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MATIAS F. TRAVIESO-DIAZ
202.663.8142
matias.travieso-diaz@shawpittman.com

August 14, 2000

BY HAND DELIVERY

Steven R. Hom, Esq.
NRC Office of General Counsel
U.S. Nuclear Regulatory Commission
M/S 15D21
11555 Rockville Pike
Rockville, MD 20852-2738

Re: Palo Verde Nuclear Generating Station, Units 1, 2 and 3 (Docket Nos. STN 50-528/529/530, Facility Operating License Nos. NPF-41, NPF-51, NPF-74) --Application By Public Service Company of New Mexico for Consent to Indirect Transfers of Control and Approval of License Amendments to Reflect Licensee's Name Change

Dear Mr. Hom:

Attached, as you requested, is a copy of the Application for Approval of Transition Plan, Part III ("Application") filed by Public Service Company of New Mexico ("PNM") with the New Mexico Public Regulation Commission on May 31, 1999 and the direct testimony of Susan A. Taylor submitted in support of the Application. Ms. Taylor's testimony was filed in support of PNM's request for recovery of stranded costs during the transition to a competitive energy market. The testimony includes a final stranded cost calculation, including nuclear decommissioning costs.

Please note that we are not enclosing the remaining exhibits to the Application since they are voluminous. They are available, however, should you desire to review them. If you have any questions on the enclosed materials or require additional information concerning

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the Application, please contact the undersigned or Terry R. Horn, PNM's Vice President and Treasurer, (505) 241-2119.

Very truly yours,

Matias F. Travieso-Diaz

Matias F. Travieso-Diaz, Esq.
SHAW PITTMAN
2300 N Street, N.W.
Washington, D.C. 20037
(202) 663-8142
matias.travieso-diaz@shawpittman.com
Counsel for Public Service Company of New Mexico

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

In the Matter of Public Service Company of New Mexico's Transition Plan Filed Pursuant to the Electric Utility Industry Restructuring Act of 1999	)	
	)	**Utility Case No. 3137**
Part III - Approval of PNM's Transition Plan	)	**PART III - Transition Plan**
	)	
Public Service Company of New Mexico,	)	
	)	
Petitioner.	)	

APPLICATION FOR APPROVAL OF TRANSITION PLAN, PART III

Public Service Company of New Mexico ("PNM" or "Company"), a utility regulated in New Mexico by the New Mexico Public Regulation Commission ("NMPRC" or "Commission"), hereby files its application ("Application") for approval of Part III of its transition plan ("Transition Plan") filed in accordance with the Electric Utility Industry Restructuring Act of 1999, NMSA 1978, §§ 62-3A-1 through 23 (1999) ("Restructuring Act" or "Act"). The approvals requested in this Application supplement and do not supersede any approvals requested in Parts I and II of this case.

I. Background and Introduction

A. The Restructuring Act requires a public utility to file its Transition Plan no later than March 1, 2000 to show how it intends to comply with the Act. NMSA 1978, § 62-3A-6(A) (1999). In its order in NMPRC Utility Case No. 3220 dated January 18, 2000, the Commission extended the time for all utilities to file their transition plans to June 1, 2000.

B. PNM has filed its Transition Plan in three parts:

- Part I, filed on November 17, 1999, requested approval of a Class II transaction creating two subsidiary "shell" corporations required in order to set in motion certain federal filings and shareholder approvals necessary to effectuate PNM's Separation Plan ("Shell Corporation Approval" or "Part I"). The Commission entered its Order Approving Recommended Decision Concerning Part I Application on February 15, 2000.

- Part II, also filed on November 17, 1999, requested by June 1, 2000 all NMPRC approvals necessary for PNM to implement its Separation Plan to separate its supply service and energy-related service assets from its distribution and transmission services assets in accordance with NMSA 1978, §§ 62-3A-6(A)(1) and 62-3A-8 (1999) and other provisions of the Public Utility Act.

- Part III, the instant filing, completes the filing of all transition plan requirements of the Restructuring Act in accordance with NMSA 1978, §§ 62-3A-6(A)(2) through (13) (1999).

C. PNM's Separation Plan, Part II, calls for PNM to form a holding company, HoldingCo, with two subsidiary corporations, PowerCo and UtilityCo. HoldingCo will provide certain services to all subsidiary companies. PowerCo will own supply service and energy-related service assets and will provide supply service and energy-related service to the public pursuant to the Restructuring Act on a competitive unregulated basis. UtilityCo will own the transmission and distribution assets and provide transmission and distribution services, and customer billing and metering to the public on a regulated basis.

As required by § 62-3A-6(A)(2) through (13), Part III includes a detailed description of PNM's:

(2) associated unbundled cost-of-service studies and an explanation of all cost allocations made to the unbundled services;

(3) proposed methodologies to allow residential and small business customers to have customer choice without requiring additional end-use metering equipment;

(4) proposals to implement customer choice and open access;

(5) proposed standard offer service tariffs, exclusive of price terms that shall be incorporated prior to customer choice, for residential and small business customers that do not select a power supplier pursuant to customer choice eligibility;

(6) proposed competitive procurement process or other process for the selection of power supply for standard offer service tariffs, together with a proposed rate setting procedure;

(7) proposed tariffs for distribution service for customers and competitive power suppliers, and tariffs for transmission service on file with the Federal Energy Regulatory Commission;

(8) projected amounts of stranded costs and transition costs sought to be recovered;

(9) proposed non-bypassable wires charges for recovery of transition costs and stranded costs allocated among customer classes;

(10) proposed system for the collection, recovery and accounting of the system benefits charge and stranded and transition costs through wires charges;

(11) proposed customer education programs, necessary computer hardware and software modifications and meter upgrades necessary to provide open access;

(12) proposed procedures for balancing, settlements and communications with competitive power suppliers; and

(13) other information, documentation or justification requested by the Commission.

D. In addition to the elements required by § 62-3A-6(A)(2) to (12), Part III also includes the following:

(1) A proposal "to address the situation of customers which, after open access pursuant to the Act, may not have genuine access to markets and suppliers beyond PNM's system, and as such could be exposed to excessive market power of a competitive power supplier." PNM agreed to include such a proposal in the Stipulation concluding Case 2761. (See Direct Testimony of Gregory C. Miller.)

(2) A proposal for providing default service to customers that will not be eligible for standard offer service. PNM agreed to include such a proposal in comments submitted to the Commission in Case 3109. (See Direct Testimony of Susan A. Taylor.)

(3) A request for findings required by the federal Public Utility Holding Company Act of 1935, 15 U.S.C. § 79z-5a(c), that the designation of PNM's generation facilities that were rate regulated on or

before October 24, 1992 as "eligible facilities" is consistent with § 32(c) of that Act. (See Direct Testimony of Terry R. Horn.)

(4) Requests for variances from certain provisions of NMPRC Rule 530 (see Direct Testimony of John D. Olmsted); NMPRC Rules 570, 571 and 591.9(A) (see Direct Testimony of Gerard T. Ortiz.)

II. Stranded Cost Recovery

In the testimony filed in support of this Application, PNM presents evidence showing that it is entitled to recovery of 100 percent of its stranded costs pursuant to NMSA § 62-3A-6(B)(1), (2) and (3). The Direct Testimonies of Terry R. Horn, A. Lawrence Kolbe, John H. Landon and Patrick T. Ortiz demonstrate that full recovery of PNM's stranded costs (1) is in the public interest, (2) is necessary to maintain the financial integrity of PNM and (3) is necessary to continue adequate and reliable service by PNM. §62-3A-6(B). With respect to the stranded costs to be recovered from residential and small business customers, it cannot be determined whether recovery of more than 50 percent of stranded costs will cause an increase in rates to those customers during the transition period, until the standard offer supply has been procured and the price is known. After procuring the standard offer supply, PNM will update its Transition Plan with this information and testimony as to the amount of stranded costs recoverable from residential and small business customers in accordance with §§ 62-3A-6B(4) and D. In addition, PNM presents evidence showing that less than 100 percent stranded cost recovery could violate the federal and state constitutions as a taking of property without compensation.

III. Approvals Required

A. PNM is requesting all approvals and determinations necessary to implement its Transition Pan, not previously requested in the Part I and II filings. Specific approvals requested to the full extent authorized and required are:

- Approval of PNM's Transition Plan — NMSA 1978, § 62-3A-6(E)(1) (1999);
- Approval of unbundled cost of service studies and cost allocations and tariffs for distribution service — §§ 6(A)(2) and (7);
- Approval of standard offer procurement process for selection of power supply for standard offer service tariffs — § 6A(6);
- Approval of standard offer service tariffs, exclusive of price terms — § 6(A)(5);
- Approval of amount of projected transition costs to be recovered — §§ 6A(8) and 7(C);
- Approval of amount of stranded costs, including decommissioning costs, to be recovered — § 6A(8);
- Approval of wires charge and true-up mechanism for collection of transition costs allocated among customer classes— § 6A(9);
- Approval of wires charge for collection of stranded costs allocated among customer classes — §§ 6A(9) and 7;
- Approval of a separate wires charge and true-up mechanism, to continue for lives of Palo Verde Units 1 and 2, for collection of nuclear decommissioning stranded costs — § 7(B)(2);
- Approval of system for collection, recovery and accounting of systems benefits charge, stranded costs and transition costs — §§ 6A(10) and 7;
- Approval of customer education programs, expenditures and customer choice notice, necessary computer hardware and software modifications and meter upgrades necessary to provide open access — § 6A(11);
- Approval of procedures for balancing, settlement and communications with Competitive Power Suppliers — § 6A(12);
- Approval of new and revised Service Rules for implementing customer choice and communications with Competitive Power Suppliers - §§ 6A(11) and (12);
- Approval of transitional default service proposal;
- Approval of proposals for implementing customer choice and open access — §§ 6A(3) and (4);
- Determinations that the designation of PNM's generation facilities that were rate regulated on or before October 24, 1992 as "eligible facilities" under the federal Public Utility Holding Co. Act of 1935 (a) will benefit consumers, (b) is in the

public interest and (c) does not violate New Mexico law — 15 U.S.C. § 79z-5a(c); and

- Approval of variances from NMPRC Rules 530, 570, 571 and 591 as set forth in ¶ IV below.

B. PNM believes that its filing complies with requirements under the above statutes and any corresponding rules. The Transition Plan proposed in this filing is required by the Restructuring Act, complies with the Act and will achieve the goals of the Act.

IV. Variances

A. NMPRC Rules 570 and 571 relate to cogeneration and small power production. They contain provisions relating, among other things, to: conditions of utility interconnection with qualifying facilities ("QFs"); contracting between utilities and QFs; metering options; interconnection and safety requirements; and power purchase requirements. Because it will no longer provide bundled service except to those customers who are eligible and choose Standard Offer Service ("SOS"), PNM will no longer be able to provide certain information that is required by, nor will it be in a position to comply with many of the requirements of, Rules 570 and 571. Accordingly, PNM seeks the following variances from the requirements imposed by Rules 570 and 571:

(1) § 570.5(f) and 571.10.2: to allow PNM to include a requirement that QFs not eligible to take SOS, and QFs eligible but not taking SOS, provide proof of an existing contract with a competitive power supplier ("CPS") to provide backup, supplemental, maintenance and buy-back services.

(2) § 570.8(a): to allow PNM to restrict the requirement that the utility buy energy produced during facility testing to QFs taking SOS.

(3) § 570.10, 16, 17, 18 and 20: to allow PNM to restrict the utility's obligation to purchase power QFs which take SOS and to allow PNM to purchase such power at rates based upon the energy component of its SOS rate.

(4) § 570.21, 22 and 23: to allow PNM to restrict the utility's obligation to provide supplementary power, backup power and maintenance power to QFs taking SOS.

(5) § 570.24: to allow PNM to restrict availability of its rates for interruptible power to QFs taking SOS.

(6) § 570.28, 29 and 30, 571.11: to permit these sections to be applicable only to QFs taking SOS.

B. NMPRC Rule 591.9(A) requires each utility to set forth in its transition plan its estimated portfolio of standard offer supply, including estimated costs and proposed sources. PNM proposes herein to procure its standard offer supply using a competitive bid process under which it will not have information on its estimated portfolios, estimated costs and proposed sources until after bids have been selected. See Direct Testimony of Gerard T. Ortiz. PNM will update its Transition Plan with this information after bid selection and seeks a variance from Rule 591.9(A) to do so.

C. NMPRC Rule 530 requires minimum data requirements to be filed in support for new rate schedules. Since PNM's proposed rates are for distribution services only, while its present rates are for bundled service, the information required by the following schedules cannot be calculated (<u>see</u> Direct Testimony of John D. Olmsted): Schedule A-2, Schedule O-1, Schedule O-2, and Schedule O-4.

Projected data associated with PNM's stranded cost calculation required in the following schedules is addressed in the testimony of Susan A. Taylor and has, therefore, been omitted from the schedules: S-1 (2000-01 omitted), P-2 (2000-04 omitted), P-4 (2000-04 omitted), P-4 (2000-04 omitted), P-7 (2000-04 omitted).

V. Testimony

Testimony and exhibits of PNM witnesses Jeffry E. Sterba, Roger J. Flynn, Patrick T. Ortiz, Susan A. Taylor, John H. Landon, A. Lawrence Kolbe, Terry R. Horn, John R. Loyack, Thomas G. Sategna, Gerard T. Ortiz, Joe Brooks, Gregory C. Miller, John D. Olmsted, Julia C. Nieman, Crystal D. McClernon, and Robert S. Childs are provided in support of the Application.

VI. Pleadings and notice should be sent to:

PUBLIC SERVICE COMPANY OF NEW MEXICO
Cynthia McGill, Vice President, Regulatory & Public Policy
Alvarado Square, MS-2704
Albuquerque, NM 87158
(505) 241-2117

WHITE, KOCH, KELLY & McCARTHY, P.A.
Benjamin Phillips
Rebecca Dempsey
Attorneys for Public Service Company of New Mexico
Post Office Box 787
Santa Fe, New Mexico 87504-0787
(505) 982-4374

EASTHAM JOHNSON MONNHEIMER & JONTZ, P.C.
Marilyn C. O'Leary
Charlotte Lamont
500 Marquette NW, Suite 1200
Albuquerque, New Mexico 87102
Post Office Box 1276
Albuquerque, New Mexico 87103
(505) 247-2315

WHEREFORE, PNM hereby requests that the Commission issue a final order granting all approvals required for PNM to implement its Transition Plan as described in this Application and PNM's testimony and exhibits.

Respectfully submitted,

WHITE, KOCH, KELLY & McCARTHY, P.A.

By: ______________________________
BENJAMIN PHILLIPS
REBECCA DEMPSEY
Post Office Box 787
Santa Fe, NM 87504-0787
(505) 982-4374

PUBLIC SERVICE COMPANY OF NEW MEXICO
Joanne Reuter, Deputy General Counsel
414 Silver, SW, M-S 0806
Albuquerque, NM 87102
(505) 241-4932

EASTHAM JOHNSON MONNHEIMER & JONTZ, P.C.
Marilyn C. O'Leary
Charlotte Lamont
500 Marquette NW, Suite 1200
Albuquerque, New Mexico 87102
Post Office Box 1276
Albuquerque, New Mexico 87103
(505) 247-2315

Attorneys for Public Service Company of New Mexico

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BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

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Public Service Company of New Mexico,	)	
Petitioner.	)	

DIRECT TESTIMONY AND EXHIBITS

OF

SUSAN A. TAYLOR

May 31, 2000

DIRECT TESTIMONY
OF
SUSAN A. TAYLOR
NMPRC UTILITY CASE NO. 3137, Part III

Q. PLEASE STATE YOU NAME, BUSINESS ADDRESS, POSITION WITH PUBLIC SERVICE COMPANY OF NEW MEXICO, AND YOUR QUALIFICATIONS.

A. My name is Susan A. Taylor. My business address is Alvarado Square, Albuquerque, New Mexico 87158. I have been employed by Public Service Company of New Mexico ("PNM") since 1986 and currently hold the position of Manager of Planning and Modeling. After separation, I will be employed by Manzano Energy Corporation ("PowerCo"). I have testified in several proceedings before the New Mexico Public Utility Commission ("NMPUC"), the predecessor to the New Mexico Public Regulation Commission ("NMPRC" or "Commission"). Since 1998, my duties have included the projection of wholesale market prices, including evaluating market forecasts prepared by outside consultants. My education and professional background are set forth in PNM Exhibit ____ (SAT-1).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is two fold: first I will project PNM's stranded costs as required in Section 62-3A-6A(8) of the Electric Utility Industry Restructuring Act of 1999 ("the Act"). This includes describing the methodology used, the underlying assumptions and the competitive retail market price projections. Second I will outline PNM's proposal for Transitional Default Service ("TDS") for customers not eligible for standard offer service.

DIRECT TESTIMONY
OF
SUSAN A. TAYLOR
NMPRC UTILITY CASE NO. 3137, Part III

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING PNM'S STRANDED COSTS.

A. The net present value ("NPV") of PNM's stranded costs is $691,619,755 in 2002 dollars excluding stranded costs attributable to nuclear decommissioning. PNM's estimate of stranded costs takes into consideration historical cost reductions and increased operating efficiencies over time.

Q. HOW DID YOU PROJECT PNM'S STRANDED COSTS?

A. The Act contains the following definition of stranded costs:

"stranded costs" means the net present value of the difference between:
(1) the regulated revenue requirements for all utility-generation-related functions, including purchased power, fuel contracts and lease and lease-related obligations, which as of the date of open access, were being recovered in rates, or if not previously recovered in rates, which the commission determines would be recoverable in rates; and
(2) the revenues that could be earned from selling the same generation-related services as specified in Paragraph (1) of this subsection at competitive retail market rates pursuant to retail competition.

I projected PNM's stranded costs in accordance with this definition. As authorized by Section 7.B.(2) of the Act I separated the costs associated with nuclear decommissioning from the other stranded costs. The remaining stranded costs have been used by PNM to determine the non-bypassable stranded costs wires charges for each class of customers. PNM proposes to collect the costs associated with nuclear decommissioning through a separate non-bypassable wires charge that will be adjusted periodically to account for increases or decreases in PNM's funding obligation. PNM witness John Olmsted provides testimony on the derivation of the wires charges.

Q. WOULD YOU PLEASE EXPLAIN HOW YOU DETERMINED PNM'S STRANDED COSTS?

A. Yes. The projection of stranded costs using the definition from the Act was accomplished in three distinct steps. First, the revenue requirements for the generation-related functions were quantified for the life of each generation resource. Second, an estimate of future market prices was used to determine the revenue that can reasonably be expected from these generation-related facilities in a competitive retail market. The final step was to discount the difference in the two revenue streams. I will address each of these steps, with Dr. Kolbe presenting the supporting testimony for the after-tax weighted cost of capital for the fully integrated utility and the methodology to determine the discount rate I used in the final step.

REVENUE REQUIREMENTS FOR GENERATION-RELATED FACILITIES

Q. WOULD YOU PLEASE EXPLAIN HOW YOU DETERMINED GENERATION-RELATED REVENUE REQUIREMENTS?

A. Yes. Initially, I accepted PNM witness Sategna's generation-related unbundled test period ending June 30, 1999 cost-of-service for the existing utility's New Mexico jurisdiction. Next, I made adjustments to this cost-of-service for Palo Verde Nuclear

Generating Station ("Palo Verde") decommissioning, purchased power expense, and related revenue credits. Finally, I constructed an annual revenue requirement for each year from 1999 through 2025 during which period all of PNM's existing assets reach the end of their normal useful life.

Q. WHAT IS DECOMMISSIONING?

A. Decommissioning costs are generally the costs necessary to return a site to its original condition after a facility has reached the end of its useful life.

Q. WHAT ADJUSTMENTS DID YOU MAKE ASSOCIATED WITH PALO VERDE DECOMMISSIONING?

A. I adjusted Palo Verde decommissioning to more accurately reflect customers' contributions to the external sinking fund. Simply stated I removed from the cost-of-service all decommissioning related rate base and expense items. I then replaced these items with the amount of funding needed to cover the New Mexico jurisdictional customers' share of the external sinking fund. This funding amount is based on the most recent TLG Services Inc. study ("TLG study") commissioned by the operator of Palo Verde for the purpose of determining participants' obligation for decommissioning. The effect of this adjustment was to reduce the revenue requirements for the purposes of projecting stranded costs. In past cases, PNM amortized the liability as an expense and made a corresponding adjustment to rate base for the difference between the expense amount and the cash funding amount for the test period. Mr. Sategna acknowledged in Case 2761, which was ultimately stipulated, that the approach previously utilized did not recognize the earnings received on the trust fund balance and that the rate making treatment needed review. The adjustment I have made results in an appropriate level of decommissioning responsibility for New Mexico customers because they contribute only what is needed to fund their share of decommissioning for Palo Verde Units 1 and 2, after crediting their share of trust fund earnings.

Q. WOULD YOU PLEASE DESCRIBE THE ADJUSTMENTS YOU MADE TO PURCHASED POWER EXPENSE?

A. In order to determine PNM's generation-related revenue requirements under regulation, I adjusted purchase power expense by removing purchases made and resold in the wholesale market. Historically, PNM purchased power and energy from the wholesale market to serve jurisdictional load as needed and for resale into the wholesale market. In 1996 PNM embarked on an expanded wholesale marketing program in anticipation of deregulation of the retail electric market. The purpose of the program has been to develop an alternative growth platform given the impending industry restructuring and to contribute to near-term earnings where the risks and rewards were borne by the shareholders rather than customers. Absent the prospect of deregulation PNM would not have pursued this enhanced marketing under the existing rules which allocate all of the benefits of the program to the customers and all of the risks to the shareholders. I adjusted the expenses associated with purchases made for resale by removing them from the stranded costs model. Therefore, I reduced purchased power expense in the test year by approximately $165 million.

Q. WOULD YOU PLEASE EXPLAIN THE ADJUSTMENTS YOU MADE TO REVENUE CREDITS?

A. Yes. The difference in revenue credits corresponds to the change to purchased power expense described above. The sales made from market purchases for resale have been removed. The impact of this adjustment amounts to a reduction of approximately $184 million to the revenue credit for the test year. It is important to note that for each year of the stranded cost projection I credited jurisdictional customers for sales made in the market from excess generation associated with assets in New Mexico rate base.

Q. HOW DOES THE GENERATION-RELATED REVENUE REQUIREMENT, WHICH YOU CALCULATED, COMPARE TO MR. SATEGNA'S?

A. The stranded cost model revenue requirements for 1999 are $15.8 million higher than Mr. Sategna's unbundled generation cost-of-service. Generally the changes described above account for the difference between the generation related revenue requirements for the first year of the stranded cost model and Mr. Sategna's cost-of-service. PNM Exhibit

____(SAT-2) compares this cost-of-service provided by Mr. Sategna to the first year in the stranded costs model.

Q. DID YOU CALCULATE THE REVENUE REQUIREMENTS FOR PNM'S GENERATION ASSETS IN ACCORDANCE WITH GENERALLY ACCEPTED RATEMAKING METHODOLOGIES?

A. Yes. The adjustments to Mr. Sategna's unbundled generation cost of service that I have described are necessary to accurately reflect the jurisdictional revenue requirements going forward.

Q. HOW DID YOU DETERMINE THE REVENUE REQUIREMENTS FOR THE PERIOD FROM 1999 THROUGH 2025?

A. Once the initial year (1999) of the stranded cost model was validated in comparison with Mr. Sategna's 1999 cost-of-service, each element of the cost-of-service was projected to the end of each plant's useful life. Next, adjustments to rate base, decommissioning expense, operation and maintenance expense ("O&M") and fuel expense were made in order to project the revenue requirements for each plant. One particular plant required calculations through 2025.

Q. HOW WAS RATE BASE PROJECTED?

A. Rate base was calculated assuming capital additions to existing plant based on historical levels and the assumption that all plants reached full depreciation at the end of their normal useful life. No new assets have been included, as all additional capacity and energy needed to meet the forecasted New Mexico jurisdictional load are based on market prices. In addition to net plant projections, the calculations include an adjustment for working capital and adjustments for Accumulated Deferred Income Taxes to recognize book-tax timing differences on generation plant assets.

Q. HOW WERE DECOMMISSIONING COSTS PROJECTED ?

A. The anticipated cost for decommissioning is included as an operational cost over the useful life of each facility. This assures that the customers that are currently receiving the benefit of the output of the plant also pay for the final decommissioning.

Decommissioning costs for Palo Verde are based on the current projection of the amount needed to decommission the plant based on the TLG study. The decommissioning revenue requirement is based on the annual cash contribution to the trust that is necessary to fund the external sinking fund at approved levels.

Decommissioning costs for fossil fuel plants are included as part of the current depreciation rates. These rates do not include escalation in decommissioning costs between the time of the decommissioning study which set the rates and the expected date of decommissioning. Therefore, I have escalated decommissioning costs to the end of the plant life for each plant and recalculated the decommissioning component of the depreciation rates. So that customers receive full credit for the contributions that have been made prior to actual decommissioning, current plant values were depreciated to a negative value to represent the projected decommissioning expense. This assures that the value of the reserves at the end of the plant life includes both depreciation and plant decommissioning.

Q. ARE ANY OTHER DECOMMISSIONING COSTS INCLUDED IN THE STRANDED COSTS CALCULATION?

A. Yes. Decommissioning for the reclamation of coal mines at the Four Corners and San Juan generating stations are included in the fuel forecast. Current fuel costs include current, on-going reclamation expense and a small portion of the final reclamation expense. At the end of 1999 PNM made accounting adjustments to recognize the liability associated with final reclamation of the existing surface mining operations at San Juan and Four Corners. PNM is currently negotiating a new coal contract to supply San Juan from an underground mine operation. If successful, the reclamation of existing surface mines could begin as early as 2002. The stranded costs projection assumes successful re-negotiation of the coal contract and early reclamation of the surface mines. Rate payers will benefit from the switch to a lower cost coal supply assumed in the stranded costs projection and therefore should bear the cost of reclamation.

Q. HOW WAS NON-FUEL O&M PROJECTED?

A. First, Mr. Sategna allocated all generation-related O&M to the various generating plants. I adjusted these amounts to exclude scheduled maintenance and then increased base operating O&M by three percent per year to the end of the life of the respective asset. This rate of increase is consistent with historical trends in inflation. The base operating O&M was then adjusted for maintenance outages based on current maintenance cycles, the expected degradation of Palo Verde Unit 1 due to additional tube plugging, and costs associated with outlet transmission required at Palo Verde.

Q. WHAT ASSUMPTIONS DID YOU MAKE REGARDING FUTURE GENERATION, FUEL AND PURCHASED POWER COSTS?

A. Annual generation for each plant was estimated based on historical usage patterns and expected future use. Any anticipated excess energy from the existing resources is assumed sold at market based prices and becomes a revenue credit. Fuel prices are based on current contract levels and increase with inflation over time except for San Juan coal, as discussed below. Power purchases include only those purchases currently under contract. Power purchases used exclusively for resale were not included in the revenue requirements for stranded costs as discussed earlier. See PNM Exhibit ____ (SAT-3).

Q. WHAT ARE THE RESULTING REVENUE REQUIREMENTS FOR EACH YEAR 1999 THROUGH 2025?

A. PNM Exhibit ___ (SAT-4) provides the resulting revenue requirement projections, based on the underlying assumptions addressed in my testimony, for the period 1999 through 2025. The period from 1999 through 2001 has been included to show the projections from the unbundled generation-related cost-of-service discussed by Mr. Sategna to the start of the stranded costs projection. Since open access is to start in 2002 our stranded cost projection begins with that year.

Q. ARE THE HISTORIC REGULATORY DECISIONS REGARDING PNM'S GENERATING ASSETS DESCRIBED BY PNM WITNESS PATRICK ORTIZ REFLECTED IN YOUR PROJECTION OF THE REVENUE REQUIREMENTS AND ULTIMATELY IN YOUR STRANDED COST PROJECTION?

A. The revenue requirements and the stranded cost projections do not include generation-related assets for which recovery was denied. Conversely, the assets which were found prudent and which are in rates today are included in both the revenue requirements and the stranded cost projections.

Q. DO THE PROJECTED REVENUE REQUIREMENTS REFLECT MITIGATION EFFORTS?

A. Yes. Although there are provisions in PNM's existing coal contract for future deliveries of coal at the San Juan plant, I have not used that contract to estimate future coal costs. Instead I have assumed that negotiations for a new contract, currently in progress, will be successfully concluded and that PNM will achieve a substantial reduction in fuel costs for San Juan. This assumption reduces PNM's projected stranded costs by $172.155 million. Further, I have assumed that ongoing O&M costs will not increase in real terms over the estimation period, even though experience shows that O&M costs do generally increase faster than inflation as plants age. Our stranded costs projection reflect PNM assuming these risks.

REVENUE FROM COMPETITIVE RETAIL MARKET

Q. HOW DID PNM ESTIMATE RETAIL MARKET REVENUES TO PROJECT STRANDED COSTS?

A. PNM's estimate of retail market revenues is based on studies from ICF Consulting (ICF) of future price of electricity in the wholesale market. PNM used ICF's wholesale market price projection to estimate retail market prices by adding losses and ancillary services to the forecasted wholesale prices.

Q. WHY WAS ICF'S PRICE FORECAST USED TO DEVELOP STRANDED COSTS?

A. PNM has engaged ICF for the purpose of providing wholesale market price forecasts since the mid-90's. With deregulation on the horizon, PNM saw the need to change its planning focus from a regulated utility perspective to that of a competitive market player. ICF has over 25 years experience working with real-world issues in power markets in the United States and abroad, and has prepared market forecasts and stranded costs projections on behalf of regulatory agencies and public utilities. ICF's combination of strategic, policy, market, and industry expertise enables them to provide credible price forecasts that can be used for business planning purposes. PNM believes that the methodology used by ICF to develop its forward price evaluations is appropriate for evaluating future business opportunities as well as for evaluating stranded costs. The results of the ICF study are market prices derived from marginal costs in a long-term market that are assumed to generally be in supply/demand equilibrium. The market equilibrium assumption results in a smoothing effect of over-build/under-build cycles that actually occur in the electric market place. Because of this smoothing, the ICF study is an effective forecast for stranded costs evaluation over the period at issue but is not necessarily a representative forecast for any particular year.

DIRECT TESTIMONY
OF
SUSAN A. TAYLOR
NMPRC UTILITY CASE NO. 3137, Part III

Q. PLEASE DESCRIBE THE METHOD USED BY ICF TO PROJECT WHOLESALE MARKET PRICES.

A. ICF unbundles the wholesale or bulk power market price into two products: electrical energy and "pure" capacity. These products are individually analyzed.

Competitive wholesale or spot electric energy prices are determined on an hourly basis by the intersection of supply and demand. In each hour, the prevailing spot price of electric energy will be approximated by the short-run marginal cost. The short-run marginal cost does not include most non-fuel O&M. Thus, the spot electric energy price in the bulk power market in a given hour is equal to the marginal energy cost in that hour. Prices must be determined hourly because power cannot be readily stored.

Capacity increases the reliability of electrical energy supply. Consequently, the power price structure must be high enough to ensure that sufficient "pure" capacity exists. To the extent that prices are above the marginal energy cost, this premium is the "pure" capacity price. It must be high enough to assure that there are adequate megawatts to meet the peak load. Based on ICF studies, no market in the United States in equilibrium will be reliable without a premium above electrical energy prices. The "pure" capacity market is not entirely separate from the energy market, but it is linked. ICF has developed a very complex modeling system to evaluate the interrelationship between "pure" capacity and electrical energy. ICF's derivation of "pure" capacity prices assumes a market that is in supply/demand equilibrium. New power plants (generally a combustion turbine) determine the basis for the capacity price. If the new power plant can make a profit on electrical energy sales, this will reduce the "pure" capacity price. For example, if a combustion turbine is setting the energy price in a given hour at $35/MWh, a combined cycle unit with a fuel cost of $21/MWh would see a profit in the energy market of $14/MWh. This profit in the energy market is used to reduce the fixed cost amount for the combined cycle that needs to be collected from the market.

The underlying assumptions for the ICF forecasts are included in PNM Exhibit ___ (SAT-5).

Q. WHAT MARKET AREA DID ICF USE TO DETERMINE MARKET PRICES?

A. For the purposes of this study the Arizona-New Mexico region was used to determine the wholesale market price. ICF's model considered all of Western Systems Coordinating Council and the inter-regional transmission flows. The New Mexico-Arizona region best represents the wholesale market that is most likely to impact competitive retail market prices in PNM's service territory.

Q. WHY DID ICF, AND ULTIMATELY PNM, USE WHOLESALE MARKET PRICE PROJECTIONS INSTEAD OF A RETAIL PRICE PROJECTION?

A. Simply stated, there is not a retail price available. The competitive retail market is still very immature and provides little insight as to what retail prices might be in the future. There is no fully competitive retail market in the Arizona-New Mexico region that can be used to validate a pricing model. Therefore, the wholesale market price was used and adjusted for retail delivery.

Q. WHAT ADJUSTMENTS TO ICF'S WHOLESALE MARKET PRICE PROJECTION DID PNM MAKE TO CALCULATE COMPETITIVE RETAIL MARKET PRICES?

A. In order to calculate retail market prices required by the Act, the wholesale prices were adjusted to account for energy losses from the Four Corners area to the load, to match PNM's retail load shape and to add costs of generation-related ancillary services necessary for delivery to the load. The amount of capacity needed in any year from the market was based on the peak demand for the year. The energy was allocated to the on and off peak periods based on PNM's system load shape and the price for energy needed in each period. Adjusting the wholesale price, as described, results in a market based price that provides the same retail service to PNM customers that is currently provided by the generation related facilities in the bundled revenue requirements. The retail market price is then applied to the total projected jurisdictional load. Making these adjustments was necessary to determine the revenues that could be earned from selling the same generation-related services in a competitive retail market. The wholesale market price projection and the adjustments leading to the retail market price are provided in PNM Exhibit ___ (SAT-6).

PROJECTION OF STRANDED COSTS

Q. HOW DID YOU PROJECT STRANDED COSTS?

A. I calculated the difference between the regulated revenue requirements and the competitive retail market revenues for the period from 2002 through 2025. I then calculated the NPV of the resulting differences at a discount rate of 6.3093%. The result of $771,898,000 is PNM's stranded cost that is applicable to the customer groups eligible for open access on January 1, 2002. I then determined the NPV of the differences for the period July 1, 2002 through 2025 using the same discount rate. This resulted in a stranded cost calculation of $702,311,000 in 2002 dollars and is applicable to customer groups eligible for open access on July 1, 2002. The calculation of these values can be found in PNM Exhibit ___ (SAT-7).

Q. WHY DID YOU APPLY A DISCOUNT RATE OF 6.3093% TO THE DIFFERENCE BETWEEN THE TWO REVENUE STREAMS?

A. Based on the methodology described by Dr. Kolbe, this rate recognizes that investors experience different investment risks in a competitive market as compared to a regulated market.

Q. HOW DID YOU APPLY DR. KOLBE'S METHODOLOGY?

A. The first step was to calculate the investor's after-tax cash stream for the period from 2002 through 2025 based on both the regulated and competitive market place. For the regulated market the cash stream was discounted using the after-tax weighted cost of capital (ATWCOC) of 8.25% for a fully integrated utility. For the competitive market the cash stream was discounted using the ATWCOC of 9.64% based on assumptions used by ICF. The 9.64% reflects the underlying assumptions in the price forecast and represents the value investors would expect to realize in a competitive market. The difference between the two streams of investor cash flows, adjusted for income tax, results in PNM's true stranded costs. See, PNM Exhibit___(SAT-8).

Q. WHAT DID YOU DO WITH THE RESULTS OF THIS CALCULATION?

A. To preserve PNM's true stranded costs it was necessary to determine a single discount rate to apply to the difference of the revenue streams in accordance with the Act. I solved for the discount rate that when applied to the stream of differences between regulated and market revenues resulted in an amount that was equal to PNM's true stranded costs.

Q. IS YOUR STRANDED COSTS PROJECTION IN ACCORDANCE WITH THE METHODOLGY REQUIRED IN SECTION 3.Z. OF THE ACT?

A. Yes.

Q. DOES YOUR STRANDED COSTS PROJECTION INCLUDE ANY COSTS THAT ARE UNREASONABLE, IMPRUDENT, UNMITIGABLE OR THAT HAVE BEEN DETERMINED TO NOT BE RECOVERABLE IN RATES?

A. No.

Q. WHY HAS PNM PROJECTED STRANDED COSTS FOR TWO SEPARATE PERIODS?

A. The Act is specific in requiring the non-bypassable wires charge for stranded costs to be designed in a manner that "*ensures that the class pays no more than the stranded costs associated with that class.*" The Act provides for different classes of customers to be eligible for customer choice at different times. Open access for some customers will begin on 1/1/2002 and for others on 7/1/2002. The customers who are not eligible until 7/1/2002 will continue to pay regulated rates for generation for six months longer than other customers. This results in a different stranded cost responsibility than for the customers who are eligible earlier.

Q. ARE THE AMOUNTS DESCRIBED ABOVE THE SAME STRANDED COSTS USED TO CALCULATE THE NON-BYPASSABLE WIRES CHARGE?

A. No. As generally described earlier, these amounts were reduced by the net present value of Palo Verde decommissioning costs which PNM is requesting to recover under a separate wires charge. I removed $44,438,000 which is the NPV of the New Mexico ratepayers share of the funding for the Palo Verde external sinking fund. The resulting amounts used to calculate the stranded cost wires charge, $727,460,000 and $659,565,000, both reflect 2002 dollars. PNM witness Olmsted then applied these stranded cost values to the appropriate classes of customers with the result being $691,619,765 of stranded costs.

Q. HAVE YOU CALCULATED THE NUCLEAR DECOMMISSIONING WIRES CHARGE?

A. No. The calculation of the nuclear decommissioning wires charge is addressed by PNM witness Olmsted along with the proposed adjustment mechanism. PNM is proposing that the wires charge for nuclear decommissioning be calculated annually based on the projected kWh sales and on PNM's Annual Funding Status Report. The annual funding amount that was used by Mr. Olmsted to calculate the nuclear decommissioning wires charge is $3,684,000.

Q. ARE THERE ANY OTHER FACTORS THAT THE COMMISSION IS TO CONSIDER WHEN IT QUANTIFIES STRANDED COSTS?

A. Yes. The Act states "*The Commission in quantifying stranded costs shall consider: . . .*

(2) reasonable methods for determining market valuations, including:

(a) the use of standard offer bid prices;

(b) appraisal by independent third-party professionals;

(c) a competitive bid sale for generation; and

any other method designed to provide a reasonable valuation;

(3) for residential and small business customers, that the standard offer bid price may reflect the current market value of supply service; . . .

Q. DID PNM CONSIDER THESE ALTERNATIVE METHODS TO DETERMINE THE MARKET VALUE OF ITS ASSETS?

A. Yes. PNM considered alternative methods and determined that they were not useful to determine PNM's stranded costs. Since PNM has not yet received any standard offer bid prices this has not been used to determine market value. PNM believes, in addition, that the standard offer bids are not reflective of the long-term retail market price. Dr. Landon describes the difficulty in using other sales in the market place as "comparables" that might be used in an appraisal process. For the reasons described in his testimony, PNM has not evaluated other plant sales in the market place. PNM is not required by the Act to divest of its generation and has determined not to have a competitive bid sale for generation.

Q. WHY DOES PNM BELIEVE THAT STANDARD OFFER BIDS ARE NOT REFLECTIVE OF THE LONG-TERM RETAIL MARKET PRICE?

A. The bid results will reflect the market price, if at all, only for a very short period of time as compared to the life of the generation assets. As such the bids have very little relationship, if any, to the long-term market price and the value of the assets over that period. The prices bid in the short-term will potentially be influenced by weather, market conditions, supply/demand ratios and suppliers' desire to enter a new marketplace. The appropriate market value to use over the extended period covered by the stranded cost calculation is very different than what would be appropriate for a shorter term bidding process that focuses on these immediate issues. To smooth the effect of the impacts seen in the near term, PNM believes the long range forecast provided by ICF adjusted for retail delivery is the appropriate value to use.

PROPOSAL TO ADDRESS TDS

Q. WHAT IS TDS?

A. TDS is supply service for customers who are not eligible for standard offer service and have not selected a competitive power supplier ("CPS") when customer choice becomes available to them. The Act does not require any utility or any CPS to provide default service for customers not eligible for standard offer service. PNM recognizes that at the onset of open access CPSs may not be available for all segments of the market. This TDS proposal is designed to provide transition of supply post open access for affected customers until they are prepared to enter the competitive market.

Q. PLEASE OUTLINE PNM'S PROPOSAL.

A. PNM's proposal is for the Commission, during the licensing process, to have CPSs indicate a desire to provide TDS either to a specific public utility or statewide. When a CPS receives its license, the Commission will notify the utility whether the CPS is willing to provide TDS. It will be the responsibility of the Transitional Default Service Provider ("TDSP") to provide each public utility the rates at which TDS will be provided. Each public utility will develop a proposal to assign a TDSP to customers who need such service.

Q. HOW WILL CUSTOMERS BE ASSIGNED TO THIS SERVICE?

A. If a customer has not selected a CPS by a date to be determined prior to when the customer is first eligible for customer choice, then the public utility will randomly assign that customer to a TDSP. The TDSP will be notified of this assignment by the utility.

Q. HOW WILL THE TDSP PLAN TO SERVE THESE LOADS?

A. Starting 90 days prior to eligibility for customer choice, the public utility will provide the TDSPs an aggregated load profile of all customers eligible for open access that have not yet selected a CPS. This profile would be for planning purposes only and would not include any individual customer data. The public utility will continue to provide this data to each TDSP periodically until customers are actually assigned to a TDSP.

Q. ARE THERE ANY OTHER ACTS WHICH THE PUBLIC UTILITY WILL UNDERTAKE PURSUANT TO YOUR PROPOSAL?

A. Yes. The public utility is to include in the customer education program, information regarding TDS including all the TDSPs in the service territory and how customers will be affected if they have not selected a CPS by the time they are eligible for open access.

Q. HOW WILL TDSPS COMPLY WITH THE REQUIREMENTS UNDER THE PROPOSED CUSTOMER PROTECTION AND CODE OF CONDUCT NOPRS?

A. When the public utility notifies a TDSP that a customer has been matched to the TDSP, that notification will be deemed the letter of agency and the customer's authorization to release individual customer data to the TDSP. No customer signature will be required, because it will not be possible for the TDSP to obtain these signatures prior to providing supply. The release of individual customer data will be needed for the TDSP to plan and meet the supply needs of that customer. If the Commission approves this method for matching customers to TDSPs, that approval should include a variance from applicable sections of the Commission's Customer Protection and Code of Conduct Rules.

Q. WHO WILL BE RESPONSIBLE FOR ACQUIRING TRANSMISSION FOR TDS?

A. The TDSP will have to enter into a network transmission agreement with the appropriate transmission provider which would include any customers matched to the TDSP.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

Document #34511

PNM EXHIBIT _____ (SAT-1)

is included on the following pages

SUSAN A. TAYLOR
EDUCATIONAL AND PROFESSIONAL SUMMARY

Name:	Susan A. Taylor
Address:	Public Service Company of New Mexico Alvarado Square Albuquerque, New Mexico 87158
Education:	B.S., Mathematics, University of New Mexico, 1973
Employment:	Employed by Public Service Company of New Mexico since 1986. Positions held within the Company include: Manager of Planning and Modeling Manager of Production Modeling Senior Financial Analyst

Testimony Filed: Proceeding	Regulatory Body	Docket Number
In the Matter of the Joint Complaint and Petition by the City of Gallup, Gallup Joint Utilities and the Pittsburg & Midway Coal Mining Co. for Declaratory Order Regarding Service Status and Abandonment Of Facilities	NMPUC	2812
In the Matter of the Commission's Investigation of the Rates for the Electric Service	NMPUC	2761
In the Matter of the City of Albuquerque To Institute Retail Pilot Load Aggregation Program and Its Request for Related	NMPUC	2782
In the Matter of the Application for Approval of Real-Time Pricing, Enhanced Time-of-Use and Interruptible Rates under Rider 10 and 11.	NMPUC	2736

Testimony Filed: Proceeding	Regulatory Body	Docket Number
In the Matter of Continued Use of PNM's Fuel and Purchased Power Cost Adjustment Clause	NMPUC	2492
In the Matter of the Abandonment of Prager, Santa Fe, and Person Generating Station	NMPUC	2530
In the Matter of the Sale of an Undivided Interest in San Juan Generating Station Unit 4 to Utah Associated Municipal Power Systems	NMPUC	2553

PNM EXHIBIT ____ (SAT-2)

is included on the following pages

PNM Exhibit ____ (SAT-2)

UNBUNDLED GENERATION COS
COMPARED TO INITIAL YEAR STRANDED COST

	COS Test Year	Stranded Costs 1999	Delta	
Net Plant in Service	466,687	467,481	(794)	
Ratebase Adjustments	(61,540)	(77,190)	15,650	Palo Verde Decommissioning
Working Capital	32,770	33,395	(625)	
Total Ratebase	437,917	423,686	14,231	
After-Tax Weighted Cost of Capital	8.74%	8.74%	(0)	
Return	38,274	37,046	1,228	
Fuel and Purchased Power	321,085	156,382	164,703	Purchases for Resale
O&M	139,368	139,381	(13)	
Depreciation	35,290	35,061	229	
Property Tax	5,067	5,067	(1)	
Payroll Tax	2,593	2,546	47	
Miscellaneous Amortization	1,835	648	1,187	
Total Operating Expense	505,237	339,085	166,152	
Income Taxes	10,897	12,710	(1,813)	
Revenue Credit	(220,355)	(39,083)	(181,272)	Sales from Purchases for Resale
Revenue Tax	1,679	1,758	(79)	
Total Revenue Requirements	335,731	351,515	15,783	

PNM EXHIBIT ____ (SAT-3)

is included on the following pages

NEW MEXICO GENERATION, FUEL AND PURCHASED POWER

	2002	2003	2004	2005	2006	2007	2008	2009
New Mexico Share of Generation	97.66%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
New Mexico Peak Demand Forecast (MW)	1,427	1,468	1,507	1,553	1,599	1,647	1,696	1,748
New Mexico Generating Capacity (MW)	1,652	1,692	1,692	1,468	1,468	1,468	1,468	1,468
Generating Reserves (MW)	248	254	254	220	220	220	220	220
Generating Capacity Needed to serve peak(MW)	1,405	1,438	1,438	1,248	1,248	1,248	1,248	1,248
Additional Capacity needed from the Market (MW)	22	30	69	305	351	399	448	500
On Peak Generation	5,536,100	5,668,749	5,684,279	5,533,845	5,533,845	5,533,845	5,549,006	5,533,845
Off Peak Generation	3,754,648	3,844,611	3,855,145	3,844,611	3,844,611	3,844,611	3,855,145	3,844,611
Total Generation	9,290,747	9,513,360	9,539,424	9,378,456	9,378,456	9,378,456	9,404,150	9,378,456
Total New Mexico Load including losses	8,307,253	8,707,680	9,040,316	9,310,380	9,575,878	9,855,510	10,142,776	10,441,822
On-Peak Load	5,399,714	5,659,992	5,876,205	6,051,747	6,224,321	6,406,081	6,592,804	6,787,184
Off-Peak Load	2,907,539	3,047,688	3,164,111	3,258,633	3,351,557	3,449,428	3,549,972	3,654,638
Excess On-Peak Generation	136,385	8,757	-	-	-	-	-	-
Excess Off-Peak Generation	847,109	796,924	691,034	585,978	493,054	395,183	305,173	189,974
New Mexico Fuel Cost	151,820	147,144	157,135	152,088	144,794	125,014	126,907	126,918
Fuel Handling	5,312	5,602	5,770	5,943	6,122	6,305	6,495	6,689
Total Fuel Expense	157,132	152,746	162,906	158,032	150,916	131,320	133,402	133,608
Total Purchased Power Cost	36,638	38,330	39,300	38,189	38,731	39,503	40,308	40,993
Total Fuel and Purchased Power	193,770	191,076	202,205	196,221	189,647	170,823	173,710	174,600
Credit for Sales of Excess Energy								
Excess Energy - On-Peak	136,385	8,757	-	-	-	-	-	-
Excess Energy - Off-Peak	847,109	796,924	691,034	585,978	493,054	395,183	305,173	189,974
Market Price for Energy - On-Peak	21.61	22.61	23.64	24.72	25.87	27.06	28.30	29.59
Market Price for Energy - Off-Peak	21.16	21.49	21.81	22.14	23.00	23.90	24.84	25.80
Credit for Sales of Excess Energy	20,872	17,320	15,072	12,972	11,342	9,446	7,579	4,902
System Sales Demand	-	-	-	-	-	-	-	-
Total Revenue Credit	20,872	17,320	15,072	12,972	11,342	9,446	7,579	4,902

NEW MEXICO GENERATION, FUEL AND PURCHASED POWER

	2010	2011	2012	2013	2014	2015	2016	2017
New Mexico Share of Generation	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
New Mexico Peak Demand Forecast (MW)	1,801	1,853	1,907	1,962	2,019	2,077	2,136	2,199
New Mexico Generating Capacity (MW)	1,468	1,276	1,126	1,106	948	948	948	587
Generating Reserves (MW)	220	191	169	166	142	142	142	88
Generating Capacity Needed to serve peak(MW)	1,248	1,085	957	940	806	806	806	499
Additional Capacity needed from the Market (MW)	553	768	950	1,022	1,213	1,271	1,330	1,700
On Peak Generation	5,533,845	4,743,024	4,097,219	4,084,272	3,456,461	3,456,461	3,465,931	1,943,290
Off Peak Generation	3,844,611	3,205,800	3,214,583	3,205,800	2,698,665	2,698,665	2,706,059	1,476,351
Total Generation	9,378,456	7,948,824	7,311,802	7,290,072	6,155,126	6,155,126	6,171,990	3,419,641
Total New Mexico Load including losses	10,748,130	11,053,773	11,368,126	11,691,646	12,024,497	12,367,343	12,721,342	13,086,428
On-Peak Load	6,986,285	7,184,952	7,389,282	7,599,570	7,815,923	8,038,773	8,268,872	8,506,178
Off-Peak Load	3,761,846	3,868,820	3,978,844	4,092,076	4,208,574	4,328,570	4,452,470	4,580,250
Excess On-Peak Generation	-	-	-	-	-	-	-	-
Excess Off-Peak Generation	82,766	-	-	-	-	-	-	-
New Mexico Fuel Cost	130,952	115,477	119,720	119,351	96,412	97,791	99,319	60,933
Fuel Handling	6,890	5,870	6,046	6,228	5,007	5,157	5,312	3,880
Total Fuel Expense	137,842	121,347	125,767	125,578	101,419	102,948	104,631	64,813
Total Purchased Power Cost	41,605	42,232	15,438	15,658	15,901	16,150	16,420	16,666
Total Fuel and Purchased Power	179,446	163,579	141,204	141,237	117,320	119,098	121,052	81,479
Credit for Sales of Excess Energy								
Excess Energy - On-Peak	-	-	-	-	-	-	-	-
Excess Energy - Off-Peak	82,766	-	-	-	-	-	-	-
Market Price for Energy - On-Peak	30.94	31.93	32.94	33.99	35.08	36.20	37.28	38.40
Market Price for Energy - Off-Peak	26.80	27.55	28.32	29.10	29.91	30.74	31.67	32.62
Credit for Sales of Excess Energy	2,218	-	-	-	-	-	-	-
System Sales Demand	-	-	-	-	-	-	-	-
Total Revenue Credit	2,218	-	-	-	-	-	-	-

NEW MEXICO GENERATION, FUEL AND PURCHASED POWER

	2018	2019	2020	2021	2022	2023	2024	2025
New Mexico Share of Generation	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
New Mexico Peak Demand Forecast (MW)	2,264	2,330	2,399	2,469	2,541	2,616	2,692	2,771
New Mexico Generating Capacity (MW)	587	587	338	206	206	56	56	28
Generating Reserves (MW)	88	88	51	31	31	8	8	4
Generating Capacity Needed to serve peak(MW)	499	499	287	175	175	48	48	24
Additional Capacity needed from the Market (MW)	1,765	1,832	2,111	2,294	2,366	2,568	2,645	2,748
On Peak Generation	1,943,290	1,943,290	958,498	840,247	840,247	244,224	244,893	122,112
Off Peak Generation	1,476,351	1,476,351	680,597	678,737	678,737	197,280	197,820	98,640
Total Generation	3,419,641	3,419,641	1,639,094	1,518,984	1,518,984	441,504	442,714	220,752
Total New Mexico Load including losses	13,463,070	13,850,272	14,248,610	14,658,404	15,079,985	15,513,690	15,959,868	16,418,879
On-Peak Load	8,750,995	9,002,677	9,261,596	9,527,963	9,801,990	10,083,898	10,373,914	10,672,271
Off-Peak Load	4,712,074	4,847,595	4,987,013	5,130,442	5,277,995	5,429,791	5,585,954	5,746,608
Excess On-Peak Generation	-	-	-	-	-	-	-	-
Excess Off-Peak Generation	-	-	-	-	-	-	-	-
New Mexico Fuel Cost	62,422	63,947	25,306	25,829	26,436	2,482	2,510	1,262
Fuel Handling	3,996	4,116	1,596	1,644	1,693	-	-	-
Total Fuel Expense	66,418	68,063	26,902	27,472	28,129	2,482	2,510	1,262
Total Purchased Power Cost	16,934	17,210	17,507	-	-	-	-	-
Total Fuel and Purchased Power	83,352	85,272	44,409	27,472	28,129	2,482	2,510	1,262
Credit for Sales of Excess Energy								
Excess Energy - On-Peak	-	-	-	-	-	-	-	-
Excess Energy - Off-Peak	-	-	-	-	-	-	-	-
Market Price for Energy - On-Peak	39.55	40.74	41.96	43.22	44.52	45.85	47.23	48.65
Market Price for Energy - Off-Peak	33.59	34.60	35.64	36.71	37.81	38.94	40.11	41.32
Credit for Sales of Excess Energy	-	-	-	-	-	-	-	-
System Sales Demand	-	-	-	-	-	-	-	-
Total Revenue Credit	-	-	-	-	-	-	-	-

PNM EXHIBIT _____ (SAT-4)

is included on the following pages

NEW MEXICO REVENUE REQUIREMENTS

Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
FERC/NM Allocator	97.66%	97.66%	97.66%	97.66%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Ferc	2.34%	2.34%	2.34%	2.34%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Ratebase																
Net Plant in Service - Current																
Reeves	5,738	2,700	(3,024)	(5,299)	(7,756)	(10,086)	-	-	-	-	-	-	-	-	-	-
Las Vegas	467	382	297	212	131	44	-	-	-	-	-	-	-	-	-	-
Four Corners	54,086	46,847	39,607	31,437	23,824	15,458	7,091	(1,275)	(9,641)	(18,007)	(20,436)	(22,670)	-	-	-	-
San Juan 1	60,576	56,589	52,601	47,470	43,352	38,098	32,843	27,588	22,334	17,079	11,824	6,569	1,315	(3,940)	(9,195)	(14,449)
San Juan 2	51,796	47,840	43,883	38,609	34,134	28,733	23,333	17,932	12,532	7,131	1,731	(3,669)	(9,070)	(14,470)	(19,871)	-
San Juan 3	137,305	128,699	120,092	109,947	102,194	91,807	81,419	71,032	60,644	50,257	39,870	29,482	19,095	8,707	(1,680)	(12,067)
San Juan 4 Included Only	98,142	92,325	86,508	79,883	75,014	68,231	61,448	54,665	47,882	41,099	34,316	27,533	20,750	13,967	7,184	401
Palo Verde 1	28,258	27,143	26,029	24,915	24,371	23,230	22,089	20,948	19,807	18,666	17,525	16,384	15,243	14,102	12,961	11,820
Palo Verde 2	31,112	29,896	28,680	27,464	26,877	25,632	24,387	23,142	21,897	20,652	19,407	18,162	16,917	15,672	14,427	13,182
Net Plant in Service - Current	467,481	432,420	394,674	354,638	322,141	281,146	252,611	214,033	175,455	136,877	104,237	71,791	64,249	34,038	3,826	(1,114)
Net Plant in Service - Incremental																
Reeves	-	2,237	2,410	2,258	1,656	-	-	-	-	-	-	-	-	-	-	-
Las Vegas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	2,932	3,241	6,356	7,497	6,846	6,228	7,882	6,776	5,546	3,057	-	-	-	-	-
San Juan 1	-	-	2,953	6,151	6,416	8,434	8,243	9,740	9,353	10,748	10,043	12,686	11,217	11,439	9,196	8,310
San Juan 2	-	969	5,779	5,674	7,241	7,196	8,352	7,658	8,614	7,626	9,791	7,771	7,001	3,803	-	-
San Juan 3	-	1,239	1,461	2,524	2,850	4,360	4,382	7,923	7,725	8,489	8,199	8,846	8,363	8,830	8,080	11,291
San Juan 4	-	188	1,104	1,337	4,150	4,518	5,337	5,283	6,131	6,095	6,930	6,788	9,706	9,233	9,694	9,042
Palo Verde 1	-	7,115	8,294	9,119	10,055	10,762	11,397	11,946	12,394	12,721	12,905	12,914	12,705	12,222	11,374	10,017
Palo Verde 2	-	9,754	13,694	17,679	24,160	24,655	24,258	23,777	23,195	22,495	21,652	20,636	19,405	17,900	16,035	13,664
Net Plant in Service - Incremental	-	24,433	38,936	51,098	64,024	66,771	68,196	74,210	74,188	73,722	72,578	69,642	68,396	63,427	54,379	52,324
Net Plant in Service - Total																
Reeves	5,738	4,936	(614)	(3,041)	(6,100)	(10,086)	-	-	-	-	-	-	-	-	-	-
Las Vegas	467	382	297	212	131	44	-	-	-	-	-	-	-	-	-	-
Four Corners	54,086	49,779	42,848	37,793	31,321	22,303	13,319	6,607	(2,865)	(12,461)	(17,379)	(22,670)	-	-	-	-
San Juan 1	60,576	56,589	55,554	53,621	49,769	46,531	41,086	37,329	31,687	27,827	21,867	19,256	12,532	7,499	1	(6,139)
San Juan 2	51,796	48,809	49,662	44,283	41,374	35,930	31,685	25,591	21,146	14,758	11,522	4,102	(2,069)	(10,667)	(19,871)	-
San Juan 3	137,305	129,937	121,553	112,471	105,044	96,167	85,801	78,955	68,369	58,746	48,069	38,328	27,457	17,538	6,400	(776)
San Juan 4	98,142	92,513	87,612	81,221	79,165	72,750	66,785	59,948	54,013	47,194	41,246	34,321	30,456	23,200	16,878	9,443
Palo Verde 1	28,258	34,258	34,323	34,034	34,425	33,992	33,486	32,894	32,200	31,387	30,430	29,298	27,948	26,323	24,335	21,837
Palo Verde 2	31,112	39,650	42,374	45,143	51,037	50,287	48,645	46,919	45,092	43,147	41,059	38,798	36,322	33,572	30,462	26,846
Net Plant in Service - Total	467,481	456,853	433,610	405,736	386,165	347,917	320,806	288,243	249,643	210,599	176,815	141,433	132,646	97,465	58,205	51,210

NEW MEXICO REVENUE REQUIREMENTS

Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Subtractive Adjustments																
ADIT																
San Juan	(101,410)	(87,084)	(81,546)	(73,712)	(67,363)	(59,159)	(50,856)	(42,423)	(33,884)	(25,138)	(15,977)	(6,521)	3,385	13,689	25,239	27,033
Four Corners	(15,361)	(13,044)	(11,065)	(8,963)	(6,987)	(4,782)	(2,530)	(34)	2,534	5,334	5,995	6,945	-	-	-	-
Palo Verde	26,997	32,826	32,418	32,006	32,351	31,918	31,499	31,128	31,219	31,733	32,342	33,017	33,715	34,437	35,218	36,095
Gas/Oil	104	3,259	4,638	4,465	4,574	4,954	3	3	2	2	2	2	2	2	-	-
Other	2,511	2,511	2,511	2,511	2,571	2,571	2,276	2,276	2,276	2,276	2,276	2,276	1,907	1,907	1,869	1,566
Total ADIT	(87,160)	(61,531)	(53,044)	(43,694)	(34,854)	(24,499)	(19,609)	(9,052)	2,147	14,207	24,638	35,718	39,009	50,035	62,326	64,893
Other	(21,696)	(16,598)	(13,497)	(12,463)	(11,669)	(10,594)	(9,519)	(8,444)	(7,369)	(6,294)	(5,219)	(4,144)	(3,069)	(2,243)	(1,710)	(1,342)
Unamortized Gain on PV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Subtractive Adjustments	(108,856)	(78,129)	(66,540)	(56,157)	(46,523)	(35,093)	(29,128)	(17,496)	(5,222)	7,913	19,419	31,574	35,940	47,792	60,616	63,351
Additive Adjustments																
San Juan	4,240	4,035	3,829	2,797	1,808	751	540	330	263	230	198	166	133	101	68	31
Four Corners	660	628	596	435	281	117	84	51	41	36	31	26	-	-	-	-
Palo Verde	9,743	9,351	8,959	8,427	8,083	7,538	7,137	6,736	6,359	5,988	5,618	5,247	4,876	4,506	4,135	3,764
Gas/Oil	75	72	68	50	32	13	1	0	0	0	0	0	0	0	-	-
CWIP																
San Juan	1,546															
Four Corners	1,824															
Palo Verde	11,483															
Gas/Oil	1,719															
General and Intangible	275															
Other	103															
Total CWIP	16,948															
Total Additive Adjustments	31,666	14,085	13,453	11,709	10,204	8,419	7,762	7,118	6,663	6,255	5,847	5,439	5,010	4,607	4,204	3,795
Ratebase Adjustments	(77,190)	(64,043)	(53,088)	(44,448)	(36,319)	(26,674)	(21,366)	(10,378)	1,441	14,168	25,266	37,013	40,950	52,399	64,819	67,147
Working Capital																
Fuel Supplies	26,961	27,769	28,602	29,461	31,071	32,004	32,964	33,953	34,971	36,020	37,101	38,214	39,360	40,541	41,757	39,851
Materials and Supplies	10,712	11,952	12,311	12,680	13,373	13,774	14,188	14,613	15,052	15,503	15,968	16,447	15,639	16,108	16,591	15,559
Stores Expense	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
Prepayments	891	891	891	891	891	891	891	891	891	891	891	891	891	891	891	891
Cash Working Capital	(5,158)	(5,158)	(5,158)	(5,158)	(5,282)	(5,282)	(4,675)	(4,675)	(4,675)	(4,675)	(4,675)	(4,675)	(3,918)	(3,918)	(3,839)	(3,216)
Total Working Capital	33,395	35,444	36,635	37,863	40,043	41,377	43,357	44,771	46,228	47,729	49,275	50,867	51,962	53,612	55,390	53,074
Total Rate Base Adjustments	(43,795)	(28,600)	(16,452)	(6,585)	3,724	14,702	21,991	34,394	47,670	61,897	74,541	87,880	92,912	106,011	120,210	120,221
Total Rate Base	423,686	428,253	417,158	399,151	389,889	362,620	342,797	322,636	297,313	272,496	251,355	229,313	225,557	203,475	178,415	171,431

NEW MEXICO REVENUE REQUIREMENTS

Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Operations and Maintenance Expense																
Fuel and Purchased Power																
Fuel Expense	121,266	123,252	130,760	151,820	147,144	157,135	152,088	144,794	125,014	126,907	126,918	130,952	115,477	119,720	119,351	96,412
Fuel Handling	4,861	5,007	5,157	5,312	5,602	5,770	5,943	6,122	6,305	6,495	6,689	6,890	5,870	6,046	6,228	5,007
Total Fuel Expense	126,127	128,259	135,917	157,132	152,746	162,906	158,032	150,916	131,320	133,402	133,608	137,842	121,347	125,767	125,578	101,419
Purchases - Demand	14,701	17,377	19,301	19,480	20,135	20,350	18,636	18,838	19,046	19,283	19,501	19,726	19,956	9,661	9,903	10,150
Purchases - Energy	15,555	16,368	16,684	17,158	18,194	18,950	19,553	19,893	20,457	21,025	21,491	21,879	22,277	5,776	5,756	5,751
Total Net Purchased Power	30,255	33,745	35,985	36,638	38,330	39,300	38,189	38,731	39,503	40,308	40,993	41,605	42,232	15,438	15,658	15,901
Production O&M																
Four Corners	5,066	5,218	5,375	5,536	5,839	6,014	6,194	6,380	6,571	6,768	6,971	7,181	-	-	-	-
San Juan	20,450	21,064	21,696	22,347	23,569	24,276	25,004	25,754	26,527	27,323	28,142	28,986	29,856	30,752	31,674	23,202
Palo Verde	15,881	16,860	21,715	22,221	23,288	23,839	24,407	24,993	25,597	26,219	26,860	27,521	28,484	31,778	33,822	31,086
Palo Verde - Lease Related Expense	66,142	66,735	66,828	68,393	70,131	70,234	70,339	70,447	70,558	70,671	70,787	70,906	71,028	71,153	71,281	71,412
Palo Verde - Decommissioning	3,983	4,991	4,046	3,598	3,684	3,684	3,684	3,684	3,684	3,684	3,684	3,684	3,684	3,684	3,684	3,684
Gas/Oil	2,504	2,580	2,657	2,737	2,886	2,973	52	53	55	57	58	60	62	64	-	-
Other		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Administrative and General	25,354	26,115	26,898	27,705	29,220	30,097	26,896	27,703	28,534	29,390	30,271	31,180	27,915	25,372	25,669	22,662
Total Production O&M	139,381	143,562	149,214	152,537	158,617	161,116	156,576	159,014	161,525	164,111	166,774	169,518	161,029	162,803	166,131	152,046
Depreciation																
Reeves	3,038	3,597	6,527	3,404	3,986	4,986	-	-	-	-	-	-	-	-	-	-
Las Vegas	85	85	85	85	87	87	44	-	-	-	-	-	-	-	-	-
Four Corners	7,240	7,533	7,600	8,965	9,437	9,507	9,612	10,337	10,625	11,139	5,485	6,018	-	-	-	-
San Juan 1	3,987	4,155	4,184	5,571	5,748	5,958	6,004	6,229	6,294	6,598	6,689	7,369	7,498	8,115	8,320	9,410
San Juan 2	3,956	4,031	4,438	5,790	6,125	6,200	6,444	6,495	6,836	6,926	7,848	7,991	8,901	9,203	12,099	-
San Juan 3	8,607	8,672	8,688	10,293	10,566	10,678	10,700	10,997	11,031	11,159	11,207	11,370	11,433	11,649	11,734	12,646
San Juan 4	5,817	5,826	5,870	6,691	7,001	7,034	7,097	7,113	7,192	7,218	7,316	7,349	7,665	7,706	7,860	7,913
Palo Verde 1 - Owned	1,114	1,182	1,197	1,211	1,255	1,271	1,289	1,307	1,328	1,351	1,375	1,402	1,432	1,465	1,502	1,544
Palo Verde 1 - Leased	-	344	425	499	590	680	781	895	1,024	1,171	1,342	1,542	1,784	2,082	2,467	2,994
Palo Verde 2 - Owned	1,216	1,305	1,348	1,395	1,504	1,528	1,545	1,563	1,582	1,604	1,627	1,652	1,680	1,711	1,745	1,783
Palo Verde 2 - Leased	-	471	702	968	1,420	1,559	1,660	1,774	1,903	2,050	2,221	2,422	2,663	2,962	3,346	3,873
Total Depreciation	35,061	37,200	41,064	44,873	47,718	49,488	45,176	46,709	47,815	49,216	45,111	47,116	43,056	44,893	49,073	40,163
Property Taxes																
Reeves	116	134	51	49	37	-	-	-	-	-	-	-	-	-	-	-
Las Vegas	8	7	5	4	2	1	-	-	-	-	-	-	-	-	-	-
Four Corners	493	477	434	417	386	326	262	220	146	65	36	-	-	-	-	-
San Juan 1	515	521	506	517	511	509	486	477	449	438	403	404	357	327	267	219
San Juan 2	440	430	453	432	435	411	399	366	349	311	304	250	208	135	50	-
San Juan 3	1,189	1,161	1,121	1,087	1,068	1,031	978	957	895	840	770	707	626	553	461	413
San Juan 4	850	826	807	780	793	763	736	698	667	625	590	541	526	468	419	354
Palo Verde 1 - Owned	712	742	739	734	744	736	727	717	705	693	678	662	645	625	603	578
Palo Verde 1 - Leased	-	90	107	121	136	148	160	170	180	187	193	195	192	184	168	139
Palo Verde 2 - Owned	745	788	801	814	861	855	843	830	816	800	782	762	741	717	691	662
Palo Verde 2 - Leased	-	124	177	234	326	339	339	338	334	328	319	305	287	262	227	180
Total Property Taxes	5,067	5,300	5,203	5,188	5,298	5,120	4,930	4,775	4,542	4,287	4,074	3,826	3,581	3,271	2,885	2,545

NEW MEXICO REVENUE REQUIREMENTS

Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Payroll Taxes																
Reeves	253	261	268	276	292	300	-	-	-	-	-	-	-	-	-	-
Las Vegas	3	3	3	3	3	3	4	4	4	4	4	4	4	4	-	-
Four Corners	263	271	279	287	303	312	321	331	341	351	362	372	-	-	-	-
San Juan 1	256	264	271	280	295	304	313	322	332	342	352	363	374	385	396	408
San Juan 2	247	254	262	270	285	293	302	311	320	330	340	350	361	372	383	-
San Juan 3	425	438	451	464	490	504	519	535	551	568	585	602	620	639	658	678
San Juan 4	267	275	283	291	307	316	326	336	346	356	367	378	389	401	413	425
Palo Verde 1 - Owned	90	93	95	98	104	107	110	113	117	120	124	127	131	135	139	143
Palo Verde 1 - Leased	311	320	329	339	358	369	380	391	403	415	427	440	453	467	481	495
Palo Verde 2 - Owned	97	100	103	106	111	115	118	122	125	129	133	137	141	145	150	154
Palo Verde 2 - Leased	336	346	356	367	387	399	411	423	436	449	462	476	490	505	520	536
Total Payroll Taxes	2,546	2,622	2,701	2,782	2,934	3,022	2,804	2,888	2,974	3,064	3,156	3,250	2,964	3,053	3,140	2,840
Miscellaneous Amortization Expense	648	648	648	3,964	3,867	3,867	2,728	2,728	505	409	409	409	409	409	409	409
Total Operating Expense	339,085	351,336	370,732	403,114	409,510	424,819	408,435	405,762	388,184	394,796	394,124	403,565	374,618	355,632	362,875	315,323
Total Ratebase	423,686	428,253	417,158	399,151	389,889	362,620	342,797	322,636	297,313	272,496	251,355	229,313	225,557	203,475	178,415	171,431
Weighted Cost of Capital	8.74%	8.74%	8.74%	8.74%	8.74%	8.74%	8.74%	8.74%	8.74%	8.74%	8.74%	8.74%	8.74%	8.74%	8.74%	8.74%
Return on Ratebase	37,046	37,445	36,475	34,900	34,091	31,706	29,973	28,210	25,996	23,826	21,978	20,050	19,722	17,791	15,600	14,989
Income Taxes	12,710	13,773	13,530	13,273	13,001	12,388	11,562	11,141	10,513	9,905	9,445	8,948	8,170	7,582	6,872	5,834
Revenue Credit	(39,083)	(30,557)	(25,467)	(20,872)	(17,320)	(15,072)	(12,972)	(11,342)	(9,446)	(7,579)	(4,902)	(2,218)	-	-	-	-
Revenue Tax	1,758	1,869	1,986	2,163	2,207	2,281	2,196	2,180	2,087	2,115	2,114	2,163	2,023	1,915	1,936	1,689
Total Revenue Requirements	351,515	373,867	397,257	432,579	441,488	456,121	439,194	435,950	417,333	423,063	422,758	432,508	404,533	382,920	387,283	337,836

NEW MEXICO REVENUE REQUIREMENTS

Description	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
FERC/NM Allocator	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Ferc	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Ratebase											
Net Plant in Service - Current											
Reeves	-	-	-	-	-	-	-	-	-	-	-
Las Vegas	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-
San Juan 1	(19,704)	(24,959)	-	-	-	-	-	-	-	-	-
San Juan 2	-	-	-	-	-	-	-	-	-	-	-
San Juan 3	(22,455)	(32,842)	(41,103)	(43,562)	(46,020)	-	-	-	-	-	-
San Juan 4 Included Only	(6,382)	(13,165)	(19,948)	(24,188)	(25,548)	(26,908)	(28,268)	(29,628)	-	-	-
Palo Verde 1	10,679	9,538	8,397	7,256	6,115	4,974	3,833	2,692	1,551	410	-
Palo Verde 2	11,937	10,692	9,447	8,202	6,957	5,712	4,467	3,222	1,977	732	-
Net Plant in Service - Current	(25,925)	(50,737)	(43,208)	(52,292)	(58,497)	(16,223)	(19,969)	(23,715)	3,528	1,142	-
Net Plant in Service - Incremental											
Reeves	-	-	-	-	-	-	-	-	-	-	-
Las Vegas	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-
San Juan 1	4,591	-	-	-	-	-	-	-	-	-	-
San Juan 2	-	-	-	-	-	-	-	-	-	-	-
San Juan 3	9,539	8,614	6,190	4,127	-	-	-	-	-	-	-
San Juan 4	9,340	8,440	8,477	7,212	9,019	6,393	4,171	-	-	-	-
Palo Verde 1	7,859	4,030	3,963	3,838	3,640	3,348	2,933	2,341	1,469	-	-
Palo Verde 2	10,496	5,663	5,477	5,243	4,948	4,578	4,112	3,518	2,743	1,678	-
Net Plant in Service - Incremental	41,824	26,747	24,108	20,420	17,606	14,319	11,216	5,859	4,211	1,678	-
Net Plant in Service - Total											
Reeves	-	-	-	-	-	-	-	-	-	-	-
Las Vegas	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-
San Juan 1	(15,113)	(24,959)	-	-	-	-	-	-	-	-	-
San Juan 2	-	-	-	-	-	-	-	-	-	-	-
San Juan 3	(12,916)	(24,228)	(34,913)	(39,434)	(46,020)	-	-	-	-	-	-
San Juan 4	2,958	(4,725)	(11,471)	(16,976)	(16,530)	(20,516)	(24,097)	(29,628)	-	-	-
Palo Verde 1	18,537	13,568	12,360	11,094	9,755	8,322	6,765	5,033	3,019	410	-
Palo Verde 2	22,432	16,354	14,924	13,444	11,905	10,290	8,579	6,740	4,720	2,410	-
Net Plant in Service - Total	15,899	(23,989)	(19,100)	(31,873)	(40,890)	(1,904)	(8,753)	(17,856)	7,739	2,820	-

NEW MEXICO REVENUE REQUIREMENTS

Description	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Subtractive Adjustments											
ADIT											
San Juan	36,008	46,586	39,817	42,990	45,830	12,945	14,341	15,971	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	37,024	38,024	39,071	40,153	41,280	42,502	43,852	45,341	47,037	49,099	25,722
Gas/Oil	-	-	-	-	-	-	-	-	-	-	-
Other	1,566	1,566	872	872	872	395	395	395	107	107	54
Total ADIT	74,597	86,176	79,760	84,014	87,982	55,842	58,589	61,708	47,144	49,207	25,776
Other	(974)	(606)	(238)	(54)	-	-	-	-	-	-	-
Unamortized Gain on PV	-	-	-	-	-	-	-	-	-	-	-
Total Subtractive Adjustments	73,623	85,570	79,522	83,960	87,982	55,842	58,589	61,708	47,144	49,207	25,776
Additive Adjustments											
San Juan	3	0	0	0	0	0	0	0	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	3,394	3,028	597	515	433	351	269	188	106	24	0
Gas/Oil	-	-	-	-	-	-	-	-	-	-	-
CWIP											
San Juan											
Four Corners											
Palo Verde											
Gas/Oil											
General and Intangible											
Other											
Total CWIP											
Total Additive Adjustments	3,397	3,028	597	515	433	351	269	188	106	24	0
Ratebase Adjustments	77,020	88,598	80,118	84,475	88,415	56,193	58,858	61,895	47,250	49,231	25,776
Working Capital											
Fuel Supplies	41,047	42,278	15,600	16,068	16,550	11,114	11,447	11,791	8,232	8,479	4,395
Materials and Supplies	16,026	16,506	6,655	6,854	7,060	4,398	4,530	4,666	2,910	2,997	1,544
Stores Expense	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
Prepayments	891	891	891	891	891	891	891	891	891	891	891
Cash Working Capital	(3,216)	(3,216)	(1,791)	(1,791)	(1,791)	(812)	(812)	(812)	(221)	(221)	(110)
Total Working Capital	54,736	56,449	21,343	22,011	22,699	15,580	16,046	16,525	11,801	12,135	6,709
Total Rate Base Adjustments	131,756	145,047	101,462	106,486	111,113	71,773	74,904	78,420	59,051	61,366	32,485
Total Rate Base	147,656	121,057	82,362	74,614	70,223	69,870	66,151	60,564	66,790	64,186	32,485

NEW MEXICO REVENUE REQUIREMENTS

Description	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Operations and Maintenance Expen											
Fuel and Purchased Power											
Fuel Expense	97,791	99,319	60,933	62,422	63,947	25,306	25,829	26,436	2,482	2,510	1,262
Fuel Handling	5,157	5,312	3,880	3,996	4,116	1,596	1,644	1,693	-	-	-
Total Fuel Expense	102,948	104,631	64,813	66,418	68,063	26,902	27,472	28,129	2,482	2,510	1,262
Purchases - Demand	10,404	10,664	10,931	11,204	11,484	11,771	-	-	-	-	-
Purchases - Energy	5,746	5,756	5,736	5,731	5,726	5,736	-	-	-	-	-
Total Net Purchased Power	16,150	16,420	16,666	16,934	17,210	17,507	-	-	-	-	-
Production O&M											
Four Corners	-	-	-	-	-	-	-	-	-	-	-
San Juan	23,898	24,615	17,042	17,553	18,080	6,772	6,975	7,184	-	-	-
Palo Verde	35,745	37,568	7,652	9,193	9,500	8,445	9,913	10,917	9,371	11,715	4,507
Palo Verde - Lease Related Expense	53,559	17,853	-	-	-	-	-	-	-	-	-
Palo Verde - Decommissioning	3,684	3,684	3,684	3,684	3,684	3,684	3,684	3,684	3,684	3,684	1,842
Gas/Oil	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-
Administrative and General	23,342	24,042	15,321	15,780	16,254	9,648	6,056	6,238	1,747	1,799	927
Total Production O&M	140,228	107,762	43,698	46,210	47,518	28,549	26,629	28,024	14,802	17,198	7,276
Depreciation											
Reeves	-	-	-	-	-	-	-	-	-	-	-
Las Vegas	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-
San Juan 1	9,846	13,314	-	-	-	-	-	-	-	-	-
San Juan 2	-	-	-	-	-	-	-	-	-	-	-
San Juan 3	12,772	13,259	11,356	6,586	7,298	-	-	-	-	-	-
San Juan 4	8,117	8,190	8,478	6,043	4,366	4,556	5,531	6,136	-	-	-
Palo Verde 1 - Owned	1,591	1,645	1,707	1,781	1,869	1,978	2,119	2,311	2,610	3,224	-
Palo Verde 1 - Leased	3,809	5,489	-	-	-	-	-	-	-	-	-
Palo Verde 2 - Owned	1,826	1,874	1,930	1,994	2,070	2,161	2,273	2,418	2,616	2,923	3,043
Palo Verde 2 - Leased	4,689	6,368	-	-	-	-	-	-	-	-	-
Total Depreciation	42,650	50,139	23,471	16,403	15,602	8,695	9,923	10,866	5,226	6,147	3,043
Property Taxes											
Reeves	-	-	-	-	-	-	-	-	-	-	-
Las Vegas	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-
San Juan 1	134	32	-	-	-	-	-	-	-	-	-
San Juan 2	-	-	-	-	-	-	-	-	-	-	-
San Juan 3	299	190	84	57	-	-	-	-	-	-	-
San Juan 4	297	221	153	100	128	93	62	-	-	-	-
Palo Verde 1 - Owned	551	520	485	447	403	352	293	224	138	19	-
Palo Verde 1 - Leased	91	-	-	-	-	-	-	-	-	-	-
Palo Verde 2 - Owned	631	596	557	515	467	414	354	285	204	107	-
Palo Verde 2 - Leased	112	-	-	-	-	-	-	-	-	-	-
Total Property Taxes	2,113	1,559	1,280	1,118	998	859	709	508	342	126	-

NEW MEXICO REVENUE REQUIREMENTS

Description	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Payroll Taxes											
Reeves	-	-	-	-	-	-	-	-	-	-	-
Las Vegas	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-
San Juan 1	420	433	-	-	-	-	-	-	-	-	-
San Juan 2	-	-	-	-	-	-	-	-	-	-	-
San Juan 3	698	719	741	763	786	-	-	-	-	-	-
San Juan 4	438	451	465	479	493	508	523	539	-	-	-
Palo Verde 1 - Owned	148	152	157	161	166	171	176	182	187	193	-
Palo Verde 1 - Leased	510	526	-	-	-	-	-	-	-	-	-
Palo Verde 2 - Owned	159	164	169	174	179	184	190	195	201	207	214
Palo Verde 2 - Leased	552	569	-	-	-	-	-	-	-	-	-
Total Payroll Taxes	2,925	3,013	1,530	1,576	1,624	863	889	916	388	400	214
Miscellaneous Amortization Expense	409	370	365	365	365	365	365	365	365	365	-
Total Operating Expense	307,422	283,894	151,824	149,025	151,379	83,740	65,987	68,807	23,606	26,746	11,794
Total Ratebase	147,656	121,057	82,362	74,614	70,223	69,870	66,151	60,564	66,790	64,186	32,485
Weighted Cost of Capital	8.74%	8.74%	8.74%	8.74%	8.74%	8.74%	8.74%	8.74%	8.74%	8.74%	8.74%
Return on Ratebase	12,911	10,585	7,201	6,524	6,140	6,109	5,784	5,296	5,840	5,612	2,840
Income Taxes	5,101	4,254	1,713	1,555	1,532	808	713	543	239	134	(213)
Revenue Credit	-	-	-	-	-	-	-	-	-	-	-
Revenue Tax	1,635	1,501	808	789	799	456	364	375	149	163	72
Total Revenue Requirements	327,068	300,233	161,546	157,894	159,850	91,113	72,849	75,021	29,834	32,655	14,493

PNM EXHIBIT _____ (SAT-5)

is included on the following pages

ICF AZ/NM Regional Analysis
Key Modeling Assumptions

Summer Net Internal Demand		
1999 Forecast (MW)	16,015	
1999-2005 Growth (%)	4.1	
2006-2020 Growth (%)	2.7	
Net Energy for Load		
1999 Forecast (GWh)	83,959	
1999-2005 Growth (%)	3.8	
2006-2020 Growth (%)	2.7	
Planning Reserve Margin (%)		
1999- 2009	16.2	
2010+	14.7	
New Power Plant Characteristics	Combined Cycles	Combustion Turbines
Capital Costs (1998$/kW)		
2000	583	368
2010	501	317
2020	431	273
Heat Rate (Btu/kWh)		
2000	6,928	10,905
2010	6,583	10,443
2020	6,255	10,219
Fixed O&M (1998$/kW-yr)	16.0	9.8
Variable O&M (1998$/MWh)	1.1	2.2
Availability (%)	90	90
New Power Plant Financing		
Debt/Equity Ratio	50/50	
Debt Rate (%)	9.0	
Return on Equity (%)	14.0	
Income Taxes (%)	41.3	
Other Taxes (%)	0.2	
Inflation Rate (%)	3.0	
Levelized Real Capital Charge Rate (%)	12.6	
Delivered Gas Price (1998$/MMBtu)		
2000	2.14	
2005	2.21	
2010	2.29	
2015	2.40	

PNM EXHIBIT _____ (SAT-6)

is included on the following pages

RETAIL MARKET PRICE

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Arizona-New Mexico												
Capacity Price 1998$/kW-yr	64.00	61.50	59.00	58.00	57.00	56.00	55.60	55.20	54.80	54.40	54.00	52.80
Capacity Price On-Year $/kW-yr	67.90	67.20	66.41	67.24	68.06	68.87	70.43	72.02	73.65	75.30	76.99	77.54
Energy Price 1998$/MWh	19.30	18.95	18.60	18.80	19.00	19.20	19.46	19.72	19.98	20.24	20.50	20.50
Energy Price On-Year $/MWh	20.48	20.71	20.93	21.79	22.69	23.61	24.65	25.73	26.85	28.02	29.23	30.10
Energy Price 1998 $/MWh - On-Peak	19.90	19.55	19.20	19.50	19.80	20.10	20.42	20.74	21.06	21.38	21.70	21.74
Energy Price On-Year $/MWh - On-Peak	21.11	21.36	21.61	22.61	23.64	24.72	25.87	27.06	28.30	29.59	30.94	31.93
Energy Price 1998 $/MWh - Off-Peak	18.60	18.70	18.80	18.53	18.27	18.00	18.16	18.32	18.48	18.64	18.80	18.76
Energy Price On-Year $/MWh - Off-Peak	19.73	20.43	21.16	21.49	21.81	22.14	23.00	23.90	24.84	25.80	26.80	27.55
New Mexico Retail Demand Forecast MW	1,336	1,381	1,427	1,468	1,507	1,553	1,599	1,647	1,696	1,748	1,801	1,853
New Mexico Retail Sales Forecast MWh	7,157,119	7,392,655	7,621,333	7,988,697	8,293,868	8,541,633	8,785,209	9,041,752	9,305,299	9,579,653	9,860,670	10,141,076
Losses Associated with Retail Sales Forecast MWh	644,141	665,339	685,920	718,983	746,448	768,747	790,669	813,758	837,477	862,169	887,460	912,697
Total Load for New Mexico Retail including Energy Losses												
MW	1,336	1,381	1,427	1,468	1,507	1,553	1,599	1,647	1,696	1,748	1,801	1,853
MWh	7,801,260	8,057,994	8,307,253	8,707,680	9,040,316	9,310,380	9,575,878	9,855,510	10,142,776	10,441,822	10,748,130	11,053,773
Ancillary Services Associated with Retail Sales Forecast												
SCHEDULE 2												
Reactive Supply and Voltage Control from Generation Sourc s Service												
Rate $/kW-yr	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58
Percentage of Peak Load	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Cost for Schedule 2 $k	774.60	800.80	827.58	851.44	874.06	900.74	927.42	955.26	983.68	1,013.84	1,044.58	1,074.74
SCHEDULE 3												
Regulation and Frequency Response Service												
Rate $/kW-yr	67.90	67.20	66.41	67.24	68.06	68.87	70.43	72.02	73.65	75.30	76.99	77.54
Percentage of Peak Load	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
Cost for Schedule 3 $k	1,360.17	1,391.80	1,421.25	1,480.58	1,538.52	1,604.40	1,689.32	1,779.34	1,873.57	1,974.43	2,079.91	2,155.18
SCHEDULE 3A												
Schedule Up Dynamic Load Service												
Rate $/kW-yr	67.90	67.20	66.41	67.24	68.06	68.87	70.43	72.02	73.65	75.30	76.99	77.54
Percentage of Peak Load	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
Cost for Schedule 3A $k	4,080.52	4,175.40	4,263.76	4,441.74	4,615.56	4,813.19	5,067.96	5,338.02	5,620.71	5,923.28	6,239.74	6,465.55
SCHEDULE 5												
Operating Reserve - Spinning Reserve Service												
Rate $/kW-yr	67.90	67.20	66.41	67.24	68.06	68.87	70.43	72.02	73.65	75.30	76.99	77.54
Percentage of Peak Load	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Cost for Schedule 5 $k	3,173.74	3,247.53	3,316.26	3,454.68	3,589.88	3,743.59	3,941.75	4,151.79	4,371.66	4,607.00	4,853.13	5,028.76
SCHEDULE 6												
Operating Reserve - Supplemental Reserve Service												
Rate $/kW-yr	67.90	67.20	66.41	67.24	68.06	68.87	70.43	72.02	73.65	75.30	76.99	77.54
Percentage of Peak Load	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Cost for Schedule 6 $k	3,173.74	3,247.53	3,316.26	3,454.68	3,589.88	3,743.59	3,941.75	4,151.79	4,371.66	4,607.00	4,853.13	5,028.76
Total Ancillary Services $k	12,563	12,863	13,145	13,683	14,208	14,805	15,568	16,376	17,221	18,126	19,071	19,753
Total Ancillary Services $/kW-yr	9.41	9.32	9.21	9.32	9.43	9.53	9.74	9.94	10.15	10.37	10.59	10.66
Total Generation Cost to Serve NM Retail Load												
Capacity Cost $k	90,678	92,787	94,750	98,705	102,568	106,960	112,621	118,623	124,905	131,628	138,661	143,679
Energy Cost $k	160,934	169,522	178,209	193,429	207,940	221,741	238,108	255,808	274,761	295,164	316,982	335,971
Firm Power Cost $k	251,612	262,309	272,959	292,134	310,508	328,700	350,730	374,431	399,666	426,792	455,643	479,650
Ancillary Services $k	12,563	12,863	13,145	13,683	14,208	14,805	15,568	16,376	17,221	18,126	19,071	19,753
Total Cost $k	264,175	275,172	286,104	305,817	324,716	343,506	366,298	390,807	416,887	444,918	474,714	499,403
Total Sales MWh	7,157,119	7,392,655	7,621,333	7,988,697	8,293,868	8,541,633	8,785,209	9,041,752	9,305,299	9,579,653	9,860,670	10,141,076
Retail Market Price for Total PNM Load $/MWh	36.91	37.22	37.54	38.28	39.15	40.22	41.69	43.22	44.80	46.44	48.14	49.25

RETAIL MARKET PRICE

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Arizona-New Mexico												
Capacity Price 1998$/kW-yr	51.60	50.40	49.20	48.00	46.88	45.79	44.72	43.68	42.67	41.67	40.70	39.76
Capacity Price On-Year $/kW-yr	78.05	78.52	78.95	79.34	79.81	80.29	80.78	81.26	81.75	82.25	82.74	83.24
Energy Price 1998$/MWh	20.50	20.50	20.50	20.50	20.50	20.50	20.50	20.50	20.50	20.50	20.50	20.50
Energy Price On-Year $/MWh	31.01	31.94	32.90	33.88	34.90	35.95	37.03	38.14	39.28	40.46	41.67	42.92
Energy Price 1998 $/MWh - On-Peak	21.78	21.82	21.86	21.90	21.90	21.90	21.90	21.90	21.90	21.90	21.90	21.90
Energy Price On-Year $/MWh - On-Peak	32.94	33.99	35.08	36.20	37.28	38.40	39.55	40.74	41.96	43.22	44.52	45.85
Energy Price 1998 $/MWh - Off-Peak	18.72	18.68	18.64	18.60	18.60	18.60	18.60	18.60	18.60	18.60	18.60	18.60
Energy Price On-Year $/MWh - Off-Peak	28.32	29.10	29.91	30.74	31.67	32.62	33.59	34.60	35.64	36.71	37.81	38.94
New Mexico Retail Demand Forecast MW	1,907	1,962	2,019	2,077	2,136	2,199	2,264	2,330	2,399	2,469	2,541	2,616
New Mexico Retail Sales Forecast MWh	10,429,473	10,726,281	11,031,649	11,346,186	11,670,956	12,005,897	12,351,440	12,706,671	13,072,119	13,448,077	13,834,848	14,232,743
Losses Associated with Retail Sales Forecast MWh	938,653	965,365	992,848	1,021,157	1,050,386	1,080,531	1,111,630	1,143,600	1,176,491	1,210,327	1,245,136	1,280,947
Total Load for New Mexico Retail including Energy Losses												
MW	1,907	1,962	2,019	2,077	2,136	2,199	2,264	2,330	2,399	2,469	2,541	2,616
MWh	11,368,126	11,691,646	12,024,497	12,367,343	12,721,342	13,086,428	13,463,070	13,850,272	14,248,610	14,658,404	15,079,985	15,513,690
Ancillary Services Associated with Retail Sales Forecast												
SCHEDULE 2												
Reactive Supply and Voltage Control from Generation Sourc												
Rate $/kW-yr	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58
Percentage of Peak Load	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Cost for Schedule 2 $k	1,106.06	1,137.96	1,171.02	1,204.66	1,238.88	1,275.42	1,313.12	1,351.60	1,391.22	1,431.99	1,473.96	1,517.15
SCHEDULE 3												
Regulation and Frequency Response Service												
Rate $/kW-yr	78.05	78.52	78.95	79.34	79.81	80.29	80.78	81.26	81.75	82.25	82.74	83.24
Percentage of Peak Load	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
Cost for Schedule 3 $k	2,232.61	2,310.89	2,391.05	2,471.73	2,557.25	2,648.52	2,743.23	2,840.62	2,941.48	3,045.91	3,154.05	3,266.03
SCHEDULE 3A												
Schedule Up Dynamic Load Service												
Rate $/kW-yr	78.05	78.52	78.95	79.34	79.81	80.29	80.78	81.26	81.75	82.25	82.74	83.24
Percentage of Peak Load	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
Cost for Schedule 3A $k	6,697.83	6,932.67	7,173.14	7,415.20	7,671.75	7,945.57	8,229.68	8,521.87	8,824.43	9,137.73	9,462.16	9,798.10
SCHEDULE 5												
Operating Reserve - Spinning Reserve Service												
Rate $/kW-yr	78.05	78.52	78.95	79.34	79.81	80.29	80.78	81.26	81.75	82.25	82.74	83.24
Percentage of Peak Load	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Cost for Schedule 5 $k	5,209.42	5,392.08	5,579.11	5,767.38	5,966.92	6,179.89	6,400.87	6,628.12	6,863.45	7,107.13	7,359.46	7,620.75
SCHEDULE 6												
Operating Reserve - Supplemental Reserve Service												
Rate $/kW-yr	78.05	78.52	78.95	79.34	79.81	80.29	80.78	81.26	81.75	82.25	82.74	83.24
Percentage of Peak Load	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Cost for Schedule 6 $k	5,209.42	5,392.08	5,579.11	5,767.38	5,966.92	6,179.89	6,400.87	6,628.12	6,863.45	7,107.13	7,359.46	7,620.75
Total Ancillary Services $k	20,455	21,166	21,893	22,626	23,402	24,229	25,088	25,970	26,884	27,830	28,809	29,823
Total Ancillary Services $/kW-yr	10.73	10.79	10.84	10.89	10.96	11.02	11.08	11.14	11.21	11.27	11.34	11.40
Total Generation Cost to Serve NM Retail Load												
Capacity Cost $k	148,841	154,059	159,403	164,782	170,483	176,568	182,882	189,375	196,098	203,061	210,270	217,736
Energy Cost $k	356,098	377,437	400,060	424,055	449,279	476,038	504,431	534,507	566,376	600,145	635,928	673,844
Firm Power Cost $k	504,938	531,497	559,463	588,838	619,763	652,607	687,313	723,882	762,475	803,206	846,198	891,579
Ancillary Services $k	20,455	21,166	21,893	22,626	23,402	24,229	25,088	25,970	26,884	27,830	28,809	29,823
Total Cost $k	525,394	552,662	581,356	611,464	643,164	676,836	712,401	749,852	789,359	831,036	875,007	921,402
Total Sales MWh	10,429,473	10,726,281	11,031,649	11,346,186	11,670,956	12,005,897	12,351,440	12,706,671	13,072,119	13,448,077	13,834,848	14,232,743
Retail Market Price for Total PNM Load $/MWh	50.38	51.52	52.70	53.89	55.11	56.38	57.68	59.01	60.38	61.80	63.25	64.74

RETAIL MARKET PRICE

	2024	2025
Arizona-New Mexico		
Capacity Price 1998$/kW-yr	38 83	37 93
Capacity Price On-Year $/kW-yr	83 74	84 24
Energy Price 1998$/MWh	20.50	20.50
Energy Price On-Year $/MWh	44.21	45 54
Energy Price 1998 $/MWh - On-Peak	21.90	21.90
Energy Price On-Year $/MWh - On-Peak	47.23	48 65
Energy Price 1998 $/MWh - Off-Peak	18 60	18 60
Energy Price On-Year $/MWh - Off-Peak	40.11	41.32
New Mexico Retail Demand Forecast MW	2,692	2,771
New Mexico Retail Sales Forecast MWh	14,642,081	15,063,192
Losses Associated with Retail Sales Forecast MWh	1,317,787	1,355,687
Total Load for New Mexico Retail including Energy Losses		
MW	2,692	2,771
MWh	15,959,868	16,418,879
Ancillary Services Associated with Retail Sales Forecast		
SCHEDULE 2		
Reactive Supply and Voltage Control from Generation Sourc		
Rate $/kW-yr	0 58	0 58
Percentage of Peak Load	100%	100%
Cost for Schedule 2 $k	1,561.62	1,607.38
SCHEDULE 3		
Regulation and Frequency Response Service		
Rate $/kW-yr	83 74	84 24
Percentage of Peak Load	1.50%	1.50%
Cost for Schedule 3 $k	3,381.99	3,502.07
SCHEDULE 3A		
Schedule Up Dynamic Load Service		
Rate $/kW-yr	83 74	84 24
Percentage of Peak Load	4.50%	4.50%
Cost for Schedule 3A $k	10,145.98	10,506 20
SCHEDULE 5		
Operating Reserve - Spinning Reserve Service		
Rate $/kW-yr	83.74	84 24
Percentage of Peak Load	3.50%	3.50%
Cost for Schedule 5 $k	7,891.31	8,171.49
SCHEDULE 6		
Operating Reserve - Supplemental Reserve Service		
Rate $/kW-yr	83 74	84 24
Percentage of Peak Load	3 50%	3 50%
Cost for Schedule 6 $k	7,891.31	8,171.49
Total Ancillary Services $k	30,872	31,959
Total Ancillary Services $/kW-yr	11.47	11.53
Total Generation Cost to Serve NM Retail Load		
Capacity Cost $k	225,466	233,471
Energy Cost $k	714,020	756,592
Firm Power Cost $k	939,486	990,064
Ancillary Services $k	30,872	31,959
Total Cost $k	970,359	1,022,022
Total Sales MWh	14,642,081	15,063,192
Retail Market Price for Total PNM Load $/MWh	66.27	67.85

PNM EXHIBIT _____ (SAT-7)

is included on the following pages

STRANDED COSTS CALCULATION

	2002	2003	2004	2005	2006	2007	2008	2009	2010
Additional Requirements from the Market									
Demand Served at Market Price MW	22	30	69	305	351	399	448	500	553
On-Peak Load Served At Market Price MWh	-	-	191,926	517,902	690,476	872,237	1,043,799	1,253,340	1,452,440
Off-Peak Load Served At Market Price MWh	-	-	-	-	-	-	-	-	-
Market Capacity Price (incl ancillary services) $/kW-yr	66.41	67.24	68.06	68.87	70.43	72.02	73.65	75.30	76.99
Market On-Peak Energy Price $/MWh	21.61	22.61	23.64	24.72	25.87	27.06	28.30	29.59	30.94
Market Off-Peak Energy Price $/MWh	21.16	21.49	21.81	22.14	23.00	23.90	24.84	25.80	26.80
Revenue Requirements from Existing Assets $k	432,579	441,488	456,121	439,194	435,950	417,333	423,063	422,758	432,508
Additional Cost to Serve Load from Market $k	1,481	2,004	9,220	33,823	42,597	52,355	62,551	74,759	87,529
Total Cost to Serve Load under Regulation $k	434,060	443,492	465,342	473,017	478,547	469,688	485,614	497,517	520,037
NM Retail Sales MWh	7,621,333	7,988,697	8,293,868	8,541,633	8,785,209	9,041,752	9,305,299	9,579,653	9,860,670
Total Price for Regulated Revenue Requirements $/MWh	56.95	55.51	56.11	55.38	54.47	51.95	52.19	51.93	52.74
PNM Retail Load Served at Retail Market Price									
Firm Retail Market Price $/MWh	37.54	38.28	39.15	40.22	41.69	43.22	44.80	46.44	48.14
Retail Sales Revenue in Competitive Market $k	286,104	305,817	324,716	343,506	366,298	390,807	416,887	444,918	474,714
Difference Between Revenue Requirements and Market for 1/1/2002 through 12/31/2005	147,956	137,675	140,626	129,511	112,249	78,881	68,727	52,599	45,323
Discount Rate	6.3093%								
NPV at Discount Rate $k for 1/1/2002 through 12/31/2025	771,898								
PV 1&2 Decommissioning	3,598	3,684	3,684	3,684	3,684	3,684	3,684	3,684	3,684
NPV of Decommissioning $k for 1/1/2002 through 12/31/2025	44,438								
Remaining Stranded Cost $k for 1/1/2002 through 12/31/2025	727,461								
Difference Between Revenue Requirements and Market for 7/1/2002 through 12/31/2005	73,978	137,675	140,626	129,511	112,249	78,881	68,727	52,599	45,323
NPV at Discount Rate $k for 7/1/2002 through 12/31/2025	702,311								
PV 1&2 Decommissioning	1,799	3,684	3,684	3,684	3,684	3,684	3,684	3,684	3,684
NPV of Decommissioning $k for 7/1/2002 through 12/31/2025	42,745								
Remaining Stranded Cost $k for 7/1/2002 through 12/31/2025	659,565								

STRANDED COSTS CALCULATION

	2011	2012	2013	2014	2015	2016	2017	2018	2019
Additional Requirements from the Market									
Demand Served at Market Price MW	768	950	1,022	1,213	1,271	1,330	1,700	1,765	1,832
On-Peak Load Served At Market Price MWh	2,441,928	3,292,063	3,515,298	4,359,462	4,582,312	4,802,941	6,562,888	6,807,705	7,059,387
Off-Peak Load Served At Market Price MWh	663,020	764,261	886,276	1,509,909	1,629,905	1,746,411	3,103,899	3,235,723	3,371,244
Market Capacity Price (incl ancillary services) $/kW-yr	77.54	78.05	78.52	78.95	79.34	79.81	80.29	80.78	81.26
Market On-Peak Energy Price $/MWh	31.93	32.94	33.99	35.08	36.20	37.28	38.40	39.55	40.74
Market Off-Peak Energy Price $/MWh	27.55	28.32	29.10	29.91	30.74	31.67	32.62	33.59	34.60
Revenue Requirements from Existing Assets $k	404,533	382,920	387,283	337,836	327,068	300,233	161,546	157,894	159,850
Additional Cost to Serve Load from Market $k	155,807	204,234	225,536	293,873	316,828	340,539	489,800	520,583	553,115
Total Cost to Serve Load under Regulation $k	560,340	587,154	612,820	631,709	643,897	640,772	651,346	678,476	712,965
NM Retail Sales MWh	10,141,076	10,429,473	10,726,281	11,031,649	11,346,186	11,670,956	12,005,897	12,351,440	12,706,671
Total Price for Regulated Revenue Requirements $/MWh	55.25	56.30	57.13	57.26	56.75	54.90	54.25	54.93	56.11
PNM Retail Load Served at Retail Market Price									
Firm Retail Market Price $/MWh	49.25	50.38	51.52	52.70	53.89	55.11	56.38	57.68	59.01
Retail Sales Revenue in Competitive Market $k	499,403	525,394	552,662	581,356	611,464	643,164	676,836	712,401	749,852
Difference Between Revenue Requirements and Market for 1/1/2002 through 12/31/2005	60,937	61,761	60,158	50,352	32,433	(2,392)	(25,489)	(33,924)	(36,887)
Discount Rate									
NPV at Discount Rate $k for 1/1/2002 through 12/31/2025									
PV 1&2 Decommissioning	3,684	3,684	3,684	3,684	3,684	3,684	3,684	3,684	3,684
NPV of Decommissioning $k for 1/1/2002 through 12/31/2025									
Remaining Stranded Cost $k for 1/1/2002 through 12/31/2025									
Difference Between Revenue Requirements and Market for 7/1/2002 through 12/31/2005	60,937	61,761	60,158	50,352	32,433	(2,392)	(25,489)	(33,924)	(36,887)
NPV at Discount Rate $k for 7/1/2002 through 12/31/2025									
PV 1&2 Decommissioning	3,684	3,684	3,684	3,684	3,684	3,684	3,684	3,684	3,684
NPV of Decommissioning $k for 7/1/2002 through 12/31/2025									
Remaining Stranded Cost $k for 7/1/2002 through 12/31/2025									

STRANDED COSTS CALCULATION

	2020	2021	2022	2023	2024	2025
Additional Requirements from the Market						
Demand Served at Market Price MW	2,111	2,294	2,366	2,568	2,645	2,748
On-Peak Load Served At Market Price MWh	8,303,099	8,687,716	8,961,743	9,839,674	10,129,021	10,550,159
Off-Peak Load Served At Market Price MWh	4,306,417	4,451,704	4,599,257	5,232,511	5,388,133	5,647,968
Market Capacity Price (incl ancillary services) $/kW-yr	81.75	82.25	82.74	83.24	83.74	84.24
Market On-Peak Energy Price $/MWh	41.96	43.22	44.52	45.85	47.23	48.65
Market Off-Peak Energy Price $/MWh	35.64	36.71	37.81	38.94	40.11	41.32
Revenue Requirements from Existing Assets $k	91,113	72,849	75,021	29,834	32,655	14,493
Additional Cost to Serve Load from Market $k	674,509	727,572	768,641	868,736	915,999	978,043
Total Cost to Serve Load under Regulation $k	765,622	800,421	843,661	898,569	948,655	992,536
NM Retail Sales MWh	13,072,119	13,448,077	13,834,848	14,232,743	14,642,081	15,063,192
Total Price for Regulated Revenue Requirements $/MWh	58.57	59.52	60.98	63.13	64.79	65.89
PNM Retail Load Served at Retail Market Price						
Firm Retail Market Price $/MWh	60.38	61.80	63.25	64.74	66.27	67.85
Retail Sales Revenue in Competitive Market $k	789,359	831,036	875,007	921,402	970,359	1,022,022
Difference Between Revenue Requirements and Market for 1/1/2002 through 12/31/2005	(23,736)	(30,615)	(31,346)	(22,833)	(21,704)	(29,486)
Discount Rate						
NPV at Discount Rate $k for 1/1/2002 through 12/31/2025						
PV 1&2 Decommissioning	3,684	3,684	3,684	3,684	3,684	1,842
NPV of Decommissioning $k for 1/1/2002 through 12/31/2025						
Remaining Stranded Cost $k for 1/1/2002 through 12/31/2025						
Difference Between Revenue Requirements and Market for 7/1/2002 through 12/31/2005	(23,736)	(30,615)	(31,346)	(22,833)	(21,704)	(29,486)
NPV at Discount Rate $k for 7/1/2002 through 12/31/2025						
PV 1&2 Decommissioning	3,684	3,684	3,684	3,684	3,684	1,842
NPV of Decommissioning $k for 7/1/2002 through 12/31/2025						
Remaining Stranded Cost $k for 7/1/2002 through 12/31/2025						

PNM EXHIBIT _____ (SAT-8)

is included on the following pages

BRATTLE GROUP METHODOLOGY TO DETERMINE DISCOUNT RATE

	2002	2003	2004	2005	2006	2007	2008	2009	2010
Revenue from Regulated Rates $k	432,579	441,488	456,121	439,194	435,950	417,333	423,063	422,758	432,508
Less: Fuel	157,132	152,746	162,906	158,032	150,916	131,320	133,402	133,608	137,842
Purchased Power	36,638	38,330	39,300	38,189	38,731	39,503	40,308	40,993	41,605
Non-Fuel O&M	152,537	158,617	161,116	156,576	159,014	161,525	164,111	166,774	169,518
Book Depreciation	44,873	47,718	49,488	45,176	46,709	47,815	49,216	45,111	47,116
Property Taxes	5,188	5,298	5,120	4,930	4,775	4,542	4,287	4,074	3,826
Payroll Taxes	2,782	2,934	3,022	2,804	2,888	2,974	3,064	3,156	3,250
Miscellaneous Amortization	3,964	3,867	3,867	2,728	2,728	505	409	409	409
Revenue Credit	(20,872)	(17,320)	(15,072)	(12,972)	(11,342)	(9,446)	(7,579)	(4,902)	(2,218)
Revenue Tax	2,163	2,207	2,281	2,196	2,180	2,087	2,115	2,114	2,163
Total Expenses $k	384,405	394,397	412,027	397,659	396,599	380,824	389,332	391,336	403,509
Pre-Tax Operating Income from Regulation $k	48,174	47,091	44,094	41,535	39,352	36,509	33,731	31,422	28,999
Income Taxes	19,072	18,643	17,457	16,444	15,579	14,454	13,354	12,440	11,481
After-Tax Operating Income from Regulation $k	29,102	28,448	26,637	25,091	23,772	22,055	20,377	18,982	17,518
Book Depreciation $k	44,873	47,718	49,488	45,176	46,709	47,815	49,216	45,111	47,116
After-Tax Cash from Regulation $k	73,975	76,166	76,125	70,267	70,482	69,870	69,593	64,093	64,634
Integrated Utility ATWCOC	8.25%								
NPV After-Tax Cash from Regulation $k	602,649								
Revenue from Competitive Market Place $k	284,623	303,814	315,496	309,683	323,701	338,452	354,336	370,159	387,185
Less: Same Expenses $k	384,405	394,397	412,027	397,659	396,599	380,824	389,332	391,336	403,509
Pre-Tax Operating Income from Competitive Market $k	(99,782)	(90,583)	(96,532)	(87,976)	(72,898)	(42,372)	(34,996)	(21,177)	(16,324)
Income Taxes	(39,504)	(35,862)	(38,217)	(34,830)	(28,860)	(16,775)	(13,855)	(8,384)	(6,463)
After-Tax Operating Income from Competitive Market	(60,278)	(54,721)	(58,315)	(53,146)	(44,037)	(25,597)	(21,141)	(12,793)	(9,861)
Book Depreciation $k	44,873	47,718	49,488	45,176	46,709	47,815	49,216	45,111	47,116
After-Tax Cash for Competitive Market $k	(15,406)	(7,003)	(8,826)	(7,970)	2,672	22,217	28,075	32,318	37,255
Competitive Utility ATWCOC	9.64%								
NPV After-Tax Case from Competitive Market $k	136,345								
Shareholder Stranded Cost	466,303								
Ratepayer Stranded Cost	771,898								

BRATTLE GROUP METHODOLOGY TO DETERMINE DISCOUNT RATE

	2011	2012	2013	2014	2015	2016	2017	2018	2019
Revenue from Regulated Rates $k	404,533	382,920	387,283	337,836	327,068	300,233	161,546	157,894	159,850
Less: Fuel	121,347	125,767	125,578	101,419	102,948	104,631	64,813	66,418	68,063
Purchased Power	42,232	15,438	15,658	15,901	16,150	16,420	16,666	16,934	17,210
Non-Fuel O&M	161,029	162,803	166,131	152,046	140,228	107,762	43,698	46,210	47,518
Book Depreciation	43,056	44,893	49,073	40,163	42,650	50,139	23,471	16,403	15,602
Property Taxes	3,581	3,271	2,885	2,545	2,113	1,559	1,280	1,118	998
Payroll Taxes	2,964	3,053	3,140	2,840	2,925	3,013	1,530	1,576	1,624
Miscellaneous Amortization	409	409	409	409	409	370	365	365	365
Revenue Credit	-	-	-	-	-	-	-	-	-
Revenue Tax	2,023	1,915	1,936	1,689	1,635	1,501	808	789	799
Total Expenses $k	376,641	357,547	364,811	317,013	309,057	285,395	152,631	149,815	152,178
Pre-Tax Operating Income from Regulation $k	27,892	25,373	22,472	20,823	18,011	14,839	8,915	8,079	7,672
Income Taxes	11,042	10,045	8,897	8,244	7,131	5,875	3,529	3,199	3,037
After-Tax Operating Income from Regulation $k	16,850	15,328	13,576	12,579	10,881	8,964	5,386	4,881	4,635
Book Depreciation $k	43,056	44,893	49,073	40,163	42,650	50,139	23,471	16,403	15,602
After-Tax Cash from Regulation $k	59,906	60,221	62,649	52,742	53,530	59,103	28,857	21,284	20,237
Integrated Utility ATWCOC									
NPV After-Tax Cash from Regulation $k									
Revenue from Competitive Market Place $k	343,596	321,159	327,126	287,483	294,636	302,625	187,036	191,818	196,737
Less: Same Expenses $k	376,641	357,547	364,811	317,013	309,057	285,395	152,631	149,815	152,178
Pre-Tax Operating Income from Competitive Market $k	(33,045)	(36,388)	(37,685)	(29,529)	(14,422)	17,231	34,404	42,004	44,559
Income Taxes	(13,083)	(14,406)	(14,920)	(11,691)	(5,709)	6,822	13,621	16,629	17,641
After-Tax Operating Income from Competitive Market	(19,963)	(21,982)	(22,766)	(17,839)	(8,712)	10,409	20,784	25,374	26,918
Book Depreciation $k	43,056	44,893	49,073	40,163	42,650	50,139	23,471	16,403	15,602
After-Tax Cash for Competitive Market $k	23,094	22,911	26,307	22,324	33,938	60,548	44,255	41,778	42,521
Competitive Utility ATWCOC									
NPV After-Tax Case from Competitive Market $k									
Shareholder Stranded Cost									
Ratepayer Stranded Cost									

BRATTLE GROUP METHODOLOGY TO DETERMINE DISCOUNT RATE

	2020	2021	2022	2023	2024	2025
Revenue from Regulated Rates $k	91,113	72,849	75,021	29,834	32,655	14,493
Less: Fuel	26,902	27,472	28,129	2,482	2,510	1,262
Purchased Power	17,507	-	-	-	-	-
Non-Fuel O&M	28,549	26,629	28,024	14,802	17,198	7,276
Book Depreciation	8,695	9,923	10,866	5,226	6,147	3,043
Property Taxes	859	709	508	342	126	-
Payroll Taxes	863	889	916	388	400	214
Miscellaneous Amortization	365	365	365	365	365	-
Revenue Credit	-	-	-	-	-	-
Revenue Tax	456	364	375	149	163	72
Total Expenses $k	84,196	66,351	69,182	23,755	26,909	11,866
Pre-Tax Operating Income from Regulation $k	6,917	6,497	5,839	6,079	5,746	2,627
Income Taxes	2,739	2,572	2,311	2,407	2,275	1,040
After-Tax Operating Income from Regulation $k	4,179	3,925	3,527	3,672	3,471	1,587
Book Depreciation $k	8,695	9,923	10,866	5,226	6,147	3,043
After-Tax Cash from Regulation $k	12,874	13,848	14,393	8,898	9,618	4,630
Integrated Utility ATWCOC						
NPV After-Tax Cash from Regulation $k						
Revenue from Competitive Market Place $k	114,849	103,463	106,366	52,666	54,359	43,979
Less: Same Expenses $k	84,196	66,351	69,182	23,755	26,909	11,866
Pre-Tax Operating Income from Competitive Market $k	30,654	37,112	37,184	28,912	27,450	32,113
Income Taxes	12,136	14,693	14,721	11,446	10,868	12,714
After-Tax Operating Income from Competitive Market	18,518	22,419	22,463	17,466	16,583	19,400
Book Depreciation $k	8,695	9,923	10,866	5,226	6,147	3,043
After-Tax Cash for Competitive Market $k	27,213	32,342	33,328	22,692	22,730	22,442
Competitive Utility ATWCOC						
NPV After-Tax Case from Competitive Market $k						
Shareholder Stranded Cost						
Ratepayer Stranded Cost						

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S TRANSITION PLAN FILED PURSUANT TO THE ELECTRIC UTILITY INDUSTRY RESTRUCTURING ACT OF 1999	)	
PUBLIC SERVICE COMPANY OF NEW MEXICO,	)	**Utility Case No. 3137**
PETITIONER.	)	**Part III**

AFFIDAVIT

STATE OF NEW MEXICO)
) **ss**
COUNTY OF BERNALILLO)

Susan A. Taylor, upon being first duly sworn according to law, under oath, deposes and states: That I have read the foregoing Testimony including Exhibits and it is true and accurate based on my own personal knowledge and belief.

SIGNED this 24TH day of May, 2000.

Susan A Taylor
SUSAN A. TAYLOR

SUBSCRIBED AND SWORN to before me this 24TH day of May, 2000.

Stella Louise Hanna
NOTARY PUBLIC IN AND FOR
THE STATE OF NEW MEXICO

My Commission Expires:

3-14-2003

Document #34436