ORIGINAL

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

ELECTRONIC	**)**	
2020 INTEGRATED RESOURCE PLAN OF	**)**	**Case No. 2020-00299**
BIG RIVERS ELECTRIC CORPORATION	**)**	

Responses to Commission Staff's
Post-Hearing Request for Information

dated
December 1, 2021

FILED: December 28, 2021

ORIGINAL

BIG RIVERS ELECTRIC CORPORATION

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

VERIFICATION

I, Russell L. ("Russ") Pogue, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Russell L. ("Russ") Pogue

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Russell L. ("Russ") Pogue on this the 22nd day of December, 2021.

Notary Public, Kentucky State at Large

Kentucky ID Number KYNP16841

My Commission Expires October 31, 2024

BIG RIVERS ELECTRIC CORPORATION

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

VERIFICATION

I, Marlene S. Parsley, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Marlene S Parsley

Marlene S. Parsley

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Marlene S. Parsley on this the 22nd day of December, 2021.

Kathern Ridley

Notary Public, Kentucky State at Large

Kentucky ID Number KYNP16841

My Commission Expires October 31, 2024

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC
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Item 1) ***Refer to the Integrated Resource Plan (IRP), Chapter 4, Section 4.7, pages 83–88, Tables 4.3–Table 4.7, and BREC's response to Commission Staff's First Request for Information, Item 20.***

a. Provide updated versions of Table 4.3, Table 4.4, Table 4.5, Table 4.6, and Table 4.7 using the $/kW capacity costs of the converted Green Station approved in Case No. 2021-00079.[2]

b. Provide updated versions of Table 4.3, Table 4.4, Table 4.5, Table 4.6, and Table 4.7 using the $/kW capacity costs of the natural gas combined cycle unit that BREC determined was optimal based on its IRP.

c. Explain how using the capacity costs of the converted Green Station and the optimal natural gas combined cycle unit effect the results of the Total Resource Cost (TRC) test.

[2] 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 Asset* (Ky. PSC June 23, 2021), Order.

Response) The discrepancy in Table 4.3 of the IRP occurred when values of the UCT (Utility Cost Test) calculated for appendix B were provided as TRC values inadvertently by Clearspring. Following the hearing, the TRC B-C values for the Program Potential were calculated for the $1 million and $2 million scenarios. The Corrected Table 4.3 is shown below.

Table 4.3

Program Potential Cost-Effectiveness (TRC Test)

Potential	TRC Test Ratio
Program - $2 million	1.86
Program - $1 million	1.86

Lifetime

a. Below are revised Tables 4.3 through 4.7 using the Green Station conversion and fixed costs. The result was that all listed TRC values shifted upward and three new measures were added to the calculation because their TRC values moved above one.

BIG RIVERS ELECTRIC CORPORATION

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Table 4.3 (Green Conversion) Program Potential Cost Effectiveness (TRC Test)	
Program - $2 million	1.909
Program - $1 million	1.909
Lifetime	

Table 4.4
Program Potential Summary (Green Conversion)

Annual Energy (MW	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Program $2 Million	20,049	40,097	60,146	80,194	100,243	120,292	140,340	160,389	179,461	198,534
Program $1 Million	10,425	20,851	31,276	41,701	52,126	62,552	72,977	83,402	93,320	103,238
Demand (MW)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Program $2 Million	4.1	8.1	12.2	16.2	20.3	24.3	28.4	32.5	36.4	40.3
Program $1 Million	2.1	4.2	6.3	8.4	10.5	12.7	14.8	16.9	18.9	21.0

Table 4.5
$1 Million Senario - Residential Savings by End-Use (Green Conversion)

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy (MWh)	HVAC	928	1,857	2,785	3,714	4,642	5,571	6,499	7,428	8,356	9,285
	Water Heating	2,224	4,448	6,672	8,896	11,120	13,344	15,568	17,792	20,017	22,241
	Appliance	752	1,503	2,255	3,007	3,758	4,510	5,262	6,013	6,258	6,502
	Lighting	48	96	144	192	239	287	335	383	431	479
	Other	105	210	315	420	525	629	734	839	944	1,049
	Total	4,057	8,114	12,171	16,228	20,285	24,342	28,399	32,456	36,005	39,555

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Demand (MW)	HVAC	0.3	0.6	1.0	1.3	1.6	1.9	2.2	2.5	2.9	3.2
	Water Heating	0.2	0.4	0.7	0.9	1.1	1.3	1.6	1.8	2.0	2.2
	Appliance	0.1	0.2	0.3	0.4	0.4	0.5	0.6	0.7	0.7	0.8
	Lighting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3
	Total	0.7	1.3	2.0	2.6	3.3	3.9	4.6	5.3	5.9	6.5

Note: MISO Summer Peak
Note: Cumulative Annual Impact

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Table 4.6
$1 Million Senario - Non-Residential Savings by End-Use (Green Conversion)

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy (MWh)	HVAC	844	1,688	2,532	3,376	4,219	5,063	5,907	6,751	7,595	8,439
	Water Heating	146	291	437	583	728	874	1,019	1,165	1,311	1,456
	Appliance	954	1,908	2,862	3,816	4,771	5,725	6,679	7,633	8,587	9,541
	Lighting	3,518	7,036	10,553	14,071	17,589	21,107	24,625	28,142	31,660	35,178
	Other	907	1,814	2,721	3,627	4,534	5,441	6,348	7,255	8,162	9,068
	Total	6,368	12,737	19,105	25,473	31,841	38,210	44,578	50,946	57,315	63,683

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Demand (MW)	HVAC	0.6	1.2	1.7	2.3	2.9	3.5	4.1	4.6	5.2	5.8
	Water Heating	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	Appliance	0.1	0.2	0.3	0.4	0.5	0.7	0.8	0.9	1.0	1.1
	Lighting	0.4	0.8	1.2	1.6	2.0	2.4	2.8	3.2	3.6	4.0
	Other	0.3	0.7	1.0	1.4	1.7	2.1	2.4	2.8	3.1	3.5
	Total	1.5	2.9	4.4	5.8	7.3	8.7	10.2	11.6	13.1	14.5

Note: MISO Summer Peak
Note: Cumulative Annual Impact

Table 4.7
Demand Response Programs Evaluation Results (Green Conversion)

Program	Sector	Type	Direct Control	TRC	UCT	PCT
Air Conditioner Cycling (25%)	Residential	Load Management	Yes	0.9	0.4	2.2
Air Conditioner Cycling (50%)	Residential	Load Management	Yes	1.8	0.8	2.2
Water Heater Cycling (25%)	Residential	Load Management	Yes	0.1	0.1	2.2
Water Heater Cycling (50%)	Residential	Load Management	Yes	0.3	0.1	2.2
Residential PTR	Residential	Load Management	No	16.8	2.1	5.8
DLC (Customer Ownership)	Non-Residential	Load Management	Yes	1.2	27.7	0.3
DLC (Utility Ownership)	Non-Residential	Load Management	Yes	1.2	1.1	1.3
Residential TOU	Residential	Dynamic Pricing	No	4.2	7.0	4.0
Residential CPP	Residential	Dynamic Pricing	No	7.8	12.9	13.3
Non-Residential TOU	Non-Residential	Dynamic Pricing	No	5.0	26.1	17.6
Non-Residential CPP	Non-Residential	Dynamic Pricing	No	1.7	8.6	6.5
Plug-In EV TOU	All	Dynamic Pricing	No	0.7	1.6	5.8

b. Below are Tables 4.3 through 4.7 revised using new Natural Gas Combined Cycle plant construction cost estimates and fixed costs. The result was that

all listed TRC values shifted upward and 14 new measures were added to the calculation because their TRC values moved above one.

Table 4.3 (New NGCC)
Program Potential Cost Effectiveness (TRC Test)

Program - $2 million	2.046
Program - $1 million	2.046
Lifetime	

Table 4.4
Program Potential Summary (New NGCC)

Annual Energy (MWh)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Program $2 Million	19,267	38,533	57,800	77,067	96,333	115,600	134,867	154,133	172,502	190,871
Program $1 Million	9,843	19,686	29,528	39,371	49,214	59,057	68,899	78,742	88,126	97,510
Demand (MW)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Program $2 Million	3.9	7.8	11.7	15.5	19.4	23.3	27.2	31.1	34.9	38.7
Program $1 Million	2.0	4.0	6.0	7.9	9.9	11.9	13.9	15.9	17.8	19.7

Table 4.5
$1 Million Senario - Residential Savings by End-Use (New NGCC)

	Category	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Energy (MWh)	HVAC	839	1,678	2,518	3,357	4,196	5,035	5,874	6,714	7,553	8,392
	Water Heating	2,010	4,020	6,031	8,041	10,051	12,061	14,071	16,082	18,092	20,102
	Appliance	991	1,983	2,974	3,965	4,957	5,948	6,939	7,931	8,463	8,996
	Lighting	43	87	130	173	216	260	303	346	390	433
	Other	114	228	342	455	569	683	797	911	1,025	1,138
	Total	3,998	7,996	11,994	15,991	19,989	23,987	27,985	31,983	35,522	39,061
	Category	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Demand (MW)	HVAC	0.3	0.6	0.9	1.1	1.4	1.7	2.0	2.3	2.6	2.9
	Water Heating	0.2	0.4	0.6	0.8	1.0	1.2	1.4	1.6	1.8	2.0
	Appliance	0.1	0.3	0.4	0.5	0.7	0.8	1.0	1.1	1.2	1.3
	Lighting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3
	Total	0.7	1.3	2.0	2.6	3.3	3.9	4.6	5.3	5.9	6.5

Note: MISO Summer Peak
Note: Cumulative Annual Impact

Table 4.6
$1 Million Scenario - Non-Residential Savings by End-Use (New NGCC)

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy (MWh)	HVAC	763	1,525	2,288	3,051	3,814	4,576	5,339	6,102	6,865	7,627
	Water Heating	132	263	395	527	658	790	921	1,053	1,185	1,316
	Appliance	862	1,725	2,587	3,450	4,312	5,174	6,037	6,899	7,761	8,624
	Lighting	3,268	6,537	9,805	13,074	16,342	19,611	22,879	26,148	29,416	32,685
	Other	820	1,639	2,459	3,279	4,098	4,918	5,737	6,557	7,377	8,196
	Total	5,845	11,690	17,535	23,380	29,224	35,069	40,914	46,759	52,604	58,449

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Demand (MW)	HVAC	0.5	1.0	1.6	2.1	2.6	3.1	3.7	4.2	4.7	5.2
	Water Heating	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	Appliance	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0
	Lighting	0.4	0.8	1.1	1.5	1.9	2.3	2.6	3.0	3.4	3.8
	Other	0.3	0.6	0.9	1.3	1.6	1.9	2.2	2.5	2.8	3.1
	Total	1.3	2.7	4.0	5.3	6.6	8.0	9.3	10.6	12.0	13.3

Note: MISO Summer Peak
Note: Cumulative Annual Impact

Table 4.7
Demand Response Programs Evaluation Results (New NGCC)

Program	Sector	Type	Direct Control	TRC	UCT	PCT
Air Conditioner Cycling (25%)	Residential	Load Management	Yes	1.8	0.8	2.2
Air Conditioner Cycling (50%)	Residential	Load Management	Yes	3.6	1.6	2.2
Water Heater Cycling (25%)	Residential	Load Management	Yes	0.3	0.1	2.2
Water Heater Cycling (50%)	Residential	Load Management	Yes	0.5	0.2	2.2
Residential PTR	Residential	Load Management	No	33.2	4.1	5.8
DLC (Customer Ownership)	Non-Residential	Load Management	Yes	2.1	46.8	0.3
DLC (Utility Ownership)	Non-Residential	Load Management	Yes	2.1	1.8	1.3
Residential TOU	Residential	Dynamic Pricing	No	6.6	10.9	4.0
Residential CPP	Residential	Dynamic Pricing	No	8.5	14.1	13.3
Non-Residential TOU	Non-Residential	Dynamic Pricing	No	6.9	35.7	17.6
Non-Residential CPP	Non-Residential	Dynamic Pricing	No	2.3	11.8	6.5
Plug-In EV TOU	All	Dynamic Pricing	No	1.0	2.2	5.8

c. By replacing Big Rivers' avoided capacity cost used in the original study with conversion and fixed costs of the Green Station or the new construction

and fixed costs of a modeled natural gas combined cycle (NGCC) unit, the benefits associated with implementing DSM measures shifted upward, while the implementation costs were assumed to stay the same. As a result, the benefit to cost ratio of all measures improved. The change in TRC values for individual measures varied depending on whether the source of benefits was primarily derived from energy use reduction or capacity reduction.

Programmatic TRC values increased as well. The programmatic TRC values reflect cumulative benefits and costs associated with measures that individually have a TRC value greater than one. As benefits are increased, it would be expected that some marginal measures, which did not achieve a TRC of one using Big Rivers' avoided capacity cost, may achieve this threshold by using the replacement values from Green Station conversion or a new NGCC. Using the Green Station conversion costs resulted in three new measures shifting above one. When the NGCC replacement values were used, 14 measures shifted above one. Increasing benefits lifts the individual measure TRC values, while introducing the new

measures into the programmatic TRC calculation resulted in downward pressure on the value since the new values were all near one and the assumed spending is distributed among all measures with a TRC above one. As a result, using the higher values had little impact on the programmatic TRC when compared to the Green Station values.

The Program Potential calculations are not based on specific program designs, but are general assessments of savings that might be achieved given assumed conditions.

Witness) Russell L. Pogue

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's
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Item 2) ***Refer to the November 23, 2021 Hearing Video Transcript (HVT) at 12:36:30 in which Mr. Pogue and Mr. Hoyt discussed a discrepancy between the results of the demand-side management (DSM) study reported in the IRP and an original or initial study provided by Mr. Hoyt.***

a. Provide a copy of the initial study provided by Mr. Hoyt to BREC.

b. Identify and explain any discrepancy between the results of the DSM study reported in the IRP and those in the initial study discussed at the hearing.

Response)

a. When Mr. Hoyt (Joshua L. Hoyt) referred to the "initial study" during the referenced time of the hearing, he was referring to the DSM Potential Study which was provided as Appendix B to Big Rivers' 2020 Integrated Resource Plan (IRP). However, the DSM Potential Study never calculated a Program Potential Total Resource Cost (TRC) value for the $1 million and $2 million scenarios. The only benefit-cost ("B-C") for the Program Potential that was calculated in the study was for the Utility Cost Test

(UCT). This is referenced in the Executive Summary of Appendix B. This data was inadvertently transmitted to Big Rivers to be used in Table 4.3 of the IRP.[2]

b. See Big Rivers' response to sub-part a, above. Following the hearing, the TRC B-C values for the Program Potential were calculated for the $1 million and $2 million options. Below is the corrected Table 4.3.

Program Potential Cost-Effectiveness (TRC Test)

Potential	TRC Test Ratio
Program - $2 million	1.86
Program - $1 million	1.86

Witnesses) Russell L. Pogue

[2] See Big Rivers' 2020 IRP Appendix B, Demand-Side Management Potential Study at page 1.6, Sections 1.4.2 and 1.4.4 for explanation of the study approach for the TRC and UCT, respectively.

BIG RIVERS ELECTRIC CORPORATION

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Item 3) ***Refer to the IRP, Table 8.10, page 160, the November 23, 2021 HVT at 11:04:20–11:07:43, BREC's response to Commission Staff's First Request for Information, Item 56.d., and BREC's response to Commission Staff's Second Request for Information, Item 26.***

a. Identify where in its IRP BREC discussed its D-rate analysis, including specifically any discussion of its use of the Effective Load Carrying Capability (ELCC) standard to determine the MISO capacity credit it would receive for solar generation assets.

b. Regardless of whether it is specifically discussed in the IRP, explain in detail how BREC utilized the ELCC standard in its modeling to determine the reserve capacity and capacity margins, whether that is reflected in BREC's Optimal LT Plan bass case (preferred plan) or in any of the scenario evaluations or sensitivity analyses. If ELCC is not reflected in the IRP results as presented, provide an updated table to BREC's response to Commission Staff's First Request for Information, Item 56.d. that reflects the impact of MISO ELCC implementation.

Response)

a. Table 5.4 "Big Rivers Generation Portfolio" on page 101 outlines the capacity values for existing resources. Table 8.11 on page 161 shows the Zonal Resource Credit ("ZRC") values of solar using the Business Practice Manual method of accreditation for the Base case as Firm Capacity MW. On page 169, Table 8.15 "LT Plan Other Scenarios" shows the results of using effective load carrying capability ("ELCC") capacity values for solar in the second to last row. Table 8.10 "Generation and Capacity Reserve Margin" on page 160 presents the MISO capacity credit (in the form of ZRCs) which Big Rivers receives for its generation, by fuel type. The difference between the net generating capability of the coal and gas resources and the amount shown is the average of the Equivalent Forced Outage Rate on Demand ("EFORd") experience of the units over the prior three years or a projection of those values, and are reflected in IRP Table 5.2 "Key Performance Indicators per IEEE[1] Standards."

[1] IEEE = Institute of Electrical and Electronics Engineers

Page 144 of the IRP notes that "In the Base Case, Big Rivers used the current MISO Business Practice Manual for the determination of firm capacity associated with these solar facilities There is a sensitivity where less firm capacity is forecasted for solar using the MISO effective load carrying capability ("ELCC") projections."

b. As noted above, ELCC was not used in the Base Case. In the IRP Section 8.2.3.3 "Other Scenarios" on page 169, the scenario using LT Plan-Solar Capacity ELCC is shown in the second to last row of Table 8.15, with the least cost-option under this scenario having Big Rivers adding 130 MW more Natural Gas Combined Cycle capacity than the Preliminary LT Plan.

See Attachment to this response for the requested table update to Big Rivers' response to Item 56d. of Commission Staff's First Request for Information ("Item 56d."). As stated in the footnote to Item 56d., the generation values in this table do not include the conversion of the Green Station coal units to natural gas.

BIG RIVERS ELECTRIC CORPORATION

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2 **Witness)** Marlene S. Parsley

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Big Rivers Electric Corporation
Case No. 2020-00299
Updated Table originally provided in Response to PSC 1-56d.

Big Rivers Coincident Peak (kW)												Total System NCP (kW)		
Year	Rural Summer CP	Rural Winter CP	Rural Annual CP	Direct Serve Annual CP	Transmission Losses	Total Annual CP	BREC Annual NCP* w/o Losses MW	MISO Obligations MW[1]	Total MISO PRMR MW[2]	**BREC Gen Capacity (UCAP MW)****	**Reserve Margin after MISO Requirement**	Non-Member Sales MW[3]	Total MISO PRMR + Non-Member Sales MW	**Reserve Margin after MISO Requirement and Non-Member Sales**
2020	483,946	484,817	483,946	127,101	15,668	626,715	611	49	660	1,032	61%	422	1,081	-5%
2021	489,218	489,893	489,218	127,101	15,803	632,122	616	49	665	1,042	61%	422	1,087	-4%
2022	489,558	491,914	489,558	322,043	20,810	832,412	812	65	876	1,043	21%	422	1,298	-20%
2023	491,639	494,177	491,639	322,043	20,864	834,546	814	65	878	**1,146**	**33%**	306	1,184	**-3%**
2024	493,376	495,970	493,376	322,043	20,908	836,327	815	65	880	**801**	**-10%**	210	1,091	**-27%**
2025	495,136	497,935	495,136	322,043	20,953	838,132	817	65	883	**798**	**-10%**	311	1,193	**-33%**
2026	496,879	499,794	496,879	322,043	20,998	839,920	819	66	884	**796**	**-11%**	311	1,196	**-33%**
2027	497,133	499,957	497,133	322,043	21,005	840,180	819	66	885	**793**	**-11%**	100	985	**-19%**
2028	498,359	500,820	498,359	322,043	21,036	841,438	820	66	886	**790**	**-12%**	100	986	**-20%**
2029	499,422	501,685	499,422	322,043	21,063	842,528	821	66	887	**788**	**-12%**		887	**-11%**
2030	500,004	501,900	500,004	322,043	21,078	843,125	822	67	888	**786**	**-12%**		888	**-11%**
2031	501,074	502,687	501,074	322,043	21,106	844,223	823	67	889	**784**	**-13%**		889	**-12%**
2032	503,128	504,331	503,128	322,043	21,158	846,330	825	67	891	**826**	**-8%**		891	**-7%**
2033	504,103	505,032	504,103	322,043	21,183	847,329	826	67	892	**824**	**-8%**		892	**-8%**
2034	504,841	505,432	504,841	322,043	21,202	848,086	827	67	893	**823**	**-8%**		893	**-8%**
2035	505,663	506,010	505,663	322,043	21,223	848,929	828	67	894	**821**	**-9%**		894	**-8%**
2036	506,495	506,574	506,495	322,043	21,245	849,782	829	67	895	**819**	**-9%**		895	**-8%**
2037	507,349	507,238	507,349	322,043	21,266	850,659	829	67	896	**818**	**-9%**		896	**-9%**
2038	508,129	507,810	508,129	322,043	21,286	851,459	830	67	897	**816**	**-10%**		897	**-9%**
2039	508,968	508,470	508,968	322,043	21,308	852,319	831	67	897	**815**	**-10%**		897	**-9%**
2040**							833	67	900	**814**	**-10%**		900	**-10%**
2041**							834	68	901	**812**	**-11%**		901	**-10%**
2042**							835	68	902	**810**	**-11%**		902	**-10%**
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 + Industrial load combined)

** 2024-2043 from IRP Base Case which does not include Green 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

Case No. 2020-00299
Attachment for Response to PSC Post-Hearing IR 3b.
Witness: Marlene S. Parsley