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. 507	)	**Case No. 14-00332-UT**
PUBLIC SERVICE COMPANY OF NEW MEXICO,	)	
Applicant	)	

DIRECT TESTIMONY AND EXHIBITS

OF

STELLA CHAN

DECEMBER 11, 2014

NMPRC CASE NO. 14-00332-UT
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WITNESS FOR
<u>PUBLIC SERVICE COMPANY OF NEW MEXICO</u>

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AFFIDAVIT

DIRECT TESTIMONY OF
STELLA CHAN
NMPRC CASE NO. 14-00332-UT

I. INTRODUCTION AND PURPOSE

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

A. My name is Stella Chan. I am the Director of Pricing and Load Research at Public Service Company of New Mexico ("PNM") where I am responsible for Pricing, Load Research and Load Forecasting. My business address is PNM Headquarters Building, 414 Silver Ave. SW, Mail Stop 1105, Albuquerque, New Mexico, 87102.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I have been in my position at PNM since July 2013. I have worked in the energy industry for over 25 years in a variety of management, pricing, rate design and analytic positions at Colorado Springs Utilities, Entergy, Enron, Duke Energy, and El Paso Energy. 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 at the New Mexico Public Regulation Commission ("NMPRC") in which I have filed testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My testimony presents PNM's proposed rate design for this rate case. In conjunction with Mr. Gerard Ortiz, who will address the policy objectives for

PNM's rate design proposals, and Dr. Daniel Hansen, who supports the pilot Revenue Balancing Account tariff, my testimony will:

(1) Present PNM's Embedded Class Cost of Service Study ("ECCOSS");

(2) Support the allocation of revenue requirements to customer classes and discuss the resulting revenue requirement by customer class;

(3) Discuss the mechanics of the various rate design proposals for this rate case; and

(4) Introduce new tariff services.

Q. WHAT EXHIBITS ARE ATTACHED TO YOUR DIRECT TESTIMONY?

A. I have attached the following exhibits to my testimony:

- PNM Exhibit SC-1 – Stella Chan Qualifications.
- PNM Exhibit SC-2 – Alphabetical listing of acronyms used in this testimony.
- PNM Exhibit SC-3 – Copies of new tariffs that PNM is proposing in this rate case.
- PNM Exhibit SC-4 – Summer and winter coincident peaks for PNM from 2007 through November 2014.
- PNM Exhibit SC-5 – Two letters sent by PNM in 2014 to customers served under Rate Schedule 11B (Water & Sewage) regarding PNM's compliance with Paragraph 39 of the Amended Stipulation to Conform to Commission Order, approved in NMPRC Case No. 10-00086-UT ("Amended Stipulation"),

concerning the determination of the 11B coincident peak ("CP") demand for cost allocation purposes.

- PNM Exhibit SC-6 -- The final revenue allocation to each customer class before and after banding.
- PNM Exhibit SC-7 – Historical hourly peak occurrences since 2007.
- PNM Exhibit SC-8 – A graph demonstrating the probability that PNM's peak period will occur outside of the current Time of Use ("TOU") pricing period of 8 AM to 8 PM.
- PNM Exhibit SC-9 – Two letters sent by PNM in 2012 and 2014 to customers in compliance with Paragraphs 28(E) and 28(F) of the Amended Stipulation regarding proposed changes to the seasonal periods and the TOU pricing periods.
- PNM Exhibit SC-10 – A comparison of the current and proposed non-volumetric charges by rate schedule.
- PNM Exhibit SC-11 – A bar graph depicting Residential electric customer charges in New Mexico as of May 2014.
- PNM Exhibit SC-12 – Examples of rates assessed by local telecommunications, Internet, and cable or satellite video service providers.
- PNM Exhibit SC-13 – A letter sent by PNM in 2012 to Streetlighting (Rate 20) customers, offering to meet with them regarding certain issues related to Streetlighting in accordance with Paragraph 38 of the Amended Stipulation.

- PNM Exhibit SC-14 – The effect of the Consolidation Adjustment Rider (Rider 35) on PNM South Streetlighting (Rate 20) customers.
- PNM Exhibit SC-15 – Summary of modifications to the Streetlighting (Rate 20) schedule and the Consolidation Adjustment Rider (Rider 35).
- PNM Exhibit SC-16 – Derivation of Revenue Balancing Account components.
- PNM Exhibit SC-17 – A detailed calculation of a cost-based Distributed Generation ("DG") Interconnection Fee for the applicable customer classes.
- PNM Exhibit SC-18 -- Calculation of Voltage Class Adjustment Factor Used in Base Fuel Rates and Variable Fuel Rates.

Q. PLEASE LIST THE 530 SCHEDULES YOU ARE SPONSORING.

A. The 530 Schedules I am sponsoring are:

- A-2, Summary of the revenue increase or decrease at the proposed rates by rate classes for Test Year Period.
- K-4, Allocation of Rate Base to rate classes for Base Period and Test Year Period.
- K-8, Allocation of total expenses to rate classes for Base Period and Test Year Period.
- L-1, Allocated cost per billing unit of demand, energy and customer for Base Period and Test Year Period.

- M-1, Allocation factors used to assign items of plant and expenses to the various rate classes for Base Period and Test Year Period.
- M-2, Classification factors used to assign items of plant and expenses to demand, energy, and customer for Base Period and Test Year Period.
- M-3, Demand and energy loss factors for Base Period and Test Year Period.
- N-1, Rate of return by rate classification for Base Period and Test Year Period.
- O-1, Total revenue requirements by rate classification for Base Period and Test Year Period.
- O-2, Proof of revenue analysis for Test Year Period.
- O-3, Comparison of rates for service under the present and proposed schedules for Test Year Period.
- P-1, Peak demand information.
- P-5, Customer information.
- P-6, Weather data.
- Q-1, Load research program.

Q. ARE ANY OF THESE SCHEDULES BEING PROVIDED ELECTRONICALLY?

A. Yes. PNM is providing 530 Schedule K-4 in electronic format on a CD, and it is fully functional and executable.

II. THE OBJECTIVES OF PNM'S RATE DESIGN PROPOSALS

Q. PLEASE STATE THE OBJECTIVES UNDERLYING PNM'S RATE DESIGN PROPOSALS IN THIS CASE.

A. The Company seeks to update its current rate design to reflect embedded cost principles in accordance with the Amended Stipulation in Case No. 10-00086-UT and to better align class cost recovery with cost causation. PNM began using marginal costs for both revenue allocation and rate design in New Mexico Public Service Commission ("NMPSC") Case No. 1554, which was instituted in 1981. In NMPRC Case No. 07-00077-UT, which was fully litigated, the Commission chose an "across-the-board" method recommended by Staff. This started with PNM's proposed allocation based on marginal revenue requirements responsibility and then applied a proportional adjustment by class to achieve an across the board reduction from PNM's proposed revenues. Subsequent rate cases generally applied an across-the-board methodology to implement base rate changes, with some exceptions. As a result, PNM's current revenue requirement allocation is outdated for many reasons, including the fact that it traces its beginnings back to the use of marginal costs. The fundamental differences in class cost allocation between marginal and embedded cost methods reflect a common factor influencing all of the Company's rate design proposals in this case. But use of across-the- board changes in allocations in recent cases means that the current rate design is not truly reflective of either marginal costs or embedded costs.

Q. WHAT PRINCIPLES HAS PNM USED TO GUIDE ITS RATE DESIGN PROPOSALS?

A. PNM's rate design proposals have been guided by the following set of principles:

(1) Fair and equitable pricing should be developed across rate classes;

(2) Cost recovery should be aligned with cost causation;

(3) Accurate price signals should be developed to provide for economic efficiency in energy usage; and

(4) The Company should have a reasonable opportunity to recover its system costs associated with PNM's conservation efforts and support of renewable energy.

My testimony, in conjunction with the testimony of Mr. Ortiz and Dr. Hansen, proposes a series of rate design changes that advance these principles. These rate design changes balance the Company's and its customers' interests, while also benefitting the New Mexico economy.

Q. ARE THESE RATE DESIGN PRINCIPLES ALWAYS COMPLEMENTARY?

A. No. The development of rates requires a balance among competing objectives. A comprehensive re-design of rates, which PNM is undertaking in this case, cannot fully advance each of these principles. For example, cost recovery cannot always be perfectly aligned with cost causation. An ideal rate design would recover all capacity-related costs in a demand charge that recognizes each customer's coincident or non-coincident peak demand. But implementing such a rate design, particularly for small customers, would be expensive and impractical. The Commission has acknowledged:

> The tensions inherent in the rate design process are reflected in Professor Bonbright's classic articulation of the attributes of a sound rate structure: (1) simplicity, understandability, public acceptability, and feasibility of application; (2) freedom from controversies as to proper interpretation; (3) effectiveness in yielding total revenue requirements under the fair-return standard; (4) revenue stability; (5) stability of rates themselves, with a minimum of unexpected changes adverse to existing customers; (6) fairness of the specific rates in apportioning total costs of service among different customer classifications; (7) avoidance of 'undue discrimination'; and (8) efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting justified types and amounts of use.[1]

The Commission went on to state:

> These principles inform the Commission's observation in its most recent rate proceedings that 'rate design is a strange mix of general economic principles and conflicting ideas of what is in the public interest. The ultimate decision is judgmental in any event and is often criticized by many with vested interests in the outcome.'"[2]

Thus, informed judgment is required to balance the applicable principles with reasonable objectives such as gradualism. PNM has balanced several, often competing, objectives in designing the rates proposed in this case. PNM's proposed rate design

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[1] NMPRC Case No. 07-00319-UT, Corrected Recommended Decision of the Hearing Examiner at page 169-70 (citing James C. Bonbright, PRINCIPLES OF PUBLIC UTILITY RATES 291 (1st ed. 1961).

[2] *Id.* citing NMPRC Case No. 07-00077-UT, Recommended Decision of the Hearing Examiner, p. 150 (internal quotation marks omitted).

takes significant steps forward in applying the accepted rate design principles, consistent with promoting public interest objectives. The result is just and reasonable rates.

Q. HOW DOES PNM'S PROPOSED RATE DESIGN ENSURE FAIR AND EQUITABLE PRICING OR BETTER ALIGN COST RECOVERY WITH COST CAUSATION WHILE BALANCING OTHER OBJECTIVES SUCH AS GRADUALISM?

A. Consistent with PNM's testimony from its last rate case, NMPRC Case No. 10-00086-UT, PNM proposes an ECCOSS that will produce more stable results than a marginal cost of service study. PNM also is introducing the use of a 3-Summer/1-Winter coincident peak methodology for allocating generation demand costs because the methodology aligns more closely with PNM's system characteristics and fairly and equitably allocates generation-related revenue requirements among classes based on cost causation. As part of the objective to avoid extreme rate class impacts, PNM employed a "banding" process as part of its revenue requirement allocation among customer classes. The "banding" objective ensures that no customer class receives a non-fuel revenue requirement decrease, and no customer class receives a non-fuel revenue requirement increase greater than 17%. The banded design takes a positive step toward moving all customer classes toward an equalized rate of return, without causing extremely large rate impacts. To promote efficiency and equity, PNM's long-term rate design objective is to fully allocate all costs associated with a particular customer class to that class. The banding proposed in this case represents a reasonable and moderate step toward full class cost recovery.

In addition, PNM's proposed changes to its TOU on-peak/off-peak periods capture system peak loads and better reflect the time period in which PNM's cost of service increases. This shift in TOU periods will better convey the cost and value of consumption at different times of the day, thus further aligning cost recovery with cost causation.

Q. PLEASE EXPLAIN THE RELATIONSHIP BETWEEN BETTER PRICE SIGNALS AND ECONOMIC EFFICIENCY IN CUSTOMER ENERGY USAGE.

A. From a macro perspective, if rates provide accurate price signals, customers know and understand the true costs the utility incurs to serve them and will use electricity in an economically efficient manner based upon their knowledge and understanding of that cost of service. For example, cost-reflective TOU rates, which equate to higher rates during on-peak hours, improve economic efficiency relative to flat rates by providing customers with the price signal to use less energy during peak hours when the cost to serve is higher. Encouraging consumers to pursue greater efficiency in the periods in which the cost to serve is higher promotes higher load factor use, leading to an improved system optimization that lowers costs to all customers.

Q. HOW DO PNM'S RATE DESIGN PROPOSALS IN THIS RATE CASE ADVANCE THE STATED PRINCIPLES OF DEVELOPING A PRICE SIGNAL TO PROVIDE FOR ECONOMIC EFFICIENCY?

A. PNM is proposing several changes to its rate design that will provide a more accurate price signal to customers, thereby promoting economic efficiency in electricity rates. First, PNM is eliminating the Consolidation Adjustment Rider ("CAR") for every rate class except for Streetlighting. The CAR was created as part of PNM's last rate case, NMPRC Case No. 10-00086-UT, to assist with the incorporation of the PNM-TNMP electric tariffs ("PNM South") into PNM North tariff structures. Substantial elimination of the CAR will ensure that nearly all customers pay a rate closer to the full cost of service, and is an important step toward full consolidation of PNM's North and South rates. Additionally, PNM is changing its customer charges and demand charges to more accurately reflect the fixed costs associated with providing service to customers and meeting their peak demand. PNM also is recommending new tariffs and modifications to existing tariffs that will better serve existing customers in a more appropriate rate class or provide for new economically efficient rates for potential future customers. All new tariffs proposed in this case are provided in PNM's Advice Notice and in PNM Exhibit SC-3.

Redlined versions reflecting the specific changes to the tariffs PNM is proposing in this case are attached to the direct testimony of Mr. Julio Aguirre as PNM Exhibit JCA-5.[3] Finally, PNM's proposal to shift its TOU periods will assure that rates accurately reflect the customers' demands on the system. This TOU shift also provides a more appropriate price signal to customers.

Q. PLEASE EXPLAIN PNM'S PROPOSALS TO ADDRESS SYSTEM COST RECOVERY RELATED TO PNM'S ENERGY EFFICIENCY EFFORTS AND SUPPORT OF RENEWABLE ENERGY.

A. PNM is presenting several rate design proposals to better align the costs of providing service with the Company's efforts in promoting energy efficiency and supporting our customers' adoption of renewable energy. The Company's proposed Revenue Balancing Account tariff removes PNM's disincentives associated with promoting energy efficiency. In addition, PNM's proposed DG Interconnection Fee addresses the cost shifting and resulting equity issues between DG customers and non-DG customers. PNM supports customers' efforts to use renewable energy, and the DG Interconnection Fee establishes a sustainable pricing model to support the continuation of such efforts, while mitigating the subsidies that flow to DG customers as a result of a rate design that does not collect all of the fixed costs to serve such customers.

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[3] In addition, a summary explanation of the modifications to PNM's existing tariffs is provided in 530 Schedule O-4.

Q. YOU PREVIOUSLY MENTIONED THE COMMISSION'S RECOGNITION OF THE TENSION INHERENT IN CLASSIC RATE DESIGN PRINCIPLES. HAS THE COMMISSION ARTICULATED PRIMARY OBJECTIVES TO BE USED IN RATE DESIGN?

A. Yes. The Commission has long recognized two major objectives in rate design: (1) providing the utility stability of earnings and thus an opportunity to earn its allowed return; and (2) minimizing the impact of the required rate increase on customers.[4]

Q. PLEASE EXPLAIN HOW THE COMMISSION'S OBJECTIVES ALIGN WITH THE PRINCIPLES UNDERLYING PNM'S PROPOSALS.

A. PNM's rate design proposals here align utility incentives for energy efficiency, better match cost causation with customer rates, and recover fixed costs through fixed charges. This leads to increased equity for ratepayers, and enhances overall efficiency. For the utility, these proposals provide the opportunity to stabilize earnings and to earn its allowed return. With respect to minimizing rate impacts, the "banding" process employed in developing the ECCOSS effectively avoids burdening any one rate class with too great of a share of the overall rate increase. Accordingly, PNM's rate design proposals appropriately balance the two primary objectives espoused by the Commission.

[4] NMPRC Case No. 07-00077-UT, Recommended Decision at page 151.

Also, PNM's guiding principles, along with the overall proposals in this case, are consistent with Professor Bonbright's objectives for development of a sound rate design. For instance, PNM is revising tariffs and proposing rate design changes that will send clearer price signals to customers, which promotes simplicity and understandability for customers. PNM also is proposing increased fixed cost recovery through a variety of rate design proposals, which should more effectively result in collection of PNM's revenue requirements.

Finally, PNM's guiding principles for this case represent a set of public policy goals that address unique circumstances affecting electric utilities, and specifically PNM, today. In particular, PNM is proposing certain rate design modifications to address increasing DG on its system, as well as its compliance with the State's energy efficiency requirements. The Company also is taking measures to promote the New Mexico economy through economic development rates and other proposals. The Commission should recognize these public policy objectives for purposes of this case.

III. COMPLIANCE WITH AMENDED STIPULATION OBLIGATIONS

Q. HOW DO PNM'S RATE DESIGN PROPOSALS HERE RELATE TO THE AMENDED STIPULATION?

A. The Amended Stipulation in Case No. 10-00086-UT included specific requirements that mandated follow-up in advance of this rate case or pertain to specific proposals in this case.

Q. PLEASE IDENTIFY THE AREAS OF OVERLAP BETWEEN THIS TESTIMONY AND THE AMENDED STIPULATION.

A. The Amended Stipulation required PNM to follow-up or to address requirements related to the following issues:

(1) Filing a rate design and class cost of service based on embedded cost principles;[5]

(2) Mandating that PNM not file an average-and-excess demand allocation in this rate case;[6]

(3) Providing notice to Large Power (Rate 4B), Water & Sewage Pumping (Rate 11B) and Manufacturing (Rate 30B) customers if PNM proposes any change to its summer peak season or proposes a winter peak season;[7]

(4) Coordinating with certain rate classes regarding modification of the TOU periods;[8]

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[5] Amended Stipulation at ¶ 34.
[6] Amended Stipulation at ¶ 39.
[7] Amended Stipulation at ¶ 28(e).

(5) Determining the appropriate Rate Schedule 11B CP demand for any month to be used for cost allocation purposes;[9]

(6) Addressing cost allocation, rate design, maintenance, re-lamping and energy efficiency issues with Streetlighting (Rate 20) customers;[10]

(7) Engaging the signatories of the Amended Stipulation regarding PNM's proposal to remove barriers and disincentives to energy efficiency;[11] and

(8) Addressing restrictions regarding any proposal related to an access fee or interconnection charge for distributed generation customers.[12]

Q. HAS PNM ADDRESSED OR COMPLIED WITH EACH OF THE REQUIREMENTS FROM THE AMENDED STIPULATION?

A. Yes. In my discussions supporting the various rate design proposals in the remainder of my testimony, I also will explain where applicable steps were taken to address or comply with each requirement or follow-up item from the Amended Stipulation.

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[8] Amended Stipulation at ¶ 28(f).
[9] Amended Stipulation at ¶ 39.
[10] Amended Stipulation at ¶ 38.
[11] Amended Stipulation at ¶ 25.
[12] Amended Stipulation at ¶ 26; *see also* Final Order Conditionally Approving Stipulation, Case No. 10-00086-UT, at ¶ 197.

IV. THE EMBEDDED CLASS COST OF SERVICE STUDY, ALLOCATING REVENUE REQUIREMENTS TO CUSTOMER CLASSES AND THE RESULTING REVENUE REQUIREMENT PER CUSTOMER CLASS

A. PNM'S ECCOSS

Q. PLEASE EXPLAIN PNM'S CLASS COST OF SERVICE STUDY.

A. Consistent with Paragraph 34 of the Amended Stipulation, the ECCOSS provided in 530 Schedule K-4 reflects the cost to serve each customer class based on embedded cost principles. This ECCOSS defines customer class cost responsibility, allocates revenue requirements to classes based upon comparisons to the system average percentage increase, and provides cost information useful in the design of rates.

Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE FULLY ALLOCATED CLASS COST-OF-SERVICE STUDIES CONTAINED IN 530 SCHEDULE K-4.

A. The development of the fully allocated class cost-of-service studies provided in 530 Schedule K-4 consisted of three major steps: (1) functionalization; (2) classification; and (3) allocation.

The first step, functionalization, categorizes embedded costs by the operating function in which the costs are primarily associated. Functionalized categories include generation, transmission, distribution and customer service. Classification further divides the functional costs into:

- demand-related categories (i.e., costs associated with being able to serve customers at the system and class peaks),
- energy-related categories (i.e., costs that vary volumetrically with the amount of energy used by customers), and,
- customer-related categories (i.e., costs that are directly related to the number of customers served).

Finally, the third step is allocation. Costs are allocated to customer classes based on a load characteristic that fairly reflects each class's responsibility for the cost.[13]

PNM follows industry standard methods prescribed by the National Association of Regulatory Utility Commissioners ("NARUC") to functionalize, classify and allocate costs to customer classes.[14]

Q. HOW ARE THE RESULTS OF THE ECCOSS USED TO DESIGN RATES?

A. After the ECCOSS is completed, class rate components are designed to recover from each rate class an amount as close as possible to the total test year cost of service

[13] Additionally, prior to allocation, some costs that can be directly linked to a class or customer are then directly assigned.
[14] *See* Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners (Jan. 1992), *available at* www.naruc.org ("NARUC Electric Utility Cost Allocation Manual").

allocated to that class. Each rate component also collects the allocated costs in a manner that reflects the way in which these costs are incurred. For example, customer-related costs are most appropriately recovered through the fixed customer charge, which does not vary with the customer's usage during the billing period. In contrast, a cost that relates to customer usage should be collected through the energy charge.

B. Allocating Revenue Requirements To Customer Classes

Q. WHAT CRITERIA DID PNM USE IN THE SELECTION AND DEVELOPMENT OF THE VARIOUS ALLOCATION FACTORS USED TO ASSIGN COSTS TO CUSTOMER CLASSES?

A. PNM uses the following criteria to judge the appropriateness of an allocation methodology: (1) the method should reflect the operating and planning characteristics of PNM's utility system; (2) the method should recognize various customer class characteristics, such as peak demand, energy usage, load factor, number and size of customers, point of delivery, etc.; (3) customers who benefit from the use of plant and equipment should bear the costs; and (4) the method should produce stable results from year to year.

Q. WHY DOES STABILITY MATTER IN TERMS OF AN APPROPRIATE ALLOCATION METHODOLOGY?

A. Stability is desirable in order to avoid large fluctuations in customer class revenue requirement allocations, which results in more stable rates for customers from rate case to rate case.

Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE ALLOCATION FACTORS USED IN THE ASSIGNMENT OF COSTS.

A. As I noted above, PNM followed the NARUC prescribed methods for cost functionalization, classification and allocation. The 530 Schedule K-4 details the classification and allocation factors used in the development of the ECCOSS. As detailed in 530 Schedule K-4, allocation is accomplished differently for the generation (also called production plant), transmission and distribution functions.

Q. WHAT METHOD DID PNM APPLY TO ALLOCATE GENERATION DEMAND COSTS TO THE CUSTOMER CLASSES?

A. Generation-demand rate base costs were allocated to customer classes using a 3-Summer/1-Winter Coincident Peak ("3S1WCP") demand allocation methodology. The 3S1WCP method considers the highest single three peak demand hours throughout the base period in the summer months and one peak demand hour from the winter months.[15] These four coincident peak demands experienced in the summer and the winter drive costs for generation demand investment and, as such, are used for allocating costs associated with generation demand to customer classes.

Q. WAS THIS THE METHOD USED BY PNM IN ITS LAST RATE CASE TO ALLOCATE GENERATION DEMAND?

A. No. PNM used an average-and-excess demand allocation in its last rate case. Pursuant to Paragraph 39 of the Amended Stipulation, PNM agreed not to file an average-and-excess demand allocation for generation rate base costs in this general rate case. The allocation method here provides a more accurate way to allocate costs.

Q. DID PNM CONSIDER OTHER METHODS FOR THE ALLOCATION OF GENERATION COSTS?

A. Yes. PNM considered a number of other standard allocation methods that are used in the industry. The alternative allocation methods considered included the following: 1) the one Coincident Peak ("1CP") Method; 2) the four (highest) Coincident Peak ("4CP") Method; and 3) the twelve Coincident Peak ("12CP") Method, which uses an average of customer class contributions to all 12 of PNM's monthly coincident peak demands. While each allocation method has merit

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[15] In this proceeding, the base period spans from July 1, 2013 to June 30, 2014. The test year period for this case is calendar year 2016.

depending on the utility's specific circumstances, the 3S1WCP method best reflects the load characteristics of the PNM system, and thus best matches cost causation to cost allocation. To comply with the Amended Stipulation, PNM did not consider using an average and excess demand method in this case.

Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE 3S1WCP ALLOCATION METHOD.

A. For the base period, PNM collected the highest three peak demand hours that fell in three summer months (June, July and August) and one non-summer month (December). With those hours, PNM then projected the test period load in each of these peak demand hours. Each class's CP is that class's average load over those four particular hours. Thus, the generation demand allocator that results from using the 3S1WCP methodology is the average "system peak" of these four peak demand hours in each of these months. The resulting generation demand allocator reflects the fact that PNM is not just a summer peaking utility since winter coincident peak demands are approximately 82% of those experienced in the summer. PNM Exhibit SC-4 demonstrates the numerical peak loads from 2007 through November 2014. This historical data validates the use of June, July and August as the peak summer months, and December as the peak winter month. Thus, the proposed 3S1WCP allocator represents a reasonable weighting between summer and winter loads.

Q. WHY IS THE 3S1WCP METHOD APPROPRIATE GIVEN PNM'S PEAK DEMAND CHARACTERISTICS?

A. For PNM, the 3S1WCP method best reflects cost causation and results in just and reasonable allocations to customer classes. For production (or generation) resources, cost causation determines the amount of production plant capacity that is necessary to meet peak demand throughout the year. Other allocation factors (1CP, 4CP or 12CP) do not accurately reflect the dual peaking nature and seasonal consumption patterns of PNM's system.

Q. HOW ARE TRANSMISSION COSTS ALLOCATED TO THE CUSTOMER CLASSES?

A. PNM allocates transmission costs to customers using the class's average monthly coincident peaks at transmission voltage, which is the 12CP method. NARUC's cost allocation manual states that the 12CP demand allocation methodology "is based on the principle that a utility installs facilities to maintain a reasonably constant level of reliability throughout the year or that significant variations in monthly peak demands are not present."[16] Under this methodology, the relative importance of each month is considered and no single peak demand has any greater significance than other monthly CP demands. The 12CP demand allocator is appropriately used for transmission costs, in accordance with the NARUC cost

[16] NARUC Electric Utility Cost Allocation Manual at 79 (1992).

allocation manual. PNM has consistently used this methodology to allocate transmission costs in prior rate cases.

Q. HOW ARE DISTRIBUTION COSTS ALLOCATED FOR THIS RATE CASE?

A. The proposal allocates distribution substations, primary lines and secondary lines to customer classes using the maximum non-coincident peak demands of each class ("NCP"), at either primary or secondary voltage levels. NARUC's cost allocation manual states that the NCP method "attempts to give recognition to the maximum demand placed upon a system during the year by all customers" and "is based on the theory that facilities are sized to meet these maximum demands."[17] Because distribution facilities must be sized to meet the maximum demands of each customer at any time, the use of the NCP cost allocation methodology is consistent with NARUC's manual, and thus, appropriate for allocating distribution costs.

Other components of distribution were allocated to classes based upon detailed analyses specific to the cost type (meters, services, etc.) and reflective of the number of customers served. These methodologies were used by PNM in its last rate case to allocate distribution costs.

[17] *Id.* at 80.

Q. HOW ARE GENERAL PLANT, OTHER ANCILLARY RATE BASE ITEMS AND OPERATING EXPENSES ALLOCATED BY CUSTOMER CLASS?

A. General plant, other ancillary rate base items and operating expenses are allocated to customer classes using a combination of allocation methods or results that underlie the reason for the expense. For example, production O&M is allocated to customer classes on the basis of the associated plant-in-service (e.g., generation), or a combination of associated investment. Fuel and other energy-related O&M expenses are allocated to customer classes using annual energy deliveries (kWh).

C. Rate Schedule 11B Customers – Water And Sewage Class's Coincident Peak Demands To Be Used For Cost Allocation Purposes

Q. PLEASE EXPLAIN THE AGREEMENT BETWEEN PNM AND THE RATE SCHEDULE 11B CUSTOMERS AS DETAILED IN THE AMENDED STIPULATION RELATED TO DETERMINING THE APPROPRIATE CP DEMAND FOR COST ALLOCATION PURPOSES IN THIS RATE CASE.

A. The Amended Stipulation included the following language at Paragraph 39:

> 39) PNM and the Rate Schedule 11B customers will determine the appropriate Rate Schedule 11B coincident peak ("CP") demand for any month to be used for cost allocation purposes in PNM's next general rate case filing for those customers. Specifically, PNM will reduce any monthly CP demand for Rate Schedule 11B where the monthly CP date and time occur during a current PNM TOU off-peak hour. The amount of the reduction will recognize Rate Schedule 11B customers' operational load shifting capabilities, and will be determined jointly, in good faith, by PNM and the Rate Schedule 11B customers. PNM and the Rate Schedule 11B

> customers will determine, in good faith, whether reductions should be made to Rate Schedule 11B CP demands occurring within a current PNM TOU on-peak hour to adjust demands to appropriately recognize Rate Schedule 11B's operations and load shifting capabilities. PNM agrees not to file an average-and-excess demand allocation in its next general rate case filing.

The Amended Stipulation requires PNM and Rate Schedule 11B customers to address a means for reducing monthly CP demand where the monthly CP date and time occur during a current PNM TOU off-peak hour. In addition, PNM and Rate Schedule 11B customers had to address reductions to Rate Schedule 11B CP demands occurring within a current PNM TOU on-peak hour.

Q. WHAT BACKGROUND INFORMATION CAN YOU PROVIDE RELATED TO THIS PROVISION OF THE AMENDED STIPULATION?

A. PNM proposed a change to its TOU hours in its last rate case, NMPRC Case No. 10-00086-UT. Because PNM was likely to propose a change to its TOU hours again in this rate case,[18] Paragraph 39 of the Amended Stipulation was meant to facilitate some means to adjust CP demand for Rate Schedule 11B customers so that the approved rates from this case would accurately reflect that these customers would immediately shift their operations outside of the new TOU on-peak period upon approval from the NMPRC. Historical experience indicates that Rate Schedule 11B customers have tailored their operations such that approximately 74.7% of their

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[18] In fact, a meeting was held May 9, 2012 with certain customers and letters were sent to these customers on May 31, 2012 and July 1, 2014, informing them of the new TOU periods to be proposed in PNM's next rate case.

energy consumption occurs in off-peak hours. Paragraph 39 of the Amended Stipulation ensures that the new TOU hours do not unduly penalize this rate class. More specifically, given that base period revenue would be based upon Rate Schedule 11B customers operating within the currently approved TOU period, some adjustment was appropriate to this rate schedule's on-peak and off-peak CP demands such that the test year period revenue could reflect the class's ability to operate a majority of the time in off-peak hours.

Q. DID PNM AND THE RATE 11B CUSTOMERS MEET TO DISCUSS A PROCESS CONSISTENT WITH PARAGRAPH 39 OF THE AMENDED STIPULATION?

A. Yes, on a few occasions. Via a letter sent on October 14, 2014, PNM invited all the Rate Schedule 11B customers to discuss a proposal to address the Paragraph 39 requirements in the Amended Stipulation. On October 28, 2014, PNM and Albuquerque Bernalillo County Water Utility Authority ("ABCWUA") held a telephone conference at the request of ABCWUA. During that call, PNM explained a proposal it developed to reduce monthly CP demand for Rate Schedule 11B customers by shifting any monthly PNM system CP demand that occurred during an off-peak hour to the nearest on-peak hour. For the three instances in the base period where this occurred, the Rate Schedule 11B customers' system load during this off-peak hour was adjusted down to the class's load during the nearest on-peak hour.

The October 14, 2014 letter, along with an attachment explaining this proposal, are attached as PNM Exhibit SC-5. It was decided at the October 28, 2014 follow-up meeting to this letter that PNM should provide additional data and analysis to ABCWUA, including data that would address reductions to Rate Schedule 11B CP demands occurring within a current PNM TOU on-peak hour. As such, additional telephone conferences were held after October 28 to continue the good faith discussions regarding resolution of the issues raised in Paragraph 39 of the Amended Stipulation. Specifically, PNM engaged in telephone conversations with ABCWUA's consultant and a follow-up telephone conference with a broader group was held on November 7, 2014. At that time, PNM and ABCWUA had an agreement in principle as to how to address on-peak and off-peak CP demand reductions for this rate case filing.

Q. WHAT WAS THE JOINTLY PROPOSED SOLUTION DISCUSSED DURING THE NOVEMBER 7, 2014 CONFERENCE CALL TO SATISFY THE REQUIREMENTS OF PARAGRAPH 39 OF THE AMENDED STIPULATION?

A. It was agreed that the simplest and most direct solution was to shift the base period data by two hours such that all hourly Rate Schedule 11B load data for the base period simulated the 11B customers' load shifting capabilities as a result of the proposed TOU period shift. Specifically, the proposed resolution moves the CP demand for the base period for the 11B class from 8 AM to 8 PM (current TOU) to 10 AM to 10 PM (proposed TOU). In addition, if the system peak for a particular month in the base period occurred during a weekend day, the proposal moves the 11B CP to the nearest on-peak hour.

Q. WHY IS THIS PROPOSED METHODOLOGY THE BEST SOLUTION TO ADDRESS THE REQUIREMENTS OF PARAGRAPH 39 OF THE AMENDED STIPULATION?

A. First, this method is simple to calculate and administer. Second, PNM fully expects that 11B customers would be responsive to the proposed 10 AM to 10 PM TOU peak period adjustment, given the historical experience with this class's operational load shifting capabilities. As such, a proposed two-hour shift to calculate reduced monthly CP demands for the base period that is consistent with a new proposed TOU peak period in this case is appropriate.

Finally, this methodology accomplishes the intended goal of Paragraph 39 of the Amended Stipulation, which is to ensure that Rate Schedule 11B customers are not unduly penalized by PNM's proposed TOU period adjustment. In particular, this methodology results in overall reductions totaling 17% to CP demands during both on-peak and off-peak hours for the 11B customers, consistent with Paragraph 39 of the Amended Stipulation. PNM memorialized this joint agreement in a letter sent to

Rate Schedule 11B customers on November 21, 2014. This letter and accompanying analysis is included in PNM Exhibit SC-5.

Q. DOES THIS AGREEMENT WITH RATE SCHEDULE 11B CUSTOMERS AFFECT PNM'S OTHER RATE CLASSES?

A. Yes and no. The energy shift that Rate Schedule 11B customers are expected to undertake to respond to the proposed 10 AM to 10 PM TOU peak period adjustment will not affect other customers. The resulting reduction of approximately 17% in CP demand, however, will reduce the Rate Schedule 11B customers' allocation of generation and transmission plant revenue responsibility in this rate case. As such, other customers will be allocated the costs associated with this reduction. While any revenue shift to other rate classes as a result of a benefit to one class deserves the Commission's consideration, PNM believes that this proposal is consistent with the Paragraph 39 requirements in the Amended Stipulation and is appropriate given the responsiveness to TOU pricing that this class has demonstrated over the years.

D. The Resulting Revenue Requirement Per Class

Q. WHAT COST CAUSATION ELEMENTS DID PNM CONSIDER IN THE RECOVERY OF THE OVERALL REVENUE DEFICIENCY FROM THE CUSTOMER CLASSES?

A. After overall costs were initially allocated to each class, the next step was to determine the appropriate levels of revenues to be collected from each class. Two cost-based considerations were examined to determine the overall revenue allocation decision:

(a) <u>Cost Causation</u> – Class Rate of Return ("ROR") on rate base under present rates depicting current cost recovery for each class relative to the system as a whole and to each other; and

(b) <u>Equalized ROR</u> – Class ROR should be set equal to the system average for all classes; revenue allocation based upon the under-collection or over- collection of revenues necessary to earn an equalized ROR.

Q. WHAT OTHER CONSIDERATIONS DID PNM USE TO ASSIST IN DETERMINING THE REVENUE RESPONSIBILITY FOR EACH CUSTOMER CLASS?

A. Even though the use of an embedded class cost of service study as compared to a marginal cost of service study yields more stable results for every customer class, other non-cost considerations enter into apportioning the revenue requirement for each customer class. Other non-cost based factors considered in determining the overall revenue requirement by rate class included:

(a) Gradualism – Revenue allocation is predicated upon equalized ROR but moderated to ensure no class receives an increase (or a decrease) significantly below or greater than the system average;

(b) Price and Tariff Relationships – Customer class unit price results from revenue allocation compared with existing unit pricing, similar pricing of other classes, and other rate design requirements; revenue allocation adjusted as needed to ensure proportionality and other desired pricing goals are met; and

(c) Other Non-Cost Ratemaking Factors – Other factors for consideration including conservation, social and environmental goals, affordability, market pricing, fairness, and equity.

Q. HOW DID PNM TAKE INTO ACCOUNT THESE COST BASED AND NON-COST BASED FACTORS IN DETERMINING THE REVENUE RESPONSIBILITY FOR EACH CUSTOMER CLASS?

A. The initial step is to review of the results of the Company's ECCOSS contained in Rule 530 Schedule K-4 to assess relative cost causation and cost recovery. The ECCOSS generates class revenue requirements at an equalized ROR under the test year period. Before finalizing class revenue requirements, PNM also considered the inter- and intra-class pricing and tariff proportionality relationships, along with the other non-cost factors listed above, such as affordability, rate stability, market pricing, etc. In particular, PNM has taken steps to ensure competitive pricing in rate classes with acute price sensitivity. If a large industrial or business customer has an option to leave New Mexico to seek out lower electric rates, or where a potential new industrial or business customer may not come to New Mexico due to unattractive electricity rates, then all customers and the New Mexico economy suffer. The proposed allocation to these customers recognizes the economic impact by making the rate competitive through the rate design process, so all customers benefit. For example, to maintain the competitiveness of Rate Schedule 30B, PNM is not proposing any non-fuel rate increase for this rate class. As such, cost increases attributable to Rate Schedule 30B are being re-allocated to other rate classes where additional costs will not yield a substantial impact on rates. In addition to Rate Schedule 30B, PNM also is minimizing the impact of the rate increase on other large industrial or business customers in an effort to keep these customers, and the jobs and local revenues they create, in New Mexico. These efforts promote economic development initiatives that will assist the State in recovering from the recession, as discussed in the testimony of Mr. Ortiz. Outside of the commercial and industrial classes, PNM also considers key non-cost factors for the other classes. In particular, the Residential customer class remains the most subsidized class under PNM's proposed rates.

After evaluation of these considerations discussed above, the final step is to apply a "banding" process to the revenue requirement allocation. This banding process establishes an upper and lower limit to rate increases for each customer class. In this case, PNM has established a system "band" or guideline whereby no class receives a non-fuel decrease and no class receives a non-fuel increase greater than 17%. As an example, the Residential subsidy of $7.3 million exists under proposed rates, even with a capped 17% increase under system banding for this class.

Q. WHAT ARE THE RESULTING REVENUE INCREASES BY RATE CLASS UNDER PNM'S PROPOSED RATES?

A. The final revenue allocation to each customer class before and after banding is presented in PNM Exhibit SC-6.

Q. WHAT IS THE EFFECT OF THE PROPOSED NEW CUSTOMER CLASSES ON THE CLASS COST OF SERVICE STUDY AND THE ALLOCATION OF REVENUE BY CUSTOMER CLASS?

A. As explained in more detail in Section VI.D of my testimony below, PNM is proposing a new retail tariff: Large Service for Customers, 3,000 kW and above, Rate Schedule 34B ("Rate Schedule 34B"). Based on the qualifying criteria for this new class, which was set at 3 MW minimum of peak demand and an 80% or better load factor, PNM has determined that three existing customers and a new customer expected to receive service in 2016 qualify for this new rate schedule. Given that the customers that will qualify for Rate Schedule 34B are known, PNM included this new class in the ECCOSS and allocated revenue in accordance with their projected billing determinants.

Also, PNM recently filed to implement a new Rate Schedule 33B applicable to Large Service for Station Power which is currently being considered by the Commission in NMPRC Case No. 14-00102-UT. In anticipation of approval of Rate Schedule 33B in that proceeding well in advance of the conclusion of this rate case, PNM also included this new class in the ECCOSS and allocated revenue in accordance with projected billing determinants.

V. PNM'S RATE DESIGN PROPOSALS

A. Designing Rates For Each Customer Class

Q. DID YOU RELY ON ANY OTHER WITNESS' TESTIMONY AND CONCLUSIONS TO DESIGN PNM'S PROPOSED RATES FOR THIS CASE?

A. Yes. I relied on the sales forecast prepared by Dr. Ahmad Faruqui to establish the billing determinants used in designing rates.

B. TOU Pricing Period

Q. WHAT CHANGE DOES PNM PROPOSE TO MAKE TO ITS TOU PRICING PERIOD FOR THIS RATE CASE?

A. As mentioned above, PNM proposes to adjust its TOU on-peak hours from the current 8 a.m. to 8 p.m. Monday through Friday period to 10 a.m. to 10 p.m. Monday through Friday.

Q. WHY IS PNM PROPOSING TO CHANGE ITS TOU PRICING PERIOD?

A. PNM is proposing a change to its TOU on-peak pricing period to better capture shifting customer peak loads and, thus, to more accurately reflect the time periods in which PNM experiences cost increases for generation and delivery. As demonstrated in PNM Exhibit SC-7, monthly system CPs are occurring in current off-peak hours. PNM Exhibit SC-7 shows that, since at least 2007, monthly system peak loads have been occurring later in the day, including during non-summer months. PNM Exhibit SC-8 further demonstrates the probability that PNM's peak period will occur outside of the current TOU pricing period of 8 AM to 8 PM. To more accurately reflect actual demands on PNM's system, PNM is modifying its TOU pricing period to reflect these monthly system peak demands that are occurring later in the day, which will better align cost recovery with cost causation.

Q. HOW WILL PNM IMPLEMENT THE CHANGE TO ITS TOU PRICING PERIOD?

A. Upon approval of the TOU pricing period in this case, a customer will remain under the current TOU period until PNM reprograms the customer's meter to register consumption and demand under the new TOU period. From a pricing perspective, PNM is proposing two sets of revenue neutral TOU rates for each applicable class in order to effectuate the transition to the new TOU period. These tariff modifications are reflected in PNM Exhibit JCA-5 and in 530 Schedule O-3.

Q. WILL PNM INCUR ANY COSTS IN SHIFTING ITS TOU PRICING PERIOD?

A. Yes, PNM has estimated that it will cost approximately $300,000 to reprogram its 9,154 TOU meters. This cost estimate is based on using non-Company contract journeymen to complete the reprogramming in approximately three (3) months. This project requires the use of contract journeymen given the number of meters that need to be reprogrammed in a short time frame, along with the existing workload of PNM's own employees. The cost estimate is based upon approximately 20 meters per day being replaced in non-rural areas at a total daily cost of approximately $591 for contract journeyman.[19] This $591 figure reflects an hourly rate of $56.93 and an hourly vehicle cost of $16.99, assuming an eight-hour work day.

[19] To illustrate the calculation, 9,154 meters divided by 20 per day is 458 total labor days. This 458 is multiplied by $591.36, which equals $270,843. The additional $30,000 not represented in this calculation

Q. WAS PNM REQUIRED TO ADDRESS ITS PROPOSED TOU CHANGES IN ACCORDANCE WITH THE AMENDED STIPULATION?

A. Yes. Paragraph 28(F) of the Amended Stipulation required PNM to confer with the affected Large Power (Rate 4B), Water & Sewage Pumping (Rate 11B) and Manufacturing (Rate 30B) customers to determine the most appropriate periods for on-peak hours for these customers. PNM also was required to notify these customers of any proposed TOU changes six (6) months prior to filing for the modification of its TOU period. PNM has complied with these requirements, as detailed in PNM Exhibit SC-9, which includes the May 31, 2012 and July 1, 2014 letters sent to customers that provided notice of PNM's intentions in this rate case regarding its TOU period changes. PNM Exhibit SC-9 also details a meeting that was held on May 9, 2012, with the above customer classes regarding PNM's proposed TOU period changes.

C. Summer Peak Season In Rates

Q. IS PNM PROPOSING TO ADJUST ITS SEASONAL PERIODS IN THIS RATE CASE?

A. No. Paragraph 28(E) of the Amended Stipulation required PNM to provide notice to all customers of any proposed changes to its seasonal periods at least six (6) months

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but included in the estimate is meant to take into account that meter reprogramming in the rural areas will progress much slower.

in advance of this rate case filing. PNM is not proposing any change to its seasonal periods, and thus, no notice was required. The summer peak season will remain as June through August and no winter peak season is being proposed.

D. Elimination of the Consolidation Adjustment Rider

Q. PLEASE EXPLAIN THE CONSOLIDATION ADJUSTMENT RIDER, OR CAR, AS SET FORTH IN PNM RIDER 35.

A. The CAR was created as part of PNM's last rate case, NMPRC Case No. 10-00086-UT, to assist with the accelerated consolidation of PNM South and North tariffs. When consolidation was first approved in NMPRC Case No. 04-00315-UT, PNM was prohibited from combining the cost of service for PNM North and PNM South prior to July 1, 2015, if a cost impact of greater than $1.5 million per year would occur for PNM North customers. See Paragraph 11 of the February 28, 2005 Stipulation approved in NMPRC Case No. 04-00315-UT. In the last rate case, NMPRC Case No. 10-00086-UT, an earlier partial consolidation schedule for PNM North and South was approved, although a rate impact was expected for PNM North customers. The CAR was created to reduce that impact by approximately $4.1 million for PNM North customers.

Even with the rate impact, accelerated consolidation meant that PNM South customers moving onto PNM North rates would receive the benefits of an advanced rate design that sent more accurate price signals, promoted conservation and aligned rate treatment to actual operation on a single system. The CAR, Rider 35, facilitated these benefits by mitigating rate impacts for PNM North customers as a result of the consolidation with PNM South. More specifically, the CAR adjustment in Rider 35 is a per kWh increase or decrease applied to PNM South customers' usage. The CAR is currently applicable to PNM South customers taking service under the following rate schedules: 1A, 1B, 2A, 2B, 3B, 3C, 4B, 6, 10A, 10B and 20.

Q. PLEASE EXPLAIN PNM'S PROPOSAL WITH RESPECT TO CAR.

A. PNM proposes to eliminate the CAR for all customer classes, except the Streetlighting class.

Q. HOW DO PNM SOUTH CUSTOMERS BENEFIT FROM ELIMINATION OF THE CAR FOR NEARLY ALL RATE CLASSES?

A. The CAR has been in place since the rates became effective as a result of NMPRC Case No. 10-00086-UT. Elimination of the CAR is an important step towards full consolidation of PNM North and South tariffs. Additionally, elimination of the CAR removes distortions in the economics of the tariff schedules. For example, due to the fact that the CAR rates are assessed as a per kWh charge to PNM South customers, inaccurate price signals for electricity consumption understates or overstates the volumetric costs for supplying power.

Q. WHY IS PNM PROPOSING TO MAINTAIN THE CAR FOR THE STREETLIGHTING CLASS?

A. PNM is proposing to prepare a single, consolidated set of Streetlighting base rates, including pole, light and ownership options for both PNM North and South Streetlighting customers. For PNM South Streetlighting customers, which are almost exclusively municipalities, full integration into the PNM North Streetlight rate design will result in very large price increases for some lights and poles, as the Streetlighting rates for PNM South customers have never truly been cost-based. Thus, in order to mitigate the bill impact for PNM South Streetlighting customers, PNM has designed new, specific, fixed light and pole combination CAR rates. More detail on the new CAR rates for Streetlighting is discussed below in the section of my testimony discussing the revised Streetlighting tariff.

E. Proposed Changes To The Customer Charges

Q. PLEASE SUMMARIZE PNM'S PROPOSAL FOR THE CUSTOMER CHARGE.

A. PNM is proposing to adjust its customer charges for all retail classes to recover all of customer-related costs. The calculation of PNM's proposed customer charge includes costs for services, meters, billing, meter reading, bill processing and other customer-related activities.[20] This proposal will adjust the customer charges for the retail classes with a two-part tariff as follows: Residential Class (Rate 1A) from $5 to $12.80; Small Power (Rate 2A) from $8.46 to $23.39; Irrigation Service (Rate 10A) from $8.19 to $43.28; and Water & Sewage Pumping Service (Rate 11B) from $491.60 to $243.93.

For retail schedules 3B/3C, 4B, 5B, 15B, 30B, 33B and 34B, the proposed customer charges have been reduced to allow PNM recovery of customer-related costs only. Previously, the customer charge for these rate schedules recovered both customer-related costs and minimum demand. PNM's proposal is that customers be subject to a separate minimum demand usage charge at the proposed seasonal demand rate. All of the proposed customer charge adjustments are set forth in PNM Exhibit SC-10.

Q. WHY ARE INCREASED CUSTOMER CHARGES APPROPRIATE GIVEN THE OTHER RATE DESIGN PROPOSALS IN THIS RATE CASE?

A. Costs for meters, billing, meter reading, bill processing, customer service and other customer-related activities are constant for every customer in a given rate class. The level of costs does not change with sales and delivery of electricity. For example, regardless of the amount of electricity a customer uses, PNM has to install a meter, read the meter monthly, set up an account in the billing system, process and bill

[20] Other customer-related activities include costs from the following FERC accounts: 901.0 (Supervision – Customer Accounts); 906.0 (Customer Service/Information Expenses); 908.0 (Customers Assistance Expenses); and 912.0 (Demo and Selling Expenses).

monthly, and have customer service available to assist the customers when the need arises. From a rate design perspective, it is appropriate to recover these customer-related costs through a fixed monthly charge. Table SC-1 provides a breakdown of the Residential customer-specific costs PNM incurs per month and per customer based on the proposed revenue requirement.

Table SC-1
Residential Customer-Related Costs
Per Customer/Per Month

Customer Service	$2.08
Customer Meter	$2.24
Customer Meter Reading	$1.77
Customer Billing and Processing	$3.56
Other Customer-Related Activities	$3.15
TOTAL	**$12.80**

Q. ARE THOSE COSTS INCLUDED IN THE PROPOSED MONTHLY CUSTOMER CHARGE THE ONLY FIXED COSTS PNM INCURS TO SERVE CUSTOMERS?

A. No. In addition to these customer-related costs, PNM incurs several other fixed costs to serve residential customers, including primary and secondary distribution costs, transmission costs, substation costs and generation demand costs. Due to the resulting rate impacts and in accordance with the well-accepted objective of gradualism, it is not practical at this time to propose to set the customer charge at a level that recovers all of these costs.

Q. WHAT WOULD THE MONTHLY CUSTOMER CHARGE FOR THE RESIDENTIAL CLASS BE IF ALL THESE OTHER FIXED COSTS WERE INCLUDED?

A. If PNM included these costs in the Residential customer charge, it would have to collect an additional $50.11 from Residential customers, which would result in a total customer charge of approximately $62.92. While PNM is not proposing this level of a customer charge, this number illustrates how little of the fixed costs PNM incurs to serve the Residential customer class is recovered from these customers currently through a fixed charge, or even as part of the proposal in this rate case. In fact, the $12.80 represents only 20% of the total demand and customer-related costs that PNM incurs in serving Residential customers. PNM is therefore proposing a relatively modest step toward fully aligning rates with the actual costs to serve Residential customers.

I also note that this proposal serves to provide more transparency to customers about the fixed costs that PNM incurs to serve them. Improved priced signals can translate into more economically efficient energy usage.

Q. HOW DOES PNM'S RESIDENTIAL CUSTOMER CHARGE COMPARE TO OTHER NEW MEXICO UTILITIES?

A. PNM's current Residential customer charge at $5.00 is one of the lowest customer charges among those of electric utilities in New Mexico. PNM Exhibit SC-11 demonstrates that PNM has the second lowest Residential customer charge of 26 electric utilities and cooperatives in New Mexico. Only the City of Farmington, at $3.25, has a lower customer charge. In New Mexico, the median customer charge is $15.38, which is over $10.00 more than PNM's current customer charge and still 20% higher than PNM's proposed residential customer charge in this case.

Q. WILL ALL CUSTOMER CLASSES WITH MONTHLY CUSTOMER CHARGES EXPERIENCE AN INCREASE AS A RESULT OF THE PROPOSED CHANGE?

A. No. With the proposed change, some of the customer classes with a monthly customer charge will see a decrease as we align the costs recovered through the customer charge to those specific costs; i.e., costs for meters, billing, meter reading, bill processing, customer service and other customer-related activities. For instance, as noted above, the Water & Sewage customer class (Rate 11B) is experiencing an over 50% decrease in its customer charge. This decrease is purely the result of PNM evaluating the customer-specific costs that apply to this customer class and finding that a decreased customer charge was appropriate given this class's customer-related costs.

Q. DOES INCREASING THE RESIDENTIAL CUSTOMER CHARGE MEAN THAT PNM WILL BE ALLOWED TO RECOVER ALL OF ITS FIXED COSTS ASSOCIATED WITH SERVING THESE CUSTOMERS?

A. No. Even with the proposed increase to the customer charge, a significant portion of the total fixed costs required to serve these customers will not be recovered through the customer charge. The proposed customer charge for the Residential class does not include any of the costs associated with PNM's fixed investments that are used to serve its customers, such as production plant, transmission lines, substations or primary/secondary distribution.

Q. FOR PERSPECTIVE, DO PROVIDERS OF OTHER SERVICES COMMONLY USED BY NEW MEXICO CONSUMERS RELY PREDOMINANTLY ON FIXED CHARGES?

A. Yes. The services that are comparable in some ways to electric service are local telecommunications service, Internet service, and cable or satellite video service. Examples of the rates assessed by the providers of these services are shown as PNM Exhibit SC-12. In each case, I provide at least one example of a standard charge for basic, "no-frills" service, as well as the charges for limited upgrades.

Three important conclusions can be drawn from this review. First, these providers assess a high fixed charge for basic service. Customers are responsible for these fixed charges regardless of whether they actually place any phone calls, surf the web, or watch television during the billing period.

Second, if customers request additional features or services, the providers usually assess higher fixed charges to reflect the additional costs or value of such enhancements. While volumetric charges are assessed on some services, such as calls for information, long-distance service for the most basic home telephone service, or movies on demand, those charges represent a relatively small portion of the total bills most customers pay for enhanced telecommunications, Internet and video services.

Third, consumers are accustomed to paying monthly fixed charges that exceed the Company's proposed Residential fixed charge. This comparison demonstrates that a fixed monthly charge of $12.80 for PNM's electric customers is in line with the fixed charges customers routinely pay for other services. The general conclusion that I draw is that fixed charges are a common feature in network industries. Insofar as those fixed charges to customers reflect the fixed charges the provider incurs, this pricing method makes sense, and can be witnessed throughout "network" markets.

Q. HOW DOES PNM'S PROPOSED RESIDENTIAL CUSTOMER CHARGE COMPARE TO OTHER LOCAL UTILITY SERVICES?

A. The City of Santa Fe charges a $19.34 fixed monthly fee for 5/8-inch water service. ABCWUA charges monthly fixed fees of $13.03 for 5/8-inch water service, which includes an $8.52 Metered Service charge and a $4.51 Metered Service Strategy Implementation charge. The New Mexico Gas Company's monthly access fee is $11.50.

F. Changes To Demand Charges

Q. PLEASE SUMMARIZE PNM'S PROPOSAL FOR CHANGING ITS DEMAND CHARGES.

A. PNM proposes to modify its demand charges for all customer classes under a three-part tariff[21] to move rates closer to or at the full cost of service level. This allows more recovery of capacity-related costs through demand charges. The customer classes with a demand charge are: General Power (Rates 3B and 3C); Large Power (Rate 4B); Large Industrial Service 8,000 kW minimum (Rate 5B); Large Service for Universities (Rate 15B); Large Service for Manufacturing (Rate 30B); and Large Service for Station Power (Rate 33B). For the new proposed Large Service for Customers 3,000 and above kW (Rate 34B), demand rates are initially set to recover all demand-related costs.

[21] A three-part tariff comprises a customer, demand and energy charge.

Q. WHAT IS THE RATIONALE FOR MODIFYING DEMAND CHARGES?

A. Company witness Mr. Ortiz addresses the policy supporting this proposal. Modifying the demand charges is consistent with one of the key rate design objectives in this case: increased recovery of fixed costs through fixed monthly charges. Also, demand charges set to recover all or nearly all the capacity-related costs PNM incurs to serve these customers will assist in developing price signals that ensure economically efficient energy usage, thus incentivizing system use optimization and promoting higher load factor use, thereby lowering costs to all customers.

Q. CAN YOU EXPLAIN HOW THE COMPANY CALCULATED THE PROPOSED DEMAND CHARGES?

A. For all three-part rate classes, PNM's proposed rates increase the amount of fixed costs being recovered through demand charges. These costs include fixed costs the Company incurs for production, transmission, substations and primary/secondary distribution. For schedules General Power (Rates 3B & 3C) and Large Power (Rate 4B), the proposed demand charges were set at approximately 69% of the cost-based level to mitigate the rate impact for customers with a low load factor (e.g., within Schedule 3C). For example, for Schedule 4B customers, demand-related costs total over $69 million. PNM is proposing to collect approximately $48 million from Schedule 4B customers through the demand charges. This will likely encourage customers to improve their load factor, which will result in a lower effective cost of electricity. PNM Exhibit SC-10 provides a summary of PNM's current and proposed demand charges.

Q. IS PNM PROPOSING OTHER CHANGES TO THE DEMAND CHARGES IN TERMS OF HOW SUCH COSTS WILL BE REFLECTED ON CUSTOMER BILLS?

A. Yes. Consistent with the changes to the customer and demand charges discussed above, PNM also is proposing modifications to existing rate schedules that change how demand charges are assessed and shown in customers' bills. A summary of these changes is reflected in 530 Schedule O-4; redlined versions of the tariffs demonstrating the specific proposed tariff changes are included in PNM Exhibit JCA-5. Under current tariffs, the customer charge includes costs related to serving the minimum demand specified on each schedule. For the purpose of improving transparency and providing more accurate price signals, the minimum demand-related costs will be recovered through the demand charge in the proposed tariffs. PNM believes that this increased transparency will aid these customers' understanding of their electric bills. Additionally, separating the customer charge from the minimum demand helps establish a clearer price signal for these larger customers, which can provide for economic efficiency in energy usage.

G. Rate Schedule Consolidation For North And South Customers And Rate Re-Design For Streetlighting And Private Area Lighting

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL TO CONSOLIDATE THE NORTH AND SOUTH STREETLIGHTING RATES?

A. After the conclusion of Case No. 10-00086-UT, when the North and South rates classes were consolidated, the rates and rate structures for PNM North and South Streetlighting customers were simply combined but not consolidated. As such, currently, PNM's North and South Streetlighting (Rate 20) customers pay different prices for identical lights and poles. Also, the North rates have separate light and pole components, while the South rates bundle lights and poles together. To resolve these issues, the Company is proposing to prepare a single, consolidated set of base rates, including pole, light and ownership options for PNM North and South customers.

Q. IN ADDITION TO CONSOLIDATION, IS PNM PROPOSING ANY OTHER CHANGES TO THE STREETLIGHTING RATES?

A. Yes, the Company is proposing to comprehensively re-design Streetlighting rates, as well as add new features to this tariff that allows customers additional opportunities to tailor their Streetlighting options. The rate re-design is needed, in part, given that the Streetlighting rates for PNM South are not cost-based.

Q. PLEASE EXPLAIN PNM'S EFFORTS TO COMPLY WITH THE AMENDED STIPULATION RELATED TO RATE DESIGN ISSUES FOR RATE 20 CUSTOMERS?

A. The Company is proposing Streetlighting rates that address cost allocation, rate design, maintenance, and energy efficiency issues in accordance with Paragraph 38 of the Amended Stipulation. Paragraph 38 of the Amended Stipulation required that within six (6) months of the issuance of the Final Order in Case No. 10-00086-UT, PNM would enter into discussions with Streetlighting (Rate 20) customers on the rate design issues noted above. PNM complied with this requirement.[22] PNM Exhibit SC-13 is a copy of a July 13, 2012 letter PNM sent to Rate 20 customers offering to meet with them regarding certain issues related to Streetlighting. This offer to meet resulted in PNM meeting separately with the following cities: Albuquerque, Deming, Lordsburg and Silver City. PNM also met with Bernalillo and Santa Fe Counties, as well as the Village of Los Ranchos. As a result of those customer meetings, PNM received information from individual customers regarding specific Streetlighting-related requests or issues that should be addressed. This information turned into considerations PNM is taking up as part of the comprehensive re-design of Rate 20 in this rate case.

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[22] *See* Order Granting Joint Request for Variance, Docket No. 10-00086-UT (issued Feb. 14, 2012) (granting a variance that would extend by six (6) months the deadline for initiation of discussions pursuant to Paragraphs 37 and 38 of the Amended Stipulation, which gave PNM an extra six (6) months to engage with Rate 20 customers).

Q. WHAT ARE THE BENEFITS OF UPDATING THE STREETLIGHTING TARIFF?

A. There are a number of benefits that will flow to customers from updating the Streetlighting (Rate 20) tariff, but the Company also will benefit from this update. The benefits can be grouped into three categories, which are: (1) simplification of the Streetlighting tariff; (2) added flexibility and increased customer choice; and (3) more stable rates over time given proposals in this case to limit class rate base increases.

Q. PLEASE IDENTIFY CHANGES IN THE CONSOLIDATED RATE STRUCTURES THAT WILL SIMPLIFY THE STREETLIGHTING TARIFF.

A. From a customer's perspective, the current rate structure is unnecessarily complicated, and so the new Streetlighting tariff simplifies the rate structure in a number of ways. First, the proposed changes to the Streetlighting tariff will reduce the total number of possible Streetlighting options. Currently, lights are categorized three separate ways: (1) PNM-owned overhead lights (i.e., served by an overhead wire), (2) PNM-owned underground lights (i.e., served by an underground wire) and (3) customer-owned lights. The proposed tariff will eliminate separate overhead and underground categories for light rates. Also, PNM is eliminating two lighting options that are no longer installed in the field, specifically: (1) 250W Mercury

Vapor Underpass Light; and (2) 150W High-Pressure Sodium Streetlight. Additionally, two 400W High-Pressure Sodium lighting options (one Streetlight and one Floodlight) are being combined into one lighting option, given that the underlying costs and the rates for both lighting options are the same. The final step to reduce the total number of options is to take the number of Streetlight poles offered from eight (four wood and four non-wood) to two (one wood and one non-wood).

The second way in which the Streetlighting tariff is being simplified is to create one common set of rates that applies to North and South Streetlighting customers. As such, a single, common set of rates for Streetlighting service will apply to all of PNM's customers. This common set of rates also unbundles the pole and light rates to provide even more clarity for customers, which is consistent with PNM North's current Streetlighting tariff.

The final step to simplifying this tariff is to correct and standardize the language used in the tariff. The proposed modifications to Rate 20, in redline form, are attached as PNM Exhibit JCA-5.[23] An explanation of the tariff changes is provided in 530 Schedule O-4.

[23] Although the proposed Rate 20 is attached to Mr. Aguirre's PNM Exhibit JCA-5, I sponsor the pricing modifications to this tariff.

Q. WHAT ARE THE MODIFICATIONS TO THE STREETLIGHTING TARIFF THAT WILL INCREASE CUSTOMER CHOICE AND ADD FLEXIBILITY TO THE LIGHTING OPTIONS?

A. During customer meetings held in 2012 as a result of Paragraph 38 of the Amended Stipulation, several customers expressed an interest in PNM providing a high-efficiency lighting option. To satisfy customer interests, as well as to further the energy efficiency goals of the State, part of the tariff re-write focuses on providing customers more flexibility in lighting options, particularly as it pertains to the ability to implement new high-efficiency lighting at the customer's discretion. To start, the Company is proposing to offer the following Company-owned LED lighting options, which are equivalent to standard Streetlighting in the following ways:

- 43W LED Light – 70W HPS Light equivalent
- 54W LED Light – 100W HPS Light equivalent
- 130W LED Light – 250W HPS Light equivalent
- 258W LED Light – 400W HPS Light equivalent

The re-designed Rate 20 also includes a new section on customer-owned and maintained lighting that is not specific to any light type and, as such, freely permits high-efficiency lighting installations by the customer. This new section uses a simplified approach that applies a monthly charge based upon calculated kWh derived from the wattage range of the light. This permits the customers the maximum flexibility to choose a high-efficiency or any other type of light that fits the customer's need. Additionally, this new section does not include any maintenance costs for the customer-owned lights, which results in lower overall Streetlighting rates for customers. Under previous versions of this Streetlighting tariff, some customers were still charged a fee for Company maintenance, even though they wished to do the maintenance themselves.

PNM also is introducing another element of flexibility that is not part of the tariff re-design but will still be an option that will appeal to small municipalities. Specifically, PNM's proposal is to allow customers to separately contract with the Company to pay for Streetlight maintenance of customer-owned and maintained lights. As such, if customers want to own their lights but do not have the manpower to maintain them, that customer can enter into a special contract with the Company to maintain their lights. Under this construct, however, the customer will be responsible for maintaining an inventory of all of its own lights and poles.

Q. HOW WILL THE MODIFICATIONS TO THE STREETLIGHTING TARIFF RESULT IN A MORE STABLE STREETLIGHTING RATE OVER TIME?

A. To start, from a cost allocation perspective, the plan is to design pole and light rates that are more reflective of the costs of providing this service. Rates that move gradually over time to align with the cost of service will naturally become more stable. Additionally, PNM is establishing limits on its investment for Company-owned lights and poles to an amount that corresponds to the capital that is recovered in rates.

Q. CAN YOU DISCUSS THE PROCESS PNM UNDERTOOK TO RE-DESIGN STREETLIGHTING RATES.

A. PNM Exhibit SC-15, pages 1 to 9, provides a detailed summary of the process PNM undertook to re-design Streetlighting rates, as well as development of the CAR, which is discussed below.

Q. CAN YOU EXPLAIN RATE CONSOLIDATION AND RE-DESIGN FOR PRIVATE AREA LIGHTS (RATE 6)?

A. Yes. PNM Exhibit SC-15, pages 10 and 11, explain the rate consolidation and rate re-design for the Private Area Lighting Schedule (Rate 6).

Q. CAN YOU EXPLAIN IN MORE DETAIL THE NEW PROPOSED CAR FOR STREETLIGHTING CUSTOMERS?

A. Yes. PNM South customers currently do not have cost-based Streetlighting rates. As such, these customers are significantly underpaying for most Streetlighting facilities and services. The new proposed CAR is meant to mitigate the impact of consolidated North and South Streetlighting rates on PNM South customers. The CAR will limit the impact to, at most, a 17% increase on current Steetlighting rates. PNM Exhibit SC-15 at page 9 explains in more detail the development of the CAR for Streetlights.[24] PNM Exhibit SC-14 demonstrates the overall rate impact for the Streetlighting customers, including the effect of the CAR on bill increases for PNM South customers.

H. Elimination Of The Banking Option For DG Customers

Q. PLEASE EXPLAIN PNM'S PROPOSAL TO ELIMINATE THE BANKING OPTION FOR DISTRIBUTED GENERATION CUSTOMERS.

A. To further its efforts to align conservation incentives with system costs, PNM is proposing to eliminate DG customers' ability to carry over excess energy produced to subsequent billing periods. Rather than carrying over these energy credits, PNM will implement a monthly cash-out provision for excess DG energy produced. The cash-out provision will pay customers on a monthly basis for excess energy pursuant to the existing Schedule 12 (Cogeneration and Small Power Production) rates. Modifications to PNM's Net Metering Service, Rider 24, are included in PNM Exhibit JCA-5; the proposed modifications also are summarized in 530 Schedule O-4.

[24] No CAR was applied to Private Area Lights (Rate 6).

Q. IF ADOPTED, WHAT ISSUES WILL PNM'S PROPOSAL REMEDY?

A. The elimination of the banking option for excess energy produced does away with a construct that assumes net metered customer have some ability to store their excess energy generated from their DG system and utilize this excess energy at some future point in time. By simply paying the customer for this excess energy on a monthly basis, as opposed to permitting customers to use the credits at a later time, PNM would send more accurate price signals to net metered customers about their true energy costs. Additionally, elimination of the banking option more closely aligns cost recovery and cost causation, given that the Company under PNM's proposal will now get paid in each month for the net energy actually used by the customer in that same month.[25] Much like the DG Interconnection Fee, this proposal also reduces intra-class subsidization between DG and non-DG customers by requiring DG customers to pay for the net energy consumed.

Q. IS PNM'S PROPOSAL CONSISTENT WITH THE COMMISSION'S RULES AND REGULATIONS?

A. Yes. 17.9.570.14(C)(3)(B) NMAC permits PNM to credit or pay each month a net metered customer for the electric energy generated in excess of electric energy the

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[25] There is a caveat to this statement in that the entire net metering construct does not permit the Company to collect all of its fixed costs of providing energy to these net metered customers. The DG Interconnection Fee is meant to serve as an additional means to assist the Company in collecting its lost fixed costs associated with net metering and reduce cross subsidization.

customer received from the grid during the billing period. PNM is electing to pay the customer, as opposed to offering the customer a credit.

Q. WILL PNM'S PROPOSED ELIMINATION OF THE BANKING OPTION FOR DG CUSTOMERS APPLY TO EXISTING DG CUSTOMERS?

A. No. PNM does not propose to eliminate the banking option for existing DG customers until the existing customer's Renewable Energy Certificate ("REC") purchase agreement expires. Upon expiration of the existing customer's REC purchase agreement, the customer will be subject to a new REC purchase agreement that does not permit banking of excess energy produced by the customer's DG system. PNM also proposes to eliminate the banking option for those customers who do not have installed systems or completed applications by December 31, 2015.

Q. WHEN PNM PAYS THE CUSTOMER EACH MONTH FOR THE EXCESS ENERGY PRODUCED BY ITS DG SYSTEM, WILL PNM ALSO ACQUIRE THE CUSTOMER'S RECS FOR THE EXCESS ENERGY PRODUCED?

A. Yes. NMSA 1978, Section 62-16-5(B)(1)(a)(2) (2007) of the Renewable Energy Act ("REA") states that RECs are owned by the generator of the renewable energy unless "the generator is a qualifying facility, as defined by the federal Public Utility Regulatory Policies Act of 1978, in which case the renewable energy certificates are owned by the public utility purchaser of the renewable energy unless retained by the generator through specific agreement with the public utility purchaser of the energy." Net metered DG systems are considered qualifying facilities under New Mexico's regulatory scheme. As such, when PNM pays DG customers for excess energy on a monthly basis at the avoided cost rate, PNM also will acquire the associated RECs.

Q. AS A RESULT OF THIS PROPOSAL, WILL PNM REVISE THE REC PURCHASE AGREEMENT FOR SOLAR SYSTEMS SMALLER THAN 10 KW?

A. Yes. Upon approval in this case of PNM's request to eliminate the banking option for solar systems under 10 kW, PNM will, as a compliance filing, submit a new REC purchase agreement for these systems. The language in the new REC purchase agreement will match the language in the REC purchase agreement for solar systems above 10 kW, which states:

> If the Solar Facility generates electricity in excess of the amount of electricity consumed each month on the Premises ("Excess Energy"), PNM shall purchase such Excess Energy at its avoided cost, and PNM shall receive from Customer, without cost, all RECs associated with such Excess Energy, to the extent authorized by the New Mexico Renewable Energy Act.

VI. PNM'S PROPOSED NEW TARIFFS

A. Revenue Balancing Account

Q. PLEASE EXPLAIN THE COMPANY'S REVENUE BALANCING ACCOUNT PROPOSAL.

A. PNM is filing for approval of a four-year pilot Revenue Balancing Account tariff to remove the disincentives for energy efficiency and load management measures. This pilot program will apply to the Residential Service (Rates 1A, 1B) and Small Power Service (Rates 2A, 2B). The Revenue Balancing Account is a decoupling mechanism that allows PNM to collect all of its fixed costs through a process that tracks the difference between the customer class revenues authorized by the Commission and the actual revenues collected for that customer class. The difference will result in future rate adjustments to collect any under-recovery from or to credit back any over-recovery to customers. By permitting PNM to collect a pre-established amount of revenue toward fixed cost recovery regardless of the actual sales revenues received during any year, PNM is indifferent to the usage levels of the customers to which the Revenue Balancing Account applies.

Both Dr. Hansen and Company witness Mr. Ortiz support the policy reasons for implementing the Revenue Balancing Account. Dr. Hansen also addresses PNM's compliance with the requirements of the Amended Stipulation as it pertains to this proposal. I am sponsoring the Revenue Balancing Account tariff (Rider 42), which is provided in the Advice Notice for this case and in PNM Exhibit SC-3. I also am supporting the calculations that develop the Revenue Balancing Account tariff (Rider 42).

Q. PLEASE EXPLAIN THE COMPONENTS OF THE REVENUE BALANCING ACCOUNT TARIFF.

A. From a high-level perspective, the Revenue Balancing Account tariff will calculate a deferral amount each month, which will be the difference between the monthly allowed revenue toward fixed costs set in this rate proceeding and the actual revenue toward fixed costs billed under the volumetric rates to those customers. PNM Exhibit SC-16 sets forth the supporting data to calculate the Revenue Balancing Account deferral, while Dr. Hansen in his testimony supports the actual formula that is used to calculate the deferral. In particular, PNM Exhibit SC-16 calculates the two key components of the deferral, which are: (1) the *FCE*, the fixed-cost portion of the energy rate for a customer class, expressed in $/kWh; and (2) the *FCC*, the fixed cost per customer and per month for a customer class. PNM Exhibit SC-16 shows how the *FCC* and *FCE* parameters are calculated for each of the two applicable customer classes (Residential and Small Power). As described by Dr. Hansen, to calculate the *FCC*, the fixed costs recovered through the volumetric rates are divided by the test year number of customers served in the customer group. To calculate the *FCE*, the fixed costs recovered through the volumetric rates are divided by the test year sales to the customer group.

Q. DOES THE AMENDED STIPULATION RELATE TO THIS REVENUE BALANCING ACCOUNT PROPOSAL?

A. Yes. Paragraph 39 of the Amended Stipulation required that before PNM could request approval of a mechanism to remove disincentives for energy efficiency programs, it was required to engage in good faith consultations with stakeholders. Dr. Hansen provides the detail regarding the September 29, 2014 and November 5, 2014 stakeholder meetings PNM held in accordance with Paragraph 39 of the Amended Stipulation.

B. DG Interconnection Fee

Q. PLEASE EXPLAIN THE PROPOSED DG INTERCONNECTION FEE.

A. PNM is proposing a fixed monthly DG Interconnection Fee (Rider 41) to be applicable to new solar and wind DG customers that take service as net metered customers.[26] New DG customers are those customers who do not have a DG system installed or a completed application as of December 31, 2015. The proposed new DG Interconnection Fee is presented in the Advice Notice for this case and in PNM Exhibit SC-3.

[26] *See* Paragraph 26 of the Amended Stipulation and Paragraph 197 of the Final Order Conditionally Approving Stipulation, both in Case No. 10-00086-UT.

Q. PLEASE DESCRIBE THE DG INTERCONNECTION FEE AND HOW PNM WILL CALCULATE THIS FEE.

A. PNM proposes to assess a fixed charge per subscribed kW-AC of installed DG capacity. PNM first calculates the fixed costs being recovered through the volumetric charge. PNM then calculates the amount of kWh that a one kW system produces in a month. The product of the fixed costs embedded in each kWh charge and the amount of kWh each one kW system produces identifies the amount of fixed costs that a DG customer avoids each month. For example, based upon the proposed rate design, a DG Interconnection Fee of $16.73 per kW per month should be charged to a Residential customer with a 1 kW photovoltaic ("PV") system. This DG Interconnection Fee includes revenue requirements related to generation, transmission and distribution. <u>See</u> PNM Exhibit SC-17, which provides a detailed calculation of the cost-based DG Interconnection Fee for the applicable customer classes. As discussed in more detail in Mr. Ortiz's testimony, PNM is proposing to cap the DG Interconnection Fee at $6 per kW-AC per month.

Q. IN DEVELOPING THE DG INTERCONNECTION FEE, HAS PNM FACTORED IN THE REASONABLY DETERMINABLE BENEFITS TO PNM'S SYSTEM PROVIDED BY THE DG INTERCONNECTION CUSTOMERS DURING THE THREE YEAR PERIOD AFTER THE DG INTERCONNECTION FEE WILL GO INTO EFFECT?

A. Yes. The DG Interconnection Fee is designed to collect fixed costs PNM incurs to serve DG customers. The benefit of avoided fuel is not realized under a net metering construct, as supported by Mr. Ortiz's testimony in NMPRC Case No. 14-00158. In addition, PNM has determined that there are no specific quantifiable benefits from net metering in addition to avoided fuel costs. In summary, PNM cannot quantify any benefits from DG interconnection customers that may be used as an offset for the fixed costs PNM incurs in serving these customers.

C. Economic Development Tariff

Q. PLEASE OUTLINE THE PURPOSE OF THE ECONOMIC DEVELOPMENT TARIFF PNM IS PROPOSING.

A. PNM is proposing an economic development tariff consistent with NMSA 1978, Section 62-6-26 (1993) of the Public Utility Act ("PUA") and 17.9.590 NMAC of the Commission's Rules ("Rule 590"). The economic development tariff will offer a discounted rate to Schedules 4B, 5B and 34B to encourage new industry to locate in

New Mexico and encourage existing customers to further invest in their business in this State.

Q. PLEASE DESCRIBE THE MECHANICS OF THE PROPOSED ECONOMIC DEVELOPMENT TARIFF.

A. PNM's economic development tariff (Rider 43) is included in the Advice Notice of this case and in PNM Exhibit SC-3. The proposed economic development tariff sets forth discounted percentages to the customer's applicable demand charge. To be eligible to be served under the economic development tariff, the customer's new demand must be greater than 500 kilowatts. Also, the tariff will offer a discounted rate to existing customers with incremental load over 200 kW. To be eligible, both new and existing customers must make at least 50% of their sales out of state. Consistent with the requirement at Section 62-6-26(C) of the PUA, which requires that a utility have excess capacity prior to offering such rates, PNM's proposal caps the amount of capacity available under the economic development tariff at 20 MW. The 20 MW represents a very small percentage – about 1% -- of PNM's planning demand. PNM has chosen to place a fairly restrictive cap on its economic development tariff given this is the first time in several years that it will offer such a program and it is unclear how well utilized the program might be. PNM does not want to over-extend its available planning capacity under this program, given the importance of reliably serving existing customers.

As to the specifics of the discount, PNM recommends that in the five consecutive 12-month billing periods beginning with the first billing period after the customer commences service under the economic development tariff, the following discounts will be given:

- A maximum of 50% for 0-12 month;
- A maximum of 40% for 13-24 months;
- A maximum of 30% for 25-36 months;
- A maximum of 20% for 37-48 months; and
- A maximum of 10% for 49-60 months

Additionally, Section 62-6-26(A) of the PUA requires that an economic development tariff be designed to recover at least the incremental cost of providing service to eligible customers. Pursuant to the economic development tariff included in the Advice Notice, when a customer requests service, PNM is required to document that the rate charged after the percentage discount over the five-year period will not go below the incremental cost of providing service to that customer. If the percentage discount does cause the rate charged to go below the incremental cost of providing service, PNM will be permitted to reduce the percentage discount as needed. The percentage discount is never to exceed the maximum discount permitted in each year.

Q. WHAT ARE THE BENEFITS OF THE ECONOMIC DEVELOPMENT TARIFF?

A. PNM believes that declining percentage discounts, starting at 50% in the first year, are one of the best methods to incentivize industry to relocate to New Mexico or for existing customers to expand in the State, while also providing protection to the Company's existing customer base. Moreover, since the discounts decline over a five-year period, existing utility customers benefit because the new customers contribute an increasing amount toward the system costs. Company witness Mr. Ortiz provides other policy reasons in support of PNM's proposed economic development tariff.

Q. ARE YOU FAMILIAR WITH OTHER JURISDICTIONS THAT HAVE IMPLEMENTED ECONOMIC DEVELOPMENT TARIFFS?

A. Yes. Many jurisdictions throughout the United States have successfully implemented economic development rates. Focusing on the Southwest, the following investor-owned utilities have implemented commission-approved economic development rates: in California, Pacific Gas & Electric and SoCal Edison; in Nevada, Sierra Pacific Power Company d/b/a NV Energy and Nevada Power d/b/a NV Energy; and in Texas, El Paso Electric Co. and Southwestern Electric Power Company ("SWEPCO").[27]

[27] SWEPCO's economic development tariff is labeled "experimental."

Q. COULD YOU DETAIL THE STRUCTURE AND INCENTIVES OFFERED BY EACH OF THESE UTILITIES?

A. Yes. PG&E and SoCal Edison share the same economic development rates ("EDR"), which include two schedules – a "Standard EDR" and an "Enhanced EDR." Under the Standard EDR, each utility applies a 12% reduction to the customer's bundled otherwise applicable tariff charge for five years. To qualify for the tariff, a customer must either be a new commercial or industrial customer with at least 200 kW load, or an existing customer who can show that without the EDR they would no longer be able to continue operating in California. The program is limited to a 200 MW cap for each utility, including both Standard and Enhanced EDR customers.

In Nevada, the Public Utilities Commission has approved Schedule EDRR for both Sierra Pacific Power and Nevada Power (doing business as NV Energy), pursuant to Nevada Revised Statutes 704.7871 through 704.7882. Schedule EDRR permits eligible customers to discount their Base Tariff Energy Rate by 30% for the first year, 20% for the second and third years, and 10% for the fourth year. To qualify, a customer must be a new commercial or industrial customer with new load demand greater than 300 kW. The program is limited to 50 MW statewide.

El Paso Electric Co. in Texas offers an economic development rate to customers that have a minimum monthly billing demand of 500 kW through Schedule No. 33 – Economic Development Rider. The rider is limited to five large industrial/commercial customer classes and allows them to discount their monthly demand charge by the following percentages: 10% for the first year, 7.5% for the second year, 5% for the third year, and 2.5% for the fourth year. The program is limited to 150 MW of total demand.

SWEPCO's Experimental Economic Development Rider is available to only the Lighting and Power and Large Lighting and Power Service schedules. Among other requirements, to qualify, a customer must increase the number of full-time employees at its facility by specified amounts and have additional load to qualify for this experimental rider. Regarding the increased load, for customers with existing load, they must have an additional load increase in excess of 1,000 kW, and for customers above 20,000 kW, they must have additional load increase of 5% of existing load. Also, businesses must fall within certain categories, which include industries manufacturing products for sale or resale, regional warehousing/distributing, scientific/industrial research and development, corporate relocations. The percentage discount to the customer's rate is determined by the number of additional full-time employees added by the business. For example, businesses with 31 or more additional employees get a 40% discount in year 1, a 30% discount in year 2 and a 20% discount in year 3.

Q. IS PNM'S PROPOSAL IN LINE WITH THE ECONOMIC DEVELOPMENT RATES OFFERED BY THESE UTILITIES?

A. Because each tariff varies, it is difficult to directly compare the tariffs. PNM's economic development tariff is being offered to both existing and new customers, which is consistent with most of the tariffs for other investor-owned utilities noted above.

In terms of the amount of discount, when viewed as a whole, PNM's proposal is largely consistent with California's Enhanced EDR. Although the discount PNM proposes for the first two years (a maximum of 50% for months 0-12 and 40% for months 12-24) is higher than the discounts offered by the investor-owned utilities cited above, PNM's average discount over the five-year lifespan of the rate is 30%. This discount is consistent with the incentives offered by PG&E and SoCal Edison under their "Enhanced EDRs," which are available in cities or counties with high unemployment rates. In deciding in favor of PG&E's Enhanced EDR, the California Public Utilities Commission stated:

> In addition to direct benefits to other ratepayers, economic attraction and retention activities also provide indirect benefits to ratepayers in the form of increased employment opportunities and improved overall local and economic vitality. Local

> communities benefit from the economic multiplier effect, resulting from local spending by newly employed, or continuously employed, workers where the businesses locate. One of the indirect results from the strengthened economic base is the more complete use of the utilities' transmission and distribution facilities which further reduces rates.[28]

As further described in Mr. Ortiz's testimony, these are precisely the benefits PNM seeks to achieve through its proposal.

Q. HOW WILL THE PROPOSED ECONOMIC DEVELOPMENT TARIFF AFFECT OTHER CUSTOMER CLASSES?

A. There will be no additional cost burden on existing customers since the discounted rates are developed to recover at least the incremental cost to serve such customers. Furthermore, since the resulting discounted rates will be higher than the incremental cost to serve, existing customers will benefit as the percentage discount to the economic development customer decreases and more system costs are recovered from that customer.

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[28] Application of Pacific Gas and Electric Company for Approval of Economic Development Rate for 2013-2017, Application 12-03-001, Decision 13-10-019 (October 9, 2013), at pages 16-18.

D. Schedule 34b -- Large Service For Customers 3,000 kW And Above Tariff

Q. PLEASE EXPAND UPON THE COMPANY'S PROPOSAL TO ADD A NEW LARGE SERVICE CLASS TO ITS RATE SCHEDULES AND TARIFFS.

A. As mentioned in my testimony above, the allocation of costs to customer classes should recognize various customer class characteristics, such as peak demand, energy usage, load factor, number and size of customers, point of delivery, etc. As PNM examined the customers that are currently served under Large Power Service (Rate 34B), it is apparent that a few customers have characteristics that are distinct from the rest of customers in that class. Therefore, from a cost allocation perspective, it is warranted to establish a separate rate class for these customers, for which PNM is proposing Rate Schedule 34B.

Specifically, the customers for which this class is being designed have peak demand that is five times the Rate Schedule 34B class average and the monthly usage is 10 times the Rate Schedule 4B class average. Moreover, these customers have greater than 90% load factor as compared to the Rate Schedule 4B class average of about 65%.

This rate schedule is included in PNM Exhibit SC-3 and in the Advice Notice to this application. This rate schedule will be offered to customers with a monthly minimum demand of 3,000 kW.

Q. ARE THERE POTENTIAL NEW CUSTOMERS THAT WILL QUALIFY FOR THIS VERY LARGE CUSTOMER CLASS?

A. Yes. PNM believes the creation of this new Large Service (Rate 34B) class might attract new industry to New Mexico. In particular, PNM believes that the parameters of this new customer class may be attractive to data centers. As such, there are added economic development benefits to creating this customer class.

VII. MODIFICATIONS TO THE VOLTAGE CLASS ADJUSTMENT FACTORS

Q. IS PNM REVISING ITS VOLTAGE CLASS ADJUSTMENT FACTORS USED TO CALCULATE BASE FUEL RATES AND VARIABLE FUEL RATES IN THIS CASE?

A. Yes. The Voltage Class Adjustment Factors reflect the energy losses for each class for the test year as compared to the Company average energy loss rate for the test year. Given that the test year losses are different from losses used in PNM's last rate case, Case No. 10-00086-UT, the Voltage Class Adjustment Factors must be modified. PNM Exhibit SC-18 shows the calculation for the Voltage Class Adjustment Factors, as well as the Base Fuel Rates, which are derived from these Voltage Class Adjustment Factors.[29]

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[29] The Voltage Class Adjustment Factors are presented in Rider 23. Rider 23 also demonstrates how to calculate the Variable Fuel Rates using the Voltage Class Adjustment Factors. Base Fuel rates, which are modified by the changes to the Voltage Class Adjustment Factors, appear in each base tariff.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

GCG#518980

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: Director, Pricing and Load Research

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

GCG # 518680-v2

Alphabetical listing of acronyms used in this testimony

PNM Exhibit SC-2

Is contained in the following page,

ACRONYMS USED IN TESTIMONY

Term	Acronym
Albuquerque Bernalillo County Water Utility Authority	ABCWUA
Coincident Peak	CP
Consolidation Adjustment Rider	CAR
Contribution in Aid of Construction	CIAC
Distributed Generation	DG
Embedded Class Cost of Service Study	ECCOSS
Four Coincident Peak	4CP
National Association of Regulatory Utility Commissioners	NARUC
New Mexico Public Regulation Commission	NMPRC
New Mexico Public Service Commission	NMPSC
Non-Coincident Peak	NCP
One Coincident Peak	1CP
Photovoltaic	PV
Public Service Company of New Mexico	PNM
Public Utility Act	PUA
Rate of Return	ROR
Time of Use	TOU
Renewable Energy Certificate	REC
Twelve Coincident Peak	12CP
3-Summer/1-Winter Coincident Peak	3S1WCP

Copies of new tariffs that PNM is proposing in this rate case.

PNM Exhibit SC-3

Is contained in the following 14 pages.

PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

ORIGINAL RATE NO. 34B

LARGE POWER SERVICE >=3,000KW-- TIME-OF-USE RATE

APPLICABILITY: The rates on this schedule are available to any retail customer who contracts for a definite capacity commensurate with customer's normal requirements but in no case less than 3,000 kW of capacity, who has a load factor of at least 80%, and takes service at PNM's primary distribution voltage. Minimum demand under this schedule shall be 3,000 kW.

Service shall be normally furnished and metered at the Company's available primary distribution voltage of 4.16 kV or higher. Service will be furnished subject to the Company's Rules and Regulations and any subsequent revisions. These Rules and Regulations are available at the Company's office and are on file with the New Mexico Public Regulation Commission. These Rules and Regulations are a part of this Schedule as if fully written herein.

TERRITORY: All territory served by the Company in New Mexico.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service delivered at the Company's available primary distribution voltage of 4.16 kV or higher. The delivery voltage of the Company will depend upon the capacity available and necessary to take care of customer's initial and contemplated future requirements. The Company shall be the sole judge as to the voltage it can make available so as to provide for adequate capacity to the customer.

SERVICE WITH A CONTRACT DEMAND OF 3,000 KW OR MORE:

1. The Company will provide service under this Rate Schedule to any retail customer who contracts for a demand of 3,000 kW and a load factor of 80% who take service from PNM's primary distribution system only if the customer agrees to a specified period of service under this tariff of not less than one year. The customer must sign a facilities contract or appropriate line extension agreement for any transmission or distribution cost incurred by the Company after initiation of the contract for the customer not covered through rates on this tariff. Liquidated damages provisions will be included in the contract or line extension agreement.
2. All contract modifications must be in writing and executed as a supplement to the contract.

DISTRIBUTION EQUIPMENT: All distribution transformers, the necessary structures, voltage regulating devices, lightning arrestors, and accessory equipment required by the customer in order to utilize the Company's service at primary distribution level shall be installed, paid for, and owned, operated, and maintained by the customer.

The customer shall also provide at customer's expense suitable protective equipment and devices so as to protect Company's system and service, to other electric users, from disturbances or faults that may occur on the customer's system or equipment.

The customer shall at all times keep each of the three phases balanced as far as practicable so as not to affect service and voltage to other customers served by the Company. The customer shall not operate any equipment in a manner that will cause voltage disturbances elsewhere on Company's system.

Advice Notice No. 507

Gerard T. Ortiz
Vice President, PNM Regulatory Affairs

PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

ORIGINAL RATE NO. 34B

LARGE POWER SERVICE >=3,000KW-- TIME-OF-USE RATE

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION (Effective upon approval): The rate for electric service provided shall be the sum of A, B, C(1), D, E, F, and G below. On-Peak period is from 8:00 am to 8:00 pm Monday through Friday (60 hours per week). Off-Peak period is all times other than On-Peak period (108 hours per week).

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION (Effective on the first billing cycle of May 2016): The rate for electric service provided shall be the sum of A, B, C(2), D, E, and F below. On-Peak period is from 10:00 am to 10:00 pm Monday through Friday (60 hours per week). Off-Peak period is all times other than On-Peak period (108 hours per week).

IN THE BILLING MONTHS OF:		June, July and August	All Other Months
(A)	CUSTOMER CHARGE: (Per Metered Account)	$3,329.23/Bill	$3,329.23/Bill
(B)	ON-PEAK PERIOD DEMAND CHARGE: (For All Billing Demand during On-Peak Period)	$27.92/kW	$24.95/kW
(C)(1)	ENERGY CHARGE:		
	On-Peak kWh	$0.0416189/kWh	$0.0359714/kWh
	Off-Peak kWh	$0.0289854/kWh	$0.0289854/kWh
(C)(2)	ENERGY CHARGE:		
	On-Peak kWh	$0.0415046/kWh	$0.0358726/kWh
	Off-Peak kWh	$0.0289058/kWh	$0.0289058/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 90 percent or higher. The Company will supply, without additional charge, a maximum of 0.48 kVAR (Reactive Kilovolt Amperes) per kW of Total Demand. The monthly bill will be increased $0.27 for each kVAR in excess of the allowed 0.48 kVAR per kW of Total Demand.

(E) FUEL AND PURCHASED POWER COST ADJUSTMENT: The above rates are based on a base fuel cost for energy approved in NMPRC Case No. 14-00332-UT. For this tariff, base rate is $0.0256507 per kWh, effective for fuel and purchased power expenses incurred beginning January 10, 2015.

All kWh usage under this tariff will be subject to a Fuel and Purchase Power Cost Adjustment Clause (“FPPCAC”) factor calculated according to the provisions in PNM’s Rider 23.

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Gerard T. Ortiz
Vice President, PNM Regulatory Affairs

PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

ORIGINAL RATE NO. 34B

LARGE POWER SERVICE >=3,000KW-- TIME-OF-USE RATE

The appropriate FPPCAC factor will be applied to all kWh appearing on bills rendered under this tariff.

(F) OTHER APPLICABLE RIDERS: Any other PNM riders that may apply to this tariff shall be billed in accord with the terms of those riders.

(G) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

MONTHLY MINIMUM CHARGE: Absent any demand or consumption, the monthly minimum charge under this Schedule is the Customer Charge plus the Total Demand multiplied by the On-Peak Demand Charge rate.

DETERMINATION OF TOTAL DEMAND: The total demand shall in no event be less than the highest of the following: (a) the actual metered on-peak kW demand, (b) 50 percent of the highest metered on-peak kW demand during the preceding 11 months, (c) the minimum demand defined on this Schedule, or (d) the contracted minimum kW demand should it exceed the minimum demand provided for on this Schedule.

Metering shall normally be at the primary distribution voltage.

Where highly fluctuating or intermittent loads which are impractical to determine properly (such as welding machine, electric furnaces, hoists, elevators, X-rays, and the like) are in operation by the customer, the Company reserves the right to determine the billing demand by increasing the 15-minute measured maximum demand and kVAR by an amount equal to 65 percent of the nameplate rated kVA capacity of the fluctuating equipment in operation by the customer.

INTERRUPTION OF SERVICE: The Company will use reasonable diligence to furnish a regular and uninterrupted supply of energy. However, interruptions or partial interruptions may occur or service may be curtailed, become irregular, or fail as a result of circumstances beyond the control of the Company, public enemies, accidents, strikes, legal processes, governmental restrictions, fuel shortages, breakdown or damages to generation, transmission, or distribution facilities of the Company, repairs or changes in the Company's generation, transmission, or distribution facilities, and in any such case the Company will not be liable for damages. Customers whose reliability requirements exceed those normally provided should advise the Company and contract for additional facilities and increase reliability as may be required. The Company will not, under any circumstances, contract to provide 100 percent reliability.

ACCESSIBILITY: Equipment used to provide electric service must be physically accessible. The meter socket must be installed on each service location at a point accessible from a public right-of-way without any intervening wall, fence, or other obstruction.

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Gerard T. Ortiz
Vice President, PNM Regulatory Affairs

PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

ORIGINAL RATE NO. 34B

LARGE POWER SERVICE >=3,000KW-- TIME-OF-USE RATE

TERMS OF PAYMENT: All bills are net and payable within twenty (20) days from the date of bill. If payment for any or all electric service rendered is not made within thirty (30) days from the date the bill is rendered, the Company shall apply an additional late payment charge as defined in Rate 16 Special Charges.

LIMITATION OF RATE: Electric service under this Schedule is not available for standby service, is not available to customers served in the downtown area of Albuquerque when served by the underground network system, and shall not be resold or shared with others.

Advice Notice No. 507

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Gerard T. Ortiz
Vice President, PNM Regulatory Affairs

PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

ORIGINAL RIDER NO. 41

DISTRIBUTED GENERATION ("DG") INTERCONNECTION FEE

PURPOSE:
Public Service Company of New Mexico ("PNM" or "Company") does not recover through its other tariffs all of the costs associated with serving customers who have installed non-utility distributed generation. This tariff is intended to compensate PNM for the embedded fixed costs incurred by the Company to serve customers that are also interconnected to distributed generation facilities not otherwise recovered by the Company.

APPLICABILITY:
This rate is applicable to all New DG customers, as defined herein, taking utility service under Schedules 1A, 1B, 2A, 2B, 3B, 3C, 4B, 5B, 10A, 10B or 11B that utilize net metering billing options per 17.9.570.14.C New Mexico Administrative Code ("NMAC") (for interconnections up to 10 kW) or 17.9.570.15.D.2 NMAC (for interconnections greater than 10 kW and less than or equal to 10 MW).

TERRITORY:
All territory served by the Company in New Mexico.

DEFINITIONS:
The following definitions apply to the terms discussed within this Schedule:

Alternating Current ("AC"): A type of electrical current in which the direction of the flow of electrons switches back and forth at regular intervals or cycles.

DG Facility: A customer-sited facility that generates electricity by means of solar radiation or wind and that is a "qualifying facility" in accordance with 17.9.570.7.F NMAC.

New DG Customers: A Customer that has a DG Facility that was installed or a completed application for a DG Facility after December 31, 2015.

TERMS OF SERVICE:
On a monthly basis, PNM will assess a $/kW charge multiplied by the AC rated capacity of the DG Facility as reflected in the Customer's interconnection agreement with the Company. The monthly rates applicable to New DG Customers with a solar DG Facility are:

PNM Base Tariffs	Monthly Rate per kW-AC
Residential Schedules 1A & 1B	$6.00
Small Power Schedules 2A & 2B	$6.00
General Power Schedules 3B & 3C	$4.50
Large Power Schedule 4B	$3.73
Large Service for Customers >=8,000kW Schedule 5B	$1.95
Irrigation Schedules 10A & 10B	$6.00
Water/Sewage Pumping Schedule 11B	$6.00

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Gerard T. Ortiz
Vice President, PNM Regulatory Affairs
GCG#519007

PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

ORIGINAL RIDER NO. 41

DISTRIBUTED GENERATION ("DG") INTERCONNECTION FEE

The monthly rates applicable to New DG Customers with a wind DG Facility are:

PNM Base Tariffs	Monthly Rate per kW-AC
Residential Schedules 1A & 1B	$6.00
Small Power Schedules 2A & 2B	$6.00
General Power Schedules 3B & 3C	$3.88
Large Power Schedule 4B	$3.21
Large Service for Customers >=8,000kW Schedule 5B	$1.68
Irrigation Schedules 10A & 10B	$6.00
Water/Sewage Pumping Schedule 11B	$6.00

SPECIAL TAX AND ASSESSMENT ADJUSTMENT:
Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the Company and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

RULES AND REGULATIONS:
Any services hereunder will be furnished subject to the Company's Rules and Regulations and any subsequent revisions. These Rules and Regulations are available at the Company's office and are on file with the New Mexico Public Regulation Commission ("NMPRC"). These Rules and Regulations are a part of this Schedule as if fully written herein.

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Gerard T. Ortiz
Vice President, PNM Regulatory Affairs

GCG#519007

PUBLIC SERVICE COMPANY OF NEW MEXICO

ORIGINAL RIDER NO. 42

REVENUE BALANCING ACCOUNT
APPLICABLE TO RETAIL RATE SCHEDULES 1A, 1B, 2A AND 2B

EXPLANATION OF RIDER:
Pursuant to the New Mexico Public Regulation Commission's ("NMPRC") Final Order in NMPRC Case No. 14-00332-UT, Public Service Company of New Mexico ("PNM" or the "Company") established the Revenue Balancing Account to provide for the recovery of the difference between the fixed costs per kWh actually recovered through rates and the fixed costs per customer authorized for recovery in NMPRC Case No. 14-00332-UT or in subsequent general rate cases.

APPLICABILITY:
This Rider is applicable to the electric energy delivered to retail customers receiving service under Schedules 1A - Residential Service, 1B – Residential Service Time of Use ("TOU") Rate; 2A - Small Power Service, and 2B - Small Power Service TOU Rate.

TERRITORY:
All territory served by the Company in New Mexico.

FIXED COST PER CUSTOMER FACTOR:
The Fixed Cost per Customer Factor ("FCC") represents the amount on a $ per customer per month basis for Residential and Small Power customers approved by the NMPRC in Case No 14-00332-UT or in a subsequent general rate case, as follows:

Residential FCC
Effective Date: Upon Approval — Factor: $50.11 per customer per month

Small Power FCC
Effective Date: Upon Approval — Factor: $135.59 per customer per month

FIXED COST PER ENERGY FACTOR:
The Fixed Cost per Energy factor ("FCE") represents the amount on a $ per kWh basis for Residential and Small Power customers approved by the NMPRC in Case No 14-00332-UT or in a subsequent general rate case, as follows:

Residential FCE
Effective Date: Upon Approval — Factor: $0.0858261 per kWh

Small Power FCE
Effective Date: Upon Approval — Factor: $0.0948458 per kWh

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Gerard T. Ortiz
Vice President, PNM Regulatory Affairs

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PUBLIC SERVICE COMPANY OF NEW MEXICO

ORIGINAL RIDER NO. 42

REVENUE BALANCING ACCOUNT
APPLICABLE TO RETAIL RATE SCHEDULES 1A, 1B, 2A AND 2B

AUTHORIZED FIXED COST RECOVERY AMOUNT:
The Authorized Fixed Cost Recovery Amount is computed by multiplying the actual number of Residential and Small Power customers by the applicable Residential or Small Power FCC rate.

ACTUAL FIXED COST RECOVERED AMOUNT :
The Actual Fixed Cost Recovered amount is computed by multiplying the actual energy sales for Residential and Small Power customers by their applicable FCE rates.

FIXED COST RECOVERY CALCULATION:
The Revenue Balancing Account Recovery is the difference between the Authorized Fixed Costs Recovery Amount and the Actual Fixed Costs Recovered Amount calculated on a monthly basis. The formula to determine the Fixed Cost Recovery amount for Residential and Small Power rate classes is:

$$FCR = (CUST \times FCC) - (SALES \times FCE)$$

Where:

FCR = Fixed Cost Recovery entered into the Revenue Balancing Account deferral account on a monthly basis

CUST = Number of Residential or Small Power customers at the end of each month

FCC = Fixed Cost per Customer factor ($/Customer per month) for Residential or Small Power customers

SALES = Actual monthly energy sales of Residential or Small Power customers for each month

FCE = Fixed Cost per Energy factor ($/kWh) for Residential or Small Power customers

FIXED COST RECOVERY (FCR) DEFERRAL BALANCING EXPLANATION:
On a monthly basis, the number of Residential and Small Power customers (CUST) is multiplied by the respective FCC factor to develop the Authorized Fixed Costs Recovery Amounts for each customer class. Similarly, the actual (billed) energy sales for Residential and Small Power customers (SALES) are multiplied by their respective FCE factors to develop the Actual Fixed Costs Recovered Amount. The difference between the two numbers represents the Fixed Cost Recovery, which will be booked by the Company on a monthly basis to deferral balancing accounts. Separate deferral balancing accounts are established for the Residential and Small Power customer classes to track the monthly Fixed Cost Recovery. Each balance will include a carrying charge based on a rate equal to the customer deposit rate published by the NMPRC being applied to the monthly balances.

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Gerard T. Ortiz
Vice President, PNM Regulatory Affairs

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ORIGINAL RIDER NO. 42

REVENUE BALANCING ACCOUNT
APPLICABLE TO RETAIL RATE SCHEDULES 1A, 1B, 2A AND 2B

FIXED COST RECOVERY ANNUAL RESET:

Effective April 1 of each year, the positive or negative balance of the Residential and Small Power deferral balances will be collected or refunded from the Residential and Small Power customers through individual factors set for each class and applied to the Residential and Small Power customers on a per-kWh basis over the next twelve months. The individual factors for Residential and Small Power will be developed separately using forecasted Residential or Small Power sales for the next twelve months and applied equally across all projected kilowatt-hours of consumption. The Fixed Cost Recovery Annual Reset process consists of: (1) summing the monthly deferral balances for Residential and Small Power customers to determine annual balances (January 1 through December 31) for each class; (2) adding to the combined balance funds collected pursuant to Rate Rider 41 – DG Interconnection Fee from the Residential and Small Power classes during the deferral balance period; (3) allocating the adjusted balance to the Residential and Small Power classes on the basis of forecasted sales for the next twelve months. The resulting annual adjusted balances for each class represents the amount of the Fixed Cost Recovery to be collected or refunded from the Residential and Small Power customers over the next twelve months.

ANNUAL REPORT AND TIMING OF FIXED COST RECOVERY ANNUAL RESET:

The Company will file an Annual Report in support of the Fixed Cost Recovery Annual Reset at least thirty (30) days prior to the Company's first billing cycle in April of each year. The Company also will file an Advice Notice for the rate change that would be effective for the first billing cycle in April. The resulting rate change will be in effect from PNM's first billing cycle in April through PNM's last billing cycle in March of the following year, but is based on annual deferral balances of January 1 through December 31. The annual reporting will include the following:

- Calculations of the deferral amounts and resulting rate changes;
- The total amount of under- or over-collection of allowed revenue by class;
- Total collection of prior deferred revenue;
- The number of customer complaints received pursuant to 1.2.2.14 and 1.2.2.15 New Mexico Administrative Code ("NMAC") regarding the Revenue Balancing Account; and
- A comparison of how revenue under traditional regulation would have differed from those collected under the Revenue Balancing Account.

RATE LIMITATION AND CARRY FORWARD:

If the Annual Reset described herein results in a rate increase that is more than five (5) percent of base revenue for the Residential or Small Power customer class (excluding fuel factor revenue and all applicable riders, and including base fuel), the excess deferral amount above the five (5) percent will be carried over to the following year. There will be no limit on the rate reduction that the Annual Reset produces.

SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or

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Gerard T. Ortiz
Vice President, PNM Regulatory Affairs

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charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DURATION:
This tariff shall be in effect for four years from the date rates go into effect as a result of NMPRC Case No. 14-00332-UT unless an extension of this tariff is approved in a future regulatory case.

PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

ORIGINAL RIDER NO. 43

ECONOMIC DEVELOPMENT RIDER ("EDR") APPLICABLE
TO RATE NOS. 4B, 5B and 34B

APPLICABILITY:

Applicable to any New Retail Customer or Existing Retail Customer that is served under Rate Nos. 4B, 5B or 34B and that meet the following criteria:

1. Eligibility under the EDR requires:

   a. A minimum demand of at least 500 kW for New Retail Customers.
   b. Incremental Demand, as defined hereafter, of at least 200 kW for Existing Retail Customers.

2. Eligibility for the EDR requires a special contract with the Company for service under the EDR.

3. Both New Retail Customers and Existing Retail Customers taking service under the EDR must maintain electric service under Rate Schedule 4B, 5B or 34B in order to receive service under the EDR.

4. Both New Retail Customers and Existing Retail Customers must make at least 50% of their sales out of state. The New Retail Customers and Existing Retail Customers will provide the Company with sufficient verifiable data to support this requirement.

5. Upon written application for service under the EDR, the Company shall determine that the rate charged to the New Retail Customer or the Existing Retail Customer after the EDR discount is applied is equal to or greater than the incremental cost of providing service to the New Retail Customer and the Existing Retail Customer.

TERRITORY:

All territory served by the Company in New Mexico.

TYPE OF SERVICE:

The service available under this Schedule shall be at the voltages available under Rate Nos. 4B, 5B and 34B.

DEFINITIONS:

The following definitions apply to the terms discussed within this Schedule:

EDR Discount: The maximum discounted percentages applied to the applicable rate schedule of the New Retail Customer or the Existing Retail Customer and as set forth herein.

PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

ORIGINAL RIDER NO. 43

ECONOMIC DEVELOPMENT RIDER ("EDR") APPLICABLE
TO RATE NOS. 4B, 5B and 34B

Existing Retail Customers: Customers with twelve (12) or more billing months of service on the Company's system as of the date they apply to the Company for service under the EDR. Existing businesses which change ownership or location are Existing Retail Customers. Those businesses must assume the same EDR Average Base Demand as though they were continuing businesses since new jobs or new capital investment are not necessarily created in the Company's service territory. Existing businesses which change ownership or location must qualify for the EDR as any other Existing Retail Customer does.

New Retail Customers: Customers that have not previously taken service from the Company under any rate schedule as of the date they apply to the Company for service under the EDR. If a business ceases to exist and the premises are occupied by a new owner and a new business is opened, it may qualify as a New Retail Customer. The designation as a New Retail Customer shall be determined by the Company, in accordance with the provisions of the EDR.

EDR Average Base Demand for Existing Retail Customers: The EDR Average Base Demand for those Existing Retail Customers who qualify for participation in the EDR program shall be the average of the actual metered demands for twelve (12) consecutive billing months of normal operations prior to the effective date of the contract for service under the EDR. The EDR Average Base Demand is determined during the application process and remains constant during the term that the Existing Retail Customer qualifies for the EDR. The EDR Average Base Demand shall be specified in the Existing Retail Customer's contract for service under the EDR.

EDR Average Base Demand for New Retail Customers: The EDR Average Base Demand for New Retail Customers is 0 kW.

Incremental Demand for Existing Retail Customers: In order to qualify for the EDR discount, Incremental Demand must be at least 200 kW above the EDR Average Base Demand for Existing Retail Customers. Incremental Demand for Existing Retail Customers is defined as all kW billing demand above the EDR Average Base Demand for Existing Retail Customers.

RULES AND REGULATIONS:

Written Application: A New Retail Customer or Existing Retail Customer seeking to participate in the EDR program shall make written application to the Company on a form to be provided by the Company. The Company will review the New Retail Customer's or Existing Retail Customer's eligibility for the EDR. The approval of all applications for participation in the EDR program shall be at the discretion of the Company in accordance with the provisions specified herein. If the application is denied, the Company will, upon request, provide the applicant with an explanation of the reasons for the denial of its application. If an applicant believes that it was improperly denied participation in the EDR program or that the applicable rate schedule or EDR has been improperly applied, it may file a complaint with the New Mexico Public Regulation Commission (NMPRC).

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Gerard T. Ortiz
Vice President, PNM Regulatory Affairs

PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

ORIGINAL RIDER NO. 43

ECONOMIC DEVELOPMENT RIDER ("EDR") APPLICABLE
TO RATE NOS. 4B, 5B and 34B

Terms and Conditions: The terms and conditions of the applicable rate schedule for a specific participant are incorporated herein to the extent such terms and conditions are not inconsistent with the EDR.

Service Limitations: Service will be furnished in accordance with the Company's Rules and Regulations and any subsequent revisions thereto. Those Rules and Regulations are available at the Company's office and are on file with NMPRC. Those Rules and Regulations are a part of this Schedule as if fully written herein.
Full Requirements Service: The Company shall provide electrical service to a New Retail Customer or Existing Retail Customer under the EDR sufficient to meet the entire capacity and energy requirements of the customer at the points of delivery specified in the Customer's Service Agreement. Subject to the other applicable provisions in the EDR, the Company will provide service under the EDR sufficient to satisfy up to the full service and load requirements of the New Retail Customer or Existing Retail Customer at any time.

Early Termination: Except as the special contract with the customer pursuant to the EDR may otherwise provide, in the event the New Retail Customer or Existing Retail Customer terminates service prior to the end of term of the special contract, the customer shall reimburse the Company for all discounts previously provided under the EDR and the terms of the special contract with the customer.

EDR LIMITS:

Duration: The EDR shall remain in effect for a maximum five (5) year period for each New Retail Customer or Existing Retail Customer from the date of approval by the NMPRC. After the maximum five (5) year period for the EDR, each New Retail Customer or Existing Retail Customer must continue taking service from the Company under the applicable rate schedule for five (5) additional years without the benefit of the EDR. Any New Retail Customer or Existing Retail Customer who terminates service with the Company before this five (5) year period after expiration of the EDR is complete is subject to the Early Termination provisions set forth herein.

Contracts and Good Credit History: If an EDR participant moves to a rate schedule that is not eligible for the EDR, the participant will no longer be eligible for the EDR. The New Retail Customer or Existing Retail Customer must maintain a good credit history to maintain service under the EDR

Cap on Program: The total amount of capacity available under the EDR is 20 Megawatts.

**PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES**

ORIGINAL RIDER NO. 43

ECONOMIC DEVELOPMENT RIDER ("EDR") APPLICABLE
TO RATE NOS. 4B, 5B and 34B

RATES:

Billing Methodology: The participant will receive a normal bill calculated as though the EDR were not in effect except that the EDR Discount, calculated as described below, will be shown on the bill.

Calculation of EDR Discount: The participant will be entitled to a discount applicable to the demand charges for all kilowatts classified as Incremental Demand in accordance with the following table. The discount will be applicable to sixty (60) consecutive billing months beginning with the first such month under the special contract entered into pursuant to the EDR.

Limitation on EDR Discount: If the percentage discount causes the rate charged to go below the incremental cost of providing service to the New Retail Customer or the Existing Retail Customer, PNM will be permitted to reduce the percentage discount. The percentage discount is never to exceed the maximum discount permitted in each year.

EDR Discount:

Billing Months in Contract Term	Percentage Discount to Base Tariff Demand Charges
1st through 12th	50% maximum
13th through 24th	40% maximum
25th through 36th	30% maximum
37th through 48th	20% maximum
49th through 60th	10% maximum

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Gerard T. Ortiz
Vice President, PNM Regulatory Affairs

Summer and winter coincident peaks for PNM from 2007 through June 2014.

PNM Exhibit SC-4

Is contained in the following page.

PNM's System Peak Hourly Loads (MW)- Actuals

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1																	
2		**Month**															
3	**Year**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Max (Jan-Dec)**	**Summer Peak Jun-Sep (MW)**	**Winter Peak Nov-Feb (MW)**	**Winter Max/Summer Max**
4	**2007**	1,552	1,524	1,431	1,362	1,462	1,872	1,925	1,933	1,755	1,441	1,508	1,606	1,933	1,933	1,606	83%
5	**2008**	1,605	1,540	1,407	1,313	1,624	1,874	1,901	1,874	1,636	1,406	1,403	1,643	1,901	1,901	1,643	86%
6	**2009**	1,465	1,439	1,276	1,293	1,511	1,654	1,851	1,866	1,674	1,394	1,457	1,531	1,866	1,866	1,531	82%
7	**2010**	1,508	1,502	1,380	1,260	1,512	1,852	1,973	1,856	1,698	1,530	1,529	1,551	1,973	1,973	1,551	79%
8	**2011**	1,547	1,709	1,313	1,286	1,472	1,912	1,938	1,883	1,815	1,348	1,377	1,645	1,938	1,938	1,709	88%
9	**2012**	1,457	1,404	1,367	1,392	1,603	1,947	1,948	1,925	1,775	1,393	1,373	1,523	1,948	1,948	1,523	78%
10	**2013**	1,576	1,418	1,278	1,323	1,511	2,008	1,884	1,796	1,780	1,298	1,421	1,527	2,008	2,008	1,576	78%
11	**2014**	1,421	1,453	1,254	1,218	1,529	1,878	1,923	1,742	1,808	1,245	1,211			N/A	N/A	N/A
12	**Monthly Average**	1,516	1,499	1,338	1,306	1,528	1,875	1,918	1,859	1,743	1,382	1,410	1,575			Average	82%
13															1,938	1,591	82%
14															Ave of Col. O	Ave of Col. P	

Two letters sent by PNM in 2014 to customers served under Rate Schedule 11B (Water & Sewage).

PNM Exhibit SC-5

Is contained in the following 22 pages.

Main Offices
Albuquerque, NM 87158-1105
P 505 241-2700
F 505 241-2347
PNM.com

October 14, 2014

Via U.S. Mail and Electronic Mail

Bagher Dayyani
Albuquerque Bernalillo County Water Utility Authority
P. O. Box 1985
Albuquerque, NM 87103-1985

Nann M. Winter, Esq.
Stelzner, Winter, Warburton, Flores, Sanchez & Dawes, P.A.
P. O. Box 528
Albuquerque, NM 87103-0528
nwinter@stelznerlaw.com

Re: ***Compliance with Paragraph 39 of the Stipulation in NMPRC Case No. 10-00086-UT Regarding Adjustment to PNM's 11B – Water and Sewage class' coincident peak demands to be used for cost allocation purposes in PNM's next General Rate Case***

Dear Mr. Dayyani and Ms. Winter:

PNM's last general rate case (NMPRC Case No. 10-00086-UT) resulted in the filing of an Amended Stipulation to Conform to Commission Order ("Amended Stipulation"), which includes certain requirements PNM needs to fulfill before the next rate case filing. PNM plans to file a rate case in late 2014.

Specifically, Paragraph 39 of the Amended Stipulation filed in NMPRC Case No. 10-00086-UT states:

> *39) PNM and the Rate Schedule 11B customers will determine the appropriate Rate Schedule 11B coincident peak ("CP") demand for any month to be used for cost allocation purposes in PNM's next general rate case filing for those customers. Specifically, PNM will reduce any monthly CP demand for Rate Schedule 11B where the monthly CP date and time occur during a current PNM TOU off-peak hour. The amount of the reduction will recognize Rate Schedule 11B customers' operational load shifting capabilities, and will be determined jointly, in good faith, by PNM and the Rate Schedule 11B customers. PNM and the Rate Schedule 11B customers will determine, in good faith, whether reductions should be made to Rate Schedule 11B CP demands occurring within a current PNM TOU on-peak hour to adjust demands to appropriately recognize Rate Schedule 11B's operations and load shifting capabilities. PNM agrees not to file an average-and-excess demand allocation in its next general rate case filing.*

Parties representing both PNM and Rate 11B customers in Case No. 10-00086-UT agreed in the Amended Stipulation that Rate 11B customers have demonstrated a longstanding ability to shift electric use in response Time-Of-Use ("TOU") periods. If PNM were to propose any change to its TOU periods in an upcoming general rate case, then it also would be appropriate to adjust any future 11B monthly CP demand if that demand occurred during a current PNM Off-Peak Hour so that the class would not be unduly penalized for its current operating practices. PNM has already provided notice that it intends to adjust its TOU hours in its next general rate case in letters provided on May 31, 2012 and July 1,2014, so a means of appropriately adjusting Rate 11B CP loads needed to be implemented consistent with the method agreed to in the Amended Stipulation.

In 2012, PNM met with Rate 11B – Water & Sewage customers (Albuquerque Bernalillo County Water Utility Authority, the City of Santa Fe, and the City of Rio Rancho), 4B customers and the 30B customer to discuss a variety of rate design matters required by the Amended Stipulation. The 2012 meeting included a brief discussion of the method to be used to accomplish the intent of Paragraph 39 of the Amended Stipulation based on questions asked during the meeting.

Pursuant to this letter, PNM is agreeing to continue the methodology that was set forth in Paragraph 39 of the Amended Stipulation for the purposes of the filing in PNM's upcoming electric rate case. Specifically, during months where PNM's System CP demand occurred during a current PNM Retail Off-Peak Hour, PNM will adjust the Water & Sewage Class' System CP demands down to the value registered during the nearest occurring current PNM Retail On-Peak Hour. This method appropriately recognizes the Water & Sewage Rate Class' unique operations and load shifting capabilities to quickly respond to TOU price signals.

In preparation of the next general rate case filing, PNM has analyzed the hourly class load data and Water & Sewage class CP demand data. The attachment to this memorandum summarizes the overall results of that analysis, which also is described below:

> During the base period[1] that will be used in PNM's upcoming general rate case, there were three months when the date and time of PNM's Retail CP demand occurred during a current PNM Retail Off-Peak Hour[2]. Those months were November 2013, March 2014, and April 2014. Utilizing the methodology described and agreed upon in the Amended Stipulation, PNM proposes to adjust the Water & Sewage Class' CP demands for those three months to the levels recorded for the nearest occurring PNM Retail On-Peak Hour.[3] Historical monthly system CPs for the Water and Sewage Class are shown in the attached

---

[1] The anticipated base period for the upcoming rate case filing is July 2013 through June 2014.

[2] PNM's current Retail Off-Peak Hours are from 8 PM to 8 AM (MDT), Monday through Friday, and all hours on Saturday and Sunday. PNM is proposing to modify its On-Peak TOU Hours in the upcoming rate case to 10 AM to 10 PM (MDT) Monday through Friday.

[3] PNM's current Retail On-Peak Hours are from 8 AM to 8 PM (MDT), Monday through Friday.

table titled Water & Sewage Class' System Coincident Peak ("CP") Demands with Adjustments (by Month in Base Year). Based upon these adjustments, the Water & Sewage Class' total of monthly System CP loads was **reduced by nearly 12.4%,** which appropriately recognizes the Water & Sewage Rate Class' unique operations and load shifting capabilities to quickly respond to TOU price signals. This is also illustrated in the attached chart titled Water & Sewage Class System Coincident Peak ("CP") Demand by Month in Base Year. Adjusting system CP amounts will have the effect of reducing the Water & Sewage Class' allocated share of certain capacity related costs in the upcoming rate case.

The adjustment described above is in accordance with the Amended Stipulation and is also consistent with the discussion held in 2012. Therefore, PNM proposes the above described methodology to be utilized to derive the Water & Sewage Class' System CP demands in PNM's next general rate case filing.

If you have any feedback to this proposed approach, **please contact me by October 28, 2014 at 241-4542 or Stella.Chan@pnmresources.com.**

Public Service Company of New Mexico

Stella Chan, Director
Pricing and Load Research

GCG #581702

Confidential

Water & Sewage Class' System Coincident Peak ("CP") Demands with Adjustments (by Month in Base Year)

(If a time of a monthly PNM System CP Demand occurs during a current Off-Peak Hour, Water & Sewage ("W&S") Class' System CP Demand share is adjusted down so that it equals the W&S class load in the nearest current On-Peak Hour in recognition of the W&S Class' ability to respond to TOU Price signals.)

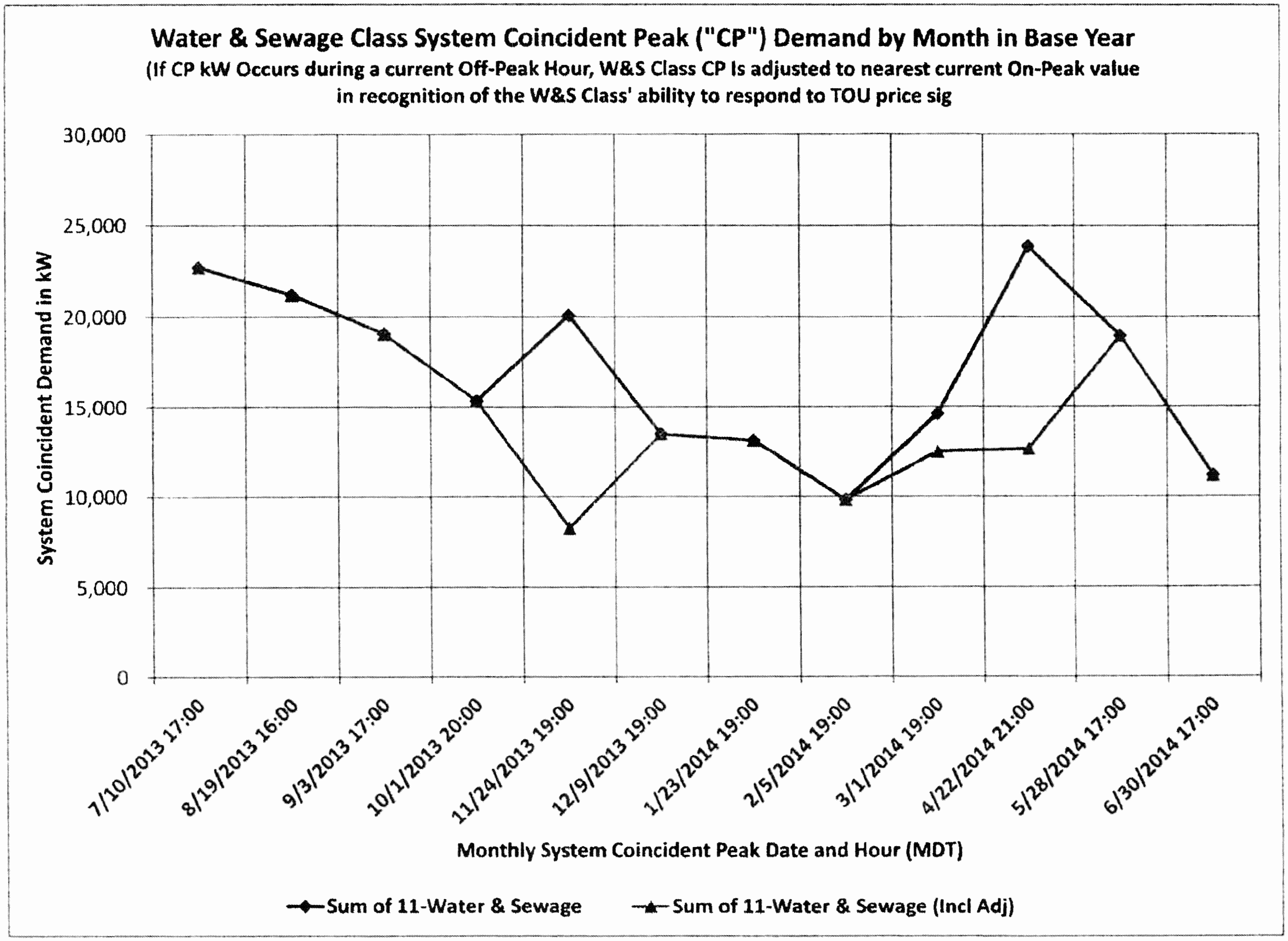
Date, Day of Week and Time (Hour Ending) of PNM's System Coincident ("SC") Peak Demand	Water & Sewage Class' Share of System CP Demand (in kW)	Water & Sewage Class' System CP Demand Adjustments (in kW) [1], [2], and [3]	Water & Sewage Class' Adjusted Share of System CP Demand (in kW)
7/10/2013, Wednesday @ Hour Ending 17:00 (MDT)	22,728	0	22,728
8/19/2013, Monday @ Hour Ending 16:00 (MDT)	21,218	0	21,218
9/3/2013, Tuesday @ Hour Ending 17:00 (MDT)	19,066	0	19,066
10/1/2013, Tuesday @ Hour Ending 20:00 (MDT)	15,340	0	15,340
11/24/2013, Sunday @ Hour Ending 19:00 (MDT)	20,088	(11,823)	8,265
12/9/2013, Monday @ Hour Ending 19:00 (MDT)	13,495	0	13,495
1/23/2014, Thursday @ Hour Ending 19:00 (MDT)	13,131	0	13,131
2/5/2014, Wednesday @ Hour Ending 19:00 (MDT)	9,828	0	9,828
3/1/2014, Saturday @ Hour Ending 19:00 (MDT)	14,621	(2,117)	12,504
4/22/2014, Tuesday @ Hour Ending 21:00 (MDT)	23,881	(11,235)	12,646
5/28/2014, Wednesday @ Hour Ending 17:00 (MDT)	18,966	0	18,966
6/30/2014, Monday @ Hour Ending 17:00 (MDT)	11,164	0	11,164
Grand Total	**203,527**	**(25,175)**	**178,351**

Notes:

* The nearest PNM Retail On-Peak Hour to Sunday, 11/24/2013 at 19:00 (MDT) is Monday, 11/25/2013 at 9:00 (MDT), where The Water & Sewage Class hourly load registered 8,265 kW, a reducton of 11,823 kW.

* The nearest PNM Retail On-Peak Hour to Saturday, 3/1/2014 at 19:00 (MDT) is Monday, 3/3/2013 at 9:00 (MDT), where The Water & Sewage Class hourly load registered 12,504 kW, a reducton of 2,117 kW.

* The nearest PNM Retail On-Peak Hour to Tuesday, 4/22/2014 at 21:00 (MDT) is Tuesday, 4/22/2013 at 20:00 (MDT), where The Water & Sewage Class hourly load registered 12,646 kW, a reducton of 11,235 kW.



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Main Offices
Albuquerque, NM 87158-1105
P 505 241-2700
F 505 241-2347
PNM.com

November 21, 2014

Bagher Dayyani
Albuquerque Bernalillo County Water Utility Authority
P.O. Box 1985
Albuquerque, NM 87103-1985
BDayyani@abcwua.org

Nann W. Winter, Esq.
Selzner, Winter, Warburton, Flores, Sanchez & Dawes, P.A.
P.O. Box 528
Albuquerque, NM 87013-0528
nwinter@stelznerlaw.com

Re: ***Mutually Agreed Upon Compliance with Paragraph 39 of the Stipulation in NMPRC Case No. 10-00086-UT Regarding Adjustment to PNM's 11B – Water and Sewage Class' Coincident Peak Demands Used for Cost Allocation in PNM's Upcoming Rate Case***

Dear Mr. Dayyani and Ms. Winter:

On October 14, 2014, PNM sent a letter regarding adjustments to the Coincident Peak (CP") demand loads for PNM's 11B – Water and Sewage Class ("Rate 11B"). These CP loads will have an impact on the allocation of Generation and Transmission Plant revenue requirements to the Rate 11B customers in PNM's soon-to-be filed general rate case. In that letter, PNM described an approach it had developed to adjust CP demands as a means of reflecting the Rate 11B customer's unique operational and load shifting capabilities to quickly respond to Time-Of-Use ("TOU") price signals. The approach as outlined in PNM's October 14 letter is referred to in this letter as the "Partial Shifting Case". The October 14 letter also asked for any feedback that Rate 11B customers had concerning this proposal by October 28, 2014.

PNM did receive feedback from the Albuquerque Bernalillo County Water Utility Authority ("ABCWUA") during a telephone conference held on October 30, 2014 and in a follow-up letter sent on October 31, 2014 from Nann Winter on behalf of ABCWUA. Given this feedback, PNM and ABCWUA worked cooperatively to develop in good faith a jointly supported methodology to adjust the Rate 11B CP demands. What follows is a description of development of the jointly supported methodology and the results of that methodology. This new methodology is referred to as the "Shifting All Hours Case".

1. As background, for this rate case PNM will propose a change to its TOU peak period, which shifts the peak period by two hours from 8 AM to 8 PM to a proposed 10 AM to 10 PM Monday through Friday.[1]

2. To adjust CP demand, all of the hourly Rate 11B load information for the Base Year[2] was shifted so that the class now appears to operate on the proposed TOU peak period of 10 AM to 10 PM Monday through Friday.

3. Using the shifted hourly loads, CP loads were then pulled for the Base Year's date and time of each monthly system CP.

4. If a CP for a month occurred during a weekend, that CP load was adjusted down to the value of the nearest proposed on-peak hour.[3]

To demonstrate the results of the shifting described above, PNM has attached to this letter a series of 14 pages of tables or graphs that compare and contrast the Partial Shifting Case and the Shifting All Hours Case, depict the overall load shape for 11B customers and show peak days and/or peak times for this rate class using shifted hourly data for each month of the Base Year These 14 pages were circulated to ABCWUA on November 13, 2014 and are summarized in the first page of the attachment called "Summary of 11B Coincident Peak Load Comparisons by Month."[4]

Pages 3-14 of the attachment also have an indexed value of PNM's hourly System Load for each of the 12 monthly peak days. As illustrated by the attached documents, both the Partial Shifting Case and the Shifting All Hours Case produce fairly similar results. However, after cooperative discussions between PNM and ABCWUA, we came to a joint agreement that the Shifting All Hours Case best captured the intent of Paragraph 39 of the Amended Stipulation to Conform to Commission Order ("Amended Stipulation") from PNM's last general rate case (NMPRC Case No. 10-00086-UT) for the following reasons:

1. A two-hour shift in PNM's TOU hours will result in Rate 11B customers shifting their operations in order to take maximum cost advantage of the TOU hours change.

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[1] More specifically, the proposed shift of the TOU peak period is as follows: from the current TOU period of 8 AM to 8 PM, Monday through Friday (60 hours per Week) to a proposed TOU period of 10 AM to10 PM, Monday through Friday (60 hours per Week). A meeting was held May 9, 2012 with customers and letters were sent to customers on May 31, 2012 and July 1, 2014 informing them of the new TOU periods to be proposed in PNM's next rate case.

[2] The Base Year began on 7/1/2013 (Hour Ending 01:00) and ended on through 6/30/2014 (Hour Ending 24:00).

[3] The Partial Shifting Case also used this same approach.

[4] A few textual edits have been made to the graphs originally sent for clean-up purposes only.

2. The method is simple to calculate and also fully comports to the Rate 11B historical response to PNM TOU price signals.

3. The method results in adjustments to CP demands during both on peak and off peak hours.

Although the Shifting All Hours Case does result in either increased or decreased adjustments to the monthly Rate 11B CP loads across the Base Year, this methodology results in a 17% reduction to CP demands overall. The resulting 17% reduction to CP demands will reduce the Rate 11B customers' allocation of Generation and Transmission plant revenue allocation in PNM's upcoming case. For the foregoing reasons and given the agreement with Rate 11B customers, PNM plans to use the methodology described in this letter for revenue allocation for Rate 11B in its upcoming rate case filing.

If you have any questions concerning the details underlying this analysis, please feel free to contact me at (505) 241-4542 or Stella.Chan@pnmresources.com.

Public Service Company of New Mexico

Stella Chan, Director
Pricing and Load Research

Encloser

Electronic Cc: Jody Garcia - JGarcia@stelznerlaw.com
Dahl Harris - dahlharris@hotmail.com
Jim Dittmer - jdittmer@utilitech.net
Joe Herz - jaherz@sawvel.com

GCG#518892

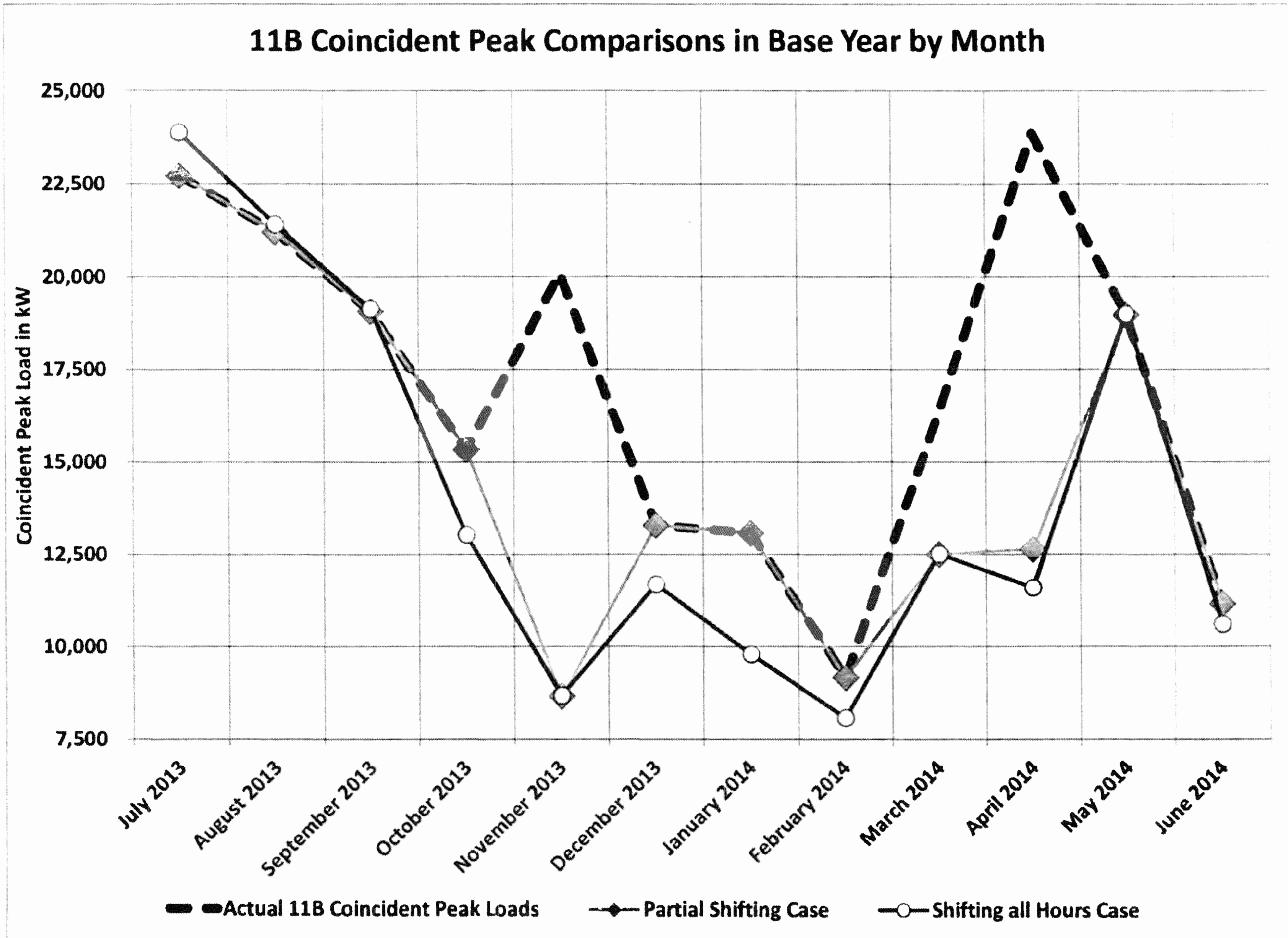
Summary of 11B Coincident Peak Load Comparisons by Month

Date (Day of Week at Local Clock Hour)	Actual 11B Coincident Peak Loads	Partial Shifting Case	Shifting all Hours Case
Jul 10, 2013 (Wed at 17:00)	22,728	22,728	**23,882**
Aug 19, 2013 (Mon at 16:00)	21,218	21,218	**21,409**
Sep 03, 2013 (Tue at 17:00)	19,066	19,066	**19,127**
Oct 01, 2013 (Tue at 20:00)	15,340	15,340	*13,021*
Nov 24, 2013 (Sun at 19:00)	20,094	*8,668*	*8,668*
Dec 09, 2013 (Mon at 19:00)	13,286	13,286	*11,671*
Jan 23, 2014 (Thu at 19:00)	13,076	13,076	*9,779*
Feb 05, 2014 (Wed at 19:00)	9,169	9,169	*8,071*
Mar 01, 2014 (Sat at 19:00)	16,337	*12,504*	*12,504*
Apr 22, 2014 (Tue at 21:00)	23,881	*12,646*	*11,579*
May 28, 2014 (Wed at 17:00)	18,966	18,966	**18,981**
Jun 30, 2014 (Mon at 17:00)	11,164	11,164	*10,590*
Totals for Base Year	204,326	*177,832*	*169,281*

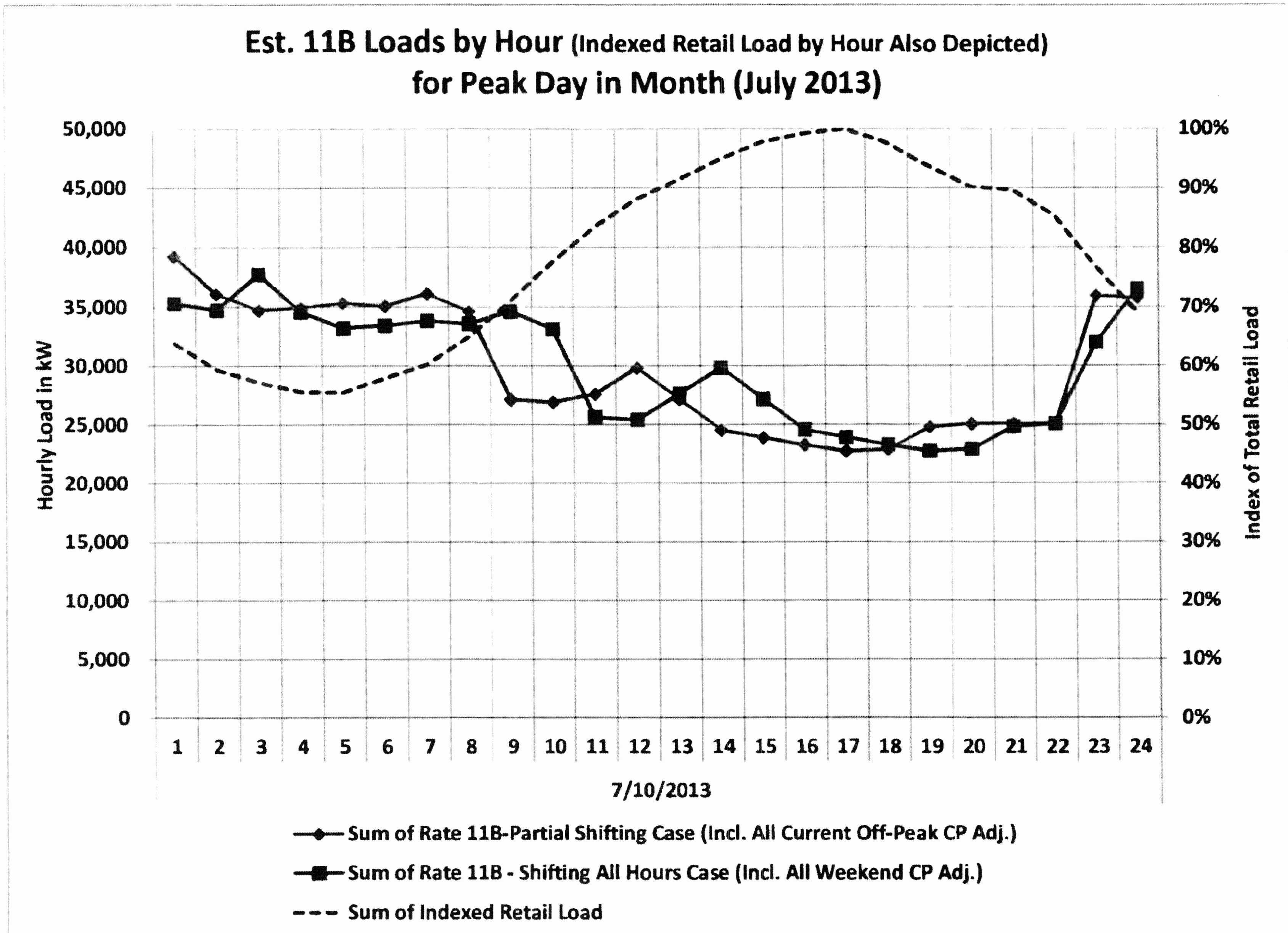
Legend

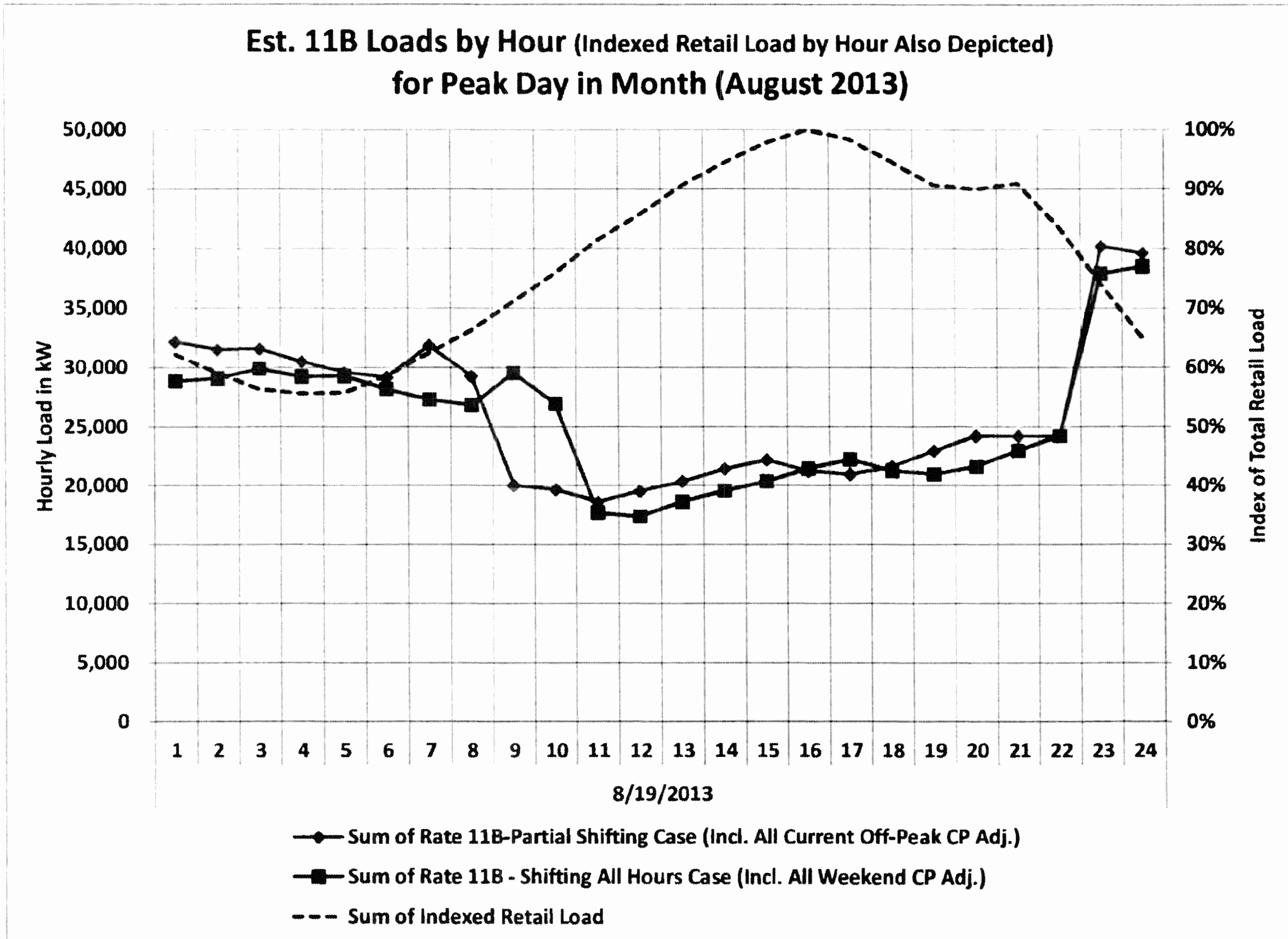
Lower Than Actual 11B Coincident Peak Loads

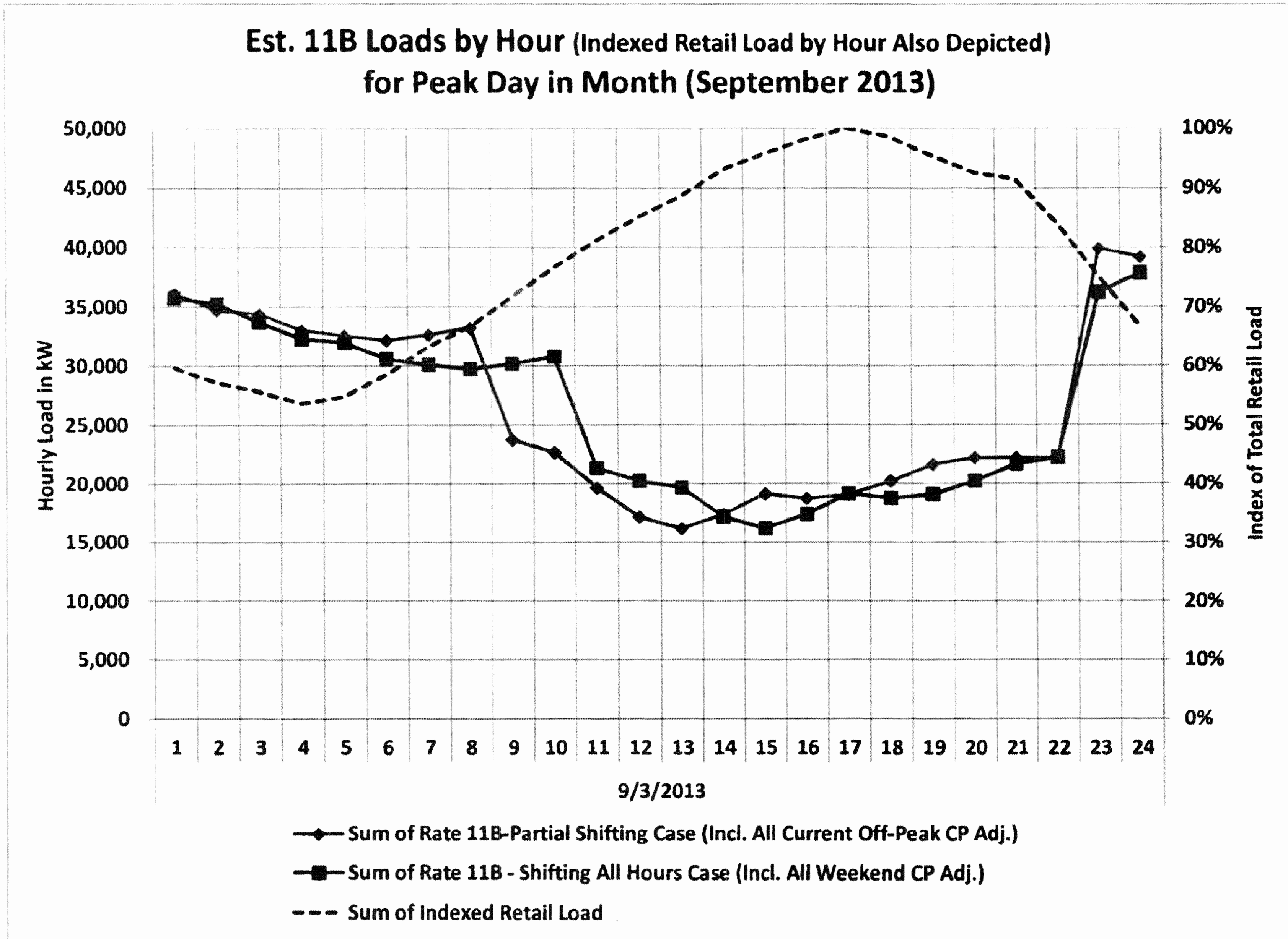
Higher Than Actual 11B Coincident Peak Loads

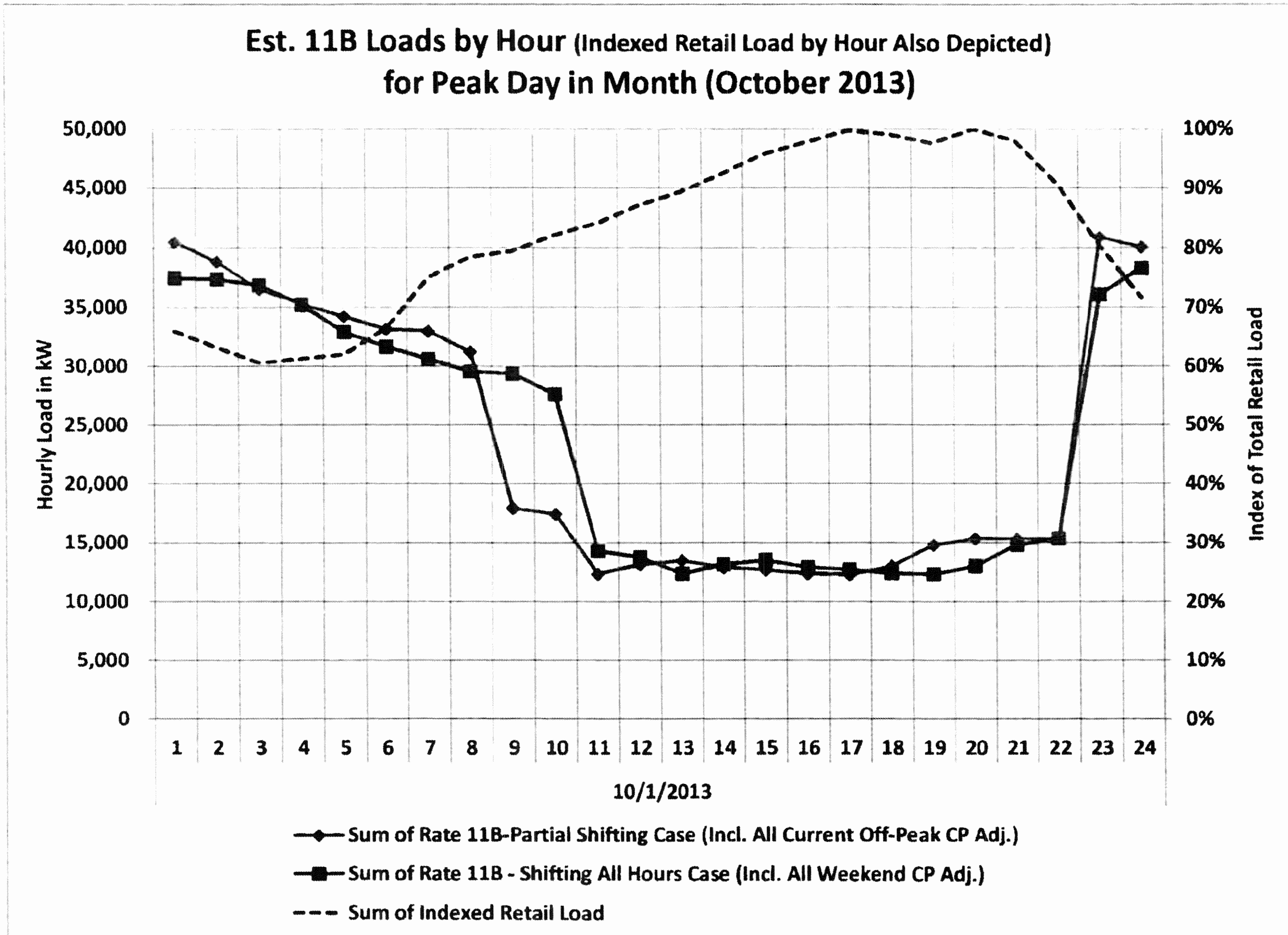


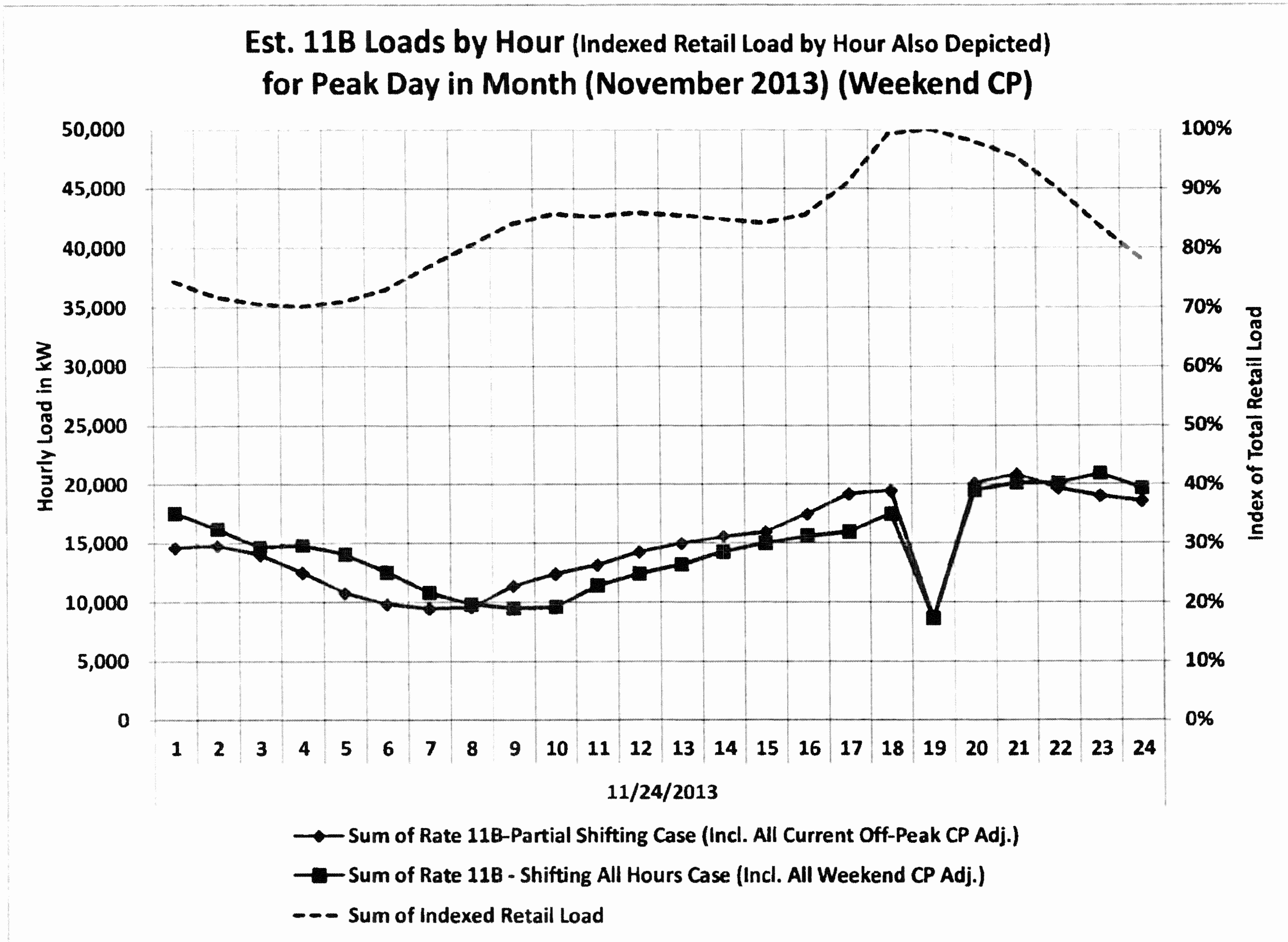
11B Coincident Peak Comparisons in Base Year by Month
Coincident Peak Load in kW
25,000
22,500
20,000
17,500
15,000
12,500
10,000
7,500
July 2013
August 2013
September 2013
October 2013
November 2013
December 2013
January 2014
February 2014
March 2014
April 2014
May 2014
June 2014
Actual 11B Coincident Peak Loads
Partial Shifting Case
Shifting all Hours Case


Est. 11B Loads by Hour (Indexed Retail Load by Hour Also Depicted)
for Peak Day in Month (July 2013)
Hourly Load in kW
Index of Total Retail Load
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
7/10/2013
Sum of Rate 11B-Partial Shifting Case (Incl. All Current Off-Peak CP Adj.)
Sum of Rate 11B - Shifting All Hours Case (Incl. All Weekend CP Adj.)
Sum of Indexed Retail Load

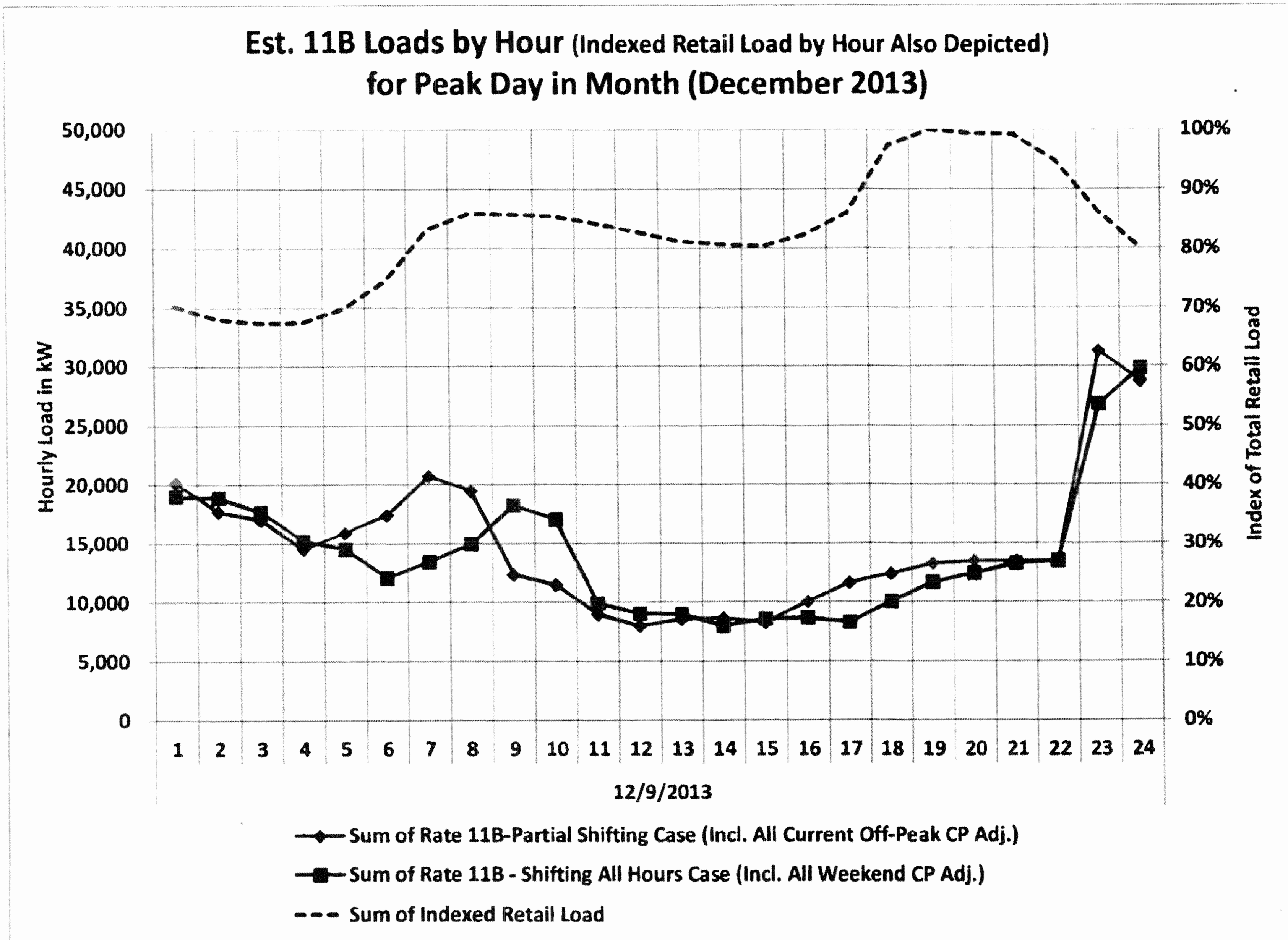

Est. 11B Loads by Hour (Indexed Retail Load by Hour Also Depicted)
for Peak Day in Month (August 2013)
Hourly Load in kW
Index of Total Retail Load
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
8/19/2013
Sum of Rate 11B-Partial Shifting Case (Incl. All Current Off-Peak CP Adj.)
Sum of Rate 11B - Shifting All Hours Case (Incl. All Weekend CP Adj.)
Sum of Indexed Retail Load


Est. 11B Loads by Hour (Indexed Retail Load by Hour Also Depicted)
for Peak Day in Month (September 2013)
Hourly Load in kW
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Index of Total Retail Load
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
9/3/2013
Sum of Rate 11B-Partial Shifting Case (Incl. All Current Off-Peak CP Adj.)
Sum of Rate 11B - Shifting All Hours Case (Incl. All Weekend CP Adj.)
Sum of Indexed Retail Load


Est. 11B Loads by Hour (Indexed Retail Load by Hour Also Depicted)
for Peak Day in Month (October 2013)
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Hourly Load in kW
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Index of Total Retail Load
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
10/1/2013
Sum of Rate 11B-Partial Shifting Case (Incl. All Current Off-Peak CP Adj.)
Sum of Rate 11B - Shifting All Hours Case (Incl. All Weekend CP Adj.)
Sum of Indexed Retail Load



Est. 11B Loads by Hour (Indexed Retail Load by Hour Also Depicted)
for Peak Day in Month (November 2013) (Weekend CP)
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Hourly Load in kW
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Index of Total Retail Load
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
11/24/2013
Sum of Rate 11B-Partial Shifting Case (Incl. All Current Off-Peak CP Adj.)
Sum of Rate 11B - Shifting All Hours Case (Incl. All Weekend CP Adj.)
Sum of Indexed Retail Load



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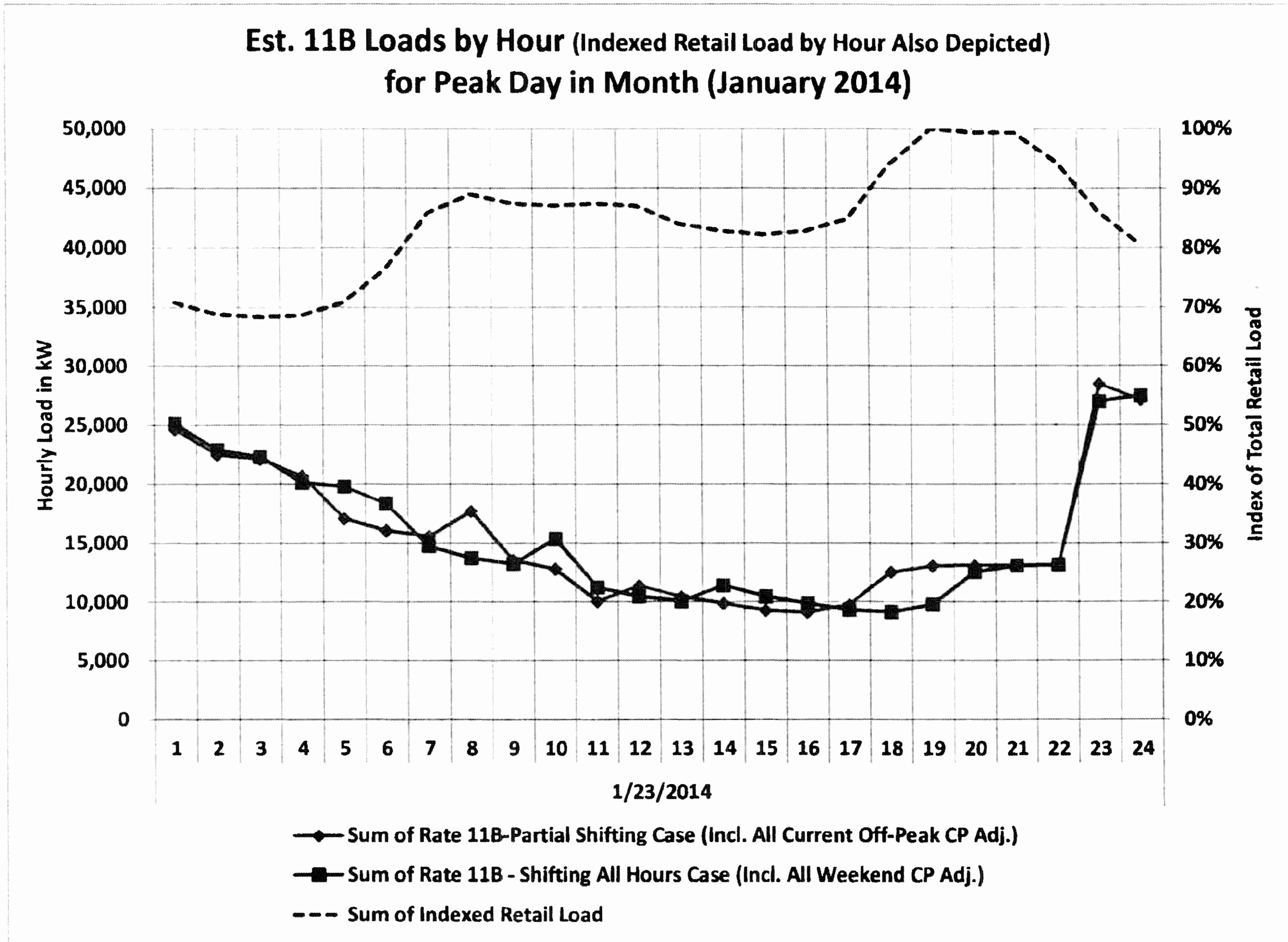
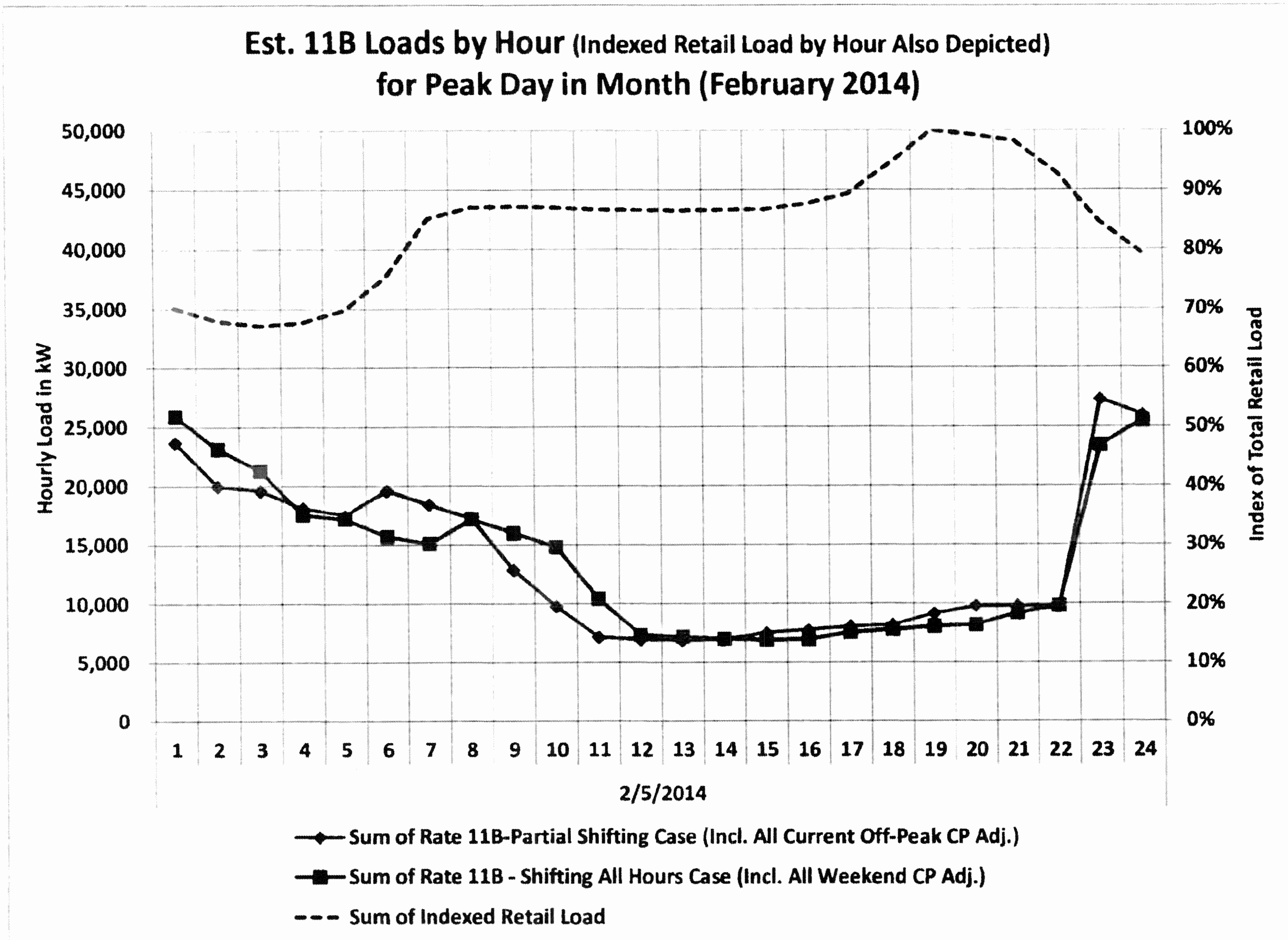
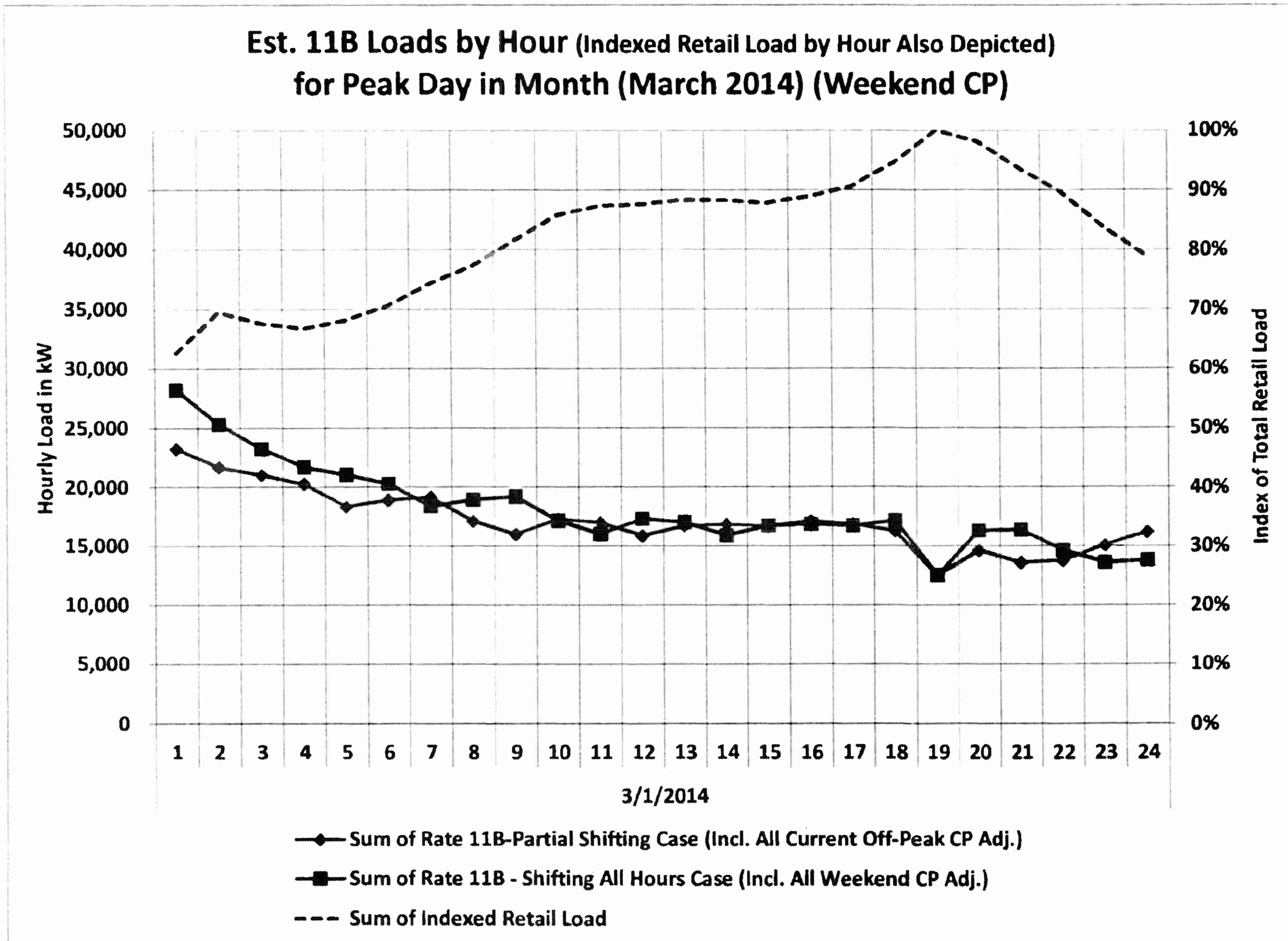
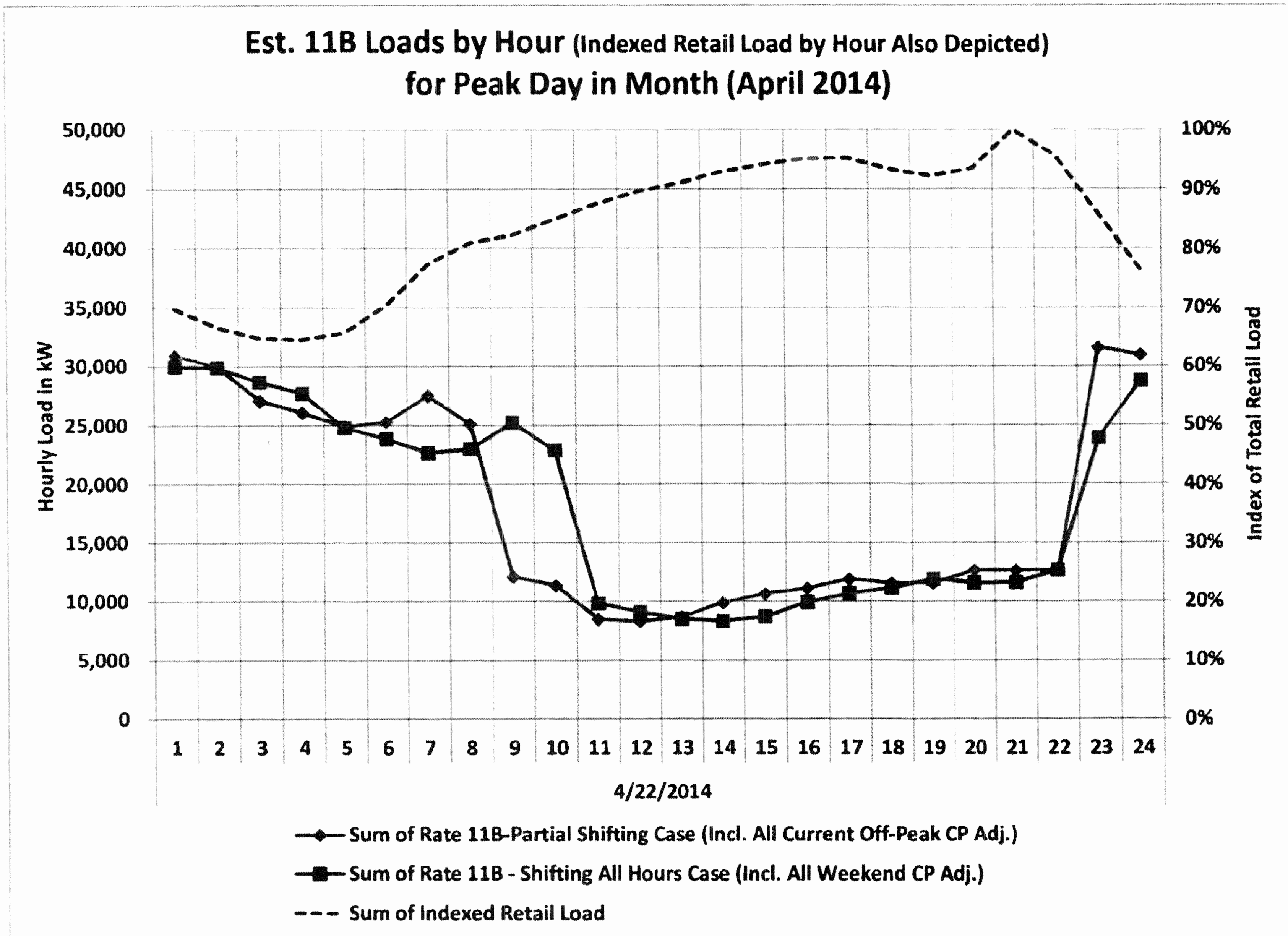

Est. 11B Loads by Hour (Indexed Retail Load by Hour Also Depicted)
for Peak Day in Month (January 2014)
Hourly Load in kW
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Index of Total Retail Load
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
1/23/2014
Sum of Rate 11B-Partial Shifting Case (Incl. All Current Off-Peak CP Adj.)
Sum of Rate 11B - Shifting All Hours Case (Incl. All Weekend CP Adj.)
Sum of Indexed Retail Load



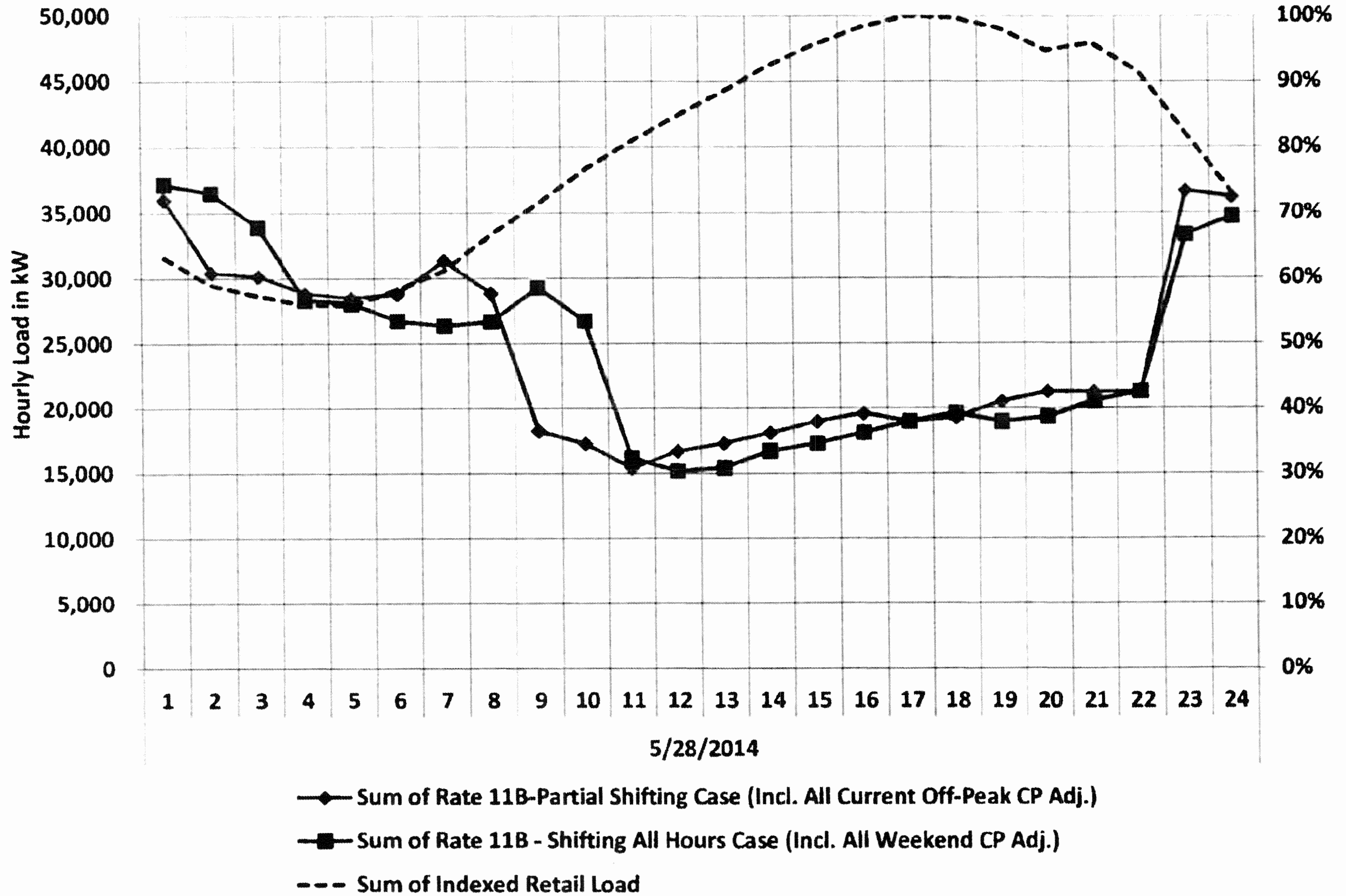
Est. 11B Loads by Hour (Indexed Retail Load by Hour Also Depicted)
for Peak Day in Month (February 2014)
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Hourly Load in kW
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Index of Total Retail Load
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
2/5/2014
Sum of Rate 11B-Partial Shifting Case (Incl. All Current Off-Peak CP Adj.)
Sum of Rate 11B - Shifting All Hours Case (Incl. All Weekend CP Adj.)
Sum of Indexed Retail Load

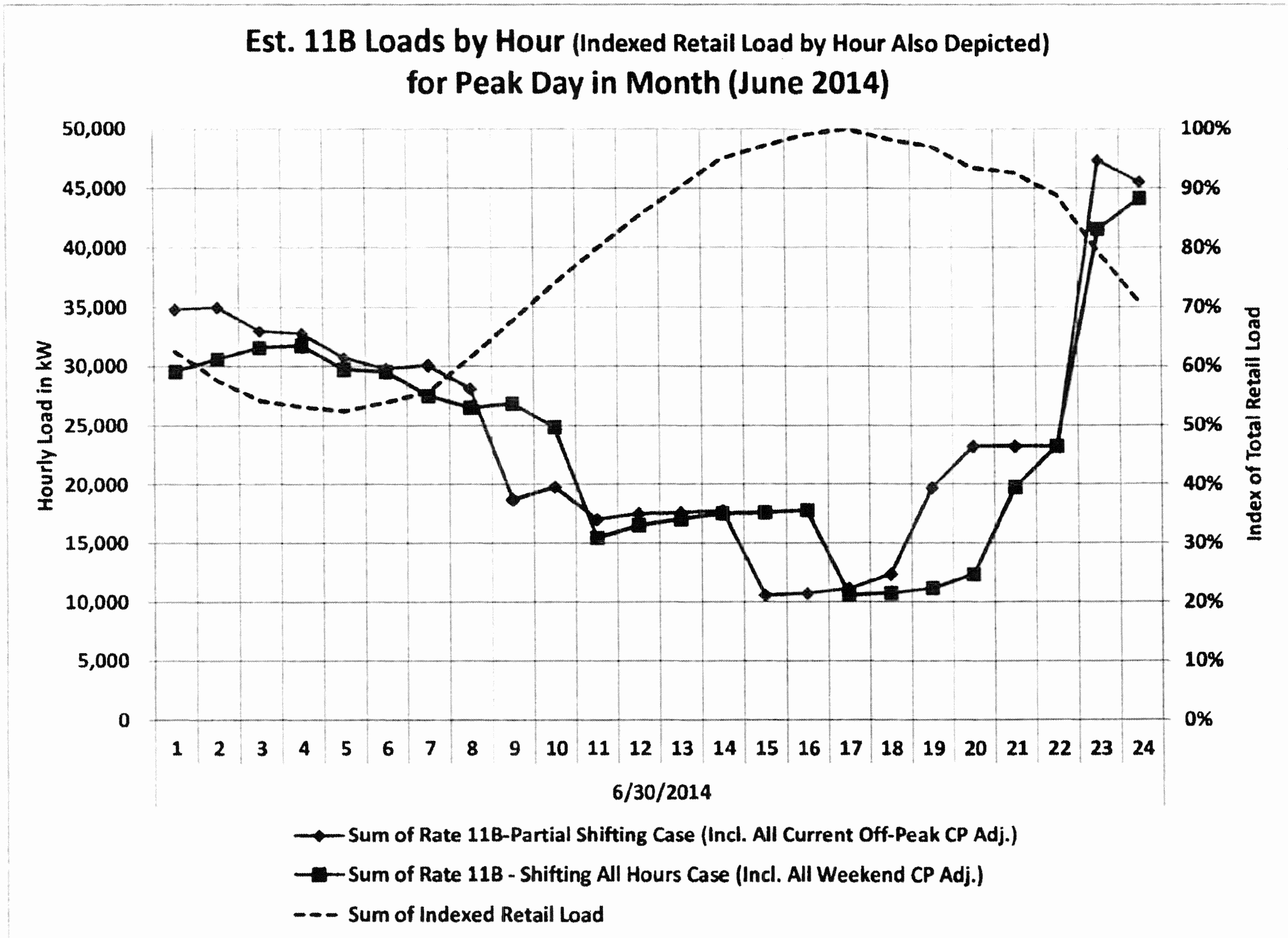

Est. 11B Loads by Hour (Indexed Retail Load by Hour Also Depicted)
for Peak Day in Month (March 2014) (Weekend CP)
Hourly Load in kW
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Index of Total Retail Load
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
3/1/2014
Sum of Rate 11B-Partial Shifting Case (Incl. All Current Off-Peak CP Adj.)
Sum of Rate 11B - Shifting All Hours Case (Incl. All Weekend CP Adj.)
Sum of Indexed Retail Load



Est. 11B Loads by Hour (Indexed Retail Load by Hour Also Depicted)
for Peak Day in Month (April 2014)
Hourly Load in kW
Index of Total Retail Load
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
4/22/2014
Sum of Rate 11B-Partial Shifting Case (Incl. All Current Off-Peak CP Adj.)
Sum of Rate 11B - Shifting All Hours Case (Incl. All Weekend CP Adj.)
Sum of Indexed Retail Load

Est. 11B Loads by Hour (Indexed Retail Load by Hour Also Depicted) for Peak Day in Month (May 2014)




Est. 11B Loads by Hour (Indexed Retail Load by Hour Also Depicted)
for Peak Day in Month (June 2014)
Hourly Load in kW
Index of Total Retail Load
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
6/30/2014
Sum of Rate 11B-Partial Shifting Case (Incl. All Current Off-Peak CP Adj.)
Sum of Rate 11B - Shifting All Hours Case (Incl. All Weekend CP Adj.)
Sum of Indexed Retail Load

The final revenue allocation to each customer class before and after banding.

PNM Exhibit SC-6

Is contained in the following 2 pages.

PUBLIC SERVICE COMPANY OF NEW MEXICO

PNM CONSOLIDATED CUSTOMER CLASS COST OF SERVICE STUDY-
BANDING
NMPRC CASE NO. 14-00332-UT

	A	B	C	D	E	F	G	H	I	J	K	L
Line			Total PNM North	Schedule 1A/1B	Schedule 2A/2B	Schedule 3B/3C	Schedule 4B	Schedule 5B	Schedule 10A/10B	Schedule 11B	Schedule 15	Schedule 30
No	Description		Jurisdiction	Res. 1A/1B	Small Power 2A/2B	General Power 3B/3C	Large Power 4B	Large Service>= 8,000kW 5B	Irrigation 10A/10B	Water & Sewage 11B	Universities 15B	Manuf. 30B
1	Revenues at Existing Rates (Non-Fuel)		$ 650,592,054	$ 299,492,887	$ 90,534,590	$ 139,788,699	$ 65,514,807	$ 4,335,819	$ 1,749,608	$ 8,144,654	$ 3,451,423	$ 18,385,399
2	Revenues at Existing Rates (Fuel)		$ 176,877,288	$ 68,540,800	$ 19,384,734	$ 41,233,515	$ 23,944,266	$ 1,786,418	$ 551,021	$ 3,540,734	$ 1,409,443	$ 10,077,915
3	Total Revenues at Existing Base Rates	L1+L2	$ 827,469,342	$ 368,033,687	$ 109,919,325	$ 181,022,214	$ 89,459,072	$ 6,122,237	$ 2,300,628	$ 11,685,388	$ 4,860,866	$ 28,463,314
4												
5	Base Fuel at Existing Rates + FPPCAC		$ 225,283,207	$ 87,298,531	$ 24,689,803	$ 52,517,994	$ 30,496,635	$ 2,275,328	$ 701,820	$ 4,509,659	$ 1,795,118	$ 12,836,032
6	Total Revenue at Existing Rates + FPPCAC	L1+L5	$ 875,875,261	$ 386,791,418	$ 115,224,393	$ 192,306,692	$ 96,011,442	$ 6,611,147	$ 2,451,428	$ 12,654,313	$ 5,246,541	$ 31,221,431
7												
8	Proposed Revenue Requirements (Non-Fuel) at Full Cost of Service		$ 765,056,912	$ 372,530,777	$ 106,563,891	$ 145,438,853	$ 77,609,205	$ 4,917,853	$ 2,563,176	$ 8,936,452	$ 3,713,210	$ 23,031,853
9	Proposed Revenue Requirements (Base Fuel) at Full Cost of Service		$ 218,259,746	$ 84,752,926	$ 23,969,854	$ 50,986,581	$ 29,341,119	$ 2,195,195	$ 681,355	$ 4,338,788	$ 1,731,153	$ 12,379,342
10	***Total Revenue Requirements at Full Cost of Service***	***L8+L9***	***$ 983,316,658***	***$ 457,283,703***	***$ 130,533,745***	***$ 196,425,435***	***$ 106,950,324***	***$ 7,113,048***	***$ 3,244,531***	***$ 13,275,240***	***$ 5,444,364***	***$ 35,411,195***
11												
12	Total Non-Fuel Revenue Deficiency Under Equalized ROR	L8-L1	$ 114,464,858	$ 73,037,890	$ 16,029,301	$ 5,650,154	$ 12,094,398	$ 582,034	$ 813,568	$ 791,798	$ 261,787	$ 4,646,454
13	% Increase (at Full Cost of Service)	L12/L6	13.07%	18.88%	13.91%	2.94%	12.60%	8.80%	33.19%	6.26%	4.99%	14.88%
14												
15	Minimum Band	0%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
16	Maximum Band	130%	16.97%	16.97%	16.97%	16.97%	16.97%	16.97%	16.97%	16.97%	16.97%	16.97%
17												
18	% Increase at Band		13.07%	16.97%	13.91%	2.94%	12.60%	8.80%	16.97%	6.26%	4.99%	14.88%
19	Banded Revenue Max	L1*(1+L16)		$ 452,429,921	$ 134,777,973	$ 224,941,138	$ 112,304,583	$ 7,733,059	$ 2,867,435	$ 14,801,750	$ 6,136,879	$ 36,519,708
20	Banded Revenue Min	L1*(1+L15)		$ 386,791,418	$ 115,224,393	$ 192,306,692	$ 96,011,442	$ 6,611,147	$ 2,451,428	$ 12,654,313	$ 5,246,541	$ 31,221,431
21												
22												
23	**Non-Fuel Revenue Requirement Banding Process**											
24	1st Revenue Allocation		$ 0	$ -	$ -	$ 4,065,460	$ -	$ -	$ -	$ -	$ -	$ (4,646,454)
25	Revenue Requirements after 1st Allocation		$ 983,316,658	$ 457,283,703	$ 130,533,745	$ 200,490,894	$ 106,950,324	$ 7,113,048	$ 3,244,531	$ 13,275,240	$ 5,444,364	$ 30,764,741
26	% Increase after 1st Allocation		13.07%	18.88%	13.91%	5.05%	12.60%	8.80%	33.19%	6.26%	4.99%	0.00%
27												
28	2nd Revenue Allocation		$ -	$ (7,300,000)	$ -	$ 7,696,765	$ -	$ -	$ (396,765)	$ -	$ -	$ -
29	Revenue Requirments after 3rd Allocation		$ 983,316,658	$ 449,983,703	$ 130,533,745	$ 208,187,659	$ 106,950,324	$ 7,113,048	$ 2,847,766	$ 13,275,240	$ 5,444,364	$ 30,764,741
30	% Increase after 3rd Allocation		13.07%	17.00%	13.91%	9.05%	12.60%	8.80%	17.00%	6.26%	4.99%	0.00%
31												
32	Final Non-Fuel Revenue Defficiency after Banding	L12 (Banded)	$ 114,464,858	$ 65,737,890	$ 16,029,301	$ 17,412,379	$ 12,094,398	$ 582,034	$ 416,803	$ 791,798	$ 261,787	$ -
33												
34	***Total Revenue Requirement (With Banding)***	***L1+L9+ L32***	***$ 983,316,658***	***$ 449,983,703***	***$ 130,533,745***	***$ 208,187,659***	***$ 106,950,324***	***$ 7,113,048***	***$ 2,847,766***	***$ 13,275,240***	***$ 5,444,364***	***$ 30,764,741***
35	% Non-Fuel Revenue Increase after Banding	L32/L6	13.07%	17.00%	13.91%	9.05%	12.60%	8.80%	17.00%	6.26%	4.99%	0.00%
36												
37	**Defficiency Summary**											
38	Non-Fuel Defficiency (As Requested)	L12	$ 114,464,858									
39	Fuel Defficiency (As Requested)	L5-L9	$ (7,023,461)									
40	Rate Defficiency (As Requested	L38+L39	$ 107,441,397									
41												
42	Rate Defficiency Percent Increase	L40/L6	12.27%									

PUBLIC SERVICE COMPANY OF NEW MEXICO

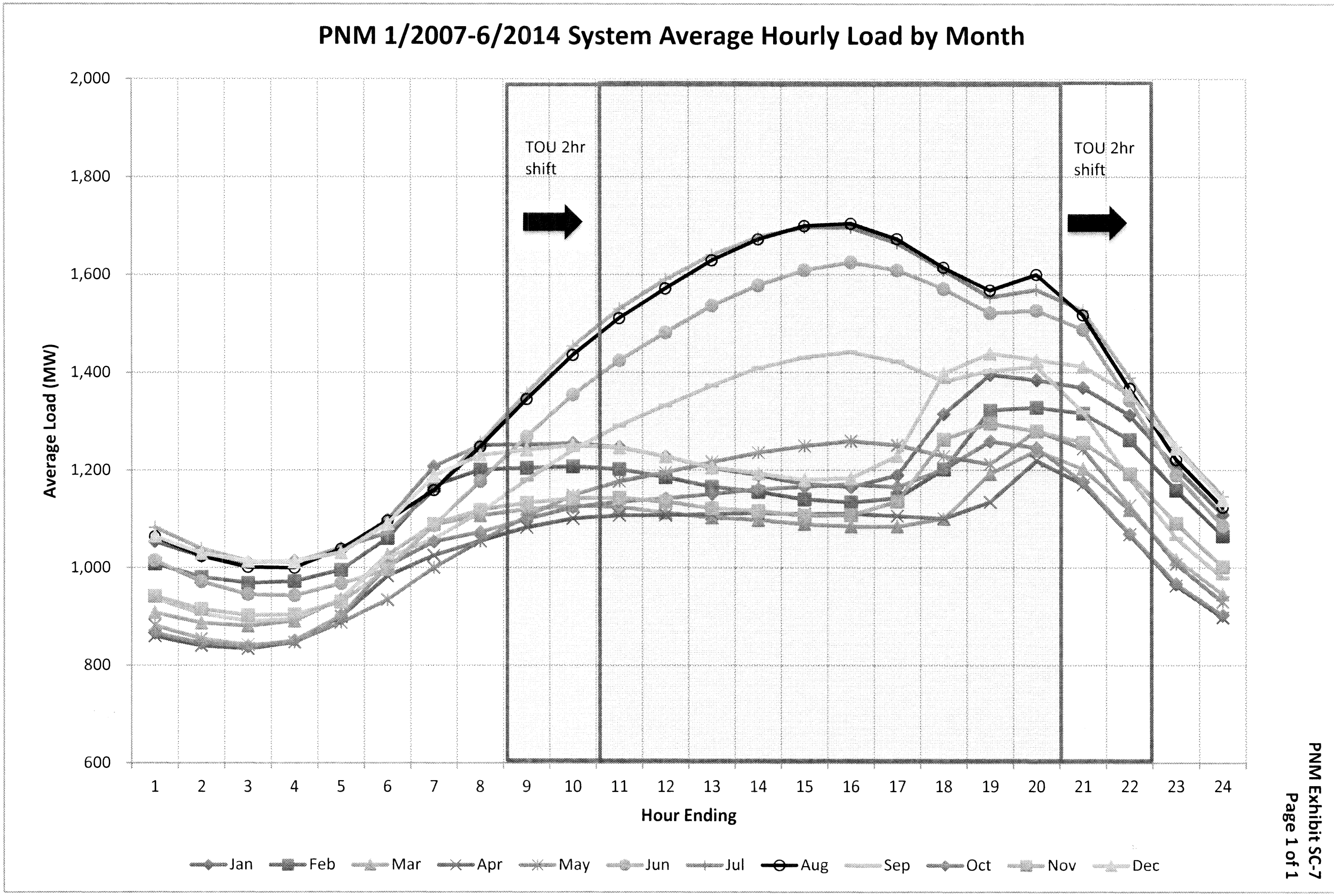
PNM CONSOLIDATED CUSTOMER CLASS COST OF SERVICE STUDY-
BANDING
NMPRC CASE NO. 14-00332-UT

Line	A	B	C	M	N	O	P
			Total PNM North	Schedule 33B	Schedule 34B	Schedule 6	Schedule 20
					Large Power Service		
No	Description		Jurisdiction	Station Power 33B	>=3,000kW 34B	Private Lighting 6	Street Lighting 20
1	Revenues at Existing Rates (Non-Fuel)		$ 650,592,054	$ 152,345	$ 9,909,708	$ 2,632,879	$ 6,499,237
2	Revenues at Existing Rates (Fuel)		$ 176,877,288	$ 67,325	$ 4,928,213	$ 345,138	$ 1,067,766
3	Total Revenues at Existing Base Rates	L1+L2	$ 827,469,342	$ 219,669	$ 14,837,921	$ 2,978,017	$ 7,567,003
4							
5	Base Fuel at Existing Rates + FPPCAC		$ 225,283,207	$ 85,747	$ 6,276,963	$ 439,593	$ 1,359,984
6	Total Revenue at Existing Rates + FPPCAC	L1+L5	$ 875,875,261	$ 238,092	$ 16,186,671	$ 3,072,472	$ 7,859,221
7							
8	Proposed Revenue Requirements (Non-Fuel) at Full Cost of Service		$ 765,056,912	$ 104,311	$ 10,201,485	$ 2,099,918	$ 7,345,928
9	Proposed Revenue Requirements (Base Fuel) at Full Cost of Service		$ 218,259,746	$ 82,692	$ 6,053,637	$ 426,775	$ 1,320,328
10	***Total Revenue Requirements at Full Cost of Service***	***L8+L9***	***$ 983,316,658***	***$ 187,003***	***$ 16,255,122***	***$ 2,526,693***	***$ 8,666,255***
11							
12	Total Non-Fuel Revenue Deficiency Under Equalized ROR	L8-L1	$ 114,464,858	$ (48,034)	$ 291,778	$ (532,961)	846,690
13	% Increase (at Full Cost of Service)	L12/L6	13.07%	-20.17%	1.80%	-17.35%	10.77%
14							
15	Minimum Band	0%	0.00%	0.00%	0.00%	0.00%	0.00%
16	Maximum Band	130%	16.97%	16.97%	16.97%	16.97%	16.97%
17							
18	% Increase at Band		13.07%	0.00%	1.80%	0.00%	10.77%
19	Banded Revenue Max	L1*(1+L16)		$ 278,496	$ 18,933,549	$ 3,593,871	$ 9,192,931
20	Banded Revenue Min	L1*(1+L15)		$ 238,092	$ 16,186,671	$ 3,072,472	$ 7,859,221
21							
22							
23	**Non-Fuel Revenue Requirement Banding Process**						
24	1st Revenue Allocation		$ 0	$ 48,034	$ -	$ 532,961	$ -
25	Revenue Requirements after 1st Allocation		$ 983,316,658	$ 235,037	$ 16,255,122	$ 3,059,654	$ 8,666,255
26	% Increase after 1st Allocation		13.07%	0.00%	1.80%	0.00%	10.77%
27							
28	2nd Revenue Allocation		$ -	$ -	$ -	$ -	$ -
29	Revenue Requirments after 3rd Allocation		$ 983,316,658	$ 235,037	$ 16,255,122	$ 3,059,654	$ 8,666,255
30	% Increase after 3rd Allocation		13.07%	0.00%	1.80%	0.00%	10.77%
31							
32	Final Non-Fuel Revenue Defficiency after Banding	L12 (Banded)	$ 114,464,858	$ -	$ 291,778	$ -	$ 846,690
33							
34	***Total Revenue Requirement (With Banding)***	***L1+L9+ L32***	***$ 983,316,658***	***$ 235,037***	***$ 16,255,122***	***$ 3,059,654***	***$ 8,666,255***
35	% Non-Fuel Revenue Increase after Banding	L32/L6	13.07%	0.00%	1.80%	0.00%	10.77%
36							
37	**Defficiency Summary**						
38	Non-Fuel Defficiency (As Requested)	L12	$ 114,464,858				
39	Fuel Defficiency (As Requested)	L5-L9	$ (7,023,461)				
40	Rate Defficiency (As Requested	L38+L39	$ 107,441,397				
41							
42	Rate Defficiency Percent Increase	L40/L6	12.27%				

Historical hourly peak occurrences since 2007.

PNM Exhibit SC-7

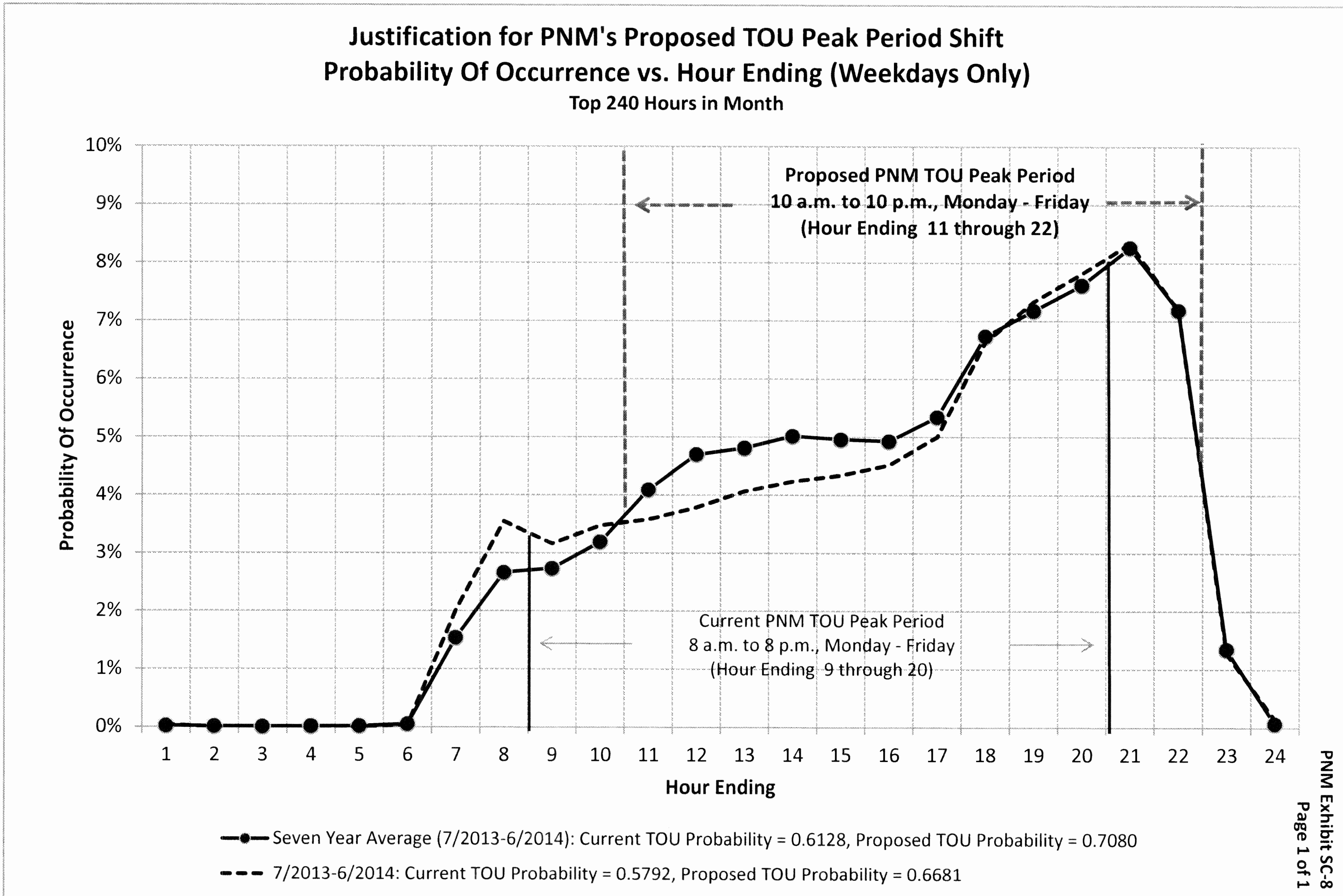
Is contained in the following page.


PNM 1/2007-6/2014 System Average Hourly Load by Month
Average Load (MW)
2,000
1,800
1,600
1,400
1,200
1,000
800
600
TOU 2hr shift
TOU 2hr shift
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour Ending
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec

A graph demonstrating the probability that PNM's peak period will occur outside of the current Time of Use pricing period of 8 AM to 8 PM.

PNM Exhibit SC-8

Is contained in the following page.



PNM Exhibit SC-8
Page 1 of 1

Copies of two letters sent by PNM in 2012 and 2014 to customers in compliance with Paragraphs 28(E) and 28(F) regarding proposed changes to the seasonal periods and the TOU pricing periods.

PNM Exhibit SC-9

Is contained in the following 3 pages.

PNM
Main Offices
Albuquerque, NM 87158-1105
PNM.com

July 1, 2014

[Name]
[Company]
[Address]
[City, State, Zip]

Dear [Customer],

As part of the Amended Stipulation in our last electric retail rate case (Case No. 10-00086-UT), PNM agreed to provide six months notice to customers in electric rate class 48 (Large Power), 118 (Water & Sewage Pumping) and 308 (Large Manufacturing >30 MW) before proposing changes on two electric rate design topics:

- The definitions of seasonal periods (Subparagraph 28(e) of the Amended Stipulation), and
- The time of use (TOU) on-peak and off-peak periods (Subparagraph 28(f) of the Amended Stipulation).

On May 9, 2012, in anticipation of submitting a general rate application, PNM discussed these rate design topics with customers in these rate classes at a meeting in Albuquerque and by telephone. After consideration of the comments of the participants and a review of relevant data, PNM sent a letter on May 31, 2012 to affected customers, the participants in the meeting, and the parties to the last PNM rate case advising that PNM intended to address the rate design matters mentioned above in its next rate case in the following way:

1. **Seasonal Periods.** PNM will not propose changes to the seasonal periods. The "Summer" season will continue to be June through August. All other months (September through May) will continue to be "Non-Summer" months.
2. **TOU on-peak and off-peak periods.** PNM will propose changes to the TOU on-peak and off-peak periods. The proposed On-Peak Hours will be 10 AM to 10 PM, Monday through Friday and the proposed Off-Peak Hours will include all other hours. (TOU on-peak times currently run from 8 AM to 8 PM weekdays). This proposed time period better reflects existing load characteristics. Under this proposal, there will continue to be 60 on-peak hours each week.

A copy of the May 31, 2012, letter is attached. PNM's intentions as expressed in that letter have not changed.

Please contact your PNM Account Manager or call (505) 241-4413 with any questions you may have about this information.

Sincerely,

Gerard Ortiz
Vice President, PNM Regulatory Affairs

Attachment

PNM
Main Offices
Albuquerque, NM 87158
PNM.com

May 31, 2012

RE: Notice of proposed actions regarding Seasonal and Time-of -Use Rates

Dear Customers,

This letter is a follow-up to (a) the discussions held on May 9, 2012, in Albuquerque with customers in PNM's rate classes 4B (Large Power), 11B (Water & Sewage Pumping) and 30B (Large Manufacturing >30 MW), and (b) our email to those customers on May 10, 2012, in which we provided materials that were requested during the customer meeting. We are sending this letter to customers in rate classes 4B, 11B and 30B, those in attendance at that meeting and the parties from the last PNM electric rate case. We are also posting the letter on the PNM website to make it available to all customers.

As we stated in our earlier communications, under the Amended Stipulation in our last rate case (Case No. 10-00086-UT), PNM agreed to communicate with specific customer groups and to provide notice to customers prior to proposing changes on two topics regarding rate design:

- The definitions of seasonal periods (addressed in Subparagraph 28(e) of the Amended Stipulation), and
- The time of use (TOU) on-peak and off-peak periods (addressed in Subparagraph 28(f) of the Amended Stipulation).

Based on our review of the relevant data, the comments made by various customers and their representatives at the customer meeting, and the other comments that have been received, PNM plans to reflect the following positions in its next general rate application before the New Mexico Public Regulation Commission.

1. **Seasonal Periods**. For seasonal rates, PNM will not propose changes at this time. The "Summer" season proposed by the Company will continue to be June through August. All other months (September through May) will continue to be "Non-Summer" months.
2. **TOU on-peak and off-peak periods**. For TOU rates, PNM will propose changes. The TOU periods proposed by the Company will utilize On-Peak Hours of 10 AM to 10 PM, Monday through Friday; Proposed Off-Peak Hours will include all other hours. This proposal would shift the start and end of the on-peak TOU period two hours later in each weekday (TOU on-peak times currently run from 8 AM to 8 PM weekdays). This proposed time period better reflects existing load characteristics. Under this proposal, there will continue to be 60 on-peak hours each week.

Please be aware that this proposal would not be effective until approved by the Public Regulation Commission in the rate case. Consequently, this letter and the proposed changes described in it have no immediate effect on the on-peak time periods or other aspects of PNM's rates.

Customers' comments and participation in this process have been, and continue to be, very much appreciated. Thank you.

Sincerely,

Gerard Ortiz
Executive Director, New Mexico Retail Regulatory Services

GCG#514470

A comparison of the current and proposed non-volumetric charges by rate schedule.

PNM Exhibit SC-10

Is contained in the following page.

Comparison of Non-Volumetric Retail Rates: Current vs. Proposed

Current Non-Volumetric Rates-SUMMARY

Schedule	Class	Rate	Customer Charge	Customer Charge-Summer	Customer Charge-Non Summer	Meter Charge	Demand Rate Summer	Demand Rate Non-Summer
Schedule 1	*Residential*							
	Residential	1A	$ 5.00					
	Residential	1B	$ 20.81			$ 5.29		
Schedule 2	*Small Power*							
	Small Power	2A	$ 8.46					
	Small Power	2B	$ 13.65			$ 5.40		
Schedule 3	*General Power*							
	General Power High Load Factor	3B Primary		$ 857.00	$ 638.50		$ 17.14	$ 12.77
	General Power High Load Factor	3B Secondary		$ 873.50	$ 655.00		$ 17.47	$ 13.10
	General Power Low Load Factor	3C Primary		$ 326.00	$ 256.50		$ 6.52	$ 5.13
	General Power Low Load Factor	3C Secondary		$ 342.50	$ 273.00		$ 6.85	$ 5.46
Schedule 4	*Large Power*	4B Primary		$ 7,915.00	$ 6,280.00		$ 15.83	$ 12.56
	Large Power	4B Secondary		$ 8,735.00	$ 7,100.00		$ 17.47	$ 14.20
Schedule 5	*Large Service for Customers >=8,000kW*	5B		$ 93,920.00	$ 78,160.00		$ 11.74	$ 9.77
Schedule 10	*Irrigation*							
	Irrigation	10A	$ 8.19					
	Irrigation	10B	$ 8.19			$ 2.81		
Schedule 11	*Water & Sewage*	11B	$ 491.60					
Schedule 15	*Universities*	15B		$ 76,480.00	$ 65,520.00		$ 9.56	$ 8.19
Schedule 30	*Large Service for Manufacturing*	30B		$ 345,600.00	$ 280,200.00		$ 11.52	$ 9.34
Schedule 33	*Station Service* [1]	33B		$ 2,695.00	$ 2,305.00		$ 5.39	$ 4.61
Schedule 34	*Large Power Service >=3,000kW*	34B		N/A	N/A		N/A	N/A

Proposed Non-Volumetric Rates-SUMMARY

Schedule	Class	Rate	Customer Charge	Customer Charge-Summer+ Min Demand[2]	Customer Charge-Non Summer+ Min Demand[2]	Meter Charge	Demand Rate Summer	Demand Rate Non-Summer
Schedule 1	*Residential*							
	Residential	1A	$ 12.80					
	Residential	1B	$ 23.85			$ 2.25		
Schedule 2	*Small Power*							
	Small Power	2A	$ 23.39					
	Small Power	2B	$ 9.96			$ 13.43		
Schedule 3	*General Power*							
	General Power High Load Factor	3B Primary		$ 1,111.30	$ 1,017.30		$ 20.85	$ 18.97
	General Power High Load Factor	3B Secondary		$ 1,127.80	$ 1,033.80		$ 21.18	$ 19.30
	General Power Low Load Factor	3C Primary		$ 588.80	$ 541.30		$ 10.40	$ 9.45
	General Power Low Load Factor	3C Secondary		$ 605.30	$ 557.80		$ 10.73	$ 9.78
Schedule 4	*Large Power*	4B Primary		$ 9,876.34	$ 8,886.34		$ 18.74	$ 16.76
	Large Power	4B Secondary		$ 10,726.34	$ 9,736.34		$ 20.44	$ 18.46
Schedule 5	*Large Service for Customers >=8,000kW*	5B		$ 134,631.96	$ 120,471.96		$ 16.50	$ 14.73
Schedule 10	*Irrigation*							
	Irrigation	10A	$ 43.28					
	Irrigation	10B	$ 12.85			$ 30.43		
Schedule 11	*Water & Sewage*	11B	$ 243.93					
Schedule 15	*Universities*	15B		$ 162,972.74	$ 142,172.74		$ 19.82	$ 17.22
Schedule 30	*Large Service for Manufacturing*	30B		$ 777,144.61	$ 695,244.61		$ 24.98	$ 22.25
Schedule 33	*Station Service* [1]	33B		$ 2,754.88	$ 2,494.88		$ 4.81	$ 4.29
Schedule 34	*Large Power Service >=3,000kW*	34B		$ 87,089.23	$ 78,179.23		$ 27.92	$ 24.95

Note:

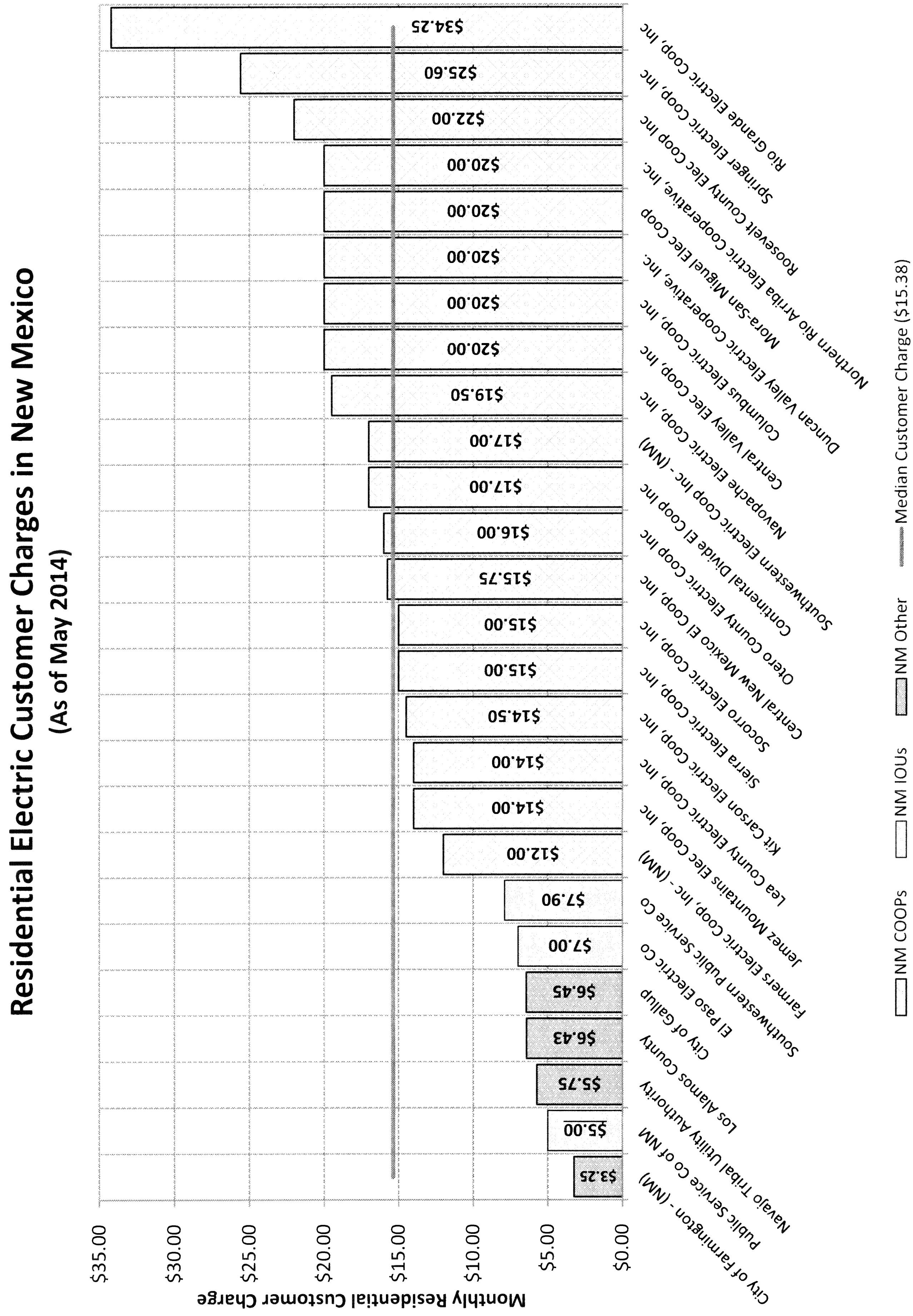
1.- Station Service Tariff 33B is pending approval in NMPRC Case No. 14-00102-UT

2.- Charge includes Schedule's Minimum Demand

A bar graph depicting Residential electric customer charges in New Mexico as of May 2014.

PNM Exhibit SC-11

Is contained in the following page.


Residential Electric Customer Charges in New Mexico
(As of May 2014)
Monthly Residential Customer Charge
$35.00
$30.00
$25.00
$20.00
$15.00
$10.00
$5.00
$0.00
$34.25
$25.60
$22.00
$20.00
$20.00
$20.00
$20.00
$20.00
$19.50
$17.00
$17.00
$16.00
$15.75
$15.00
$15.00
$14.50
$14.00
$14.00
$12.00
$7.90
$7.00
$6.45
$6.43
$5.75
$5.00
$3.25
Rio Grande Electric Coop, Inc
Springer Electric Coop, Inc
Roosevelt County Elec Coop Inc
Northern Rio Arriba Electric Cooperative, Inc.
Mora-San Miguel Elec Coop
Duncan Valley Electric Cooperative, Inc.
Columbus Electric Coop, Inc
Central Valley Elec Coop, Inc
Navopache Electric Coop Inc - (NM)
Southwestern Electric Coop Inc
Continental Divide El Coop Inc
Otero County Electric Coop Inc
Central New Mexico El Coop, Inc
Socorro Electric Coop, Inc
Sierra Electric Coop, Inc
Kit Carson Electric Coop, Inc
Lea County Elec Coop, Inc
Jemez Mountains Electric Coop, Inc
Farmers Electric Coop, Inc - (NM)
Southwestern Public Service Co
El Paso Electric Co
City of Gallup
Los Alamos County
Navajo Tribal Utility Authority
Public Service Co of NM
City of Farmington - (NM)
NM COOPs
NM IOUs
NM Other
Median Customer Charge ($15.38)

Examples of rates assessed by local telecommunications, Internet, and cable or satellite video service providers.

PNM Exhibit SC-12

Is contained in the following 2 pages.

EXAMPLES OF RATES ASSESSED BY LOCAL TELECOMMUNICATIONS, INTERNET, AND CABLE OR SATELLITE VIDEO SERVICE PROVIDERS.

Local Phone Service

Service Type	Company	Service Name	Monthly Charge	Usage Charge
Residential Phone Service	CenturyLink	Basic Phone Service	$16.50 per month	Long Distance Charges apply
Residential Phone Service	CenturyLink	Home Phone Unlimited	$47 per month	N/A
Residential Phone Service	Comcast	XFINITY Voice Local with More	$34.95 per month	Long Distance Charges apply

Cable Television Service

Service Type	Company	Service Name	Monthly Charge	Usage Charge
Cable TV	Comcast	Digital Starter TV	$39.99 per month	N/A
Cable TV	Cable ONE	Standard Cable TV	$62 per month	N/A
Cable TV	Cable ONE	Economy Cable TV	$29 per month	N/A

Internet Service

Service Type	Company	Service Name	Monthly Charge	Usage Charge
Internet Service	CenturyLink	Internet Only	$29.95 per month	N/A
Internet Service	Comcast	Performance Internet (download up to 25 Mbps)	$39.99 per month	N/A
Internet Service	Comcast	Blast! (download up to 50 Mbps)	$49.99 per month	N/A

Bundled Services

Service Type	Company	Service Name	Monthly Charge	Usage Charge
Cable Television and Internet	Comcast	Digital Starter and Starter Internet	$59.99 per month with a 2-year agreement	N/A
Internet and DirectTV	CenturyLink	Double Bundle	$54.94 per month	

**For all pricing quotes, a randomly chosen Albuquerque address was used if required.

A letter sent by PNM in 2012 to Rate 20 (Streetlighting) customers.

PNM Exhibit SC-13

Is contained in the following page.

July 13, 2012

<<First>><<Last>>
<<Title>>
<<Address>>
<<City, State, Zip>>

Dear <<First>>,

Under the Amended Stipulation in our last rate case (NMPRC Case No. 10-00086-UT), PNM agreed to enter into discussions with Rate 20 Customers (Street Lighting and Floodlighting Service) regarding certain issues related to street lighting including cost allocation, rate design, maintenance, re-lamping, and energy efficiency.

If you are interested in discussing any of these issues, please feel free to contact me prior to July 27, 2012 to arrange a meeting. Your comments and participation in this process are very much appreciated. Thank you.

Sincerely,

Wesley Wilson

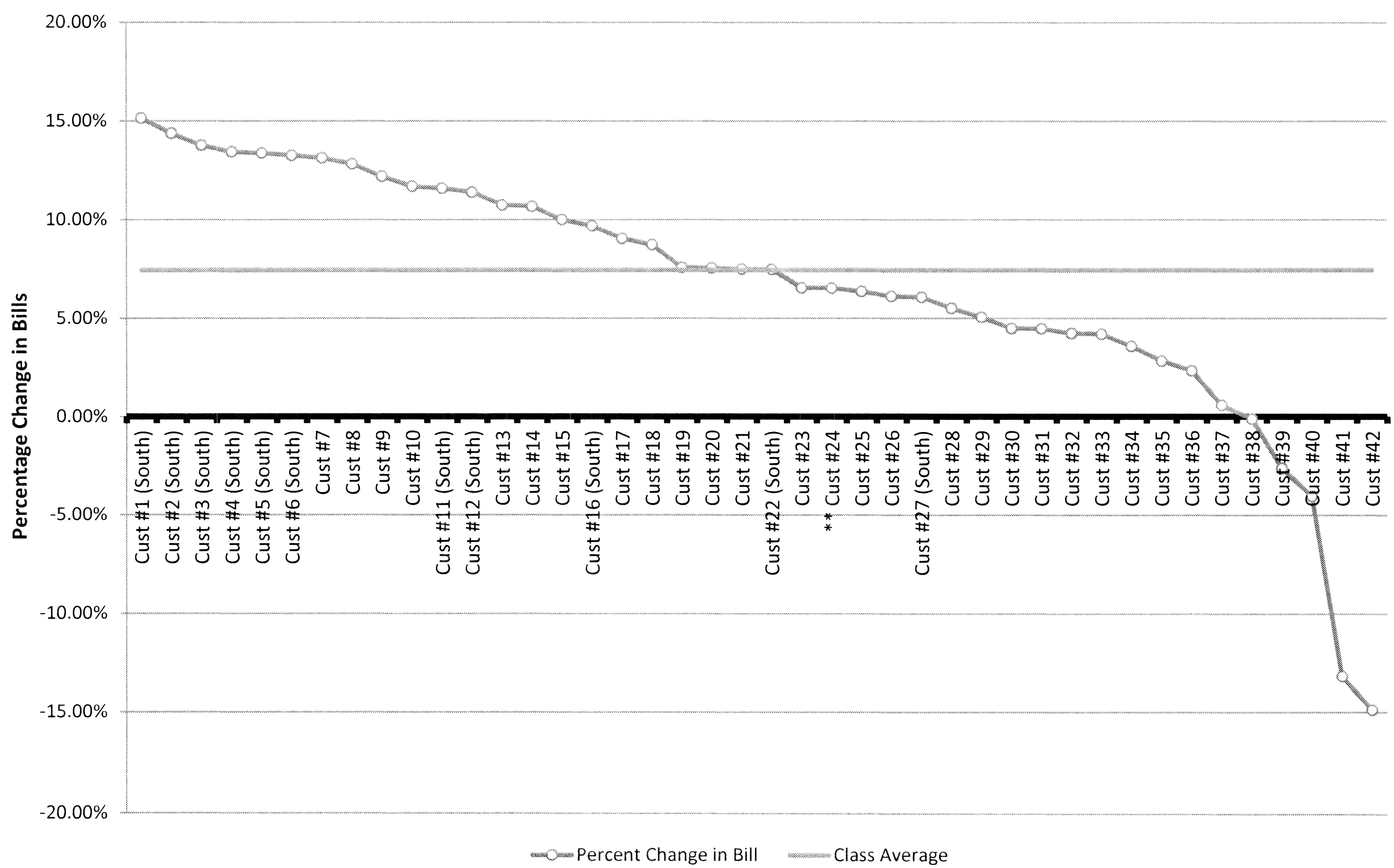
Wes Wilson
Sr. Technical Account Manager
(505) 241-4472
Wesley.Wilson@pnm.com

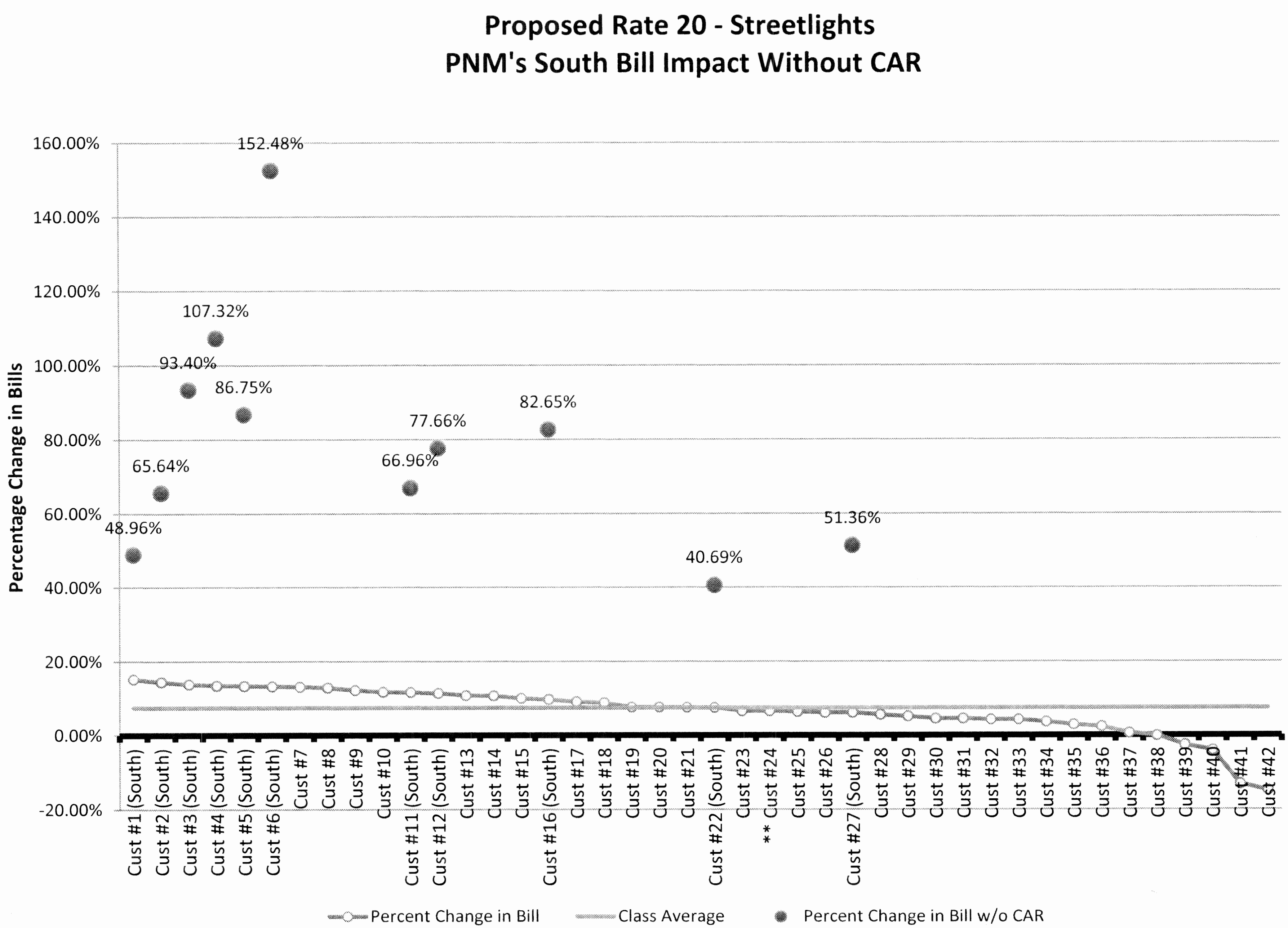
The effect of the Consolidation Adjustment Rider (Rider No. 35) on PNM South Streetlighting customers (20)

PNM Exhibit SC-14

Is contained in the following 2 pages.

Proposed Rate 20 - Streetlights
Percentage Change in Bills by Customer with CAR





Proposed Rate 20 - Streetlights
PNM's South Bill Impact Without CAR
Percentage Change in Bills
160.00%
140.00%
120.00%
100.00%
80.00%
60.00%
40.00%
20.00%
0.00%
-20.00%
152.48%
107.32%
93.40%
86.75%
82.65%
77.66%
66.96%
65.64%
48.96%
51.36%
40.69%
Cust #1 (South)
Cust #2 (South)
Cust #3 (South)
Cust #4 (South)
Cust #5 (South)
Cust #6 (South)
Cust #7
Cust #8
Cust #9
Cust #10
Cust #11 (South)
Cust #12 (South)
Cust #13
Cust #14
Cust #15
Cust #16 (South)
Cust #17
Cust #18
Cust #19
Cust #20
Cust #21
Cust #22 (South)
Cust #23
** Cust #24
Cust #25
Cust #26
Cust #27 (South)
Cust #28
Cust #29
Cust #30
Cust #31
Cust #32
Cust #33
Cust #34
Cust #35
Cust #36
Cust #37
Cust #38
Cust #39
Cust #40
Cust #41
Cust #42
Percent Change in Bill
Class Average
Percent Change in Bill w/o CAR

Summary of modifications to the Streetlighting (20) schedule and the Consolidation Adjustment Rider (Rider No. 35)

PNM Exhibit SC-15

Is contained in the following 11 pages.

Summary of Rate Re-design Steps for Rate 20 (Streetlighting), Rider 35 (Consolidation Adjustment Rider ("CAR")) and Rate 6 (Private Area Lighting)

Rate 20 & Rider 35 – Rate Design Methodology

To place PNM South current Streetlighting base light/pole rates on an equal cost footing with PNM North rates, PNM first developed a single current consolidated set of current light and pole rates. In the consolidation Process, where PNM North had a light that was available for PNM South, the PNM North rate was used. Otherwise, for the remainder of lights, the PNM South rate was utilized (see Table 1).

Table 1: Consolidated Light and pole rates based on NMPRC Case No. 10-00086-UT

	Co.-Owned Overhead (OH)	Co.-Owned Underground (UG)	Cust. Owned
Mercury Vapor Lights			
175W MV Streetlight	$12.69	$13.98	$6.98
250W MV Light	$0.00	$0.00	$9.64
400W MV Streetlight	$21.99	$23.30	$15.10
Low Pressure Sodium Lights			
55W LPS Streetlight	$9.68	$9.68	$2.68
135W LPS Streetlight	$13.90	$13.90	$6.04
High Pressure Sodium Lights			
70W HPS Streetlight	$10.86	$12.33	$5.01
100W HPS Streetlight	$11.09	$12.40	$5.46
150W HPS Streetlight	$13.80	$15.22	$6.97
200W HPS Streetlight	$12.24	$12.24	$8.53
250W HPS Streetlight	$18.06	$19.47	$10.73
400W HPS Floodlight	$25.28	$26.56	$16.41
400W HPS Streetlight	$23.94	$25.54	$16.34

	Co.-Owned OH or UG
Poles	
30' Wood Pole	$3.44
35' Wood Pole	$3.74
40' Wood Pole	$4.39
45' Wood Pole	$5.21
23' Ornamental Pole	$7.73
28' Ornamental Pole	$8.95
38' Ornamental Pole	$14.72
40' davit pole	$14.65

Using the rates from Table A, PNM applied these rates to each PNM South light/pole rate available and then imputed a light/pole fixed CAR rate to reconfigure current PNM South Rate 20/Rider 35 rates.

Table B: Current Stipulation Rate 20 & CAR Rates by Rate Code ("SRAT"), and Derivation of Imputed Current Rate 20 & CAR Rates by SRAT Assuming use of Fully Consolidated Rate 20 Base Rates

Line #	Rate Code (SRAT)	Rate Desc	Stip Rates	Current FPPCAC	Stip CAR	Total Stip Rate	Current Cons. kWh Rate	Current Cons. Sch 20 Light Rate	Current Cons. Sch. 20 Pole Rate	Current FPPCAC	Imputed Current CAR (Assuming Cons. Sch. 20 Rates)	Total Stip Rate
			[A]	[B]	[C]	[D] = [A] + [B] + [C]	[E]	[F]	[G]	[B]	[H] = [D] - [E] - [F] - [G] - [B]	[I] = [E] + [F] + [G] + [B] + [H]
1	**L1Z5**	**Sch I, Metered Muni Lts (PNM)**	$0.1038625	$0.0058460	$0.0000219	$0.1097304	$0.1038625			$0.0058460	**$0.0000219**	$0.1097304
2	**L2Z5**	**Sch II, Metered Muni Lts (Cust)**	$0.0958706	$0.0058460	$0.0000219	$0.1017385	$0.0958706			$0.0058460	**$0.0000219**	$0.1017385
3	**L3A2**	**Sch III (OH-WP): 100W HPS (45 kWh)**	$9.68	$0.26	$0.00	$9.94		$11.09	$3.74	$0.26	($5.15)	$9.94
4	**L3A4**	**Sch V (UG-WP): 100W HPS (45 kWh)**	$12.52	$0.26	$0.00	$12.78		$12.40	$3.74	$0.26	($3.62)	$12.78
5	**L3C2**	**Sch III (OH-WP): 400W HPS (165 kWh)**	$16.66	$0.96	$0.00	$17.62		$23.94	$3.74	$0.96	($11.02)	$17.62
6	**L3D1**	**Sch VI (Cust.): 175W MV (73 kWh)**	$7.00	$0.43	$0.00	$7.43		$6.98	$0.00	$0.43	**$0.02**	$7.43
7	**L3D2**	**Sch III (OH-WP): 175W MV (73 kWh)**	$7.41	$0.43	$0.00	$7.84		$12.69	$3.74	$0.43	($9.02)	$7.84
8	**L3D4**	**Sch V (UG-WP): 175W MV (73 kWh)**	$7.41	$0.43	$0.00	$7.84		$13.98	$3.74	$0.43	($10.31)	$7.84
9	**L3F2**	**Sch III (OH-WP): 400W MV (162 kWh)**	$16.66	$0.95	$0.00	$17.61		$21.99	$3.74	$0.95	($9.07)	$17.61
10	**L3T2**	**Sch III (OH-WP): 200W HPS (89 kWh)**	$12.24	$0.52	$0.00	$12.76		$12.24	$3.74	$0.52	($3.74)	$12.76
11	**L3T4**	**Sch V (UG-WP): 200W HPS (89 kWh)**	$14.70	$0.52	$0.00	$15.22		$12.24	$3.74	$0.52	($1.28)	$15.22
12	**L3U2**	**Sch III (OH-WP): 55W LPS (28 kWh)**	$9.68	$0.16	$0.00	$9.84		$9.68	$3.74	$0.16	($3.74)	$9.84
13	**L3U4**	**Sch V (UG-WP): 55W LPS (28 kWh)**	$9.68	$0.16	$0.00	$9.84		$9.68	$3.74	$0.16	($3.74)	$9.84
14	**L3V2**	**Sch III (OH-WP): 135W LPS (63 kWh)**	$13.90	$0.37	$0.00	$14.27		$13.90	$3.74	$0.37	($3.74)	$14.27
15	**L4A2**	**Sch IV (OH-MP): 100W HPS (45 kWh)**	$17.83	$0.26	$0.00	$18.09		$11.09	$8.95	$0.26	($2.21)	$18.09
16	**L4A4**	**Sch V (UG-MP): 100W HPS (45 kWh)**	$12.52	$0.26	$0.00	$12.78		$12.40	$8.95	$0.26	($8.83)	$12.78
17	**L4C2**	**Sch IV (OH-MP): 400W HPS (165 kWh)**	$23.57	$0.96	$0.00	$24.53		$23.94	$8.95	$0.96	($9.32)	$24.53
18	**L4C4**	**Sch V (UG-MP): 400W HPS (165 kWh)**	$23.57	$0.96	$0.00	$24.53		$25.54	$8.95	$0.96	($10.92)	$24.53
19	**L4D2**	**Sch IV (OH-MP): 175W MV (73 kWh)**	$7.41	$0.43	$0.00	$7.84		$12.69	$8.95	$0.43	($14.23)	$7.84
20	**L4D4**	**Sch V (UG-MP): 175W MV (73 kWh)**	$7.41	$0.43	$0.00	$7.84		$13.98	$8.95	$0.43	($15.52)	$7.84
21	**L4F2**	**Sch IV (OH-MP): 400W MV (162 kWh)**	$19.13	$0.95	$0.00	$20.08		$21.99	$8.95	$0.95	($11.81)	$20.08
22	**L4F4**	**Sch V (UG-MP): 400W MV (162 kWh)**	$19.13	$0.95	$0.00	$20.08		$23.30	$8.95	$0.95	($13.12)	$20.08
23	**L4T2**	**Sch IV (OH-MP): 200W HPS (89 kWh)**	$19.89	$0.52	$0.00	$20.41		$12.24	$8.95	$0.52	($1.30)	$20.41
24	**L4T4**	**Sch V (OH-MP): 200W HPS (89 kWh)**	$20.78	$0.52	$0.00	$21.30		$12.24	$8.95	$0.52	($0.41)	$21.30
25	**L4U2**	**Sch IV (OH-MP): 55W LPS (28 kWh)**	$9.68	$0.16	$0.00	$9.84		$9.68	$8.95	$0.16	($8.95)	$9.84
26	**L4U4**	**Sch V (UG-MP): 55W LPS (28 kWh)**	$9.68	$0.16	$0.00	$9.84		$9.68	$8.95	$0.16	($8.95)	$9.84
27	**L4V4**	**Sch V (UG-MP): 135W LPS (63 kWh)**	$13.90	$0.37	$0.00	$14.27		$13.90	$8.95	$0.37	($8.95)	$14.27
28	**L6F2**	**Sch IV (OH-MP): 2-400W MV (324 kWh)**	$33.52	$1.89	$0.01	$35.42		$43.98	$8.95	$1.89	($19.40)	$35.42
29	**L6F4**	**Sch V (UG-MP): 2-400W MV (324 kWh)**	$33.52	$1.89	$0.01	$35.42		$46.60	$8.95	$1.89	($22.02)	$35.42
30	**L7A1**	**Sch VI (Cust.): 100W HPS (45 kWh)**	$4.31	$0.26	$0.00	$4.57		$5.46	$0.00	$0.26	($1.15)	$4.57
31	**L7A2**	**Sch III (OH-WP): 100W HPS (45 kWh)**	$9.68	$0.26	$0.00	$9.94		$11.09	$0.00	$0.26	($1.41)	$9.94
32	**L7A3**	**Sch VI (Cust.): 100W HPS (45 kWh)**	$4.31	$0.26	$0.00	$4.57		$5.46	$0.00	$0.26	($1.15)	$4.57
33	**L7C1**	**Sch VI (Cust.): 400W HPS (165 kWh)**	$15.82	$0.96	$0.00	$16.78		$16.34	$0.00	$0.96	($0.52)	$16.78
34	**L7C2**	**Sch III (OH-WP): 400W HPS (165 kWh)**	$16.66	$0.96	$0.00	$17.62		$23.94	$0.00	$0.96	($7.28)	$17.62
35	**L7C3**	**Sch VI (Cust.): 400W HPS (165 kWh)**	$15.82	$0.96	$0.00	$16.78		$16.34	$0.00	$0.96	($0.52)	$16.78
36	**L7D1**	**Sch VI (Cust.): 175W MV (73 kWh)**	$7.00	$0.43	$0.00	$7.43		$6.98	$0.00	$0.43	**$0.02**	$7.43
37	**L7D2**	**Sch III (OH-WP): 175W MV (73 kWh)**	$7.41	$0.43	$0.00	$7.84		$12.69	$0.00	$0.43	($5.28)	$7.84
38	**L7D3**	**Sch VI (Cust.): 175W MV (73 kWh)**	$7.00	$0.43	$0.00	$7.43		$6.98	$0.00	$0.43	**$0.02**	$7.43
39	**L7F1**	**Sch VI (Cust.): 400W MV (162 kWh)**	$15.53	$0.95	$0.00	$16.48		$15.10	$0.00	$0.95	**$0.43**	$16.48
40	**L7F2**	**Sch III (OH-WP): 400W MV (162 kWh)**	$16.66	$0.95	$0.00	$17.61		$21.99	$0.00	$0.95	($5.33)	$17.61
41	**L7F3**	**Sch VI (Cust.): 400W MV (162 kWh)**	$15.53	$0.95	$0.00	$16.48		$15.10	$0.00	$0.95	**$0.43**	$16.48
42	**L7T1**	**Sch VI (Cust.): 200W HPS (89 kWh)**	$8.53	$0.52	$0.00	$9.05		$8.53	$0.00	$0.52	**$0.00**	$9.05
43	**L7T2**	**Sch III (OH-WP): 200W HPS (89 kWh)**	$12.24	$0.52	$0.00	$12.76		$12.24	$0.00	$0.52	**$0.00**	$12.76
44	**L7T3**	**Sch VI (Cust.): 200W HPS (89 kWh)**	$8.53	$0.52	$0.00	$9.05		$8.53	$0.00	$0.52	**$0.00**	$9.05
45	**L7U2**	**Sch III (OH-WP): 55W LPS (28 kWh)**	$9.68	$0.16	$0.00	$9.84		$9.68	$0.00	$0.16	**$0.00**	$9.84
46	**L7V2**	**Sch III (OH-WP): 135W LPS (63 kWh)**	$13.90	$0.37	$0.00	$14.27		$13.90	$0.00	$0.37	($0.00)	$14.27
47	**L8A1**	**Sch VI (Cust.): 100W HPS (45 kWh)**	$4.31	$0.26	$0.00	$4.57		$5.46	$0.00	$0.26	($1.15)	$4.57
48	**L8A2**	**Sch IV (OH-MP): 100W HPS (45 kWh)**	$17.83	$0.26	$0.00	$18.09		$11.09	$0.00	$0.26	**$6.74**	$18.09
49	**L8A3**	**Sch VI (Cust.): 100W HPS (45 kWh)**	$4.31	$0.26	$0.00	$4.57		$5.46	$0.00	$0.26	($1.15)	$4.57
50	**L8C1**	**Sch VI (Cust.): 400W HPS (165 kWh)**	$15.82	$0.96	$0.00	$16.78		$16.34	$0.00	$0.96	($0.52)	$16.78
51	**L8C2**	**Sch IV (OH-MP): 400W HPS (165 kWh)**	$23.57	$0.96	$0.00	$24.53		$23.94	$0.00	$0.96	($0.37)	$24.53
52	**L8C3**	**Sch VI (Cust.): 400W HPS (165 kWh)**	$15.82	$0.96	$0.00	$16.78		$16.34	$0.00	$0.96	($0.52)	$16.78
53	**L8D1**	**Sch VI (Cust.): 175W MV (73 kWh)**	$7.00	$0.43	$0.00	$7.43		$6.98	$0.00	$0.43	**$0.02**	$7.43
54	**L8D2**	**Sch IV (OH-MP): 175W MV (73 kWh)**	$7.41	$0.43	$0.00	$7.84		$12.69	$0.00	$0.43	($5.28)	$7.84
55	**L8D3**	**Sch VI (Cust.): 175W MV (73 kWh)**	$7.00	$0.43	$0.00	$7.43		$6.98	$0.00	$0.43	**$0.02**	$7.43
56	**L8F1**	**Sch VI (Cust.): 400W MV (162 kWh)**	$15.53	$0.95	$0.00	$16.48		$15.10	$0.00	$0.95	**$0.43**	$16.48
57	**L8F2**	**Sch IV (OH-MP): 400W MV (162 kWh)**	$19.13	$0.95	$0.00	$20.08		$21.99	$0.00	$0.95	($2.86)	$20.08
58	**L8F3**	**Sch VI (Cust.): 400W MV (162 kWh)**	$15.53	$0.95	$0.00	$16.48		$15.10	$0.00	$0.95	**$0.43**	$16.48
59	**L8T1**	**Sch VI (Cust.): 200W HPS (89 kWh)**	$8.53	$0.52	$0.00	$9.05		$8.53	$0.00	$0.52	**$0.00**	$9.05
60	**L8T2**	**Sch IV (OH-MP): 200W HPS (89 kWh)**	$19.89	$0.52	$0.00	$20.41		$12.24	$0.00	$0.52	**$7.65**	$20.41
61	**L8T3**	**Sch VI (Cust.): 200W HPS (89 kWh)**	$8.53	$0.52	$0.00	$9.05		$8.53	$0.00	$0.52	**$0.00**	$9.05
62	**L8U2**	**Sch IV (OH-MP): 55W LPS (28 kWh)**	$9.68	$0.16	$0.00	$9.84		$9.68	$0.00	$0.16	**$0.00**	$9.84

In order to develop a cost based allocator for Company-owned light and pole facilities, PNM first looked at the replacement costs for each light and pole that PNM is proposing in this case. In order to address other factors, PNM made several adjustments to the installed costs to develop light and pole cost allocation factors (See Table C). Those other factors are: 1) reducing the number of Company owned light and pole options, 2) adding new LED Light Options, 3) limiting future light and pole ratebase additions, and 4) the fact that Current LED Lights are more expensive and have a significantly shorter lifespan than other light types.

Table C: Deemed Replacement Costs & Revenue Requirements for PNM Owned Lights & Poles

Line No.	Light Type	OH Replacement Cost	UG Replacement Cost	OH Deemed Replacement Cost	UG Deemed Replacement Cost	Average 2 Year Revenue Requirement Factor	OH Deemed 2 Year Average Revenue Requirement	UG Deemed 2 Year Average Revenue Requirement
		[A]	[B]	[C]	[D]	[E]	[F] = [C] * [E]	[G] = [D] * [E]
	Mercury Vapor Lights							
1	175W MV Streetlight [1]	$1,720.44	$1,960.88	**$1,000.00**	**$1,000.00**	0.1538	$153.77	$153.77
2	250W MV Light [2]							
3	400W MV Streetlight [3]	$1,806.93	$2,205.69	**$1,050.00**	**$1,050.00**	0.1538	$161.46	$161.46
	Low Pressure Sodium Lights							
4	55W LPS Streetlight	$1,949.86	$2,190.31	**$1,130.00**	**$1,130.00**	0.1538	$173.76	$173.76
5	135W LPS Streetlight	$2,282.67	$2,681.43	**$1,320.00**	**$1,320.00**	0.1538	$202.98	$202.98
	High Pressure Sodium Lights							
6	70W HPS Streetlight [4]	$1,720.44	$1,960.88	**$1,000.00**	**$1,000.00**	0.1538	$153.77	$153.77
7	100W HPS Streetlight	$1,720.44	$1,960.88	**$1,000.00**	**$1,000.00**	0.1538	$153.77	$153.77
8	150W HPS Streetlight [5]							
9	200W HPS Streetlight	$1,681.92	$1,922.37	**$980.00**	**$980.00**	0.1538	$150.70	$150.70
10	250W HPS Streetlight	$1,806.93	$2,205.69	**$1,050.00**	**$1,050.00**	0.1538	$161.46	$161.46
11	400W HPS Flood Light	$1,807.81	$2,216.21	**$1,050.00**	**$1,050.00**	0.1538	$161.46	$161.46
12	400W HPS Streetlight	$1,816.91	$2,074.28	**$1,050.00**	**$1,050.00**	0.1538	$161.46	$161.46
	Light Emitting Diode ("LED") Lights							
13	43W LED Street Light [6]	$1,913.35	$2,153.81	**$770.00**	**$770.00**	0.1839	$141.62	$141.62
14	54W LED Street Light [6]	$1,913.35	$2,153.81	**$770.00**	**$770.00**	0.1839	$141.62	$141.62
15	130W LED Street Light [6]	$1,902.50	$2,301.24	**$760.00**	**$760.00**	0.1839	$139.78	$139.78
16	258W LED Street Light [6]	$2,838.32	$3,207.43	**$1,140.00**	**$1,140.00**	0.1839	$209.67	$209.67

Line No.	PoleType	Replacement Cost	Deemed Replacement Cost	Average 2 Year Revenue Requirement Factor	Deemed 2 Year Average Revenue Requirement	
		[H]	[I]	[E]	[J] = [I] * [E]	
17	30' Wood Pole [7]	$1,423.87	$600.00	0.1538	$92.26	Wood Poles (Consolidated)
18	35' Wood Pole	$1,423.87	$600.00	0.1538	$92.26	
19	40' Wood Pole	$1,610.84	$600.00	0.1538	$92.26	
20	45' Wood Pole	$2,028.86	$600.00	0.1538	$92.26	
21	23' Ornamental Pole	$1,437.96	$900.00	0.1538	$138.40	Non-Wood Poles (Consolidated)
22	28' Ornamental Pole	$2,093.50	$900.00	0.1538	$138.40	
23	38' Ornamental Pole	$1,878.87	$900.00	0.1538	$138.40	
24	40' Davit Pole	$2,410.69	$900.00	0.1538	$138.40	

Notes

1 175W MV Streetlight no longer installed (Assumes 100W HPS Streetlight as replacement)
2 250W MV Light no longer AVAILABLE
3 400W MV Streetlight no longer installed (Assumes 250W HPS Streetlight as replacement)
4 70W HPS Streetlight is the same light as 100W HPS Streetlight (dual wattage head)
5 150W HPS Streetlight no longer AVAILABLE
6 LED Lights Newly available as light options
7 30' Wood Pole no longer installed (Assumes 35' Wood Pole as replacement)
8 All Light costs assume lamp, arm, and 150' of secondary.
9 All Light & Pole costs provided by M. Adams (PNM Streetlight Administrator)

Please note the following concerning Table C

1. eemed eplacement Cost represents the ma imum amount of investment that the compan will place into ratebase for each new Compan -owned light and pole installed. These values, for light and pole t pes that are available for new installations, are included as a table in ate 20 SP CI L CON ITIONS, Section I.a.
2. PNM utilizes the same eemed eplacement Cost for both the overhead served and the underground served lights in order to be able to combine the two options for pricing purposes (Table C Items C and).
3. s the eemed eplacement Costs are the same for both the 400 HPS Streetlight and the 400W HPS Flood Light options, and thus the will be priced identicall , PNM proposes to combine these two light t pes.
4. s the eemed eplacement Costs are the same for each of the four current wood pole options, PNM proposes to combine these four pole options into a single option (Wood Poles).
5. s the eemed eplacement Costs are the same for each of the four current ornamental pole options, PNM proposes to combine these four pole options into a single option (Non-Wood Poles).
6. ecause L Lights have a shorter lifespan than other t pes of lighting equipment, revenues on L plant additions must also be recovered more quic l . This results in a higher verage 2 ear evenue equirement Factor being applied to L Lights (Table C Item).
7. The eemed 2 ear verage evenue equirements (Table C Items F , G and) listed in the table provide a relative cost basis for deriving the Compan -owned lights and poles revenue requirements to Compan -owned lights and poles.

The proposed revenue requirement in this case for the Streetlight Class is $8,666,255. To apportion this revenue requirement for each light and pole offered in ate 20, that revenue requirement must be functionalized and allocated as appropriate to each light class. The functional components of this revenue requirement are depicted in table -1 elow. There are two items of note in Table -1 1) PNM, for this proposal, was able to allocate 90 [1] of the Compan -owned lights and poles revenue requirement directl to Compan -owned lights and poles (with the remainder being assessed to all lights), and 2) That the C discounts that are derived for PNM South light and pole combinations are allocated bac to all light t pes on an iterative basis.

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[1] PNM e amined various iterations of its Streetlighting rate design on total bill impacts to individual Streetlighting customers. llocating more than 90 of this revenue requirement directl to Compan -owned lights and poles in this rate case resulted in either some PNM North Streetlighting Customer having larger bill impacts than the PNM South customers (who are indirectl capped b the C), or requiring the ma imum cap for the C to be significantl increased from the target 17 (which corresponds to the ma imum non-Fuel anding limit for overall class revenue allocation).

Table D-1: Components for Rate 20 Revenue Requirements

Line No.	Description Of Costs		Revenue Requirement	Annual kWh	Rate Per kWh	Notes
1	Base Fuel		$1,320,328	49,986,012	$0.0264139	Common to all lights
2	Fuel Related Non-Fuel		$311,027	49,986,012	$0.0062223	Common to all lights
3	Generation		$981,218	49,986,012	$0.0196299	Common to all lights
4	Transmission		$470,663	49,986,012	$0.0094159	Common to all lights
5	Substation		$139,180	49,986,012	$0.0027844	Common to all lights
6	Primary Distribution		$432,101	49,986,012	$0.0086444	Common to all lights
7	Secondary Distribution		$372,540	49,986,012	$0.0074529	Common to all lights
8	Customer Costs		$12,990	49,986,012	$0.0002599	Common to all lights
9	CAR + Rounding (Allocated Back to All Lights)		$366,554	49,986,012	$0.0073331	Common to all lights
10	Total Allocation to All Lights		$4,406,601	49,986,012	$0.0881567	Common to all lights
11	O&M (Alloc. only to MV, LPS and HPS Lights)		$793,293	49,656,684	$0.0159755	Not Appl. to Cust. Owned & Maint. Lights
12	Intra Class Subsidy (Co. Owned Lts. & Poles)	10%	$383,292	49,986,012	$0.0076680	Not Appl. To Alt. Lights
13	Co. Owned Lts. & Poles	90%	$3,449,624			Only Appl. To Co. Lights & Poles
14	Company Owned Lights and Poles		$3,832,916			Line 12 + Line 13
15	Total Revenue Requirements		$8,666,255			Lines 1 - 8 + Lines 11 - 13

Using Table -1, Lines 10, 11 and 12, the revenue requirements common to all lights are then allocated to each light t pe as depicted in Table -2

Table D-2: Components of Common Costs Allocated to Light Types

Line No.	Light Or Pole Type	kWh per Unit	Rate per kWh per Unit	Monthly Common Cost per Unit	Notes
	Mercury Vapor Lights				
16	175W Mercury Vapor and Streetlight	73	$0.1118002	$8.16	Rate = Table D-1, Lines 10, 11 and 12
17	250W Mercury Vapor Underpass Light	N/A	N/A	N/A	N/A
18	400W Mercury Vapor Streetlight	162	$0.1118002	$18.11	Rate = Table D-1, Lines 10, 11 and 12
	Low Pressure Sodium Lights				
19	55W Low Pressure Sodium Street Light	28	$0.1118002	$3.13	Rate = Table D-1, Lines 10, 11 and 12
20	135W Low Pressure Sodium Street Light	63	$0.1118002	$7.04	Rate = Table D-1, Lines 10, 11 and 12
	High Pressure Sodium Lights				
21	70W High Pressure Sodium Street Light	31	$0.1118002	$3.47	Rate = Table D-1, Lines 10, 11 and 12
22	100W High Pressure Sodium Street Light	45	$0.1118002	$5.03	Rate = Table D-1, Lines 10, 11 and 12
23	150W High Pressure Sodium Streetlight	N/A	N/A	N/A	N/A
24	200W High Pressure Sodium Street Light	89	$0.1118002	$9.95	Rate = Table D-1, Lines 10, 11 and 12
25	250W High Pressure Sodium Street Light	107	$0.1118002	$11.96	Rate = Table D-1, Lines 10, 11 and 12
26	400W High Pressure Sodium Flood Light	165	$0.1118002	$18.45	Rate = Table D-1, Lines 10, 11 and 12
27	400W High Pressure Sodium Street Light	165	$0.1118002	$18.45	Rate = Table D-1, Lines 10, 11 and 12
	Light Emitting Diode ("LED") Lights				
28	43W LED Street Light	15	$0.1041322	$1.56	Rate = Table D-1, Lines 10 and 11
29	54W LED Street Light	19	$0.1041322	$1.98	Rate = Table D-1, Lines 10 and 11
30	130W LED Street Light	46	$0.1041322	$4.79	Rate = Table D-1, Lines 10 and 11
31	258W LED Street Light	92	$0.1041322	$9.58	Rate = Table D-1, Lines 10 and 11
	Metered Lights				
32	Company Owned		$0.1118002	$0.1118002	Rate = Table D-1, Lines 10, 11 and 11
33	Customer Owned		$0.0958247	$0.0958247	Rate = Table D-1, Line 10

Then, the allocated costs for Compan -owned lights and poles (Table -1, Line 13) are apportioned to Compan -owned lights as depicted in Table -3

Table D-3: Costs Allocated to Company Owned Light and Pole Types

Line No.	Light Or Pole Type	Light Units [A]	Deemed 2 Year Average Revenue Requirement [B]	Allocated Light and Pole Costs [C] = [B] * 0.6769 (Iterative Scaler)	Allocated Revenue [D] = [A] * [C]	Test Year Energy [E]	Notes
	Mercury Vapor Lights						
31	175W Mercury Vapor and Streetlight	52,464	$153.77	$8.67	$454,863	3,829,872	
32	250W Mercury Vapor Underpass Light						
33	400W Mercury Vapor Streetlight	6,252	$161.46	$9.11	$56,956	1,012,824	
	Low Pressure Sodium Lights						
34	55W Low Pressure Sodium Street Light	12,708	$173.76	$9.80	$124,538	355,824	
35	135W Low Pressure Sodium Street Light	396	$202.98	$11.45	$4,534	24,948	
	High Pressure Sodium Lights						
36	70W High Pressure Sodium Street Light	324	$153.77	$8.67	$2,809	10,044	
37	100W High Pressure Sodium Street Light	112,824	$153.77	$8.67	$978,184	5,077,080	
38	150W High Pressure Sodium Streetlight						
39	200W High Pressure Sodium Street Light	10,944	$150.70	$8.50	$93,024	974,016	
40	250W High Pressure Sodium Street Light	66,492	$161.46	$9.11	$605,742	7,114,644	
41	400W High Pressure Sodium Flood Light	8,904	$161.46	$9.11	$81,115	1,469,160	
42	400W High Pressure Sodium Street Light	6,084	$161.46	$9.11	$55,425	1,003,860	
	Light Emitting Diode ("LED") Lights						
43	43W LED Street Light	0	$141.62	$7.99	$0	0	
44	54W LED Street Light	0	$141.62	$7.99	$0	0	
45	130W LED Street Light	0	$139.78	$7.88	$0	0	
46	258W LED Street Light	0	$209.67	$11.83	$0	0	
	Poles						
47	Wood Pole	105,792	$92.26	$5.20	$550,118		
48	Ornamental Pole	49,104	$138.40	$7.81	$383,502		
	Metered Lights						
49	Company Owned	502,656		$0.1177251	$59,175	502,656	Alloc Ligh Cost = (Sum of Lines 31-42, Item [D]) / (Sum of Lines 31-42, Item [E])
50	Table Totals				$3,449,987	21,374,928	
51	Target Revenue (Co. Owned Lts. & Poles Revenue Requirement				$3,449,624		
52	Difference				$363		

Combining the results of Table -2 and -3 provide the lights and pole rates as depicted in Table -4 below

Table D-4: Rate 20 - Base Rates for Lights and Poles (Both Company-Owned and Customer-Owned)

Line No.	Light Or Pole Type	Company Owned Lights and Poles	Customer Owned Lights	Notes
	Mercury Vapor Lights			
53	175W Mercury Vapor and Streetlight	$16.83	$8.16	Co.-Owned: Ln 16 + Ln 31, Cust.-Owned: Ln 16
54	250W Mercury Vapor Underpass Light			
55	400W Mercury Vapor Streetlight	$27.22	$18.11	Co.-Owned: Ln 18 + Ln 33, Cust.-Owned: Ln 18
	Low Pressure Sodium Lights			
56	55W Low Pressure Sodium Street Light	$12.93	$3.13	Co.-Owned: Ln 19 + Ln 34, Cust.-Owned: Ln 19
57	135W Low Pressure Sodium Street Light	$18.49	$7.04	Co.-Owned: Ln 20 + Ln 35, Cust.-Owned: Ln 20
	High Pressure Sodium Lights			
58	70W High Pressure Sodium Street Light	$12.14	$3.47	Co.-Owned: Ln 21 + Ln 36, Cust.-Owned: Ln 21
59	100W High Pressure Sodium Street Light	$13.70	$5.03	Co.-Owned: Ln 22 + Ln 37, Cust.-Owned: Ln 22
60	150W High Pressure Sodium Streetlight			
61	200W High Pressure Sodium Street Light	$18.45	$9.95	Co.-Owned: Ln 24 + Ln 39, Cust.-Owned: Ln 24
62	250W High Pressure Sodium Street Light	$21.07	$11.96	Co.-Owned: Ln 25 + Ln 40, Cust.-Owned: Ln 25
63	400W High Pressure Sodium Flood Light	$27.56	$18.45	Co.-Owned: Ln 26 + Ln 41, Cust.-Owned: Ln 26
64	400W High Pressure Sodium Street Light	$27.56	$18.45	Co.-Owned: Ln 27 + Ln 42, Cust.-Owned: Ln 27
	Light Emitting Diode ("LED") Lights			
65	43W LED Street Light	$9.55		Co.-Owned: Ln 28 + Ln 43
66	54W LED Street Light	$9.97		Co.-Owned: Ln 29 + Ln 44
67	130W LED Street Light	$12.67		Co.-Owned: Ln 30 + Ln 45
68	258W LED Street Light	$21.41		Co.-Owned: Ln 31 + Ln 46
	Poles			
69	Wood Pole	$5.20		Co.-Owned: Ln 47
70	Ornamental Pole	$7.81		Co.-Owned: Ln 48
	Metered Lights			
71	Company Owned	$0.2295253		Co.-Owned: Ln 32 + Ln 49
72	Customer Owned		$0.0958247	Cust.-Owned: Ln 33

For the proposed Customer-Owned and Maintained option, to allow for ma imum fle ibilit , the Compan utilized a wattage range structure, where the customer provides the Compan information supporting the total wattage of lights that will be installed. ased on that information, those lights are placed and billed under the appropriate wattage range depicted in Table -5 below.

Table D-5: Monthly Charges for Customer-Owned and Maintained Lighting

Line No.	Fixture Wattage Range (Wattage includes all ballast losses if applicable - Customer Supplied)				Monthly kWh Usage (1), (2)	Monthly Rate Per Unit (2) Monthly kWh Usage * $0.0881567 per kWh
1	0.0	to	10.0	Watts	3.555	$0.34
2	10.1	to	20.0	Watts	7.110	$0.68
3	20.1	to	30.0	Watts	10.665	$1.02
4	30.1	to	40.0	Watts	14.220	$1.36
5	40.1	to	50.0	Watts	17.775	$1.70
6	50.1	to	60.0	Watts	21.330	$2.04
7	60.1	to	70.0	Watts	24.885	$2.38
8	70.1	to	80.0	Watts	28.440	$2.73
9	80.1	to	90.0	Watts	31.995	$3.07
10	90.1	to	100.0	Watts	35.550	$3.41
11	100.1	to	110.0	Watts	39.105	$3.75
12	110.1	to	120.0	Watts	42.660	$4.09
13	120.1	to	130.0	Watts	46.215	$4.43
14	130.1	to	140.0	Watts	49.770	$4.77
15	140.1	to	150.0	Watts	53.325	$5.11
16	150.1	to	160.0	Watts	56.880	$5.45
17	160.1	to	170.0	Watts	60.435	$5.79
18	170.1	to	180.0	Watts	63.990	$6.13
19	180.1	to	190.0	Watts	67.545	$6.47
20	190.1	to	200.0	Watts	71.100	$6.81
21	200.1	to	210.0	Watts	74.655	$7.15
22	210.1	to	220.0	Watts	78.210	$7.49
23	220.1	to	230.0	Watts	81.765	$7.84
24	230.1	to	240.0	Watts	85.320	$8.18
25	240.1	to	250.0	Watts	88.875	$8.52
26	250.1	to	260.0	Watts	92.430	$8.86
27	260.1	to	270.0	Watts	95.985	$9.20
28	270.1	to	280.0	Watts	99.540	$9.54
29	280.1	to	290.0	Watts	103.095	$9.88
30	290.1	to	300.0	Watts	106.650	$10.22
31	300.1	to	310.0	Watts	110.205	$10.56
32	310.1	to	320.0	Watts	113.760	$10.90
33	320.1	to	330.0	Watts	117.315	$11.24
34	330.1	to	340.0	Watts	120.870	$11.58
35	340.1	to	350.0	Watts	124.425	$11.92
36	350.1	to	360.0	Watts	127.980	$12.26
37	360.1	to	370.0	Watts	131.535	$12.60
38	370.1	to	380.0	Watts	135.090	$12.94
39	380.1	to	390.0	Watts	138.645	$13.29
40	390.1	to	400.0	Watts	142.200	$13.63

Notes

(1) Monthly kWh usage = Maximum Wattage in range x 355.5 hours per month / 1,000 Watts per kW.

(2) For Customer Owned and Maintianed lights larger than 400W, the applicable usage and rate shall be the sum of the 390.1 - 400.0 Watts row in the table above plus a wattage range such that the resulting range encompasses the actual wattage of the light (Example: for a 600 Watt light, the applicable usage and charge is determined by adding the 390.1 – 400.0 Watts row and the 190.1 – 200.0 Watts row together, resulting in a 590.1 – 600.0 Watt Range with a monthly usage of 213.300 kWh and a monthly charge of $20.44.)

Concurrent with the Rate 20 light and pole charges calculated above, Rider 35 charges are also calculated on an iterative basis subject to the following limit: that no combination of light rate + pole rate + CAR rate can result in a total bundled increase greater that 17%. Table E below depicts the Proposed CAR Rates.

Table E: Calculation of Proposed PNM South CAR Rates by Light and Pole Type

Line No.	Banner Rate (PNM South)	Rate Description	Total Stip Rate [A] Rate 20 WP #5, item (l)	Proposed Rate per kWh [B] Rate 20 WP #4, Table 4	Proposed Light Rate [C] Rate 20 WP #4, Table 4	Proposed Pole Rate [D] Rate 20 WP #4, Table 4	Proposed FPPCAC Rate [E] $0 (Value reset)	Proposed CAR (Capped so that Total Rate Change is Between -24.3% and 17.0%) [F] Min((A) * 117.0% - (B) - (C) - (D) - (E)),0)	Proposed Total Rate [G] (B) + (C) + (D) + (E) + (F)	Proposed Total Rate Change in Percent [H] (G) / (A)
1	L1Z5	Sch I, Metered Muni Lts (PNM)	$0.1097304	$0.2295253			$0.0000000	($0.1011407)	$0.1283846	17.0%
2	L2Z5	Sch II, Metered Muni Lts (Cust)	$0.1017385	$0.0958247			$0.0000000	$0.0000000	$0.0958247	-5.8%
3	L3A2	Sch III (OH-WP): 100W HPS (45 kWh)	$9.94		$13.70	$5.20	$0.00	($7.27)	$11.63	17.0%
4	L3A4	Sch V (UG-WP): 100W HPS (45 kWh)	$12.78		$13.70	$5.20	$0.00	($3.95)	$14.95	17.0%
5	L3C2	Sch III (OH-WP): 400W HPS (165 kWh)	$17.62		$27.56	$5.20	$0.00	($12.14)	$20.62	17.0%
6	L3D1	Sch VI (Cust.): 175W MV (73 kWh)	$7.43		$8.16	$0.00	$0.00	$0.00	$8.16	9.8%
7	L3D2	Sch III (OH-WP): 175W MV (73 kWh)	$7.84		$16.83	$5.20	$0.00	($12.86)	$9.17	17.0%
8	L3D4	Sch V (UG-WP): 175W MV (73 kWh)	$7.84		$16.83	$5.20	$0.00	($12.86)	$9.17	17.0%
9	L3F2	Sch III (OH-WP): 400W MV (162 kWh)	$17.61		$27.22	$5.20	$0.00	($11.82)	$20.60	17.0%
10	L3T2	Sch III (OH-WP): 200W HPS (89 kWh)	$12.76		$18.45	$5.20	$0.00	($8.72)	$14.93	17.0%
11	L3T4	Sch V (UG-WP): 200W HPS (89 kWh)	$15.22		$18.45	$5.20	$0.00	($5.84)	$17.81	17.0%
12	L3U2	Sch III (OH-WP): 55W LPS (28 kWh)	$9.84		$12.93	$5.20	$0.00	($6.62)	$11.51	17.0%
13	L3U4	Sch V (UG-WP): 55W LPS (28 kWh)	$9.84		$12.93	$5.20	$0.00	($6.62)	$11.51	17.0%
14	L3V2	Sch III (OH-WP): 135W LPS (63 kWh)	$14.27		$18.49	$5.20	$0.00	($6.99)	$16.70	17.0%
15	L4A2	Sch IV (OH-MP): 100W HPS (45 kWh)	$18.09		$13.70	$7.81	$0.00	($0.34)	$21.17	17.0%
16	L4A4	Sch V (UG-MP): 100W HPS (45 kWh)	$12.78		$13.70	$7.81	$0.00	($6.56)	$14.95	17.0%
17	L4C2	Sch IV (OH-MP): 400W HPS (165 kWh)	$24.53		$27.56	$7.81	$0.00	($6.67)	$28.70	17.0%
18	L4C4	Sch V (UG-MP): 400W HPS (165 kWh)	$24.53		$27.56	$7.81	$0.00	($6.67)	$28.70	17.0%
19	L4D2	Sch IV (OH-MP): 175W MV (73 kWh)	$7.84		$16.83	$7.81	$0.00	($15.47)	$9.17	17.0%
20	L4D4	Sch V (UG-MP): 175W MV (73 kWh)	$7.84		$16.83	$7.81	$0.00	($15.47)	$9.17	17.0%
21	L4F2	Sch IV (OH-MP): 400W MV (162 kWh)	$20.08		$27.22	$7.81	$0.00	($11.54)	$23.49	17.0%
22	L4F4	Sch V (UG-MP): 400W MV (162 kWh)	$20.08		$27.22	$7.81	$0.00	($11.54)	$23.49	17.0%
23	L4T2	Sch IV (OH-MP): 200W HPS (89 kWh)	$20.41		$18.45	$7.81	$0.00	($2.38)	$23.88	17.0%
24	L4T4	Sch V (OH-MP): 200W HPS (89 kWh)	$21.30		$18.45	$7.81	$0.00	($1.84)	$24.92	17.0%
25	L4U2	Sch IV (OH-MP): 55W LPS (28 kWh)	$9.84		$12.93	$7.81	$0.00	($9.23)	$11.51	17.0%
26	L4U4	Sch V (UG-MP): 55W LPS (28 kWh)	$9.84		$12.93	$7.81	$0.00	($9.23)	$11.51	17.0%
27	L4V4	Sch V (UG-MP): 135W LPS (63 kWh)	$14.27		$18.49	$7.81	$0.00	($9.60)	$16.70	17.0%
28	L6F2	Sch IV (OH-MP): 2-400W MV (324 kWh)	$35.42		$54.44	$7.81	$0.00	($20.81)	$41.44	17.0%
29	L6F4	Sch V (UG-MP): 2-400W MV (324 kWh)	$35.42		$54.44	$7.81	$0.00	($20.81)	$41.44	17.0%
30	L7A1	Sch VI (Cust.): 100W HPS (45 kWh)	$4.57		$5.03	$0.00	$0.00	$0.00	$5.03	10.1%
31	L7A2	Sch III (OH-WP): 100W HPS (45 kWh)	$9.94		$13.70	$0.00	$0.00	($2.07)	$11.63	17.0%
32	L7A3	Sch VI (Cust.): 100W HPS (45 kWh)	$4.57		$5.03	$0.00	$0.00	$0.00	$5.03	10.1%
33	L7C1	Sch VI (Cust.): 400W HPS (165 kWh)	$16.78		$18.45	$0.00	$0.00	$0.00	$18.45	10.0%
34	L7C2	Sch III (OH-WP): 400W HPS (165 kWh)	$17.62		$27.56	$0.00	$0.00	($6.94)	$20.62	17.0%
35	L7C3	Sch VI (Cust.): 400W HPS (165 kWh)	$16.78		$18.45	$0.00	$0.00	$0.00	$18.45	10.0%
36	L7D1	Sch VI (Cust.): 175W MV (73 kWh)	$7.43		$8.16	$0.00	$0.00	$0.00	$8.16	9.8%
37	L7D2	Sch III (OH-WP): 175W MV (73 kWh)	$7.84		$16.83	$0.00	$0.00	($7.66)	$9.17	17.0%
38	L7D3	Sch VI (Cust.): 175W MV (73 kWh)	$7.43		$8.16	$0.00	$0.00	$0.00	$8.16	9.8%
39	L7F1	Sch VI (Cust.): 400W MV (162 kWh)	$16.48		$18.11	$0.00	$0.00	$0.00	$18.11	9.9%
40	L7F2	Sch III (OH-WP): 400W MV (162 kWh)	$17.61		$27.22	$0.00	$0.00	($6.62)	$20.60	17.0%
41	L7F3	Sch VI (Cust.): 400W MV (162 kWh)	$16.48		$18.11	$0.00	$0.00	$0.00	$18.11	9.9%
42	L7T1	Sch VI (Cust.): 200W HPS (89 kWh)	$9.05		$9.95	$0.00	$0.00	$0.00	$9.95	9.9%
43	L7T2	Sch III (OH-WP): 200W HPS (89 kWh)	$12.76		$18.45	$0.00	$0.00	($3.52)	$14.93	17.0%
44	L7T3	Sch VI (Cust.): 200W HPS (89 kWh)	$9.05		$9.95	$0.00	$0.00	$0.00	$9.95	9.9%
45	L7U2	Sch III (OH-WP): 55W LPS (28 kWh)	$9.84		$12.93	$0.00	$0.00	($1.42)	$11.51	17.0%
46	L7V2	Sch III (OH-WP): 135W LPS (63 kWh)	$14.27		$18.49	$0.00	$0.00	($1.79)	$16.70	17.0%
47	L8A1	Sch VI (Cust.): 100W HPS (45 kWh)	$4.57		$5.03	$0.00	$0.00	$0.00	$5.03	10.1%
48	L8A2	Sch IV (OH-MP): 100W HPS (45 kWh)	$18.09		$13.70	$0.00	$0.00	$0.00	$13.70	-24.3%
49	L8A3	Sch VI (Cust.): 100W HPS (45 kWh)	$4.57		$5.03	$0.00	$0.00	$0.00	$5.03	10.1%
50	L8C1	Sch VI (Cust.): 400W HPS (165 kWh)	$16.78		$18.45	$0.00	$0.00	$0.00	$18.45	10.0%
51	L8C2	Sch IV (OH-MP): 400W HPS (165 kWh)	$24.53		$27.56	$0.00	$0.00	$0.00	$27.56	12.4%
52	L8C3	Sch VI (Cust.): 400W HPS (165 kWh)	$16.78		$18.45	$0.00	$0.00	$0.00	$18.45	10.0%
53	L8D1	Sch VI (Cust.): 175W MV (73 kWh)	$7.43		$8.16	$0.00	$0.00	$0.00	$8.16	9.8%
54	L8D2	Sch IV (OH-MP): 175W MV (73 kWh)	$7.84		$16.83	$0.00	$0.00	($7.66)	$9.17	17.0%
55	L8D3	Sch VI (Cust.): 175W MV (73 kWh)	$7.43		$8.16	$0.00	$0.00	$0.00	$8.16	9.8%
56	L8F1	Sch VI (Cust.): 400W MV (162 kWh)	$16.48		$18.11	$0.00	$0.00	$0.00	$18.11	9.9%
57	L8F2	Sch IV (OH-MP): 400W MV (162 kWh)	$20.08		$27.22	$0.00	$0.00	($3.73)	$23.49	17.0%
58	L8F3	Sch VI (Cust.): 400W MV (162 kWh)	$16.48		$18.11	$0.00	$0.00	$0.00	$18.11	9.9%
59	L8T1	Sch VI (Cust.): 200W HPS (89 kWh)	$9.05		$9.95	$0.00	$0.00	$0.00	$9.95	9.9%
60	L8T2	Sch IV (OH-MP): 200W HPS (89 kWh)	$20.41		$18.45	$0.00	$0.00	$0.00	$18.45	-9.6%
61	L8T3	Sch VI (Cust.): 200W HPS (89 kWh)	$9.05		$9.95	$0.00	$0.00	$0.00	$9.95	9.9%
62	L8U2	Sch IV (OH-MP): 55W LPS (28 kWh)	$9.84		$12.93	$0.00	$0.00	($1.42)	$11.51	17.0%

Rate 6 – Rate Design Methodology

The rate re-design of Rate 6 – Private Area Lighting, while incorporating many similarities to Rate 20 – Streetlighting, was simpler for a number of reasons including:

1. There are fewer light and pole options.
2. All lights are served overhead
3. All lights are Company-owned.
4. Since the overall rate levels between PNM North and PNM South customers are fairly close under current rates, there was no pressing need to maintain a Consolidation Adjustment Rider.

The proposed revenue requirement in this case for the Private Area Lighting Class is $3,059,654. This revenue requirement is provided, by revenue category, in Table F below:

Table F: Rate 6 - Private Area Lighting Class Revenue Requirements by Category

Line No.	Category of Revenue	Revenue Requirement
1	Base Fuel	$426,775
2	Fuel Related Non-Fuel	$162,029
3	Generation	$508,649
4	Transmission	$241,921
5	Substation	$72,505
6	Primary Distribution	$225,102
7	Secondary Distribution	$194,073
8	Customer Costs	$0
9	O&M	$256,419
10	Company-Owned Lights and Poles	$972,181
11	Total Revenue Requirements	$3,059,654

Lines 1-9 of Table F represent costs that are allocated to individual lights on a on a per kWh basis. Line 10 of Table F represents costs that are allocated to lights and poles on a per unit basis. Table G below, used the revenue requirements from Table F and allocates those revenue requirements to each light and pole based on the per kWh and per unit method, with small rounding adjustments used to balance class revenue recovery.

Table G: Rate 6 - Private Area Light and Pole Rate Design and Component Proof-Of-Revenue

Line No.	Component Type and Description		Monthly kWh per Unit [A]	Light and Pole Units [B]	kWh Usage [C] = [A] * [B]	Replacement Cost [D]	Class Replacement Cost [E] = [B] * [D] / 12	Company Owned Lights and Poles Allocator [F] = [E] / Sum of [E]	Allocation of Company Owned Lights and Poles [G] = $972,181 * [F]	Company Owned Light & Pole Recovery [H] = [F] / [B]	Remaining Private Light Revenue Requirement [I] = $2,087,473 / 16,157,184 kWh * [A]	Rounding Adjustments [J]	Proposed Light and Pole Rates [K] = [H] + [I] + [J]	Component Proof-Of-Revenue [L = [B] * [J]
12	Area Lights	175W MV AL	73	48,396	3,532,908	$1,607.75	$6,484,056	0.205754	$200,030	$4.13	$9.43	($0.09)	**$13.47**	$651,894
13	Area Lights	400W MV AL	162	3,180	515,160	$1,681.92	$445,709	0.014143	$13,750	$4.32	$20.93	($0.09)	**$25.16**	$80,009
14	Area Lights	100W HPS AL	45	91,476	4,116,420	$1,607.75	$12,255,878	0.388907	$378,088	$4.13	$5.81		**$9.94**	$909,271
15	Area Lights	200W HPS AL	89	10,824	963,336	$1,681.92	$1,517,092	0.048141	$46,802	$4.32	$11.50	$0.11	**$15.93**	$172,426
16	Flood Lights	200W HPS FL	89	804	71,556	$1,681.92	$112,689	0.003576	$3,476	$4.32	$11.50	$0.11	**$15.93**	$12,808
17	Flood Lights	400W HPS FL	165	38,316	6,322,140	$1,816.91	$5,801,394	0.184092	$178,970	$4.67	$21.32	$0.11	**$26.10**	$1,000,048
18	Flood Lights	400W MH FL	162	3,192	517,104	$1,782.57	$474,164	0.015046	$14,628	$4.58	$20.93	$0.01	**$25.52**	$81,460
19	Flood Lights	1,000W MH FL	380	312	118,560	$2,030.06	$52,782	0.001675	$1,628	$5.22	$49.10		**$54.32**	$16,948
20	Poles	Wood		21,780		$1,423.87	$2,584,324	0.082007	$79,725	$3.66	$0.00		**$3.66**	$79,715
21	Poles	30' Wood		6,480		$1,423.87	$768,690	0.024399	$23,720	$3.66	$0.00		**$3.66**	$23,717
22	Poles	35' Wood		8,388		$1,423.87	$995,285	0.031583	$30,704	$3.66	$0.00		**$3.66**	$30,700
23	Poles	40' Wood		180		$1,423.87	$21,358	0.000678	$659	$3.66	$0.00		**$3.66**	$659
24	Totals			233,328	16,157,184		$31,513,619	1.000000	$972,181					$3,059,654
25	Target Totals													$3,059,654
26	Difference													($0)

Please note the following concerning Table F:

1. Replacement Cost (Table G, Item [D]) represents the current cost to replace each light and pole.
2. 175W Mercury Vapor area light is no longer available (assumes 100W High Pressure Sodium area light as replacement).
3. 400W Mercury Vapor area light is no longer available (assumes 200W High Pressure area light as replacement).
4. 30' Wood pole no longer available (assumes 35' Wood pole as replacement).
5. All light costs assume lamp, arm, and 150' of secondary.
6. All light and pole replacement costs provided by PNM's Streetlight Administrator.
7. Replacement costs for all wood poles are set at $1,423.87, which is the replacement cost of a 35' wood pole.
8. Because all costs are rounded to the nearest $0.01, in order to balance total Private Area Lighting revenue recovery to the total target revenue requirement, three adjustments were used.
   a. The two negative adjustments depicted in Table G (Item [J], lines 12 & 13) were applied to the light types that experience the largest proposed base rate increase under this re-design, thus mitigating some of that increase.
   b. There were three lights which received a $0.11 adjustment in Table G (Item [J], lines 15-17). These were applied to the three lights that received a proposed base rate decrease under this re-design, thus mitigating some of that decrease.
   c. A small adjustment of $0.01 in Table G (Item [J], Line 18) was made to complete the balancing of Private Area Lighting revenue recovery to the total target revenue requirement.
9. No rounding adjustment utilized in Table G impacted the total proposed base rate for the light by more than 0.7%.

Derivation of Revenue Balancing Account components

PNM Exhibit SC-16

Is contained in the following page.

PNM Exhibit SC-16

Development of Rate 42- Revenue Balancing Account

		Schedule 1A/1B			Schedule 2A/2B			
	A	B	C	D	E	F	G	
		Residential			Small Power			
Line No.	Description	Revenue - $	Unit Costs/ Customer	Unit Costs/ kWh	Revenue - $	Unit Costs/ Customer	Unit Costs/ kWh	
	Test Period Units							
1	Annual Number of Customers			5,495,445			634,785	Cust
2	Annual Energy Sales			3,208,643,660			907,469,792	Sales
3	**Revenue Requirements by Cost Component**							
4	Customer Revenue Requirements (Fixed)	$ 70,358,006	$ 12.80	$ 0.02193	$ 14,848,546	$ 23.39	$ 0.01636	$/Cust
5	Demand Revenue Requirements (Fixed)	$ 275,389,989	$ 50.11	$ 0.08583	$ 86,068,807	$ 135.59	$ 0.09484	$/Cust
6	**Total Fixed Cost Requirements**	$ 345,747,995	$ 62.92	$ 0.10776	$ 100,917,353	$ 158.98	$ 0.11121	L4+L5
7	Energy (Non-Fuel) Revenue Requirements (Variable)	$ 19,482,782	$ 3.55	$ 0.00607	$ 5,646,539	$ 8.90	$ 0.00622	$/kWh
8	Base Fuel Requirements (Variable)							$/kWh
9	**Total Variable Cost Requirements**	$ 19,482,782	$ 3.55	$ 0.00607	$ 5,646,539	$ 8.90	$ 0.00622	L7+L8
10	***Total Revenue Requirements***	***$ 365,230,777***	***$ 66.46***	***$ 0.11383***	***$ 106,563,891***	***$ 167.87***	***$ 0.11743***	L6+L9
	Total Revenue Requirements Inc. Fuel	$ 449,983,703			$ 130,533,745			Rev. Req.
11	**Pricing by Revenue Component**							
12	Customer Charge Revenues	$ 70,362,497	$ 12.80	$ 0.02193	$ 14,847,621	$ 23.39	$ 0.01636	$/Cust
13	Demand Charge Revenues	$ -			$ -			
14	**Total Fixed Cost Revenues**	$ 70,362,497	$ 12.80	$ 0.02193	$ 14,847,621	$ 23.39	$ 0.01636	L12+L13
15	**Total Variable (Energy Charge) Revenues**	$ 379,621,212	$ 69.08	$ 0.11831	$ 115,686,137	$ 182.24	$ 0.12748	kWh Revenue
16	***Total Revenues***	***$ 449,983,708***	***$ 81.88***	***$ 0.14024***	***$ 130,533,758***	***$ 205.63***	***$ 0.14384***	L14+L15
17								
18	Fixed Costs Recovered by Variable (Energy) Charges	$ 275,385,498	$ 50.11	$ 0.08583	$ 86,069,731	$ 135.59	$ 0.09485	L6-L14
19								
20	**Fixed Costs Per Customer Factor (FCC)**	**$ 275,385,498**	***$ 50.11***		**$ 86,069,731**	***$ 135.59***		L18/L1
21	**Fixed Costs per Energy Factor (FCE)**	**$ 275,385,498**	***$ 0.0858261***		**$ 86,069,731**	***$ 0.0948458***		L18/L2

A detailed calculation of a cost-based Distributed Generation Interconnection Fee for the applicable customer classes

PNM Exhibit SC-17

Is contained in the following page.

Development of Distributed Generation Interconnection Fee - Rider No. 41
Based on New Mexico Rate Case No. 14-00332-UT Determinants

	A	B	C	D	E	F	G	H	
Line No.	Description	Schedule 1 Residential Service	Schedule 2 Small Power Service	Schedule 3 General Power Service	Schedule 4 Large Power Service	Schedule 5 Large Service for Customers >=8,000kW	Schedule 10 Irrigation Service	Schedule 11 Water/Sewage Pumping	Notes
1	Annual Number of Customers	5,495,445	634,785	52,002	2,594	24	3,792	1,884	
2	Annual Energy Sales (kWh)	3,208,643,660	907,469,792	1,930,290,534	1,131,474,613	86,000,000	25,795,279	167,315,661	
3									
4	**Revenue Requirements by Cost Component**								
5	Customer Revenue Requirements (Fixed)	$ 70,358,006	$ 14,848,546	$ 3,577,863	$ 1,313,455	$ 63,167	$ 164,118	$ 459,573	
6	Production Demand Revenue Requirements (Fixed)	$ 170,599,485	$ 53,576,286	$ 89,055,954	$ 47,834,006	$ 3,364,729	$ 1,028,242	$ 4,506,565	
7	Transmission Demand Revenue Requirements (Fixed)	$ 38,902,436	$ 10,334,865	$ 18,991,240	$ 10,051,164	$ 722,685	$ 187,914	$ 859,556	
8	Distribution Demand Revenue Requirements (Fixed)	$ 65,888,067	$ 22,157,655	$ 32,569,334	$ 11,498,742	$ 250,154	$ 652,176	$ 2,088,677	
9	Total Demand Revenue Requirements (Fixed)	$ 275,389,989	$ 86,068,807	$ 140,616,528	$ 69,383,911	$ 4,337,567	$ 1,868,332	$ 7,454,798	L6 + L7 + L8
10	Total Fixed Cost Requirements	$ 345,747,995	$ 100,917,353	$ 144,194,391	$ 70,697,366	$ 4,400,734	$ 2,032,450	$ 7,914,371	
11	Energy (Non-Fuel) Revenue Requirements (Variable)	$ 19,482,782	$ 5,646,539	$ 13,006,687	$ 6,911,839	$ 517,118	$ 133,961	$ 1,022,081	
12	Base Fuel Requirements (Variable)	$ 84,752,926	$ 23,969,854	$ 50,986,581	$ 29,341,119	$ 2,195,195	$ 681,355	$ 4,338,788	
13	Total Variable Cost Requirements	$ 104,235,708	$ 29,616,393	$ 63,993,268	$ 36,252,958	$ 2,712,314	$ 815,316	$ 5,360,869	L11 + L12
14									
15	Total Revenue Requirements	$ 449,983,703	$ 130,533,745	$ 208,187,659	$ 106,950,324	$ 7,113,048	$ 2,847,766	$ 13,275,240	L9 + L13
16									
17	**Pricing by Revenue Component**								
18	Customer Charge Revenues	$ 70,362,497	$ 14,847,621	$ 3,577,740	$ 1,313,601	$ 63,167	$ 164,118	$ 459,564	
19	Demand Charge Revenues	$ -	$ -	$ 96,036,832	$ 47,746,967	$ 3,475,076	$ -	$ -	
20	Energy Charge Revenues	$ 379,621,212	$ 115,686,137	$ 108,573,082	$ 57,889,761	$ 3,574,804	$ 2,683,648	$ 12,815,679	
21	Total Revenues	$ 449,983,708	$ 130,533,758	$ 208,187,654	$ 106,950,329	$ 7,113,047	$ 2,847,765	$ 13,275,243	L18 + L19 + L20
22	Fixed Cost Recovery: Customer and Demand Charges	$ 70,362,497	$ 14,847,621	$ 99,614,572	$ 49,060,568	$ 3,538,243	$ 164,118	$ 459,564	L18 + L19
23	Fixed Cost Recovery: Variable Energy Charges	$ 275,385,498	$ 86,069,731	$ 44,579,819	$ 21,636,798	$ 862,491	$ 1,868,333	$ 7,454,806	L10 - L22
24									
25	**DG Fixed Cost Recovery Requirements**								
26	**Fixed Cost Recovery on kWh Basis**	**$ 0.08583**	**$ 0.09485**	**$ 0.02309**	**$ 0.019123**	**$ 0.010029**	**$ 0.072429**	**$ 0.044555**	L23 / L2
27									
28	Solar Hours per month (kWh per 1kW-AC Capacity)	194.92	194.92	194.92	194.92	194.92	194.92	194.92	Monthly sun hours
29	**Solar DG Interconnection Fee - per kW-AC**	**$ 16.73**	**$ 18.49**	**$ 4.50**	**$ 3.73**	**$ 1.95**	**$ 14.12**	**$ 8.68**	L26 * L28
30									
31	**Proposed Solar DG Interconnection Fee per kW-AC**	$ 6.00	$ 6.00	$ 4.50	$ 3.73	$ 1.95	$ 6.00	$ 6.00	
32									
33	Wind Hours per month (kWh per 1kW-AC Capacity)	167.90	167.90	167.90	167.90	167.90	167.90	167.90	Monthly wind hours
34	**Wind DG Interconnection Fee - per kW-AC**	**$ 14.41**	**$ 15.92**	**$ 3.88**	**$ 3.21**	**$ 1.68**	**$ 12.16**	**$ 7.48**	L26 * L28
35									
36	**Proposed Wind DG Interconnection Fee per kW-AC**	$ 6.00	$ 6.00	$ 3.88	$ 3.21	$ 1.68	$ 6.00	$ 6.00	

Test Period Proposed Base Fuel Proof of Revenue

PNM Exhibit SC-18

Is contained in the following page.

Test Year Proposed Base Fuel Rate Proof of Revenue

Line No.	Description	Value	Notes
1	Base Fuel	$218,259,746	*[A]*
2	Consolidated kWh at Meter	8,312,976,406	*[B]*
3	Average Base Fuel Rate	$0.0262553	*[C] = [A] / [B]*

Consolidated Class Base Fuel Allocations

Line No.	Rate Class	Voltage Class	Consolidated kWh at Meter *[D]*	Cumulative Loss Factor *[E]*	Consolidated kWh at Generator *[F] = [D] * [E]*	Voltage Class Adjustment Factors *[G] = [E] / [E] $_{TOTAL}$*	Base Fuel Rate per kWh *[H] = [C] * [G]*	Base Fuel Revenue by Rate Class *[I] = [D] * [H]*
4	1 - Residential	Sec. Dist	3,208,643,660	1.0808	3,467,857,385	1.0060429	$0.0264140	$84,752,998
5	2 - Small Power	Sec. Dist	907,469,792	1.0808	980,780,714	1.0060429	$0.0264140	$23,969,874
6	3B/3C - General Power	Sec. Dist	1,930,290,534	1.0808	2,086,231,128	1.0060429	$0.0264140	$50,986,625
7	4B - Large Power	Pri. Dist	1,131,474,613	1.0611	1,200,555,028	0.9876749	$0.0259317	$29,341,068
8	5B - Large Service for Customers >=8,000kW	Subtransmission	86,000,000	1.0444	89,820,931	0.9722005	$0.0255254	$2,195,186
9	10 - Irrigation	Sec. Dist	25,795,279	1.0808	27,879,178	1.0060429	$0.0264140	$681,356
10	11B - Wtr/Swg Pumping	Pri. Dist	167,315,661	1.0611	177,530,857	0.9876749	$0.0259317	$4,338,781
11	15B - Universities 115 kV	Transmission	67,984,267	1.0419	70,833,676	0.9698579	$0.0254639	$1,731,146
12	30B - Manuf. (30 MW)	Substation	482,610,203	1.0496	506,526,633	0.9769729	$0.0256507	$12,379,301
13	33B - Large Service for Station Power	Transmission	3,247,400	1.0419	3,383,508	0.9698579	$0.0254639	$82,692
14	34B - Large Power Service >=3,000kW	Substation	236,001,800	1.0496	247,697,202	0.9769729	$0.0256507	$6,053,617
15	6 - Private Lighting	Sec. Dist	16,157,184	1.0808	17,462,459	1.0060429	$0.0264140	$426,775
16	20 - Streetlighting	Sec. Dist	49,986,012	1.0808	54,024,186	1.0060429	$0.0264140	$1,320,329
17	Totals		8,312,976,406	1.0743	8,930,582,887	1.0000000	$0.0262553	$218,259,746

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. 507	)	**Case No. 14-00332-UT**
PUBLIC SERVICE COMPANY OF NEW MEXICO, Applicant.	)	

AFFIDAVIT

STATE OF NEW MEXICO)
) ss
COUNTY OF BERNALILLO)

STELLA CHAN, Director of Pricing and Load Research for Public Service Company of New Mexico ("PNM" or "Company"), upon being duly sworn according to law, under oath, deposes and states: I have read the foregoing **Direct Testimony and Exhibits of Stella Chan** and it is true and accurate based on my own personal knowledge and belief.

GCG # 519029

SIGNED this 8th day of December, 2014.

STELLA CHAN

SUBSCRIBED AND SWORN to before me this 8th day of December, 2014.

NOTARY PUBLIC IN AND FOR
THE STATE OF NEW MEXICO

My Commission Expires:

OFFICIAL SEAL
Ronda Morehead
NOTARY PUBLIC
STATE OF NEW MEXICO
My Commission Expires: 7/5/15

GCG # 519029