In the Matter of the Petition of	)	
The Empire District Electric	)	
Company for Approval of its	)	Docket No. 18-EPDE-184-PRE
Customer Savings Plan.	)	

DIRECT TESTIMONY

PREPARED BY

Collin Cain, M.Sc.

ON BEHALF OF THE STAFF OF

THE KANSAS CORPORATION COMMISSION

March 1, 2018

I. STATEMENT OF QUALIFICATIONS

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

A. My name is Collin Cain. I am a Principal with the Energy Practice of Bates White, LLC (Bates White or "the firm"), an economic and litigation consulting firm. My business address is 1300 Eye Street, N.W., Suite 600, Washington, DC 20005.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Staff of the Kansas Corporation Commission ("Staff"). My testimony should be read in conjunction with that of Mr. Nicolas Puga.[1] Mr. Puga's testimony addresses issues arising from risks which were unaccounted for in Empire's analysis of the economics of their proposed acquisition and long term ownership of wind projects with a total capacity of 800 MW, and to which Empire's ratepayers would be exposed if the wind projects underperform with respect to Empire's expectations.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. I have a Bachelor of Arts degree in Economics and Political Science from the University of Toronto and a Master of Science degree in Economics from the London School of Economics. I have 20 years of experience in power sector economic

[1] Testimony of J. Nicolas Puga on behalf of the Staff of the Kansas Corporation Commission in Docket No. 18-EPDE-184-PRE, March 1, 2018.

analysis, including development of energy market pricing and risk analysis models, forensic analysis of the conduct and application of forecasts, market evaluation, and risk assessment by other parties, and economic analysis of power supply procurement alternatives. Prior to joining Bates White, I was a consultant in the energy practice of NERA economic consulting in New York and Washington, DC. A copy of my curriculum vitae is attached as Exhibit No. CC-1.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE COMMISSION?

A. Yes, I testified in KCC Docket No. 11-KCPE-581-PRE, regarding the rationale, assumptions, analytical methods and conclusions presented by Kansas City Power & Light ("KCP&L") in its filing supporting the proposed environmental retrofit at the LaCygne power plant.

Q. PLEASE SUMMARIZE THE ISSUES YOU ADDRESSED IN THE LACYGNE RETROFIT DOCKET.

A. My focus was on evaluating the analysis and production cost modeling conducted by KCP&L, including an assessment of the assumptions and scenario analyses performed using the MIDAS model, and the extent to which the model results supported the derived conclusions justifying the proposed retrofit. As part of that assignment, I also helped develop inputs and scenario cases for independent modeling of the economic benefits of retrofit alternatives using PROMOD.

Q. BRIEFLY DESCRIBE OTHER REPRESENTATIVE CONSULTING EXPERIENCE RELEVANT TO THIS PROCEEDING.

A. I have performed evaluations of power supply alternatives, for power procurement RFPs, asset valuations, and contract disputes. I have also developed risk evaluation methods and assessed the application of such methodologies by others. I have conducted historical analyses and forecasts of locational energy and capacity prices in Regional Transmission Organizations. In addition, I have performed evaluations of wind project revenue models and related power purchase agreements ("PPAs").

II. INTRODUCTION

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by Staff to evaluate the Customer Savings Plan ("CSP") advanced by the Empire District Electric Company ("Empire" or "the Company"), encompassing the proposed acquisition of 800 MW of Wind Projects and retirement of the Asbury Generating Station. In particular, I have been asked to assess the rationale and economic analyses advanced by Empire to support its proposals.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. My conclusions and recommendations are as follows:

1) Because Empire's Generation Fleet Savings Analysis ("GFSA") does not evaluate specific wind projects, but only generic ones, it is not possible to determine reliably whether the proposal to acquire 800 MW of Wind Projects meets the statutory criteria of being "reasonable and efficient" or "necessary

and beneficial to Kansas ratepayers." Consequently, it is my recommendation that the Commission deny the requested authorizations to allow such assets to be placed in rate base, unless and until Empire presents a comprehensive evaluation of actual projects it has selected through its RFP process.

2) In my opinion, the GFSA provides insufficient information to be able to determine whether it is appropriate to retire Asbury immediately. The GFSA analyses Empire has performed do not address the full range of alternatives that would properly address that question. Given the notably altered priorities of the U.S. Environmental Protection Agency ("EPA") under the current administration, predicating an immediate retirement decision on the assumption that the Coal Combustion Residuals ("CCR") rule will remain completely unmodified does not appear justified.

3) The proposed acquisition of 800 MW of wind assets is not proposed or needed to meet energy, capacity, or renewable attributes requirements of customers. In my opinion, the proposal does not meet the basic standard for regulatory approval that an investment is "reasonably necessary" for the utility "to maintain reasonably sufficient and efficient service."

4) The GFSA is flawed in several critical ways that make the study's estimates of Wind Project benefits unreliable. The assumed SPP energy prices that are applied to sales of Wind Project generation are too high to be plausible, given both the observed impacts of increased wind generation on the SPP system and the expected further expansion of wind capacity in coming years. The high energy price estimates appear to derive from a combination of the underlying regional price forecast, which has compound annual price growth of 6.8% over the period of the Tax Equity Partnership, and Empire's

methodology for calculating nodal price basis differentials, which involves an underweighting of more current price data. A plausible alternative price path would completely eliminate estimated benefits from the Wind Projects.

5) Projected sales revenue is also inflated by the exaggerated output assumed for the Wind Projects. A very high capacity factor is assumed for the plants in the Base plan, significantly in excess of performance actually achieved at wind farms in Kansas. In addition, the GFSA assumes constant production at that high level over thirty years, with no performance degradation. Reasonable modifications of these assumptions cause a reduction in 20-year NPV sales revenue of $249 million.

6) The Commission should not rule on Empire's request to retain a portion of net Wind Project net sales revenues under K.S.A. 66-1245 because Empire has not provided enough information to determine qualification. In addition to the doubtful qualification of the Wind Projects under the statute, it is unreasonable to allow shareholders to retain any portion of an uncertain revenue stream that is the only means by which ratepayers will be compensated for an involuntary investment in a risky venture.

7) Regarding a prudence determination, my understanding is that an original cost estimate is required in a determination of prudence of the decision to build the additional wind generation and subsequent determination of the prudence of the construction. Because Empire has not recommended or provided an original cost estimate for specific facilities it proposes to acquire, it is my opinion that there is insufficient basis for the Commission to make a determination on the prudence of Empire's proposal, or to establish a benchmark for determining the prudence of the construction of the facilities.

At a minimum, Empire should be required to update its petition to provide original costs, following its evaluation and selection of project offers from its RFP process.

8) Ultimately, the Wind Projects proposal is more akin to a merchant generation project, not a traditional utility project to meet system requirements. The proposal entails certain (i.e., unavoidable) costs being imposed on ratepayers, while providing uncertain benefits, thus exposing ratepayers to inappropriate risk. In contrast, shareholders would receive certain benefits through rate basing of wind assets and bear little or no risk associated with market prices or asset performance. If there is value in the projects that balances against the significant risks, then it may be an appropriate investment for an unregulated entity, such as Empire's own corporate parent, or an affiliate, but not as a speculative business venture imposed on captive ratepayers.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. In Section III, I discuss my understanding of the statutory requirements applicable to the proposals under what Empire terms as its CSP. In Section IV, I present my assessment of the proposed retirement of the Asbury Generating Station ("Asbury") and, separately, my analysis of the proposed Wind Projects and the reliability of benefits estimates presented by Empire in its GFSA.

III. STATUTORY REQUIREMENTS

Q. WHAT IS YOUR UNDERSTANDING OF THE STATUTORY REQUIREMENTS THAT ARE APPLICABLE WITH RESPECT TO EMPIRE'S PROPPOSALS UNDER THE CSP?

A. My understanding, based on consultation with KCC Staff, is that, as an electric public utility, Empire's obligation is "to furnish reasonably efficient and sufficient service and facilities" within its service territory at "just and reasonable" rates.[2] The Commission has the power to require Empire to establish just and reasonable rates when such rates are "reasonably necessary" for the utility "to maintain reasonably sufficient and efficient service."[3]

With regard to operating expenses, the Kansas Court of Appeals has stated that "[t]he reasonableness of the expense to the utility, for ratemaking purposes, will depend, among other factors, on whether the services provided themselves are necessary or beneficial to Kansas ratepayers."[4]

Kansas statute also establishes specific requirements for utilities proposing to construct or participate in new generation facilities or contracts. Prior to such an undertaking, a public utility can ask the Commission to determine rate-making principles and treatment that will apply to recovery in wholesale or retail rates of the cost incurred by the utility.[5] In filing its request, the utility must provide information

[2] K.S.A. 66-101b.

[3] *Id.*

[4] Southwestern Bell Tel. Co. v. State Corp. Comm'n of Kansas, 4 Kan. App. 2d 44, 49, 602 P.2d 131, 136-37 (1979)

[5] K.S.A. 2016 Supp. 66-1239(c)(1).

that includes (A) a description of its conservation measure, (B) a description of its demand side management efforts, (C) its ten-year generation and load forecasts, and (D) a description of "all power supply alternatives considered to meet the public utility's load requirements."[6] In determining whether to grant a Petition for Predetermination, under K.S.A. 66-1239(c)(3), the Commission will first consider evidence in the record as a whole to decide if Empire's selected plan is reasonable, reliable, and efficient.

Q. WOULD A POSITIVE PREDETERMINATION FINDING CONSTITUTE A FINDING OF PRUDENCE?

A. No, my understanding is that prudence would still be subject to review. In Docket 11-581, the Commission determined that a finding that a utility's proposal is reasonable, reliable, and efficient under the predetermination statute does not necessarily constitute a finding of prudence under K.S.A 66-128g. Thus, the issue of prudence does not end with a finding that the project was the least cost option at the time the decision was made, but extends to ongoing actions of the utility to ensure the decision remains prudent. The utility is expected to continue to be careful, use caution, be attentive, and use good judgment in addressing changes that arise and in making future decisions regarding the project. Accordingly, the Commission found that the predetermined original cost estimate established a "definitive estimate by which it will be judged in future proceedings" and, if the project is completed within the definitive estimate, absent a showing of fraud or other intentional imprudence in

[6] K.S.A. 2016 Supp. 66-1239(c)(2).

the project, the Commission will find the amount was prudently incurred and will not address additional prudency issues regarding the value of the project under K.S.A. 66-128. However, the utility bears the burden of proving any costs exceeding the definitive estimate was prudently incurred and is reasonable to recover from ratepayers.

IV. ANALYSIS

Q. WHAT ARE THE MAIN ELEMENTS OF EMPIRE'S PETITION?

A. The Petition seeks authorizations from the Commission that would allow Empire to:

1) Acquire 800 MW of new wind generation assets ("Wind Projects") through a partnership with one or more tax equity investors, add Empire's asset share to its rate base, and retain a portion of associated net revenues for shareholders; and,
2) Retire Asbury Generating Station and recover the plant undepreciated balance through creation of a regulatory asset.

Q. HAS EMPIRE PROVIDED INFORMATION SUFFICIENT FOR THE COMMISSION TO PROVIDE THE AUTHORIZATIONS BEING SOUGHT?

A. No, I do not believe it has. In particular, because Empire has, to date, provided an economic assessment of the Wind Projects only in generic form, and not based on specific projects it may contract to acquire as a result of its RFP, it is simply not possible to make a reliable determination whether the projects are "reasonable and efficient" or "necessary and beneficial to Kansas ratepayers." As I discuss below, it is certainly doubtful that the Wind Projects can be said to be necessary to Kansas ratepayers, since they do not represent a needed or cost-effective source of capacity, they are not required to meet statutory renewable requirements, and they would provide energy vastly in excess of customer load. As a vehicle to make market sales and extract value from federal production tax credits ("PTCs"), the Wind Projects are more akin to a merchant generation project, not a traditional utility project to meet system requirements. And the extent to which they might be economically beneficial is highly uncertain.

Q. HOW ARE THE WIND PROJECTS AND THE RETIREMENT OF ASBURY LINKED?

A. The Wind Projects and the Asbury retirement are linked by Empire simply by both being incorporated into the Company's CSP and the asserted urgency of acting on both proposals immediately. In fact, there is no necessary linkage between the two proposed actions. Empire makes no claim that acquisition of the Wind Projects would eliminate a need for Asbury, or would facilitate early retirement of the plant, or would affect the economics of Asbury in any way. Neither has the Company claimed that retiring Asbury would create a need to pursue the Wind Projects. The proposed Wind Projects and retirement of Asbury are independent matters that can and should be evaluated separately.

Q. WHAT FACTORS DOES EMPIRE IDENTIFY THAT WARRANT RETIRING ASBURY?

A. Empire's assessment, presented in its GFSA, is that the Asbury plant is likely to be uneconomic across both a 20-year and a 30-year model horizon. In Direct Testimony, Company witness Mertens describes that, despite substantial plant upgrade investments in 2014 to comply with environmental rules and to improve the steam turbine efficiency and output, a fall in natural gas prices and an increase in wind generation on the Southwest Power Pool ("SPP") system have reduced the economic value of Asbury.[7] However, the proximate driver of the proposed retirement is the potential need for $20 million to $30 million in additional investments to comply with the EPA's CCR Final Rule.[8] Empire cites April 2019 as the compliance deadline under the existing CCR rule.[9]

Q. WHAT IS THE STATUS OF EPA'S CCR RULE?

A. The EPA announced in September 2017 that it had granted two petitions to reconsider substantive provisions of the final CCR rule.[10] In a subsequent status update submitted to the U.S. Court of Appeals for the D.C. Circuit in litigation over the CCR rule, the EPA stated that it would review the rule in two phases. A proposal addressing three issues on remand from a prior court ruling, as well as 12 other prioritized issues will be issued in March 2018. Finalization of that rulemaking will take place by June 14, 2019. A second phase will include all remaining issues. Modifications to the CCR rule will be proposed in September 2018 and finalized by December 2019.[11]

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[7] Direct Testimony of Blake A. Mertens ("Mertens Direct"), p. 12, line 19 to p. 13, line 13.

[8] Mertens Direct, p. 14, line 8 to p. 15, line 8.

[9] Mertens Direct, p. 14, line 14.

[10] See: https://www.epa.gov/newsreleases/epa-reconsider-certain-coal-ash-rule-provisions, accessed February 23, 2018.

[11] S&P Global, "EPA identifies multiple issues with coal ash rule," (November 17, 2017).

Q. WHAT ARE THE ECONOMICS OF CONTINUED OPERATION OF ASBURY?

A. Excluding consideration of the capital costs required to achieve compliance with the CCR rule, Empire's modeling indicates that Asbury would continue to be economic in terms of total operating cost – fuel, variable O&M, and fixed O&M – relative to SPP market revenue. In the detailed results for GFSA Plan 1 and Plan 4, in which Asbury is kept in operation, Asbury is economic in 13 out of 17 years of its remaining life, and provides $34 million in NPV net benefit over the period. Retention of Asbury's capacity provides additional benefits in allowing for earlier retirement of the Energy Center units and deferred acquisition of additional capacity.

Q. HOW DO THE CCR COMPLIANCE COSTS AFFECT ASBURY'S ECONOMICS?

A. The assumed near-term required investment to comply with the CCR rule causes retention of Asbury to be uneconomic overall in GFSA Plan 4 (which also includes the 800 MW of Wind Projects) compared to Plan 2 (in which Asbury is retired in conjunction with the addition of wind) by $26 million on an NPV basis over 20 years, and by $9 million on an NPV basis over 30 years.

It is somewhat counterintuitive that there is benefit from keeping Asbury in operation that extends beyond the plant's remaining life (this is indicated by the NPV cost of keeping Asbury being lower over 30 years than over 20 years, even though Asbury retires after 17 years). This lower NPV stems from the benefit (when keeping Asbury in service) of deferring other capacity acquisitions.

Even when accounting for the cost of CCR upgrades, retaining Asbury produces annual net benefits in each of the last 22 out of 30 model years. The NPV net cost results from the fact that near-term upgrade costs are discounted less than longer-term benefits. On an undiscounted basis, retaining Asbury produces positive net benefits of $138 million over 30 years.

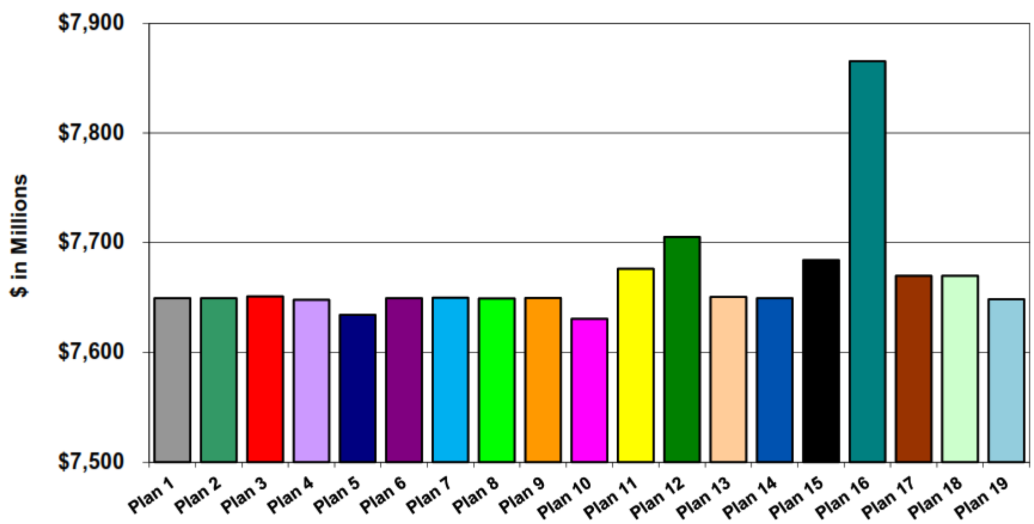
Q. IS IT YOUR OPINION THAT ASBURY SHOULD NOT BE RETIRED?

A. No. There is insufficient information for me to be able to form an opinion as to whether it is appropriate to retire Asbury immediately. The GFSA analyses Empire has performed do not address the full range of alternatives that would properly address that question. In particular, there is no assessment of the effects of revised or delayed CCR compliance. Given the notably altered EPA priorities under the current administration, predicating an immediate retirement decision on the assumption that the CCR rule will remain completely unmodified does not appear justified. This is particularly true considering the fact that the evaluated economics of the Asbury plant have apparently changed radically since Empire committed to spending more than $100 million on the 2014 environmental upgrades. In Empire's 2016 IRP analyses, performed less than two years prior to the GFSA, the Company examined nineteen plans, one of which was "a special 'what-if' case to determine the impact of an early retirement of the Asbury coal-fired unit for any reason, but particularly due to potential greenhouse gas regulations."[12] That plan, Plan 16 shown in Figure 1 below,

[12] Volume 6 Integrated Resource Plan and Risk Analysis – April 2016, p. 12.

had Asbury retire in 2022, and was by far the most costly case Empire examined, in stark contrast to the results of the GFSA. In the 2016 IRP analysis, keeping Asbury in operation was estimated to provide substantial benefits even while accounting for CCR compliance costs.

Figure 1: 2016 IRP Deterministic 20-Year NPV of Revenue Requirements (NPVRR) by Plan [13]



The high cost of an Asbury retirement was confirmed in probabilistic analyses, which showed the retirement case to be substantially more costly across the entire cumulative probability range examined.[14] The fact that no probabilistic case examined in the 2016 IRP indicated Asbury might be uneconomic casts significant doubt on the extent to which Empire's probabilistic assessment methodology reasonably captures the landscape of potential futures.

[13] 2016 IRP Summary – April 2016, Figure 6-5, p. 27.

[14] Volume 6 Integrated Resource Plan and Risk Analysis – April 2016, Figure 6-126, p. 161.

Even if the model updates applied in the GFSA properly capture circumstances not known in the 2016 IRP, the GFSA is incomplete for the purposes of assessing the economics of retiring Asbury. As described above, Plan 4 shows that keeping Asbury in operation through 2034 provides benefits by allowing accelerated retirement of the Energy Center units and deferred investment in other capacity additions. Yet the GFSA only allows assessment of these benefits via two cases, Plan 2 (retire Asbury) and Plan 4 (retain Asbury), that both include the 800 MW of Wind Projects. As I discuss below, the modeling incorporates faulty assumptions regarding the Wind Projects. As a result, the GFSA does not allow for a complete and reliable assessment of the Asbury retirement decision.

Q. ARE YOU TESTIFYING AS TO THE PRUDENCE OF THE 2014 ASBURY UPGRADE EXPENDITURES OR THE ABILITY OF EMPIRE TO RECOVER THOSE COSTS THROUGH THE PROPOSED REGULATORY ASSET OR OTHERWISE?

A. No, I am not. I am only addressing the justification for a decision to retire Asbury in 2019. Staff Witness Justin Grady discusses Staff's suggestion for the proposed regulatory asset if Asbury is closed prematurely.

Q. WHAT DO YOU CONCLUDE REGARDING THE RETIREMENT OF ASBURY AND THE REQUESTED REGULATORY ASSET TO RECOVER PLANT UNDEPRECIATED BALANCE?

A. I conclude that it is appropriate to defer the decision on whether to retire Asbury until there is more definitive information available regarding potential modification of the CCR rule and compliance deadlines, and until a comprehensive analysis of the retirement decision is performed. Determination of what costs should be recoverable and under what mechanism should be deferred until a well-founded decision on when, or if, to retire the plant early has been made.

Wind Projects

Q. PLEASE DESCRIBE EMPIRE'S WIND PROJECTS PROPOSAL.

A. Simply put, Empire proposes to acquire 800 MW of Wind Projects, place its equity ownership of the projects into rate base, and sell the energy output of the wind farms into the SPP centralized market at prevailing prices. There are various complexities related to the proposal's tax equity partnership structure, but that is the essence of the proposal.

Q. ARE THE WIND PROJECTS NECESSARY TO PROVIDE ELECTRIC SERVICE TO KANSAS CUSTOMERS?

A. No, they are not. First, the Wind Projects are not required to meet a renewables need. Empire already has substantial wind resources through PPAs for all of the generation from the 150 MW Elk River Wind Farm and the 105 MW Meridian Way Wind Farm, both located in Kansas. These PPAs provide well in excess of the non-solar renewable requirements that Empire must meet with respect to its Missouri load.[15] The Kansas Renewable Portfolio Standard was changed in 2015 to a voluntary goal, and in any case Kansas as a state is a major wind generator. In 2016, Kansas ranked

[15] See, for example, Empire's 2017 Annual Renewable Energy Compliance Plan (April 2017), filed with the Missouri Public Service Commission.

fourth in total wind energy generated, after Texas, Iowa and Oklahoma, and for 2017 through November generated more than a third of its electric energy from wind.[16]

Second, the Wind Projects are not needed to meet Empire's SPP capacity obligations. Empire's all-time peak load was 1,199 MW, which occurred in 2010. SPP's 2017 Resource Adequacy Report shows Empire's forecasted net peak load for 2017-2022 ranging from 1,116 MW to 1,128 MW, and a capacity reserve margin above 30% in each year compared to the SPP target reserve margin of 12%.[17] Empire's excess capacity in each year is greater than the summer or winter capability of Asbury, so Empire would meet its capacity obligation even if Asbury were retired.[18]

And third, the Wind Projects are not required to meet Empire's energy needs. In 2016, Empire's generation resources produced 5,877 GWh of energy, 10% above its native customer load of 5,260 GWh.[19] Even accounting for transmission and distribution losses, Empire was making significant net sales to the SPP market. Empire's 2017 Integrated Resource Plan Annual Update Report states that its updated 2017-2021 load forecast "demonstrates modest growth with annual peak and energy growth rates less than one quarter percent during the five year period."

Far from meeting an energy need, generation from the Wind Projects would entail very large net energy sales to the SPP market. Figure 2 shows the modeled

[16] Based on state generation data from the Energy Information Administration ("EIA") Electricity Data Browser, accessed at: https://www.eia.gov/electricity/data/browser/.

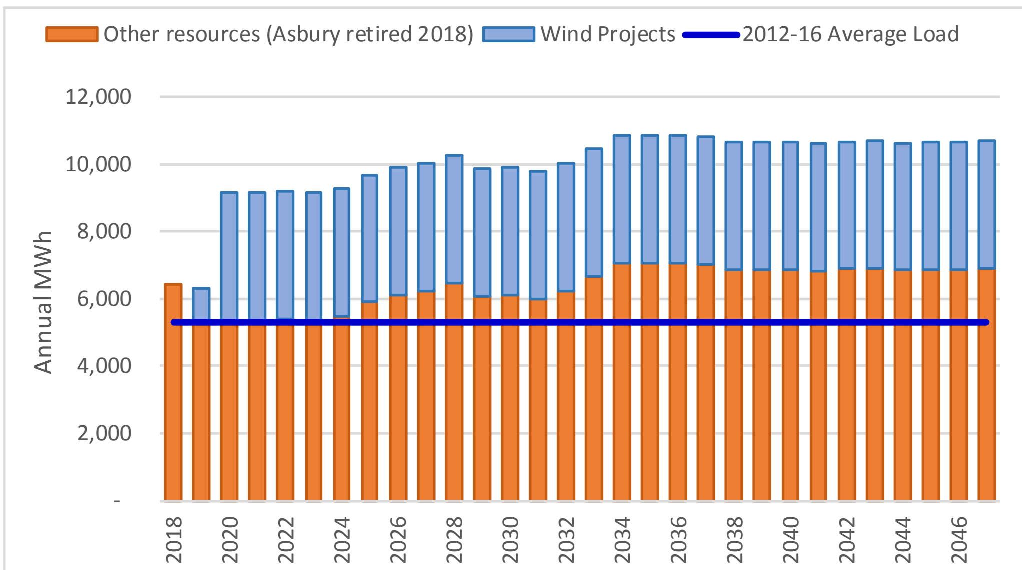
[17] SPP 2017 Resource Adequacy Report (June 2017), p. 23, available at: https://www.spp.org/documents/52237/june%202017%20resource%20adequacy%20report.pdf

[18] Empire's lowest excess capacity for 2017-22 shown in the SPP 2017 Resource Adequacy Report is 204 MW; EIA reports Asbury's capacity rating for summer and winter as 198 MW (2016 Form EIA-860).

[19] GFSA, pp. 4-6.

energy from Empire resources in the GFSA for Plan 2, with the added 800 MW of Wind Projects and the retirement of Asbury prior to 2019, compared to Empire's 5-year average load from 2012-16. The load line does not include the "less than one quarter percent" anticipated growth rate, which would make little difference to the relationship of resources to load. (A 0.25% annual growth rate across the thirty model years would result in annual load in 2047 of 5,725 GWh, i.e., less than Empire's actual total resource energy in 2016.)

Figure 2: Plan 2 Modeled Supply Resource Energy Relative to 2012-16 Average Load[20]



[20] GFSA work papers and historical energy data from the investor presentation, "The Empire District Electric Company Annual 2015 Investor Update," (February 26, 2016), accessed via S&P Global Market Intelligence.

Q. HOW DOES THE PROPOSAL TO PROCURE CAPACITY AND ENERGY IN EXCESS OF NEED BEAR UPON EVALUATION OF EMPIRE'S REQUESTED AUTHORIZATIONS?

A. There are several important considerations raised by the proposal to procure generation in excess of need. First among these is that the Wind Projects are simply not "reasonably necessary" under the statutory criteria summarized in Section III of my testimony. Whether the Wind Projects would prove to be beneficial to ratepayers is, as I discuss below, highly uncertain. Nevertheless, even if the assessment performed by Empire in the GFSA did not suffer from apparent defects, the Wind Projects proposal would still raise important concerns because of the extent to which it deviates from traditional utility practice. The Wind Projects are not being proposed to meet the electricity needs of Empire's customers, but rather are advanced as a means to profit from sales in the energy market. In this respect, the Wind Projects resemble a merchant generation investment, with the important distinction that under Empire's proposal, customers would be forced to bear risks normally shouldered by a merchant developer. Mr. Puga discusses these risks in his direct testimony in this docket.

Q. DOES EMPIRE ADDRESS THE FACT THAT ALL ENERGY FROM THE WIND PROJECTS WOULD BE SOLD INTO THE SPP MARKET?

A. Absolutely. Empire's summary of the Wind Projects transaction states clearly that energy from the projects would be sold into the SPP energy market (see, for example, the table summary in the Direct Testimony of Todd Mooney, p. 16), and the economic analysis in the GFSA reflects this fact. Yet it is important to clarify that this is not simply an artifact of the way the SPP system functions. While it is true that the SPP market settlement system effectively treats all generation, including that from Empire's legacy units such as Asbury, as energy sales at applicable locational marginal prices ("LMPs"), that should not obscure the fact that generation from the Wind Projects would be fully in excess of Empire's net generation need to meet load. In the GFSA modeling of Plan 2 (with Asbury retired prior to 2019 and the 800 MW of Wind Projects fully operational as of 2020), Empire's non-Wind Project resources are projected to supply 27.0 GWh of energy from 2020-2024. This compares to estimated load over the five-year period of about 26.8 GWh, indicating that essentially all generation from the Wind Projects would be excess sales to the wholesale market.[21] While the resource energy total excludes losses, the comparison also excludes an accounting of market purchases Empire would make when economic. As discussed below, the benefits Empire has estimated to derive from the Wind Projects depend critically on projected net revenue from the excess energy sales to the SPP market.

[21] Empire's load does not appear in the GFSA model output. I have estimated the load total over the 2020-2024 period based on Empire's average load from 2012-2016, with a 0.2% annual growth rate.

Q. WHAT ARE THE CLAIMED BENEFITS TO CUSTOMERS FROM THE PROPOSED WIND PROJECTS?

A. Putting aside the question of cost for the moment, there are three potential sources of value from the Wind Projects: capacity, energy and renewable attributes. Empire estimates that approximately 15% of the nameplate capacity of the Wind Projects would qualify as capacity for the purposes of meeting SPP obligations.[22] Under this assumption, the 800 MW of Wind Projects would translate to approximately 120 MW of capacity. As I have described above, Empire is expected to exceed its capacity obligation based on existing resources at least through 2022, even if Asbury were to be retired. However, the Wind Projects could still provide capacity benefits through effects on Empire's capacity expansion plan – allowing accelerated retirement of less economic plants and deferred acquisition of additional capacity to meet SPP obligations in the future. This potential value is reflected in the GFSA analyses.

With respect to renewable attributes, again, as noted above, Empire already exceeds its statutory requirements for non-solar renewable energy (applicable to its Missouri load). According to testimony, Empire intends to receive all renewable energy credits ("RECs") produced by the Wind Projects,[23] though the Company has not reflected any value for the RECs in its economic analyses. The potential market value of the RECs is likely quite low, however, given the large amount of wind power already being generated in SPP and the significant wind capacity expected to be

[22] Direct Testimony of James McMahon ("McMahon Direct"), page 23, lines 9-12
[23] Mooney Direct, p. 15, lines 5-6.

added over the next several years. There are no publicly available price data for RECs in SPP, but reported data for Texas indicate that prices have averaged below $0.50/MWh over the past three years.[24]

Ultimately, it is the projected revenue from sales of energy into the SPP market that drives the benefit to customers that Empire has estimated. As I will demonstrate, the uncertainty of this projected revenue poses substantial risks to any benefits customers might realize from the Wind Projects. Additional risks of project development and plant ownership are discussed by Mr. Puga in his direct testimony in this docket.

Q. WHAT ABOUT THE VALUE OF THE PTCS?

A. The PTCs have little direct effect on the value of the Wind Projects for Empire's customers. Under the assumed terms of the Tax Equity Partnership, Empire would receive 1% of all PTCs produced by the Wind Projects, with 99% of the PTCs going to the Tax Equity Partner. The real value of the PTCs for Empire is in facilitating the acquisition of the Wind Projects at a discounted capital cost. Under Empire's assumptions, the Tax Equity Partner would contribute approximately 60% of required capital, while Empire would contribute the remainder, and at the end of the 10-year transaction term Empire would assume at least 95% ownership of the Wind Projects. This roughly supports the claim that the proposed transaction would "allow Empire to acquire up to 800 MW of wind generation for as little as 40 cents on the dollar."[25] (In

[24] S&P Global Market Intelligence.
[25] Mooney Direct, p. 4, lines 11-13.

an update to reflect effects of the new federal tax law, the expected Empire share of project capital costs was revised to approximately 46%, which, with 95% ownership at the end of the transaction would then give a value of '48 cents on the dollar'.)[26]

Q. DOES THE OPPORTUNITY TO PAY 40 (OR 48) CENTS ON THE DOLLAR FOR OWNERSHIP OF THE WIND PROJECTS WARRANT URGENT ACTION?

A. No, not in itself. The claim of '40 cents on the dollar' (available only for a limited time) has a persuasive ring to it, but it should not distract from a proper evaluation of the value of ownership. As Mr. Puga explains in his direct testimony, there are significant risks that are attendant on ownership as compared to contracting a PPA. In terms of capacity alone, which provides the aforementioned benefits of allowing accelerated retirement of less economic generation and deferred addition of other capacity later, '40 cents on the dollar' for the Wind Projects is not a very good deal at all. The assumed cost of the Wind Projects is approximately $1,700/kW of installed capacity, and 40% of that is only $680/kW, which happens to be equal to the cost EIA identifies for a new combustion turbine.[27] But since only 15% of the nameplate Wind Project volume would qualify as capacity to meet SPP obligations, the true capacity cost is actually more than $4,500/kW ($680/kW ÷ 15% = $4,533/kW).

[26] Updated Analysis Results – SUPPLEMENTAL TAX REFORM, James McMahon, January 24, 2018 in response to Missouri PSC Staff DR 2-14.

[27] EIA, "Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2018," (February 2018), Total overnight cost for Adv Combustion Turbine, Table 8.2. Accessed at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

Q. WHAT IS THE SOURCE OF THE LARGE BENEFIT VALUES EMPIRE HAS ESTIMATED?

A. The vast majority of the benefit estimated by Empire to flow to customers from the Wind Projects derives from sales of energy into the SPP market. The GFSA results show a 20-year NPV revenue requirement for the Wind Projects of $902 million, which includes operating costs plus recovery of $570 million placed into rate base, plus Empire's allowed return. The 20-year NPV benefit from energy sales into the SPP market is shown as $1,262 million, giving an overall NPV benefit for the Wind Projects of $361 million.[28]

Q. IN YOUR OPINION, ARE EMPIRE'S BENEFIT ESTIMATES RELIABLE?

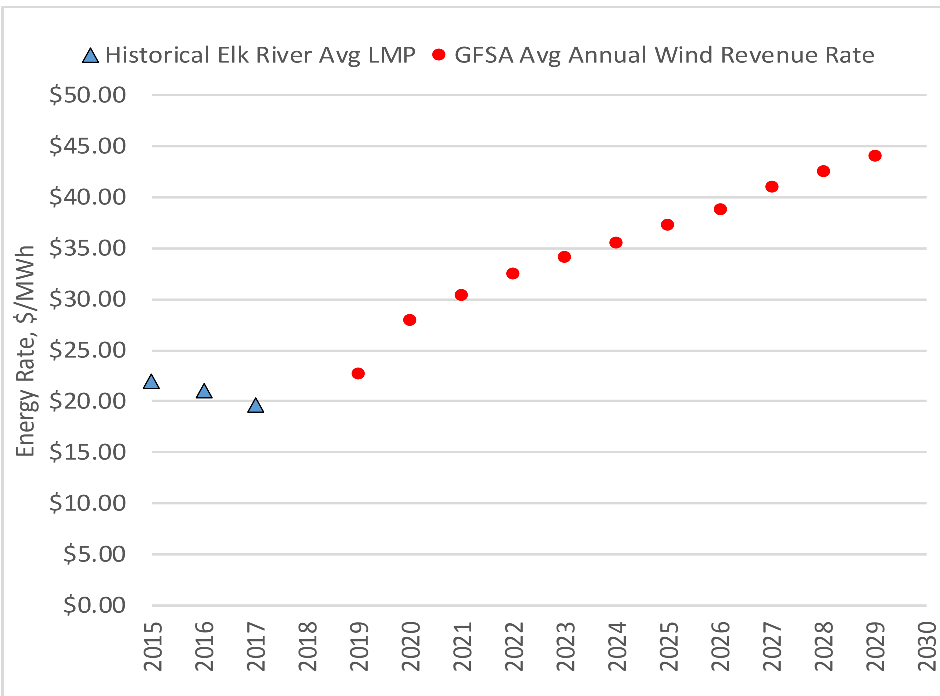
A. No. In my opinion, the estimated benefits are not reliable. I have several concerns regarding the representation of the Wind Projects in the GFSA, and the modeled SPP energy prices. Addressing the latter concern first, I do not find the modeled SPP energy prices that are applied to sales of Wind Project generation to be plausible.

In part because Empire did not have specific projects to evaluate at the time it performed the GFSA, it adopted a proxy methodology for estimating market revenue from the Wind Projects. For example, it was assumed that low-levelized-cost-of-energy ("LCOE") Wind Projects, which constitute the full 800 MW of projects in the

[28] These values are drawn from the tab 'roll up 1-2' of the Excel file 'Attachment CURB 1-25 and CURB 1-26 Generation Fleet Savings Analysis - DH 2017 1103.xlsb', provided as an attachment in response to data requests CURB 1-25 and 1-26. The summary provided in the tab shows that these values are components of the $325 million of estimated net benefit relative to the 2016 IRP plan, which value is referenced in Empire's testimony, for example in Mooney Direct, p.4, line 11, and McMahon Direct, p. 8, line 9. The $325 million figure includes other differences between Plan 1 and Plan 2, including effects from the retirement of Asbury.

Base Plan or Plan 2, would sell energy at LMPs approximating those at the existing Elk River Wind Project, located in Butler County, Kansas. In principle, this is a reasonable approach, but in practice, the modeled LMPs applicable to the Wind Projects are simply not credible, based on recent historical data and the anticipated effects of significant additional wind generation in coming years. Figure 3 shows the large discrepancy between the modeled SPP LMPs used in the GFSA to calculate sales revenue for the proposed Wind Projects and the historical average Day Ahead LMPs for the Elk River pricing node.[29]

Figure 3: Historical Day Ahead LMPs at Elk River and Modeled Wind Project LMPs[30]

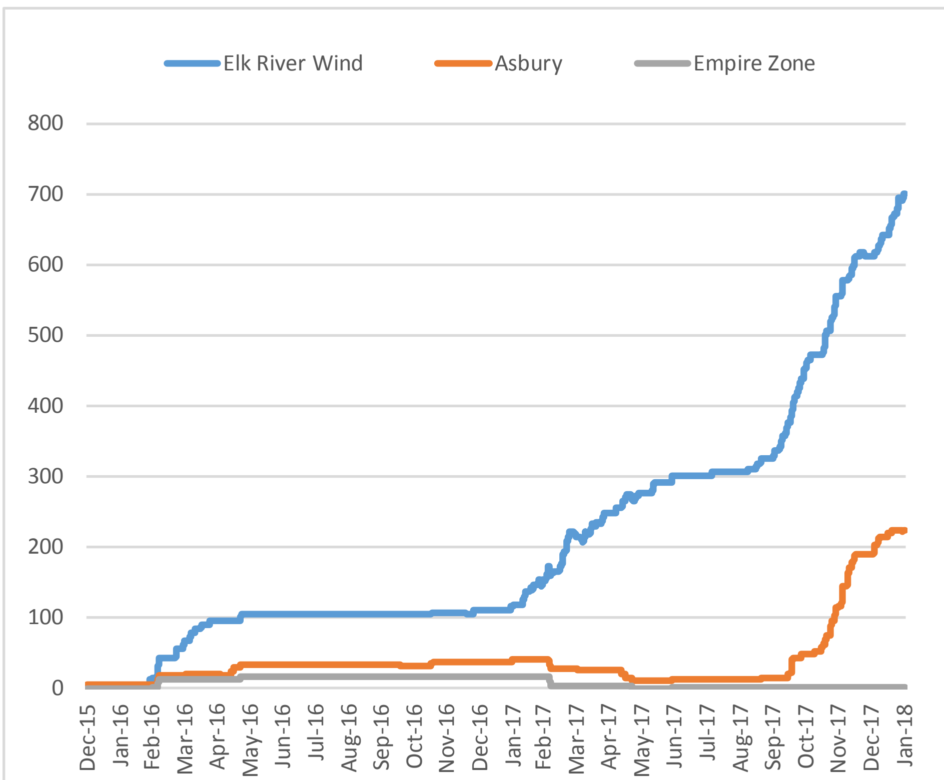


[29] The GFSA model results indicate slightly different LMP pricing for energy from Elk River compared to energy from the Wind Projects, with the Wind Projects generally priced somewhat higher, though it is not clear why this discrepancy occurs, given the described nodal proxy methodology.

[30] Historical Day Ahead LMP data from SPP; Wind Projects revenue rates from GFSA work papers, Plan 2.

The declining historical LMP price trend for Elk River reflects the impact of increasing quantities of wind generation across SPP in recent years. This impact is most striking in the growing number of hours when LMPs are clearing at negative prices. Figure 4 charts the rolling 12-month count of hours when three relevant pricing nodes have cleared at negative prices, with data through January 2018. As noted, the GFSA analysis uses Elk River as a nodal proxy for evaluating Low LCOE wind in the Base Plan. The GFSA also applies a proxy based on LMPs at the Asbury pricing node for what it defines as Mid LCOE wind projects, which are evaluated as part of Plans 3, 7, 8, and 9.

Figure 4: 12-month rolling count of hours with negative DA LMP by SPP pricing node[31]



[31] SPP historical Day Ahead price data, from SPP.

At Elk River, 8.0 percent of hours in the 12 months through January 2018 had negative Day Ahead LMPs. At the Asbury node, 2.6% of hours had negative Day Ahead LMPs over the same period. The prevalence of negative LMPs is even more extreme in the Real Time market, with 12.0% of hours clearing at negative prices for Elk River, 5.5% of hours for Asbury, and 1.2% for the Empire load zone itself.

Q. IS THE LMP PRICE TREND LIKELY TO BE SUBSTANTIALLY REVERSED IN COMING YEARS, AS IMPLIED BY THE GFSA REVENUE PROJECTIONS?

A. No, it is not. Given the large quantity of wind in the SPP interconnection queue, it is very likely that the downward pressure on LMPs in SPP will continue. More than 7,400 MW of wind projects have either a full Interconnection Agreement ("IA") or an IA pending, and an additional 42,000 MW of projects are at the system impact study stage.[32]

Q. WHAT EXPLAINS THE HIGH ENERGY PRICES APPLIED IN THE GFSA?

A. There are two potential sources of error to explain the implausibly high LMPs assumed to apply to energy sales from the proposed Wind Projects. The pricing methodology applied in the GFSA is actually a two-step process. The underlying price projection is an "SPP-Kansas-Missouri price forecast" provided by ABB, which is then adjusted based on historical nodal price data to account for expected price basis differentials corresponding to the Elk River and Asbury pricing nodes.[33] One

[32] SPP, Generation Interconnection Active Queue, updated February 16, 2018, accessed at https://studies.spp.org/SPPGeneration/GI_ActiveRequests.cfm.

[33] See McMahon Direct, page 28, lines 10 to 17.

source of potential error is the underlying forecast, and the other is the derived basis differentials. I have concerns about both elements of the price projection methodology. The Wind Project revenue rates in the GFSA imply an underlying forecast at odds with trends in SPP and across the electricity industry. Assuming that the nodal basis differentials were applied consistently across the modeled years, the rate of price growth must be driven by the underlying price forecast. That growth rate is a 6.8% compound annual growth rate from 2019-2029, and 4.4% compound annual growth rate over the full period between 2019 and 2047.[34] I do not find either growth rate credible given the expected growth in wind penetration in SPP, anticipated growth of energy storage encouraged by FERC's rule on energy storage finalized in February 2018,[35] and natural gas futures continuing to trade at $3.00/mmBtu or less years into the future.[36]

Q. ARE THE BASIS DIFFERENTIALS APPLIED IN THE PRICING METHODOLOGY ALSO A CONCERN?

A. Yes, they are. The basis differentials appear to be low relative to that indicated by current market data. This means that the LMPs assumed to apply to sales from the Wind Projects are not reduced enough from the underlying SPP-Kansas-Missouri

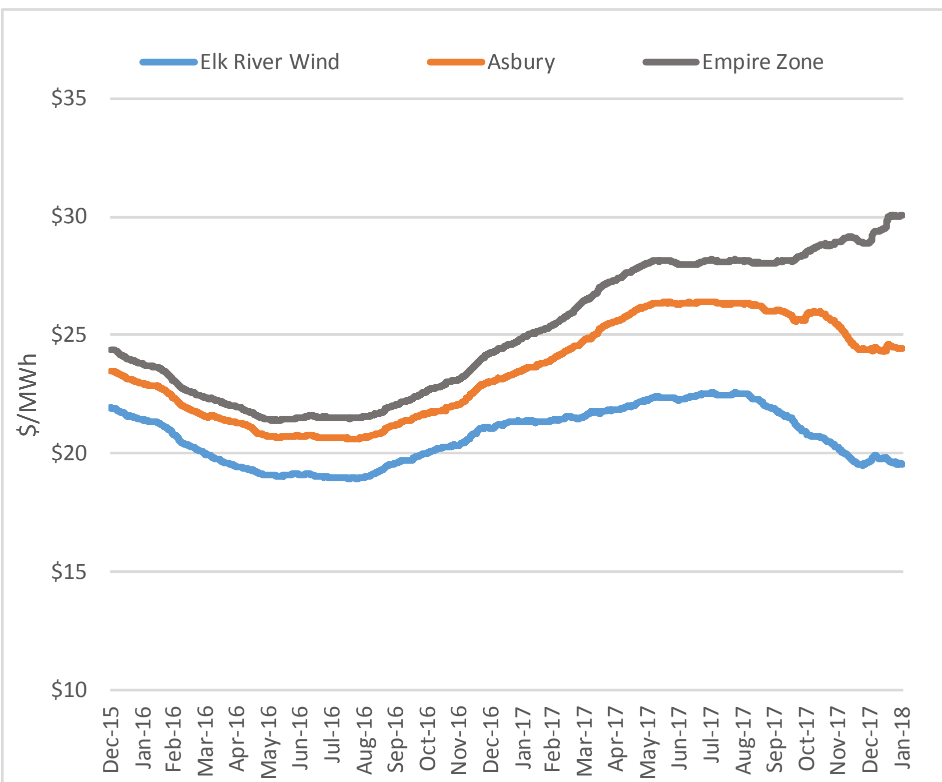
[34] Calculated from data in the, 'Attachment CURB 1-25 and CURB 1-26 Generation Fleet Savings Analysis - DH 2017 1103.xlsb', attached to Empire's response to data requests CURB 1-25 and CURB 1-26.

[35] The FERC rule directs operators of centralized electricity markets to develop rules to allow storage to participate in the wholesale energy, capacity and ancillary services markets. See, https://www.utilitydive.com/news/ferc-order-opens-floodgates-for-energy-storage-in-wholesale-markets/517326/

[36] Henry Hub futures prices accessed on February 27, 2018 show the first year with an average price above $3.00/mmBtu to be 2027; http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html

price forecast. The reason for this is that Empire's method of calculating the basis differentials relies on averages from January 2015 through September 2017, overweighting data from an earlier period when price differentials were relatively narrow and constant, and underweighting more recent data with greater price separation. Data since September 2017 have confirmed a continued trend toward increased basis differentials. This is shown in Figure 5, which charts the 12-month average Day Ahead LMPs for the pricing points used in Empire's basis differential calculations over the period January 2015 to present, consistent with Empire's analysis, but updated to include data since September 2017.

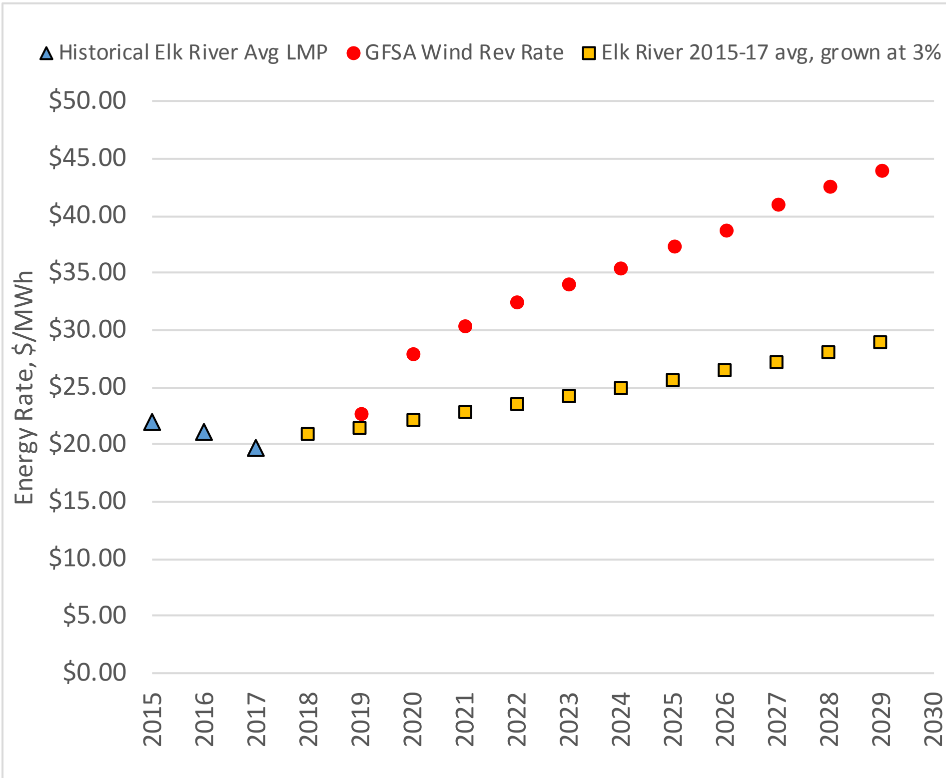
Figure 5: Rolling 12-month average Day Ahead LMPs for Elk River, Asbury and Empire



Q. WHAT IS THE IMPACT OF THE IMPLAUSIBLY HIGH ENERGY PRICES ASSUMED TO APPLY TO ENERGY SALES FROM THE WIND PROJECTS?

A. It is not possible to determine the impact with a high degree of certainty without correcting the problems and rerunning the entire modeling process, beginning with the underlying price forecast. However, a rough estimate indicates the potential magnitude of the effect. If the modeled prices applicable to the wind sales in Plan 2 were changed to be equal to the average 2015-17 Day Ahead LMP at Elk River, adjusted for a 3% annual growth rate (a percentage point above the inflation rate assumed in the GFSA), I calculate that the NPV of Wind Project sales revenue would be lower by $466 million, which more than eliminates the net benefits estimated for Plan 2. For reference, Figure 6 is a revision to Figure 3 to include the alternative price series that produces this result.

Figure 6: Comparison of GFSA LMPs and Elk River Historical LMPs grown at 3.0%[37]

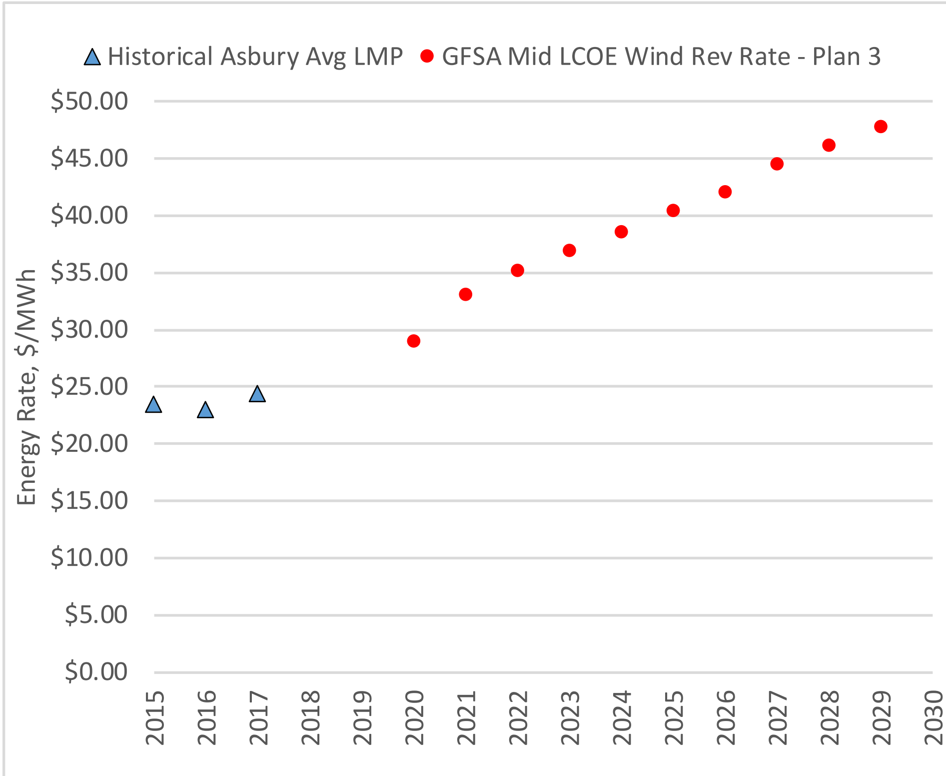


Q. DO YOU HAVE SIMILAR CONCERNS REGARDING PROJECTED WHOLESALE MARKET REVENUES FOR THE MID LCOE WIND PROJECTS EMPIRE EVALUATED?

A. Yes, I do. The same issues apply with respect to the Mid LCOE wind cases in the GFSA. Figure 7 charts historical average Day Ahead LMPs at Asbury, which is the proxy node Empire assumed to applicable for Mid LCOE wind projects.

[37] Historical Day Ahead LMP data from SPP; Wind Projects revenue rates from GFSA work papers, Plan 2.

Figure 7: Historical Day Ahead LMPs at Asbury and Modeled Mid LCOE Wind Project LMPs[38]



As in the case of the wholesale prices assumed for Low LCOE wind, the price projection for Mid LCOE wind is very aggressive, with a 5.6% compound annual growth rate from 2020 to 2030, which also appears inconsistent with recent pricing patterns observed in SPP and expected substantial additions of new wind generation.

Q. WHAT VALUE IS PROVIDED BY THE PRICE HEDGE EMPIRE ASSUMES TO BE PART OF THE PROJECT TRANSACTION?

A. As Empire has characterized it, the hedge would be a form of "fixed for floating swap" that would apply over the first 10 years of project operation, when the Tax

[38] Historical Day Ahead LMP data from SPP; Wind Projects revenue rates from GFSA work papers, Plan 3.

equity partnership is in effect.[39] The effect of the hedge would be to ensure stable revenue flow to the Wind Project Company for energy at the fixed hedge price, smoothing out the effect of volatile LMPs on revenue. When market LMPs are below the fixed hedge price, Empire would pay to the Wind Project Company the price differential for each MWh of production, and when market LMPs are above the hedge price, Empire would receive payment of the price difference for each MWh generated.

Ultimately, the hedge should have no effect on the overall economics of the Wind Projects, which will be determined by project costs relative to market revenue. Indeed, Empire has not incorporated the hedge in its estimates of customer benefits. Empire assumes the hedge price to be equal to the levelized cost of energy for the Wind Projects, so by definition the assumed hedge covers all project costs including investor returns, and the net profitability of the project is determined entirely by the actual SPP LMPs. For the purposes of the GFSA analyses, therefore, the hedge can be ignored since in all years, the profitability of the project, and the potential benefits to customers would be determined by prevailing SPP LMPs.

Q. DOES THE HEDGE PROTECT EMPIRE RATEPAYERS?

A. No, it does not. As noted, the primary function of the hedge would be to ensure a minimum revenue stream for the Wind Project Company. While the hedge would provide a mechanism to flow net energy sales revenue to Empire's customers, it is equally a mechanism under which Empire customers would be required to make up

[39] See Mooney Direct, p. 15, lines 1-6.

revenue to the Wind Project Company if LMPs turn out to be consistently lower than the fixed hedge rate.

Consider a hypothetical situation in which the SPP LMPs applicable to the Wind Projects are constant at precisely the hedge price for the 10 years of the Tax Equity Partnership. In such a situation, there would be no energy revenue flow to Empire customers. They would benefit from the 1% allocation of the PTCs, but otherwise the Wind Projects would represent only a cost to ratepayers, through the estimated $570 million of Empire's capital investment placed into rate base. Coincidentally, the hedge price assumed by Empire, equal to the LCOE for high-output wind projects, is very nearly equal to the average LMP at Elk River for 2015-17, the location Empire says it selected as a nodal price proxy. In response to data request CURB 1-20, Empire indicated that it assumed a hedge price of $20.51/MWh, while the average Day Ahead LMP at Elk River over the 36 months from 2015 through 2017 was $20.88/MWh. Wind Project LMPs at those levels would entail a substantial loss for Empire's customers: certain fixed costs with little or no offsetting net revenue. If prices trends continued down, customers would be forced to make up a revenue shortfall to the Wind Project Company, exacerbating the economic loss.

For reference, the average Wind Projects revenue rate modeled in the GFSA through the end of the Tax Equity Partnership in 2029 is $36.07/MWh. It is these high assumed market revenue rates that drive the benefits Empire has estimated from the Projects.

Q. HAVE YOU IDENTIFIED ANY ADDITIONAL PROBLEMS WITH THE WIND PROJECTS VALUE ESTIMATED IN THE GFSA?

A. Yes. The modeled value in the GFSA is based on the assumption that the Wind Projects operate consistently at a very high capacity factor, with no degradation in performance over time. For example, sales revenue calculated for Plan 2 is based on annual generation of an effectively constant 3,794 GWh, which corresponds to 800 MW at a 54.1% capacity factor.[40] Even for a new wind farm in a quality wind location, 54.1% is a high capacity factor for actual performance in SPP. For wind farms 100 MW or greater in size, currently operating in Kansas, I have identified no facilities that have operated at an annual capacity factor as high as 50% based on generation data for calendar years 2014 through 2017. Data for the respective wind farms by year are shown in Table 1.

[40] There is a variation of +/- 3 GWh in annual generation from year to year in the model with no trend. For example generation is shown as 3,795 GWh in years 2024 and 2047.

Table 1: Annual Capacity Factors of Kansas Wind Farms, 100+ MW, 2014-2017[41]

Kansas Wind Farms 100+ MW	2016 Operating Capacity, MW	Annual Capacity Factor			
		2014	2015	2016	2017*
Flat Ridge 2 Wind Farm	470	46.6%	42.2%	42.8%	42.7%
Buffalo Dunes Wind Project	250	37.3%	41.0%	41.9%	37.2%
Buckeye Wind Energy Project	206	NA	15.5%	45.4%	45.3%
Meridian Way Wind Farm (Cloud County)	201	37.0%	32.6%	32.8%	34.7%
Post Rock Wind Farm Facility	201	48.0%	44.3%	43.1%	44.3%
Caney River Wind	200	42.5%	39.2%	39.6%	42.0%
Waverly Wind Farm LLC	199	NA	NA	44.0%	*
Cedar Bluff Wind Farm	199	NA	4.0%	46.7%	*
Ironwood Wind Plant - Duke	168	43.6%	42.8%	44.4%	47.8%
Cimarron Wind Energy	166	49.6%	48.2%	48.3%	*
Elk River Wind	150	43.2%	38.8%	38.5%	*
Slate Creek Wind Project	150	NA	2.9%	47.6%	*
Smoky Hills II	149	41.5%	42.0%	40.8%	*
Spearville	149	36.6%	35.4%	31.3%	*
Cimarron II Wind Plant	131	49.7%	47.9%	49.4%	*
Gray County Wind Farm	112	14.1%	29.9%	24.5%	*
Spearville 3 Wind Project	108	42.6%	42.9%	42.9%	*
Shooting Star Wind Project	104	42.9%	47.0%	47.8%	*
Smoky Hills Wind Farm	101	43.3%	42.3%	42.1%	*

* Preliminary data for 2017; information for some generators reporting annually is not available.

Even granting the possibility of superior production potential from the proposed Wind Projects, it is important to consider that variations in the generation output for wind facilities tend to be correlated regionally. This means that when generation at a facility is high, market prices are likely to be low and, conversely, market prices may be highest when the facility is producing least. It is not clear that such real-world effects are captured in the GFSA modeling.

[41] Based on generation data from Form EIA-923 for 2014, 2015 and 2016, download from https://www.eia.gov/electricity/data/eia923/, and capacity data from various owner/operator web sites.

A potentially more significant problem in the GFSA analyses is the failure to account for any degradation in wind generator performance over time. Mr. Puga discusses wind plant degradation and other equipment and performance risks in his direct testimony in this docket.

Q. HAS EMPIRE INDICATED THAT PERFORMANCE DEGRADATION WAS REFLECTED IN ITS ASSESSMENTS?

A. Yes, though somewhat obliquely. Data request Staff 4-35 b asked, "As the assumption [of constant annual output] does not appear to reflect likely real-world performance degradation, has Empire incorporated in its analyses estimated operating and/or refurbishment/repowering costs that would be required to maintain as-new performance over 30 years?". Mr. Mooney responded that, "[t]he wind energy assumptions included a 1.7% annual degradation factor in creating the average annual energy assumption provided to ABB."[42] I do not know what this means. However, it is clear from the GFSA work papers that generation from the Wind Projects was assumed to be constant on an annual basis, and that estimated revenue from the SPP market corresponds to that annual generation level multiplied by the revenue rates discussed above and plotted in Figure 3.

[42] Response to Staff's Fourth Set of Data Requests, STAFF 4-35.

Q. WHAT WOULD BE THE EFFECT ON THE ESTIMATION OF BENEFITS FROM THE WIND PROJECTS OF PROPERLY REFLECTING PERFORMANCE DEGRADATION?

A. The effect would be substantial. Taking the modeled market prices as given, performance degradation of 1.7% per year, which corresponds to the figure in Mr. Mooney's response, would reduce the 20-year NPV value of project sales revenue by $99 million. If the as-new P50 performance turned out to be a 48% capacity factor rather than the assumed 54.1%, that would compound the degradation effect, reducing 20-year NPV revenues by a total of $249 million. Both of these effects are calculated with no modification to the high LMP rates reflected in the GFSA.

Q. DOES EMPIRE AIM TO RETAIN A PORTION OF THE NET SALES REVENUE FROM THE PROJECT?

A. Yes. Empire has requested that it be allowed to retain a portion of net revenues under K.S.A. 66-1245.[43] Witness Christopher D. Krygier cites the statute in his direct testimony, and he argues that the Wind Projects would meet the qualification criteria because: Empire is an electric public utility, the Wind Projects will be new, the facilities will likely be located in a county where the population has not increased more than 5% between the two most recent censuses, and generation would serve customers inside and outside Kansas.[44] The implication of the quoted K.S.A. 66-

[43] Petition of the Empire District Electric Company for Approval of its Customer Savings Plan, III.11.6, p. 8.
[44] Direct Testimony of Christopher D. Krygier, p.13, lines 24-28.

1245(a) is that Empire could seek to retain for shareholders up to 10% of net energy sales from the Projects.

Based on consultation with KCC Staff, my understanding is that K.S.A. 66-1245(b), which was also quoted by Mr. Krygier, may make the Wind Projects ineligible under the statute. K.S.A. 66-1245(b) states:

> *(b) The provisions of this section* ***shall not apply to net revenues*** *which are subject to the provisions of K.S.A. 66-1,184a, and amendments thereto.* (Emphasis added).

The referenced K.S.A. 66-1,184(a) relates to "net revenues" from renewable resources (like a wind farm), which would appear to preclude qualification of the Wind Projects under K.S.A. 66-1245.

Q. ARE YOU OFFERING A LEGAL OPINION REGARDING THE APPLICABILITY OF K.S.A. 66-1245?

A. No, I am not. However, I find the potential for Empire shareholders to retain a portion of net energy revenues from the project to be extremely troubling. The net energy revenue in question is not incidental to the project or to its alleged value to customers. It is not as if Empire is proposing to build a slightly oversized power plant to meet customer load, and is asking to share in profits from opportunity sales from the plant's excess capability. The Wind Projects are <u>not</u> proposed to meet a customer need for energy, capacity, or renewable attributes, but are arguably being pursued with the intention to expand Empire's rate base while making a speculative play on extracting value from the federal PTC and selling all production as excess energy at uncertain market prices. As I describe above, the only thing that could make the Wind Projects economic for ratepayers is if the generation sales results in large net revenues. The project could produce significant net sales revenue and still not offset the costs that customers must bear with certainty. And, the risks are repeated each year. Net energy revenue could be high one year, and the next year customers might be on the hook for making up a revenue shortfall for the Wind Project Company.

By seeking to retain a portion of net energy revenue, Empire highlights a stark asymmetry in the allocation of risks and potential rewards from its proposal. By putting the capital cost of the Projects into rate base, Empire would ensure its shareholders (or those of its parent Algonquin Power) of recovering their investment plus profit. If plant output and LMPs are favorable, Empire also seeks to retain up to 10% of net sales revenue. If plant output or LMPs are lower than projected, ratepayers could be required to pay the Project Company to make up for insufficient revenue, and would still be on the hook for paying the cost of the rate-based asset. Shareholders make out fine either way, while ratepayers have to hope that Empire's estimates are correct.

Q. IS EMPIRE'S PROPOSED OWNERSHIP OF THE WIND PROJECTS THE ONLY WAY FOR CUSTOMERS TO ACCESS THE VALUE OF WIND PRODUCTION AND THE PTCS?

A. Clearly not. As Mr. Puga discusses in his direct testimony, PPAs, such as those Empire already has with wind facilities in Kansas, are an obvious alternative mechanism to procure wind, with the benefit that PPAs can help shield customers from a variety of development, operational and ownership risks.[45] Moreover, Empire's customers would benefit from wind additions in SPP in the absence of direct ownership through access to lower prices for energy available for purchase from the SPP wholesale market. Empire has confirmed that it did not assume that the proposed Wind Projects would be incremental to total SPP wind additions; that is, Empire's proposed ownership of wind projects is not expected to increase wind generation in SPP.[46] In its December 12, 2017 conference call regarding the CSP, Empire indicated that there was a certain quantity of tax equity appetite for investment in wind projects and that Empire's advantageous position as a regulated utility would make it a desirable partner for a portion of the available tax equity. Again, that suggests that the volume of wind investment and development will not be affected by whether Empire is allowed to acquire the Wind Projects as proposed.

Q. HOW SHOULD THE COMMISSION EVALUATE THE PRUDENCE OF THE DECISION TO ACQUIRE THE WIND PROJECTS AND THE PRUDENCE OF CONSTRUCTION AND OPERATION?

A. As described above in Section III, the Commission views prudence as having two dimensions: the immediate question of the prudence of the decision to build additional generation and the subsequent determination of prudence of the

[45] The fact that PPAs are an alternative to ownership does not mean that they would necessarily be any more economic than ownership of the Wind Projects, as the underlying projects would be exposed to the same market pressures described in my testimony.

[46] For example, in response to data request STAFF 3-30 b, Mr. McMahon states that "Empire did not assume any change in total wind additions in SPP stemming from the proposed CSP."

construction. My understanding is that an original cost estimate is required in a determination of prudence in both contexts. Because Empire has not recommended or provided an original cost estimate for specific facilities it proposes to acquire, it is my opinion that there is insufficient basis for the Commission to make a determination on the prudence of Empire's proposal, or to establish a benchmark for determining the prudence of the construction of the facilities. At a minimum, Empire should be required to update its petition to provide original costs, following its evaluation and selection of project offers from its RFP process.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. Thank you.

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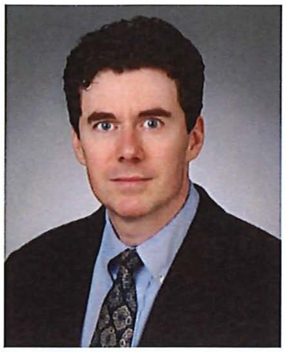

COLLIN CAIN,MSC
Principal

AREAS OF EXPERTISE

- Energy
- Cost benefit analysis
- Asset valuation
- Regulatory and market analysis
- Power market modeling
- Forensic analysis

SUMMARY OF EXPERIENCE

Collin Cain specializes in in power sector economic analysis, including market design, strategic advisory work related to electric market restructuring, evaluation of market power and market conduct, damages estimation, power supply procurement evaluation, asset valuation and cost benefit analysis. He has testified at FERC and before state regulatory commissions on cost benefit analysis of power plant investment, allocation of investment costs, the conduct and application of forecasts, market behavior, market power, risk assessment by contract counterparties, and contract damages. In addition to expert testimony, Mr. Cain has provided market design analysis and strategic support to regulators and utilities related to electric industry restructuring in Maryland, New Jersey, Maine, Massachusetts and Ontario.

He has extensive experience developing energy market pricing and risk analysis models and has applied these models in a variety of consulting assignments to value power supply offers and generation assets and to develop supply hedging strategies. He has undertaken strategic advisory work on issues such as asset divestment, stranded cost recovery, and rate unbundling.

SELECTED EXPERIENCE

- On behalf of the Electric Power Supply Association, evaluated the Department of Energy's *Grid Resiliency* proposal and filed testimony in the associated FERC docket. Testimony addressed the likely effects on wholesale power markets of out-of-market payments to baseload coal and nuclear plants otherwise uneconomic under prevailing energy and capacity market clearing prices.
- On behalf of the Mississippi Public Service Commission (MPSC), evaluated costs and benefits of Entergy's proposal to join the Midwest Independent System Operator (MISO) regional transmission organization. The analysis included assessment of prior cost-benefit studies as well as independent production cost modeling of the benefits to the Entergy region from joining MISO.
- Developed RFP documents and evaluation procedures for the Ontario Ministry of Energy's 2500MW RFP. Directed the economic evaluation of generator proposals, including development of models used to estimate energy market revenues and contingent capacity support payments, and created analytical tools to evaluate aggregate costs, including transmission upgrade cost impacts, for every possible portfolio of submitted bids.

- Calculated damages and submitted expert testimony on behalf of PG&E, SCE and SDG&E in separate cases before the U.S. Court of Federal Claims and Los Angeles Superior Court regarding unresolved claims stemming from energy sales by defendants into the PX and ISO markets during the California energy crisis.
- On behalf of the MPSC, submitted testimony in FERC proceeding regarding damages associated with electric power sales under the Entergy System Agreement (ESA). Testimony addressed the methodology for calculating damages and the appropriate measure of economic cost for resources deemed the source of off-system power sales.
- On behalf of Occidental Chemical Corporation, evaluated proposed changes to cost allocation methods in the Entergy production cost sharing mechanism, in support of testimony in FERC proceeding (Docket No. ER07-682-000). The evaluation estimated the impact on the individual Entergy operating companies and assessed compliance with regulatory accounting principles.
- Directed power market projections and economic benefit analyses in various applications, including: study of economic benefits for the Niagara Power Project (NYPA); cost-benefit analysis of environmental protection alternatives related to fueling of Salem Generation Station (PSE&G) and Indian Point Nuclear Power Plant (Entergy) and to the operation of Danskammer Point Generating Station (Dynegy).
- Submitted testimony at FERC on behalf of the MPSC regarding the allocation of settlement benefits among the Entergy operating companies. The testimony quantified shortfalls in benefits owed to Entergy Mississippi related to a settlement by Entergy resolving damage claims from a coal transportation disruption that restricted output at two of Entergy's generating plants.
- Developed forecast model of the CFE (Mexican electric utility) short-run cost of generation (CTCP) in support of the acquisition of a large scale wind project in Oaxaca, México. The model allowed for evaluation of potential project revenue impacts associated with increased gas-fired and renewable generation on the CFE system.
- In support of a major wind farm development in Mexico conducted a due diligence review of the project PPA price model and its application in projecting project revenues. The evaluation addressed the representation of the renewable energy banking mechanism and the priority lists for allocating project energy and capacity to load centers, and consistency with the CFE interconnection agreement.
- Developed probabilistic risk management model for market price forecasting, asset valuation and power supply cost analysis. Adapted and implemented the model in applications for Oglethorpe Power Corporation (OPC), Central Maine Power Company, Vermont Yankee Nuclear Power Corporation, Commonwealth Electric Company, and Connecticut Yankee Atomic Power Company. Analyses included forecasting market clearing energy and capacity prices, and estimating hedge values for retained capacity, new unit construction, power supply bids, and financial derivatives.

- Evaluated power supply proposals for short-term and long-term RFPs by OPC, directing and assessing PROMOD scenarios for alternative supply portfolios. Created and applied an independent price forecasting model and Monte Carlo analysis to evaluate risk profiles of supply alternatives.
- Provided analytical support for RFP design and portfolio evaluation in the Ireland 500 MW capacity procurement.
- Conducted due diligence assessment of the financial modeling of off-taker PPA revenues for the 396MW Mareña wind power project in southern Mexico, including the representation of off-taker priority list weighting and energy banking under CRE renewable interconnection rules.
- Assisted the development and implementation of BG&E's solicitation of standard offer supply service. Estimated market energy and capacity prices in a 15-year forecast applying a proprietary linear programming/optimal system expansion model.
- Served as testifying expert and produced expert report for OPC in arbitration proceedings between OPC and LG&E Power Marketing (LG&E) regarding LG&E's valuation of coal supply contracts associated with a long-term power purchase and sale agreement.
- Evaluated the Public Service Company of Oklahoma's 2008 Supply Side RFP in support of testimony for a potential bidder. Assessed bid evaluation methodology, credit and collateral requirements, and implementation of debt equivalence adjustments.
- Managed the Data and Rate Design Committees and Backup Bidding Team for the annual auctions of New Jersey Basic Generation Service (BGS). Participated in development of auction process, rules and protocols, and regulatory filings. Directed bidder information procedures and auction Data Room Team. Conducted PJM wholesale market price assessment to determine starting prices for the descending clock auction.
- Submitted testimony on behalf of Constellation Energy Commodities Group, Inc. in a complaint proceeding before FERC (Docket No. EL07-47-000) regarding the Illinois electricity supply auction. Analyzed the conduct, bidding behavior and outcome of the auction, addressing auction structure and rules, and allegations of market manipulation.
- Evaluated the proposed spin-merge of Entergy's transmission assets to ITC Holdings Corp., and advised the MPSC on the costs and benefits to Mississippi, including impacts on state regulatory control.
- On behalf of Catalyst Paper Operations, Inc., conducted an analysis of FERC's market power screens and submitted testimony supporting Catalyst's market based rate application associated with its acquisition of power generating facilities at Rumford Paper Mill in Maine.
- Submitted testimony at the Public Utility Commission of Texas (PUCT) regarding a proposal to build a $590 million transmission line to import power to the Houston area. Testimony addressed justification for proposed line and potential impacts on the ERCOT market, including effects on market incentives for new generation construction.

- Conducted economic assessment of KCP&L's proposed $1.2 billion environmental retrofit of La Cygne Generating Station, and testified before the Kansas Corporation Commission on behalf of Commission Staff. Developed analysis framework and key factor inputs for alternative economic assessment and evaluated supporting analyses submitted by KCP&L.
- Conducted independent validation of Southern California Edison's (SCE) internal power supply risk assessment model, including the model's theoretical underpinnings, implementation, and interpretation of outputs. The SCE model assesses procurement cost risk based on stochastic simulation that accounts for dispatchable resources, supply contracts, power forward and gas forward positions.
- Quantified effects on New Jersey energy costs of the prospective merger between PSEG and Exelon Corp as part of a comprehensive cost-benefit analysis for the NJ BPU. Effects included wholesale price impacts from changes to nuclear plant availability, direct costs to the state arising from planned staff reductions, and reductions in PSE&G's regulated cost of service arising from estimated merger synergies.
- Conducted benefits analysis of proposed hydroelectric power plant development in New York State, including reliability benefits, environmental benefits and wholesale market price impacts.
- Directed economic analyses and produced white papers on the economic benefits of baseload generation from nuclear power plants on behalf of Exelon Corporation. Benefit analysis examined impacts on wholesale market prices, and peak hour power flow impacts. (Separate assignments for 5 nuclear plants: Oyster Creek, Limerick, TMI, Peach Bottom, and proposed restart of Zion).
- Evaluated PJM proposals to modify OATT allocation of cost responsibility for transmission upgrades under the Regional Transmission Expansion Plan (RTEP), supporting testimony in FERC Docket EL07-57-000 (Consolidated).
- Advised the Ontario Power Authority in generator contract dispute arising from rule modifications by the Independent Electric System Operator (IESO). Provided assessment of background and intent of contract payment mechanisms and preliminary analysis of revenue impacts of rule changes on generator counterparties.
- Submitted testimony before FERC on behalf of the MPSC regarding Entergy Louisiana's proposal to allocate cancelation costs of the Little Gypsy Repower Project through the Entergy Service Agreement's rough production cost equalization mechanism.
- As an advisor to a major capital finance entity, evaluated the project financial model for a proposed hydroelectric generation project in western Mexico. The model review considered representation of the renewable energy banking mechanism under Mexican energy regulation, representation of seasonal production and demand patterns, and the associated projection of profit and loss and debt service coverage of the life of the project.

- Conducted detailed valuation analysis of qualifying facility (QF) hydro plants for New York State Electric & Gas Corporation (NYSEG), supporting settlement negotiations with plant owners. The analysis considered the value to NYSEG of buying out the contracts or assuming ownership under expected default by the plant owners.
- Conducted assessment of potential effects on wholesale markets and default service procurement of the proposed merger of Exelon Corp. and Constellation Energy Group Inc., in support of testimony submitted to the Maryland Public Service Commission on behalf of Commission Staff.
- Evaluated power market modeling employed by a party in a major supply contract litigation. Evaluated the party's application of PROMOD and MIDAS models used to value the transaction, and associated risk analyses used to assess value at risk (VaR). Identified substantive errors in inputs, contemporaneous market assumptions, risk analysis and economic inference.
- Conducted valuations of all Central Maine Power (CMP) power plants, supporting negotiated sale of generation assets to FPL. Applied market price forecasts and extensive monte carlo analyses to examine multiple transaction scenarios, including the value of retaining hydroelectric facilities as a supply hedge during the transition to competition. FPL Energy agreed to pay $845 million for all of CMP's non-nuclear generating assets.
- Produced power plant valuation of the TNP One lignite-fueled unit for Texas-New Mexico Power Company to support asset sale strategy as well as litigation with respect to stranded costs.
- Directed power market price forecasts for multiple clients, applying proprietary linear programming model to evaluate optimal capacity expansion for fuel price, demand growth and technology scenarios.
- Provided consulting assistance to the U.S. Department of Justice in defending claims related to spent nuclear fuel breach of contract in *Vermont Nuclear Power Corporation, and Entergy Nuclear Vermont Yankee, LLC et al., v. The United States* in the United States Court of Federal Claims (Nos. 02898C & 03-2663C) and *Portland General Electric Company et al., v United States of America* in the United States Court of Federal Claims (No. 04-0009C).
- Assessed the benefit-cost evaluation methods and assumptions applied to the 2010-12 energy efficiency plans in Massachusetts, for the Office of the Attorney General of Massachusetts.
- Conducted extensive analyses for a California IOU in refund proceedings related to the California energy crisis. Examined impacts of the calculation and application of mitigated market clearing prices (MMCPs) in the determination of refunds owed by generators selling into the California markets.
- For Baltimore Gas & Electric (BGE) testimony before the Maryland Public Service Commission, estimated rate impacts for alternative supply scenarios. Conducted power market analysis, estimation of wholesale market impacts on retail supply auction results, and self-build generation analysis.

- Managed a multi-disciplinary team in the development of a new pricing mechanism for liquid fuels in South Africa. The work, performed for the South African Department of Minerals and Energy, established pricing methods and regulatory accounts to ensure that fuel prices appropriately reflect costs, and enhance industry investment incentives.
- Estimated benefits of competition in electric markets through four empirical analyses, and quantified the dollar benefits to Maryland consumers of wholesale competition in PJM and state retail restructuring.
- Developed economic analysis of PJM transmission cost allocation proposals for merchant transmission entity. Supported testimony filed at FERC in Docket No. ER06-880-000, *et al.*
- Directed the evaluation of the benefit-cost ratio methodology used to validate energy efficiency measures in Massachusetts.
- Evaluated PJM price formation, demand responsiveness, and DR compensation proposals for comments submitted on FERC's ANOPR on "Wholesale Competition in Regions with Organized Electric Markets" (Docket Nos. RM07-19-000 and AD07-7-000).
- Performed strategic consulting work for BGE. Prepared expert testimony submitted in Maryland electric utility restructuring proceedings and consulted on utility regulatory strategy. Addressed market impact and economic rationale of competition policy, strategic aspects of asset disposition, stranded cost recovery, and retail access.
- Consulted on asset valuation alternatives and stranded cost recovery strategy, including the application of an auction appraisal of generation assets, for Niagara Mohawk Power Corporation.
- Directed study reviewing current methods of load profiling for retail settlement and energy imbalance services in the U.S. and Canada. The work was included in a series of load profiling studies for Japan's Ministry of Economy, Trade, and Industry.
- For ISO-NE, the NYISO and PJM Interconnection, in the evaluation of the proposed centralized resource adequacy model (CRAM): assessed capacity cost recovery for varied market conditions and implications for timing and frequency of capacity auctions.
- Conducted an analysis of reserve margin impacts on energy price volatility in the development of a power supply procurement process for Acquirente Unico, the Italian electric market single buyer.
- Directed analysis of optimal market hedge ratios by customer class for Dayton Power and Light. Analysis examined risk exposure due to price-driven customer migration under proposed retail access program.
- Produced pro forma valuation for the non-nuclear portion of the Connecticut Yankee nuclear site. Study considered unique site value and costs for a new generating plant, project financing costs, and the future competitive environment including market energy and capacity prices.

- Served as testifying expert on market modeling before the Massachusetts Department of Telecommunications and Energy on behalf of Commonwealth Electric. Testimony supported analysis of Commonwealth Electric's stranded costs and buyout options for legacy power purchase agreements.
- Directed new coal generation feasibility study for proposed investment in the Four Corners region of New Mexico. The analysis included market demand, competing supply, availability and cost of electrical transmission, cost and deliverability of coal, availability of water, and environmental concerns.
- Conducted a comprehensive review of the retail access experience in New England states. Developed state-by-state profiles that outlined the regulatory regime, transition period, standard-offer and default-service provisions. Evaluated end-user and supplier exposure to variable market prices.
- Provided consulting services to Niagara Mohawk Power Corporation on the modeling of transaction value for outsourcing standard offer service.
- Evaluated the competitive market of potential suppliers for PSE&G's auction of standard offer supply.
- Advised on the theoretic foundations of economic cost concepts and regulatory applications in avoided cost cases for a group of northeast electric utilities.
- Evaluated measures of competitiveness in present and future wholesale power markets and developed several models for use in assessing forward product prices for a large U.S. public power company.
- Participated in power purchase prudence analyses for PG&E, Nevada Power Company, Texas New Mexico Power Company, and Public Service Company of Colorado.

EXPERT TESTIMONY

- On behalf of the Electric Power Supply Association, *Grid Reliability and Resilience Pricing,* Federal Energy Regulatory Commission (Docket No. RM18-1-000)
- On behalf of Calpine Corporation and NRG Energy, Inc., *Application of Centerpoint Energy Houston Electric, LLC to Amend a Certificate of Convenience and Necessity for* a *Proposed 345-Kv Transmission Line (…)*, Public Utility Commission of Texas (Docket No. 473-15-3595).
- On behalf of Catalyst Paper Operations, Inc., *Catalyst Paper Operations Inc.,* Federal Energy Regulatory Commission (Docket No. ER15-794-002).
- On behalf of the Mississippi Public Service Commission, *Entergy Services, Inc.*, Federal Energy Regulatory Commission (Docket No. ER13-432-002).

- On behalf of Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company and the State of California, *Pacific Gas and Electric Company and Southern California Edison Company v. The United States; San Diego Gas & Electric Company v. The United States*, in the U.S. Court of Federal Claims (No. 07-157C and No. 07-167C, Consolidated; No. 07-184C).
- On behalf of the Mississippi Public Service Commission, *Louisiana Public Service Commission v. Entergy Services, Inc., et al.*, before the Federal Energy Regulatory Commission, (Docket No. EL09-61-004).
- On behalf of the Mississippi Public Service Commission, *Louisiana Public Service Commission v. Entergy Services, Inc., et al.*, before the Federal Energy Regulatory Commission, (Docket No. ER12-1384 et al.).
- On behalf of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, *Electric Refund Cases*, in the Superior Court of the State of California for the County of Los Angeles (Judicial Council Coordination Proceeding No. JCCP 4512).
- On behalf of the Staff of the Kansas Corporation Commission, *In the Matter of the Petition of Kansas City Power & Light Company ("KCP&L") for Determination of the Ratemaking Principles and Treatment that Will Apply to Recovery in Rates of the Cost to be Incurred by KCP&L for Certain Electric Generation Facilities Under K.S.A. 66-1239*, before the Kansas Corporation Commission (Docket No. 11-KCPE-581-PRE).
- On behalf of Constellation Energy Commodities Group, Inc., *The People of the State of Illinois, ex rel. Illinois Attorney General Lisa Madigan v. Exelon Generation Co., LLC, et al.*, before the Federal Energy Regulatory Commission (Docket No. EL07-47-000).
- On behalf of Oglethorpe Power Corporation, in contract dispute brought by LG&E Energy Corp. and LG&E Energy Marketing, Inc. (CPR Arbitration proceeding).
- On behalf of Commonwealth Electric Company, *Petition of Cambridge Electric Light Company and Commonwealth Electric Company requesting approval of their Transition Charge Reconciliation Filing*, before the Massachusetts Department of Telecommunications and Energy (Docket No. DTE 99-90).

PROFESSIONAL EXPERIENCE

Prior to joining Bates White, Mr. Cain served as a Consultant at National Economic Research Associates (NERA). In this position, he conducted a variety of power sector analyses in NERA's energy practice. Mr. Cain also served as an Economist with Jones Lang Wootton USA, where he directed economic research and market analysis for a range of corporate clients. Previously, Mr. Cain was a Consultant with Apogee Research, where he conducted economic impact analyses, and participated in a variety of transportation and environmental economics consulting assignments.

EDUCATION

- MSc, Economics, London School of Economics
- BA, Economics and Political Science, University of Toronto

PUBLICATIONS AND PRESENTATIONS

- "Clean Energy Certificates: The Key to Renewable Energy Financing," with Nicolás Puga. Electricity Future Forum Mexico 2014 (November 2014).
- "Beyond Loan Guarantees: Fostering U.S. Nuclear Investment in a Post-Fukushima World," with Glenn George. Conference paper and presentation, Center for Research in Regulated Industries 30th Annual Eastern Conference. Skytop, PA (May 2011).
- "Retail Rate Comparisons and the Electric Restructuring Debate," with Jonathan Lesser. Bates White briefing paper, 2008-E-11-01. (November 2008).
- "Economic and System Reliability Benefits of the Three Mile Island Generating Station," with Spencer Yang and Jonathan Lesser. White paper (April 2008).
- "Trends in Electricity Deregulation." Conference presentation at DTN/Meteorlogix Energy Summit. Minneapolis (June 2008).
- "A Common Sense Guide to Wholesale Electric Markets," with Jonathan Lesser. White paper (April 2007).
- "Utility Mergers: The Exelon-PSEG Merger." Workshop presentation, Market Power, Mergers, and Governance, Center for Research in Regulated Industries. Newark (January 2007).
- "The Fallacy of High Prices," with Howard Axelrod and David DeRamus. Public Utilities Fortnightly 144 (November 2006).
- "Nuclear Power in Future Electric Rate Cases." Conference presentation, Managing the Modern Utility Rate Case, Law Seminars International. Las Vegas (February 2006).
- "Applications of Probabilistic Price Modeling." Workshop presentation, Marginal Cost Working Group. Washington, DC (September 2004).
- "The 2004 BGS Auctions," Presentation to American PowerNet. PJM Interconnection, Norristown, PA (December 2003).
- "RTO Formation in the Central and Southeast United States." Presentation to Iberdrola S.A. Washington, DC (July 2003).
- "Risk Analysis in U.S. Power Markets." Presentation to Companhia Energetica de Pernambuco. New York (December 2000).

VERIFICATION

STATE OF KANSAS)
) ss.
COUNTY OF SHAWNEE)

Collin Cain, of lawful age, being duly sworn upon his oath deposes and states that he is employed by Bates White, LLC, consultants to the Staff of the State Corporation Commission of the State of Kansas; that he has read and is familiar with the foregoing *Direct Testimony,* and attests that the statements therein are true and correct to the best of his knowledge, information and belief.

Collin Cain

Collin Cain, Principal
Bates White, LLC

SUBSCRIBED AND SWORN to before me this 1st day of March, 2018.

Reshida Kingsbury

Notary Public

My Appointment Expires: January 14, 2023

RESHIDA KINGSBURY
NOTARY PUBLIC
MY COMMISSION EXPIRES 1/14/2023
DISTRICT OF COLUMBIA

CERTIFICATE OF SERVICE

18-EPDE-184-PRE

I, the undersigned, certify that a true and correct copy of the above and foregoing Direct Testimony of Collin Cain on Behalf of the Kansas Corporation Commission was served via electronic service this 1st day of March, 2018, to the following.

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