BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF NEW MEXICO FOR APPROVAL OF ELECTRIC ENERGY EFFICIENCY PROGRAMS AND PROGRAM COST TARIFF RIDER PURSUANT TO THE NEW MEXICO PUBLIC UTILITY AND EFFICIENT USE OF ENERGY ACTS	)	**Case No. 12-00317-UT**
PUBLIC SERVICE COMPANY OF NEW MEXICO,	)	
Applicant.	)	

DIRECT TESTIMONY

OF

FRANK C. GRAVES

October 5, 2012

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CASE NO. 12-00317-UT

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, PROFESSIONAL AFFILIATION, AND ADDRESS.

A. I am Frank C. Graves, a Principal and co-leader of the utility practice group at The Brattle Group, an economics consulting firm with offices in several cities in the United States and Europe. My office is at 44 Brattle Street, Cambridge, Massachusetts 02138.

Q. ON WHOSE BEHALF ARE YOU APPEARING, AND WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am testifying on behalf of Public Service Company of New Mexico ("PNM") in regard to the appropriate incentive compensation on its energy efficiency and load management ("efficiency" or "EE") programs and activities, which are being filed now in 2012 to go into effect next year ("2012 Plan"). I understand that, under the Efficient Use of Energy Act ("EUEA"), utilities are entitled to an opportunity to earn a profit on EE through Commission-approved incentives. With satisfactory program performance, the profit is required to be "financially more attractive to the utility than supply-side utility resources." The rates to collect the costs of the efficiency programs and the profit incentives must satisfy the Public Utility Act ("PUA"), which requires rates to be just and reasonable.

I have analyzed PNM's 2012 Plan and its foregone profits from displacing conventional supply alternatives, and I have recommended an incentive allowance based on how much profit would be foregone from the investments avoided or deferred by the beneficial efficiency programs contained in the 2012 Plan. I also show that this amount of profit incentive is reasonable in comparison to what many other utilities receive as incentive compensation for their efficiency programs in a variety of states with similar policies. As such, the incentive energy efficiency rates I recommend are consistent with statutory goals and objectives and are clearly just and reasonable, properly balancing the overall public interest and the interests of customers and investors.

Q. BRIEFLY, WHAT ARE YOUR QUALIFICATIONS FOR OFFERING THESE OPINIONS?

A. I have been involved in consulting to utilities on resource planning, market price forecasting, avoided cost measurement, and service design and pricing for more than 30 years. This extensive involvement in utility planning and regulatory approvals has given me a strong understanding of cost/benefit assessments of all of the types of demand- and supply-side resources that utilities can bring to bear in meeting their customers' needs, and I have used (and often helped develop or enhance) many of the kinds of modeling tools used for financial and operational performance assessment of alternative plans and programs. I have testified numerous times before state regulatory agencies on the prudence of proposed actions, the performance of markets under prevailing rules and procedures, and the impacts of new regulatory policies under consideration. A full Curriculum Vitae of my consulting, research, and testimonial experience is attached to my testimony as PNM Exhibit FCG-1.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I will discuss some economic principles related to why an efficiency incentive is reasonable and why it must be considered in relation to the effects EE has on the risk profile of the total utility business, together with the value provided by EE, rather than simply considering the risk attributes associated with recovery of the program costs in isolation. Then I present a short overview of the history of PNM EE activities, in order to introduce the nature of their expected benefits. Next I discuss the five types of EE incentive practices that are commonly observed in the U.S. utility industry. With this foundation, I present the economic logic for the recommended PNM incentive, which is for approximately $4.206 million of allowed incentive to be earned in equal parts based on verified energy and capacity savings achieved from the 2012 Plan. I show the amount is reasonable in comparison to the amount and structure of EE incentives of utilities in six states within the U.S. that have similar incentive structures to what is contemplated by the EUEA (though the EUEA includes a stronger profit incentive than is the case in many of those states). I find that the recommended amount is consistent with industry norms, and is reasonable on several measures.

II. BACKGROUND ON INCENTIVES FOR ENERGY EFFICIENCY

Q. WHY IS IT APPROPRIATE AND DESIRABLE TO CREATE A PROFIT INCENTIVE FOR UTILITY EE ACTIVITIES?

A. Electricity conservation and efficiency activities are very desirable socially, in terms of the savings they can provide to society and to utility customers. This is reflected in their favorable benefit/cost ratios of avoided future energy and capacity costs (of conventional supply) vs. the direct costs (utility program plus customer efficiency investment costs) of the EE activities themselves. These ratios (based on present values of life-cycle benefits vs. costs) are often from 1.5X to over 3X. Utility customers who participate in EE see their usage and bills go down directly. Non-participants also benefit from programs that have positive benefit/cost ratios and they have the opportunity (and incentive) to gain more of the EE benefits by participating in the programs. Further, since EE is a resource that produces no emissions, it is good for long-term air, water, and natural resource conservation goals.

However, these customer and social advantages of EE do not translate directly into a share of the benefits going to the utility and its investors who must find, sponsor and oversee the activities. To the contrary, absent regulatory adjustments, EE by itself can undermine the financial health and profit opportunity of a utility and its investors. Without an adequate profit incentive as required by the EUEA, EE becomes at best a "break-even" business proposition for the utility, but more likely makes the utility a less attractive investment opportunity for shareholders.

Q. ARE YOU FAMILIAR WITH THE TRADITIONAL WAY A REASONABLE PROFIT FOR UTILITIES IS DETERMINED?

A. Yes, I am. Because the traditional utility business of generating and delivering electricity to customers to meet their needs is capital-intensive, a return on investment (also called the rate base) is generally considered to be the most appropriate way to derive the appropriate amount of profit to be included in a just and reasonable rate. The amount of profit is determined by the return on equity ("RoE") component of the return on rate base. It is not susceptible of precise mathematical calculation, and thus is not the product of a rigid mathematical formula. Rather it is dependent on the exercise of informed and reasonable judgment, taking into account all relevant factors, often relying on a number of relevant economic indicators and formulae to establish the "zone of reasonableness" within which just and reasonable rates may be set. To inform the Commission's judgment, financial analysts provide the Commission with their analyses, which may include use of the discounted cash flow model (and variations of it), a risk premium analysis, the capital asset pricing model, and comparable earnings analyses.

Q. HOW DOES THE DERIVATION OF A REASONABLE PROFIT INCENTIVE FOR EE PROGRAMS DIFFER FROM THE DERIVATION OF A REASONABLE RETURN ON EQUITY?

A. The derivation of a profit incentive for EE is also dependent on the exercise of informed and reasonable judgment, taking into consideration all relevant factors. It differs to the extent that different profitability measures must be used to derive the reasonable profit level due to the practical consideration that EE programs do not result in a rate base upon which a return may be granted. Importantly, EE programs impose risks on the utility apart from how the EE program costs themselves are incurred or recovered.

Q. HOW DO TRADITIONAL RATEMAKING PRACTICES INFORM THE DETERMINATION OF REASONABLE PROFITS THAT SHOULD BE ALLOWED AS AN INCENTIVE FOR EFFICIENCY ACTIVITIES UNDER THE EUEA?

A. The EUEA requires an incentive opportunity that is financially more attractive than the profits that would have been otherwise obtained under conventional utility investment displaced by EE. This lost profit is precisely the same return on equity that is associated with the generation, transmission and distribution assets included in PNM's rate base. Thus, the return on equity component of PNM's WACC is a critical factor in deriving the needed incentive.

Q. PLEASE EXPLAIN HOW A UTILITY IS EXPOSED TO RISKS OF ADVERSE FINANCIAL CONSEQUENCES FROM ITS EE EFFORTS THAT THEREFORE MERIT THE TYPE OF INCENTIVE CONTEMPLATED IN THE EUEA.

A. The financial drawbacks to normal utility profitability from EE efforts arise in at least two ways. First, pursuing EE involves asking (or requiring) the utility to shrink its own sales base for its products. No competitive business or industry is asked to do this, which is contrary to the interests of its shareholders. The ability to grow and expand services is normally a vital part of the financial appeal of a firm to investors, and having that opportunity also motivates a firm's managers to innovate, cut costs, and enhance the customer interface. Having to shrink the base cuts the other way, making it more difficult to recover the costs of other necessary infrastructure upgrades (e.g., to transmission and distribution systems), and it makes the firm less attractive to investors compared to financial opportunities in other sectors of the economy. It also complicates other utility planning activities, such as load forecasting, resource planning, and pricing/cost recovery, making their results more difficult to predict.

Second, the way regulated utilities typically recover their sunk and fixed costs under cost of service ratemaking from non-EE activities is undermined by successful EE efforts. The majority of revenues from most customers' bills comes in the form of a volumetric fee per kWh of electricity consumed. Despite this pricing practice, most of a utility's non-fuel costs are not sensitive to volumes sold; instead, they are costs such as return on investment, depreciation, and fixed O&M that are fixed in the short run between rate cases. This means that EE programs reduce the profitability of already approved assets, leaving the utility at an economic disadvantage compared to having not done the EE programs. This problem is exacerbated when the volumetric rates increase with higher usage due to the use of inclining block rates that include more fixed cost recovery in the higher usage blocks. Such is the case with PNM's rates.

Building a profit incentive into EE activities is a critical component of an effective EE regulatory regime to address these increased risks and cost recovery problems, and it makes EE "financially attractive" to the utility rather than at best a break-even business activity that reduces the profitability and profit potential of the traditional utility business.

Q. DOES RELIABLE AND CONCURRENT COST RECOVERY FOR EE ACTIVITIES CURE THESE PROBLEMS?

A. No, EE program cost recovery and incentives are separate issues. It is important and reasonable that utilities gain timely and reliable cost recovery for their EE activities, because they are cost effective and approved by the Commission before being undertaken by the utility. However, that only assures there are no losses tied to the EE expenditures themselves. It doesn't address the concerns about what having an EE program does to the rest of a utility's business activities, in terms of cost recovery and growth potential.

Q. DO MECHANISMS SUCH AS "DECOUPLING" CURE THE PROBLEMS YOU JUST DESCRIBED?

A. They help, but are not a complete cure. The purpose of such mechanisms is to make a utility's revenues insensitive or less sensitive to volume sold, so that the utility does not suffer losses from energy efficiency. This can be done through a variety of different approaches, such as increasing fixed charges in tariffs or by assessing surcharges or refunds for prior lost or gained fixed cost recovery on the balance of sales volume. If implemented well, these mechanisms can cure the lost recovery of fixed and sunk costs, but will not cure the problem that the utility's growth opportunities have shrunk, reducing the profitability and profit potential of the utility's traditional business and making it less attractive to investors. Traditional ratemaking has always understood that, between rate cases, the growth in electric sales, especially the growth in sales per customer from new uses, helped cover the normal inflation in costs. Mechanisms to address this issue are an additional component of an effective EE regulatory regime by addressing the "through-put" incentive issue, i.e. the incentive for utilities to "build and sell" because that is how they traditionally make money. But they do not address the need for a profit incentive related to the EE business itself.

Notably, there is no decoupling mechanism in place for PNM, though I understand that the Commission may consider adopting decoupling or other mechanisms to address regulatory disincentives to EE in the future. I also understand that PNM has agreed not to apply for a ratemaking mechanism to address the "through-put" incentive issue I have described until its next general rate case. My point here is that the profit incentive for EE question is not the same as the fixed cost recovery problem. As I show below, most utilities with EE profit incentive allowances also have decoupling or a lost revenue recovery mechanism.

Q. ARE THERE OTHER REASONS FOR ENDORSING AND ALLOWING EE PROFIT INCENTIVES?

A. Yes. Identifying and capturing the best EE opportunities is not easy or certain – utilities will have the incentive to do a better job of expanding EE to more potential participants and new technologies if it is more than a "break-even" business activity to which they are financially indifferent. Many states with significant regulatory goals for EE attainment have recognized this issue and allow some kind of additional, performance-based compensation to reward successful EE programs. The EUEA is not unique in providing for such a profit incentive, though it appears to require a stronger profit incentive to be allowed than others, due to its requirement for a financially more attractive profit than on supply side investments.

Q. PLEASE ELABORATE ON SOME OF THE DIFFICULTIES OF ACHIEVING EE SUCCESS.

A. I understand that PNM is under an obligation to meet aggressive goals for EE penetration through 2020. To satisfy the legislative goal of 10% reductions relative to 2005 consumption by 2020, PNM estimates it will have to find EE programs that eliminate an additional 662 GWh of cumulative energy demand from 2014-2020. PNM's retail load was about 9,290 GWh per year in 2011, so this future reduction is equivalent to about 7.1% of that demand. This is more per year than PNM expects to have saved by 2014, even though it has exceeded the projections for EE savings from EE programs over the past five years. There are several reasons why achieving the future, remaining goals is likely to require serious management attention and resources and involve significant risks. The "low hanging fruit" of least efficient end-uses and customers most inclined towards EE participation has already been substantially harvested – 192 GWh realized by 2011, projected to grow to 411 GWh from ongoing existing and proposed new programs by 2014. Thereafter, EE savings must come from customers who were not inclined to participate in the early stages, and in customer premises and facilities that are already relatively more efficient than the average in 2008. And the prospective economic conditions in which PNM must market efficiency investments to customers are less auspicious:

- The painfully slow economic recovery and the long-lasting fall in household wealth through reduced home prices since the 2008 – 2009 recession, has likely altered growth rates downward going forward for several years, as have revised consumer attitudes towards housing as a source of increased wealth that can be tapped financially as a "safe" investment.
- Low gas and power prices that are pushing avoided costs down, and that could remain low for several years, making participation in EE less attractive for customers, and more difficult to find opportunities that are cost-effective for PNM.

PNM witness Steven Bean provides more information about the past success and future outlook for EE in PNM's territory in his testimony.

Q. HOW DO EE PROGRAMS AFFECT THE WAY WALL STREET PERCEIVES UTILITIES?

A. Financial ratings agencies sometimes regard EE programs as a negative factor in regard to bond security and financial health. For instance, Moody's notes that a utility is more likely to receive a lower score on cost recovery and return factors in its ratings methodology if it has EE programs that:

- put pressure on sales revenues;

- do not have a decoupling mechanism aimed at "de-linking" a utility's revenues and profits from volume.[1]

Q. HOW HAVE REGULATORS IN OTHER STATES WITH SIGNIFICANT EE GOALS RESPONDED TO THE NEGATIVE SIDE-EFFECTS AND INVESTOR PERCEPTIONS OF EE PROGRAMS?

A. Partly as a result of such reservations, a majority of states in the country with EE programs have developed mechanisms for significant lost revenue protection, as well as additional incentives for performance or for a portion of foregone returns on the next best (avoided conventional supply) alternative. In the next section of my testimony, I provide a profile of the structure and terms of the most commonly utilized mechanisms.

III. REVIEW OF EFFICIENCY PERFORMANCE INCENTIVES USED IN THE INDUSTRY

Q. HAVE UTILITY PROGRAMS AND SPENDING BEEN INCREASING THE SIZE OF THE ENERGY EFFICIENCY AND DEMAND RESPONSE RESOURCES IN THE U.S. IN THE PAST FIVE YEARS?

A. Yes. A recent report by the Institute for Energy Efficiency ("IEE") indicates that U.S. electric utility energy efficiency programs have grown from a cost of $2.7 billion in 2007

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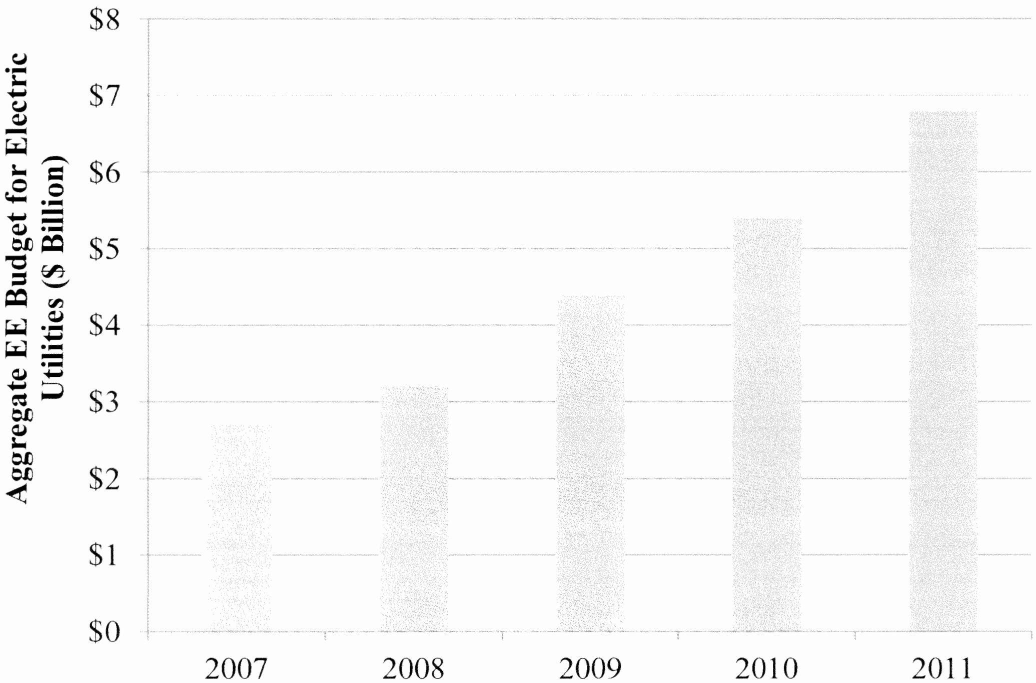
[1] Moody's Investors Service, Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality, June 18, 2010

to $6.8 billion in 2011[2], or an annual growth rate of over 25% per year, as summarized graphically below in Figure 1. This growth indicates that many state governments, regulators and policy makers have recognized the merits of the policy recommendations in the U.S. DoE and EPA's July 2006 *National Action Plan for Energy Efficiency*[3] that included the development of policies to align utility incentives and adjust ratemaking policies to promote the delivery of cost effective EE.

Figure 1 – Aggregate Electric Efficiency Budgets for U.S. Electric Utilities



[2] Institute for Electric Efficiency, the Edison Foundation, *State Electric Efficiency Regulatory Frameworks*, July 2012, p. 1.

[3] U.S. Department of Energy and U.S. Environmental Protection Agency, *National Action Plan for Energy Efficiency*, at p. ES-2 (July 2006).

Q. HAS THIS GROWTH BENEFITTED UTILITY CUSTOMERS?

A. Yes, I believe so. Generally the approval to spend resources by the state commissions comes after the programs have been shown to be cost-effective and to produce net benefits for customers. The tests are generally similar to the benefit-cost tests PNM programs passed to gain Commission approval and, as described in the testimony of PNM witness Steven Bean, are passed again for the 2012 Plan. Broadly, these tests require that the avoided costs of energy and capacity displaced by EE (calculated as a present value) must exceed the utility's direct program costs, plus the additional out of pocket costs of participating customers. The ratio of benefits to costs is often 1.5 – 2.5 and above, so there is typically a material net benefit.

Q. HAVE STATE POLICIES FOR INCLUDING THE UTILITY SHAREHOLDERS IN THE BENEFITS (OR REDUCING THE FINANCIAL RISKS) OF EE PROGRAMS ALSO BECOME MORE COMMON AS THE SIZE OF THE EE PROGRAM BUDGETS HAVE GROWN?

A. Yes, the same IEE report shows that 27 of 51 state-level jurisdictions (D. C. is counted) have mechanisms for fixed cost recovery, and eight more are pending. Twenty three states have performance incentives and six more are pending[4]. Incentives are more prevalent for states where legislative mandates have been enacted setting efficiency resource savings goals and providing for profits and the elimination of disincentives.

[4] The IEE report is a valuable resource, but some states have different policies for individual utilities and some of these are changing. I have supplemented the data in the report with additional information from my staff's research.

While the details vary considerably from state to state and utility to utility, it is useful to observe that there are basically five different kinds of financial incentives in use by state regulatory commissions (though the details of similar plans can vary from state to state). They are:

1. shared net benefits or shared savings;
2. value pricing or Save-a-Watt plans;
3. capitalizing the direct costs as a regulatory asset and allowing a superior return on equity for this asset;
4. incentives based on a percentage of direct costs, such as the program budget; and,
5. incentives based on quantities of kWh of energy savings and kW-years of demand savings, on a verified basis, relative to targets.

Figure 2 below shows which of these types of incentives have been put in place for the 23 states with performance incentives.

Figure 2 – Overview of Incentive Policies for Twenty-three States

No.	State	Shared Net Benefits / Shared Savings	Value Pricing or Save a Watt	Capitalized Expenditures / Bonus RoE	Payment Based on % of Cost	Payment for kWh Saved and kW-years of Peak Demand Reduced
1	Arizona	X				
2	Arkansas	X				
3	California	X				
4	Colorado	X				
5	Connecticut				X	
6	Georgia	X				
7	Indiana	X			X	
8	Kentucky	X				
9	Massachusetts				X	
10	Michigan				X	
11	Minnesota					X
12	Montana			X		
13	Nevada (prior policy)			(X)		
14	New Hampshire	X			X	X
15	New Mexico					X
16	New York					X
17	North Carolina	X	X			
18	Ohio	X	X			
19	Oklahoma	X				
20	Rhode Island				X	X
21	South Carolina	X	X			
22	Texas	X				
23	Wisconsin			X		
	Total of All States instituting polices, including Nevada	**13**	**3**	**3**	**6**	**5**
	Total in Last 5 Years, excluding Nevada	**10**	**3**	**1**	**2**	**2**

Notes:

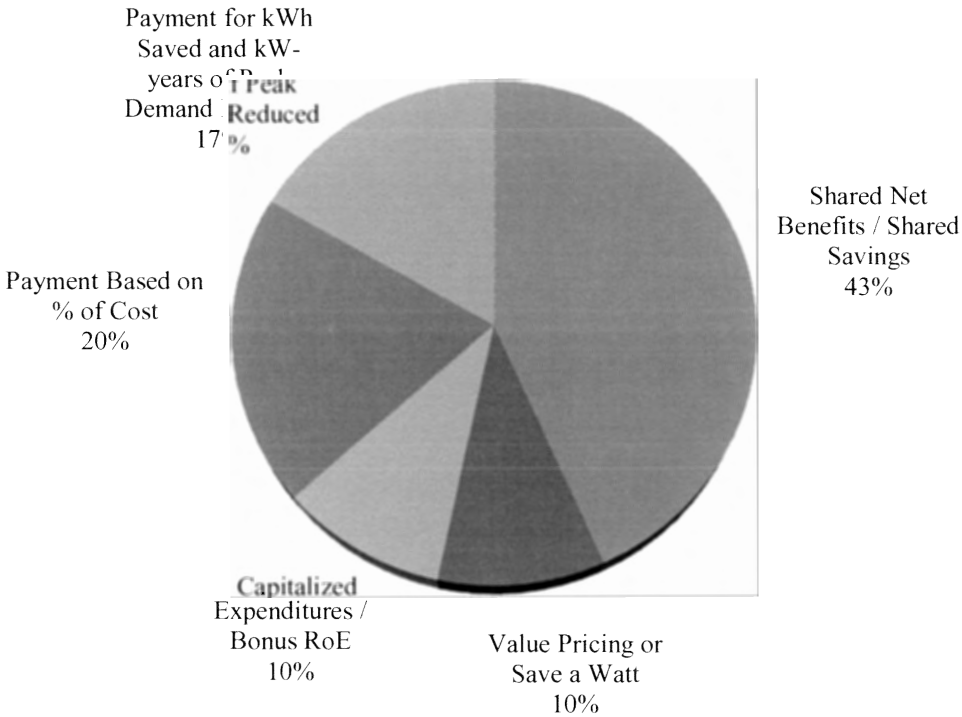
1. Some states have more than one policy.

2. States that had incentive policies in place before 2005 indicated in grey. This is not determinative, as some have adjusted their policies.

3. States without grey shading have instituted incentives since 2005. Nevada was excluded although it did adopt its Capitalization with Bonus RoE incentive in the modern period since 2005. In 2010, NVrecinded that incentive policy. It is now legal for commission in NV to grant an incentive, but no utility has been given one.

Figure 3 shows the frequency of the five incentive types across the states in Figure 2.

Figure 3 – Shares of Incentive Mechanisms for Efficiency Programs



Q. HAVE YOU IDENTIFIED COMPARABLE STATES TO ASSIST IN DEVELOPING A REASONABLE PROFIT INCENTIVE FOR PNM?

A. Figure 4 shows the comparisons in terms of the core policies for financial incentives, lost fixed revenue recovery/decoupling, and concurrent cost recovery with a rider for six states I have determined to have comparable EE policies.

Figure 4 – Comparison of Efficiency Compensation Terms among States with Similar Core Policies for EE Incentives

States	New Mexico	Arizona	Arkansas	Colorado	Indiana	Oklahoma	Texas
Utilities	**PNM 2012**	**APS 2011**	**Entergy AR 2011**	**PSCo (Xcel) 2011**	**Duke Indiana 2012**	**OG&E 2011**	**El Paso Electric 2011**
Financial Incentive	✓	✓	✓	✓	✓	✓	✓
Lost Fixed Revenue Recovery/Decoupling	stipulated to	✓	✓	✓ fixed $ amount	✓ 3 years limit	✓	×
Rider for Direct Program Cost Recovery	✓	✓	✓	✓	✓	✓	✓

Notes: Texas El Paso is Non-ERCOT

Q. DO YOU HAVE INFORMATION ON THE INCENTIVE PARAMETERS UNDER WHICH THESE COMPARABLE UTILITIES ARE OPERATING?

A. Yes, an overview of their programs is shown below in Figure 5.

Figure 5 -- Detailed Comparison of Incentive Policy Parameters

State	New Mexico	Arizona	Arizona	Arkansas	Colorado	Indiana	Oklahoma	Texas
Utility	PNM 2012 Plan	Arizona Public Service Company 2011	Tucson Electric Power 2011	Entergy AR Plan 2011	PSCo (Xcel) 2011	Duke Indiana 2012	OG&E 2011	El Paso Electric 2011
Performance Incentive								
Policy in place	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Type of incentive	Equal energy and capacity incentives based on perfomace relative to goals.	Shared Savings on TRC* (Societal Cost Test)	Shared Savings (Societal Cost Test)	Shared Savings	Shared Savings (Societal Cost Test)	Share of Program Costs, not Save a Watt as in some other Duke states	Shared Savings	Shared Savings based on the Utility Cost Test
Basic parameters of incentive at 100% of target	Equal shares of $2.05 million separately achievable for target energy MWh and target capacity kW-years savings	Share 7% of Net Benefit in range 96% to 105% of MWh goal. Steps of 1% up and down based on performance ranges. Share percentage of 10% (not $) capped above 125% of goal.	10% of Net Benefit (NB)	10% of NB	Share 4% at 100% of annual MWh goal; Share 12% at 150%. Sliding scale.	12% of Costs, at 100% of GWh goal	15% of NB	Sharing % is one half of % achievement above 100% target
Cap on size, in terms of $ or % applied to a $ magnitude	Yes, $ incentives cap at 110% of each goal	Cap is smaller of: Share percentage of NB above, or the % of Direct Costs. Direct cost % = 2X the Share %.	10% of Direct Costs or 10% of Net Benefits, whatever smaller	Total incentive capped at 7% of budget for achievement between 100% and 110% of goal; 5% of proposed budget for achievement between 80% and 100% of goal	Yes, 25% of direct cost + 50% of Disincentive Offset	< 40% kWh goal, - 4% of Direct Costs (DC); 40%-60% => 0%; 60%-80% => 6%, 80%-90% => 8%; 90%-100%=>10%; 100%-120%=>12%; >110%=>15%	No	Yes, 20% of Program Costs

** TRC is assumed unless otherwise noted.*

Q. WHAT ARE THE RELATIVE FEATURES AND ADVANTAGES OF THE DIFFERENT INCENTIVE POLICY APPROACHES, STARTING WITH SHARED SAVINGS?

A. Shared net benefits approach, or shared savings, has the longest history and is the most frequently used, as shown above in Figure 3. Generally, this method determines the total or gross benefits as the dollar savings in avoided future energy and capacity costs from lower usage and peak demands brought about by the efficiency measures over their lifetimes. These avoided costs (or savings) are present-valued at the utility's discount rate, typically its WACC. There are two measures for the direct costs. The Program

Administrator or Utility Costs measure focuses on the well-defined, recorded costs of the utility for EE implementation, measurement and verification ("M&V"), and participant rebates. The Total Resource Cost ("TRC") measure starts there and then includes the estimated costs of what customers pay beyond the rebates they receive for participation in the utility programs and excludes utility costs that are transfer payments, thus achieving a measure of the real economic costs of the program. The present value of these direct utility and customer costs are compared to the present value of the avoided costs in order to determine whether there is a favorable overall benefit-cost ratio.

The shared savings approach sets the financial incentive as a share of the difference between the present values of the avoided costs and the program costs. The lower the cost measure and the greater the benefits, the greater the difference will be and thus the greater the savings to share.

Shared savings has several elements of a good incentive. First, it is performance-based and only rewards to the extent that the chosen programs produce credible net savings. If there is no net benefit, there is no profit. This encourages both good program choices and efficiency in the implementation of the programs. Second, by awarding a share of net benefits, it encourages the installation of measures that have the highest value in terms of avoided cost savings. That is, it prioritizes EE management efforts towards the most productive EE activities. For example, if commercial air conditioning both consumes significant amounts of more costly summer electricity and it adds to the system peak demand, then EE programs targeting highly efficient commercial air conditioning equipment with a long lifetime are likely to provide greater social benefits and rewards to the utility, simultaneously, thus aligning customer and investor interests.

Q. PLEASE DESCRIBE THE VALUE PRICING OR SAVE-A-WATT INCENTIVE.

A. Value pricing is more akin to competitive market business models and pricing, in that the allowed EE revenue is not directly tied to costs but to gross benefits, with no other direct compensation for EE program costs. That is, for a given year's program, the utility gets a revenue stream based on a large portion of the total or gross avoided costs, just like the first half of the net benefits calculation. That revenue is set at expected levels of benefits per kWh and then is trued up to the actual energy savings achieved in the year, when both the measures installed have been counted and the M&V assessments have been completed, generally at a true-up after several years. Just like revenues for a shoe store, this value-based revenue stream may or may not reliably cover costs with an acceptable profit. It was initially set with an expectation that it will be adequate, but there is no explicit recovery of EE costs or lost fixed revenues.

This value pricing idea was originally proposed by Duke Energy in several states around 2007 (Save-a-Watt is the Duke "brand"). The initially proposed percentage of avoided cost value retention by Duke was significant, at about 90%. In the course of reaching settlements and gaining approval in the states of North Carolina, South Carolina and Ohio, the percentage was cut to 50-55% of avoided energy costs and 75% of avoided capacity costs. However, a separate payment for the lost fixed revenue was instituted. Moreover in some cases, there were caps set on the total annual performance incentive. In Indiana, Duke eventually was given a share of the program cost as the incentive rather than Save-a-Watt.

Value pricing has the same two good attributes of a good incentive structure: higher rewards for efficiency in program direct costs and for emphasizing programs that have higher benefits, i.e., higher avoided cost values. However, it is not particularly transparent as to how well it relates to realized actual costs and normal levels of profitability, so it can be difficult for regulators and customers to understand and accept. The plans that have been approved for Duke have been modified from the pure value pricing model to reflect a blend of cost recovery and shared benefits that achieve the needed transparency and acceptability.

Q. PLEASE EXPLAIN THE CAPITALIZED EXPENDITURES AND BONUS ROE APPROACH.

A. Capitalization of the EE expenditures of the utility and then allowing a better-than-normal return has been featured in the states of Montana, Nevada, and Wisconsin. In Nevada, state law called for a bonus return on equity of 500 basis points, or 5%, against the equity portion of capitalized program costs of the required Demand Side Plan ("DSP"). The costs were typically amortized over three years. For comparison, the allowed return on equity for Nevada Energy at the time was 10%-11%, so this was a 45% to 50% increase in the return (for just the capitalized DSP costs). This same policy had previously been implemented for certain supply side investments that were deemed critical facilities to state energy policy, and which were normally capitalized.

Capitalization of DSP expenditures has been argued to be reasonable because the customers get their savings over the lifetimes of the measures, in the form of avoided fuel costs, lower capital expenditures, and thus lower bills. Capitalizing and then amortizing the DSP costs with a return correspondingly spreads out the payments for an EE effort to a degree, although not necessarily over an average life for EE measures. However, it must be appreciated that the efficiency investments are owned by the customers, not the utility, so capitalizing the expenditures is done by creating a regulatory asset under commission jurisdiction. Effectively, the utility is just financing the EE costs for the customers at its own cost of capital. Such financing costs are real costs that the utility would not otherwise incur if it expensed all of its EE costs, as generally accepted accounting principles would require. This means that the 500 basis point Bonus RoE or other adder is the only profit incentive. Though its description as a 45% increase over the normal equity return may sound large, the bonus equity return on capitalized EE costs is generally low in dollar amounts in relation to the utility's total book equity (backed by the generation and T&D assets), and as a result the actual financial benefit of the Bonus RoE can be small in comparison to shared savings or other forms of incentives, which are more prevalent. Moreover, in order to earn an after-tax Bonus RoE of 5% (or any other level), rates to customers must be grossed up for federal and state corporate income taxes, imposing an added cost on customers that does not accrue to shareholders as an incentive.

Concerns about funding the expenditures and waiting for the expenses to be recovered via capitalization and amortization and other issues led Nevada to change its policy in 2010.[5] The recovery of lost fixed revenues was also instituted. Nevada no longer capitalizes EE expenditures or uses the Bonus RoE for EE.

Q. PLEASE DESCRIBE THE PERCENTAGE OF COST INCENTIVE STRUCTURE.

A. There are several states that set the performance incentive as a percentage of the actual expenditures. This usually comes conditionally upon also achieving a performance goal, often measured in terms of kWh of annual savings or percentage savings relative to utility base-year kWh sales. This share-of-EE-costs approach has the advantage of being relatively easy to calculate, but that is about all that an economist can say to endorse it. One problem is that basing the incentive on incurred costs does not in itself incentivize cost effectiveness. Rather, it is based on expenditures regardless of efficacy, with no prioritization for higher benefit-to-cost programs. Recognizing this, the states using this approach must address the enforcement of efficiency of the EE programs' implementation in other ways.

Many of these performance incentives have evolved in states where the energy efficiency programs have been in place since the 1990s. The use of the percentage of costs evolved

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[5] PUC Nevada, *Order,* Docket No. 09-07016, June 30, 2010.

out of their long experience, which initially involved benefit/cost tests and even shared savings or other incentives.

Q. PLEASE DESCRIBE THE INCENTIVE PAYMENT BASED ON THE QUANTITIES OF KWH AND KW-YEARS OF EFFICIENCY SAVINGS ACHIEVED.

A. This is more of a method of monetizing the incentive than an incentive design by itself, as the overall incentive target value could be set by other means and then realized through per kWh and per kW charges or through the percentages of target kWh and kW-years achieved. However, this mode of estimation and true-up can have some incentive impacts depending on the relative size of the energy and capacity components. Generally, the kWh of savings across the year and the kW of peak savings achieved by any efficiency program are measured both on an annual basis and on a cumulative useful life basis. Certain of these volumes of projected energy and capacity savings are the basic data to which the avoided costs payment rates are applied. These kW and kWh savings are usually also predicated on EE program performance determined by M&V audits of program effectiveness. Thus, it very concretely sets performance payments on percentage of aggregate kWh and kW-year goals achieved, or on a per kWh and per kW (or kW-year) of savings basis. The goal setting would normally be supplemented by the prior evaluations of benefits and costs, overall long-term savings goals, and other metrics, to get these simple, physical incentive metrics to levels where the overall incentive payment is reasonable.

The usefulness of an incentive based on kWh and peak kW-year saved is that the results are known and verified soon after the program year is concluded, and the complexity of accounting for multiple years of benefits over time is avoided by impounding the life-cycle benefits into the first year of the program. The payments can be subject to true-up as soon as the M&V results are available. One disadvantage of these simple metrics, if they are set arbitrarily, is that neither the value nor the cost of the program is a direct part of the incentive. However, it is easy to rectify that by constraining the rewards to yield an acceptable share of expected program net benefits.

Q. DO MANY STATES REQUIRE UTILITIES TO INVEST CAPITAL INTO EE IN ORDER TO RECEIVE A PROFIT INCENTIVE?

A. No. EE is generally not capital intensive from the utility point of view. Requiring capital investment ignores the nature of most cost-effective EE whereby the utility plans, markets and implements investments owned by the customers. The bonus RoE approach I describe above is a way of artificially creating a utility "investment" but it is not widely used and, as I mentioned, Nevada has recently abandoned it.

IV. OVERVIEW OF PNM ENERGY EFFICIENCY AND LOAD MANAGEMENT PROGRAMS

Q. PLEASE BRIEFLY DESCRIBE YOUR UNDERSTANDING OF THE PNM EE PROGRAMS.

A. The PNM EE program being addressed here was started in 2008. Over the past 4 years (excluding the 2012 calendar year), PNM has spent the following monies and achieved the following reductions in demand and energy shown in Figure 6:

Figure 6 -- Summary of PNM Efficiency Plans 2008 – 2011

No.		Units	2008	2009	2010	2011	Annual Growth Rate '08 - '11
1	**EE Energy Savings**	Annual GWh	35.2	39.9	58.8	57.6	*18%*
2	**EE Cumulative Savings**	Annual GWh (Start 2008)	35	75	134	192	*NA*
3	**EE Demand Savings**	Annual MW	7.5	6.3	9.9	9.7	*9%*
4	**Load Mgmt ("LM") Dispatchable Ld**	MW	47.4	53.4	67	56.9	*6%*
5	**EE Lifetime Savings**	GWh	302	352	529	491	*18%*
6	**Total EE & LM Program Costs Incurred**	$mm	8.0	12.0	16.6	16.6	*28%*
7	**EE Program Cost Incurred**	$mm	4.0	6.2	9.9	8.7	*30%*
8	**Cost of EE Programs Per Lifetime kWh**	$/kWh	0.013	0.018	0.019	0.018	*10%*
9	**Total Resource Benefit to Cost Ratio (excluding financial incentives as costs)**		2.71	1.56	2.20	1.81	*-13%*

Source: PNM Witness Bean

PNM measures its conserved volumes on both an annual basis (for a full program year) and a life-cycle basis, i.e. reflecting all the savings achieved over all of the future years that each identifiable EE activity, or measure, has a load-reducing effect. For instance, if compact fluorescent lights ("CFLs") are installed in one year but have an average performance life of 7 years, then the lifetime savings are 7 times the annual kWh savings that are reported for the year the CFLs are installed. This is a good way of recognizing that there are ongoing effects due to prior efforts different from the expected costs and benefits of new programs under consideration by policy makers and the utilities.

Q. ARE THE OUTCOMES OF THE ANNUAL EE PROGRAMS FAIRLY EASY TO PREDICT IN TERMS OF EITHER THE PROGRAMS' SUCCESS OR THEIR IMPACTS ON OTHER SYSTEM NEEDS AND COSTS?

A. No, the outcomes are not easily predictable. There are over a dozen different programs directed at a number of very different market segments. The marketing of energy efficiency involves getting households and large and small businesses to plan and act upon complicated (and often somewhat unfamiliar) matters with difficult-to-measure outcomes that occur over long periods of time. This is complex marketing, and it requires complex systems to monitor, measure, and predict success.

Figure 7 shows the variances in several metrics of efficiency program success for PNM over the first four years since this has become a major energy policy for New Mexico. This shows that the outcomes have considerable variability. For instance, the program costs have varied from budget by as much as $2.5 million per year, and annual energy savings have swung from -11% to +21% of target.

Figure 7 -- Variability in the Efficiency Plan Outcomes

No.			2008	2009	2010	2011	*Std Dev*
1	Savings Target	Annual GWh	27.7	44.3	60.9	57.5	*NA*
2	EE Energy Savings	Annual GWh	35.2	39.9	58.8	57.6	*NA*
3	**Variance from Target Reductions**	**Annual GWh**	**7.5**	**-4.4**	**-2.1**	**0.1**	***4.5***
4	**Variance from Target Reductions**	**%**	**21%**	**-11%**	**-4%**	**0%**	***12%***
5	Budgets Approved	$ mm	7.6	10.9	14.1	15.9	*NA*
6	Total EE & LM Program Costs Incurred	$ mm	8.0	12.0	16.6	16.6	*NA*
7	**Variance from Planned Costs**	**$ mm**	**0.4**	**1.1**	**2.5**	**0.7**	***0.8***
8	**Variance from Planned Costs**	**%**	**5%**	**9%**	**15%**	**4%**	***4%***

Source: PNM Witness Bean
NA = not applicable

Q. WHAT ARE THE PLANNING AND FINANCIAL IMPLICATIONS OF THIS UNCERTAINTY IN EE EFFICACY?

A. It complicates decisions that depend on knowing future demands with reasonable confidence. An obvious example is resource planning. PNM assiduously attends to maintaining an adequate reserve margin for serving peak load, which requires looking ahead several years to anticipate needs (because it takes several years to build new generation if there should appear to be an emerging shortfall). The more uncertainty there is in future loads, the harder it is to decide how much generation to build and when to do so. A more subtle example is the fact that successful EE shrinks the base of sales over which the costs of future expansion of delivery infrastructure (the T&D system) can be spread. Some replacements and upgrades are needed in these functions, often at incremental costs (e.g. per circuit mile) that are much larger today than they were in the past. Such costs, or any other major infrastructure expansion costs, have a bigger impact on average cost rates in a world where EE has dampened growth. This impact makes the needed revenues more difficult to obtain, even with more frequent rate cases.

Q. WHAT ARE YOUR OBSERVATIONS ABOUT HOW SUCCESSFUL THE PNM EE EFFORTS HAVE BEEN?

A. PNM's efforts have put the program just on schedule for achieving its 2014 mid-course demand reductions relative to 2005 consumption, as is further discussed by PNM witness Bean. However, it is also noteworthy, as seen in the last row of Figure 6, that the TRC ratios have been declining in the past few years. They were 2.71 in 2008 but are now down to 1.70. This is partly due to having lower avoided costs today (due to reductions in wholesale electricity forecast prices and natural gas forward prices) and deferred needs for future capacity. This reduction is consistent with observations I made above about the risks of future success becoming progressively greater, due to having harvested the better opportunities already and having low demand growth from which to conserve. The trend in Figure 1, Row 8 also suggests that costs per lifetime kWh are increasing somewhat over time. Note that some of the increased difficulties arise in part because of the success of the programs to date!

Q. IS THE OBJECT OF YOUR INCENTIVE PROPOSAL THE INDIVIDUAL EE PROGRAMS OR THE PORTFOLIO?

A. I propose that the profit incentive be applied to the results of the portfolio of all programs as a whole, specifically to the total kWh savings and kW-year savings on a lifetime basis, rather than to the individual activities that comprise it. The benefits arise from their collective success, not differently from each type of activity. Also, there is more uncertainty surrounding the individual components than the portfolio. Figure 8 shows the expected direct PNM costs and expected impacts of that portfolio. PNM witness Bean describes the individual programs in detail. Figure 9 shows the avoided costs benefits by component, net benefits and benefit cost ratios, for the portfolio.

Figure 8 -- PNM EE Program Costs and Energy and Capacity Savings from the 2012 Efficiency Plan

Efficiency Portfolio	PNM Direct Cost	Energy Savings (1st Year Retail Metered)	Capacity Savings (1st Year Retail Metered)	Energy Savings (Lifetime Retail Metered)	Capacity Savings (Lifetime Retail Metered)	Useful Life in Yrs
	('000 $)	*('000 kWh)*	*('000 kW-yr)*	*('000 kWh)*	*('000 kW-yr)*	
Total Portfolio	$22,493	82,494	75.98	643,314	201.14	7.8

Source: PNM Witness Bean

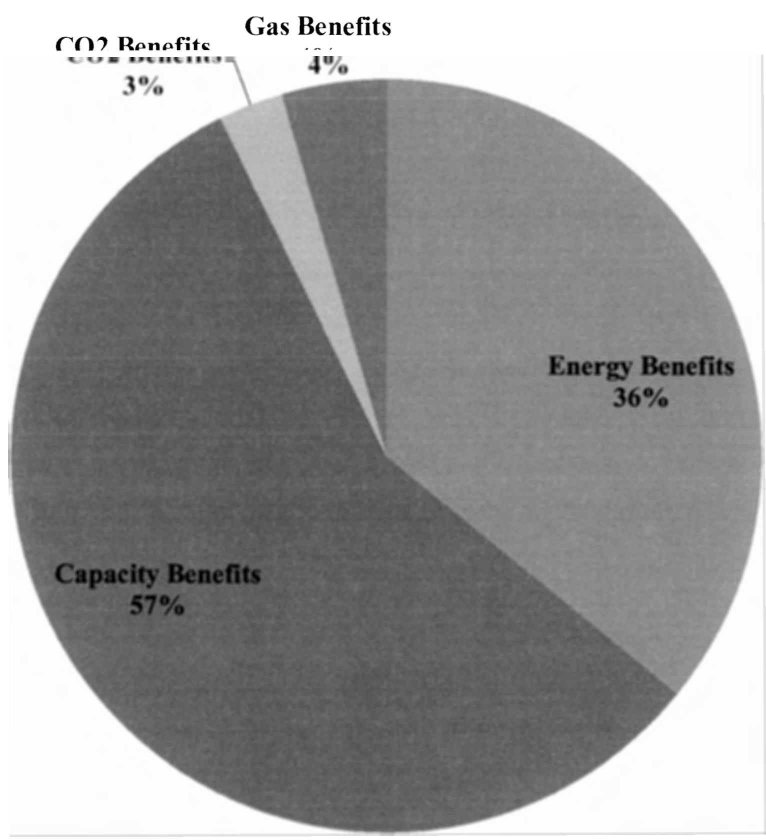
Figure 9 -- PNM Total and Net Benefits, and TRC Tests for the 2012 Efficiency Plan

Efficiency Portfolio	Energy Benefits	Capacity Benefits	CO2 Benefits	Gas Benefits	NPV Total Benefits	Net Benefits	TRC, Excl. incentive
	('000 $)	*('000 $)*	*('000 $)*	*('000 $)*	*('000 $)*	*('000 $)*	
Total Portfolio	$13,336	$21,129	$1,033	$1,697	$37,195	$15,336	1.70

Source: PNM Witness Bean

Figure 10 below shows the sources of the shares of the total benefits created by all the programs. The benefits are about 57% avoided future capacity (deferring or eliminating the need for capacity that would otherwise be installed beginning 2015) and about 43% avoided energy consumption plus avoided CO_2 costs and natural gas savings.

Figure 10 -- Shares of Total Benefits from PNM 2012 Efficiency Plan



The 2012 Plan's gross benefits (in present value terms) are about $37.19 million versus a program TRC cost (including customer costs but without incentives) of $21.86 million, thus yielding a net benefit of $15.34 million (values rounded).

Q. HOW ARE THE AVOIDED-COST BENEFITS OF THESE ACTIVITIES CALCULATED?

A. The benefits in terms of avoided capacity and energy are explained in detail by PNM witness Patrick O'Connell and are based on how PNM's current resource assessment is altered by the expected success of its EE activities.

V. RECOMMENDED INCENTIVE ALLOWANCE FOR PNM

Q. HAVE YOU DETERMINED WHAT A REASONABLE PROFIT INCENTIVE SHOULD BE FOR PNM?

A. Yes. I begin with the statutory language authorizing a profit that is more financially attractive than conventional supply-side alternatives. Those alternatives are the new generation capacity investments (and later their operations) that are displaced or avoided by the EE activities and, as was shown above in Figure 10, those capacity savings are responsible for slightly more than half (57%) of the total net benefits, with an average benefit of $124/kW-year. That amount includes all the types of fixed operating and financial costs of generation that will be avoided annually (per kW) by the 2012 Plan capacity savings realized over future years. However, to find out how much incentive PNM would need to receive in order for EE to be more attractive than conventional investments, I focus on just the lost (or avoided) profits (returns on equity) that PNM would otherwise have had the opportunity to earn. To do this, I have reduced the avoided capacity cost amounts in PNM witness O'Connell's PNM Exhibit PJO-1 to include only the portion of fixed revenue requirements that arises from the allowed return on equity (using a rate of 10%, the return authorized in PNM's last rate case). This turns out to be \$35.53/kW-year (on a present value basis over the programs' life-cycle). Details of these calculations are shown in PNM Exhibit FCG-2.

For PNM to be financially indifferent between EE and the conventional supply approach, it would need to receive an incentive this large for all the lifetime kW-years of avoided generation expansion. For PNM to <u>prefer</u> EE, a somewhat larger incentive would be needed. For this purpose, I have applied an increase of 10% to the \$35.53/kW-year, bringing it up to \$39.08 per kW-year, as a reasonable and meaningful increase to make EE financially more attractive than supply-side resources.

Q. HOW MUCH OF A TOTAL INCENTIVE PAYMENT WOULD BE REQUIRED TO SATISFY THIS STANDARD?

A. The 2012 Plan is projected to avoid 201,137 kW-years of future capacity payments as measured at the customer meters. This quantity must be increased for avoided line losses (i.e., moved upstream to the generation capacity avoided) by multiplying by the PNM loss factor of 1.07. Then this quantity of capacity savings is multiplied by \$39.08/kW-year to determine the needed incentive, which equals \$8,411,312.

However, this calculation assumes that all the future capacity needs avoided or deferred by the 2012 Plan would be built and owned by PNM. In practice some of this generation may be procured under power purchase agreements ("PPAs") from merchant generators or other utilities with power to sell. For instance, in the period 2000 – 2011, 994 MW of generation capacity was added to PNM, about 48% of which was been obtained under long term contracts from third parties. Capacity under such contracts does not involve foregone equity returns for PNM. If this pattern of contracting would continue in the future, then it is possible that only about half of the EE-avoided capacity might be PNM-owned. On this basis, I assume conservatively that only 50% of the avoided (or needed) capacity going forward is PNM-owned and its profits are lost. I assume the other 50% is under contract and does not have lost profit. This reduces my estimate of foregone profits needing compensation by half, so the total needed incentive is reduced to $4,205,656 for the 2012 Plan.

Q. HOW DOES THIS AMOUNT OF INCENTIVE COMPARE TO OTHER UTILITIES' EE INCENTIVES?

A. That depends on how you normalize it for comparison. This can be done in several ways – as a portion of net benefits or program costs, or on a per kWh or kW saved basis (or per system kWh and kW), or on financial bases as well (e.g. percentage of income or RoE). As shown in Figure 16 below, six other states recently creating or expanding their EE programs, including several that are in the southwest region, typically have incentives and placed caps in the range of 2 to 17% of program net benefits, and 8 to 24% of program costs. A PNM allowance of $4.206 million is at the upper end of these ranges, but I believe it is reasonable and consistent with the strong incentives required by the EUEA.

Another reasonableness test that can be used is to look at the effect the incentive payments have on the TRC. Technically, the incentive payment is a transfer of a share of the net benefits and not a true economic cost of the program, and so is not considered to be part of the TRC calculation. However, including it in the calculation of TRC assures that PNM is keeping only a reasonable share of the benefits. As explained in the testimony of PNM witness Bean, this level of incentive leaves the 2012 Plan with a favorable net TRC ratio, with the overall TRC falling slightly from 1.70 before incentives (seen above in Figure 9) to 1.44 after incentives.

This is not a large incentive payment in relation to the return (annual net income, or profits) PNM normally would expect to earn on its New Mexico utility jurisdictional equity. That amount was $112 million, based on a 10% return against its June 2010 equity underlying its rate base. The proposed incentive would be less than 3.8% of the normal return, or an incremental return of only 38 basis points.

Q. HOW SHOULD THE $4.206 MILLION IN TOTAL INCENTIVE ALLOWANCE BE ALLOCATED TO THE PROGRAM PERFORMANCE RESULTS IN ORDER TO DETERMINE THE VERIFIED INCENTIVE FOR THE 2102 PLAN?

A. This should be done in the same general manner as the benefits of the program are created, i.e., in proportion to the dollar benefits that come from the life-time energy (kWh) and capacity (kW-years) avoided by the 2012 Plan. As was shown above in Figure 10, PNM expects 57% of this year's program benefits to be from capacity savings, and 43% to be from energy and commodity benefits. Recognizing that there is variability and uncertainty in the relative share of these benefits over time (e.g. with energy benefits rising when fuel and wholesale power prices are high, and falling when they are low), I recommend using a 50-50 split between the two components to allocate the incentive. This has been done in Figure 11 below, which shows how the energy and capacity incentives can sum to $4.206 million in total if the two kinds of savings should be 100% achieved and verified.

Figure 11 -- Energy and Capacity Incentives for EE Portfolio at 100% of Targets

	Energy Incentive	Capacity Incentive	Total of Incentives
Units	kWh over lifetimes	kW-years over lifetimes	Not Applicable (NA)
100% Physical Savings Target (Lifetime Units)	643,314,102	201,137	NA
Contribution of Portfolio	**$2,102,828**	**$2,102,828**	**$4,205,656**

Source: of 100% targets , PNM witness Bean

Q. HOW SHOULD THE INCENTIVE AMOUNTS BE EARNED AND PAID OUT TO PNM?

A. The incentive target amounts should be split in two equal parts and then realized[6] separately, in proportion to their respective validated lifetime kWh and lifetime kW-years that are achieved by the portfolio of programs, relative to (or as a percentage of) the quantities assumed in the overall program benefits calculations for the approved plan, which targets are 643,314,102 kWh and 201,137 kW-years, respectively. The target quantities should be set on a lifetime basis reflecting validated savings over the life of the programs. It is natural and appropriate to use a lifetime approach, because that is the basis for choosing the activities in the first place and for determining the TRC values of the needed incentive total amount for a successful program. I propose that the payments

[6] PNM witness Bean discusses how this profit incentive would be allowed in the PNM EE rider for collection from customers subject to true-up.

be linear, i.e. strictly proportional to program success, except that they be capped at <u>10% above</u> the target levels. As discussed in PNM witness Bean's testimony, PNM proposes to include the target profit incentive allowance of $4.206 million in the revised tariff rider proposed in this case. Because the EUEA provides for a profit incentive based on satisfactory program performance, I propose that the future reconciliation process provide for a reconciliation of the profit incentive based on the performance of the portfolio relative to the targeted savings I described above. That is, PNM's profit incentive would be trued-up based on the percentage of the verified savings relative to the targets, up to 110% of the target profit incentive. Here are the steps in calculating the two separate energy and capacity profit incentives.

1. The Percentage of Energy Savings (PES) is calculated

   PES = Verified kWh of lifetime savings *Divided by* 643,314,102 kWh[7]

2. The Percentage of Capacity Savings (PCS) is calculated

   PCS = Verified kW-years of lifetime savings *Divided by* 201,137 kW-years

   a. If PES or PCS is calculated to be greater than 110%, then the value is reduced and set to exactly 110%

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[7] If the period of implementation is not a complete twelve months, then the target lifetime kWh here and the target lifetime kW-years in step 2 would need to be prorated to the actual period.

3. Profit Incentive (PI) for Energy = PES *Multiplied by* $2.1028 million
4. Profit Incentive (PI) for Capacity = PCS *Multiplied by* $2.1028 million
5. Total Profit Incentive for PNM = PI for Energy + PI for Capacity
6. PES and PCS are continuous variables, calculated to 5 decimal places.

These allowances are trued-up based on actual verified kW and kWh savings from the EE activities.

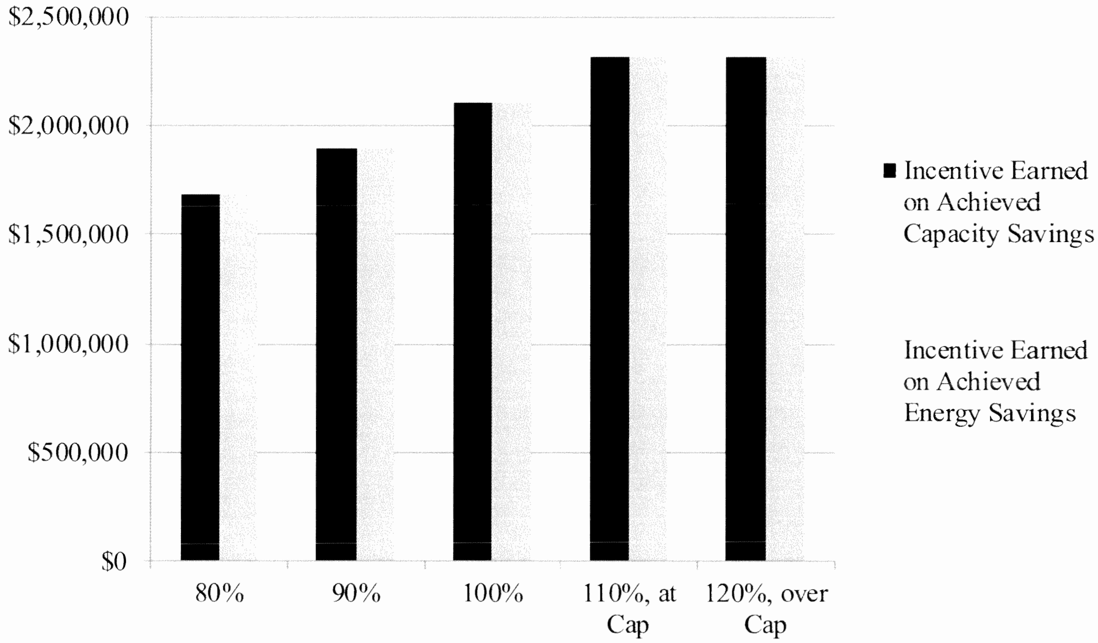
Figure 12 gives a simple example of calculating the incentive under different levels of hypothetical achieved EE savings; Figure 13 depicts those results graphically to show the linearity and cap in the method. While the values 80%, 90%, and so forth are shown in Figures 12 and 13 as discrete values, these are purely illustrative. This two-part profit incentive does not contain any steps, i.e. it is continuous in percentages and in dollars, though each part does reach a maximum or cap at 110%, which is $2,313,111.

Figure 12 Examples of Different Efficiency Incentive Payments for Illustrative Levels of Achieved Lifetime Savings

	Percentage of Target Achieved	80%	90%	100%	110%, at Cap	120%, over Cap
1	Target kW-years of Lifetime Savings in Capacity	201.137	201.137	201.137	201.137	201.137
2	Achieved kW-years of Lifetime Savings in Capacity	160.910	181.023	201.137	221.251	241.364
3	Incremental kW-years Achievement compared to Target	(40.227)	(20.114)	-	20.114	40.227
4	Award kW-years after Cap is imposed	160.910	181.023	201.137	221.251	221.251
5	**Incentive Earned on Achieved Capacity Savings ($ Thousands)**	**$1,682**	**$1,893**	**$2,103**	**$2,313**	**$2,313**
6	Target kWhs of Lifetime Savings in EE	643,314	643,314	643,314	643,314	643,314
7	Achieved kWhs ofLifetime Savings in EE	514,651	578,983	643,314	707,646	771,977
8	Incremental kWhs Achievement compared to Target	(128,663)	(64,331)	-	64,331	128,663
9	Award kWhs after Cap is imposed	514,651	578,983	643,314	707,646	707,646
10	**Incentive Earned on Achieved Energy Savings ($ Thousands)**	**$1,682**	**$1,893**	**$2,103**	**$2,313**	**$2,313**
11	**Total Incentive Earned on Energy and Capacity ('000 $))**	**$3,365**	**$3,785**	**$4,206**	**$4,626**	**$4,626**

Source: PNM Witness Bean

Figure 13 Chart of Profit Incentives for Energy and Capacity at Various EE Program Performance Levels



Note that these tables and graphs show the energy and capacity components of the portfolio at equal illustrative possible levels of success, which in general need not and may not be the actual case. For instance, verified energy savings could achieve 95% of its target and the capacity savings 105% of its target, and each type of incentive would be earned and paid separately.

Q. CONSIDERING THAT THE $4.206 MILLION WAS CALCULATED TO RESTORE PROFITS ON AVOIDED CAPACITY INVESTMENTS, WHY DO YOU SUGGEST HAVING HALF OF THE INCENTIVE BE ALLOCATED AND COLLECTED FOR ENERGY SAVINGS?

A. Reductions in energy consumption are one of the key goals of the fourteen EE-specific programs discussed by PNM witness Bean. These EE-specific programs are targeted to save large amounts of kWh and produce almost all of the energy benefits, as load management programs produce kW-years savings almost exclusively. The fourteen EE programs will also avoid large amounts of capacity costs (avoided $/kW-years) and produce substantial capacity benefits. In total, kWh savings over the lifetimes of all energy efficiency and load management programs create about 43% of the total benefits, as shown in Figure 10 above.

If the incentive were only paid on kW-years avoided, there could be a bad economic signal for PNM to focus more (or even predominantly) on capacity deferral rather than on energy consumption savings. Both energy savings and capacity savings are valuable, so both should have an incentive. Moreover, these energy-oriented efforts create more observable cost savings for PNM's customers (than avoided capacity expansions), as well as important environmental benefits. The customer experiences the reduction in volumes consumed as direct and immediate bill savings, while from an environmental perspective, the reduced consumption means less marginal fuel is burned and emissions are lowered.

Therefore, I support an incentive that equally rewards energy savings and capacity savings on a portfolio basis, regardless of where these savings come from.

VI. COMPARING THE RECOMMENDED PNM INCENTIVE WITH OTHER INCENTIVES IN EFFECT IN OTHER STATES

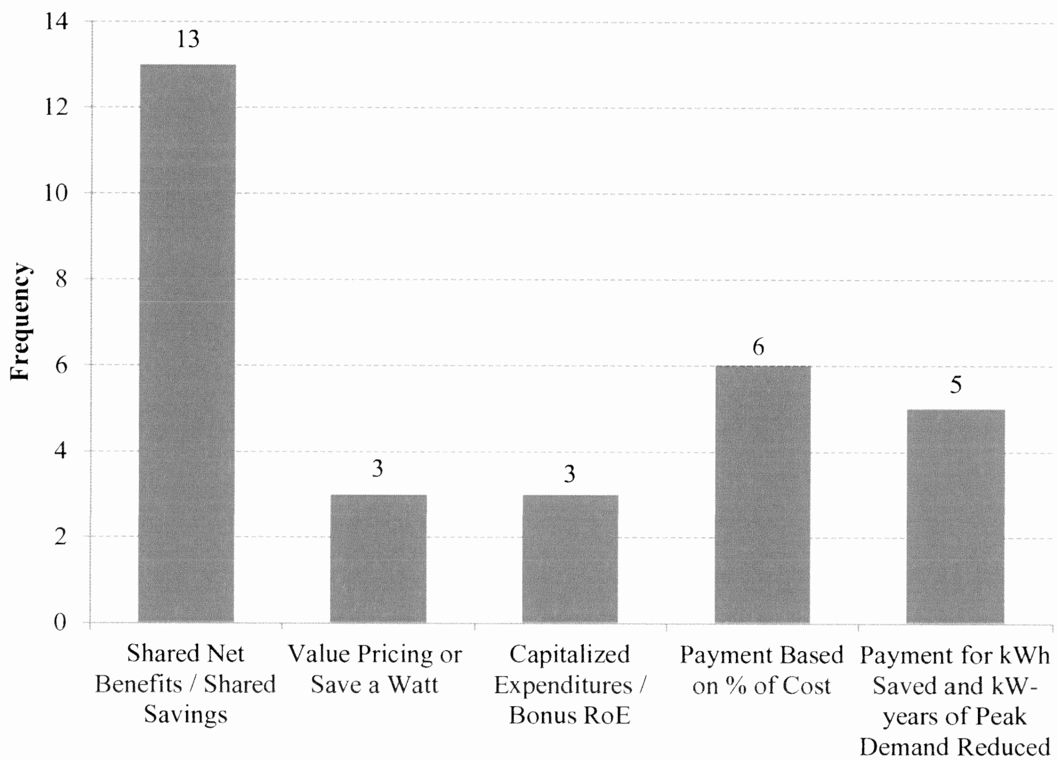
Q. HAVE YOU COMPARED YOUR PROPOSED FINANCIAL INCENTIVE WITH OTHER COMMON INCENTIVE APPROACHES USED BY STATES WITH SIMILAR POLICY GOALS TO NEW MEXICO?

A. Yes. I discussed in Section III above the wide variety of the financial incentive approaches in place and being proposed across the U.S. Now I will summarize the key results that relate to my recommendation for the financial incentive for PNM. There are "recent adopters" that have initiated and developed enhanced efficiency along with financial incentives in the last half dozen or so years, as concerns over the possible negative impacts of global climate change have grown. I pay close attention to the six comparable states I identified in section III, including the four that are adjacent to New Mexico. In addition to the recent adopters, there are another dozen or so states that initiated efficiency programs 15 or 20 years ago, such as California and in New England.

Q. PLEASE REVIEW BRIEFLY THE KINDS OF FINANCIAL INCENTIVES AND THEIR FREQUENCY FOR THE RECENTLY ADOPTING STATES.

A. In section III above, I identified the five different kinds of financial incentives in use by state regulatory commissions and discussed in some detail the general terms and conditions typically associated with each of them. Figure 3 above showed the different frequencies of occurrence across these five performance incentives. The same data with a count of the policies instead of percentages is repeated in Figure 14 (a state can have more than one policy).

Figure 14 – Count of Efficiency Incentive Policies in 23 States



Q. HOW DOES PNM'S REQUESTED INCENTIVE COMPARE IN STRUCTURE TO THESE COMMON APPROACHES?

A. Structurally, the PNM approach is the fifth type, being a payment based on the performance relative to the targets for lifetime kWh and kW-years. Moreover, the 2012 Plan is well grounded in experience and rigorous benefit-cost analysis, as discussed by PNM witness Bean. Beyond that the PNM approach is a hybrid, in several respects.

First, it is motivated by a partial value pricing concept, namely relating the EE incentive to the foregone investments displaced by the efficiency efforts. However, unlike the original Duke Save-a-Watt approach, it only seeks the lost equity returns, not the full avoided value of the displaced capacity, and is more transparent. Second, it will be subject to true-up based on the actual performance of the 2012 Plan relative to its estimated savings. Third, the true-up is subject to a cap on the amount of additional incentive allowed for superior performance, assuring that customers retain a reasonable amount of the net benefits realized. Fourth, the incentive target amounts are a modest share of net benefits. Finally, the proposed approach recognizes that those benefits occur in two roughly equal sized and equally important forms, capacity and energy, so it is collected in proportion to success along those two performance measures – making it similar to a per-unit of success approach.

Q. HOW DOES IT COMPARE IN LEVELS OF INCENTIVE COMPENSATION TO THE OTHER STATES YOU HAVE STUDIED AND REGARD AS COMPARABLE?

A. I selected six states and their utilities that I believe are most comparable to and representative of what New Mexico policies and practices aim to achieve. In many cases, these utilities are in states that have state energy efficiency policies, goals, and incentive structures directly comparable to New Mexico. This happens to include all of the states surrounding New Mexico, probably stemming from the fact that these states have recognized a common importance of conservation in ensuring the region's future energy and water supplies and environmental resources. The comparable states are those that have financial incentives and riders for direct cost recovery. They generally have lost fixed revenue recovery mechanisms rather than decoupled ratemaking.

Figure 15 compares the sizes and efficacy of the EE programs for the selected utilities in these states to the PNM EE programs. One important caveat in trying to quantitatively compare different utility financial incentives is that the metrics are somewhat imprecise. For example, the cost effectiveness measured in $ per kWh of lifetime savings can be skewed by the relative size of the load management programs. Load management programs can incur significant costs to reduce costly peak demand (kW) but frequently save little or no energy (kWh). Although having a benefit/cost ratio well above 1.0, load management can raise total costs on a $ per kWh basis. In Figure 6, Row 8 above, the time series of PNM's Cost of EE Programs per lifetime kWh was presented by removing the costs and impacts of the LM programs. However, in the cross sectional analysis below, the PNM and other utility cost, impact and avoided cost savings measures do reflect the contributions of both EE and LM. We did not attempt to remove the LM program impacts of the different utilities.

Figure 15 -- Normalized Efficiency Program Statistics for Comparable States and Utilities

States		New Mexico	Arizona	Arizona	Arkansas	Colorado	Indiana	Oklahoma	Texas
Utility	Unit	PNM 2012 Plan	Arizona Public Service 2011	Tucson Electric Power 2011	Entergy Arkansas Inc 2011	PSCo (Xcel) 2011	Duke Indiana 2012 Plan (50/50)	OG&E 2011	El Paso Electric 2011
SIZE OF UTILITY									
Total Retail Sales	GWh	9,290	28,210	9,332	21,584	28,486	27,810	25,764	7,661
Size of Company Retail kWh relative to PNM Retail kWh		1.0	3.0	1.0	2.3	3.1	3.0	2.8	0.8
SIZE OF IMPACT OF DSM PROGRAM									
Annual kWh savings as percentage of total kWh Retail sales	%	0.9%	1.6%	1.5%	0.2%	1.1%	1.0%	0.2%	0.3%
COST OF DSM PROGRAM									
Utility Direct Costs as % of Annual Retail Revenue	%	2.5%	1.8%	1.5%	0.8%	2.4%	1.9%	0.9%	0.5%
Utility Direct Cost per Annual kWh saved	$/kWh	$0.27	$0.14	$0.09	$0.32	$0.20	$0.15	$0.29	$0.19
BENEFIT/COST RATIO									
TRC Benefit/Cost Ratio		1.70	2.34	3.15	1.40	2.85	NA	1.84	3.17
Net Benefit (TRC) / Total Retail Revenues	%	1.7%	4.6%	6.2%	0.6%	8.5%	NA	0.9%	1.1%

Notes:

1. PNM is normed on the 2011 actual retail sales and revenues. Metrics measuring program costs per kWH and net benefit values are indicative but not fully comparable. Different utilities have different sized Load Management programs that provide cost savings predominantly through kW, not kWh savings. Benefits may or may not include externalities to become a Societal Cost Test. PNM benefits are down in 2013 plan, from lower natural gas prices and low economic growth. PNM company size variables kWH and Retail Revenues are based on 2011 actuals, not forecast.

2. The Duke IN 2012 plan/results were used because the savings and direct cost forecasts are nearly four times larger than the 2011 results (from a truncated year). The year 2012 is more representative of the current, mature program. The company data used to norm the results are 2011 actuals for Duke IN.

PNM is generally smaller in jurisdictional sales volume than most of the utilities in the above set, although there are two in its size range (Tucson and El Paso). However, after scaling EE program costs and impacts for relative size, PNM's EE program is within the range of parameters, actual outcomes and planned outcomes for this peer group.

Figure 16 presents how these incentive terms and conditions translate into annual dollar amounts awarded, which can then be compared to the proposed allowance for PNM.

Figure 16 -- Size of the Performance Incentives in Comparable Utilities and States

States		New Mexico	Arizona	Arizona	Arkansas	Colorado	Indiana	Oklahoma	Texas
Utility	Unit	PNM 2012 Plan	Arizona Public Service 2011	Tucson Electric Power 2011	Entergy Arkansas Inc 2011	PSCo (Xcel) 2011	Duke Indiana 2012 Plan (50/50)	OG&E 2011	El Paso Electric 2011
INCENTIVES									
Total $ incentive (before income taxes)	$ mm	**$4.21**	$8.78	$1.10	-	$15.52	$6.34	$3.10	$0.67
Incentive / Annual MWh saved	$/MWh	**$50.98**	$19.89	$7.90	-	$49.80	$22.26	$49.17	$30.71
Incentive / EE program direct costs	%	**18.7%**	16.0%	8.3%	0%	24.3%	15.0%	17.0%	15.8%
Incentives / Net Benefits (Shared Saving %)		**27.4%**	6.4%	2.1%	0%	6.9%	NA	17.0%	7.3%

NOTE

Entergy Arkansas, Inc. missed the cutoff for receiving its incentive, getting 79.6% of target, when 80% of target was required. Another 0.4% would have resulted in an incentive of $991,000 or 7.4% of program direct costs.

Q. WHAT DO YOU CONCLUDE ABOUT THE RECOMMENDED INCENTIVE ALLOWANCE FOR PNM, COMPARED TO THESE BENCHMARKS?

A. PNM is within the range of accepted incentive policy parameters across the comparable states. The range cannot be established with great precision for a number of reasons, including the Note below the table. The figures from the other states are 2011 vintage, which were likely higher in avoided costs because of natural gas prices. Figure 16 shows that a $4.206 million allowance for PNM results in an allowance that is about 18.7% of program costs and 27.4% of net benefits. Again, it must be remembered that net benefits become more difficult to realize as time goes on, and we are comparing later vintage programs for PNM with earlier vintage programs for the comparable utilities.

This share of benefits is above average and the share of costs is higher than the utilities in the peer group. This is consistent with the EUEA, which is stronger in providing financial incentives to utilities than what exists in many other states by requiring a profit on energy efficiency programs that is financially more attractive than supply-side resources. Thus, a higher than average incentive allowance (in terms of share of savings) is reasonable.

Q. IS THE RISK OF RECOVERY OF EE PROGRAM COSTS A RELEVANT CONSIDERATION IN DETERMINING THE AMOUNT OF THE FINANCIAL INCENTIVE?

A. No. As explained earlier in my testimony, it is not the risks of recovering the EE costs that are relevant, but rather the way the EE programs affect the riskiness and financial attractiveness of the rest of PNM's business. The way EE program costs are recovered is an insignificant factor, at most, in assessing the riskiness of the EE business. Instead, the profit incentive is a mechanism for recognizing how EE affects the rest of the business, and for motivating the company to find and pursue the best mix of potential new EE.

VIII. SUMMARY AND CONCLUSIONS

Q. WHAT ARE YOUR CONCLUSIONS?

A. I endorse the Legislature's and Commission's policies of allowing reliable cost recovery for EE programs plus a meaningful incentive to pursue those activities. Having such compensation is reasonable in light of negative economic consequences that EE programs tend to have for other utility activities, and for financial market concerns.

Although I am not an attorney, as an expert in the field of EE incentives and how they affect the utility business as a whole, I believe that a modified value-based approach to EE incentives is necessary and appropriate to meet the directives and purposes of the EUEA. That is, the EUEA states an objective of making EE more profitable than what would have been enjoyed from the foregone, conventional activities. My approach provides for replacing the foregone profit opportunity associated with conventional generating plant investment with a reasonably higher comparable amount. This structure results in energy vs. capacity shares of the incentive monies that are comparable to the energy vs. capacity shares of the benefits of the EE programs.

The resulting proposed allowance is conservative in relation to exceeding actual foregone profits from investment activities that PNM would have otherwise pursued (and customers would need), but as a result it is reasonable in relation to what other, similar utilities earn for EE incentives. It results in a share of net benefits that is at the upper end of the range of my comparison group, but those comparison utilities appear to calculate benefits in a manner that is less conservative than PNM and the data available from those other utilities may include higher avoided costs than are applicable in today's environment. As such, the comparison is based on data that may overstate where the proposed PNM incentive allowance falls within the range of incentives for the comparable utilities. Furthermore, the impacts of PNM's proposed incentives on rates and profits are both small and again reasonable in comparison to industry norms. The proposal contains a modest share of program benefits targeted for shareholders, is tied to program performance, as required by the EUEA, and the amount of the profit earned is capped in order to assure that customers retain an appropriate share of the program benefits. As such, the proposed approach and levels satisfy the criteria of being utility-specific, based on performance, is related to costs (both those avoided and those incurred) and the risks faced by PNM because of its EE activities. The proposed approach results in EE rates that properly balances the public interest and the interests of customers and investors and are therefore just and reasonable.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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