COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2020 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	)))	CASE NO. 2020-00299

O R D E R

On January 12, 2021, the Commission established a procedural schedule that allowed for two rounds of discovery and a formal hearing. On its own motion, the Commission finds that the report that summarizes Commission Staff's review (Staff Report) of Big Rivers Electric Corporation's (BREC) 2019 Integrated Resource Plan (IRP) should be filed into the case record, pursuant to 807 KAR 5:058, Section 11(3). The Staff Report is attached as an Appendix to this Order.

IT IS THEREOFRE ORDERED that the Staff Report attached as an Appendix to this Order shall be entered into the record of this matter.

By the Commission

ENTERED

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KENTUCKY PUBLIC SERVICE COMMISSION

ATTEST:

Executive Director

APPENDIX

AN APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2020-00299 DATED NOV 22 2021

FORTY-THREE PAGES TO FOLLOW

Kentucky Public Service Commission

Staff Report on the

2020 Integrated Resource Plan

of Big Rivers Electric Corporation

Case No. 2020-00299

November 2021

SECTION 1

INTRODUCTION

In 1990, the Kentucky Public Service Commission (Commission) promulgated 807 KAR 5:058 to create an integrated resource planning process to provide for review of the long-range resource plans of Kentucky's jurisdictional electric generating utilities by Commission Staff (Staff). 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.

Big Rivers Electric Corporation (BREC) is a generation and transmission (G&T) cooperative located in Henderson, Kentucky. It supplies electricity to three distribution cooperatives that, in turn, provide electric service to retail customers located in 22 western Kentucky counties. These member cooperatives, Kenergy Corporation, (Kenergy), Meade County Rural Electric Cooperative Corporation (Meade RECC), and Jackson Purchase Energy Corporation (Jackson Purchase Energy), serve approximately 118,000 customers, of which nearly 90 percent are residential.[1] BREC also serves 21 large industrial customers directly from its transmission system and is expected to serve another large industrial customer beginning in 2022.[2] Finally, BREC provides wholesale service to non-members, which notably include Owensboro Municipal Utilities (OMU) and the Kentucky Municipal Energy Agency (KY MEA).[3]

BREC filed its 2020 Integrated Resource Plan (IRP) on September 21, 2020.[4] The IRP includes BREC's plan to meet its customers' electricity requirements for the period 2020-2034.[5]

BREC's total energy requirements are forecasted at 4,853 GWH in 2020 and then increasing significantly through 2022 with the addition of Direct Serve load and Non-Member load. Between 2027 and 2029, BREC will experience declines with the expiration of Non-Member contracts, with slow growth from that point until 2039. Compound annual growth rates for BREC's entire system are 13.51 percent for 2019-2024 period and 1.66 percent through 2039.[6]

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[1] IRP at 11.

[2] *Id.*, Appendix A at 27, Table Big Rivers Direct Serve Class.

[3] *Id.*, Appendix A at 39.

[4] BREC was assisted in the preparation of its IRP by Clearspring Energy Advisors, LLC (Clearspring).

[5] While the planning period is 2020 through 2034, much of the information that was provided was through 2039, and Staff has included the information through 2039 where available.

[6] IRP at 44–45.

As of the IRP filing date, BREC owned 1,444 MW of nameplate generating capacity at four generating stations: (1) the 130 MW Robert A. Reid Plant (Reid Station), (2) the 443 MW Kenneth C. Coleman Plant (Coleman Station), (3) the 454 MW Robert D. Green Plant (Green Station), and (4) the 417 MW D. B. Wilson Plant (Wilson Station).[7] BREC also had a 178 MW of contracted hydroelectric capacity from the Southeastern Power Administration (SEPA). Thus, at the time it filed its IRP, BREC's total nameplate capacity was 1,622 MW.[8]

However, BREC's 443 MW Coleman Station and 65 MW Reid Station Unit 1 have been idle since 2014 and 2016, respectively, and both were fully retired at or about the end of 2020. Further, after filing this IRP, BREC requested and received approval from the Commission to convert Units 1 and 2 at Green Station from coal fired to natural gas fired units. The conversion of Green Units 1 and 2 to gas fired units will reduce the nameplate capacity to 414 MW.[9]

BREC also contracted to purchase 260 MW of solar power consisting of 160 MW from Geronimo Energy[10] from a facility located on the Henderson/Webster County line and 100 MW from Community Energy at two different sites located in Meade County (40 MW) and McCracken County (60 MW).[11] The Commission approved BREC's request to enter into those solar purchase power contracts during the pendency of this matter,[12] and the owners of those facilities have or are in the process of obtaining necessary approvals from the Kentucky State Board on Electric Generation and Transmission Siting to begin

[7] *Id.* at 13.

[8] *Id.*

[9] Case No. 2021-00079, *Electronic Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity Authorizing the Conversion of the Green Station Units to Natural Gas-Fired Units and an Order Approving the Establishment of a Regulatory Assert* (filed Mar. 1, 2021), Application 6.

[10] Note that Unbridled Solar LLC, is a subsidiary of National Grid Renewables, which includes the renewable energy development company formally known as Geronimo Energy. *See* Case No. 2020-00242, *Electronic Application of Unbridled Solar, LLC for a Certificate of Construction for an Approximately 160 Megawatt Merchant Electric Solar Generating Facility and Nonregulated Electric Transmission Line in Henderson and Webster Counties, Kentucky* (filed Dec. 8, 2020), Application at 2.

[11] IRP at 17.

[12] Case No. 2020-00183, *Electronic Application of Big Rivers Electric Corporation for Approval of Solar Power Contracts Termination of Contracts and a Declaratory Order and for Authority to Establish a Regulatory Asset*, Order (Ky. PSC Sept. 28, 2020).

construction.[13] The proposed additions of three solar power purchase agreements will bring total nameplate capacity to 1,334 MW, including the slight reduction in capacity from the Green Station conversion.[14]

BREC is a member of the Midcontinent Independent System Operator, Inc. (MISO). MISO directs BREC's generation dispatch and determines the reserves required to maintain resource adequacy within its multi-state footprint.

The Commission established a procedural schedule for this case, which allowed for two rounds of data requests to BREC, an opportunity for intervenors to file comments, and an opportunity for BREC to file reply comments. Intervenors include the Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention (Attorney General), and the Sierra Club (Sierra Club).

BREC responded to two rounds of data requests from Staff and each of the intervenors. The Attorney General and Sierra Club submitted written comments to which BREC filed reply comments.

The purpose of this report is to review and evaluate BREC's 2020 IRP in accordance with 807 KAR 5:058, Section 11(3), which requires Staff to issue a report summarizing its review of each IRP filing and make suggestions and recommendations to be considered in future IRP filings. Staff recognizes resource planning is a dynamic and ongoing process. Specifically, the Staff's goals are to ensure that:

- All resource options are adequately and fairly evaluated;
- Critical data, assumptions, and methodologies for all aspects of the plan are adequately documented and are reasonable; and
- The report includes an incremental component, noting any significant changes from BREC's prior IRP filed in 2017.

In the current IRP, BREC states that its primary planning goal is to provide for its customers' electricity needs over the next 15 years through a mix of resources at the

[13] *See* Case No. 2020-00242, *Electronic Application of Unbridled Solar, LLC* (Ky. PSC June 4, 2021), Order (approving the construction as discussed therein); Case No. 2020-00390, *Electronic Application of Meade County Solar, LLC for a Certificate of Construction for an Approximately 40 Megawatt Merchant Electric Solar Generating Facility in Meade County, Kentucky Pursuant to KRS 278.700 and 807 KAR 5:110,* Application (filed June, 3, 2021); Case No. 2020-00392, *Electronic Application of McCracken County Solar, LLC for a Certificate of Construction for an Approximately 60 Megawatt Merchant Electric Solar Generating Facility in McCracken County, Kentucky Pursuant to KRS 278.700 and 807 KAR 5:110,* Application (filed May 11, 2021).

[14] The IRP indicates that the generation capacity including the solar contracts was 1,374 MW. IRP at 13. However, that sum did not include the reduction from converting Green Station to natural gas fired units.

lowest reasonable cost by minimizing the net present value of the production and capital cost for serving the load. To meet this goal, BREC identified the following planning objectives:[15]

- Maintain a current and reliable load forecast;
- Identify potential new supply-side resources;
- Provide competitively priced power to its Members;
- Maintain adequate planning reserve margins;
- Maximize reliability while ensuring safety, minimizing costs, risks and environmental impacts;
- Develop and maintain a more diversified supply portfolio aligned with anticipated Member-Owner load; and
- Meet North American Electric Reliability Corporation (NERC) guidelines and requirements.

Member system energy and peak demand requirements are projected to reach 4,602 GWH and 852 MW, respectively, by 2039, and are projected to increase at average compound rates of 1.65 percent and 1.56 percent, respectively, per year from 2019 through 2039.[16] Continued increases in employment and number of households, air conditioning saturation levels, appliance efficiencies, consumer energy conservation awareness, and decreases in the price of retail electricity are expected to impact growth in Member energy sales over the near term. Increased sales to direct-serve customers will have positive impacts on Member sales over the near term. Member peak requirements are projected to increase from 627 MW to 852 MW by the summer of 2039.[17]

The remainder of this report is organized as follows:

- Section 2, Load Forecasting, reviews BREC's projected load growth and load forecasting methodology.
- Section 3, Demand-Side Management and Energy Efficiency, summarizes BRC's evaluation of DSM opportunities.
- Section 4, Supply-Side Resource Assessment, focuses on supply resources available to meet BREC's load requirements and environmental compliance

[15] IRP at 24.

[16] *Id*. at 21, 24.

[17] *Id*. at 24.

planning.

- Section 5, Demand and Supply Integration, discusses BREC's overall assessment of supply-side and demand-side options and their integration into an overall resource plan.

It is noted that departures from the filing schedule in 807 KAR 5:058 have caused overlaps of IRP filings. To help minimize future overlaps, Staff recommends to the Commission a filing date for BREC's next IRP on September 21, 2023.

SECTION 2

LOAD FORECASTING

INTRODUCTION

The 20 year forecast period extends from 2020-2039. BREC prepared its 2020 forecast with the assistance of Clearspring Energy Advisors, LLC (Clearspring). BREC's forecast results meet Rural Utility Service (RUS) requirements and will be used in United States Department of Agriculture loan applications.[18]

FORECASTING APPROACH AND MODELS

The load forecasting process is a bottoms-up approach with each of the three Member-Owners forecast developed separately and then integrated into BREC's forecast.[19] For each Member-Owner, individual retail rate class forecasts include Residential, General Commercial and Industrial (GCI), Large Commercial and Industrial (LCI), Irrigation, Street & Highway, and Direct Serve consumers.

Rural System Requirements equals the sum of the individual rate class sales plus BREC's own use. Native system Requirements equals the sum of Rural System Requirements plus Direct Serve consumer sales and transmission losses.[20] Adding in sales to Non-Members yields Total System Requirements.[21]

Ordinary least squares econometric models were developed for Residential energy use per consumer, GCI consumers, GCI use per consumer and the Rural System monthly load factors. Model explanatory variable projections are derived from demographic and economic projections and weather normalized values. The number of Residential consumers was forecasted using the number of households' growth index, provided by Woods & Poole Economics, Inc. (Woods & Poole Economics).[22] LCI and Direct Serve loads were developed based upon historical data and Member-Owner input.

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[18] *Id.*, Appendix A at 5-6.

[19] *Id.* Also see BREC's Response to Staff's First Request for Information (Staff's First Request), (filed Mar. 19, 2021), Items 46b and 49 for an explanation of how county level data was transformed to fit each Member-Owner's service territory.

[20] IRP, Appendix A at 7. Note that various Tables alternatively label Native System requirements as Total Member System Requirements. For example, see Chapter 1 at 22, Table 1.2 and at 23, Table 1.3.

[21] IRP Chapter 3 at 46, Table 3.1 and at 48, Table 3.2.

[22] *Id*., Appendix A at 18.

Judgement and trend analysis were used to forecast Irrigation and Street & Highway, BREC's own use, and distribution losses.[23]

Weather Impacts

Weather variables are incorporated for each rate class forecast. Weather variables include cooling degree days (CDD) and heating degree days (HDD) and peak temperatures. CDD and HDD are calculated assuming a 65-degree normal temperature for the previous 15 years.[24] Weather data was collected from weather stations in or near each of the Member-Owners' service territory.[25]

Residential Energy Sales

Woods & Poole Economics provided third party county level household growth projections. Projections are weighted to each specific distribution service territory using the number of residential consumers within each county. Household growth projections are further refined based upon distribution cooperative staff discussions.[26] The number of residential consumers is expected to grow from 100,314 to 103,282 over the 2020-2028 forecast period and then slowly decline to 101,718 by 2039. The initial growth in households is attributable to the addition of a large industrial consumer. Over the entire forecast period, residential consumer growth increases at an average annual rate of 0.09 percent.[27]

Residential use per consumer is an econometric forecast using monthly data and is modeled as a function of electricity price, alternate fuel prices, CDD, HDD, appliance saturation levels, appliance efficiencies, and monthly binary variables.[28] Over the forecast period, use per consumer declines from 14,195 to 13,994 kWh at an average annual rate of 0.03 percent.[29] Multiplying use per consumer by the number of consumers yields Residential Energy Sales. Residential Energy Sales increase slowly from 1,423,914 to 1,448,868 MWh over the forecast period 2020 - 2026, and then declines

[23] *Id.* at 15. Also see BREC's Response to Staff's First Request (filed Mar. 19, 2021), Item 52d, Member-Owner 2020 load Forecast Studies, Section 6.2, Model Development.

[24] *See* BREC's Response to Staff's First Request (filed Mar. 19, 2021), Item 51 for a description of how the weather variables were constructed.

[25] IRP, Appendix A at 12–14.

[26] *Id.,* Appendix A at 18.

[27] *Id.,* Appendix A at 17, Table Big Rivers Residential Class.

[28] *Id.,* Appendix A at 19, 89, 93, and 97 and BREC's Response to Staff's First Request (filed Mar. 19, 2021), Item 48d.

[29] IRP, Appendix A at 17, Table Big Rivers Residential Class.

down to 1,423,491 MWh by 2039. Over the entire forecast period, sales increase at an average annual rate of 0.06 percent.[30]

General Commercial and Industrial Class

The GCI class is defined as total commercial and industrial load minus Direct Serve and LCI loads. An econometric model was used to project the number of GCI consumers. The projected number of consumers is a function of gross regional product (GRP) and total retail sales in each specific Member-Owner service territory.[31] The number of GCI consumers increases slowly from 18,188 to 22,149 at an average annual rate of 1.12 percent.[32]

Similarly, GCI use per consumer is forecast using an econometric model with monthly data as an input. GCI use per consumer is modeled as a function of electricity price, employment per consumer, CDD, HDD, and monthly binary variables within the individual Member-Owner service territories.[33] Over the entire forecast period, GCI use per consumer is essentially flat, declining from 34,138 to 33,988 kWh or at an average annual rate of 0.01 percent.[34] GCI Energy sales is the product of the number of GCI consumers and use per consumer. Over the entire forecast period, GCI Energy Sales increase from 620,892 to 752,795 MWh or at an average annual rate of 1.11 percent.[35]

Large Commercial and Industrial Class

LCI customers are the largest on the Member-Owner systems but due to their smaller size, are not served under BREC's Large Industrial Customer (LIC) tariff. Customers served under BREC's LIC tariff are Direct Serve consumers and have an annual demand of 117,931 kW as of 2019. Sales forecasts of LCI customers are based upon staff judgement and knowledge. BREC's LCI consumers currently number 31 and are projected to remain at that level over the entire forecast period. LCI use per consumer is projected to increase from 5,064 in 2020 to 5,075 by 2022 and remain flat over the rest of the forecast period.[36] BREC LCI Energy Sales are forecast to initially increase from

[30] *Id*.

[31] *Id.,* Appendix A at 22.

[32] *Id.,* Appendix A at 21, Table Big Rivers General C&I Class. Also, see individual Member-Owner GCI Consumer model regression results in Appendix A at 90, 94, and 98.

[33] *Id.,* Appendix A at 23.

[34] *Id.,* Appendix A at 21, Table Big Rivers General C&I Class. Also, see individual Member-Owner GCI Use Per Consumer model regression results in Appendix A at 91, 95, and 99.

[35] *Id.,* Appendix A at 21, Table Big Rivers General C&I Class.

[36] *Id.,* Appendix A at 24 and 25, Table Big Rivers Large C&I Class.

160,778 MWh in 2020 to 170,333 MWh in 2022 and then decrease to 157,311 MWh in 2023 and remain at that level through the rest of the forecast period.[37]

Street and Highway Lighting and Irrigation Classes

The forecasts for Street & Highway Lighting consumers represents a very small proportion of BREC total sales. The forecasts were made by hand and held steady at 2020 levels over the entire forecast period. There are 108 Street & Highway Lighting projected with a Use Per Consumer at 28,892 kWh for total Energy Sales of 3,120 MWh.[38]

Similarly, the Irrigation class was forecast by hand and held steady at 202 levels over the entire forecast period. There are five Irrigation consumers projected with a Use Per Consumer of 21,652 kWh and total Energy Sales of 108 MWh.

Direct Serve Class

These consumers are served directly from BREC's transmission system. The number of consumers and use per consumer projections are based on manager and staff knowledge with input from Member-Owners. The number of Direct Serve consumers is projected to grow by 1 to 22 in 2022 and remain at that level for the rest of the forecast period. Use Per Consumer is also expected to increase from 47,026 MWh in 2020 to 92,671 MWh in 2022 and, with minor exceptions, remain at that level for the rest of the forecast period.[39] Energy Sales is projected to increase 106 percent from 987,552 MWh in 2020 to 2,038,752 MWh in 2022 and is expected to remain at about that level for the rest of the forecast period. Over the entire forecast period, Direct Serve customers' Energy Sales increase at an average annual rate of 3.85 percent.[40]

Non-Member Sales

During periods when BREC has excess resources, it buys and / or sells resources either through bilateral contracts or through the Midcontinent Independent System Operator (MISO). Specifically, BREC has long term contracts with various Non-Member entities—OMU, KY MEA, and three entities in the state of Nebraska—and BREC makes short term capacity sales in the bilateral market when it has capacity that is not otherwise committed to serve its native load or third parties.[41] Non-Member energy sales are

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[37] *Id.,* Appendix A at 25, Table Big Rivers Large C&I Class.

[38] *Id.,* Appendix A at 28 and 29, Table Big Rivers Street & Highway Class.

[39] *Id.,* Appendix A at 27, Table Big Rivers Direct Serve Class. There are temporary one-time increases of 130 MWh in 2024 and 2028.

[40] *Id.*

[41] *Id.,* Appendix A at 39. *Also see* Case No. 2021-00079, *Electronic Application of Big Rivers Electric Corporation,* (filed Mar. 1, 2021), Application, Exhibit B, Direct Testimony of Mark Eacret at 5 (explaining BREC's long and short term sales).

projected to be 1,466,620 MWh in 2020, growing to 1,784,986 MWh in 2022 and then declining to 255,500 MWh in 2029. However, BREC's projections only included Non-Member sales and purchases for the period of current contracts, so no Non-Member sales are projected after 2029.[42]

Total System Energy Sales

BREC defines Rural System energy requirements as the sum of energy sales from the following rate classes: Residential, GCI, LCI, Irrigation, and Street & Highway plus Distribution losses and BREC's own use. As seen from the Table below, Rural System energy requirements increase steadily at an average annual rate of 0.37 percent over the 2020-2039 forecast period from 2,313,997 to 2,448,197 MWh. BREC's Total Native System energy requirements are defined as Rural System requirements plus Direct Serve customers and Transmission losses. Transmission losses are forecast to be 2.5 percent over the forecast period.[43] BREC's Total Native System energy requirements increase at an average annual rate of 1.65 percent over the 2020-2039 forecast period from 3,386,237 to 4,601,999 MWh.

Adding in Non-Member energy sales yields BREC's Total System Energy Requirements. As seen from the Table below, BREC's Total System Energy Requirements increase and then decrease as the additional Non-Member contract sales rise and fall through the 2020-2029 forecast period. For the 2030-2039 forecast period, Total System requirements equal Native System Requirements.

[42] IRP at 60 and Appendix A at 30, Table Non-Member Sales Under Contract as of 2020. Note that forecasted energy sales to OMU are net of its allocation from the Southeastern Power Administration Cumberland System. Forecasted energy sales to the Nebraska entities are net if their allocation from the Western Area Power Administration, renewable purchases and other purchased power.

[43] *Id.,* Appendix A at 34.

Big Rivers Total System Energy Summary (MWh)[44]

Year	Total Rural Requirements	Direct Serve	Transmission Losses	Total Native Requirements	Non-Member Requirements	Total System Energy Requirements
2015	2,325,204	946,873	66,970	3,339,047		3,339,047
2016	2,330,037	915,310	73,420	3,318,766		3,318,766
2017	2,209,837	919,895	77,928	3,207,660		3,207,660
2018	2,366,988	953,822	86,858	3,407,668	75,404	3,483,072
2019	2,271,772	957,994	83,431	3,313,197	578,276	3,891,473
2020	2,313,997	987,552	84,688	3,386,237	1,466,620	4,852,857
2021	2,342,004	987,552	85,373	3,414,929	1,750,832	5,165,761
2022	2,345,137	2,038,752	112,407	4,496,296	1,784,986	6,281,282
2023	2,357,028	2,038,752	112,712	4,508,492	1,713,663	6,222,155
2024	2,366,988	2,041,632	113,042	4,521,662	1,722,453	6,244,114
2025	2,376,885	2,038,752	113,221	4,528,859	1,726,630	6,255,489
2026	2,386,410	2,038,752	113,466	4,538,628	1,732,865	6,271,493
2027	2,388,504	2,038,752	113,519	4,540,776	613,200	5,153,976
2028	2,394,976	2,041,632	113,759	4,550,367	613,200	5,163,567
2029	2,400,628	2,038,752	113,830	4,553,210	255,500	4,808,710
2030	2,403,821	2,038,752	113,912	4,556,486		4,556,486
2031	2,409,248	2,038,752	114,051	4,562,051		4,562,051
2032	2,419,240	2,038,752	114,307	4,572,299		4,572,299
2033	2,424,117	2,038,752	114,433	4,577,302		4,577,302
2034	2,427,766	2,038,752	114,526	4,581,044		4,581,044
2035	2,431,849	2,038,752	114,631	4,585,232		4,585,232
2036	2,435,950	2,038,752	114,736	4,589,439		4,589,439
2037	2,440,157	2,038,752	114,844	4,593,753		4,593,753
2038	2,444,021	2,038,752	114,943	4,597,716		4,597,716
2039	2,448,197	2,038,752	115,050	4,601,999		4,601,999

Peak Demand

Coincident peak (CP) demand is measured as the demand coincident to the annual peak demand occurrence of the entire BREC system. A monthly CP demand forecast was made for each Member-Owner by econometrically forecasting the predicted load factor and then multiplying by the forecast energy requirement. Load factor is modeled as a function of monthly peak day temperature, CDD, HDD, appliance

[44] *Id.,* Appendix A at 35, Table Total Native System Energy Summary and at 41, Table Total System Energy Forecast. Note that the 2019 Total Native System Energy Requirement entry of 3,317,632 in the Table on page 35 is incorrect. The corresponding entry in the Table above is correct.

saturations and efficiencies.[45] The Rural CP is the sum of the Member-Owner CP demands. The Table below presents the Rural Summer, Rural Winter and Rural Annual CP demands.

Total System CP and NCP (kW)[46]

Year	Rural Summer CP	Rural Winter CP	Rural Annual CP	Direct Serve Annual CP	Trans Losses	Total Annual CP	Non-Member Capacity Sales	Total System NCP
2015	504,990	566,553	566,553	121,143	11,253	698,949	513,000	1,211,949
2016	486,690	484,768	486,690	120,750	13,855	621,295	450,000	1,071,295
2017	504,269	474,971	504,269	114,378	15,538	634,184	487,000	1,121,184
2018	502,549	556,742	556,742	95,530	16,382	668,654	314,200	982,854
2019	480,171	490,895	490,895	117,931	15,995	624,821	376,200	1,001,021
2020	483,946	484,817	483,946	127,101	15,668	626,715	421,500	1,048,215
2021	489,218	489,893	489,218	127,101	15,803	632,122	421,900	1,054,022
2022	489,558	491,914	489,558	322,043	20,810	832,412	421,500	1,253,912
2023	491,639	494,177	491,639	322,043	20,864	834,546	305,900	1,140,446
2024	493,376	495,970	493,376	322,043	20,908	836,327	210,300	1,046,627
2025	495,136	497,935	495,136	322,043	20,953	838,132	310,700	1,148,832
2026	496,879	499,794	496,879	322,043	20,998	839,920	311,100	1,151,020
2027	497,133	499,957	497,133	322,043	21,005	840,180	100,000	940,180
2028	498,359	500,820	498,359	322,043	21,036	841,438	100,000	941,438
2029	499,422	501,685	499,422	322,043	21,063	842,528		842,528
2030	500,004	501,900	500,004	322,043	21,078	843,125		843,125
2031	501,074	502,687	501,074	322,043	21,106	844,223		844,223
2032	503,128	504,331	503,128	322,043	21,158	846,330		846,330
2033	504,103	505,032	504,103	322,043	21,183	847,329		847,329
2034	504,841	505,432	504,841	322,043	21,202	848,086		848,086
2035	505,663	506,010	505,663	322,043	21,223	848,929		848,929
2036	506,495	506,574	506,495	322,043	21,245	849,782		849,782
2037	507,349	507,238	507,349	322,043	21,266	850,659		850,659
2038	508,129	507,810	508,129	322,043	21,286	851,459		851,459
2039	508,968	508,470	508,968	322,043	21,308	852,319		852,319

[45] *Id.,* Appendix A at 42. Also see Member-Owner load factor models in Appendix A at 92, 96, and 100.

[46] *Id.,* Appendix A at 43, Table Big Rivers Coincident Peak (kW) and at 45, Table Total System NCP (kW).

The Table's seasonal Rural Summer and Winter CP values are the actual seasonal peaks. Even though misleading, the Rural Annual CP and hence the Total Annual CP values are reflective of the actual and forecasted system peaks. The difference is that at the time of the winter CP peaks, the system as a whole was not at a peak.[47]

DSM Impacts

BREC conducted a DSM potential study in 2020 that was used to quantify the impact of new DSM spending on energy usage and peak demand. The impacts of any previous DSM programs, EE measures, and appliance efficiencies are already accounted for in the historical energy use and peak demand data.[48] BREC produced two alternate load forecast scenarios based upon additional DSM spending of $1 million or $2 million. Individual appliance end use impacts were calculated and then scaled up to capture any additional decreases in distribution and transmission losses.[49]

The impacts of $1 million in new DSM spending results in a reduction in total Native System Energy requirements of 11,186 MWh in 2021, and then increasing to 110,775 MWh in the 2030-2039 forecast period. The total Native System CP is reduced by 2,264 kW in 2021, increasing to 22,511 kW through 2030-2039.[50] Over the 2020-2039 forecast period, DSM spending's impact on projected energy use increases from 0.3 percent to 2.4 percent. Similarly, reductions in peak demand range from 0.4 percent increasing to 2.6 percent.

The impacts of spending $2 million in new DSM spending results in a greater reduction in total Native System Energy requirements of 21,512 MWh, and then increasing to 213,029 MWh by 2031 and to 213,032 MWh by 2039. The total Native System CP is reduced by 4,353 kW in 2021, and then increasing to and remaining at 43,291 kW through the 2030-2039 forecast period.[51] Spending an additional $2 million in new DSM spending over the 2020-2039 forecast period results in a reduction in energy from 0.6 percent increasing to 4.6 percent. Similarly, reductions in peak demand range from 0.7 percent increasing to 5.1 percent.

Sensitivity Analysis

[47] IRP, Appendix A at 88, Table Big Rivers Monthly Forecast.

[48] *Id.*, Appendix A at 46.

[49] *Id.*

[50] *Id.*, Appendix A at 47, Table Big Rivers DSM Spending Scenarios (MWh) and at 48, Table Big Rivers DSM Spending Scenarios (kW).

[51] *Id.*

BREC conducted a sensitivity analysis by altering weather and economic variables. Four scenarios were modeled: Extreme weather with normal economic growth, Mild weather with normal economic growth, high economic growth and normal weather, and low economic growth with normal weather.[52] In order to model weather extremes, the CDD and HDD variables for the Residential and GCI rate classes, energy use models were altered to the annual 15 year maximum and minimum values and then redistributed across each month based on the average monthly CDD and HDD distribution.[53] Similarly, for modeling the extreme weather effects on peak demand, the load factor models were adjusted to use the monthly weather conditions consistent with those in the energy use models.

CHANGES FROM PREVIOUS 2017 IRP

In BREC's previous IRP filing, BREC utilized a Statistical End Use (SAE) approach for its load forecast. In the current IRP, BREC made multiple changes in its load forecast methodology.[54]

- Economic and demographic variables are weighted based on calculated customer counts in each member-owner county served.
- As opposed to using a Statistical End Use approach, BREC used econometric modeling to directly estimate customer counts and use-per-customer.
- The electricity prices was modeled directly in relation to an alternative fuel (natural gas and propane) price index.
- BREC used an econometric model to estimate the electric price elasticity based on the relative impact of electricity prices and the alternative fuel price index.
- Weather normalization is based on a 15-year period, as opposed to the 20-year period used previously. In addition, different weather stations were used to gather data.
- Daily high and low temperatures were used for the load factor econometric model to forecast peak demands as opposed to hourly values.

BREC'S RESPONSES TO PREVIOUS STAFF RECOMMENDATIONS

[52] IRP, Appendix A at 49.

[53] *Id.* Note that energy use by Direct Serve and rate classes other than Residential and GCI are assumed to not be affected by variations in weather.

[54] *Id.,* Appendix A at 62–63 and BREC's Response to Staff's Request (filed Mar. 19, 2021), Item 52d, Section 6.4 of the Member-Owner 2020 Load Forecast Studies.

The Staff Report to BREC's previous IRP contained four recommendations pertaining to load forecasting:

- Continue to explore ways to enhance residential and small C&I load forecasts and provide discussions of any refinements to forecasting methodology. (1)

- Continue to provide comparisons of actual to forecasted results for the residential and small C&I classes along with discussions of reasons for any differences between forecasted and actual results. (2)

- Continue to provide comparisons of actual and forecasted summer and winter peak demands using a variety of normalization periods. Provide a discussion of the reasons for any significant differences between actual and forecasted peak demands. (3)

- Continue to explore new markets, including economic development efforts within its service territory, to replace the loss of smelter loads and provide a discussion of BREC's efforts and how its efforts are reflected in the load forecast. (4)

In responding to the 2017 Staff Report recommendations, BREC provided the information summarized below, which is also noted and discussed in other portions of this report.[55]

Recommendation Number	2020 IRP Reference	BREC's Response
(1)	IRP - Section 3.7; Appendix A - Section 7.5	Big Rivers contracted with Clearspring Energy Advisors for the 2020 Long Term Load Forecast, as compared to recent forecasts prepared by GDS Associates, Inc. Clearspring's method used some different approaches from GDS, as highlighted in Section 7.5 of Appendix A, including a 15 year weather normal for the base case load forecasts compared to GDS' 20 year weather normal.
(2)	IRP - Sections 3.3.1, 3.3.2; Appendix A - Sections 2.1.1, 2.2.1, 8	Appendix A Load Forecast Report Chapter 8 Tracking Analysis highlights Comparisons to the 2017 Forecasts by Class, as well as comparison of previous forecasts to actual loads.

[55] IRP, Appendix D at 1–2.

(3)	IRP - Sections 3.4, 3.6; Appendix A - Sections 6, 8	IRP Section 3.4 includes a table comparing historical actual and weather-normalized Winter/Summer demand and energy. Section 3.6 discusses various normalization periods.
(4)	IRP - Section 2.7, 3.3.8; Appendix A - Sections 2.7; 3.2, 3.3	IRP Section 2.7 discusses short and intermediate-term sales, and participating with local partners in economic development efforts. This has so far resulted in significant member load growth with the addition of a Direct Serve consumer as discussed in Sections 3.2 and 3.3.4. Section 3.3.8 discusses Non-Member Sales achieved.

INTERVENOR COMMENTS

There were no intervenor comments pertaining to the load forecast.

DISCUSSION OF REASONABLENESS

For the purposes of this IRP, Staff is satisfied that BREC's responses to previous Staff recommendations are reasonable.

RECOMMENDATIONS FOR BREC'S NEXT IRP

- BREC's load forecasting methodology shifted from a SAE modeling framework to a pure econometric framework. There was insufficient explanation as to why the change in methodologies was made or why it was judged superior. Even though elements of SAE modeling were included in select variable construction for the econometric modeling methodology, many utilities have adopted the SAE methodology. The shift toward econometric modeling does not appear to be as comprehensive as SAE modeling in capturing all of the effects of energy efficiency and DSM programs, though larger efforts such as HVAC were included. For the next IRP, BREC should provide a clear comparison of the efficacy of its current forecasting methodology versus SAE modeling. In addition, if BREC shifts forecasting methodologies again, it should provide a clear explanation of the change and the advantage of the new methodology over econometric modeling.

- A 15-year weather normalization is the shortest of any utility's IRP filed this far. For the next IRP, BREC should provide a comparison of forecasts using both a 20 and 30-year weather normalization with the 15-year normalization. If a different weather normalization benchmark is selected, BREC should provide a clear explanation why the change provides better forecasts.

- Continue to provide comparisons of actual to forecasted results for the residential and small C&I classes along with discussions of reasons for any differences between forecasted and actual results.

- Continue to provide comparisons of actual and forecasted summer and winter peak demands using a variety of normalization periods. Provide a discussion of the reasons for any significant differences between actual and forecasted peak demands.

- Continue to explore new markets, including economic development efforts within its service territory. In addition, provide an update on the current and future status of Non-Member sales contracts.

SECTION 3

DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY

INTRODUCTION

This section discusses the Demand-Side Management (DSM)/Energy Efficiency (EE) (DSM/EE) aspects of the BREC IRP. DSM and EE programs have been designed with the goal to increase the efficient use of electricity by making the production and delivery of energy more cost-effective. Demand Response (DR) programs reduce consumption at peak times while EE programs reduce energy usage on a day–to–day basis. Each of BREC's three Member Cooperatives budgets, plans, administers and implements DSM/EE programs independently. Member Cooperatives invoice BREC monthly for costs incurred for promotion and incentives and BREC tracks retail member participation and calculates program impacts for reporting purposes.

The Commission approved the discontinuation and phase-out of BREC's existing DSM programs in July 2018.[56] The same Order approved the only remaining DSM program that BREC offers,[57] the Low-Income Weatherization Support Program (Low-Income Program) as of the filing date of this IRP.[58] The Low-Income Program launched in the early months of 2020, in coordination with the Community Action Agencies (CAA) in the region. The program launch began at nearly the same time as the government initiated COVID-19 restrictions. This unusual state of affairs caused the Low-Income Program to have an extremely slow start.[59] As the COVID-19 restrictions begin to wane, BREC will continue to work to initiate weatherization projects in coordination with CAA and the Kentucky Housing Corporation (KHC).

DSM/EE PROGRAM SCREENING & EVALUATION PROCESS

BREC commissioned Clearspring to conduct a DSM Potential Study (DSM Study) in 2020 to quantify the impact of additional DSM spending on future energy and peak requirements. The base case forecast uses prior DSM program impacts captured indirectly through the historical peak and energy data.[60] The modeling process inputs the

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[56] Case No. 2018-00236, *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.* (Ky. PSC Dec. 12, 2018).

[57] IRP at 35.

[58] *See* Case No. 2019-00193, *Demand-Side Management Filing of Big Rivers Electric Corporation to Implement a Low-Income Weatherization Support Program.* (Ky. PSC Nov. 13, 2019), for a description of the program and the Order approving the program on a pilot basis.

[59] IRP at 42.

[60] *Id.,* Appendix A at 46.

data. No additional DSM spending in the future is assumed by the base case forecast and additional future DSM impacts are set to zero.[61]

Clearspring's method of analysis differs from the prior contractor, GDS Associates, in that it includes estimates of the impact of the usage of electricity per consumer, "direct modeling of the electricity price", and by calculating price elasticity with the impact to the price and the alternative fuel index.[62] Clearspring also uses a 15–year weather normalization for the load forecasts in the base case, as well as specific changes to weather details.[63] The DSM Study covered the ten-year period of 2021-2030. Clearspring used the EE indexes provided by the Energy Information Administration (EIA). Clearspring also used the historical end-use surveys conducted by BREC for information about appliance and end-use saturations for each of the Member's systems.[64]

The DSM Study objective was to identify possible demand-side opportunities that would reduce demand and consumption of electricity, with the idea that cost effective demand reduction may lead to a future reduction in the need for supply-side resources.[65] BREC directed Clearspring to start by establishing a baseline for end-use energy characteristics (residential and non-residential), and to identify potential demand-side measures for EE and DR. Clearspring would then evaluate and develop estimates of the measure potential. Clearspring developed an inclusive set of DSM measures to be evaluated for residential, commercial, and industrial customers. The four areas in which the measures were evaluated for potential were technical, economic, achievable, and program potential.[66] DSM measure lists were compiled using current Technical Resource Manuals (TRM).

The Total Resource Cost (TRC) test was used to screen DSM measures. Benefits included in the TRC test are the avoided capacity costs to BREC, the reduction in capacity costs to BREC, and the operation and maintenance benefits of implementing the measure.[67] In addition, the Participant Cost (PC) Utility Cost (UC) and Rate Impact Measure (RIM) were other tests used to measure the net costs of an energy measure or program against the total costs of the program.[68]

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[61] *Id.* at 66.

[62] *Id*. at 26.

[63] *Id.*

[64] *Id.* at 77.

[65] IRP, Appendix B-DSM Study (Appendix B) at 1-2.

[66] *Id* at 1-4.

[67] Response to Staff's First Request for Information (Staff's First Request), (filed March 19, 2021), Item 20.

[68] IRP at 1-5.

Clearspring compiled results for the residential segment for EE potential with 60 measures passing the technical potential screening.[69] Out of those 60, only 18 measures showed economic potential by passing the TRC test and yielding a benefit-cost ratio greater than one.[70] The economic potential showed an approximate savings of 17 percent of forecasted sales by 2030.[71] Two scenarios were applied for the 18 remaining measures based on total energy efficiency budgets of $1 million and $2 million[72]. Lighting, insulation, and water heat-related measures proved to have the highest TRC score.[73] The program potential at the $1 million incentive scenario showed an approximate savings of 4 percent of forecasted sales by 2030.[74]

Clearspring results for the non-residential segment of EE potential show that 73 measures passed the Technical Potential screening.[75] Out of those 73, 45 measures showed Economic Potential by passing the TRC test and yielding a benefit-cost ratio greater than one.[76] All of the 45 measures qualify for Achievable EE potential as they all yielded a benefit higher than the cost of use.[77] Program potential uses specific assumptions of differing EE budget scenarios and is the most realistic potential estimate. Two scenarios were applied for the 45 remaining measures based on total energy efficiency budgets of $1 million and $2 million[78]. Lighting Power Density Reduction and Insulate HVAC Pipes for boiler or AC resulted in the highest scores for TRC.[79]

Staff inquired as to the reason for the efficiency budgets of $1 million and $2 million, to which BREC responded that these amounts represent the Program potential scenarios and the amounts are consistent with prior IRP analysis.[80]

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[69] IRP, Appendix B at 3-1.

[70] *Id.,* Appendix B at 3-3.

[71] *Id.* at 81–82.

[72] *Id.,* Appendix B at 3-6.

[73] *Id*., Appendix B at C-1.

[74] *Id.* at 81–82.

[75] *Id.*, Appendix B at 4-1.

[76] *Id.*, Appendix B at 4-2.

[77] *Id.*, Appendix B at 4-4.

[78] *Id.*, Appendix B at 3-6.

[79] *Id.*, Appendix B at C-2.

[80] BREC's Response to Staff's First Request, (filed March 19, 2021), Item 19.

Based on the conclusions of the DSM Study, BREC states that it has no plans to pursue additional EE or DR programs.[81] In the future, BREC will continue to evaluate EE programs to determine if future programs can be effective for retail members. BREC's efforts will be focused on higher value EE programs rather than DR programs as the DR programs analyzed in the DSM Study were not cost-effective. BREC states that for future DR programs to be successful, the value of capacity in the region would need to increase enough to equal the avoided cost of a peaking unit. BREC states that it will continue to monitor opportunities for DR and new technologies that may provide the benefits of peak demand reduction at a feasible cost.[82]

BREC also promises to maintain residential and non-residential education for the Member-Owners staff and provide onsite efficiency evaluations for commercial and industrial members, as well as to work with Member-Owners to evaluate EE measures in both the residential and non-residential sectors.[83]

RESPONSE TO RECOMMENDATIONS ON 2017 IRP

The 2017 Staff Report made two recommendations regarding BREC's DSM and EE programs.

- Continue to work with the Member Systems and community action agencies to look for ways to enhance the low-income weatherization program. (1)

- Continue to monitor new technologies and best practices that may lower BREC's DSM program costs and or enhance program benefits. Provide updates on consideration of existing and potential DSM programs in BREC's service territory. (2)

In responding to the 2017 Staff Report recommendations, BREC provided the information summarized below, which is also noted and discussed in other portions of this report.[84]

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[81] IRP at 89.

[82] *Id.* at 90.

[83] *Id.*

[84] *Id.*, Appendix D at 2

Recommendation Number	2020 IRP Reference	BREC's Response
(1)	IRP - Section 2.9	In Case No. 2019-00193 Big Rivers filed to implement DSM-14 Low-Income Weatherization Support program, which has been approved as a pilot and was launched in early 2020. As of filing this IRP, the COVID outbreak has disrupted work on the program.
(2)	IRP - Section 4.9; Appendix B	IRP Section 4.9 outlines the conclusions of the 2020 DSM Potential Study, including that Big Rivers will continue to monitor the cost-effectiveness of DR, work with Member-Owners to evaluate EE in both residential and non-residential sectors, maintain education for Member-Owners staff, as well as monitor opportunities for new technologies and demand response.

DISCUSSION OF REASONABLENESS

For the purposes of the current IRP, Staff is satisfied with BREC's evaluation and implementation of its DSM program. The various barriers preventing implementation of cost-effective DR programs explained in the DMS Study and reiterated in BREC's response to Staff's first data request suggest, at that time, that new DR programs will not be feasible in the near future. However, BREC should continue to look for opportunities to provide EE measures to its members. Staff supports BREC's assistance to its low-income customers and retail customer education and assessment programs.

RECOMMENDATIONS FOR BREC'S NEXT IRP

The following are Staff's recommendations on DSM/EE for BREC's next IRP:

- Continue to support Member Systems with educational opportunities and work with CAA to enhance the low-income weatherization program.

- Continue to look for and provide updates of future opportunities to support Member-Owners with new DSM/EE programs.

SECTION 4

SUPPLY-SIDE RESOURCE ASSESSMENT

In this section, Staff reviews, summarizes, and comments on BREC's supply-side analysis and activities, including environmental compliance.

INTRODUCTION

BREC owns and operates three coal fired plants: Coleman Station (443 MW), Green Station (454 MW), and Wilson Station (417 MW). In addition, BREC has 178 MW of hydroelectric capacity contracted from SEPA. However, Unit 1 at Reid Station (65 MW) and Coleman Station were retired at or about the end of 2020, and BREC is in the process of converting Green Station to gas-fired units, which will reduce its name-plate capacity to 414 MW. BREC is working to add an additional 260 MW of solar power purchase agreements (PPAs). When completed, BREC will have nameplate capacity of 1,334 MW.[85]

BREC utilized the Plexos production cost modeling software for its 2020 IRP. Under the least cost Base Case, BREC will have a total generating capacity of 1,010 MW. In particular, the Base Case supports:

- Adding three solar PPAs totaling 260 MW of new solar capacity
- Adding 90 MW of a new 592 MW NGCC unit located at Sebree in 2024
- Idling both the Green Station coal units
- Remaining in the SEPA hydroelectric contract
- Keeping Wilson Station as coal-fired and operational
- Keeping Reid Station as a natural gas peaking unit.[86]

MISO RESERVE MARGINS

[85] *Id.* at 13. The Green Station and Reid Station are located at BREC's Sebree generating station. Note that in the IRP at 17, BREC's optimal plan calls for the idling of the Green Station units and the addition of 90 MW of a new 592 MW natural gas combined cycle unit (NGCC) contingent upon finding partners for the additional capacity. Subsequent to filing its IRP, BREC stated that it had made the decision to repower the Green Station coal units with natural gas. *See* Case No. 2021-00058, *An Electronic Examination of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 2018 Through October 31, 2020*, (filed March 22, 2021) Direct Testimony of Natalie R. Hankins at 4.

[86] IRP at 171.

BREC is located in MISO's Local Resource Zone (LRZ) 6 along with entities in Indiana. As a MISO member, BREC is required to follow its FERC approved tariff, including its Module E-1 Resource Adequacy mechanism.[87] BREC's MISO obligations include maintaining an adequate reserve margin above peak demand. BREC's planning reserve margin (PRM) over the next few years is expected to remain in the range of 8 to 10 percent above its unforced capacity (UCAP) level.[88]

The resource adequacy principals developed by MISO contain three primary points: a footprint-wide resource planning reserve margin, standardized capacity resource qualifications, and member entities complying with Load Serving Entity (LSE) compliance requirements.[89] Among BREC's MISO obligations is that of maintaining system reliability in operation and planning while offering Member services at the lowest cost. MISO annually performs studies, based on information provided by Market Participants, to evaluate current market conditions to forecast future planning environments. These studies are used to develop the Loss of Load Expectation (LOLE), which is utilized in setting the reserve margins for the upcoming planning year and a 9-year planning reserve margin (PRM) forecast.

MISO utilizes the Strategic Energy and Risk Valuation Model ("SERVM") to calculate the LOLE for the applicable planning year. Then, the required PRM is determined by the outcome of the LOLE study in accordance with the MISO Business Practice Manual (BPM) BPM011. These PRMs are determined by probabilistic analysis, such that the LOLE is one (1) day in ten (10) years, or 0.1 day per year, in order to reliably serve MISO's Coincident Peak Demand. MISO's 2020 analysis showed that its system would achieve this requirement when the installed capacity (ICAP) is 1.18 times greater than its CP demand. In other words, the BPM-calculated ICAP planning reserve margin for members in the planning year 2020-2021 is 18.0 percent, which equates to a UCAP PRM of 8.9 percent.[90]

MISO's location-specific approach in its Planning Resource Auction (PRA) is intended to provide efficient price signals to encourage the appropriate resources to participate in the locations where they provide the most benefit. This methodology creates a variety of options for LSEs to obtain the resources required to meet their PRM requirements, including Fixed Resource Requirements, bilateral transactions, self-scheduling, capacity deficiency payments, and auction purchases. The results of the MISO LOLE analysis sets a minimum PRM requirement for BREC to meet its tariff obligations. BREC's PRM provides a level of acceptable reliability and minimizes economic costs. In its IRP supporting analyses, BREC maintained a PRM of 8 to

[87] *Id.* at 116.

[88] *Id.* at 131.

[89] *Id.* at 116.

[90] *Id.* at 120.

10 percent.[91] BREC stated that it will continue to comply with MISO's tariff requirements and be flexible enough to account for varying amounts of planning reserves.[92]

PLEXOS MODELING

The Plexos model was used to develop BREC's long-term and short-term resource assessment and acquisition plans to ensure that BREC is able to meet their forecasted capacity and energy requirements both adequately and reliably. BREC's plan is to meet internal demand requirements, plus MISO's PRM, at the lowest reasonable cost while maintaining risk at tolerable level.[93] This tolerable level is based upon criteria set by BREC's Board of Directors. The Plexos model attains this goal by yielding an optimal set of supply-side resources that will satisfy the resource needs on a net-present-value (NPV) basis.

The Plexos LT Plan (LT Plan) optimizes BREC's fleet of energy and capacity resources over time by determining when to retire existing units or acquire new assets. The LT Plan model uses advanced algorithms that analyze all the possible portfolio options based on the inputs and constraints entered and provides the certainty of what and when to optimally invest or retire capacity resources. Furthermore, the Plexos model is structured to perform in the same manner as MISO would, i.e., all of BREC's load is purchased at market prices and BREC's generation resources are economically dispatched at market prices.[94] The LT Plan's objective is to minimize the NPV of the capital and production costs.[95] Capital costs include the cost of building new generation resources and environmental compliance costs for existing energy generators. Production costs include the expense of operating the BREC's generation fleet, the market cost of energy not served by native generation, and the market revenues from energy sold to market.[96] The LT Plan includes environmental compliance with CCR and ELG for BREC's current generation portfolio and uses a 20-year planning period from 2024-2043.[97]

The Plexos ST Plan (ST Plan) emulates the economic commit and hourly dispatch of the optional generation resources. It does not solve for large-scale capacity changes,

[91] *Id.* at 131.

[92] *Id.* at 131–132.

[93] *Id.* at 134.

[94] *Id.* at 137–138.

[95] *Id.* at 134.

[96] *Id.*

[97] *Id.* at 136.

but rather displays the minute details of the various portfolio choices.[98] Generally, the LT plan is first used to select the major changes and additions to BREC's operating portfolio, and the ST Plan modeling supports those results.

In the modeling process, BREC stated that it developed its Base Case using inputs, constraints, and assumptions based on the best information available at the time the IRP was prepared. Consequently, BREC stated that the LT Plan model results included in the IRP do not constitute a commitment to a specific course of action.[99] To account for uncertainty, BREC conducted 49 model "sensitivities" to build insights into a broader range of future portfolios.[100]

BREC considered the following options in their 2024-2043 LT plan in order to find the optimal, least-cost scenario:

- Wilson Station will remain coal-fired and operational;
- Green Station units can remain coal-fired (and come into compliance with environmental regulations), suspend operations, or convert to natural gas (NG);
- Reid Station can stay natural gas-fired or suspend operation;
- Continue or exit the SEPA contract;
- Three solar PPAs will be in operation by 2024 (no solar beyond these facilities was considered);[101]
- Find partners for an NGCC unit to provide BREC with capacity in 10 MW increments;
- A new 237 MW natural gas combustion turbine can be built; and
- Optional market purchases in 10 MW increments.[102]

ENVIRONMENTAL COMPLIANCE

[98] *Id.* at 135.

[99] *Id.* at 138.

[100] *Id.* at 163.

[101] *Id.* at 144.

[102] *Id.* at 137.

BREC's generators must comply with both federal and state environmental regulations. In particular, EPA's Cross State Air Pollution Rule (CSAPR), Mercury and Air Toxics Standards (MATS), and Coal Combustion Residuals (CCR) rules have been large points of focus for BREC. BREC must comply with the stipulations set by these rules or face closure of facilities.

Cross State Air Pollution Rule (CSAPR)

The EPA's CSAPR was created to address the poor air quality and the formation of soot and smog in downwind states caused by air pollution originating from upwind states. The rule replaced the 2005 Clean Air Interstate Rule (CAIR) that was vacated by federal courts on July 11, 2008. The rule requires certain states in the eastern half of the U.S. to improve air quality by reducing power plant emissions that can cross state lines. CSAPR links the downwind states that aren't meeting or maintaining the National Ambient Air Quality Standards (NAAQS), and other air requirements, to the upwind states that may be affecting them. The quality of air and the formation of these pollutants is primarily due to the emission of sulfur dioxide (SO_2) and nitrogen oxides (NO_X). To remedy this, the EPA sets a pollution limit (or emission budget) for each of the states covered by the CSAPR, and then further grants allowances to affected sources based on specific state budgets. Allowances can be bought, sold, or saved as long as the generation source holds enough allowances to account for its emissions by the end of the compliance period.

CASPR Phase I allowances ran through calendar year 2016. Beginning on January 1, 2017, Phase II decreased the allowances on SO_2 and NO_x both annually and seasonally, primarily affecting fossil fuel fired electric generating units (EGU).[103] The Phase II allowance allocations were reduced by approximately 55 percent for SO_2, 10 percent for NO_x annual, and 50 percent for NO_x seasonal as compared to Phase 1 allocations.[104]

BREC's current active coal fired units are Green Unit 1, Green Unit 2, and Wilson Station, and its only active natural gas unit is the Reid Station. Natural gas emits only trace amounts of $SO_2$and much lower levels of nitrogen oxides compared to coal, so CSAPR primarily applies to BREC's coal units. BREC states that its current SO_2 allowances under CSAPR Phase II are sufficient to meet the emission requirements of its facilities as a whole, but the Wilson Station is has historically operated under a SO_2 allowance deficit.[105] To remedy this, BREC's 2020 environmental compliance plan (ECP) sought Commission approval for a project to recycle the FGD system from the Coleman Station for use at the Wilson Station.[106] With the new FGD system in place, the Wilson

[103] *Id.* at 102.

[104] *Id*.

[105] *Id*.

[106] *See* Case No. 2019-00435, *Electronic Application of Big Rivers Electric Corporation for Approval of Its 2020 Environmental Compliance Plan, Authority to Recover Costs Through a Revised Environmental*

Station will be in compliance. In addition, BREC maintains a bank of approximately 42,000 SO_2 allowances.[107] BREC made no comments on its NO_x allowances or specifics on unit NO_x emissions.

On September 7, 2016, the EPA updated the CSAPR NO_X program for the 2008 Ozone NAAQS (CAPSR Update). The intent was to further reduce summertime emissions of NO_x from power plants located in the Eastern U.S. On December 6, 2018, the EPA concluded that the CAPSR Update was sufficient to address the "Good neighbor" provisions of the Clean Air Act and that most states would not have to continue to reduce emissions under the rule.[108] On September 13, 2019, the U.S. Court of Appeals for the District of Columbia Circuit held that the CASPR Update unlawfully allows a significant contribution to continue beyond downwind attainment deadlines and remanded the rule aback to the EPA for further consideration.[109] BREC is monitoring the EPA for its response.[110]

Mercury and Air Toxics Standards (MATS)

The Mercury and Air Toxics Standards were announced on December 21, 2011. These standards were created to limit mercury, acid gases and other toxic pollution from power plants. In order to meet the requirements of MATS, BREC installed Activated Carbon Injection with Dry Sorbent Injection (DSI) on Green Units 1 and 2 and updated the DSI system for the Wilson Station in 2016.[111] Wilson Station will comply with the mercury pollution guidelines with its Selective Catalytic Reduction (SCR) and the recycled FGD system from the Coleman Station. Since being idled and now set to retire, the Coleman Station units and Reid Station Unit 1, will not be subject to MATS compliance.[112] The matters surrounding the MATS compliance are currently under litigation and BREC is monitoring the proceedings for potential operational impacts.[113]

Coal Combustion Residuals (CCR)

Surcharge and Tariff, the Issuance of a Certificate of Public Convenience and Necessity for Certain Projects, and Appropriate Accounting and Other Relief, (Ky. PSC Aug. 6, 2020).

[107] IRP at 102.

[108] *Id*. at 103.

[109] *Id*.

[110] *Id*.

[111] *Id*.

[112] *Id.* at 104.

[113] *Id.*

The CCR Rule provides regulations for the safe disposal of coal combustion residuals, including fly ash, bottom ash, and scrubber waste, in landfills or surface impoundments (ash ponds). The rule requires that minimum design criteria are met for new and existing sites, or to close the sites when those requirements cannot be met. The final rule was published by the EPA in the Federal Register on April 17, 2015, and largely vacated on August 21, 2018. In response to appeals, the Parts A and B revised rules were proposed and published in the Federal Register on August 28, 2020 and November 12, 2020, respectively.[114] Among other things, Parts A and B proposes establishing a new closure initiation deadline of April, 2021, for all unlined surface impoundments, established procedures to allow facilities to request approval to use an alternate liner for CCR surface impoundments, and defined the requirements for annual closure progress reports.[115]

BREC complied with the original CCR rules for any facilities that utilized ash ponds, including the Coleman Station and Green Station. However, rather than comply with the more recent changes in CCR compliance requirements, BREC's 2020 ECP[116] sought authority to close the Coleman Station and Green Station ash ponds.[117] These actions are expected to be complaint with the requirements of the final CCR rules. Of the two special waste landfills operated by BREC, both landfills had existing groundwater monitoring wells, which made them CCR compliant. In addition, the 2020 ECP sought to include projects for a final cover system for the Wilson Station landfill, and has been approved by the Commission.[118]

In Case Number 2021-00079,[119] BREC submitted an application requesting a Certificate of Public Convenience and Necessity (CPCN) to convert the two coal-fired generating units at the Green Station to natural gas-fired generating units. The filing was, in part, a response to the accelerated closure deadline of the Green Station ash ponds provided by Final CCR Rules, and, in part, a way for BREC to address its anticipated capacity shortfall.

OTHER SUPPLY-SIDE ACTIVITIES

[114] *Id.* at 105.

[115] *Id.*

[116] *See* Case No. 2019-00435 .*Electronic Application of Big Rivers Electric Corporation for Approval of its 2020 Environmental Compliance Plan, Authority to Recover Costs Through a Revised Environmental Surcharge and Tariff, the Issuance of a Certificate of Public Convenience and Necessity for Certain Projects a, and Appropriate Accounting and Other Relief,* (filed Feb 7, 2020).

[117] IRP at 106.

[118] *Id.* at 106-107 and Case No. 2019-00435, *Electronic Application of Big Rivers Electric Corporation* (Ky. PSC Aug 6, 2020) final Order.

[119] Case No. 2021-00079, *Electronic Application of Big Rivers Electric Corporation* (filed Mar. 1, 2021),

BREC intends to increase generation efficiency through programs such as employee training simulators, coal pulverizer tuning, high performance human machine interfaces, minimizing controllable losses, maintenance, instrument tuning, and re-deploying highly experienced personnel from retired/idled units.[120] Most of these measures were part of BREC's 2017 IRP,[121] and BREC maintains that these efforts continue to offer generation performance improvements.[122] Furthermore, wholesale power market prices have declined and by lowering its minimum generation limits, BREC has been able to minimize losses in the MISO power market during off-peak hours as well as minimizing unit shutdowns and startups.[123]

BREC utilizes Navigant Consulting's GKS® benchmarking service, which compares generating unit performance against its peers across the nation. Measures of cost, performance, and safety, all factor into a unit's relative standing. BREC's Wilson Station has been the medium plant category runner-up for the Operation Excellence Award five times in the period 2010-2014.[124] Other performance indicators include 52 Governor's Safety and Health Awards from the Kentucky Labor Cabinet for numbers of hours worked without experiencing lost-time injuries, four continued "no lost-time incident" milestones in 2020, and multiple OSHA safety milestones.[125]

INTERVENOR COMMENTS

Attorney General's Comments on Supply Side Analysis and Activities:

The Attorney General discussed updates to the CCR Rule that occurred shortly after the filing of BREC's 2020 IRP. On August 28, 2020, the EPA published, in the Federal Register, certain changes to the CCR Rule requirements, which accelerated the compliance deadline for closure of the Green Station ash pond to October 31, 2023. The changes required BREC to cease coal-firing operations at Green Station or upgrade its existing landfills. The Attorney General commended BREC for its ability to identify and pursue least-cost resources for its members and end-use customers even in the face of such rapidly changing federal regulatory mandates.[126]

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[120] *Id.* at 93–95.

[121] *See* Case No. 2017-00384, *2017 Integrated Resource Plan of Big Rivers Electric Corporation*, (Ky. PSC Dec. 5, 2019).

[122] IRP at 94.

[123] *Id*. at 92.

[124] *Id.* at 95.

[125] *Id.* at 28.

[126] Attorney General's Comments to BREC's 2020 IRP (filed Sept. 3, 2021) at 2.

The Attorney General also made comments regarding BREC’s Commission-approved solar PAAs. In particular, the Attorney General discussed the benefits, but expressed concern over large-scale, rapid adoptions of renewable resources in Kentucky. Those concerns are as follows: (1) Kentucky’s climate does not provide adequate wind and solar capacity to make large-scale, rapid adoptions of renewable resources cost-effective for utility ratepayers; (2) The intermittent nature of renewable supply-side resources carry reliability risks; and (3) The Commission’s IRP regulations do not require Kentucky’s electric generating utilities to factor-in costs of additional transmission capacity that are frequently necessary to wheel out-of-state power into the utilities’ respective service territories.[127]

Sierra Club’s Comments on Supply Side Analysis and Activities:

Sierra Club made comments on the pertinent regulatory developments that have occurred since the filing of BREC’s 2020 IRP. Sierra Clubs stressed the importance of BREC to reevaluate their needs and update their modeling inputs before moving forward with any of the 2020 IRP plans, due to newly outdated conditions and assumptions.[128]

RESPONSE TO RECOMMENDATIONS ON 2017 IRP

In its Staff Report on BREC's prior IRP in Case No. 2017-00384, Staff made the following recommendations concerning supply-side resources.

- BREC's next IRP should continue to include scenarios where one or more existing coal-fired units are retired, converted to use alternate fuels, or sold. (1)
- Consideration of renewable generation to meet its customers' goals in its modeling and provide a discussion of its assessment of renewable power in its next IRP, especially when considering the future impact of GHG/carbon regulation and related costs per ton of CO_2. (2)
- Include a discussion of its consideration of and costs associated with distributed generation in its next IRP. (3)
- Include information from its member-owner cooperatives on their customers' net metering statistics and activities in its next IRP. (4)
- Include current and accurate cost assumptions in its modeling for renewable resources. (5)
- Include a detailed discussion of the specific generation efficiency improvements and activities undertaken. (6)

[127] *Id.* at 3–4.

[128] Sierra Club’s Comments to BREC’s 2020 IRP (filed Sept. 3, 2021) at 2–3.

- Include a detailed discussion of the endeavors to increase generation and transmission efficiency should include the impact of the efforts instituted to comply with environmental regulations. (7)

- Include a detailed discussion of compliance actions relating to current and pending environmental regulations. (8)

- Address more fully the Sierra Club's comments regarding the Coleman Station and Reid Station Unit 1 regarding the cost assumptions and the SWEA's comments regarding renewables in the modeling for supply-side resources. (9)

In responding to the 2017 Staff Report recommendations, BREC provided the information summarized below, which is also noted and discussed in other portions of this report.[129]

Recommendation Number	2020 IRP Reference	BREC's Response
(1)	IRP – Section 1.22, Chapters 5, 8	IRP Section 1.2.2 and Chapter 2 discuss retirement of Coleman and Reid 1 and three solar power purchase agreements totaling 260 MW. Chapter 8 discusses the treatment of Existing and New or Potential Big Rivers Assets included in this IRP analysis
(2)	IRP – Chapters 5, 8	Sections 5.6 and 5.7 discuss Big Rivers' Environmental Compliance Plans. Chapter 8 discusses the treatment of Existing and New or Potential Big Rivers Assets included in this IRP analysis, including the proposed 260 MW solar PPAs.
(3)	IRP - Section 5.5	Section 5.5 says the Big Rivers works with MISO on generation interconnections, including proposed projects on the sub-transmission system. MISO transmission planning allows distributed generation as alternatives to planned transmission projects. And Big Rivers works with direct-serve consumers who wish to build generation for co-generation purposes.
(4)	IRP - Section 5.5.1	Net-metered distributed generation installations among retail members of the Member-Owners has risen to more than 2.5 MW since 2016.
(5)	IRP - Chapter 8 (Table 8.4)	Solar resources were included at current PPA prices.

[129] IRP, Appendix D at 2–5.

(6)	IRP – Sections 5.1, 5.2	As wholesale power market prices have dropped over the past few years, Big Rivers has been able to significantly lower the historical minimum generation limits on its generators in order to minimize losses in the MISO power market during off-peak hours, thereby keeping the units running and available for the peak hours in the market. For the Big Rivers base load units, the heat rate has improved 137 BTU/kWh or 1.2% in the 11-year period from 2009 to 2019. Investments in high performance human machine interfaces, operations training simulators, reducing controllable losses, maintenance, instrument tuning, and coal pulverizer tuning, all help keep Big Rivers units operating efficiently.
(7)	IRP - Sections 5.5, 6.1, 6.3	As a member of MISO, Big Rivers participates in coordinated short-and long-term planning, that supports development of infrastructure sufficiently robust to meet local and regional standards. Big Rivers has analyzed all relevant environmental compliance provisions and outlined plans to achieve compliance, and will comply with MISO coordinated planning process.
(8)	IRP - Section 5.6.1, 5.6.2, 5.6.3, 5.6.5	Big Rivers has closely analyzed all relevant environmental compliance provisions and has outlined plans to achieve compliance within the time allowed by the regulations.
(9)	IRP - Sections 1.2.2, 2.9, 5.6	Coleman Station and Reid 1 retiring in 2020, renewables including hydropower and solar included in this analysis.

<u>RECOMMENDATIONS FOR BIG RIVERS' NEXT IRP</u>

- Recommendations pertaining to the Supply Section are included in the Demand and Supply Integration Section below.

SECTION 5

DEMAND AND SUPPLY INTEGRATION

BREC utilized the Plexos LT production cost model to formulate its LT Plan. The model optimizes existing generation capacity and energy resources over time and determines if and when to retire existing resources and / or acquire new resources. The optimal plan represents the least cost NPV of the existing and potential resource capital and production costs.[130] Capital costs included that of building new generation and environmental compliance costs for existing generation. Production costs include existing fleet operating costs, market costs of energy (non-native Member generation), and market revenues of energy sold.[131] BREC utilized its 2019-2033 Long Term Financial Plan to develop forecasted fixed O&M production costs. Compliance costs for CCR and ELG are also included. The Plexos LT model is constrained to meet BREC's MISO capacity reserve margin requirements, though there are no constraints on amounts of energy produced. The model mimics MISO in that all energy is purchased at market prices and all generation is dispatched at market prices.[132] The modeled MISO reserve margin constraints are 8 to 10 percent.[133]

Once the optimal LT Plan has been selected, BREC utilizes the Plexos ST module to emulate the economic commitment and hourly dispatch of generation resources. The ST Plan results provide data for all generation resource options to evaluate the optimal LT Plan and other generation resource portfolio options, i.e., sensitivity analyses.[134]

The table below lists the resource options made available to the Plexos LT model. Note that the 592 MW natural gas combined cycle (NGCC) unit modeled as built with assumed additional partners. BREC modeled its ownership and capacity share in 10 MW increments and the model selected the appropriate share of capacity in formulating the least cost LT Plan.[135] Also, purchases of both capacity and energy were made available to the model in 10 MW increments at forecasted prices.[136]

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[130] IRP at 134.

[131] *Id.*

[132] *Id.* at 137–138.

[133] *Id.* at 155.

[134] *Id.* at 135.

[135] *Id.* at 137.

[136] *Id.* at 138.

Generation Resources Existing, New, and Potential[137]

Generation Resources			
Existing (Currently Operating) Big Rivers Assets			
Generation Resource	Capacity, MW	Option	2024-2043
Wilson Unit 1	417	Coal -Fired	X
Green Unit 1	231	Coal -Fired	X
		NG Conversion	X
		Idled	X
Green Unit 2	223	Coal-Fired	X
		NG Conversion	X
		Idled	X
Reid CT	65	NG-Fired	X
		Idled	X
SEPA	178	Continue	X
		Exit Contract	X
Total	1,114		

New or Potential Big Rivers Assets			
Generation Resource	Capacity, MW	Option	2024-2043
Henderson Solar Facility	160	PSC Approved (Built)	X
McCracken Solar Facility	60	PSC Approved (Built)	X
Meade Solar Facility	40	PSC Approved (Built)	X
Natural Gas Combined Cycle	592	10 MW incremental at Sebree	X
		10 MW incremental at Coleman	X
Natural Gas Combustion Turbine	237	Build Asset	X
Market (PPA - Block)	800	10 MW incremental up to 800 MW	X

A preliminary LT Plan resulted in both Green Station units being idled, exiting the SEPA contract and adding 260 MW of NGCC unit at Sebree. The ST Plan model was used to test five generation portfolio options. The table below lists the seven options from most costly to least cost to serve load. It is worth noting that approximately $3 million separates the four options with varying amounts of NGCC capacity added to the generation portfolio.

[137] IRP at 139, Table 8.1.

2024 – 2043 ST Plan Portfolio Results – Base Case[138]

Generation Portfolio	Rank	Comment
Status Quo (Wilson, Reid CT, SEPA, Green)	7	No Solar Added
+ Solar	6	Current Position
+ Solar, Green Idled + 80 MW PPA	5	Proposed Option
+ Solar, Green & Reid Idled, + 150 MW NGCC - Sebree	4	Proposed Option
+ Solar, Green Idled, Exit SEPA, + 260 NGCC - Sebree	3	Proposed Option
+ Solar, Green & Reid Idled, Exit SEPA + 330 NGCC - Sebree	2	Proposed Option
+ Solar, Green Idled + 90 MW NGCC - Sebree	**1**	**Least Cost (Base Case)**

The least cost optimal LT Plan calls for BREC adding the three solar PPAs totaling 260 MW capacity, adding 90 MW of a new NGCC at Sebree station in 2024, idling both Green Station units, staying in the SEPA contract and keeping the Wilson Station baseload coal unit and the Reid Station CT as a peaking unit.[139] Note that BREC stated that it had studied converting the Green Station units to natural gas as opposed constructing a NGCC unit. In order for the NGCC unit to attain a low enough heat rate to be cost competitive, a minimum capacity of 600 MW needed to be built.[140]

Based upon BREC's forecast demand and the optimal least cost LT Plan, the table below provides BREC's reserve margin positions.

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[138] *Id.* at 155 and 157, Table 8.8 (select information).

[139] *Id.* at 155 and Appendix G for more detailed information.

[140] *See* Response to Staff's First Request (filed Mar. 19, 2021), Item 40d. However, BREC filed Case No. 2021-00079 to convert the Green Station units to natural gas as its best short term option while it seeks additional partners for the NGCC unit. *See* Case No. 2021-00079, *Electronic Application of Big Rivers Electric Corporation,* (filed Mar. 1, 2021).

Big Rivers Coincident and Non-Coincident Peaks[141]

Year	Trans. Losses (kW)	Total Annual CP (kW)	BREC Annual NCP* w/o Losses MW	MISO Req.[1]	Total MISO PRMR MW[2]	BREC Gen Capacity (UCAP MW)**	Reserve Margin after MISO Req.	Non-Member Sales MW[3]	Total MISO PRMR + Non-Member Sales MW	Reserve Margin after MISO Req. and Non-Member Sales
2020	15,668	626,715	611	49	660	1,032	**61%**	422	1,081	**-5%**
2021	15,803	632,122	616	49	665	1,042	**61%**	422	1,087	**-4%**
2022	20,810	832,412	812	65	876	1,043	**21%**	422	1,298	**-20%**
2023	20,864	834,546	814	65	878	1,193	**39%**	306	1,184	**1%**
2024	20,908	836,327	815	65	880	917	**5%**	210	1,091	**-16%**
2025	20,953	838,132	817	65	883	915	**4%**	311	1,193	**-23%**
2026	20,998	839,920	819	66	884	914	**4%**	311	1,196	**-24%**
2027	21,005	840,180	819	66	885	913	**3%**	100	985	**-7%**
2028	21,036	841,438	820	66	886	911	**3%**	100	986	**-8%**
2029	21,063	842,528	821	66	887	910	**3%**		887	**3%**
2030	21,078	843,125	822	67	888	909	**3%**		888	**2%**
2031	21,106	844,223	823	67	889	908	**2%**		889	**2%**
2032	21,158	846,330	825	67	891	906	**2%**		891	**2%**
2033	21,183	847,329	826	67	892	905	**2%**		892	**1%**
2034	21,202	848,086	827	67	893	904	**1%**		893	**1%**
2035	21,223	848,929	828	67	894	902	**1%**		894	**1%**
2036	21,245	849,782	829	67	895	901	**1%**		895	**1%**
2037	21,266	850,659	829	67	896	900	**1%**		896	**0%**
2038	21,286	851,459	830	67	897	898	**0%**		897	**0%**
2039	21,308	852,319	831	67	897	897	**0%**		897	**0%**
2040**			833	67	900	896	**0%**		900	**0%**
2041**			834	68	901	895	**-1%**		901	**-1%**
2042**			835	68	902	893	**-1%**		902	**-1%**
2043**			836	68	903	892	**-1%**		903	**-1%**

* BREC Annual NCP (non-coincident with MISO) w/o Losses from 2020 Long Term Load Forecast (where it is called BREC Annual CP to indicate highest one hour Rural plus Industrial Load Combined).

** 2024-2043 from IRP Base Case which does not include the Green Station Conversion to Gas.

*** Long Term Load forecast extends only through 2039. In Base case, Growth rate remains constant for 2040 through 2043.

1 MISO Obligations MW includes a MISO coincidence Factor, Transmission Losses, and Planning Reserve Margin (PRM). MISO Obligations held constant through 2043.

2 Total MISO PRMR = Load plus MISO Obligations MW.

3 Non-Member Sales obligations are purchased rather than generated when beneficial to Members.

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[141] BREC's Response to Staff's First Request (filed Mar. 19, 2021), Item 56d (Select information from table provided).

Note that column Generation Capacity UCAP MW includes the three solar PPA contracts where the capacity value is calculated using MISO's Resource Adequacy Business Practice Manual BPM-011-r24 Appendix H. An alternate methodology is pending (Effective Load Carrying Capability) that will reduce the solar capacity values significantly.[142]

Sensitivity Analysis

Using the LT Plan model, BREC ran 30 single variable sensitivity analyses to find breakpoints where the least cost LT Plan shifts to a different generation mix least cost solution. Ten sensitivities were run for changes in market clearing energy prices, coal prices and natural gas prices. Each set of price changes was bounded by a 50 percent swing up and down in 10 percent increments.[143] Generally, the results indicate that under these various price swings, the Wilson Station unit and the solar PPAs do not shift. When LMPs rise or when natural gas prices fall, the NGCC capacity is more cost effective and replaces the Reid Station and the SEPA capacity because of its lower heat rate and higher capacity factor. When LMPs fall or when natural gas prices rise, the opposite holds because of lower fixed production costs. In these instances, additional capacity is purchased from the market. When coal prices vary up or down, the SEPA contract is canceled and all additional capacity is made up through the NGCC.[144]

Twelve multivariable price sensitivity scenarios were run to recognize that energy prices are correlated to some degree and often move together. Generally, the results track the single price variable variations. Higher energy and fuel prices favors adding NGCC capacity, idling the Reid Station, and canceling SEPA. Lower energy prices and fuel prices tend to favor the Reid Station and the SEPA contract, though in many instances some NGCC capacity is added to the least cost generation mix as well.[145]

BREC ran seven additional scenarios. Two different carbon tax scenarios were run; ACES estimated price with 2034-implementation date and IHS Market with a higher price and 2030 implementation date. A NGCC unavailability scenario was also included based upon the inability to acquire partners. A zero capacity price scenario was run to simulate very low capacity prices. Two Renewable Energy Credit price scenarios were run. One with Ohio market solar prices and the other with a zero price. Finally, a solar firm capacity at ELCC, which is lower than what was modeled in the Base Case. Across these varied scenarios, several interesting results stand out. For example, in the zero capacity price scenario, the Reid Station is idled, SEPA canceled with the capacity deficit made up through market PPAs. In the ACES carbon tax scenario, the Reid Station is idled and the SEPA contract is canceled and replaced with large amounts of NGCC

[142] BREC's Response to Staff's Second Request (filed May 11, 2021), Item 26.

[143] IRP at 163.

[144] *Id.* at 163–164; 165, Table 8.12; and Appendix G for more detailed information.

[145] *Id.* at 165–167; 168, Table 8.14; and Appendix G for more detailed information.

capacity. In the IHS carbon tax scenario, both the Reid Station and SEPA remain, and small amounts of NGCC and market PPA capacity is added.[146]

INTERVENOR COMMENTS

Attorney General Comments

The Attorney General notes that shortly after BREC filed its IRP, which concluded that converting Green Station to gas-fired generation would not be economical, BREC requested a CPCN from the Commission in Case No. 2021-00079 to convert Green Station to gas-fired generation. The Attorney General attributes this change to a change in the deadline for compliance with relevant CCR rules. The Attorney General indicated that BREC should be commended for continuing to identify and pursue least-cost resources for its members and end-use customers in the face of such rapidly changing federal regulatory mandates.

The Attorney General also commended BREC's decision to adopt significant quantities of renewably sourced power into its supply-side resources, given the percentage of development candidates interested in renewable energy options and the reduced risk associated with the diversification of generation, among other things. However, the Attorney General indicated that it had three concerns regarding the large-scale, rapid adoption of renewable resources—the Attorney General argued that Kentucky's climate does not have sufficient wind or solar resources to make such generation cost effective, the Attorney General argued that renewable resources carry reliability risks, and the Attorney General argued that the Commission's IRP regulations do not require Kentucky's electric generating utilities to factor-in costs of additional transmission capacity that is frequently necessary to wheel out-of-state into utilities' respective service territories.

The Attorney General noted that the value of demand response programs in MISO is currently low. However, the Attorney General argued that the value of capacity is likely to increase in MISO given the likely penetration of intermittent renewable resources in the years ahead. Thus, the Attorney General encouraged BREC to continue to monitor the cost-effectiveness of demand response, and seek Commission permission to implement demand response programs for peak time rebate and/or critical peak pricing, if and when MISO capacity pricing should reach levels conducive to the success of such programs.

Sierra Club Comments

Sierra Club first noted that BREC's 2020 IRP has become substantially outdated in light of prominent interceding developments, including the 260 MW of solar power BREC contracted to purchase, BREC's decision to convert Green Station to gas-fired units, despite the finding in the IRP that such a conversion would not be optimal, and the election of a new US President with markedly distinct policies. Sierra Club noted that

[146] *Id.* at 169-170; 169, Table 8.15; and Appendix G for more detailed information.

BREC could not be blamed for not anticipating with certainty such developments but argued that those changes require significant reevaluation of at least some aspects of the 2020 IRP. More specifically, Sierra Club noted that BREC's plan to convert Green Station to gas-fired generation was not factored into BREC's case for the combined cycle plant and that there is now no showing of a need for that combined cycle plant or that its construction will not result in wasteful duplication.

Sierra Club urged BREC to conduct, and submit for review no later than their 2023 IRP, a fresh evaluation of when its D.B. Wilson Station, a 417 MW coal-fired power plant, can be most economically replaced. Sierra Club argued that the Wilson Station could be replaced by a clean energy portfolio this decade even before factoring in more stringent, eventually forthcoming environmental regulations that Sierra Club argues will disproportionately hamper coal-fired generation, among other trends disfavoring coal.

Lastly, Sierra Club asked BREC to provide a discussion about the feasibility of re-attracting at least one of the two Century Aluminum smelters that terminated their contracts with BREC—and, more specifically, about whether Century could be re-attracted by way of building out cost-effective clean energy, as Sierra Club contends that Century has publicly stated interest in lowering their carbon footprint.

DISCUSSION OF REASONABLENESS

Commission Staff generally finds BREC's supply-side resource assessment to be reasonable. However, Commission Staff do have a few issues with BREC's assessment and its methodology. Most notably, Commission Staff believe that it was unreasonable for BREC to assess its generation capacity needs and the most cost effective way to meet those needs without accounting for generation capacity it contracted to provide to third parties in MISO Zone 6 for more than one year.

As noted above, BREC contracted to provide wholesale power to both OMU and KY MEA, which are located in Miso Zone 6 and, therefore, will be served with BREC's native generation capacity or capacity purchases in the Miso market.[147] Section 3 of Miso's Business Practice Manual, Resource Adequacy, No. 11 requires a LSE, like BREC, to include the demand and energy attributed to their wholesale customers in the LSE's demand and energy forecasts when calculating the LSE's PRM.[148] Thus, BREC was required by contract and by MISO to have the capacity and/or energy necessary to serve OMU and KY MEA in each year BREC contracted to provide wholesale service.

However, the modeling for BREC's 2020 IRP included a constraint on available excess capacity, as compared to native load only, that prevented the model from selecting

[147] Case No. 2021-00079, *Electronic Application of Big Rivers Electric Corporation* (filed Mar. 1, 2021), Application, Exhibit B, Direct Testimony of Mark Eacret at 6–7 (discussing how the Nebraska contracts are not part of BREC's MISO position but indicating that the OMU and KY MEA contracts are part of its MISO position).

[148] MISO BPM011, Section 3.

a resource that provided long-term capacity significantly above its native load. This meant that the 2020 IRP model selected generation capacity as if BREC had no obligation to serve OMU and KY MEA, despite BREC's contractual obligation to do so, at least in part, for a number of years. Using that method, BREC determined that it was most economical to close Green Station while covering any capacity short falls with purchases on Miso's market.[149]

Conversely, when BREC ran a short-term model through the end of 2029 that included its obligation to serve OMU and KY MEA, BREC found that it would be necessary to make much larger capacity purchases from MISO to meet its obligations to OMU and KY MEA, which BREC argued significantly increased its market risks. BREC's short-term model also indicated that the cost of the Green Station conversion was roughly equivalent to market purchases over than period.[150] Thus, several months after BREC filed its IRP, BREC requested a CPCN to convert Green Station to gas-fired generation, despite finding in the IRP that it was not economical.[151]

Commission Staff believe that it is unreasonable for BREC to assess its supply side resources excluding supply obligations it contracted to provide in Miso Zone 6 for a number of years. Commission Staff believe that this resulted in an analysis that did not account for all of BREC's generation obligations.

STAFF RECOMMENDATIONS FOR THE NEXT IRP

- BREC provided well thought out sensitivity analyses and supporting tables in the Appendices. For the next IRP, BREC should continue to rigorously test its base case least cost plan and provide appropriate supporting tables and documentation. In addition, it would also be helpful to be able to visualize (in tabular form) when various levels of capacity are added over the forecast period. This information should be provided in the next IRP.

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[149] *See* Case No. 2021-00079, *Electronic Application of Big Rivers Electric Corporation* (filed Mar. 1, 2021), Application, Exhibit A Direct Testimony of Michael T. Pullen (Pullen Testimony) at 12–13.

[150] *See* Case No. 2021-00079, *Electronic Application of Big Rivers Electric Corporation,* (filed Mar. 26, 2021) Response to Staff's First Request, Item 3.b. ("Excluding or including the OMU or KYMEA load does not change the short term or long-term ST Plan model results. It just changes the amount of market risk. In the Green Evaluation short-term ST Plan models, the economics of the Green Unit natural gas conversion were found to be comparable or nearly equal to the market without market risk."); *See also* Case No. 2021-00079, *Electronic Application of Big Rivers Electric Corporation,* Pullen Testimony at 9–13 (discussing the change in the analysis that led to BREC's new conclusion that Green Station should be converted to a gas fired unit); Case No. 2021-00079, *Electronic Application of Big Rivers Electric Corporation* (filed Apr. 16, 2021) Response to Staff's Second Request for Information, Item 15 (indicating that operating Green Station with coal fired units would be uneconomical even if the CCR rules did not exist).

[151] *See generally*, Case No. 2021-00079, *Electronic Application of Big Rivers Electric Corporation* (filed Mar. 1, 2021), Application.

- BREC's LT Plan was premised on the 2020 Load forecast for its Members only and did not include any energy or capacity requirements from its Non-Member customers. As long as BREC has the excess capacity to provide service to these customers or that BREC intends to purchase any energy or capacity shortfalls, then, everything else being equal, there is no need to include them in its forecast modeling. However, if that is not the case, then BREC should include Non-Member obligations in its modeling to provide a more complete analysis of potential LT Plans. For the next IRP, BREC should include Non-Member obligations in its forecasts and modeling or provide a detailed explanation as to why it is not included.

- Only four months after filing this IRP, BREC filed Case No. 2021-00079 to convert the Green Station units to natural gas. While Staff notes that BREC continued its analysis of least cost generation options for the benefit of its owner-Members, in the IRP, BREC had no additional partners for the NGCC unit and was only modeled as a single sensitivity run based on the existing LT Plan. In that instance, the Green Station unit conversions had already been rejected. Staff appreciates that modeling runs take place well in advance of filing the IRP and that the IRP represents only a snapshot in time of BREC's ongoing analyses; however, additional assumptions could have been made that would realistically acknowledge that partners would not be found immediately and that Green Station's conversion may be a viable option. For the next IRP, BREC should carefully weigh the reasonableness of and when various technologies will be available or implemented.

- Staff appreciates that the forecasts were run at least two years ago. However, natural gas prices have increased substantially and it is unclear whether another coal-fired unit will ever be built. While renewable and battery costs are forecast to continue to decline, MISO is changing the method of assigning capacity to renewables. The potential role of energy efficiency, DSM, and cogeneration could be more important in the future. For the next IRP, BREC should include these options as potential resources in its modeling.

- To ensure greater clarity and understanding, BREC should ensure that information provided in tables is described completely and is consistent across tables. For example, in Tables 8.10 and 8.11, there is a 4-5 MW difference between the natural gas generation capacity, which carries over to the Total column in Table 8.10 and Firm Capacity in Table 8.11. Also, the Table provided in BREC's response to Staff's first information request, Item 56 contains much more detailed explanation in column headings and in footnotes that would have been helpful in understanding information and explanations provided in the IRP text. In addition, information provide in the response does not match exactly with information provided in Tables 8.10 or 8.11. Without proper contextual and descriptive information, the information provided in Tables 8.10 and 8.11 could be misconstrued as providing a complete picture of BREC's forecasted positions.

*Angela M Goad
Assistant Attorney General
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Roger Hickman
Big Rivers Electric Corporation
201 Third Street
P. O. Box 24
Henderson, KY 42420

*Joe F. Childers
Childers & Baxter PLLC
300 Lexington Building, 201 West Sho
Lexington, KENTUCKY 40507

*Tyson Kamuf
Corporate Attorney
Big Rivers Electric Corporation
201 Third Street
P. O. Box 24
Henderson, KY 42420

*John G Horne, II
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Larry Cook
Assistant Attorney General
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Matthew Miller
Sierra Club
50 F Street, NW, Eighth Floor
Washington, DISTRICT OF COLUMBIA 20001

*J. Michael West
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Big Rivers Electric Corporation
201 Third Street
P. O. Box 24
Henderson, KY 42420