

Exhibit No. 203P

Exhibit No.: _____
Issue(s): Asbury/Market Price Projection
Mechanism/Fuel Adjustment Clause (FAC)
Witness/Type of Exhibit: Mantle/Direct
Sponsoring Party: Public Counsel
Case No.: ER-2021-0312

DIRECT TESTIMONY

OF

LENA M. MANTLE

Submitted on Behalf of the Office of the Public Counsel

**THE EMPIRE DISTRICT ELECTRIC COMPANY
D/B/A LIBERTY**

FILE NO. ER-2021-0312

**

**

**Denotes Highly Confidential and Confidential Information
that has been Redacted**

October 29, 2021

PUBLIC

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**

In the Matter of the Request of The)
Empire District Electric Company d/b/a)
Liberty for Authority to File Tariffs) Case No. ER-2021-0312
Increasing Rates for Electric Service)
Provided to Customers in its Missouri)
Service Area)

AFFIDAVIT OF LENA M. MANTLE

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Lena M. Mantle, of lawful age and being first duly sworn, deposes and states:


1. My name is Lena M. Mantle. I am a Senior Analyst for the Office of the Public Counsel.
2. Attached hereto and made a part hereof for all purposes is my direct 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.


Lena M. Mantle
Senior Analyst

Subscribed and sworn to me this 29th day of October 2021.



TIFFANY HILDEBRAND
My Commission Expires
August 8, 2023
Coke County
Commission #15637121


Tiffany Hildebrand
Notary Public

My Commission expires August 8, 2023.

TABLE OF CONTENTS

Testimony	Page
Introduction	1
Planning Reserve Margin vs Resource Adequacy	3
Market Price Protection Mechanism	11
OPC's Recommended Modifications to Empire's FAC	26

DIRECT TESTIMONY
OF
LENA M. MANTLE
THE EMPIRE DISTRICT ELECTRIC COMPANY
FILE NO. ER-2021-0312

INTRODUCTION

What are your name and business address?

A. My name is Lena M. Mantle and my business address is P.O. Box 2230, Jefferson City, Missouri 65102.

Q. By whom are you employed and in what capacity?

A. I am employed by the Missouri Office of the Public Counsel (“OPC”) as a Senior Analyst.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the OPC.

Q. To what are you testifying?

A. I am testifying on three different issues. First, I provide support for the recommendations on recovery of the costs of The Empire District Electric Company’s (“Empire’s”) Asbury plant provided by OPC witness Dr. Geoff Marke through a discussion of how, even though Empire is meeting the Southwest Power Pool (“SPP”) reserve margin requirement, the retirement of its Asbury plant resulted in a worsening of Empire’s resource adequacy and increased costs to Empire’s customers. Second, I raise concerns with and recommend changes to the market price protection mechanism (“MPPM”) that the Commission adopted in Case No. EA-2019-0010¹ (“CCN case”) based on information that is now known,

¹ *In the Matter of the Application of The Empire District Electric Company for a Certificates of Convenience and Necessity Related to Wind Generation Facilities*, Case No. EA-2019-0010, Report and Order, effective June 29, 2019, p. 59.

1 but was estimated when the Commission adopted the MPPM. Third, I recommend
2 modifications to Empire’s fuel adjustment clause (“FAC”).

3 **Q. What are your experience, education, and other qualifications, particularly on**
4 **the topics to which you are testifying?**

5 A. I began employment at the OPC in my current position as Senior Analyst in August
6 2014. In this position, I have provided expert testimony in electric and water cases
7 before the Commission on behalf of the OPC. I am a Registered Professional
8 Engineer in the State of Missouri.

9 Prior to being employed by the OPC, I worked for the Staff of the Missouri
10 Public Service Commission (“Staff”) from August 1983 until I retired as Manager of
11 the Energy Unit in December 2012. During my employment at the Missouri Public
12 Service Commission (“Commission”), I worked as an Economist, Engineer,
13 Engineering Supervisor and Manager of the Energy Unit. After the Missouri
14 Legislature passed Section 366.266, RSMo in 2005, enabling the electric utilities to
15 request a fuel adjustment clause (“FAC”), I was instrumental in the development and
16 application of the Commission’s FAC rules and the FACs of the electric utilities in
17 Missouri. I have provided testimony regarding FACs in numerous general rate cases,
18 FAC rate change cases, and FAC prudence cases, both during my time on the
19 Commission Staff and since my employment at the OPC.

20 I was an active participant on behalf of the OPC in the cases filed before this
21 Commission by Empire regarding the planning and construction of the Kings Point,
22 North Fork Ridge, and Neosho Ridge wind projects (“wind projects”). I provided
23 testimony on behalf of the OPC in both the EO-2018-0092 and EA-2019-0010 cases.

24 Attached as Schedule LMM-D-1 is a brief summary of my experience with
25 the OPC and Staff, and a list of the Commission cases in which I filed testimony,
26 Commission rulemakings in which I participated, and Commission reports in rate
27 cases to which I contributed as Staff. Attached as Schedule LMM-D-2 is the
28 *Electric Utility Fuel Adjustment Clause in Missouri: History and Application*

1 *Whitepaper* that I wrote to provide background and a description on various aspects
2 of the FAC in Missouri.

3 **Planning Reserve Margin vs Resource Adequacy**

4 **Q. Why are you testifying about Asbury?**

5 A. As provided in the direct testimony of OPC witness John Robinett, Empire made
6 considerable investment in its Asbury plant to extend the life of the plant while
7 meeting state and federal environmental standards. When Empire chose to retire
8 the Asbury plant, Empires' customers had not received the full benefits of these
9 improvements as promised. The purpose of my testimony is to describe the
10 resource adequacy benefits of Asbury to Empire's customers that no longer exist
11 and show that Asbury still had economic value when and after Empire retired it.
12 OPC witness Dr. Marke uses this information in determining his recommendations
13 regarding the recovery of Asbury costs.

14 **Q. What is planning reserve margin?**

15 A. Planning Reserve Margin, calculated as the percentage by which installed capacity
16 exceeds peak demand, is a deterministic metric that produces a single value for the
17 peak period of a single future season (typically summer or winter when electricity
18 loads are higher). This metric has two inputs: resources and forecasted load.²

19 **Q. What planning reserve margin does the SPP require of Empire?**

20 A. The SPP planning criteria sets the planning reserve margin for Empire to be 12%.

² *Resource Adequacy Primer for State Regulators*, July 2021, page 6.

1 **Q. What were Empire’s SPP planning reserve margins after it retired its coal-**
2 **fired Asbury generating plant?**

3 A. The summer after retiring Asbury, Empire barely met the SPP planning requirement
4 with a reserve margin for the summer of 2020 of 12.05%.³ With the additional
5 capacity from its wind projects, Empire’s 2021 summer SPP planning reserve
6 margin increased to 16.02%.⁴

7 **Q. What do you know about Empire’s planning reserve margin in the near**
8 **future?**

9 A. Because Empire is experiencing very little load growth and I am not aware of
10 Empire adding any generation in 2022, I expect Empire’s summer reserve margin
11 to be nearly the same for 2022 as it was for 2021. However, SPP is implementing
12 new accreditation policies for wind resources that will go into effect in the 2023
13 summer season that could change the capacity accreditation of Empire’s wind
14 resources.⁵

15 **Q. What is resource adequacy?**

16 A. Unlike reserve margin, which looks at a single point in time - the peak hour - and
17 measures how much generation is available at that point in time, resource adequacy
18 is the ability of the electricity system to supply aggregate electric power and energy
19 to meet the requirements of consumers at all times, taking into account scheduled
20 and unscheduled outages of system components. Resource adequacy is
21 foundational for providing reliable electric service across all hours.⁶

³ 2020 SPP Resource Adequacy Report, page 19.

⁴ 2021 SPP Resource Adequacy Report, page 22.

⁵ Resource Adequacy Primer for State Regulators, July 2021, page 48.

⁶ Resource Adequacy Primer for State Regulators, July 2021, page 6.

1 Resource adequacy for a vertically integrated utility means that the utility
2 has the resources that it needs to meet its customers' needs at all times without
3 depending on its regional transmission organization markets for energy.

4 **Q. Has retiring Asbury affected Empire's resource adequacy?**

5 A. Yes. However, with the exception of the outages during the winter storm in
6 February 2021, Empire customers' needs have been met. Empire belongs to the
7 SPP and has relied on other utilities' resources. However, on a stand-alone basis
8 Empire does not have resources that can meet the needs of its customers every hour,
9 even though it exceeds the SPP planning reserve margin requirement. The
10 retirement of this dispatchable resource greatly decreased Empire's ability to meet
11 its customer's needs with its own resources.

12 **Q. Why should a utility that is part of regional transmission organization be**
13 **concerned about resource adequacy if it satisfies the regional transmission**
14 **organization's reserve margin requirement for it?**

15 A. While their customers are likely to always have the energy they need, relying on
16 the market exposes customers to high energy price risk. If a utility has adequate
17 resources, the cost of extreme weather events such as the one which occurred in
18 February 2021 will be significantly lower for those utilities that have adequate
19 resource capacity. The generation resources of these utilities will provide revenue
20 that offsets the cost of the energy at the load. Those utilities with inadequate
21 resources will not have those revenues.

22 Generation resources are hedges to market prices. Some types of generation
23 are better hedges against extreme market prices (dispatchable) than others
24 (intermittent).

1 **Q. How are generation resources hedges to market prices?**

2 A. The benefit of any resource is the difference between the cost to produce energy
3 and the market price for that energy. If a utility owns its wind resources, the entire
4 revenue provided by the market is a benefit. Whenever the wind resources are
5 generating, they are a hedge against prices regardless of whether the price is high
6 or low. This is the benefit of an owned wind resource.

7 Dispatchable resources provide a hedge when the market price is greater
8 than the cost for that resource to produce electricity. The benefit is the difference
9 between the market price and the cost of producing the electricity. When market
10 prices are high and the dispatchable resources are producing electricity, the
11 dispatchable resources are a hedge against market prices because they are able to
12 provide electricity at the time when market prices exceed the cost for that resource
13 to produce electricity.

14 The difference is in the energy source. Dispatchable resources use fuel that
15 is typically available upon demand. Intermittent resources provide benefits when
16 their energy source—wind or light—is available.

17 **Q. Given the recent time of extreme market prices in February 2021, were both**
18 **types of resources hedges against market prices?**

19 A. Yes. Whatever resources were generating were hedges against market prices.
20 However, dispatchable resources with on-site fuel were better hedges because they
21 were available more hours.

22 **Q. Why is this important in this discussion of resource adequacy?**

23 A. Resources that are good hedges increase resource adequacy. Asbury was a
24 dependable resource that Empire had updated at considerable expense to meet state
25 and federal environmental standards. Its availability and its on-site fuel source
26 made it a good hedge increasing the adequacy of Empire's resource portfolio.

1 **Q. Would you generally explain the resource adequacy of Empire's current**
2 **resources?**

3 A. All of Empire's remaining generation resources have operating constraints
4 reducing their resource adequacies in varying amounts.

5 Natural gas or oil is the fuel for 73% of Empire's capacity.⁷ These resources
6 are available for Empire to dispatch. Over half of Empire's natural gas generation
7 is from efficient combined cycle ("CC") plants. When natural gas prices are low,
8 as they were in 2020, these plants are reliable and inexpensive sources of electricity.

9 The rest of Empire's natural gas generation resources are combustion
10 turbines that, while quick to start up and run, can be expensive to run for long
11 periods of time even when the price of natural gas is low. They can quickly respond
12 to a need but cannot be relied upon to generate for long periods of time.

13 Natural gas is not stored on site. Empire has firm natural gas transportation
14 for much of its natural gas fired capacity. Typically, Empire can rely on delivery
15 of natural gas to these generation plants as it is needed. However, natural gas
16 delivery to these generation facilities may be interrupted due to other demands on
17 the pipelines as demonstrated during the February 2021 extreme weather event
18 when Empire's customers desperately needed electricity to heat their home.

19 Less than 10% of Empire's accredited capacity is renewable resources.
20 These are intermittent resources where Empire has little to no control over when
21 these resources will provide energy for Empire's customers. This is reflected in the
22 low SPP capacity accreditation for intermittent resources in comparison to their
23 maximum design capacity. The rated turbine capacity of the newly added wind
24 projects is approximately 600 MW. SPP only accredits Empire 30 MW for this 600
25 MW of wind. This reflects the resource adequacy of wind. The SPP's accreditation
26 of these wind projects demonstrates that the SPP recognizes that wind resources

⁷ The capacity referred to in this answer is Empire's SPP accredited capacity.

1 cannot be relied upon to provide electricity at their maximum capacity when
2 customers need it.

3 Empire’s remaining resources are fueled by coal. Coal plants typically
4 maintain more than a 30-day supply of coal on site, and are inexpensive to run, but
5 take time to ramp up their electricity output. However, with the retirement of
6 Asbury, Empire is not the majority owner of any of its coal resources. In an October
7 26, 2021 resource planning meeting, Empire informed Staff, OPC, and other parties
8 that *** _____
9 _____
10 _____

11 _____ *** These are decisions to which Empire has little to
12 no input or control but which impact the adequacy of Empire’s generation resources
13 available to meet its customers’ needs. Empire does not make the dispatch,
14 management, and inventory decisions for these plants.

15 Asbury was a low cost, dispatchable resource with the ability to have an
16 inventory of fuel on site. When it retired Asbury, Empire lost its only resource for
17 which it had a stable supply of fuel and that it could dispatch based on its customers’
18 requirements.

19 **Q. Did Empire consider resource adequacy when it decided to retire Asbury?**

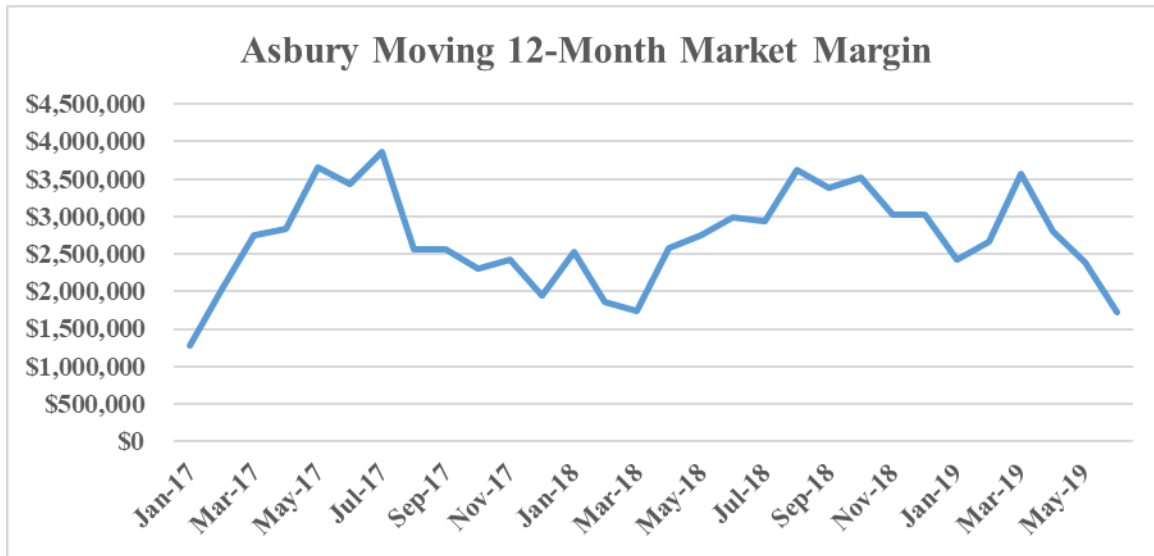
20 A. I have not seen any documentation that Empire reviewed the impact of retiring
21 Asbury on its ability to adequately meet its customers’ needs. The modeling done
22 by Empire always allowed Empire to purchase energy from the SPP to meet its
23 load. It was not restricted to energy from its own resources.

24 Empire has continuously stated that it retired Asbury because keeping the
25 plant running was uneconomic and its retiring of Asbury would lower costs to
26 customers in the long run. In fact, Empire’s “customer savings plan” first presented

1 to the Commission in Case EO-2018-0092⁸ is replete with references to how the
2 wind generation would replace Asbury once it was retired. Asbury provided energy
3 when customers needed it.⁹ The wind generation that Empire touted as “replacing”
4 Asbury provides energy when the wind is blowing irrespective of its customers
5 need for electricity. If customers need electricity and the wind is not blowing, then
6 Empire has to turn to other dispatchable resources or the SPP market. If the wind
7 is blowing and customers do not need the energy, Empire must sell it to the market
8 – sometimes at a negative cost.

9 **Q. Was Asbury uneconomic in the SPP energy market when Empire retired it?**

10 A. No. As the graph below shows, Asbury’s market margin was positive, meaning the
11 revenues Empire received from SPP for Asbury were greater than Empire’s fuel
12 costs to run Asbury, even in 2017 and 2018 when the decision was being made to
13 retire Asbury.

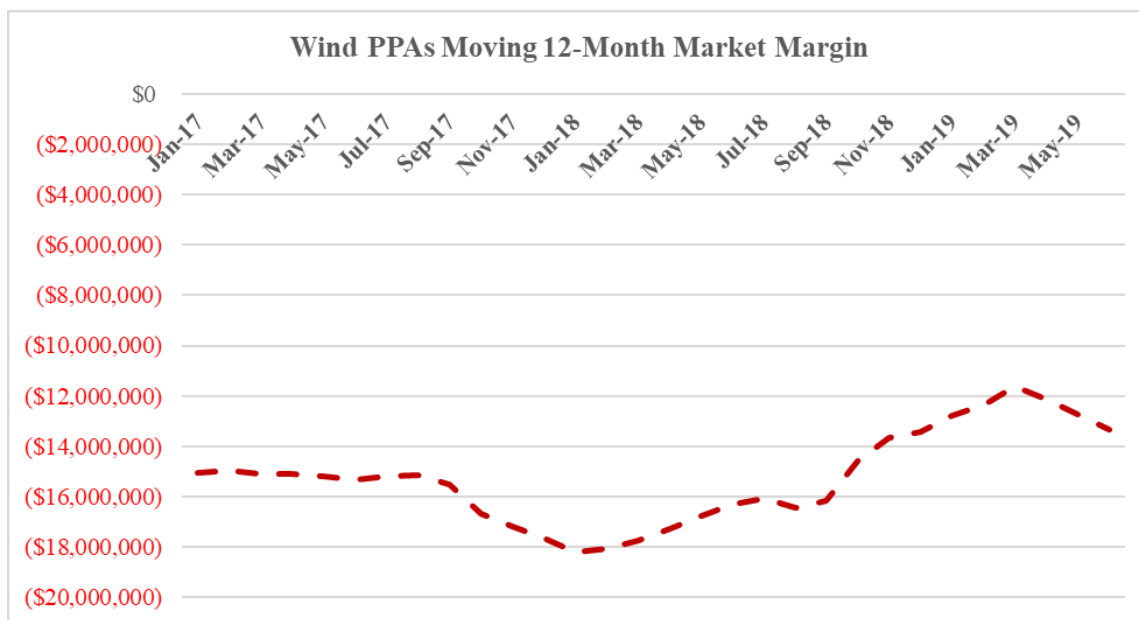


14
⁸ *In the Matter of the Application of The Empire District Electric Company for Approval of Its Customer Savings Plan*, EO-2018-0092

⁹ While Asbury did have unexpected forced outages, outages for maintenance were planned at times low cost energy was available from other resources and expected customer demand was low.

1 **Q. Were all of Empire’s other generating resources economic in the SPP energy**
2 **market in 2017 and 2018?**

3 A. No. The margins from the generation from Empire’s two wind purchased power
4 agreements (“PPA”) were, and still are, consistently negative. The graph below
5 shows the moving 12- month market margins for the same time period for the wind
6 PPAs.



7
8 As shown in this graph, judged just on the market margin, the wind PPAs were
9 drastically uneconomic at the same time the decision was being made to retire
10 Asbury, even though Asbury was showing a positive margin.

11 **Q. There is no fuel cost for wind is there?**

12 A. No. However, there is a cost to customers for these wind PPAs that must be paid
13 regardless of the market price when the wind is blowing.

14 **Q. Would you summarize this section of your testimony?**

15 A. Empire made considerable investment in its Asbury plant to extend the life of the
16 plant while meeting state and federal environmental standards. When Empire chose

1 to retire the Asbury plant, Empires’ customers had not received the full benefits of
2 these improvements as promised. Asbury was still generating a positive margin
3 from the SPP IM and, by being a good hedge against market prices, it increased the
4 resource adequacy of Empire’s resource portfolio. For these reasons, the
5 Commission should adopt the Asbury cost recovery recommendations of OPC
6 witness Dr. Marke.

7 **Market Price Protection Mechanism**

8 **Q. What is the Market Price Protection Mechanism?**

9 A. In the wind projects CCN case EA-2019-0010, Empire, Staff, Missouri Energy
10 Consumers’ Group (“MECG”), Renew Missouri, and the Missouri Department of
11 Energy (“DE”) filed a *Non-unanimous Stipulation and Agreement* recommending
12 the Commission grant Empire a Certificate of Convenience and Necessity (“CCN”)
13 with numerous conditions, one of which was a market price protection plan.¹⁰ The
14 Commission granted the CCN with conditions, including the market price
15 protection mechanism (“MPPM”). In its *Report and Order*, the Commission stated
16 the MPPM was designed to mitigate risks to customers of the revenues from the
17 wind projects not being as expected, and added a layer of protection for the low
18 probability events related to the supply side generation.¹¹

19 **Q. Were you part of the drafting and design of the MPPM?**

20 A. Initially I was. However during the drafting process it became clear that the MPPM
21 the other parties were agreeable to would leave customers almost entirely exposed
22 to all downside risk while Empire and the tax equity partners were guaranteed a
23 profit. The OPC told the parties that it could not agree to such a MPPM and we
24 were excluded from negotiating the final design of the MPPM.

¹⁰ OPC objected to the non-unanimous stipulation and agreement on April 12, 2019, *The Office of the Public Counsel's Objection to the Non-Unanimous Stipulation and Agreement Filed April 5, 2019*

¹¹ Page 49.

1 **Q. What is your understanding of why the MPPM was developed and what the**
2 **MPPM does?**

3 A. It was clear that Empire was not building its new wind projects to meet customer
4 load. Empire wanted to build these wind projects and recover the cost plus a return
5 on the cost of the wind projects. It promoted these wind projects as a good deal for
6 customers based on its belief that the revenues received from these wind projects
7 would be greater than the costs to its customers resulting in lower customer bills.
8 Because this was speculative generation built to “beat the market,” not generation
9 built to meet a need, some of the parties in the case and Empire negotiated the
10 MPPM to cover the possibility that the wind projects would not provide more
11 benefits than the costs in the first ten years they operated.

12 The MPPM tracks the benefits provided to the customers from the wind
13 projects and the costs of the wind projects paid for by the customers during the first
14 ten years of the projects. The MPPM in the Stipulation and Agreement requires a
15 shared the risk of the first \$52.5 million of losses between Empire and its customers.
16 If, after ten years, losses were greater than \$52.5 million, the parties could propose
17 to the Commission alternatives for the treatment of the amounts greater than \$52.5
18 million that Empire’s customers will have already paid.

19 **Q. Based on your review, do you have any concerns about the MPPM?**

20 A. I support the goal of providing customers protections, but I am concerned with the
21 details of the MPPM.

22 **Q. What are your concerns about the details of the MPPM?**

23 A. Appendix B to the *Non-unanimous Stipulation and Agreement* defines the wind
24 revenue requirement (“WRR”) for the MPPM to include the following costs: 1)
25 operation and maintenance, 2) labor, 3) tax equity payments/credits, 4) property
26 taxes, 5) return on and of, and 6) income taxes.

1 The MPPM should include all of the costs customers will be paying. It does
2 not, but should, include renewable energy credit costs. *** _____

3 _____
4 *** The other cost that I am aware of that is not included in the MPPM, but should
5 be included is the cost to customers of Empire’s election of plant in-service
6 accounting (“PISA”) for the wind projects.

7 **Q. Do you have concerns with any of the WRR components listed in Appendix B?**

8 A. Yes. My understanding is that what Empire categorized as tax equity
9 payments/credits is actually the aggregate of a benefit (paygo) and a cost (tax equity
10 distributions).

11 **Q. What is paygo?**

12 A. My understanding is that this is a payment made to the wind project holding
13 company from the tax equity partner that is passed on to Empire when the number
14 of production tax credits achieved by the wind project is greater than a pre-
15 determined amount. Empire witness Todd Mooney defines paygo in footnote 9 on
16 page 14 of his direct testimony as:

17 Contingent Contributions (referred to as “Paygo”) represent additional
18 contributions of cash by the tax equity partners to Empire Wind Holdings,
19 LLC based on actual production in excess of a threshold. Paygo
20 contributions received by Empire Wind Holdings, LLC are distributed to
21 Empire and hence reduce the cost of service to customers.

22 **Q. What are tax equity distributions?**

23 A. Tax equity distributions are the partnership cash distributions that will be made by
24 the wind holding companies to Empire and the tax equity partners.¹³ *** _____

25 _____
¹² Renewable energy credits, are tradable, non-tangible commodities that represent proof that one MWh of electricity was generated from a renewable energy resource and was then fed into the shared system of power lines that transport energy. (<https://energywatch-inc.com/renewable-energy-credits-recs-explained/>)

¹³ Empire response to OPC data request 8010 in case EA-2019-0010.

1 _____
2 _____
3 _____
4 _____

5 _____ *** The MPPM shows the total cash distribution as estimated to
6 be paid out by the wind holding companies with an adjustment for the distribution
7 paid to the tax equity partner.

8 **Q. Why do combining the tax equity distributions and paygo in the calculation of**
9 **the WRR concern you?**

10 A. They do not reflect what will actually transpire. Paygo will be a benefit. If SPP
11 revenues are greater than the costs in the years when some of the cash distribution
12 is provided to the tax equity partners, then this will be a decrease in costs and
13 benefits. Combining the paygo and tax equity distributions as a cost obscures
14 information on both.

15 **Q. How should the MPPM be modified to address your concerns?**

16 A. To address the tax equity payments, the MPPM should be modified to reflect the
17 actual amounts that will flow to Empire. *** _____

18 _____
19 _____
20 _____
21 _____

22 _____ *** The MPPM should reflect
23 only costs and benefits to Empire customers.

24 To get a clearer picture of actual costs, paygo should be tracked separately
25 as a benefit. In his direct testimony in this case, OPC witness John Riley
26 recommends that an estimated amount of annual paygo be included in Empire's
27 revenue requirement. Between rate cases the difference between the estimated

1 paygo and the actual paygo should be tracked with Empire’s customers receiving
2 any extra benefits or reimbursing Empire if the estimated benefits were too high
3 through rates set in Empire’s next rate case. Paygo is not a fuel, purchased power,
4 or transportation related revenue and should therefore not be included in Empire’s
5 FAC.

6 **Q. What benefits are included in the MPPM described in Appendix B?**

7 A. The only benefit shown in the MPPM are SPP integrated market (“IM”) revenues.

8 **Q. Are there other benefits associated with the wind projects?**

9 A. Yes, in addition to paygo described above and the SPP integrated market revenues,
10 there are revenues from the sale of the wind projects’ RECs, and production tax
11 credit values, both of which should be included in the MPPM.

12 **Q. Why not just include net REC revenues instead of showing the costs of RECs
13 separate from the revenue from selling RECs?**

14 A. There is a fluctuating market for RECs with prices influenced by supply and
15 demand. There will be a flood of wind RECs with all of the wind generation that
16 is being added in the SPP. Empire may choose to hold on to its RECs waiting for
17 an increase in the price or may choose not to sell RECs because the price is lower
18 than the cost waiting for market values to increase.

19 Since the timing of the purchase and the sale of RECs may be different, they
20 should be tracked separately.

21 **Q. How should Empire’s customers realize the benefits of the SPP IM and REC
22 revenues from the wind projects?**

23 A. SPP IM revenues from Empire’s other generation currently flows through its FAC
24 as does the revenue from the sale of RECs from the current wind purchased power
25 agreements (“PPAs”). Therefore the SPP IM revenues and the cost and revenues
26 from RECs should flow through Empire’s FAC. This will result in most of these

1 benefits flowing back to customers between general rate cases. However, to assure
2 customers receive all of the revenues from the wind projects as measured by the
3 MPPM, either 100% of the SPP IM and REC revenues should flow through
4 Empire’s FAC or the difference from what is actually received and what is returned
5 to Empire’s customers should be tracked and netted until Empire’s next general rate
6 case. Any resulting regulatory liability would returned to the customers in that next
7 rate case, amortized over a time-period consistent with the tracking. Likewise, any
8 resulting regulatory asset would be amortized, and recovered from Empire’s
9 customers over a time period consistent with the tracking.

10 **Q. Why should production tax credits be included in the MPPM?**

11 A. It is unknown when or how the tax credits will be utilized, and whether, when
12 utilized, will result in revenue, or a lower tax liability. Nonetheless, Empire has
13 stated its willingness to provide to customers this known value. This is a benefit
14 and should therefore be included in the MPPM.

15 **Q. How should Empire’s customers realize the production tax credit benefits?**

16 A. Production tax credits (“PTCs”), while a benefit, are not a realized revenue. Empire
17 has committed to providing a revenue credit commensurate with the values
18 associated with the PTCs Empire gets. PTCs are not directly tied to fuel, purchased
19 power, or transportation, so no portion of these benefits should flow through
20 Empire’s FAC. An estimated amount of these revenues Empire will be providing
21 should be included in its revenue requirement used for designing its rates, and the
22 differences between the estimated revenue and the achieved revenue should be
23 tracked. If the result is a regulatory liability, it should be returned to Empire’s
24 customers, or, if it is a regulatory asset, it should be amortized and the amortized
25 amount included in Empire’s revenue requirement for designing Empire’s rates in
26 its next general rate case.

1 **Q. Other than more specificity regarding the costs and benefits that should be**
2 **included in the MPPM, do you have any other concerns regarding the MPPM?**

3 A. Yes. Appendix B states that the rate base cost and carrying cost will be calculated
4 every year. In addition, Exhibit A of Appendix B states that a Missouri
5 jurisdictional allocator be applied in year 10 to the cumulative Annual Sharing
6 Value if it is negative. It does not specify how the jurisdictional value is to be
7 calculated.

8 **Q. Why is calculating the rate base cost and carrying cost every year a concern?**

9 A. The MPPM is supposed to compare the costs and the benefits of the wind projects
10 to Empire's customers. The MPPM that is shown in the Stipulation and Agreement
11 shows the wind projects' rate base and return changing every year. However, in
12 practice, that rate base and return paid by the customers will only change each time
13 when new Empire rates go into effect.

14 **Q. How do you recommend that the wind projects' rate base cost and carrying**
15 **cost be accounted for in the MPPM?**

16 A. The MPPM should track the actual rate base cost and carrying costs paid by
17 Empire's customers, meaning these costs should remain constant between Empire
18 rate cases.

19 **Q. How do you recommend the MPPM jurisdictional allocation factor be**
20 **calculated?**

21 A. The wind projects generate energy; therefore, the energy jurisdictional allocation
22 factor should be used in the MPPM.

23 **Q. Do have concerns that would require more substantial modifications to the**
24 **MPPM?**

25 A. Yes.

1 **Q. What are they?**

2 A. As I previously stated, these wind projects were not built because Empire needed
3 more generation to meet the needs of its customers. They were not built in an effort
4 to increase Empire's resource adequacy to serve its customers. The wind projects
5 are a speculative venture for which Empire is asking its customers to not only pay
6 for, but also to provide Empire with a return on.

7 Since the Commission issued its order in the CCN case more than two years
8 ago, there is more certainty on some aspects of the wind projects. The most critical
9 being that the actual cost of the wind projects, due to many factors, is almost ***

10 _____
11 _____ ***Empire's revenue requirement due to the wind projects.

12 At this time the greatest uncertainty regarding the wind projects is the
13 revenues that they will generate. The direct testimony of Empire witness Frank C.
14 Graves shows how the projections used by Empire in its planning processes through
15 the years have consistently over-projected market prices which are key to the
16 benefits that will be realized by the customers.

17 In addition, as provided in the testimony of OPC witness Dr. Geoff Marke,
18 there is considerable uncertainty about how the presence of gray bats in the area of
19 the Kings Point and North Fork Ridge wind projects will affect the availability of
20 the wind turbines to generate electricity.

21 At this point, the risk for Empire is low and the risk for the customers is
22 high. Customers will pay Empire for the projects. This is very likely. The benefits
23 the customers will receive are the great unknown. The MPPM should be modified
24 to balance the risks of Empire and its customers.

14 Todd Mooney Direct, page 5, cost estimates as of March 30, 2021.

1 **Q. Do you know how this increase in the cost of the wind projects impacted the**
2 **MPPM examples that are in Appendix B of the *Non-unanimous Stipulation***
3 ***and Agreement*?**

4 A. No, not specific to the change in cost. However, Empire provided on October 19,
5 2021, in response to OPC data request 8075, Excel spreadsheets of an update of the
6 Wind Data Sheet, the PPA Replacement Value, and the P50 Mid Market Price
7 Market Protection Provision¹⁵ of Appendix B of the CCN *Non-unanimous*
8 *Stipulation and Agreement*. This update included changes in the cost of the Wind
9 projects, increases in the PPA replacement value and decreases in the SPP market
10 revenues.¹⁶ The updated analysis, shows a ** _____ ** meaning
11 Empire is now estimating, with its updates, that the costs, over the first ten years of
12 the wind projects, will be greater than the benefits. For the MPPM, as shown in the
13 *Non-unanimous Stipulation and Agreement*, the estimated cumulative annual wind
14 value in year ten was a positive \$145 million meaning that, at that time given
15 Empire's inputs and assumptions, benefits were estimated to be \$145 million
16 greater than cost over ten years.

17 This was a swing of ** _____ **, which demonstrates the risk of these
18 wind projects to Empire's customers.

19 **Q. What changes do you recommend the Commission make to the MPPM?**

20 A. I recommend the following changes:

- 21 1. The cumulative Annual Wind Values should include interest at the same
22 rate that is provided on customer deposits;
- 23 2. An energy jurisdictional allocator be applied to each year's annual wind
24 value;

¹⁵ Exhibits B, C, and D respectively of Appendix B.

¹⁶ Empire also included REC revenues and PTC benefits in its Wind Data calculation that were not shown or mentioned in Appendix B to the Stipulation and Agreement in the CCN case.

- 1 3. A cap of \$26.25 million losses accumulated over the first ten years for
2 Empire’s customers; and
3 4. No “PPA replacement” benefit be included in the MPPM.

4 **Q. Why do you recommend that the cumulative Annual Wind Values include**
5 **interest?**

6 A. This is a ten-year mechanism with customers not seeing any relief from losses until
7 after year ten. There will be losses in the first years because that is when the wind
8 projects rate base is the highest. It is also when energy market prices are estimated
9 to be the lowest. Therefore it is most likely that the wind projects will show benefits
10 greater than costs in the later of the ten years. Without including interest, the dollar
11 of profit in year ten is the same as the dollar of losses in year one. Yet had the
12 dollar in year one earned even minimal interest, it would have been greater than the
13 dollar in year ten. Including interest values the customers’ funding of the losses in
14 the early years of the MPPM.

15 **Q. Why do you recommend that an energy jurisdictional allocation factor be**
16 **applied annually?**

17 A. Jurisdictional factors change over time. The jurisdictional factor in year one of the
18 MPPM could be much different from the jurisdictional factor in year ten due to
19 customer growth and changing usage characteristics. Applying jurisdictional
20 allocation factors annually will more accurately tie the costs Missouri ratepayers
21 paid for to the benefits they received in that year. Annual Wind Values are
22 calculated. Annual jurisdictional factors should be applied to these values.

1 **Q. The MPPM provides that the jurisdictional factor used will be based on the**
2 **jurisdictional allocation ratios of Empire’s prior rate case. Do you agree with**
3 **this approach?**

4 A. No. Energy jurisdictional allocation factors are simply the amount of energy for
5 each jurisdiction divided by the sum of the energies of all the jurisdictions. It is not
6 a difficult or complex calculation. It should be done for each year’s Annual Wind
7 Value.

8 **Q. Why do you recommend that the limit of no more than \$26.25 million of wind**
9 **projects losses at the end of the ten-year MPPM be moved from Empire’s**
10 **shareholders to its customers?**

11 A. As shown in the difference in the estimate of the cumulative annual wind values
12 from the CCN case and Empire’s response to OPC data request 8075 provided on
13 October 19, 2021, the risk to Empire’s customers is great over these ten years. At
14 the same time, Empire is projecting that it will see a return on equity on these wind
15 projects of \$295 million. There is little to no risk to Empire surrounding this
16 amount. If Empire does not recover the \$295 million from its customers, it can
17 come in and ask for more revenue from its customers to make sure that it earns this
18 return.

19 Limiting the amount of losses Empire’s customers would be required to
20 cover reduces their risk. If Empire is correct in its projection of the net profit of
21 these wind projects that it made in its CCN case, the cap will not matter and the
22 MPPM will simply be a tracking exercise.

23 A less attractive alternative would be to split the amount of losses at the end
24 of the ten years. While this may seem to evenly split the risks of the wind projects,
25 it would not. Empire would still earn a return on the wind projects (reducing its
26 risk) and its customers would be covering the losses in the early years (increasing
27 their risk).

1 **Q. Why do you recommend the MPPM be changed to remove the power purchase**
2 **agreement replacement value in the MPPM?**

3 A. These wind projects are not replacing Empire’s current wind PPAs. Empire built
4 these wind projects to make money, not to replace its wind PPAs. In fact, Empire
5 consistently has characterized these wind projects as replacing coal-fired
6 generation with wind generation. The wind projects were built to earn a return for
7 shareholders with a potential for lower customers’ bills over twenty years.

8 **Q. Why did Empire enter into its existing wind power purchase agreements?**

9 A. Empire entered into the wind PPAs because, at the time Empire was considering
10 entering into these PPAs, Empire’s modelling predicted the PPAs to be cost
11 effective resources to meet its customers’ needs over the next 20 years. At the time
12 Empire was also adding coal generation to its available resources, the addition of
13 the wind PPAs provided diversity to its generation resources. After Missouri
14 adopted renewable energy standards (“RES”) in 2008,¹⁷ these PPAs provided
15 Empire with more than enough energy to meet the RES, not only in the early years
16 of the RES when the RES required the investor-owned utilities to generate 2% of
17 their needs with renewables but also through the time when they needed to meet
18 15% of their customers’ electric usage with renewables.

19 Now in 2021 with the SPP IM the wind PPAs are costing ratepayers
20 between \$1 million and \$2 million a month. Since the IM market started, the wind
21 PPAs only had a positive margin two months soon after the market started. The
22 only economic benefit to the customers from these wind PPAs is that they do not
23 have to pay for additional resources to meet the Missouri RES. Yet they are costly
24 electric energy and capacity resources.

¹⁷ [Missouri Revisor of Statutes - Revised Statutes of Missouri, RSMo Section 393.1020](#)

1 **Q. Will Empire be able to use the wind projects to satisfy the requirements of the**
2 **renewable energy standard when its current power purchase agreements**
3 **expire?**

4 A. If the wind projects are certified by the Division of Energy, Empire will be able use
5 them as RES resources.

6 **Q. Is there an alternative to your recommendation of not including the**
7 **replacement value of the PPAs in the MPPM?**

8 A. Yes. Instead of a PPA replacement value based on the amount of generation of the
9 current PPAs, a benefit could be included in the MPPM equal to the lesser of the
10 least-cost manner of meeting the RES at the time renewables are needed or the
11 portion of the wind projects revenue requirement consistent with the RES
12 requirement. The RES requirement of the wind projects would be the RES MWh
13 needed after taking into account the energy generated at Empire’s Ozark Beach
14 Dam. The wind projects benefit calculation would also take into account the 1.25
15 multiplier for energy generated in Missouri.

16 **Q. Have you estimated the impacts of your recommendations on the MPPM**
17 **cost/benefit estimate that Empire provided in response to your data request**
18 **number 8075?**

19 A. Empire’s MPPM, when updated assuming a rate case every four years to reset rate
20 base, a Missouri jurisdictional allocation factor of 0.88, RES benefit calculated as
21 a portion of the wind project revenue requirement, and accounting for interest at
22 3.25%, provides the following estimates:

1 **

2 **

3 The \$130 million that Empire would be required to return to its customer is a large
4 amount of money. It would be a large amount that customers would have already
5 paid. However, it is less than 45% of the return that Empire’s customers would
6 have paid on these wind projects. It is also important to remember that at the end
7 of year ten customers would have already paid this amount because Empire had
8 represented to the Commission that these wind projects would be beneficial to its
9 customers.

10 If in the alternative, the losses were split 50/50, Empire would return to
11 customers ** _____ ** of the return customers had already paid
12 to Empire.

13 **Q. Do you have any other recommendations regarding the MPPM?**

14 A. Yes. The Commission should require the submission of monthly reports that
15 itemize the costs and the benefits included in the MPPM along with the cumulative
16 value of costs and benefits that are being tracked for amortization in the next rate
17 case.

18 **Q. Would you summarize this section of your testimony regarding the MPPM?**

19 A. The MPPM is a mechanism that compares the costs and benefits of the wind
20 projects. As such a mechanism, it should include all costs and benefits. Based on
21 the shift in the estimates of the outcome of the MPPM, the risk of costs being greater
22 than benefits in the first ten years should shift away from the customers at the end
23 of year ten, to Empire.

1 I am not requesting that the Commission find Empire imprudent and
2 disallow costs, I am asking the Commission to make modifications to the MPPM.
3 If Empire’s analysis and projections are correct, my recommended changes are
4 nothing more than tracking. I recommend that the Commission modify the MPPM
5 to provide Empire’s customers surety if time shows that Empire’s modeling and
6 assumptions were inaccurate.

7 **Q. Would you summarize your recommendations regarding the MPPM?**

8 **A.** The following are my recommendations:

- 9 1. The MPPM should include all costs and benefits as paid and received by
10 Empire’s customers
- 11 • Costs as included in revenue requirement remain the same until revenue
 - 12 requirement is changed;
 - 13 • Include the cash distributions to Empire;
 - 14 • Include PISA costs;
 - 15 • Separately identify paygo as a benefit; and
 - 16 • Separately identify REC costs and revenues.
- 17 2. Estimated benefits of paygo and PTCs should be included in Empire’s rate
18 case revenue requirement with tracking mechanisms to reconcile to actuals
19 in Empire’s next rate case.
- 20 3. SPP IM revenues and REC revenues should be included in Empire’s FAC
21 with tracking mechanisms to reconcile to actuals in Empire’s next rate case.
- 22 4. Interest should be paid on the Annual Wind Values.
- 23 5. Energy jurisdictional allocation factor should be applied each year based on
24 the energy usage of all jurisdictions for that year.
- 25 6. Cap of \$26.25 million on losses absorbed by customers.
- 26 • Alternative would be to split losses 50/50.
- 27 7. No PPA replacement value in MPPM.

- Alternative would be to include a benefit equal to the lesser of the least-cost manner of meeting the RES at the time renewables are needed or the portion of the wind projects revenue requirement consistent with the RES requirement.

I have attached as Schedule LMM-D-3 a description of the revised MPPM with changes I am recommending.

OPC’s Recommended Modifications to Empire’s FAC

Q. What modifications to Empire’s FAC do you recommend that the Commission order?

A. I recommend the Commission modify Empire’s FAC to:

1. Include language that would allow the mitigation of the impact of extraordinary net fuel and purchase power costs;
2. Explicitly prohibit recovery of retirement and/or decommissioning costs related to the retirement of a generation plant;
3. Explicitly prohibit recovery of fuel and purchased power costs for research and development;
4. Update the percentage of SPP costs recovered; and
5. Include the same percentage of SPP transmission revenues associated with the SPP transmission costs recovered.

Q. Why are you recommending that Empire’s FAC be modified to accommodate extreme cost changes?

A. The extended freeze in mid-February 2021 resulted in increases in fuel, purchased power and market revenues that, if passed through Empire’s FAC would have had a tremendous impact on its customers’ ability to pay their electric bills. The restriction by statute that FACs can only be changed in rate cases limited the remedies available in this situation. Even so, the utilities are looking at different ways to recover their winter storm costs.

1 The utilities' FACs should be modified to provide clarity to the companies,
2 their customers, and the Commission for how this type of sudden, sharp change in
3 costs will be handled in a manner that is affordable to customers while still allowing
4 the utilities cost recovery with an opportunity for the Commission to review the
5 prudence of those extraordinary costs.

6 **Q. Do you have specific language that you are recommending be added to**
7 **Empire's FAC tariff sheets?**

8 **A.** I recommend the following language for recovery of extraordinary costs:

9 When extraordinary net costs have been incurred in an accumulation period,
10 for good cause the Commission may allow (after opportunity for any party
11 to be heard) the recovery period to extend beyond six months. The amount
12 not recovered will be added to subsequent recovery periods with a true-up
13 for the extraordinary cost at the end of the Commission approved recovery
14 time period for the extraordinary cost.

15
16 While in all likelihood the party asking for an extended recovery period for
17 extraordinary cost would be Empire, this provision would allow for the
18 Commission or any party to ask for an extension of the time over which
19 extraordinary costs would be recovered. While any party can ask for an extended
20 recovery period, the extension must be Commission approved.

21 Under this tariff sheet provision, the recovery period could be extended.
22 Customers would be responsible for interest at the short-term interest rate
23 prescribed for the FAC by statute and would only pay 95% of the costs above the
24 amount included in the base rates. However, the language does not preclude
25 Empire from requesting in a case before the Commission, different treatment for
26 deferring extraordinary costs in a liability account for potential future recovery.

27 This language is similar to the tariff language the Commission recently
28 approved for The Empire District Gas Company and Liberty Utilities Midstates
29 Natural Gas in their purchased gas adjustment tariff sheets. I recommended similar

1 language be added to the Ameren Missouri FAC tariff sheet in Ameren Missouri's
2 rate case ER-2021-0240.

3 **Q. Why are you recommending that the Commission order language added to**
4 **Empire's FAC tariff sheets to explicitly prohibit Empire from recovering**
5 **retirement and/or decommissioning costs related to the retirement of a**
6 **generation plant through its FAC?**

7 A. Empire's FAC includes fuel costs associated with generating plants. Retirement
8 and decommissioning costs are not costs incurred to generate electricity therefore
9 these costs should not flow through a FAC.

10 **Q. Why are you making this recommendation now?**

11 A. Empire and Evergy Metro both included in their FACs final "coal inventory
12 adjustments" for basemat coal of generation plants at retirement, only to remove
13 them when opposed. Modifying the FAC to specifically state retirement and
14 decommissioning costs are not FAC costs should prevent this from happening
15 again.

16 **Q. Does this mean that Empire cannot recover retirement and decommissioning**
17 **costs?**

18 A. No. It can still request recovery of such costs, but not through its FAC.

19 **Q. Why do you recommend Empire's FAC be modified to require removal of fuel**
20 **and purchased power costs for research and development projects?**

21 A. While I am not aware that Empire has any such research and development project,
22 Ameren Missouri does have such a project, and the issue arose there. For Empire
23 this is preventative language. It is better to have such language and not need it than
24 to need it and not have clear language in the FAC tariff sheets.

1 **Q. What is your recommendation regarding the percentage of SPP transmission**
2 **costs and revenues that should be included in Empire’s FAC?**

3 A. I am recommending that the Commission continue with the methodology it has
4 approved for Empire and the other Missouri electric utilities using the fuel and
5 purchased power costs estimated by Staff and based on the most currently available
6 information.

7 **Q. On what is the current percentage based?**

8 A. In its *Report and Order* in the Empire rate case ER-2014-0351, the Commission
9 found the Empire’s transmission costs that should be included in its FAC were:

- 10 1) The costs to transmit electric power it did not generate to its own
11 load (true purchased power); and
12 2) The costs to transmit excess electric power it is selling to third
13 parties to locations outside the SPP (off-system sales).

14 Empire and the parties in its next general rate case, ER-2016-0023, agreed
15 to continue to use this methodology to determine how much of the non-
16 administrative SPP costs were to be included in its FAC. In the last rate case,
17 ER-2019-0374, Empire asked, as it has in this case, for the all of its SPP
18 transmission costs to be included in its FAC. The Commission found changing to
19 100% of SPP costs being included in Empire’s FAC would be inconsistent with
20 prior Commission rulings and with the transmission percentages included in the
21 other Missouri electric utilities’ FACs.

22 This is still the way the percentage of regional transmission organization
23 (“RTO”) transmission costs included in the other utilities FACs are calculated and
24 for the percentage of transmission revenues Ameren Missouri includes in its FAC
25 also.

1 **Q. Why are you proposing transmission revenues be included in Empire’s FAC?**

2 A. Empire receives revenues under the same SPP schedules for which it is assessed
3 charges. For consistency, the costs should be offset by the revenues received for
4 that same service.

5 **Q. Does this conclude your direct testimony?**

6 A. Yes.