35B customers would receive an increase of about 72%. The Transitional IIPR will reduce the rate increase for these customers to 15.76%, which is PNM's proposed upper band.

Importantly, there is an overall benefit to all customers in providing a transition for these eight customers. The largest Rider 8 customers are in businesses that have narrow margins and/or operations in other cities or states, such that any significant rate increase will have a negative impact on their operations within PNM's service territory. Negative impacts may include reduced usage, cutting personnel to balance the budget and/or shifting New Mexico operations to other cities or states. As noted above, PNM is concerned, based upon customer meetings that certain Rider 8 customers will re-locate, reduce production or shift their operations to outside of PNM's service territory. All of PNM's other customers would be required to cover the system's fixed costs that would have been borne by these Rider 8 customers. PNM estimates that losing the Rider 8 – IIPR customer load could amount to a multi-million dollar revenue loss that will increase the revenue deficiency in a future rate case. Therefore, PNM's proposal to mitigate harmful rate impacts with the aim of keeping the Rider 8 customers' businesses at current levels in the local economies within PNM's service territory for a period of time will benefit all customers.

Q. HOW DOES PNM PROPOSE TO REVISE THE IIPR UNDER THE TRANSITIONAL IIPR?

A. Following the Commission's principle of gradualism, PNM proposes to revise the rider so that the eight customers will continue to receive a discount based on 60% of the current Rider 8 – IIPR discount. The proposed discount will continue for at least four years. This discount will be offered pursuant to the terms of the Transitional IIPR, attached as PNM Exhibit SC-8. As noted above, before PNM discontinues the Transitional IIPR, it will re-evaluate with its customers the impact that eliminating the newly reduced discount will have on them and may propose that the Transitional IIPR be extended or whether it should consider seeking approval for a new load retention tariff or interruptible offering.

Q. HOW WILL THE DISCOUNT UNDER THE TRANSITIONAL IIPR BE ALLOCATED TO OTHER RATE CLASSES AND WHAT WILL THE IMPACT BE?

A. PNM proposes to allocate the reduced discount under the Transitional IIPR to all rate classes as opposed to the Commission ordered allocation to just Rates 3C – General Power Low Load Factor, 4B – Large Power and 35B, which are the rate classes under which the current Rider 8 customers are served. This proposal is consistent with the principles inherent in banding, which spread reallocations of disparate cost responsibility equitably among other classes. As stated above, all customers will benefit from PNM keeping the Rider 8 customers' incremental demand, as the loss of the revenue associated with this demand will increase allocated costs to all customer classes. Furthermore, allocating the reduced discount among all rate classes imposes about a 0.1% impact in terms of revenue deficiencies for each of the Company's other rate classes. The public interest would be served by approval of the Transitional IIPR, which provides these eight customers with a gradual transition off of the discount that has been an important component of their rate structure since Rider 8 was originally approved.

VIII. TIME-OF-USE RATE DESIGN

Q. WHAT SPECIFIC DIRECTION WAS PROVIDED BY THE COMMISSION IN THE FINAL ORDER FROM THE 2015 RATE CASE REGARDING PNM'S TOU RATE?

A. The Commission appointed William Hermann as a facilitator to meet with PNM and stakeholders to mediate proposals regarding improving PNM's current TOU rates.

Q. HAS PNM MET WITH STAKEHOLDERS ON TOU RATE DESIGN?

A. Yes. The mediator has convened three mediation sessions among PNM and interested parties to discuss potential actions that will move the Company toward a more effective TOU rate design. I have attended each session and presented various options to the stakeholders for consideration as part of this mediated process.

Q. HAVE PNM AND STAKEHOLDERS COMPLETED THE MEDIATION PROCESS?

A. No. While PNM and stakeholders have engaged in productive discussions in order to develop an effective TOU rate design, including discussing various approaches that might be taken, the parties have not agreed upon a specific course of action. However, the parties have agreed to continue discussions with the common goal of developing a rate design that will influence behavioral change and reduce system peak demands.

Q. IS PNM PROPOSING ANY CHANGES TO ITS TOU RATES OR ON- AND OFF-PEAK TOU PERIODS?

A. No. Based on the outcome of PNM's TOU proposals in the 2015 Rate case, PNM believes that the best way forward is to work with stakeholders as part of the mediated process the Commission has set up with Mr. Hermann to determine whether a collaborative approach to designing an effective TOU program for residential customers can be achieved. The give-and-take discussion has allowed PNM and stakeholders to exchange views, as well as share regional and national data and experience gained from other utilities. PNM supports continuation of the mediation process to see if an agreement can be reached before PNM unilaterally proposes to overhaul its TOU rates or on- and off-peak periods.

Q. DOES PNM CONTINUE TO BELIEVE THAT IT IS IMPORTANT TO DEVELOP MORE EFFECTIVE TOU RATES IN THE FUTURE?

A. PNM believes that it is important that it find a solution in the near future to address peak demand and, in particular, peak demand usage by residential customers. As detailed in the testimony above, residential UPC is declining when the various adjustments (EE, DG and Codes and Standards) are taken into consideration. The residential class's contribution to peak demand usage, however, is increasing at the same time.

At this time, PNM believes that the best solution to address residential peak demand is an effective TOU rate. While PNM is willing to consider other options, the Company's current trajectory is to work with interested parties to design and implement improved TOU rates. If PNM cannot reach agreement with stakeholders, it may at a later time make its own proposal aimed at addressing peak demand usage.

However, PNM also believes that some concrete interim steps can be taken to support future TOU rates. As a first step to this process of developing a rate design to address peak demand usage, PNM is proposing to flatten its inclining block rates. This proposal, as supported by PNM Witness Aguirre, represents the first step the Company can undertake to develop effective TOU rates that do not result in rate arbitrage. As fully explained by PNM Witness Aguirre, the current inclining block rates permit residential customers to switch to a TOU rate without any change in behavior. Since the main purpose of a TOU rate would be to change customer behavior regarding on-peak usage, PNM must first address its inclining block rates in preparation for evaluating more effective TOU options.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

GCG#522674

Qualifications of Stella Chan

PNM Exhibit SC-1

Is contained in the following 2 pages

STELLA CHAN: EDUCATIONAL AND PROFESSIONAL SUMMARY

Name: Stella Chan

Address: Public Service Company of New Mexico
Main Offices
Albuquerque, New Mexico 87158-1105

Position: Executive Director, Strategic Marketing and Product Management

Education: University of Houston, Houston, Texas

- MBA with concentration in Finance
- BBA with major in Finance

Language Skills:
Fluent in English, Mandarin Chinese and Cantonese

Employment: Public Service Company of New Mexico, Albuquerque, New Mexico:
Director, Pricing & Load Research: 2013 to present

Colorado Springs Utilities, Colorado Springs, Colorado
Manager, Pricing & Forecasting, Planning and Finance Division:
2003-2013

University of Houston, Houston, Texas, New Mexico:
Adjunct Faculty – Finance Department: 2003

Independent Consultant: 2002 to 2003

- Challenger Development, L.C.
- Boyce Power System

Energy Wholesale Operations, Houston, Texas
Director, Government and Regulatory Affairs: 2001

Enron Corporation, Houston, Texas
Director, Government Affairs: 2000-2001
General Manager, Operations, SK-Enron, Seoul, South Korea: 1999-2000
Director, Regulatory Affairs, Enron International: 1997-1999
Manager, Rates and Tariffs, Enron Energy Services: 1997

El Paso Energy, Houston, Texas
Staff Analyst, Research and Competitive Analysis: 1996-1997
Consultant, Business Development: 1995-1996

Employment (Continued):
Duke Energy (formerly Texas Eastern), Houston, Texas

Project Leader, Strategic Planning: 1994-1005
Project Leader, Market Planning and Analysis: 1992-1994

El Paso Energy (formerly Tenneco Gas), Houston, Texas
Senior Analyst, Cost Allocation and Rate Design: 1990-1992
Analyst, Special Projects: 1987-1989

Community Activities (Colorado Springs, Colorado):
Board Chair, Urban Peak Colorado Springs
Treasurer, Urban Peak Colorado Spring
Board Member, CASA (Court Appointed Special Advocate), Pikes Peak Region
Steering Committee, Community Focus Fund, Colorado Springs Utilities

Testimony Filed Before the New Mexico Public Regulation Commission:

Case Number	Proceeding/Subject Matter
Un-Docketed	Advice Notice No. 478, relating to the revision of PNM Rate No. 20- Integrated System Streetlighting and Floodlighting Service, September 27, 2013
Un-Docketed	Advice Notice Nos. 480 and 65, regarding consolidation of PNM's North and South Rules, updates to service rules, and changes to Rule 15 - Line Extension Policy, November 15, 2013
14-00118-UT	Matter of PNM's Advice Notice 493, relating to modification to the qualifying criteria for service under Rate No. 5B-Large Service to Customers, April 22, 2014
14-00150-UT	Matter of PNM's Application for Approval of the City of Rio Rancho Underground Project Rider Pursuant to Advice Notice No. 495, May 25, 2014
14-00158-UT	PNM's Renewable Energy Portfolio Procurement Plan for 2015 and Proposed 2015 Rider No. 36 Rate, June 2, 2014
14-00310-UT	PNM's Application for Approval of 2014 Electric Energy Efficiency and Load Management Program Plan and Revision to Tariff Rider No. 16, October 6, 2014
14-00332-UT	Application of PNM for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 507
14-00337-UT	Application of PNM for Approval of the City of Albuquerque 2014 Underground Project Rider pursuant to Advice Notice No. 502
15-00166-UT	In the Matter of Public Service Company of New Mexico's Renewable Energy Portfolio Procurement Plan for 2016 and Proposed 2016 Rider Rate Under Rate Rider No. 36
15-00261-UT	In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 513

GCG#522472

Alphabetical listing of acronyms used in this testimony

PNM Exhibit SC-2

Is contained in the following 2 pages

ACRONYMS USED IN TESTIMONY

Term	Acronym
Applied Energy Group	AEG
Bureau of Business and Economic Research	BBER
Coincident Peak	CP
Cooling Degree Days	CDDs
Distributed Generation	DG
Economic Development Rider No. 45	EDR
Efficient Use of Energy Act	EUEA
Embedded Class Cost of Service Study	ECCOSS
Energy Efficiency	EE
Heating Degree Days	HDDs
Integrated Resource Plan	IRP
National Oceanic and Atmospheric Administration	NOAA
National Renewable Energy Laboratory	NREL
New Mexico Public Regulation Commission	NMPRC or Commission
NMPRC Case No. 13-00390-UT	BART Case
NMPRC Case No. 15-00261-UT	2015 Rate Case
Public Service Company of New Mexico	PNM or Company
Rate Design Model	RD Model
Rate 1A – Residential Service	Rate 1A – Residential
Rate 1B – Residential Service Time-of-Use	Rate 1B – Residential TOU
Rate 2A – Small Power Service	Rate 2A – Small Power
Rate 2B – Small Power Service Time-of-Use	Rate 2B – Small Power TOU
Rate 3B – General Power Service Time-Of-Use	Rate 3B – General Power
Rate 3C – General Power Service (Low Load Factor) Time-of-Use	Rate 3C – General Power (Low Load Factor) (together with Rate 3B – General Power, "Rate 3B/3C – General Power")
Rate 4B – Large Power Service Time-of-Use	Rate 4B – Large Power
Rate 5B – Large Service for Customers >= 8,000 kW	Rate 5B – Large Service >=8,000 kW
Rate 6 – Private Area Lighting Service	Rate 6 – Private Lighting
Rate 10A – Irrigation Service	Rate 10A – Irrigation
Rate 10B – Irrigation Service Time-of-Use	Rate 10B – Irrigation TOU (together with Rate 10A – Irrigation, "Rate 10A/10B – Irrigation")
Rate 11B – Water and Sewage Pumping Time-Of-Use Rate	Rate 11B – Water and Sewage
Rate 15B – Large Service for Public Universities > 8,000 kW	Rate 15B –Universities
Rate 20 – Integrated System Streetlighting and Floodlighting Service	Rate 20 – Streetlighting or Streetlighting

Term	**Acronym**
Rate 30B – Large Service for Manufacturing >= 30,000 kW	Rate 30B – Manufacturing
Rate 33B – Large Service for Station Power	Rate 33B – Station Power
Rate 35B – Large Power Service >=3,000kW	Rate 35B
Rate 36B – Special Service Rate – Renewable Energy Resource	Rate 36B
Rider 8 – Incremental Interruptible Power Rate	Rider 8 – IIPR or Rider 8
Schedule showing the underlying data used to determine Base Period and Test Period production, transmission, distribution and other allocators	Summary Allocators
Schedule showing the application of the Test Period Billing Determinants	Test Period Billing Determinants
Time-of-Use	TOU
Transitional Rider 8 – Incremental Interruptible Power Rate	Transitional Rider 8 – IIPR or Transitional IIPR
Twelve Coincident Peak method	12 CP
Usage Per Customers	UPC
3-Summer/1-Winter Coincident Peak	3S1WCP

Analysis of the Relationship Between Income Levels and Energy Consumption for PNM's Residential Customers

PNM Exhibit SC-3

Is contained in the following 5 pages

Analysis of the Relationship Between Income Levels and Energy Consumption for PNM's Residential Customers

PNM conducted an analysis of 2013, 2014 and 2015 customer usage data, utilizing U.S. Census Block Groups ("CBG") and Median Household Income ("MHI") as reported by the U.S. Census Bureau to determine whether there is a relationship between energy usage and income levels for residential customers.

To conduct this analysis to determine the relationship between energy usage and income levels, the following steps were taken:

1. Analysis was conducted for 2013, 2014 and 2015.[1]
2. Certain data was filtered out of the sample, including:
    a. Accounts that had blank readings[2] for two or more billing cycles in a 14-month cycle;[3]
    b. Accounts that have distributed generation, given that metered data from such accounts does not reflect the amount of energy consumed by the customers; and
    c. Accounts with no annual consumption.
3. Filtered information on an annual basis was exported to a geographical database.
4. MHI for each CBG was established. MHI estimates were obtained from the U.S. Census Bureau's American Community Survey. Specifically, the 2010 through 2014 five-year estimate in 2014 inflation adjusted dollars was used for this analysis.
5. Individual account records were spatially aggregated using mapping software, associating accounts with CBG areas and creating a mean kilowatt-hour consumption attribute for each CBG.
6. The resulting correlation between the MHI and mean kilowatt-hour consumption per CBG for the three relevant years (2013, 2014 and 2015) was graphed.
7. Descriptive statistics were calculated for each year to evaluate the strength of the relationship between the variables.

As the attached graphs indicate, the model uses Best Fit characteristics to evaluate the results. If the representative sample points in each graph were tightly clustered or matched the Best Fit, it would indicate that there is a direct relationship between income and consumption. The variability seen in the graphs in terms of the representative sample points indicates a poor correlation between income and usage.

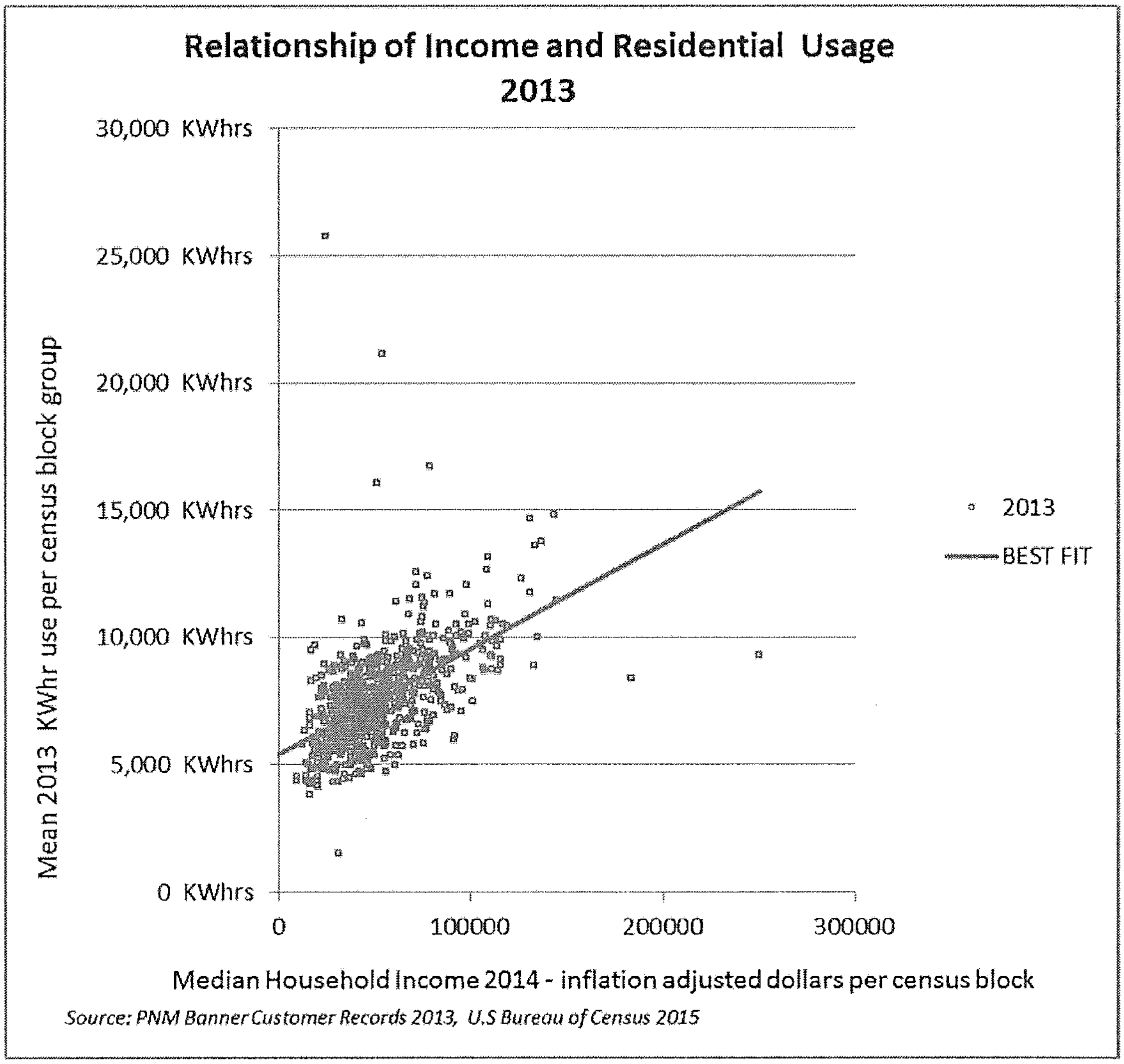
In addition to the graph, PNM also analyzed the R-squared value or correlation coefficient. The R-squared value is a ratio of the variability observed between income and consumption. An R-squared of 1.0 indicates that the regression line perfectly fits the data. The R-squared for 2013 is

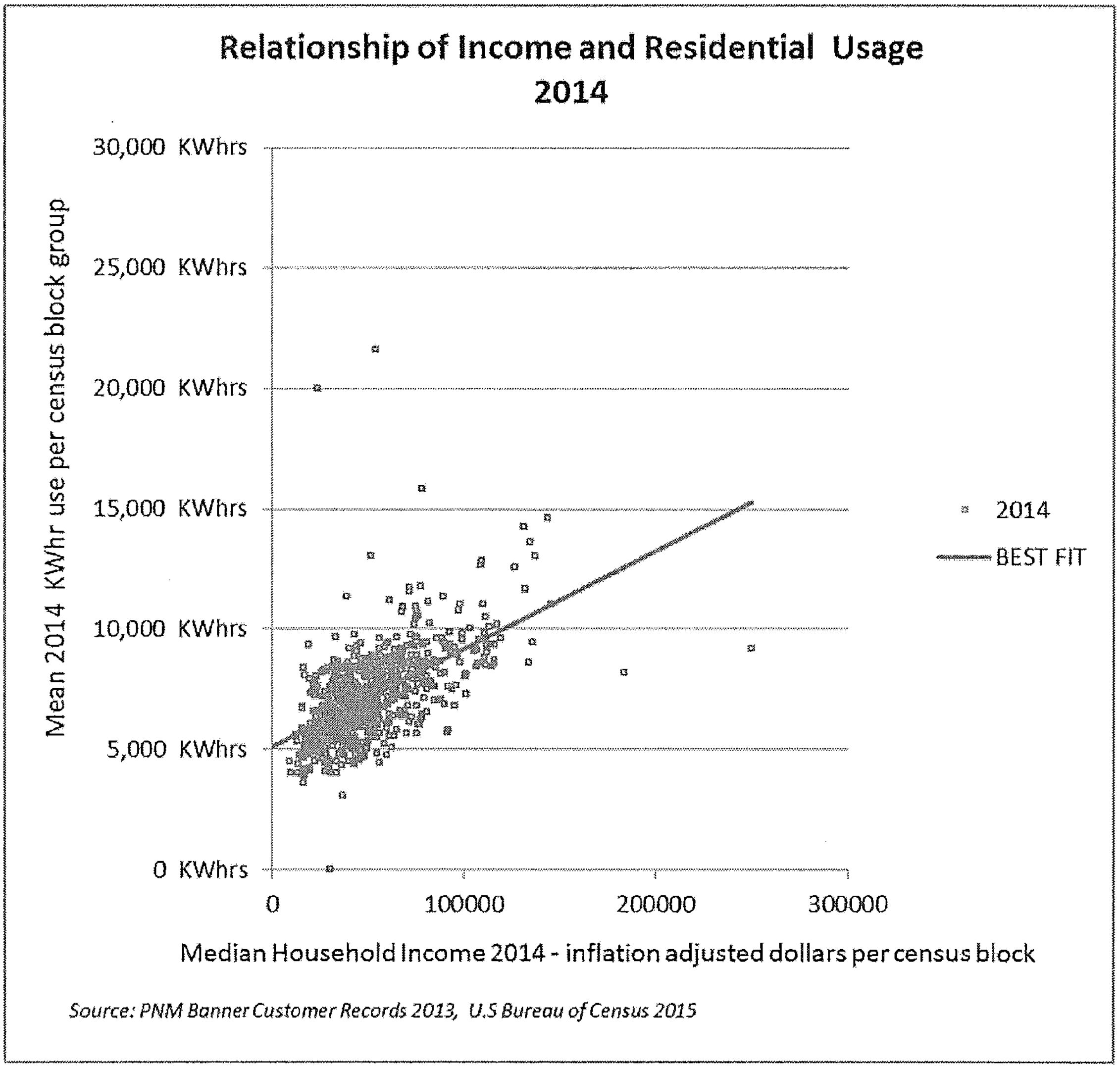
[1] While calendar years were used to conduct the analysis, PNM used December of 2012 and January of 2016 to filter the data.

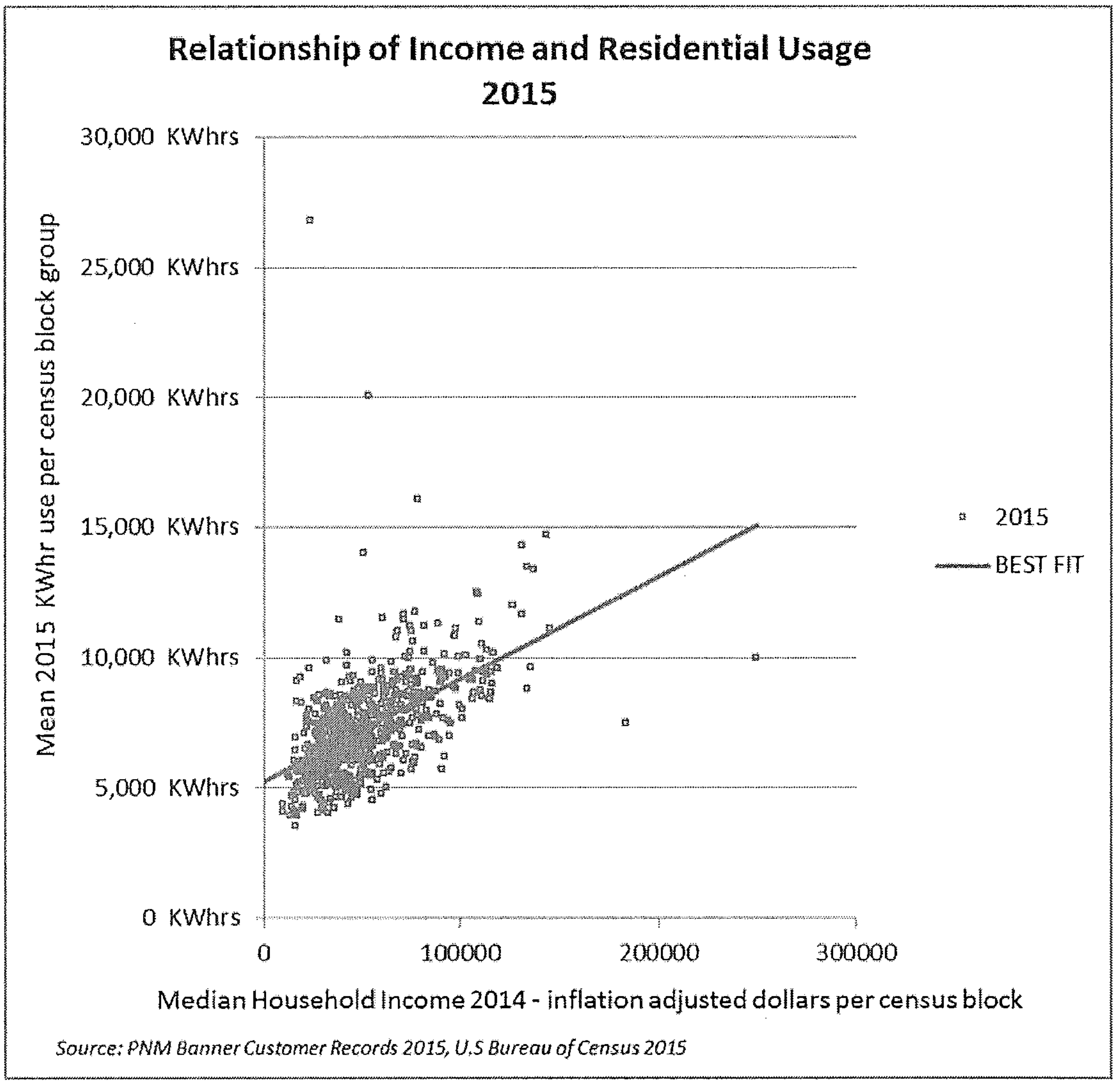
[2] Blank readings occur if no meter read was taken or if the account was closed.

[3] While the analysis was conducted on calendar year basis, PNM used December of each prior year and January of the following year to filter data. For instance, for 2013, PNM looked to December 2012 and January 2014 to filter the 2013 data.

0.28; the R-squared for 2014 is 0.32; and the R-squared for 2015 if .0.29. As such, the R-squared value indicates a poor correlation between income and usage.


Relationship of Income and Residential Usage
2013
30,000 KWhrs
25,000 KWhrs
20,000 KWhrs
15,000 KWhrs
10,000 KWhrs
5,000 KWhrs
0 KWhrs
Mean 2013 KWhr use per census block group
0
100000
200000
300000
Median Household Income 2014 - inflation adjusted dollars per census block
2013
BEST FIT
Source: PNM Banner Customer Records 2013, U.S Bureau of Census 2015


Relationship of Income and Residential Usage
2014
30,000 KWhrs
25,000 KWhrs
20,000 KWhrs
15,000 KWhrs
10,000 KWhrs
5,000 KWhrs
0 KWhrs
Mean 2014 KWhr use per census block group
0
100000
200000
300000
Median Household Income 2014 - inflation adjusted dollars per census block
2014
BEST FIT
Source: PNM Banner Customer Records 2013, U.S Bureau of Census 2015


Relationship of Income and Residential Usage
2015
30,000 KWhrs
25,000 KWhrs
20,000 KWhrs
15,000 KWhrs
10,000 KWhrs
5,000 KWhrs
0 KWhrs
Mean 2015 KWhr use per census block group
0
100000
200000
300000
Median Household Income 2014 - inflation adjusted dollars per census block
2015
BEST FIT
Source: PNM Banner Customer Records 2015, U.S Bureau of Census 2015

Base Period and Test Period Demand and Energy Allocators

PNM Exhibit SC-4

Is contained in the following 10 pages

Demand Allocators at Generation Peak (kW)
Base Period Ending: 06/30/16

	Column	A	B	C	D	E	F	G
		Fri 07/24/2015	Wed 08/05/2015	Wed 09/02/2015	Thu 10/01/2015	Mon 11/16/2015	Tue 12/15/2015	Mon 01/11/2016
		Hour: 1700	Hour: 1800	Hour: 1700	Hour: 1700	Hour: 1900	Hour: 1900	Hour: 1900
		Generation Peak	Generation Peak	Generation Peak	Generation Peak	Generation Peak	Generation Peak	Generation Peak
1	**Distribution-Secondary**							
2	Residential Total - 1A & 1B	863,857	877,031	681,006	628,185	594,583	646,066	630,357
3	Small Power Total - 2A & 2B	238,085	216,954	230,818	216,654	118,988	130,368	123,285
4	General Power- 3B	271,910	280,559	306,484	280,187	237,739	252,807	231,727
5	General Power- 3C Low Load Factor	31,778	33,709	34,860	30,172	19,992	21,810	25,083
6	Irrigation - 10A & 10B	3,398	4,409	6,216	3,042	75	393	106
7	Street Lights-Public	0	0	0	0	12,531	12,375	11,898
8	Street Lights-Private	0	0	0	0	3,847	3,767	3,647
9	**Subtotal**	1,409,028	1,412,662	1,259,383	1,158,239	987,756	1,067,587	1,026,103
10								
11	**Distribution-Primary**							
12	Large Power - 4B	188,313	178,484	192,486	180,422	140,544	143,703	144,815
13	Company Use	3,277	3,276	3,638	3,464	3,011	3,130	3,496
14	Water & Sewage - 11B	21,378	16,132	20,375	18,988	13,558	11,961	16,942
15	**Subtotal**	212,967	197,893	216,500	202,874	157,113	158,794	165,253
16								
17	**Subtotal - Secondary & Primary**	1,621,995	1,610,555	1,475,882	1,361,113	1,144,868	1,226,381	1,191,356
18								
19	**Distribution-Primary/Substation**							
20	Lrg. Srv. Manufacturing - 30B	54,792	54,350	54,459	51,850	48,657	48,781	48,849
21	Lrg. Srv. Manufacturing HL Factor - 35B	25,790	26,937	25,560	23,770	25,360	23,399	17,197
22								
23	**Subtotal**	80,581	81,287	80,019	75,620	74,017	72,180	66,046
24								
25	**Total Distribution**	1,702,577	1,691,842	1,555,901	1,436,734	1,218,885	1,298,561	1,257,403
26	Deviation Due to Rounding							

Demand Allocators at Generation Peak (kW)
Base Period Ending: 06/30/16

	Column	H	I	J	K	L
		Wed 02/03/2016	Tue 03/08/2016	Mon 04/25/2016	Tue 05/31/2016	Wed 06/22/2016
		Hour: 1900	Hour: 2000	Hour: 2100	Hour: 1800	Hour: 1700
		Generation Peak	Generation Peak	Generation Peak	Generation Peak	Generation Peak
1	**Distribution-Secondary**					
2	Residential Total - 1A & 1B	627,241	509,438	407,368	409,562	886,390
3	Small Power Total - 2A & 2B	129,494	96,035	96,834	192,177	259,415
4	General Power- 3B	228,581	193,047	211,494	254,583	290,311
5	General Power- 3C Low Load Factor	24,653	21,810	38,912	41,366	46,011
6	Irrigation - 10A & 10B	88	2,534	4,135	4,629	6,361
7	Street Lights-Public	11,587	11,065	12,315	0	0
8	Street Lights-Private	3,555	3,381	3,754	0	0
9	**Subtotal**	1,025,199	837,311	774,812	902,317	1,488,489
10						
11	**Distribution-Primary**					
12	Large Power - 4B	146,096	141,565	140,924	170,358	190,987
13	Company Use	2,976	2,685	2,674	2,754	1,834
14	Water & Sewage - 11B	11,774	14,110	33,904	16,374	19,867
15	**Subtotal**	160,846	158,360	177,502	189,486	212,688
16						
17	**Subtotal - Secondary & Primary**	1,186,045	995,671	952,314	1,091,803	1,701,177
18						
19	**Distribution-Primary/Substation**					
20	Lrg. Srv. Manufacturing - 30B	47,332	44,671	44,644	46,770	48,045
21	Lrg. Srv. Manufacturing HL Factor - 35B	22,421	16,852	23,825	24,664	26,016
22						
23	**Subtotal**	69,753	61,523	68,469	71,434	74,061
24						
25	**Total Distribution**	1,255,798	1,057,194	1,020,782	1,163,237	1,775,238
26	Deviation Due to Rounding					

Demand Allocators at Generation Peak (kW)
Base Period Ending: 06/30/16

	Column	A	B	C	D	E	F	G
		Fri 07/24/2015 Hour: 1700 Generation Peak	Wed 08/05/2015 Hour: 1800 Generation Peak	Wed 09/02/2015 Hour: 1700 Generation Peak	Thu 10/01/2015 Hour: 1700 Generation Peak	Mon 11/16/2015 Hour: 1900 Generation Peak	Tue 12/15/2015 Hour: 1900 Generation Peak	Mon 01/11/2016 Hour: 1900 Generation Peak
27								
28	**Reclassified Distribution**							
29	Mining - 5B	7,789	11,699	10,631	16,612	13,929	12,098	12,089
30	**Total**	7,789	11,699	10,631	16,612	13,929	12,098	12,089
31								
32	**Dist. + Reclassified Dist.**	1,710,366	1,703,541	1,566,532	1,453,346	1,232,815	1,310,659	1,269,491
33	Deviation Due to Rounding							
34								
35	**Transmission**							
36	Lrg. Srv. Universities -15B	12,252	10,971	25,488	11,652	4,132	1,847	1,675
37	Station Service 33B	456	524	440	0	0	468	478
38	Navopache (without WAPA)	52,217	61,057	48,987	48,221	64,450	70,928	66,939
39	City of Aztec	6,520	6,710	6,614	6,348	5,533	6,224	5,119
40	Jicarilla	2,851	2,847	3,044	2,807	3,183	3,450	3,652
41	**Total**	74,296	82,109	84,572	69,028	77,297	82,916	77,862
42								
43	Navopache WAPA	5,000	4,000	3,000	3,000	4,000	4,000	4,000
44	**Total System**	**1,784,662**	**1,785,650**	**1,651,104**	**1,522,374**	**1,310,112**	**1,393,575**	**1,347,353**
45	Deviation Due to Rounding							
46								
47	**Jurisdictional Breakdown**							
48	New Mexico	1,719,797	1,711,759	1,588,821	1,461,534	1,233,936	1,309,843	1,268,148
49	FERC	61,588	70,614	58,645	57,376	73,166	80,601	75,709
50	**Subtotal**	1,781,385	1,782,374	1,647,466	1,518,910	1,307,101	1,390,445	1,343,857
51	Company Use	3,277	3,276	3,638	3,464	3,011	3,130	3,496
52	**Total**	**1,784,662**	**1,785,650**	**1,651,104**	**1,522,374**	**1,310,112**	**1,393,575**	**1,347,353**
53								
54	**Jurisdictional Breakdown (With Company Use Allocated Using Demand)**							
55	New Mexico	1,722,961	1,714,906	1,592,330	1,464,867	1,236,778	1,312,792	1,271,447
56	FERC	61,701	70,744	58,774	57,507	73,334	80,783	75,906
57	**Total**	1,784,662	1,785,650	1,651,104	1,522,374	1,310,112	1,393,575	1,347,353
58								
59								

Demand Allocators at Generation Peak (kW)
Base Period Ending: 06/30/16

Line		H	I	J	K	L
	Column	Wed 02/03/2016 Hour: 1900 Generation Peak	Tue 03/08/2016 Hour: 2000 Generation Peak	Mon 04/25/2016 Hour: 2100 Generation Peak	Tue 05/31/2016 Hour: 1800 Generation Peak	Wed 06/22/2016 Hour: 1700 Generation Peak
27						
28	**Reclassified Distribution**					
29	Mining - 5B	10,025	11,872	11,590	3,595	7,532
30	**Total**	10,025	11,872	11,590	3,595	7,532
31						
32	**Dist. + Reclassified Dist.**	1,265,823	1,069,066	1,032,373	1,166,832	1,782,769
33	Deviation Due to Rounding					
34						
35	**Transmission**					
36	Lrg. Srv. Universities -15B	3,321	5,170	6,754	16,074	13,355
37	Station Service 33B	523	439	393	450	0
38	Navopache (without WAPA)	68,222	51,020	47,892	47,058	66,660
39	City of Aztec	5,008	4,778	4,244	4,426	7,465
40	Jicarilla	3,605	3,097	2,627	2,450	3,176
41	**Total**	80,680	64,504	61,910	70,458	90,657
42						
43	Navopache WAPA	4,000	4,000	3,000	3,000	4,000
44	**Total System**	**1,346,503**	**1,133,571**	**1,094,282**	**1,237,290**	**1,873,426**
45	Deviation Due to Rounding					
46						
47	**Jurisdictional Breakdown**					
48	New Mexico	1,266,691	1,071,991	1,036,847	1,180,602	1,794,290
49	FERC	76,835	58,895	54,762	53,934	77,302
50	**Subtotal**	1,343,527	1,130,886	1,091,609	1,234,536	1,871,592
51	Company Use	2,976	2,685	2,674	2,754	1,834
52	**Total**	**1,346,503**	**1,133,571**	**1,094,282**	**1,237,290**	**1,873,426**
53						
54	**Jurisdictional Breakdown (With Company Use Allocated Using Demand)**					
55	New Mexico	1,269,498	1,074,536	1,039,386	1,183,236	1,796,049
56	FERC	77,006	59,035	54,896	54,054	77,378
57	**Total**	1,346,503	1,133,571	1,094,282	1,237,290	1,873,426
58						
59						

Demand Allocators at Generation Peak (kW)
Base Period Ending: 06/30/16

	Column	A	B	C	D	E	F	G
		Fri 07/24/2015 Hour: 1700 Generation Peak	Wed 08/05/2015 Hour: 1800 Generation Peak	Wed 09/02/2015 Hour: 1700 Generation Peak	Thu 10/01/2015 Hour: 1700 Generation Peak	Mon 11/16/2015 Hour: 1900 Generation Peak	Tue 12/15/2015 Hour: 1900 Generation Peak	Mon 01/11/2016 Hour: 1900 Generation Peak
60								
61	**FERC and NMPRC Customers w/o Company Use**							
62	Retail	1,719,797	1,711,759	1,588,821	1,461,534	1,233,936	1,309,843	1,268,148
63	Aztec	6,520	6,710	6,614	6,348	5,533	6,224	5,119
64	Navopache	52,217	61,057	48,987	48,221	64,450	70,928	66,939
65	Jicarilla	2,851	2,847	3,044	2,807	3,183	3,450	3,652
66		1,781,385	1,782,374	1,647,466	1,518,910	1,307,101	1,390,445	1,343,857
67								
68	**FERC and NMPRC Customers with Company Use Allocated**							
69	Retail	1,722,961	1,714,906	1,592,330	1,464,867	1,236,778	1,312,792	1,271,447
70	Aztec	6,532	6,723	6,629	6,362	5,546	6,238	5,132
71	Navopache	52,313	61,169	49,095	48,331	64,598	71,087	67,113
72	Jicarilla	2,856	2,852	3,051	2,814	3,190	3,458	3,661
73		1,784,662	1,785,650	1,651,104	1,522,374	1,310,112	1,393,575	1,347,353
74								
75	**Adjustments to Base Period**							
76	**Remove Gallup and Annualize Jicarilla**							
77								
78	**Adjusted Base Period Allocator - Generation Demand**							
79	**FERC and NMPRC Customers w/o Company Use**							
80	Retail	1,719,797	1,711,759	1,588,821	1,461,534	1,233,936	1,309,843	1,268,148
81	Aztec	0	0	0	0	0	0	0
82	Navopache	52,217	61,057	48,987	48,221	64,450	70,928	66,939
83	Jicarilla	0	0	0	0	0	0	0
84	Total	1,772,014	1,772,817	1,637,808	1,509,755	1,298,386	1,380,771	1,335,087
85								
86	**FERC and NMPRC Customers with Company Use Allocated**							
87	Retail	1,722,961	1,714,906	1,592,330	1,464,867	1,236,778	1,312,792	1,271,447
88	Aztec	0	0	0	0	0	0	0
89	Navopache	52,313	61,169	49,095	48,331	64,598	71,087	67,113
90	Jicarilla	0	0	0	0	0	0	0
91	Total	1,775,274	1,776,075	1,641,425	1,513,198	1,301,376	1,383,879	1,338,560

Demand Allocators at Generation Peak (kW)
Base Period Ending: 06/30/16

Line	Column	H	I	J	K	L			
		Wed 02/03/2016	Tue 03/08/2016	Mon 04/25/2016	Tue 05/31/2016	Wed 06/22/2016			
		Hour: 1900	Hour: 2000	Hour: 2100	Hour: 1800	Hour: 1700			
		Generation Peak	Generation Peak	Generation Peak	Generation Peak	Generation Peak			
60							Period End June 2016		
61	FERC and NMPRC Customers w/o Company Use								
62	Retail	1,266,691	1,071,991	1,036,847	1,180,602	1,794,290	1,387,022	95.42%	95.42%
63	Aztec	5,008	4,778	4,244	4,426	7,465	5,749	0.40%	4.58%
64	Navopache	68,222	51,020	47,892	47,058	66,660	57,804	3.98%	
65	Jicarilla	3,605	3,097	2,627	2,450	3,176	3,066	0.21%	
66		1,343,527	1,130,886	1,091,609	1,234,536	1,871,592	1,453,641	100.00%	
67									
68	FERC and NMPRC Customers with Company Use Allocated								
69	Retail	1,269,498	1,074,536	1,039,386	1,183,236	1,796,049	1,389,899	95.42%	95.42%
70	Aztec	5,020	4,789	4,254	4,435	7,473	5,761	0.40%	4.58%
71	Navopache	68,373	51,142	48,009	47,163	66,725	57,927	3.98%	
72	Jicarilla	3,613	3,104	2,633	2,455	3,180	3,072	0.21%	
73		1,346,503	1,133,571	1,094,282	1,237,290	1,873,426	1,456,659	100.00%	
74									
75	**Adjustments to Base Period**								
76	**Remove Gallup and Annualize Jicarilla**								
77							Adjusted Base Period		
78	Adjusted Base Period Allocator - Generation Demand						Period End June 2016		
79	FERC and NMPRC Customers w/o Company Use								
80	Retail	1,266,691	1,071,991	1,036,847	1,180,602	1,794,290	1,387,022	96.00%	96.00%
81	Aztec	0	0	0	0	0	0	0.00%	4.00%
82	Navopache	68,222	51,020	47,892	47,058	66,660	57,804	4.00%	
83	Jicarilla	0	0	0	0	0	0	0.00%	
84	Total	1,334,913	1,123,011	1,084,738	1,227,660	1,860,950	1,444,826	100.00%	
85									
86	FERC and NMPRC Customers with Company Use Allocated								
87	Retail	1,269,498	1,074,536	1,039,386	1,183,236	1,796,049	1,389,899	96.00%	96.00%
88	Aztec	0	0	0	0	0	0	0.00%	4.00%
89	Navopache	68,373	51,142	48,009	47,163	66,725	57,927	4.00%	
90	Jicarilla	0	0	0	0	0	0	0.00%	
91	Total	1,337,871	1,125,677	1,087,395	1,230,399	1,862,774	1,447,825	100.00%	

Energy Allocators (MWh)
Base Period Ending: 06/30/16

Line	Column	A	B	C	D	E	F	G	H	I
Line	Energy	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16
1	Retail	952,098	981,272	864,775	765,180	756,177	849,462	839,125.03	733,798	734,193
2	Aztec (1)	3,498	3,666	3,233	2,759	2,894	3,336	3,491	2,820	2,847
3	Navopache (1)	34,759	34,814	31,103	31,334	37,160	45,619	45,100	36,885	33,770
4	Jicarilla (1)	1,652	1,726	1,599	1,695	1,880	2,194	2,325	2,043	1,936
5	FERC Losses (4)	1,397	1,339	1,197	1,192	1,396	1,703	1,696	1,390	1,284
6	***System(CAT 83)(1)***	***993,404***	***1,022,817***	***901,906***	***802,160***	***799,508***	***902,313***	***891,737***	***776,936***	***774,030***
7										
8	***Economy Service (5)***	64,954	63,514	63,249	66,905	66,089	69,363	69,536	66,602	70,551
9	***Retail without Economy Service***	***887,144***	***917,758***	***801,526***	***698,275***	***690,088***	***780,099***	***769,589***	***667,196***	***663,642***
10	***System without Economy Service (CAT 525) (1)***	928,450	959,303	838,657	735,255	733,419	832,950	822,201	710,334	703,479
11	(1) Data Warehouse CAT 525 hourly data									
12	*(3) Excludes Navopache's WAPA allocation.*									
13	*(4) Estimated Losses*									
14	*(5) Source: General Ledger*									
15										
16										
17										
18	**Losses - Allocation**									
21	Aztec	122.43	122.09	107.66	91.89	96.38	111.07	116.25	93.91	94.80
22	Navopache	1,216.57	1,159.29	1,035.71	1,043.41	1,237.44	1,519.10	1,501.83	1,228.25	1,124.55
23	Jicarilla	57.81	57.49	53.25	56.45	62.60	73.05	77.43	68.02	64.47
24										
25										
26	**Retail and FERC Customers with Losses Applied**									
27	Retail	952,098	981,272	864,775	765,180	756,177	849,462	839,125	733,798	734,193
28	Retail without Economy Service	887,144	917,758	801,526	698,275	690,088	780,099	769,589	667,196	663,642
29	Aztec	3,621	3,788	3,341	2,851	2,991	3,447	3,607	2,914	2,942
30	Navopache	35,976	35,973	32,138	32,377	38,398	47,138	46,602	38,113	34,895
31	Jicarilla	1,710	1,784	1,652	1,752	1,942	2,267	2,403	2,111	2,001
32		928,450	959,303	838,657	735,255	733,419	832,950	822,201	710,334	703,479
33										
34		FERC Loss Factors								
35		Effective June 1 2015	3.33%							
36		Effective June 1 2016	3.50%							
37										
38										
39										
40										
41	**Adjusted Base Period**									
42										
43	**FERC and NMPRC Customers**									
44	Retail	952,098	981,272	864,775	765,180	756,177	849,462	839,125	733,798	734,193
45	Retail without Economy Service	887,144	917,758	801,526	698,275	690,088	780,099	769,589	667,196	663,642
46	Aztec	-	-	-	-	-	-	-	-	-
47	Navopache	35,976	35,973	32,138	32,377	38,398	47,138	46,602	38,113	34,895
48	Jicarilla	-	-	-	-	-	-	-	-	-
49		923,120	953,731	833,664	730,652	728,486	827,237	816,191	705,309	698,537

Energy Allocators (MWh)
Base Period Ending: 06/30/16

	Column	J	K	L	M				
Line	Energy	*Apr-16*	*May-16*	*Jun-16*	*Total*				
1	Retail	695,647	755,794	934,520	9,862,041				
2	Aztec (1)	2,754	2,824	3,492	37,614				
3	Navopache (1)	31,175	32,131	34,841	428,690				
4	Jicarilla (1)	1,740	1,685	1,687	22,161				
5	FERC Losses (4)	1,188	1,220	1,333	16,334				
6	***System(CAT 83)(1)***	***732,503***	***793,653***	***975,873***	10,366,840				
7									
8	***Economy Service (5)***	56,424	68,617	64,958	800,762				
9	***Retail without Economy Service***	***629,223***	***687,177***	***869,562***	9,061,279				
10	***System without Economy Service (CAT 525) (1)***	666,079	725,036	910,915	9,566,078				
11	(1) Data Warehouse CAT 525 hourly data								
12	*(3) Excludes Navopache's WAPA allocation.*								
13	*(4) Estimated Losses*								
14	*(5) Source: General Ledger*								
15									
16									
17									
18	**Losses - Allocation**								
21	Aztec	91.69	94.03	116.28					
22	Navopache	1,038.14	1,069.96	1,160.22					
23	Jicarilla	57.93	56.10	56.17					
24						**Period End June 2016**			
25									
26	**Retail and FERC Customers with Losses Applied**								
27	Retail	695,647	755,794	934,520					
28	Retail without Economy Service	629,223	687,177	869,562		9,061,279	94.7%	94.72%	NMPRC
29	Aztec	2,845	2,918	3,608		38,872	0.4%	5.28%	FERC
30	Navopache	32,213	33,201	36,002		443,025	4.6%		
31	Jicarilla	1,797	1,741	1,743		22,902	0.2%		
32		666,079	725,036	910,915		9,566,078	100.0%	100.0%	
33									
34									
35									
36									
37									
38									
39									
40						**Adjusted Base Period**			
41	**Adjusted Base Period**					**Period End June 2016**			
42									
43	**FERC and NMPRC Customers**								
44	Retail	695,647	755,794	934,520					
45	Retail without Economy Service	629,223	687,177	869,562		9,061,279	95.3%	95.34%	NMPRC
46	Aztec	-	-	-		-	0.0%	4.66%	FERC
47	Navopache	32,213	33,201	36,002		443,025	4.7%		
48	Jicarilla	-	-	-		-	0.0%		
49		661,436	720,377	905,564		9,504,304	100.0%	100.0%	

Demand Allocators at Generation Peak (MW)
Test Period Ending: 12/31/2018

Test Period Allocator - Generation Demand

	Jan-18	*Feb-18*	*Mar-18*	*Apr-18*	*May-18*	*Jun-18*	*Jul-18*	*Aug-18*	*Sep-18*	*Oct-18*	*Nov-18*	*Dec-18*	Test Period End Dec 2018		
													Total		
Retail	1,321	1,237	1,151	1,153	1,383	1,900	1,805	1,782	1,549	1,296	1,382	1,448	17,406	100%	100% Retail
Navopache	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	0% FERC
Aztec	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	
Jicarilla	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	
System Total	1,321	1,237	1,151	1,153	1,383	1,900	1,805	1,782	1,549	1,296	1,382	1,448	17,406	100%	

Energy Allocators (MWh)
Test Period Ending: 12/31/2018

Total Retail and FERC Customers at Generation	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Test Period End Dec 2018 Total		
Retail	725,307	534,497	610,057	671,215	707,944	909,544	882,829	906,542	714,942	652,236	719,192	793,599	8,827,904	100%	100% Retail
Navopache	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	0% FERC
Aztec	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	
Jicarilla	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	
System Total	725,307	534,497	610,057	671,215	707,944	909,544	882,829	906,542	714,942	652,236	719,192	793,599	8,827,904	100%	

Test Period Billing Determinants

PNM Exhibit SC-5

Is contained in the following 14 pages

Test Period Billing Determinants

A Line No.	B Desc	C Tariff	D Test Period Determinants	E Rates 15-00261-UT	F Test Period Revenues
1	Summer Customers	01A - Residential	1,437,485	$7.00	$10,062,397
2	Summer Block 1 kWh (1st 450 kWh)	01A - Residential	520,245,451	$0.0767429	$39,925,145
3	Summer Block 2 kWh (Next 450 kWh)	01A - Residential	255,399,661	$0.1221238	$31,190,377
4	Summer Block 3 kWh (All All Other kWh)	01A - Residential	169,309,364	$0.1472299	$24,927,401
5	Summer Total kWh	01A - Residential	944,954,476		
6	Non-Summer Customers	01A - Residential	4,176,632	$7.00	$29,236,423
7	Non-Summer Block 1 kWh (1st 450 kWh)	01A - Residential	1,429,514,856	$0.0767429	$109,705,116
8	Non-Summer Block 2 kWh (Next 450 kWh)	01A - Residential	522,833,656	$0.1053759	$55,094,067
9	Non-Summer Block 3 kWh (All All Other kWh)	01A - Residential	263,929,600	$0.1198334	$31,627,581
10	Non-Summer Total kWh	01A - Residential	2,216,278,112		
11	Customers	01A - Residential	5,614,117		$39,298,820
12	Block 1 kWh	01A - Residential	1,949,760,307		$149,630,260
13	Block 2 kWh	01A - Residential	778,233,317		$86,284,444
14	Block 3 kWh	01A - Residential	433,238,964		$56,554,982
15	Total kWh	01A - Residential	3,161,232,588		
16					
17	Summer Customers	01B - Residential TOU	372	$20.81	$7,731
18	Summer Customers (Mtr)	01B - Residential TOU	372	$5.29	$1,965
19	Summer On Peak kWh	01B - Residential TOU	271,123	$0.1866117	$50,595
20	Summer Off Peak kWh	01B - Residential TOU	430,893	$0.0599494	$25,832
21	Summer Total kWh	01B - Residential TOU	702,016		
22	Non-Summer Customers	01B - Residential TOU	1,080	$20.81	$22,485
23	Non-Summer Customers (Mtr)	01B - Residential TOU	1,080	$5.29	$5,716
24	Non-Summer On Peak kWh	01B - Residential TOU	1,001,957	$0.1452852	$145,570
25	Non-Summer Off Peak kWh	01B - Residential TOU	1,925,545	$0.0599494	$115,435
26	Non-Summer Total kWh	01B - Residential TOU	2,927,502		
27	Customers	01B - Residential TOU	1,452		$30,216
28	Customers (Mtr)	01B - Residential TOU	1,452		$7,681
29	On Peak kWh	01B - Residential TOU	1,273,080		$196,164
30	Off Peak kWh	01B - Residential TOU	2,356,438		$141,267
31	Total kWh	01B - Residential TOU	3,629,518		
32					
33	Summer Customers	2A - Small Power	159,605	$15.53	$2,478,661
34	Summer Total kWh	2A - Small Power	266,128,782	$0.1123065	$29,887,992
35	Summer Total kWh	2A - Small Power	266,128,782		
36	Non-Summer Customers	2A - Small Power	463,779	$15.53	$7,202,490
37	Non-Summer Total kWh	2A - Small Power	636,224,067	$0.0894494	$56,909,861
38	Non-Summer Total kWh	2A - Small Power	636,224,067		
39	Total Customers	2A - Small Power	623,384		$9,681,152
40	Total kWh	2A - Small Power	902,352,849		$86,797,853
41	Total kWh	2A - Small Power	902,352,849		
42					
43	Summer Customers	02B - Small Power TOU	2,690	$7.43	$11,885
44	Summer Customers (Mtr)	02B - Small Power TOU	2,690	$8.10	$12,957
45	Summer On Peak kWh	02B - Small Power TOU	1,389,221	$0.2020195	$219,715
46	Summer Off Peak kWh	02B - Small Power TOU	2,338,040	$0.0581698	$104,469
47	Summer Total kWh	02B - Small Power TOU	3,727,261		
48	Non-Summer Customers	02B - Small Power TOU	7,822	$7.43	$34,567
49	Non-Summer Customers (Mtr)	02B - Small Power TOU	7,822	$8.10	$37,684
50	Non-Summer On Peak kWh	02B - Small Power TOU	3,352,248	$0.156660	$389,367
51	Non-Summer Off Peak kWh	02B - Small Power TOU	5,964,439	$0.058170	$254,632
52	Non-Summer Total kWh	02B - Small Power TOU	9,316,687		
53	Customers	02B - Small Power TOU	10,512		$46,452
54	Customers (Mtr)	02B - Small Power TOU	10,512		$50,641
55	On Peak kWh	02B - Small Power TOU	4,741,469		$609,082
56	Off Peak kWh	02B - Small Power TOU	8,302,479		$359,101
57	Total kWh	02B - Small Power TOU	13,043,948		

Test Period Billing Determinants

A Line No.	B Desc	C Tariff	D Test Period Determinants	E Rates 15-00261-UT	F Test Period Revenues
58					
59	Summer Customers	03B - General Power TOU Sec	10,201	$80.64	$822,598
60	Summer On-Peak kWh	03B - General Power TOU Sec	196,214,830	$0.0324655	$6,370,213
61	Summer Off-Peak kWh	03B - General Power TOU Sec	257,443,183	$0.0151145	$3,891,125
62	Summer Total kWh	03B - General Power TOU Sec	453,658,013		
63	Summer Billable kW	03B - General Power TOU Sec	1,119,302		
64	Summer Billed kW	03B - General Power TOU Sec	1,119,302	$25.16	$28,161,646
65	Summer Billed RkVA	03B - General Power TOU Sec	28,884	$0.27	$7,799
66	Non-Summer Customers	03B - General Power TOU Sec	29,428	$80.64	$2,373,114
67	Non-Summer On-Peak kWh	03B - General Power TOU Sec	461,943,820	$0.0268950	$12,423,979
68	Non-Summer Off-Peak kWh	03B - General Power TOU Sec	644,698,997	$0.0151145	$9,744,303
69	Non-Summer Total kWh	03B - General Power TOU Sec	1,106,642,817		
70	Non-Summer Billable kW	03B - General Power TOU Sec	2,791,650		
71	Non-Summer Billed kW	03B - General Power TOU Sec	2,791,650	$18.78	$52,427,178
72	Non-Summer Billed RkVA	03B - General Power TOU Sec	58,432	$0.27	$15,777
73	Customers	03B - General Power TOU Sec	39,629		$3,195,712
74	On-Peak kWh	03B - General Power TOU Sec	658,158,649		$18,794,192
75	Off-Peak kWh	03B - General Power TOU Sec	902,142,180		$13,635,428
76	Total kWh	03B - General Power TOU Sec	1,560,300,830		
77	Billable kW	03B - General Power TOU Sec	3,910,952		
78	Billed kW	03B - General Power TOU Sec	3,910,952		$80,588,824
79	Billed RkVA	03B - General Power TOU Sec	87,316		$23,575
80					
81	Snmmer Customers	03B - General Power TOU Pri	251	$80.64	$20,274
82	Summer On-Peak kWh	03B - General Power TOU Pri	9,798,080	$0.0324655	$318,100
83	Summer Off-Peak kWh	03B - General Power TOU Pri	12,130,471	$0.0151145	$183,346
84	Summer Total kWh	03B - General Power TOU Pri	21,928,551		
85	Summer Billable kW	03B - General Power TOU Pri	65,402		
86	Summer Billed kW	03B - General Power TOU Pri	65,402	$24.83	$1,623,941
87	Summer Billed RkVA	03B - General Power TOU Pri	6,492	$0.27	$1,753
88	Non-Snmmer Customers	03B - General Power TOU Pri	721	$80.64	$58,102
89	Non-Summer On-Peak kWh	03B - General Power TOU Pri	25,839,791	$0.0268950	$694,961
90	Non-Summer Off-Peak kWh	03B - General Power TOU Pri	33,856,613	$0.0151145	$511,726
91	Non-Summer Total kWh	03B - General Power TOU Pri	59,696,404		
92	Non-Summer Billable kW	03B - General Power TOU Pri	181,145		
93	Non-Summer Billed kW	03B - General Power TOU Pri	181,145	$18.45	$3,342,117
94	Non-Summer Billed RkVA	03B - General Power TOU Pri	14,150	$0.27	$3,821
95	Customers	03B - General Power TOU Pri	972		$78,376
96	On-Peak kWh	03B - General Power TOU Pri	35,637,871		$1,013,061
97	Off-Peak kWh	03B - General Power TOU Pri	45,987,083		$695,072
98	Total kWh	03B - General Power TOU Pri	81,624,954		
99	Billable kW	03B - General Power TOU Pri	246,547		
100	Billed kW	03B - General Power TOU Pri	246,547		$4,966,058
101	Billed RkVA	03B - General Power TOU Pri	20,642		$5,573

Test Period Billing Determinants

A Line No.	B Desc	C Tariff	D Test Period Determinants	E Rates 15-00261-UT	F Test Period Revenues
102					
103	Summer Cust. Charge	03C - General Power LLF TOU Sec	2,730	$80.64	$220,127
104	Summer On-Peak kWh	03C - General Power LLF TOU Sec	27,931,992	$0.1136428	$3,174,270
105	Summer Off-Peak kWh	03C - General Power LLF TOU Sec	29,531,806	$0.0512165	$1,512,516
106	Summer Total kWh	03C - General Power LLF TOU Sec	57,463,798		
107	Summer Billable kW	03C - General Power LLF TOU Sec	284,190		
108	Summer Billed kW	03C - General Power LLF TOU Sec	284,190	$7.98	$2,267,839
109	Summer Billed RkVA	03C - General Power LLF TOU Sec	11,143	$0.27	$3,009
110	Non-Summer Customers	03C - General Power LLF TOU Sec	8,171	$80.64	$658,885
111	Non-Summer On-Peak kWh	03C - General Power LLF TOU Sec	67,690,933	$0.0856073	$5,794,838
112	Non-Summer Off-Peak kWh	03C - General Power LLF TOU Sec	73,197,116	$0.0512165	$3,748,900
113	Non-Summer Total kWh	03C - General Power LLF TOU Sec	140,888,049		
114	Non-Summer Billable kW	03C - General Power LLF TOU Sec	704,000		
115	Non-Summer Billed kW	03C - General Power LLF TOU Sec	704,000	$5.96	$4,195,841
116	Non-Summer Billed RkVA	03C - General Power LLF TOU Sec	29,638	$0.27	$8,002
117	Customers	03C - General Power LLF TOU Sec	10,900		$879,012
118	On-Peak kWh	03C - General Power LLF TOU Sec	95,622,926		$8,969,108
119	Off-Peak kWh	03C - General Power LLF TOU Sec	102,728,922		$5,261,416
120	Total kWh	03C - General Power LLF TOU Sec	198,351,847		
121	Billable kW	03C - General Power LLF TOU Sec	988,190		
122	Billed kW	03C - General Power LLF TOU Sec	988,190		$6,463,680
123	Billed RkVA	03C - General Power LLF TOU Sec	40,782		$11,011
124					
125	Summer Customers	03C - General Power LLF TOU Pri	55	$80.64	$4,456
126	Summer On-Peak kWh	03C - General Power LLF TOU Pri	1,585,728	$0.1136428	$180,207
127	Summer Off-Peak kWh	03C - General Power LLF TOU Pri	1,292,167	$0.0512165	$66,180
128	Summer Total kWh	03C - General Power LLF TOU Pri	2,877,896		
129	Summer Billable kW	03C - General Power LLF TOU Pri	14,734		
130	Summer Billed kW	03C - General Power LLF TOU Pri	14,734	$7.65	$112,717
131	Summer Billed RkVA	03C - General Power LLF TOU Pri	4,014	$0.27	$1,084
132	Non-Summer Customers	03C - General Power LLF TOU Pri	157	$80.64	$12,682
133	Non-Summer On-Peak kWh	03C - General Power LLF TOU Pri	4,557,288	$0.0856073	$390,137
134	Non-Summer Off-Peak kWh	03C - General Power LLF TOU Pri	4,338,128	$0.0512165	$222,184
135	Non-Summer Total kWh	03C - General Power LLF TOU Pri	8,895,416		
136	Non-Summer Billable kW	03C - General Power LLF TOU Pri	52,361		
137	Non-Summer Billed kW	03C - General Power LLF TOU Pri	52,361	$5.63	$294,795
138	Non-Summer Billed RkVA	03C - General Power LLF TOU Pri	12,726	$0.27	$3,436
139	Customers	03C - General Power LLF TOU Pri	213		$17,138
140	On-Peak kWh	03C - General Power LLF TOU Pri	6,143,017		$570,344
141	Off-Peak kWh	03C - General Power LLF TOU Pri	5,630,296		$288,364
142	Total kWh	03C - General Power LLF TOU Pri	11,773,312		
143	Billable kW	03C - General Power LLF TOU Pri	67,096		
144	Billed kW	03C - General Power LLF TOU Pri	67,096		$407,511
145	Billed RkVA	03C - General Power LLF TOU Pri	16,740		$4,520

Test Period Billing Determinants

A Line No.	B Desc	C Tariff	D Test Period Determinants	E Rates 15-00261-UT	F Test Period Revenues
146					
147	Non-Fuel (Energy)	04B - Large Power TOU Sec	286	$577.08	$165,159
148	Summer On-Peak kWh	04B - Large Power TOU Sec	39,342,305	$0.0297957	$1,172,232
149	Summer Off-Peak kWh	04B - Large Power TOU Sec	55,740,245	$0.0154744	$862,547
150	Summer Total kWh	04B - Large Power TOU Sec	95,082,549		
151	Summer Billable kW	04B - Large Power TOU Sec	191,467		
152	Summer Billed kW	04B - Large Power TOU Sec	191,467	$25.25	$4,834,550
153	Summer Billed RkVA	04B - Large Power TOU Sec	8,409	$0.27	$2,271
154	Non-Summer Customers	04B - Large Power TOU Sec	822	$577.08	$474,356
155	Non-Summer On-Peak kWh	04B - Large Power TOU Sec	94,404,269	$0.0233972	$2,208,796
156	Non-Summer Off-Peak kWh	04B - Large Power TOU Sec	139,816,137	$0.0154744	$2,163,571
157	Non-Summer Total kWh	04B - Large Power TOU Sec	234,220,405		
158	Non-Summer Billable kW	04B - Large Power TOU Sec	494,943		
159	Non-Summer Billed kW	04B - Large Power TOU Sec	494,943	$18.14	$8,978,272
160	Non-Summer Billed RkVA	04B - Large Power TOU Sec	16,454	$0.27	$4,443
161	Customers	04B - Large Power TOU Sec	1,108		$639,515
162	On-Peak kWh	04B - Large Power TOU Sec	133,746,573		$3,381,027
163	Off-Peak kWh	04B - Large Power TOU Sec	195,556,382		$3,026,118
164	Total kWh	04B - Large Power TOU Sec	329,302,955		
165	Billable kW	04B - Large Power TOU Sec	686,411		
166	Billed kW	04B - Large Power TOU Sec	686,411		$13,812,822
167	Billed RkVA	04B - Large Power TOU Sec	24,864		$6,713
168					
169	Summer Customers	04B - Large Power TOU Pri	411	$577.08	$237,047
170	Summer On-Peak kWh	04B - Large Power TOU Pri	84,845,971	$0.0297957	$2,528,045
171	Summer Off-Peak kWh	04B - Large Power TOU Pri	127,308,794	$0.0154744	$1,970,027
172	Summer Total kWh	04B - Large Power TOU Pri	212,154,766		
173	Summer Billable kW	04B - Large Power TOU Pri	435,274		
174	Summer Billed kW	04B - Large Power TOU Pri	435,274	$23.36	$10,167,992
175	Summer Billed RkVA	04B - Large Power TOU Pri	55,511	$0.27	$14,988
176	Non-Summer Customers	04B - Large Power TOU Pri	1,205	$577.08	$695,405
177	Non-Summer On-Peak kWh	04B - Large Power TOU Pri	223,514,294	$0.0233972	$5,229,609
178	Non-Summer Off-Peak kWh	04B - Large Power TOU Pri	341,732,888	$0.0154744	$5,288,111
179	Non-Summer Total kWh	04B - Large Power TOU Pri	565,247,181		
180	Non-Summer Billable kW	04B - Large Power TOU Pri	1,218,659		
181	Non-Summer Billed kW	04B - Large Power TOU Pri	1,218,659	$16.25	$19,803,215
182	Non-Summer Billed RkVA	04B - Large Power TOU Pri	135,599	$0.27	$36,612
183	Customers	04B - Large Power TOU Pri	1,616		$932,451
184	On-Peak kWh	04B - Large Power TOU Pri	308,360,265		$7,757,654
185	Off-Peak kWh	04B - Large Power TOU Pri	469,041,682		$7,258,139
186	Total kWh	04B - Large Power TOU Pri	777,401,947		
187	Billable kW	04B - Large Power TOU Pri	1,653,933		
188	Billed kW	04B - Large Power TOU Pri	1,653,933		$29,971,207
189	Billed RkVA	04B - Large Power TOU Pri	191,110		$51,600
190					
191	Summer Customers	5B - Lg. Svc. (8 MW) TOU	6	$3,026.64	$18,586
192	Summer On-Peak kWh	5B - Lg. Svc. (8 MW) TOU	7,245,481	$0.0326547	$236,599
193	Summer Off-Peak kWh	5B - Lg. Svc. (8 MW) TOU	11,600,913	$0.0144708	$167,874
194	Summer Total kWh	5B - Lg. Svc. (8 MW) TOU	18,846,394		
195	Summer Billable kW	5B - Lg. Svc. (8 MW) TOU	49,125		
196	Summer Billed kW	5B - Lg. Svc. (8 MW) TOU	49,125	$18.74	$920,611
197	Summer Billed RkVA	5B - Lg. Svc. (8 MW) TOU	4,992	$0.27	$1,348
198	Non-Summer Customers	5B - Lg. Svc. (8 MW) TOU	18	$3,026.64	$54,054
199	Non-Summer On-Peak kWh	5B - Lg. Svc. (8 MW) TOU	19,415,531	$0.023307	$452,512
200	Non-Summer Off-Peak kWh	5B - Lg. Svc. (8 MW) TOU	32,334,642	$0.0144708	$467,908
201	Non-Summer Total kWh	5B - Lg. Svc. (8 MW) TOU	51,750,173		
202	Non-Summer Billable kW	5B - Lg. Svc. (8 MW) TOU	142,875		
203	Non-Summer Billed kW	5B - Lg. Svc. (8 MW) TOU	142,875	$11.38	$1,625,912
204	Non-Summer Billed RkVA	5B - Lg. Svc. (8 MW) TOU	21,503	$0.27	$5,806
205	Customers	5B - Lg. Svc. (8 MW) TOU	24		$72,639
206	On-Peak kWh	5B - Lg. Svc. (8 MW) TOU	26,661,012		$689,111
207	Off-Peak kWh	5B - Lg. Svc. (8 MW) TOU	43,935,555		$635,783
208	Total kWh	5B - Lg. Svc. (8 MW) TOU	70,596,567		
209	Billable kW	5B - Lg. Svc. (8 MW) TOU	192,000		
210	Billed kW	5B - Lg. Svc. (8 MW) TOU	192,000		$2,546,523
211	Billed RkVA	5B - Lg. Svc. (8 MW) TOU	26,495		$7,154

Test Period Billing Determinants

A Line No.	B Desc	C Tariff	D Test Period Determinants	E Rates 15-00261-UT	F Test Period Revenues
212					
213	Summer Customers	10A - Irrigation Power	366	$9.93	$3,636
214	Summer Total kWh	10A - Irrigation Power	1,696,099	$0.0790071	$134,004
215	Summer Total kWh	10A - Irrigation Power	1,696,099		
216	Non-Summer Customers	10A - Irrigation Power	1,063	$9.93	$10,553
217	Non-Summer Total kWh	10A - Irrigation Power	2,301,224	$0.0720028	$165,695
218	Non-Summer Total kWh	10A - Irrigation Power	2,301,224		
219	Total Customers	10A - Irrigation Power	1,429		$14,190
220	Total kWh	10A - Irrigation Power	3,997,323		$299,698
221	Total kWh	10A - Irrigation Power	3,997,323		
222					
223	Summer Customers	10B - Irrigation Power TOU	661	$7.39	$4,885
224	Summer Customers (Mtr)	10B - Irrigation Power TOU	661	$2.54	$1,679
225	Summer On Peak kWh	10B - Irrigation Power TOU	2,900,445	$0.1192932	$346,003
226	Summer Off Peak kWh	10B - Irrigation Power TOU	5,199,480	$0.0543285	$282,480
227	Summer Total kWh	10B - Irrigation Power TOU	8,099,926		
228	Non-Summer Customers	10B - Irrigation Power TOU	1,920	$7.39	$14,189
229	Non-Summer Customers (Mtr)	10B - Irrigation Power TOU	1,920	$2.54	$4,877
230	Non-Summer On Peak kWh	10B - Irrigation Power TOU	3,917,891	$0.109190	$427,795
231	Non-Summer Off Peak kWh	10B - Irrigation Power TOU	7,412,637	$0.054329	$402,717
232	Non-Summer Total kWh	10B - Irrigation Power TOU	11,330,529		$0
233	Customers	10B - Irrigation Power TOU	2,581		$19,073
234	Customers (Mtr)	10B - Irrigation Power TOU	2,581		$6,556
235	On Peak kWh	10B - Irrigation Power TOU	6,818,337		$773,798
236	Off Peak kWh	10B - Irrigation Power TOU	12,612,118		$685,197
237	Total kWh	10B - Irrigation Power TOU	19,430,454		
238					
239	Summer Customers	11B - Water & Sewage TOU	504	$442.44	$43,470
240	Summer On Peak kWh	11B - Water & Sewage TOU	12,600,011	$0.1363239	$127,640
241	Summer Off Peak kWh	11B - Water & Sewage TOU	40,775,401	$0.0263178	$74,528
242	Summer Total kWh	11B - Water & Sewage TOU	53,375,413		
243	Non-Summer Customers	11B - Water & Sewage TOU	1,464	$442.44	$126,427
244	Non-Summer On Peak kWh	11B - Water & Sewage TOU	27,170,788	$0.087835	$210,275
245	Non-Summer Off Peak kWh	11B - Water & Sewage TOU	87,962,256	$0.026318	$185,015
246	Non-Summer Total kWh	11B - Water & Sewage TOU	115,133,044		
247	Customers	11B - Water & Sewage TOU	1,968		$169,897
248	On Peak kWh	11B - Water & Sewage TOU	39,770,799		$337,914
249	Off Peak kWh	11B - Water & Sewage TOU	128,737,657		$259,543
250	Total kWh	11B - Water & Sewage TOU	168,508,457		$0
251					
252	Summer Customers	15B - Universities 115 kV TOU	3	$3,609.00	$11,081
253	Summer On-Peak kWh	15B - Universities 115 kV TOU	8,298,219	$0.0206640	$171,474
254	Summer Off-Peak kWh	15B - Universities 115 kV TOU	12,620,849	$0.0082494	$104,114
255	Summer Total kWh	15B - Universities 115 kV TOU	20,919,069		
256	Summer Billable kW	15B - Universities 115 kV TOU	56,320		
257	Summer Billed kW	15B - Universities 115 kV TOU	56,320	$20.31	$1,143,865
258	Summer Billed RkVA	15B - Universities 115 kV TOU	0	$0.27	$0
259	Summer Reserved Substation kW	15B - Universities 115 kV TOU	16,801	$0.77	$12,937
260	Non-Summer Customers	15B - Universities 115 kV TOU	9	$3,609.00	$32,227
261	Non-Summer On-Peak kWh	15B - Universities 115 kV TOU	16,661,882	$0.0161506	$269,099
262	Non-Summer Off-Peak kWh	15B - Universities 115 kV TOU	26,102,931	$0.0082494	$215,334
263	Non-Summer Total kWh	15B - Universities 115 kV TOU	42,764,813		
264	Non-Summer Billable kW	15B - Universities 115 kV TOU	146,158		
265	Non-Summer Billed kW	15B - Universities 115 kV TOU	146,158	$12.29	$1,796,280
266	Non-Summer Billed RkVA	15B - Universities 115 kV TOU	0	$0.27	$0
267	Non-Summer Reserved Substation kW	15B - Universities 115 kV TOU	48,863	$0.77	$37,625
268	Customers	15B - Universities 115 kV TOU	12		$43,308
269	On-Peak kWh	15B - Universities 115 kV TOU	24,960,101		$440,574
270	Off-Peak kWh	15B - Universities 115 kV TOU	38,723,781		$319,448
271	Total kWh	15B - Universities 115 kV TOU	63,683,882		
272	Billable kW	15B - Universities 115 kV TOU	202,478		
273	Billed kW	15B - Universities 115 kV TOU	202,478		$2,940,145
274	Billed RkVA	15B - Universities 115 kV TOU	0		$0
275	Reserved Substation kW	15B - Universities 115 kV TOU	65,664		$50,561

Test Period Billing Determinants

A Line No.	B Desc	C Tariff	D Test Period Determinants	E Rates 15-00261-UT	F Test Period Revenues
276					
277	Summer Customers	30B - Manuf. (30 MW) TOU	3	$23,874.89	$73,304
278	Summer On-Peak kWh	30B - Manuf. (30 MW) TOU	33,295,199	$0.0115228	$383,654
279	Summer Off-Peak kWh	30B - Manuf. (30 MW) TOU	59,708,151	$0.0056220	$335,679
280	Summer Total kWh	30B - Manuf. (30 MW) TOU	93,003,350		
281	Summer Billable kW	30B - Manuf. (30 MW) TOU	128,684		
282	Summer Billed kW	30B - Manuf. (30 MW) TOU	128,684	$28.79	$3,704,815
283	Summer Billed RkVA	30B - Manuf. (30 MW) TOU	11,892	$0.27	$3,211
284	Non-Summer Customers	30B - Manuf. (30 MW) TOU	9	$23,874.89	$213,195
285	Non-Summer On-Peak kWh	30B - Manuf. (30 MW) TOU	96,897,406	$0.0089352	$865,798
286	Non-Summer Off-Peak kWh	30B - Manuf. (30 MW) TOU	173,765,738	$0.0056220	$976,911
287	Non-Summer Total kWh	30B - Manuf. (30 MW) TOU	270,663,144		
288	Non-Summer Billable kW	30B - Manuf. (30 MW) TOU	374,260		
289	Non-Summer Billed kW	30B - Manuf. (30 MW) TOU	374,260	$20.35	$7,616,189
290	Non-Summer Billed RkVA	30B - Manuf. (30 MW) TOU	33,993	$0.27	$9,178
291	Customers	30B - Manuf. (30 MW) TOU	12		$286,499
292	On-Peak kWh	30B - Manuf. (30 MW) TOU	130,192,605		$1,249,452
293	Off-Peak kWh	30B - Manuf. (30 MW) TOU	233,473,889		$1,312,590
294	Total kWh	30B - Manuf. (30 MW) TOU	363,666,494		
295	Billable kW	30B - Manuf. (30 MW) TOU	502,944		
296	Billed kW	30B - Manuf. (30 MW) TOU	502,944		$11,321,004
297	Billed RkVA	30B - Manuf. (30 MW) TOU	45,886		$12,389
298					
299	Summer Customers	33B - Lg. Svc. For Station Power TOU	3	$438.38	$1,346
300	Summer On-Peak kWh	33B - Lg. Svc. For Station Power TOU	280,644	$0.0236874	$6,648
301	Summer Off-Peak kWh	33B - Lg. Svc. For Station Power TOU	581,919	$0.0117375	$6,830
302	Summer Total kWh	33B - Lg. Svc. For Station Power TOU	862,563		
303	Summer Billable kW	33B - Lg. Svc. For Station Power TOU	5,495		
304	Summer Billed kW	33B - Lg. Svc. For Station Power TOU	5,495	$5.25	$28,851
305	Summer Billed RkVA	33B - Lg. Svc. For Station Power TOU	6,014	$0.27	$1,624
306	Non-Summer Customers	33B - Lg. Svc. For Station Power TOU	9	$438.38	$3,915
307	Non-Summer On-Peak kWh	33B - Lg. Svc. For Station Power TOU	914,064	$0.0193429	$17,681
308	Non-Summer Off-Peak kWh	33B - Lg. Svc. For Station Power TOU	1,577,767	$0.0117375	$18,519
309	Non-Summer Total kWh	33B - Lg. Svc. For Station Power TOU	2,491,831		
310	Non-Summer Billable kW	33B - Lg. Svc. For Station Power TOU	15,526		
311	Non-Summer Billed kW	33B - Lg. Svc. For Station Power TOU	15,526	$3.62	$56,202
312	Non-Summer Billed RkVA	33B - Lg. Svc. For Station Power TOU	118,615	$0.27	$32,026
313	Customers	33B - Lg. Svc. For Station Power TOU	12		$5,261
314	On-Peak kWh	33B - Lg. Svc. For Station Power TOU	1,194,708		$24,328
315	Off-Peak kWh	33B - Lg. Svc. For Station Power TOU	2,159,686		$25,349
316	Total kWh	33B - Lg. Svc. For Station Power TOU	3,354,394		
317	Billable kW	33B - Lg. Svc. For Station Power TOU	21,021		
318	Billed kW	33B - Lg. Svc. For Station Power TOU	21,021		$85,054
319	Billed RkVA	33B - Lg. Svc. For Station Power TOU	124,630		$33,650
320					
321	Summer Customers	35B - Lg. Svc. (3 MW) TOU	12	$2,687.80	$33,010
322	Summer On-Peak kWh	35B - Lg. Svc. (3 MW) TOU	18,487,920	$0.0128509	$237,586
323	Summer Off-Peak kWh	35B - Lg. Svc. (3 MW) TOU	37,376,551	$0.0066741	$249,455
324	Summer Total kWh	35B - Lg. Svc. (3 MW) TOU	55,864,472		
325	Summer Billable kW	35B - Lg. Svc. (3 MW) TOU	83,120		
326	Summer Billed kW	35B - Lg. Svc. (3 MW) TOU	83,120	$24.07	$2,000,698
327	Summer Billed RkVA	35B - Lg. Svc. (3 MW) TOU	5,373	$0.27	$1,451
328	Non-Summer Customers	35B - Lg. Svc. (3 MW) TOU	36	$2,687.80	$96,005
329	Non-Summer On-Peak kWh	35B - Lg. Svc. (3 MW) TOU	47,732,027	$0.0100912	$481,673
330	Non-Summer Off-Peak kWh	35B - Lg. Svc. (3 MW) TOU	102,259,207	$0.0066741	$682,488
331	Non-Summer Total kWh	35B - Lg. Svc. (3 MW) TOU	149,991,234		
332	Non-Summer Billable kW	35B - Lg. Svc. (3 MW) TOU	222,249		
333	Non-Summer Billed kW	35B - Lg. Svc. (3 MW) TOU	222,249	$15.49	$3,442,631
334	Non-Summer Billed RkVA	35B - Lg. Svc. (3 MW) TOU	11,561	$0.27	$3,121
335	Customers	35B - Lg. Svc. (3 MW) TOU	48		$129,014
336	On-Peak kWh	35B - Lg. Svc. (3 MW) TOU	66,219,947		$719,260
337	Off-Peak kWh	35B - Lg. Svc. (3 MW) TOU	139,635,758		$931,943
338	Total kWh	35B - Lg. Svc. (3 MW) TOU	205,855,705		
339	Billable kW	35B - Lg. Svc. (3 MW) TOU	305,369		
340	Billed kW	35B - Lg. Svc. (3 MW) TOU	305,369		$5,443,329
341	Billed RkVA	35B - Lg. Svc. (3 MW) TOU	16,934		$4,572

Test Period Billing Determinants

A Line No.	B Desc	C Tariff	D Test Period Determinants	E Rates 15-00261-UT	F Test Period Revenues
342					
343	Summer Customers	36B - SSR - Renew. Energy Res.	3	$3,609.00	$10,827
344	Summer System Supplied kWh	36B - SSR - Renew. Energy Res.	8,398,339	$0.0055429	$46,551
345	Summer Cont. to Production kWh (FRNF)	36B - SSR - Renew. Energy Res.	8,398,339	$0.0231074	$194,064
346	Summer Remaining kWh	36B - SSR - Renew. Energy Res.	17,660,514		
347	Summer Total kWh	36B - SSR - Renew. Energy Res.	26,058,852		
348	Summer Transmission Demand	36B - SSR - Renew. Energy Res.	74,500	$3.80	$283,100
349	Non-Summer Customers	36B - SSR - Renew. Energy Res.	9	$3,609.00	$32,481
350	Non-Summer System Supplied kWh	36B - SSR - Renew. Energy Res.	29,567,919	$0.0055429	$163,892
351	Non-Summer Cont. to Production kWh (FRNF)	36B - SSR - Renew. Energy Res.	29,567,919	$0.0231074	$683,238
352	Non-Summer Remaining kWh	36B - SSR - Renew. Energy Res.	43,276,587		
353	Non-Summer Total kWh	36B - SSR - Renew. Energy Res.	72,844,506		
354	Non-Summer Transmission Demand	36B - SSR - Renew. Energy Res.	194,200	$3.80	$737,960
355	Customers	36B - SSR - Renew. Energy Res.	12		$43,308
356	System Supplied kWh	36B - SSR - Renew. Energy Res.	37,966,258		$210,443
357	Cont. to Production kWh (FRNF)	36B - SSR - Renew. Energy Res.	37,966,258		$877,302
358	Remaining kWh	36B - SSR - Renew. Energy Res.	60,937,100		
359	Total kWh	36B - SSR - Renew. Energy Res.	98,903,358		
360	Transmission Demand	36B - SSR - Renew. Energy Res.	268,700		$1,021,060
361					
362	LA12-175W MV AL (PNM, 73 kWh/Unit)	06 - Private Lighting - Units	30,432	$11.39	$346,620
363	LA1A-175W MV AL (PNM, 73 kWh/Unit)	06 - Private Lighting - Units	14,304	$11.39	$162,923
364	LAFA-400W MV AL (PNM, 162 kWh/Unit)	06 - Private Lighting - Units	2,820	$22.55	$63,591
365	LA32-100W HPS AL (PNM, 45 kWh/Unit)	06 - Private Lighting - Units	62,688	$9.15	$573,595
366	LA3A-100W HPS AL (PNM, 45 kWh/Unit)	06 - Private Lighting - Units	26,604	$9.15	$243,427
367	LAOA-200W HPS FL (PNM, 89 kWh/Unit)	06 - Private Lighting - Units	672	$14.94	$10,040
368	LATA-200W HPS AL (PNM, 89 kWh/Unit)	06 - Private Lighting - Units	10,128	$14.94	$151,312
369	LA42-400W HPS FL (PNM, 165 kWh/Unit)	06 - Private Lighting - Units	22,056	$24.99	$551,179
370	LA4A-400W HPS FL (PNM, 165 kWh/Unit)	06 - Private Lighting - Units	300	$24.99	$7,497
371	LB42-400W HPS FL (PNM, 165 kWh/Unit) WP	06 - Private Lighting - Units	6,276	$27.98	$175,602
372	LC42-400W HPS FL (PNM, 165 kWh/Unit) WP	06 - Private Lighting - Units	8,124	$27.98	$227,310
373	LD42-400W HPS FL (PNM, 165 kWh/Unit) WP	06 - Private Lighting - Units	180	$27.98	$5,036
374	LAMA-400W MH FL (PNM, 162 kWh/Unit)	06 - Private Lighting - Units	3,036	$24.54	$74,503
375	LANA-1,000W MH FL (PNM, 380 kWh/Unit)	06 - Private Lighting - Units	264	$53.03	$14,000
376	L0LA-Pole Charge (wood)	06 - Private Lighting - Units	20,784	$2.99	$62,144
377	LA12-175W MV AL (PNM, 73 kWh/Unit)	06 - Private Lighting - kWh	2,221,536		
378	LA1A-175W MV AL (PNM, 73 kWh/Unit)	06 - Private Lighting - kWh	1,044,192		
379	LAFA-400W MV AL (PNM, 162 kWh/Unit)	06 - Private Lighting - kWh	456,840		
380	LA32-100W HPS AL (PNM, 45 kWh/Unit)	06 - Private Lighting - kWh	2,820,960		
381	LA3A-100W HPS AL (PNM, 45 kWh/Unit)	06 - Private Lighting - kWh	1,197,180		
382	LAOA-200W HPS FL (PNM, 89 kWh/Unit)	06 - Private Lighting - kWh	59,808		
383	LATA-200W HPS AL (PNM, 89 kWh/Unit)	06 - Private Lighting - kWh	901,392		
384	LA42-400W HPS FL (PNM, 165 kWh/Unit)	06 - Private Lighting - kWh	3,639,240		
385	LA4A-400W HPS FL (PNM, 165 kWh/Unit)	06 - Private Lighting - kWh	49,500		
386	LB42-400W HPS FL (PNM, 165 kWh/Unit) WP	06 - Private Lighting - kWh	1,035,540		
387	LC42-400W HPS FL (PNM, 165 kWh/Unit) WP	06 - Private Lighting - kWh	1,340,460		
388	LD42-400W HPS FL (PNM, 165 kWh/Unit) WP	06 - Private Lighting - kWh	29,700		
389	LAMA-400W MH FL (PNM, 162 kWh/Unit)	06 - Private Lighting - kWh	491,832		
390	LANA-1,000W MH FL (PNM, 380 kWh/Unit)	06 - Private Lighting - kWh	100,320		
391	L0LA-Pole Charge (wood)	06 - Private Lighting - kWh	0		

Test Period Billing Determinants

A Line No.	B Desc	C Tariff	D Test Period Determinants	E Rates 15-00261-UT	F Test Period Revenues
392					
393	L2Z5-Metered Streetlighting (Cust Owned)	20 - Street Lighting - Units	180		
394	L3D1-175W MV SL (Cust, 1x73 kWh/Unit)	20 - Street Lighting - Units	0	$5.54	$0
395	L7D1-175W MV SL (Cust, 1x73 kWh/Unit)	20 - Street Lighting - Units	0	$5.54	$0
396	L8D1-175W MV SL (Cust, 1x73 kWh/Unit)	20 - Street Lighting - Units	0	$5.54	$0
397	L7D3-175W MV SL (Cust, 1x73 kWh/Unit)	20 - Street Lighting - Units	0	$5.54	$0
398	L8D3-175W MV SL (Cust, 1x73 kWh/Unit)	20 - Street Lighting - Units	0	$5.54	$0
399	L7F1-400W MV SL (Cust, 1x162 kWh/Unit)	20 - Street Lighting - Units	0	$12.30	$0
400	L8F1-400W MV SL (Cust, 1x162 kWh/Unit)	20 - Street Lighting - Units	0	$12.30	$0
401	L7F3-400W MV SL (Cust, 1x162 kWh/Unit)	20 - Street Lighting - Units	0	$12.30	$0
402	L8F3-400W MV SL (Cust, 1x162 kWh/Unit)	20 - Street Lighting - Units	948	$12.30	$11,660
403	L7A1-100W HPS SL (Cust, 1x45 kWh/Unit)	20 - Street Lighting - Units	0	$3.42	$0
404	L8A1-100W HPS SL (Cust, 1x45 kWh/Unit)	20 - Street Lighting - Units	156	$3.42	$534
405	L7A3-100W HPS SL (Cust, 1x45 kWh/Unit)	20 - Street Lighting - Units	0	$3.42	$0
406	L8A3-100W HPS SL (Cust, 1x45 kWh/Unit)	20 - Street Lighting - Units	0	$3.42	$0
407	L7T1-200W HPS SL (Cust, 1x89 kWh/Unit)	20 - Street Lighting - Units	0	$6.76	$0
408	L8T1-200W HPS SL (Cust, 1x89 kWh/Unit)	20 - Street Lighting - Units	0	$6.76	$0
409	L7T3-200W HPS SL (Cust, 1x89 kWh/Unit)	20 - Street Lighting - Units	0	$6.76	$0
410	L8T3-200W HPS SL (Cust, 1x89 kWh/Unit)	20 - Street Lighting - Units	0	$6.76	$0
411	L7C1-400W HPS SL (Cust, 1x165 kWh/Unit)	20 - Street Lighting - Units	0	$12.53	$0
412	L8C1-400W HPS SL (Cust, 1x165 kWh/Unit)	20 - Street Lighting - Units	12	$12.53	$150
413	L7C3-400W HPS SL (Cust, 1x165 kWh/Unit)	20 - Street Lighting - Units	0	$12.53	$0
414	L8C3-400W HPS SL (Cust, 1x165 kWh/Unit)	20 - Street Lighting - Units	684	$12.53	$8,571
415	L1Z5-Metered Streetlighting (PNM Owned)	20 - Street Lighting - Units	264		
416	L3D2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - Units	3,720	$19.00	$70,680
417	L4D2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - Units	120	$23.59	$2,831
418	L7D2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - Units	7,176	$14.14	$101,469
419	L8D2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - Units	0	$14.14	$0
420	L3D4-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - Units	72	$19.00	$1,368
421	L4D4-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - Units	468	$23.59	$11,040
422	L3F2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - Units	480	$26.33	$12,638
423	L4F2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - Units	12	$30.92	$371
424	L7F2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - Units	1,212	$21.47	$26,022
425	L8F2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - Units	0	$21.47	$0
426	L4F4-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - Units	24	$30.92	$742
427	L3U2-55W LPS SL (PNM, 1x28 kWh/Unit)	20 - Street Lighting - Units	5,280	$17.56	$92,717
428	L4U2-55W LPS SL (PNM, 1x28 kWh/Unit)	20 - Street Lighting - Units	12	$22.15	$266
429	L7U2-55W LPS SL (PNM, 1x28 kWh/Unit)	20 - Street Lighting - Units	3,936	$12.70	$49,987
430	L8U2-55W LPS SL (PNM, 1x28 kWh/Unit)	20 - Street Lighting - Units	0	$12.70	$0
431	L3U4-55W LPS SL (PNM, 1x28 kWh/Unit)	20 - Street Lighting - Units	1,260	$17.56	$22,126
432	L4U4-55W LPS SL (PNM, 1x28 kWh/Unit)	20 - Street Lighting - Units	1,164	$22.15	$25,783
433	L3V2-135W LPS SL (PNM, 1x63 kWh/Unit)	20 - Street Lighting - Units	12	$21.99	$264
434	L7V2-135W LPS SL (PNM, 1x63 kWh/Unit)	20 - Street Lighting - Units	12	$17.13	$206
435	L4V4-135W LPS SL (PNM, 1x63 kWh/Unit)	20 - Street Lighting - Units	264	$26.58	$7,017
436	L3A2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - Units	7,896	$16.88	$133,284
437	L4A2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - Units	72	$21.47	$1,546
438	L7A2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - Units	6,912	$12.02	$83,082
439	L8A2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - Units	48	$12.02	$577
440	L3A4-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - Units	1,332	$16.88	$22,484
441	L4A4-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - Units	1,584	$21.47	$34,008
442	L3T2-200W HPS SL (PNM, 1x89 kWh/Unit)	20 - Street Lighting - Units	1,500	$19.85	$29,775
443	L4T2-200W HPS SL (PNM, 1x89 kWh/Unit)	20 - Street Lighting - Units	1,764	$24.44	$43,112
444	L7T2-200W HPS SL (PNM, 1x89 kWh/Unit)	20 - Street Lighting - Units	1,068	$14.99	$16,009
445	L8T2-200W HPS SL (PNM, 1x89 kWh/Unit)	20 - Street Lighting - Units	0	$14.99	$0
446	L3T4-200W HPS SL (PNM, 1x89 kWh/Unit)	20 - Street Lighting - Units	36	$19.85	$715
447	L4T4-200W HPS SL (PNM, 1x89 kWh/Unit)	20 - Street Lighting - Units	7,404	$24.44	$180,954
448	L3C2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	324	$26.56	$8,605
449	L4C2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	12	$31.15	$374
450	L7C2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	408	$21.70	$8,854
451	L8C2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	0	$21.70	$0
452	L4C4-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	36	$31.15	$1,121
453	LAD1-175W MV SL (Cust, 1x73 kWh/Unit)	20 - Street Lighting - Units	660	$5.54	$3,656
454	LAD3-175W MV SL (Cust, 1x73 kWh/Unit)	20 - Street Lighting - Units	27,624	$5.54	$153,037
455	LAF1-400W MV SL (Cust, 1x162 kWh/Unit)	20 - Street Lighting - Units	756	$12.30	$9,299
456	LWF1-400W MV SL (Cust, 2x162 kWh/Unit)	20 - Street Lighting - Units	12	$24.60	$295
457	LAF3-400W MV SL (Cust, 1x162 kWh/Unit)	20 - Street Lighting - Units	2,856	$12.30	$35,129
458	LWF3-400W MV SL (Cust, 2x162 kWh/Unit)	20 - Street Lighting - Units	12	$24.60	$295
459	LAS1-70W HPS SL (Cust, 1x31 kWh/Unit)	20 - Street Lighting - Units	24	$2.35	$56
460	LAS3-70W HPS SL (Cust, 1x31 kWh/Unit)	20 - Street Lighting - Units	540	$2.35	$1,269
461	LAA1-100W HPS SL (Cust, 1x45 kWh/Unit)	20 - Street Lighting - Units	492	$3.42	$1,683
462	LAA3-100W HPS SL (Cust, 1x45 kWh/Unit)	20 - Street Lighting - Units	145,812	$3.42	$498,677

Test Period Billing Determinants

A Line No.	B Desc	C Tariff	D Test Period Determinants	E Rates 15-00261-UT	F Test Period Revenues
463	LAB1-250W HPS SL (Cust, 1x107 kWh/Unit)	20 - Street Lighting - Units	22,404	$8.12	$181,920
464	LWB1-250W HPS SL (Cust, 2x107 kWh/Unit)	20 - Street Lighting - Units	216	$16.24	$3,508
465	LAB3-250W HPS SL (Cust, 1x107 kWh/Unit)	20 - Street Lighting - Units	50,184	$8.12	$407,494
466	LWB3-250W HPS SL (Cust, 2x107 kWh/Unit)	20 - Street Lighting - Units	4,512	$16.24	$73,275
467	LAI1-400W HPS FL (Cust, 1x165 kWh/Unit)	20 - Street Lighting - Units	12	$12.53	$150
468	LAI3-400W HPS FL (Cust, 1x165 kWh/Unit)	20 - Street Lighting - Units	720	$12.53	$9,022
469	LWI3-400W HPS FL (Cust, 2x165 kWh/Unit)	20 - Street Lighting - Units	36	$25.06	$902
470	LAC1-400W HPS SL (Cust, 1x165 kWh/Unit)	20 - Street Lighting - Units	1,404	$12.53	$17,592
471	LWC1-400W HPS SL (Cust, 2x165 kWh/Unit)	20 - Street Lighting - Units	132	$25.06	$3,308
472	LAC3-400W HPS SL (Cust, 1x165 kWh/Unit)	20 - Street Lighting - Units	47,796	$12.53	$598,884
473	LWC3-400W HPS SL (Cust, 2x165 kWh/Unit)	20 - Street Lighting - Units	4,824	$25.06	$120,889
474	LID2-175W MV SL (PNM, 2x73 kWh/Unit)	20 - Street Lighting - Units	24	$33.14	$795
475	LBD2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - Units	6,600	$19.00	$125,400
476	LCD2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - Units	14,280	$19.00	$271,320
477	LDD2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - Units	336	$19.00	$6,384
478	LED2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - Units	12	$19.00	$228
479	LFD2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - Units	12	$23.59	$283
480	LGD2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - Units	12	$23.59	$283
481	LAD2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - Units	17,172	$14.14	$242,812
482	LFD4-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - Units	444	$23.59	$10,474
483	LGD4-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - Units	156	$23.59	$3,680
484	LBF2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - Units	24	$26.33	$632
485	LCF2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - Units	48	$26.33	$1,264
486	LDF2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - Units	24	$26.33	$632
487	LEF2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - Units	24	$26.33	$632
488	LJF2-400W MV SL (PNM, 2x162 kWh/Unit)	20 - Street Lighting - Units	48	$52.39	$2,515
489	LFF2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - Units	84	$30.92	$2,597
490	LGF2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - Units	1,392	$30.92	$43,041
491	LHF2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - Units	36	$30.92	$1,113
492	LAF2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - Units	1,488	$21.47	$31,947
493	LGF4-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - Units	588	$30.92	$18,181
494	LLF4-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - Units	60	$30.92	$1,855
495	LAF4-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - Units	12	$21.47	$258
496	LBS2-70W HPS SL (PNM, 1x31 kWh/Unit)	20 - Street Lighting - Units	24	$15.81	$379
497	LCS2-70W HPS SL (PNM, 1x31 kWh/Unit)	20 - Street Lighting - Units	204	$15.81	$3,225
498	LAS2-70W HPS SL (PNM, 1x31 kWh/Unit)	20 - Street Lighting - Units	84	$10.95	$920
499	LBA2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - Units	14,628	$16.88	$246,921
500	LCA2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - Units	37,044	$16.88	$625,303
501	LDA2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - Units	264	$16.88	$4,456
502	LEA2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - Units	12	$16.88	$203
503	LFA2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - Units	144	$21.47	$3,092
504	LGA2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - Units	24	$21.47	$515
505	LAA2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - Units	43,776	$12.02	$526,188
506	LFA4-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - Units	1,608	$21.47	$34,524
507	LGA4-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - Units	36	$21.47	$773
508	LSA4-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - Units	780	$21.47	$16,747
509	LIB2-250W HPS SL (PNM, 2x107 kWh/Unit)	20 - Street Lighting - Units	24	$39.44	$947
510	LBB2-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - Units	540	$22.15	$11,961
511	LCB2-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - Units	5,172	$22.15	$114,560
512	LDB2-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - Units	168	$22.15	$3,721
513	LEB2-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - Units	0	$22.15	$0
514	LJB2-250W HPS SL (PNM, 2x107 kWh/Unit)	20 - Street Lighting - Units	1,392	$44.03	$61,290
515	LFB2-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - Units	216	$26.74	$5,776
516	LGB2-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - Units	20,328	$26.74	$543,571
517	LHB2-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - Units	36	$26.74	$963
518	LAB2-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - Units	31,092	$17.29	$537,581
519	LCB4-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - Units	0	$22.15	$0
520	LJB4-250W HPS SL (PNM, 2x107 kWh/Unit)	20 - Street Lighting - Units	48	$44.03	$2,113
521	LFB4-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - Units	108	$26.74	$2,888
522	LGB4-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - Units	6,216	$26.74	$166,216
523	LHB4-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - Units	60	$26.74	$1,604
524	LLB4-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - Units	36	$26.74	$963

Test Period Billing Determinants

A Line No.	B Desc	C Tariff	D Test Period Determinants	E Rates 15-00261-UT	F Test Period Revenues
525	LII2-400W HPS FL (PNM, 2x165 kWh/Unit)	20 - Street Lighting - Units	456	$48.26	$22,007
526	LBI2-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	264	$26.56	$7,012
527	LCI2-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	2,568	$26.56	$68,206
528	LDI2-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	228	$26.56	$6,056
529	LEI2-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	228	$26.56	$6,056
530	LFI2-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	36	$31.15	$1,121
531	LGI2-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	0	$31.15	$0
532	LHI2-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	0	$31.15	$0
533	LAI2-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	4,164	$21.70	$90,359
534	LCI4-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	48	$26.56	$1,275
535	LJI4-400W HPS FL (PNM, 2x165 kWh/Unit)	20 - Street Lighting - Units	48	$52.85	$2,537
536	LKI4-400W HPS FL (PNM, 2x165 kWh/Unit)	20 - Street Lighting - Units	0	$52.85	$0
537	LFI4-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	36	$31.15	$1,121
538	LGI4-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	48	$31.15	$1,495
539	LHI4-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	204	$31.15	$6,355
540	LAI4-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	12	$21.70	$260
541	LIC2-400W HPS SL (PNM, 2x165 kWh/Unit)	20 - Street Lighting - Units	0	$48.26	$0
542	LCC2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	252	$26.56	$6,693
543	LDC2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	216	$26.56	$5,737
544	LEC2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	144	$26.56	$3,825
545	LJC2-400W HPS SL (PNM, 2x165 kWh/Unit)	20 - Street Lighting - Units	36	$52.85	$1,903
546	LGC2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	540	$31.15	$16,821
547	LHC2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	12	$31.15	$374
548	LLC2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	0	$31.15	$0
549	LAC2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	1,932	$21.70	$41,924
550	LKC4-400W HPS SL (PNM, 2x165 kWh/Unit)	20 - Street Lighting - Units	228	$52.85	$12,050
551	LGC4-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	108	$31.15	$3,364
552	LHC4-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	1,344	$31.15	$41,866
553	LLC4-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - Units	312	$31.15	$9,719
554	L2Z5-Metered Streetlighting (Cust Owned)	20 - Street Lighting - kWh	310,428	$0.06	17441.05571
555	L3D1-175W MV SL (Cust, 1x73 kWh/Unit)	20 - Street Lighting - kWh	0		
556	L7D1-175W MV SL (Cust, 1x73 kWh/Unit)	20 - Street Lighting - kWh	0		
557	L8D1-175W MV SL (Cust, 1x73 kWh/Unit)	20 - Street Lighting - kWh	0		
558	L7D3-175W MV SL (Cust, 1x73 kWh/Unit)	20 - Street Lighting - kWh	0		
559	L8D3-175W MV SL (Cust, 1x73 kWh/Unit)	20 - Street Lighting - kWh	0		
560	L7F1-400W MV SL (Cust, 1x162 kWh/Unit)	20 - Street Lighting - kWh	0		
561	L8F1-400W MV SL (Cust, 1x162 kWh/Unit)	20 - Street Lighting - kWh	0		
562	L7F3-400W MV SL (Cust, 1x162 kWh/Unit)	20 - Street Lighting - kWh	0		
563	L8F3-400W MV SL (Cust, 1x162 kWh/Unit)	20 - Street Lighting - kWh	153,576		
564	L7A1-100W HPS SL (Cust, 1x45 kWh/Unit)	20 - Street Lighting - kWh	0		
565	L8A1-100W HPS SL (Cust, 1x45 kWh/Unit)	20 - Street Lighting - kWh	7,020		
566	L7A3-100W HPS SL (Cust, 1x45 kWh/Unit)	20 - Street Lighting - kWh	0		
567	L8A3-100W HPS SL (Cust, 1x45 kWh/Unit)	20 - Street Lighting - kWh	0		
568	L7T1-200W HPS SL (Cust, 1x89 kWh/Unit)	20 - Street Lighting - kWh	0		
569	L8T1-200W HPS SL (Cust, 1x89 kWh/Unit)	20 - Street Lighting - kWh	0		
570	L7T3-200W HPS SL (Cust, 1x89 kWh/Unit)	20 - Street Lighting - kWh	0		
571	L8T3-200W HPS SL (Cust, 1x89 kWh/Unit)	20 - Street Lighting - kWh	0		
572	L7C1-400W HPS SL (Cust, 1x165 kWh/Unit)	20 - Street Lighting - kWh	0		
573	L8C1-400W HPS SL (Cust, 1x165 kWh/Unit)	20 - Street Lighting - kWh	1,980		
574	L7C3-400W HPS SL (Cust, 1x165 kWh/Unit)	20 - Street Lighting - kWh	0		
575	L8C3-400W HPS SL (Cust, 1x165 kWh/Unit)	20 - Street Lighting - kWh	112,860		
576	L1Z5-Metered Streetlighting (PNM Owned)	20 - Street Lighting - kWh	473,460	$0.19	91854.55422
577	L3D2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - kWh	271,560		
578	L4D2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - kWh	8,760		
579	L7D2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - kWh	523,848		
580	L8D2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - kWh	0		
581	L3D4-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - kWh	5,256		
582	L4D4-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - kWh	34,164		
583	L3F2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - kWh	77,760		
584	L4F2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - kWh	1,944		
585	L7F2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - kWh	196,344		
586	L8F2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - kWh	0		
587	L4F4-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - kWh	3,888		
588	L3U2-55W LPS SL (PNM, 1x28 kWh/Unit)	20 - Street Lighting - kWh	147,840		
589	L4U2-55W LPS SL (PNM, 1x28 kWh/Unit)	20 - Street Lighting - kWh	336		
590	L7U2-55W LPS SL (PNM, 1x28 kWh/Unit)	20 - Street Lighting - kWh	110,208		
591	L8U2-55W LPS SL (PNM, 1x28 kWh/Unit)	20 - Street Lighting - kWh	0		
592	L3U4-55W LPS SL (PNM, 1x28 kWh/Unit)	20 - Street Lighting - kWh	35,280		
593	L4U4-55W LPS SL (PNM, 1x28 kWh/Unit)	20 - Street Lighting - kWh	32,592		

Test Period Billing Determinants

A Line No.	B Desc	C Tariff	D Test Period Determinants	E Rates 15-00261-UT	F Test Period Revenues
594	L3V2-135W LPS SL (PNM, 1x63 kWh/Unit)	20 - Street Lighting - kWh	756		
595	L7V2-135W LPS SL (PNM, 1x63 kWh/Unit)	20 - Street Lighting - kWh	756		
596	L4V4-135W LPS SL (PNM, 1x63 kWh/Unit)	20 - Street Lighting - kWh	16,632		
597	L3A2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - kWh	355,320		
598	L4A2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - kWh	3,240		
599	L7A2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - kWh	311,040		
600	L8A2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - kWh	2,160		
601	L3A4-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - kWh	59,940		
602	L4A4-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - kWh	71,280		
603	L3T2-200W HPS SL (PNM, 1x89 kWh/Unit)	20 - Street Lighting - kWh	133,500		
604	L4T2-200W HPS SL (PNM, 1x89 kWh/Unit)	20 - Street Lighting - kWh	156,996		
605	L7T2-200W HPS SL (PNM, 1x89 kWh/Unit)	20 - Street Lighting - kWh	95,052		
606	L8T2-200W HPS SL (PNM, 1x89 kWh/Unit)	20 - Street Lighting - kWh	0		
607	L3T4-200W HPS SL (PNM, 1x89 kWh/Unit)	20 - Street Lighting - kWh	3,204		
608	L4T4-200W HPS SL (PNM, 1x89 kWh/Unit)	20 - Street Lighting - kWh	658,956		
609	L3C2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	53,460		
610	L4C2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	1,980		
611	L7C2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	67,320		
612	L8C2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	0		
613	L4C4-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	5,940		
614	LAD1-175W MV SL (Cust, 1x73 kWh/Unit)	20 - Street Lighting - kWh	48,180		
615	LAD3-175W MV SL (Cust, 1x73 kWh/Unit)	20 - Street Lighting - kWh	2,016,552		
616	LAF1-400W MV SL (Cust, 1x162 kWh/Unit)	20 - Street Lighting - kWh	122,472		
617	LWF1-400W MV SL (Cust, 2x162 kWh/Unit)	20 - Street Lighting - kWh	3,888		
618	LAF3-400W MV SL (Cust, 1x162 kWh/Unit)	20 - Street Lighting - kWh	462,672		
619	LWF3-400W MV SL (Cust, 2x162 kWh/Unit)	20 - Street Lighting - kWh	3,888		
620	LAS1-70W HPS SL (Cust, 1x31 kWh/Unit)	20 - Street Lighting - kWh	744		
621	LAS3-70W HPS SL (Cust, 1x31 kWh/Unit)	20 - Street Lighting - kWh	16,740		
622	LAA1-100W HPS SL (Cust, 1x45 kWh/Unit)	20 - Street Lighting - kWh	22,140		
623	LAA3-100W HPS SL (Cust, 1x45 kWh/Unit)	20 - Street Lighting - kWh	6,561,540		
624	LAB1-250W HPS SL (Cust, 1x107 kWh/Unit)	20 - Street Lighting - kWh	2,397,228		
625	LWB1-250W HPS SL (Cust, 2x107 kWh/Unit)	20 - Street Lighting - kWh	46,224		
626	LAB3-250W HPS SL (Cust, 1x107 kWh/Unit)	20 - Street Lighting - kWh	5,369,688		
627	LWB3-250W HPS SL (Cust, 2x107 kWh/Unit)	20 - Street Lighting - kWh	965,568		
628	LAI1-400W HPS FL (Cust, 1x165 kWh/Unit)	20 - Street Lighting - kWh	1,980		
629	LAI3-400W HPS FL (Cust, 1x165 kWh/Unit)	20 - Street Lighting - kWh	118,800		
630	LWI3-400W HPS FL (Cust, 2x165 kWh/Unit)	20 - Street Lighting - kWh	11,880		
631	LAC1-400W HPS SL (Cust, 1x165 kWh/Unit)	20 - Street Lighting - kWh	231,660		
632	LWC1-400W HPS SL (Cust, 2x165 kWh/Unit)	20 - Street Lighting - kWh	43,560		
633	LAC3-400W HPS SL (Cust, 1x165 kWh/Unit)	20 - Street Lighting - kWh	7,886,340		
634	LWC3-400W HPS SL (Cust, 2x165 kWh/Unit)	20 - Street Lighting - kWh	1,591,920		
635	LID2-175W MV SL (PNM, 2x73 kWh/Unit)	20 - Street Lighting - kWh	3,504		
636	LBD2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - kWh	481,800		
637	LCD2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - kWh	1,042,440		
638	LDD2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - kWh	24,528		
639	LED2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - kWh	876		
640	LFD2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - kWh	876		
641	LGD2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - kWh	876		
642	LAD2-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - kWh	1,253,556		
643	LFD4-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - kWh	32,412		
644	LGD4-175W MV SL (PNM, 1x73 kWh/Unit)	20 - Street Lighting - kWh	11,388		
645	LBF2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - kWh	3,888		
646	LCF2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - kWh	7,776		
647	LDF2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - kWh	3,888		
648	LEF2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - kWh	3,888		
649	LJF2-400W MV SL (PNM, 2x162 kWh/Unit)	20 - Street Lighting - kWh	15,552		
650	LFF2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - kWh	13,608		
651	LGF2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - kWh	225,504		
652	LHF2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - kWh	5,832		
653	LAF2-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - kWh	241,056		
654	LGF4-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - kWh	95,256		
655	LLF4-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - kWh	9,720		
656	LAF4-400W MV SL (PNM, 1x162 kWh/Unit)	20 - Street Lighting - kWh	1,944		
657	LBS2-70W HPS SL (PNM, 1x31 kWh/Unit)	20 - Street Lighting - kWh	744		
658	LCS2-70W HPS SL (PNM, 1x31 kWh/Unit)	20 - Street Lighting - kWh	6,324		
659	LAS2-70W HPS SL (PNM, 1x31 kWh/Unit)	20 - Street Lighting - kWh	2,604		

Test Period Billing Determinants

A Line No.	B Desc	C Tariff	D Test Period Determinants	E Rates 15-00261-UT	F Test Period Revenues
660	LBA2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - kWh	658,260		
661	LCA2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - kWh	1,666,980		
662	LDA2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - kWh	11,880		
663	LEA2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - kWh	540		
664	LFA2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - kWh	6,480		
665	LGA2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - kWh	1,080		
666	LAA2-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - kWh	1,969,920		
667	LFA4-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - kWh	72,360		
668	LGA4-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - kWh	1,620		
669	LSA4-100W HPS SL (PNM, 1x45 kWh/Unit)	20 - Street Lighting - kWh	35,100		
670	LIB2-250W HPS SL (PNM, 2x107 kWh/Unit)	20 - Street Lighting - kWh	5,136		
671	LBB2-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - kWh	57,780		
672	LCB2-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - kWh	553,404		
673	LDB2-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - kWh	17,976		
674	LEB2-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - kWh	0		
675	LJB2-250W HPS SL (PNM, 2x107 kWh/Unit)	20 - Street Lighting - kWh	297,888		
676	LFB2-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - kWh	23,112		
677	LGB2-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - kWh	2,175,096		
678	LHB2-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - kWh	3,852		
679	LAB2-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - kWh	3,326,844		
680	LCB4-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - kWh	0		
681	LJB4-250W HPS SL (PNM, 2x107 kWh/Unit)	20 - Street Lighting - kWh	10,272		
682	LFB4-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - kWh	11,556		
683	LGB4-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - kWh	665,112		
684	LHB4-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - kWh	6,420		
685	LLB4-250W HPS SL (PNM, 1x107 kWh/Unit)	20 - Street Lighting - kWh	3,852		
686	LII2-400W HPS FL (PNM, 2x165 kWh/Unit)	20 - Street Lighting - kWh	150,480		
687	LBI2-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	43,560		
688	LCI2-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	423,720		
689	LDI2-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	37,620		
690	LEI2-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	37,620		
691	LFI2-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	5,940		
692	LGI2-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	0		
693	LHI2-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	0		
694	LAI2-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	687,060		
695	LCI4-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	7,920		
696	LJI4-400W HPS FL (PNM, 2x165 kWh/Unit)	20 - Street Lighting - kWh	15,840		
697	LKI4-400W HPS FL (PNM, 2x165 kWh/Unit)	20 - Street Lighting - kWh	0		
698	LFI4-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	5,940		
699	LGI4-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	7,920		
700	LHI4-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	33,660		
701	LAI4-400W HPS FL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	1,980		
702	LIC2-400W HPS SL (PNM, 2x165 kWh/Unit)	20 - Street Lighting - kWh	0		
703	LCC2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	41,580		
704	LDC2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	35,640		
705	LEC2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	23,760		
706	LJC2-400W HPS SL (PNM, 2x165 kWh/Unit)	20 - Street Lighting - kWh	11,880		
707	LGC2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	89,100		
708	LHC2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	1,980		
709	LLC2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	0		
710	LAC2-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	318,780		
711	LKC4-400W HPS SL (PNM, 2x165 kWh/Unit)	20 - Street Lighting - kWh	75,240		
712	LGC4-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	17,820		
713	LHC4-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	221,760		
714	LLC4-400W HPS SL (PNM, 1x165 kWh/Unit)	20 - Street Lighting - kWh	51,480		

Test Period Billing Determinants

A Line No.	B Desc	C Tariff	D Test Period Determinants	E Rates 15-00261-UT	F Test Period Revenues
715					
716	35B - Lg. Svc. (3 MW) - IID (Summer)	Rider 08 - IIPR	36,819	($15.83)	($582,839.14)
717	4B - Large Power (4.2 Pri T1) - IID (Summer)	Rider 08 - IIPR	3,887	($15.83)	($61,529.63)
718	03C - General Power LLF TOU (3.2 Pri NT1) - IID (Summer)	Rider 08 - IIPR	9,108	($6.85)	($62,387.06)
719	03C - General Power LLF TOU (3.0 Sec NT1) - IID (Summer)	Rider 08 - IIPR	3,709	($6.85)	($25,406.11)
720	35B - Lg. Svc. (3 MW) - IID (Non-Summer)	Rider 08 - IIPR	109,705	($7.38)	($809,625.52)
721	4B - Large Power (4.2 Pri T1) - IID (Non-Summer)	Rider 08 - IIPR	12,880	($4.08)	($52,550.81)
722	03C - General Power LLF TOU (3.2 Pri NT1) - IID (Non-Summer)	Rider 08 - IIPR	29,241	($0.38)	($11,111.73)
723	03C - General Power LLF TOU (3.0 Sec NT1) - IID (Non-Summer)	Rider 08 - IIPR	11,272	($0.38)	($4,283.39)
724	35B - Lg. Svc. (3 MW) - IID	Rider 08 - IIPR	146,524		($1,392,464.67)
725	4B - Large Power (4.2 Pri T1) - IID	Rider 08 - IIPR	16,767		($114,080.44)
726	03C - General Power LLF TOU (3.2 Pri NT1) - IID	Rider 08 - IIPR	38,349		($73,498.79)
727	03C - General Power LLF TOU (3.0 Sec NT1) - IID	Rider 08 - IIPR	14,981		($29,689.50)

Test Period Billing Determinants

A Line No.	B Desc	C Tariff	D Test Period Determinants	E Rates 15-00261-UT	F Test Period Revenues
728					
729	L2Z5-Metered Streetlighting (Cust Owned)	R35-Rate 20 (kWh)	310,428	$0.0000000	$0
730	L3D1-175W MV SL (Cust, 1x73 kWh/Unit)	R35-Rate 20 (Units)	0	$0.00	$0
731	L7D1-175W MV SL (Cust, 1x73 kWh/Unit)	R35-Rate 20 (Units)	0	$0.00	$0
732	L8D1-175W MV SL (Cust, 1x73 kWh/Unit)	R35-Rate 20 (Units)	0	$0.00	$0
733	L7D3-175W MV SL (Cust, 1x73 kWh/Unit)	R35-Rate 20 (Units)	0	$0.00	$0
734	L8D3-175W MV SL (Cust, 1x73 kWh/Unit)	R35-Rate 20 (Units)	0	$0.00	$0
735	L7F1-400W MV SL (Cust, 1x162 kWh/Unit)	R35-Rate 20 (Units)	0	$0.00	$0
736	L8F1-400W MV SL (Cust, 1x162 kWh/Unit)	R35-Rate 20 (Units)	0	$0.00	$0
737	L7F3-400W MV SL (Cust, 1x162 kWh/Unit)	R35-Rate 20 (Units)	0	$0.00	$0
738	L8F3-400W MV SL (Cust, 1x162 kWh/Unit)	R35-Rate 20 (Units)	948	$0.00	$0
739	L7A1-100W HPS SL (Cust, 1x45 kWh/Unit)	R35-Rate 20 (Units)	0	$0.00	$0
740	L8A1-100W HPS SL (Cust, 1x45 kWh/Unit)	R35-Rate 20 (Units)	156	$0.00	$0
741	L7A3-100W HPS SL (Cust, 1x45 kWh/Unit)	R35-Rate 20 (Units)	0	$0.00	$0
742	L8A3-100W HPS SL (Cust, 1x45 kWh/Unit)	R35-Rate 20 (Units)	0	$0.00	$0
743	L7T1-200W HPS SL (Cust, 1x89 kWh/Unit)	R35-Rate 20 (Units)	0	$0.00	$0
744	L8T1-200W HPS SL (Cust, 1x89 kWh/Unit)	R35-Rate 20 (Units)	0	$0.00	$0
745	L7T3-200W HPS SL (Cust, 1x89 kWh/Unit)	R35-Rate 20 (Units)	0	$0.00	$0
746	L8T3-200W HPS SL (Cust, 1x89 kWh/Unit)	R35-Rate 20 (Units)	0	$0.00	$0
747	L7C1-400W HPS SL (Cust, 1x165 kWh/Unit)	R35-Rate 20 (Units)	0	$0.00	$0
748	L8C1-400W HPS SL (Cust, 1x165 kWh/Unit)	R35-Rate 20 (Units)	12	$0.00	$0
749	L7C3-400W HPS SL (Cust, 1x165 kWh/Unit)	R35-Rate 20 (Units)	0	$0.00	$0
750	L8C3-400W HPS SL (Cust, 1x165 kWh/Unit)	R35-Rate 20 (Units)	684	$0.00	$0
751	L1Z5-Metered Streetlighting (PNM Owned)	R35-Rate 20 (kWh)	473,460	($0.10)	($45,930.50)
752	L3D2-175W MV SL (PNM, 1x73 kWh/Unit)	R35-Rate 20 (Units)	3,720	($11.90)	($44,268.00)
753	L4D2-175W MV SL (PNM, 1x73 kWh/Unit)	R35-Rate 20 (Units)	120	($16.49)	($1,978.80)
754	L7D2-175W MV SL (PNM, 1x73 kWh/Unit)	R35-Rate 20 (Units)	7,176	($7.04)	($50,519.04)
755	L8D2-175W MV SL (PNM, 1x73 kWh/Unit)	R35-Rate 20 (Units)	0	($7.04)	$0.00
756	L3D4-175W MV SL (PNM, 1x73 kWh/Unit)	R35-Rate 20 (Units)	72	($11.90)	($856.80)
757	L4D4-175W MV SL (PNM, 1x73 kWh/Unit)	R35-Rate 20 (Units)	468	($16.49)	($7,717.32)
758	L3F2-400W MV SL (PNM, 1x162 kWh/Unit)	R35-Rate 20 (Units)	480	($10.34)	($4,963.20)
759	L4F2-400W MV SL (PNM, 1x162 kWh/Unit)	R35-Rate 20 (Units)	12	($12.24)	($146.88)
760	L7F2-400W MV SL (PNM, 1x162 kWh/Unit)	R35-Rate 20 (Units)	1,212	($5.48)	($6,641.76)
761	L8F2-400W MV SL (PNM, 1x162 kWh/Unit)	R35-Rate 20 (Units)	0	($2.79)	$0.00
762	L4F4-400W MV SL (PNM, 1x162 kWh/Unit)	R35-Rate 20 (Units)	24	($12.24)	($293.76)
763	L3U2-55W LPS SL (PNM, 1x28 kWh/Unit)	R35-Rate 20 (Units)	5,280	($7.39)	($39,019.20)
764	L4U2-55W LPS SL (PNM, 1x28 kWh/Unit)	R35-Rate 20 (Units)	12	($11.98)	($143.76)
765	L7U2-55W LPS SL (PNM, 1x28 kWh/Unit)	R35-Rate 20 (Units)	3,936	($2.53)	($9,958.08)
766	L8U2-55W LPS SL (PNM, 1x28 kWh/Unit)	R35-Rate 20 (Units)	0	($2.53)	$0.00
767	L3U4-55W LPS SL (PNM, 1x28 kWh/Unit)	R35-Rate 20 (Units)	1,260	($7.39)	($9,311.40)
768	L4U4-55W LPS SL (PNM, 1x28 kWh/Unit)	R35-Rate 20 (Units)	1,164	($11.98)	($13,944.72)
769	L3V2-135W LPS SL (PNM, 1x63 kWh/Unit)	R35-Rate 20 (Units)	12	($7.68)	($92.16)
770	L7V2-135W LPS SL (PNM, 1x63 kWh/Unit)	R35-Rate 20 (Units)	12	($2.82)	($33.84)
771	L4V4-135W LPS SL (PNM, 1x63 kWh/Unit)	R35-Rate 20 (Units)	264	($12.27)	($3,239.28)
772	L3A2-100W HPS SL (PNM, 1x45 kWh/Unit)	R35-Rate 20 (Units)	7,896	($6.93)	($54,719.28)
773	L4A2-100W HPS SL (PNM, 1x45 kWh/Unit)	R35-Rate 20 (Units)	72	($2.64)	($190.08)
774	L7A2-100W HPS SL (PNM, 1x45 kWh/Unit)	R35-Rate 20 (Units)	6,912	($2.07)	($14,307.84)
775	L8A2-100W HPS SL (PNM, 1x45 kWh/Unit)	R35-Rate 20 (Units)	48	$0.00	$0.00
776	L3A4-100W HPS SL (PNM, 1x45 kWh/Unit)	R35-Rate 20 (Units)	1,332	($3.83)	($5,101.56)
777	L4A4-100W HPS SL (PNM, 1x45 kWh/Unit)	R35-Rate 20 (Units)	1,584	($8.42)	($13,337.28)
778	L3T2-200W HPS SL (PNM, 1x89 kWh/Unit)	R35-Rate 20 (Units)	1,500	($7.70)	($11,550.00)
779	L4T2-200W HPS SL (PNM, 1x89 kWh/Unit)	R35-Rate 20 (Units)	1,764	($3.95)	($6,967.80)
780	L7T2-200W HPS SL (PNM, 1x89 kWh/Unit)	R35-Rate 20 (Units)	1,068	($2.84)	($3,033.12)
781	L8T2-200W HPS SL (PNM, 1x89 kWh/Unit)	R35-Rate 20 (Units)	0	$0.00	$0.00
782	L3T4-200W HPS SL (PNM, 1x89 kWh/Unit)	R35-Rate 20 (Units)	36	($5.02)	($180.72)
783	L4T4-200W HPS SL (PNM, 1x89 kWh/Unit)	R35-Rate 20 (Units)	7,404	($2.98)	($22,063.92)
784	L3C2-400W HPS SL (PNM, 1x165 kWh/Unit)	R35-Rate 20 (Units)	324	($10.61)	($3,437.64)
785	L4C2-400W HPS SL (PNM, 1x165 kWh/Unit)	R35-Rate 20 (Units)	12	($7.67)	($92.04)
786	L7C2-400W HPS SL (PNM, 1x165 kWh/Unit)	R35-Rate 20 (Units)	408	($5.75)	($2,346.00)
787	L8C2-400W HPS SL (PNM, 1x165 kWh/Unit)	R35-Rate 20 (Units)	0	$0.00	$0.00
788	L4C4-400W HPS SL (PNM, 1x165 kWh/Unit)	R35-Rate 20 (Units)	36	($7.67)	($276.12)

kWh at Meter by Month

	Test Period
1 - Residential	3,164,862,106
2 - Small Power	915,396,797
3B - General Power	1,641,925,784
3C - General Power Low LF	210,125,160
4B - Large Power	1,106,704,902
5B - Lg. Svc. (8 MW)	70,596,567
10 - Irrigation	23,427,777
11B - Wtr/Swg Pumping	168,508,457
15B - Universities 115 kV	63,683,882
30B - Manuf. (30 MW)	363,666,494
33B - Lg. Svc. (Station Power)	3,354,394
35B - Lg. Svc. (3 MW)	205,855,705
36B - SSR - Renew. Energy Res.	37,966,258
6 - Private Lighting	15,388,500
20 - Streetlighting	49,850,940
Total	8,041,313,722

Codes and Standards Adjustment Detail

PNM Exhibit SC-6

Is contained in the following 6 pages

Codes and Standards Adjustment

RESIDENTIAL CUSTOMERS

There are several standards in effect during the forecast horizon. Some of the standards were in place in 2014, and the effects of those standards continue to produce energy savings as appliances are replaced on failure in each year of the forecast period. The standards are described below, and a timeline that summarizes the appliance standards can be found in PNM Figure SC-6-1 on page 3 of this exhibit.

- **Lighting Standards.** The Energy Independence and Security Act of 2007 ("EISA") was signed into law in December 2007 and established the energy efficiency standards for light bulbs and other consumer products. The law was phased-in over three years, starting in January 2012 and ending on January 2014. The Department of Energy ("DOE") codified these standards in the Code of Federal Regulations, 10 CFR Part 430, § 430.32.

  The energy conservation standards for standard-spectrum general service incandescent lamps are summarized below:

Rated Lumen Ranges	*Maximum Rated Wattage*	*Effective Date*
1490-2600	72	1/1/2012
1050-1489	53	1/1/2013
750-1049	43	1/1/2014
310-749	29	1/1/2014

  - The consequence of these standards is to essentially eliminate general service incandescent lamps from the marketplace. As these lamps burn out during the Test Period, consumers must replace them with more efficient lamps.

- **Central Air Conditioners and Heat Pumps.** On June 27, 2011, amended standards were issued for central air conditioners and heat pumps. The energy conservation standards are specified in the Code of Federal Regulations, 10 CFR Part 430, § 430.32. The minimum standard for single package air conditioners was raised from Seasonal Energy Efficiency Ratio ("SEER") 13 to SEER 14. The minimum standard for single package heat pumps was raised from SEER 13, Heating Seasonal Performance Factor ("HSPF") 7.7 to SEER 14, HSPF 8. The standards apply to equipment manufactured on or after January 1, 2015.

- **Room Air Conditioners.** In August 2011, the DOE issued amended standards for room air conditioners that took effect on June 1, 2014. The energy conservation standards are specified in the Code of Federal Regulations, 10 CFR Part 430, § 430.32. The minimum standard for an 8,000 to 13,999 Btu/h room air conditioners was raised from the Energy Efficiency Ratio ("EER") of 9.8 to EER 10.9. For room air conditioners less than 8,000 Bth/h, the EER of 9.7 was raised to EER 11.0.

- **Refrigerators and Freezers.** On September 15, 2011, amended standards were issued for residential refrigerators and freezers. The energy conservation standards are specified in the Code of Federal Regulations, 10 CFR Part 430, § 430.32. The standards apply to equipment manufactured on or after September 15, 2014. The standards are expressed as the maximum annual energy consumption based on adjusted volume. The energy savings are in the range of 20-30% depending on the product class.

- **Clothes Washers.** In May 2012, the DOE issued amended standards for clothes washers. The energy conservation standards are specified in the Code of Federal Regulations, 10 CFR Part 430, § 430.32. Clothes washers have a two-phase standard, with one effective March 2015 and the other effective January 2018. The energy savings for clothes washers are expressed in IMEF (integrated modified energy factor) and IWF (integrated water factor). Previously the metrics were expressed in MEF (modified energy factor) and WF (water factor). In March 2015, the MEF for top load clothes washer changed from 1.26 to 1.72 (IMEF 1.29). In January 2018, the MEF will be 2.0 (IMEF 1.57).

- **Clothes Dryers.** In August 2011, the DOE adopted standards for clothes dryers that took effect on January 1, 2015. The energy conservation standards are specified in the Code of Federal Regulations, 10 CFR Part 430, § 430.32. The efficiency of clothes dryer is measured by a new metric, combined energy factor ("CEF") in lbs/kWh, which incorporates standby energy consumption. The current CEF standard is 3.73 for electric dryers. The previous standard was 3.01 (measured in EF or energy factor).

- **Dishwashers.** In May 2012, the DOE issued amended standards for dishwashers that took effect on May 30, 2013. The energy conservation standards are specified in the Code of Federal Regulations, 10 CFR Part 430, § 430.32. The standard-size dishwasher is required to use no more than 307 kWh/year and 5.0 gallons/cycle.

The Codes and Standards listed above continue to affect new appliance purchases through 2023 as old units are replaced upon failure. Codes and Standards in 2016 and 2017 were already in place in 2015.

In 2020, the Codes and Standards adjustment increases by 61 percent, which is higher than the growth rate in previous years. This jump is attributable to the EISA legislation, which calls for a second-tier improvement in efficiency beginning in 2020. It requires a minimum lamp efficiency of 45 lumens per Watt for general service lamps. The additional savings in 2020 are a result of this standard.

PNM Figure SC-6-1
Residential Standards

2013's Efficiency or Standard Assumption

1st Standard (relative to 2013's standard)
2nd Standard (relative to 2013's standard)

<table>
<tr><th>End Use</th><th>Technology</th><th>2013</th><th>2014</th><th>2015</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th><th>2020</th><th>2021</th><th>2022</th><th>2023</th></tr>
<tr><td rowspan="2">Cooling</td><td>Central AC</td><td colspan="2">SEER 13</td><td colspan="9">SEER 14</td></tr>
<tr><td>Room AC</td><td>EER 9.7</td><td colspan="10">EER 11.0</td></tr>
<tr><td>Cooling/Heating</td><td>Heat Pump</td><td colspan="2">SEER 13.0/HSPF 7.7</td><td colspan="9">SEER 14.0/HSPF 8.0</td></tr>
<tr><td rowspan="2">Water Heating</td><td>Water Heater (<=55 gallons)</td><td colspan="2">EF 0.90</td><td colspan="9">EF 0.95</td></tr>
<tr><td>Water Heater (>55 gallons)</td><td colspan="2">EF 0.90</td><td colspan="9">Heat Pump Water Heater</td></tr>
<tr><td>Lighting</td><td>Screw-in/Pin Lamps</td><td>Incandescent</td><td colspan="6">Advanced Incandescent - tier 1 (20 lumens/watt)</td><td colspan="4">Adv Incandescent - tier 2 (45 lumens/watt)</td></tr>
<tr><td rowspan="5">Appliances</td><td>Refrigerator/2nd Refrigerator</td><td>NAECA Standard</td><td colspan="10">25% more efficient</td></tr>
<tr><td>Freezer</td><td>NAECA Standard</td><td colspan="10">25% more efficient</td></tr>
<tr><td>Dishwasher</td><td colspan="11">14% more efficient than 2010 standard (307 kWh/yr)</td></tr>
<tr><td>Clothes Washer</td><td colspan="2">Conventional (MEF 1.26 for top loader)</td><td colspan="3">MEF 1.72 for top loader</td><td colspan="6">MEF 2.0 for top loader</td></tr>
<tr><td>Clothes Dryer</td><td colspan="2">EF 3.01</td><td colspan="9">EF 3.73</td></tr>
</table>

COMMERCIAL CUSTOMERS

The timeline and description of how Codes & Standards for Commercial customers were implemented in the modeling are summarized in PNM Figure SC-6-2 on page 6.

- **General Service Lamps.** The Energy Independence and Security Act of 2007 ("EISA") was signed into law December 2007 and established the energy efficiency standards for light bulbs and other consumer products. The law was phased-in over three years, starting in January 2012 and ending on January 2014. The DOE codified these standards in the Code of Federal Regulations, 10 CFR Part 430, § 430.32.

  The energy conservation standards for standard-spectrum general service incandescent lamps are summarized below:

Rated Lumen Ranges	*Maximum Rated Wattage*	*Effective Date*
1490-2600	72	1/1/2012
1050-1489	53	1/1/2013
750-1049	43	1/1/2014
310-749	29	1/1/2014

- **Linear Fluorescent Lamps.** Standards for linear fluorescent lamps that were initially established by the Energy Policy Act ("EPACT") of 1992 were updated in June 2009. The updated standards went into effect on July 14, 2012 (10 CPR Part 430). The efficiency standards vary by type of lamp, but the standard for the most common lamp type (4 foot medium bipin, ≤ 4500 K) is 89 lumens per watt, which can be met by T8 lamps . The consequence of this standard is to essentially eliminate T12 lamps from the marketplace. As these lamps burn out during the forecast period, consumers must replace them with the more efficient T8 lamps.

  The energy conservation standards for general fluorescent lamps effective July 14, 2012 are summarized below. The DOE published a final rule for updated standards in January 2015, as follows:

Lamp type	*Correlated color temperature*	*Energy conservation standard (lm/W)*
4-Foot Medium Bipin	≤ 4500 K	89
	>4,500 K and ≤7,000K	88
2-Foot U-Shaped	≤ 4500 K	84
	>4,500 K and ≤7,000K	81
8-Foot Slimline	≤ 4500 K	97
	>4,500 K and ≤7,000K	93
8-Foot High Output	≤ 4500 K	92
	>4,500 K and ≤7,000K	88
4-Foot Miniature Bipin Standard Output	≤ 4500 K	86
	>4,500 K and ≤7,000K	81

Lamp type	*Correlated color temperature*	*Energy conservation standard (lm/W)*
4-Foot Miniature Bipin High Output	≤ 4500 K	76
	>4,500 K and ≤7,000K	72

- **Small Electric Motors.** The DOE published a final rule in March 2010 to establish energy conservation standards for small electric motors (1/4 to 3 horsepower), effective March 2015. The small motors must have an average full load efficiency as specified in the Code of Federal Regulations, 10 CFR § 431.446. The minimum efficiency standards depend on the horsepower and the number of poles.

PNM Figure SC-6-2
Commercial Standards

2013's Efficiency or Standard Assumption

1st Standard (relative to 2013's standard)
2nd Standard (relative to 2013's standard)

End Use	Technology	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Lighting	Screw-in/Pin Lamps	Incandescent	Advanced Incandescent - tier 1 (20 lumens/watt)						Adv incand. - tier 2 (45 lumens/watt)			
	Linear Fluorescent	T8										
Miscellaneous	Small Motors	62.3% Efficiency		70% Efficiency								

Unadjusted Energy Forecast, the Effect of the Adjustments on the Energy Forecast, and Adjusted Energy Forecast by Rate Class

PNM Exhibit SC-7

Is contained in the following 4 pages

PNM Exhibit SC-7: Unadjusted Energy Forecast, Adjustments to Energy Forecast, and Final Adjusted Energy Forecast by Rate Class

Residential (Rates 1A and 1B)							
Year	Unadjusted Load Forecast	Distributed Generation	Sales Forecast Less DG	Energy Efficiency	Sales Forecast Less PV and EE	Codes and Standards	Final Load Forecast
2017	3,314,041,289	(26,277,465)	3,287,763,824	(49,700,385)	3,238,063,439	(59,358,991)	3,178,704,448
2018	3,362,292,361	(52,844,066)	3,309,448,295	(80,790,858)	3,228,657,437	(63,795,332)	3,164,862,106
2019	3,423,102,410	(79,308,968)	3,343,793,443	(112,942,370)	3,230,851,073	(96,223,035)	3,134,628,037
2020	3,486,065,601	(104,089,272)	3,381,976,329	(143,189,227)	3,238,787,102	(123,766,232)	3,115,020,870
2021	3,549,570,012	(104,689,272)	3,444,880,740	(162,695,037)	3,282,185,703	(152,264,575)	3,129,921,128
2022	3,613,565,254	(105,960,441)	3,507,604,814	(173,055,049)	3,334,549,765	(172,822,550)	3,161,727,214
2023	3,678,037,125	(107,249,406)	3,570,787,719	(190,911,495)	3,379,876,224	(175,909,085)	3,203,967,138

Small Power (Rates 2A and 2B)							
Year	Unadjusted Load Forecast	Distributed Generation	Sales Forecast Less DG	Energy Efficiency	Sales Forecast Less PV and EE	Codes and Standards	Final Load Forecast
2017	949,566,634	(2,277,622)	947,289,012	(10,519,172)	936,769,840	(12,438,745)	924,331,096
2018	952,919,120	(3,205,921)	949,713,199	(17,604,535)	932,108,664	(16,711,867)	915,396,797
2019	958,560,462	(3,954,273)	954,606,189	(24,611,878)	929,994,311	(19,210,226)	910,784,085
2020	964,041,204	(4,609,464)	959,431,741	(31,324,671)	928,107,070	(24,361,657)	903,745,413
2021	968,739,550	(4,610,982)	964,128,568	(38,921,306)	925,207,262	(24,484,210)	900,723,052
2022	973,343,492	(4,768,743)	968,574,750	(47,162,263)	921,412,487	(24,604,518)	896,807,969
2023	977,997,926	(4,928,712)	973,069,214	(53,430,797)	919,638,417	(24,726,412)	894,912,005

General Power (Rates 3B and 3C)

Year	Unadjusted Load Forecast	Distributed Generation	Sales Forecast Less DG	Energy Efficiency	Sales Forecast Less PV and EE	Codes and Standards	Final Load Forecast
2017	1,908,961,390	(9,957,098)	1,899,004,292	(25,962,811)	1,873,041,481	-	1,873,041,481
2018	1,909,516,798	(14,015,351)	1,895,501,447	(43,450,504)	1,852,050,943	-	1,852,050,943
2019	1,910,072,369	(17,286,927)	1,892,785,442	(60,745,623)	1,832,039,819	-	1,832,039,819
2020	1,910,628,101	(21,496,035)	1,889,132,066	(77,313,750)	1,811,818,316	-	1,811,818,316
2021	1,911,183,995	(20,157,865)	1,891,026,130	(96,063,328)	1,794,962,802	-	1,794,962,802
2022	1,911,740,050	(20,466,446)	1,891,273,604	(116,403,186)	1,774,870,418	-	1,774,870,418
2023	1,912,296,267	(20,779,347)	1,891,516,921	(131,874,816)	1,759,642,105	-	1,759,642,105

Large Power (Rate 4B)

Year	Unadjusted Load Forecast	Distributed Generation	Sales Forecast Less DG	Energy Efficiency	Sales Forecast Less PV and EE	Codes and Standards	Final Load Forecast
2017	1,133,405,146	(4,267,328)	1,129,137,818	(20,430,458)	1,108,707,360	-	1,108,707,360
2018	1,146,903,217	(6,006,579)	1,140,896,638	(34,191,736)	1,106,704,902	-	1,106,704,902
2019	1,151,273,628	(7,408,683)	1,143,864,946	(47,801,482)	1,096,063,464	-	1,096,063,464
2020	1,153,927,810	(7,291,433)	1,146,636,377	(60,839,143)	1,085,797,234	-	1,085,797,234
2021	1,155,072,235	(8,639,085)	1,146,433,150	(75,593,418)	1,070,839,732	-	1,070,839,732
2022	1,155,467,077	(9,314,175)	1,146,152,902	(91,599,104)	1,054,553,798	-	1,054,553,798
2023	1,156,409,756	(9,998,716)	1,146,411,040	(103,773,921)	1,042,637,119	-	1,042,637,119

Irrigation (Rates 10A and 10B)							
Year	Unadjusted Load Forecast	Distributed Generation	Sales Forecast Less DG	Energy Efficiency	Sales Forecast Less PV and EE	Codes and Standards	Final Load Forecast
2017	23,155,348	-	23,155,348	-	23,155,348	-	23,155,348
2018	23,427,777	-	23,427,777	-	23,427,777	-	23,427,777
2019	23,724,413	-	23,724,413	-	23,724,413	-	23,724,413
2020	24,062,575	-	24,062,575	-	24,062,575	-	24,062,575
2021	24,400,736	-	24,400,736	-	24,400,736	-	24,400,736
2022	24,738,897	-	24,738,897	-	24,738,897	-	24,738,897
2023	25,077,057	-	25,077,057	-	25,077,057	-	25,077,057

Lighting (Rates 6 and 20)							
Year	Unadjusted Load Forecast	Distributed Generation	Sales Forecast Less DG	Energy Efficiency	Sales Forecast Less PV and EE	Codes and Standards	Final Load Forecast
2017	65,239,440	-	65,239,440	-	65,239,440	-	65,239,440
2018	65,239,440	-	65,239,440	-	65,239,440	-	65,239,440
2019	65,239,440	-	65,239,440	-	65,239,440	-	65,239,440
2020	65,239,440	-	65,239,440	-	65,239,440	-	65,239,440
2021	65,239,440	-	65,239,440	-	65,239,440	-	65,239,440
2022	65,239,440	-	65,239,440	-	65,239,440	-	65,239,440
2023	65,239,440	-	65,239,440	-	65,239,440	-	65,239,440

Water and Sewage (Rate 11B)

Year	Unadjusted Load Forecast	Distributed Generation	Sales Forecast Less DG	Energy Efficiency	Sales Forecast Less PV and EE	Codes and Standards	Final Load Forecast
2017	171,349,451	-	171,349,451	(611,267)	170,738,184	-	170,738,184
2018	169,531,453	-	169,531,453	(1,022,996)	168,508,457	-	168,508,457
2019	169,401,606	-	169,401,606	(1,430,196)	167,971,410	-	167,971,410
2020	168,133,752	-	168,133,752	(1,820,270)	166,313,482	-	166,313,482
2021	166,777,218	-	166,777,218	(2,261,709)	164,515,509	-	164,515,509
2022	165,508,709	-	165,508,709	(2,740,590)	162,768,119	-	162,768,119
2023	164,742,309	-	164,742,309	(3,104,854)	161,637,455	-	161,637,455

Other (Rates 5B, 15B, 30B, 33B, 35B and 36B)

Year	Unadjusted Load Forecast	Distributed Generation	Sales Forecast Less DG	Energy Efficiency	Sales Forecast Less PV and EE	Codes and Standards	Final Load Forecast
2017	727,136,910	-	727,136,910	(1,984,846)	725,152,064	-	725,152,064
2018	809,372,494	-	809,372,494	(3,321,772)	806,050,722	-	806,050,722
2019	1,067,178,453	-	1,067,178,453	(4,643,982)	1,062,534,471	-	1,062,534,471
2020	1,296,831,062	-	1,296,831,062	(5,910,603)	1,290,920,459	-	1,290,920,459
2021	1,519,114,098	-	1,519,114,098	(7,344,000)	1,511,770,098	-	1,511,770,098
2022	1,738,084,474	-	1,738,084,474	(8,898,975)	1,729,185,499	-	1,729,185,499
2023	1,831,379,914	-	1,831,379,914	(10,081,776)	1,821,298,138	-	1,821,298,138

Redlined Transitional Rider 8 – Incremental Interruptible Power Rate

PNM Exhibit SC-8

Is contained in the following 5 pages

PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

13~~2~~TH REVISED RIDER NO. 8
CANCELING 12~~4~~TH REVISED RIDER NO. 8

TRANSITIONAL INCREMENTAL INTERRUPTIBLE POWER RATE
APPLICABLE TO RATE NOS. ~~3B,~~ 3C, 4B and 35B x

EXPLANATION OF RIDER: Public Service Company of New Mexico (the Company) is offering ~~an~~ Transitional Incremental Interruptible Power Rate ("IIPR") Rider ("Transitional IIPR") to ~~qualifying~~ Customers x who qualified for the 12th Revised Rider No. 8, Incremental Interruptible Power Rate ("12th Revised Rider No. 8"), as of December 31, 2017. ~~can interrupt their incremental On-Peak billed demand requirements during the on-peak period. The Company's purpose in offering this Rider is to promote efficient and flexible~~ x ~~utilization of the Company's generation and transmission capacity now and in the future.~~

The Company may petition to revise the terms and conditions of the Transitional ~~Rider~~ IIPR in the future to accommodate changing conditions and experience. ~~Potential changes may include but not be limited to requiring participants to install direct load control equipment, reducing the response time to 10 minutes, or changes in the rates to reflect changing costs and requirements. All such changes will be submitted to the New Mexico Public Regulation Commission ("NMPRC") for approval with appropriate notice to Customers.~~ The Transitional IIPR is closed to new customers and will expire on December 31, 2021 or the effective date of new rates approved for implementation after December 31, 2021, whichever is later.

DEFINITIONS:

1. Base Period Billing Determinants will consist of Average Base Demand, Peak Base Demand, On-Peak Average Base Energy and Off-Peak Minimum Base Energy. These Base Period Billing Determinants shall be determined as of December 31, 2017 in accordance with the terms of the 12th Revised Rider No. 8 and the Contract for Service between PNM and the Customer. These Base Period Billing Determinants shall no longer be adjusted upon approval of this Transitional IIPR.
2. Contract for Service is the existing contract pursuant between PNM and its Customer pursuant to the terms of Rider No. 8, Incremental Interruptible Power Rate, as it existed prior to December 31, x 2017 x
3. Customer shall mean the customer who qualified for the 12th Revised Rider No. 8 as of December 31, 2017 and had an existing Contract for Service with PNM prior to December 31, 2017.
4. Incremental Interruptible Demand ("IID") is that portion of the Customer's monthly-metered on-peak demand above the Average Base Demand that is served under this Transitional IIPR and was formerly interruptible pursuant to the 12th Revised Rider No. 8. The IID cannot be modified after December 31, 2017.
5. Otherwise Applicable Rate Schedule is the Rate 3C, Rate 4B or Rate 35B rate schedule that is applicable to the Customer.

Advice Notice No. 533~~29~~

Gerard T. Ortiz
Vice President, PNM Regulatory Affairs

PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

13~~2~~TH REVISED RIDER NO. 8
CANCELING 12~~1~~TH REVISED RIDER NO. 8

TRANSITIONAL INCREMENTAL INTERRUPTIBLE POWER RATE
APPLICABLE TO RATE NOS. ~~3B,~~ 3C, 4B and 35B x

ELIGIBILITY: This Transitional ~~rider~~IIPR is available only to C~~c~~ustomers who were taking service under PNM's 12th Revised Rider No. 8"~~Rider 8~~ as of December 31, 2017~~the date of the execution of the Stipulation in NMPRC Case 2761~~. To maintain eligibility for the Transitional Rider, Q~~q~~ualifying customers must maintain a Contract for Service with the Company for service under this Transitional Rider.~~also meet each of the following conditions:~~

~~1. Eligibility for this Rider requires a Customer to maintain a special contract with the Company for service under this Rider.~~]

~~2. Continued eligibility for this Rider requires Incremental Interruptible Demand ("IID") of at least 100 kW on average over the Base Period above the Base Demand, as described below that can be interrupted within 30 minutes after notice from the Company.~~

~~3. Customers taking service under this Rider cannot take service under any other PNM Economic Development rider.~~

APPLICATION: Applications are no longer accepted for service under this Transitional R~~r~~ider.

~~BASE PERIOD BILLING DETERMINANTS: Base Period billing determinants will consist of Average Base Demand, Peak Base Demand, On-Peak Average Base Energy and Off-Peak Minimum Base energy. These billing determinants shall be determined for each of the two PNM seasonal billing periods, the Summer period (June, July and August) and the Other period (all remaining months). The Average Base Demands shall be the 3-month average peak demand in the Summer period and the 9-month average peak demand in the Other period. The Peak Base Demands shall be the highest peak demand in the Summer period and the highest peak demand in the Other period.~~

~~These billing determinants may be adjusted to reflect the Customer's normal operations as specified in paragraph 2 of the Contract section below, and may be adjusted to include any incremental demand not designated as IID. To the extent that some portion of the Customer's incremental demand is not designated as IID, the Base Period billing determinants shall be specified in accordance with an analysis of the nature of the designated IID and its impact on the Customer's load profile that is acceptable to both the Company and Customer. For existing Customers, the Base Period shall be the 12 billing months immediately preceding the effective date of the contract for service under this Rider. Base Demand and Base Energy shall be zero for Customers with no billing history only to the extent that all incremental demand is designated as IID.~~

~~INCREMENTAL INTERRUPTIBLE DEMAND (IID):~~

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APPLICABLE TO RATE NOS. ~~3B,~~ 3C, 4B and 35B x

~~1. IID is that portion of the Customer's monthly metered on-peak demand above the Average Base Demand that is served under this Rider. This also means that if the Customer's load grows and the Customer does not wish to interrupt this additional load, the Customer must notify the Company to adjust Base Period billing determinants accordingly. Such adjustments may require review and analysis by the Company. The Customer shall provide 60 days advance written notice of the need for such adjustments.~~

~~2. That portion of the Customer's IID load above the Peak Base Demand is subject to interruptions, which begin during the Company's on-peak period with a 30-minute notice. The on-peak period is defined under the base rate schedules under which Rider 8 customers receive service. An interruption may be extended up to two (2) hours into off-peak period, but the initial notice to the customer (the notice that an interruption will begin in 30 minutes) must have occurred during the Company's on-peak period. Interruptions will be made for two reasons: (i) for testing purposes; (ii) in the event of a PNM system emergency.~~

~~3. Interruptions for testing purposes will be made to test interrupting or monitoring equipment and the ability of the Customer to effect the required interruption.~~

~~4. Test Interruptions will be limited to 2 (two) per calendar year.~~

~~5. For system emergency interruptions, which are called during on-peak periods, the Company will endeavor to interrupt participants receiving service under the Rider before interrupting or curtailing service to firm customers.~~

~~6. During the period of interruption the Customer's metered demand shall be no greater than the Peak Base Demand. Failure of the Customer to make the required interruption within the specified time for response or to maintain the required interruption shall result in the discount rate applicable to IID be set to $0.00 per kW for that billing month as described in paragraph 1 of the Rates Section below. In addition, future application of this Rider shall be discontinued if the Customer has failed to make the required interruption more than two times during any calendar year as requested by the Company.~~

~~7. In the event of an interruption under this Rider, the Company will endeavor to provide notices of interruption to all participants receiving service under the Rider at or about the same time, consistent with the interruption notification arrangements in place between the Company and the Customer.~~

CONTRACT:

1. Existing Customer C~~c~~ontracts for Service will be automatically renewed for subsequent one-year periods except as follows: no less than one year prior to the end of the contract period, Customer gives notice to PNM of its desire to renew the contract for a period of less than one year. The

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PUBLIC SERVICE COMPANY OF NEW MEXICO
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13~~2~~TH REVISED RIDER NO. 8
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TRANSITIONAL INCREMENTAL INTERRUPTIBLE POWER RATE
APPLICABLE TO RATE NOS. ~~3B,~~ 3C, 4B and 35B x

Customer has the right to terminate the C~~c~~ontract for Service at any time by giving thirty (30) days written notice to the Company. In the event that amended terms and conditions of the Transitional Rider are approved by the NMPRC, participants' C~~c~~ontracts for Service will be subject to such amended terms and conditions.

2. IID shall exclude increases in billed demand resulting from resumption of normal Customer operations following a strike, fire, equipment failure, plant shutdown, or other interruption of operations in the Base Period. ~~In the event that such an occurrence has taken place during the Base Period, the base period billing determinants will be adjusted to reflect normal operations.~~

~~3. The Company will install and the Company shall be responsible for the cost of installation, and maintenance of all equipment or modifications necessary for the Customer to fulfill its interruption obligation. Such equipment shall include but not be limited to communication equipment such that interruption notification from the Company to the Customer can be reliably accomplished. Any special requirements regarding interruption notification procedures or equipment shall be specified in the contract for service under this Rider. Customers will provide and pay for dedicated phone lines as required.~~

~~4. The contract may contain provisions concerning sub-metering of the IID portion of the Customer's load.~~

TERRITORY: All territory served by the Company.

RATE RIDER LIMITS: It is intended that the rates charged to the Customer under the Otherwise Applicable Rate Schedule after application of ~~contained in~~ this Transitional Rider shall be greater than or equal to the incremental cost of providing electric service to the C~~c~~ustomer. If the Company becomes aware that the continued offering of the Transitional Rider is detrimental to other existing c~~C~~ustomers on the Company's system or that the rates charged to the Customer under the Otherwise Applicable Rate Schedule after application of ~~contained in~~ the Transitional Rider are no longer projected to be greater than or equal to the incremental cost of providing electric service to the Customer, the Company shall discontinue the availability of the Transitional Rider to participants or petition the NMPRC for appropriate adjustments in the Transitional Rider. If the Company elects to discontinue the availability of the Transitional Rider, the Company will promptly notify the NMPRC of such discontinuance. If the Company discontinues the availability of the Transitional Rider, Customers with existing C~~c~~ontracts for Service will be given notice of non-renewal of such C~~c~~ontracts for Service but will continue to receive service under the Transitional Rider until the expiration of the existing contract period.

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PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

13~~2~~TH REVISED RIDER NO. 8
CANCELING 12~~1~~TH REVISED RIDER NO. 8

TRANSITIONAL INCREMENTAL INTERRUPTIBLE POWER RATE
APPLICABLE TO RATE NOS. ~~3B,~~ 3C, 4B and 35B X

DURATION: This Transitional Rider shall remain in effect until December 31, 2021 or the effective date of new rates approved for implementation after December 31, 2021, whichever is later~~it is expressly discontinued~~.

RATES:

1. The C~~c~~ustomer's monthly base electric bill shall be calculated in accordance with the terms and conditions set for the in the C~~c~~ustomer's ~~base electric tariff~~Otherwise Applicable Rate Schedule (Schedules ~~3B,~~ 3C, 4B & 35B). ~~In addition to monthly base electric charges, all billable demand above the customer's Average Base Demand ("IID Demand")~~ The IID shall be subject to the discount rates described below: X

	Summer Months (Jun. – Aug.)	Other Months (Sep. – May)
Substation ~~(35B)~~	~~$15.83~~$9.50 per kW-mo. Discount	~~$7.38~~ $4.43 per kW-mo. Discount
Primary ~~(4B)~~	~~$15.83~~ $9.50 per kW-mo. Discount	~~$4.08~~ $2.45 per kW-mo. Discount
Secondary ~~(3B & 3C)~~	~~$6.85~~ $4.11 per kW-mo. Discount	~~$0.38~~ $0.23 per kW-mo. Discount

X

~~2. As described in paragraph 6 of the Incremental Interruptible Demand Section above, Customers that fail to make their required interruption will be billed under the normally applicable rate schedule for the billing month in which the failure occurred. All demand and energy will be billed at the normally applicable rates.~~

3. All other terms and conditions of the applicable rate schedule for a specific Customer are incorporated herein to the extent such terms and conditions are not inconsistent with this Transitional Rider.

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Gerard T. Ortiz
Vice President, PNM Regulatory Affairs

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF NEW MEXICO FOR REVISION OF ITS RETAIL ELECTRIC RATES PURSUANT TO ADVICE NOTICE NO. 533	)	**Case No. 16-00276-UT**
PUBLIC SERVICE COMPANY OF NEW MEXICO,	)	
Applicant	)	

AFFIDAVIT

STATE OF NEW MEXICO)
) ss
COUNTY OF BERNALILLO)

STELLA CHAN, Executive Director, Strategic Marketing and Product Management for Public Service Company of New Mexico, upon being duly sworn according to law, under oath, deposes and states: I have read the foregoing **Direct Testimony of Stella Chan** and it is true and accurate based on my own personal knowledge and belief.

GCG # 522508

SIGNED this 2nd day of December, 2016.

STELLA CHAN

SUBSCRIBED AND SWORN to before me this 2nd day of December, 2016.

NOTARY PUBLIC IN AND FOR
THE STATE OF NEW MEXICO

OFFICIAL SEAL
Ronda Morehead
NOTARY PUBLIC
STATE OF NEW MEXICO
My Commission Expires: 7/5/19

My Commission Expires: