4-58

BEFORE THE

NEW MEXICO PUBLIC SERVICE COMMISSION

PUBLIC SERVICE OF NEW MEXICO

CASE No. 2004

Testimony of

Paul Chernick

on Behalf of the

New Mexico Attorney General

May 7, 1986

ANALYSIS AND INFERENCE, INC. RESEARCH AND CONSULTING

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Table of Contents

1 QUALIFICATIONS

Q: Mr. Chernick, would you please state your name, position, and office address.

A: My name is Paul L. Chernick. I am employed by Analysis and Inference, Inc., as a Research Associate. My office address is 10 Post Office Square, Suite 970, Boston, Massachusetts 02109.

Q: Please describe briefly your professional education and experience.

A: I received a S.B. degree from the Civil Engineering Department of the Massachusetts Institute of Technology in June, 1974, and a S.M. degree from the same school in February, 1978 in Technology and Policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, to membership in the engineering honorary society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi. I am the author of several publications, which are listed in my resume, attached as Appendix A.

My professional experience includes over three years as a Utility Rate Analyst for the Utilities Division of the Massachusetts Attorney General. In this capacity, I was involved in review and analysis of utility proposals on a number of topics, particularly load forecasting, capacity planning, and rate design. One of my first major projects for the Attorney General was an investigation of the extended 1977-78 maintenance outages and associated derating of the Pilgrim power plant.

My current position with Analysis and Inference, Inc. has involved a number of utility-related projects. These include a study of nuclear decommissioning insurance for the Nuclear Regulatory Commission, analyses of gas and electric rate designs, nuclear power cost estimation, design of conservation programs, and several other topics.

Q: Have you testified previously as an expert witness?

A: Yes. I have testified more than forty times before such agencies as the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Siting Council, the Massachusetts Division of Insurance, the Atomic Safety and Licensing Board of the Nuclear Regulatory Commission, and before the utility commissions of Texas, Michigan, Illinois, New Hampshire, Connecticut, the District of Columbia, Pennsylvania, Maine, and Vermont. My resume lists my previous testimony.

Q: Have you testified previously before this Commission?

A: Yes. I testified on the economics of the Eastern Interconnection Project of Public Service of New Mexico in Case 1974, and on El Paso Electric's nuclear decommissioning fund in Case 1833, Phase II.

Q: Have you testified previously regarding performance targets for utility power plants?

A: Yes. I testified in Massachusetts Department of Public Utilities (MDPU) docket numbers 1048 and 1509, the first two reviews of Boston Edison's proposed power plant performance standards, under the new fuel clause statute, M.G.L. c. 164, section 94G (effective August 6, 1981). That statute eliminated the essentially automatic recovery of fuel costs, and required that the fuel adjustment charge be based on "the efficient and cost-effective operation of individual generating units".

I also testified before the Michigan Public Service Commission in the 1984 Power Supply Cost Recovery proceedings of Detroit Edison (Case No. U-7775) and Consumers Power (Case No. U-7785), on performance targets for those companies' nuclear power plants.

In addition to power plant performance cases, I have also testified on nuclear capacity factors in a number of planning and ratemaking proceedings, including Massachusetts DPU 20055, 20248, 84-25, 84-49/84-50, 84-145, 84-152, and 85-270; NHPUC DE 81-312; Illinois Commerce Commission 82-0026; Connecticut PUCA 83-03-01; NMPSC 1794; MEFSC 83-24; Maine PUC 84-113 Phase I, 84-113 Phase II, and 84-120; and Pennsylvania PUC R-842651 and R-850152; among others. This testimony is also listed in my resume.

Q: Have you authored any publications on power plant performance standards?

A: Yes. My paper "Power Plant Performance Standards: Some Elementary Principles," published in Public Utilities Fortnightly, is attached as Appendix B to this testimony.

2 INTRODUCTION

Q: Please describe the subject matter and purpose of your testimony.

A: My testimony discusses the performance standards to be imposed on the share of Palo Verde Nuclear Generating Station (PVNGS) owned by Public Service of New Mexico (PNM). PVNGS consists of three pressurized water reactors (PWRs), each of 1270 MW net design electrical rating.

Q: Why is it appropriate to set standards for power plant performance, rather than simply allowing PNM to recover its actual fuel costs, regardless of how well, or how poorly, PVNGS performs?

A: This Commission has a legitimate concern with the reasonableness of PNM's rates. If PVNGS does not perform as well as it should, and PNM recovers both the costs of PVNGS and the cost of power to replace PVNGS output when it is not operating, rates will be unnecessarily high.

It may also be important to insure that PNM's past projections for PVNGS performance is consistent with the performance for which consumers will be asked to pay. In particular, PNM's cost recovery for PVNGS is determined by the inventory stipulation. It is my understanding that the settlement which established the inventory procedure was premised in part on the projected costs and benefits of

PVNGS, including the number of kWh's each unit would generate annually, and the rate at which deferred return on the units increase their cost. If PVNGS does not perform as well as was assumed at the time of the inventory stipulation, consumers will end up paying more for PVNGS than had been anticipated.

Q: What is the fundamental goal of the standard-setting process?

A: In setting power plant performance standards, the objective is to develop <u>normative</u> or <u>prescriptive</u> goals, specifying how the plant <u>should</u> behave. This is a very different concept from <u>positive</u> or <u>descriptive</u> projections, which predict how the plant <u>will</u> behave. These two types of analyses have very different purposes and may yield very different results. For example, if a utility breaks a plant in 1986, an accurate positive analysis might project a 1987 capacity factor of zero. It may be appropriate to base 1987 power supply cost recovery on the costs which should have been incurred reasonably and prudently if the plant had not been broken. Thus, the normative standard may be different from both the actual performance, and from the best estimate of future performance.

Q: What measure of performance is most important for PVNGS?

A: In economic terms, the important performance parameter for PVNGS, or any other nuclear plant, is the amount of power the plant produces. The high cost of nuclear capacity is justified, if at all, by its low fuel costs and by the ability to spread the initial investment over many kilowatt-hours each year. Since nuclear fuel is relatively inexpensive, the economics of a nuclear plant depend more on the ability to produce many kWh, than on the ability to produce those kWh efficiently.[1] Hence, the capacity factor (CF) may be the most significant measure of PVNGS performance.

Q: Is capacity factor the only important measure of nuclear plant performance?

A: No. There are times when a plant does not produce all the energy of which it is capable, for reasons unrelated to its technical capabilities. The potential capacity factor, if not for economic and other systems constraints, is called the equivalent availability factor (EAF). The major difference between the capacity factor and the EAF for most units is a practice called "load following" or "cycling," in which the units' output increases at times of high demand and falls during periods of low demands. Utilities rarely have all their available units operating at full capacity, simply

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1. This description is slightly less true for PNM than for most other utilities, including the other owners of PVNGS. The fuel costs of Four Corners are not very different than those of PVNGS, at least in the next few years. San Juan fuel is more expensive, but is still only about one cent/kWh more than PVNGS fuel. Since PNM has already backed out most of its gas use, the fuel savings from PVNGS operation will be rather limited in the near term. Still, the net cost of PVNGS will be largely determined by the number of kWh it produces, for PNM's own use or for off-system sales.

because the amount of power necessary to meet peak loads in the middle of a weekday is not needed for other hours, particularly at night and on weekends. However, except in the Pacific Northwest, with its large hydroelectric capacity, nuclear plants are rarely if ever involved in load following. With their low fuel costs, nuclear plants are generally among the first units dispatched to meet load, and virtually all other plants will be turned down before the nuclear units' output is affected.

Other factors do produce differences between CF and EAF for most nuclear units. Transmission line failures can force units off line, even though there is nothing wrong with the generating plant. Power output is sometime reduced to delay the refueling of a nuclear plant, in order to avoid having several nuclear units (or other baseload plants) out of service simultaneously, to allow a unit to remain in service through the peak season, or to permit the utility's crews to complete refueling of another nuclear unit before starting on this unit.

Q: Which of these factors is a better indicator of the performance of a nuclear plant?

A: It is difficult to define one measure as more important than the other. The capacity factor reflects the plant's actual energy production, the real bottom line. CF is also an objective measure of performance, determined by the metered output of the unit, and by its rated capacity. On the other hand, there are times when increased capacity factor would be impossible for reasons independent of the plant's performance (e.g., there is nowhere for the power to go), or would be uneconomical. The EAF does not penalize the plant for these reductions in output, and is therefore a better measure of the plant's performance.

Unfortunately, EAF is not an objective measure. EAF is a subjective measure, reported by the operating utility and representing only the utility's opinion of what the unit might have done, if not for factors which the utility may wish to consider to be "economic". Furthermore, the calculation of EAF assumes that the unit would have run <u>perfectly</u> if not for the "economic" limitation.

Considering all of the preceding factors, it is probably most useful to state nuclear power plant performance targets in terms of EAF, but to use the metered CF as a reality check. Differences between EAF and CF of more than 0.1% points should be thoroughly explained, including identification of the hours during which power was voluntarily reduced, and a description of the reason for each reduction. Differences of more than 0.5% are quite uncommon: if the reported EAF performance is to be used for ratemaking, such large differences should generally trigger an investigation to ensure that the reported EAF reasonably represents the plant's capability.

Q: How is the remainder of this testimony organized?

A: Section 3 describes the principles and concepts upon which power plant performance targets may be based. Section 4 discusses the PVNGS capacity factor projections utilized by PNM, and PNM's testimony on the propriety of performance standards for PVNGS. In Section 5, I suggest equivalent availability factor performance standards to be applied to PNM's share of PVNGS.

3 PRINCIPLES OF POWER PLANT PERFORMANCE STANDARD-SETTING

Q: What basic approaches can be taken to establishing standards for power plant performance?

A: There are three basic types of alternative approaches. First, each unit's performance standard can be determined by a self-referent standard, based on the unit's past performance. Self-referent standards may be set at various levels of stringency, such as:

- The unit will perform at least as well as its best past performance.
- The unit will perform at least as well as its average past performance.
- The unit will perform at least as well as its worst past performance.

Any of these standards may be calculated from any time period (e.g., last year, or the plant's entire life) and for a variety of intervals (monthly data, annual data).

Q: Do these self-referent methods generally produce fair and even-handed standards?

A: Not usually. Self-referent standards are inherently stricter for those units with good performance histories than for those with poor past performance. This is hardly a fitting reward for those utilities which have historically taken the greatest care in plant operation. In fact, it penalizes the best past performers and rewards the worst. There is generally no compelling reason for believing that the unit's history is representative of an appropriate level of performance (neither extraordinary nor inadequate), so self-referent standards are not likely to be useful in identifying efficient and cost-effective operations.

Q: What is the next category in your list of standard-setting approaches?

A: In the second group of options, standards are based on <u>comparative</u> analyses, which aggregate the experience of other units. This approach would include such standards as:

- The unit will perform as well as the average comparable unit.
- The unit will perform as well as the average <u>competently run</u> unit.
- The unit will perform better than half (or any other percentage) of the comparable units.

Q: How may comparative targets be derived?

A: The comparisons may simply average data from a set of units which share some common characteristics, or they may involve more complex statistical analyses, such as regression. Simple comparisons are generally performed on a set of very similar units, as it is difficult to justify direct comparisons between units which are known to vary in any relevant manner. The differences which are relevant are those which can be expected to affect performance: vintage, age, operating pressure, size, fuel type, and so on. The resulting data sets tend to be small, and the comparability of the units is always subject to some dispute. Various statistical techniques may mitigate these limitations. In multiple regressions, for example, several descriptive variables may be incorporated simultaneously, facilitating the merging of data from a greater variety of units. Statistical tests can also be useful in determining whether particular units belong in a comparison group.

Q: You have stated that the purpose of analyzing power plant performance is to establish normative standards. Is this consistent with the use of actual operating data in these first two types of approaches?

A: Yes, normative standards can be derived from actual operating data. Positive models describe the way things are (or have been), leading to such conclusions as "Once they reach maturity, 1200-MW PWR's have an average capacity factor of 60%." This sort of statement is not a performance standard; it only becomes a standard when a prescription is added, such as "Therefore, PVNGS 1 should have a 55% mature capacity factor." The way things are <u>may</u> be the basis for determining the way things should be, but this relationship is not automatic.

Q: What is the third group of standard-setting approaches?

A: Finally, standards may be based on <u>absolute</u> measures of proper performance, such as:

- The unit will perform as was promised, or expected.
- The unit will perform as well as the utility has assumed for other purposes, such as rate design, setting rates to be paid to small power producer, and capacity planning.
- The unit will perform well enough to justify its fixed costs.

None of these various absolute standards depend on actual performance data, either for the subject plant or for other plants. The first example suggests that, when the utility (and hence, the ratepayers) buy a generating unit, it should get what it (and they) expected. The second example suggests the standards applied in a plant performance standard review, where over-optimistic projections cause problems for the utility, should be the same as those used in proceedings where over-optimistic projections cause problems for ratepayers, such as capacity planning and rate design. The last example suggests that, regardless of what the utility expected, or predicted, or should have expected for the unit, the real issue is whether the unit is paying its own way.

Q: Is one particular approach to standard-setting preferable in all applications?

A: No. The various kinds of standards are appropriate for different situations. As noted above, self-referent standards raise major equity issues. If applied on a rolling basis (e.g., if the standard in any year is determined by performance in the preceding three years), serious and perverse incentive problems may be created. Self-referent standards are also inherently inapplicable to new units. There are special circumstances in which self-referent standards are useful, particularly when no other basis for standard-setting exists; these are the exceptions, rather than the rule.

Comparative standards are appealing wherever a reasonable comparison group exists. They are not applicable for experimental units and other unique designs.[2] Comparative analyses establish business-as-usual standards, which simply ask utilities to keep up with general industry performance levels.

Absolute standard-setting approaches rely on other concepts of fairness, which may be applicable even where business is far from usual. For example, using pre-operational

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2. The concept of uniqueness must be applied carefully. In one sense, no steam power plant is unique, since all such plants are alike in having a boiler, a turbine, and a heat sink. In another sense, every unit is unique, except for those few sister units which are exact carbon copies. Generally speaking, if a group of similar units can be defined, a meaningful comparative analysis can be conducted, and statistical tests can determine whether differences between plants are important.

expectations to set performance standards is intrinsically appealing: if a utility sets out to build a plant which will operate in a particular manner, it should be able to explain why the actual plant is significantly different than the expected one. Similarly, utilities should not be allowed to change their stories to suit their positions in different proceedings, projecting wonderful operating results if they are allowed to build the plants of their choice; assuring regulators that good generating performance will make marginal costs so low that volume discounts to large energy users are justified, conservation is counter-productive, and small power producers are unnecessary; and then denying that it is realistic to expect performance at those levels.

The application of this approach is limited by performance factors and units for which expectations and representations are either unavailable or otherwise of limited usefulness. For many fossil units constructed prior to the establishment of regulatory review, no reliability measures were ever projected. For other technologies, early performance expectations were widely held, based on virtually no data, and seriously incorrect; this certainly was true of projections for nuclear capacity factors made in the 1960's and early 1970's. In such cases, it seems unfair to hold an individual utility responsible for a universal, and perhaps understandable, error.

As an alternative to the projection standard, the cost-effectiveness standard may be particularly appealing: this standard asks only that the ratepayers be better off with the plant than without it, but this may be all that can be expected from new (and especially from exotic) generating units. This standard can be derived for all units, regardless of the existence of a comparison group, of prior data on the unit's own performance, or of pre-operational projections.

4 PNM'S APPROACH

Q: What are PNM's projections of the performance of its nuclear units?

A: Table 1 lists the equivalent availability factors projected by PNM for each PVNGS unit, as of 10/1/85. Except for changes in the in-service dates, and minor revisions in the intervals between refuelings, these EAF projections appear to be the same as those PNM has used for several years. The projections in Table 1 have been used in many applications, such as for rate design, in evaluation of the Eastern Interconnection Project, and during the negotiations which produced the inventory stipulation.

Q: Are these projections likely to be achieved?

A: No. Table 2 displays the capacity factors of all the PWRs of over 1000 MW which were in operation through the end of 1982. The average capacity factors (which in most cases are very similar to the EAFs) have been running between 55% and 60%.

Table 3 provides the results for PVNGS of Analysis and Inference's most recent regression analyses of PWR capacity factors, which are described in more detail in Appendix C. The same table lists the PVNGS capacity factor projections of Energy Systems Research Group, the consultant on power plant performance standards for the Attorney General and PNM.

Q: For how long has there been evidence that PNM's projections of PVNGS capacity factor have been overstated?

A: This has been evident for several years. Table 4 lists the capacity factors for all PWR's of more than 800 MW, through 1985, and the averages through 1975, 1977, 1979, and 1981. The data clearly shows that PNM's projections are inconsistent with the experience of the industry even in the late 1970's.

Statistical analyses also indicated many years ago that capacity factors of large PWRs were much lower than PNM's projections for PVNGS. Komanoff (1976) projected from available experience that 1150 MW PWRs would have average capacity factors in their first ten years of 47.6%. Updates (Komanoff 1977 and 1978) revised the projections of levelized capacity factors to 55% and 59%. An analysis performed at Sandia National Laboratory for the Department of Energy (Easterling 1978) concluded that average capacity factors for 1100 MW PWRs in years 2-10 of operation would be about 57%. Applying Easterling's results to a unit with a 1270 MW DER (and assuming that the maximum generator nameplate, or MGN, rating Easterling uses would be 4% higher than the DER rating) would project a mature capacity factor of 55.5%.

Q: What is PNM's position regarding performance standards for PVNGS?

A: PNM opposes such standards. As explained in the testimony of Mr. Begley, PNM's principal argument for not imposing standards is the assertion that poor PVNGS performance would have much greater effects on shareholders than on ratepayers, due to the operation of the inventory ratemaking arrangement.

Q: Is it true that the inventory process would cause shareholders to bear a much larger burden than the ratepayers, if PVNGS performance is below PNM's projections?

A: Not really. Table 5 displays PNM's estimates of the present value burdens on ratepayers and shareholders, for various levels of PVNGS availability. Mr. Begley computes the percentage increases in the burdens as EAF falls from 74% to lower levels,[3] and concludes that the shareholders are affected much more by lower performance than are the ratepayers. That analysis is flawed in three respects.

First, Mr. Begley's criterion is fundamentally irrelevant. The question he asks is "By what percentage does each group's burden increase when EAF declines?" The percentage change depends on the initial value: the lower the shareholder burden is assumed to be at 74% mature EAF, the higher the

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3. PNM does not clearly describe the lower performance levels used in its analyses. PNM's current projections of annual immature availabilities are not clearly stated in either Mr. Begley's testimony or Mr. Fisher's testimony, although I assume that they are identical to the 10/1/85 projections. Mr. Begley's testimony suggests that the 65%, 55%, and 45% availabilities used in his change cases are comparable to the 74% mature EAF in the base case, but does not explicitly say so.

percentage effect of any increase. For example, if the base case shareholder cost were $1 million, a $1 million increase would be a 100% increase, but if the initial shareholder cost were $4 million, the same increase would be only 25% of the base value. Thus, the percentage increases in Mr. Begley's testimony are of almost no practical significance.

Second, the base values are entirely inconsistent, as Mr. Begley defines them. The shareholder burden is limited to the costs which would have been recovered under full ratebase treatment, but which are not recovered under the inventory process. The ratepayer burden is defined much more broadly, to include both the additional AFUDC costs due to inventory, and the entirety of system production costs.[4] Since the ratepayer burden includes costs which are not affected by inventory, the percentage increases due to low PVNGS capacity factors appears much smaller than if the base case included only inventory effects. This point is illustrated in Table 5: the ratios of the increases in ratepayer burdens to the base case inventory-related burden of increased AFUDC are much larger than the ratio of the increases to the entire cost of PNM's production system. Conversely, if the measure of shareholder welfare also included non-inventory effects -- for example, if it were defined as total return on equity --

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4. "System production costs" appears to include capital recovery and operating costs for the entire retail generation system, including costs which have little or nothing to do with PVNGS.

the base value would be higher and the percentage increases from a reduction in PVNGS performance would be lower.

Third, contrary to Mr. Begley's conclusions, the ratepayers bear the bulk of the burden due to low PVNGS availability. Table 5 also shows the percentage of the present value cost increases which are borne by shareholders: depending on the EAF, shareholders would be responsible for only 11% to 17% of the increased cost. It is not surprising that the shareholders wind up with only a small fraction of the present value burden, since in most years they would assume only a small fraction of the excess production costs due to lower performance, even while the plant is still in inventory. Table 6 compares my rough estimate of the costs of lower performance, based on an average 3 cent/kWh value of power from PVNGS for 1986-1995,[5] to the total shareholder losses estimated by PNM. While this comparison is obviously only an approximation, it is clear that the shareholders pay only a very small portion of the excess costs due to low availability, even in those years in which the inventory methodology places them at risk. The stockholders bear no performance risk once the capacity leaves inventory.

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5. This estimate, which includes both the cost of replacement power and the sales price of off-system sales, is probably too low for the 1990's. The higher the value of PVNGS power, the lower the fraction of the cost which is assumed by the shareholders.

Q: Do you agree with PNM's position that there is no empirical evidence that performance standards improve plant performance?

A: I am not aware of any study which has attempted to measure such an effect. There are reasons to believe that the effect would be difficult to detect, even if it were important. First, performance standards have tended to be imposed where plants are not performing well, so the presence of standards may well correlate with poor performance. Second, most performance programs are fairly recent, so little data is available concerning their long-term effects, once management and maintenance has been adjusted to the new conditions. Third, there is very high annual variability in nuclear power plant performance, so even real and immediate improvements will be hard to sort out from the background noise.

Of course, improved performance is not the only reason for implementing power plant performance standards, and such improvement may not be the primary objective of a standard-setting program. Equity concerns, such as fairness and proper allocation of materialized risk, are at least equally important.

Q: Is Mr. Begley correct in stating that "the Inventory Stipulation protects current ratepayers by deferring those incremental costs arising from any operational inefficiencies of PVNGS. Future ratepayers are protected by the cap on AFUDC" (page 9)?

A: Only partially. Current ratepayers are protected by the deferral of costs. Future ratepayers, however, pay for both the deferred costs (up to the AFUDC cap) and the additional cost of any poor PVNGS performance once the capacity is out of inventory. The inventory rules provide some limited protection of future ratepayers from poor performance while the plant is in inventory, but no protection once it is out of inventory.

5 RECOMMENDATIONS

Q: What type of performance standard would you recommend be applied to PNM's share of PVNGS?

A: I recommend that the Commission institute an absolute performance standard based on PNM's representations regarding the EAFs of the PVNGS units. Table 7 lists these representations in terms of availability between refuelings, the period between refuelings, and the length of the refueling outages, from Case No. 1916. Table 1 provides PNM's projections for calendar year EAFs, for the commercial operation dates assumed as of 10/1/85. Variation in commercial operation dates and startup periods (which affects the time from commercial operation to the first refueling) may cause changes in the annual EAFs, even given PNM's basic assumptions.

To moderate the effects of poor performance on earnings, I would suggest that the shareholders assume only half of the EAF risk, and that cost recovery be calculated as if PVNGS had operated at the average of its actual EAF and PNM's projection. This could be achieved by calculating power supply cost recovery and inventory effects as the average of actual costs and the costs which would have resulted had

PVNGS operated at the standard.[6] I suspect that it will be easier to calculate cost recovery as if PVNGS availability were equal to the average of actual EAF and the performance target. Either approach will require the use of a production costing model to determine cost recovery, but the inventory arrangement will require the use of such a model anyway, to compute sales from inventoried capacity to the retail jurisdiction, and to allocate revenues from off-system sales to inventoried and jurisdictional capacity.

Q: Should an EAF performance standard of 68.4% be imposed for PVNGS 1 immediately?

A: Yes. While the inventory process causes the shareholders to bear a small portion of the cost of poor performance at PVNGS, that portion is minuscule compared to the costs borne by the ratepayers. Unfortunately, PNM has not presented its results in a form which allows for easy comparison of the shareholder burden to the total losses in each year due to poor performance.[7] Therefore, I would recommend that the performance standard be imposed during the inventory period, as well as after the capacity emerges from inventory.

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6. The average may be a weighted average, if the Commission wishes to set the shareholder portion of the risk at a value other than 50%. At this point, I see no reason to deviate from the 50% risk allocation.

7. The ratepayers costs due to increased AFUDC accrual are reported in the year they are paid, rather than in the year the AFUDC accrues.

Q: For what period of time would you suggest that PNM be held to these standards?

A: I would suggest that the standard be applied for at least until the last portion of the plant is taken out of inventory. PNM should have known for at least the last eight years that it was using highly aggressive projections of availability. It seems fair to apply the representations standard several years to come, especially in light of the role of that representation in the inventory stipulation. Continuation of this standard, or another performance standard,[8] may be appropriate after the end of the initial performance standard program, but that issue need not be addressed for several years. If the inventory arrangement is radically revised, or if declining load growth results in PVNGS remaining in inventory for much longer than is currently projected, the performance standard should be re-examined.

Q: Is it necessary to have a "dead band" around the standard, so that small deviations have no effect?

A: No. Small deviations would produce small rewards or penalties, which will not matter much. A dead band would only make sense where the deviation is so small that the effort of running the production costing model is not

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8. In particular, a comparative standard is likely to be appropriate for PVNGS, once the prior representations standard is abandoned.

justified. As I noted above, the production costing runs will be necessary in any case.

Indeed, there are disadvantages to dead bands, which argue against their use except where they are required for administrative convenience. Depending on the distribution of outcomes around the target, applying a dead band on an annual basis may result in a net reward for poor performance, or a penalty for good performance. For example, if a plant often operates at an EAF 5 points above its target, but occasionally has a very bad year and operates 15 points below target, a 10 point dead band would result in penalties and no bonuses. In addition, dead bands may encourage utilities to manipulate maintenance outages, to keep one performance period within the dead band (even if very close to the bottom), while pushing another above the top of the dead band. In these situations, overall performance of a plant may be decreased, while the utility receives a performance incentive reward.

Q: Would the standard you have proposed have any other benefits?

A: Yes. This precedent would tend to encourage more accurate performance projections by PNM and other New Mexico utilities for new plants. So long as utilities can justify cost recovery for their new plants by projecting (among other things) optimistic future operating performance, there is a positive disincentive for PNM to offer realistic projections to this Commission. If the Company's cost recovery is tied to the performance of the plant, this strategy no longer works. Promising stellar performance to get a plant into rate base is much less effective, if the utility bears some of the cost of not achieving that performance.

Q: Does this conclude your testimony?

A: Yes.

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TABLES TO ACCOMPANY

THE TESTIMONY OF

PAUL CHERNICK

TABLE 1: PALO VERDE EQUIVALENT AVAILABILITIES USED IN PNM'S OCTOBER 1, 1985 FILING (PERCENT)

Year	Palo Verde #1	Palo Verde #2	Palo Verde #3
1986	68	68	
1987	60	68	68
1988	69	67	68
1989	74	70	66
1990	74	74	73
1991	74	74	74
1992	74	74	74
1993	74	74	74
1994	74	74	74
1995	74	74	74
1996	71	74	74
1997	74	71	74
1998	74	74	71
1999	74	74	74
2000	74	74	74
2001	74	74	74
2002	74	74	74
2003	74	74	74
2004	74	74	74

Source: Testimony of Eugene W. Fisher, Exhibit EWF-2.

Note: Equivalent Availability (%) = (1.0 - Maintenance Outage Rate) * (1.0 - Effective Forced Outage Rate) * 100%.

TABLE 2: HISTORICAL CAPACITY FACTORS (DER), UNITS SIMILAR TO PVNGS

UNIT	DER NET [1]	first full year	1	2	3	4	5	6	7	8	9	10	11	12
			CAPACITY FACTOR BY CALENDAR YEAR [2]											
ZION 1	1050	74	37.8%	53.4%	51.6%	54.7%	73.6%	60.2%	70.6%	67.3%	51.0%	43.7%	61.7%	52.3%
ZION 2	1050	75	52.5%	50.3%	68.2%	73.2%	51.8%	57.2%	57.2%	56.1%	67.2%	64.9%	55.6%	
COOK 1	1090	76	71.1%	50.1%	65.8%	59.3%	67.5%	71.0%	56.1%	55.4%	78.9%	22.2%		
TROJAN	1130	77	65.6%	16.8%	53.2%	61.2%	64.9%	48.5%	41.2%	47.7%	69.8%			
SALEM 1	1090	78	47.4%	21.4%	59.4%	64.8%	42.9%	56.3%	22.2%	94.3%				
COOK 2	1100	79	61.8%	69.3%	66.3%	72.6%	72.8%	55.5%	59.0%					
SEQUOYAH 1	1148	82	48.8%	73.0%	60.5%	40.4%								
SALEM 2	1115	82	81.3%	7.5%	32.7%	51.4%								
MCGUIRE 1	1180	82	41.6%	44.8%	61.9%	65.6%								
SEQUOYAH 2	1148	83	66.5%	63.5%	55.8%									
AVERAGES:														
ALL UNITS [3]	1106		57.4%	51.5%	57.5%	60.3%	62.2%	58.1%	51.0%	64.2%	66.7%	43.6%	58.7%	52.3%
FIRST SIX [3]	1085		56.0%	55.8%	60.7%	64.3%	62.2%	58.1%	51.0%	64.2%	66.7%	43.6%	58.7%	52.3%

ADJUSTMENT FOR DEVIATIONS AT SALEM 1 AND TROJAN

ALL UNITS:												
Salem/Trojan deviation [4]		64.8%										
unit-years [5]		70										
deviation/unit-year		0.9%										
ADJUSTED AVERAGE (all units) [5]	56.5%	50.6%	56.6%	59.4%	61.3%	57.2%	50.1%	63.2%	65.8%	42.7%	57.7%	51.4%
all years	56.5%											
>5 years	56.2%											
FIRST SIX UNITS:												
Salem/Trojan deviation [6]		73.3%										
unit-years [5]		55										
deviation/unit-year		1.3%										
ADJUSTED AVERAGE (first six) [7]	54.7%	54.4%	59.4%	63.0%	60.9%	56.8%	49.7%	62.8%	65.4%	42.2%	57.3%	51.0%
all years	57.4%											
>5 years	55.8%											

NOTES TO TABLE 2:

1. Original reported value.
2. Computed from NRC-reported net output and original DER; Grey Book, January of each year to 1986.
3. Values for year 2 for Trojan and Salem 1 are excluded from averages.
4. 2*51.5% - 16.8% - 21.4%.
5. Excludes Salem 1 and Trojan second years.
6. 2*55.8% - 16.8% - 21.4%.
7. Simple averages minus Salem/Trojan deviation per unit/year.

TABLE 3: PWR CAPACITY FACTOR PROJECTIONS FOR PALO VERDE NUCLEAR GENERATING STATION UNIT 1, FROM REGRESSION RESULTS

	Analysis and Inference					
	With Aging [6]		With CE Effect [7]			
YEAR	Pre-1979 Conds.	Avg. 1979-83 Conds.	Pre-1979 Conds.	Avg. 1979-83 Conds.	Average of four cases	ESRG
	[1]	[2]	[3]	[4]	[5]	[8]
1986	62.94%	55.78%	66.69%	59.66%	61.26%	
1987	55.24%	48.08%	59.45%	52.42%	53.79%	
1988	57.55%	50.39%	61.75%	54.72%	56.11%	
1989	59.86%	52.71%	64.06%	57.03%	58.42%	
1990	62.18%	55.02%	66.37%	59.34%	60.73%	
1991-1997	63.34%	56.18%	67.52%	60.49%	61.88%	61.90%
1998-2025	52.45%	45.29%	67.52%	60.49%	56.44%	

Notes:

Calculated for a 1270 MW unit with a General Electric turbine, and a COD of 1/1/86.

[1],[3] Assumes pre-1979 conditions exist in the projection years; therefore YR79_83 variable is set equal to 0.

[2],[4] Adjusts the projected capacity factor by the coefficient of the YR79_83 variable.

[5] Average of columns [1] through [4].

[6] Uses data from 1973-1985 for all units of more than 300 MW. Includes decrease in capacity factor after 12 years of operation.

[7] Excludes data for Palisades and San Onofre 1. Includes credit for aging effect.

[8] ESRG (1986), Volume II, page I-26. Projections for 1991-95 are averaged and reported on 1991-97 line.

TABLE 4: ANNUAL PWR CAPACITY FACTORS, 1968-85 (%) UNITS 800 MW +

Plant	DER	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
-----	---	----	----	----	----	----	----	----	----	----	----	----	----	----	----
Palisades	821	24.5%	33.5%	1.1%	33.8%	39.5%	70.7%	36.5%	47.7%	33.0%	48.2%	46.5%	52.4%	11.3%	73.7%
Surry 1	823		48.0%	46.0%	54.3%	60.8%	69.7%	65.2%	31.3%	34.2%	33.0%	76.1%	56.7%	46.2%	77.9%
Maine Yankee	825			51.6%	65.1%	85.4%	74.3%	77.4%	65.6%	63.5%	75.3%	65.4%	67.0%	74.2%	77.4%
Surry 2	823			36.5%	70.1%	46.2%	61.8%	74.5%	8.5%	31.0%	71.4%	76.2%	56.7%	72.3%	56.5%
Oconee 1	886			51.5%	68.1%	51.3%	50.8%	65.1%	64.4%	65.7%	38.6%	66.4%	66.2%	79.5%	91.0%
Indian Point 2	873			43.5%	63.9%	29.6%	68.1%	57.1%	62.8%	55.6%	39.9%	58.1%	0.8%	37.8%	87.2%
Zion 1	1050			37.8%	53.4%	51.6%	54.7%	73.6%	60.2%	70.6%	67.3%	51.0%	43.7%	61.9%	52.3%
Oconee 2	886				64.0%	54.3%	49.3%	61.7%	76.9%	49.8%	66.9%	44.3%	66.2%	94.0%	65.2%
TMI 1	819				77.2%	60.3%	76.1%	79.1%							
Zion 2	1050				52.5%	50.3%	68.2%	73.2%	51.8%	57.2%	57.2%	56.1%	67.2%	65.1%	55.6%
Oconee 3	986				58.3%	54.9%	60.7%	70.2%	37.7%	60.2%	72.6%	24.5%	82.2%	62.0%	56.2%
Arkansas 1	850				65.5%	52.1%	68.5%	70.5%	44.6%	50.7%	65.8%	50.0%	43.2%	61.8%	69.7%
Rancho Seco	913					27.5%	73.5%	62.4%	71.4%	55.1%	32.9%	42.1%	35.6%	47.1%	24.2%
Calvert Cliffs 1	845					84.9%	66.0%	63.2%	56.7%	61.1%	82.5%	72.4%	75.2%	84.1%	58.9%
Cook 1	1090					71.1%	50.1%	65.8%	59.3%	67.5%	71.0%	56.1%	55.4%	79.1%	22.2%
Millstone 2	828					62.4%	59.9%	62.0%	60.2%	67.1%	84.0%	69.1%	33.8%	91.1%	48.2%
Trojan	1130						65.6%	16.8%	53.2%	61.2%	64.9%	48.5%	41.2%	47.8%	69.8%
Indian Point 3	873						72.2%	71.4%	62.7%	40.0%	39.7%	18.8%	0.8%	79.0%	61.8%
Beaver Valley 1	852						39.8%	33.2%	23.8%	4.0%	62.5%	36.0%	62.7%	63.6%	79.1%
St. Lucie 1	802						76.1%	71.2%	69.5%	73.8%	70.4%	96.6%	15.2%	60.2%	83.5%
Crystal River 3	825							35.9%	52.1%	46.3%	56.5%	68.0%	52.2%	89.6%	39.4%
Calvert Cliffs 2	845							70.6%	74.2%	86.4%	73.2%	67.6%	82.6%	72.1%	75.3%
Salem 1	1090							47.4%	21.4%	59.4%	64.8%	42.9%	56.3%	22.3%	94.3%
Davis-Besse 1	906							32.9%	39.4%	26.3%	55.0%	40.5%	61.5%	54.1%	24.5%
Farley 1	829							81.5%	24.0%	63.2%	36.0%	71.8%	82.4%	74.2%	80.3%
Cook 2	1100								61.8%	69.3%	66.3%	72.6%	72.8%	55.7%	59.0%
North Anna 1	907								52.7%	70.7%	58.4%	30.2%	66.8%	47.6%	73.0%
Arkansas 2	912										54.1%	47.7%	55.4%	77.7%	58.3%
North Anna 2	907										71.1%	50.9%	73.0%	59.4%	85.3%
Farley 2	829										72.9%	50.9%			

AVERAGES THROUGH:	1975	1977	1979	1981
	====	====	====	====
Cumulative	50.0%	56.2%	56.1%	56.9%
Immature Years (1-4)	50.0%	56.0%	56.0%	56.3%
Mature Years (5+)		60.0%	56.2%	57.2%

TABLE 5: PNM ESTIMATE OF PRESENT VALUE EFFECTS AT VARIOUS AVAILABILITIES ($ MILLION)

	Base Case			
1. Equivalent Availability	74%	65%	55%	45%
2. Ratepayers Outcomes:				
a. AFUDC Revenue Requirements	$311.32	$338.34	$361.10	$374.76
Change From Base Case		$27.02	$49.78	$63.44
b. System Production Costs	$2,617.7	$2,670.7	$2,733.5	$2,816.3
Change From Base Case		$52.90	$115.72	$198.53
c. Total Ratepayer Costs	$2,929.1	$3,009.0	$3,094.6	$3,191.0
Change From Base Case		$79.93	$165.50	$261.97
Change as % of Base Case Total		2.73%	5.65%	8.94%
Change as % of Base Case AFUDC		25.67%	53.16%	84.15%
3. Shareholder Costs	$37.64	$47.30	$65.74	$92.84
Change From Base Case		$9.67	$28.10	$55.20
Change as % of Base Case		25.68%	74.66%	146.67%
4. Total Cost Increase		$89.59	$193.60	$317.18
Change as % of Base Case		3.02%	6.53%	10.69%
5. Shareholder Cost Increase as % of Total Cost Increase		10.79%	14.51%	17.41%

Source: Exhibit DAB-1, pages 12-14.

Notes: [1] All present values at 11.811%.

Table 6: SHAREHOLDER COST AS PERCENTAGE OF TOTAL COSTS DUE TO POOR PERFORMANCE

CHANGES IN COSTS FROM BASE CASE ($ MILLION)

		|--to 65% (9% decrease)--|			|--to 55% (19% decrease)-|			|-to 45% (29% decrease)-|		
Year ----	Units in Service --[1]--	Total Cost --[2]--	Share-holder Cost --[3]--	Share-holder Cost as % of Total --[4]--	Total Cost --[2]--	Share-holder Cost --[3]--	Share-holder Cost as % of Total --[4]--	Total Cost --[2]--	Share-holder Cost --[3]--	Share-holder Cost as % of Total --[4]--
1986	1.3	$4.0	$0.7	16.4%	$8.4	$1.4	16.8%	$12.9	$2.2	17.1%
1987	2.3	$7.1	$1.2	16.4%	$14.9	$2.5	17.0%	$22.8	$4.4	19.3%
1988	3	$9.2	$1.4	14.8%	$19.5	$4.2	21.7%	$29.7	$8.6	28.9%
1989	3	$9.2	$1.1	12.5%	$19.5	$2.9	14.9%	$29.7	$6.2	20.9%
1990	3	$9.2	$2.8	30.5%	$19.5	$6.3	32.2%	$29.7	$9.8	32.9%
1991	3	$9.2	$2.7	29.7%	$19.5	$6.7	34.6%	$29.7	$10.7	35.9%
1992	3	$9.2	$2.1	23.2%	$19.5	$6.5	33.4%	$29.7	$10.8	36.5%
1993	3	$9.2	$1.2	13.4%	$19.5	$5.5	28.0%	$29.7	$10.3	34.5%
1994	3	$9.2	$1.3	13.9%	$19.5	$4.9	25.4%	$29.7	$11.7	39.3%
1995	3	$9.2	$1.2	12.8%	$19.5	$3.0	15.4%	$29.7	$11.9	39.9%

Notes: [1] Assumes that Unit 2 enters service in 10/86, Unit 3 in 10/86.

[2] [1] x 8760 hours x 130 MW x availability decrease x 3 cents/kwh.

[3] From Exhibit DAB-1, pages 12-14.

TABLE 7: PNM EAF PROJECTIONS AS INTERVALS, EAF BETWEEN REFUELINGS, AND LENGTH OF REFUELINGS

	UNIT 1	UNIT 2	UNIT 3
1. EAF from COD to first refueling	68.4%	68.4%	68.4%
2. Months from COD to end of first refueling	12	16	16
3. Weeks for first refueling outage	7	7	7
4. EAF from end of first refueling to end of second refueling	78.5%	78.5%	78.5%
5. Months from end of first refueling to end of second refueling	12	12	12
6. Weeks for second refueling outage	7	7	7
7. Mature EAF between refueling	85.4%	85.4%	85.4%
8. Mature months between refueling	12	12	12

Source: Exhibit JRH-2, Case # 1916.