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October 11, 2018

RECEIVED

OCT 12 2018

PUBLIC SERVICE
COMMISSION

Gwen R. Pinson
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: In the Matter of The 2017 Integrated Resource Plan Of Big Rivers Electric Corporation, Case No. 2017-00384

Dear Ms. Pinson:

Please find enclosed for filing in Case No. 2017-00384 before the Kentucky Public Service Commission the original and ten (10) copies of the ***public*** version of Ben Taylor and Sierra Club's Comments on the 2017 Integrated Resource Plan of Big Rivers Electric Corporation ("Comments") and the ***public*** version of the attachment ("Synapse Report").

Also enclosed is one (1) sealed copy of the ***confidential*** information being filed pursuant to previously filed petitions for confidential treatment. Pages 4 through 8 of the Comments and pages 2 and 5 of the attached Synapse Report include confidential information that is subject to petitions for confidential treatment filed in this proceeding on July 20, 2018 and September 14, 2018. Please let me know if you have any questions.

Thank you for your attention to this matter.

Sincerely,

Joe F. Childers

Joe F. Childers

Enc.

Public Version

RECEIVED

OCT 12 2018

PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF: THE 2017 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	: : :	**Case No. 2017-00384**

BEN TAYLOR AND SIERRA CLUB'S COMMENTS ON THE 2017 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION

(PUBLIC VERSION)

Intervenors Ben Taylor and Sierra Club (collectively "Environmental Intervenors") hereby comment on Big Rivers Electric Corporation's ("Big Rivers" or "Company") 2017 Integrated Resource Plan ("IRP"). Big Rivers' IRP suffers from shortcomings similar to those that plagued its 2014 IRP, as the Company has failed to openly and transparently evaluate the range of risks facing the Company or the variety of resource options for minimizing and responding to such risks. Now, more than four years after losing approximately 60% of its customer load, the utility's rates have nearly doubled, while the Company has had only limited success in acquiring new customers. Yet Big Rivers' 2017 IRP proposes a continuation of this flawed strategy while failing to meaningfully consider retiring some or all of its coal capacity and/or ramping up lower cost clean energy resources. Based on these shortcomings, Big Rivers has failed to satisfy the requirements or purpose of the IRP process and is not on the path to achieving a least-cost, least-risk energy future for its ratepayers.

As discussed below, the IRP is a flawed document that fails to satisfy the standards of Kentucky law because, among other reasons:

- Big Rivers' strategy of maintaining all the generation that it owns while attempting to acquire new non-member customers is costly for its captive customers;

- Big Rivers continues to keep the Coleman Station and Reid Unit 1 idled, rather than retiring those plants, thus forcing its customers to cover the cost of maintaining capacity even though the significant cost of bringing that capacity back online makes it highly unlikely that Big Rivers would ever do so;

- Big Rivers' purported evaluation of whether to retire the Wilson and Green plants was fatally flawed and biased in favor of continued operation of those plants;

- Big Rivers failed to make a real effort to diversify its energy portfolio by dismissing renewable energy resources in its IRP after only a cursory consideration that relied on outdated information; and

- Big Rivers has chosen to eliminate nearly all of its Energy Efficiency and Demand Response programs even though its own studies show that the programs provide additional savings for its customers.

Until these serious shortcomings in Big Rivers' IRP are remedied, the reasonableness of the Company's future actions relying on this resource planning is suspect. As such, the Commission Staff should find the IRP to be inadequate and require Big Rivers to address each of these shortcomings in all future resource planning and decision-making.

I. IRP Standards

The IRP process in Kentucky is governed by 807 KAR 5:058, which requires Big Rivers to submit every three years a plan that discusses historical and projected demand, resource options for satisfying that demand, and the financial and operating performance of Big Rivers' system.[1] Core elements of the filing include:

- A base load forecast that is "most likely to occur and, to the extent available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system."[2]

- A "resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost."[3]

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[1] 807 KAR 5:058 Section 1(2).
[2] 807 KAR 5:058 Section 7(3).
[3] 807 KAR 5:058 Section 8(1).

- A consideration of "the potential impacts of selected, key uncertainties and . . . the assessment of potentially cost effective resource options available to the utility.[4]

- The revenue requirements and average system rates resulting from the plan set forth in the IRP.[5]

As the Commission Staff stated in reviewing Big Rivers' last IRP filing:

> The Commission's goal was to ensure that all reasonable options for the future supply of electricity were being examined in order to provide ratepayers a reliable supply of electricity at the lowest possible cost.[6]

The Staff further explained that, in reviewing an IRP, their goals are to ensure that:

1. All resource options are adequately and fairly evaluated;

2. Critical data, assumptions, and methodologies for all aspects of the plan are adequately documented and are reasonable; and

3. The report includes an incremental component addressing the Staff's findings regarding the utility's previous IRP.[7]

Evaluation of an IRP should also be guided by the overall requirement that utility rates are "fair, just, and reasonable."[8] As the Commission has explained, it has long been recognized that "'least cost' is one of the fundamental principles utilized when setting rates that are fair, just, and reasonable."[9] A utility's rates will almost certainly not be fair, just, and reasonable if they do not result from planning processes that seek to determine the least-cost/least-risk resource plan.

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[4] *Id.*
[5] 807 KAR 5:058 Section 9.
[6] Kentucky PSC, Staff Report on the 2014 Integrated Resource Plan of Big Rivers Electric Corporation, Case No. 2014-00166 (Dec. 2015), at 2 (hereinafter "2014 IRP Staff Report").
[7] *Id.* at 3.
[8] KRS § 278.030(1); KRS § 278.040; *Kentucky Public Service Com'n v. Com. ex rel. Conway*, 324 S.W.3d 373, 377 (Ky. 2010).
[9] *In the Matter of: Application of Kentucky Power Co.*, Case No. 2009-00545, 2010 WL 2640998 (Ky. P.S.C. 2010).

II. Big Rivers' Strategy of Maintaining All of Its Owned Generation While Attempting to Acquire New Non-Member Customers Is Costly for Its Captive Customers.

Rather than shedding its excess capacity, the Company continues to attempt to mitigate the loss of nearly two-thirds of its peak load through a strategy of selling some of the excess capacity and energy to non-members, while idling rather than retiring the rest. The result of this strategy has been to greatly increase rates for Big Rivers' captive customers. For example, wholesale rates for the rural customer class have skyrocketed in recent years, from $37.26/MWh in 2010[10] to $83.60/MWh in 2017[11]—and those rates are forecasted to [redacted].[12] Large industrial rates have also escalated, though not as steeply, going from $33.93/MWh in 2010[13] to $64.52/MWh in 2017.[14]

Further evidence of the uneconomic nature of Big Rivers' strategy is shown by the fact that the Company's MISO market expenses of $52,841,000 in 2017 exceeded its MISO market revenues of $14,869,000 that year by a factor of more than three.[15] Similarly, the Company's own modeling projects that its total generation will decline by more than 1.5 million MWhs between 2019 and 2023, and that the Company will rely on MISO market purchases to meet between 34,000 and 513,000 MWhs of its total energy demand in each year from 2021 through 2026.[16]

[10] SC 2-35.
[11] SC 1-32. While presented differently, similar increases in Big Rivers' prices were also shown in a recent power point presentation by Kentucky PSC Staff, which showed average electricity prices for Big Rivers' residential and commercial customers increasing from around 7 cents per kWh in 2010 to nearly 11 cents per kWh in 2016. *See* Electric Generation in Kentucky, Kentucky Public Service Commission, June 7, 2018, *available at* http://www.lrc.ky.gov/CommitteeMeetingDocuments/262/index.html.
[12] SC 1-32 CONFIDENTIAL.
[13] SC 2-35.
[14] SC 1-32.
[15] PSC 2-6a Attachment.
[16] Big Rivers Electric Corporation 2017 Integrated Resource Plan (Sept. 21, 2017) ("IRP") at 124, Table 7.9.

When asked in discovery why a utility with significant levels of excess capacity would be acquiring substantial amounts of energy from the MISO market, Big Rivers explained that it was "strictly due to economics," as the Company's modeling projects that it would be more economic for Big Rivers to acquire such amounts of energy from the MISO market than to generate it.[17] This suggests a serious shortcoming in Big Rivers' resource strategy, which is compounded by the fact that Big Rivers has failed to demonstrate that its non-member contracts are profitable. Instead, as detailed in the attached memo from Synapse Energy Economics, Big Rivers' assessment of those contracts suffers from three primary flaws.

First, [redacted].[18] [redacted]. Second, [redacted]

To keep its coal fleet operational, Big Rivers is required to incur costs for capital and major maintenance spending, along with other fixed O&M expenses. [redacted].[19] Finally, there is no mention of the sensitivity of the contracts to fuel price fluctuations. When Big Rivers modeled high coal price sensitivities in its IRP, the model recommended a switch to gas at the Green 1 and 2 units.[20] This switch would involve an additional capital investment that would increase the contract costs and subject the contracts to any volatility in gas price that might occur.

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[17] SC 1-28.
[18] SC 2-32 CONFIDENTIAL.
[19] SC 2-2 CONFIDENTIAL.
[20] IRP at 138.

In short, the available evidence shows that Big Rivers' strategy of maintaining all of the generation that it owns while attempting to acquire new non-member customers is costly for its captive customers. Unfortunately, as discussed below, Big Rivers' 2017 IRP fails to meaningfully evaluate options to reduce those costs by retiring excess capacity and pursuing lower cost resource options.

III. Big Rivers Continues to Delay Any Meaningful Evaluation of Whether to Retire, Rather than Idle, the Coleman Station and Reid Unit 1.

Despite the increasing costs that the Company's resource strategy is placing on captive customers who are being asked to support increasingly uneconomic generation, Big Rivers' 2017 IRP proposes to continue that same strategy without meaningfully evaluating other, lower-cost, lower-risk options such as retirement of excess capacity.

One area where such costly inertia is proposed to continue is the Company's plan for long-term idling of its Coleman Station and Reid Unit 1 plants. The Coleman Station has been idled since May 2014 at an annual cost of approximately $2.55 million in 2017 and $2.8 million in 2016.[21] Big Rivers incurs these costs to keep the plant idled apparently on the hope that it will someday be economic to bring Coleman back online. But there is simply no reasonable basis to conclude that it would ever be economic for Coleman to come back online, given that the Company has excess capacity, that market conditions are increasingly unfavorable for aging coal units, and that by the Company's own estimate it would need to make nearly [redacted] in capital expenditures to restore the Coleman Station and bring the unit into environmental compliance.[22]

[21] SC 1-5.
[22] AG 1-7 CONFIDENTIAL.

The unreasonableness of this long-term idling strategy is further illuminated by the fact that Big Rivers cannot identify the market conditions under which the Coleman plant could be economically returned to service. Big Rivers was unable to identify the likelihood that the plant, which has now been removed from the MISO interconnection queue,[23] would ever be economic during the IRP planning period assuming either the base case market conditions or any of the seven market scenarios that the Company modeled in its IRP.[24] In fact, Big Rivers did not even include the Coleman Station in the IRP modeling process.[25] Instead, Big Rivers weakly contends only that it is waiting for "clarity surrounding the Clean Power Plan" to make a decision regarding the future of the Coleman Station.[26] But as the Commission Staff noted in the context of Big Rivers' 2010 IRP, "waiting until events are known tends to defeat the purpose of prudent risk analysis and planning."[27] This is especially true given that the Coleman Station is plainly uneconomic to return to service even if one assumes that no carbon regulation is put into place during the IRP planning process.[28]

Big Rivers has also failed to meaningfully evaluate whether to retire the Reid Unit 1 plant. Reid Unit 1 has been idled since April 2016 at an annual cost of approximately $2.5 million in 2017.[29] Additionally, Big Rivers estimates that it would need to make approximately [redacted] in capital expenditures to return the unit to service by converting it to gas and

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[23] SC 1-6.
[24] SC 2-30.
[25] SC 2-30.
[26] *See* Focused Management Audit Progress Report Oct. 4, 2017, Recommendation 3.
[27] Kentucky PSC, Staff Report on the 2010 Integrated Resource Plan of Big Rivers Electric Corporation, Case No. 2010-00443 (Dec. 2011), at 21.
[28] Big Rivers also contends that retiring Coleman would "increase costs," SC 2-12, which is presumably a reference to costs related to decommissioning the plant and recovering its remaining net book value. But those costs will ultimately be incurred whenever the plant inevitably retires, of course, and therefore do not provide a basis to continue spending additional sums to keep idling a plant that is plainly uneconomic to return to service.
[29] SC 2-23.

bringing the unit into environmental compliance.[30] Although [redacted], Big Rivers did not include Reid Unit 1 in the IRP modeling process.[31] The Company stated that it intends to keep Reid Unit 1 idled through 2032 or until economic market conditions could support the necessary capital expenditures and provide economic benefit to its members.[32] However, Big Rivers has not even attempted to evaluate the levels to which energy prices, capacity prices, peak demand, and/or energy requirements would have to increase in order for it to be economic to bring Reid Unit 1 back online.[33] It simply makes no economic sense to continue spending millions of dollars per year to maintain an idled generating unit for which the Company has no idea whether or under what market conditions it might return to service in the future.

By failing to even evaluate the future of Coleman Station and Reid Unit 1 in the 2017 IRP, Big Rivers has not ensured "that all reasonable options for the future supply of electricity were being examined in order to provide ratepayers a reliable supply of electricity at the lowest possible cost." As a result, the Company's filing fails to satisfy the basic standards for an IRP set forth in 807 KAR 5:058.

IV. Big Rivers' Purported Evaluation of Whether to Retire the Wilson and Green Units Was Fatally Flawed and Biased Against Such Retirement.

Big Rivers purports to have evaluated, in the IRP, whether to retire the Wilson or Green units by letting its model select retirement of one or more of those units if it deemed such retirement to be the most economic option. However, this modeling was fatally flawed in at least

[30] *Id.* CONFIDENTIAL.
[31] IRP at 138.
[32] AG 1-8.
[33] SC 2-23.

two ways, each of which biased the results against the retirements that were purportedly being evaluated.

First, the Company included in the modeling the remaining net book value for the Wilson and Green units as a cost that would be incurred if one of those units were retired.[34] As of January 1, 2017, that value was approximately $415 million for Wilson and $172 million for the Green units.[35] Remaining net book value, however, is a sunk cost that will be recovered from customers regardless of whether those generating units are retired or continue operating. As such, that value is irrelevant to the question of whether, moving forward, it would be lower cost to retire versus continue operating the Wilson or Green units. Certainly, if it is determined that retirement of one or more of those units is the least-cost option, there should be an evaluation of the most reasonable ways to provide for recovery of the remaining net book value. But factoring that sunk cost into the evaluation of whether to retire the unit in the first place improperly skews the analysis against retirement.

A second way that the modeling analysis was biased against retirement of Wilson and/or the Green units was by limiting the model to only three potential replacement resources – 20 MW solar units, 100 MW gas combustion turbine, and/or a 702 MW gas combined cycle plant.[36] In doing so, Big Rivers apparently limited its universe of potential replacement options to only those for which 2016 EIA capital cost data existed.[37] As discussed in the attached memo from Synapse Energy Economics, however, that EIA data is outdated, overly conservative, and does not provide a reasonable assessment of what costs are likely to be in even the next few years much less the 15-year IRP planning period at issue here. Given the wealth of information

[34] SC 1-19.
[35] SC 1-38(f).
[36] IRP at 114-15.
[37] *Id.* at 114.

available regarding the costs of new and existing generation resources, there is simply no reasonable basis to restrict the pool of potential replacement options to only a subset of those identified in the 2016 EIA report.

In addition, the 702 MW gas combined cycle option is especially ill-suited to this retirement analysis given the significant levels of excess capacity that would result from using it to replace Wilson or either (or both) of the Green units. As the Company acknowledged in response to a data request, replacement of Wilson or a Green unit with a 702 MW gas combined cycle plant would lead to a reserve margin of between 72.9% and 96.9%, when the Company only needs 15.8%.[38] In fact, the only way for Big Rivers to include the 702 MW gas combined cycle plant was to allow for a maximum reserve margin of 105%, which is so excessively high as to render the analysis essentially meaningless.[39] There is simply no reasonable basis for Big Rivers to model such excessively high reserve margins especially given that the Company already has excess capacity.

In short, any assessment of the economics of retiring the Wilson and/or Green units should be based on reasonable forecasts of only the forward-looking costs and revenues of those units compared. Those costs and revenues should be compared to a full range of potential replacement resources, including reasonably priced renewables and storage, and increased efficiency and demand response. And the capacity of replacement resources assumed in a retirement scenario should reasonably closely match the level of capacity that Big Rivers would need to maintain the 15.8% reserve margin that it has identified, rather than continuing Big

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[38] SC 1-26 and Attachment.

[39] IRP at 122. Big Rivers' decision to model a 702 MW gas combined cycle plant as a replacement option is especially questionable given that the 2016 EIA report also provided data regarding a 429 MW gas combined cycle and 237 MW gas combustion turbine, both of which were inexplicably excluded from Big Rivers' modeling. SC 2-26.

Rivers' status as a utility with significant levels of excess capacity. Big Rivers' failure to take such an approach renders its purported evaluation of whether to retire the Wilson and/or Green units essentially meaningless.

V. Big Rivers' IRP Fails to Assess and Pursue Cost-Effective Clean Energy Resources.

In order to achieve the core purpose of the IRP process, an IRP must not be limited to a single resource plan, but instead must "describe and discuss all options considered for inclusion in the plan," including an assessment of existing generation sources, potential new generation sources, and nonutility generation options.[40] The resource plan must also "consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility."[41] Through such a process, the utility can then determine which potential resource portfolio performs best under a range of potential future conditions, so that the utility can develop a plan that provides "an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost."[42]

As detailed in the attached memo from Synapse Energy Economics, Big Rivers has failed to properly assess likely cost-effective resource options such as solar, wind, and energy storage. Instead, Big Rivers dismisses such resources on the claims that "solar has not been proven to be economical in western Kentucky,"[43] and that "western Kentucky is currently not a viable location for onshore wind."[44] However, Big Rivers relied on outdated and overly conservative capital cost assumptions to model utility-scale solar and to choose not to consider onshore wind

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[40] 807 KAR 5:058 Section 8(2).
[41] 807 KAR 5:058 Section 8(1).
[42] 807 KAR 5:058 Section 8(1).
[43] SC 1-22.
[44] IRP at 133.

or energy storage. Furthermore, Big Rivers acknowledges that it did not attempt to obtain the market data needed to include power purchase agreements for renewables as a resource option in any of the modeling scenarios[45] or sensitivities presented in the IRP, or the data needed to evaluate building, acquiring, or contracting wind generating sources beyond its western Kentucky service area.[46]

Big Rivers failed to properly evaluate onshore wind and energy storage by relying on overly-conservative cost assumptions and out-of-date studies. The Company did not include energy storage in its IRP modeling process because it considered the technology too expensive at the assumed capital cost of $2,724 per kW, which is more than a third higher than Lazard's reported costs of $1,388 to $1,700 per kW for 2017 and $1,166 per kW in 2018. As for onshore wind, Big Rivers used out-of-date wind resource potential studies from 1986 and 2010; only evaluated wind potential at 10 and 50 meters even though wind blows stronger at higher elevations and generation potential jumps significantly; and did not explore siting alternatives outside of the northwest Kentucky region, such as abutting states with very high wind resource potential. Big Rivers' decision to exclude onshore wind and energy storage from the IRP modeling process is problematic because it obscures the full resource input assumptions (e.g., annual cost decline, battery size and duration, and use case) and does not allow the utility to understand the impact of alternative cost decline assumptions.

Big Rivers did not make a real effort to evaluate and pursue solar power. Big Rivers only considered three solar resources in its IRP because the Company believes that "while solar construction costs are projected to come down, solar energy costs are currently not competitive

[45] SC 2-20.
[46] SC 2-21.

with other power source options."[47] As a result, Big Rivers determined in its IRP that only including the 20 MW fixed solar unit as a possible generation resource was sufficient.[48] However, Big Rivers relied on outdated capital cost assumptions from November 2016 without applying a technology cost decline factor, or inflation, to convert the value to 2017 costs. Additionally, Big Rivers relied on cost assumptions generally based on retrospective analysis and observed trends rather than forward pricing. Lazard's *2017 Levelized Cost of Energy* study, which is focused on the cost of projects today and what the market can expect to see in the next few years, reports capital costs of $1,100 to $1,400 per kW for utility-scale solar—more than 50% lower than the values that Big Rivers relied on. Big Rivers' claims are also questionable in light of the Kentucky Municipal Energy Agency's ("KyMEA") recently executed agreement to bring a new solar power plant to western Kentucky that will be among the top 2%-largest solar power plants in the nation and the largest in Kentucky by nearly tenfold.[49] Additionally, Owensboro Municipal Utilities has entered into a power purchase agreement with KyMEA to purchase 32 MW of the 86 MW solar farm.

Thus, although Big Rivers suggests otherwise, renewables are in fact viable, economical generation resources for utilities in Kentucky. Big Rivers' failure to meaningfully evaluate such wind, solar, and energy storage resources is a missed opportunity to reduce costs and risks for its customers, and represents a significant shortcoming in its 2017 IRP.

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[47] SC 1-22.
[48] *Id.*
[49] *Solar Power Project to Supply Part of Energy Needs in Area in 2022*, The Daily Independent, Sept. 4, 2018, http://www.dailyindependent.com/kentucky/news/solar-power-project-to-supply-part-of-energy-needs-in/article_0d1c93f7-5e3f-5f64-9a6a-f2cb51e17f94.html.

VI. Big Rivers' IRP Eliminates Nearly All of Its Demand-Side Management Programs Even Though Its Own Studies Show That the Programs Provide Its Customers Additional Savings.

Big Rivers plans to forgo opportunities for additional member savings by proposing to eliminate nearly all of its energy efficiency and demand response programs even though the studies that the Company has commissioned show that these demand-side management ("DSM") programs benefit its customers. For one, Big Rivers commissioned an Energy Efficiency and Demand Response Potential study, which identified a "$2 million" energy efficiency program that would yield $43 million in net benefits, which the Company is choosing not to pursue.[50] Instead, the Company has chosen to pursue another, "$1 million" energy efficiency program with the least amount of net benefits among the options it considered.[51] At less than $19 million in net benefits, the $1 million program is expected to yield less than half the net benefits of the $2 million program. Furthermore, Big Rivers has proposed to phase out nearly all of its DSM programs, including four programs with a Total Resource Cost ("TRC") greater than 1.0, three of which are near or greater than 2.0.[52] According to the Company, "TRC values have continued to trend down with most programs becoming non-cost effective,"[53] but Big Rivers' own studies show otherwise. Big Rivers' proposed decision to eliminate nearly all of its DSM programs defies the record and prevents its customers from benefiting from the additional savings that would result from pursuit of cost-effective DSM programs.

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[50] IRP, Appendix B at 3.
[51] *Id.*
[52] *In re Demand-Side Management Filing of Big Rivers Electric Corporation on Behalf of Itself, Jackson Purchase Energy Corporation, and Meade County R.E.C.C. and Request to Establish a Regulatory Liability*, Case No. 2018-00236, Big Rivers Electric Corporation Application, July 6, 2018, Exhibit A at 6.
[53] SC 2-24.

VII. Conclusion

Big Rivers has failed to satisfy the basic standards for an IRP set forth in 807 KAR 5:058. As explained above, Big Rivers proposes to implement a strategy of maintaining all the generation that it owns, including the idled Coleman Station and Reid Unit 1, while attempting to acquire new non-member customers. This strategy forces its captive customers to cover the cost of maintaining capacity even though the significant cost of bringing the idled plants back online makes it highly unlikely that Big Rivers would ever do so. Furthermore, the Company's purported evaluation of whether to retire the Wilson and Green plants was fatally flawed and biased in favor of continued operation of those plants. Big Rivers also failed to adequately evaluate renewable energy resources in its IRP and has chosen to eliminate nearly all of its DSM programs even though its own studies show that the programs provide additional savings for its customers. As a result, the Commission Staff should find the IRP to be inadequate and require Big Rivers to address these shortcomings in all future resource planning and decision-making.

Respectfully submitted,

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Dated: October 11, 2018

CERTIFICATE OF SERVICE

Counsel certifies that an original and ten (10) copies of the ***public*** version of the foregoing (including the public attachment) and one (1) sealed copy of the ***confidential*** version of the foregoing (including the confidential attachment) were transmitted to the Commission via overnight courier for filing; counsel further states that true and accurate copies of both the confidential and public versions of the foregoing (including the public attachment and the confidential attachment), were mailed via First Class U.S. Mail to:

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This 11th day of October, 2018.

JOE F. CHILDERS

Public Version

Synapse Energy Economics, Inc.

Memorandum

TO: SHANNON FISK AND MYCHAL OZAETA, EARTHJUSTICE

FROM: DEVI GLICK, SYNAPSE ENERGY ECONOMICS

DATE: OCTOBER 10, 2018

RE: BIG RIVERS 2017 INTEGRATED RESOURCE PLAN

Introduction

Big Rivers Electric Corporation's (BREC) 2017 Integrated Resource Plan recommended that the utility continue to idle Coleman and Reid Unit 1, operate its three coal units (along with the gas combustion turbine (CT), and the hydro purchase from the Southeastern Power Administration (SEPA)) to serve member and non-member load, and exit from the Henderson Municipal Power & Light (HMP&L) contract. The IRP did not recommend any renewable capacity additions and assumed that BREC will continue to sell excess capacity through both short and long-term contracts, rather than retiring an additional coal unit.

Synapse Energy Economics has reviewed the reasonableness of the alternative resource assumptions used in the model, and the profitability of non-member contracts for short and long-term sales. We found that Big Rivers relied on unreasonably conservative cost assumptions for renewable resources, and omitted battery storage and wind from the model altogether. Additionally, we found that the revenue from some of the long-term contracts is not sufficient to cover the contract's share of system average fixed costs, and that continued reliance on short-term optimized sales will subject the utility to volatile and uncertain revenue streams that could fall short of covering the associated production costs.

Alternative Resource Options

Big Rivers failed to adequately consider solar photovoltaic (PV), onshore wind, and battery storage as alternative resource options in its IRP. The utility relied on outdated (2016) and overly conservative capital cost assumptions from the U.S. Energy Information Administration (EIA) to model utility-scale solar PV. Big Rivers did not consider onshore wind due to the utility's determination that there are no viable locations to site a wind plant in the region. Additionally, the utility dismissed battery storage from consideration based on its assessment that the technology costs were too high to warrant including in the model. As a result, Big Rivers failed in its IRP to identify and evaluate the potential to pursue clean energy resources that could diversify its resource portfolio while reducing cost and risk for its customers.

Solar PV

Big Rivers only considered one type of solar resource in its IRP - a 20 megawatt (MW) utility-scale fixed axis solar PV facility at a capital cost of $2,399 per kilowatt (kW).[1] [redacted]

These capital cost inputs came from the EIA's *Capital Cost Estimates for Utility Scale Electricity Generating Plans* published in November 2016. However, Big Rivers used the 2016 value for 2017 without applying a technology cost decline factor (or inflation) to convert the value to 2017 costs.[2]

The EIA's cost assumptions that Big Rivers relied upon are incredibly conservative. EIA itself admitted that it "did not anticipate the sharp decline in solar PV costs seen over the past several years."[3] Additionally, the EIA costs are generally based on retrospective analysis and observed trends; they are not focused on forward pricing. In contrast, Lazard's *2017 Levelized Cost of Energy* study provides cost projections focused on what projects cost today and what the market can expect to see in the next few years. Lazard's 2017 study reports capital costs of $1,100 to $1,400 per kW for utility-scale solar PV. These costs are more than 50 percent lower than the values that Big Rivers relied on. A third source for costs, NREL's *U.S. Solar Photovoltaic System Cost Benchmark* report, reports a 2017 installed cost for utility-scale PV of $1.11 per watt for one-axis tracker and $1.03 per watt for fixed-tilt,[4] which is generally consistent with the Lazard numbers cited above. In SC 2-27, Big Rivers claims that it reviews this report annually, yet it has not integrated the costs from this report into its IRP analysis.

Additionally, Big Rivers did not run any solar cost sensitivities or scenarios to understand the impact on resource portfolio results if solar costs decline faster than projected. Big Rivers also did not issue any requests for proposals (RFP) or other competitive procurement processes to gather information on the availability and cost of installing utility-scale solar in the region. The utility claims that it did not evaluate tracking solar resources because it "has not been proven to be economical in western Kentucky" and is still not competitive with other generation resources.[5] This claim is unsubstantiated and questionable in light of the recent announcement from Kentucky Municipal Energy Agency (KyMEA) that the agency has signed a contract for 86 MW of solar that will begin in 2022.[6]

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[1] Big Rivers IRP, Page 114.

[2] In response SC 2-15, Big Rivers claims that this error should not matter because uncertainty surrounding the Section 201 Solar Tariff case caused module prices to rise in late 2017 anyway. This claim distracts from the incorrect methodology that BREC used in projecting solar costs.

[3] Wind and Solar Data and Projections from the U.S. Energy Information Administration: Past Performance and Ongoing Enhancements. March 2016.

[4] U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017. NREL. September 2017.

[5] SC 1-22.

[6] Weaver, J. 2018. "Kentucky tips crown to solar power with one project to triple capacity." *PV Magazine*, September 12, 2018.

Battery Storage

Big Rivers did not include battery storage in its model because the utility considered the technology too expensive at the assumed capital cost of $2,724 per kW.[7] The EIA cost assumptions the utility used to make this decision are, as with solar PV, conservative (see above for a full explanation). Lazard's *Levelized Cost of Storage Analysis Version 3.0* reports capital costs of $1,388 to $1,700 per kW for 2017 and projects a cost of $1,166 per kW in 2018 for 4-hour Lithium-ion batteries in a Peaker replacement use case.[8] Big Rivers assumed capital costs are more than a third higher than Lazard's reported costs.

The decision to omit battery storage is problematic because it obscures the full resource input assumptions (e.g., annual cost decline, battery size and duration, and use case) and does not allow the utility to understand the impact of alternative cost decline assumptions. Additionally, the utility now has no way to model the value to the system of solar and wind paired with battery storage in providing firm and peaking energy resources as part of a least cost portfolio in its region. The Company's reliance on a high capital cost and its decision to omit the resource from the model reflect completely inappropriate IRP practices and have produced incomplete modeling results.

Wind

Big Rivers did not model wind in its IRP because the Company claims there are no viable sites for wind farms in the northwestern part of Kentucky.[9] The Company used out-of-date wind resource potential studies, only evaluated wind potential at 10 meters (m) and 50 m, and did not explore siting alternatives outside of the northwest Kentucky region.[10] This decision to omit wind resources from the model is problematic because, as with battery storage, it obscures the full resource input assumptions and does not allow the utility to understand the impact of alternative cost decline assumptions.

It is reasonable for the utility to evaluate resource potential for wind as a modeling input; however, the utility did not accurately assess wind resource potential in the region. Big Rivers cites a 2010 wind resource potential map (which the utility erroneously says is from 2012)[11] produced by NREL which shows that there is poor wind resource potential in northwestern Kentucky at 50-meter turbine heights.[12] The Company also produced a 1986 wind resource study conducted by LBNL on wind resource potential at 10 m and 50 m.[13]

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[7] Wind and Solar Data and Projections from the U.S. Energy Information Administration: Past Performance and Ongoing Enhancements. March 2016.

[8] Lazard. 2017. *Levelized Cost of Storage Analysis - Version 3.0.*

[9] SC 1-22.

[10] SC 1-31(c); Staff 1-27.

[11] Attachment for Response to SC 1-31 a, b. The discovery response says the map is from 2012, however the map is dated from June 2010.

[12] SC 1-31(a).

[13] Attachment for Response to SC 1-31 a, b.

Big Rivers should be using updated potential studies that evaluate regional wind potential at higher elevations (over 100 m). Wind turbine height and capacity have been steadily increasing and, according to the *2017 Wind Technology Market Report*, the median turbine height in developer applications was around 500 ft (or 152 m) in 2018.[14] This is important because the wind blows stronger at higher elevations. As wind turbine size increases, the generation potential jumps significantly. The wind resource potential for the region at 100 m is significantly higher than what Big Rivers cites.[15]

Additionally, Big Rivers attempts to defend the utility's decision not to evaluate wind resource potential outside the region,[16] stating that the company does not have the data to choose a prospective site outside the region.[17] There is very high wind resource potential in abutting states, including Indiana and Illinois, so uncertainty about where precisely to site a wind farm does not justify omitting the resource from the model. BREC should model and explore wind siting options outside of the region and issue RFPs, if necessary, to determine whether it can procure low-cost wind resources in the area.

Contract Sales

Big Rivers' generation fleet consists of three coal generators (Wilson, Green 1, and Green 2) and one gas CT. In addition, BREC has a hydro contract with SEPA, and a contract with the HMP&L Station 2 coal plant that the utility is exiting from at the end of 2019. Two other generators owned by Big Rivers – Coleman and Reid Unit 1 – have been idled since 2014 and 2016, respectively, and were excluded from the Company's IRP modeling.

The utility provides electricity directly to its own members, as well as to non-member customers in Nebraska, Missouri, and elsewhere in the region through several long-term capacity and energy contracts and short-term sales agreements. BREC has entered into these long- and short-term contracts to sell off the surplus energy and capacity that it was left with when two large aluminum smelters left the Big Rivers system and started purchasing electricity from the market. Big Rivers does not need the capacity from all three coal units to serve its members, therefore it only makes sense for the utility to enter into short- and long-term contracts to non-members if it can earn enough revenue to cover the full cost of the most expensive assets in its portfolio. Otherwise, the utility should retire the most expensive assets.

Big Rivers attempts to demonstrate the profitability of these non-member contracts by comparing the projected revenue per year under each contract to the variable and incremental costs of generating the energy provided under the contract. The amount by which the projected revenue exceeds the variable

[14] U.S. Department of Energy. 2017. *Wind Technologies Market Report*. p 35.
[15] NREL. "United States – Land-Based and Off shore Annual Average Wind Speed at 100 m." Available at https://www.nrel.gov/gis/images/100m_wind/awstwspd100onoff3-1.jpg
[16] SC 1-31(c).
[17] Big Rivers made additional statements about why modeling wind outside of the state would not provide meaningful results in SC 2-21(b).

and incremental costs is then identified as the contract's contribution to the fixed costs for the capacity needed to generate such energy. There are several problems, however, with how Big Rivers attempts to defend the profitability of its contracts.

First, the utility presents the variable cost associated with several of its contracts based on [redacted]. Second, [redacted] To keep its coal fleet operational, Big Rivers is required to incur costs for capital and major maintenance spending, along with other fixed O&M expenses. However, [redacted] And finally, there is no mention of the sensitivity of the contracts to fuel price fluctuations. When BREC modeled high coal price sensitivities in its IRP, the model recommended a switch to gas at Green 1 and 2. This would involve an additional capital investment that would increase the contract costs even more and then subject the contracts to any volatility in gas price that might occur.

Here is a more specific break-down of several of the contracts:

- **KyMEA:** Variable costs for the KyMEA contract are provided based on the [redacted] rather than based on system average costs or the cost of [redacted] This makes it appear that the KyMEA contract is contributing more to fixed costs than it truly is. BREC does not present KyMEA's actual share of the fixed costs or the contract's net margin.

- **Owensboro Municipal Utility (OMU):** Variable costs are provided based on the system average variable cost, therefore the OMU contract also appears to be contributing more to fixed costs than it really is. However, the larger issue with the OMU contract is that, even assuming that it is appropriate to base its analysis on average variable costs, the resulting contribution to fixed costs is low in all years and does not come close to covering the contract's share of fixed costs. [redacted]

- **MISO short-term sales:** Big Rivers' revenue from the short-term optimization sales is projected to cover the system average production costs associated with the energy sales.[19] However, the margin is much smaller when projected revenue is compared with the average production costs of the [redacted]. If Big Rivers' actual revenue from MISO energy and capacity sales falls below projected levels, the utility could fall short of covering its full production costs.

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[18] Revenue and expenses for the OMU contract are provided in confidential Response SC 2-2(c).

[19] Volume and revenue of short-term optimization sales are provided in confidential response SC 2-7.

Big Rivers itself admits that it is trying to reduce reliance on MISO Planning Resource Auctions for capacity, and MISO hourly energy markets, because of the market volatility. In fact, historical market data shows that in 2017 MISO market revenue fell far short of covering expenses.[20]

[20] Attachment for Response to PSC 2-6(a).