Exhibit No. 204P

Public Counsel – Exhibit 204P
Geoff Marke
Rebuttal Testimony
File Nos. EO-2022-0040 & EO-2022-0193

Exhibit No.: 204NP
Issue(s): Stranded Asset: Asbury Power Plant/ Securitized Utility Tariff Charge
Witness/Type of Exhibit: Marke/Rebuttal
Sponsoring Party: Public Counsel
Case No.: EO-2022-0040 and EO-2022-0193

REBUTTAL TESTIMONY

OF

GEOFF MARKE

Submitted on Behalf of the Office of the Public Counsel

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NOS. EO-2022-0040 AND EO-2022-0193

*** ***
Denotes Highly Confidential information that has been redacted

May 13, 2022

PUBLIC

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financial Order the Authorizes the Issuance of Securitized Utility Tariff Bonds for Qualified Extraordinary Costs	)))))	Case No. EO-2022-0040
In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Energy Transition Costs Related to the Asbury Plant	))))))	Case No. EO-2022-0193

AFFIDAVIT OF GEOFF MARKE

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Geoff Marke, of lawful age and being first duly sworn, deposes and states:

1. My name is Geoff Marke. I am a Chief Economist for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my rebuttal testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Geoff Marke
Chief Economist

Subscribed and sworn to me this 13th day of May 2022.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI
TIFFANY HILDEBRAND
My Commission Expires
August 8, 2023
Cole County
Commission #15637121

My Commission expires August 8, 2023.

Tiffany Hildebrand
Notary Public

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REBUTTAL TESTIMONY

OF

GEOFF MARKE

THE EMPIRE DISTRICT ELECTRIC COMPANY

d/b/a

LIBERTY

CASE NO. EO-2022-0040 & EO-2022-0193

I. INTRODUCTION

Q. Please state your name, title, and business address

A. Geoff Marke, PhD, Chief Economist, Office of the Public Counsel (OPC or Public Counsel), P.O. Box 2230, Jefferson City, Missouri 65102.

Q. What are your qualifications and experience?

A. I have been in my present position with OPC since 2014 where I am responsible for economic analysis and policy research in electric, gas, water, and sewer utility operations.

Q. Have you testified previously before the Missouri Public Service Commission?

A. Yes. A listing of the Commission cases in which I have previously filed testimony and/or comments is attached in Schedule GM-1.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of this testimony is to respond to the direct testimony of Empire District Electric Company ("Empire" or "Company") witnesses Frank C. Graves and Karen S. Hall regarding the securitization of the Company's stranded asset: the Asbury Power Plant and the Securitized Utility Tariff Charge respectively.

Q. What is your position?

A. I recommend the Commission reject Empire's proposal to include any costs related to the Asbury Power Plant in its securitization application. Simply put, these costs have not only already been collected from ratepayers, but have actually been over collected. Specifically, the remaining balance on Empire's Air Quality Control System ("AQCS") investment in Asbury following its last operational date in December 2019 represent costs collected by ratepayers that should have been borne by shareholders. The two-part rationale for my position follows as such:

1. The sum of Asbury's accumulated depreciation, favorable tax treatment, and payments collected to date through the Asbury regulatory asset offset Empire's claimed unrecovered plant balance to the tune of $32,593,521.53. When Empire's estimated $25,378,724 decommissioning costs are considered this would result in $7,214,797 in overpaid costs related to Asbury that should be flown back to customers. The accounting and depreciation balances are discussed in greater detail in the OPC testimony of John Riley and John Robinett. Importantly, this recommendation is before we consider costs collected to date for the AQCS.

2. Empire's ratepayers have overpaid for Asbury as it pertains to costs related to its 2014 AQCS investment. As such, I recommend that the Commission either A.) Offset the negative balance against the outstanding Storm Uri request or B.) Direct the overpaid costs into a regulatory liability to be reconciled in Empire's next general rate case.

My testimony will provide a response to Empire's direct testimony and is divided into the following sections: 1) The stranded Asbury Power Plant (or how we got here); 2) Resource Modeling (premised on shifting risk to ratepayers, momentarily creating excess capacity, and the unintended consequences of those actions); 3) The regulatory compact (and issues of fairness); and finally 4) The Securitized Utility Tariff Charge.

These recommendations are generally consistent with previous recommendations I made in Case Nos. ER-2019-0301, ER-2021-0321 as well as filings in previous IRP and Empire wind related dockets in which the Commission did not consider the stranding of Asbury ripe for consideration.

II. STRANDED ASSET: ASBURY POWER PLANT

Q. What is a stranded asset? [1]

A. A "stranded asset" is a term that has different meanings depending on the context. Assets become stranded if their expected cash flow is less than their remaining book value—in other words, if the asset is expected to generate less revenues than it will cost from a point in time until the end of its useful life. Regulation-based stranded assets differ from market-based stranded assets. The latter simply compares the book value of an asset relative to some future market value of the asset. For example, if an oil reserve has $1 billion book value but sliding demand due to carbon taxes or other environmental regulations reduces its market value to $400 million, the result is $600 million in stranded assets. By contrast, regulation-based assets are assets that are subject to cost-of-service or other rate-of-return regulation. Government regulators have explicitly approved this type of asset to earn a return over a defined period at some point in the past if the asset is deemed "used" and "useful."[2] A regulated supply-side asset is meant to provide service throughout its life to the captive customers who are paying for its use. That is, absent government-sanctioned intervention or a categorical loss in load (*i.e.*, "a death spiral"), a regulated asset should not become stranded.

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[1] Economist Robert Michaels made a compelling argument in a 1994 essay that, in "220 years of speculating on the nature of competition since Adam Smith, economists got along fine without ever developing such a concept as "stranded costs." The idea is a new invention. No other business has had such a "right" in its arsenal to shield itself from the effects of dynamic competition. See, Michaels, R. (1994), "Unused and Useless: The Strange Economics of Stranded Investment," *The Electricity Journal*, October, pp. 12-22.

[2] To ensure affordability and full utilization of the asset, the cost recovery generally is amortized throughout its expected "useful life." The asset costs are allocated to all customers on a pro-rata basis, and are generally recovered on a volumetric basis. As the number of customers change, the volumetric charge is adjusted so that the utility only recovers the value of the asset (including associated potential profit).

Q. What is an example of a government-sanctioned intervention that could strand a regulated asset?

A Deregulation is the most obvious recent historical example. At the turn of the century, many states passed laws to deregulate their vertically integrated electric utilities and create a competitive generation market. In theory, under deregulation, electricity prices would more closely align with economic, not accounting, costs. In vertically-integrated regulated states (like Missouri) electricity prices are based on utilities' actual expenditures, and utilities have little reason to control costs, because cost reductions ultimately are passed on to consumers. Additionally, regulators allow utilities to earn a specified rate of return on capital expenditures to "incentivize" investment in capital-intensive facilities. That is, utilities have a perverse incentive to increase their capital investments, i.e., rate base. In contrast, in a competitive market, asset owners reap more benefits for lower costs and, thus, are incentivized to minimize their costs, as cost-recovery is not guaranteed.[3]

Another historical example of a stranded asset is the significant cost overruns associated with mismanaged nuclear power plants that never became "used and useful." Whether or not these stranded investment costs were recovered from captive ratepayers varied depending on the circumstances and the government regulator. Some utilities had to write off their uneconomic assets, while others did not.

A final example scenario where an asset may be a stranded investment is where there is an aggressive government-sanctioned compliance policy that makes the asset uneconomic. Examples of such policies are renewable portfolio standards ("RPS"), carbon pricing schemes (see Regional Greenhouse Gas Initiative "RGG" states), and carbon-emission reduction standards (see California and its historical natural gas distribution investment or the now defunct U.S. Clean Power Plan "CPP").

[3] Deregulation or "industry restructuring" is different from the wholesale markets, which each of our investor-owned electric utilities in Missouri participate in. In a wholesale market, utilities buy and sell power among themselves or from independent merchant generators at prices that reflect conditions of supply and demand.

Q. Have Missouri electric utilities been subjected to any events beyond their control that could strand their investments?

A. No. Missouri did not deregulate the generation assets of its regulated utilities. It is a vertically integrated state (distribution, transmission, and generation are owned by the same entity).

Moreover, Section 393.135, RSMo, is in place. It prevents the cost recovery of investment in any existing or new facility of an electric corporation before it is "fully operational and used for service." This voter-driven initiative was spurred, in part, from the large capital overruns of nuclear power plants across the United States in the 1970s, including Union Electric Company's Callaway nuclear plant.

Missouri does have a RPS, but a 1% retail rate impact cap tempers any excessive costs associated with this mandate, and that standard has not stranded any asset.

Finally, Missouri electric utilities do not experience any carbon pricing penalty and are not subject to any enforceable state-level emission reduction targets.

There are no events beyond its management's control that could be said to have induced Empire to strand its investment in the Asbury power plant.

Q. Then why is Asbury a stranded asset?

A. Current Empire management chose to retire Asbury fifteen years before the end of its useful life. It chose to build 600 MW of nameplate wind capacity to replace the 200 MW of firm capacity of Asbury, thereby increasing Empire's excess capacity when it was not needed to serve its load and when it expected no load growth. There remains a significant remaining book value that Empire has not yet recovered for its environmental capital investments in Asbury that it made before Empire's management chose to last operate Asbury on December 12, 2019, due to lack of fuel and to retire Asbury on its books as of March 1, 2020.

Q. Has the OPC previously raised the issue of stranded cost rate impacts due to Empire retiring Asbury?

A. Yes. We filed testimony in Case Nos. ER-2019-0374 and ER-2021-0312; however, the Commission did not address the stranded asset issue in either case. As such, this is OPC's third opportunity. That Empire was contemplating prematurely retiring Asbury was raised first by Empire witnesses in Case No. EO-2018-0047 as part of Empire's "Customer Savings Plan" where Empire sought regulatory guidance for building up to 800 MW of wind generation and retiring Asbury; however, the non-unanimous stipulation and agreement all parties except the City of Joplin and the OPC executed included Empire's agreement to defer deciding when it would retire Asbury.

The issue of Asbury's premature retirement was not part of any prefiled testimony in Case No. EA-2019-0010 (Empire's 2nd wind case); however all parties, except OPC,[4] entered into a last-minute non-unanimous stipulation and agreement in that case which included three separate provisions related to an Asbury retirement.[5,6] Despite that agreement, the Commission ruled in its Report and Order that:

> In this case, the sale or retirement of Asbury is not certain. In fact, from the evidence presented, it is not known whether the removal of Asbury from Empire's generation fleet, if it occurs, will be accomplished through a sale or a closure. Thus, the effect on rates from the undepreciated plant value, the capital costs, depreciation expense, property taxes, operations and maintenance expense, fuel costs, SPP revenues and any deferred income tax effects are completely unknown. Further, there has not been sufficient evidence provided to show that this sale or retirement would be "extraordinary" under the definition as set out in the USOA. Further, because these events have not yet occurred, when they do occur, the signatories could present this

[4] The City of Joplin was not an intervening party in that case.

[5] Filed Friday, April 5th before the evidentiary hearing on Monday, April 8th.

[6] The regulatory asset contemplated in that non-unanimous stipulation and agreement included an undepreciated balance of the Asbury facility estimated at approximately $200 million.

> to the Commission as a formal request for an accounting authority order where the facts can be reviewed with more certainty, less speculation, and under the appropriate burden of proof.
>
> Empire and the other signatories to the *Non-Unanimous Stipulation and Agreement* have not shown that conditions related to possible Asbury closure or sale are reasonable or necessary. The Commission finds it would be premature to set out any conditions related to the possible sale or closure of Asbury. Additionally, the parties have not proven that this possible sale or closure will produce an extraordinary circumstance such that the Commission should take the unusual step of conditioning the grant of a certificate of convenience and necessity on this particular accounting treatment. The Commission will not impose the conditions set out in Paragraph 17 of the *Non-Unanimous Stipulation and Agreement*.[7]

Empire was required to file its new triennial IRP before the Commission took evidence in its main evidentiary hearing in Empire's Wind CCN case; however, Empire asked for and received an extension to file that IRP until the end of June, after the Commission decided Empire's Wind CCN case. On June 28th, 2019 Empire filed its triennial IRP which included the retirement of Asbury as part of its preferred modeled plan.

Pre-Acquisition Treatment of Asbury

Q. When was Asbury commissioned?

A. The Asbury Power Plant Unit 1 was originally commissioned in 1970 with an accredited capacity of 213 MW.

Q. What did Empire do in 2015 to extend its useful life?

A. To comply with federal air quality regulations in order to continue to run Asbury beyond 2015, in 2015 Empire installed a state-of-the-art Air Quality Control System ("AQCS") to remove

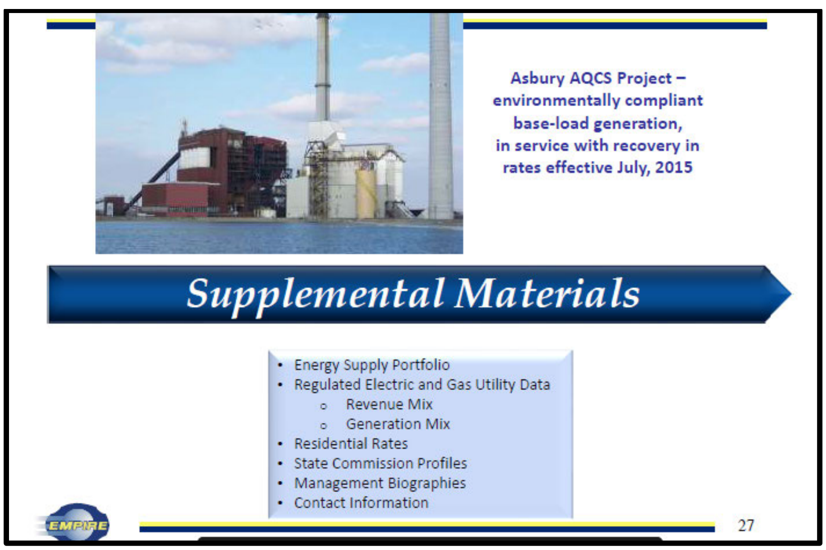
[7] EA-2019-0010 Report and Order p. 48.

sulfur dioxide, particulate, mercury, and other pollutants. Asbury was also retrofitted with a Selective Catalytic Reduction ("SCR") located upstream of the AQCS and a Distributed Control System ("DCS"). The facility *also* switched to Powder River Basin ("PBR") coal at a ratio of approximately 90% with approximately 10% local (Illinois) coal.[8] Asbury was also able to burn up to approximately 2% rubber tire derived fuel ("TDF") but let its contract expire in March of 2018. These collective upgrades extended the useful life of the plant more than twenty years and made the coal unit one of the cleanest in Missouri.[9]

Q. Were these upgrade decisions prudent?

A. I believe so. No party challenged the cost recovery of these investments when they went into rates in Empire's rate case, Case No. ER-2016-0023. Figure 1 includes a snippet from The Empire District Electric Company 2015 Annual Investor Update on February 26, 2016 highlighting the environmental compliance modification and recovery in rates.

Figure 1: 2016 Empire Investor highlight Asbury AQCS Project [10]



[8] For reference, Ameren Missouri's Labadie and Rush Island Power Plants did not elect to invest in scrubbers but instead relied on PBR coal to meet environmental compliance standards.

[9] A more detailed look at the history of Asbury investments can be found in the Direct Testimony of OPC witness John Robinett in this case.

[10] The Empire District Electric Company: Annual 2015 Investor Update (2016). http://www.snl.com/Cache/1500083524.PDF?Y=&O=PDF&D=&fid=1500083524&T=&iid=3005475.

Algonquin Acquisition

Q. Were you involved in both Empire's last general rate case before Algonquin Power & Utilities Corp. acquired it and the acquisition case where Algonquin Power & Utilities Corp. obtained Commission authorization to close its indirect acquisition of Empire?

A. Yes.

Q. Did you object to Algonquin Power & Utilities Corp. acquiring Empire?

A. Yes, initially. I initially recommended that the Commission reject APUC's acquisition of Empire. My rebuttal testimony opened with the following statements:

> As it stands, Empire ratepayers and regulators operate under the assurance of a known, stable local utility with over one-hundred years of operating experience. Approval of this acquisition would represent an increase in orders of magnitude at the level of organizational and affiliate complexity as well as a heightened risk of diluted managerial and fiduciary responsibility. There are no proposed standards from which to judge success, no cost-savings benchmarks to strive towards, and no proposed ring fence provisions to ensure captive ratepayers will not be exposed to increased harm. Instead, there are only aspirational, vague and often redundant claims of benefits generalized across four testimonies.[11]

Q. Did you testify in that case that Empire had no need for additional capacity post-acquisition due to the significant supply-side investments it had already made?

A. Yes. In my surrebuttal testimony I stated:

> For example, approval of the merger would not change the fact Empire has just added an additional 100MW in capacity in its Riverton 12 combined cycle unit. Moreover, according to Empire's recently filed triennial IRP, there will be no need

[11] EM-2016-0213 Rebuttal Testimony of Geoff Marke p. 3, 12-20.

for a MEEIA[12] and **no need for future capacity until 2029** as reprinted here in Table 1:

Table 1: Empire's Twenty-year Plan 5 (Preferred IRP Plan)[13]

Year	Common to All IRP Plans (Applies to Preferred Plan)	Plan 5 (Preferred Plan)
2016	By Mid-2016, Riverton 12 begins combined cycle operation (100 MW addition to the Empire system)	
2017		
2018		
2019		
2020		
2021		
2022		
2023	Energy Center Unit 1 assumed to retire for IRP purposes (82 MW loss)	
2024		
2025		
2026	Energy Center Unit 2 assumed to retire for IRP purposes (82 MW loss)	
2027		
2028	Meridian Way 105 MW Wind PPA expires (19 MW loss)	
2029		100 MW Combined Cycle, 100 MW Wind Resource
2030	Elk River 150 Wind PPA expires after 5-year extension (17 MW loss)	
2031		150 MW Wind Resource
2032		
2033	Riverton Units 10 and 11 assumed to retire for IRP purposes (33 MW loss)	
2034		
2035	Asbury Unit 1 assumed to retire for IRP purposes (194 MW loss)	200 MW Combined Cycle

[12] EO-2016-0223. The Empire District Electric Company Triennial Compliance Filing. Volume 7 Resource Acquisition Strategy Selection 7-8: "Empire's decision makers have selected Plan 5 as the Preferred Plan. Plan 5 contains no Missouri DSM portfolio and supply-side resources are not added until the latter part of the study period."

[13] EO-2016-0223. The Empire District Electric Company Triennial Compliance Filing. Volume 7 Resource Acquisition Strategy Selection 7-9.

> Even if Empire needed to build additional capacity (which they do not), there is no guarantee that renewable capacity would be the preferred generation, the prudent choice, or the least cost option. **<u>It is OPC's position ratepayers should not have to pay for any additional capacity in the near future</u>**. This is especially true considering ratepayers have experienced a compounded increase in rates of 62.23% over the past ten years.[14] (Emphasis not in original cited testimony).

Q. Did other OPC witnesses express concerns about the acquisition?

A. Yes. OPC's consultants stated a variety of concerns including, but not limited to, the timing of capital investments, uncertainty-surrounding costs associated with a new Customer Information System ("CIS"), and diluted local managerial control. Liberty President, David Pasieka's surrebuttal testimony offered the following general observations regarding the OPC's rebuttal testimonies:

> A conceptual theme that runs throughout the testimony filed by the OPC witnesses is OPC's belief that Empire will be more risky within Algonquin's corporate structure because it will no longer be a pure-play, vertically integrated electric utility, but rather will become an operating subsidiary within Algonquin's corporate structure.[15]

Q. Did OPC ultimately sign onto a settlement agreement in that case which recommended that the Commission authorize the acquisition?

A. Yes.

Q. If OPC agreed to the Commission authorizing Algonquin to acquire Empire, then why is it raising concerns now?

A. I thought there were reasonable ring-fencing provisions in place to address those. I now believe I was wrong.

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[14] Case No. EM-2016-0213 Surrebuttal Testimony of Geoff Marke.

[15] Case No. EM-2016-0213 Surrebuttal Testimony of David Pasieka p. 6, 17-21.

Q. Are there any circumstances during that timeframe of which the Commission should be aware?

A. Yes. Context is important. At the time, it seemed highly likely that US Environmental Protection Agency's ("EPA") Clean Power Plan would take effect and be enforced, with greater restrictions on and federal oversight of carbon emissions. To be clear, Empire (that is, pre-acquisition Empire) was the utility best in position, in Missouri, to meet any new federal emissions standards because of its diverse fuel mix and significant environmental capital investments.

Q. Did the State of Missouri oppose the Clean Power Plan?

A. Yes. Missouri and 20 others states sued the EPA for exceeding its authority with the Clean Power Plan.[16]

Q. Did the Missouri Public Service Commission file comments with the EPA expressing concerns with the Clean Power Plan?

A. Yes. The Missouri Public Service Commission filed comments on December 1, 2014, that included the following comments on stranded assets:

> To meet the EPA interim goal, Missouri would need to develop a state compliance plan taking into account the time needed to finance, permit, construct or commission new generation. The MoPSC notes that the interim goal does not adequately take into account potential delays in timing due to right-of-way obtainment or construction of new pipelines, transmission or generation facilities, which may be needed to achieve the interim goal. Additionally, **accelerated construction to meet aggressive goals may ultimately result in unintended stranded resources**. . . .

And

> The EPA notes that timing flexibility, such as that provided with the interim goals, allows states to develop plans that will help states achieve a number of goals including

[16] Herndon-Dunn, R. (2016) Clean Power Plan stayed by SCOTUS. *The Missouri Times.* https://themissouritimes.com/26920/clean-power-plan-stayed-by-scotus/.

> addressing concerns about stranded assets. Yet, in order to effectively meet a state's goals under the proposed timeline, it will be necessary to re-dispatch affected sources or add new generating capacity. **Accelerated construction to meet aggressive goals may ultimately result in unintended stranded resources**.[17] (Emphases added).

Q. Was it clear then how Missouri would comply with the Clean Power Plan?

A. No. There was a lot of uncertainty on the compliance end, but much less discussion on what would happen if the Clean Power Plan did not materialize. I did not believe that a utility would voluntarily accelerate construction of assets (not needed to meet load) to strand existing serviceable assets in place. I certainly did not believe that a utility would continue to seek recovery of its investment in and an earnings profit off of that self-imposed stranded asset.

Project Red Balloon[18] ***

Q. ______________________________

A. ______________________________

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[17] Kenny, R. et. al (2014) Re: Missouri Public Service Commission's Comments on the Clean Power Plan Proposed Rule under Section 111(d) of the Clean Air Act, Docket ID:EPA-HQ-OAR-2013-0602. https://www.ieca-us.com/wp-content/uploads/MO-Public-Service-Commission_12.01.14.pdf; see also Sch. GM-2.

[18] See Sch. GM-3.

Q.

A.

Q.

A.

Q.

A.

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[19] Ibid.
[20] Ibid.

[redacted]

Q. [redacted]

A. [redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

Q. [redacted]

A. [redacted]

Q.

A.

Public

Q.

A.

[redacted]

Q. [redacted]

A. [redacted]

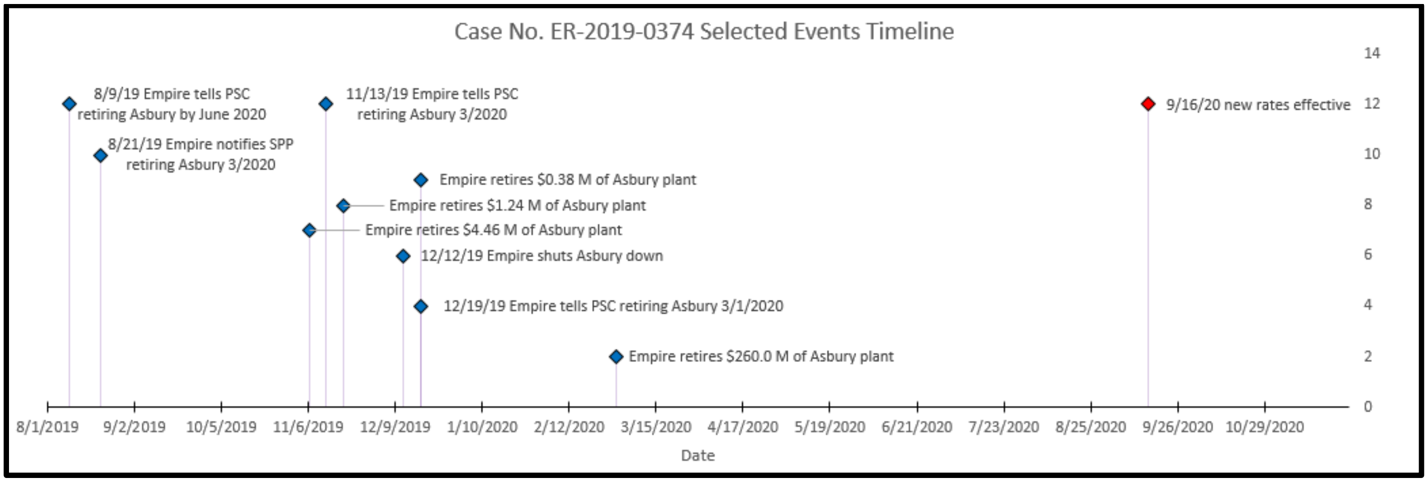
Q. [redacted]

A. [redacted] ***

Q. When did Empire retire Asbury?

A. That is a bit of a loaded question. Figure 2 below provides a timeline of pertinent dates in which Empire either confirmed retirement, retired various pieces of the Asbury plant and when it ceased operating entirely. For my purposes, "retirement" would effectively be 12/12/19 when the Company shut the plant down and could no longer operate it.

Figure 2: Empire Asbury Retirement(s) Timeline



Q. Could Empire have sold Asbury?

A. Yes. That would certainly offset the financial penalty. Three problems quickly emerge for shareholders. First, Asbury would then be an asset that would be directly competing with the wind investments. Second, the wind farm that is set to be placed at Asbury would have incurred additional investment costs for SPP interconnection. Presently, those SPP interconnection investments should be small or nonexistent because the infrastructure is already largely in place at Asbury; however, these costs are still unknown at this time.

Q. Could Empire have operated Asbury seasonably during months of high demand; thus mitigating market exposure to its customers?

A. Yes. That is exactly the plan Xcel Energy has proposed in Minnesota.[21] However, Empire's SPP wind project interconnection challenge would remain.

Q. Could Empire have mothballed Asbury and waited to see if another solution presented itself in the future?

A. Yes. In that hypothetical scenario, I would have recommended that shareholders, not ratepayers, bear the financial responsibility of that unit not running. If the market, policy, or technology changes that

[21] Morehouse, C. (2020) Xcel Minnesota: Running coal seasonally will save customers millions, reduce emissions. *Utilitydive*. https://www.utilitydive.com/news/xcel-minnesota-running-coal-seasonally-will-save-customers-millions-reduc/569971/.

would necessitate Asbury running again (e.g., a Storm Uri), then ratepayers would resume that cost burden. That is, in the mothball scenario, the principles of "used" and "useful" would continue to apply.

Q. Could there have been other options?

A. I am sure there probably were. However, based on my discovery with the Company, Empire management did not even explore the options I articulated above.

Q. To be clear, are customers receiving the benefits of Empire's investments in Asbury for which they are paying?

A. No. Empire's investments in Asbury have not been used or useful for a number of years now.

Q. If the Commission does not include Empire's net investment in the Asbury AQCS in the amount it allows Empire to securitize will Algonquin shareholders still be financially better off than they were when Asbury was operational?

A. About ten times better off (and likely much more than that into the future). This is because Empire's rate base is many times bigger than it otherwise would be and the risk inherent in the wind farms with poor wind profiles are borne primarily by ratepayers.

Q. Has Algonquin made any representations on how the subsidiary utilities it owns treat their customers and the community they serve through planned investments?

A. Yes. In October 2019, Algonquin Power Utility Company ("APUC") made a failed bid to acquire the Jacksonville Electric Authority ("JEA"). Their initial "sales pitch" was made public through that process. In its JEA bid Algonquin stated:

> History is strewn with examples of first movers and early technology adopters that in the fullness of hindsight turn out to be cost transient undertakings: AMR vs. AMI, CFB's [sic] vs LED technology, investing in IGCC, new nuclear, coal gasification, etc. There is certainly a place for technology pioneers and first movers, but this is a model that is rarely applicable to the utility industry that has an obligation to serve its customers reliably, to make prudent investment decisions and provide its services at an affordable cost. **<u>Jumping in with some new bet on some costly nascent</u>**

> **<u>"disruptive" concept</u>** (like cloud electric trading technology) **<u>is not what companies who care about their customers can practically do. Utilities cannot be failure pioneers when working with other people's money and when impacting their community's everyday quality of life.</u>**[22] (Emphasis added).

Q. Does Algonquin accurately portray your experience with Empire as a subsidiary of Algonquin and its subsidiary Liberty Utilities?

A. No. In multiple cases now, I have been a vocal critic of the Company's decision to depart from the traditional cost-of-service model to place a bet, "with other people's money," on a captive retail customer-backed, merchant generation scheme by acquiring and adding an additional 600 MW or more of wind generation to its rate base. The lack of objective, empirical analysis, the needless 45% increase to Empire's rate base, and the shifting of risk to be borne by ratepayers is an enormous concern, and is a substantial cost moving forward. APUC/Liberty/Empire's actions to date look exactly like they have made Empire into a utility that has placed itself in a position to be a "failure pioneer" with other people's money. If Empire's "Customer Savings Plan" does not materialize as planned, then Empire's retail customers (not insulated shareholders or tax equity partners) will experience a negative impact on their everyday quality of life. I believe such an outcome is likely for a variety of reasons, including (but not limited to) Empire's refusal to update its models with accurate data, and its failure to account for the diminishing marginal utility of excessive wind generation coming onto the SPP market.

Q. Did Algonquin make any representations about stranded costs in conjunction in its response to the City of Jacksonville regarding its interest in acquiring JEA?

A. Yes, in passing, Algonquin stated:

> Load balancing and operating safety, effective cyber-security, least cost energy supply security, dynamic billing/metering, being socially responsible and helping out low income/special need customers, providing backstop safety-net supply, **<u>and</u>**

[22] See GM-4.

> **dealing with stranded costs are some of these issues that need holistic answers/approaches that are fair and responsible.** The "big thinkers" outside of the industry often underestimate these challenges and their importance in being a utility that actually benefits it's [sic] community.[23] (Emphasis added).

Q. Do you believe Empire is being fair and responsible with its self-imposed stranding of Asbury?

A. I have seen no evidence that APUC/Liberty/Empire intends to deal with the self-imposed stranding of the Asbury power plant (fifteen-years before the end of its planned life) in a manner that is fair and responsible to its customers. Instead, APUC/Liberty/Empire continue to want to earn a profit and recover the remaining balance on an asset that is no longer used or useful. Again, this action favors investors and penalizes Empire's captive customers.

Q. Did Algonquin make any other representations regarding its operations in Missouri in conjunction with its response to the City of Jacksonville regarding its interest in acquiring JEA?

A. Yes. Algonquin referenced its merchant wind generation investment bet and the premature retirement of Asbury as follows:

> One example of rhetoric made action is the Respondents Midwest "greening the fleet" initiative. This was one of the first such projects in the country that was not a simple "demo" project using tax dollars or rate surcharges to subsidize cost inefficient technology applications. **It was the real substitution of a perfectly usable mid-life 600mW[sic] coal plant and replacing that with 400mW [sic] of renewable (wind) generation**. While such a substitution may on the surface seem commonplace, to do so at a cost that resulted in a net savings to the customer was highly innovative. **The full levelized cost of the power generated from the new**

[23] Ibid.

> **wind turbine fleet was proven to be lower than the incremental variable operating costs of the mid-life coal fired generation plant**.[24] (Emphasis added).

Q. Is Algonquin's characterization of its "greening the fleet" initiative at Empire accurate?

A. No. First, there is no real "substitution" here. If Empire had offered to substitute its 198 MW Asbury Coal Plant in exchange for "a return on and of" 600 MW of wind there *might* be a lopsided argument for an equitable substitution, but the Company wants it all (even if securitization is marginally better than what they asked for in the last rate case), but I want to address the claim that "the levelized cost of the power generated from the new wind turbine fleet was proven to be lower than the incremental variable operating costs of the mid-life coal fired generation plant."

The *cost* of the *energy*, does not necessarily say anything about the *value* of that energy over the lifetime of a generating plant. Value depends not solely on the cost of generating the energy being sold in a market; it also depends on the price for which that energy can be sold in that market. When prices vary continuously over time in increments as small as five minutes, and by location, it is not appropriate to look solely at the LCOE as the north star of supply-side generation economic feasibility metrics—at least not in the merchant generation business where revenue margins are the only thing that matters. Most price value derives from generating electricity when demand for electricity is highest, *i.e.*, when people most need electricity. That is, primarily during hot summer days when wind output is low or nonexistent.

Q. Could you illustrate your point by an analogy?

A. Yes. Let's say we wanted to look at the levelized cost of shelter ("LCOS"). That is, what's the cheapest shelter where the metric of importance is just keeping us dry when it rains. We could look at the all-in cost assumptions of homes, apartments, shacks, and tents. That

[24] Ibid.

analysis would show that tents have the lowest "LCOS" compared to the alternatives. What that analysis does not say is how well that tent will perform when it snows or over thirty years of wear-and-tear from the elements, or how comfortable it is or whether such a domicile can hold many people. The LCOS narrowly defines one attribute at the expense of glossing over other valued elements. The LCOE does much the same thing by omitting that energy prices fluctuate greatly and that having reliable, dispatchable generation during periods of huge price fluctuations can be a valuable resource. Look no further than this docket for evidence of that.

III. RESOURCE MODELING

Q. What economic models does Mr. Graves rely on for his argument that Empire's decisions to add an air quality control system to Asbury that it completed in 2015, then retire Asbury December 12, 2019, were prudent?

A. Various iterations of Empire's integrated resource plans ("IRP's") and the Company's Customer Savings Plan.

Q. What is your response to Mr. Graves's testimony on Empire's historical IRP modeling results?

A. Mr. Graves makes a compelling argument that Empire has not modeled its resource planning very well to date, but little to support his argument that shareholders, who saw a 45% increase to rate base from the ratepayer-backed wind farms, should also be allowed cost recovery on the AQCS investment that Empire made before it chose to strand Asbury. Empire's preferred plan selection within those various modeled scenarios from previous IRPs have not resulted in optimal outcomes for ratepayers to date. Empire's high cost of service and poor customer satisfaction scores are testaments to that. More to the point, regulatory approval at the time of investment does not form a basis for full cost recovery in light of management actions that resulted in Empire choosing to strand (in Empire's words) "a perfectly usable mid-life coal plant."[25]

The regulatory system leaves entrepreneurial decisions and capital management in the hands of utility management, not regulators. I believe Empire's decision to invest in the AQCS and lock the Asbury unit into a path-dependent trajectory for the next twenty years was supported at the time by management's decision to both be more efficient and environmentally sound. Retrofitting Asbury and extending its useful life for twenty-five years was a management choice to not deviate from having a diverse portfolio of resources as a hedge against uncertainty (like erratic weather) for a comparatively small utility.

It was Empire's management who took the risk of doubling-down on its historic coal investment by retrofitting Asbury into one of the most efficient and environmentally sound coal plants in the country, and if Asbury were still operational, I would not be arguing for a partial disallowance of that investment.

It was also Empire's management (albeit a different set of managers) who assumed the risk by stranding an efficient baseload asset with fifteen years remaining life so that it could utilize Asbury's SPP interconnection lines for its intermittent North Fork Ridge Wind Farm. Empire's management is also taking the risk that it will be allowed to recover its remaining balance and earn a return in the form of its WACC on an asset that is no longer used and useful.

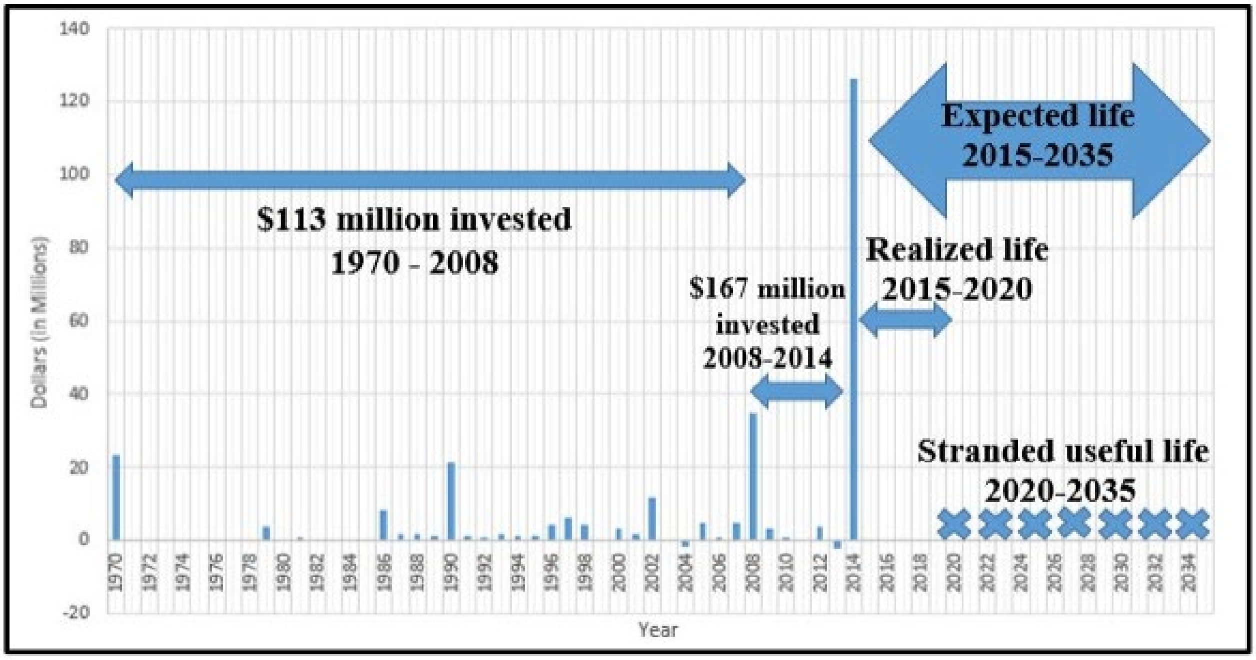
Empire's AQCS investment in Asbury is not a trivial amount,[26] to place Empire's investments in Asbury in perspective, consider that Empire invested a total of $113 million in Asbury from when it built Asbury (1970) to 2008. Now consider that in the years 2008 through 2015 Empire more than doubled that capital investment by retrofitting Asbury with an additional $167 million in environmental and efficiency investments that extended its

[25] See GM-4 p. 15

[26] Not a trivial amount from a historical perspective, but perhaps more trivial compared to the more than one billion dollars investment in Empire's three wind farms that "replaced" Asbury.

operational life through 2035. Figure 3 shows the dollars (in millions) invested over the course of Asbury's life with an emphasis placed on expected vs actual operation life from the ACQS investment.

Figure 3: Asbury Plant year-over-year capital investments in millions of dollars



To be clear, I am not arguing that all of Asbury's stranded investment be written down. I am arguing that just the remaining undepreciated balance on the ACQS (approximately 62% of total) should be borne by shareholders, and that Empire should no longer earn a profit off of its investment in a power plant that is no longer used and useful and, further, no longer exists.

Q. What is your response to Mr. Graves's testimony where he relies on Empire's 2019 IRP to justify the prudency of Empire stranding its investment in Asbury?

A. Mr. Graves omits two very important Company actions that influenced its 2019 IRP preferred plan outcome.

Public

1. The Company's decision to gamble in the SPP market with its wind project—three wind farms—funded by ratepayer-backed capital that exceeds $1 billion in total; and that
2. Asbury was an extremely efficient unit; it only became less efficient as Liberty decided efficiency no longer mattered when trying to maximize profits from the unit in the SPP market, which directly impacted the unit's average capacity factor.

The 2019 IRP is premised on Empire suddenly having excess capacity when no additional capacity was needed and the Company was losing customers. Moreover, this excess capacity needs to be sold at a premium in the SPP market to realize the espoused benefits from another model from the Charles Rivers-informed Customer Savings Plan. The mental gymnastics in producing speculative "benefits" from prematurely stranding the refurbished and more environmentally sound Asbury unit only materialize if the newly acquired billion dollar plus wind investments are put forward. In part because the wind investments need the Asbury transmission interconnection and because supply now greatly exceeds demand.

When Mr. Graves speaks of "benefits" to customers based on the 2019 IRP modeling (i.e., retiring Asbury), he is talking about a modeled outcome based on certain assumptions that were highly contested. Importantly, these models and assumptions were not accurate then, and have proven to be wholly inaccurate since.

Stated differently, Empire had more than enough generation to meet its customers' load. Empire management elected to prematurely retire one of its large, reliable and efficient assets it just invested copious amount of money into to replace it with three separate investments that are ten times the cost of the remaining balance of the asset that it retired, assets that are much less reliable. It then faced a situation in where it had less reliable generation resources available and was exposed to volatile price swings in the SPP during Winter Storm Uri, which resulted in it incurring net fuel and purchased power costs that exceeded the remaining balance of the stranded Asbury asset. The Company now wants recovery for all three (Asbury, the wind investments, and fuel and purchased power costs from Storm Uri) and has the nerve to take the position that this situation is unfair to shareholders as customers are getting all of the benefits from this arrangement based on modeling assumptions that were suspect to begin with and have utterly failed to be accurate to date. And nothing has changed about the risk exposure to Empire's ratepayers moving forward.

Q. Can a utility select a preferred plan using an IRP where the assumptions underlying that plan are wrong?

A. Yes. Empire has done this consistently. Empire's high cost of service and poor customer satisfaction scores are testaments to that.

Q. What if parties don't agree with a utility's IRP?

A. There is no real recourse in the IRP process. Stakeholders can voice their concerns and file recommendations, but the prudency of management's decisions are based on management's actions. IRPs are a modeling exercise that is constantly evolving. Any deficiencies or concerns voiced are historically corrected in the next filing. For example, carbon pricing has yet to occur for any of our utilities, but they continue to model scenarios with various cost assumptions (depending on the utility in question) as if various types of carbon pricing will happen. The end result is a complete overstatement of "benefits" on this one metric alone.

Q. Does that mean IRP serves no purpose?

A. I don't believe so, but Missouri is not a preapproval state and the IRP process is not Missouri's bright line test for prudent investments nor has anyone seriously argued that it should be until now. In fact, treating the IRP as such would enable utilities to game the regulatory process more than they already can. Consider that utilities routinely change direction in preferred plans, and the only recourse for stakeholders is to document historical grievances, wait until their next IRP filing or address it in a rate case (or this case, a securitization case) after the fact.

Q. Did OPC raise concerns about Empire's modeling assumptions for its wind projects and Empire's analysis of the economic viability of Asbury before Empire retired Asbury?

A. Yes, this was made clear in Case No. EA-2019-0010. Empire delayed its triennial filing until the Commission had opined on a CCN for the wind projects in that case, apparently in part, to avoid OPC's objections that it needed to update its modeling assumptions regarding its Customer Savings Plan. Unsurprisingly to me, Empire filed its new IRP nine days after the Commission issued its Report and Order in Case No. EA-2019-0010, creating a scenario where Asbury generation would actively hurt Empire ratepayers because ratepayers now were in the precarious position of being merchant generation investors (without the monetary reward) in three recently built wind farms.

I strongly recommend that the Commission refrain from buying into this rhetorical argument. Missouri is not a preapproval state. Commission affirmation that the IRP process serves as the bright line for prudency will result in an absurd outcome which utilities will exploit to no end as they effectively have absolute control over the IRP process.

Regulators and consumer advocates have neither the resources, nor responsibility, to create and guarantee utility investment plans, and cannot be expected to match the deep supply of outside consultants and resources available to utilities. That is why utility management is compensated as well as it is—to manage.

Q. What about Asbury's diminished capacity factor?

A. Simply put, Asbury was an extremely efficient unit until the Company decided that it wouldn't be by changing how it operated Asbury. The 2019 IRP's "benefits" created from stranding Asbury came as a result of the Company's decision to have the unit run differently than how it was designed to run. No modeling was done to consider seasonal dispatch, mothballing, or selling the unit. OPC witness John Robinett addresses the issue of efficiency and managerial actions in greater detail in his rebuttal testimony.

Q. What is your response to Mr. Graves's argument that disallowing any return of or profit on Empire's stranded investment in Asbury would unfairly punish investors?

A. When Algonquin first acquired Empire they effectively found themselves in a situation of lemons. That is, Empire was long on capacity with new capital investments made to secure the Company for the next twenty-five years. The new management then somehow managed to make lemonade out of its lemons by getting approval to have ratepayers back 600MW of wind farms in areas with poor wind profiles to the tune of over a billion dollars. The Company accomplished this feat, in part, through very untraditional schemes to finance a categorically large increase to rate base when no such investment was needed. This whole scenario, retiring Asbury, tax equity financing, etc… was assessed prior to Algonquin's acquisition of Empire and exercised many years before it was recommended by their outside evaluator, and now investors are seeing a windfall of rewards. Investors are also in a position for even further capital investment moving forward because of this management-created scenario to reduce the risk of investors by continuing to expose its already burdened customers with market volatility. Investors are doing extremely well even if the Commission were to fully disallow the remaining undepreciated balance of Asbury, a result that is above and beyond my recommendation.

V. THE REGULATORY COMPACT

Q. Does Mr. Graves rely on the regulatory compact as part of his argument in this case?

A. In part. His testimony implied as much throughout and he concluded his testimony with the following rationale for why investors should be prioritized over ratepayers above and beyond the 45% increase to rate base that investors will earn *additional* profits off of from Empire's ratepayer-backed market wind bet:

> Because of these economic findings, **and because of the traditional and well justified regulatory compact between a utility, its Commission, and its customers**, the proper treatment of Liberty's undepreciated investments and other

> energy transition costs at the Asbury coal plant is to allow Liberty to recover those past investment costs via a securitized utility tariff bond.[27] (emphasis added)

Q. What is the regulatory compact?

A. I view it as a theoretical agreement between the utilities and the state. The concept of a regulatory compact has long underpinned regulation of electric utilities: In exchange for a government-conferred monopoly over utility services, the company submits itself to government oversight, which—in theory at least—out to prevent the emergence of monopolistic prices and other anticompetitive inefficiencies.[28] Rather than try to prevent monopolies, the government allows them but then tries to mitigate anti-competitive behavior through regulation. With the basic premise that regulators make the monopoly as efficient as competition, the regulator is supposed to ensure that the public pays a fair price for service.[29]

Q. Mr. Graves argues that disallowing costs associated with Asbury's AQCS investment would violate the regulatory compact. What is your response?

A. The regulatory compact is a metaphor not a "legally binding" contract. In fact, according to Harvard Law School's Director of the Electricity Law Initiative at the Harvard Law School Environmental and Energy Law Program, Ari Peskoe:

> Framing utility regulation as a "compact" is a rhetorical device that has been invoked by industry to argue against competition and in favor of rate increases and cost recovery for investments that did not benefit ratepayers. While several PUCs have used the term "regulatory compact" as a shorthand description of regulation, no

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[27] Case No. EO-2022-0193 Direct Testimony of Frank Graves p. 55, 14-18.

[28] This is not always regarded as successful. As former NARUC president Travis Kavulla stated, "[T]his is a monopoly industry laden with perverse incentives to over-invest in capital on the part of the utility. I'm very skeptical of the type of corporate behavior that results from a cost-of-service regulatory monopoly." https://www.greentechmedia.com/articles/read/the-republican-case-for-distributed-energy

[29] This concept is not universally shared. A compelling argument can be made that this is a misnomer implying contractual rights when it actually is a private entity consenting to additional oversight to engage in activities that as a member of the general public it could not otherwise perform. See also Hempling, Scott. What "Regulatory Compact"? https://energiahoy.com/2019/07/02/what-regulatory-compact/

court or PUC has concluded that a utility is legally entitled to relief, such as cost recovery, under a "regulatory compact." On the contrary, PUCs and courts have explicitly rejected such arguments.[30]

Q. What is your view of Empire's regulatory obligations with regard to its resource planning, specifically Asbury?

A. As an analogy, consider a hypothetical scenario involving an airline's contract with an airplane manufacturer articulated by writer Scott Alexander.

- The airline says they'll buy X planes over the next ten years;
- The manufacturer says they'll provide them at such-and-such a price.

At the moment of signing, both parties think it's a good idea. If they both knew it would stay a good idea, a contract would be unnecessary. But something might change. The air travel market might crash, and then the airline would regret having ordered more planes, and want to back out. The price of raw materials might go up, and then the manufacturer would regret offering such a low price, and want to back out themselves. But it would be unfair for the airline to make the airline manufacturer commit to a complicated course of action - building new factories, hiring lots of workers - and then change their mind, leaving them in a worse position than when they started. And it would be unfair for the manufacturer to make the airline commit to a complicated course of action - opening new routes, signing contracts with more airports - and then pull the rug out from under them and demand a higher price. So if you're committing to a mutual enterprise where both sides are going to make big irreversible changes to satisfy the other, you want a contract where

[30] Peskoe, A. (2016) "Utility Regulation Should not be Characterized as a "Regulatory Compact." Harvard Law School: Environmental Law Program Policy Initiative. http://eelp.law.harvard.edu/wp-content/uploads/Harvard-Environmental-Policy-Initiative-QER-Comment-There-Is-No-Regulatory-Compact.pdf

> they both agree not to back out, and agree to suffer heavy social and financial sanctions if they do.[31]

Empire's management is the one that backed out of its regulatory obligations by reversing course and finding a way to increase rate base. Shareholders are made whole many times over from the wind investments alone.

Keep in mind, that Empire's wind investments <u>increased rate base by over 45%</u> for investors.

It is ratepayers that are overwhelmingly in a worse position being charged *three times* (each more expensive) for actual usable capacity.[32]

Q. Economically, who are those ratepayers?

A. Table 2 provides an updated listing by county of key economic data from the most recent American Community Survey.

[31] Alexander, S. (2021) There's A Time For Everyone. https://astralcodexten.substack.com/p/theres-a-time-for-everyone

[32] 1.) The Asbury costs pre-AQCS (as Asbury would have retired in 2020 without those investments); 2.) The AQCS costs (which extended the life of Asbury to 2035); and 3.) The wind investments. This is before one considers that ratepayers are also being asked to cover the Storm Uri fuel costs because Empire didn't have reliable generation on hand or a coordinated plan covering emergency curtailments. Which will most likely result in 4.) Additional capital costs to account for the unreliable generation.

Table 2. Select 2020 American Community Survey Economic Data of relevant service territory (italics denotes a number below the Missouri average).

Area	Mean Household Income	Median Household Income	Below Poverty Rate % Below $26,200 family of four in Missouri	Child Poverty Rate % Under 18
Empire MO Counties				
Barry	*$66,284*	*$45,811*	*18.2%*	*31.0%*
Barton	*$62,774*	*$44,510*	*20.7%*	*22.0%*
Cedar	*$62,300*	*$39,408*	*18.2%*	*23.4%*
Christian	$79,855	$64,442	10.0%	13.3%
Dade	*$67,067*	*$52,442*	*19.1%*	*34.3%*
Dallas	*$57,106*	*$40,404*	*19.4%*	*29.3%*
Greene	*$65,190*	*$47,053*	*15.3%*	14.9%
Hickory	*$42,290*	*$33,342*	*13.8%*	13.0%
Jasper	*$62,198*	*$49,155*	*17.7%*	*24.9%*
Lawrence	*$58,172*	*$44,060*	*17.0%*	*27.3%*
McDonald	*$57,288*	*$42,876*	*19.3%*	*32.0%*
Newton	$78,240	*$52,067*	*13.7%*	*18.3%*
Polk	*$62,041*	*$47,614*	*15.7%*	*18.3%*
St. Clair	*$52,360*	*$39,000*	*16.5%*	*17.7%*
Stone	*$69,336*	*$51,476*	12.3%	*18.9%*
Taney	*$60,007*	*$47,860*	*15.7%*	*24.2%*
Other				
US	$91,547	$64,994	12.8	17.5%
Missouri	$78,194	$57,290	13.0%	17.4%

Q. What is important to note from your Table 2 data?

A. Empire's customers have lower overall mean and median household incomes, and higher poverty rates relative to the United States and Missouri averages.[33] Although insufficient time prevented me from performing the analysis, based on the aforementioned data, it would not be out of the realm of reasonableness to surmise that Empire's southwest Missouri residential customers have one of, or possible the largest, energy burden of residential customers in the United States.[34]

Q. Are you aware of anything else that bears on the ability of Empire's already economically challenged customers to afford yet further increases to their electric bills?

A. Yes. Inflation has surged in 2022 and is at a 40-year high. Furthermore, household spending is projected to rise a record 8% over the next year and overall inflation expected to rise by 3.9% three years from now, according to a New York Fed survey of consumers. [35] Figure 4 shows the Consumer Price Index changes since January of 2021.

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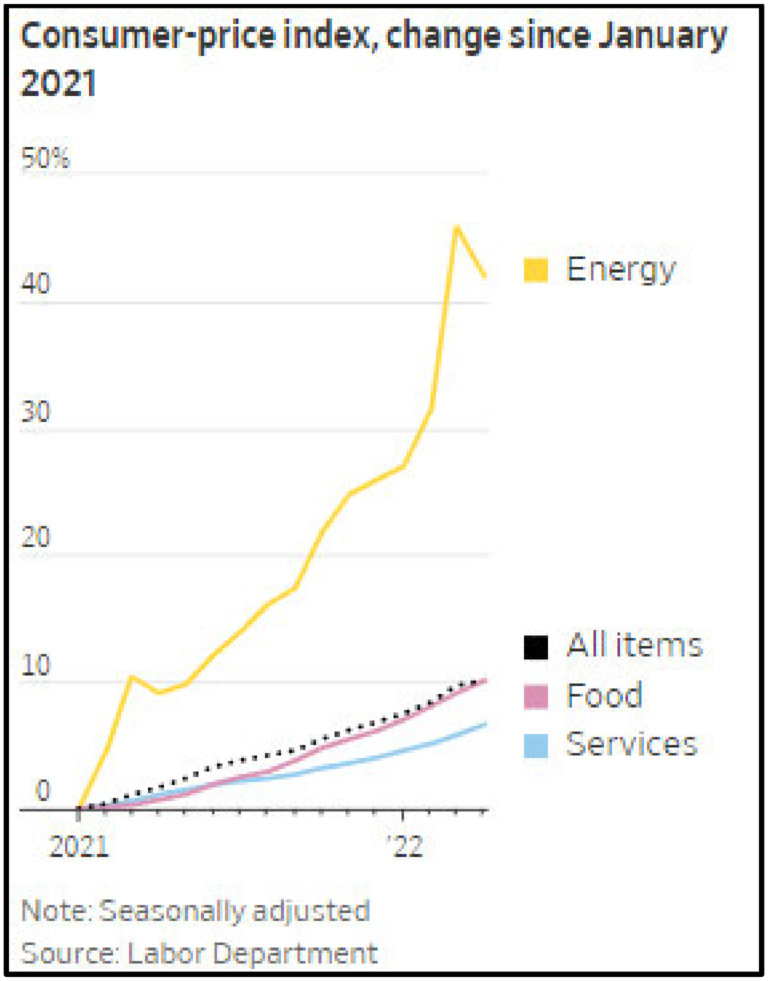
[33] Christian County being the sole exception when compared to the Missouri average across the select data.

[34] A household's energy burden—the percentage of household income spent on energy bills—provides an indication of energy affordability

[35] Tanzi, A. (2022) Longer-Term Inflation Expectations Rise in New York Fed Survey. *Bloomberg*. https://www.bloomberg.com/news/articles/2022-05-09/longer-term-inflation-expectations-rise-in-new-york-fed-survey

Figure 4: Consumer Price Index changes since January of 2021 [36]



An overall decrease in the purchasing power of the dollar coupled with Empire's recently approved rate increase and now the requested increase for securitization costs will impact vulnerable households most of all.

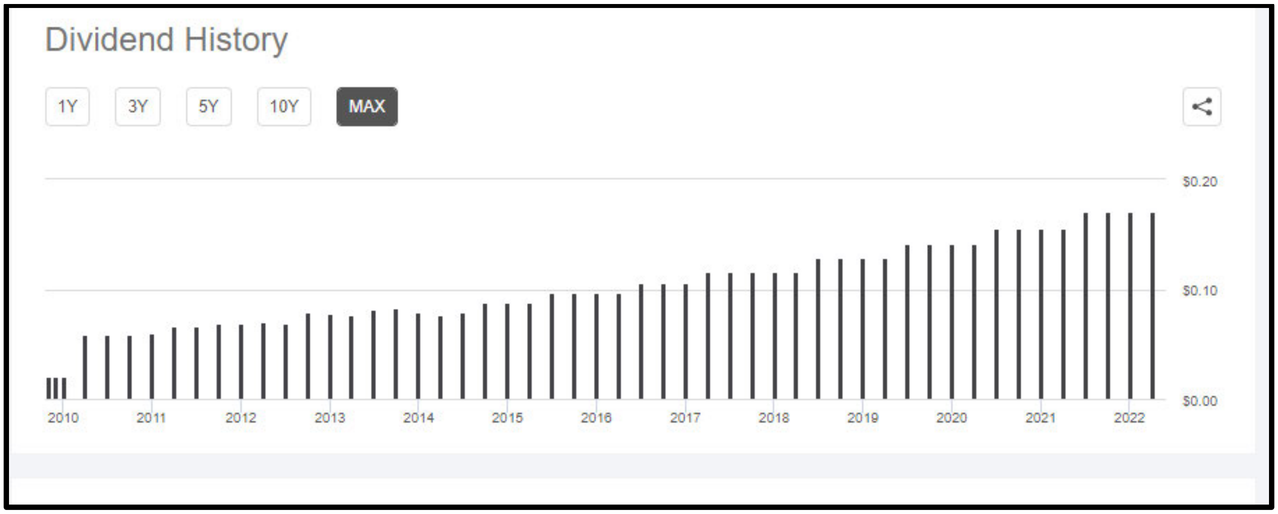
Q. What about Algonquin investors?

A. As referenced earlier, Algonquin's investors are about to begin recouping the financial benefit of a more than 45% increase to rate base from Empire's three wind investments.

[36] Guilford, Gwynn. (2022) Inflation Slipped in April, but Upward Pressures Remain. *Wall Street Journal*. https://www.wsj.com/articles/us-inflation-consumer-price-index-april-2022-11652218520 5/11/2022

Moreover, despite a global pandemic/recession and a forty-year high in inflation Algonquin's investors have experienced a categorical increase in dividend payouts and enjoyed a year-over-year increase in each of the past twelve years in common equity dividend payouts as shown in Figure 5.

Figure 5: AQN – Algonquin Power & Utilities Corp. Dividend History[37]



And the good news keeps coming, as today, Algonquin announced that they are raising dividends an additional 6% for their investors.[38]

Increasing its Missouri rate base by over 45% no doubt enabled Algonquin to make recent purchases including New York American Water and AEP's Kentucky Power. The latter acquisition includes more than $113 million in ratepayer benefits including:[39]

[37]Seeking Alpha (2022) AQN- Algonquin Power & Utilities Corp. Dividends: Dividend History https://seekingalpha.com/symbol/AQN/dividends/history

[38]Singh, Meghavi (2022) Algonquin Power & Utilities raises dividend by 6% to $0.1808/share. Seeking Alpha. https://seekingalpha.com/news/3838355-algonquin-power--utilities-raises-dividend-by-6-to-01808share?mailingid=27698563&messageid=2900&serial=27698563.1232&utm_campaign=rta-stock-news&utm_content=link-1&utm_medium=email&utm_source=seeking_alpha&utm_term=27698563.1232 5/13/2022.

[39] Unlike Kentucky ratepayers who are going to see a $113 million in cost savings, the acquisition of Empire District Electric in 2016 was based on the sole premise of "no net detriment to ratepayers", that is, no explicit cost savings. Stranding a generation investment fifteen years before the end of its useful life, hundreds of millions of dollars in excess fuel costs due to unreliable generation against a large winter storm and more than a billion dollars in wind

- Reduced transmission costs for Kentucky ratepayers by $30 million.
- Ensured Kentucky Power ratepayers do not pay for over $43 million in damage repairs resulting from Kentucky's 2021 winter storms.
- Secured $40 million in Fuel Adjustment Credits for Kentucky Power ratepayers. Kentucky Power's average residential customer will receive a monthly credit of $32.72 during the winter months and $1.40 during non-winter seasons.
- Required Kentucky Power to pay 50 percent of the carrying cost charges on the Big Sandy Decommissioning Rider, charges that cannot be collected directly or indirectly from ratepayers.[40]

Q. If the Commission does not include the remaining balance of the Asbury AQCS in the amount to be securitized, do you believe it would be fair to characterize that shareholders "got the rug pulled out from under them."

A. No. Shareholders have made out better than they could have imagined, even if the Commission does not include the AQCS amount for securitization. Because, unlike the securitization statute which replaces an undepreciated coal plant's balance dollar-for-dollar for reinvestment, shareholders got to replace a $150 million dollar coal plant with $1.2 billion dollars in wind investments.

Rate base will be five times greater these first ten years and then more thereafter (the remaining undepreciated balance from buying out the tax equity partner) for shareholders to increase profit more from an original scenario where no such opportunity existed before— regardless of how the wind farms actually perform. Leaving the remaining balance

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investments in farms with poor wind profiles to play the SPP market when no such investment was needed calls into question whether that no net detriment to ratepayers has been realized.

[40] See also: Cassady, R (2022) Kentucky Power sale OK'd, with more than $113 million in ratepayer benefits approved. Appalachian News-Express https://news-expressky.com/news/kentucky-power-sale-ok-d-with-more-than-113-million-in-ratepayer-benefits-approved/article_5ea296ee-cd13-11ec-8fef-63863d282cce html

of the AQCS in the securitization proceeding and allowing the Company to earn its weighted average cost of capital ("WACC") on it would be categorically one-sided.

Q. If the Commission includes the remaining balance of the AQCS in the amount it authorizes Empire to securitize do you believe it would be fair to characterize that ratepayers "got the rug pulled out from under them."

A. Yes. Ratepayers would effectively be experiencing a perfect storm of awful outcomes.

First, they would be paying the remaining balance and WACC on an asset that is no longer used and useful.

Second, they would be paying many times over for its effective "replacement" generation (the three wind farms) that is less reliable than what they had or could otherwise have purchased.

Third, Empire's ratepayers are now being asked to pay hundreds of millions in fuel costs for Storm Uri. Costs that were exacerbated because the Company stranded its only fully owned dispatchable coal plant fifteen years before the end of its useful life.

And the parade of horrible outcomes continues as half of Empire's replacement generation capacity (specifically, the Neosho Wind Farm in Kansas) currently is not operational nor expected to be operational anytime soon as we approach peak summer conditions. Despite all the wind we've had recently, the turbines in Neosho County, haven't been turning. According to a KOAM News Now Report on April 11, 2022, District One Commissioner Paul Westhoff says it's been more than two weeks since they were last operating "What I was told is that their main transformer blew up, shorted out, whatever, and then their backup one did, and that's why they're down, so now they're waiting on another transformer."[41]

[41] See also, Warner, C. (20222) Neosho Ridge wind turbines no longer working, raising concerns with a county official. KOAM News Now. https://www koamnewsnow.com/neosho-ridge-wind-turbines-no-longer-working-raising-concerns-with-a-county-official/ April 11, 2022

Q. Do you have anything further to say on Empire's resource planning and the inclusion of Empire's stranded investment in its Asbury AQCS?

A. As glowing of a scenario as it is for investors, Empire's customers are not reaping the benefits of Empire's managerial decisions. The lack of reliable generation exacerbated by Empire's ratepayer-backed bet on the SPP market has already created hundreds of millions of dollars in outstanding fuel costs that necessitated passing securitization legislation to limit the financial impact on customers (who will pay the one week spike in fuel costs off over decades).

I ask the Commission to consider for a moment an excerpt from my rebuttal testimony in the first Empire wind project case, Case No. EO-2018-0092:

> Make no mistake of it, what Empire is requesting here is unprecedented. The Commission would be well advised to keep in mind the urgency (or scarcity) principle and have a healthy degree of skepticism when it comes to regulatory requests that apply an "act now, limited time only pressured sales pitch."[42] Because of past managerial decisions, Empire cannot afford to shift risk onto its ratepayers by locking them into a scenario where they would increasingly be exposed to the uncertainty of excessive costs on the SPP market with an excessive amount of generation capacity. The decision in front of the Commission is not to build a coal [plant] or wind farm. The coal plant is built. Nor does OPC believe this is merely a decision to retire Asbury and replace it with wind. Instead, what is at stake is a complete departure from how Empire has operated to date—namely, to provide safe and adequate service to meet its native load. Figures 1-3 provides a breakdown of the stated and unstated investment and operational decisions for the Commission's consideration.

[42] See also Cialdini, R.B. (2006) *Influence: The Psychology of Persuasion*. Harvard Business.

Figure 1: Graphical illustration of Asbury generation to serve load (current state)

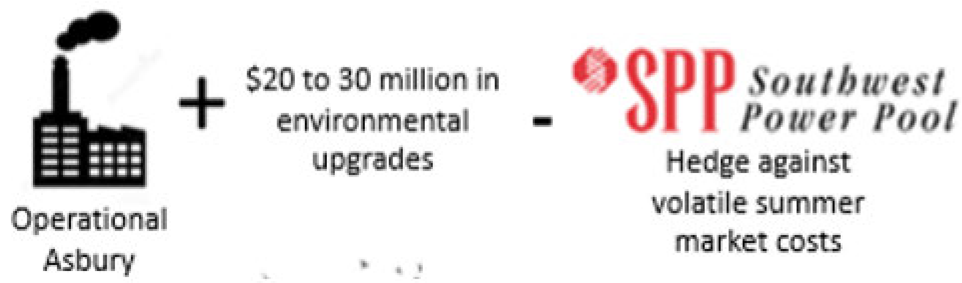

Figure 2: Graphical illustration of Company's proposed application

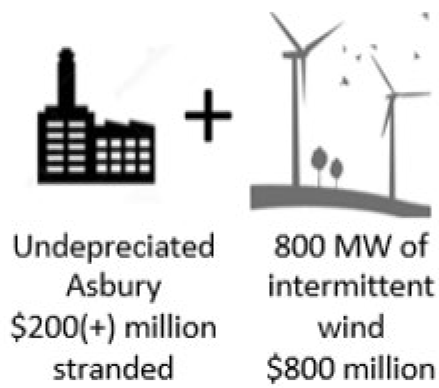

Figure 3: Graphical illustration of OPC's interpretation of Company's proposed application

The ratepayer "benefits" hoped to be obtained in this transaction are based on projecting assumptions far out into the future based on narrowly defined parameters. In contrast, the "benefits" to shareholders are guaranteed, at least in the short-term.

> OPC's greatest fear in this proposal is locking-in Empire's largely rural southwest Missouri ratepayers into volatile, excessive rates into the future.[43]

It is now more than 4 years and 3 months since I originally wrote this, and sixteen months before Empire filed its 2019 IRP, and I contend that my offered outcome has proven more accurate than Empire's 2019 preferred plan. We are now realizing Figure 3's outcome (from my 2019 testimony), only at slightly smaller scale and albeit with a different season (winter) of volatile market prices.

The fact that this outcome was realized in such a short amount of time is extremely troubling and sets up a future where ratepayers are no doubt going to be asked to shoulder even more capital costs that would have been unnecessary prior to this acquisition.

While it "may" seem unfair to Mr. Graves to only partially disallow some of Empire's undepreciated balance of Empire's stranded investment in Asbury, it is profoundly unfair to Empire's customers for Empire's shareholders to recover from them amounts for its excessive and "gamed" utility investments. Nobody persuaded Empire to make any of these investments. Anyone arguing that automatic full recovery is entitled to shareholders because of utility-backed and approved IRP and Customer Savings Plan models based on the Company's own select assumptions are over-relying on regulation to get the Company out of the compromising situation it alone created.

Q. Are you concerned with the precedent if the Commission dismisses your argument?

A. Yes. Given the anti-competitive nature of monopolies, regulators are the only protection the public has from unfair and overly burdensome utility prices. Captive consumers do indeed pay a regulatory premium for utility service. As a normal course of business, regulation allows the pass-through of high operating costs that competition would never allow. Further, inflated and obsolete assets are too often virtually guaranteed recovery plus a return.

[43] Case No. EO-2018-0092, Rebuttal Testimony of Geoff Marke p.3, 7 to p. 4, 11.

The combined orchestrated efforts by Empire over six proceedings (one merger/acquisition case, two wind cases, two rate cases and now a securitization docket) represents a windfall for investors and an onerous cost for its captive consumers. Such a situation creates a moral hazard in which one agent (the utility) decides how much risk to take, while another agent (consumers) bear the negative consequences of risky choices. The Commission weighed in on such a situation in its response to a PSC Staff alleged concern in Ameren Missouri's 2020 Integrated Resource Plan in Case No: EO-2021-0021. There the Commission stated:

> However, the Commission shares Staff's concern (Concern C) that adding large amounts of renewable generation that are not required to meet MISO resource adequacy requirements or Missouri statutory or rule requirements, including providing safe and adequate service, may place an undue level of risk on ratepayers based on the speculation that market revenues will exceed the overall cost of the assets. Ameren Missouri inherently benefits its shareholders by investing in renewable energy while seeking a return on those investments through future rates. However, that same investment may shift risk to ratepayers that market revenues from investments may not exceed the cost of the investments.[44]

Consider for a moment that this statement is being applied to a utility with approximately 1.2 million Missouri customers and contrast that with Empire's approximate 170 thousand Missouri customers. Simply put, the margin of error for horrific financial consequences is much, much greater for Empire if those early 2018 models continue to prove inaccurate. One year into this Savings Plan has already cost ratepayers hundreds of millions of dollars in fuel related costs from Storm Uri. I legitimately fear for what could follow.

[44] Case No: EO-2021-0021. Order Regarding 2020 Integrated Resource Plan, pg. 4.

Q. Would you summarize your testimony on including Empire's stranded investment in its Asbury AQCS in the amount the Commission authorizes Empire to securitize and on allowing Empire carrying costs based on its weighted average cost of capital?

A. The present day situation is as follows, Empire's customers are more exposed to SPP market volatility today than when Asbury was an available generating resource. This combined docket is evidence of that fact. Investors have realized financial gains that would not have seemed possible after Empire was acquired by Liberty through the approval of the "Customer Savings Plan" and a categorical increase to rate base.

The sum of Asbury's accumulated depreciation, favorable tax treatment, and payments collected to date through the Asbury regulatory asset should offset Empire's claimed unrecovered plant balance and estimated decommissioning costs. The remaining negative balance of $7,214,797 should be either be offset against Storm Uri costs or put into an account to be reconciled and flown back to customers in the next rate case.

Empire's ratepayers have overpaid for Asbury as it pertains to costs related to its 2014 AQCS investment whose remaining balance since its last operational use should be disallowed in recognition of the used and useful principle, matters of equity and fairness, and because the retirement was entirely the result of actions taken by Empire management from the excess capacity it momentarily created. As such, I recommend that the Commission either A.) Offset the AQCS balance against the outstanding Storm Uri request and/or the remaining decommissioning costs; and/or B.) Direct the AQCS costs into a regulatory liability to be reconciled in Empire's next general rate case.

Failure to order one or some combination of the aforementioned recommendations will result in some of the more financially strapped customers being more harmed than they otherwise already are. It would also set a terrible precedent surrounding how a utility can game its rate base valuation through selective IRP modeling effectively creating a moral hazard for its captive customers.

The state granting to a monopoly of exclusive franchises with captive customers has strings attached—economic regulation—to ensure safe and reliable service at just, reasonable and affordable rates, and it is incumbent on the Commission to say investors are getting enough and that Empire's ratepayers are paying enough. I continue to recommend the Commission order a disallowance on the remaining undepreciated balance of the AQCS and reject a WACC profit for Empire on the balance of stranded Asbury investment remaining thereafter.

VI. SECURITIZED UTILITY TARIFF CHARGE

Q. What is Empire witness Hall's recommendation on the class allocation of the securitization costs related to Storm Uri?

A. Ms. Hall states:

> Based on the class revenue targets from witness Lyons' rate design which, as he explains in his Direct Testimony filed in Case No.: ER-2021-0312, was established by the Class Cost of Service Study. Specifically, I calculated the percentage of the Company's total distribution revenue requirement that would be contributed by each of Liberty's rate classes and used the result to determine how much of the cost of the securitization bonds should be recovered from each class.[45]

Q. Do you agree with her approach?

A. No. Rate design is not set by statute. These are fuel and purchased power costs that would have flowed through Empire's FAC based on usage had they not been extraordinary. As such, I recommend the kWh charge be uniformly based on usage across classes. Empire witness Hall's recommendation would be overly punitive to the private lighting class. Market rates are generally at the lowest when private lighting uses electricity. There is no compelling cost causative reason for this class to pay more. A uniform per kWh charge can be rationalized in this case based on the nature of the costs that Empire incurred.

[45] Case No. EO-2022-0040 Direct Testimony of Karen S. Hall p. 13, 3-8

Q. Does this conclude your testimony?

A. Yes.

CASE PARTICPATION OF
GEOFF MARKE, PH.D.

Company Name	Employed Agency	Case Number	Issues
Empire District Electric Company d/b/a Liberty	Office of Public Counsel (OPC)	EO-2022-0040	**Rebuttal:** Stranded Asset: Asbury Power Plant, Securitized Utility Tariff Charge
Empire District Gas Company d/b/a Liberty	OPC	GR-2021-0320	**Direct:** Low-Income Programs and Late Fees
Empire District Electric Company d/b/a Liberty	OPC	EU-2021-0274	**Rebuttal:** Accounting Authority Order Storm Uri
Evergy Missouri West	OPC	EO-2022-0061	**Rebuttal:** Special High Load Factor Market Rate for a Data Center Facility
Empire District Electric Company d/b/a Liberty	OPC	ER-2021-0312	**Direct:** Cost and Quality of Service, Stranded Asset, Customer Savings Plan, AMI, Low-Income Recommendations, Late Fees, Data Privacy & Green Button **Rebuttal**: Customer Experience, Stranded Assets, T&D Investments, CCOS, Rate Design **Surrebuttal**: Stranded Asset, Wind Investments, Resource Adequacy, Peer Ranking, Billing, Community Involvement, Low Income Programs, Late Fees, Data Access, PISA
Empire District Electric Company /Evergy Metro / Evergy West /Union Electric Company d/b/a Ameren Missouri	OPC	EO-2022-0057 EO-2022-0056 EO-2022-0055 EO-2022-0054	**Memo:** "Economic" Generation / Additive Manufacturing / Urban Heat Island
Evergy Missouri West & Evergy Missouri Metro	OPC	EO-2021-0349 EO-2021-0350	**Memo:** TOU Rate Design Report Evergy Missouri West & Evergy Missouri Metro Comments
Union Electric Company d/b/a Ameren Missouri	OPC	GR-2021-0241	**Direct**: AMI, PAYS, Late Fees, Low-Income Recommendations **Rebuttal**: COVID-19 Response, Customer Affordability, Residential Rate Design, Decoupling Tracker, 12M Aluminum Smelter Rate, Class Cost of Services Studies, Low-Income Programs, Community Solar, Green Button **Surrebuttal**: High Prairie Wind Farm, PISA, Voltage Optimization, Rate Design, CCOS, Advertising, Low-Income Programs, Late Fees
Union Electric Company d/b/a Ameren Missouri	OPC	ER-2021-0240	**Direct:** Wind Farm (High Prairie), Plant-In-Service-Accounting, Cryptocurrency,

			Advertising, EEI Dues, Keeping Current, Late Fees
Working Case: FERC 2222 Regarding Participation of DER Aggregators into the RTOs	OPC	EW-2021-0267	**Memo:** Aggregators of Retail Customers (ARCs) for Commercial & Industrial Demand Response
Evergy Missouri West & Evergy Missouri Metro	OPC	ET-2021-0151	**Rebuttal:** EV subsidies and EV charging stations **Surrebuttal**: Response to ChargePoint
Spire Missouri Inc.	OPC	GR-2021-0108	**Direct:** AMI, Corporate Governance: Workplace Discrimination **Rebuttal**: Subsidized Natural Gas Expansion / Multi-Family Pilot / Energy Efficiency / Rate Design / Low-Income Programs **Surrebuttal**: AMI / AMI Opt-Out / Corporate Governance: Workplace Discrimination / Propane Storage / Research and Development / Bad Debt & Uncollectable / Rate Design
Empire District Electric Company /Kansas City Power & Light & KCP&L Greater Missouri Operations Company/Union Electric Company d/b/a Ameren Missouri	OPC	EO-2021-0069 EO-2021-0068 EO-2021-0067 EO-2021-0066	**Memorandum:** Impact of falling energy market prices in SPP(Metro, West, and Empire specific) / Reliable Power / Additive Manufacturing ("AM" or 3D Printing") / Virtual Power Plants / Small Modular Reactors / Combustion Turbine Conversion to Combined Cycle Units / Grain Belt Express Energy / Long Duration Storage **Memorandum:** Response to Sierra Club's Evergy Metro and West Recommendations **Memorandum:** Response to Sierra Club and NRDC's Ameren Missouri Recommendations
Missouri American Water	OPC	WR-2020-0344	**Direct:** COVID-19 / Future Test Year/ Cost Allocation Manual and Affiliate Transaction Rules for Large Water Utilities **Direct:** Rate Design **Surrebuttal:** Policy / Future Test Year / Affiliate Transactions Rule / Consolidated Tariff Pricing / Rate Design / Lead Line Replacement
Evergy Missouri West & Evergy Missouri Metro	OPC	EO-2020-0227	**Rebuttal:** Inefficient Management / Residential Demand Response **Surrebuttal:** Demand Response Programs
Working Case: To consider best practices for recovery of past-due utility customer	OPC	AW-2020-0356	**Memorandum:** Response to Staff Report on COVID-19 Past-Due Utility Customer Payments

payments after the COVID-19 pandemic			
Spire Missouri Inc.	OPC	GO-2020-0416	**Memorandum:** Notice of prudency concerns regarding natural gas Advanced Metering Infrastructure ("AMI") investment
Evergy Missouri West & Evergy Missouri Metro	OPC	EU-2020-0350	**Rebuttal:** Authorized Accounting Order for: Lost Revenues /COVID-19 Expenses / Bad Debt Expense **Surrebuttal:** Disconnection Moratorium / Arrearage Management Plans / Economic Relief Pilot Program / Outreach / Energy Efficiency / Administrative Procedures
Empire District Electric Company	OPC	EO-2020-0284	**Memorandum:** Customer Savings Plan / Stateline Combined Cycle Upgrade / DSM / COVID-19 Impact on Modeling / Executive Order on Securing the US Bulk-Power System / SPP Effective Load Carrying Capability / All-Source RFP
Evergy Missouri West	OPC	EO-2020-0281	**Memorandum:** Wind Power PPAs / DSM / COVID-19 Impact on Modeling / Executive Order on Securing the US Bulk-Power System / SPP Effective Load Carrying Capability / Utility-Scale Solar / All-Source RFP
Evergy Missouri Metro	OPC	EO-2020-0280	**Memorandum:** Wind Power PPAs / DSM / COVID-19 Impact on Modeling / Executive Order on Securing the US Bulk-Power System / SPP Effective Load Carrying Capability / Utility-Scale Solar / All-Source RFP
Empire District Electric Company	OPC	ER-2019-0374	**Direct:** Cost and Quality of Service, Stranded Asset, AMI/CIS deployment **Rebuttal**: Customer Experience / Weather Normalization Rider / Energy Efficiency / Low-Income Pilot Program **Rebuttal:** Class Cost of Service / Rate Design / Low Income Pilot Program **Surrebuttal:** Cost and Quality of Service / Reliability Metrics / Asbury Power Plant / Rate Design & CCOS / DSM Programs
Union Electric Company d/b/a Ameren Missouri	OPC	EA-2019-0371	**Rebuttal:** Solar + Storage
Union Electric Company d/b/a Ameren Missouri	OPC	ER-2019-0335	**Direct:** Keeping Current Bill Assistance Program **Rebuttal**: Smart Energy Plan, Keeping Current, Coal Power Plants, CCOS, Rate Design, Pure Power RECs

			Surrebuttal: Coal Power Plants
Rule Making	OPC	AW-2020-0148	**Memorandum:** Residential Customer Disconnections and Data Standardization **Presentation:** Service Disconnection Data Standardization Virtual Rulemaking Workshop
Empire District Electric Company /Kansas City Power & Light & KCP&L Greater Missouri Operations Company/Union Electric Company d/b/a Ameren Missouri	OPC	EO-2020-0047 EO-2020-0046 EO-2020-0045 EO-2020-0044	**Memorandum:** Additive Manufacturing, Cement Block Battery Storage, Virtual Power Plant, Customer-Side Renewable Generation, Historical Review of energy forecasts (KCPL, GMO and Empire-Specific) and Rush Island and Labadie Power Plant Environmental Retrofits (Ameren specific)
Union Electric Company d/b/a Ameren Missouri	OPC	EA-2019-0309	**Rebuttal:** Need for the Wind Project/ Economic Valuation / Pre-Site Energy Assessment Omissions
KCP&L Greater Missouri Operations Company & Kansas City Power and Light Company	OPC	EO-2019-0132	**Rebuttal:** Response to KCPL's MEEIA application, Equitable Energy Efficiency Baseline, WattTime: Automated Emissions Reduction, PAYS, Urban Heat Island Mitigation **Surrebuttal**: Market Potential Study, Single Family Low-Income
KCP&L Greater Missouri Operations Company	OPC	EC-2019-0200	**Surrebuttal:** Deferral Accounting and Stranded Assets
Union Electric Company d/b/a Ameren Missouri	OPC	ED-2019-0309	**Memorandum:** on the "Aluminum Smelter Rate"
Empire District Electric Company	OPC	EO-2019-0046	**Memorandum:** Response to The Empire District Electric Company d/b/a Liberty Plant In Service Accounting (PISA) Report
KCP&L Greater Missouri Operations Company	OPC	EO-2019-0067	**Rebuttal:** Renewable Energy Credits
Union Electric Company d/b/a Ameren Missouri	OPC	EO-2019-0314	**Memorandum:** Notice of Deficiency to Annual IRP Update
Rule Making	OPC	WX-2019-0380	**Memorandum:** on Affiliate Transaction Rules for Water Corporations
Working Case: Evaluate Potential Mechanisms for Facilitating Installation of Electric Vehicle Charging Stations	OPC	EW-2019-0229	**Memorandum:** on Policy Surrounding Electric Vehicles and Electric Vehicle Charging Stations
Rule Making	OPC	EX-2019-0050	**Memorandum** on Solar Rebates and Low Income Customers
Union Electric Company d/b/a Ameren Missouri	OPC	GR-2019-0077	**Direct:** Billing Practices **Rebuttal**: Rate Design, Decoupling, Energy Efficiency, Weatherization, CHP

Empire District Electric Company	OPC	EA-2019-0010	**Rebuttal:** Levelized Cost of Energy, Wind in the Southwest Power Pool **Surrebuttal**: SPP Market Conditions, Property Taxes, Customer Protections
Empire District Electric Company /Kansas City Power & Light & KCP&L Greater Missouri Operations Company/Union Electric Company d/b/a Ameren Missouri	OPC	EO-2019-0066 EO-2019-0065 EO-2019-0064 EO-2019-0063	**Memorandum:** Additive Manufacturing and Cement Block Battery Storage (IRP: Special Contemporary Topics)
Working Case: Allocation of Solar Rebates from SB 564	OPC	EW-2019-0002	**Memorandum** on Solar Rebates and Low Income Customers
Rule Making Workshop	OPC	AW-2018-0393	**Memorandum:** Supplemental Response to Staff Questions pertaining to Rules Governing the Use of Customer Information
Union Electric Company d/b/a Ameren Missouri	OPC	ET-2018-0132	**Rebuttal:** Line Extension / Charge Ahead – Business Solutions / Charge Ahead – Electric Vehicle Infrastructure **Supplemental Rebuttal:** EV Adoption Performance Base Metric
Union Electric Company d/b/a Ameren Missouri	OPC	EO-2018-0211	**Rebuttal:** MEEIA Cycle III Application **Surrebuttal:** Cost Effectiveness Tests / Equitable Energy Efficiency Baseline
Union Electric Company d/b/a Ameren Missouri	OPC	EA-2018-0202	**Rebuttal:** Renewable Energy Standard Rate Adjustment Mechanism/Conservation **Surrebuttal:** Endangered and Protected Species
Kansas City Power & Light & KCP&L Greater Missouri Operations Company	OPC	ER-2018-0145 ER-2018-0146	**Direct:** Smart Grid Data Privacy Protections **Rebuttal:** Clean Charge Network / Community Solar / Low Income Community Solar / PAYS/ Weatherization/Economic Relief Pilot Program/Economic Development Rider/Customer Information System and Billing **Rebuttal:** TOU Rates / IBR Rates / Customer Charge / Restoration Charge **Surrebuttal:** KCPL-GMO Consolidation / Demand Response / Clean Charge Network / One CIS: Privacy, TOU Rates, Billing & Customer Experience
Union Electric Company d/b/a Ameren Missouri	OPC	ET-2018-0063	**Rebuttal:** Green Tariff
Liberty Utilities	OPC	GR-2018-0013	**Surrebuttal:** Decoupling

Empire District Electric Company	OPC	EO-2018-0092	**Rebuttal:** Overview of proposal/ MO PSC regulatory activity / Federal Regulatory Activity / SPP Activity and Modeling / Ancillary Considerations **Surrebuttal** Response to parties **Affidavit** in opposition to the non-unanimous stipulation and agreement
Great Plains Energy Incorporated, Kansas City Power & Light Company, KCP&L Greater Missouri Operations Company, and Westar Energy, Inc.	OPC	EM-2018-0012	**Rebuttal:** Merger Commitments and Conditions / Outstanding Concerns
Missouri American Water	OPC	WR-2017-0285	**Direct:** Future Test Year/ Cost Allocation Manual and Affiliate Transaction Rules for Large Water Utilities / Lead Line Replacement **Direct:** Rate Design / Cost Allocation of Lead Line Replacement **Rebuttal**: Lead Line Replacement / Future Test Year/ Decoupling / Residential Usage / Public-Private Coordination **Rebuttal**: Rate Design **Surrebuttal**: Affiliate Transaction Rules / Decoupling / Inclining Block Rates / Future Test Year / Single Tariff Pricing / Lead Line Replacement
Missouri Gas Energy / Laclede Gas Company	OPC	GR-2017-0216 GR-2017-0215	**Rebuttal:** Decoupling / Rate Design / Customer Confidentiality / Line Extension in Unserved and Underserved Areas / Economic Development Rider & Special Contracts **Surrebuttal:** Pay for Performance / Alagasco & EnergySouth Savings / Decoupling / Rate Design / Energy Efficiency / Economic Development Rider: Combined Heat & Power
Indian Hills Utility	OPC	WR-2017-0259	**Direct:** Rate Design
Rule Making	OPC	EW-2018-0078	**Memorandum:** Cogeneration and net metering - Disclaimer Language regarding rooftop solar
Empire District Electric Company	OPC	EO-2018-0048	**Memorandum:** Integrated Resource Planning: Special Contemporary Topics Comments
Kansas City Power & Light	OPC	EO-2018-0046	**Memorandum:** Integrated Resource Planning: Special Contemporary Topics Comments

KCP&L Greater Missouri Operations Company	OPC	EO-2018-0045	**Memorandum:** Integrated Resource Planning: Special Contemporary Topics Comments
Missouri American Water	OPC	WU-2017-0296	**Direct:** Lead line replacement pilot program **Rebuttal:** Lead line replacement pilot program **Surrebuttal:** Lead line replacement pilot program
KCP&L Greater Missouri Operations Company	OPC	EO-2017-0230	**Memorandum** on Integrated Resource Plan, preferred plan update
Working Case: Emerging Issues in Utility Regulation	OPC	EW-2017-0245	**Memorandum** on Emerging Issues in Utility Regulation / **Presentation**: Inclining Block Rate Design Considerations **Presentation**: Missouri Integrated Resource Planning: And the search for the "preferred plan." **Memorandum**: Draft Rule 4 CSR 240-22.055 DER Resource Planning
Rule Making	OPC	EX-2016-0334	**Memorandum** on Missouri Energy Efficiency Investment Act Rule Revisions
Great Plains Energy Incorporated, Kansas City Power & Light Company, KCP&L Greater Missouri Operations Company, and Westar Energy, Inc.	OPC	EE-2017-0113 / EM-2017-0226	**Direct**: Employment within Missouri / Independent Third Party Management Audits / Corporate Social Responsibility
Union Electric Company d/b/a Ameren Missouri	OPC	ET-2016-0246	**Rebuttal**: EV Charging Station Policy **Surrebuttal**: EV Charging Station Policy
Kansas City Power & Light		ER-2016-0285	**Direct:** Consumer Disclaimer **Direct:** Response to Commission Directed Questions **Rebuttal:** Customer Experience / Greenwood Solar Facility / Dues and Donations / Electric Vehicle Charging Stations **Rebuttal:** Class Cost of Service / Rate Design **Surrebuttal:** Clean Charge Network / Economic Relief Pilot Program / EEI Dues / EPRI Dues
Union Electric Company d/b/a Ameren Missouri	OPC	ER-2016-0179	**Direct:** Consumer Disclaimer / Transparent Billing Practices / MEEIA Low-Income Exemption **Direct**: Rate Design **Rebuttal:** Low-Income Programs / Advertising / EEI Dues

			Rebuttal: Grid-Access Charge / Inclining Block Rates /Economic Development Riders
KCP&L Greater Missouri Operations Company	OPC	ER-2016-0156	**Direct:** Consumer Disclaimer **Rebuttal:** Regulatory Policy / Customer Experience / Historical & Projected Customer Usage / Rate Design / Low-Income Programs **Surrebuttal:** Rate Design / MEEIA Annualization / Customer Disclaimer / Greenwood Solar Facility / RESRAM / Low-Income Programs
Empire District Electric Company, Empire District Gas Company, Liberty Utilities (Central) Company, Liberty Sub-Corp.	OPC	EM-2016-0213	**Rebuttal:** Response to Merger Impact **Surrebuttal:** Resource Portfolio / Transition Plan
Working Case: Polices to Improve Electric Regulation	OPC	EW-2016-0313	**Memorandum** on Performance-Based and Formula Rate Design
Working Case: Electric Vehicle Charging Facilities	OPC	EW-2016-0123	**Memorandum** on Policy Considerations of EV stations in rate base
Empire District Electric Company	OPC	ER-2016-0023	**Rebuttal:** Rate Design, Demand-Side Management, Low-Income Weatherization **Surrebuttal:** Demand-Side Management, Low-Income Weatherization, Monthly Bill Average
Missouri American Water	OPC	WR-2015-0301	**Direct:** Consolidated Tariff Pricing / Rate Design Study **Rebuttal:** District Consolidation/Rate Design/Residential Usage/Decoupling **Rebuttal**: Demand-Side Management (DSM)/ Supply-Side Management (SSM) **Surrebuttal:** District Consolidation/Decoupling Mechanism/Residential Usage/SSM/DSM/Special Contracts
Working Case: Decoupling Mechanism	OPC	AW-2015-0282	**Memorandum:** Response to Comments
Rule Making	OPC	EW-2015-0105	Missouri Energy Efficiency Investment Act Rule Revisions, Comments
Union Electric Company d/b/a Ameren Missouri	OPC	EO-2015-0084	Triennial Integrated Resource Planning Comments

Union Electric Company d/b/a Ameren Missouri	OPC	EO-2015-0055	**Rebuttal**: Demand-Side Investment Mechanism / MEEIA Cycle II Application **Surrebuttal**: Potential Study / Overearnings / Program Design **Supplemental Direct:** Third-party mediator (Delphi Panel) / Performance Incentive **Supplemental Rebuttal:** Select Differences between Stipulations **Rebuttal:** Pre-Pay Billing
The Empire District Electric Company	OPC	EO-2015-0042	Integrated Resource Planning: Special Contemporary Topics Comments
KCP&L Greater Missouri Operations Company	OPC	EO-2015-0041	Integrated Resource Planning: Special Contemporary Topics Comments
Kansas City Power & Light	OPC	EO-2015-0040	Integrated Resource Planning: Special Contemporary Topics Comments
Union Electric Company d/b/a Ameren Missouri	OPC	EO-2015-0039	Integrated Resource Planning: Special Contemporary Topics Comments
Kansas City Power & Light	OPC	ER-2014-0370	**Direct** (Revenue Requirement): Solar Rebates **Rebuttal:** Rate Design / Low-Income Weatherization / Solar Rebates **Surrebuttal:** Economic Considerations / Rate Design / Cyber Security Tracker
Rule Making	OPC	EX-2014-0352	**Memorandum** Net Metering and Renewable Energy Standard Rule Revisions,
The Empire District Electric Company	OPC	ER-2014-0351	**Rebuttal:** Rate Design/Energy Efficiency and Low-Income Considerations
Rule Making	OPC	AW-2014-0329	Utility Pay Stations and Loan Companies, Rule Drafting, Comments
Union Electric Company d/b/a Ameren Missouri	OPC	ER-2014-0258	**Direct:** Rate Design/Cost of Service Study/Economic Development Rider **Rebuttal:** Rate Design/ Cost of Service/ Low Income Considerations **Surrebuttal:** Rate Design/ Cost-of-Service/ Economic Development Rider
KCP&L Greater Missouri Operations Company	OPC	EO-2014-0189	**Rebuttal:** Sufficiency of Filing **Surrebuttal:** Sufficiency of Filing
KCP&L Greater Missouri Operations Company	OPC	EO-2014-0151	Renewable Energy Standard Rate Adjustment Mechanism (RESRAM) Comments
Liberty Natural Gas	OPC	GR-2014-0152	**Surrebuttal:** Energy Efficiency
Summit Natural Gas	OPC	GR-2014-0086	**Rebuttal:** Energy Efficiency **Surrebuttal:** Energy Efficiency
Union Electric Company d/b/a Ameren Missouri	OPC	ER-2012-0142	**Direct:** PY2013 EM&V results / Rebound Effect **Rebuttal:** PY2013 EM&V results **Surrebuttal:** PY2013 EM&V results

			Direct: Cycle I Performance Incentive **Rebuttal:** Cycle I Performance Incentive
Kansas City Power & Light	Missouri Public Service Commission Staff	EO-2014-0095	**Rebuttal:** MEEIA Cycle I Application testimony adopted
KCP&L Greater Missouri Operations Company	Missouri Division of Energy (DE)	EO-2014-0065	Integrated Resource Planning: Special Contemporary Topics Comments
Kansas City Power & Light	DE	EO-2014-0064	Integrated Resource Planning: Special Contemporary Topics Comments
The Empire District Electric Company	DE	EO-2014-0063	Integrated Resource Planning: Special Contemporary Topics Comments
Union Electric Company d/b/a Ameren Missouri	DE	EO-2014-0062	Integrated Resource Planning: Special Contemporary Topics Comments
The Empire District Electric Company	DE	EO-2013-0547	Triennial Integrated Resource Planning Comments
Working Case: State-Wide Advisory Collaborative	OPC	EW-2013-0519	**Presentation:** Does Better Information Lead to Better Choices? Evidence from Energy-Efficiency Labels **Presentation:** Customer Education & Demand-Side Management **Presentation:** MEEIA: Strengths, Weaknesses, Opportunities and Threats (SWOT) Analysis
Independence-Missouri	OPC	Indy Energy Forum 2014	**Presentation:** Energy Efficiency
Independence-Missouri	OPC	Indy Energy Forum2015	**Presentation:** Rate Design
NARUC – 2017 Winter, Washington D.C.	OPC	Committee on Consumer Affairs	**Presentation:** PAYS Tariff On-Bill Financing
NASUCA – 2017 Mid-Year, Denver	OPC	Committee on Water Regulation	**Presentation:** Regulatory Issues Related to Lead-Line Replacement of Water Systems
NASUCA – 2017 Annual Baltimore,	OPC	Committee on Utility Accounting	**Presentation:** Lead Line Replacement Accounting and Cost Allocation
NARUC – 2018 Annual, Orlando	OPC	Committee on Consumer Affairs	**Presentation:** PAYS Tariff On-Bill Financing Opportunities & Challenges
Critical Consumer Issues Forum (CCIF)—New Orleans	OPC	Examining Polices for Delivering Smart Mobility	**Presentation:** Missouri EV Charging Station Policy in 4 Acts: Missouri Office of the Public Counsel Perspective
Michigan State, Institute of Public Utilities, 2019	OPC	Camp NARUC: Fundamentals	**Presentation:** Revenue Requirement
NARUC/US AID, Republic of North Macedonia, Skopje 2019	OPC	NARUC /US AID: Cybersecurity	**Presentation:** Case Study: The Missouri Experience, Cybersecurity and Data Privacy

Kansas, Clean Energy Business Council ("CEBC"), 2020	OPC	Climate and Energy Project	**Presentation:** Energy Efficiency and Pay as You Save (PAYS)
Michigan State, Institute of Public Utilities, 2020	OPC	Camp NARUC: Fundamentals	**Presentation:** Fundamentals of Economic Regulation / Performance Base Regulation
Renew Missouri	OPC	MoBar Continued Learning Education Credit	**Presentation:** Regulatory Incentives and Utility Performance
Missouri Bar Association	OPC	MoBar Fall Environmental & Energy Law Committee	**Presentation:** The Virus, The Economy and Regulated Utility Service: An Overview of Utilities and Stakeholders Response to COVID-19 and the Recession to Date
University of Missouri and City of Columbia, MO., 2021	OPC	Advancing Renewables in the Midwest	**Presentation:** The Heat Is On: Demand Side Management of Urban Heat Islands
NARUC/US AID, Indonesia, Jakarta 2021	OPC	Indonesia Ministry of Energy and Mineral Resources (MEMR)	**Presentation**: Introduction to Tariff Setting & Review: Utility Revenue Requirement, Cost Allocation & Rate Design
Michigan State, Institute of Public Utilities, 2021	OPC	Camp NARUC: Fundamentals	**Presentation**: Fundamentals of Economic Regulation
National Community Action Partnership	OPC	2022 Management Leadership & Training Conference	**Presentation:** Maximizing Weatherization Funds in Public Utility Commission Proceedings
Rocky Mountain Institute 2022	OPC	E-Accelerator Electricity Innovation Lab (Champion)	**Presentation:** Project Voltron (First Statewide Inclusive Utility Investment Program)
The American Council for an Energy-Efficient Economy (ACEEE)	OPC	2022 Energy Efficiency Finance Forum	**Presentation:** When You Build It . . . A Case Study of Pay As You Save (PAYS) at Scale

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1200 Pennsylvania Ave, NW.
Washington D.C. 20460

Re: Missouri Public Service Commission's Comments on the Clean Power Plan Proposed Rule under Section 111(d) of the Clean Air Act, Docket ID:EPA-HQ-OAR-2013-0602

Dear Administrator McCarthy:

The Missouri Public Service Commission (MoPSC), respectfully submits this letter and the attached comments to articulate its position on the Clean Power Plan Proposed Rule developed under Section 111(d) of the Clean Air Act (CAA), 42 U.S.C. §7411.

The MoPSC, through regulation of Missouri's investor owned utilities (IOUs), ensures safe and adequate service at just and reasonable rates. The MoPSC is the state agency responsible for setting rates for the IOUs, for administering the Missouri Renewable Energy Standard (RES), Mo. Rev. Stat. § 393.1020 to 393.1030, and the Missouri Energy and Efficiency Investment Act (MEEIA), Mo. Rev. Stat. § 393.1075, as well as ensuring resource adequacy through the MoPSC's integrated resource planning process, 4 CSR 240-22.010 to 240-22.080.

The MoPSC offers these comments to provide suggestions aimed at improving the rule and to express some concerns with the proposed rule. These concerns include: the ability to reach the interim goal; the ability to improve heat rate efficiencies of thermoelectric generating units; and the ability of the existing interstate pipeline to handle increased capacity associated with new natural gas combined cycle (NGCC) generation. These comments also provide the MoPSC's analysis related to complying with renewable energy standards and demand-side energy efficiency program guidelines; a discussion of questions that need to be addressed when considering a regional or multi-state approach; transmission issues; providing credit for coal plant retirements; and the ability of efficiencies achieved in the water sector that reduce carbon emissions to be credited for state compliance.

To meet the EPA interim goal, Missouri would need to develop a state compliance plan taking into account the time needed to finance, permit, construct or commission new generation. The MoPSC notes that the interim goal does not adequately take into account potential delays in timing due to right-of-way obtainment or construction of new pipelines, transmission or generation facilities, which may be needed to achieve the interim goal. Additionally, accelerated construction to meet aggressive goals may ultimately result in unintended stranded resources.

In response to MoPSC questions, Missouri's investor-owned electric utilities (IOUs) and the Association of Missouri Electric Cooperatives, Inc. (AMEC) indicate that the six percent power plant efficiency is not achievable in part because investments in heat rate efficiency have already been made. Missouri's IOUs estimate that a further heat rate improvement of 1-1.73 percent may be achievable. The EPA should clarify whether the six percent heat rate efficiency goal is a relative increase in efficiency or an absolute increase in efficiency.

Increasing the utilization of NGCC units to seventy percent presents challenges. For instance, natural gas pipelines serving Missouri were designed for winter heating load. These comments question whether existing pipelines have the capacity to serve winter natural gas heating load while simultaneously providing natural gas capacity to off-set displaced coal-fired generation. The cost and timing of constructing additional pipeline capacity to serve new demand should be taken into account in drafting the final rule.

Many of Missouri's existing renewable projects were developed in response to the Missouri RES. The proposed rule, however, does not provide an opportunity for a state to receive credit for pre-2012 renewable energy projects. The MoPSC requests that the final rule allow states to receive credit for early adoption of renewable projects undertaken to meet state renewable portfolio standards, as well as credit for incremental improvements in nuclear and hydropower generation from existing facilities as an option for compliance with state goals.

The most recent IOU integrated resource plans and potential studies assert that the EPA's assumption that a 1.5 percent annual incremental savings rate is unattainable unless Missouri IOUs can meet the maximum achievable potential analysis, which by definition, is the hypothetical upper limit of achievable potential; while MEEIA is measured relative to realistic achievable potential, which establishes a realistic target for demand-side savings that a utility can expect to achieve. AMEC expresses the same concerns noting that in rural areas, energy programs have never achieved a cumulative impact of over 1 percent on an annual basis.

Many Missouri electric utilities own electric generating units that are not located in Missouri and this important geographic element should be acknowledged in the rules as it will be a factor in regional carbon emissions compliance. The regional carbon emissions compliance approach leads to many questions, as discussed in the attached comments that require clarification in the final rules. Additionally, Missouri IOUs participate in two RTOs both of which have indicated that additional transmission resources will be needed for their members' states to comply with the proposed rule. The RTOs have existing processes for the development of regional transmission projects and the MoPSC urges the EPA to be conscious of these processes when drafting the final rule.

Missouri's IOUs have identified several coal-fired power plants for retirement in the next two decades regardless of the adoption of the proposed rule. Retirement of coal-fired generation will result in some amount of corresponding reduction in CO_2 emissions. Therefore, the MoPSC recommends the final rule include a means of capturing the emission off-set for retirement of coal plants.

About two to four percent of the total energy used in the United States is used by water and waste water systems. This equals approximately 187 million MWh per year. Improving water pump and motor efficiency from the existing average of 55 percent to the optimal efficiency of 80 percent would save significant amounts of energy. Such an approach in meeting the state specific goals should be considered by the EPA.

As demonstrated by the attached comments, there are still many issues that need to be addressed before a final rule can be published. To the extent there are any proven flaws in the EPA analyses and assumptions, the EPA should be willing to recalculate the associated state or regional goal(s). More time is likely needed to develop a plan that is mindful of the resource requirements and costs associated with implementation.

In submitting these comments, the MoPSC is not offering an opinion regarding the legality of the EPA's authority to promulgate rules under Section 111(d). Further, nothing in these comments binds the MoPSC in its decisions in any future proceeding. Finally, nothing in these comments binds any other Missouri state agency.

Sincerely,

Robert S. Kenney
Chairman

Stephen M. Stoll
Commissioner

William P. Kenney
Commissioner

Daniel Y. Hall
Commissioner

AA

Enclosures (1)

cc: Sara Parker Pauley, Director
Missouri Department of Natural Resources
Lewis Mills, Director
Missouri Department of Economic Development, Division of Energy
Karl Brooks, Regional Administrator, Region 7
U.S. Environmental Protection Agency

Missouri
Public Service
Commission

Comments on the Environmental Protection Agency “Emission Guidelines for Existing Stationary Sources: Electric Generating Units”

December 1, 2014

Technical Contacts

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Commissioner Scott Rupp voted no on the comments due to his objection to the proposed rule.

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I. Introduction

On June 2, 2014, the Environmental Protection Agency (EPA) released its "Emission Guidelines for Existing Stationary Sources: Electric Generating Units" (proposed rules), proposing guidelines for states to follow in developing plans to address greenhouse gas emissions from existing fossil fuel-fired electric generating units (EGUs). The Missouri Public Service Commission (MoPSC) would like to take this opportunity to thank the EPA for the "broad range of options available to states, including flexibility in timing requirements both for plan submission and compliance deadlines under those plans".[1]

On August 18, 2014, the MoPSC held a workshop and posed several questions to stakeholders related to the potential impacts of the EPA's proposed rules.[2] These comments present a synopsis of issues that were raised in the workshop and subsequent filings, which are of utmost importance to the MoPSC and the State of Missouri, including concerns related to the interim goal; the ability to improve heat rate efficiencies without further clarification; the ability of the existing interstate pipeline to handle increased capacity associated with new natural gas combined cycle (NGCC) generation; concerns related to complying with renewable energy standards and demand-side energy efficiency programs; a discussion of questions that need to be addressed when considering a regional/multi-state approach; transmission issues; and providing credit for coal plant retirements. While the comments may appear to address some aspects of the proposed rules in a vacuum, the MoPSC is cognizant that the EPA has provided flexibility to states in how the various building blocks are used in developing a state plan.

II. Interim goal

The EPA "recognizes that, with many measures, states can achieve emission reductions in the short-term, though the full effects of implementation of other measures, such as demand-side energy efficiency (EE) programs and the addition of renewable energy (RE) generating capacity, can take longer. Thus, the EPA is proposing interim goals that states must meet beginning in 2020. The proposed interim goals would apply over a 2020-2029 phase-in period."[3] In reality, the interim goal is unrealistic. If individual state plan approval is anticipated in June 2017, or perhaps even June 2018 if the state receives an extension, it will be very difficult for states to begin meeting the interim goal in 2020, even if the proposed rule anticipates the interim goal being averaged over 10 years.

The EPA states that "Of the four building blocks considered by the EPA in developing state goals, only the first block, heat rate improvements, involves capital investments at the affected EGUs which, if mandated in a state rule, might give rise to remaining useful life

[1] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34832 (proposed June 18, 2014).

[2] *See, generally*, Docket No. EW-2012-0065, *In the Matter of an Investigation of the Cost to Missouri's Electric Utilities Resulting from Compliance with Federal Environmental Regulations,* accessible at https://www.efis.psc.mo.gov/mpsc

[3] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34837 (proposed June 18, 2014).

considerations at a particular facility. The other building blocks – re-dispatch among affected sources, addition of new generating capacity, and improvement in end-use energy efficiency – do not generally involve capital investments by the owner/operator at the affected EGU".[4] As further discussed throughout these comments, to meet the EPA goals, a state must take into consideration the time needed to finance, permit, construct or commission new generation. The interim goal does not allow for delays in timing due to right-of-way obtainment or construction of new pipelines, transmission or generation facilities as more specifically discussed in these comments.

The EPA notes that timing flexibility, such as that provided with the interim goals, allows states to develop plans that will help states achieve a number of goals including addressing concerns about stranded assets.[5] Yet, in order to effectively meet a state's goals under the proposed timeline, it will be necessary to re-dispatch affected sources or add new generating capacity. Accelerated construction to meet aggressive goals may ultimately result in unintended stranded resources.

III. Building Block 1

In response to MoPSC questions, Missouri's investor-owned electric utilities (IOUs) and the Association of Missouri Electric Cooperatives, Inc. (AMEC) indicate the 6 percent power plant efficiency as reflected in Building Block 1 is not achievable. The IOUs and AMEC have already implemented efficiency improvements. For instance, Ameren Missouri (Ameren) indicates that since 1998 it has upgraded at least one of the steam turbines on 9 of the 12 units in its fleet and the entire turbine train has been replaced on all eight of its largest units. However, projects completed prior to 2012 will not be counted toward the 6 percent heat rate reduction. Ameren estimates that an additional 1-1.5 percent heat rate improvement could be achieved.[6] The Empire District Electric Company (Empire) recently completed efficiency projects for a total heat rate improvement of 4.45 percent. Empire estimates it can achieve another 1.73 percent heat rate reduction.[7] Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company (collectively, KCP&L) identified 35 projects that would decrease the heat rate at its coal-fired generating units, for a total heat rate reduction of 1.6 percent.[8]

On December 16, 2011, the EPA signed the Mercury and Air Toxics Standards (MATS) to reduce emissions of toxic air pollutants from power plants. Compliance with MATS can be accomplished through technologies such as wet and dry scrubbers, dry sorbent injection systems, activated carbon injection systems and fabric filters. These additional plant controls increase plant heat rates that will offset some portion of the heat rate improvements required by the proposed rule.

[4] *Id*. at 34926.
[5] *Id.* at 34897.
[6] Stakeholder Questions – Ameren Missouri Response, Pages 2-3. Case No. EW-2012-0065. August 25, 2014.
[7] Empire's Response to Order Directing Response to Certain Questions, Non-Proprietary Version, Page 1. Case No. EW-2012-0065. August 26, 2014.
[8] Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company's Response to Commission Orders, Exhibit 1 Page 1. Case No. EW-2012-0065. August 25, 2014.

Sierra Club, in its reply to various stakeholder responses, indicates, “the utilities may confuse a relative increase in efficiency with an absolute increase in efficiency", providing the following example.

> An increase in efficiency from 36% to 39% is a relative increase of about 8% (3/36), but an absolute increase of only 3% (39-36). EPA’s Building Block 1 refers to a 6% increase in the heat rate of an affected unit, and therefore requires only a relative 6% improvement and an absolute improvement of slightly over 2%. Associating Building Block 1 with an absolute 6% efficiency improvement, as some utilities may be doing, exaggerates the reductions projected assumed under that Block.[9]

While it appears questionable whether Missouri utilities can meet the anticipated heat rate reductions given the efficiency projects already completed on Missouri’s coal-fired fleet, it is clear there is confusion related to Building Block 1. At a minimum, Building Block 1 requires clarification in the final rules as to whether the heat rate reduction percentage is “relative” or “absolute”.

IV. Building Block 2

Building Block 2 necessitates that coal-fired steam generation and oil/gas-fired steam generation in each state be displaced by increasing generation from existing natural gas combined cycle capacity toward a 70 percent target utilization rate.[10] Natural gas-fired combined-cycle turbines are supplied by fairly large diameter pipelines that have inlet pressures of several hundred pounds. It is estimated that “[a] new 1000 MW combined-cycle gas-fired unit that operates all 24 hours in a day will burn 168,000 MMBtu per day.”[11] To put the capacity concerns in perspective, 168,000 MMBtu per day exceeds the daily peak pipeline capacity contracted by Ameren to serve central Missouri communities and is approximately 25 percent of Laclede Gas Company-St. Louis Division’s contracted interstate pipeline capacity for a cold winter day. (Appendix A is a map depicting natural gas pipelines in Missouri.)

It is important to examine the potential risks associated with an increased dependence on natural gas. Unlike coal and fuel oil, natural gas is not typically stored on site. As a result, real-time delivery of natural gas through a network of pipelines and bulk storage is critical for Building Block 2. Other states along interstate transmission pipelines presumably would also need additional capacity to meet Building Block 2. For instance, along the Panhandle Eastern Pipe Line, extra capacity may not only be needed to meet the capacity of new natural gas-fired power plants in Missouri, but also new capacity in Kansas, Illinois, Indiana, Ohio and Michigan.

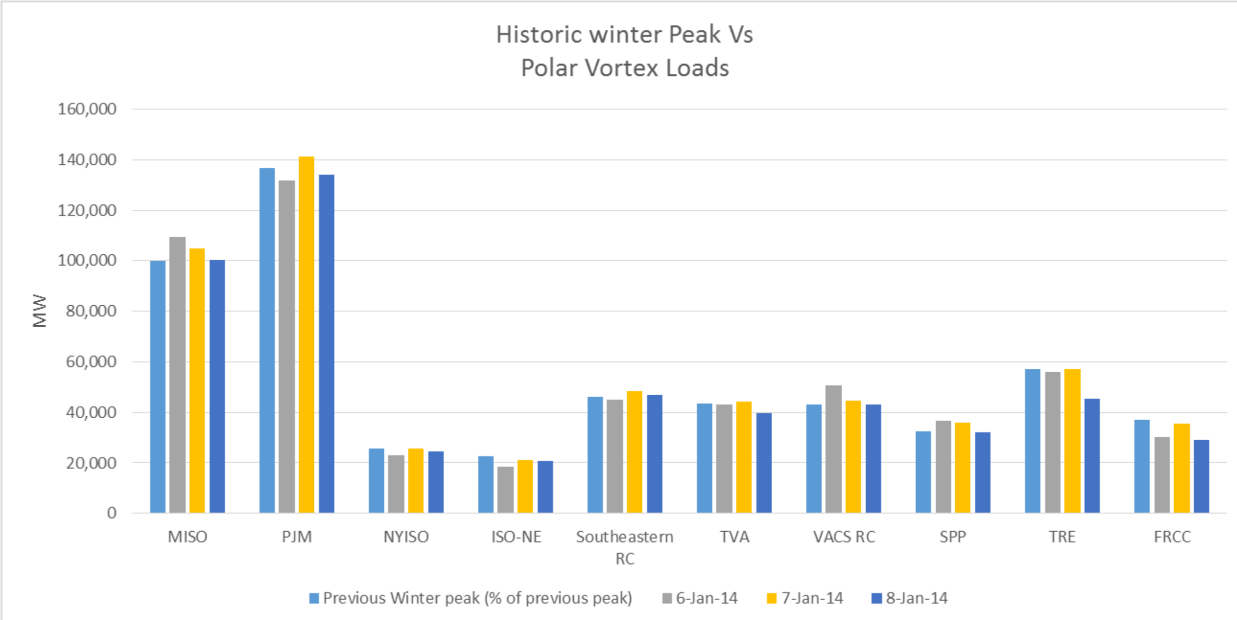
[9] Sierra Club’s Response to Various Stakeholders’ Comments, Pages 1-2. Case No. EW-2012-0065. September 16, 2014.
[10] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34851 (proposed June 18, 2014).
[11] Aspen Environmental Group. Implications of Greater Reliance on Natural Gas for Electricity Generation -Aspen Environmental Group. Pages 6-7.
www.publicpower.org/files/PDFs/ImplicationsOfGreaterRelianceOnNGforElectricityGeneration.pdf

Missouri IOUs operate in the Regional Transmission Organizations/Independent System Operators (RTOs) of the MidContinent Independent System Operators (MISO), Southwest Power Pool (SPP). Missouri rural electric cooperatives operate in Associated Electric Cooperative, Inc. (AECI). The RTO/AECI construct provides for reliability in the transmission network and compensates utilities for economic dispatch of energy. The proposed rules will change the dispatch of generating units by replacing economic generating resources with less economic resources potentially causing higher market clearing prices. Replacing economical dispatch with 70 percent NGCC could result in additional costs and could affect the reliability of the national electric grid. SPP suggests a comprehensive and independent analysis of the impacts of the proposed rules on the reliability of the nation's electric grid.[12] The MoPSC supports this recommendation.

In addition, natural gas pipelines serving Missouri were designed for winter heating load. They do not have the capacity to serve winter natural gas heating load while simultaneously providing natural gas capacity to off-set displaced coal-fired generation. During the winter of 2014, the Midwest, South Central and East Coast regions of North America experienced extreme cold weather conditions known as the polar vortex. The extreme temperatures had a drastic impact on load, with many of the reliability coordinators (i.e., SPP and MISO) reporting record or near record winter peak demands.

As demonstrated by the following graph, system operators had many challenging decisions due to lost capacity from extreme weather conditions exceeding the design of generating units and from lost fuel due to the lack of natural gas transportation. Demand for natural gas increased, resulting in a significant amount of gas-fired generation being unavailable due to curtailments.

[12] Supplemental Responsive Comments of Southwest Power Pool, Inc. Exhibit A. Case No. EW-2012-0065. October 13, 2014.

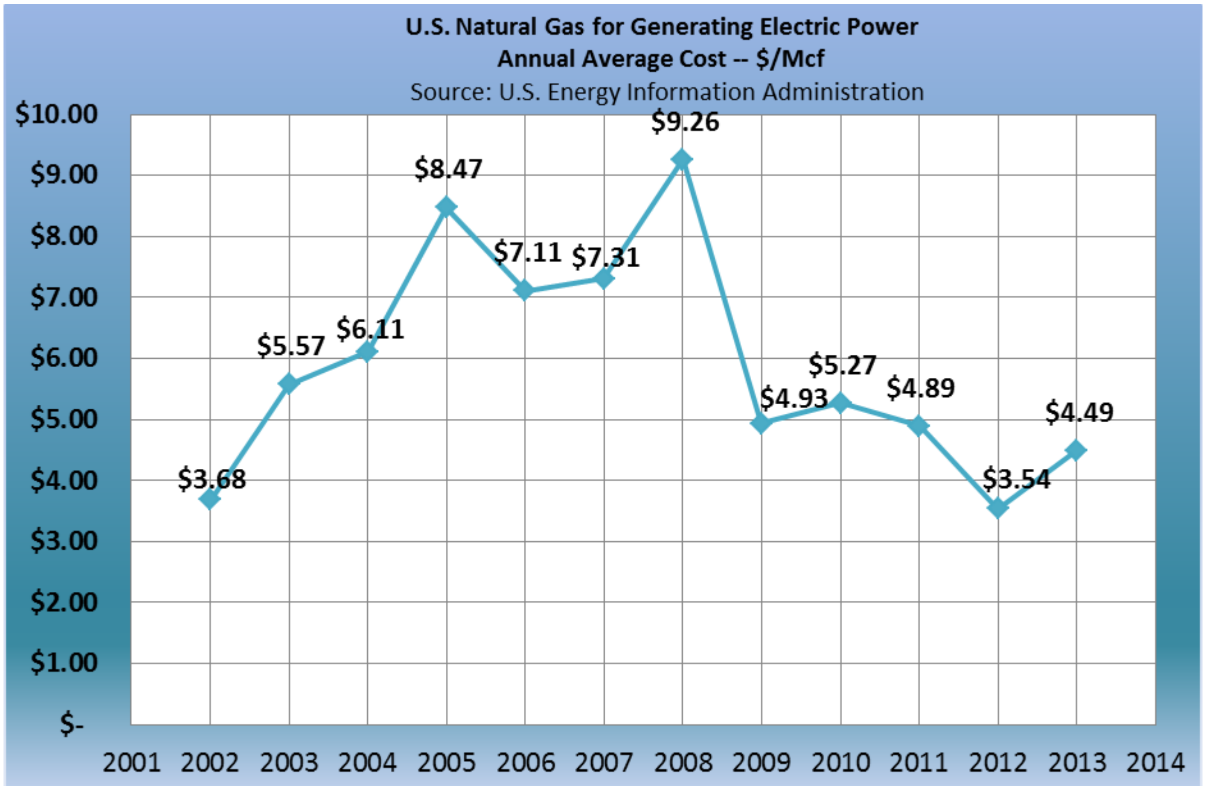


Historic All-Time Winter Peaks vs. Polar Vortex Loads[13]

In the GHG Abatement Measures Technical Support Document[14], the EPA discusses natural gas prices noting that advances in the production of natural gas have helped to reduce natural gas prices, using 2011/2012 in the analysis supporting the proposed rules. As demonstrated by the following chart, 2012 is not representative of natural gas prices, and is in fact represents the lowest price year in the past 12 years. The MoPSC recommends the EPA either select an earlier year where prices were higher or use an average of multiple years to capture the variability in natural gas prices.

[13] *See:* http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf (vii)

[14] *See:* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf



V. Building Block 3

The EPA anticipates that Building Block 3 will reduce CO_2 emissions at all affected EGUs by expanding the amount of lower-carbon generating capacity. According to the EPA, this can be accomplished by completing all nuclear units under construction, avoiding retirement of about six percent of existing nuclear capacity and increasing renewable generation capacity consistent with state renewable portfolio standards.[15]

[15] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34851 (proposed June 18, 2014).

Missouri's Renewable Energy Standard (MoRES), Mo. Rev. Stat. §§ 393.1020 to 393.1030, includes a requirement for all IOUs to generate or purchase electricity generated from renewable energy resources.[16] The MoRES states, "[a]ny renewable mandate required by law shall not raise the retail rates charged to the customers of electric retail suppliers by an average of more than one percent in any year, and all the costs associated with any such renewable mandate shall be recoverable in the retail rates charged by the electric supplier. Solar rebates shall be included in the one percent rate cap provided for in this section."[17]

Many of Missouri's existing renewable projects were developed in response to the MoRES; yet the proposed rules do not provide an opportunity for a state to receive credit for pre-2012 renewable energy projects. Further, the MoRES places a limitation such that any renewable mandate shall not raise IOU retail rates by an average of more than one percent in any year, and all the costs associated with such mandate shall be recoverable in the retail rates of that IOU. The final rules should be cognizant of state mandates that may conflict or cause inconsistencies with federal mandates.

The EPA is proposing that a state be allowed to account for all CO_2 emission reductions from renewable energy measures implemented by the state, whether they occur in the state or in other states.[18] The MoPSC supports this approach. Missouri IOUs have entered into 15 and 20 year agreements to purchase wind from Northeast Iowa and Kansas.[19] Renewables purchased from another state to meet Missouri demand, which are paid for by Missouri ratepayers, should count toward Missouri CO_2 emission reduction.

The EPA acknowledges that state renewable portfolio standards (RPS) requirements allow for interstate trading of RE attributes through the existence of renewable energy credits (RECs) and is seeking comment on how to avoid double counting emission reductions using this approach. The MoRES allows such REC trading as a means of state compliance. One method of compliance would be a system where emission reduction credits are tied to the RECs traded among states.

[16] The portfolio requirement provides that electricity from renewable energy resources constitutes the following portions of each electric utility's sales:

> (1) No less than two percent for calendar years 2011 through 2013;
> (2) No less than five percent for calendar years 2014 through 2017;
> (3) No less than ten percent for calendar years 2018 through 2020; and
> (4) No less than fifteen percent in each calendar year beginning in 2021.
>
> At least two percent of each portfolio requirement is required to be derived from solar energy, unless exempted from this requirement.
>
> A regulated utility may comply with the standard in whole or in part by purchasing renewable energy credits (RECs). Each kilowatt-hour of eligible energy generated in Missouri counts as 1.25 kilowatt-hours for purposes of compliance with the RES.

[17] *See* Mo. Rev. Stat § 393.1045.

[18] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34922 (proposed June 18, 2014).

[19] *See:* http://psc.mo.gov/Electric/Renewable_Energy_Standard_Compliance_Reports.

The EPA also notes that, “[n]uclear generating capacity facilitates CO_2 emission reductions at fossil fuel-fired EGUs by providing carbon-free generation that can replace generation at those EGUs”[20], yet no net credit is given for the remaining useful life of the Callaway Energy Center (Callaway), presumably because “the generation from [this] unit is currently helping to avoid CO_2 emissions from fossil fuel-fired EGUs.”[21] In its comments, Ameren indicated it does not believe Callaway is “at risk” for closure.[22] The EPA should allow a percentage of nuclear generation to be used in meeting a state’s goal for CO_2 emission reduction. Ameren estimates that if, under the proposed rule methodology, Callaway does not achieve a 90 percent capacity factor, Missouri will necessarily be required to meet its goals from other building blocks.[23]

The National Association of Regulatory Utility Commissioners (NARUC), at its 2014 Annual Meeting, passed a resolution urging the EPA, “to the extent it regulates carbon from existing power plants under Section 111(d) of the Clean Air Act” to adopt final rules that: “1) will encourage States to preserve, life-extend, and expand existing nuclear generation; and 2) remove the generic approximately 6 percent at-risk nuclear and nuclear under construction from the calculation of State-specific emissions targets” and indicate “that States may include in compliance plans and thus receive emissions credit related to all output of new nuclear capacity (including uprates of existing plants) that begins operating after the issuance date of the proposed rule.”[24] The MoPSC supports this recommendation.

Similarly, hydropower generation is excluded from the 2012 generation baseline because including “large amounts of existing hydropower generation could distort regional targets that are later applied to states lacking that existing hydropower capacity.”[25] The MoPSC suggests that states should be allowed to consider incremental improvements in nuclear and hydropower generation from existing facilities as an option for compliance with state goals.

VI. Building Block 4

To estimate the potential CO_2 reductions at affected EGUs that could be supported by implementation of Building Block 4, the EPA developed a “best practices” demand-side energy efficiency scenario, which “represents a feasible policy scenario showing the reductions in fossil fuel-fired electricity generation resulting from accelerated use of energy efficiency…consistent with a level of performance that has already been achieved or required by policies…of the

[20] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34870 (proposed June 18, 2014).
[21] *Id* at 34858.
[22] Ameren has filed for a 20-year license extension from the Nuclear Regulatory Commission, which would extend the operation of Callaway through 2044.
[23] Stakeholder Questions – Ameren Missouri Response, Page 7. Case No. EW-2012-0065. August 25, 2014.
[24] *Resolution Recognizing the Importance of Nuclear Power in Meeting Greenhouse Gas Goals*. Sponsored by the Committee on Electricity. Recommended by the NARUC Board of Directors on November 18, 2014. Adopted by the NARUC Committee of the Whole November 19, 2014.
[25] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34867 (proposed June 18, 2014).

leading states."[26] The "leading states" have either achieved, or have policies that will lead them to achieve annual incremental savings rates of at least 1.5 percent; therefore, the EPA determined the 1.5 percent annual incremental savings rate was a reasonable estimate of the energy efficiency policy that can be achieved at reasonable costs by all states.[27]

> The Missouri Energy Efficiency Investment Act (MEEIA), Mo. Rev. Stat. § 393.1075, provides:
> 3. It shall be the policy of the state to value demand-side investments equal to traditional investments in supply and delivery infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs. In support of this policy, the commission shall:
>
> (1) Provide timely cost recovery for utilities;
> (2) Ensure that utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that sustains or enhances utility customers' incentives to use energy more efficiently; and
> (3) Provide timely earnings opportunities associated with cost-effective measurable and verifiable efficiency savings.

It should be noted that MEEIA is voluntary, not mandatory, and only applies to IOUs. There is an expectation that an IOU's demand-side programs can achieve a goal of all cost-effective demand-side savings.[28]

[26] *Id* at 34872.
[27] *Id.*
[28]
1. For 2012: three-tenths percent (0.3%) of total annual energy and one percent (1.0%) of annual peak demand;
2. For 2013: eight-tenths percent (0.8%) of total annual energy and two percent (2.0%) of annual peak demand;
3. For 2014: one-and-five-tenths percent (1.5%) of total annual energy and three percent (3.0%) of annual peak demand;
4. For 2015: two-and-four-tenths percent (2.4%) of total annual energy and four percent (4.0%) of annual peak demand;
5. For 2016: three-and-five-tenths percent (3.5%) of total annual energy and five percent (5.0%) of annual peak demand;
6. For 2017: four-and-eight-tenths percent (4.8%) of total annual energy and six percent (6.0%) of annual peak demand;
7. For 2018: six-and-three-tenths percent (6.3%) of total annual energy and seven percent (7.0%) of annual peak demand;
8. For 2019: eight percent (8.0%) of total annual energy and eight percent (8.0%) of annual peak demand; and
9. For 2020 and for subsequent years, unless additional energy savings and demand savings goals are established by the commission: nine-and-nine-tenths percent (9.9%) of total annual energy and nine percent (9.0%) of annual peak demand for 2020, and then increasing by one-and-nine-tenths percent (1.9%) of total annual energy and by one percent (1.0%) of annual peak demand each year after 2020.

See: Rule 4 CSR 240-20.094(2).

The IOUs are required to submit triennial integrated resource plans (IRPs) with annual updates, that include the principles by which potential demand-side resource options shall be developed and analyzed for cost effectiveness, with a goal of achieving all cost-effective demand-side savings. In addition, when an IOU files for approval of demand-side programs, the IOU must provide a current market potential study which uses primary data and analysis for the utility's service area. Although not subject to MEEIA or the Commission's IRP rules, Missouri cooperatives provide energy efficiency programs designed to meet the needs of their membership. In 2008, AMEC launched its "Take Control and Save Program," which to date has resulted in a projected lifetime kilowatt-hour savings of approximately 1,096,086, 235 kWh.[29] A review of the most recent IRPs and potential studies indicates the EPA's assumption that a 1.5 percent annual incremental savings rate is aggressive unless Missouri IOUs can meet the maximum achievable potential (MAP) analysis. Maximum achievable potential, by definition, is the ***hypothetical upper limit*** of achievable potential; while MEEIA is measured relative to realistic achievable potential which establishes a realistic target for demand-side savings that a utility can expect to achieve.[30] AMEC expresses the same concerns noting that in rural areas, energy programs have never achieved a cumulative impact of over 1 percent on an annual basis.[31]

The EPA requests comment on whether industrial combined heat and power (CHP) approaches warrant consideration as a potential way to avoid affected EGU emissions. The IOUs, in their potential studies, have completed an analysis of CHP. As an example, the KCP&L potential study identified 60 candidate customers for CHP, including customers in the chemicals, food, healthcare, and industrial sectors.[32] The MoPSC recommends CHP be included as a viable option to reduce CO_2 emissions and state credit should include energy savings from CHP projects.

MEEIA also provides opportunity for customers to "opt-out" of IOU demand-side programs when certain criteria are met.[33] The MoPSC suggests that final rules provide flexibility for states to receive credit for non-utility efforts toward reducing CO_2 emissions.

The proposed rule indicates the EPA intends to provide guidance for evaluation, monitoring and verification (EM&V) of renewable energy and demand-side energy efficiency programs and measures. The EPA is requesting comment on whether minimum EM&V requirements could be developed for RE and demand-side EE measures and programs where a

[29] Response of Missouri's Rural Electric Cooperatives, Page 11. Case No. EW-2012-0065. August 26, 2014.
[30] *See:* Rule 4 CSR 240-3.164(2)(A).
[31] Reply Comments of Missouri's Rural Electric Cooperatives, Page 2. Case No. Ew-2012-0065. September 16, 2014.
[32] Direct Testimony of Kim Winslow, Schedule KHS-5, Page 100. Case No. EO-2014-0095. January 7, 2014.
[33] *See:* Rule 4 CSR 240-20.094(6)(A): 1. The customer has one or more accounts within the service territory of the electrical corporation that has a demand of five thousand kilowatts or more; 2. The customer operates an interstate pipeline pumping station, regardless of size; or 3. The customer has accounts within the service territory of the electrical corporation that have, in aggregate, a demand of two thousand five hundred kilowatts or more, and the customer has a comprehensive demand-side or energy efficiency program and can demonstrate an achievement of savings at least equal to those expected from utility-provided programs.

substantial base of experience has been established nationally for the evaluation of measure and program outcomes.[34] As the EPA notes, regardless of the evaluation approach, state public utility commissions or energy efficiency program administrators strive to strike a balance between the transaction costs of EM&V activities (i.e., expense, time and resources) and the reliability, validity and usefulness of the estimated energy savings results.[35] These same principles should apply to EM&V for state compliance plans. Developing minimum EM&V requirements for those programs where outcomes are well-established provides an opportunity to minimize resources expended on EM&V, allowing efforts to concentrate on areas for programs that are less established such as building codes, and programs that alter consumer behavior.

VII. Regional/multi-state approach

Many Missouri electric utilities own electric generating units that are not located in Missouri and this important geographic element should be acknowledged in the rules as it will be a factor in regional carbon emissions. The EPA is proposing that states participating in a multi-state plan submit a single, joint plan on behalf of all the participating states. The individual state performance goals would be replaced with an equivalent multi-state performance goal.[36] This approach leads to many questions that require clarification in the final rules.

Who is responsible for ensuring reliability among the region?

A regional approach to reliability is already established through the RTO construct. As such, the MoPSC suggests the RTO should be responsible for ensuring reliability among the region. Missouri utilities operate in MISO, SPP and AECI. It is not clear how a regional approach will work in a state with multiple operating organizations. The MoPSC suggests it may be more reasonable to allow a state such as Missouri, which has differing organizational participation structures, to develop multiple state plans applicable to meet the requirements of the different regions of the state; thus, aligning the responsibilities of reliability with the applicable RTO structure.

Who is responsible for enforcement of the regional/multi-state goal?

The state environmental agency and the state public utility commission are the entities with experience and knowledge of enforcement at the state level. Therefore, the MoPSC suggests an alliance of each region's state agencies would be best equipped to enforce compliance with regional/multi-state goals.

[34] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34921 (proposed June 18, 2014).
[35] *See:* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-state-plan-considerations.pdf
[36] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34851 (proposed June 18, 2014).

How will a regional or multi-state approach work if some states meet the multi-state performance goal and other states do not meet the performance goal? Are all states penalized? Do the other states in the multi-state approach have to "pick up the slack"?

Although designed as a regional/multi-state approach, the MoPSC suggests that states be held individually accountable for compliance with each state's achievements, or lack thereof, toward contributing to the regional goal. However, a process should be in place to allow for modification of over- and under-compliance with the regional goals allowing states to "share" accomplishments toward the regional goal.

How do states incorporate a RES across borders when different states have different renewable portfolio requirements?

In the proposed rule, the EPA noted "renewable resource potential varies regionally"[37] and, as a result of this assumption, divided the states into six regions when developing the best practices scenarios. Since renewable generation is subject to metering, it should be rather easy to identify the source of generation and, presumably, the EPA's pre-defined grouping would enhance the regions ability to incorporate a RES across borders. However, as previously mentioned, Missouri utilities operate in MISO, SPP and AECI so simply dividing states into regions may not be sufficient. The MoPSC suggests it may be more reasonable to allow a state such as Missouri, to develop multiple state plans combining states in the same organizational participation structure into a region.

It should be noted that, for Missouri, regional compliance is further complicated since the MoRES is subject to the one percent retail rate impact previously discussed.

How do you count EE across borders?

One of the challenges with measuring CO_2 emission reduction associated with energy efficiency is determining the amount of the avoided MWh from the specific program and then quantifying that amount as an emission reduction. As the EPA notes in the draft rules, states already have measurement and verification processes in place. Those processes could be defined through regional protocols designed to measure the impacts of energy efficiency savings at the regional level.

Do states share costs for new plants/upgrades in the region that are designed to meet the regional/multi-state goal?

The MoPSC suggests cost of compliance should apply to all electric customers across the region. If new plants/upgrades in the region are designed to meet the regional-multi-state goal, a portion of the costs associated with those plants/upgrades should be apportioned to each state relative to the contribution the plant/upgrade provides to the corresponding state goal.

[37] *Id* at 34866.

Is there an opportunity for arbitrage between states with different rate structures?

To avoid arbitrage opportunities between states with different rate structures, RTO dispatch formulas will likely need to be revised. However, opportunities for arbitrage may not be limited to regional/multi-state approaches, but also individual state plans. For instance, there may be an opportunity for resource shuffling by importing low-cost renewable resources to replace high CO_2 resources. The MoPSC suggests final rules be drafted to specifically discourage such examples of arbitrage.

VIII. Transmission

MISO and SPP completed analyses on the impact of the proposed rules on their respective regions. MISO's findings indicate that compliance costs in the MISO footprint could be reduced by approximately $3 billion annually by using a regional (MISO-wide) approach to CO_2 emission reductions. MISO also determined that, while compliance might be achieved using the proposed building blocks, other actions, such as building new gas generation, may reduce compliance costs. The MISO study also determined that the most cost-effective means to comply with the proposed rules may be to retire more coal generation than was originally planned to retire under other EPA regulations, such as MATS.[38]

SPP performed a transmission system impact evaluation, first assuming available unused electric generation capacity that currently exists would be used to replace projected retired capacity; and second assuming projected EGU retirements would be replaced by increased output of existing generation and new generation capacity modeled according to resource planning information used in SPP's 10-year transmission planning assessment. The evaluation indicated the SPP region will experience numerous thermal overloads and low voltage occurrences under both scenarios. If assumed EGU retirements were to occur absent corresponding transmission and generation infrastructure improvements, the electric grid would suffer extreme reactive deficiencies, exposing it to widespread reliability risks. The second scenario demonstrated that even with generation capacity added to replace EGU retirements, additional transmission infrastructure will be needed to maintain reliability.[39]

SPP indicates that in its region, as many as eight years have been required to study, plan and construct new transmission facilities. Compliance with the proposed rules becomes an issue if new transmission facilities are required to meet capacity. Capital and financing needs, technical and logistical needs, site permitting and land lease agreement requirements are all issues or constraints that need to be addressed prior to any construction, whether it is construction of additional transmission lines, pipelines or generation facilities.

[38] *See:* https://www.misoenergy.org/Library/Repository/Communication%20Material/EPA%20Regulations/MISOEPACO2EmissionReductionAnalysis.pdf

[39] *See:* Supplemental Responsive Comments of Southwest Power Pool, Inc. Exhibit A. Case No. Ew-2012-0065. October 13, 2014.

IX. Coal retirements

Through the Missouri IRP process, the IOUs choose the preferred resource plan[40] that will "provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance will all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies". Part of the IRP planning process is to identify potential plant retirements over the planning cycle. Ameren's IRP identifies approximately one-third of its coal-fired generating capacity (1,808 MW) that will be retired in the next 20 years. KCP&L identifies retirements of 170 MW in 2016, 195 MW by 2019 and 340 MW in 2021, partially attributable to current or proposed environmental regulations including MATS, Ozone National Ambient Air Quality Standards (NAAQS), Particulate Matter NAAQS, SO_2, NAAQS Clean Water Act Section 316(a) and (b), Effluent Guidelines and Coal Combustion Product Rule. Empire recently retired one coal unit and has plans to retire another 104 MW in mid-2016. Retirement of coal-fired generation will result in some amount of corresponding reduction in CO_2 emissions. Therefore, the MoPSC recommends the final rules include a means of capturing the emission off-set for retirement of coal plants.

X. Energy/Water Nexus

The energy/water nexus provides an additional opportunity for CO_2 emission reductions not contemplated in the proposed rules. About 2-4 percent of the total energy used in the United States is used by water and waste water systems. This equates to approximately 187 million MWh per year.[41] The following chart gives the percentage break down of energy used in delivering safe and reliable water and wastewater services to the public.

ENERGY USED FOR WATER TREATMENT AND DELIVERY	
Ground Water Utility	
Well Pumping	33%
Chlorination	1%
Booster Pumping	66%
Surface Water Utility	
Raw Water Pumping	9%
Treatment	5%
Finished Water Pumping	86%

[42]

It is estimated that improving water pump and motor efficiency from the existing average of 55 percent to the optimal efficiency of 80 percent would save enough electricity to light up

[40] 4 CSR 240-22

[41] American Water Company comments in response to the proposed rules. (EPA-HQ-OAR-2013-0602). November 4, 2014.

[42] "It's Not Just a 'Nexus' – Energizing Water-Energy Integration". Aldie Warnock, Senior Vice President, External Affairs, Communications and Public Policy, American Water. The National Association of Water Companies. October 2014.

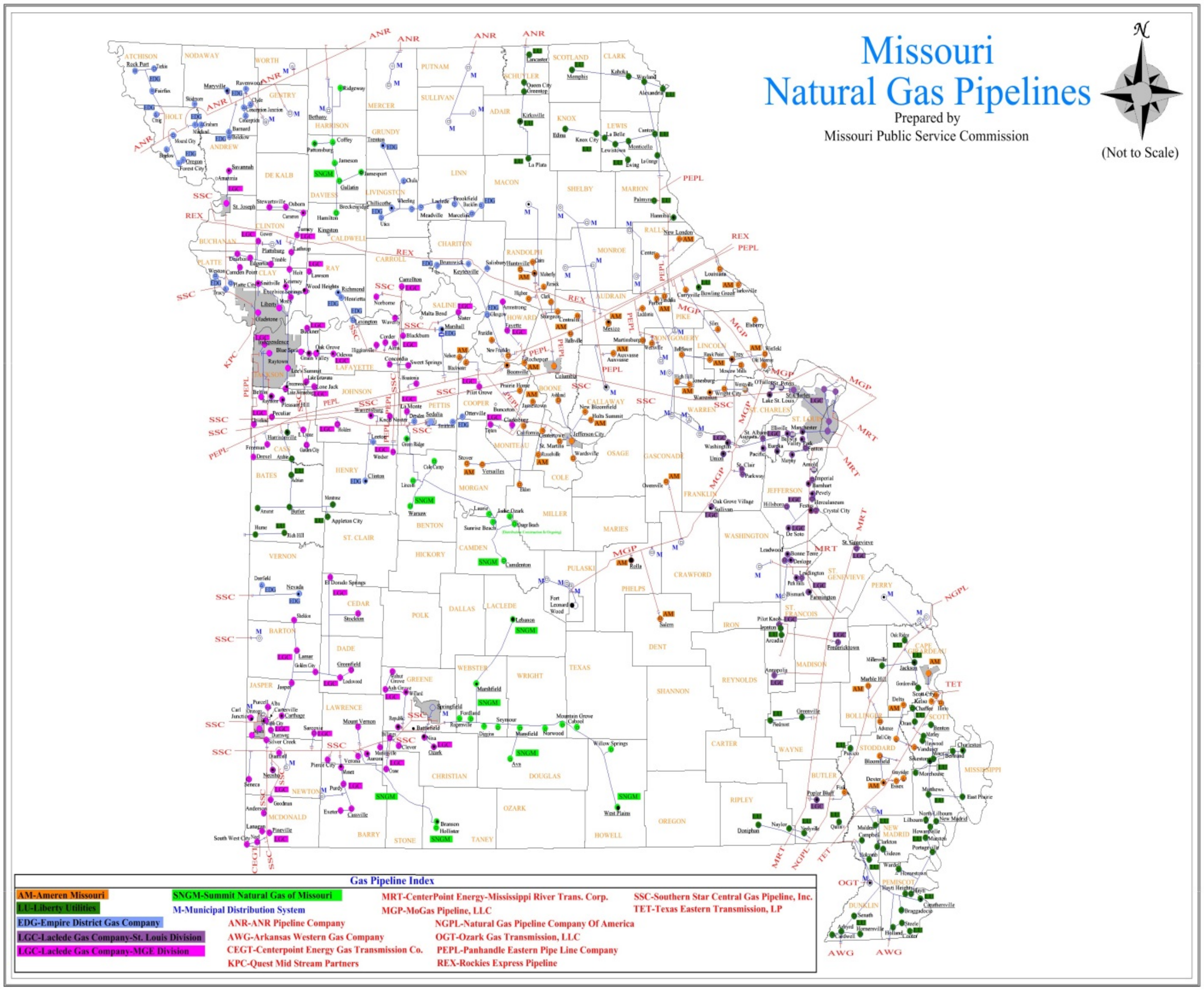
Chicago for over 2 years, enabling the permanent retirement of seven coal-fired plants.[43] Over the last four years, American Water has replaced or refurbished 140 water pumps with more energy efficient pumps. American Water estimates the more efficient pumps will result in energy savings of 12 million kWh per year, for a reduction in CO_2 of 18 million pounds per year.[44] Missouri American Water Company estimates that if it replaced all of its pumps and motors in its St. Louis County system with 10 percent more efficient pumps and motors; it would reduce its carbon footprint by about 13,000 tons per year.[45]

NARUC, at its 2014 Annual Meeting, passed a *Resolution Regarding the Water-Energy Nexus*, which ended, "**RESOLVED**, That, as the EPA moves forward with its proposed rules for reducing carbon emissions from existing stationary sources, NARUC recommends that States be provided maximum flexibility to support energy efficiency measures stemming from the water-energy nexus and to incorporate those efforts, and their positive impacts on the environment, into any compliance plan that might emerge."[46] The MoPSC supports this recommendation. These are quantifiable emission reductions that should be included in the final rules and captured through state plans.

XI. Conclusion

In conclusion, the MoPSC acknowledges the significant efforts the EPA has undertaken to draft proposed rules that provide the states the flexibility and latitude to draft state compliance plans. As demonstrated by these comments, there are still many issues that need to be addressed before a final rule can be published. To the extent there are any proven flaws in the EPA analyses and assumptions, the EPA should be willing to recalculate the associated state or regional goal(s). More time is likely needed to develop a plan that is mindful of the resource requirements and costs associated with implementation.

[43] *Id.*
[44] *Id.*
[45] Energy-Water Nexus comments to Missouri Comprehensive State Energy Plan Steering Committee Meeting. Missouri American Water Company. October 23, 2014.
[46] *Resolution Regarding the Water-Energy Nexus*. Sponsored by the Committees on Energy Resources and the Environment, Gas, and Water. Recommended by the NARUC Board of Directors November 18, 2014. Adopted by the NARUC Committee of the Whole November 19, 2014.


Missouri
Natural Gas Pipelines
Prepared by
Missouri Public Service Commission
(Not to Scale)
N
Gas Pipeline Index
AM-Ameren Missouri
LU-Liberty Utilities
EDG-Empire District Gas Company
LGC-Laclede Gas Company-St. Louis Division
LGC-Laclede Gas Company-MGE Division
SNGM-Summit Natural Gas of Missouri
M-Municipal Distribution System
ANR-ANR Pipeline Company
AWG-Arkansas Western Gas Company
CEGT-Centerpoint Energy Gas Transmission Co.
KPC-Quest Mid Stream Partners
MRT-CenterPoint Energy-Mississippi River Trans. Corp.
MGP-MoGas Pipeline, LLC
NGPL-Natural Gas Pipeline Company Of America
OGT-Ozark Gas Transmission, LLC
PEPL-Panhandle Eastern Pipe Line Company
REX-Rockies Express Pipeline
SSC-Southern Star Central Gas Pipeline, Inc.
TET-Texas Eastern Transmission, LP

Appendix A

Case No. EO-2022-0040
& EO-2022-0193

Schedule GM-3 to

Geoff Marke's

Rebuttal Testimony

has been deemed

"Highly Confidential"

in its entirety

ALGONQUIN
Power & Utilities Corp.

354 Davis Road
Oakville, Ontario
Canada L6J 2X1

October 4, 2019

JEA Procurement Bid Office
21 West Church Street
Customer Center
1st Floor
Jacksonville, Florida
USA 32202

RE: Response to the City of Jacksonville's Invitation to Negotiate in respect of strategic alternative for the Jacksonville Electric Authority .

Ladies & Gentleman,

Algonquin Power & Utilities Corp. ("***APUC***"), on behalf of itself and its affiliates, is pleased to submit this response in respect of the City of Jacksonville's ("**Invitee**") Invitation to Negotiate Strategic Alternatives ("**ITN**") regarding its municipally owned water, wastewater and electric utility, the Jacksonville Electric Authority (the "**JEA**").

1. Contact Information

Please direct correspondence regarding this Proposal to:

Algonquin Power & Utilities Corp. / Liberty Utilities Co.
354 Davis Road, Suite 100
Oakville, Ontario, Canada L6J 2X1

Attn: Ed Pamatat, Vice President, Utility Planning
Tel: 905-465-4551
Email: ed.pamatat@libertyutilities.com

and

Attn: Kevin Melnyk, Vice President, Regulated Infrastructure Development
Tel: 905-465-6718
Email: kevin.melnyk@libertyutilities.com

2. Identity of Representative Authorized to Legally Bind Proponent

APUC's and Liberty's authorized signing officer and representative in respect of this submission is its Chief Executive Officer, Ian Robertson, who's signature is contained in the signature block section of this submission.

3. Legal Name

Algonquin Power & Utilities Corp., through its wholly owned Liberty Utilities Co. subsidiary, is the intended respondent (the "**Respondent**"). APUC is headquartered in Oakville, Ontario, Canada with regional offices throughout the United States from Concord, New Hampshire across to Downey, California.

4. Respondent Information

APUC is a corporation constituted under the laws of Canada on October 24, 2009. APUC is the successor entity of the Algonquin Power Income Fund originally constituted under the Laws of Canada on September 8, 1997. APUC currently owns approximately $9 billion worth of power generation and utility assets. APUC's common shares, Series A preferred shares and Series D preferred shares, and Series A subordinated notes are listed on the Toronto Stock Exchange and/or the New York Stock Exchange. Through two primary business groups, APUC provides rate regulated natural gas, water, and electricity generation, transmission, and distribution utility services to over 766,000 connections across North America, and is committed to being a global leader in the generation of clean energy through its ownership of long term contracted wind, solar and hydroelectric generating facilities representing approximately 1.7 GW of installed capacity.

APUC's rate regulated utility businesses are currently located throughout North America and operated under the Liberty Utilities brand and are organized under its Liberty Utilities Co. subsidiary, a Delaware corporation formed on December 9, 2010, created then to facilitate the pending acquisition of a large block of electric utility assets and to assume ownership of APUC's pre-existing utility assets then held by Liberty Sub Corp., previously known as Algonquin Water Resources of America, which was originally incorporated on March 6, 2001.

5. Respondent's EIN

Liberty's Federal Employer Identification Number is EIN 27-444001.

APUC looks forward to participating in JEA's strategic alternatives development process.

Please feel free to call should you have any questions or require any clarification of the matters contained in this submission.

Yours truly,

For and on behalf of **Algonquin Power & Utilities Corp.**

Ian Robertson
Chief Executive Officer

127-19 APPENDIX A – RESPONSE FORM

Company Name: ALGONQUIN POWER + UTILITIES CORP.

Company's Address 354 DAVIS DRIVE OAKVILLE, ONTARIO L6J-2X1

Phone Number 905 465-4500 FAX No: 905 465 4543 Email Address: ____________

☒ **I have read and understood the Sunshine Law/Public Records clauses contained within this solicitation. I understand that in the absence of a redacted copy my proposal will be disclosed to the public "as-is".**

RESPONDENT CERTIFICATION

By submitting this Response, the Respondent certifies that it has read and reviewed all of the documents pertaining to this Solicitation, that the person signing below is an authorized representative of the Respondent Company, that the Company is legally authorized to do business in the State of Florida, and that the Company maintains in active status an appropriate contractor's license for the work (if applicable). The Respondent also certifies that it complies with all sections (including but not limited to Conflict of Interest) of this Solicitation.

We have received addenda

1 through ALL

Handwritten Signature of Authorized Officer of Company or Agent — Date: OCT 4/19

IAN ROBERTSON CEO

Printed Name and Title

SECTION TWO: Executive Summary

APUC, Algonquin Power & Utilities Corp. ("**APUC**") is not tied to a singular proposal concept in respect of JEA. APUC, through its Liberty Utilities group business unit, wishes to deploy large amounts of capital and to concurrently assert an operational participation in the ongoing operations where it has deployed such capital. Beyond those requirements, infinite permutations of a final arrangement might be agreeable to APUC.

From that previously articulated preference, APUC is not proposing to act in solely a lending moneys capacity nor to relegate its role to passive participation in the operations.

Beyond the aforementioned limitation, APUC is open to exploring a wide range of participation structures, be they the outright purchase of all or some smaller sub component of the JEA operations or assets through to variants of concession or lease arrangements of a time limited duration, in respect of all or some smaller subcomponent of the JEA operations/assets.

APUC is open to the exploration of other transaction constructs that have not yet been envisioned as and when those ideas develop through this strategic alternatives exploration process. APUC is an entrepreneurial-minded organization and has demonstrated capacity to think through and negotiate complex arrangements to find mutually beneficial transaction arrangements and will bring that nimbleness and flexibility to this JEA alternative strategies exploration process.

SECTION THREE: Statement of Interest and Qualifications

APUC is interested in transaction variants that would concurrently allow it to invest significant amounts of capital and concurrently exercise significant operational control.

APUC would be interested in the potential purchase of all of or almost any subcomponent of the JEA operations/assets be that the water utility operation and assets with or without, or alternatively just, the wastewater utility operations and assets. In addition, APUC would be interested in the potential purchase of all or a sub components of the electric system be that the distribution or transmission subcomponents.

APUC would be interested in the purchase of some but not all of the generation operations/assets in a transaction that is independent of the transmission and or distribution operations or assets. APUC has limited interest in the acquisition of legacy thermal electrical generating assets however, would undertake such as part of a larger transaction.

APUC is not interested in acting as a lender or in any capacity that does not include significant operational participation and is not proposing transaction variants that are essentially only recapitalization constructs.

APUC would be interested in and would show preference of a non-purchase transaction constructs of a concession or lease type arrangement that are front loaded or have prepayments obligations, as such furthers the ability to deploy capital earlier rather than later. APUC would be most receptive to such arrangements if they are accompanied by a significant operation role.

APUC would be interested in participating in the above described transaction variants as either the sole counterparty or as a member of a larger consortium where it had a major stake in either the purchase of a subcomponent of the operations/assets or all of the operations/assets. APUC is not interested in participating as a passive minority partner or investor.

APUC has a stated strategy and mandate to aggressively grow its regulated utility business footprint. APUC has successfully executed on this strategy over the past decade with over 40 utility acquisitions. The acquisition of some or all of JEA's operations and assets is consistent with APUC's growth strategy.

Through the successful accumulation of its existing portfolio of regulated utility assets, including the recently completed acquisition of New Brunswick Gas, and a 44% interest in Atlantica Yield PLC, APUC has demonstrated that it is a highly experienced acquirer, with the proven ability to complete due diligence and negotiate mutually acceptable agreements for the acquisition of regulated utility and similar businesses. Furthermore, APUC's unblemished record of successfully consummating every announced acquisition demonstrates a capacity and commitment to obtain all required approvals required to close any transaction it might negotiate here.

SECTION FOUR: Organizational Overview

1. Organization Structure

APUC is a corporation constituted under the laws of Canada with is head office in Oakville, Ontario. APUC is a publically traded entity whose common shares, Series A preferred shares and Series D preferred shares, and Series A subordinated notes are listed on the Toronto Stock Exchange and/or the New York Stock Exchange.

APUC conducts its operations through two primary business groups or subsidiaries, including those entities which hold project assets. Utility operations are conducted through its Liberty Utilities (**"LU"**) subsidiary tower while its electrical generation operations are conducted through its Algonquin Power subsidiary group. The following table lists most of the subsidiaries with short descriptions of the business activities contained therein. The voting securities of each subsidiary are held in the form of common shares, share quotas or partnership interests in the case of partnerships and their foreign equivalents, and units in the case of trusts.

Significant Subsidiaries	Description	Jurisdiction	Ownership of Voting Securities
LIBERTY POWER GROUP			
AAGES (AY Holdings) B.V. (**"AY Holdings"**)	Owner of equity interest in Atlantica	Netherlands	100%
Algonquin Power Co. (or **"APCo"** dba Liberty Power)		Ontario	100%
St. Leon Wind Energy LP (**"St. Leon LP"**)	Owner of the St. Leon Wind Facility	Manitoba	100%
Minonk Wind, LLC		Delaware	100%

	Owner of the Minonk Wind Facility		
Senate Wind, LLC	Owner of the Senate Wind Facility	Delaware	100%
GSG6, LLC	Owner of the Shady Oaks Wind Facility	Illinois	100%
Odell Wind Farm, LLC	Owner of the Odell Wind Facility	Minnesota	100%
Deerfield Wind Energy, LLC	Owner of the Deerfield Wind Facility	Delaware	100%
LIBERTY UTILITIES GROUP			
Liberty Utilities (Canada) Corp. ("**LU Canada**")		Canada	100%
Liberty Utilities Co.		Delaware	100%
Liberty Utilities (CalPeco Electric), LLC	Owner of the CalPeco Electric System	California	100%
Liberty Utilities (Granite State Electric) Corp.	Owner of the Granite State Electric System	New Hampshire	100%
Liberty Utilities (EnergyNorth Natural Gas) Corp.	Owner of the EnergyNorth Gas System	New Hampshire	100%

2. Operational Details

APUC's operations are either rate regulated natural gas, water, and electricity distribution generation, transmission, and distribution utility services or power generation activities. Its power generating activities are from renewable sources of wind, sun or hydro augmented by small amounts of traditional thermal.

3. Financial Details

APUC currently owns and operates approximately U.S. $9B worth of utility and power generation assets. As a publicly traded corporation APUC is an SEC filer and produces audited financial statements which are attached hereto as Appendix A.

4. Number of Current Electric and Water Customers

APUC currently provides rate regulated utility services to over 766,000 connections across North America. A number of these are natural gas utility customers however the majority are electric and water/wastewater utility customers.

5. Union Interaction

APUC has a workforce of over 2,400 employees of which just under 700 are members of three different unions (i.e. UWUA, IBEW, and USW) represented by 14 different bargaining units. APUC has concluded approximately 14 collective bargaining negotiations over the past 10 years. APUC has not experienced a work stoppage or any other material job action associated with these unions relationships.

6. Economic Development Activities

APUC, through its various local utility operations, partners with local, regional, and state economic development organizations to attract, retain, and support the expansion of local businesses. APUC often (i) offers economic development incentives to qualifying businesses in conjunction with other local and state incentives; (ii) administers various educational programs aimed at improving local business competitiveness through efficient energy use; and (iii) administers energy efficiency programs and funds. APUC has approximately 26 individuals employed as Business and Community Development Managers who are located throughout its service territories. These individuals reside in the service territories and are trained to support local businesses to ensure their continued success.

7. Other Relevant Information

APUC is currently an experienced utility owner and operator with a long history of delivering stable, reliable and affordable utility services.

SECTION FIVE: Process Goals

1. Up- front City Benefit

APUC is aware of the City of Jacksonville's desire to realize U.S. $3B of value through this potential transaction from the sale of all of the operations and assets of JEA. APUC's presumption is that this expectation would be prorated for the operations/assets that might ultimately be acquired by APUC. To the extent that the ultimate transaction is different than an outright sale, that being a concession or lease arrangement, the timing and prorated share of such realized value would be proportional.

2. Up-front Customer Benefit

APUC is aware of the City of Jacksonville's desire to see customers realize U.S. $400M of value through this potential transaction from the sale of all of the operations and assets of JEA. APUC's presumption is that this expectation would be prorated for the operations/assets that might ultimately be acquired by APUC in amounts per type of customer connection. To the extent that the ultimate transaction is different than an outright sale, that being a concession or lease arrangement, the timing and prorated share of such realized value would be proportional. APUC does make the observation that a disproportionate amount of such benefit is tied to water focused services and may be difficult to allocate in the context of maintaining rationale rates for those services into the future but that it has not concluded such detailed financial calculations.

3. Rate Stability

APUC would be prepared to commit to rate stability for the initial 3 years under the ultimate arrangement be it an outright sale or a concession type arrangement.

4. Renewable Energy Commitment

APUC is prepared to commit to providing 100% renewable electricity for the City of Jacksonville and the Duval County Public School System. APUC is one of North America's principal developers of renewable energy facilities having built numerous wind and solar facilities. APUC has experience incorporating such renewable power sources with minimal impact on customer rates.

5. Water Source Development

APUC is prepared to develop additional sources of water in the amounts requested in the ITN. APUC has experience developing such source be they from the traditional ground water or surface water source, or from more technically advanced sources such as reverse osmosis treatment of sea or brackish.

6. Employee Retirement Benefits

APUC is prepared to make commitments for the protection of certain employee retirement benefits for an appropriate period of time following closing of a transaction.

7. Employee Compensation Maintenance

APUC is prepared to make commitments for maintenance of substantially comparable employee compensation for a minimum period of 3 years following a transaction.

8. Retention Payments

APUC is prepared to make commitments for the payment of employee retention payments in the amounts as articulated in the ITN.

9. Economic Development Activities

APUC is prepared to make commitments regarding the future location of offices, facilities, and employees' workplace locations related to the JEA operations.

SECTION SIX: Response to Evaluation Criteria

1. Achieve JEA's Goals as articulated in the ITN

Respondent's is aware of the stated goals being 1) the realization of $3 Billion of value for the City of Jacksonville, 2) the realization of $400 Million of value for customers, 3) the realization of 3 years of contractually committed rate stability, 4) a commitment to develop and provide 100% renewable energy to the City and the Duval County Public School system by 2035, 5) commitment to develop 40MDU of alternative water supply capacity, 6) commitment to protect certain employee retirement benefits, 7) commitment to maintain substantially comparable employee compensation and benefits for three year, 8) make retention payments to all full time employees of 100% of current base compensation, 9) commitment to employees , headquarters and contributing to economic development in Jacksonville. Respondent's presumption is that this expectation would be prorated for the operations/assets that might ultimately be acquired by Respondent. To the extent that the ultimate transaction is different than an outright sale, say in the case of a concession or lease arrangement, the timing and prorated share of such realized value would be proportional.

2. Experience and Customer Commitment

a) The Respondent's is currently, and has been for more than the past 10 years, been a real utility holding company with real utility operations and has been the owner and operator of real utility assets that currently serve almost 800,000 customers. These utility connections serve the Respondent's customers with electric distribution, water distribution, wastewater collection or natural gas distribution services. The Respondent handles all aspects of the operation of these utility business with its own employees with minimal outsourcing. These activities include all aspects of customer interaction ranging from general inquirers, service requests, meter reading, bill generation, payment processing, complaint management through to disagreement resolution.

b) The Respondent measures and benchmarks its customer interaction performance with all the industry best practices protocols and procedures including tracking customer calls, measuring call wait times, tracking disconnected or dropped calls, measuring average interaction times and tracking resolution success metrics. The Respondent tracks its overall performance in relation to its customer interactions with a number of third party evaluations including but not limited to bi-annual JD Power assessments. Respondent's respective utility operations consistently rank in the top quartile of its peer group in these third party assessments.

c) The Respondent has purchased over 40 individual utility operations over the past 20 years and has never divested of a single utility operation demonstrating its commitment as a long term owner and operator of the utilities under its stewardship.

d) The Respondent tracks service disruption frequency and service outage duration times at each of its 40 utility operations using standard measurement metrics like SAIDI and SAIFI and benchmarks those against the IEEE standards for the respective geographic regions where those utilities are located. The Respondents reliability performance is consistently in the top half of its respective peer group for each of it's utility operations.

e) Respondent is always cognisant of stakeholder sensitivity to utility rates and tariffs and particularly to the rate shock that may be occasioned by unique events. The Respondent manages such concerns across its 40 individual utility operations. A utility owner has many tools at its disposal for the responsible management of customer tariffs including the timing and lumpiness of capital expenditures, maintaining or enhancing operating cost efficiency, effective use of debt and equity, etc. Such situations are always easier when a utility owner is free to manage all the various elements impacting rates and to engage in long term advance planning. Respondent is confident that it can find a path to reconcile the City of Jacksonville's goals respecting this proposed transaction with the need to manage customer rates in a responsible fashion.

3. Economic Development and Benefits to Jacksonville

Respondent supports the economic development aspirations of each of the communities in which it operates a utility businesses. Respondent maintains a staff of over 26 individuals across its various utility operations through which these initiatives are undertaken. At a minimum each of the Respondent's utilities participates in regular interaction with community economic development staff and community based business groups so as to support their initiatives or address the issues that they encounter respecting utility services. Respondent has cooperated with community leaders to tailor utility service packages so as to attract employers to an area or to facilitate the timely commissioning of new commercial facilities. The Respondent understands it's obligations as a utility to support the economic development aspirations of its host community in whatever way is most helpful.

4. Employee Retention and Benefits

Respondent's regulated utility operations are predicated on a decentralized operating model. Under such a model, each individual utility operation is resourced and staffed to permit a near standalone operation with the requisite operating staff located within the service territory. Customer service functions, regulatory affairs management, and senior decision makers are typically located within the service territory. Consistent with this management philosophy, Respondent can confirm, based on the information reviewed during this process that retention of employees currently engaged in the management and/or operation of the operation on terms and conditions substantially similar with those preceding the transaction is anticipated for a minimum period of three (3) years. In past interactions with prospective employees, regulators, community leaders, customers, and other stakeholders, this sort of local, responsive, and caring utility management model has been found to be compelling. Stakeholders have been supportive of maintaining or creating additional local employment, maintaining local employee decision making and empowerment, maintaining local customer personal interaction options, and retaining in-jurisdiction regulatory and stakeholder interface.

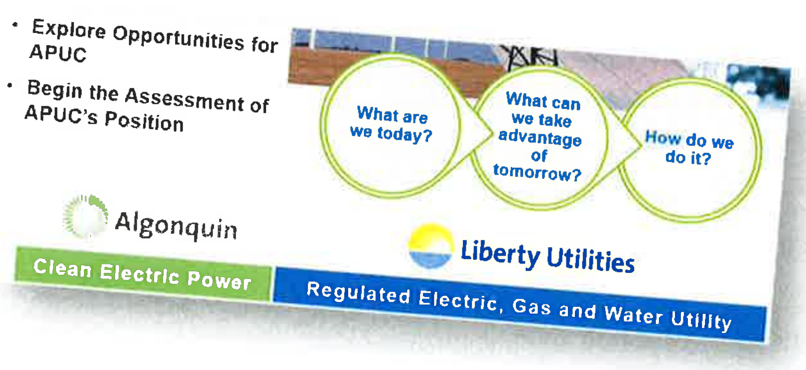
Respondent will commit to respecting any collective bargaining agreement which might be in place at the time of its consummating any transaction respecting the JEA operations or assets and to protecting certain employee retirement benefits related to the transitioned employees.

Respondent acknowledges JEA's goals and would commit to the funding of retention payments to all full time employees with such commitment being prorated to the employees associated with that segment of the operations or assets the Respondent might come to own or otherwise take possession of.

In addition, Respondent will commit to maintain the existing regional headquarters, current service locations, and local decision making authority within the service territories for an indefinite period (>5 years) following closing as long as Respondent continues to be the majority owner of the operation.

5. Innovation Plan

Respondent has been grappling with the same questions that face the JEA operations like, 1) Positioning its utility businesses for the future, 2) Generating new Revenue Channels so operations are less reliant on traditional base rates or historic tariff structures or, 3) how to Future Proof the utility business. As recently as April 2019, "industry experts" have been engaged by the Respondent to work with the organization to explore their respective visions of the future for the energy utility sector and how best to position oneself be remain relevant and competitive in the face of rapid change



Developing technologies, competitive threats, and cultural/social changes are now seemingly speeding up a desire to reach definitive actionable plans that are implementable today. There are some specific concepts that have already made their way into the utility space mainstream and have practical economical application: increasing use of distributed solar generation, energy storage, microgrids, grid modernization (and resiliency), increasing use of data analytics, and the Internet of Things (IoT) related concepts/technology (eg real time energy trading).

While emerging technologies and liberal free thinking are generating many interesting ideas for utilities, few have risen to the level that they are sufficiently clear and actionable enough to build an implementable master plan around or even to understand how they are all going to fit together in such a way that results in operations that are really significantly dissimilar to how utilities serve their customers today.

History is strewn with examples of first movers and early technology adopters that in the fullness of hindsight turn out to be costly transient undertakings: AMR vs. AMI, CFB's vs. LED technology, investing in IGCC, new nuclear, coal gasification, etc. There is certainly a place for technology pioneers and first movers, but this is a model that is rarely applicable to the utility industry that has an obligation to serve its customers reliably, to make prudent investment decisions and provide its services at an affordable cost. Jumping in with some bet on some costly and nascent "disruptive" concept (like cloud electric trading technology) is not what companies who care about their customers can practically do. Utilities cannot be failure pioneers when working with other people's money and when impacting their community's everyday quality of life.

Obviously being a larger organization with its associated scale offers the potential option to invest resources so as to play in the forefront of evolving technologies and test concepts and try new ideas. Respondent has always subscribed to the think big, test small and scale fast approach. Being a monopoly utility operation with an obligation to provide the most cost effective dependable services means these are serious issues to address and there is little room for waste or mistakes.

Load balancing and operating safety, effective cyber-security, least cost energy supply security, dynamic billing/metering, being socially responsible and helping out low income/special need customers, providing backstop safety-net supply, and dealing with stranded costs are some of these issues that need holistic answers/approaches that are fair and responsible. The "big thinkers" outside of the industry often underestimate these challenges and their importance in being a utility that actually benefits it's community.

6. Environmental Social Governance

Respondent has a stated ESG policy and a significant staff, headed by a Chief Sustainability Officer, employed to assist the organization in moving ever closer to an optimal ESG position.

Respondent's customers, regulators, investors and employees expect it to demonstrate responsible ESG behaviors such that it becomes good, perhaps even indispensable, business practice to live such optimal ESG behaviors.

Respondent's ESG policy is not much different in context and commitment then the many others one might read, but unlike some, Respondent consistently demonstrates tangible progress in achieving what it articulates.

One example of rhetoric made action is the Respondents Midwest "greening the fleet" initiative. This was one of the first such projects in the country that was not a simple "demo" project using tax dollars or rate surcharges to subsidize cost-inefficient technology applications. It was the real substitution of a perfectly usable mid-life 600mW coal plant and replacing that with 400mW of renewable (wind) generation. While such a substitution may on the surface seem commonplace, to do so at a cost that resulted in a net savings to the customer was highly innovative. The full levelized cost of the power generated from the new wind turbine fleet was proven to be lower than the incremental variable operating costs of the mid-life coal fired generation plant. Similarly, Respondent was the first utility in the country's to install a rate-based solar generation facility (in California no less) that it successfully proved to the regulator made economic sense to implement under such a utility ownership structure to replace energy the utility was buying in the competitive open market.

Furthermore, in terms of accountability, Respondent Executive Scorecard and compensation as outlined in the Company's Management Information Circular has specific ties to ESG factors including Customers and Communities (safety, customer satisfaction, service affordability), and People and Team (employee engagement).

Fundamentally Respondent believes the approach to any of this starts with clear and succinct ESG goals. If one can hold true to these larger ESG goals one can expect to get to an optimal place over time which (at its extreme) may even result in dissolving the traditional business and morphing into some other delivery or ownership structure/construct.

7. Community Stewardship

Recognizing that the City Council wants is looking for a supportive citizen in it's utility and that utility's owner, Respondent can attest that it lives up to that expectation in every one of the communities that its serves. Respondent is and proposes to continue to:

1. Be a cash contributor donor to worthwhile community events or programs be they sponsored by the city or local charities or public services groups. The Respondent contributes millions of dollars annually to such undertakings across its various utilities;
2. Provide manpower and logistics support to local community events. One such example is its fleet of community events trailers that supply drinking and rinse water at local community events so that the public can access plentiful clean water and refrain from buying or using disposable bottled;

3. Encourages its employee to engage in their wider communities. Respondent has two specific country wide programs that support such employee engagement. Their Community Spirit Awards recognizes and rewards employee volunteers active in local community events. The second program is Respondent's "Liberty Days" where each of its employees have available paid time away from work to help organize and staff community events that are authorized through a support approval process;
4. Maintains local advisory Boards at each utility consisting of 3 to 5 members drawn from the local community to assure that local issues, concerns or interests can be appropriately raise and championed in so far at the local utility is concerned.
5.

8. **Financial Stability**

Respondent (APUC the holding company entity) was initially established in 1987 although the individual utility entities that currently make up the group have individual histories some of which go back over 100 years.

The Respondent has been appropriately profitable relative to its invested capital each and every year of its existence. The Respondent has consistently paid out a dividend or distribution to its shareholders each and every year in an amount that is comparable to the dividend yield customary in the utility industry.

The Respondent maintains a standard and Poor's BBB investment grade credit rating. It has articulated its intention to conduct its financial affairs in such a way as to maintain that specific rating as it has concluded that maintaining such a position that affords it access to limitless amounts of capital at the optimal cost of such capital which it can then deploy for the benefit of its customers and other stakeholders.

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of U.S. dollars)

	December 31, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 46,819	$ 43,484
Accounts receivable, net (note 4)	245,728	244,617
Fuel and natural gas in storage	43,063	44,414
Supplies and consumables inventory	52,537	45,074
Regulatory assets (note 7)	59,037	66,567
Prepaid expenses	27,283	31,005
Derivative instruments (note 23)	9,616	16,099
Other assets and long-term investments (notes 8 and 11)	7,522	7,110
	491,605	498,370
Property, plant and equipment, net (note 5)	6,393,558	6,304,897
Intangible assets, net (note 6)	54,994	51,103
Goodwill (note 6)	954,282	954,282
Regulatory assets (note 7)	391,437	374,959
Derivative instruments (note 23)	53,192	54,115
Long-term investments (note 8)		
Investment carried at fair value	814,530	—
Notes receivable from equity investees	101,416	30,060
Other long-term investments	32,955	37,271
Deferred income taxes (note 18)	72,415	61,357
Other assets (note 11)	28,584	29,153
	$ 9,388,968	$ 8,395,567

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Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of U.S. dollars)

	December 31, 2018	December 31, 2017
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 89,740	$ 119,887
Accrued liabilities	235,586	280,144
Dividends payable (note 15)	62,613	50,445
Regulatory liabilities (note 7)	39,005	37,687
Long-term debt (note 9)	13,048	12,364
Other long-term liabilities (note 12)	42,337	46,754
Derivative instruments (note 23)	14,339	14,126
Other liabilities	2,313	2,623
	498,981	564,030
Long-term debt (note 9)	3,323,747	3,067,187
Regulatory liabilities (note 7)	539,587	538,437
Deferred income taxes (note 18)	444,145	399,148
Derivative instruments (note 23)	88,503	54,818
Pension and other post-employment benefits obligation (note 10)	191,915	168,189
Other long-term liabilities (note 12)	263,582	242,105
	4,851,479	4,469,884
Redeemable non-controlling interests (note 17)		
Redeemable non-controlling interests, held by related party	307,622	—
Redeemable non-controlling interests	33,364	41,553
Equity:		
Preferred shares (note 13(b))	184,299	184,299
Common shares (note 13(a))	3,562,418	3,021,699
Additional paid-in capital	45,553	38,569
Deficit	(595,259)	(524,311)
Accumulated other comprehensive loss (note 14)	(19,385)	(2,792)
Total equity attributable to shareholders of Algonquin Power & Utilities Corp.	3,177,626	2,717,464
Non-controlling interests (note 17)	519,896	602,636
Total equity	3,697,522	3,320,100
Commitments and contingencies (note 21)		
Subsequent events (notes 8, 9, 13 and 23)		
	$ 9,388,968	$ 8,395,567

See accompanying notes to consolidated financial statements

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Algonquin Power & Utilities Corp.
Consolidated Statements of Operations

(thousands of U.S. dollars, except per share amounts)	Year ended December 31	
	2018	**2017**
Revenue		
Regulated electricity distribution	$ 831,196	$ 763,501
Regulated gas distribution	430,377	376,806
Regulated water reclamation and distribution	128,437	140,082
Non-regulated energy sales	235,359	217,542
Other revenue	22,018	24,007
	1,647,387	1,521,938
Expenses		
Operating expenses	472,466	450,231
Regulated electricity purchased	265,166	222,443
Regulated gas purchased	183,012	141,689
Regulated water purchased	8,796	9,503
Non-regulated energy purchased	27,164	19,590
Administrative expenses	52,710	49,640
Depreciation and amortization	260,772	251,314
Loss (gain) on foreign exchange	(58)	323
	1,270,028	1,144,733
Operating income	377,359	377,205
Interest expense on long-term debt and others	152,118	142,439
Interest expense on convertible debentures and amortization of acquisition financing (notes 9(b) and 12(h))	—	13,383
Change in value of investment carried at fair value (note 8(a))	137,957	—
Interest, dividend, equity and other income (note 8)	(53,139)	(9,238)
Pension and post-employment non-service costs (note 10)	3,914	9,035
Other net losses	2,725	664
Acquisition-related costs, net (note 12(f))	687	47,708
Loss (gain) on derivative financial instruments (note 23(b)(iv))	636	(1,918)
	244,898	202,073
Earnings before income taxes	132,461	175,132
Income tax expense (note 18)		
Current	11,347	7,517
Deferred	42,025	65,910
	53,372	73,427
Net earnings	79,089	101,705
Net effect of non-controlling interests (note 17)		
Net effect of non-controlling interests	108,521	47,770
Net effect of non-controlling interests held by related party	(2,622)	—
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$ 184,988	$ 149,475
Series A and D Preferred shares dividend (note 15)	8,027	8,020
Net earnings attributable to common shareholders of Algonquin Power & Utilities Corp.	$ 176,961	$ 141,455
Basic and diluted net earnings per share (note 19)	$ 0.38	$ 0.37

See accompanying notes to consolidated financial statements

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