

**BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION**

**IN THE MATTER OF PUBLIC SERVICE )**  
**COMPANY OF NEW MEXICO'S )**  
**ABANDONMENT OF SAN JUAN ) Case No. 19-00018-UT**  
**GENERATING STATION UNITS 1 AND 4 )**

**REBUTTAL TESTIMONY**

**OF**

**FRANK GRAVES**

**November 15, 2019**

**NMPRC CASE NO. 19-00018-UT  
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FRANK GRAVES**

**WITNESS FOR  
PUBLIC SERVICE COMPANY OF NEW MEXICO**

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PNM Exhibit FG-1 (Rebuttal)

Resume

AFFIDAVIT

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**I. INTRODUCTION**

1

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

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

5

6   **Q.     PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**  
7       **PROFESSIONAL EXPERIENCE.**

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

14

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

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1 and cost of capital in a wide variety of settings for energy infrastructure and utility  
2 investments.

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

9  
10 **Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN NEW MEXICO**  
11 **PUBLIC REGULATION COMMISSION PROCEEDINGS?**

12 **A.** Yes, I provided direct and rebuttal testimony on behalf of PNM in 2012/13 in  
13 Case No. 12-000317-UT in regard to incentive compensation for energy  
14 efficiency programs.

15  
16 **Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS**  
17 **PROCEEDING?**

18 **A.** My testimony responds to certain testimonies submitted by Utility Division Staff  
19 (“Staff”) of the New Mexico Public Regulation Commission (“Commission”) and  
20 certain intervenors in this case with respect to i) the appropriateness of PNM’s  
21 full recovery of the associated undepreciated investment in those San Juan coal  
22 plant units; ii) the benefits of PNM’s proposal to securitize the undepreciated  
23 investment for PNM’s customers and iii) the benefits and prudence of PNM’s

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1 decision to abandon units 1 and 4 of the San Juan Generating Station (“San Juan  
2 coal plant”) in 2022 and replace them with a portfolio of renewable, storage and  
3 gas-fired peaking resources rather than pursue carbon capture utilization and  
4 storage (“CCUS”) at the San Juan coal plant. Specifically, I respond to  
5 testimonies opposing these positions submitted by Dhiraj Solomon, Anthony  
6 Sisneros, and Beverly Eschberger on behalf of Staff; Andrea Crane on behalf of  
7 the New Mexico of Attorney General (“NMAG”); and Steven Fetter and  
8 Charlotte Grubb on behalf of New Energy Economy (“NEE”).  
9

10 **Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF THE OPINIONS**  
11 **PROVIDED BY THE INTERVENORS’ WITNESSES TO WHOM YOU**  
12 **ARE RESPONDING IN YOUR TESTIMONY.**

13 **A.** I respond to the following opinions offered by the intervenor witnesses:

- 14 • According to the Staff witnesses, PNM’s proposed abandonment and full cost  
15 recovery of the San Juan coal plant should be denied because 1) the Energy  
16 Transition Act may not apply to the San Juan coal plant decisions, hence  
17 excluding the plant from securitization-based cost recovery,<sup>1</sup> and 2) PNM has  
18 not i) demonstrated that abandonment of the San Juan coal plant results in  
19 higher net public benefits (or no net detriment) for customers in the future  
20 compared to continuing to operate the San Juan coal plant with a carbon

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<sup>1</sup> See Eschberger’s Direct Testimony, *In The Matter Of Public Service Company Of New Mexico’s Abandonment Of San Juan Generating Station Units 1 And 4* (October 18, 2019).

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capture system;<sup>2</sup> ii) hence has not satisfied all of the “Commuters’ Committee factors” in its abandonment application to justify its proposal.<sup>3</sup> It appears that the main concern is suspicion that the fourth factor on the availability of substitute service was not fully investigated.

- The Staff witnesses recommend that if the Energy Transition Act does not apply, and if the Commission approves abandonment, no more than half of the undepreciated investment in the San Juan coal plant should be paid by customers, and that PNM’s return on that amount should be limited to just the cost of debt.<sup>4</sup> The rationale provided by the Staff witnesses are: i) the San Juan coal plant would no longer be used and useful after the abandonment;<sup>5</sup> ii) the regulatory compact protects customers from monopoly abuse, and it does not guarantee full recovery on utility investment; iii) principles of utility regulation, e.g., as articulated by Bonbright, indicate that regulation does not protect utility against mismanagement or adverse business conditions (such as the new carbon emissions standards under the Energy Transition Act; iv) allowing PNM to fully recover the undepreciated ratebase would not represent a fair “balancing of interests” and would create a perverse incentive to

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<sup>2</sup> See Solomon’s Direct Testimony, *In The Matter Of Public Service Company Of New Mexico’s Abandonment Of San Juan Generating Station Units 1 And 4*, page 18 (October 18, 2019). PNM Witness Mark Fenton lists these four factors as “(1) the extent of the carrier’s loss on the particular branch or portion of the service, and the relation of that loss to the carrier’s operation as a whole; (2) the use of the service by the public and prospects for future use; (3) a balancing of the carrier’s loss with the inconvenience and hardship to the public upon discontinuance of service; and (4) the availability and adequacy of substitute service” (Fenton’s Direct Testimony, page 8).

<sup>3</sup> *Ibid.*

<sup>4</sup> See Sisneros’s Direct Testimony, *In The Matter Of Public Service Company Of New Mexico’s Abandonment Of San Juan Generating Station Units 1 And 4* (October 18, 2019).

<sup>5</sup> *Ibid.* at page 10.

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1 “venture into more risky investments”;<sup>6</sup> and v) partial disallowance of the  
2 recovery of undepreciated investments at the San Juan coal plant would be  
3 “just and reasonable.”<sup>7</sup>

- 4 • Specifically, NMAG Witness Crane argues that PNM’s proposal to recover all  
5 of the undepreciated investment in units 1 and 4 is not a reasonable balancing  
6 of shareholder and customer interests.<sup>8</sup> Instead, she recommends a 50/50  
7 sharing of these costs (similar to the prior regulatory treatment of  
8 undepreciated investments at the San Juan coal plant units 2 and 3 as part of a  
9 comprehensive settlement) as being more equitable. The rationales provided  
10 by NMAG Witness Crane are: i) PNM management made all past investment  
11 decisions at the San Juan coal plant, and its shareholders assume some risk of  
12 non-recovery whenever they invest in the company; ii) while shareholders  
13 may not be responsible for environmental mandates, neither are customers; iii)  
14 the San Juan coal plant will no longer be used and useful after the  
15 abandonment; iv) PNM’s return on equity already includes a risk premium  
16 over risk-free interest rates (“stock market is a risky business”<sup>9</sup>), reflecting the  
17 expectation that shareholders are subject to risk in recovering the costs of  
18 investments; and v) “If shareholders wanted to eliminate all risks of their  
19 investment, then they should have invested in risk-free instruments, or

---

<sup>6</sup> *Ibid.*, at 4, page 8.

<sup>7</sup> *Ibid.*, page 9, October 18, 2019.

<sup>8</sup> See Crane’s Direct Testimony, *In The Matter Of Public Service Company Of New Mexico’s Abandonment Of San Juan Generating Station Units 1 And 4* (October 18, 2019).

<sup>9</sup> *Ibid.*

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1           accepted a low risk-free rate in exchange for assurances that 100% of their  
2           investment would be returned.”<sup>10</sup>

- 3           • According to NEE Witness Grubb, under the terms of the Energy Transition  
4           Act, “the Commission no longer has regulatory power to amend any financing  
5           order, giving PNM an unprecedented power.”<sup>11</sup> In addition, NEE Witness  
6           Fetter argues that the Energy Transition Act is a “significant departure” from  
7           other securitization laws and that the result undermines the core of the  
8           Commission’s fundamental purpose and role to regulate utilities and to protect  
9           customers.<sup>12</sup>

10  
11   **Q.   PLEASE SUMMARIZE YOUR RESPONSES TO THESE OPINIONS BY**  
12   **INTERVENOR WITNESSES.**

13   **A.**   I do not have nor offer an opinion about whether the Energy Transition Act  
14           applies to the San Juan coal plant. I understand that PNM asserts that the Energy  
15           Transition Act applies, and I believe that there are clear benefits from its  
16           application in this case. Regardless of its applicability, I disagree with the  
17           intervenors’ interpretations of the regulatory compact and rejection of PNM’s  
18           analyses in support of its proposal to abandon the San Juan coal plant and replace  
19           it with renewables, storage and some fast-response gas-fired aeroderivatives.  
20           Instead, I conclude that a careful and complete understanding of regulatory

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<sup>10</sup>   *Ibid.*, page 54.

<sup>11</sup>   See Grubb’s Direct Testimony, *In The Matter Of Public Service Company Of New Mexico’s Abandonment Of San Juan Generating Station Units 1 And 4*, page 20 (October 18, 2019).

<sup>12</sup>   See Fetter’s Direct Testimony, *In The Matter Of Public Service Company Of New Mexico’s Abandonment Of San Juan Generating Station Units 1 And 4*, page 4 (October 18, 2019).

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1 principles supports full cost recovery for the San Juan coal plant, and that PNM  
2 has proposed a sound and beneficial strategy of early retirement and replacement  
3 of the San Juan coal plant units 1 and 4.

4  
5 I base these conclusions on a review of PNM's own analyses and on my own  
6 supplemental analysis I report herein, which both demonstrate why carbon  
7 capture at the San Juan coal plant can be expected to cost much more and be  
8 riskier than the Scenario 1 portfolio of renewable, storage and gas peaking  
9 resources PNM has proposed to replace the San Juan coal plant. Because of that  
10 economic finding, and because of the norms of the traditional and well-justified  
11 regulatory compact between a utility, its Commission and its customers, the  
12 proper treatment of PNM's undepreciated investments at the San Juan coal plant  
13 is to allow PNM to fully recover those past investment costs in retail rates (which  
14 can include non-bypassable charges). This is true regardless of the applicability  
15 of the Energy Transition Act. I also conclude that PNM's proposal to securitize  
16 those undepreciated investments as a cost recovery mechanism is beneficial to the  
17 customers.

18  
19 **Q. PLEASE SUMMARIZE THE REASONS FOR YOUR SPECIFIC**  
20 **CONCLUSIONS REGARDING THE PNM ANALYSES, SAN JUAN COAL**  
21 **PLANT RETIREMENT AND REPLACEMENT, AND ITS COST**  
22 **RECOVERY.**

23 **A.** My specific findings and the basis for those conclusions are as follows:

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1           1. The undepreciated investment amount for the San Juan coal plant in PNM's  
2           ratebase largely reflects past investments that the Commission previously has  
3           allowed PNM to recover over the last 30-plus years in retail rates. More  
4           specifically, the majority (about 80%) of the approximately \$350 million of  
5           undepreciated net book value in the San Juan coal plant units 1 and 4 as of the  
6           end of 2018 reflects amounts left over from expenditures made before 2015  
7           that have been reviewed by the NMPRC and were authorized for inclusion in  
8           PNM's ratebase. These do not include the Commission's disallowed recovery  
9           of the increased ownership of San Juan coal plant unit 4 and certain other  
10          excluded investments in the past.

11          2. Based on my review of testimonies submitted by PNM's witnesses in July  
12          2019, associated system analyses behind those opinions, and my own  
13          economic review, PNM's request to abandon the San Juan coal plant units 1  
14          and 4 in 2022 and replace these units with a portfolio of new gas/solar/battery  
15          resources would save several hundreds of millions of dollars in costs for  
16          customers over the new assets' lifetimes compared to continue to operating  
17          the San Juan coal plant as is (if that were feasible) or compared to operating  
18          the plant with carbon capture, utilization, and storage (CCUS) (to comply with  
19          the Energy Transition Act) beyond 2022.

20          3. PNM's review of the San Juan coal plant replacement alternatives in its July  
21          2019 analyses did consider the status of CCUS technology and the possibility  
22          that it could be viable or beneficial at the plant, though it did not rely upon  
23          detailed system modeling to reach its conclusion that CCUS would not be

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1           economical. Prior to that, in its 2010 evaluations, I understand that PNM also  
2           considered the possibility of using carbon capture, utilization for enhanced oil  
3           recovery (“EOR”) and storage at the San Juan coal plant and found it to be far  
4           too expensive and too unproven. PNM Witness Phillips explains more fully  
5           in his Rebuttal Testimony how this conclusion was reached, and how it was  
6           reconfirmed in PNM’s recent review of how CCUS costs have changed and  
7           other incentives for CCUS that have been put in place. In addition, he  
8           presents new quantifications PNM has completed in response to Staff’s  
9           concerns that CCUS might have been overlooked.

10  
11          In parallel, I have also evaluated the Staff-suggested option to continue  
12          operating the San Juan coal plant with CCUS, and I find that except under  
13          optimistic assumptions, the CCUS option would at best roughly break even  
14          and more likely would cost quite a bit more than continuing to operate the  
15          plant without CCUS. But even under those optimistic conditions where  
16          CCUS could pay for itself, it would not be as beneficial as the Scenario 1  
17          strategy that produces roughly \$400 million in likely cost savings.

18  
19          Since the mix of replacement resources in Scenario 1 (even with recovery of  
20          the sunk costs on the San Juan coal plant) is likely less expensive than just  
21          continuing operations at the plant without CCUS, while the CCUS option is  
22          mostly and possibly greatly unattractive for customers, the renewable  
23          replacement strategy PNM has recommended should be preferred. In addition

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1 to likely costing more, the CCUS approach to satisfying the carbon emission  
2 rate standards under the Energy Transition Act would be much riskier in terms  
3 of uncertainty surrounding initial capital commitments, technology  
4 performance, and market offsets (from EOR revenues) than the relatively  
5 predictable consequences of the Scenario 1 replacement resources. Thus,  
6 while I understand why Staff raised the question about CCUS being a possible  
7 solution, I do not believe it is an overlooked superior alternative to PNM's  
8 proposal.

9  
10 4. Longstanding and economically well-justified principles and standards in the  
11 utility industry strongly indicate that prudent investments should be fully  
12 recoverable from customers, even if they should eventually prove less  
13 economic than when originally intended. In fact, prudent planning for  
14 resource development by utilities should entail the expectation that the chosen  
15 assets will *mostly, but not only or under all circumstances*, result in cost  
16 savings for customers. That is, a prudent resource plan will, from the day it is  
17 planned, be exposed to potential cost increases versus other alternatives, in  
18 some (but less than the majority of) planning scenarios. This is because they  
19 involve long-lived assets that will operate over a horizon that cannot possibly  
20 be precisely forecasted or controlled, and it is economically better that they be  
21 chosen when they produce robust expected but not guaranteed savings. This  
22 means that from inception, prudent investment decisions will have a built-in  
23 modest risk of possible future disappointment. Otherwise, uneconomic,

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1           overly risk-averse decisions are chosen, causing expected savings to be lost --  
2           for example waiting too long or for too much certainty to build, or the utility  
3           choosing resource options that have lower investment risk (purchased power)  
4           at higher expected cost to customers.

5  
6           5. PNM should not be penalized (through a disallowance of past investment  
7           costs) for proposing to adopt a strategy like the San Juan coal plant  
8           abandonment and replacement it has proposed. If PNM would save costs for  
9           customers going forward, inclusive of fully recovering all the sunk costs of  
10          the abandoned plant, then it should be encouraged to do so with full recovery  
11          of past investments. Such a disallowance would create a bad signal to  
12          investors and resource planners that prior regulatory approvals cannot be  
13          relied upon. It also creates a *per se* expectation going forward that utility  
14          investments cannot, in general, be expected to recover a full return on and of  
15          their costs – because they will only break even in the conditions where they  
16          remain attractive, and sometimes they will lose part of their value when  
17          disallowed despite having been prudent *ex ante*. The proposed disallowance  
18          is not in customers' long-run interests and violates the tenets established in  
19          *Hope* and *Bluefield*<sup>13</sup> by impairing (biasing downwards) the opportunity for

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<sup>13</sup> *Federal Power Commission et al v. Hope Natural Gas Co.* ("Hope"), 320 U.S. 591, 603 (1944); and *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia* ("Bluefield"), 262 U.S. 679 (1923). These two decisions together provide criteria for fair and effective cost of service regulation of public utilities. They require that allowed returns be commensurate with investments of comparable risk, such that the utility can, with good management, sustain its financial health and attract capital to discharge its public duties.

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1           the utility to earn its cost of capital. These tenets are foundational to  
2           regulatory policy everywhere in the U.S.

3  
4           6. PNM's allowed cost of equity does not compensate investors for the risk of  
5           not recovering prudently incurred but no longer used and useful costs. *Not*  
6           *every type of risk, even though foreseen by investors as possible, is priced into*  
7           *the cost of equity.* In particular, asymmetric risks that involve sudden, large,  
8           uncontrollable, non-standard possibilities of loss (only, with no upside) are  
9           neither measured nor compensated in cost of equity allowances.

10  
11          7. Applying the used and useful standard on an *ex-post* basis is a flawed  
12          construct for deciding on cost recovery of prudently incurred past  
13          investments: it conflicts with prudent planning practices and creates a *per se*  
14          expectation of under-recovery of the allowed cost of capital. "Used and  
15          useful" can be applied when there is a concurrent finding of imprudence, but  
16          not otherwise. There is no such finding regarding the San Juan coal plant in  
17          this instance.

18  
19          8. The proposals by the Staff and the NMAG witnesses for 50/50 cost sharing of  
20          undepreciated San Juan coal plant costs have no basis in fairness or economic  
21          efficiency. Customers already get all the benefit of any utility resource  
22          proving more valuable than was expected when it was selected and built, in  
23          that they enjoy all of its savings compared to the next best alternative (because

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1           it is priced on a cost of service basis). It is not a balancing of interests to have  
2           customers and shareholders split 50/50 on losses if/when prudently developed  
3           assets lose their economic advantage due to circumstances beyond the utility's  
4           control. That might be fair if there was also a 50/50 sharing of benefits  
5           if/when the assets perform well, but there is no such value-based pricing under  
6           utility regulation. Balancing of interests already occurs under regulation by  
7           only (and always) allowing full cost-based recovery of prudently chosen  
8           investments that the utility was obligated to make.

9  
10          Securitization is a beneficial approach for providing full cost recovery at low  
11          cost to customers. It appears that in this case, it would cut the carrying costs  
12          of sunk cost recovery almost in half compared to traditional cost of service  
13          recovery, increasing the benefits to customers of pursuing the San Juan coal  
14          plant replacement resources. Several states have recognized this advantage  
15          for both customers and utility investors and have promulgated rulemaking or  
16          legislation that authorizes securitization for cost recovery of prematurely  
17          shutdown assets.

18  
19      **Q.     HOW IS YOUR TESTIMONY ORGANIZED?**

20      **A.**    I discuss the above in detail, first explaining in Section II how the undepreciated  
21           book value of San Juan coal plant was accrued and previously approved. I then  
22           shift in Section III to a discussion of the regulatory compact, how risk is measured  
23           and compensated in capital market, the risk sharing under traditional regulation

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1 based on cost based compensation for assets prudently procured under an  
2 obligation to serve, and why these require full recovery of prudently incurred  
3 sunk investment costs like at the San Juan coal plant, even if the associated asset  
4 would be no longer used and useful. These opinions do not depend on whether  
5 the Energy Transition Act applies or would allow recovery under securitization.  
6 Because there is a question raised about the completeness of PNM's alternatives  
7 to San Juan coal plant abandonment, I next present in Section IV a simplified  
8 analysis I have conducted of how a CCUS capability at the San Juan coal plant  
9 would affect its economics – adversely it turns out. I close in Section V with a  
10 short explanation of why securitization of the San Juan coal plant undepreciated  
11 investment will be helpful for customers and for future New Mexico energy  
12 policy.<sup>1</sup>

13  
14 **II. PAST INVESTMENTS AT THE SAN JUAN COAL PLANT**

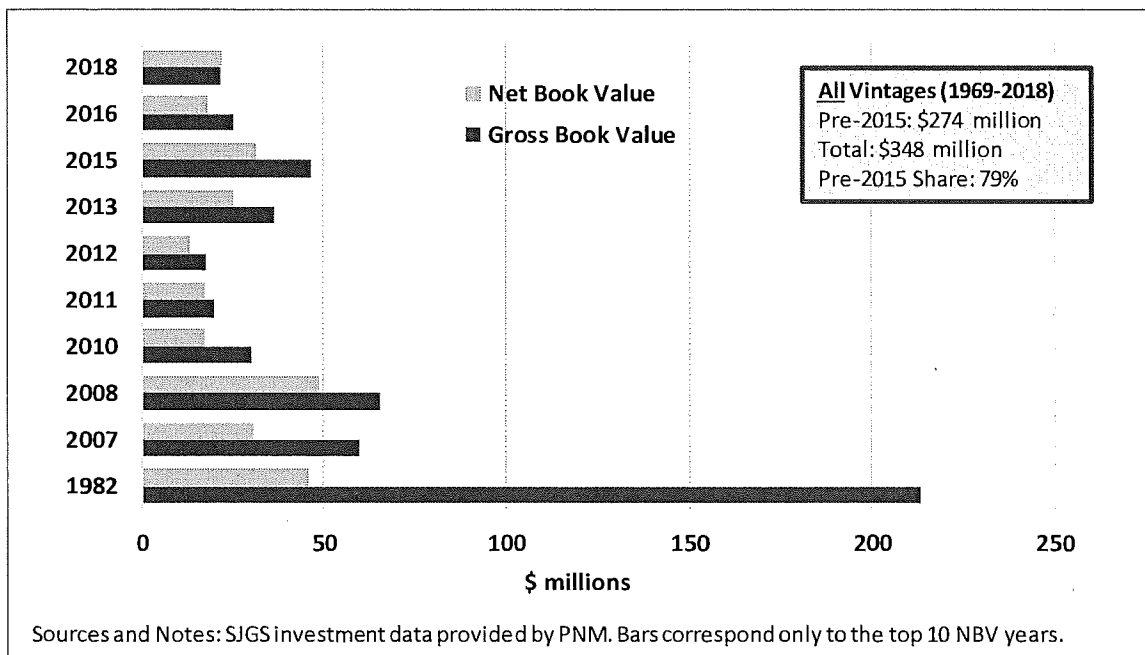
15 **Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF THE**  
16 **UNDEPRECIATED INVESTMENTS THAT PNM IS PROPOSING TO**  
17 **RECOVER IN RATES AFTER THE ABANDONMENT OF SAN JUAN**  
18 **COAL PLANT.**

19 **A.** I understand that the undepreciated investments at the San Juan coal plant as of  
20 the end of 2018 has a total net plant book value of about \$348 million. Based on  
21 a detailed database provided by PNM on its entire history of past capital  
22 expenditures at the San Juan coal plant, this total reflects undepreciated portions

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of investments made in various vintages over the past fifty years. As PNM Figure FG-1 (Rebuttal) shows, the largest three components of the remaining undepreciated investments are \$49 million remaining from 2008 (when significant environmental controls were installed), \$46 million from 1982 (when the San Juan coal plant unit 4 came online), and \$32 million in 2015 (when the SNCR control system was installed). In total, approximately \$274 million (or 79%) of the 2018 undepreciated book value comes from investments made and approved prior to 2015.

**PNM Figure FG-1 (Rebuttal): Gross and Net Book Values by Vintage Year(Top 10 Net Book Value Vintages and All Other)**



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1   **Q.    IS THERE ANY REASON TO BELIEVE THE PAST SAN JUAN COAL**  
2       **PLANT INVESTMENTS THAT COMPRISE THE UNDEPRECIATED**  
3       **BALANCE AS OF 2018 WERE NOT THE RESULT OF PRUDENT**  
4       **INVESTMENTS?**

5   **A.**   No, there is not. My opinion is based on the following observations. First, the  
6       Commission already reviewed most of these past investments spanning the past  
7       nearly fifty years, and in so doing, it approved PNM's requests or settlements to  
8       include them in the ratebase and to recover such costs from customers. Further, in  
9       2015 the Commission issued a certificate of convenience and necessity for the  
10      acquisition of an additional 78 MW of capacity in San Juan Unit 4.<sup>14</sup> This is in  
11      addition to the multiple previous instances where the Commission approved cost  
12      recovery rates for San Juan coal plant.

13  
14      Second, and relatedly, the Commission has recently disallowed some of PNM's  
15      investments at the San Juan coal plant in the past from recovery in rates. For  
16      example, in the 2015 rate case, the Commission denied PNM's request to recover  
17      a \$52.3 million expenditure associated with a balanced draft system.<sup>15</sup> Therefore,  
18      PNM's current undepreciated investment of about \$350 million already excludes  
19      those parts of the cost of the San Juan coal plant that were disallowed investments  
20      from ratebase.

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<sup>14</sup> Case No. 13-00390-UT.

<sup>15</sup> Final Order Partially Adopting Corrected Recommended Decision, *In the Matter of the Application of Public Service Company of New Mexico for Revisions of Its Retail Electric Rates Pursuant to Advice Notice No. 513* (September 28, 2016).

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1  
2       Third, long-term industry outlooks for key determinants of the economics of  
3       retaining and investing in coal plants were generally favorable throughout the  
4       plant's history prior to 2015, when the investments representing a majority of the  
5       current undepreciated balance were made. In particular, expectations of high  
6       long-run prices for natural gas price, steady load growth, and high costs for  
7       renewables had been the widespread industry viewpoint just a few years prior to  
8       2015 and 2016 decisions. Those conditions favored the economics of retaining  
9       many of the existing coal plants and making additional investments to comply  
10      with new environmental regulations, instead of abandoning or retiring the San  
11      Juan coal plant.

12  
13      Fourth, since the San Juan coal plant is a jointly-owned plant, the other owners  
14      and their state regulators also reviewed the appropriateness and prudence of the  
15      past investments at the plant when those investments were made. For example,  
16      one of the co-owners of the San Juan coal plant, Tucson Electric Power, invested  
17      \$82 million in emission control upgrades for the plant between 2007 and 2010,  
18      and the Arizona Corporation Commission did not question the appropriateness  
19      and prudence of this investment.<sup>16</sup> The plant's history is one of being repeatedly  
20      found helpful to projected system economics.

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<sup>16</sup> See Ralph Smith's Public Direct Testimony of on Behalf of the Utilities Division Staff, Arizona Corporation Commission, Docket no. E-01933A-12-0291, <https://docket.images.azcc.gov/0000141166.pdf>.

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**III. PROPER REGULATORY TREATMENT OF PRUDENTLY INCURRED  
PAST INVESTMENTS AT THE SAN JUAN COAL PLANT**

**Q. SEVERAL INTERVENORS ARGUE THAT A “BALANCING OF  
INTERESTS”, “USED AND USEFUL” CONSIDERATIONS, AND PRIOR  
COMPENSATION FOR RISK IN THE ALLOWED COST OF EQUITY  
ALL ARGUE FOR FAR LESS THAN FULL RECOVERY OF THE  
UNDEPRECIATED INVESTMENT IN THE SAN JUAN COAL PLANT.  
HOW DO YOU RESPOND?**

**A.** First, I reiterate given the regulatory results I just described for how most of the sunk costs of the San Juan coal plant were previously accepted as prudent and useful, it would be a shocking reversal of prior approvals to now disallow those investment costs that were previously deemed necessary and beneficial. PNM has also shown that it has found a cost-saving alternative to continued use of the San Juan coal plant. This alternative even has enough benefit to fully cover sunk costs while producing ratepayer savings.

Based on U.S. Supreme Court precedent in the *Hope* and *Bluefield* cases, it is reasonable for regulated utilities such as PNM to expect they have the opportunity to fully recover their prudently-incurred costs and earn a fair and reasonable rate of return on capital investments. As such, standard and appropriate regulatory policy would and should extend full cost recovery for the abandoned plant. There does not need to be a partial disallowance (e.g., 50/50 cost sharing) to create a “balancing of interests” between customers and shareholders. As explained

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1 below, the intervenors' suggested loss sharing would purely impair the  
2 opportunity for PNM to recover its allowed cost of money on prudently incurred  
3 assets.

4  
5 **Q. WHY DO YOU REJECT THE 50/50 STRANDED COST SHARING AS A**  
6 **FAIR BALANCING OF INTERESTS?**

7 **A.** Such loss sharing would be contrary to a true balancing of interests because it  
8 ignores history and other aspects of how utility service is provided: PNM's  
9 customers have already obtained years of benefits from the San Juan coal plant in  
10 excess of its costs paid (in rates) while the plant was more economical than its  
11 replacement or than other resources that could have been built at the time (instead  
12 of the San Juan coal plant). That is an intended outcome under cost of service  
13 ratemaking, and indeed why it is called **cost** of service: the utility has an  
14 obligation to invest in a least cost manner to meet agreed needs, while customers  
15 get the benefits of those choices in exchange for bearing the full costs (and no  
16 more). *This regulatory principle and practice already is a balancing of interests.*  
17

18 **Q. WHY IS CONTINUED COST RECOVERY A FAIR OR NECESSARY**  
19 **ARRANGEMENT, GIVEN THAT PRIVATE FIRMS IN UNREGULATED**  
20 **MARKETS OPERATE WITHOUT ANY SUCH STRANDED COST**  
21 **RECOVERY PROTECTIONS?**

22 **A.** The utility situation is quite unlike what happens in unregulated markets, where  
23 firms can choose to enter when and where they want, at whatever scale they are

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1 comfortable with, and they can charge whatever price the market will bear. If  
2 they develop a product that is very attractive, they can charge amounts far in  
3 excess of costs, and they can exit markets that are not as profitable as they would  
4 like. Of course, they may have to eat their sunk costs if they are unsuccessful, but  
5 that risk of loss is offset by control over the opportunity for large unregulated  
6 profits in well-chosen market niches.

7  
8 In contrast, if a utility builds, say, a coal plant that is far cheaper than replacement  
9 power, as was clearly the case for coal in 2006-2008 and many other times over  
10 the last few decades, the utility still charges a price equal to just the cost of  
11 running the coal plant. There is no markup for success; the customer gets all the  
12 savings from that plant's cost advantage. This would not be the case in many  
13 unregulated markets. The balancing of interests against ratepayers getting all of  
14 these benefits is that the utility must be able to expect to recover its full cost of  
15 any prudently designed and approved investments that were required of it under  
16 its obligation to serve.

17  
18 If a plant becoming uneconomical (such as the San Juan coal plant here) would  
19 generally cause the utility to lose its opportunity to continue to recover the  
20 investment, then it can only be that on average the utility cannot expect to earn its  
21 allowed cost of capital. That is because it is virtually inevitable that some plants,  
22 some of the time, will become uneconomical and so will lose some portion of  
23 their ongoing cost recovery under a "share the losses" (but none of the gains)

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1 policy. This disallowance policy would create a “heads I breakeven, tails I lose”  
2 situation that is not a fair game. (In contrast the unregulated firm plays a “heads I  
3 win, tails I lose” game – balanced, but more risky.)  
4

5 **Q. WHAT ABOUT THE USED AND USEFUL PRINCIPLE?**

6 **A.** This is a concept that sounds superficially reasonable, but it creates lots of  
7 distortions in utility financial health and incentives if applied literally to mean that  
8 an asset can only recover its costs if/when it is productive. That is true in  
9 unregulated markets, but again those providers have no obligation to serve and  
10 can charge what the market will bear when their assets are in service. That is a  
11 wise policy. Incentivizing and rewarding (or at least protecting) prudent long-run  
12 decision making should be recognized as the standard for regulatory policy. That  
13 means that you cannot punish bad luck outcomes from previously good decisions.  
14 As explained above, that disallowance policy would create a *per se* bias against  
15 utility investors expecting to recover their invested costs with a reasonable return.  
16

17 I understand that New Mexico law also recognizes that the “used and useful”  
18 concept is not a sufficient basis for deciding whether cost recovery of utility  
19 expenditures is merited.<sup>17</sup>  
20

---

<sup>17</sup> For example, see *New Mexico Industrial Energy Consumers v. New Mexico Public Service Commission*, 104 N.M. 565, 725 P.2d 244 (1986); *Alto Village Services v. New Mexico Public Service Comm.*, 92 N.M. 323, 587 P.2d 1334 (1978)(whether utility property is “used and useful” and therefore to be included in rate base is a factual determination).

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1   **Q.   SOME INTERVENORS HAVE SUGGESTED THAT WHILE**  
2       **SHAREHOLDERS ARE NOT RESPONSIBLE FOR ENVIRONMENTAL**  
3       **REQUIREMENTS AND ASSOCIATED EXPENDITURES, NEITHER ARE**  
4       **CUSTOMERS, SO THE LATTER SHOULD NOT HAVE TO PAY FULLY**  
5       **FOR THEM.**

6   **A.**   This argument has no special relevance for environmental expenditures as  
7       opposed to anything else needed at a working plant. Shareholders are not  
8       responsible for the fact that a coal plant needs a boiler or a CT needs a rotor, and  
9       neither are customers. But if the plant and its rotors are needed, and they are  
10      prudently planned and procured under an obligation to serve the customers'  
11      needs, then the customers should pay for the whole plant.

12

13   **Q.   DOESN'T THE COST OF EQUITY THAT HAS BEEN ALLOWED AS A**  
14       **RETURN ON INVESTMENT COVER SHAREHOLDERS' EXPOSURE**  
15       **TO POSSIBLE DISALLOWANCES?**

16   **A.**   No, not large and abrupt ones arising from uncontrollable circumstances, for  
17       several reasons. First, while it is generally understood and agreed in financial  
18       economics that investors in an efficient financial market (such as we have in the  
19       U.S.) are aware of essentially all material future risks, it is not the case that all  
20       those risks are recognized in the same way. Risks that involve sharing in the  
21       variability of the economy as a whole tend to be priced into the cost of capital,

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1       because they tend to be undiversifiable.<sup>18</sup> Risks that are unique or “idiosyncratic”  
2       to just the firm or product in question (such as whether an invention will work, or  
3       a large contract will be executed) tend to be priced into the valuation of those  
4       companies via assumptions about what it will do to their expected cash flows, but  
5       not via an adjustment to their cost of capital. So, it is not correct to say that any  
6       risk that utility investors can imagine, such as plant disallowances if prematurely  
7       shutdown, has already been reflected in the cost of capital.

8  
9       Second, because risks like disallowance affect forecasted cash flows, they also  
10      affect equity valuation. This means that if we calculate the cost of equity for a  
11      firm facing this problem, both its growth in expected dividends and its company  
12      valuation will reflect the problem, and will do so in a mostly offsetting way (as  
13      long as the growth forecast and price are contemporaneous). As a result, the  
14      measured return on equity will not be greater for firms facing potential  
15      disallowances than for firms that are not.

---

<sup>18</sup>       The Capital Asset Pricing Model, or CAPM, commonly used in cost of capital estimation, is one example of formal codification of this idea about market-wide versus idiosyncratic risks, but it is not unique in this regard. There are several other “multi-factor” models that assume the same kinds of investor priority for undiversifiable risk, but they allow for more possible economy-wide risk factors than just the return on the stock market as a whole.

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1   **Q.    CAN YOU PROVIDE SOME INTUITION FOR WHY AN EXPECTED**  
2       **LOSS IS NOT OFFSET BY AN INVESTOR DEMAND FOR MORE**  
3       **PROFITS IN THE FUTURE?**

4   **A.**   The reason is that there is no mechanism to force that recovery. An example may  
5       help. Consider two very similar homes with similar valuations, but one suddenly  
6       becomes aware that it was built in a region that is going to be close to a new  
7       airport. The value of the airport-exposed home will fall, but it will not thereafter  
8       be expected to appreciate at a higher rate than the other home, simply because it  
9       became aware of new risk. It can only recover that lost value if the risk goes  
10      away. Similarly, the value of a stock will fall if it faces a downside risk like a  
11      catastrophe loss, but once that is reflected in its price, the stock will now  
12      appreciate just like a normal stock in its industry. More formally, the expected  
13      cash flows of the firm will fall, but the discount rate on its future will not increase.  
14      (The same is true of the home now near the future airport.)

15

16   **Q.    NMAG WITNESS CRANE SUGGESTS THAT IF SHAREHOLDERS**  
17       **DON'T LIKE THIS KIND OF (DISALLOWANCE) RISK THEY SHOULD**  
18       **INVEST IN SOMETHING ELSE THAT IS LESS RISKY. HOW DO YOU**  
19       **RESPOND?**

20   **A.**   I suspect Witness Crane is being somewhat whimsical or sarcastic with this  
21       suggestion, but it is worth noting that it confuses the issue at stake here. She is  
22       correct that investors can always turn away from PNM and hold low-risk  
23       securities. However, investors would not have reasonably expected that past

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1 prudent investments in the San Juan plant would now be exposed to disallowance  
2 because the utility has found an alternative resource plan, many years later, that is  
3 now cheaper for customers. More importantly, the goal of regulation should not  
4 be to encourage investors to go elsewhere but to make sure they have a basis for  
5 being content with the level of risk they can expect when they make sound  
6 investments in the utility. The disallowances she proposes would undermine that  
7 confidence.

8  
9 **Q. SEVERAL INTERVENORS ASSERT THAT PNM AND ITS CUSTOMERS**  
10 **STRUCK A “BALANCING OF INTERESTS” IN A PREVIOUS CASE IN**  
11 **WHICH THE SAN JUAN COAL PLANT UNITS 2 AND 3 WERE**  
12 **ABANDONED, INVOLVING 50/50 SHARING OF THE STRANDED**  
13 **COSTS. IF THAT WAS OKAY THEN, WHY NOT NOW?**

14 **A.** There are several reasons. First, that was part of a decision made by many parties  
15 in settlement. Other benefits, costs, and risks were simultaneously allocated  
16 among them in mutually satisfying ways, and none of those tradeoffs are still in  
17 play or being offered here. The 50/50 part is not usable in isolation, and  
18 settlements in general are not useful (or recognized legally) for precedent.

19  
20 Second, as a matter of the math of the disallowance proposal currently at hand, I  
21 understand it to include only a debt return on the 50/50 slice of stranded costs that  
22 intervenors would allow for recovery. That level of return is not a mechanism for  
23 giving the full value of their “50” to the shareholders: they will recover only the

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1 return of that half of the investment, plus enough to service its interest carrying  
2 costs, but with no return on this portion for their opportunity cost of equity  
3 capital. So the proposed 50/50 for San Juan Units 1 and 4 is not really 50/50 even  
4 on its own terms, regardless of whether any such sharing is appropriate.

5  
6 **Q. HOW HAVE OTHER STATE REGULATORY COMMISSIONS**  
7 **TREATED THE RECOVERY OF UNDEPRECIATED INVESTMENT AT**  
8 **RETIRING COAL PLANTS?**

9 **A.** Other state regulatory commissions have broadly allowed full recovery of  
10 prudently incurred past investment costs, including costs such as construction  
11 work in progress and those associated with unusable inventory, when shifting  
12 economics and new regulatory mandates have driven early plant retirements. For  
13 example, in 2011, the Alabama Public Utilities Commission issued a blanket  
14 order to Alabama Power Company, allowing it to recover “unrecovered plant  
15 asset balance and the unrecovered costs associated with site removal and closure”  
16 through the establishment of regulatory assets.<sup>19</sup> This was to enable Alabama  
17 Power Company to respond responsibly to new environmental regulations,  
18 without worry that formerly established prudent investments would be disallowed.  
19 In essence, the Commission recognized not only the fairness of this approach, but  
20 also the incentive benefits of making it possible for the utility to continue to seek  
21 cost savings without having to protect sunk costs.

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<sup>19</sup> Alabama Public Utilities Commission, Informal Docket No. U -5033, September 7, 2011.

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1  
2 As another example, the Public Utilities Commission of Nevada approved in 2014  
3 for Nevada Power Company to recover the net book values of the retiring coal  
4 plants (Reid Gardner coal units 1-4 and the company's share of Navajo coal plant)  
5 through regulatory asset treatment. The early retirement of coal units were  
6 mandated by legislature in Senate Bill 123 to close at least 800 MW of coal-fired  
7 generation capacity and to replace them with renewable or non-coal conventional  
8 generation.<sup>20</sup>

9  
10 General public and regulatory awareness of the benefits of early fossil plant  
11 retirements and replacement with renewable resources is growing, with several  
12 states considering policies somewhat similar to the Energy Transition Act that  
13 would allow cost recovery and sometimes securitization of sunk costs, including  
14 Minnesota, Colorado, Kansas, Missouri, North Carolina and perhaps others.<sup>21</sup>  
15 The point is that decarbonization of the generation fleet is encouraged by and  
16 facilitated through a full recovery of unrecovered investment.

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<sup>20</sup> Public Utilities Commission of Nevada, Docket Nos. 14-05003 and 14-06022, October 27, 2014.  
<sup>21</sup> <https://www.renewableenergyworld.com/2019/05/28/power-plant-securitization-coming-to-a-state-capitol-near-you/>

<https://energynews.us/2019/05/01/midwest/kansas-missouri-among-latest-states-to-debate-refinancing-for-aging-coal-plants/>

<https://energynews.us/2019/06/05/southeast/in-controversial-n-c-ratemaking-bill-a-tool-to-help-retire-duke-coal-plants/>

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1   **Q.   PLEASE SUMMARIZE YOUR VIEWS OF WHY THE REGULATORY**  
2       **COMPACT ACTUALLY CALLS FOR THE OPPOSITE OF WHAT**  
3       **STAFF HAS PROPOSED?**

4   **A.**   Any valid interpretation of the “regulatory compact” has to honor the long-  
5       standing, validated, and broadly applied *Hope* and *Bluefield* standards that a  
6       utility with an obligation to serve and cost of service pricing must be given a fair  
7       opportunity to earn its cost of capital – not a guarantee, but also not any  
8       arrangements that guarantees it will not happen. The proposal from Staff to apply  
9       “used and useful” operational standards or a “balancing of interests” to stranded  
10      cost recovery, despite no findings or even allegations of imprudence in the way  
11      the undepreciated sunk costs were incurred, breaches the long run balancing of  
12      interests that is in the interests of customers. The proposed disallowances would  
13      also create perverse incentives for PNM (or other New Mexico utilities) to quit  
14      looking for opportunities to improve their asset mix in mid-life for those  
15      resources, or to make timely investments in assets that are expected to save long-  
16      run costs but which could, under adverse circumstances, result in assets moving  
17      “out of the money”.

18

19      Further, if some of the Staff’s position is arising because they doubt whether the  
20      PNM replacement strategy might not be as cheap as San Juan coal plant with  
21      CCUS, I show below that this is not the case. CCUS would likely be much more  
22      costly than PNM’s recommended Scenario 1.

23

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**IV. EXPECTED COST SAVINGS TO CUSTOMERS FROM  
ABANDONMENT OF THE SAN JUAN COAL PLANT**

**Q. PLEASE SUMMARIZE PNM'S PROPOSAL TO ABANDON AND  
REPLACE SAN JUAN COAL PLANT.**

**A.** PNM proposes to abandon its interest in the San Juan coal plant Units 1 and 4 by mid-2022, when the current San Juan coal agreement and ownership agreements will expire, and to replace it with renewable generation, storage, and gas peakers. It is important to note that with the exception of the City of Farmington, all plant owners have made a decision to not continue operating the San Juan coal plant after 2022.<sup>22</sup>

When selecting the preferred resources to replace the San Juan coal plant's capacity and energy, PNM considered the various policy requirements and constraints in the Energy Transition Act, which was signed into law on March 22, 2019 and went into effect on June 14, 2019. This led them to develop and evaluate four replacement scenarios:<sup>23</sup>

- Scenario 1: a mix of clean resources selected based on Energy Transition Act policy factors and system integration requirements; battery system's maximum capacity of 40MW; combined battery additions not to exceed 130 MW in 2022; 280 MW aero-derivatives for fast ramping, capacity adequacy, and backup when renewables are not available or sufficient
- Scenario 2: Same as Scenario 1, with at least 450 MW of replacement resources to be located in the school district
- Scenario 3: Same as Scenario 1, but with no new fossil fuel resources
- Scenario 4: Same as Scenario 3 with no storage options

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<sup>22</sup> Public Service Company of New Mexico's verified compliance filing pursuant to paragraph 19 of the modified stipulation, Case No.13-00390-UT, PNM Exhibit TGF-4.

<sup>23</sup> Phillips's Direct Testimony, *In The Matter Of Public Service Company Of New Mexico's Abandonment Of San Juan Generating Station Units 1 And 4* (July 1, 2019).

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1

2       In addition, both the San Juan coal plant continuation analysis and the four  
3       replacement scenarios include downstream adjustments in subsequent years to  
4       further meet needs and minimize retail costs on PNM's system.

5

6       Scenario 1 had the lowest cost and is the best fit to the needs of the PNM retail  
7       system, with a net savings in present value revenue requirements relative to  
8       retaining the San Juan coal plant of \$399 million.<sup>24</sup>

9

10   **Q.   PLEASE BE MORE SPECIFIC ABOUT HOW PNM ANALYZED THE**  
11       **COSTS AND CUSTOMER BENEFITS FROM ITS SAN JUAN COAL**  
12       **PLANT ABANDONMENT AND REPLACEMENT POSSIBILITIES?**

13   **A.**   PNM evaluated the abandonment of the San Juan coal plant Units 1 and 4 in its  
14       2017 Integrated Resource Plan (IRP). In that analysis, PNM constructed two  
15       options: continue operating the San Juan coal plant until 2038 or abandon the  
16       plant in 2022. Within each option, 21 scenarios were developed based on  
17       alternative load forecasts, gas prices, and carbon prices. PNM analyzed these  
18       scenarios using the i) Strategist model to identify the best mix of capacity  
19       expansion, ii) the economic hourly dispatch model Aurora XMP to evaluate total  
20       production costs, and iii) the SERVIM model for sub-hourly system reliability  
21       assessments. PNM found that over the 20-year planning period, abandonment of

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<sup>24</sup> Direct Corrected Testimony of Nicholas Phillips, September 20, 2019, page 19.

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1 the San Juan coal plant in 2022 with several possible replacements would lead to  
2 long-term cost savings in most scenarios.

3  
4 After the 2017 IRP, PNM further examined the abandonment of the San Juan coal  
5 plant Units 1 and 4 and solicited bids for replacement resources.<sup>25</sup> PNM  
6 performed additional analyses using updated assumptions about coal and natural  
7 gas costs, operations and maintenance costs, replacement resource costs, among  
8 others. Analyzing the cost savings of the above mentioned four types of  
9 replacement power strategies relative to continuing to operate the San Juan coal  
10 plant, PNM found that Scenario 1 would yield a present value revenue  
11 requirements (PVRR) savings of \$399 million. This estimate is a conservative  
12 statement of the savings over continuing to operate the San Juan coal plant  
13 because the analysis did not include either the carbon-reduction costs for the plant  
14 that would be required by the Energy Transition Act or the costs of potential  
15 requirements by Environmental Protection Agency to install additional (non-CO<sub>2</sub>)  
16 pollution control equipment under continued San Juan coal plant operations. The  
17 analysis also assumed that PNM's responsibility for O&M costs of San Juan coal  
18 plant would not increase due to other owners' plans for abandonment of the plant  
19 in 2022.

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<sup>25</sup> Phillips's Direct Testimony, *In The Matter Of Public Service Company Of New Mexico's Abandonment Of San Juan Generating Station Units 1 And 4* (July 1, 2019).

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1   **Q.   DO YOU CONSIDER PNM’S ANALYSES OF COST SAVINGS FROM**  
2       **THE ABANDONMENT TO BE REASONABLE?**

3   **A.**   Yes. The modeling techniques used are sophisticated and comprehensive, looking  
4       at both long-run optimality and shorter-period reliability, with reasonable  
5       assumptions for operating conditions. Based on my independent review of the  
6       analyses and findings described in the testimony of PNM’s Witness Phillips, I  
7       conclude that PNM’s analysis is reasonable and likely results in a conservative  
8       estimate of the cost savings for customers.

9

10   **Q.   HAS PNM ALSO ESTIMATED THE BENEFITS OF CONTINUING TO**  
11       **OPERATE SAN JUAN COAL PLANT WITH CARBON CAPTURE**  
12       **INSTEAD OF ABANDONING AND REPLACING IT?**

13   **A.**   I understand that PNM has considered the option to continue operating the San  
14       Juan coal plant with carbon capture, utilization, and sequestration (“CCUS”), and  
15       found it extremely likely to be more expensive and risky than just retaining the  
16       plant or abandoning and replacing it. In a study commissioned by PNM in 2010,  
17       Sargent & Lundy (“S&L”) found “considerable risk due to the uncertainty in cost  
18       and performance” related to retrofitting San Juan coal plant at that time with  
19       CCUS technology.<sup>26</sup> All projects in operation then were for demonstration  
20       purposes with various levels of support from the U.S. government. The rebuttal  
21       testimony of PNM witness Phillips provides more discussion of PNM’s prior

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<sup>26</sup> See page ES-6 of Alternatives Study, San Juan Generating Station, PNM, Sargent & Lundy, published on February 25, 2010.

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1 evaluations of CCUS, as well as its results from a new, detailed analysis of San  
2 Juan coal plant with CCUS prepared for this proceeding.

3  
4 **Q. HAVE YOU CONDUCTED YOUR OWN ANALYSIS OF THE BENEFITS**  
5 **OF CONTINUING TO OPERATE SAN JUAN COAL PLANT WITH**  
6 **CARBON CAPTURE?**

7 **A.** Yes, in collaboration with PNM for key assumptions about system conditions and  
8 plant capabilities, I have conducted my own analysis of the economics of CCUS  
9 at the San Juan coal plant (relative to continuing to operate the plant without  
10 CCUS). This analysis takes an isolated look in a spreadsheet model at just the  
11 plant itself as-is and with CCUS (plus replacement energy and capacity) in order  
12 to allow easier understanding of the sources of net value or cost. This analysis  
13 does not require a detailed system model because I am comparing the San Juan  
14 coal plant without CCUS to the San Juan coal plant with CCUS supplemented by  
15 a mix of increased generation at San Juan coal plant, new gas peakers and market  
16 purchases to offset the lost capacity and energy from the CCUS parasitic load  
17 itself. My analysis shows that the CCUS is an unattractive option compared to  
18 San Juan coal plant as-is, under a range of conditions. Note however that  
19 continuing to use the plant as-is is not a feasible alternative under the Energy  
20 Transition Act: it either has to be equipped with additional CO<sub>2</sub> controls or be  
21 replaced with cleaner generation. I use the San Juan coal plant as-is just for  
22 reference and for consistency with PNM's analysis of Scenario 1 and other San  
23 Juan coal plant replacement options, where they found that replacement is much

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1 cheaper than continuing to operate the plant without CCUS. Now I show that,  
2 except under optimistic assumptions, the CCUS option is at best break even (and  
3 likely more costly) compared to the option to continue operating without CCUS.  
4 Therefore, PNM's recommended abandonment and replacement is likely much  
5 cheaper than continuing to operate the San Juan coal plant with CCUS.

6  
7 As I explain further below, there are conceivable circumstances under which  
8 CCUS at the San Juan coal plant could be cheaper than continuing with the plant  
9 as-is. However, those circumstances involve reliance on high EOR prices that  
10 exceed the \$15-20/ton range considered in the S&L study, high CO<sub>2</sub> prices, and  
11 depend on S&L's preliminary estimate of the CCUS capital costs that are  
12 substantially lower than the actual capital costs of the two existing CCUS projects  
13 in Texas and Canada.

14  
15 **Q. WHAT IS YOUR RESPONSE TO STAFF WITNESS SOLOMON'S**  
16 **DESCRIPTION OF THE POTENTIAL FOR COST SAVINGS DUE TO**  
17 **TAX BENEFITS AND EOR CO<sub>2</sub> SALES FROM CONTINUING TO MAKE**  
18 **IT ATTRACTIVE TO OPERATE THE SAN JUAN COAL PLANT WITH**  
19 **CARBON CAPTURE?**

20 **A.** My modeling captures this benefit in reaching my conclusion that CCUS is not  
21 likely to be beneficial to customers. Staff Witness Solomon described economic  
22 benefits from installing carbon capture that arise from the new tax credit under  
23 Section 45Q of the Internal Revenue Code ("45Q tax credit") and revenues from

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1 selling the captured CO<sub>2</sub> for the purpose of enhanced oil recovery (EOR). Under  
2 Section 45Q, a generator that captures CO<sub>2</sub> and uses for enhanced oil or natural  
3 gas recovery can earn tax credits for 12 years: \$27.61 per ton of captured CO<sub>2</sub> in  
4 2023, increasing to \$35/ton in 2026 and growing by inflation afterwards. To  
5 qualify, the plant's construction must begin before 2024. These tax credit savings  
6 can reduce the need for revenues to pay the normal capital charges for return on  
7 and of the San Juan coal plant and its CCUS.

8  
9 Revenue from sale of CO<sub>2</sub> for the purpose of EOR can also bring additional  
10 benefits that help offset its costs. Specifically, the San Juan coal plant can supply  
11 the captured CO<sub>2</sub> to the Permian Basin oil fields through the nearby Cortez  
12 compressed CO<sub>2</sub> pipeline. The 2019 S&L study estimates that the facility could  
13 then earn \$15-\$20 per ton of compressed and purified CO<sub>2</sub>.<sup>27</sup> If a facility the size  
14 of the San Juan coal plant were to operate essentially around the clock at an 85%  
15 capacity factor (which S&L assumed, but which significantly exceeds the plant's  
16 recent historical capacity factor) it could capture about 6 million tons of CO<sub>2</sub> per  
17 year. The revenues from these two benefits (45Q tax credits and EOR payments)  
18 could be very significant, perhaps hundreds of millions dollar per year to offset  
19 some of the incremental costs from CCUS retrofit. In light of these potential  
20 benefits, the option of continuing the San Juan coal plant with CCUS may seem

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<sup>27</sup> See page 4-3, Sargent & Lundy study, Exhibit DS-1 in Solomon's Direct Testimony, October 18, 2019 filing.

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1       like it could be appealing – but as my analysis and PNM’s recent evaluation  
2       shows, the value of these benefits is not likely to offset the incremental costs.

3  
4       As noted, I have taken these tax credit and EOR revenue benefits into account in  
5       my CCUS evaluations, in fact liberally assuming that the tax credits could always  
6       be fully captured by PNM. My model essentially calculates the revenue  
7       requirements for just the San Juan coal plant as is versus with CCUS and its EOR  
8       plus 45Q tax benefits, and compares the present value of those customer costs  
9       discounted at PNM’s weighted average cost of capital (WACC). Even with the  
10      assumed large non-retail benefits from EOR and 45Q, I find that adding CCUS to  
11      the plant under its likely use for serving PNM’s retail load still raises costs.  
12      Unless PNM can sell the captured CO<sub>2</sub> for a significantly higher price for EOR  
13      than S&L has indicated is likely, these benefits are not enough to make CCUS  
14      attractive at the San Juan coal plant. And again, even in those favorable CCUS  
15      conditions, the benefits would likely not be as great as PNM has found from its  
16      recommended the San Juan coal plant replacement portfolio (Scenario 1).

17  
18   **Q.     ARE THE RISKS OF THE CCUS STRATEGY COMPARABLE TO THE**  
19   **RISKS OF THE PROPOSED REPLACEMENT PORTFOLIO PLAN PNM**  
20   **PREFERS?**

21   **A.**   No. The replacement strategy involves proven and standard assets with little cost  
22       or performance risk. In contrast, installing and operating carbon capture at this  
23       early stage in that technology’s development imposes several significant cost and

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1 technological risks, and it requires making a much larger, upfront, irreversible  
2 investment commitment. Specifically, carbon capture at the San Juan coal plant  
3 would require several types of incremental costs compared to continuing to  
4 operate the plant without carbon capture, or compared to the Scenario 1 plan.  
5 These include: i) substantial capital expenditures for both the capture equipment  
6 at the plant and pipeline infrastructure to transport the captured CO<sub>2</sub> emissions; ii)  
7 increase in operating and maintenance costs; iii) additional ongoing capital  
8 investments on the CCUS facility; iv) additional costs to decommission the CCUS  
9 facility at the end of the economic life of the San Juan coal plant; and v)  
10 additional costs to replace the reduction in capacity and energy due to auxiliary  
11 power consumption of the carbon capture system (though this category also arises  
12 for the Scenario 1 proposal).

13  
14 **Q. PLEASE DESCRIBE HOW YOU ESTIMATED THE NET COSTS OR**  
15 **SAVINGS ON A LIFECYCLE BASIS FROM RUNNING CARBON**  
16 **CAPTURE AT THE SAN JUAN COAL PLANT THROUGH 2038.**

17 **A.** I conducted a high-level analysis of the costs of the San Juan coal plant with  
18 and without CCUS (and with corresponding adjustments for efficiency and  
19 operating differences created by the carbon controls) to evaluate potential cost  
20 increases or savings with carbon capture over the remaining life of the San Juan

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1 coal plant (until 2038).<sup>28</sup> The categories of incremental costs that I assumed for  
2 CCUS at the San Juan coal plant are as follows:

- 3 • Project capital cost of \$1.295 billion derived from the recent S&L pre-  
4 feasibility study. I applied a level-nominal fixed charge rate of 12.07%  
5 derived from PNM's current cost of capital to achieve an after tax return on  
6 equity that is equal to the allowed rate of return.<sup>29</sup> (Equivalently, this rate  
7 allows the total after tax cash flows to have a present value equal to the costs  
8 of the invested capital in the CCUS and other system upgrades it would  
9 require.) This initial project cost includes the \$40 million construction cost of  
10 a 20-mile lateral pipeline linking the San Juan coal plant to the nearest CO<sub>2</sub>  
11 pipeline, the Cortez pipeline.
- 12 • Fixed and variable operations & maintenance costs based on estimates from  
13 the 2019 S&L report.
- 14 • Certain costs not considered in the S&L report that I believe should have been  
15 included. Specifically, I believe there will be ongoing capital investments to  
16 maintain the CCUS facility (estimated at \$13 million/year) and  
17 decommissioning costs of the CCUS facility at the end of the plant's life  
18 (\$130 million in 2038). These were not recognized in the S&L report.
- 19 • Replacement power needs due to steam extraction and auxiliary power usage  
20 of the new CCUS plant, which S&L estimate would require about 30% of the

---

<sup>28</sup> I understand that the current coal contract for the San Juan coal plant expires prior to 2038, but I have assumed that the contract could be extended under the same terms.

<sup>29</sup> I estimated the fixed charge rate based on PNM's cost of capital parameters and a 16-year period for cost recovery.

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1 plant's current capacity, or about a 145 MW that would otherwise have been  
2 available for serving retail loads. This parasitic load of the CCUS will have to  
3 be supplied either by increased output from the San Juan coal plant itself,  
4 relative to how much it would have otherwise run, or from new sources  
5 outside of the plant such as a new CT, running other plants more heavily  
6 elsewhere on the PNM system, or market purchases.

7  
8 It turns out that a mix of these is possible. Because of its position in the  
9 dispatch ladder of PNM's system, the plant is often running at less than full  
10 capacity without the CCUS, so it theoretically would be able to run more and  
11 supply its own CCUS needs about 85% of the time. In the other 15% of the  
12 time CCUS runs (which in total is about 85% of the year, essentially equal to  
13 running all the time when the plant is available because it needs steady  
14 operations to be efficient) I am replacing its energy (and capacity) with a gas  
15 CT and with market purchases assumed to be made at the Palo Verde hub.

16  
17 I find that these replacement power costs in the year 2023 would cost a total  
18 of \$47.1 million (in 2019 dollars).

- 19  
20 • Projected capacity factor of the San Juan coal plant derived from PNM's  
21 system simulations reflecting the use of the plant just for serving PNM's retail  
22 needs. PNM simulations with the Encompass model show how the San Juan  
23 coal plant would be used for the purposes of supporting retail load, with and

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1 without the CCUS, and I have applied those usage rates in my analysis. The  
2 plant has a lower capacity factor (i.e., is used less as a percentage of its  
3 maximum possible output per year) without CCUS than with, for two reasons.  
4 First, the CCUS equipment needs to be run on a fairly steady basis for  
5 efficiency. Second, the EOR revenues it obtains from the sale of carbon can  
6 be thought of as a reduction in its variable cost of operations, making it more  
7 attractive to dispatch with the CCUS. (As noted above, much of this extra  
8 dispatch goes towards supporting the CCUS's own electrical requirements,  
9 but it also results in more CO<sub>2</sub> and 45Q tax credits being earned.). On  
10 average, I assumed in the base case about a 70% capacity factor on average  
11 (varying each year in proportion to how the plant would be operated without  
12 CCUS). Due to the partial loading of the San Juan coal plant in some hours,  
13 this allows the CCUS to be used in about 85% of all hours. S&L in its pre-  
14 feasibility study projected an 85% capacity factor for both the plant and its  
15 CCUS. I am consistent with their CCUS usage, but their power plant output is  
16 substantially higher than PNM projects and higher than the historical average  
17 capacity factor of 70%.

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- 1           • Finally, the S&L study examines the CCUS option from the perspective of a  
2           single owner of the entire plant, whereas my model assumes that PNM will  
3           bear only the costs proportional to its current share of the plant.<sup>30</sup>  
4

5   **Q.   WHAT ARE THE CONSEQUENCES OF THESE DIFFERENT**  
6   **ASSUMPTIONS ON THE COST OF CARBON REDUCTIONS IN YOUR**  
7   **ANALYSIS VERSUS THE S&L STUDY?**

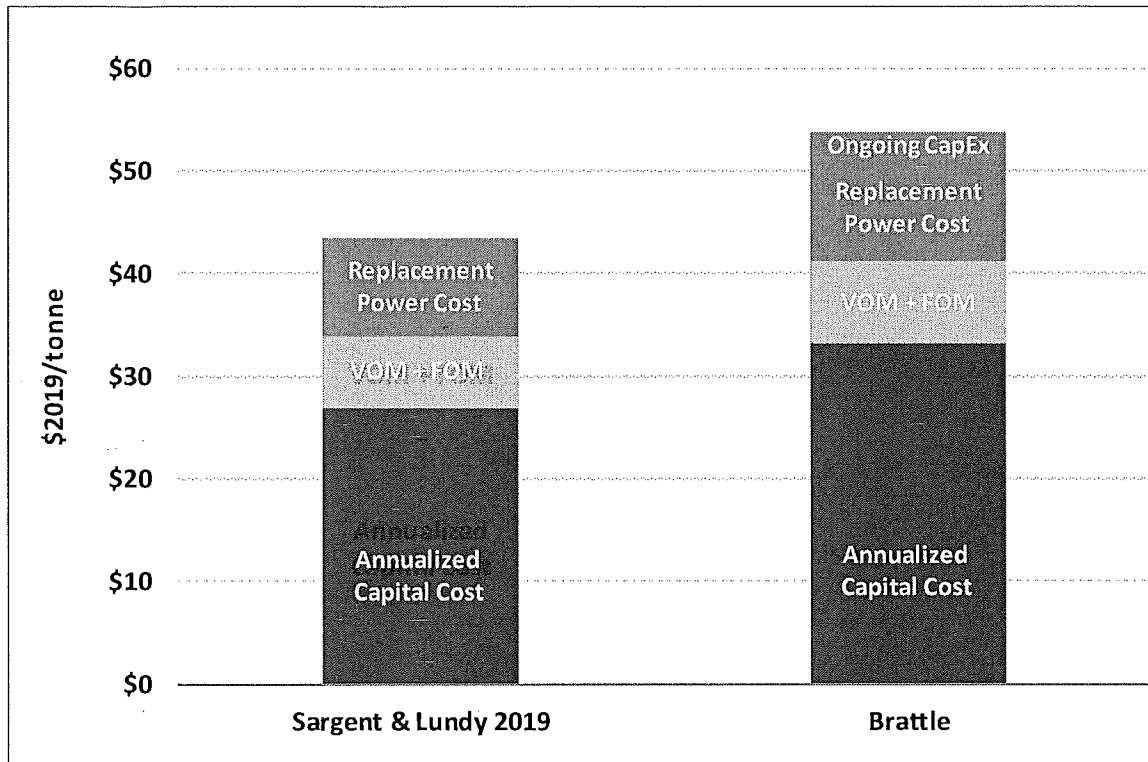
8   **A.**   As shown in PNM Figure FG-2 (Rebuttal) below, I find that the cost of CO<sub>2</sub>  
9           capture in 2023, before tax credits and EOR revenues, would be about \$53.68/ton  
10          in 2019 dollars, which is about 23% higher than S&L's \$43.49/ton cost estimate.  
11          The increase in my estimate compared to S&L is largely due to the lower capacity  
12          factor for the plant, resulting in the full costs of the CCUS being amortized across  
13          a smaller amount of CO<sub>2</sub> avoided.  
14  
15

---

<sup>30</sup> All the San Juan coal plant co-owners, with the exception of the City of Farmington, expressed that they planned to abandon their share of the San Juan coal plant, so our estimate here is conservative.

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**PNM Figure FG-2 (Rebuttal): First-Year Cost of CCUS in 2023**



**Q. HAVE YOU ESTIMATED THE IMPACT OF POTENTIAL TAX CREDIT AND EOR REVENUE BENEFITS FROM CCUS THAT WOULD OFFSET SOME OF THESE DIRECT COSTS PER TON OF ABATEMENT OVER THE LIFE OF THE PLANT?**

**A.** Yes. Beyond the environmental benefits of reducing CO<sub>2</sub>, there are possible financial benefits from installing carbon capture that will affect the facility's net costs. These come from the 45Q tax credit and revenue from selling the captured CO<sub>2</sub> for the purpose of EOR. Specifically, if the retrofit can be completed by 2023 as proposed, PNM may receive tax benefits (assuming sufficient tax liability to monetize those credits) until 2034, the end of its 12 years of eligibility. The unit value of these 45Q benefits will increase to \$35 per ton of captured CO<sub>2</sub> (before

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1       adjusted for inflation) during this 12-year period. The EOR value of the captured  
2       CO<sub>2</sub> will depend on the oil price as well as the supply of competing naturally-  
3       sourced CO<sub>2</sub>.<sup>31</sup> S&L estimates that the facility owner could sell CO<sub>2</sub> for \$15-\$20  
4       per ton. Applying the upper estimate of \$20 per ton, I estimate that PNM would  
5       earn about \$54 million on average per year for EOR revenues during the lifetime  
6       of the plant. These are substantial, but as seen above, not enough to offset the  
7       fixed costs and replacement energy requirements of the plant.

8

9       **Q.   WHAT IS THE NET EFFECT OF ALL THESE ASSUMPTIONS OVER**  
10       **THE REMAINING LIFE OF THE PLANT?**

11       **A.**   Relative to the cost of continuing to operate the San Juan coal plant as-is without  
12       CCUS, the present value of costs to PNM customers under the CCUS option  
13       would be approximately the same (\$3 million more expensive). This result is  
14       based on adopting the CCUS capital cost assumption from the S&L study, as well  
15       as the high-end of the EOR price range that was presented in the S&L study and  
16       the testimony of Witness Solomon.

17

---

<sup>31</sup> Kinder Morgan mines CO<sub>2</sub> from the McElmo Dome. It then transports the CO<sub>2</sub> through the Cortez pipeline. Kinder Morder has ownership interest in both the dome and the pipeline.

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**Q. HOW DOES THE CCUS CAPITAL COST SUGGESTED BY S&L IN ITS 2019 UPDATE ON THE SAN JUAN COAL PLANT COMPARE TO THE COSTS OF CCUS AT OTHER PROJECTS AND PREVIOUS ESTIMATES?**

**A.** Currently, there are only two operating commercial-scale CCUS systems in coal-fired power plants in North America: SaskPower's Boundary Dam plant in Canada and the Petra Nova plant in the Texas, jointly owned by NRG and the Japan-based multinational corporation JX. Both plants were recently built (in 2014 and 2017), and both use post-combustion CO<sub>2</sub> capture technology (like the San Juan coal plant would use) to remove about 90% of the CO<sub>2</sub> in the flue gas stream, and the captured CO<sub>2</sub> is also used for enhanced oil recovery. After the retrofit of its 160-MW generating unit, the Boundary Dam plant began capturing about 1 million tons of CO<sub>2</sub> annually. The 240-MW carbon capture system at the Petra Nova plant captures 1.6 million tons of CO<sub>2</sub> annually.<sup>32</sup> The Petra Nova CCUS gets its steam and electricity from an auxiliary natural gas combined cycle power plant, while the CCUS facility at Boundary Dam uses steam and electricity from the existing power plant,<sup>33</sup> similar to the proposed design for the San Juan coal plant. Both of these existing CCUS facilities are significantly smaller than the CCUS facility that the San Juan coal plant would require.

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<sup>32</sup> See Mantripragada et al., *Boundary Dam or Petra Nova – Which is a Better Model for CCS Energy Supply?* published in *International Journal of Greenhouse Gas Control* in 2019.

<sup>33</sup> *Ibid.*

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1 The CCUS unit capital cost reported as possible for the San Juan coal plant by  
2 S&L (\$2,155/kW<sub>net</sub>) is substantially lower than the actual capital costs incurred at  
3 these two existing CCUS power plants. For example, the Boundary Dam CCUS  
4 project has a similar design to the San Juan coal plant's proposed design but a  
5 much smaller net capacity of 110 MW after 90% CO<sub>2</sub> capture retrofit.<sup>34</sup>  
6 Boundary Dam's CCUS component costed \$638 million, and the entire project  
7 \$1.276 billion,<sup>35</sup> which translates to a unit capital cost of \$5,800/kW<sub>net</sub> -- more  
8 than double (per kW<sub>net</sub>) S&L's estimate for the San Juan coal plant. This  
9 Boundary Dam CCUS cost per kW<sub>net</sub> is also well above S&L's 2010 estimates of  
10 \$3,632/kW<sub>net</sub> and \$3,011/kW<sub>net</sub> for hypothetical CCUS at Units 1 and 4,  
11 respectively.<sup>36</sup>

12  
13 Petra Nova reportedly has a total capital cost of \$1 billion,<sup>37</sup> inclusive of the  
14 carbon capture and storage facility, the 70 MW natural gas cogeneration unit, the  
15 CO<sub>2</sub> pipeline, and facilities at the oilfield. However, details of the project's cost  
16 breakdown are proprietary and are not available. Assuming a cost of \$1000/kW  
17 for the cogeneration unit, or \$70 million, the \$930 million balance translates to a  
18 unit capital cost is \$3,875/kW for CCUS-related components, almost twice as

---

<sup>34</sup> [http://sequestration.mit.edu/tools/projects/boundary\\_dam.html](http://sequestration.mit.edu/tools/projects/boundary_dam.html).

<sup>35</sup> IEAGHG, "Details from the IEAGHG – U.S. DOE Report on the Saskpower Boundary Dam Power Station Integrated CCS Project," <http://www.wyia.org/wp-content/uploads/2017/06/carolyn-preston.pdf>. Converted to USD using the IRS 2014 average currency exchange rates, <https://www.irs.gov/individuals/international-taxpayers/yearly-average-currency-exchange-rates>.

<sup>36</sup> See Alternatives Study, San Juan Generating Station, PNM, SL-010117, Revision 1, Final Report, Project No. 11278-018, Sargent & Lundy, February 25, 2010.

<sup>37</sup> [http://sequestration.mit.edu/tools/projects/wa\\_parish.html](http://sequestration.mit.edu/tools/projects/wa_parish.html).

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1 high as S&L. Thus, recent experience is not especially supportive of S&L's  
2 estimates for the San Juan coal plant.

3  
4 A Clean Air Task Force report<sup>38</sup> published earlier this year estimates that the unit  
5 capital cost for retrofitting a 200 MW and 400 MW high heat rate units with  
6 CCUS would be \$2,224/kW and \$1,724/kW (2017 dollars). However, the report  
7 modeled coal retrofits based on a Petra Nova-like design. Additionally, these  
8 costs are for Nth-of-a-kind, where N is at least five. Petra Nova is the first of its  
9 kind, and Shand Power Station is the only CCUS retrofit project that is currently  
10 under consideration in North America. The San Juan coal plant would be very  
11 early in the learning curve for CCUS. The PNM Table FG- 1 provides a summary  
12 of the comparison of S&L's assumed capital costs for CCUS at the San Juan coal  
13 plant against the capital costs of the two existing CCUS projects.

---

<sup>38</sup> Clean Air Task Force, "Carbon Capture and Storage in the United States Power Sector", February 2019, posted at [https://www.catf.us/wp-content/uploads/2019/02/CATF\\_CCS\\_United\\_States\\_Power\\_Sector.pdf](https://www.catf.us/wp-content/uploads/2019/02/CATF_CCS_United_States_Power_Sector.pdf).

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**PNM Table FG- 1 (Rebuttal): Comparison to Cost Estimates from  
Existing Carbon Capture Projects**

Project Name	Gross Capacity MW	Net Capacity MW	Equivalent Capital Cost for a 601 MW		Additional Comments
			Cost \$/kW <sub>net</sub>	(net) unit \$	
Boundary	160	110	5,800	\$3.5 billion	2014 exchange rate
Petra Nova	240	240	3,875	\$2.3 billion	Excludes gas cogeneration unit
San Juan 2019 Study	914	601	2,155	\$1.295 billion	

**Q. WHAT ARE SOME OF THE UNCERTAIN FACTORS IN YOUR ESTIMATE THAT AFFECT COSTS OF CCUS AT THE SAN JUAN COAL PLANT?**

**A.** There are several, and their omission or my base assumptions about them tend to make my analysis of potential cost savings from CCUS option conservative, i.e., understating the advantages of Scenario 1, for a number of reasons:

- First, as noted above, the tax benefits now offered to CCUS are significant, but it is possible that PNM might not be able to utilize all of them, hence receive their full benefit since it may not have the sufficient amount of future tax liability to monetize these tax credits by itself.
- Second, the San Juan coal plant's performance may be affected during the CCUS construction period. If the plant cannot operate during the retrofitting period, PNM will be forced to purchase replacement capacity and energy. My analysis effectively assumes CCUS retrofit can be done overnight, or at least completely unobtrusively until ready for operations, then plugged in with no reduction in plant availability. This likely underestimates the overall costs.

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- 1           • Third, my analysis does not include any O&M costs for the lateral pipeline  
2           connecting the San Juan coal plant to the Cortez pipeline. Data on O&M  
3           costs is not publicly available, though some suggest that it would be on the  
4           same scale as that of natural gas pipeline.<sup>39</sup> Additionally, to use the Cortez  
5           pipeline, the facility owner must pay transportation fees to Kinder Morgan to  
6           at least cover their own O&M costs. One report suggests that the cost of  
7           transportation of CO<sub>2</sub> from source to assigned EOR storage sites in the Texas  
8           Permian Basin area is \$4.72 per metric ton.<sup>40</sup> At an annual capture level of  
9           2.7 million metric tons, this amounts to about \$13 million per year in  
10          additional costs.
- 11          • Fourth, and probably most importantly, there is considerable risk associated  
12          with the initial cost itself. CCUS remains an immature technology: it has not  
13          been demonstrated at scale at many locations, and its capital costs to date have  
14          been very high, multiples of the estimate that S&L has recently made. I am  
15          not offering an engineering opinion as to why or whether CCUS costs would  
16          be high at the San Juan coal plant, but it is prudent to at least consider that  
17          outcome a significant possibility.
- 18

---

<sup>39</sup> See King et al., *The System-Wide Economics of a Carbon Dioxide Capture, Utilization, and Storage Network: Texas Gulf Coast with Pure CO<sub>2</sub>-EOR Flood*, published in Environmental Research Letters in 2013.

<sup>40</sup> *Ibid.* at 38.

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**Q. PLEASE PROVIDE SOME EXAMPLES FOR WHY INITIAL CCUS  
INSTALLATION COST UNCERTAINTY IS QUITE HIGH.**

**A.** To date, Petra Nova and Boundary are the only two commercial scale power plants with post-combustion carbon capture, both at capital costs much higher than S&L estimate.

Another CCUS project in North America was planned for Kemper County, Mississippi. The Kemper plant would use pre-combustion integrated gasification combined cycle (IGCC) technology to capture 65% of the CO<sub>2</sub> emissions. Slated to come online in May 2014 in Kemper County, the Kemper plant ran into a host of issues, causing cost to balloon to \$7.5 billion, three times higher than the original budget.<sup>41</sup> After multiple delays and cost overruns, the CCUS project was cancelled.

Construction and technology risks that ultimately result in significant delays and cost overruns have not been uncommon among CCUS projects. For example, earlier design of the Boundary Dam project envisioned a 300-MW plant, but the final project was much smaller owing to technical issues and escalating costs.<sup>42</sup> Even after completion, design and construction deficiencies prevented the plant from operating at an acceptable level of reliability and performance and forced the

---

<sup>41</sup> <https://www.theguardian.com/environment/2018/mar/02/clean-coal-america-kemper-power-plant>

<sup>42</sup> [http://sequestration.mit.edu/tools/projects/boundary\\_dam.html](http://sequestration.mit.edu/tools/projects/boundary_dam.html).

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1 plant to be taken offline a number of times, including a two-month outage.<sup>43</sup>  
2 Citing high investment costs and changing economics of power generation, the  
3 CEO of SaskPower indicated that his company would not recommend further  
4 carbon capture projects.<sup>44</sup> Indeed, the company recently scuttled plans to retrofit  
5 Boundary Dam Units 4 and 5 with CCUS.<sup>45</sup>

6  
7 Significantly, both of the existing CCUS plants received substantial financial  
8 support from the government, reducing financial risks for the developers.<sup>46</sup> The  
9 Petra Nova project received more than \$190 million from the U.S. federal  
10 government, or 19% of the total project cost. Additionally, the Japanese  
11 government through its export credit agencies provided support to JX in the form  
12 of a \$250 million low-interest loan. Similarly, the Canadian government provided  
13 the Boundary Dam project with C\$240 million to offset the nearly C\$1.5 billion  
14 project cost. Other than success incentives (45Q tax credits), no such protections  
15 seem to be available to the San Juan coal plant.

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<sup>43</sup> SaskPower 2015-16 Annual Report. Available at <https://www.saskpower.com/-/media/SaskPower/About-Us/Reports/Past-Reports/Report-AnnualReport-2015-16.ashx?la=en&hash=E1FC23D4532FD919B0FDD1256293BAFB2FA0C4FD>.

<sup>44</sup> <https://www.cbc.ca/news/canada/saskatchewan/saskpower-carbon-capture-unlikely-future-1.4386411>.

<sup>45</sup> <https://www.cbc.ca/news/canada/saskatoon/saskpower-abandons-carbon-capture-at-boundary-dam-4-and-5-1.4739107>.

<sup>46</sup> See Peter Folger, *Carbon Capture and Sequestration (CCS) in the United States*, published by Congressional Research Service in 2019. Available at <https://fas.org/sgp/crs/misc/R44902.pdf>.

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**Q. HOW DID YOU INCORPORATE THE EFFECTS OF THESE RISKS ON THE NET COSTS OF CARBON CAPTURE?**

**A.** In order to examine the robustness of our model, I consider an “upside” and a “downside” scenario by using the sensitivities on projections for future nationwide CO<sub>2</sub> prices, EOR prices from selling the captured CO<sub>2</sub>, and initial capital cost of the CCUS.

In the “downside” scenario, I assumed the capital cost of the CCUS would be double that of the cost estimate in the 2019 S&L study (based on the higher actual costs at Boundary Dam and Petra Nova projects I discussed above). In addition, the “downside” scenario assumes lower EOR revenues (\$15/ton) based on the low-end of the EOR price range in the S&L study, smaller portion of the replacement energy from the San Juan coal plant self-supply, and higher replacement energy prices based on the possibility that the replacement energy would need to be purchased at costs of on-peak Palo Verde hub prices.

In the “upside” scenario, I assumed much higher prices for EOR (about \$31/ton on average over 16 years),<sup>47</sup> and lower replacement energy costs implied by off-peak Palo Verde hub prices and increased portion of replacement energy from the San Juan coal plant self-supply.

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<sup>47</sup> This corresponds to EOR prices starting at \$26/ton in 2020 and increasing to \$40/ton in 2050, per the NARUC study cited on page 15 of the testimony of Witness Solomon.

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PNM Table FG- 2 (Rebuttal) below shows the results of these variations compared to my base estimate of \$3 million cost increase due to CCUS (relative to continued operations without CCUS). The “downside” scenario results in a much larger, \$1,058 million cost increase for the San Juan coal plant. In contrast, the “upside” scenario involves conditions whereby the CCUS option results in NPV savings of \$296 million in costs relative to the no-CCUS option.

**PNM Table FG- 2 (Rebuttal): Sensitivities of CCUS Cost Savings  
relative to no CCUS**

	Base	Downside	Upside
Replacement Energy - Option 1	SJGS Self-Supply 85% of Replacement Energy Need Aeroderivative @ 10% CF	SJGS Self-Supply 50% of Replacement Energy Need Aeroderivative @ 10% CF	SJGS Self-Supply 100% of Replacement Energy Need Aeroderivative @ 10% CF
Replacement Energy - Option 2	Palo Verde Market Purchases	Palo Verde On-Peak Market Purchases	Palo Verde Off-Peak Market Purchases
Replacement Energy - Option 3			
CCUS Capital Cost	\$1,295,280,000	\$2,590,560,000	\$1,295,280,000
CO2 National Price	PACE - Low	PACE - Low	PACE - Low
EOR Sale Price (\$/tonne)	\$20	\$15	NARUC
45Q Tax Credit Monetization Rate	100%	100%	100%
<b>20-year NPV @ end of 2019 (\$ million)</b>	<b>(3)</b>	<b>(1,058)</b>	<b>296</b>

This shows that in principle, the CCUS option is most likely to be much costlier than the San Juan coal plant as-is, but could be somewhat beneficial compared to no CCUS under optimistic theoretical conditions. I believe the downside potential is much larger than the upside, not only because of the size of the numbers in this table: The capital cost uncertainty given the newness of CCUS is very large, while the possibility of much higher oil prices and higher payments for EOR CO<sub>2</sub> is less plausible. Thus, except under extremely favorable scenarios

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1 with high EOR prices, the CCUS option is more expensive than the no-CCUS  
2 option.

3  
4 In contrast, the PNM system analysis of replacement strategies showed that  
5 Scenario 1 is likely to be almost \$400 million cheaper than retaining the San Juan  
6 coal plant without CCUS under low CO<sub>2</sub> prices assumption. This amount of  
7 savings is by itself larger than the optimistic estimate I present above for CCUS,  
8 even ignoring the possibility of CCUS being entirely uneconomical. The rebuttal  
9 testimony of Witness Phillips compared the CCUS option against Scenario 1, and  
10 also concluded that the CCUS option is likely more expensive.

11  
12 **V. BENEFITS OF SECURITIZATION AS A COST RECOVERY**  
13 **MECHANISM**

14 **Q. THE ENERGY TRANSITION ACT ALLOWS SECURITIZATION OF**  
15 **CERTAIN STRANDED AND TRANSITION COSTS FROM MEETING**  
16 **ITS CLEAN ENERGY OBJECTIVES. DO YOU SUPPORT THIS**  
17 **APPROACH?**

18 **A.** Yes, securitization is a way of allowing full cost recovery that has lower out-of-  
19 pocket cash costs to customers than continued recovery as if the affected assets  
20 were still in service and in ratebase. The equity component is avoided, and the  
21 debt carrying cost (interest rate) is reduced. I believe Staff witnesses opposing the  
22 abandon and replace plan are in agreement with me on this benefit. So to the

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1 extent the stranded costs were prudent and reasonable, securitization is a helpful  
2 way of dealing with them.

3  
4 **Q. NEE WITNESS FETTER IS WORRIED THAT THE ENERGY**  
5 **TRANSITION ACT GRANTS TOO MUCH POWER TO THE UTILITY**  
6 **TO DEFINE ITS OWN SECURITIZABLE COSTS WITHOUT**  
7 **COMMISSION OVERSIGHT. DO YOU AGREE?**

8 **A.** I do not have an opinion about the proper scope of the Energy Transition Act, but  
9 I suspect that this characterization is obscuring the fact that even if it could be  
10 argued that the Energy Transition Act is over-reaching, that has not occurred in  
11 this case. The initial and now-added evidence about the merits of the PNM  
12 proposal show that it is a robust alternative for resource planning, regardless of  
13 the Energy Transition Act, that has considerable environmental and economic  
14 benefits (savings) that are in the interests of ratepayers. Further, the amounts  
15 which would be securitized are not arbitrary preferences of PNM but are based on  
16 prudent past expenditures and transition costs.

17  
18 NEE Witness Fetter's questioning of the benefits of the Energy Transition Act as  
19 an overall framework is irrelevant to the scope of this proceeding. But I will say  
20 that if that debate is held, it may be helpful to frame it in terms of how much  
21 importance the state and its citizens place on having a cleaner energy supply and  
22 lower carbon footprint relatively soon. This Energy Transition Act policy  
23 provides considerable clarity to encourage New Mexico utilities to seek and find

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1 new, efficient clean energy options, which often may be (as here) fully paid for  
2 while also improving the environment, lowering rates, and preserving the  
3 financial health of the utility. The San Juan coal plant abandonment proposal  
4 from PNM is only the first of many such changes that New Mexico may want to  
5 have its utilities adopt, and those will necessarily occur ahead of completing the  
6 engineering lifetimes of the affected older assets (if not, why have the Energy  
7 Transition Act at all). Regulatory rehashing of investment history and “balancing  
8 of interests” every time a similar opportunity is found will be both slow and  
9 discouraging to the utility investors and planners.

10  
11 I suspect that there are material benefits behind the goals of the Energy Transition  
12 Act sufficient to make everyone better off from a proactive policy, so making that  
13 process less contentious (provided there is a showing of benefits as is the case  
14 here) is a good idea for all stakeholders in New Mexico.

15  
16 Several other states that are moving towards clean energy policies are also  
17 considering or have enacted pro-securitization arrangements to facilitate that  
18 transition, including Minnesota, Colorado, Kansas, Missouri, North Carolina and  
19 perhaps others.

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1

**VI. CONCLUSION**

2   **Q.   PLEASE SUMMARIZE YOUR CONCLUSIONS.**

3   **A.**   The proposals to deny full cost recovery of past investments do not fairly balance  
4           interests and are contrary to sound regulatory principles. They also are not  
5           supported by concerns that perhaps PNM had failed to consider enough  
6           alternatives (especially CCUS at San Juan) to conclude its proposal was  
7           beneficial. My own analysis and that of PNM have demonstrated that CCUS is  
8           unlikely to be economical at all, and that in any event Scenario 1 is a less risky,  
9           lower cost strategy. The use of securitization provides further benefits to  
10          customers.

11

12   **Q.   DOES THIS CONCLUDE YOUR TESTIMONY?**

13   **A.**   Yes it does.

*GCG#526365*

Resume

# PNM Exhibit FG-1 (Rebuttal)

Is contained in the following 39 pages.

**FRANK C. GRAVES**  
Principal

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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, and risk analysis of many kinds of long range planning 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 integrated resource planning (IRPs), energy contract disputes, the prudence of investment and contracting decisions, risk management, 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, 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.

#### **AREAS OF EXPERTISE**

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

#### **PROFESSIONAL AFFILIATIONS**

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

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## Recent Activities

### Client Engagements

- 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, 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.
- 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

On behalf of both Southern California Edison and Pacific Gas & Electric Company, presented direct end 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 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**

“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.****REPRESENTATIVE ENGAGEMENTS***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 the feedbacks between offered electricity prices, customers’ propensities to use DERs, declining technology costs, cost shifting to non-users, and other interdependencies.
- 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.

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- 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.

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- 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.

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- 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.

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- 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 SO<sub>2</sub> 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

## FRANK C. GRAVES

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.

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- 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

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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

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buyer (lessor), the extent of defeasance, and compliance with prevailing guidelines for true-lease status.

*Financial Analysis and Commercial Litigation*

- 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.

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- 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

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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.

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- 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.

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- 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.

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- 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.

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**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

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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

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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**

On behalf of both Southern California Edison and Pacific Gas & Electric Company, presented direct end 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 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.

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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.

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**IN THE MATTER OF PUBLIC SERVICE )**  
**COMPANY OF NEW MEXICO'S )**  
**ABANDONMENT OF SAN JUAN ) Case No. 19-00018-UT**  
**GENERATING STATION UNITS 1 AND 4 )**

COMMONWEALTH OF MASSACHUSETTS )  
 ) ss  
COUNTY OF SUFFOLK )

GCG#526321

SIGNED this 12<sup>th</sup> day of November, 2019.

  
FRANK C. GRAVES

SUBSCRIBED AND SWORN to before me this 12<sup>th</sup> day of November, 2019.

  
NOTARY PUBLIC IN AND FOR  
THE COMMONWEALTH OF MASSACHUSETTS

My Commission Expires:

September 4, 2023

