BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF NEW MEXICO FOR APPROVAL OF THE ABANDONMENT OF THE FOUR CORNERS POWER PLANT AND ISSUANCE OF A SECURITIZED FINANCING ORDER	)	**Case No. 21-00017-UT**
PUBLIC SERVICE COMPANY OF NEW MEXICO,	)	
Applicant	)	

SUPPLEMENTAL TESTIMONY

OF

FRANK C. GRAVES

March 15, 2021

NMPRC CASE NO. 21-00017-UT
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I. INTRODUCTION

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

A. My name is Frank Graves. I am a Principal at The Brattle Group, located in our headquarters office at One Beacon Street, Suite 2600, Boston MA, 02108.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. For most of my professional career spanning over 30 years as a consultant, I have worked in regulatory and financial economics, especially regarding long-range planning for electric and gas utilities, and in litigation matters related to securities litigation and risk management. My education includes an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975.

In regard to the utility resource planning and cost recovery risks, which are central matters in this case, I have extensive experience in system planning with capacity optimization and production costing models, load forecasting, fuel procurement and risk management, and pollution control compliance. Recently, I have focused on evaluating pathways to deep decarbonization of our energy sector as well as the benefits and impacts of distributed energy resources. In regard to customer and financial impacts, I have developed or used many utility financial projections for revenue requirements and rate projections, and I have evaluated financial risk and cost of capital in a wide variety of settings for energy infrastructure and utility investments.

I have given expert testimony on financial and regulatory issues before the Federal Energy Regulatory Commission ("FERC"), many state regulatory commissions (including New Mexico), and state and federal courts. My background and qualifications are described in greater detail in the résumé attached as PNM Exhibit FG-1 (3-15-21 Supplemental).

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN NEW MEXICO PUBLIC REGULATION COMMISSION PROCEEDINGS?

A. Yes, I provided direct and rebuttal testimony on behalf of PNM in 2012/13 in Case No. 12-000317-UT in regard to incentive compensation for energy efficiency programs. I also testified in Case No. 19-00018-UT related to the prudency of retiring San Juan Generating Station.

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I was retained by PNM to independently evaluate the prudence of its past investments at Four Corners Power Plant ("FCPP"), specifically about PNM's participation in the decision by joint owners of FCPP in late 2013 to extend the FCPP coal supply agreement and the joint ownership agreement instead of abandoning its share of FCPP by the end of 2016. This supplemental testimony is filed as ordered by the Commission in Case No. 21-00017-UT.[1] My testimony presents an affirmative case for the prudence of PNM's decisions regarding FCPP, but is not intended to provide an opinion on whether the Commission need make a finding or determination on prudence in order to approve PNM's request for abandonment and securitized financing of FCPP. I am aware that the context for this issue includes the requests from third parties, especially Sierra Club and New Energy Economy ("NEE"), for a review of why PNM did not withdraw from its share of the plant earlier, with some specific examples having been raised about investments or decision points they question. I address those misgivings herein. I also opine on the appropriateness of recovering PNM's undepreciated past investments at FCPP from its customers.

Q. PLEASE SUMMARIZE THE FINDINGS FROM YOUR ANALYSES.

A. I find that the relevant history to evaluate is the set of decisions made by PNM around 2012-13 to extend the Coal Supply Agreement ("CSA") and the Joint Operating Agreement ("JOA") as well as to support installing Selective Catalytic Reduction ("SCR") equipment at FCPP. This was the time period in which PNM had to make decisions on whether to continue to use FCPP or commit to an alternative resource. The analyses PNM performed at that time found material benefits (at least $33 million in present value customer savings) from its decision

[1] Order on Sufficiency of PNM's Application and Scope of Issues in Proceeding, *In the Matter of the Application of Public Service Company of New Mexico for Approval of the Abandonment of the Four Corners Power Plant and Issuance of a Securitized Financing Order*, Case No. 21-00017-UT (February 26, 2021).

to remain a participant in FCPP. While some intervenors in previous related proceedings have criticized PNM's decision-making process as incomplete, I find that when those criticisms and related adjustments are accommodated, a reasonable decision-maker would have continued with the FCPP option. That is, had PNM performed an updated analysis just prior to its December 2013 decision to extend its participation at FCPP, it would have continued to find future cost savings from retaining FCPP under a range of reasonable scenarios – including additional scenarios it did not consider at the time. In fact, my analysis indicates that updating the key assumptions in PNM's May 2012 study to reflect changes in long-term outlook by late 2013 would have resulted in a larger present value of $46 million of estimated savings for PNM's customers from retaining FCPP.[2] Among the additional factors that I consider include the ongoing capital expenditures ("capex") for both FCPP and the new combined cycle gas plant ("gas CC"), which was the other viable resource alternative, exit costs for abandoning FCPP in 2016, and changes in gas, coal, and CO_2 price outlooks between May 2012 and late 2013.

Considering some reasonable sensitivities in making such adjustments, I estimate the possible savings could have been as high as $180 million and perhaps as low as negative $34 million, depending on what future circumstances emerged over the remaining life of the plant. Since this range of estimated savings as of late 2013 from retaining FCPP is anchored on a $46 million benefit (or more) with potential

[2] Savings here, and throughout my testimony, refers to the difference in present value of revenue requirements, or PVRR, between two different resource plans. PVRR is a measure of what the customers will pay for the use of the system assets, year after year, into the future.

upside of substantial additional savings and a possibility of more modest negative savings under some scenarios, I conclude that PNM's decision in late 2013 to extend its participation beyond 2016 was prudent.

I also note that the analyses and decisions in question are complex in nature. Their outcomes depend on a number of variables that change more frequently in the near-term outlook than in the long-term and are difficult to forecast.[3] As a result, not every change would prompt a complete re-evaluation of the results.

Further, it is important to understand that any utility resource is chosen and sustained over a long life while constantly facing future uncertainty. A prudently chosen asset is expected to be mostly beneficial, but it will also always include some chance that it may not turn out so at some point over its remaining life. Such outcomes, though contrary to initial expectations, may not even be unfortunate. It is very possible for a resource to be a good idea when built and when maintained for many years, then something else to come along which is an even better idea. Or, the resource may no longer perform as hoped even if it previously provided many years of benefits that accrued to the customers under cost of service ratemaking. FCPP appears to be such a resource: not imprudent, yet now better

[3] That is, there is a tendency for short run volatility to be greater than long run, because there are tendencies for market conditions to drift back towards "normal" conditions if/after they become disequilibrated by short run events and economic surprises.

replaced. Thus, it is not appropriate for penalization because of changing circumstances.

Beyond these economic calculations, there are sound regulatory principles of fairness, efficiency, and desirable incentives served by allowing full cost recovery of the undepreciated prudent investment costs in the plant, even if it is not used for its projected full depreciation life (which often differs from the operating or operable life of a facility).

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I first review the sources and amounts of net investment remaining in the plant. I then turn to a detailed unpacking of the system planning analyses done in early 2012, when PNM began comparing extending the coal supply and contract life of its ownership in FCPP to swapping the plant out for a new gas CC. This analysis found benefits to keeping the plant but has been criticized by intervenors. Next, I review how market conditions changed between those findings and PNM's agreement to extend the CSA and JOA at the end of 2013. I show that with these considerations, there was still an expected benefit to continuing with the plant, albeit subject to the uncertainty that is always present in utility resource planning. Next, I address other criticisms of FCPP from intervenors in recent past proceedings, including concerns about impacts of load forecast changes, costs of replacement gas CC plant, and the availability factor of the plant. I also explain how the other co-owners of the plant were evaluating their shares in the plant during this time and why the decisions of some parties to reduce their shares does not suggest PNM should have done the same. In addition, I comment on the deficiencies of NEE's claim in the 2016 rate case that exiting FCPP in 2017 would have produced significant savings. I close with a discussion of regulatory principles for why the history of decisions behind the expected use of the plant justifies full cost recovery of the sunk costs of the plant.

II. REMAINING UNDEPRECIATED INVESTMENT COSTS AT FCPP

Q. PLEASE SUMMARIZE PNM'S RECENT APPLICATION TO EXIT FCPP BY 2024.

A. The Company has negotiated an agreement for early exit from FCPP by transferring its ownership to the Navajo Transitional Energy Corporation ("NTEC"), a co-tenant of the plant. Under the agreement, NTEC would also assume on-going fuel, operational and capital costs. In exchange, PNM would pay NTEC $75 million for a portion of its previous future cost obligations under the CSA, which will be borne at shareholders' expense.[4]

According to PNM witness Phillips, PNM's early exit coupled with deployment of more sustainable resources will lead to substantial customer net benefits compared to retaining FCPP, with savings ranging from $30 to $300 million on a present

[4] Direct Testimony of Nicholas L. Phillips, Case No. 21-00017-UT, page 6 (January 8, 2021).

value basis.[5] The median expected savings would be about $142 million. Further, these analyses show that the proposed early exit from FCPP would provide savings to PNM customers under virtually *all* potential future scenarios that PNM analyzed.

Q. PLEASE DESCRIBE PNM'S PARTICIPATION AT FCPP.

A. PNM currently owns 13 percent (or about 200 MW) of FCPP units 4 and 5, which were built in 1969/1970. Arizona Public Service Company ("APS") operates the units with a current ownership share of 63 percent, and the other owners are Salt River Project Agricultural Improvement and Power District ("SRP"), NTEC, and Tucson Electric Power ("TEP").[6] The ownership rights and obligations and the operation of the plant are governed under three contracts, which I refer in my testimony as the Joint Ownership Agreement (JOA).[7] The plant is served by a dedicated coal mine owned and operated by NTEC, under a coal supply agreement ("CSA") between NTEC and the joint owners of FCPP.

Q. COULD YOU SUMMARIZE THE HISTORY OF PNM'S PARTICIPATION UNDER THE JOA AND THE CSA?

A. The current agreements comprising the JOA (including the lease with the Navajo Nation) were initially executed in late 1960s among the current owners and the previous owners Southern California Edison ("SCE") and El Paso Electric ("EPE").

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[5] Direct Testimony of Nicholas L. Phillips, Case No. 21-00017-UT, page 3 (January 8, 2021).
[6] S&P Global Market Intelligence, accessed February 24, 2021.
[7] These contracts are the Co-Tenancy Agreement, Operating Agreement, and Navajo Nation Lease Agreement.

SCE and EPE decided in the early 2010s to exit their FCPP participation and ultimately sold their shares to APS or its affiliate. These two transactions were eventually carried out in December 2013 and July 2016, respectively.[8] The terms of the current CSA were negotiated over the course of 2012 and 2013, and the CSA was executed in December 2013 and amended in July 2018 to supply coal to FCPP until July 2031.[9] Prior to the extension of the CSA in 2013, the terms of the CSA and the JOA were set to expire in July of 2016. In March 2015, the current owners, including PNM, extended the Co-Tenancy agreement through July 2041.[10]

Q. WHAT ARE THE MAJOR COMPONENTS OF PNM'S SHARE OF UNDEPRECIATED PAST INVESTMENTS AT FCPP?

A. As of the end of 2020, PNM's total net book value of the past investments at FCPP was $234 million. As shown in PNM Figure FG-1 below, about 77 percent (or $181 million) of that amount comes from investments in or after 2013, including $87 million of undepreciated investment for the SCR emissions control equipment

8 Amended and Restated Four Corners 2013 Coal Supply Agreement, page 1. Certification of Stipulation, *In the Matter of El Paso Electric Company's Application for Approval of Abandonment and Sale of Its Seven Percent Four Corners Units 4 and 5 Ownership Interest*, Case No. 15-00109-UT, pages 13-14 (February 2, 2016).

9 Amended and Restated Four Corners 2016 Coal Supply Agreement, pages 3-4.

10 Arizona Corporation Commission Decision No. 73130, *In the Matter of the Application of Arizona Public Service Company for Authorization for the Purchase of Generating Assets from Southern California Edison and for an Account Order*, Docket No. E-01345A-10-0474, page 4 and 43 (April 24, 2012). Certification of Stipulation, *In the Matter of El Paso Electric Company's Application for Approval of Abandonment and Sale of Its Seven Percent Four Corners Units 4 and 5 Ownership Interest*, Case No. 15-00109-UT, pages 13-14 (February 2, 2016). *See also* Certification of Stipulation, *In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 533*, Case No. 16-00276-UT, page 29 (October 31, 2017).

installed after 2017.[11] As I explain further below, in several economic studies conducted between 2011 and 2013, PNM evaluated the continued participation at FCPP beyond 2016 (including the cost obligations associated with the SCR equipment) against the alternative of an exit from FCPP participation by the end of 2016. In all of these studies, PNM concluded that extending the FCPP participation beyond 2016 would have lower future costs for its customers compared to its abandonment and replacement after 2016.

The supplemental testimonies of PNM witnesses Fallgren and Baker provide further detail on PNM's FCPP capital investments over time.

PNM Figure FG-1: Net Book Value Composition of FCPP as of 2020[12]

	Pre-2013	2013-2020	Total	Post-2013 as % of Total
	($ millions)	*($ millions)*	*($ millions)*	*(%)*
	[1]	[2]	[3]	[4]
SCR	-	87	87	**100%**
Other	53	94	148	**64%**
Total	**53**	**181**	**234**	**77%**

Source and Notes:
[1]: All additions to NBV from 1968 to 2013.
[2]: All additions to NBV from 2013 to 2020.
[3]: [1] + [2].
[4]: [2] / [3].

11 Per requirements of a Federal Implementation Plan issued by the Environmental Protection Agency (EPA), the notice to EPA was provided in December 2013. The notice includes the selection of SCRs to be installed by the owners on units 4 and 5 when units 1-3 would be retired. *See also* Supplemental Testimony of Thomas G. Fallgren, Case No. 21-00017-UT (March 15, 2021).

12 Utilizing data provided by PNM for the Net Book Value (NBV) as of December 2020. The NBV for SCR investments was obtained for the capital projects between 2017-2018 related to the installation of SCR in Units 4 and 5, by filtering on the cost item descriptions having the keywords "SCR," "Selective," "Catalytic" and "Reduction."

Q. WHAT ASPECTS OF THIS HISTORY HAVE BEEN CRITICIZED BY INTERVENORS AND HEARING EXAMINERS IN PREVIOUS PROCEEDINGS?

A. Criticisms related to the prudency of the SCR investment and ultimately PNM's decision to extend its FCPP participation can be grouped into four categories:

1. PNM's May 2012 study omitted FCPP's future ongoing capital expenditures.[13] Inclusion of this item would have shown that it was more cost-effective to exit FCPP than to continue.
2. PNM's May 2012 analysis was of little temporal relevance to the more-than-a-year-later decision to extend the CSA. PNM should have considered changes in the energy market fundamentals (*e.g.*, changes in natural gas prices and load growth, among other factors) before deciding in December 2013 to continue its FCPP participation.[14]
3. Decisions of SCE and EPE to exit FCPP should have prompted PNM to re-examine its decision in 2013 to extend its participation at FCPP.[15]
4. PNM should have updated its analysis of savings from retaining FCPP before the JOA was executed in 2015.[16]

As I demonstrate below, even if PNM had performed an updated analysis just before its decision in late 2013 to continue its FCPP participation, the Company would have found cost savings from retaining the plant under a number of

[13] Certification of Stipulation, Case No. 16-00276-UT, page 21 (October 31, 2017).
[14] *Ibid.*, page 22.
[15] *Ibid.,* page 41.
[16] *Ibid.,* page 47.

scenarios. Two of the other co-owners, APS and TEP, conducted similar analyses into the economics of keeping FCPP and arrived at similar conclusions. Although SCE and EPE eventually reached different conclusions, each co-owner's situation is unique, given the variances in their system characteristics and circumstances, so it is not surprising that different co-owners could disagree on the net benefits of keeping FCPP in their systems. But this at least shows it was not a black and white issue based solely on the economics of the plant by itself.

Further, these resource valuation analyses and decisions are very complex and dependent on a number of variables that change more frequently for the near-term outlook than for the long-term. In addition, such analyses need to be made many years in advance in order to be vetted to obtain necessary regulatory approvals and to plan for new replacement resources. As a result, decisions such as whether or not to keep FCPP need to be made many months, if not years, in advance of the execution, and they are not amenable to being reconsidered frequently. Nonetheless, I show below that further reconsiderations by PNM just before the contract extensions would have supported their earlier conclusions.

III. PNM'S PAST ECONOMIC ANALYSES OF COST SAVINGS FROM RETAINING FCPP

Q. PLEASE SUMMARIZE THE ECONOMIC ANALYSES BY PNM OVER THE LAST 10 YEARS AND THE RESULTS THAT SHOWED ESTIMATED COST SAVINGS FROM RETAINING FCPP.

A. Over the last 10 years, PNM has conducted a number of analyses to evaluate the cost savings to ratepayers from retaining FCPP. Until recently, the Company has found consistently that retaining FCPP was less expensive relative to options to orderly retire or exit the plant. PNM Figure FG-2 below provides a summary of the studies over the years and their findings.

PNM Figure FG-2: Summary of Findings Related to Retiring versus Retaining FCPP[17]

Study	FCPP Exit Year	Findings
2011 IRP	2017	Most Cost Effective Portfolio indicated \$179-\$196 MM savings from retaining FCPP compared to exiting in 2016
May-12	2017	\$33-\$44 MM savings from retaining FCPP compared to exiting in 2016
January-14	2017	\$132 MM savings from retaining FCPP compared to exiting in 2017
2017 IRP	2031	\$48 MM savings from exiting FCPP in 2031 in Mid Load, Mid Gas, Mid CO_2 Price scenario
2021 study	2024	\$30-\$300MM savings from FCPP exit by the end of 2024

In its 2011 Integrated Resource Plan ("IRP"), PNM examined the benefits of retaining FCPP through 2030 compared to retiring the plant in 2017 (the year after the then-CSA would expire), assuming that emissions control equipment such as SCR would have already been installed.[18] The Company found that the early retirement option would result in higher lifecycle costs (20-year present value revenue requirements, or PVRR) compared to retaining the plant.[19]

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17 In the January 2014 Study, PNM estimated the savings by comparing the estimated costs from a December 2013 study that assumed retaining FCPP against a January 2014 study that assumed exiting FCPP participation.

18 PNM's 2011 IRP assumes that all scenarios, including the coal retirement scenarios, would incur the costs of emissions control equipment, so the \$179-\$196 million in savings does not need to be adjusted for the cost of SCRs. See PNM 2011 IRP, page 136.

19 For example, retaining FCPP would lead \$179 million in savings in the case of high load growth, medium gas prices, and high CO_2 price. Savings increased to \$196 million for medium load growth, medium gas prices, and high CO_2 price. See PNM 2011 IRP, pages 128-129.

Q. BEFORE EXPLAINING THESE AND ADDITIONAL ANALYSES, PLEASE CLARIFY WHY YOU ARE USING PVRR AS A METRIC OF BENEFIT, AND HOW IT RELATES TO WHETHER SOME OF THE INVESTMENTS IN THE PLANT WERE IMPRUDENT.

A. PVRR means the Present Value of Revenue Requirements. Revenue requirements are the sum of the costs of operating the system plus paying taxes and earning the allowed returns (for debt and equity) on and of the net (depreciated) investment costs in the underlying assets. It is the same thing as the costs used as the basis for setting rates. Thus, it is the measure of what customers will pay for the use of the system assets, year by year, into the future if a particular slate of assets is chosen in the resource plan.

PNM's resource planning is conducted on the basis of finding the mix of resources that will produce the lowest PVRR over the coming 20 years, per expected conditions at the time the decisions have to be made. Alternative resource plans are determined via modeling using scenario and sensitivity analysis and these are compared to find the plan most likely to have lowest cost that durably and reasonably meets other goals such as acceptable reliability and attainment of environmental goals across foreseeable conditions.

This approach assures PNM is pursuing the assets most likely to minimize long-term customer costs – but of course there is no guarantee that the expected conditions will materialize. This uncertainty is mediated in two ways. First, PNM has to present and explain its recommended choices in proceedings such as its integrated resource planning processes and resource acquisition filings. Other parties' views of the future get weighed in that process. Second, risk analyses are conducted in the planning evaluations, asking what would be the relative ranking (or comparative PVRR) of portfolios if different conditions should ensue than the perceived most likely conditions.

In particular, many uncontrollable and external factors such as future natural gas prices, technology prices, and load growth have to be forecasted and alternatives considered. The strategy that is best under the expected conditions and is fairly robust as the preferred alternative under most other conditions is chosen – but even with that there is no guarantee. In this regard, it is somewhat like investing in stocks – they mostly appreciate at a rate higher than the less risky rate of interest on bonds, but sometimes they lose value. There is no way to find stocks that "only go up." Similarly, there are no utility assets to be found that always save money for customers no matter what conditions evolve – so they should not be criticized after-the-fact if conditions move against them, provided they were chosen with reasonable recognition of that possibility.

Thus, PVRR is a very appropriate and indeed a widely used measure for identifying the most attractive portfolio of resources to pursue. A finding of some scenarios with a negative net PVRR (*i.e.* identifying future conditions in which it might cost more to keep the asset compared to some other alternative on a present value basis) does not mean that some portion of the asset or its costs are a bad idea, nor does a particular scenario result by itself even inform whether the planning decision was prudent. It would be imprudent *not* to consider such risks, as well as impossible to find some available assets with no chance of not always being the best choice. What is important for prudence is that the range of scenarios considered was centered on an expectation of net benefits (savings compared to other alternatives). Below, I examine PNM's studies and present supplemental analyses that show retaining FCPP as of the 2012/2013 period when a decision was necessary comported with this standard.

Q. PLEASE EXPLAIN MORE ABOUT THE SEQUENCE OF DECISIONS THAT LED TO THE CURRENT COMMITMENTS AND COSTS AT FCPP SINCE 2012.

A. During the negotiation of the new CSA and revised operating agreement for FCPP, PNM analyzed in May 2012 the benefits of the option to retain FCPP with SCR relative to the option to abandon the plant in 2016 and replace it with a new combined cycle gas plant. This analysis also took into account the fact that coal prices would change under the new CSA. Results show that retaining FCPP ownership with SCR was \$33-\$44 million less expensive (in 2012 PVRR)[20] than replacing the FCPP capacity with a CC gas plant. However, as intervenors such as NEE in the 2016 rate case pointed out, ongoing capital expenditures for maintaining FCPP were not included in this analysis. I examine below how the overall results

[20] The range PNM found depended on alternative possible coal prices. Herein, I examine that issue separately so have anchored my calculations on the lower, more conservative \$33 million expected savings.

would change when accounting for the FCPP ongoing capital expenditure, as well as market changes that took place between the May 2012 study and late 2013 when PNM decided to extend the CSA and the JOA contracts.

In January 2014, PNM re-evaluated the benefits of retaining FCPP using inputs from the 2014 IRP and confirmed that keeping FCPP would be $132 million less expensive than exiting it.[21]

Analysis in PNM's 2017 IRP shows potential long-term cost savings should PNM abandon FCPP in 2031, when the extended CSA would expire.[22] For example, under "mid" gas prices and CO_2 prices and mid load, retiring FCPP at the end of 2031 would lead to a $48 million lower cost in rates to customers on a present value basis relative to keeping the plant beyond 2031. PNM witness Fallgren's testimony provides more information on the reasonableness and necessity of investments in FCPP planned and made from 2016 to the present.

Since 2012, the long-term industry outlooks for natural gas prices, load growth and costs of renewable generation have mostly been decreasing. In particular, renewables have become increasingly economical relative to older fossil-fueled plants just in the last few years. Together, these three drivers have eventually

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[21] The 2014 analysis was discounted in the 2016 rate case hearing (Case No. 16-00276-UT), where some of the intervenor criticisms of the 2012 analysis were raised. I will use the May 2012 study as the starting point for my analysis and only rely on inputs from the January 2014 study when appropriate.

[22] PNM 2017 IRP, Figures 40 and 41, page 106.

eliminated the previously expected cost advantages of retaining FCPP. These cumulatively strong but unexpected shifts in industry long-term outlook for key market fundamentals over the last ten years have changed the economics of coal plants industry-wide. Thus, it is not surprising that PNM is now finding in its most recent study that an early exit from FCPP would save future costs for its customers – even though PNM was estimating in its studies about eight years ago that retaining FCPP would have saved costs.

Q. HOW DID THE TIMING OF PNM'S PAST STUDIES ON RETAINING FCPP RELATE TO THE INVESTMENT AND PARTICIPATION DECISIONS BY PNM AND OTHER FCPP OWNERS DURING THAT TIMEFRAME?

A. During the 2012/2013 timeframe, PNM and other FCPP co-owners made three key decisions: selecting a pathway to comply with the EPA's Regional Haze regulation (through retiring FCPP Units 1-3 and installing SCR at the remaining Units 4-5), extending the Coal Supply Agreement, and extending the joint ownership agreement. These decisions are summarized in PNM Figure FG-3 below.

PNM Figure FG-3: Timeline of Key Developments

Date	Key Development
2005	EPA issued final amendments to its Regional Haze Rule
August-12	EPA's Final BART Determination for FCPP
October-13	PNM Board of Director reviewed the Amended and Restated 2010 FCPP Coal Supply Agreement, the 2016 Coal Supply Agreement, and Amendment No. 8 to the Four Corners Co-Tenancy Agreement
December-13	FCPP owners informed the EPA of the planned closing of FCPP Units 1-3, and SCR installation at Units 4-5; the CSA and related amendments were executed
March-15	FCPP owners completed the execution of the Co-Tenancy Agreement (Amendment No. 9)

In 2005, the EPA issued final amendments to its Regional Haze Rule that required power plants to use Best Available Retrofit Technology emission controls, also known as "BART."[23] According to the EPA's final BART determination in August 2012, FCPP owners could install post-emission control technology on all five units by 2017 to comply with the Regional Haze Rule. Alternatively, FCPP Units 1-3 could be closed and emission control technology could be installed at the Units 4-5. FCPP owners in December 2013 informed the EPA that they had selected the second alternative: FCPP Units 1-3 would shut down by the beginning of 2014, and post-combustion NO_x control equipment would be installed at FCPP Units 4 and 5 by July 31, 2018.

[23] Supplemental Testimony of Thomas Fallgren, Case No. 21-00017-UT (March 15, 2021). *See also* EPA, "Source Specific Federal Implementation Plan for Implementing Best Available Retrofit Technology for Four Corners Power Plant; Navajo Nation; Extension of Notification Deadline. https://www.govinfo.gov/content/pkg/FR-2013-07-11/pdf/2013-16078.pdf.

Around the same time, PNM Board of Directors reviewed and approved the execution of three FCPP agreements.[24] First, the Amended and Restated Four Corners Coal Supply Agreement would accommodate the pending closure of FCPP Units 1-3 and NTEC's purchase of the mine. Second, the Amended and Restated Coal Supply Agreement would be replaced by the 2016 Coal Supply Agreement with new prices and volumes. Third, an amendment to the Co-Tenancy Agreement would extend the term of the agreement from July 2016 to July 2041, when the FCPP lease with the Navajo Nation would also expire. PNM and the current FCPP co-owners ultimately deferred the actual execution of the agreed-upon amendments to the Co-Tenancy Agreement to March 2015, concurrent with the amendments that reflected the agreement to transfer EPE's interests to an affiliate of APS.

IV. EVALUATION OF CRITICISMS OF PNM'S MAY 2012 ANALYSIS

Q. IN THE 2016 RATE CASE, WHAT WERE THE INTERVENORS' MAIN CRITICISMS OF PNM'S MAY 2012 STUDY IN EVALUATING THE COST SAVINGS FROM RETAINING FCPP?

A. Criticisms of PNM's May 2012 study from intervenors mainly revolve around the omission of FCPP ongoing capital expenditures. For example, Mr. Fetter on behalf of NEE indicated that PNM's estimate of $33-44 million in PVRR savings from retaining FCPP was overstated due to omitting certain capital costs of maintaining

[24] Rebuttal Testimony in Support of Revised Stipulation of Chris M. Olson, Case No. 16-00276-UT, PNM Exhibit CMO Rebuttal-2 (October 31, 2017).

and operating FCPP.[25] As I explain further below, this criticism ultimately falls short because it was incomplete and one-sided. A thorough adjustment would have to account for other cost and savings items that were omitted as well, affecting not only FCPP but its alternatives.

Q. PLEASE EXPLAIN FURTHER THE CRITICISM OF OMITTED FCPP COSTS IN PNM'S MAY 2012 STUDY.

A. While the May 2012 study included operating and maintenance costs for FCPP through year 2033, it did not consider the costs of anticipated future capital improvements that would be required to sustain the plant's life till then. This omission consequently inflated the savings associated with retaining FCPP.

Q. WHAT WOULD BE THE IMPACT OF ACCOUNTING FOR THE FUTURE FCPP CAPITAL EXPENDITURES ON THE ESTIMATED COST SAVINGS FROM RETAINING FCPP?

A. The present value of FCPP's revenue requirements from the ongoing capital costs in 2014 through 2033 for both units would be \$88.5 million (2014 Present Value, or about \$75 million in 2012 Present Value). This amount, noted as missing from the original PNM analysis, would in isolation more than offset the prior estimate of net savings of \$33 million (2012 PV).[26] Hence accounting only for FCPP's ongoing capital costs would reverse the findings that retaining FCPP would lead to a positive

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[25] Direct Testimony of Steven M. Fetter, Case No. 16-00276-UT (October 31, 2017).
[26] Unless otherwise noted, reported savings values in this section are in 2012 Present Value terms.

net savings, at least superficially. This finding was the basis for Mr. Fetter's criticism. However, simply adding these ongoing FCPP costs does not complete the analysis.

Q. WERE THERE OTHER COST OR SAVINGS ITEMS THAT ALSO NEED TO BE CONSIDERED IN THE MAY 2012 ANALYSIS?

A. Yes. While the May 2012 study omitted FCPP's ongoing capital expenditures, it also did not account for the ongoing capital expenditures of the new replacement gas-fired combined cycle plant. Including the ongoing capex of the new gas CC plant would likewise increase the gas CC plant cost, and thus would add to the net savings related to retaining FCPP, making the option to keep FCPP more financially attractive. To estimate what the ongoing capital investment amount might be for the new gas CC plant, I relied on proxy information from PNM's Afton gas CC plant. In terms of required ongoing capital expenses, Afton is a good proxy for an alternative new gas CC plant because of their similar capacities (230 MW for Afton versus 252 MW for the new gas CC). Afton was also relatively new in 2012, having come online in 2007.

In addition, regardless of whether PNM might have decided in May 2012 to exit FCPP, the Company would still need to pay for the plant's ongoing capital expenditures in the years leading up to the 2016 exit. In essence, the omitted capital expenditures over these years were not avoidable in either plant scenario, so the 2014-2016 portion of FCPP's ongoing capital costs should not be included in the comparative analysis with the gas CC plant and should be credited back to the FCPP net savings.

Q. WHAT WOULD BE THE IMPACT OF ACCOUNTING FOR THESE TWO COST FACTORS?

A. Between 2017 and 2033, Afton was expected to incur $24 million in 2012 PVRR from recovery of its ongoing capital expenditures. I therefore assume that this same amount of ongoing capital expenditures would have to be paid for a new gas CC plant and should be added as a cost to that alternative.

For FCPP, the unavoidable present value of its ongoing capital investments during 2014-2016 would amount to $23 million, which should be deducted from the costs under the FCPP retention (or alternatively added to the cost of the gas CC alternative).

Together, these two effects would increase the 2012 present value savings of retaining FCPP by $47 million.

Q. WERE THERE ANY OTHER CONSERVATIVE ASSUMPTIONS IN PNM'S ESTIMATE OF COST SAVINGS FROM RETAINING FCPP IN ITS MAY 2012 STUDY?

A. Yes. PNM's May 2012 study did not consider that the Company would have some residual cost obligations in FCPP had it exited in 2016. However, PNM's exit in

2016 would have required the approvals of the remaining owners of the plant under the ownership agreements in effect. There was no expectation or guarantee that one or more of the joint owners would have agreed to purchase PNM's share of FCPP and assume PNM's ongoing obligations under the ownership agreements. Thus, there would be additional ongoing costs associated with its ownership interests even if PNM exited in 2016.

In fact, PNM explored the possibility of such a sale of FCPP prior to 2011, but determined that it was not feasible.[27] Even if PNM were to have been successful in finding a buyer of its share at the time, the Company would have been required to account for the value of the future cost obligations caused by PNM's past usage that a new buyer would assume. In particular, based on my review of EPE's experience in transfer of its share in FCPP to the APS affiliate in 2015, such cost obligations would include accelerated plant decommissioning costs as well as other costs,[28] subject to negotiation.

[27] Rebuttal Testimony in Support of Revised Stipulation of Patrick J. O'Connell, Case No. 16-00276-UT, page 10 (July 21, 2017). EPE also had difficulty in finding a potential buyer prior to APS agreeing to purchase EPE's share of FCPP. See Certification of Stipulation, *In the Matter of El Paso Electric Company's Application for Approval of Abandonment and Sale of Its Seven Percent Four Corners Units 4 and 5 Ownership Interest*, Case No. 15-00190-UT, page 12 (April 22, 2016).

[28] In addition, PNM and its customers would have been exposed to potentially higher mine reclamation costs as a result of the 2016 exit. Such costs (at FCPP and San Juan Generating Station) are subject to a cap on recoverability in rates, which may have been reached regardless of decisions in 2013. PNM shareholders would then bear those responsibilities.

Q. WHAT IS THE IMPACT OF ACCOUNTING FOR PNM'S POST-2016 COST OBLIGATIONS ON PNM'S ESTIMATE OF THE COST SAVINGS FROM RETAINING FCPP?

A. Including such post-2016 cost obligations under the FCPP exit option increases the savings from retaining FCPP, largely because PNM's responsibility for paying a share of those costs would move up in time due to the early abandonment. Pinpointing now precisely what those cost obligations would have been prior to the 2012-2013 time frame is uncertain, due to escalation risks and those costs being subject to negotiations between PNM and the other owners. However, I have approximated such costs for PNM by using the data developed by PNM in its May 2012 study for the additional costs of accelerating plant decommissioning. For a 2038 exit, PNM estimated these costs to be $147 million (nominal, as spent in the future upon retirement) for the whole plant. I adjust this amount for inflation (assuming an inflation factor of 2.5 percent per year) to calculate the corresponding level of spending required if the plant incurred early retirement in 2016 and decommissioned then, which is around $85 million. Applying PNM's 2012 discount rate of 5 percent for decommissioning cash flows, I find that FCPP co-owners would have expected in 2012 to pay $26 million more to retire the plant early, of which PNM's share would be $3 million.[29] Put differently, this approach would lead to a net adjustment of $3 million in favor of retaining FCPP.

[29] The $26 million is the PV in 2012 of $85 million for 2016 cleanup less PV in 2012 of $147 million for 2038 cleanup. PNM share is 13 percent of that amount.

Alternatively, the decommissioning paid by EPE at its spin-off transaction serves as another good data point on what PNM might have had to pay. When APS purchased EPE's share of FCPP in 2015, EPE estimated the decommissioning cost of $96 million.[30] I assume that with a similar early FCPP exit in 2016, PNM would incur proportionately the same costs, amounting to $12 million (in 2016 dollars) for PNM's ownership share. This represents $4 million (in 2012 PV) more than what PNM would have to pay for its share of decommissioning costs in 2038 if retaining its stake in FCPP until 2031.[31] In other words, this is a $4 million penalty for abandoning FCPP early which was not included in its May 2012 analysis.

Q. WHAT IS THE COMBINED IMPACT OF THE ADJUSTMENTS YOU DESCRIBED ABOVE ON PNM'S ESTIMATED SAVINGS IN ITS MAY 2012 STUDY FROM RETAINING FCPP?

A. PNM Figure FG-4 below provides a summary of the adjustments that should be made to the estimated savings in PNM's May 2012 study from retaining FCPP. Starting with the $33 million, the lower bound of the savings estimated in the study, I would:

- Subtract $75 million of FCPP omitted ongoing capex;
- Add $23 million for the FCPP ongoing capex that PNM would have to pay prior to a 2016 exit;

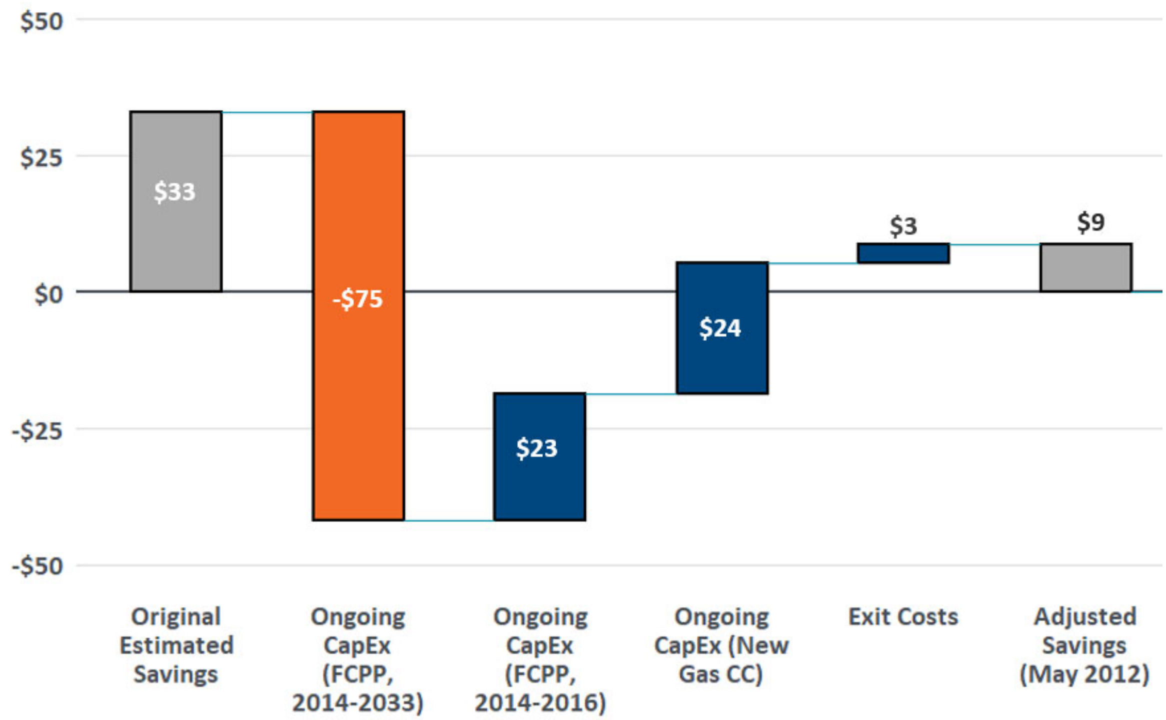
[30] Direct Testimony of David Van Winkle, Case No. 16-00276-UT, page 18 (July 7, 2017).

[31] I calculated PNM's 2038 exit costs by inflating EPE's estimates to the year 2038 at 2.5 percent annual inflation rate and converting it to 2012 Present Value using PNM's discount rate of 5 percent for decommissioning cash flows.

- Add $24 million of ongoing capex that PNM would have to pay for the new gas CC unit; and
- Add $3 million for the accelerated decommissioning costs.

Accounting for all of these costs would lead to a net savings of $9 million from retaining FCPP. Therefore, based on the information available to PNM as of May 2012, but making all the intervenors adjustments and other corresponding omissions, retaining FCPP beyond 2016 would have resulted in cost savings for customers when compared to abandoning FCPP and serving customers from a gas CC plant. The figure below displays these adjustments incrementally and additively, starting from the estimate PNM found in its 2012 analysis.

PNM Figure FG-4: Savings from Retaining FCPP as of May 2012 (2012 PVRR, millions)



V. PRUDENCY OF PNM'S DECISION TO EXTEND THE FCPP COAL SUPPLY AGREEMENT AND JOINT OPERATING AGREEMENT IN LATE 2013

Q. PLEASE EXPLAIN NEE'S POSITION IN THE 2016 RATE CASE THAT PNM SHOULD HAVE UPDATED ITS MAY 2012 STUDY PRIOR TO ITS DECISION IN DECEMBER 2013 TO EXTEND PARTICIPATION IN FCPP.

A. NEE witnesses in the 2016 rate case argued that PNM's decision to extend CSA and JOA in late 2013 was not prudent because PNM should have updated its May 2012 analysis prior to its commitments in late 2013 to account for the interim change in outlook for gas price and cost of replacement generation capacity by late 2013.[32]

Q. WERE THERE OTHER CHANGES BETWEEN MAY 2012 AND LATE 2013 THAT WOULD HAVE ALSO AFFECTED THE ESTIMATED SAVINGS FROM RETAINING FCPP?

A. Yes, in addition to the changes mentioned by NEE, the coal price forecast for FCPP under the CSA and the industry outlook for the future carbon prices changed between the May 2012 study and late 2013. I explain below the impacts of each change mentioned by NEE and the other key changes on the estimated cost savings from retaining FCPP if PNM had updated its May 2012 study.

V.A. CHANGE IN GAS PRICE OUTLOOK

Q. HOW DID THE GAS PRICE OUTLOOK CHANGE BETWEEN THE MAY 2012 STUDY AND LATE 2013?

A. The change in gas price outlook varied in a fairly wide range depending on the source of forecast. I have identified three reasonable sources to evaluate the change in gas price outlook: NYMEX futures (the underlying source for PNM's gas price outlook in the May 2012 study), PNM's fundamental forecasts supplied by PACE Consulting, and EIA's Annual Energy Outlook. The differences in these gas price outlooks not only reflect the wide range of industry-anticipated outcomes, but they

[32] Direct Testimony of Steven M. Fetter, Case No. 16-00276-UT, pages 11-13 (July 7, 2017).

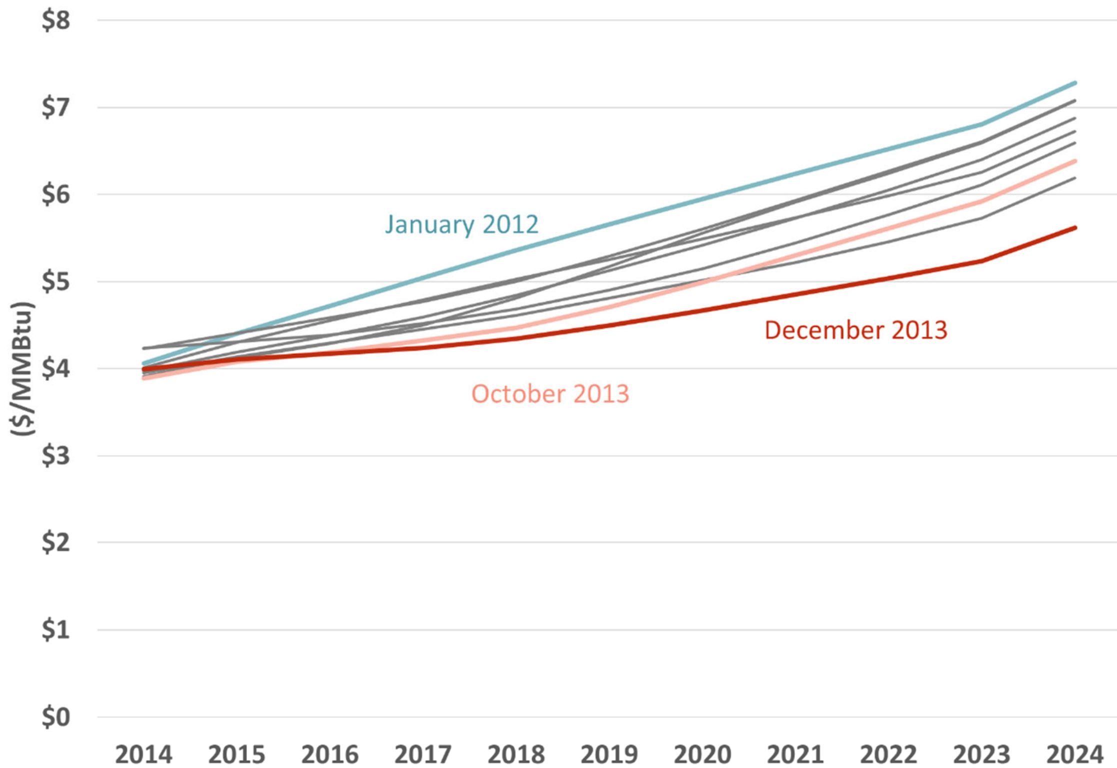
also represent the high level of uncertainty in the gas industry at the time, and consequently the challenges related to gas price forecasting (and resource planning).

Q. HOW DID YOU ESTIMATE THE CHANGE IN GAS PRICE OUTLOOK BY USING THE NYMEX FUTURES?

A. I understand that the gas price outlook in PNM's May 2012 study relied on the NYMEX futures as of January 2012 for the first three years (2012-2014). Prices in the out-years thereafter were extrapolated using a 3.5 percent nominal annual growth rate. Therefore, by identifying the change in NYMEX futures between May 2012 and late 2013, one could construct an updated gas price forecast consistent with PNM's methodology in the May 2012 study.

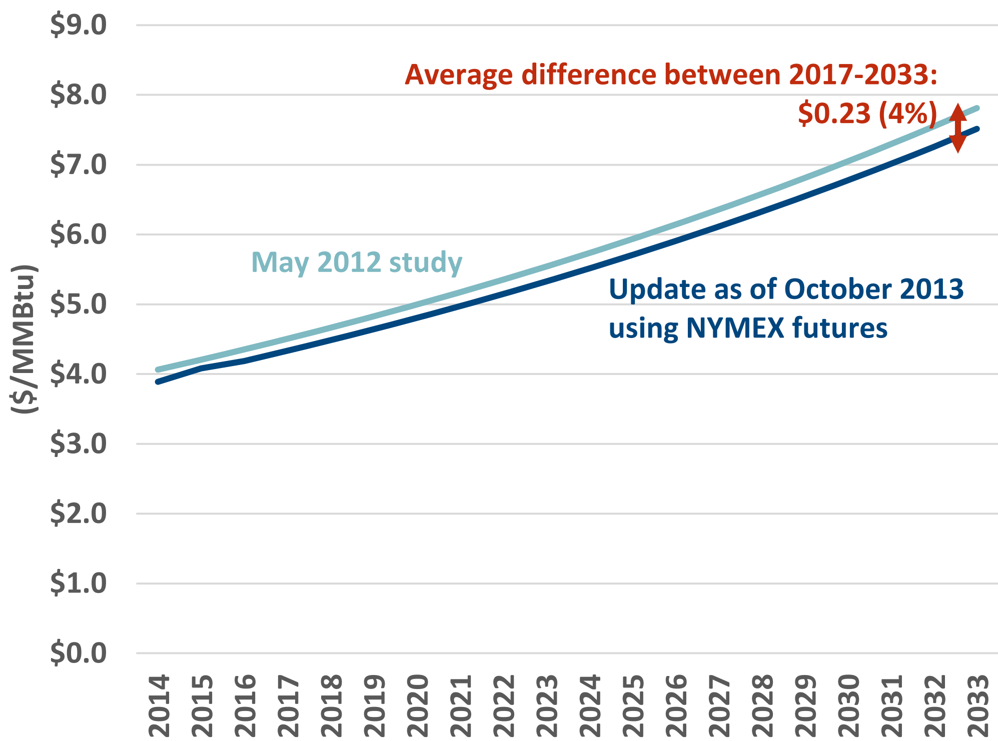
I started with the January 2012 futures used in PNM's May 2012 study, and compared them to the October 2013 futures to represent the futures market data available to PNM shortly before its decision in December 2013 to extend the FCPP participation. I note that it might have been equally credible to use an earlier forward strip. Given the complexity of updating resource planning studies, there is no single, necessary date that might have been selected for the updated reference point. For example, PNM's January 2014 analysis could readily reflect a market price outlook as of the latter part of 2013. PNM Figure FG-5 below shows the NYMEX Henry Hub futures for 2014 and beyond as of each month in the January 2012 to December 2013 period. They mostly gradually decline, such that the futures as of October 2013 are about $0.34 per MMBtu lower than the January 2012 futures for the delivery periods 2014-2016 and about $0.9 lower for the 2024 delivery year.

PNM Figure FG-5: NYMEX Futures between January 2012 and December 2013



By applying the same 3.5 percent per year long-term growth rate used in the May 2012 study to the October 2013 futures for 2016 delivery, I estimated the future long-term gas prices PNM might have expected by late 2013. PNM Figure FG-6 below compares the resulting gas price outlook against the one used in the May 2012 study. The updated approach results in a modest decrease in gas price outlook by late 2013, on average by $0.23 per MMBtu (in nominal dollars) for the period 2017-2033 (between the first year the new gas CC would come online and the last year of PNM's planning period).

PNM Figure FG-6: Henry Hub Gas Price Forecasts (May 2012 Study vs. Update as of Late 2013)



Q. HOW DID YOU ESTIMATE THE CHANGE IN GAS PRICE OUTLOOK BY COMPARING PNM'S MAY 2012 FORECAST AGAINST PNM'S FORECAST IN ITS JANUARY 2014 STUDY?

A. As the second source for gas price outlook adjustment, I rely on the change in PNM's gas price forecasts between the May 2012 study and its January 2014 study, which used a long-term gas price forecast developed by PACE Consulting in late 2013. This approach results in an *increase* in gas price outlook by 2013, on average by $1.86 per MMBtu for the period 2017-2033. Among the reasons PACE was forecasting high gas prices in the future were: likelihood of future CO_2 prices that would be applied in the next few years, additional coal plant retirements and higher demand for gas-fired generation, and increased use of gas for LNG exports.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED A THIRD POSSIBLE CHANGE IN GAS PRICE OUTLOOK BY USING THE CHANGE IN EIA'S LONG-TERM GAS PRICE OUTLOOK BETWEEN 2012 AND 2013?

A. As the third source, I use the change in long-term gas price forecasts at Henry Hub between EIA's Annual Energy Outlook in 2012 and 2013. This approach results in a large *decrease* in gas price outlook by late 2013 by $1.10 per MMBtu on average for the period 2017-2033.

Q. WHAT WOULD BE THE IMPACT OF THE CHANGES IN GAS PRICE OUTLOOK ON PNM'S MAY 2012 ESTIMATE OF THE SAVINGS FROM RETAINING FCPP?

A. Any changes in gas price outlook will be positively correlated with the net savings from retaining FCPP. That is, lower gas prices mean that it would be less expensive to operate a gas CC plant, and the economic attractiveness of keeping FCPP relative to building a new gas plant would therefore be reduced. Thus, the reduction in gas price outlook using NYMEX futures data would lead to a decrease of $14 million in PVRR savings from keeping FCPP.[33] A greater reduction in gas price results in a greater reduction in PVRR savings: The EIA AEO gas price outlook in 2013 is

[33] This analysis assumes that the new gas CC plant would generate the same amount of electricity as the FCPP plant would in the case of continued operation. Generation data is taken from the May 2012 EnCompass analysis.

lower than outlook in the previous year ($1.1 per MMBtu of difference on average for the 2017-2033 period), hence lowering net savings from FCPP retention by $62 million.

On the other hand, higher gas prices mean that it would be more expensive to operate a gas CC plant, raising its costs (and likely power market prices) leading to higher savings for retaining FCPP.[34] Using the change in PNM's long-term gas price outlook (difference of negative $1.86 per MMBtu on average during 2017-2033) increases PVRR savings by $109 million. PNM Figure FG-7 below summarizes how each of these three possible revisions in gas price outlook by late 2013 would have affected the overall PVRR savings from retaining FCPP across the three different scenarios. Note that there is quite a range, and that it remained ambiguous as to whether gas prices were going to turn up and favor the FCPP plant or turn down and make it less attractive.

[34] My calculations of gas price impacts are restricted to changes in the operating costs of the gas units on the PNM system. This is conservative because it omits the likely correlated effects on the price of power in the trading hubs of WECC.

PNM Figure FG-7: Impact of Changes in Gas Price Outlook between May 2012 and Late 2013

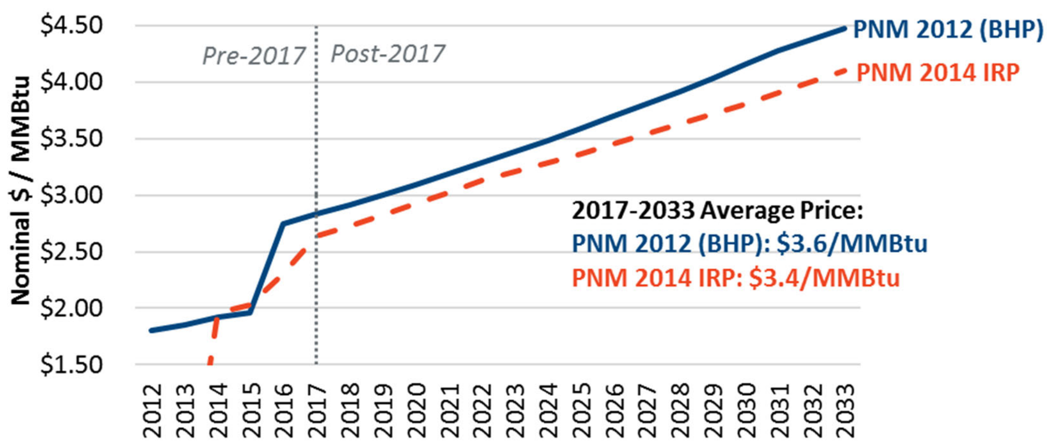
Description	Avg. Change in Gas Price (2017-2033)	Savings Impact
	(Nominal $/MMBtu)	*($ millions)*
PNM 2012 vs. IRP 2014	$1.86	$109.0
2012 NYMEX vs. 2013 NYMEX	($0.23)	($14.0)
AEO 2012 vs. AEO 2013	($1.10)	($61.8)

V.B. CHANGE IN CSA COAL PRICE FORECAST

Q. HOW DID THE FORECAST FOR FCPP COAL PRICES UNDER THE CSA CHANGE BETWEEN THE MAY 2012 STUDY AND LATE 2013?

A. In the May 2012 study, PNM evaluated multiple possibilities for the future coal prices due to active negotiations on the ultimate coal prices agreed to in the 2016 CSA. By December 2013, PNM updated its forecast coal prices under the CSA to be lower than the range of forecasts in the May 2012 study, based on the final contract pricing. PNM Figure FG-8 below compares the two coal price forecasts used in the May 2012 study for estimating the $33-$44 million range in PVRR savings from retaining FCPP against the PNM forecast in December 2013 for the future coal prices under the CSA. PNM's coal price forecast as of December 2013 was $0.25 per MMBtu lower on average during the period 2017-2033 compared to the coal price forecast underlying the $33 million PVRR savings estimate in the May 2012 study (using BHP coal prices).

PNM Figure FG-8: Change in Coal Price Outlook between 2012 and 2013



Q. WHAT WOULD BE THE IMPACT OF THIS DECREASE IN COAL PRICE FORECAST ON PNM'S MAY 2012 ESTIMATE FROM RETAINING FCPP?

A. The decrease in coal price forecast would make operating FCPP less expensive, assuming the same capacity factor (which might actually improve) and heat rate. Using the coal price forecast as of December 2013 would reduce FCPP fuel costs by $19 million, meaning that PVRR savings would increase by as much.

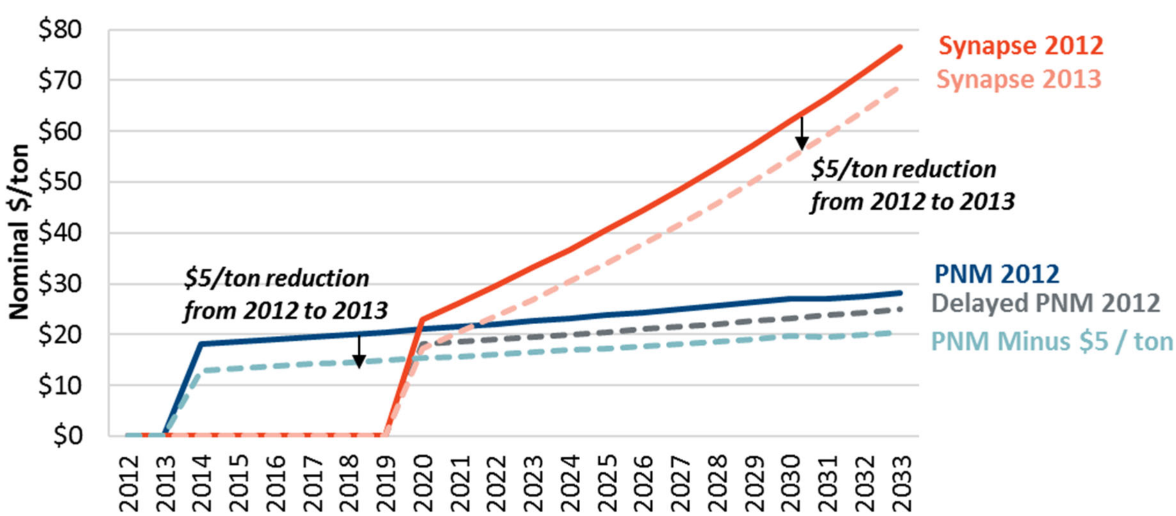
V.C. CHANGE IN CARBON PRICE OUTLOOK

Q. HOW DID THE INDUSTRY OUTLOOK FOR FUTURE CARBON PRICES CHANGE IN 2013 COMPARED TO WHAT PNM ASSUMED IN ITS 2012 STUDY?

A. Consistent with the New Mexico PRC's rule requiring IRP NPV estimates to include carbon emissions penalty costs, in its May 2012 study PNM assumed a CO_2

price of $20 per metric ton starting in 2014. The price level would be escalated at 2.5 percent per year. Of course, carbon pricing policy faced strong headwinds and has never materialized nationally and is now not needed in resource evaluations in New Mexico because the complete decarbonization goals of the state will be undertaken regardless of assumed social costs of not doing so.[35] However, those realizations were not in place in 2013, and nearly all utilities were using some penalty on carbon in their resource plans even if they did not actually pay it in actual operating costs. According to surveys of those assumed prices conducted by Synapse, the typical industry carbon price forecast was revised downward by about $5 per ton of CO_2 between 2012 and 2013 (see PNM Figure FG-9 below).

PNM Figure FG-9: Change in Carbon Price Outlook between 2012 and 2013



Sources: 2012 Synapse Carbon Dioxide Price Forecast, 2013 Synapse Carbon Dioxide Price Forecast, accessed at: https://www.synapse-energy.com/project/synapse-carbon-dioxide-

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35 At the time, the $20 per metric ton price was in the range of industry outlooks for the post-2020 period, but quite high compared to any then-prevailing or subsequent market prices. Carbon prices in California and the Regional Greenhouse Gas Initiative program were much lower.

price-forecast. "Delayed PNM 2012" and "PNM Minus $5 / ton" created based on adjustments to the forecast used in PNM's 2012 study.

Q. WHAT WOULD BE THE IMPACT OF THIS DECREASE IN CARBON PRICE OUTLOOK ON PNM'S MAY 2012 ESTIMATE FROM RETAINING FCPP?

A. Because a coal plant has higher carbon emission intensity than a gas CC plant, a lower carbon price means that the same amount of generation from FCPP would result in greater cost savings compared to generation from the replacement gas CC plant.[36] Likewise, a higher carbon price would lead to lower savings from retaining FCPP because its simulated operations would be penalized more than those of a gas plant.

To examine the impact of changes in carbon price outlook on the PVRR of keeping FCPP in late 2013, I develop three carbon price scenarios:

1) No Change: same carbon price outlook as in May 2012 study (no impact on PVRR);
2) Lower Carbon Price: reduction of $5 per ton of CO_2 relative to May 2012 study outlook; and
3) Delayed Carbon Price: same as May 2012 study, but would start in 2020.

[36] I assume an emissions factor of 0.45 ton of CO_2 per MWh for the gas CC unit and 1.06 ton of CO_2 per MWh for FCPP. U.S. Department of Energy, "Environment Baseline, Volume 1: Greenhouse Gas Emissions from the U.S. Power Sector," June 2016, page 18.

PNM Figure FG-9 above illustrates the carbon price series across the three scenarios, which together capture the high level of uncertainty of carbon price outlook as of 2013. I find that the lower carbon price case (reduction of $5 per ton of CO_2) would then lead to a $33 million increase in savings from retaining FCPP. Savings would be even greater at $43 million for the Delayed Carbon Price case, when carbon prices would begin in 2020.

V.D. COMBINED IMPACT OF ALL CHANGES BY LATE 2013

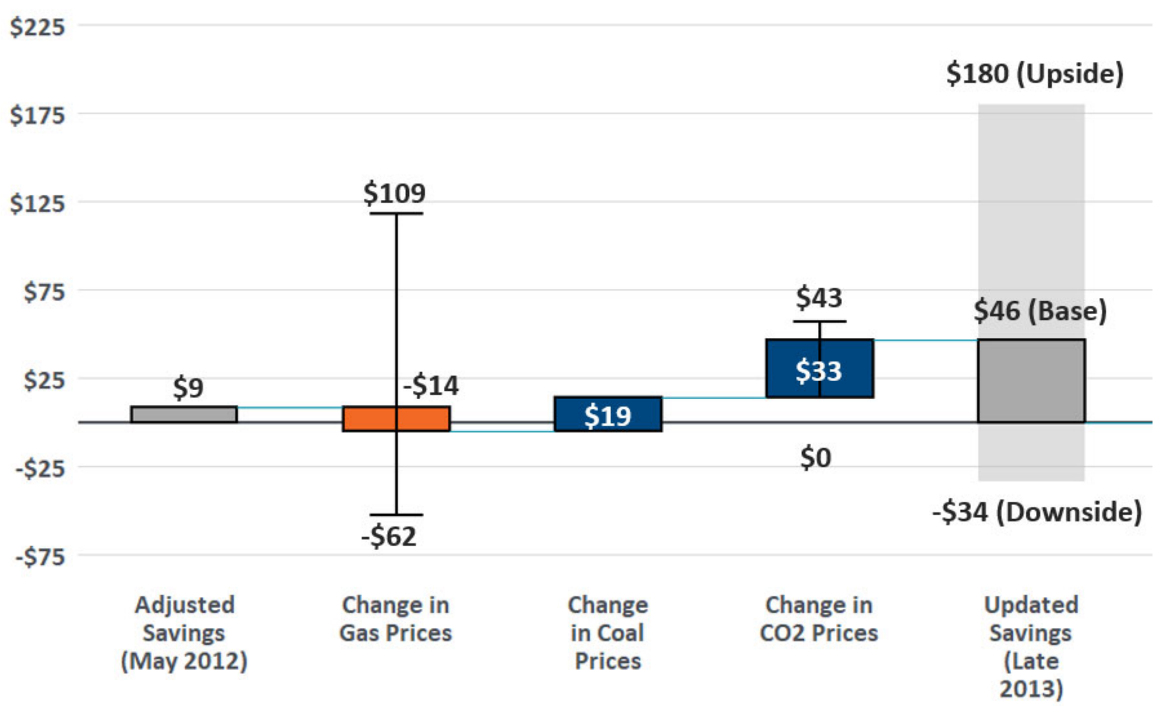
Q. WHAT IS YOUR ESTIMATE ON THE COMBINED EFFECTS OF ALL THE CHANGES YOU DESCRIBED ABOVE BETWEEN THE MAY 2012 STUDY AND LATE 2013?

A. I estimate that the combined effects of the adjustments I described above would lead to an increased benefit from retaining the plant, reaching an updated expectation of $46 million PVRR savings from retaining FCPP. This would arise from:

- $9 million in savings from adjustments as of May 2012;
- $14 million penalty from lower gas price outlook (with a range of $62 million penalty to $109 million in savings);
- $19 million in additional savings from lower coal prices; and
- $33 million in additional savings from lower CO_2 price outlook (with a range of $0 to $43 million in savings).

As shown in PNM Figure FG-10**Error! Reference source not found.** below, the uncertainty associated with each adjustment factor (shown by the vertical bars centered on each factor) means that the decision to retain FCPP could have saved PNM customers as much as $180 million in 2012 PVRR by retaining FCPP, if every factor turned out to be in PNM's favor. On the other hand, adverse conditions could have resulted in total cost disadvantage of $34 million, but the balance was mostly favorable to retaining the plant.

PNM Figure FG-10: Savings from Retaining FCPP as of Late 2013 (2012 PVRR, millions)



Q. WHAT IS YOUR CONCLUSION ON THE PRUDENCY OF PNM'S DECISIONS IN LATE 2013 TO EXTEND THE PARTICIPATION IN FCPP?

A. My sensitivities show that there were factors moving in both directions, for and against the retention and extension of FCPP, but on balance they tended to reaffirm the 2012 decision to extend the life of the plant. The CSA was in fact negotiated under better terms than were expected. Overall, this shows me that they continued to be prudent in pursuing more life from the plant. The events and trends that have since made the plant unattractive to retain were not in evidence at the time the decisions had to be made.

While PNM did not conduct the sensitivity analyses I have overlaid on its 2012 study above likely due in part due to the uncertainties surrounding choosing the best forecast for the observed changes or deciding on their long term durability, and because detailed system modeling is complex and time-consuming for the required planning resources and for regulatory review. The analyses I have presented here are incremental to the plans designed in 2012, *i.e.* adjustments as if those changes could be made in isolation with no impact on other system costs. In fact, a fully updated system modeling analysis would have also revised the long-term resource plans. These potential changes in long-term resource modeling outputs are likely secondary effects to what I have shown above, but they would have been necessary for PNM to make a credible "from scratch" updated filing. Thus, their omission is understandable over such a short time window from the prior assessments.

VI. OTHER CRITICISMS OF RETAINING FCPP

Q. ARE THERE OTHER CRITICISMS OF FCPP FROM INTERVENORS THAT YOU WOULD LIKE TO ADDRESS?

A. Yes. Intervenors previously pointed to a number of factors to argue that PNM's decision to continue its FCPP participation was not prudent. These factors include load forecast changes, costs of the replacement gas CC plant, and FCPP's availability factor. I explain below that even with expected load changes, FCPP's capacity would still be needed to meet system needs. I also show that the cost and availability assumptions are reasonable at the time the studies were conducted.

Some intervenors also maintained that the decision in 2013 by EPE to exit its participation at FCPP by the end of 2016 should have prompted PNM to reconsider its own decision to extend FCPP participation.[37] This criticism ignores the utility-specific nature of potential savings from retaining FCPP and the decisions by other joint owners of FCPP at that time to retain FCPP based on their studies that found cost savings under that strategy. Moreover, as I have demonstrated thus far in my testimony, accounting for changes between May 2012 and late 2013 would lead PNM to the same conclusion, that retaining FCPP would produce savings to PNM's customers. Further, resource planning analyses often require a long time to develop, and as a matter of practice are not continuously conducted or revised every time some inputs change until the persistency of input changes is established.

[37] Direct Testimony of Steven M. Fetter, Case No. 16-00276-UT, page 7 (July 7, 2017).

In addition, I must address NEE's conclusions based on its request in the 2016 rate case to conduct a Strategist run without FCPP. According to the results of this run, an exit from FCPP would save customers $446 million, compared to retaining FCPP until 2031. However, as I explain in more detail below, this scenario is highly stylized and was not based on reasonable modeling assumptions, so its results should be discounted.

VI.A. CHANGE IN LOAD FORECAST

Q. HOW DID PNM'S LOAD FORECAST CHANGE BETWEEN THE ASSUMPTIONS IN THE MAY 2012 STUDY AND LATE 2013?

A. PNM's load forecasts in the 2014 IRP were lower than the May 2012 and January 2014 studies (*see* PNM Figure FG-11 below). Relative to these two studies, the 2014 IRP forecast shows a reduction of about 200 MW that persists all the way through 2020.

It is my understanding that the lower growth in the 2014 IRP was the result of methodology changes (*e.g.*, end use sales forecasting approach) and commercial factors, among which is the loss of City of Gallup load starting in 2014.[38] Between 2014 and 2030, Gallup's load was expected to increase from 41 MW to 62 MW (about 2 to 2.3 percent of the total system load).[39] In addition, PNM's 2014 IRP load forecast accounted for the declining trend in system load factor.[40]

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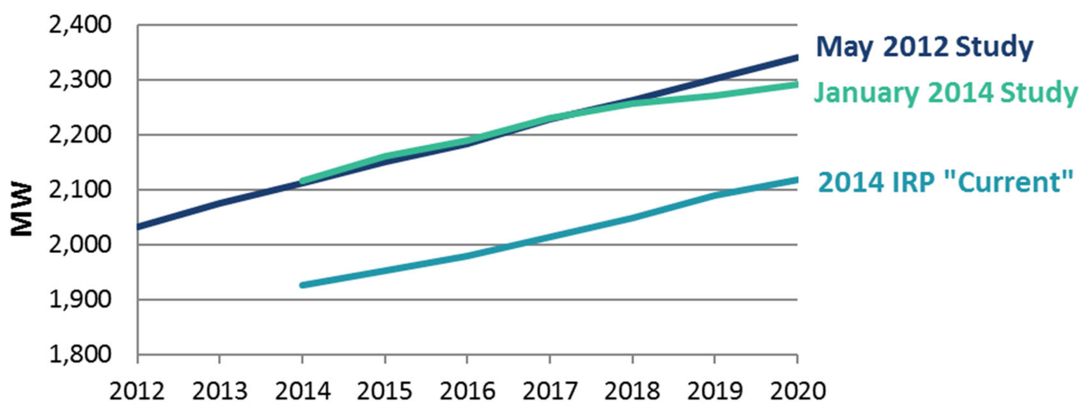
[38] PNM 2014 IRP, page 46.
[39] PNM 2011 IRP, page 183.
[40] PNM 2014 IRP, page 46.

PNM Figure FG-11: Comparison of Peak Demand Forecasts

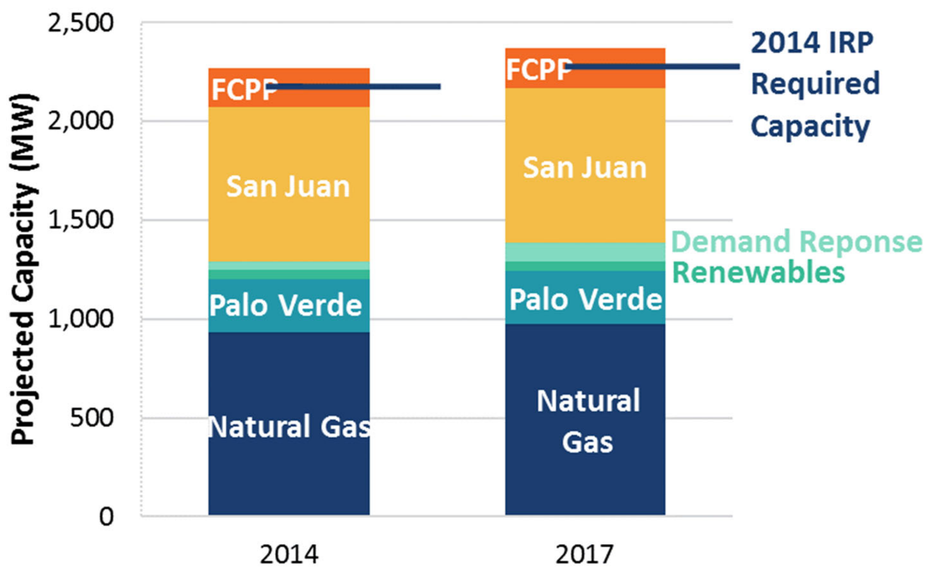


Q. WHAT WOULD BE THE IMPACT OF THIS DECREASE IN LOAD FORECAST ON PNM'S MAY 2012 ESTIMATE FROM RETAINING FCPP?

A. The decrease in load growth forecast suggests a decrease in attractiveness of retaining FCPP because the unit's capacity might not be needed. However, my review of PNM's supply plan in the 2014 IRP indicates that despite load changes, the Company would barely have any margin of slack capacity in 2014 through 2017. That is, it needed FCPP's capacity or some replacement of the kind it already was considering.

In PNM Figure FG-12 below, I reconstructed PNM's total available supply, with FCPP's capacity at the top of the stack. In 2014, PNM expected to have 2,271 MW of capacity. Against the required capacity of 2,178 MW (expected load of 1,927 MW load plus 13 percent), PNM would have an extra 93 MW of capacity in 2014, but without FCPP, PNM's reserve margin would fall to 7 percent, well below the required margins. The Company certainly could not satisfy the reserve margin requirement without capacity from both FCPP and San Juan Generating Station. Repeating the same analysis for the year 2017 shows that FCPP capacity is crucial in helping PNM meet its reserve margin in that year. Therefore, even with the decreased forecast for load growth by late 2013, the option of exiting FCPP in 2016 would have required replacing it with a new resource. PNM's analyses already evaluated that substitution, so there is no need for additional adjustments.

PNM Figure FG-12: PNM's Total Supply versus Required Capacity in 2014 and 2017



Note: Projected load and resource capacity sourced from 2014 IRP forecast, where relied on "132 MW" case (larger acquisition of San Juan capacity). Excess capacity determined by adding a 13 percent reserve margin to net system peak demand. Renewables capacity credit determined based on technology type and peak hour contribution.

VI.B. CHANGE IN COST OF A NEW GAS CC

Q. WHAT WAS THE INDUSTRY OUTLOOK FOR THE COST OF A NEW GAS CC PLANT IN THE PERIOD FROM THE MAY 2012 STUDY TO LATE 2013?

A. The replacement resource considered by PNM in evaluating the FCPP exit option in its May 2012 study was a new gas-fired combined-cycle plant. PNM assumed an *installed* capital cost of $1,300/kW for that new gas CC.[41] Between 2012 and 2013, EIA's assumption for the *overnight* capital cost of a generic new gas CC remained about the same at approximately $1,000/kW.[42] Adjusting the EIA's generic cost estimate to express it on an installed cost basis (by adding AFUDC of approximately 13%)[43] and to account for approximately 20% premium for regional cost differences in the Southwest[44] (which typically arise due to additional costs for air cooling due to cooling water restrictions and altitude adjustments) from the national average would result in a similar installed capital cost estimate to PNM's capital cost estimate for the replacement gas CC. Therefore, PNM's capital cost estimate for the new gas CC option was fully credible, consistent with EIA's estimates in 2012 and 2013.

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41 Rebuttal Testimony in Support of Revised Stipulation of Patrick J. O'Connell, Case No. 16-00276-UT, PNM Exhibit PJO-2 Rebuttal (July 21, 2017).

42 EIA, "Capital Cost for Electricity Plants," April 12, 2013, available at: https://www.eia.gov/outlooks/capitalcost/. *See also,* EIA, "Updated Capital Cost Estimates for Electricity Generation Plants," November 2010, page 7. *See also,* EIA, "Updated Capital Cost Estimates for Electricity Generation Plants," April 2013, page 6. See values for "Advanced NGCC" or "Advanced CC."

43 In PNM's 2014 IRP, AFUDC was approximately equal to 13 percent of overnight capital cost for a new 250 MW gas CC. See 2014 IRP, page 135.

44 The EIA began publishing regional values for overnight capital cost in the 2016 AEO, where it assumed that overnight costs for gas CCs built in the "AZNM" (WECC Southwest) region would be 14-28 percent larger than national assumptions, depending on if a new gas CC was "conventional" or "advanced." See EIA, "Assumptions to the Annual Energy Outlook 2016," January 2017, pages 107-108.

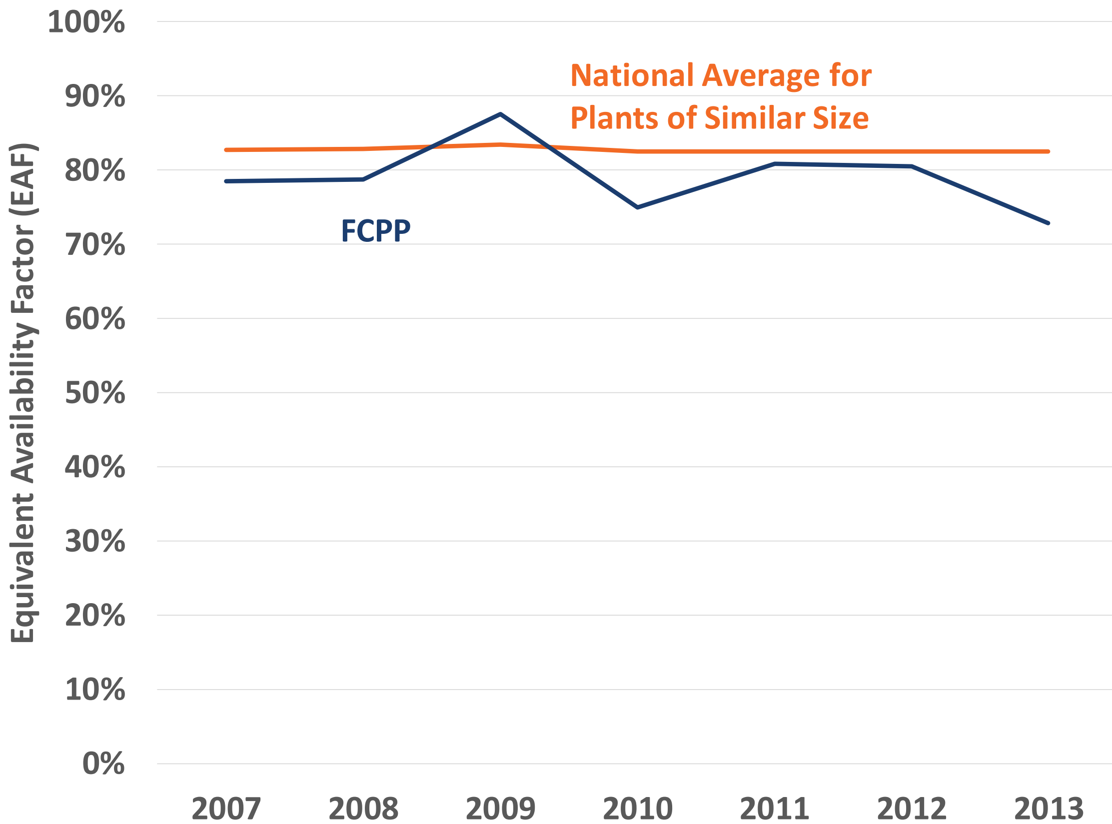
VI.C. AVAILABILITY PERFORMANCE OF FCPP

Q. HOW DID THE AVAILABILITY OF FCPP CHANGE DURING THE YEARS PRIOR TO 2013?

A. The average historical equivalent availability factor (EAF) for FCPP between 2007 and 2013 was 79 percent, or about 4 percent below the national average for plants of similar size (*see* PNM Figure FG-13 below). The year 2009 was an exception to this trend, when FCPP's EAF was 5 percent higher than the national average. From the 2012 and 2013 perspective, it was reasonable to expect that the plant would maintain similar performance going forward. Indeed, a review of historical FCPP's heat rates and capacity factors as of 2013 reinforces this viewpoint in performance continuity: over the 2009-2013 period, FCPP's heat rate averaged 10,180 Btu/kWh, with little deviation across the years, *i.e*. there was no apparent sign of any loss of efficiency.[45] During this period, the plant's heat rate fluctuated between 10,056 Btu/kWh and 10,301 Btu/kWh. Similarly, FCPP's average capacity factor for this period is nearly 80 percent, which is typical for coal power plants of this size and vintage.

[45] S&P Global Market Intelligence, accessed February 24, 2021.

PNM Figure FG-13: 2007-2013 Historical Equivalent Availability Factor for FCPP Compared to National Average for Similar-Size Coal Plants



Q. BASED ON THE INFORMATION AVAILABLE BY LATE 2013 ON FCPP AVAILABILITY PERFORMANCE, WOULD IT HAVE BEEN PRUDENT FOR PNM TO ASSUME A LOWER FUTURE AVAILABILITY FOR THE FCPP IN EVALUATING THE SAVINGS FROM RETAINING THE PLANT?

A. No. It might have been a possibility, but it is also true that adjusted maintenance practices, a different duty cycle, and as-needed repairs can improve availability. In fact, APS and PNM planned and implemented successful capital projects starting in 2015 to improve and maintain the reliability and performance of FCPP in future years.[46] It was operating as a credible and important baseload unit, and reasonable to assume that would continue.

VI.D. ANALYSES FROM OTHER FCPP CO-OWNERS

Q. PLEASE DESCRIBE EPE'S FINDINGS THAT LED TO THE COMPANY'S DECISION TO LEAVE FCPP.

A. EPE's decision to leave its seven percent share of FCPP was based at least in part on a 2013 study that found the benefits of exiting on the order of $11-$24 million.[47] As I noted above, EPE had begun planning its exit as early as 2009, and had already obtained approval to construct a portion of the needed replacement resources in 2012. EPE also identified significant non-quantifiable benefits specific to its system such as improved system reliability by transitioning away from remote coal toward local gas peakers, which also had the ramping capabilities to better match EPE's load profile.[48] For EPE, new local generation would alleviate transmission constraints and voltage support for EPE's system as well. (These are benefits that have nothing to do with the operating costs of FCPP.) EPE updated its 2013 analysis in 2016, and found a net benefit of $124.6 million related to the sale of its FCPP share and updated gas prices.[49]

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[46] Direct Testimony of Chris M. Olson, Case No. 16-00276-UT, pages 47-48 (December 7, 2016). *See also* Supplemental Testimony of Thomas G. Fallgren, Case No. 21-00017-UT (March 15, 2021).

[47] Stipulation Testimony of Scott D. Wilson, Case No. 15-00109-UT, pages 5-6 (February 2, 2016).

[48] Direct Testimony of Ricardo Acosta, Case No. 15-00109-UT, pages 6-7 (April 27, 2015).

[49] Certification of Stipulation, Case No. 15-00109-UT, page 14 (April 22, 2016). See also Stipulation Testimony of Scott D. Wilson, page 6 (February 2, 2016).

Q. SHOULD PNM HAVE COPIED EPE'S DECISION?

A. No. In the 2016 rate case, Mr. Van Winkle argued that EPE's findings indicate that PNM, too, should have found it was advantageous to leave FCPP. Based on scaling EPE's results for PNM's ownership share, he determined that the equivalent net benefit should be at least $231 million.[50] However, such simplistic scaling exercise is inappropriate because it ignores the differences in needs and constraints across power systems. As acknowledged by another NEE witness, the local benefits to EPE's system would not necessarily materialize for another co-owner's system.[51] On the contrary, keeping FCPP was critical to maintaining PNM's reliability. Notably, by the time of its application to exit FCPP, EPE had already gained approvals for four new gas-fired plants located in EPE's service area, two of which were already online in March 2015, as well as for 50 MW of long-term solar power purchase agreement.[52] An FCPP replacement would also have been needed for PNM.

Other co-owners conducted similar contemporaneous analyses of the pros and cons of the FCPP plant and arrived at very different conclusions than EPE. In its 2012 IRP, Tucson Electric Power found that continued participation in FCPP would save $115 million over the 2012-2027 period instead of retiring FCPP and replacing it

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[50] Supplemental Testimony of David Van Winkle, page 4 (July 14, 2017).

[51] On behalf of NEE, Mr. Fetter testified that the analysis conducted by EPE was unique to that utility and that EPE's conclusions on savings are not applicable to other FCPP participants. Case No. 16-00276-UT, Transcript of Proceedings Volume 5 (Fetter) at 1012.

[52] El Paso Electric Company's Application for Approval of Abandonment and Sale of Its Four Corners Units 4 and 5 Ownership Interest, Case No. 15-00109-UT, page 3 (April 27, 2015).

with a combined cycle unit.[53] Likewise, APS determined that acquiring SCE's 48 percent stake in FCPP Units 4-5 (or 739 MW) would be more economic than upgrading Units 1-3 or building a new gas CC (PVRR savings of about $500 million).[54] The Arizona Corporation Commission subsequently authorized APS to pursue the transaction because the utility's acquisition of SCE's share and plan to retire FCPP Units 1-3 would "[preserve] its existing interest in a reliable, low-cost generation resource as well as the substantial economic benefits to the Navajo Nation and surrounding communities."[55] Further, the proposed plan would result in lower emissions and environmental improvements while maintaining the balance of APS' diverse resource portfolio.

Q. SUPPOSE THAT FCPP WERE TO BE REPLACED BY ALTERNATIVE RESOURCES; WHEN WOULD PNM HAVE HAD TO BEGIN THE PLANNING AND CONSTRUCTION OF A NEW RESOURCE?

A. Because of the protracted nature of these development processes, PNM at a minimum would have had to make its decision regarding an alternative to FCPP participation during the time the CSA was being negotiated and preliminary pricing for a coal supply had been identified. This timeline to procure an alternative sources of power would be needed to ensure a continuation of reliable service for customers.

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[53] Tucson Electric Power Company 2012 IRP, page 324.

[54] Arizona Corporation Commission Decision No. 73130, Docket No. E-01345A-10-0474, pages 8-9 (April 24, 2012).

[55] *Ibid.,* pages 32-33.

Confirming this need for material lead time, EPE's application for the abandonment of FCPP stated that EPE had been planning for the July 2016 termination of its FCPP participation since 2009, and it filed for approval of new gas-fired replacement resources in 2012 and 2013 in order for them to available in the 2015-2017 time period.[56]

Q. SHOULD PNM HAVE UPDATED ITS ANALYSIS BETWEEN JANUARY 2014 AND MARCH 2015, WHEN PNM AND OTHER CO-OWNERS FINALLY SIGNED AMENDMENT NO. 9 TO THE CO-TENANCY AGREEMENT?

A. It is understandable to wish that these high-value decisions could be updated in almost real time to improve their benefits, but that is not practical nor consistent with the way they are analyzed, reviewed and approved. These decisions are also very complex and dependent on uncertain factors that often move more in the short run than in the long run, making it hard to know when to adjust assumptions, and costly and time-consuming to revise analyses. As I noted above, decisions such as a plant life-extension transactions or plant replacements generally need to be made months, or possibly years in advance of the execution. The operative decision point revolved around securing the coal supply. Because EPE had determined it was exiting, it appears that the owners delayed further amendments to the JOA until APS and EPE completed their transaction and the owners executed Amendment No. 8 to remove EPE from the JOA effective with the closing of the sale to APS.

[56] El Paso Electric Company's Application for Approval of Abandonment and Sale of Its Four Corners Units 4 and 5 Ownership Interest, Case No. 15-00109-UT, pages 2-3 (April 27, 2015).

The fact that subsequent amendments to the Joint Operating Agreement were not all ultimately executed simultaneously with the CSA is not an accurate depiction of when actual decisions on FCPP were required to be made by PNM.

VI.E. NEE'S CLAIM OF $446 MILLION SAVINGS FROM EXITING FCPP IN 2017

Q. PLEASE EXPLAIN NEE'S ASSERTION IN 2017 THAT PNM'S ABANDONMENT OF FCPP IN 2017 WOULD HAVE SAVED $446 MILLION IN COSTS FOR PNM'S CUSTOMERS.

A. In 2017, NEE requested a Strategist run by PNM purportedly to evaluate the customer cost impacts of removing FCPP from modeling as of that year versus retaining FCPP until 2031.[57] In this 2017 exit sensitivity, NEE requested PNM to assume that, starting in 2017, there would be no FCPP fuel, O&M, ongoing capital expenditures or SCR costs included in the model. NEE's witness Anna Sommer used the results of these two sensitivity runs to conclude that PNM's exit from FCPP in 2017 would have been $446 million cheaper in present value compared to a 2031 exit.[58]

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57 NEE's Sixth Set of Interrogatories, Item 6-1 Part A and Part D, Case No. 16-00276-UT, May 10, 2017.
58 Direct Testimony of Anna Sommer, July 14, 2017, Case No. 16-00276-UT, pages 2-3.

Q. WHAT IS THE RELEVANCE OF THE SENSITIVITY RUNS REQUESTED BY NEE IN 2017 TO THE PRUDENCY OF PNM'S DECISION IN LATE 2013 TO EXTEND PARTICIPATION AT FCPP?

A. None whatsoever. These 2017 sensitivity runs have no relevance to the prudency question for two reasons. First, if these sensitivity runs were intended to simulate an exit decision in 2017 for abandoning FCPP in 2017, then NEE should have included in its assumptions and inputs PNM's continuing cost obligations at FCPP as of 2017 for many years into the future under PNM's ownership obligations until 2031 for the coal supply agreement and until 2041 under the joint ownership agreement. But NEE requested PNM to unrealistically assume PNM could simply walk away from all residual CPP costs and obligations starting in 2017. In addition, abandonment of FCPP in 2017 would have required multiple years for PNM to obtain regulatory approvals and build replacement generation plant(s) in order to meet its load obligations. This too was ignored and excluded by NEE's design, therefore modeling of a 2017 exit as of 2017 was not depicting a feasible option.

Second, if NEE's requested sensitivity runs were intended to evaluate PNM's decision in late 2013 to extend participation in FCPP beyond 2016, the modeling assumptions for future market fundamentals (such as gas prices, carbon prices, load growth, renewable costs, etc.) should have been based on the information available as of 2013, not as of 2017. Such a sensitivity run is an improper hindsight analysis which does not have any relevance to prudence of PNM's decision in 2013 to extend participation at FCPP.

I understand PNM's witness Patrick J. O'Connell articulated similar concerns in 2017 with respect to the relevance and validity of the assumptions in NEE's requested sensitivities.[59]

VII. APPROPRIATENESS OF PNM'S FULL RECOVERY OF PRUDENTLY INCURRED PAST INVESTMENTS

Q. PLEASE SUMMARIZE WHY YOU BELIEVE THE FULL COSTS OF AMORTIZING SUNK COSTS IN FOUR CORNERS WITH RETURN SHOULD BE ALLOWED, RATHER THAN PENALIZING PNM BY EXCLUDING SOME PORTION OF ITS COSTS.

A. There are several reasons discussed in detail below, but at the highest level, the fundamental reason is that I believe there is no basis for finding that PNM was imprudent in maintaining and sustaining its use of the plant until current opportunities arose to move beyond it. Simply disallowing a portion of costs because the plant is now "out of the money" compared to new, better alternatives is not a proper basis for disallowance. Doing so would contravene established and thoroughly justified standards for cost recovery for any utility operating under an obligation to serve and cost-based ratemaking, and it would create perverse incentives adverse to customers' long-term interests.

[59] Rebuttal Testimony of Patrick J. O'Connell In Support of Revised Stipulation, Case No. 16-00276-UT, pages 18-26 (July 21, 2017).

Q. IN REACHING THAT CONCLUSION, WHY DO YOU NOT GIVE MORE WEIGHT TO SCENARIOS OR CONDITIONS WHERE FCPP WAS PROJECTED TO BECOME UNECONOMICAL FOR PNM (AS IS NOW THE SITUATION)?

A. First, it is true that the market has evolved to more closely resemble the low-value scenarios than the center of the ranges that prevailed in 2012-13. But we should not be swayed by hindsight as though it all should have been foreseen as an inevitable outcome. The parameters for future market conditions that PNM used, and the ones I have applied to extend and test its analyses, were within (and spanned) the range of what industry planners all across the industry were using and considered reasonable at the time.

Second, a resource should be preferred if it has expected savings relative to the next best alternative that are fairly robust across most *but not all* circumstances. It is impossible to find resources that are always going to be preferred no matter what the future unfolds, and looking or waiting for them will mean making worse choices for customers. Thus, it will (and should be) possible at each point of ongoing commitment to a plant for it to become uneconomical sometime in the future – without meaning that is a bad choice. If/when that happens, we need to find a better alternative (which could be entirely fortuitous and previously unexpected) and possibly reevaluate whether the original analyses were naïve, unreasoned, or biased. Here none of those errors happened. Instead, other technologies and market conditions simply shifted to invite a better alternative.

Further, even if some analysts would have given more weight at the time to the lower value scenarios where retaining FCPP was not attractive, it is undeniable that the plant could be attractive in some scenarios, possibly greatly so. The extent to which it might appear unattractive in some scenarios could be overwhelmed by other possible, more favorable circumstances for the plant. We should temper any inclination to assert imprudence by considering whether it was strongly or only very weakly evident that something else might have been better. Here, there was clearly no dominant alternative, so simply disagreeing on what conditions might ensue, or concluding that different conditions ultimately did occur, is not a basis for a finding of imprudence.

Importantly, co-tenants in the plant, considering essentially the same market outlook (but different local needs, and in the case of SCE a significant change in laws) reached different conclusions about the plant's ongoing value, both around 2012 and thereafter. If it were a *per se* bad plant, the majority of the co-tenants would not have decided to continue in the plant. And in fact, the other owners are still indicating that they will continue to rely on the plant until 2031.[60]

[60] In particular, APS has recently reviewed the FCPP plant for its system, finding that with the help of a resource planning study by E3 that FCPP is more economical and more reliable through 2031 than shifting to a portfolio of over 2000 MWs of solar, wind and storage that would be required to replace it earlier. This does not indicate that that is also true for PNM, as each system is different, but it does show that the plant is not intrinsically uneconomical under current circumstances. See the Rebuttal Testimony of Brad J. Albert on behalf of APS in Docket No. E-01345A-19-0236.

Q. ARE THERE PRACTICAL LIMITS ON HOW FREQUENTLY THE UPDATES TO ANALYSES CAN OCCUR FOR RESOURCE PLANNING IF CONDITIONS START TO CHANGE?

A. Yes, as is quite familiar to the Commission and to regular intervenors, the analyses underlying a resource plan are complex, requiring huge amounts of data and complex, somewhat cumbersome models. Setting them up, agreeing on internally consistent sets of assumptions for scenarios, vetting the results, and formalizing that information for regulatory review is a multi-month process. Part of the difficulty is that the parameters are uncertain and volatile (especially fuel costs, but also sometimes state and federal policies, market decisions of other major participants, and ups and downs of the economy itself; witness the various swings in environmental policies over the past several years). Thus, if they change in one direction, it is possible they will change back in the other direction in the not distant future. There is some need to wait and see if a persistent trend has emerged. It is not practical to ask or expect that a few months after such analyses were conducted (in mid-2012) that they would be entirely reconstructed within a year or so.

Here, there were changes between the 2012 finding of a net positive value (savings) to retaining FCPP in May 2012 before the contract to extend the CSA was signed in late 2013. For instance, gas prices moved both up and down in this period, and depending on what forecasting entity you relied upon, the expected magnitudes were quite different. At the same time, the final coal price was lower than assumed initially. When intervenors assert or imply that PNM should have fully retested its findings from 2012 before committing to continue with the plant, they are ignoring that PNM assessed offsetting market changes in its more limited update of its analysis; intervenors are also ignoring the complexity of related ongoing negotiations necessary to have contracts to execute prior to the termination of prior agreements.

Q. HOW DOES THE MIX OF REASONS FOR AND TYPES OF INVESTMENTS UNDERLYING THE REMAINING BOOK VALUE IN PNM'S SHARE OF FCPP AFFECT YOUR VIEW OF ITS COST RECOVERY?

A. Some of the current remaining net book value of the plant ($53 million as of December 2020) arose from expenditures prior to 2013, when there was no doubt about the benefits of the plant to the PNM system.

For the investments after 2013 (representing about $181 million of the December 2020 total net book value of the plant), I have shown above that the decision to retain FCPP as of 2012 and 2013 was expected to result in customer cost savings (compared to abandoning FCPP in 2016) under most of the reasonable expectations as of that period. At the very least, this bulk of previously approved and useful expenditures indicates that it is totally unreasonable to condemn the whole plant even if some of its expenditures might be questioned. The post-2016 expenditures, especially the air quality control equipment and the SCRs, were also reviewed and the amounts of those investments were found to be allowable (in New Mexico and by other regulators for the co-tenant utilities).

Even if there is a problem with some of PNM's investments, their entire cost is not a fair or rational amount to exclude. Instead, any disallowed value should be based only on how much less the next best alternative would have cost, and that delta is assuredly a fraction of the direct cost of the original asset. (And, I have found no evidence for an FCPP expenditure that had an alternative with a cheaper expected cost.) Relatedly, the SCR portion of the past investments has already been partially disallowed, in that PNM has been only earning a debt return on this portion of its cost. These foregone costs should be netted against any finding that some portion of the SCR costs were imprudent.

Q. WOULD THERE BE ADVERSE SIDE EFFECTS AND UNDESIRABLE INCENTIVES FROM ANY DISALLOWANCE OF FCPP COSTS?

A. Yes. There is a danger of improperly disallowing costs through a review focused too narrowly on the current changes in economics that have made it better to be replaced. Such a focus that entirely ignores the economic basis for why a plant was developed in the first place, how much benefit it has already produced, and what would have been the relative costs of the next best alternative based on information knowable at the times decisions were made. A reasonable decision-making process does not require (and cannot live up to a standard of) perfect foresight. As explained above, all prudently chosen resources are "born with" (selected with) some chance that they will not always produce benefits, especially in light of the longevity of these resources. This is desirable and unavoidable, especially given the shifting regulatory goals and constraints (especially environmental) and the changes in the cost and performance of available new technology over the life of a plant. If a plant is always going to be penalized if/when any of these possible adverse outcomes occur, but it only recovers its normal costs when they do not occur (no extra profits for being successful), *then it can never expect to cover its full costs in the first place.* (A plant should not be guaranteed of that full recovery but having that opportunity should be a fair expectation when a plant is first developed.)

There is also a danger from oversimplifying the cost recovery decision based on naïve application of used-and-useful standards. When properly applied, the used and useful standard looks to whether a plant has actually been used to serve customers; if so, then the reasonable costs that were incurred during the time the plant was in service are recoverable, even if it no longer is preferred. A naïve used-and-useful standard creates a "heads I break even, tails I lose" situation for the utility investors, which is a game that they will not want to play. Applying such a standard would create a chilling adverse incentive for all New Mexico utilities.

It is also important to recognize discrepancies between the period over which the plant's sunk costs have been allowed to be recovered versus the period the plant actually operates or was intended to operate. In fact, FCPP has an amortized cost recovery that extends beyond the coal supply agreement and expected operational life of the plant. Had it been depreciated on that basis rather than the period of the Navajo lease and the JOA, more of its sunk costs would have already been returned to investors during the times when the plant was more beneficial, eliminating some of the amounts now included in the requested abandonment costs.

Here, it seems particularly counterproductive to have tasked PNM with exploring better ways to serve customers and then penalize the utility when it voluntarily came forward with a plan to pursue that alternative. This is desirable behavior that should not be penalized. Doing so has the unintended implication that if/when the utility can find an improvement, it will be construed as evidence that the utility has not done a good job in the past and that it must forgo recovery of the sunk costs in the assets to be replaced. This would be a perverse signal to avoid finding such improvements in the future.

VIII. CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR OPINIONS AND RECOMMENDATIONS.

A. First, I will re-emphasize that I believe the focus of inquiry should be on PNM's decisions up to and around late 2013, when it had to decide whether to commit to an extended CSA and JOA. Analyses focused thereafter are prone to hindsight opportunism and may not describe the actual alternatives the Company faced when it negotiated the current arrangements.

At that time, PNM's own studies found meaningful present value benefits to staying with the plant. Intervenors have pointed out some omissions and alternative assumptions that would have improved those studies; their point may be valid but is also incomplete and overlooks the fact that capital expenditures were omitted from the gas CC alternative as well as from the continuation of FCPP. Also, those criticisms did not recognize that there were financial consequences and exit fee side-effects to the suggestions to abandon the plant without having a successor which would assume responsibilities for the ongoing costs associated with PNM's abandoned ownership interest. When more complete adjustments are made, the results recapitulate PNM's findings and validate the decision made by PNM. My reassessment of the value of the plant at the end of 2013, capturing mostly changes in fuel and carbon price forecasts since the May 2012 study, confirms it remained attractive to retain FCPP with the extension of CSA and JOA.

Several of my reassessments are supplemental to what PNM did at the time, which might suggest PNM's determinations were inadequate – but that is not the case. PNM correctly identified expected value benefits from FCPP that remained robust across more updated analyses in 2013. PNM planners would have been generally aware of how durable those results were to changes in conditions, and several of those changes were favorable for retaining the plant (e.g. the CSA price was lower than the forecasted price in 2012). It is not reasonable to ask or imply that PNM should have repeatedly and on short notice re-evaluated its prior findings every time a projected cost item changed. Careful resource planning is time-consuming, and updated analyses at the time would have shown (as I find) that there was a range of possible values for the plant, centered in savings and with a material chance that it was going to remain attractive in the future (even if it could also turn out to not be so in some scenarios).

The recent PNM decision to abandon and sell its share of FCPP is also a good one, saving customers' money and positioning PNM for sponsoring/hosting a cleaner resource mix in the future. Even if it were regrettable in hindsight that the plant was not abandoned sooner (which has not been shown, as there would be some adverse consequences to now owning a recently installed gas CC[61]), hindsight is not an appropriate frame of reference for judging resource decisions. Even if hindsight is given a lot of (undue) weight, based on a thorough consideration of the knowable inputs for FCPP and an alternative, only a small portion of the plant's net cost today could be eligible for criticism of being imprudent. Such criticism, however, must rely on over-weighting of only the most unfavorable, rather than the full range of reasonable, inputs at the time. I note that previous disallowances (debt-only return for SCR costs) should be credited against any claimed penalties.

Finally, I note that there would be many adverse, perhaps unintended consequences of seeking a disallowance in this instance. The "standards" of being used and useful or balancing of customer vs. investor interests that might seem to invite a

[61] With the hindsight view, if PNM had abandoned FCPP in 2016 and installed a replacement gas CC plant in 2017, the New Mexico renewable portfolio standards of 50 percent by 2030 and 80 percent by 2040 under the recent Energy Transition Act (ETA) would likely have required retiring that new gas CC plant before or no later than 2040, and hence would have resulted in stranded investment costs of the gas CC to be recovered from PNM's customers.

disallowance would in fact be unfair and perverse if applied to a plant that was prudently developed and maintained and that has been beneficial for customers for many decades (i.e. saving them money relative to alternatives not needed or not chosen). All prudently chosen utility resources face some possibility they could eventually under-perform relative to expectations, or have their expected operational life cut short by changed policies or unforeseen market and technological changes. If those circumstances, should they arise, are constantly penalized, the investors are not being given a fair chance to earn their allowed cost of capital. PNM made a prudent decision in 2013, just as PNM has followed through on its subsequent commitment to look for and find a way to make a cost-effective exit from this plant. Disallowing a part of its sunk costs (the amount of which depends on authorized depreciation rates) imposes a penalty for saving customers money in the future.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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Mr. Frank C. Graves is a Principal of The Brattle Group who specializes in regulatory and financial economics, especially for electric and gas utilities, and in litigation matters related to securities litigation, damages from breached energy contracts, and risk management.

He has over 35 years of experience assisting utilities in forecasting, valuation, financial planning, and risk management for many kinds of long range investment and service design decisions, such as generation and network capacity expansion, fuel and gas supply procurement and hedging, pricing and cost recovery mechanisms, cost and performance benchmarking, renewable asset selection and contracting, and new business models for distributed energy technologies. He has testified before many state regulatory commissions and the FERC as well as in state and federal courts and arbitration proceedings on such matters as the prudence of investment and contracting decisions, risk management, cost of capital, costs and benefits of new services, policy options for industry restructuring, adequacy of market competition, and competitive implications of proposed mergers and acquisitions.

In the area of financial economics, he has assisted and testified in civil cases in regard to contract damages estimation, securities litigation suits, special purpose audits of non-standard business transactions and their accounting, tax disputes, risk management, and cost of capital estimation, and he has testified in criminal cases regarding corporate executives' culpability for securities fraud.

He received an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975.

Mr. Graves is also a professional violinist and chairman of the Dean's Advisory Council to the Jacobs School of Music at Indiana University

AREAS OF EXPERTISE

- Utility Planning and Operations
- Financial Analysis and Commercial Litigation
- Regulated Industry Policy and Restructuring
- Energy Market Competition

PROFESSIONAL AFFILIATIONS

- IEEE Power Engineering Society
- Mathematical Association of America
- American Finance Association

Recent Activities

Client Engagements

- Liability for wildfire damages drove PG&E to bankruptcy in 2020. Mr. Graves was part of an advisory team that helped appraise and explain the financial benefits to alternative means of compensating victims as part of the debtor's Plan of Reorganization, including securitized debt or contingent payments tied to future financial stability of the company.
- Uncertainty over the pace and extent of potential distributed energy resources (DERs) adoption by customers makes load forecasting and system planning much more complex, possibly involving future "tipping points" when DER use could accelerate rapidly. However, statistical histories on these improving technologies are not yet very informative as to when or why such a shift might occur. Mr. Graves has assisted several distribution utilities with a new, behavior-based modeling technique for long range system planning that simulates possible paths to DER adoption, utilizing system dynamics methods that recognize the feedbacks between offered electricity prices, customers' propensities to use DERs, declining technology costs, cost shifting to non-users, and other interdependencies.
- With improvements in performance and cost of microgeneration, as well as low cost natural gas, many hospitals, universities, and similar campuses are considering combined heat and power supply as an alternative to utility energy services. Mr. Graves has helped several such entities evaluate potential benefits of CHP, including choosing the preferred size and mix of technology and design of risk sharing terms in financial and operating contracts for the CHP systems.
- Several states and cities have set goals of deep decarbonization of their local economies, often dubbed "80 by 50" if they aspire to 80% reductions in GHG emissions by 2050. Achieving this will involve radical change in the economy of those regions, potentially with dramatic load growth due to electrification and massive investment in new infrastructure for end-use and power supply and delivery. Mr. Graves has built models that show what types and degree of change could arise, and what they might cost depending on how such transformations are incentivized or enforced.
- Wildfires in California have become catastrophic in the past few years, creating both financial turmoil for the utilities and controversy over how to insure and manage this problem. Mr. Graves has been extensively involved in estimating the expected, growing cost of this problem and the design of mechanisms to insure it and compensate investors for the likelihood of uncompensated costs from fire damages.

Testimony

In an arbitration matter involving alleged lost productivity at a wind farm due to wake effects from another upstream wind fleet, Mr. Graves provided rebuttal testimony on the claimed damages. Capacity and energy values, as well as risks and drivers of uncertainty for the likely output quantities were presented, explaining how prices and utilization of the facilities were likely to change over a twenty-year horizon in a deeply decarbonizing power system.

For PacifiCorp before the Oregon Public Utility Commission (Docket UE-374, February 2020), Mr. Graves prepared testimony on the difficulties in forecasting short-term power system balancing and trading transactions and the resulting tendency for these to be underestimated in projected operating costs, hence under-collected in rates. Based on a comparison to other states practices, he proposed that such costs be allowed to be fully recovered on a flow-through basis without risk-sharing, subject to prudence.

On behalf of Public Service Company of New Mexico, presented testimony before the New Mexico Public Regulation Commission on the merits of replacing the San Juan Generating Station coal units with a fleet of renewables, storage and gas-fired peakers, and on the reasons for appropriateness of allowing full recovery of sunk costs despite early retirement. Case No. 19-00018-UT, November 15, 2019.

For Dominion Energy Kewaunee, Mr. Graves filed expert testimony in the U.S. Court of Federal Claims (Case No. 18-808 C, July 25, 2019) in regard to the ability of the plaintiff (Kewaunee Nuclear) to have had all its spent nuclear fuel removed by the U.S. DoE, had the government met its obligations to perform under the Standard Contract with the nuclear industry. His modeling of tradeable rights for position in the waste removal queue showed why the government ought to be liable for damages from otherwise unnecessary storage costs at the site. Similar testimonies were filed on behalf of NorthStar for Vermont Yankee (Aug. 2019) and on behalf of Duke Power in regard to the Crystal River nuclear plant (Sept. 2019).

For Nicor Gas, a natural gas distribution company, Mr. Graves co-authored testimony on the cost of equity capital utilizing a broad spectrum of risk-pricing methods and explaining how financial leverage affects it. Testimony was filed with the Illinois Commerce Commission, Docket 18-xxxx, November 9, 2018.

For the electric transmission division of Pacific Gas & Electric, Mr. Graves presented testimony and co-authored an accompanying report on the cost of capital impacts from the extreme risks arising from potential liability for damages caused by large wildfires in California. Testimony before the FERC, Docket ER19- ___ - 000, Exhibit PGE-0019, October 1, 2018.

For the Government of Colombia, written and oral testimony in regard to apparent misrepresentations of coal mine development costs and expected profitability by Glencore Corporation that adversely affected royalty payments for Colombia. Heard in the International Court of Arbitration, ICSID Case No ARB/16/6, Washington DC, June 2018.

Publications

"2020 CAISO Blackouts and Beyond: The Future of California Resource Planning" with John Tsoukalis and Sophie Leamon for LSI's Electric Power in the West Conference, January 2021.

"Clean Energy and Sustainability Accelerator – Opportunities for Long Term Deployment" on recommended targets and mechanisms for use of a $100 billion economic recovery and decarbonization program for the Biden administration. With Bob Mudge, Roger Lueken, and Tess Counts. Prepared for the Coalition for Green Capital, January 14, 2021.

"Emerging Value of Carbon Capture for Utilities" with Kasparas Spokas and Katie Mansur, Public Utilities Fortnightly, October 2020, p. 36-41

"Impacts and Implications of COVID-19 for the Energy Industry" for Energy Bar Association's Virtual Fall Conference, October 13, 2020. (Also several presentations with co-authors Bob Mudge, Tess Counts, Josh Figueroa, Lily Mwalenga, and Shivangi Panon the same topic at earlier dates, for public release and other conferences.)

"System Dynamics Modeling: An Approach to Planning and Developing Strategy in the Changing Electricity Industry" (with Toshiki Bruce Tsuchida, Philip Q Hanser, and Nicole Irwin), Brattle White Paper, April 2019.

"California Megafires: Approaches for Risk Compensation and Financial Resiliency Against Extreme Events" (with Robert S. Mudge and Mariko Geronimo Aydin), Brattle White Paper, October 1, 2018.

"Retail Choice: Ripe for Reform?" (with Agustin Ros, Sanem Sergici, Rebecca Carroll and Kathryn Haderlein), Brattle White Paper, July 2018.

"Resetting FERC RoE Policy; a Window of Opportunity" (with Robert Mudge and Akarsh Sheilendranath), Brattle White Paper, May 2018

Full C.V.

Financial Analysis and Commercial Litigation

- Liability for wildfire damages drove PG&E to bankruptcy in 2020. Mr. Graves was part of an advisory team that helped appraise and explain the financial benefits to alternative means of compensating victims as part of the debtor's Plan of Reorganization, including securitized debt or contingent payments tied to future financial stability of the company.
- A public power utility faced viability-threatening financial distress after a major baseload power plant project proved uneconomic when only partly completed. Mr. Graves led a team that reassessed the decision path that resulted in this outcome, in order to identify what expenditures or contract commitments might be deemed imprudent. He developed system and financial models of the company under alternative resource plans, which also informed how much financial burden would ensue from different kinds of penalties.
- Wildfires in California have become catastrophic in the past 5 years, creating both financial turmoil for the utilities and controversy over how to insure and manage this problem. Mr. Graves has been extensively involved in estimating the expected, growing cost of this problem and the design of mechanisms to insure it and compensate investors for the likelihood of uncompensated costs from fire damages.
- Despite well settled financial economics, there is great regulatory controversy surrounding how or whether to make adjustments in cost of capital measurements for differences in leverage between the proxy firms used to estimate the rate and the capital structure of the target utility. Mr. Graves has lead analyses of how to demonstrate the need for this adjustment, with testimony given to explain the foundations.
- For the government of Colombia, Mr. Graves testified in arbitration about misrepresentations that occurred in the negotiation of royalties over coal mining production. Those negotiations resulted in a royalty scheme that was much more favorable to the coal company than would have been acceptable to Colombia had more realistic representations occurred. He showed that the mining companies own studies projected much higher value and more favorable operating conditions for the facility, and that alternative schedules for running the mine would have produced more value than was asserted possible by its owners.
- For the co-owners of the SONGS nuclear power plant that had become inoperable due to failed and irreparable steam generators, Mr. Graves provided written and oral testimony in arbitration over what damages had been incurred by the utilities from having to replace the nuclear plant with new generation, purchased power, and transmission upgrades, as well as accelerated decommissioning liabilities. His report evaluated the impacts of the lost plant on the entire western power market, including how it would change the needs and costs for emission allowances in the California GHG market. He estimated that damages were nearly $7 billion dollars.

- For an international energy company seeking to expand its operations in the US, Mr. Graves lead an assessment of the market performance risks facing a possible acquisition target, in order to determine what contingencies or market shifts were critical to it being an attractive target. Uncertain long run wholesale energy conditions, tightening environmental regulations, and disruptive technology development prospects were considered.
- For an international technology firm that had experienced a recent bankruptcy, Mr. Graves assisted in the design of a study of how the remaining valuable assets could be deemed assignable to disparate country-specific claims. Company operating practices for research and development risk and profit sharing were evaluated to identify an equitable approach.
- For a merchant power company with a prematurely terminated development contract, Mr. Graves co-lead a team to value the lost contract. The contract included several different kinds of revenue streams of different risks, for which Brattle developed different discount rates and debt carrying-capacity assessments. The case was settled with a very large award consistent with the Brattle valuations.
- Holding company utilities with many subsidiaries in different states face differing kinds of regulatory allowances, balancing accounts with differing lags and allowed returns for cost recovery, possibly different capital structures, as well as different (and varying) operating conditions. Given such heterogeneity, it can be difficult to determine which subsidiaries are performing well vs. poorly relative to their regulatory and operational challenges. Mr. Graves developed a set of financial reporting normalization adjustments to isolate how much of each subsidiary's profitability was due to financial, vs. managerial, vs. non-recurring operational conditions, so that meaningful performance appraisal was possible.
- Many banks, insurance firms and capital management subsidiaries of large multinational corporations have entered into long term, cross border leases of properties under sale and leaseback or lease in, lease out terms. These have been deemed to be unacceptable tax shelters by the IRS, but that is an appealable claim. Mr. Graves has assisted several companies in evaluating whether their cross border leases had legitimate business purpose and economic substance, above and beyond their tax benefits, due to likelihood of potentially facing a role as equity holder with ownership risks and rewards. He has shown that this is a case-specific matter, not per se determined by the general character of these transactions.
- For a private energy hedge fund providing risk management contracts to industrial energy users, a breach of contract from one industrial customer was disputed as supposedly involving little or no loss because the fund had not been forced to liquidate positions at a loss that corresponded precisely to the abruptly terminated contract. Mr. Graves provided analysis demonstrating how the portfolio loss was borne, but other fund management metrics used to control positions, and other unrelated hedging positions, also changed roughly concurrently in a manner that disguised the way the economic damage was realized over time. The case was settled on favorable terms for Mr. Graves' client.

- Many utilities have regulated and unregulated subsidiaries, which face different types and degrees of risk. Mr. Graves lead a study of the appropriate adjustments to corporate hurdle rates for the various lines of business of a utility with many types of operations.
- A company that incurred Windfall Tax liabilities in the U.K. regarded those taxes as creditable against U.S. income taxes, but this was disputed by the IRS. Mr. Graves lead a team that prepared reports and testimony on why the Windfall Tax had the character of a typical excess profits tax, and so should be deemed creditable in the U.S. The tax courts concurred with this opinion and allowed the claimed tax deductions in full.
- For a defendant in a sentencing hearing for securities' fraud, Mr. Graves prepared an analysis of how the defendant's role in the corporate crisis was confounded by other concurrent events and disclosures that made loss calculations unreliable. At trial, the Government stipulated that it agreed with Mr. Graves' analysis.
- For the U.S. Department of Justice, Mr. Graves prepared an event study quantifying bounds on the economic harm to shareholders that had likely ensued from revelations that Dynegy Corporation's "Project Alpha" had been improperly represented as a source of operating income rather than as a financing. The event study was presented in the re-sentencing hearing of Mr. Jamie Olis, the primary architect of Project Alpha.
- Mr. Graves has assisted leasing companies with analyses of the tax-legitimacy of complex leasing transactions. These analyses involved reviewing the extent and quality of due diligence pursued by the lessor, the adequacy of pre-tax returns, the character, time pattern, and degree of risk borne by the buyer (lessor), the extent, purpose and cost of defeasance, and compliance with prevailing guidelines for true-lease status.
- For a utility facing significant financial losses from likely future costs of its Provider of Last Resort (POLR) obligations, Mr. Graves prepared an analysis of how optimal hindsight coverage of the liability would have compared in costs to a proposed restructuring of the obligation. He also reviewed the prudence of prior, actual coverage of the obligation in light of conventional risk management practices and prevailing market conditions of credit constraints and low long-term liquidity.
- Several banks were accused of aiding and abetting Enron's fraudulent schemes and were sued for damages. Mr. Graves analyzed how the stock market had reacted to one bank's equity analyst's reports endorsing Enron as a "buy," to determine if those reports induced statistically significant positive abnormal returns. He showed that individually and collectively they did not have such an effect.
- Mr. Graves lead an analysis of whether a corporate subsidiary had been effectively under the strategic and operational control of its parent, to such an extent that it was appropriate to "pierce the corporate veil" of limited liability. The analysis investigated the presence of untenable debt capitalization in the subsidiary, overlapping management staff, the adherence to normal corporate governance protocols, and other kinds of evidence of excessive parental control.

- As a tax-revenue enhancement measure, the IRS was considering a plan to recapture deferred taxes associated with generation assets that were divested or reorganized during state restructurings for retail access. Mr. Graves prepared a white paper demonstrating the unfairness and adverse consequences of such a plan, which was instrumental in eliminating the proposal.
- For a major electronics and semiconductor firm, Mr. Graves critiqued and refined a proposed procedure for ranking the attractiveness of research and development projects. Aspects of risk peculiar to research projects were emphasized over the standards used for budgeting an already proven commercial venture.
- In a dispute over damages from a prematurely terminated long-term power tolling contract, Mr. Graves presented evidence on why calculating the present value of those damages required the use of two distinct discount rates: one (a low rate) for the revenues lost under the low-risk terminated contract and another, much higher rate, for the valuation of the replacement revenues in the risky, short-term wholesale power markets. The amount of damages was dramatically larger under a two-discount rate calculation, which was the position adopted by the court.
- The energy and telecom industries, especially in the late 1990s and early 2000s, were plagued by allegations regarding trading and accounting misrepresentations, such as wash trades, manipulations of mark-to-market valuations, premature recognition of revenues, and improper use of off-balance sheet entities. In many cases, this conduct has preceded financial collapse and subsequent shareholder suits. Mr. Graves lead research on accounting and financial evidence, including event studies of the stock price movements around the time of the contested practices, and reconstruction of accounting and economic justifications for the way asset values and revenues were recorded.
- Dramatic natural gas price increases in the U.S. have put several natural gas and electric utilities in the position of having to counter claims that they should have hedged more of their fuel supplies at times in the past. Mr. Graves developed testimony to rebut this hindsight criticism and risk management techniques for fuel (and power) procurement for utilities to apply in the future to avoid prudence challenges.
- As a means of calculating its stranded costs, a utility used a partial spin-off of its generation assets to a company that had a minority ownership from public shareholders. A dispute arose as to whether this minority ownership might be depressing the stock price, if a "control premium" was being implicitly deducted from its value. Using event studies and structural analyses, Mr. Graves identified the key drivers of value for this partially spun-off subsidiary, and he showed that value was not being impaired by the operating, financial and strategic restrictions on the company. He also reviewed the financial economics literature on empirical evidence for control premiums, which he showed reinforced the view that no control premium de-valuation was likely to be affecting the stock.
- A large public power agency was concerned about its debt capacity in light of increasing competitive pressures to allow its resale customers to use alternative suppliers. Mr. Graves lead

a team that developed an Economic Balance Sheet representation of the agency's electric assets and liabilities in market value terms, which was analyzed across several scenarios to determine safe levels of debt financing. In addition, new service pricing and upstream supply contracting arrangements were identified to help reduce risks.

- Wholesale generating companies intuitively realize that there are considerable differences in the financial risk of different kinds of power plant projects, depending on fuel type, length and duration of power purchase agreements, and tightness of local markets. However, they often are unaware of how if at all to adjust the hurdle rates applied to valuation and development decisions. Mr. Graves lead a Brattle analysis of risk-adjusted discount rates for generation; very substantial adjustments were found to be necessary.
- A major telecommunications firm was concerned about when and how to reenter the Pacific Rim for wireless ventures following the economic collapse of that region in 1997-99. Mr. Graves lead an engagement to identify prospective local partners with a governance structure that made it unlikely for them to divert capital from the venture if markets went soft. He also helped specify contracting and financing structures that create incentives for the venture to remain together should it face financial distress, while offering strong returns under good performance.
- There are many risks associated with operations in a foreign country, related to the stability of its currency, its macro economy, its foreign investment policies, and even its political system. Mr. Graves has assisted firms facing these new dimensions to assess the risks, identify strategic advantages, and choose an appropriate, risk-adjusted hurdle rate for the market conditions and contracting terms they will face.
- The glut of generation capacity that helped usher in electric industry restructuring in the US led to asset devaluations in many places, even where no retail access was allowed. In some cases, this has led to bankruptcy, especially of a few large rural electric cooperatives. Mr. Graves assisted one such coop with its long term financial modeling and rate design under its plan of reorganization, which was approved. Testimony was provided on cost-of-service justifications for the new generation and transmission prices, as well as on risks to the plan from potential environmental liabilities.
- Power plants often provide a significant contribution to the property tax revenues of the townships where they are located. A common valuation policy for such assets has been that they are worth at least their book value, because that is the foundation for their cost recovery under cost-of-service utility ratemaking. However, restructuring throws away that guarantee, requiring reappraisal of these assets. Traditional valuation methods, e.g., based on the replacement costs of comparable assets, can be misleading because they do not consider market conditions. Mr. Graves testified on such matters on behalf of the owners of a small, out-of-market coal unit in Massachusetts.
- Stranded costs and out-of-market contracts from restructuring can affect municipalities and cooperatives as well as investor-owned utilities. Mr. Graves assisted one debt-financed utility in an evaluation of its possibilities for reorganization, refinancing, and re-engineering to

improve financial health and to lower rates. Sale and leaseback of generation, fuel contract renegotiation, targeted downsizing, spin-off of transmission, and new marketing programs were among the many components of the proposed new business plan.

- As a means of reducing supply commitment risk, some utilities have solicited offers for power contracts that grant the right but not the obligation to take power at some future date at a predetermined price, in exchange for an initial option premium payment. Mr. Graves assisted several of these utilities in the development of valuation models for comparing the asking prices to fair market values for option contracts. In addition, he has helped these clients develop estimates of the critical option valuation parameters, such as trend, volatility, and correlations of the future prices of electric power and the various fuel indexes proposed for pricing the optional power.
- For the World Bank and several investor-owned electric utilities, Mr. Graves presented tutorial seminars on applying methods of financial economics to the evaluation of power production investments. Techniques for using option pricing to appraise the value of flexibility (such as arises from fuel switching capability or small plant size) were emphasized. He has applied these methods in estimating the value of contingent contract terms in fuel contracts (such as price caps and floors) for natural gas pipelines.
- Mr. Graves prepared a review of empirical evidence regarding the stock market's reaction to alternative dividend, stock repurchase, and stock dividend policies for a major electric utility. Tax effects, clientele shifting, signaling, and ability to sustain any new policies into the future were evaluated. A one-time stock repurchase, with careful announcement wording, was recommended.
- For a division of a large telecommunications firm, Mr. Graves assisted in a cost benchmarking study, in which the costs and management processes for billing, service order and inventory, and software development were compared to the practices of other affiliates and competitors. Unit costs were developed at a level far more detailed than the company normally tracked, and numerical measures of drivers that explained the structural and efficiency causes of variation in cost performance were identified. Potential costs savings of 10-50 percent were estimated, and procedures for better identification of inefficiencies were suggested.
- For an electric utility seeking to improve its plant maintenance program, Mr. Graves directed a study on the incremental value of a percentage point decrease in the expected forced outage rate at each plant owned and operated by the company. This defined an economic priority ladder for efforts to reduce outage that could be used in lieu of engineering standards for each plant's availability. The potential savings were compared to the costs of alternative schedules and contracting policies for preventive and reactive maintenance, in order to specify a cost reduction program.
- Mr. Graves conducted a study on the risk-adjusted discount rate appropriate to a publicly-owned electric utility's capacity planning. Since revenue requirements (the amounts being discounted) include operating costs in addition to capital recovery costs, the weighted average cost of capital for a comparable utility with traded securities may not be the correct rate for

every alternative or scenario. The risks implicit in the utility's expansion alternatives were broken into component sources and phases, weighted, and compared to the risks of bonds and stocks to estimate project-specific discount rates and their probable bounds.

Utility Planning and Operations

- Uncertainty over the pace and extent of potential distributed energy resources (DERs) adoption by customers makes load forecasting and system planning much more complex, possibly involving future "tipping points" when DER use could accelerate rapidly. However, statistical histories on these improving technologies are not yet very informative as to when or why such a shift might occur. Mr. Graves has assisted several distribution utilities with a new, behavior-based modeling technique for long range system planning that simulates possible paths to DER adoption, utilizing system dynamics methods that recognize feedbacks between electricity prices, customers' propensities to use DERs, declining technology costs, cost shifting to non-users, load shapes, and financial performance.
- Many large high-tech firms are selling power supply services relying entirely on renewable resources. This can only be done for average or cumulative power needs, but the resulting green energy production will not match the time pattern of those firms' demand. Mr. Graves lead a team evaluating how much risk is borne by a utility from offering such service over many years, when it will have to balance a significant green supply (such as rooftop and utility-scale solar) against its own load and the regional market.
- With improvements in performance and cost of microgeneration, many hospitals, universities, and similar campuses are considering combined heat and power supply as an alternative to utility energy services. Mr. Graves has helped several such entities evaluate potential benefits of CHP, including choosing the preferred size and mix of technology and risk analysis of terms in financial and operating contracts for the CHP systems.
- Many utilities are facing a concern through the expected useful lives of their coal plants are being shortened by low gas prices and increased use of renewables. Mr. Graves helped a utility justify early retirement of a coal plant with full recovery of its stranded costs, when that plan could be replaced more economically with new wind plants while the tax incentives for their development were still in effect.
- Mr. Graves developed a valuation and risk analysis model showing that a utility's RFP for new generation could be better served by deferring new plant construction for a few years via a less costly and less risky transitional market-based power supply contract with price and quantity terms shaped to match the shifting needs over time until supply shortfalls were large enough to justify the investment in a new power plant at efficient scale. The parties negotiated a multi-year contract along these lines in lieu of pursuing the construction alternative that initially came out of the RFP selection.
- In Maryland the electric distribution companies administer SOS (Standard Offer Service) supply procurement and accounting to backup customers who do not use a competitive retail power supplier. The utilities are authorized to recover both the direct and financing costs of

that service plus a return on equity. Mr. Graves developed a method for sizing an appropriate equity return for the SOS risks and administrative services based on analogies to various intermediation businesses on the internet, such as EBay, PayPal, and others—in which, like SOS intermediation, the businesses do not take ownership for the products conveyed. Testimony was provided.

- Mr. Graves co-lead a team of Brattle analysts to assess the relative influence of different factors that were affected by the "Polar Vortex" cold snap of early 2014 that caused dramatic spikes in local power and gas prices in parts of the mid-Atlantic and northeastern US. The risks of similar recurring events were assessed in light of pending expansions of the electric and gas transmission grids, as well as likely coal plant retirements.
- For the Board of Directors or executive management teams of several utilities, Mr. Graves has lead strategic retreats on disruptive issues facing the electric industry in the future and how a utility should choose which risks and opportunities to embrace vs. avoid.
- Air quality and other power plant environmental regulations are being tightened considerably in the period from about 2014-2018. Mr. Graves has co-developed a market and financial model for determining what power plants are most likely to retire vs. retrofit with new environmental controls, and how much this may alter their profitability. This has been used to help several power market participants assess future capacity needs, as well as to adjust their price forecasts for the coming decade.
- Successful merchant power plant development and financing depends in part on obtaining a long term power purchase agreement. Mr. Graves directed a study of what pricing points and risk-sharing terms should be attractive to potential buyers of long-term power supply contracts from a large baseload facility.
- Many utilities are pursuing smart meters and time-of-use pricing to increase customer ability to consume electricity economically. Mr. Graves has led a study of the costs and benefits of different scales and timing of installation of such meters, to determine the appropriate pace. He has also evaluated how various customer incentives to increase conservation and demand response might be provided over the internet, and how much they might increase the participation rates in smart meter programs.
- Wind resources are a critical part of the generation expansion plans and contracting interests of many utilities, in order to satisfy renewable portfolio standards and to reduce long run exposure to carbon prices and fuel cost uncertainty. Mr. Graves has applied Brattle's risk modeling capabilities to simulate the impacts of on- and off-shore wind resources on the potential range of costs for portfolios of wholesale power contracts designed to serve retail electricity loads. These impacts were compared to gas CCs and CTs and to simply buying more from the wholesale market to identify the most economical supply strategy.
- For a municipal utility with an opportunity to invest in a nuclear power plant expansion, Mr. Graves lead an analysis of how the proposed plant fit the needs of the company, what market and regulatory (environmental) conditions would be required for the plant to be more economical than conventional fossil-fired generation, and how the development risks could be

shared among co-owners to better match their needs and risk tolerances. He also assessed the market for potential off-take contracts to recover some of the costs and capacity that would be available for a few years, ahead of the needs of the municipal utility.

- The potential introduction of environmental restrictions or fees for CO2 emissions has made generation expansion decisions much more complex and risky. He helped one utility assess these risks in regard to a planned baseload coal plant, finding that the value of flexibility in other technologies was high enough to prefer not building a conventional coal plant.
- Mr. Graves helped design, implement, and gain regulatory approvals for a natural gas procurement hedging program for a western U.S. gas and electric utility. A model of how gas forward prices evolve over time was estimated and combined with a statistical model of the term structure of gas volatility to simulate the uncertainty in the annual cost of gas at various times during its procurement, and the resulting impact on the range of potential customer costs.
- Generation planning for utilities has become very complex and risky due to high natural gas prices and potential CO2 restrictions of emission allowances. Some of the scenarios that must be considered would radically alter system operations relative to current patterns of use. Mr. Graves has assisted utilities with long range planning for how to measure and cope with these risks, including how to build and value contingency plans in their resource selection criteria, and what kinds of regulatory communications to pursue to manage expectations in this difficult environment.
- For a Midwestern utility proposing to divest a nuclear plant, Mr. Graves analyzed the reasonableness of the proposed power buyback agreement and the effects on risks to utility customers from continued ownership vs. divestiture. The decommissioning funds were also assessed as to whether their transfer altered the appropriate purchase price.
- Several utilities with coal-fired power plants have faced allegations from the U.S. EPA that they have conducted past maintenance on these plants which should be deemed "major modifications", thereby triggering New Source Review standards for air quality controls. Mr. Graves has helped one such utility assess limitations on the way in which GADS data can be used retrospectively to quantify comparisons between past actual and projected future emissions. For another utility, Mr. Graves developed retrospective estimates of changes in emissions before and after repairs using production costing simulations. In a third, he reviewed contemporaneous corporate planning documents to show that no increase in emissions would have been expected from the repairs, due to projected reductions in future use of the plant as well as higher efficiency. In all three cases, testimony was presented.
- The U.S. Government is contractually obligated to dispose of spent nuclear fuel at commercial reactors after January 1998, but it has not fulfilled this duty. As a result, nuclear facilities that are shutdown or facing full spent fuel pools are facing burdensome costs and risks. Mr. Graves prepared developed an economic model of the performance that could have reasonably been expected of the government, had it not breached its contract to remove the spent fuel.

- Capturing the full value of hydroelectric generation assets in a competitive power market is heavily dependent on operating practices that astutely shift between real power and ancillary services markets, while still observing a host of non-electric hydrological constraints. Mr. Graves led studies for several major hydro generation owners in regard to forecasting of market conditions and corresponding hydro schedule optimization. He has also designed transfer pricing procedures that create an internal market for diverting hydro assets from real power to system support services firms that do not yet have explicit, observable market prices.
- Mr. Graves led a gas distribution company in the development of an incentive ratemaking system to replace all aspects of its traditional cost of service regulation. The base rates (for non-fuel operating and capital costs) were indexed on a price-cap basis (RPI-X), while the gas and upstream transportation costs allowances were tied to optimal average annual usage of a reference portfolio of supply and transportation contracts. The gas program also included numerous adjustments to the gas company's rate design, such as designing new standby rates so that customer choice will not be distorted by pricing inefficiencies.
- An electric utility with several out-of-market independent power contracts wanted to determine the value of making those plants dispatchable and to devise a negotiating strategy for restructuring the IPP agreements. Mr. Graves developed a range of forecasts for the delivered price of natural gas to this area of the country. Alternative ways of sharing the potential dispatch savings were proposed as incentives for the IPPs to renegotiate their utility contracts.
- For an electric utility considering the conversion of some large oil-fired units to natural gas, Mr. Graves conducted a study of the advantages of alternative means of obtaining gas supplies and gas transportation services. A combination of monthly and daily spot gas supplies, interruptible pipeline transportation over several routes, gas storage services, and "swing" (contingent) supply contracts with gas marketers was shown to be attractive. Testimony was presented on why the additional services of a local distribution company would be unneeded and uneconomic.
- A power engineering firm entered into a contract to provide operations and maintenance services for a cogenerator, with incentives fees tied to the unit's availability and operating cost. When the fees increased due to changes in the electric utility tariff to which they were tied, a dispute arose. Mr. Graves provided analysis and testimony on the avoided costs associated with improved cogeneration performance under a variety of economic scenarios and under several alternative utility tariffs.
- Mr. Graves has helped several pipelines design incentive pricing mechanisms for recovering their expected costs and reducing their regulatory burdens. Among these have been Automatic Rate Adjustment Mechanisms (ARAMs) for indexation of operations and maintenance expenses, construction-cost variance-sharing for routine capital expenditures that included a procedure for eliciting unbiased estimates of future costs, and market-based prices capped at replacement costs when near-term future expansion was an uncertain but probable need.

- For a major industrial gas user, he prepared a critique of the transportation balancing charges proposed by the local gas distribution company. Those charges were shown to be arbitrarily sensitive to the measurement period as well as to inconsistent attribution of storage versus replacement supply costs to imbalance volumes. Alternative balancing valuation and accounting methods were shown to be cheaper, more efficient, and simpler to administer. This analysis helped the parties reach a settlement based on a cash-in/cash-out design.
- The Clean Air Act Amendments authorized electric utilities to trade emission allowances (EAs) as part of their approach to complying with SO2 emissions reductions targets. For the Electric Power Research Institute (EPRI), Mr. Graves developed multi-stage planning models to illustrate how the considerable uncertainty surrounding future EA prices justifies waiting to invest in irreversible control technologies, such as scrubbers or SCRs, until the present value cost of such investments is significantly below that projected from relying on EAs.
- For an electric utility with a troubled nuclear plant, Mr. Graves presented testimony on the economic benefits likely to ensue from a major reorganization. The plant was to be spun off to a jointly-owned subsidiary that would sell available energy back to the original owner under a contract indexed to industry unit cost experience. This proposal afforded a considerable reduction of risk to ratepayers in exchange for a reasonable, but highly uncertain prospect of profits for new investors. Testimony compared the incentive benefits and potential conflicts under this arrangement to the outcomes foreseeable from more conventional incentive ratemaking arrangements.
- Mr. Graves helped design Gas Inventory Charge (GIC) tariffs for interstate pipelines seeking to reduce their risks of not recovering the full costs of multi-year gas supply contracts. The costs of holding supplies in anticipation of future, uncertain demand were evaluated with models of the pipeline's supply portfolio that reveal how many non-production costs (demand charges, take-or-pay penalties, reservation fees, or remarketing costs for released gas) would accrue under a range of demand scenarios. The expected present value of these costs provided a basis for the GIC tariff.
- Mr. Graves performed a review and critique of a state energy commission's assessment of regional natural gas and electric power markets in order to determine what kinds of pipeline expansion into the area was economic. A proposed facility under review for regulatory approval was found to depend strongly on uneconomic bypass of existing pipelines and LDCs. In testimony, modular expansion of existing pipelines was shown to have significantly lower costs and risks.
- For several electric utilities with generation capacity in excess of target reserve margins, Mr. Graves designed and supervised market analyses to identify resale opportunities by comparing the marginal operating costs of all this company's power plants not needed to meet target reserves to the marginal costs for almost 100 neighboring utilities. These cost curves were then overlaid on the corresponding curve for the client utility to identify which neighbors were competitors and which were potential customers. The strength of their relative threat or

attractiveness could be quantified by the present value of the product of the amount, duration, and differential cost of capacity that was displaceable by the client utility.

- Mr. Graves specified algorithms for the enhancement of the EPRI EGEAS generation expansion optimization model, to capture the first-order effects of financial and regulatory constraints on the preferred generation mix.
- For a major electric power wholesaler, Mr. Graves developed a framework for estimating how pricing policies affect the relative attractiveness of capacity expansion alternatives. Traditional cost-recovery pricing rules can significantly distort the choice between two otherwise equivalent capacity plans, if one includes a severe “front end load” while the other does not. Price-demand feedback loops in simulation models and quantification of consumer satisfaction measures were used to appraise the problem. This “value of service” framework was generalized for the Electric Power Research Institute.
- For a large gas and electric utility, Mr. Graves participated in coordinating and evaluating the design of a strategic and operational planning system. This included computer models of all aspects of utility operations, from demand forecasting through generation planning to financing and rate design. Efforts were split between technical contributions to model design and attention to organizational priorities and behavioral norms with which the system had to be compatible.
- For an oil and gas exploration and production firm, Mr. Graves developed a framework for identifying what industry groups were most likely to be interested in natural gas supply contracts featuring atypical risk-sharing provisions. These provisions, such as price indexing or performance requirements contingent on market conditions, are a form of product differentiation for the producer, allowing it to obtain a price premium for the insurance-like services.
- For a natural gas distribution company, Mr. Graves established procedures for redefining customer classes and for repricing gas services according to customers' similarities in load shape, access to alternative gas supplies, expected growth, and need for reliability. In this manner, natural gas service was effectively differentiated into several products, each with price and risk appropriate to a specific market. Planning tools were developed for balancing gas portfolios to customer group demands.
- For a Midwestern electric utility, Mr. Graves extended a regulatory pro forma financial model to capture the contractual and tax implications of canceling and writing off a nuclear power plant in mid-construction. This possibility was then appraised relative to completion or substitution alternatives from the viewpoints of shareholders (market value of common equity) and ratepayers (present value of revenue requirements).
- For a corporate venture capital group, Mr. Graves conducted a market-risk assessment of investing in a gas exploration and production company with contracts to an interstate pipeline. The pipeline's market growth, competitive strength, alternative suppliers, and regulatory exposure were appraised to determine whether its future would support the purchase volumes needed to make the venture attractive.

- For a natural gas production and distribution company, he developed a strategic plan to integrate the company's functional policies and to reposition its operations for the next five years. Decision analysis concepts were combined with marginal cost estimation and financial pro forma simulation to identify attractive and resilient alternatives. Recommendations included target markets, supply sources, capital budget constraints, rate design, and a planning system. A two-day planning conference was conducted with the client's executives to refine and internalize the strategy.
- For the New Mexico Public Service Commission, he analyzed the merits of a corporate reorganization of the major New Mexico gas production and distribution company. State ownership of the company as a large public utility was considered but rejected on concerns over efficiency and the burdening of performance risks onto state and local taxpayers.

Regulated Industry Policy and Restructuring

- Several states and cities have set goals of deep decarbonization of their local economies, often dubbed “80 by 50” if they aspire to 80% reductions in GHG emissions by 2050. Achieving this will involve radical change in the economy of those regions, potentially with dramatic load growth due to electrification and massive investment in new infrastructure for end-use and power supply and delivery. Mr. Graves has built models that show what types and degree of change could arise, and what they might cost depending on how such transformations are incentivized or enforced.
- As wholesale power and natural gas prices have fallen, interest in “retail choice” for energy supply has increased. At the same time, some state regulatory agencies have become concerned that misleading marketing and non-competitive pricing are too common in the mass market, especially afflicting low income and senior residential customers. Mr. Graves lead a review of such concerns that compared practices and market performance in several states to identify what could be done to improve such services.
- For a group of utilities responding to a state mandate to consider means of encouraging distributed technologies to be assessed and incentivized in parity with central station generation, Mr. Graves and others at Brattle prepared alternative means of incorporating marginal cost and externality value considerations into new cost/benefit assessment tools, procurement mechanisms, and supply contracting.
- For a mid-Atlantic gas distribution utility, Mr. Graves assessed mark to market losses that had occurred from gas supply hedges entered before spot prices declined precipitously. Concerns were voice that this outcome indicated the company’s hedging practices were no longer attune to market conditions, so Mr. Graves developed and lead workshop between the company, intervener groups, and state commission staff to define new appropriate goals, mechanisms and review standards for revised risk management approach.

- For a major participant in the Japanese power industry contemplating reorganization of that country's electric sector following Fukushima, Mr. Graves lead a research project on the performance of alternative market designs around the US and around the world for vertical unbundling, RTO design, and retail choice.
- For several utilities facing the end of transitional "provider of last resort" (or POLR) prices, Mr. Graves developed forecasts and risk analyses of alternative procurement mechanisms for follow-on POLR contracts. He compared portfolio risk management approaches to full requirements outsourcing under various terms and conditions.
- For a large municipal electric and gas company considering whether to opt-in to state retail access programs, Mr. Graves lead an analysis of what changes in the level and volatility of customer rates would likely occur, what transition mechanisms would be required, and what impacts this would have on city revenues earned as a portion of local electric and gas service charges.
- Many utilities experienced significant "rate shock" when they ended "rate freeze" transition periods that had been implemented with earlier retail restructuring. The adverse customer and political reactions have led to proposals to annual procurement auctions and to return to utility-owned or managed supply portfolios. Mr. Graves has assisted utilities and wholesale gencos with analyses of whether alternative supply procurement arrangements could be beneficial.
- The impacts of transmission open access and wholesale competition on electric generators risks and financial health are well documented. In addition, there are substantial impacts on fuel suppliers, due to revised dispatch, repowerings and retirements, changes in expansion mix, altered load shapes and load growth under more competitive pricing. For EPRI, Mr. Graves co-authored a study that projected changes in fuel use within and between ten large power market regions spanning the country under different scenarios for the pace and success of restructuring.
- As a result of vertical unbundling, many utilities must procure a substantial portion of their power from resources they do not own or operate. Market prices for such supplies are quite volatile. In addition, utilities may face future customer switching to or from their supply service, especially if they are acting as provider of last resort (POLR). This problem is a blending of risk management with the traditional least-cost Integrated Resource Planning (IRP). Regulatory standards for findings of prudence in such a hybrid environment are often not well understood or articulated, leaving utilities at risk for cost disallowances that can jeopardize their credit-worthiness. Mr. Graves has assisted several utilities in devising updated procurement mechanisms, hedging strategies, and associated regulatory guidelines that clarify the conditions for approval and cost recovery of resource plans, in order to make possible the expedited procurement of power from wholesale market suppliers.
- Public power authorities and cooperatives face risks from wholesale restructuring if their sales-for-resale customers are free to switch to or from supply contracting with other wholesale suppliers. Such switching can create difficulties in servicing the significant debt capitalization

of these public power entities, as well as equitable problems with respect to non-switching customers. Mr. Graves has lead analyses of this problem, and has designed alternative product pricing, switching terms and conditions, and debt capitalization policies to cope with the risks.

- As a means of unbundling to retain ownership but not control of generation, some utilities turned to divesting output contracts. Mr. Graves was involved in the design and approval of such agreements for a utility's fleet of generation. The work entailed estimating and projecting cost functions that were likely to track the future marginal and total costs of the units and analysis of the financial risks the plant operator would bear from the output pricing formula. Testimony on risks under this form of restructuring was presented.
- Mr. Graves contributed to the design and pricing of unbundled services on several natural gas pipelines. To identify attractive alternatives, the marginal costs of possible changes in a pipeline's service mix were quantified by simulating the least-cost operating practices subject to the network's physical and contractual constraints. Such analysis helped one pipeline to justify a zone-based rate design for its firm transportation service. Another pipeline used this technique to demonstrate that unintended degradations of system performance and increased costs could ensue from certain proposed unbundling designs that were insensitive to system operations.
- For several natural gas pipeline companies, Mr. Graves evaluated the cost of equity capital in light of the requirements of FERC Order 636 to unbundle and reprice pipeline services. In addition to traditional DCF and risk positioning studies, the risk implications of different degrees of financial leverage (debt capitalization) were modeled and quantified. Aspects of rate design and cost allocation between services that also affect pipeline risk were considered.
- Mr. Graves assisted several utilities in forecasting market prices, revenues, and risks for generation assets being shifted from regulated cost recovery to competitive, deregulated wholesale power markets. Such studies have facilitated planning decisions, such as whether to divest generation or retain it, and they have been used as the basis for quantifying stranded costs associated with restructuring in regulatory hearings. Mr. Graves has assisted a leasing company with analyses of the tax-legitimacy of complex leasing transactions by reviewing the extent and quality of due diligence pursued by the lessor, the adequacy of pre-tax returns, the character, time pattern, and degree of risk borne by the buyer (lessor), the extent of defeasance, and compliance with prevailing guidelines for true-lease status.

Market Competition

- Mr. Graves assisted a nuclear plant owner with an assessment of whether a proposed merger of a company in whom it had a partial investment interest would alter the co-owner's incentives to manage the plant for maximum stand-alone value of the asset. Structural and behavioral models of the relevant market were developed to determine that there would be no material changes in incentive or ability to affect the value of the asset.

- Mr. Graves has testified on the quality of retail competition in Pennsylvania and on whether various proposals for altering Default Service might create more robust competition.
- Regulatory and legal approvals of utility mergers require evidence that the combined entity will not have undue market power. Mr. Graves assisted several utilities in evaluating the competitive impacts of potential mergers and acquisitions. He has identified ways in which transmission constraints reduce the number and type of suppliers, along with mechanisms for incorporating physical flow limits in FERC's Delivered Price Test (DPT) for mergers. He has also assessed the adequacy of mitigation measures (divestitures and conduct restrictions) under the DPT, Market-Based Rates, and other tests of potential market power arising from proposed mergers.
- A major concern associated with electric utility industry restructuring is whether or not generation markets are adequately competitive. Because of the state-dependent nature of transmission transfer capability between regions, itself a function of generation use, the quality of competition in the wholesale generation markets can vary significantly and may be susceptible to market power abuse by dominant suppliers. Mr. Graves helped one of the largest ISOs in the U.S. develop market monitoring procedures to detect and discourage market manipulations that would impair competition.
- Vertical market power arises when sufficient control of an upstream market creates a competitive advantage in a downstream market. It is possible for this problem to arise in power supply, in settings where the likely marginal generation is dependent on very few fuel suppliers who also have economic interests in the local generation market. Mr. Graves analyzed this problem in the context of the California gas and electric markets and filed testimony to explain the magnitude and manifestations of the problem.
- The increased use of transmission congestion pricing has created interest in merchant transmission facilities. Mr. Graves assisted a developer with testimony on the potential impacts of a proposed line on market competition for transmission services and adjacent generation markets. He also assisted in the design of the process for soliciting and ranking bids to buy tranches of capacity over the line.
- Many regions have misgivings about whether the preconditions for retail electric access are truly in place. In one such region, Mr. Graves assisted a group of industrial customers with a critique of retail restructuring proposals to demonstrate that the locally weak transmission grid made adequate competition among numerous generation suppliers very implausible.
- Mr. Graves assisted one of the early ISOs with its initial market performance assessment and its design of market monitoring tests for diagnosing the quality of prevailing competition.

Electric and Gas Transmission

- Substantial fleets of wind-based generation can impose significant integration costs on power systems. Mr. Graves assisted in assessing what additional amounts and costs for ancillary services would be needed for a Western utility with a large renewable fleet. The approach included a statistical analysis of how wind output was correlated with demand, and how much forecasting error in wind output was likely to be faced over different scheduling horizons. Benefits of geographic diversity of the wind fleet were also assessed.
- For a utility seeking FERC approval for the purchase of an affiliate's generating facility, Mr. Graves analyzed how transmission constraints affecting alternative supply resources altered their usefulness to the buyer.
- As part of a generation capacity planning study, he lead an analysis of how congestion premiums and discounts relative to locational marginal prices (LMPs) at load centers affected the attractiveness of different potential locations for new generation. At issue was whether the prevailing LMP differences would be stable over time, as new transmission facilities were completed, and whether new plants could exacerbate existing differentials and lead to degraded market value at other plants.
- Mr. Graves assisted a genco with its involvement in the negotiation and settlement of "regional through and out rates" (RTOR) that were to be abolished when MISO joined PJM. His team analyzed the distribution of cost impacts from several competing proposals, and they commented on administrative difficulties or advantages associated with each.
- For the electric utility regulatory commission of Colombia, S.A., Mr. Graves led a study to assess the inadequacies in the physical capabilities and economic incentives to manage voltages at adequate levels. The Brattle team developed minimum reactive power support obligations and supplement reactive power acquisition mechanisms for generators, transmission companies, and distribution companies.
- Mr. Graves conducted a cost-of-service analysis for the pricing of ancillary services provided by the New York Power Authority.
- On behalf of the Electric Power Research Institute (EPRI), Mr. Graves wrote a primer on how to define and measure the cost of electric utility transmission services for better planning, pricing, and regulatory policies. The text covers the basic electrical engineering of power circuits, utility practices to exploit transmission economies of scale, means of assuring system stability, economic dispatch subject to transmission constraints, and the estimation of marginal costs of transmission. The implications for a variety of policy issues are also discussed.
- The natural gas pipeline industry is wedged between competitive gas production and competitive resale of gas delivered to end users. In principle, the resulting basis differentials between locations around the pipeline ought to provide efficient usage and expansion signals, but traditional pricing rules prevent the pipeline companies from participating in the marginal value of their own services. Mr. Graves worked to develop alternative pricing mechanisms and

service mixes for pipelines that would provide more dynamically efficient signals and incentives.

- Mr. Graves analyzed the spatial and temporal patterns of marginal costs on gas and electric utility transmission networks using optimization models of production costs and network flows. These results were used by one natural gas transmission company to design receipt-point-based transmission service tariffs, and by another to demonstrate the incremental costs and uneven distribution of impacts on customers that would result from a proposed unbundling of services.

TESTIMONY

For PacifiCorp before the Oregon Public Utility Commission (Docket UE-374, February 2020), Mr. Graves prepared testimony on the difficulties in forecasting short-term power system balancing and trading transactions and the resulting tendency for these to be underestimated in projected operating costs, hence under-collected in rates. Based on a comparison to other states practices, he proposed that such costs be allowed to be fully recovered on a flow-through basis without risk-sharing, subject to prudence.

On behalf of Public Service Company of New Mexico, presented testimony before the New Mexico Public Regulation Commission on the merits of replacing the San Juan Generating Station coal units with a fleet of renewables, storage and gas-fired peakers, and on the reasons for allowing full recovery of the coal plant's sunk costs despite early retirement. Case No. 19-00018-UT, November 15, 2019.

On behalf of both Southern California Edison and Pacific Gas & Electric Company, presented direct and rebuttal testimony co-authored with Robert Mudge in regard to cost of wildfire risk under AB 1054, a state policy to create a fire insurance mechanism. Applications 19-04-014 and 19-04-015, September 4, 2019.

For Dominion Energy Kewaunee, Mr. Graves filed expert testimony in the U.S. Court of Federal Claims (Case No. 18-808 C, July 25, 2019) in regard to the ability of the plaintiff (Kewaunee Nuclear) to have had all its spent nuclear fuel removed by the U.S. DoE, had the government met its obligations to perform under the Standard Contract with the nuclear industry. Modeling shows why the government ought to be liable for damages from otherwise unnecessary storage costs at the site. Similar testimonies were filed on behalf of NorthStar for Vermont Yankee (Aug. 2019) and on behalf of Duke Power in regard to the Crystal River nuclear plant (Sept. 2019).

For Nicor Gas, a natural gas distribution company, Mr. Graves co-authored testimony on the cost of equity capital utilizing a broad spectrum of risk-pricing methods and explaining how financial leverage affects it. Testimony was filed with the Illinois Commerce Commission, Docket 18-xxxx, November 9, 2018.

For the electric transmission division of Pacific Gas & Electric, Mr. Graves presented testimony and co-authored an accompanying report on the cost of capital impacts from the extreme risks arising from potential liability for damages caused by large wildfires in California. Testimony before the FERC, Docket ER19- ___ - 000, Exhibit PGE-0019, October 1, 2018.

For the Government of Colombia, written and oral testimony in regard to apparent misrepresentations of coal mine development costs and expected profitability by Glencore Corporation that adversely affected royalty payments for Colombia. Heard in the International Court of Arbitration, ICSID Case No ARB/16/6, Washington DC, June 2018.

Before the Pennsylvania Public Utility Commission, written direct testimony for Philadelphia Gas Works, Docket No. R-2017-2586783, June 2017, regarding financial benchmarking of the company vs. investor owned and public agency peers, and the need for a rate increase to maintain financial metrics and cover future costs.

Direct testimony in regard to a claim for a share of lime consumption reduction costs obtained by Plum Point as one of SMEPA's power plant operator/suppliers, on behalf of SMEPA, before the American Arbitration Association in the matter of Southwest Mississippi Electric Power Association vs. Plum Point Energy Associates, Case No. 01-15-0002-6062, September 2016.

Direct, Rebuttal and Supplementary Rebuttal reports regarding damages from loss of a nuclear generation facility, on behalf of Southern California Edison Company, Edison Material Supply LLC., San Diego Gas and Electric Company and City of Riverside before the International Chamber of Commerce in the matter of Southern California Edison v. Mitsubishi Nuclear Energy Systems, Inc. and Mitsubishi Heavy Industries, Ltd., Case No. 19784/AGF/RD, July 27, 2015 (direct), January 19, 2016 (rebuttal) and March 14, 2016 (supplemental).

Direct report re determination of an appropriate level of return needed for Standard Offer Service (SOS), on behalf of Delmarva Power & Light Company and Potomac Electric Power Company before the Maryland Public Service, Case Nos. 9226 and 9232, July 24, 2015.

Direct testimony in regard to the prudence of its gas hedging, on behalf of Hope Gas, Inc., before the West Virginia Public Service Commission, Case No. 12-1070-G-30C, June 24, 2013.

Direct testimony on behalf of Public Service Company of New Mexico before the NM Public Regulation Commission re appropriate profit incentives for energy conservation activities, Case No. 12-00317-UT, October 5, 2012.

Rebuttal testimony on behalf of Rocky Mountain Power Company before the Public Service Commission of Utah in regard to hedging practices for natural gas supply, Docket 11-035-200, July 2012.

Rebuttal testimony on behalf of Rocky Mountain Power Company before the Public Service Commission of Wyoming in regard to gas supply hedging and loss-sharing, Docket No. 20000-405-ER-11, June 2012.

Direct testimony on behalf of Ohio Power Company before the PUC of Ohio in regard to performance of PJM capacity markets, in Ohio Power's application for its ESP service charges, Case No. 10-2929-EL-UNC, March 30, 2012.

Expert report and oral testimony on behalf of Pepco Holdings, Inc. before the Maryland Public Service Commission in regard to inadequacies in the MD PSC's RFP for new combined cycle generation development in SWMAAC, Case No. 9214, January 31, 2012.

Direct testimony on behalf of Columbus Southern Power Company and Ohio Power Company before the Public Utilities Commission of Ohio in the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company, Case No. 10-2929 -EL-UNC, August 31, 2011.

Rebuttal report on spent nuclear fuel removal on behalf of Yankee Atomic Electric Company, Connecticut Yankee Atomic Power Company, Maine Yankee Atomic Power Company before the United States Court of Federal Claims, Nos. 07-876C, No. 07-875C, No. 07-877C, August 5, 2011.

Direct Testimony on rehearing regarding the allowance of swaps in Rocky Mountain Power's fuel adjustment cost recovery mechanism, on behalf of Rocky Mountain Power before the Public Service Commission of the State of Utah, July 2011.

Comments and Reply Comments on capacity procurement and transmission planning on behalf of New Jersey Electric Distribution Companies before the State of New Jersey Board of Public Utilities in the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning, NJ BPU Docket No. EO11050309, June 17, 2011; July 12, 2011.

Rebuttal testimony regarding Rocky Mountain Power's hedging practices on behalf of Rocky Mountain Power before the Public Service Commission of the State of Utah, Docket No. 10-035-124, June 2011.

Expert and Rebuttal reports regarding contract termination damages, on behalf of Hess Corporation before the United States District Court for the Northern District of New York, Case No. 5:10-cv-587 (NPM/GHL), April 29, 2011, May 13, 2011.

Expert and Rebuttal reports on spent fuel removal at Rancho Seco nuclear power plant, on behalf of Sacramento Municipal Utility District before the U.S. Court of Federal Claims, No. 09-587C, October 2010, July 1, 2011.

Rebuttal testimony on the Impacts of the Merger with First Energy on retail electric competition in Pennsylvania, on behalf of Allegheny Power before the Pennsylvania Public Utility Commission, Docket Nos. A-2010-2176520 and A-2010-2176732, September 13, 2010.

Expert and Rebuttal reports on the interpretation of pricing terms in a long term power purchase agreement, on behalf of Chambers Cogeneration Limited Partnership before the Superior Court of New Jersey, Docket No. L-329-08, August 23, 2010, September 21, 2010.

Expert and Rebuttal reports on spent fuel removal at Trojan nuclear facility, on behalf of Portland General Electric Company, The City of Eugene, Oregon, and PacifiCorp before the United States Court of Federal Claims No. 04-0009C, August 2010, June 29, 2011.

Rebuttal and Rejoinder testimonies on the approval of its Smart Meter Technology Procurement and Installation Plan before the Pennsylvania Public Utility Commission on behalf of West Penn Power Company d/b/a Allegheny Power, Docket No. M-2009-2123951, October 27, 2009, November 6, 2009.

Supplemental Direct testimony on the need for an energy cost adjustment mechanism in Utah to recover the costs of fuel and purchased power, on behalf of Rocky Mountain Power before the Public Service Commission of Utah, Docket No. 09-035-15, August 2009.

Expert and Rebuttal reports on spent nuclear fuel removal on behalf of Yankee Atomic Electric Company, Connecticut Yankee Atomic Power Company, Maine Yankee Atomic Power Company before the United States Court of Federal Claims, Nos. 98-126C, No. 98-154C, No. 98-474C, April 24, 2009, July 20, 2009.

Expert report in regard to opportunistic under-collateralization of affiliated trading companies, on behalf of BJ Energy, LLC, Franklin Power LLC, GLE Trading LLC, Ocean Power LLC, Pillar Fund LLC and Accord

Energy, LLC before the United States District Court for the Eastern District of Pennsylvania, No. 09-CV-3649-NS, March 2009.

Rebuttal report in regard to appropriate discount rates for different phases of long-term leveraged leases, on behalf of Wells Fargo & Co. and subsidiaries, Docket No. 06-628T, January 15, 2009.

Oral and written direct testimony regarding resource procurement and portfolio design for Standard Offer Service, on behalf of PEPCo Holdings Inc. in its Response to Maryland Public Service Commission, Case No. 9117, October 1, 2008 and December 15, 2008.

Direct testimony regarding considerations affecting the market price of generation service for Standard Service Offer (SSO) customers, on behalf of Ohio Edison Company, et al., Docket 08-125, July 24, 2008.

Direct testimony in support of Delmarva's "Application for the Approval of Land-Based Wind Contracts as a Supply Source for Standard Offer Service Customers," on behalf of Delmarva Power & Light Company before the Public Service Commission of Delaware, July 24, 2008.

Oral direct testimony in regard to the Government's performance in accepting spent nuclear fuel under contractual obligations established in 1983, on behalf of plaintiff Dairyland Power Cooperative before the United States Court of Federal Claims (No. 04-106C), July 17, 2008.

Direct testimony for Delmarva Power & Light on risk characteristics of a possible managed portfolio for Standard Offer Service, as part of Delmarva's IRP filings (PSC Docket No. 07-20), March 20, 2008 and May 15, 2008.

Oral direct testimony regarding the economic substance of a cross-border lease-to-service contract for a German waste-to-energy plant on behalf of AWG Leasing Trust and KSP Investments, Inc before U. S. District Court, Northern District of Ohio, Eastern Division, Case No. 1:07CV0857, January 2008.

Expert report (October 15, 2007) and oral testimony (September 21 and 22, 2010) in Commonwealth of Pennsylvania Department of Environmental Protection, et al., v. Allegheny Energy Inc, et al. regarding flaws in the plaintiffs' assessment of emissions attributed to repairs at certain power plants, Civil Action No, 2:05ev1885.

Direct testimony regarding portfolio management alternatives for supplying Standard Offer Service, on behalf of Potomac Electric Power Company and Delmarva Power & Light Company before the Public Service Commission of Maryland, Case No. 9117, September 14, 2007.

Direct testimony in regard to preconditions for effective retail electric competition, on behalf of New West Energy Corporation before the Arizona Commerce Commission, Docket No. E-03964A-06-0168, August 31, 2007.

Direct and rebuttal testimonies regarding the application of OG&E for an order of commission granting preapproval to construct Red Rock Generating Facility and authorizing a recovery rider, on behalf of Oklahoma Gas & Electric Company (OG&E) before the Corporation Commission of the State of Oklahoma, Case No. PUD 200700012, January 17, 2007 and June 18, 2007.

Testimony in regard to whether defendant's role in accounting misrepresentations could be reliably associated with losses to shareholders, on behalf of defendant Mark Kaiser before U.S. District Court of New York SI:04Cr733 (TPG).

Rebuttal testimony on proposed benchmarks for evaluating the Illinois retail supply auctions, on behalf of Midwest Generation EME L.L.C. and Edison Mission Marketing and Trading before the Illinois Commerce Commission Docket No. 06-0800, April 6, 2007.

Direct and rebuttal testimonies on the shareholder impacts of Dynegy's Project Alpha for the sentencing of Jamie Olis, on behalf of the U.S. Department of Justice before the United States District Court, Southern District of Texas, Houston Division, Criminal No. H-03-217, September 12, 2006.

Direct and rebuttal testimony on the need for POLR rate cap relief for Metropolitan Edison and Pennsylvania Electric and the prudence of their past supply procurement for those obligations, on behalf of FirstEnergy Corp before the Pennsylvania Public Utility Commission, Docket Nos. R-00061366 and R-00061367, August 24, 2006.

Direct testimony regarding Deutsche Bank Entities' opposition to Enron Corp's amended motion for class certification, on behalf of the Deutsche Bank Entities before the United States District Court, Southern District of Texas, Houston Division, Docket No. H-01-3624, February 2006.

Expert and Rebuttal reports regarding the non-performance of the U.S. Department of Energy in accepting spent nuclear fuel under the terms of its contract, on behalf of Pacific Gas and Electric Company before the United States Court of Federal Claims, Docket No. 04-0074C, into which has been consolidated No. 04-0075C, November 2005.

Direct testimony regarding the appropriate load caps for a POLR auction, on behalf of Midwest Generation EME, LLC before the Illinois Commerce Commission, Docket No. 05-0159, June 8, 2005.

Affidavit regarding unmitigated market power arising from the proposed Exelon—PSEG Merger, on behalf of Dominion Energy, Inc. before the Federal Energy Regulatory Commission, Docket No. EC05-43-000, April 11, 2005.

Expert and rebuttal reports and oral testimonies before the American Arbitration Association on behalf of Liberty Electric Power, LLC, Case No. 70 198 4 00228 04, December 2004, regarding damages under termination of a long-term tolling contract.

Oral direct and rebuttal testimony before the United States Court of Federal Claims on behalf of Connecticut Yankee Atomic Power Company, Docket No. 98-154 C, July 2004 (direct) and August 2004 (rebuttal), regarding non-performance of the U.S. Department of Energy in accepting spent nuclear fuel under the terms of its contract.

Direct, supplemental and rebuttal testimony before the Public Service Commission of Wisconsin, on behalf of Wisconsin Public Service Corporation and Wisconsin Power and Light Company, Docket No. 05-EI-136, February 27, 2004 (direct), May 4, 2004 (supplemental) and May 28, 2004 (rebuttal) in regard to the benefits of the proposed sale of the Kewaunee nuclear power plant.

Testimony before the Public Utility Commission of Texas on behalf of CenterPoint Energy Houston Electric LLC, Reliant Energy Retail Services LLC, and Texas Genco LP, Docket No. 29526, March 2004 (direct) and June 2004 (rebuttal), in regard to the effect of Genco separation agreements and financial practices on stranded costs and on the value of control premiums implicit in Texas Genco Stock price.

Rebuttal and additional testimony before the Illinois Commerce Commission, on behalf of Peoples Gas Light and Coke Company, Docket No. 01-0707, November 2003 (rebuttal) and January 2005 (additional rebuttal), in regard to prudence of gas contracting and hedging practices.

Rebuttal testimony before the State Office of Administrative Hearings on behalf of Texas Genco and CenterPoint Energy, Docket No. 473-02-3473, October 23, 2003, regarding proposed exclusion of part of CenterPoint's purchased power costs on grounds of including "imputed capacity" payments in price.

Rebuttal testimony before the Federal Energy Regulatory Commission (FERC) on behalf of Ameren Energy Generating Company and Union Electric Company, Docket No. EC03-53-000, October 6, 2003, in regard to evaluation of transmission limitations and generator responsiveness in generation procurement.

Rebuttal testimony before the New Jersey Board of Public Utilities on behalf of Jersey Central Power & Light Company, Docket No. ER02080507, March 5, 2003, regarding the prudence of JCP&L's power purchasing strategy to cover its provider-of-last-resort obligation.

Oral testimony (February 17, 2003) and expert report (April 1, 2002) before the United States District Court, Southern District of Ohio, Eastern Division on behalf of Ohio Edison Company and Pennsylvania Power Company, Civil Action No. C2-99-1181, regarding coal plant maintenance projects alleged to trigger New Source Review.

Expert Report before the United States District Court on behalf of Duke Energy Corporation, Docket No. 1:00CV1262, September 16, 2002, regarding forecasting changes in air pollutant emissions following coal plant maintenance projects.

Direct testimony before the Public Utility Commission of Texas on behalf of Reliant Energy, Inc., Docket No. 26195, July 2002, regarding the appropriateness of Reliant HL&P's gas contracting, purchasing and risk management practices, and standards for assessing HL&P's gas purchases.

Direct and rebuttal testimonies before the Public Utilities Commission of the State of California on behalf of Southern California Edison, Application No. R. 01-10-024, May 1, 2002, and June 5, 2002, regarding Edison's proposed power procurement and risk management strategy, and the regulatory guidelines for reviewing its procurement purchases.

Rebuttal testimony before the Texas Public Utility Commission on behalf of Reliant Resources, Inc., Docket No. 24190, October 10, 2001, regarding the good-cause exception to the substantive rules that Reliant Resources, Inc. and the staff of the Public Utility Commission sought in their Provider of Last Resort settlement agreement.

Direct testimony before the Federal Energy Regulatory Commission (FERC) on behalf of Northeast Utilities Service Company, Docket No. ER01-2584-000, July 13, 2001, in regard to competitive impacts of a proposed merchant transmission line from Connecticut to Long Island.

Direct testimony before the Vermont Public Service Board on behalf of Vermont Gas Systems, Inc., Docket No. 6495, April 13, 2001, regarding Vermont Gas System's proposed risk management program and deferred cost recovery account for gas purchases.

Affidavit on behalf of Public Service Company of New Mexico, before the Federal Energy Regulatory Commission (FERC), Docket No. ER96-1551-000, March 26, 2001, to provide an updated application for market based rates.

Affidavit on behalf of the New York State Electric and Gas Corporation, April 19, 2000, before the New York State Public Service Commission, In the Matter of Customer Billing Arrangements, Case 99-M-0631.

Supplemental Direct and Reply Testimonies of Frank C. Graves and A. Lawrence Kolbe (jointly) on behalf of Southern California Edison Company, Docket Nos. ER97-2355-00, ER98-1261-000, ER98-1685-000, November 1, 1999, regarding risks and cost of capital for transmission services.

Expert report before the United States Court of Federal Claims on behalf of Connecticut Yankee Atomic Power Company, Connecticut Yankee Atomic Power Company, Plaintiff v. United States of America, No. 98-154 C, June 30, 1999, regarding non-performance of the U.S. Department of Energy in accepting spent nuclear fuel under the terms of its contract.

Expert report before the United States Court of Federal Claims on behalf of Maine Yankee Atomic Power Company, Maine Yankee Atomic Power Company, Plaintiff v. United States of America, No. 98-474 C, June 30, 1999, regarding the damages from non-performance of the U.S. Department of Energy in accepting spent nuclear fuel and high-level waste under the terms of its contract.

Expert report before the United States Court of Federal Claims on behalf of Yankee Atomic Electric Company, Yankee Atomic Electric Company, Plaintiff v. United States of America, No. 98-126 C, June 30, 1999, regarding the damages from non-performance of the U.S. Department of Energy in accepting spent nuclear fuel and high-level waste under the terms of its contract.

Prepared direct testimony before the Federal Energy Regulatory Commission on behalf of National Rural Utilities Cooperative Finance Corporation, Inc., Cities of Anaheim and Riverside, California v. Deseret Generation & Transmission Cooperative, Docket No. EL97-57-001, March 1999, regarding cost of service for rural cooperatives versus investor-owned utilities, and coal plant valuation.

Expert report and oral examination before the Independent Assessment Team for industry restructuring appointed by the Alberta Energy and Utilities Board on behalf of TransAlta Utilities Corporation, January 1999, regarding the cost of capital for generation under long-term, indexed power purchase agreements.

Oral testimony before the Commonwealth of Massachusetts Appellate Tax Board on behalf of Indeck Energy Services of Turners Falls, Inc., Turners Falls Limited Partnership, Appellant vs. Town of Montague, Board of Assessors, Appellee, Docket Nos. 225191-225192, 233732-233733, 240482-240483, April 1998, regarding market conditions and revenues assessment for property tax basis valuation.

Direct and joint supplemental testimony before the Pennsylvania Public Utility Commission on behalf of Pennsylvania Electric Company and Metropolitan Edison Company, No. R-00974009, et al., December 1997, regarding market clearing prices, inflation, fuel costs, and discount rates.

Direct Testimony before the Pennsylvania Public Utilities Commission on behalf of UGI Utilities, Inc., Docket No. R-00973975, August 1997, regarding forecasted wholesale market energy and capacity prices.

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BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF NEW MEXICO FOR APPROVAL OF THE ABANDONMENT OF THE FOUR CORNERS POWER PLANT AND ISSUANCE OF A SECURITIZED FINANCING ORDER	)	**Case No. 21-00017-UT**
PUBLIC SERVICE COMPANY OF NEW MEXICO,	)	
Applicant.	)	

SELF AFFIRMATION

FRANK C. GRAVES, Principal, The Brattle Group, upon being duly sworn according to law, under oath, deposes and states: I have read the foregoing **Supplemental Testimony of Frank C. Graves** and it is true and accurate based on my own personal knowledge and belief.

DATED this 15th day of March, 2021.

/s/ *Frank C. Graves*
FRANK C. GRAVES

GCG # 527769