ORIGINAL

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

Responses to Commission Staff's
First Request for Information
dated February 26, 2021

FILED: March 19, 2021

ORIGINAL

BIG RIVERS ELECTRIC CORPORATION

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

VERIFICATION

I, Nathanial A. ("Nathan") Berry, 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.

Nathanial A. Berry

Nathanial A. ("Nathan") Berry

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Nathanial A. ("Nathan") Berry on this the 19th day of March, 2021.

Kathryn P. Day

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, Christopher S. ("Chris") Bradley, 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.

Christopher S. Bradley

Christopher S. ("Chris") Bradley

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Christopher S. ("Chris") Bradley on this the 19th day of March, 2021.

Katherine Foley

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, Duane E. Braunecker, 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.

Duane E. Braunecker
Duane E. Braunecker

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Duane E. Braunecker on this the 19th day of March, 2021.

Kathrine Rasley
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, Lindsay N. Durbin, 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.

Lindsay N. Durbin
Lindsay N. Durbin

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Lindsay N. Durbin on this the 19th day of March, 2021.

Katherine Ribley
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, Mark J. Eacret, 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.

Mark J. Eacret

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Mark J. Eacret on this the 19th day of March, 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

<u>VERIFICATION</u>

I, Steven A. ("Steve") Fenrick, 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.

Steve Fenrick
Steven A. ("Steve") Fenrick

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Steven A. ("Steve") Fenrick on this the 19th day of March, 2021.

Katherine Roby
Notary Public, Kentucky State at Large
Kentucky ID Number KYNP16841
My Commission Expires October 30, 2024

BIG RIVERS ELECTRIC CORPORATION

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

VERIFICATION

I, Joshua P. ("Josh") Hoyt, 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.

Joshua P. ("Josh") Hoyt

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Joshua P. ("Josh") Hoyt on this the 19th day of March, 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, Michael S. ("Mike") Mizell, 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.

Michael S. ("Mike") Mizell

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Michael S. ("Mike") Mizell on this the 19th day of March, 2021.

Katherine Ridley
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 19th day of March, 2021.

Katherine Bly

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, 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 19th day of March, 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, Matthew S. ("Matt") Sekeres, 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.

Matthew Sekeres

Matthew S. ("Matt") Sekeres

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Matthew S. ("Matt") Sekeres on this the 19th day of March, 2021.

Kathern Reley

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, Paul G. Smith, 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.

Paul Smith
____
Paul G. Smith

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Paul G. Smith on this the 19th day of March, 2021.

Kathie Roley
____
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

Response to Commission Staff's
First Request for Information
dated February 26, 2021

March 19, 2021

Item 1) ***Refer to the IRP, Chapter 1, Section 1.2.6, Figure 1.6, page 20. Confirm the increase in direct serve sales from 2019–2039 is due to the addition of Nucor Steel. If this cannot be confirmed, provide an explanation of the increased direct sales from 29 percent of total sales to 44 percent.***

Response) [redacted].

Witness) Marlene S. Parsley

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC
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CASE NO. 2020-00299

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March 19, 2021

Item 2) ***Refer to the IRP, Chapter 1, Section 1.2.6, Table 1.2, page 22. Provide an update to the table that includes the annual percent increases in the total coincident peak (CP) load.***

Response) Please see the updated table provided as an attachment to this response.

Witnesses) Matthew S. Sekeres and
Steven A. Fenrick

Big Rivers Electric Corporation
Case No. 2020-00299
Updated Table 1.2
Chapter 1, Section 1.2.6, Page 22
Big Rivers 2020 Integrated Resource Plan

Year	Rural Summer CP	Rural Winter CP	Rural Annual CP	Direct Serve Annual CP	Transmission Losses	**Total Annual CP**	**Total Annual CP % Growth**
2015	504,990	566,553	566,553	121,143	11,253	**698,949**	
2016	486,690	484,768	486,690	120,750	13,855	**621,295**	**-11.11%**
2017	504,269	474,971	504,269	114,378	15,538	**634,184**	**2.07%**
2018	502,549	556,742	556,742	95,530	16,382	**668,654**	**5.44%**
2019	480,171	490,895	490,895	117,931	15,995	**624,821**	**-6.56%**
2020	483,946	484,817	483,946	127,101	15,668	**626,715**	**0.30%**
2021	489,218	489,893	489,218	127,101	15,803	**632,122**	**0.86%**
2022	489,558	491,914	489,558	322,043	20,810	**832,412**	**31.69%**
2023	491,639	494,177	491,639	322,043	20,864	**834,546**	**0.26%**
2024	493,376	495,970	493,376	322,043	20,908	**836,327**	**0.21%**
2025	495,136	497,935	495,136	322,043	20,953	**838,132**	**0.22%**
2026	496,879	499,794	496,879	322,043	20,998	**839,920**	**0.21%**
2027	497,133	499,957	497,133	322,043	21,005	**840,180**	**0.03%**
2028	498,359	500,820	498,359	322,043	21,036	**841,438**	**0.15%**
2029	499,422	501,685	499,422	322,043	21,063	**842,528**	**0.13%**
2030	500,004	501,900	500,004	322,043	21,078	**843,125**	**0.07%**
2031	501,074	502,687	501,074	322,043	21,106	**844,223**	**0.13%**
2032	503,128	504,331	503,128	322,043	21,158	**846,330**	**0.25%**
2033	504,103	505,032	504,103	322,043	21,183	**847,329**	**0.12%**
2034	504,841	505,432	504,841	322,043	21,202	**848,086**	**0.09%**
2035	505,663	506,010	505,663	322,043	21,223	**848,929**	**0.10%**
2036	506,495	506,574	506,495	322,043	21,245	**849,782**	**0.10%**
2037	507,349	507,238	507,349	322,043	21,266	**850,659**	**0.10%**
2038	508,129	507,810	508,129	322,043	21,286	**851,459**	**0.09%**
2039	508,968	508,470	508,968	322,043	21,308	**852,319**	**0.10%**
Average Annual Growth Rates							
Previous 10 Years	-0.34%	-1.32%	-1.32%	0.98%	11.50%	**-0.74%**	
Previous 5 Years	-0.04%	-4.44%	-4.44%	-1.03%	9.24%	**-3.60%**	
Next 5 Years	0.54%	0.21%	0.10%	22.25%	5.50%	**6.00%**	
Next 10 Years	0.39%	0.22%	0.17%	10.57%	2.79%	**3.03%**	
Next 20 Years	0.29%	0.18%	0.18%	5.15%	1.44%	**1.56%**	

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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March 19, 2021

Item 3) ***Refer to the IRP, Chapter 1, Section 1.2.6, Table 1.3, page 23. Provide an update to the table that includes the annual percent increases in total system energy requirements.***

Response) Please see the updated table provided as an attachment to this response.

Witnesses) Matthew S. Sekeres and
Steven A. Fenrick

Big Rivers Electric Corporation
Case No. 2020-00299
Updated Table 1.3
Chapter 1, Section 1.2.6, Page 23
Big Rivers 2020 Integrated Resource Plan

Year	Total Rural Requirements	Direct Serve	Transmission Losses	**Total System Energy Requirements**	**Total System Energy Requirements % Growth**
2015	2,325,204	946,873	66,970	**3,339,047**	
2016	2,330,037	915,310	73,420	**3,318,766**	**-0.61%**
2017	2,209,837	919,895	77,928	**3,207,660**	**-3.35%**
2018	2,366,988	953,822	86,858	**3,407,668**	**6.24%**
2019	2,271,772	957,994	83,431	**3,317,632**	**-2.64%**
2020	2,313,997	987,552	84,688	**3,386,237**	**2.07%**
2021	2,342,004	987,552	85,373	**3,414,929**	**0.85%**
2022	2,345,137	2,038,752	112,407	**4,496,296**	**31.67%**
2023	2,357,028	2,038,752	112,712	**4,508,492**	**0.27%**
2024	2,366,988	2,041,632	113,042	**4,521,662**	**0.29%**
2025	2,376,885	2,038,752	113,221	**4,528,859**	**0.16%**
2026	2,386,410	2,038,752	113,466	**4,538,628**	**0.22%**
2027	2,388,504	2,038,752	113,519	**4,540,776**	**0.05%**
2028	2,394,976	2,041,632	113,759	**4,550,367**	**0.21%**
2029	2,400,628	2,038,752	113,830	**4,553,210**	**0.06%**
2030	2,403,821	2,038,752	113,912	**4,556,486**	**0.07%**
2031	2,409,248	2,038,752	114,051	**4,562,051**	**0.12%**
2032	2,419,240	2,038,752	114,307	**4,572,299**	**0.22%**
2033	2,424,117	2,038,752	114,433	**4,577,302**	**0.11%**
2034	2,427,766	2,038,752	114,526	**4,581,044**	**0.08%**
2035	2,431,849	2,038,752	114,631	**4,585,232**	**0.09%**
2036	2,435,950	2,038,752	114,736	**4,589,439**	**0.09%**
2037	2,440,157	2,038,752	114,844	**4,593,753**	**0.09%**
2038	2,444,021	2,038,752	114,943	**4,597,716**	**0.09%**
2039	2,448,197	2,038,752	115,050	**4,601,999**	**0.09%**
Average Annual Growth Rates					
Previous 10 Years	0.15%	-2.27%	11.89%	**-0.45%**	
Previous 5 Years	-1.22%	-0.17%	8.91%	**-0.70%**	
Next 5 Years	0.82%	16.34%	6.26%	**6.39%**	
Next 10 Years	0.55%	7.85%	3.16%	**3.22%**	
Next 20 Years	0.37%	3.85%	1.62%	**1.65%**	

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 4) ***Refer to the IRP, Chapter 1, Section 1.3, page 24. Explain why no additional solar was considered as a supply-side option beyond the 260 MW proposed in Case No. 2020-00183.***[2]

Response) Please see page 144 of Big Rivers' 2020 IRP, which states, "At the base case inputs and the current proposed PPA costs, the model would continue to add solar until reserve margins were met. Big Rivers chose to limit the model's flexibility to add additional solar beyond the proposed facilities until we have more experience with the resource and there is more clarity about the effect of intermittent resources on the transmission system." A portfolio with 100% solar generation would expose Big Rivers Member/Owners to significant market risk for capacity and energy. Extreme events such as the recent Polar Vortex would exacerbate those risks. Overreliance on intermittent resources has been identified as a factor in the California brownouts in 2020 and the ERCOT price volatility and brownouts in February of 2021.

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[2] Case No. 2020-00183, *Electronic Application of Big Rivers Electric Corporation for Approval of Solar Power Contracts* (Ky. PSC Sept. 28, 2020).

Witness) Mark J. Eacret

Item 5) ***Refer to the IRP, Chapter 2, Section 2.2, page 26. Provide situations when, and explain why, the price for SEPA Cumberland ZCR differs from the market clearing price in MISO Zone 6.***

Response) An example from MISO's 2020/2021 Planning Resource Auction shows Zone E28 (where the SEPA Cumberland resource is located) Auction Clearing Price was $4.90/MW-Day and Zone 6 (where Big Rivers' load is located) Auction Clearing Price was $5.00/MW-Day. The reason for this price difference is that SEPA Cumberland Zonal Resource Credits ("ZRC") receive the Auction Clearing Price based upon the External Resource Zone where the Planning Resource underlying the ZRC is physically located. The External Zone definition is based on the geographical locations of the SEPA Cumberland resources located in Kentucky and Tennessee, within the TVA Balancing Authority. Big Rivers load pays the Auction Clearing Price based on the zone where the load is located.

MISO's auction clearing engine uses aggregate supply curves for each Local Resource Zone and External Resource Zone, along with import and export constraints and other inputs to determine the least–cost set of offers and the resulting Auction Clearing Price for each Local Resource Zone and External Resource Zone.

Witness) Marlene S. Parsley

Item 6) ***Refer to the IRP, Chapter 2, Section 2.3, page 27.***

a. ***Provide BREC's Pay for Performance Plan.***

b. ***Explain if this plan includes incentive pay or bonuses tied to financial performance.***

Response)

a. Beginning with the March 2020 salaried employee increase, Big Rivers implemented a pay for performance structure allowing managers to recognize individual performance. Managers have the ability to allocate the annual budgeted increase to employees in their department based on performance. Managers may allocate between zero and six percent to each employee as long as they do not exceed the total budget dollars allocated to their department. All recommendations must be substantiated by the employee's performance appraisal document.

b. This plan does not include incentive pay or bonuses tied to financial performance.

Witness) Lindsay N. Durbin

BIG RIVERS ELECTRIC CORPORATION

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

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dated February 26, 2021

March 19, 2021

Item 7) ***Refer to the IRP, Chapter 2, Section 2.7, page 32. Provide any updates to BREC's credit ratings.***

Response) Copies of the following rating agency reports are provided as attachments to this response.

- Attachment 1 – S&P Global Ratings report dated April 1, 2020, which affirmed BB+ rating and stable outlook.
- Attachment 2 – Fitch Ratings report dated November 25, 2020, which affirmed BBB- rating and revised the outlook to positive from stable.
- Attachment 3 - Moody's report dated December 2, 2020, which upgraded the rating to an investment grade credit rating of Baa3 with a stable outlook.

Witness) Paul G. Smith

S&P Global
Ratings

RatingsDirect®

Big Rivers Electric Corp., Kentucky Ohio County; Rural Electric Coop

Primary Credit Analyst:
David N Bodek, New York (1) 212-438-7969; david.bodek@spglobal.com

Secondary Contact:
Scott W Sagen, New York (1) 212-438-0272; scott.sagen@spglobal.com

Table Of Contents

Case No. 2020-00299
Attachment 1 for Response to PSC 1-7
Witness: Paul G. Smith

Big Rivers Electric Corp., Kentucky Ohio County; Rural Electric Coop

Credit Profile		
Big Rivers Electric Corp. ICR		
Long Term Rating	BB+/Stable	Affirmed
Ohio Cnty, Kentucky		
Big Rivers Electric Corp., Kentucky		
Ohio Cnty (Big Rivers Electric Corp.) RURELCCOO		
Long Term Rating	BB+/Stable	Affirmed

Rating Action

S&P Global Ratings affirmed its 'BB+' issuer credit rating on Big Rivers Electric Corp. (BREC), Ky. At the same time, S&P Global Ratings affirmed its 'BB+' rating on Ohio County, Ky.'s $83.3 million pollution control refunding revenue bonds, series 2010A (Big Rivers Electric Corp. Project), issued for BREC. The outlook on all ratings is stable.

Credit overview

BREC is a generation and transmission cooperative serving three member distribution cooperatives. Key rating drivers include:

- The wholesale utility's reliance on significant, but declining, market sales where the utility is a price-taker;
- The short tenor of five wholesale power contracts with nonmembers that will help displace market sales;
- The meaningful contributions of industrial customers to its member distribution cooperatives' revenues, which we view as an exposure because of illness related to the coronavirus and measures taken to limit the outbreak, which are taking a toll on economic activity; and
- The utility's almost exclusive reliance on coal-fired generation assets for the electricity it produces, tempered by market purchases that are produced with other fuels.

Moreover, we believe that although projected debt service coverage (DSC) ratios of at least 1.4x in 2020-2021 are robust, they do not fully compensate for the exposures the utility faces. We also take into consideration nonamortizing debt representing 35% of the utility's debt portfolio, which enhances the DSC ratios by approximately 30 basis points compared with a fully amortizing scenario.

Members provided 72% of 2018's operating revenues and revenues from the sale of surplus energy production in competitive wholesale markets provided nearly 30%. BREC projects market revenues will decline to less than 4% by 2023 as its members add steel manufacturer Nucor Corp. as a customer and multi-year contracts between BREC and municipal utility systems begin. Although Energy Information Administration (EIA) data shows that members' energy sales to industrial customers account for 75% of energy sales, BREC reports that it transmits power others produce to two smelter customers and that those sales should be excluded from member energy sales. This adjustment halves

Case No. 2020-00299
Attachment 1 for Response to PSC 1-7
Witness: Paul G. Smith

members' energy sales to industrial customers. Adding Nucor will raise industrial concentration to about 50% of member energy sales. The industrial concentration is mitigated by plans to not earn a margin on half of the energy it sells to Nucor. BREC projects that once Nucor opens a new facility within the service territory of distribution member Meade County Rural Electric Cooperative Corp., which it plans to do in 2022, it will help absorb surplus capacity and increase member sales revenues by more than 20%. Although BREC projects the Nucor facility will add a 200-megawatt (MW) load, at the same time, adding the company will expand the customer base's industrial concentration. We view the Nucor load as providing a cushion that can help mitigate any nonrenewals by the municipal contract customers.

BREC has added contracts with municipal utilities that are providing greater and more stable revenues than market sales. These contracts and the Nucor addition will almost eliminate exposure to market sales by 2022. However, because of their tenor, the nonmember contracts will provide only medium-term revenue stream security and predictability. The municipal contracts expire in 2026 and 2029, with 240 MW of the contracted capacity rolling off in 2026 and another 100 MW in 2029. Nucor's 200 MW load should help temper the possibility that BREC is unable to renew the municipal contracts. BREC reports nearly 1,200 MW of generation capacity.

Unlike many other cooperative utilities, BREC does not have autonomous rate-setting authority. Rather, the Kentucky Public Service Commission establishes the cooperative's wholesale rates and its members' retail rates. Tempering the absence of rate-setting autonomy is a history of supportive regulatory decisions and utility projections that assume that BREC will not need rate increases through 2027.

Environmental, social and governance factors

We believe BREC's generation fleet presents meaningful environmental exposures as the national focus on reducing greenhouse gas emissions advances, which could jeopardize generator dispatch and financial performance. The utility's use of coal to produce electricity represented nearly 100% of the utility's self-generation in 2019 and 80% of the electricity BREC sold that year.

Although EIA data show that the residential rates BREC's members charge their customers were 13%-18% higher than the state average in 2018, BREC reports that the EIA data does not reflect member bill credits tied to the use of its rate stabilization fund, which reduce rates by about 5%. Applying this discount, we nevertheless believe the utility presents social risk that could limit financial flexibility, especially in light of income levels and the negative economic pressures of directives to limit the spread of coronavirus. The rate disparities reflect BREC's allocation to remaining customers, and costs from smelter loads lost in 2013. Before their departure, the smelters accounted for about two-thirds of BREC's energy sales. Although the duration of the recently negotiated nonmember contracts is relatively short, we believe that management is mitigating governance risk through efforts to secure purchasers for the surplus capacity that customer departures created. The utility also benefits from a proactive regulator that in addition to overseeing the utility's rates, has demonstrated a commitment to monitoring management and board actions.

Stable Two-Year Outlook

The stable outlook reflects improved prospects for stable financial performance with the anticipated addition of the Nucor load and the medium-term municipal contracts to sell surplus power to nonmember public power utilities. We

Case No. 2020-00299
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view these developments as sharply reducing BREC's exposure to market prices for energy sales, at least through the life of the contracts.

Downside scenario

We could lower the ratings if the utility cannot sustain sound financial performance because of poor prospects for renewing or replacing nonmember contracts, weak market conditions, or poor plant performance. Similarly, if the financial profiles of BREC's members erode, we could lower the ratings. We could also lower the ratings if declining economic activity attributable to the outbreak of coronavirus or measures limiting the spread of COVID-19 negatively affect financial margins.

Upside scenario

We do not expect to raise the ratings within our two-year outlook horizon without prospects for a more secure long-term revenue stream that aligns predictable revenues with debt maturities. We view several additional exposures as constraining the ratings. These include rates we consider high relative to low income levels; an almost exclusively coal-fired generation portfolio and its exposure to more stringent emissions regulations; the presence of nonamortizing debt, which we believe distorts DSC levels relative to utilities with greater percentages of amortizing debt; meaningful industrial loads in a declining economy; and DSC levels that do not compensate fully for these exposures.

Credit Opinion

BREC reported $733 million of debt as of Dec. 31, 2019. About 35% of its debt will not amortize before maturity, which contributes to more robust DSC ratios, relative to utilities with a greater percentage of amortizing debt. The cooperative projects adding 26% more debt through 2021, bringing debt balances up to $921 million. Nevertheless, the utility projects maintaining a favorable debt-to-capitalization ratio for a cooperative utility of 67% in 2021. The aging generation units help reduce the debt to capitalization ratios. With the debt additions, the utility projects robust DSC metrics of at least 1.4x through 2022. We performed a scenario analysis that suggests that coverage would be about 30 basis points lower if the cooperative had a fully amortizing debt portfolio.

Although we view coverage levels and liquidity as providing resilience, our rating conclusions assign significant weight to the relative brevity of the municipal power sales agreements. If BREC is unable to renew these contracts and must rely on market sales for margins, we believe the utility could be vulnerable to earning comparatively thin margins in competitive markets, compared with those it earns under the municipal contracts. At the same time, we view favorably the addition of Nucor as a members' customer, as helping reduce market exposure. Additional factors we view as constraining the rating include the industrial concentration among members' customers, and members' high retail rates that can limit financial flexibility when viewed through the lens of the state's low income levels.

We view external liquidity facilities as providing an added measure of lender protection. External facilities increase balance-sheet liquidity from a weak 40 days' operating expenses to about four months' operating expenses.

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FitchRatings

RATING ACTION COMMENTARY

Fitch Affirms Big Rivers Electric Corporation at 'BBB-'; Outlook Positive

Wed 25 Nov, 2020 - 12:09 PM ET

Fitch Ratings - New York - 25 Nov 2020: Fitch Ratings has affirmed the following ratings on Big Rivers Electric Corporation, Kentucky at 'BBB-':

--Issuer Default Rating (IDR).

The Outlook was revised to Positive from Stable.

ANALYTICAL CONCLUSION

The affirmation of the IDR at 'BBB-' reflects the corporation's improving financial margins and leverage ratio in the context of its midrange revenue defensibility and strong operating risk profile. The leverage ratio declined to 7.5x in fiscal 2019 from nearly 14.0x just four years prior, the result of stronger financial performance and a steady decline in long-term debt.

The Positive Outlook reflects the expectation of continued strong financial performance from increasing contracted sales to nonmembers over the next several years, and depreciation of regulatory assets, leading to greater margins and further declines in leverage. Even with a presumed additional stress on sales due to potential coronavirus pandemic lockdowns in 2021, The Fitch Analytical Stress Test (FAST) indicates positive operating performance for the year and funds available for debt service (FADS) of almost $90 million, leading to a leverage ratio that peaks at 8.3x, but declines in subsequent years to approximately 6.0x as sales volumes return to prior levels. If the leverage ratio continues to trend lower, the rating could be upgraded.

Fitch continues to assess Big Rivers' three members to have midrange credit quality, which constrains the corporation's overall revenue defensibility when coupled with the absence of independent rate-setting authority, and likely limits the upside of the overall IDR. Lastly, a consistently low operating cost burden, manageable capital needs and a supportive regulatory regime are also important rating considerations. Fitch continues to view the ongoing rebalancing of Big Rivers' previously long resource position favorably, limiting the need to generate margin from potentially volatile noncontracted market sales.

CREDIT PROFILE

Big Rivers is a nonprofit generation and transmission cooperative formed in 1961, and it provides all-requirements wholesale electric and transmission service to three electric distribution cooperatives, pursuant to all-requirements contracts through Dec. 31, 2043. The three members provide service to a total of approximately 118,000 retail customers located in 22 western Kentucky counties. Demographic indicators and financial performance of the three distribution systems are satisfactory and provide sufficient support for the rating.

Pandemic's Impact Expected to be Manageable

The recent outbreak of coronavirus is expected to have a limited impact on the corporation's financial performance in fiscal 2020 (YE Dec. 31). Management projects a significant decline in total sales in 2020 due to the pandemic and milder weather, but the declines are mainly from off-system market sales into the Midcontinent Independent System Operator (MISO), which contribute much less to the corporation's margin than sales to the members and direct industrial customers. Sales declines to contracted customers was approximately 6.4% on a combined basis, and fully reflected in Big Rivers' expected 2020 financial performance.

While the revenue losses are projected to be close to $40 million in fiscal 2020, total operating expenses will also be about $30 million lower, limiting the impact on gross margin. Contracted sales to nonmembers will increase over the next few years and largely replace the need for spot market sales. Fitch views positively the decreasing reliance on spot sales and believes the corporation is well-positioned to meet potential re-implementation of stay-at-home directives or additional pandemic-related governmental restrictions that may cause a decline in demand next year.

Revenue Defensibility: 'bbb'

Strong Contractual Framework, Midrange Member Credit Quality

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Revenue defensibility is midrange despite otherwise very strong revenue source characteristics provided by the long-term all-requirements contracts. The midrange assessment principally reflects the credit quality of the member utilities along with the regulatory framework within which Big Rivers and its customers operate. While the regulatory regime has been constructive historically, neither Big Rivers nor its three customers have autonomy over rate-setting.

Operating Risk: 'a'

Coal-Dominated Resource Base, Low Cost Burden

The strong operating risk assessment begins with a low operating cost burden that has averaged 5.0 cents/KWh over the past five years. Operating cost flexibility is assessed at neutral, as Big Rivers has idled or retired 695MW of coal capacity over the past several years. As a result, reliance on coal-fired capacity is lower than historical amounts and sits just below Fitch's threshold for a neutral assessment.

Management is in the process of adding renewable solar capacity over the next several years through three separate purchase power agreements (PPAs) totaling 260MW, which will further diversify the resource base. The PPAs have been executed with commercial operation expected in late 2022 and 2023.

Financial Profile: 'bbb'

Improved Margins, Leverage to Decline

Big Rivers' midrange financial profile remains midrange but margins and leverage ratios are improving. The solid financial results achieved in fiscals 2017-2019 are expected to continue, as Big Rivers provides greater amounts of contracted energy and capacity to various nonmember utilities over the next few years. In addition, management anticipates lower operating expenses from the recent reduction in capacity coupled with higher noncash expenses, that will lead to further improvement in margins and leverage.

ASYMMETRIC ADDITIONAL RISK CONSIDERATIONS

There are no additional asymmetric risks affecting the rating.

RATING SENSITIVITIES

Factors that Could, Individually or Collectively, Lead to Positive Rating Action/Upgrade

--Continued positive trend in financial performance and a leverage ratio that is below 8.0x on a sustained basis;

--A positive shift in purchaser credit quality that results in a higher assessment of revenue defensibility.

Factors that Could, Individually or Collectively, Lead to Negative Rating Action/Downgrade

--A weakening in margins or higher debt levels that lead to a reversal in leverage to levels closer to 10.0x or higher on a sustained basis;

--A downward shift in purchaser credit quality that results in a lower assessment of revenue defensibility.

BEST/WORST CASE RATING SCENARIO

International scale credit ratings of Sovereigns, Public Finance and Infrastructure issuers have a best-case rating upgrade scenario (defined as the 99th percentile of rating transitions, measured in a positive direction) of three notches over a three-year rating horizon; and a worst-case rating downgrade scenario (defined as the 99th percentile of rating transitions, measured in a negative direction) of three notches over three years. The complete span of best- and worst-case scenario credit ratings for all rating categories ranges from 'AAA' to 'D'. Best- and worst-case scenario credit ratings are based on historical performance. For more information about the methodology used to determine sector-specific best- and worst-case scenario credit ratings, visit [https://www.fitchratings.com/site/re/10111579].

SECURITY

Big Rivers' IDR reflects Fitch's assessment of the utility's vulnerability to default on its financial obligations.

REVENUE DEFENSIBILITY

Strong Contractual Framework

Revenue source characteristics are very strong. All three of Big Rivers' customers are signed to long-term all-requirements take-and-pay power contracts. All costs associated with the delivery of power and energy/services, including debt service on the bonds, are billed to the customers on a monthly basis, leading to a de facto unlimited step-up. Given there are only three members, the rating on the bonds is heavily correlated to the credit quality of all three customers.

Rates are Regulated

The Kentucky Public Service Commission (KPSC) is charged with approving the wholesale and retail rates of Big Rivers and its members. Wholesale rates charged to the members consist of a demand charge and an energy charge per kWh consumed, as approved by KPSC. Big Rivers has certain approved riders, including a fuel adjustment clause and an environmental surcharge, which helps provide timely pass-through of variable charges. Supportive regulatory policies, including reclassification of certain assets as regulatory assets for recovery through existing rates, successful historical rate case approvals and recent approval to allow for the ability to utilize excess net margin to amortize future regulatory liabilities in lieu of providing all excess margin as a bill credit to members, point to a constructive regulatory environment.

On the member level, rates are set for full cost recovery. However, while the regulatory environment for rate recovery has been supportive, approval of rate cases by an outside entity could result in delayed revenue recovery, potentially higher revenue variability and weaker overall revenue defensibility compared with nonregulated entities, and thus limits rate flexibility in Fitch's view.

Midrange Purchaser Credit Quality

Revenue defensibility primarily reflects the member credit quality as evaluated using Fitch's purchaser credit index (PCI), which reflects the weighted average credit quality of the relevant obligors. Fitch's current PCI score of 3.22 is based on an evaluation of all three member cooperatives: Meade County Rural Cooperative Corporation, KY comprising 17% of Big Rivers' revenues; Kenergy Corporation, KY (61% of revenues); and Jackson Purchase Energy Corporation, KY (22% of revenues). The overall scoring for each member ranged from midrange to relatively weak, with one member demonstrating a weaker profile than the prior year, resulting in a PCI that worsened from 3.05 to its current level. A PCI score above 3.50 would indicate further member credit deterioration and would likely limit the upward potential of the overall rating of the IDR.

The PCI reflects the strength of the member's service area, retail rate competitiveness and ability to absorb rate increases through an analysis of its service area, as well as each members' 2019 financial performance. Fitch assessed the service area characteristics for the largest member, Kenergy, to be midrange based on the relatively low median household income (MHI) and average unemployment rate.

Contributing to Kenergy's midrange score are its proportionally low amount of revenues derived from residential users (23% of total revenues) and MHI that is just 83% of the U.S. average. In addition, 2019 financial performance was weak. On the positive side, Kenergy's customer base is slowly growing and retail rates are very competitive.

OPERATING RISK

Big Rivers' strong operating risk assessment reflects a consistently low operating cost burden averaging 5 cents/KWh since 2015. Operating costs are anticipated to remain low as resource capacity is expected to remain sufficient to meet existing member and newly added customer load, and capital needs are manageable. In addition, power is supplied mainly by low-cost vintage generating units and contracted purchases, all of which is further supported by access to the MISO market.

Operating Cost Flexibility

Fitch assesses Big Rivers' operating cost flexibility as neutral, as its past reliance on coal-fired generation has declined. The assessment considers the corporation's current resource base that includes four owned generating facilities as well as contracted hydroelectric capacity. In 2019, approximately 78% of total capacity is coal-fired, followed by hydro capacity at 16% and a small amount of natural gas.

Big Rivers currently owns and operates 1,000MW of net generating capacity consisting of the following coal-fired facilities: Green generating station, a two-unit 454MW facility that has the ability to burn high sulfur and low-cost coal; Wilson generating station, a 417MW single-unit facility; and the smallest of BR's generating assets, Reid Station, a single-unit 65 MW gas-fired plant. In addition, Big Rivers also receives power through contract with Southeastern Power Administration (SEPA) for 178MW of hydroelectric capacity, bringing total current capacity to over 1,100MW. Big Rivers' decision to retire the 443MW three-unit Coleman Station and coal-fired Reid Unit 1 (65MW) helped improve its resource mix.

Environmental Considerations

The Commonwealth of Kentucky does not currently have a renewable portfolio standard. However, Big Rivers is actively pursuing adding solar capacity through long-term fixed-price PPAs. After a request for proposal, Big Rivers selected three separate projects from two developers/counterparties, Geronimo Energy and Community Energy Solar. The projects are expected to achieve commercial operation over the next couple of years and lower coal-fired capacity to closer to 63% of total capacity.

Capital Planning and Management

Capital planning and management are assessed to be midrange. Big Rivers had an exceptionally high, Fitch-calculated average age of plant of 55 years in 2019, which incorporates the age of the power generating stations, but also indicates high lifecycle needs. This is somewhat offset by capital spending that averaged 129% of annual depreciation over the prior five years and an acceleration in annual depreciation expense expected over the next five years.

Additionally, Big Rivers received approval to treat several of its generating facilities as regulatory assets. The regulatory asset designation allows Big Rivers to include a larger proportion of the depreciation of these assets in its rating case with regulators for future cost recovery.

Management anticipates capital spending for 2020-2023 to total a fairly sizeable $280 million, which continues a recent trend of sound capital reinvestment undertaken over the past few years. In addition to routine systemwide upkeep and renewal projects, Big Rivers expects to spend roughly $120 million in 2021 to remove the existing scrubber system from Coleman Station and reassemble it onto the Wilson facility, which is expected to lower operating costs at Wilson while also lowering the capital costs for needed environmental upgrades at this facility. Roughly $280 million in additional debt is expected to be issued to fund the proposed capital spending over the next four years.

Off-System Sales Continue

Termination of the smelter contracts resulted in the loss of 850MW of load in 2014, leaving Big Rivers in a very long resource position. Big Rivers worked to rebalance capacity with new contracted load through a combination of supply-side and demand-side management. These efforts, together with the idling of the capacity at Coleman Station and Reid Unit 1, and with the decommissioning of the Henderson plant, have led to a much more balanced resource portfolio relative to current and new demand.

Growth in the member customer base coupled with bilateral contracts with Kentucky Municipal Energy Agency (A/Stable), a consortium of Nebraska-based utilities, and full-requirements sales to the city of Owensboro, KY beginning in 2020, significantly lowers reliance on short-term market sales, but the reliance remains an additional asymmetric consideration.

FINANCIAL PROFILE

Improved Financial Results, Leverage Trending Lower

Fitch-calculated debt service coverage improved to 1.7x by fiscal YE 2019 from very weak levels, while coverage of full obligations (COFO) improved to 1.5x. The improved performance is largely attributable

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to the full implementation of the cooperative's risk mitigation strategy and approved rate plan from 2014. The mitigation reserves have been fully utilized, and Fitch believes the improved leverage ratios that resulted from a steady decline in net debt and rise in FADS over the past few years is likely to continue. Cash remains near historical norms and at 52 days on hand is considered neutral to the financial profile assessment. A senior secured revolving credit agreement was recently increased to $150 million and extended to 2023, and provides additional liquidity. Audited fiscal 2020 results (YE Dec. 31) are not expected to be available for several months, but are anticipated to be sound despite a decline in market sales.

Fitch Analytical Stress Test (FAST)

Fitch's base case is informed by Big Rivers' financial pro forma results for fiscals 2020-2023, which incorporate a decline in energy sales and revenues in 2020 due to a softening in both member demand and MISO market sales. The decreased demand is expected to result in a decline in revenues, however margin is less impacted due to lower expected operating expenses for the year. FADS is expected to remain strong, leading to a further increase in COFO and even lower leverage in 2020. Big Rivers' forecast includes a return in sales volumes in 2021 (year one) with stable demand in subsequent years, greater depreciation expense, and approximately $280 million in total capital spending, most of which will be funded with additional debt. The base case shows a decline in leverage in year one to 6.3x, followed by a further modest decline in the leverage ratio.

While Big Rivers' forecast indicates a return to historical sales volumes in 2021, Fitch's stress analysis incorporates a 5% decline in sales due to potential additional pandemic lockdowns next year, with growth in sales in the following two years (2022 and 2023). Also included in the stress analysis is forecast capital spending and roughly $330 million of outstanding principal to be retired, including cash defeasance of a portion of the Rural Utilities Service (RUS) note maturing in 2023, although a portion of the capital plan will be funded with additional debt. The results of this stress indicate an increase in the leverage ratio to 8.3x in year two (2021) before an expected return of sales growth and presumed rate increases that would allow the utility to maintain at least 1.0x coverage and a minimal amount of cash in subsequent years. The leverage ratio is projected to decline to around 6.0x by 2022, which would lead to a higher rating.

Debt Profile

The debt profile is neutral to the rating. Big Rivers had approximately $700 million in total outstanding debt as of fiscal YE 2019. All of the outstanding debt is fixed-rate, maturing no later than 2032, and includes a large bullet maturity of $245 million due in 2023. Management expects to cash-fund roughly half of this payment and refinance the rest with a long-term amortizing RUS financing.

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In addition to the sources of information identified in Fitch's applicable criteria specified below, this action was informed by information from Lumesis.

REFERENCES FOR SUBSTANTIALLY MATERIAL SOURCE CITED AS KEY DRIVER OF RATING

The principal sources of information used in the analysis are described in the Applicable Criteria.

ESG CONSIDERATIONS

Unless otherwise disclosed in this section, the highest level of ESG credit relevance is a score of '3'. This means ESG issues are credit-neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity. For more information on Fitch's ESG Relevance Scores, visit www.fitchratings.com/esg.

RATING ACTIONS

ENTITY/DEBT	RATING			PRIOR
Big Rivers Electric Corporation (KY)	LT IDR	BBB- Rating Outlook Positive	Affirmed	BBB- Rating Outlook Stable
• Big Rivers Electric Corporation (KY) /Issuer Default Rating/1 LT	LT	BBB- Rating Outlook Positive	Affirmed	BBB- Rating Outlook Stable

VIEW ADDITIONAL RATING DETAILS

FITCH RATINGS ANALYSTS

Andrew DeStefano
Director
Primary Rating Analyst
+1 212 908 0284
Fitch Ratings, Inc.
Hearst Tower 300 W. 57th Street New York, NY 10019

Parker Montgomery
Associate Director
Secondary Rating Analyst
+1 212 908 0356

Dennis Pidherny
Managing Director
Committee Chairperson
+1 212 908 0738

MEDIA CONTACTS

Sandro Scenga
New York
+1 212 908 0278
sandro.scenga@thefitchgroup.com

Additional information is available on www.fitchratings.com

APPLICABLE CRITERIA

Public Sector, Revenue-Supported Entities Rating Criteria (pub. 27 Mar 2020) (including rating assumption sensitivity)

U.S. Public Power Rating Criteria (pub. 30 Mar 2020) (including rating assumption sensitivity)

APPLICABLE MODELS

Numbers in parentheses accompanying applicable model(s) contain hyperlinks to criteria providing description of model(s).

FAST Public Power - Fitch Analytical Stress Test Model, v1.1.3 (1)

ADDITIONAL DISCLOSURES

Dodd-Frank Rating Information Disclosure Form

Solicitation Status

Endorsement Policy

ENDORSEMENT STATUS

Big Rivers Electric Corporation (KY)	EU Endorsed

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SOLICITATION STATUS

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Utilities and Power US Public Finance North America United States

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MOODY'S
INVESTORS SERVICE

Rating Action: Moody's assigns investment grade rating of Baa3 to Big Rivers Electric Corporation senior secured term loan; outlook is stable

02 Dec 2020

Approximately $83.3 million of debt affected

New York, December 02, 2020 -- Moody's Investors Service, ("Moody's") today assigned a Baa3 rating to Big Rivers Electric Corporation's (Big Rivers) $83.3 million senior secured 10-year term loan agreement with National Rural Utilities Cooperative Finance Corporation (CFC), due 2030. The rating outlook is stable.

Big Rivers is using proceeds from the term loan to repay the $83.3 million previously borrowed under its $150 million syndicated senior secured bank revolver led by CFC to repay in full its 6.0% $83.3 million of County of Ohio, Kentucky Pollution Control Refunding Revenue Bonds (Big Rivers Electric Corporation Project), due 2031 when that issue initially became callable in July 2020.

RATINGS RATIONALE

"The rating action reflects Moody's views about Big Rivers' significant progress in securing replacement loads to create better balance between its available capacity and load profile, obtaining Kentucky Public Service Commission (KPSC) approval for rate-neutral recovery of costs associated with its sizable regulatory assets and executing strategies to reduce interest expense and mitigate refinancing risk relating to the above mentioned pollution control bonds and another bullet maturity due in 2023," said Vice-President-Senior Analyst, Kevin Rose. "Although Big Rivers' status as a rate regulated electric generation and transmission cooperative represents a unique risk not present for most of its peers, the risk is balanced by a history of credit supportive decisions from the KPSC which have been part of the impetus for Big Rivers' strengthened financial metrics during the past five years and that trend is likely to be sustainable for the foreseeable future," Rose added.

The outcomes in Big Rivers' rate cases from October 2013 and April 2014, KPSC support for retiring the Station Two plant in 2019 and other mitigation strategies have collectively supported Big Rivers' net margins for fiscal years ended (FYE) December 31, 2017-19 in a range of approximately $12.9 - $16.7 million. While the reported net margin for FYE 2019 was $16.7 million, Big Rivers actually earned a margin of $44.5 million. The reported net margin for FYE 2019 reflects the effects of an initial amortization of Big Rivers' regulatory asset balance according to the terms of the KPSC approved settlement agreement in 2018 to end the operating agreement with Henderson Municipal Power and Light (HMPL) and retire the Station Two plant in early 2019. The reported net margin for FYE 2019 produced a 1.45 times interest earned ratio (TIER), a contractual margins for interest (MFI) ratio of 1.45x and a debt service coverage (DSC) ratio of 1.63x, all as defined in the cooperative's debt documents.

For FYE 2017-19, including Moody's standard adjustments Big Rivers' funds from operations (FFO) coverage of interest, FFO to debt and DSC ratios showed steady improvement in each year and averaged 2.0x, 5.1% and 1.2x, respectively. Big Rivers is likely to continue the strengthening trend for these metrics in 2020 and beyond owing to several credit supportive KPSC orders received during 2020.

Big Rivers' equity to capitalization ratio also steadily strengthened during 2017-19 and averaged 38.6% during the period. The strength of its equity to total capitalization of 41.4% at FYE 2019 bodes well for Big Rivers' commitment under an August 2020 KPSC order to use 80% of its equity in excess of minimum levels required in its debt documents to accelerate amortization of its regulatory assets in 2021. While doing so is likely to result in a reduction in its equity ratio to near 35%, the resulting level is quite strong compared to peers.

By implementing both supply-side and demand-side strategies, as well as reducing staff and controlling other expenses, Big Rivers has made good progress towards reducing its excess capacity situation and replacing the roughly two-thirds of its annual energy sales (which equates to just under 60% of its system demand and in excess of 60% of its annual revenues) previously derived from the contracts it had with two aluminum smelters.

During the past six years, Big Rivers' supply-side initiatives have included idling its 443 MW Coleman plant in

May 2014 and then retiring the plant effective September 30, 2020, idling its 65 MW Reid Unit 1 in April 2016 and then retiring the plant effective September 30, 2020, and terminating its operating agreement with HMPL during 2018, which led to the closure of the HMPL Station Two plant on January 31, 2019 and eliminated its rights to about 187 MW of coal-fired capacity from the HMPL Station Two plant. Taking into account the 260 MW of solar capacity to be phased in under Power Purchase Agreements (PPAs) during 2022-23, these supply-side strategies offset about 435 MW of load lost when the smelters terminated their contracts in 2013 and 2014, respectively.

Big Rivers' demand-side strategies include securing a long-term contract with Nucor Corporation (Nucor: Baa1 stable), medium-term contracts for the sale of capacity and energy to load serving municipal-distribution entities in Nebraska and Kentucky, serving incremental load resulting from industrial expansion in the service territory, making short-term off system sales and participating in the capacity markets. The 20-year contract with Nucor, which is constructing a steel plate manufacturing mill in the service territory of one of Big Rivers' members, Meade County Rural Electric Cooperative Corporation, was approved by the KPSC in August 2020 and takes effect in 2022. The Nucor contract will add about 200 MW of full-requirements load, effectively establishing Nucor as one of Meade County's members. The construction and subsequent operations at the Nucor plant will also provide additional economic stimulus within the service territory. Big Rivers also has 340 MW of previously arranged power sales contracts with entities in Nebraska and Kentucky, including three contracts in place to sell capacity and energy to three Nebraska entities over nine years, which will grow to about 85 MW. Power being provided under the contracts with the Nebraska entities began flowing in 2018 and is scheduled to reach full output in 2022. In Kentucky, Big Rivers has a 10-year contract to transmit as much as 100 MW from its coal-fired Wilson Station to Kentucky Municipal Energy Agency (KyMEA) and sales to KyMEA began in May 2019. In June 2018, the City of Owensboro, Kentucky awarded Big Rivers its full-requirements contract, approximating 180 MW. The City of Owensboro contract runs from June 2020 through December 2026 and represents the municipal utility's full annual energy requirements estimated at 825,000 megawatt hours and annual peak load of about 155 MW, net of its 25 MW provided through a contract with the Southeast Power Administration. The combination of these contracts and economic development rates that contribute to industrial expansion in the service territory have increased Big Rivers' load demand by about 575 MW. When these demand-side strategies are combined with the aforementioned supply-side decisions that ultimately reduce net available capacity by 435 MW, they collectively create better balance between Big Rivers' future available generation capacity and load demand requirement.

Big Rivers' credit profile continues to benefit from credit supportive decisions by the KPSC. In May 2020, the KPSC approved Big Rivers' request to increase the size of its senior secured bank credit facility, thus enhancing the cooperative's liquidity position, and in June the KPSC approved virtually all aspects of Big Rivers' request to create and provide a rate neutral means to recover the cooperative's sizable regulatory assets resulting from its various supply-side decisions. The June KPSC order is credit positive because it enables the cooperative to avoid the risk of potential write-offs to its equity if it was otherwise unable to recover the costs of remaining net investments from its customers as a regulatory asset. Two additional credit supportive decisions from the KPSC were rendered in August 2020, one which largely supports strategic plans and provides a means for cost recovery relating to Big Rivers' proposed 2020 Environmental Compliance Plan and the other approved the retail contract for electric service between Meade County and Nucor and the wholesale letter agreement between Big Rivers and Meade County.

Big Rivers maintains ample liquidity by supplementing its existing cash on hand and internally generated cash flow with a $150 million syndicated senior secured credit agreement with six financial institutions, led by CFC, which expires June 11, 2023. The agreement has the option, subject to the banks agreeing, for two one-year extensions of the expiration date. As of September 30, 2020, Big Rivers had a cash and temporary investments balance of about $33.1 million and had $61.7 million available under the CFC credit agreement. The availability under the credit agreement is anticipated to increase to about $145 million upon when proceeds from the term loan are used to repay a like amount outstanding under the syndicated agreement. Big Rivers is likely to have some moderate need for new debt financing for the next eight quarters to fund a portion of its capital spending program, while also meeting scheduled debt maturities. The debt maturities are largely comprised of scheduled amortizations of long-term debt to be paid at roughly $8 million - $10 million per quarter. The CFC syndicated credit agreement has no ongoing material adverse change clause, but does include a specific interest coverage covenant, which largely mirrors the covenant that exists in its mortgage indenture. The CFC agreement also separately requires Big Rivers to maintain a minimum equity balance at each fiscal quarter-end and year-end of $417 million plus 50% of the cooperative's cumulative positive net margins for each of the preceding fiscal years, beginning with the fiscal year ended December 31, 2019. Big Rivers is comfortably in compliance with these covenants.

Big Rivers also has RUS approval for loans to be funded no later than December 2023 which would provide reimbursement for certain transmission asset investments already made and would refinance half of its Series B Note which has a $245.5 million balloon payment due in December 2023, with the remainder intended to be satisfied with cash. This funding source from the RUS reduces any potential refinancing risk at Big Rivers that otherwise existed.

RATING OUTLOOK

The stable rating outlook reflects a prevailing credit supportive regulatory environment, including approvals for regulatory asset cost recovery, and the likelihood that Big Rivers can sustain its trend of strengthening financial metrics, while also benefitting from establishing better balance between its available capacity and load profile following the loss of significant load from aluminum smelters several years ago. The outlook also considers the cooperative's progress toward reducing refinancing risk and limited new debt financing needs during the next three years. The outlook additionally incorporates the likelihood that Big Rivers will remain resilient to the potential negative effects of the coronavirus pandemic and that the smelters will continue to operate and that the Nucor load will materialize, thus providing support for the local economy, including employment levels.

FACTORS THAT COULD LEAD TO AN UPGRADE OR DOWNGRADE OF THE RATINGS

What Could Change the Rating -- Up

Achieving further strengthening of financial metrics by recovering a significant regulatory asset balance as approved by the KPSC and completing additional strategies to better align the cooperative's capacity supply and load profile on a longer-term sustainable basis.

Achieving stronger metrics to balance unique business and financial risks; for example, FFO coverage of interest and debt improving to 2.4x and in a range of 6%-7%, respectively, with the DSC ratio tracking at close to 1.2x or better on a sustained basis.

What Could Change the Rating -- Down

A negative rating action is unlikely in the next two years because of the prevailing credit supportive regulatory environment; however, a negative rating action could result if there was a shift to a less credit supportive regulatory environment or if liquidity unexpectedly deteriorates.

Negative rating pressure would also increase if substantial assurance for recovery of environmental compliance costs and sizable regulatory assets over time do not occur as defined under the recently approved KPSC regulatory orders.

A scenario under which either or both of the smelters discontinued operations would be credit negative because of the potential residual negative effects on the local economy or if the Nucor load does not materialize.

In terms of metrics, FFO to debt and DSC ratios below 4% and 1.2x, respectively, for a sustained period would pressure the rating.

Big Rivers Electric Corporation is an electric generation and transmission cooperative headquartered in Henderson, Kentucky and owned by its three member system distribution cooperatives— Jackson Purchase Energy Corporation; Kenergy Corp; and Meade County Rural Electric Cooperative Corporation. These member system cooperatives provide retail electric power and energy to approximately 116,000 residential, commercial, and industrial customers in 22 Western Kentucky counties.

The principal methodology used in these ratings was US Electric Generation & Transmission Cooperatives published in August 2018 and available at https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_1130742. Alternatively, please see the Rating Methodologies page on www.moodys.com for a copy of this methodology.

REGULATORY DISCLOSURES

For further specification of Moody's key rating assumptions and sensitivity analysis, see the sections Methodology Assumptions and Sensitivity to Assumptions in the disclosure form. Moody's Rating Symbols and Definitions can be found at: https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_79004.

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The ratings have been disclosed to the rated entity or its designated agent(s) and issued with no amendment resulting from that disclosure.

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At least one ESG consideration was material to the credit rating action(s) announced and described above.

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Kevin Rose
Vice President - Senior Analyst
Project Finance
Moody's Investors Service, Inc.
250 Greenwich Street
New York, NY 10007
U.S.A.
JOURNALISTS: 1 212 553 0376
Client Service: 1 212 553 1653

A.J. Sabatelle
Associate Managing Director
Project Finance
JOURNALISTS: 1 212 553 0376
Client Service: 1 212 553 1653

Releasing Office:
Moody's Investors Service, Inc.
250 Greenwich Street

New York, NY 10007
U.S.A.
JOURNALISTS: 1 212 553 0376
Client Service: 1 212 553 1653

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Item 8) ***Refer to the IRP, Chapter 2, Section 2.11, page 42. Provide an update to the number of applicants for the low-income weatherization program.***

Response) In 2020, Big Rivers received one application. To date in 2021, Big Rivers has received one application. Please see the attachment to this response.

Witness) Russell L. Pogue

Big Rivers Electric Corporation
2020 Low-Income Weatherization Support Program Report

2020 Program Summary

The launch of the Low-Income Weatherization Support Program (DSM-14) began prior to 2020 with coordination meetings and conference calls with staff from the four Community Action Agencies (CAA) that serve retail members of Jackson Purchase Energy, Meade County RECC and Kenergy Corp. and the Kentucky Housing Corp.

- West Kentucky Allied Services
- Pennyrile Allied Community Services
- Audubon Area Community Services
- Central Kentucky Community Action

The program became active in January 2020, at the same time the Covid pandemic became an issue in the United States, which may have impacted the participation rates of the CAA's. One project was completed under the program on October 6th 2020. Six potential projects have been identified by CAA's for 2021.

2020 Project Summary

The first project completed under the Low-Income Weatherization Support Program tariff was finished on October 6th by the West Kentucky Allied Services Inc., a Community Action Agency (CAA) in the Jackson Purchase service area. The home is 1060 square feet and was built in 1918.

The homeowner lives alone and has an annual income of less than $10,000 according to her application. Her annual heating/cooling costs were more than $2,300 and included electric space heaters and vent-less propane fireplace heaters.

The Low-Income Weatherization Support Program (LIWSP) paid for 13.8% of the $18,416 project cost, funded by JPEC and Big Rivers. This project exceeded the combined DOE weatherization and LIHEAP funding limits and would not have happened without the funding from Big Rivers. The LIWSP funding included the following measures for Heating, Ventilation and Air Conditioning (HVAC) and Health and Safety measures:

$845.36	Air Infiltration Reduction – Health & Safety
$1,702.51	Energy Star Ducted Air Handler – HVAC/Health & Safety

The overall project included the following improvements:

Lighting Retrofits
Infiltration Reductions
Attic Insulation
Pipe Insulation
Smoke Detector
CO Monitor
Fix Improper Clothes Dryer Ventilation
Fix Attic Ventilation
Water Heater pressure Valve Piping
Bathroom Exhaust
Attic Repair and Insulation (R49)
Install Mini-Split HVAC System

The new mini-split HVAC system is among the most efficient systems on the market. Blower door tests show a 30% reduction in air infiltration in the home. The home was equipped with appropriate smoke and CO detectors and the vent-less fireplace space heaters were removed. Overall, the energy use in the home will be substantially reduced, while the air quality, comfort and safety of the home will be dramatically improved.

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Item 9) ***Refer to the IRP, Chapter 3, Section 3.1 page 46. For the nonmember requirements:***

a. If BREC is unable to supply this power, explain whether the nonmember contracts will then be null or void.

b. Explain whether any of the nonmember contracts can be terminated, and if so, what instances can cause this termination and the consequences for both BREC and the nonmember.

Response)

a. Big Rivers' obligations under the contracts are independent of its energy position. Big Rivers would purchase the energy if it were unable to generate the energy.

b. Other than standard provisions regarding an Event of Default or Force Majeure, one of the contracts has an additional provision that each party has a right to terminate the agreement on two years' prior notice in the event of a change in law relating to carbon legislation.[1] Upon default, financial damages would be calculated and owed to the non-defaulting party.

Witness) Mark J. Eacret

[1] The Non-Member contracts identified in the IRP, Chapter 3, Section 3.3.8 page 60 can be found at on the Commission's website at: https://psc.ky.gov/Home/Library?type=Tariffs&folder=Electric%5CBig%20Rivers%20Electric%20Corporation%5CContracts

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Item 10) ***Provide the calculations of all the variables used in the regression model equations in Excel spreadsheets with all cells visible, unprotected, and formulas intact.***

Response) Please refer to the **CONFIDENTIAL** Excel file provided with this response.

Witnesses) Matthew S. Sekeres and
Steven A. Fenrick

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Item 11) ***Refer to the IRP, Chapter 3, Section 3.3.1, page 51. Explain the assumption that the real cost of electricity is declining during the forecast period.***

Response) While the price of electricity and the rate of inflation are forecasted to increase, the forecast price for the retail cost of electricity is growing at a slower rate than the forecasted rate of inflation. Thus, the real (inflation-adjusted) price of electricity is forecasted to decline.

Witnesses) Matthew S. Sekeres and
Steven A. Fenrick

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Item 12) ***Refer to the IRP, Chapter 3, Section 3.3.3, Table 3.7, page 55. Explain the volatility in energy sales between 2020 and 2023.***

Response) Please see Big Rivers' response to Item 52 of Commission Staff's First Request for Information.

Witnesses) Matthew S. Sekeres and
Steven A. Fenrick

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Item 13) ***Refer to the IRP, Chapter 3, Section 3.3.8, page 60 and Load Forecast Study, Section 2.7, page 39.***

a. ***BREC indicates that it optimizes the capacity and energy transactions in the day-ahead and real-time markets in order to service nonmember sales by evaluating the costs to deliver BREC's generation versus buying on the market. Provide a step-by-step explanation of how BREC accomplishes these actions for the benefit of its members.***

b. ***In the instances when it is cheaper to purchase versus generate to service nonmember obligations, explain whether the model correspondingly adjusts its own generation levels.***

c. ***Explain whether BREC modeled a cessation of nonmember sales after 2029, and if so, explain why.***

d. ***Refer to table 3.12. Provide a breakdown of total sales by contract.***

Response)

a. The Day–Ahead ("DA") and Real–Time ("RT") markets are pertinent only to energy transactions. Terms of bilateral capacity transactions are generally for a year or more with terms that align with MISO planning years.

The delivery point for the OMU[1] transaction is [redacted]. Prior to the month of delivery, Big Rivers watches for opportunities to enter into hedging transactions at prices below [redacted]. If such an opportunity is identified, Big Rivers will execute the transaction at IndyHub and, if possible, purchase financial transmission rights (FTR's) between [redacted] and IndyHub. This secures a supply cost below [redacted] with protection against basis risk between IndyHub and [redacted]. [redacted]

[1] OMU = Owensboro Municipal Utilities.

[redacted]. Because energy consumption under the KYMEA[2] contract is less predictable than the OMU contract, Big Rivers does not use monthly transactions to hedge it.

[redacted].

b. In instances when it is cheaper to purchase versus generate to service non-member obligations, the model will produce lower generation levels.

---

[2] KYMEA = Kentucky Municipal Energy Association.

c. Big Rivers did not assume renewal of the Nebraska[3] and OMU contracts after [redacted], or the KYMEA contract after [redacted]. It is too early in the contract terms for any substantive discussions with the counterparties on extensions.

d. Please see the **CONFIDENTIAL** attachment, filed with a Motion for Confidential Treatment, to this response.

Witness) Mark J. Eacret

[3] The Nebraska contracts include the Cities of Wakefield and Wayne, Nebraska, and the Northeast Nebraska Public Power District.

Big Rivers Electric Corporation
Case No. 2020-00299
Non-Member Sales under Contract as of 2020 [1]

Calendar Year	Total		ST Bilateral Capacity [5]	Voltus (Purchase)	NextEra (Sale)	Missouri Munis (Sale)	Calpine (Sale)	IMPA (Sale)
	MW	MWh	MW	MW	MW	MW	MW	MW
2015	513	-	[redacted]					
2016	450	-	[redacted]					
2017	487	-	[redacted]					
2018	314	75,404	[redacted]					
2019	376	578,276	[redacted]					
2020	422	1,466,620	[redacted]					
2021	[redacted]							
2022	[redacted]							
2023	[redacted]							
2024	[redacted]							
2025	[redacted]							
2026	[redacted]							
2027	[redacted]							
2028	[redacted]							
2029	[redacted]							

Notes:

1.- Capacity sales with or without associated energy sales - spot energy sales not included.

2.- OMU is net of their Allocation of Southeastern Power Administration Cumberland system hydropower, and future expected renewables purchase

[redacted]

5.- ST bilateral capacity transactions with no associated energy.

Big Rivers Electric Corporation
Case No. 2020-00299
Non-Member Sales under Contract as of 2020 [1]

Calendar Year	Total		EDF (Sale)	IPL (Sale)	Shell (Sale)	SIPC (Sale)	WVPA (Sale)	Hoosier (Sale)
	MW	MWh	MW	MW	MW	MW	MW	MW
2015	513	-	[redacted]					
2016	450	-						
2017	487	-						
2018	314	75,404						
2019	376	578,276						
2020	422	1,466,620						
2021								
2022								
2023								
2024								
2025								
2026								
2027								
2028								
2029								

Notes:

1.- Capacity sales with or without associated energy sales - spot energy sales not included.

2.- OMU is net of their Allocation of Southeastern Power Administration Cumberland system hydropower, and future expected renewables purchase

[redacted]

5.- ST bilateral capacity transactions with no associated energy.

Big Rivers Electric Corporation
Case No. 2020-00299
Non-Member Sales under Contract as of 2020 [1]

Calendar Year	Total		DTE Electric (Sale)	OMU [2] (Sale)		Nebraska [3] (Sale)		KYMEA [4] (Sale)	
	MW	MWh	MW	MW	MWH	MW	MWH	MW	MWH
2015	513	-	[redacted]						
2016	450	-	[redacted]						
2017	487	-	[redacted]						
2018	314	75,404	[redacted]						
2019	376	578,276	[redacted]						
2020	422	1,466,620	[redacted]						
2021	[redacted]								
2022	[redacted]								
2023	[redacted]								
2024	[redacted]								
2025	[redacted]								
2026	[redacted]								
2027	[redacted]								
2028	[redacted]								
2029	[redacted]								

Notes:

1.- Capacity sales with or without associated energy sales - spot energy sales not included.

2.- OMU is net of their Allocation of Southeastern Power Administration Cumberland system hydropower, and future expected renewables purchase

[redacted]

5.- ST bilateral capacity transactions with no associated energy.

Item 14) ***Refer to the IRP, Chapter 3, Section 3.3.4, Table 3.8, page 56. Explain why the percent change per year in consumers from 2018 to 2019 is not zero, even though the number of consumers did not change.***

Response) The value for the number of consumers is an average of the twelve monthly values for the consumer count in any given year. The consumer counts, therefore, frequently do not represent whole numbers and are rounded in the tables. In this particular case, the 2018 consumer value is 20.83 and the 2019 consumer value is 21.00.

Witnesses) Matthew S. Sekeres and
Steven A. Fenrick

BIG RIVERS ELECTRIC CORPORATION

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Item 15) ***Refer to the IRP, Chapter 3, Section 3.3.9, page 61. Confirm that the voluntary interruptible and curtailable loads were excluded from the load forecast, and if so, explain why.***

Response) Confirmed. The voluntary interruptible and curtailable loads were excluded from the load forecast due to lack of participation in the last decade. Additionally, the voluntary nature of the tariff made the interruption and curtailment unreliable.

Witness) Russell L. Pogue

BIG RIVERS ELECTRIC CORPORATION

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Item 16) ***Refer to the IRP, Chapter 3, Section 3.3.9, page 61. Looking forward, explain whether BREC plans to add any direct load control programs or an interruptible or curtailable contract or tariff.***

Response) Big Rivers and its Member-Owners do not have current plans to add direct load control, interruptible or curtailment programs.

Witness) Russell L Pogue

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March 19, 2021

Item 17) ***Refer to the IRP, Chapter 3, Section 3.7, page 78. One of the key load forecasting assumptions is that electrical heating saturations levels are projected to remain flat through the forecast period. Provide an explanation supporting this assumption.***

Response) There is not a distinctive trend in either direction from Clearspring's examination of prior end–use appliance surveys conducted on the Member Systems by Big Rivers. Given the lack of a clear trend, and no other empirical or apparent rationale. Clearspring did not increase or decrease the electrical heating saturation assumptions during the forecast period.

Witnesses) Matthew S. Sekeres and
Steven A. Fenrick

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's
First Request for Information
dated February 26, 2021

March 19, 2021

Item 18) ***Refer to the IRP, Chapter 3, Section 3.8, Research and Development, page 78. Provide the most recent residential survey report.***

Response) See the attached residential appliance saturation survey.

Witness) Russell L. Pogue

2019 RESIDENTIAL CONSUMER SURVEY

Prepared by:

TSE Services
December 2019

Confidential Information

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STATEMENT OF CONFIDENTIALITY

Preserving a high level of participation in the 2019 Residential Consumer Survey project maximizes the potential benefits for Big Rivers Electric Corporation and the consumer-owners that they serve. TSE Services believes that consumer participation is maximized only when survey participants are assured that their responses will remain confidential. TSE Services has developed survey procedures that protect individual respondent privacy concerns.

To address the concerns of participating cooperatives, TSE Services has also developed procedures to reduce the risk of unauthorized use or disclosure of reports that utilize survey results. All reports that include compilations or analyses of survey data are marked "confidential", and access to them is limited to staff of TSE Services, Big Rivers Electric Corporation and the involved member cooperative.

KEY FINDINGS

Key findings included in this report are summarized for the Big Rivers Electric Corporation system cooperatives listed below:

- Jackson Purchase Energy Corporation
- Kenergy Corporation
- Meade County Rural Electric Cooperative Corporation

Household Demographics

- Nearly all residential customers, approximately 98%, indicated the main use of their home was year-round.
- About eight out of ten residential customers live in a single family, detached home.
- Manufactured homes account for approximately one out of six homes built or sited in member cooperative service areas.
- Over 90% of members own their home.
- More than seven out of ten homes are at least 20 years old. Approximately four out of ten homes were built before 1980.
- About three out of four member homes occupied less than 2,500 square feet. Approximately 8% of members lived in homes containing 3,000 square feet or more of living space. About one out of twelve were unsure of the size of their home.
- More homes were built during 1990's than any other decade. The "Great Recession" (2007-2009) impacted new home construction during the last years of the decade and residual impacts are still felt today.
- The typical household responding to the survey reflected middle-aged adults (45-64) with one or two people living in the household. The majority of households did not have children living at home.
- Less than one out of five members indicated having children under 18 years old living in their home.

Heating and Cooling

- More than nine out of ten households stated they used a Central Air Conditioning (AC) system in their home. Window AC units were less prevalent as only about one out of nine stated using the equipment. Less than 1% of respondents stated they had no AC of any kind in their home.
- Over six out of ten AC units were 10 years old or newer. Approximately one out of five AC units were more than 15 years old.

- Electricity was the most commonly used fuel for heating their home. Electricity was used as the primary heat source in nearly one-half of homes. Gas systems (propane and natural gas) account for about one-half of heating systems used.
  - Homes using gas heating systems use less electricity on an annual basis than homes using electric heating systems.
  - The most prevalent electric heating equipment is the air source heat pump, followed by an electric furnace.
- Most heating systems are ten years old or less. Heating equipment more than 15 years old can be found in approximately one out of four homes.
- A larger share of older heating systems (over 15 years old) are fueled by either propane or natural gas.
- About one-half of households had a fireplace, the majority of which are fueled by propane or natural gas. One out of four fireplaces are fueled by wood

Water Heating

- The vast majority of homes use only one water heater.
- Over six out of ten water heaters are between 40 and 60 gallons.
- The fuel of choice for water heating is electricity. Electric water heating is present in over two-thirds of member homes.
- Nearly six out of ten electric water heaters are ten years old or less.
- On average, homes with electric water heaters use significantly more electricity than homes with natural gas water heaters.

Appliances

- Electric cooking appliances continue to garner a large market share within member cooperative households. Electric refrigerators, microwave ovens, clothes washers and electric dryers were present in over 90% of member homes.
  - The majority of kitchen appliances were ten years old or less.
  - Refrigerators were the oldest of the kitchen appliances with more than one out of four more than ten years old.
- Room ceiling fans were present in nine out of ten homes.
- Electric cooktops, ovens and dishwashers were owned by more than seven out of ten members.
- About one out of five members indicated owning a well/water pump.
- Dehumidifiers and whole house fans were owned by less than one out of five members.

- Less than one out of ten members owned a waterbed heater, hospital grade medical equipment or an air purifier.
- The survey inquired about ownership of outdoor electric items. Most prevalent among members was electric yard equipment including an electric corded leaf blower and corded yard trimmer. Portable generators were present in about one out of five homes.
- Swimming pool pumps were present in about one out of eight member homes while hot tubs and saunas appeared in about one out of twenty-five residences.
- Gas appliances were found with less regularity in member homes.
    - Outdoor gas grills were present in one out of four households while gas cook tops were in one out of five homes.
    - About one out of four households used a gas log/fireplace. Less than one out of six used a gas oven. Gas clothes dryers were found in only one out of twenty-five homes.

Energy Conservation

- A list of energy saving items was presented to members. Nearly one-half of members indicated having and using a programmable thermostat.
- Other energy saving items were present in 5% or less of member's homes including water heater timers, supplemental generators and solar power systems.
- Over one-half of members indicated they turned their computers off or to sleep mode when not in use. In addition, 44% of members stated they unplugged their electric charging devices when not in use.
- One out of three households indicated using timers or photocells to control their outdoor lighting.
- The most popular energy conservation measures taken during the past five years included purchasing energy star appliances, caulking and weather stripping doors and windows, utilizing insulated curtains or shades, and adding ceiling insulation. Least common activities included the use of water heater timers, solar power systems and energy use display monitors.
    - Nearly one-third of members indicated they hadn't completed any conservation measures at their location in the past five years.

Lighting

- Light-emitting diode **(**LED**)** lighting is the most prevalent type of light bulbs used in members' homes.
    - LED bulbs appear in greater numbers within members' homes as more than one-fourth of households indicated using more than ten bulbs.
    - LED bulbs have surpassed incandescent bulbs as the most common light bulb.
    - CFL bulbs were used least frequently and were more prevalent in quantities of ten or less.

Electronics & Computers

- The vast majority of members are connected to the internet. About eight out of ten members indicated they had access to the internet at home.
- Eight out of ten members stated they owned some form of computing device (desktop PC, laptop PC or tablet device).
- Computing devices appear to be growing more mobile. Portable Laptop PCs now outnumber stationary desktop PCs.
    - One out of eight households own two or more laptops.
    - Over one-half of households own tablet computers such as the iPad or Kindle. More people own tablet devices than own desktop computers.
    - Three-quarters of households own at least one smartphone. Over 50% of households indicated owning two or more smartphones.
- Over nine out of ten members owned at least one television (conventional tube TV, plasma TV, LCD TV or LED TV).
    - Flat screen LCD/LED TVs were the most commonly mentioned type of TV owned with one-half of members indicating ownership. About one out of seven members stated they owned three or more LED TVs.
    - Plasma/Projection TVs were least common with less than one out of ten households owning one.
- About three-quarters of households own a DVR/DVD/VCR while only about one out of four own a game console.
- Less than one percent of members stated they owned an electric vehicle.
- Only 5% of households stated they owned a smart thermostat that allows them to control the temperature setting in their home using a web-enabled device.
    - Smart thermostat ownership tends to be most prevalent in newer homes.
    - Although ownership of smart thermostats was low, nearly one-quarter of respondents indicated they would be interested in purchasing one in the future.

<u>Usage Characteristics</u>

- Participating cooperative members were asked to provide 12 months of usage history with their member contact information.
- The number of members in a home produced a linear relationship with electricity usage. Annual kWh electricity usage increases with each person added to the household.
- Not surprisingly, home size is positively correlated to electric usage. For homes in the most common size range (1,500 to 1,999 square feet), annual usage was approximately 15,200 kWh. Homes with more than 3,000 square feet of living space used approximately 22,900 kWh per year.
- Homes built between 2000 and 2009 appeared to have the highest electricity use. Homes built prior to 1970 had considerably lower electricity usage.
- Presence of gas heating greatly reduced the annual electric usage at the home.
- Homes with natural gas water heating used less electricity than residences heating water with electricity.

Recommendations and Conclusions

The 2019 Residential Consumer Survey results provide a unique opportunity to evaluate the physical housing characteristics and energy usage behaviors within Big Rivers Electric Corporation's member households. The following section attempts to highlight recommendations and conclusions from this research project.

Using a combination of online and paper surveys pays significant dividends. About one out of five members responded to the survey cover letter soliciting an online survey response. The online responses reduced the processing cost of the full survey packet by saving additional postage and processing cost. Future surveys should continue to utilize online data collection methods for response maximization and cost efficiencies especially as the population gets more attuned to using digital media.

Survey results provide insight into marketing and forecasting activities. Residential Consumer Survey results are representative of a member household census for Big Rivers Electric Corporation. The insight contained within this report provides guidance on identifying marketing and segmentation opportunities for cooperative programs and intelligence for increasing the efficiency and accuracy of future load forecasts.

Member homes are getting older. Many areas in Kentucky experienced a strong period of new construction prior to the Great Recession in the late 2000's. While new construction has started to make a comeback, the vast majority of homes were built prior to 2000. Based on their age, many structures are excellent candidates for energy efficiency upgrades and should be targeted by electric cooperatives for such programs.

Newer homes equal bigger homes. Homes built since 2000 tend to be bigger and use more energy than older homes. Although new construction declined noticeably in the years immediately after the "Great Recession", new construction has rebounded recently. Homes built today are bigger than homes built prior to 2000.

Larger homes are important targets for energy efficiency. Electricity usage is highest for larger homes. Research indicates higher bills are inversely related to member satisfaction. Targeting larger homes with high use for energy efficiency programs will help these households gain greater control over their electricity expenses.

Electric load is impacted in areas where natural gas competition exists. Competition for heating and water heating load exists, especially in metro areas where natural gas is prevalent. The competitive cost of natural gas and marketing efforts by natural gas utilities create challenges for electric cooperatives marketing electric heating and water heating options.

***Loss of electric load in new construction reduces lifetime value*.** Once a fuel source takes root in a home, it is difficult to transplant another fuel in its place. In areas where natural gas gains a foothold, it may be difficult for electric heating and water heating to gain back lost load. The vast majority of homeowners prefer to replace their existing system with a similar system. In homes where natural gas heating and water heating exist, yearly kWh usage is dramatically lower. All electric homes will have long lasting monetary payback to the electric cooperative.

***Expect efficiency gains when HVAC equipment is replaced*.** About one-third of heating systems are more than ten years old. As these systems are replaced, the efficiency ratings for new systems will be noticeably higher (SEER 13 / SEER 14) than when the original equipment was installed. Since HVAC equipment generally uses more energy than anything else in the home, members replacing systems should benefit from lower energy use.

Nearly all members are connected to the internet. The extremely high incidence of internet access and computing devices provides significant opportunities for Big Rivers Electric Corporation member cooperatives. Online billing and information portals, electronic communications through email and social media and access to smart home technologies are now all within reach of the typical member household. As members' online experience matures, so will their expectation for online offerings originating from their local electric cooperative.

Continued efficiency gains from lighting technology are inevitable. Cooperative members continue to make the progression from incandescent lighting to high-efficiency CFLs and LEDs. Most are doing so without incentives. Although lighting load reflects only about 10%-15% of the total household energy consumption, members transitioning to CFLs and LEDs will reap the benefits of a lower monthly electric bill.

Necessity drives conservation measures but opportunities exist for more. The majority of cooperative members stated they had completed some energy conservation steps during the past five years. Replacement of appliances ranked highest on the list of conservation measures taken and is generally initiated by "necessity." Incentives appear to provide only modest motivation to initiate energy saving steps. Nonetheless, a sizeable portion of members have not taken any conservation measures nor does it appear they would do so in the future. Understanding more about those members who engage in conservation activities will help cooperatives better target programs to the most receptive audience.

Members previously making efficiency improvements are inclined to do so in the future. Cooperative members stating they had completed some energy conservation steps during the past five years were much more likely to take additional conservation steps in the future than members who had not done anything in the recent past. Previous program participants would appear to be an excellent target audience for future programs and services.

OVERVIEW

The purpose of the 2019 Residential Consumer Survey is to collect consumer data such as appliance saturation, housing stock characteristics, consumer demographics, energy usage, and use of other utility services. Additional information was collected to understand energy conservation and efficiency behaviors among cooperative members.

Objectives

The goal of the 2019 Residential Consumer Survey is to provide reliable, valid and relevant consumer information for decision making by individual distribution cooperatives. As the electric industry continues to evolve, the need for accurate consumer information is critical. This project focuses on residential members, which represent the vast majority of all members served by rural electric cooperatives.

The 2019 Residential Consumer Survey is designed to meet a number of specific data needs. It meets the consumer survey recommendations of the Rural Utilities Services. The data from the project can be used for a number of planning and research activities such as:

- Exploring household and demographic factors that affect energy usage
- Tracking appliance saturations for major appliances, electronics and personal computer usage
- Validating trends in energy usage to assist in load forecasts
- Understanding energy conservation and household usage behaviors

Methodology

Historically, the Residential Consumer Survey has been conducted as a self-reported, mail survey. TSE Services and Big Rivers Electric staff designed the survey instrument in coordination with the three participating cooperatives.

In September 2019, a survey packet including cover letter, survey, and business reply envelope was sent to the target population of 1,000 randomly sampled members requesting their participation in the study. The cover letter included a brief introduction to the survey and explained the option of filling out the survey online with a web address and instructions for using the unique user passcode. The survey included 4 pages of questions about household energy use and member demographics. The survey web address is below:

www.KYcooperativesurvey.com

The online survey was hosted by Bellomy Research, Winston-Salem, North Carolina. Once at the survey site, members entered their unique ID number and were granted access to the survey. Alternatively, members could complete the paper survey and return it using the prepaid envelope.

Sample Design

The target population consisted of all residential homes located within each Cooperative's service area. Each Cooperative's residential rate class was used as the population frame. The class contains all residential accounts; however, it also includes seasonal homes, barns, pumps, chicken houses, workshops, and other type structures. In attempts to omit non-dwelling structures, accounts with average monthly usage in 2019 less than 400 kWh were removed from the population frame prior to sample selection.

Sample Selection

A sample of 1,000 customers was selected from each cooperative for the study. A systematic sampling process was used to select the sample. All accounts were sorted in ascending order using average monthly kWh usage (twelve month period). Once sorted, every n^{th} account was selected, beginning with a randomly selected starting value. The value of n was dependent upon the total number of qualified accounts in the population. In calculating n, the total qualified population was divided by the desired sample size. The quotient was rounded down to the nearest whole number in order to ensure that the sample included the required number of accounts. For example, if there were 52,300 qualified accounts for a cooperative 52,300 would be divided by 1,000 to yield 52.3. Therefore n for this cooperative would be 52 and every *52nd* account would be selected for sampling.

Residential members with either very large or very small annual usage were excluded from the sample as to eliminate outliers such as non-dwelling structures from the sample frame.

Implementation

Once the member sample was selected, a survey packet, including a cover letter which explained why the survey was being conducted and invited customer response, the 4-page survey and business reply envelope was mailed to all selected members. The survey packet cover letter explained the link to the online survey and instructions for using the supplied user code. The printed survey also contained the survey URL address and user code for the online survey. If the member chose to mail-in the survey as opposed to accessing online, a postage-paid return envelope was provided for the customer to return the completed paper form.

In order to increase member response to the survey, those completing the survey online or via mail were entered into a drawing to win one of two $250 gift cards per cooperative.

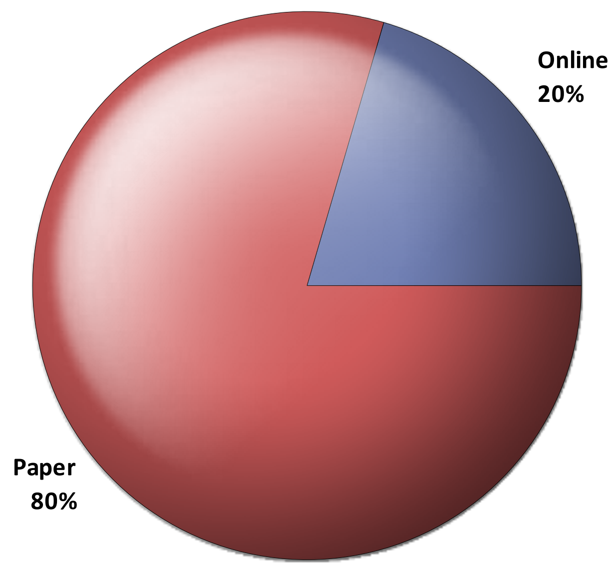
Completed print surveys were returned to a centralized post office box used to receive completed surveys for all Big Rivers Electric member cooperatives participating in the 2019 survey. The responses for each completed paper questionnaire were scanned into electronic files for processing, and then the scanned data were 100% validated against the original forms to ensure responses were accurately recorded. The results were tabulated and reviewed.

A total of 3,000 survey packets were mailed out. Overall, 1,108 valid responses were collected, including 881 paper surveys and 227 online responses. The resulting total response rate was 36.9%.

Survey Response

One out of five surveys were completed online during the data collection period. The majority of surveys were returned through the mail. The cooperative with the highest percentage of online returns was Meade County. The cooperative with the lowest online return rate was Kenergy.

Survey Response Method



Survey Response Method	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Online	20%	21%	18%	22%
Paper	80%	79%	82%	78%

	Total	*Online*		*Paper*	
	Count	*Count*	*Percent*	*Count*	*Percent*
Jackson Purchase	345	72	21%	273	79%
Kenergy	368	67	18%	301	82%
Meade County	395	88	22%	307	78%

Interpretation of Results

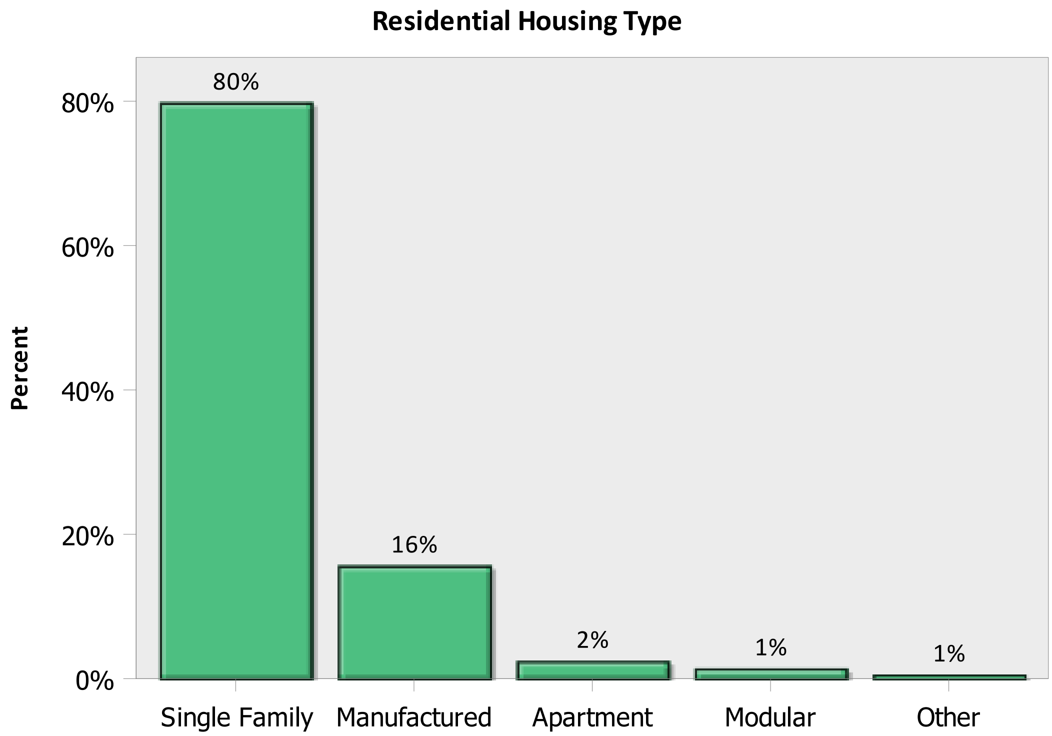
The results presented in this report are based on the most accurate data available. The original sample size for each cooperative was designed to yield a confidence level of 95% and an accuracy of plus or minus 5% for results, assuming a 35% response rate. In other words, our goal was to be able to conclude that we are 95% confident that the results are accurate within plus or minus 5%. The results presented in this report are at the 95% confidence level and the accuracy intervals are adjusted to reflect the actual response rate for the cooperative. Response rates less than 35% will experience slightly larger margin of errors. Conversely, cooperatives with higher response rates will see smaller margin of errors.

Please refer to Appendix A for a table of accuracy intervals based on the total respondents and varying saturation rates. An example of how to use the accuracy intervals is provided with the table. Individual survey responses were checked for accuracy. Survey responses were validated and analyzed in order to identify inconsistent replies by the respondents and to correct or eliminate errors.

HOUSING CHARACTERISTICS

Housing characteristics provide insight into the physical characteristics of the member home. Housing characteristics such as type of home, square footage and age of the structure impact overall energy usage.

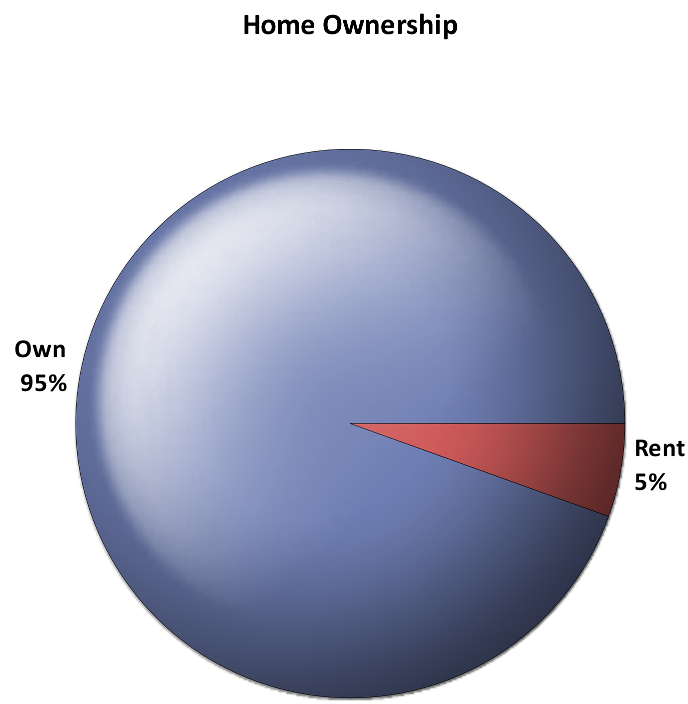
A. Type of Housing Unit



Residential Housing Type	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Single Family	80%	81%	84%	73%
Manufactured	16%	15%	13%	22%
Apartment	2%	3%	2%	3%
Modular	1%	1%	1%	2%
Other	1%	1%	0%	0%

The vast majority of residential members live in site-built, single-family homes.

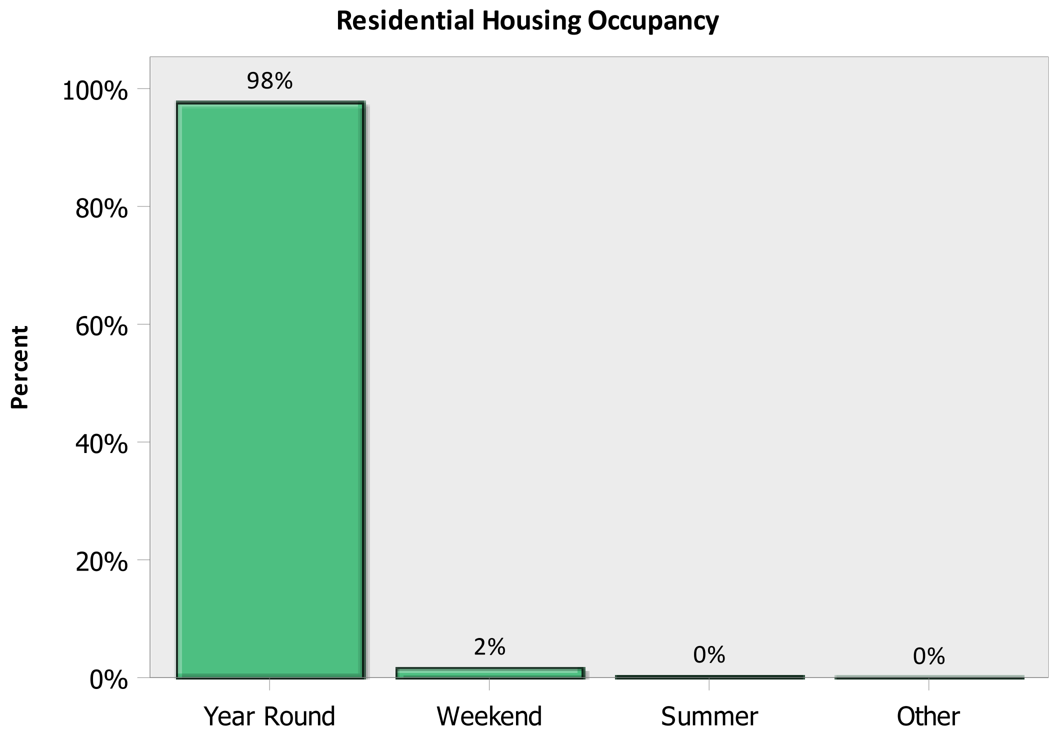
B. Home Ownership



Home Ownership	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Own	95%	95%	95%	93%
Rent	5%	5%	5%	7%

The majority of study participants own their home. This is true across all member cooperatives.

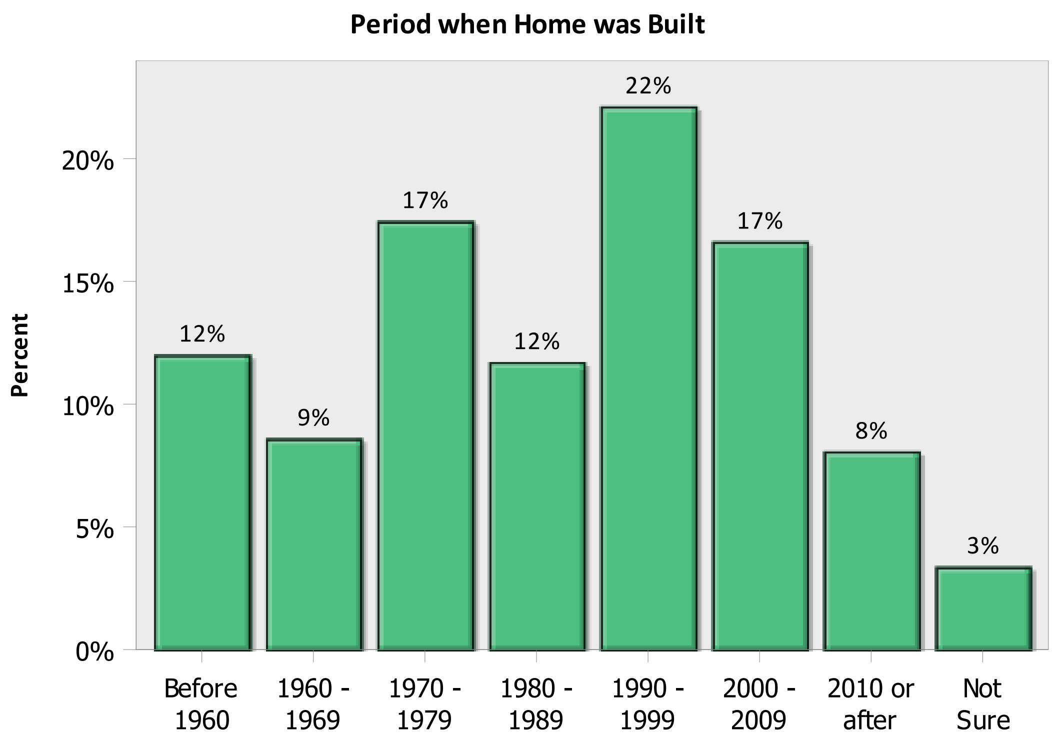
C. Year-round vs Seasonal Residence



Residential Housing Occupancy	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Year Round	98%	98%	99%	96%
Weekend	2%	2%	0%	4%
Summer	0%	1%	0%	0%
Other	0%	0%	0%	0%

Almost all residential households participating in the study indicated they were year-round residences of the electric cooperative.

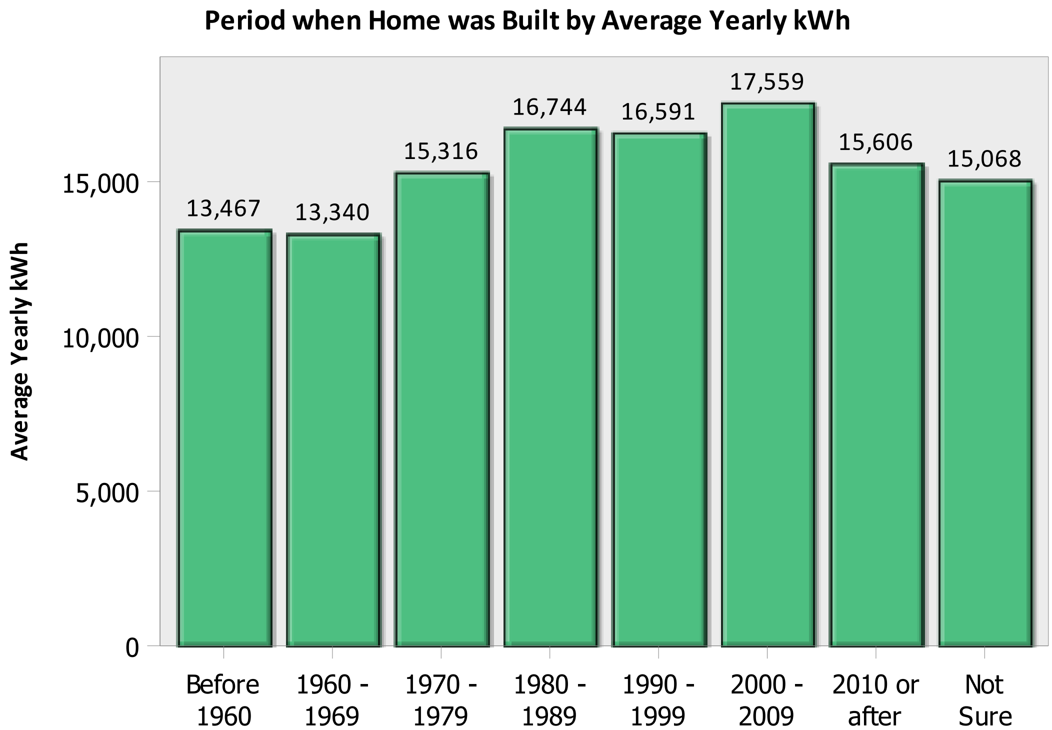
D. Age of Residence



Period when Home was Built	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Before 1960	12%	12%	14%	9%
1960 - 1969	9%	8%	10%	8%
1970 - 1979	17%	21%	17%	15%
1980 - 1989	12%	13%	11%	12%
1990 - 1999	22%	20%	22%	25%
2000 - 2009	17%	15%	17%	18%
2010 or after	8%	6%	8%	9%
Not Sure	3%	5%	2%	4%

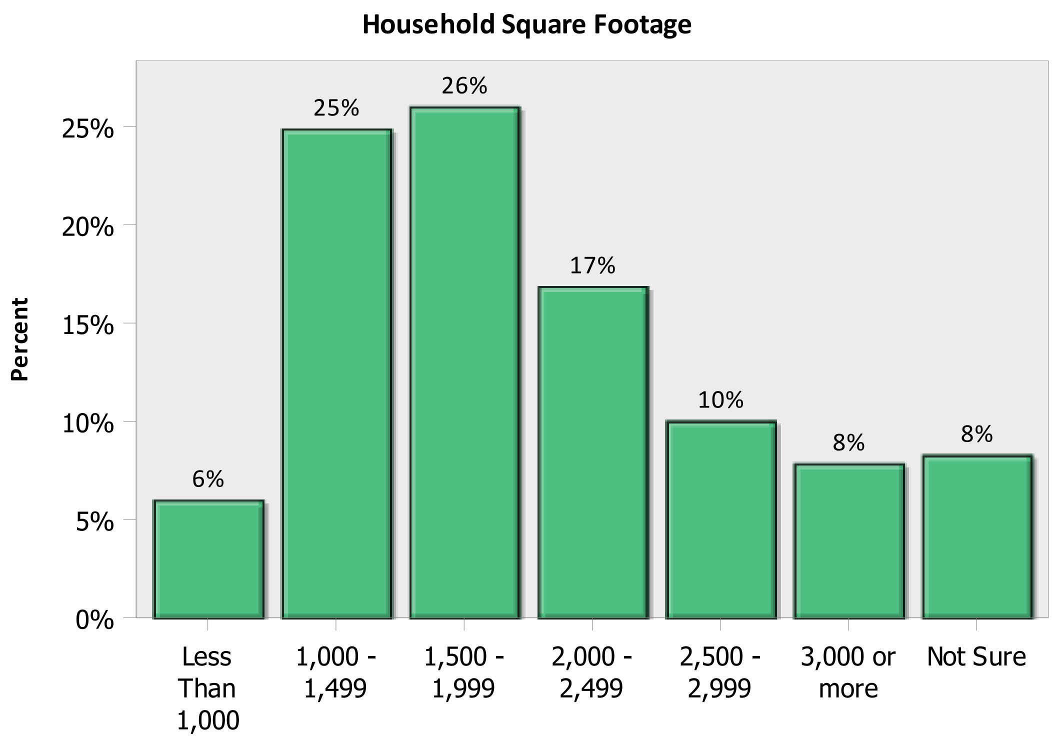
The majority of Big Rivers members’ homes were built between 1970 and 2009.

E. Energy Usage by Age of Home



Homes built prior to 1970 appear to use considerably less electricity than homes built between 1970 and 2009. This may be the result of older homes being smaller in size and occupied by older members who typically use less electricity.

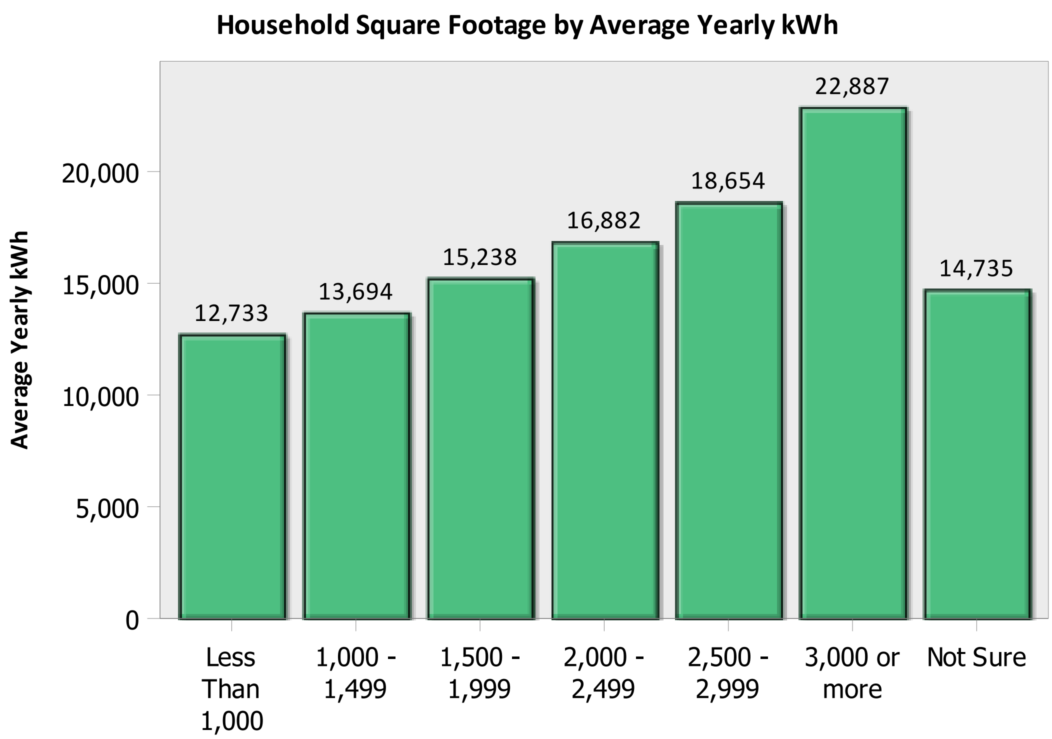
F. Size of the Home



Household Square Footage	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Less Than 1,000	6%	6%	5%	8%
1,000 - 1,499	25%	21%	28%	24%
1,500 - 1,999	26%	28%	25%	25%
2,000 - 2,499	17%	19%	17%	15%
2,500 - 2,999	10%	9%	11%	9%
3,000 or more	8%	9%	8%	7%
Not Sure	8%	8%	7%	11%

The size of the home can strongly influence the amount of energy consumed. The majority of member homes were between 1,000 and 2,500 square feet.

G. Energy Usage by Home Size



Household Square Footage by Average Yearly kWh	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Less Than 1,000	12,733	11,823	14,011	12,023
1,000 - 1,499	13,694	14,903	13,996	12,164
1,500 - 1,999	15,238	16,142	14,967	14,788
2,000 - 2,499	16,882	18,964	16,470	15,335
2,500 - 2,999	18,654	20,837	17,617	18,797
3,000 or more	22,887	28,586	22,503	17,328
Not Sure	14,735	18,101	13,893	13,578

This graph presents the average energy consumption (kWh) over a 12-month period for member homes by size of the unit. The data represents 12 months from approximately January 2018 through December 2018 and has not been weather normalized. Clearly, size of the home has a positive correlation with the amount of energy consumed over the year. Larger homes use more electricity than smaller homes. Homes with > 3,000 square feet of living space use almost 80% more electricity than homes with < 1,000 square feet.

H. Additional Housing Information

	Square Feet of Living Space					
Period when Home was Built	*Less Than 1,000*	*1,000 - 1,499*	*1,500 - 1,999*	*2,000 - 2,499*	*2,500 - 2,999*	*3,000 or more*
Before 1960	6%	42%	28%	13%	8%	3%
1960 - 1969	13%	29%	30%	17%	5%	5%
1970 - 1979	5%	30%	34%	19%	8%	4%
1980 - 1989	7%	33%	26%	19%	8%	7%
1990 - 1999	3%	24%	26%	21%	15%	12%
2000 - 2009	7%	19%	32%	17%	13%	13%
2010 or after	7%	20%	26%	20%	14%	13%

Evaluating home size by age of home reveals that homes have stayed approximately the same size. About half of homes built before 1970 occupied less than 1,500 square feet of living space. Today, less than three out of ten homes are constructed in this size range.

There was a rise in home sizes 2,000 sq. ft. or larger from 1990-1999. However, homes returned to the smaller size during the 2000s. Since 2010, it appears new home sizes have increased in size to pre-recession levels.

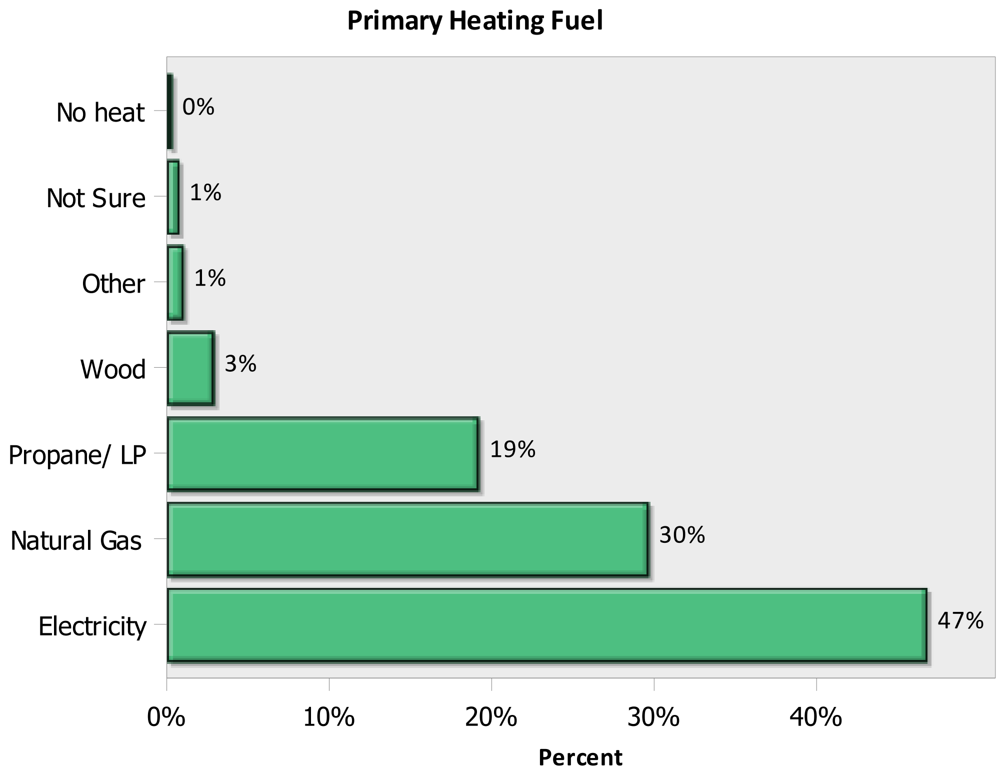
	Count					
Rooms	*None(0)*	*One(1)*	*Two(2)*	*Three(3)*	*Four(4)*	*Five or more(5+)*
Bedrooms	0%	2%	17%	61%	17%	2%
Full Bathrooms	2%	26%	58%	13%	1%	0%
Half Bathrooms	76%	22%	2%	0%	.	.

The majority of members live in homes with three bedrooms with at least two full bathrooms. Over three-quarters of member homes had no half bathrooms.

HEATING CHARACTERISTICS

Home heating constitutes a significant portion of energy consumption in the home. Understanding the type of heating equipment used, the age of the equipment and the fuel source is important to predicting future electricity usage.

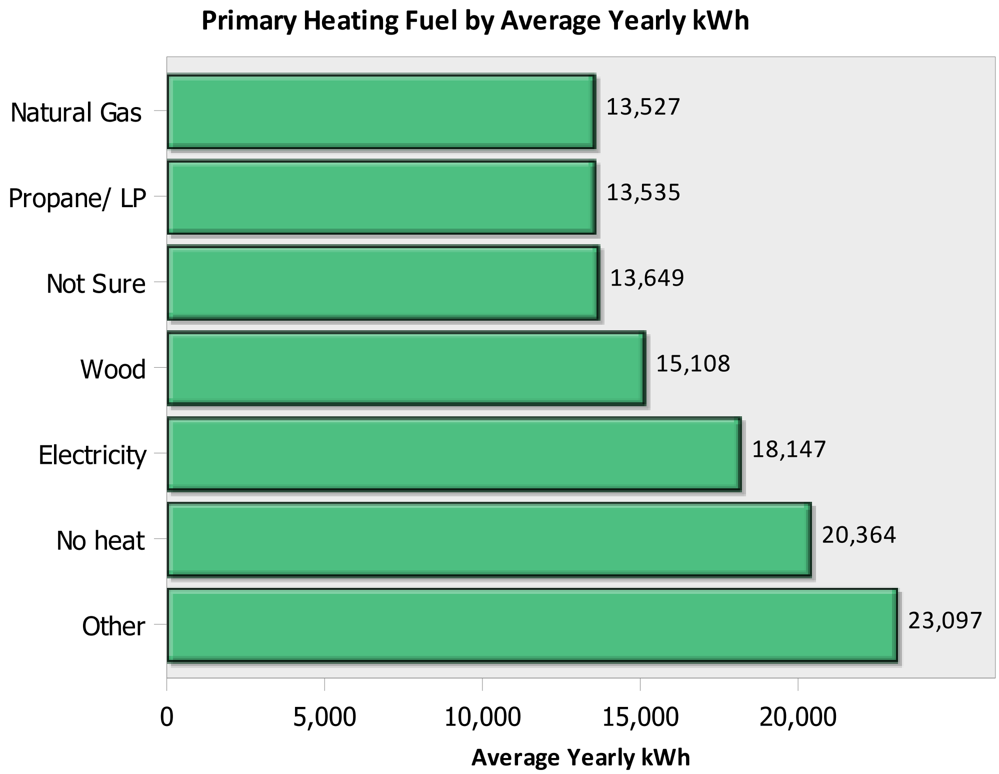
A. Primary Heating Source



Primary Heating Fuel	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Not Sure	1%	0%	1%	0%
Other	1%	2%	1%	1%
No heat	0%	0%	.	1%
Wood	3%	2%	2%	4%
Propane/ LP	19%	23%	16%	20%
Natural Gas	30%	28%	41%	13%
Electricity	47%	44%	39%	61%

Approximately one-half of member households are heated using electricity. Meade County experiences the highest penetration of electric heat at over 60%. Natural gas heat is most common in Kenergy households. Nearly 3% of members use wood as their primary heating source.

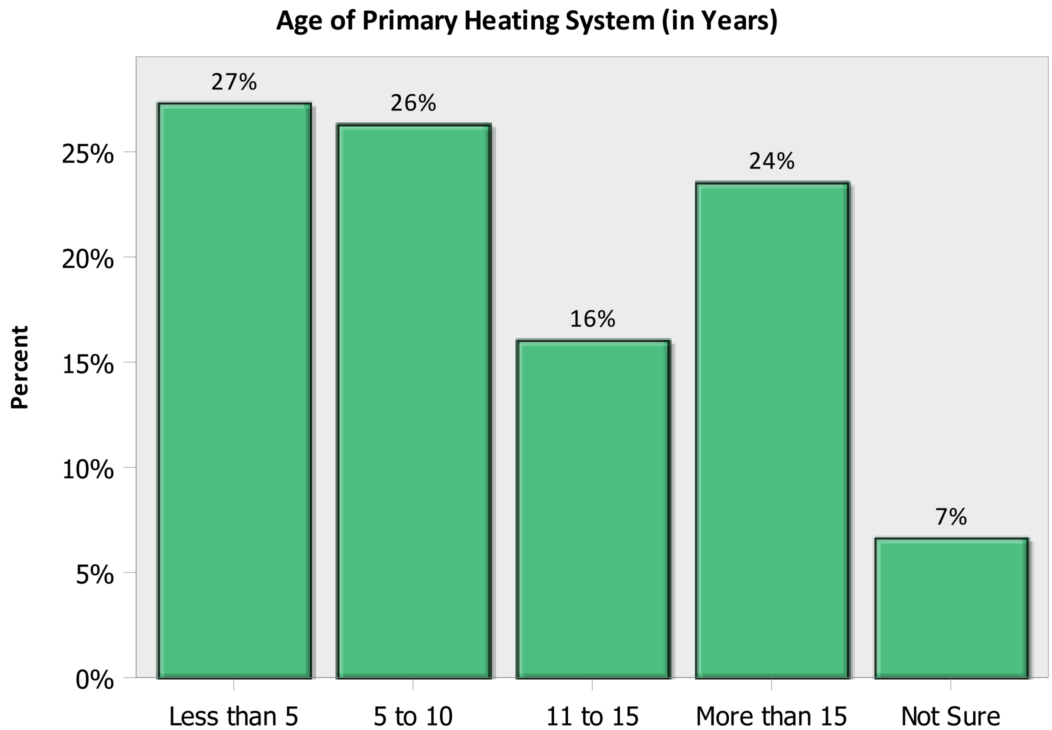
B. Heating System Source by Usage



On average, homes with electric heat use significantly more electricity than homes heating with natural gas or propane.

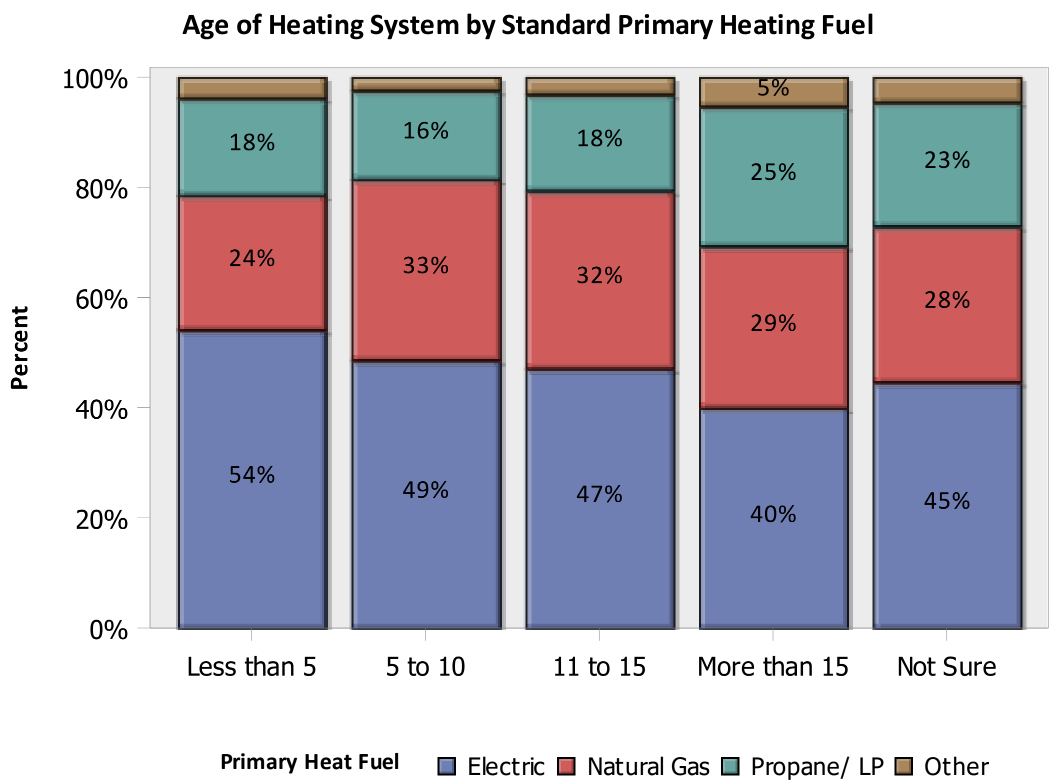
Homes with no heat or "other" fuel types represent a very small number of households. Due to the small sample size for these fuel types, their results should be viewed with caution.

C. Age of Primary Heating System



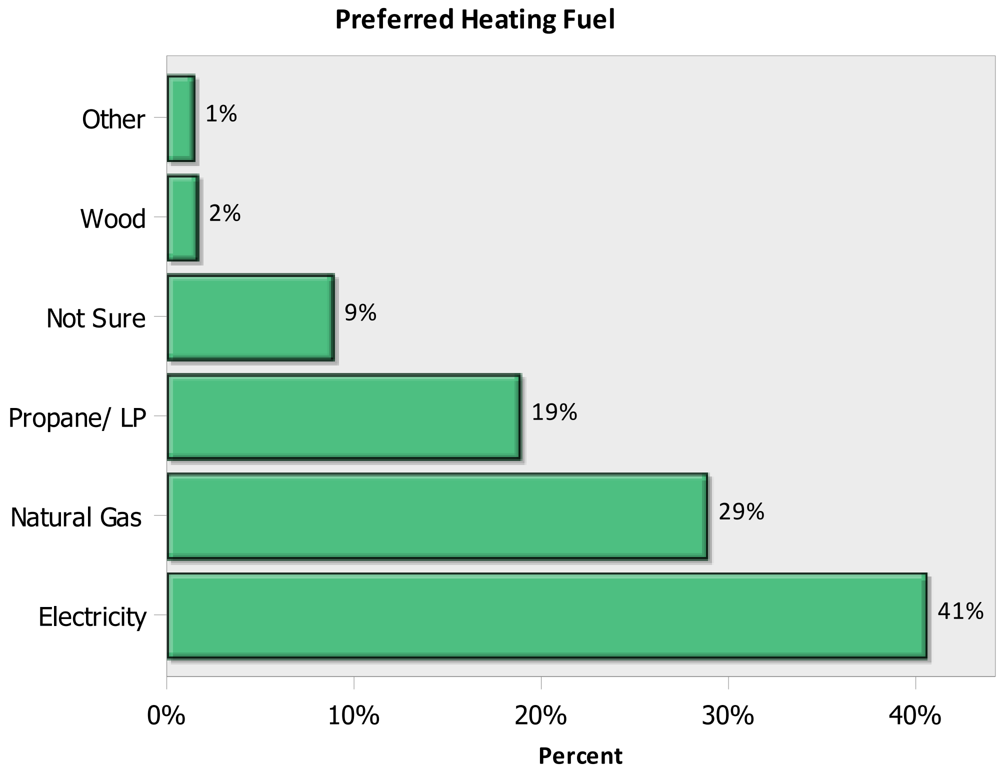
The American Council for an Energy Efficient Economy reported that the average lifespan of a heating system is 15 to 20 years. The households with heating systems 11 to 15 years old and over 15 years old are important target populations for possible installation of new systems. Survey results indicate that 40% of heating systems, i.e. households with heating systems greater than ten years old, are nearing replacement age.

D. Age of Heating System by Primary Heating



Of the heating systems that are more than 15 years old, over 50% of them are propane or natural gas. The use of electric systems has increased steadily over the last 15 years.

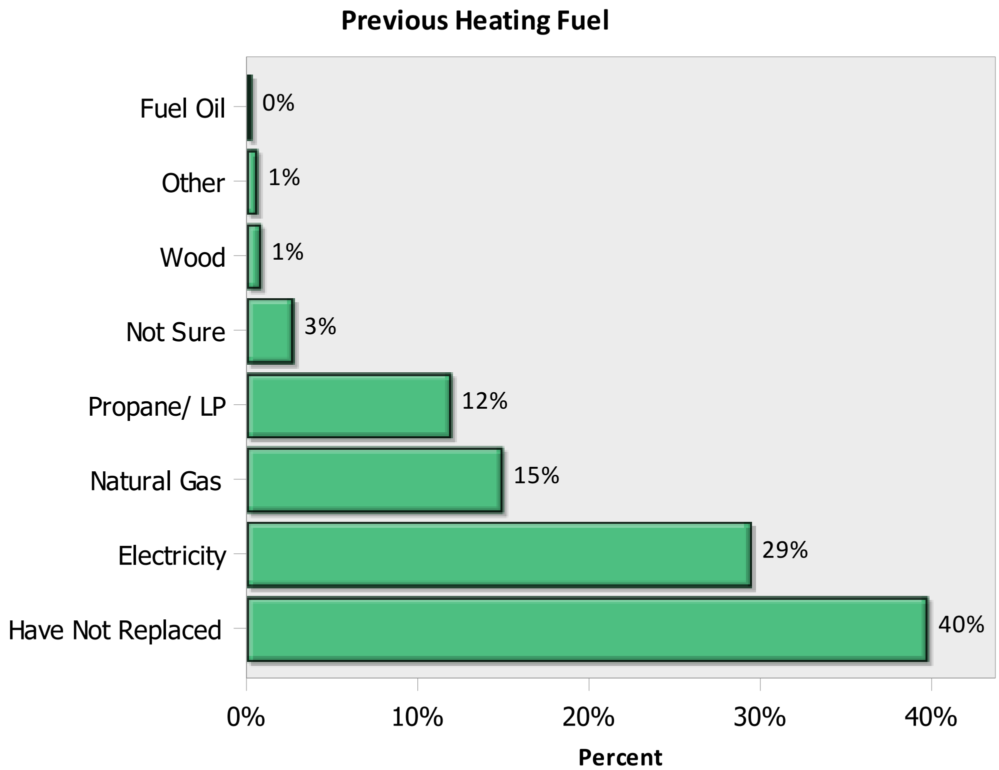
E. Primary Heating Fuel of Choice



Preferred Heating Fuel	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Other	1%	1%	1%	2%
Wood	2%	1%	1%	2%
Not Sure	9%	9%	7%	11%
Propane/ LP	19%	23%	19%	16%
Natural Gas	29%	31%	39%	11%
Electricity	41%	35%	33%	58%

Members were asked, if they needed to replace the primary heating system which fuel would they choose. The member was also instructed to choose only a fuel that was available at their home. The majority (41%) would choose an electric system followed by a preference for a natural gas system (29%). Kenergy members prefer natural gas, while Jackson Purchase and Meade County members prefer electricity.

F. Previous Heating Fuel Used



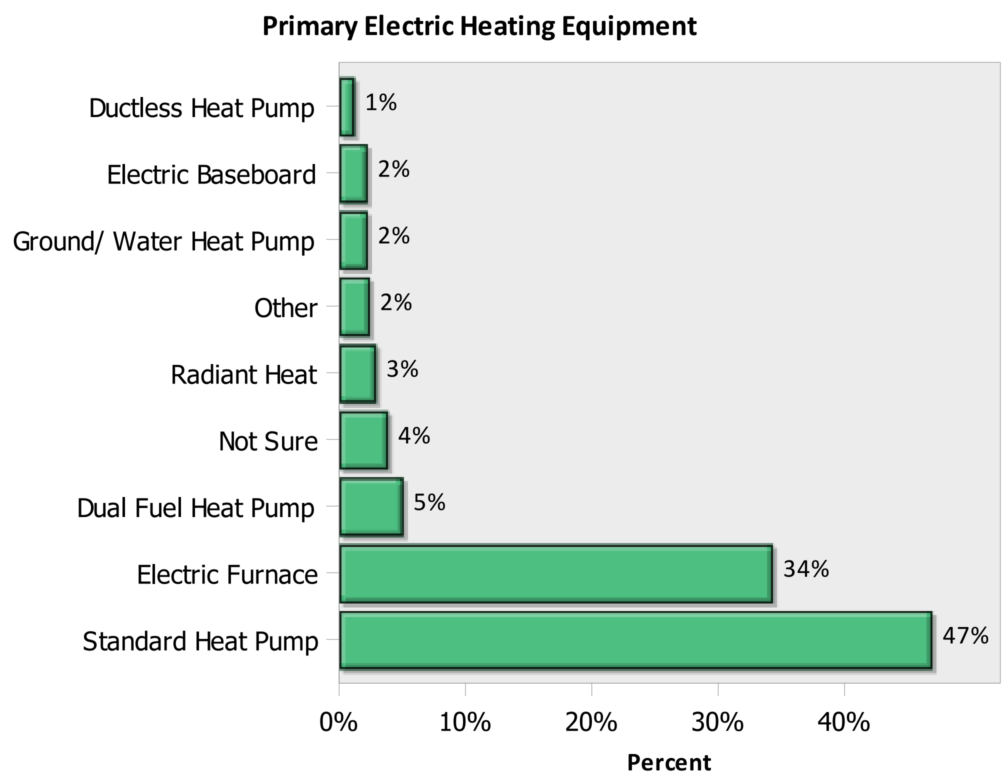
Previous Heating Fuel	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Fuel Oil	0%	.	.	1%
Other	1%	1%	1%	.
Wood	1%	.	1%	1%
Not Sure	3%	3%	1%	4%
Propane/ LP	12%	13%	13%	10%
Natural Gas	15%	15%	20%	6%
Electricity	29%	29%	25%	36%
Have Not Replaced	40%	39%	38%	43%

Of those members replacing their heating systems during the past five years, the most common fuel used in their previous system was electricity. Four out of ten members have not replaced their heating system in the past five years.

	Primary Heating Fuel				
Previous Heating Fuel	*Electricity*	*Natural Gas*	*Propane LP*	*Wood*	*Other*
Electricity	93%	4%	2%	1%	.
Natural Gas	2%	98%	.	0%	.
Propane/ LP	10%	2%	82%	2%	2%
Wood	28%	.	26%	46%	.
Fuel Oil	.	.	100%	.	.
Other	21%	47%	.	.	32%

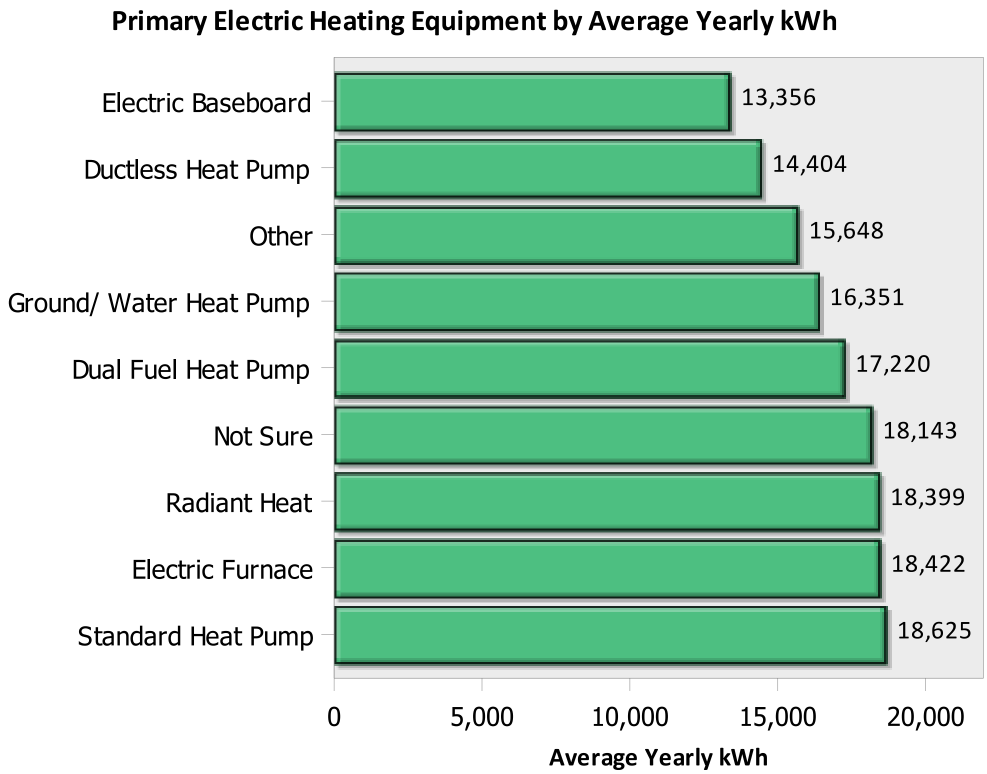
Members were asked if they needed to replace their primary heating system in the near future, what fuel would they choose. The member was instructed to choose only a fuel that was available at their home. Overwhelmingly, members who used electricity for heating their home chose to replace their existing system with another electric heating system. The same trend holds true for Propane or Natural Gas heating systems. Once a fuel source occupies a place in home HVAC equipment, it is difficult to unseat that fuel.

G. Primary Electric Heating Equipment



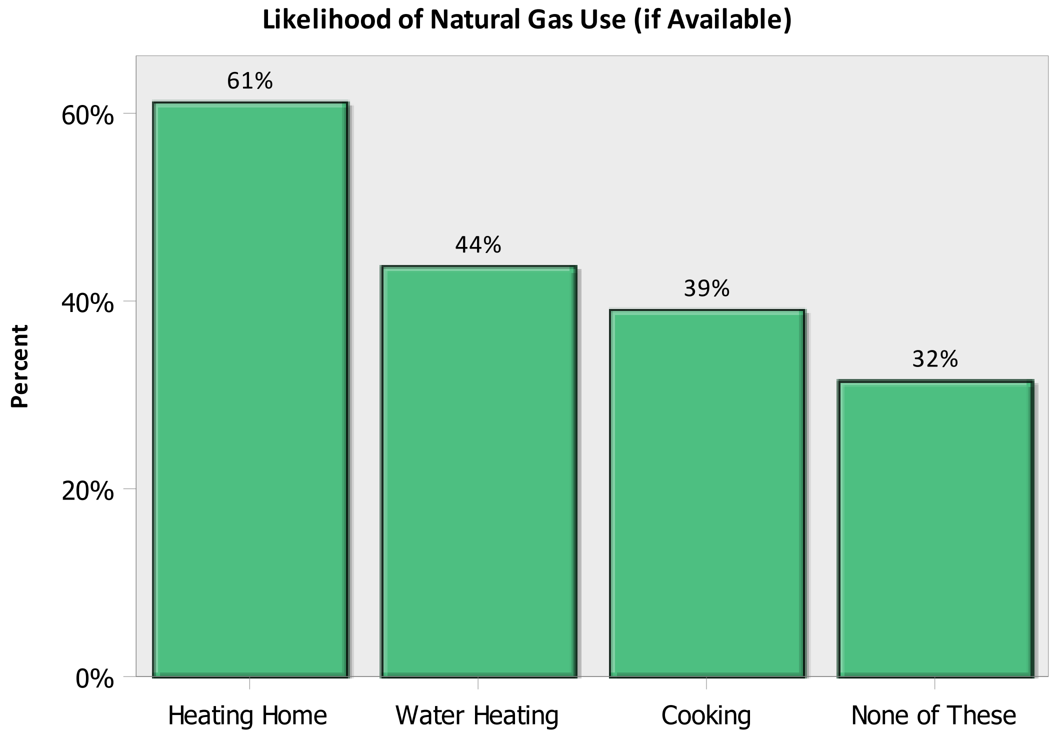
The most common type of electric heating systems used among Big Rivers' Electric Corporation member households are standard heat pumps (47%). About one-third of households utilized an electric furnace.

H. Primary Electric Heating Equipment by Usage



Annual electric usage was highest among households utilizing radiant heat, electric furnaces and standard heat pumps.

I. Prospects for Natural Gas Usage



Likelihood of Natural Gas Use (if Available)	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Heating Home	61%	68%	67%	48%
Water Heating	44%	51%	48%	33%
Cooking	39%	44%	44%	28%
None of These	32%	27%	25%	45%

Members were asked, if natural gas was available in your area, would you consider using it for heating your home, water heating, or cooking. About 61% of members stated they would use it for heating purposes while approximately four out of ten would use it for either water heating or cooking. Interestingly, about one-third of respondents stated they wouldn't use natural gas for any of these activities at their home even if given the option to do so.

J. Additional Heating Characteristics

Use a Secondary Heating System	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Uses a Secondary Heating System	28%	20%	28%	35%
No Secondary Heating System	72%	80%	72%	65%

Secondary Heating System	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Electricity	42%	36%	54%	28%
Propane/ LP	30%	43%	22%	35%
Wood	22%	3%	27%	23%
Natural Gas	10%	12%	8%	13%
Not Sure	1%	0%	0%	2%
Kerosene	3%	1%	5%	0%
Other	2%	5%	2%	1%
Fuel Oil	0%	0%	0%	0%
No Secondary Heat	0%	0%	0%	0%

About three out of ten member households indicate using a secondary heat source. Among households that have a secondary heating system, electricity is the primary fuel used.

Secondary Heating System (can heat entire home)	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Yes	38%	32%	36%	43%
No	62%	68%	64%	57%

Of those households currently using secondary heating systems, only about four out of ten are able to heat the entire home using the secondary source.

Have a Fireplace in Home	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Yes	47%	54%	48%	40%
No	53%	46%	52%	60%

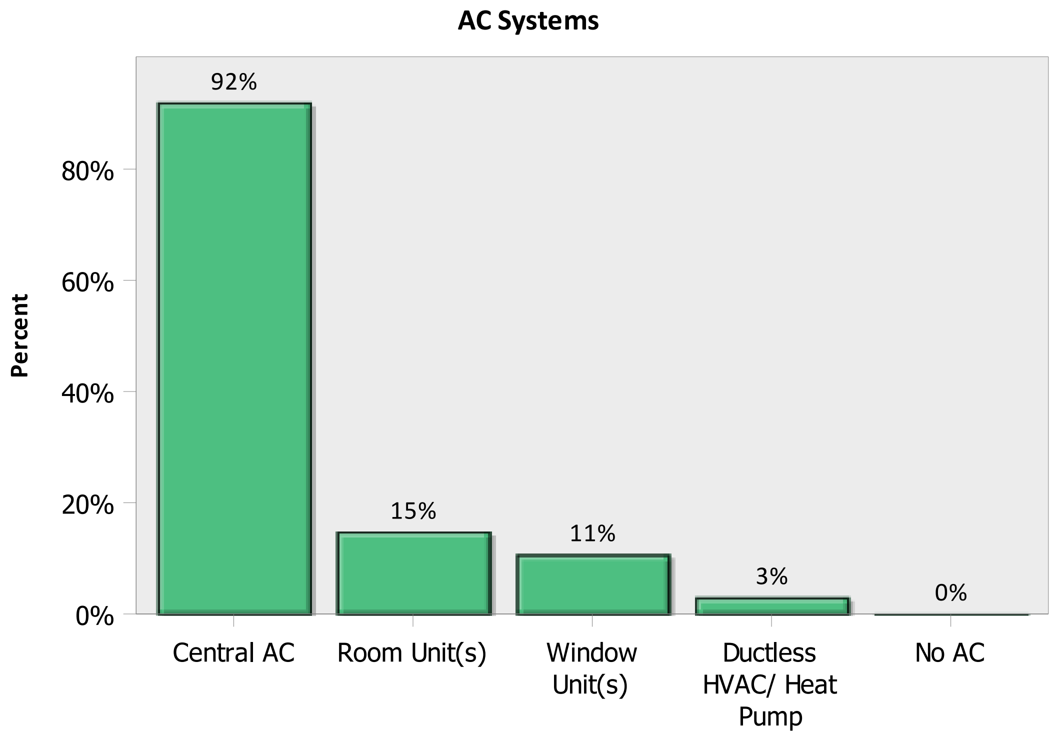
Fuel Used in Fireplace	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Natural Gas	31%	36%	37%	14%
Propane	35%	40%	28%	44%
Wood	25%	17%	27%	29%
None/ Don't Use It	4%	3%	4%	7%
Electricity	3%	1%	2%	5%
Other	2%	2%	3%	1%

About one-half of households have a fireplace in their home. The primary fuel source of fireplaces is propane.

AIR CONDITIONING CHARACTERISTICS

Air conditioning is a key driver of electricity consumption during peak summer months. Determining equipment age can predict future efficiency gains from system replacements.

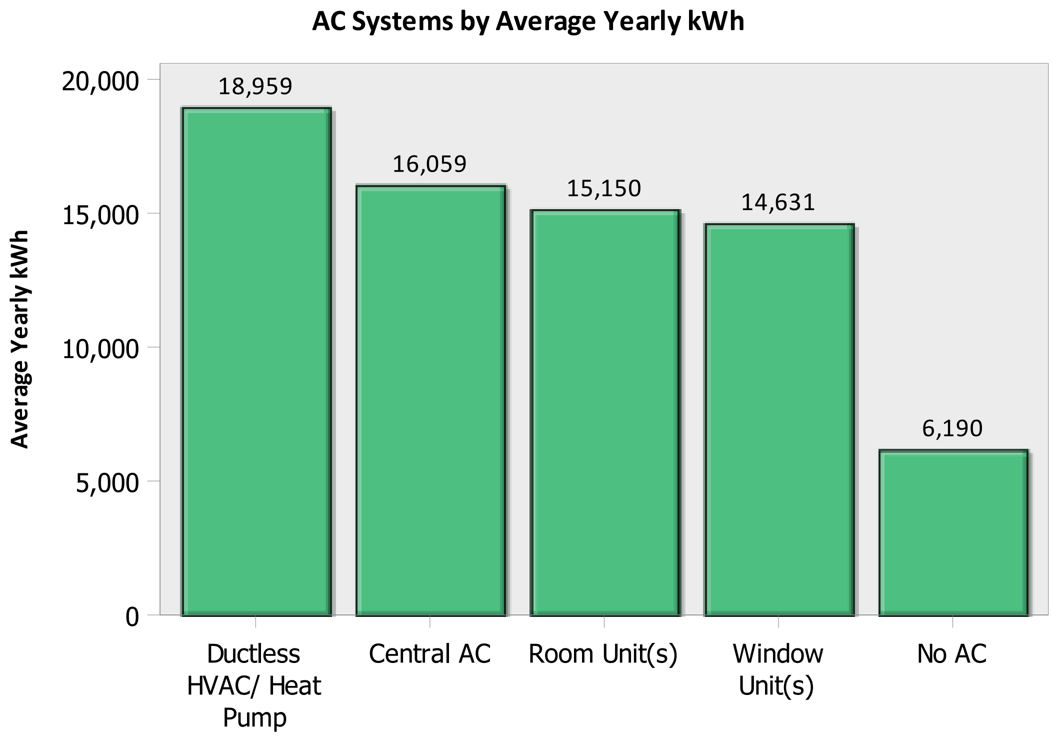
A. Penetration of Air Conditioning



AC Systems	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Central AC	92%	91%	95%	88%
Window Unit(s)	11%	10%	9%	15%
Ductless HVAC/ Heat Pump	3%	4%	3%	3%
Room Unit(s)	15%	15%	13%	17%
No AC	0%	0%	0%	0%

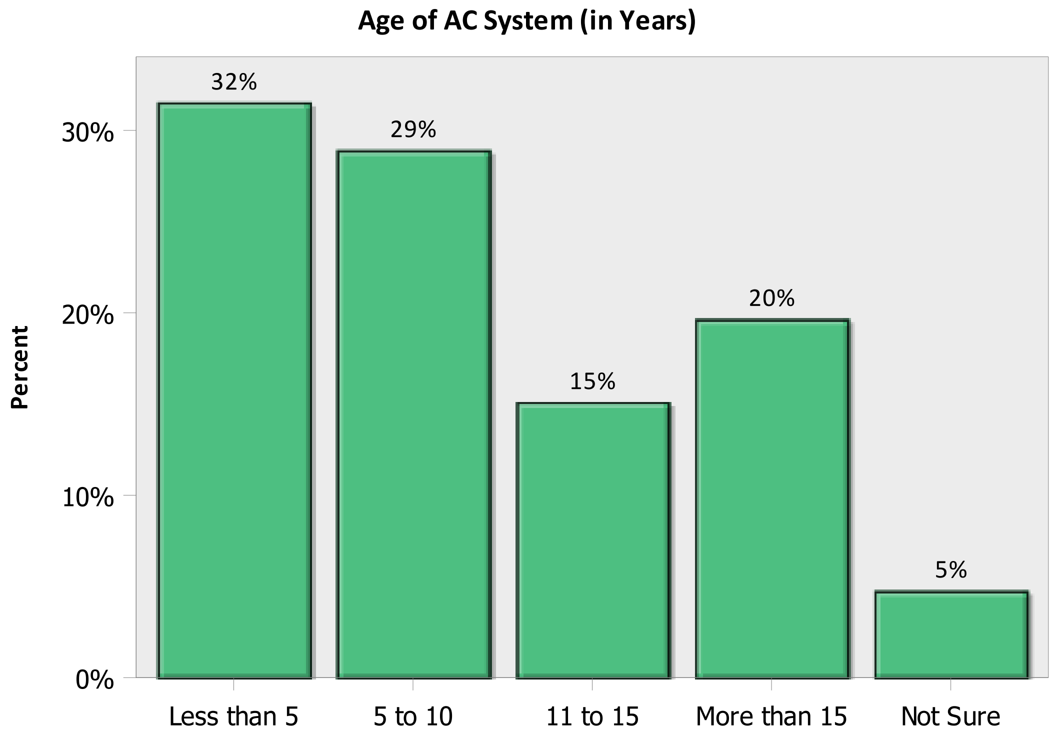
Central AC systems are the most commonly cited in roughly nine out of ten homes.

B. Primary Cooling System by Usage



More electricity is used on average in households with Ductless HVAC/Heat Pump; however, homes with central AC or homes with three or more room units are not far behind with their annual consumption.

C. Age of Primary Air Conditioning System

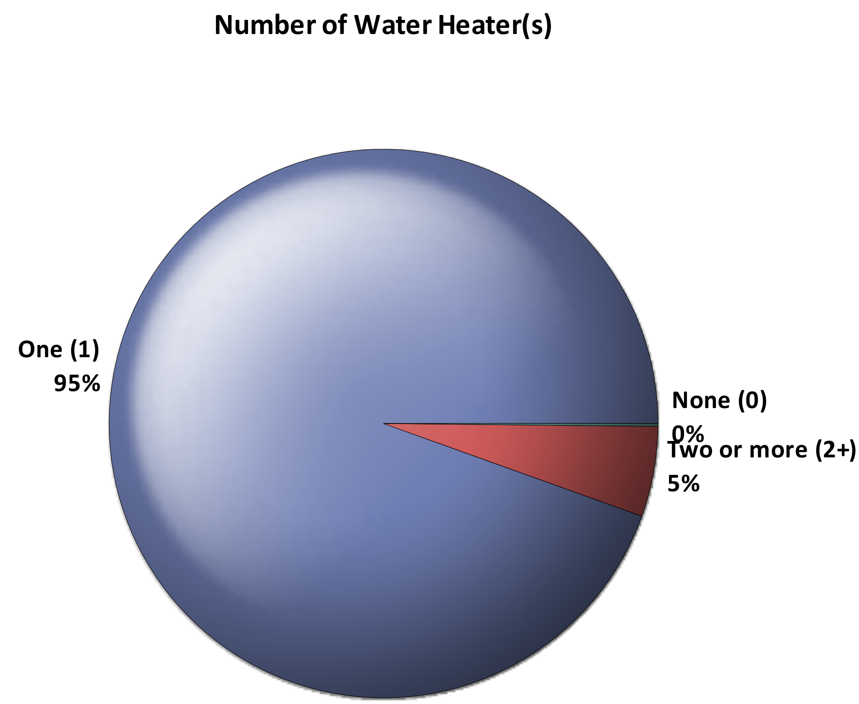


Households with cooling systems more than ten years old are important target populations for possible system replacements and energy efficiency improvements. Survey results indicate that one-third of cooling systems are nearing replacement age. Conversely, nearly two-thirds of cooling systems are less than ten years old.

WATER HEATING CHARACTERISTICS

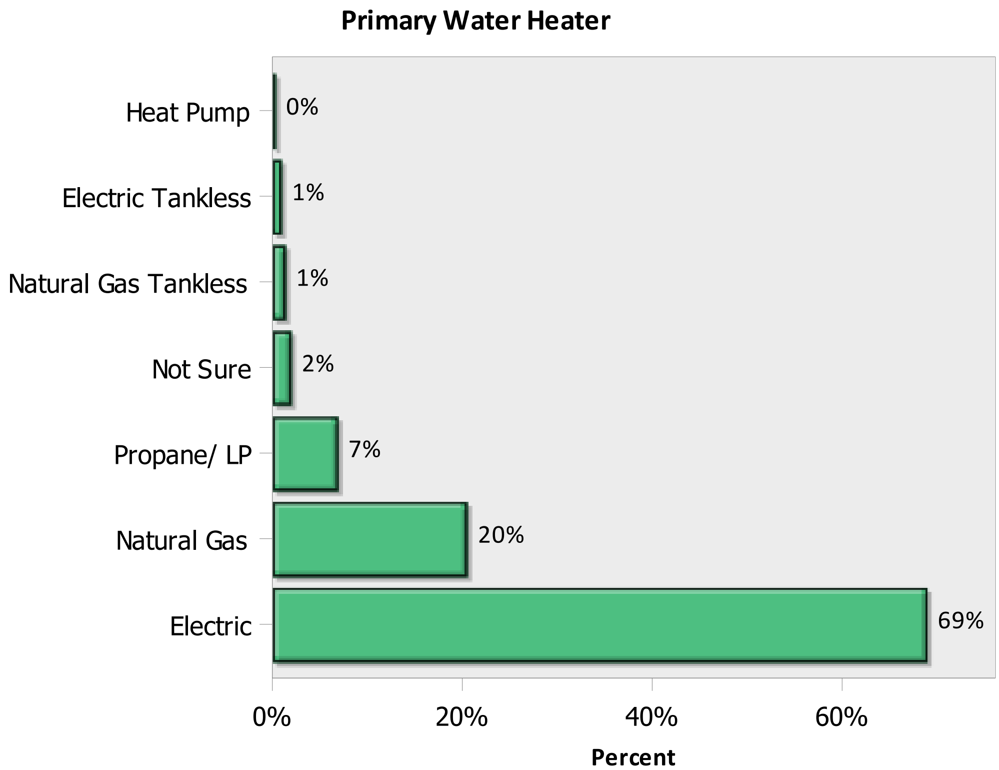
After heating and cooling systems, water heating equipment represents a significant component in year-round home energy consumption. Age of equipment, tank size and fuel source contained in this section provide insight into home energy consumption.

A. Primary Water Heating Quantity



Over nine out of ten members indicated owning only one water heater. Five percent of households own two or more water heaters.

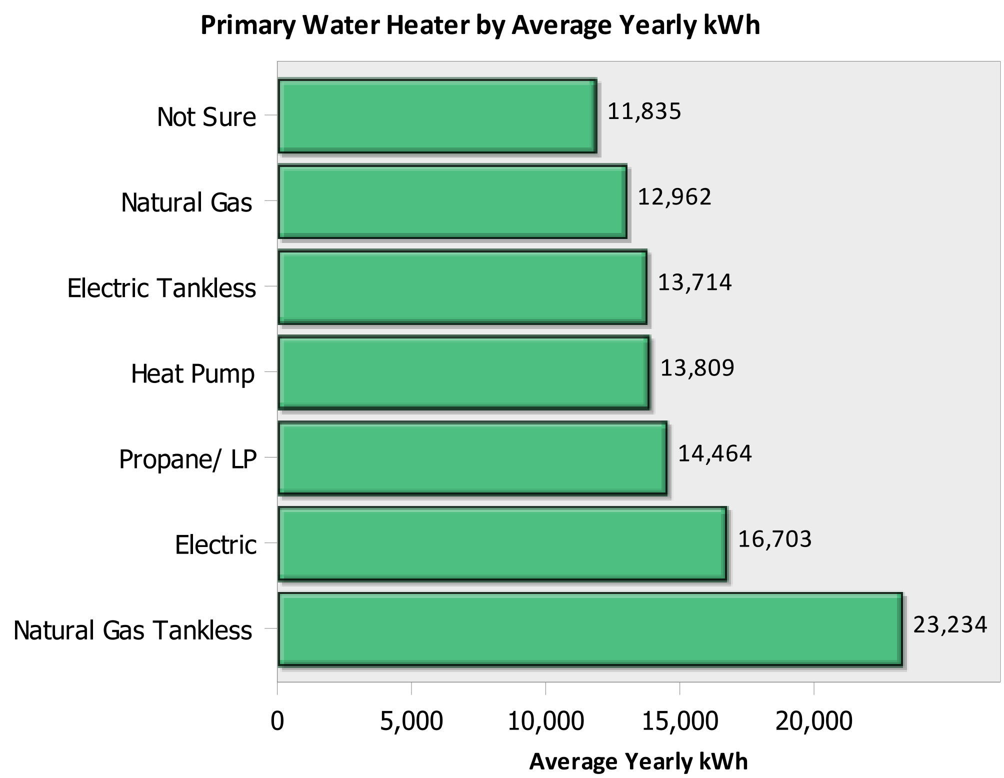
B. Primary Water Heating Fuel Source



Primary Water Heater	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Heat Pump	0%	0%	.	0%
Electric Tankless	1%	0%	1%	1%
Not Sure	2%	2%	2%	1%
Natural Gas Tankless	1%	3%	1%	1%
Propane/ LP	7%	6%	6%	8%
Natural Gas	20%	15%	31%	8%
Electric	69%	73%	59%	81%

The main fuel source used to heat water is electricity. Over two-thirds of members indicated they used electricity as the primary fuel source for their water heating equipment with Meade County members being the highest. Natural gas water heaters represent just over 20% of residential units. Just over 1% of members mentioned they had a tankless or instantaneous water heater.

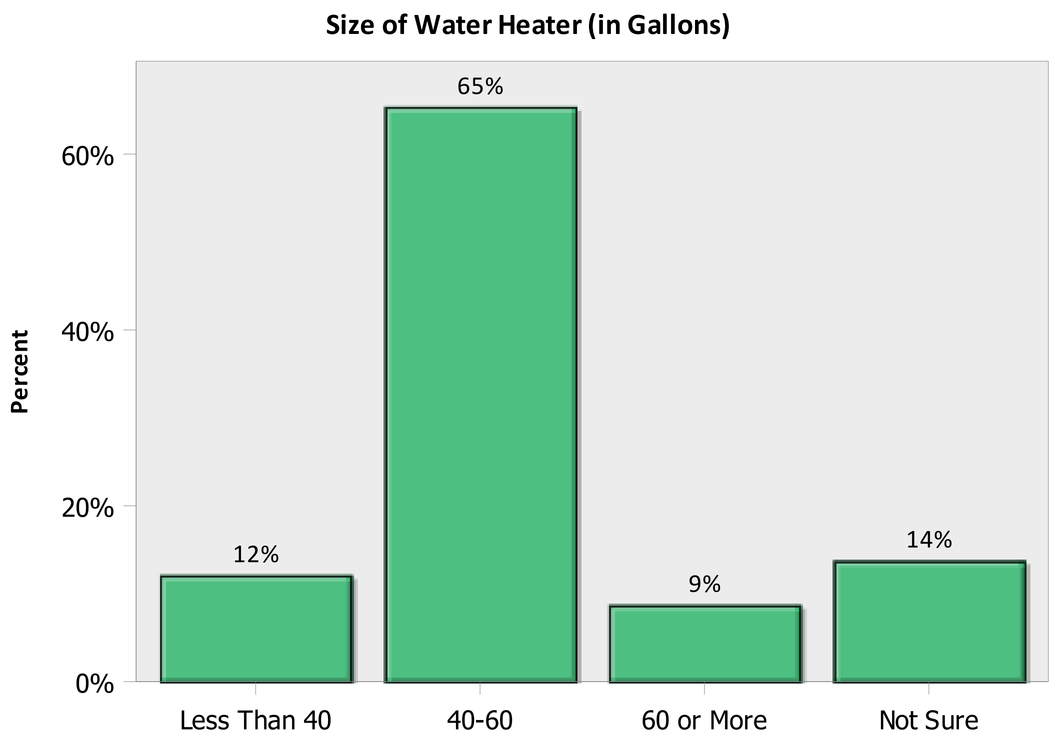
C. Primary Water Heating System by Usage



Homes with natural gas or propane water heaters generally use less electricity than homes with water heaters fueled by electricity.

Please note that homes using heat pump water heaters or tankless water heaters represent a very small percentage of overall households. The average yearly kWh usage reported for these groups can have a wide confidence interval associated with them. Usage numbers reported for these categories should be viewed with caution.

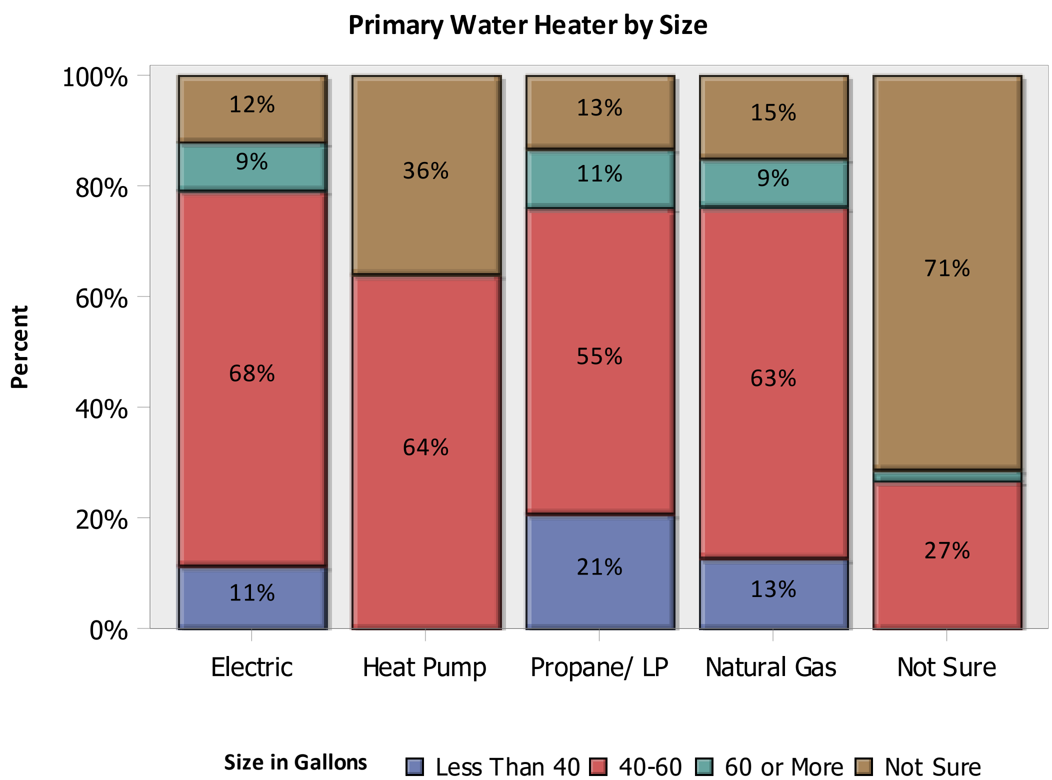
D. Size of Primary Water Heating System



Size of Water Heater	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Less Than 40 Gallons	12%	13%	11%	13%
40-60 Gallons	65%	69%	67%	61%
60 Gallons or More	9%	7%	9%	11%
Not Sure	14%	12%	14%	16%

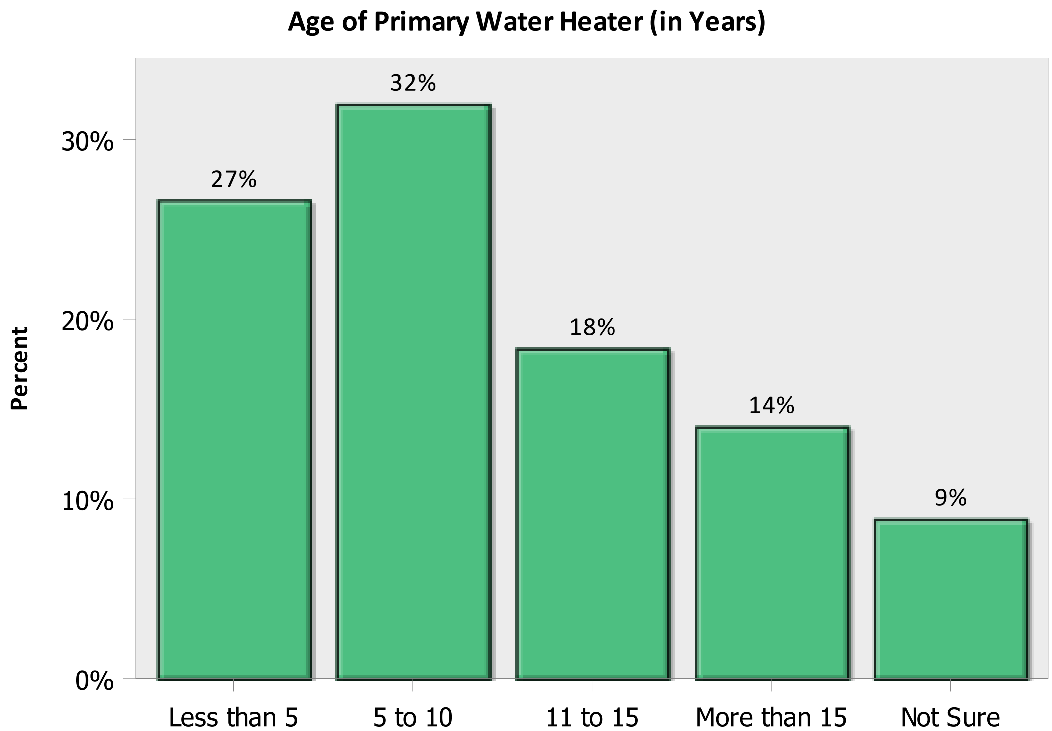
The majority of member households have water heaters that are 40 to 60 gallons in size. These findings are consistent across all cooperatives. One out of seven members were not sure of their water heater size.

E. Primary Water Heating System by Size



Regardless of the fuel source, the most popular water heater tank size holds between 40 to 60 gallons.

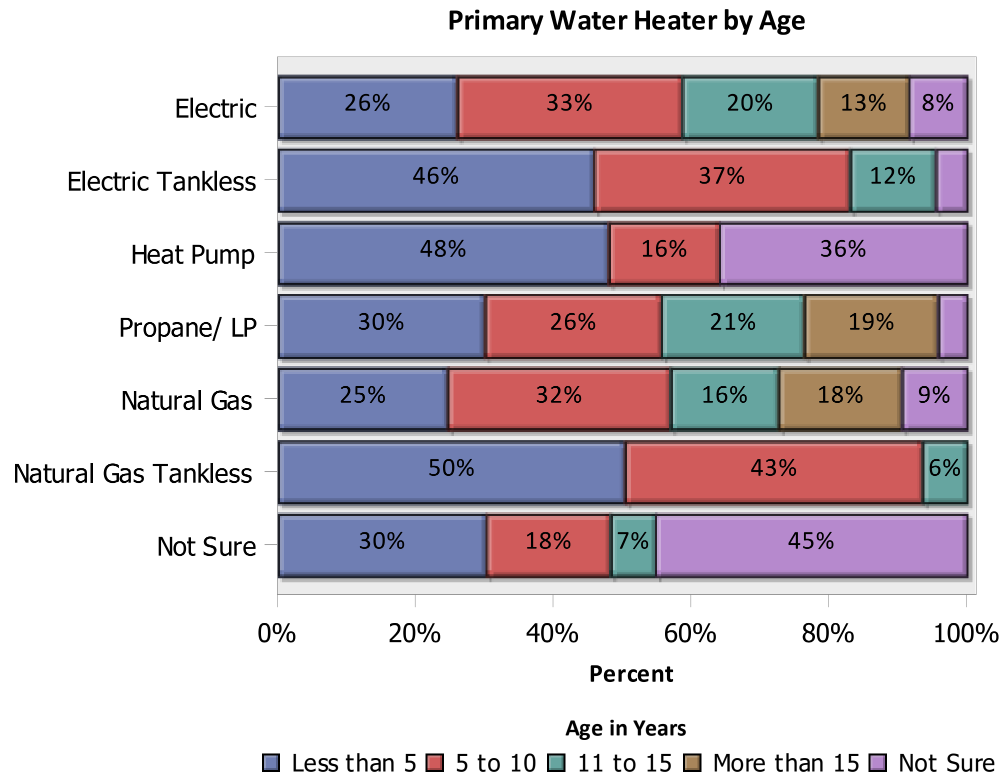
F. Age of Primary Water Heating System



Age of Water Heater	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Less than 5 Years	27%	35%	21%	29%
5 to 10 Years	32%	33%	34%	28%
11 to 15 Years	18%	14%	21%	17%
More than 15 Years	14%	9%	15%	16%
Not Sure	9%	8%	8%	10%

The American Council for an Energy Efficient Economy reported that the average lifespan of a water heater is 10 to 15 years. Households with water heaters 11 to 15 years old and over 15 years old are important target households for replacement programs and represent approximately one-quarter of households.

G. Primary Water Heating System by Age



The majority of water heaters are less than 11 years old. However, about one-quarter of electric, propane and natural gas units are nearing replacement age.

H. Additional Water Heating Information

Fuel Used in Old Water Heater	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Electric	44%	52%	34%	51%
Have Not Replaced	30%	25%	35%	28%
Natural Gas	13%	10%	21%	5%
Propane/ LP	5%	5%	3%	7%
Not Sure	5%	5%	5%	5%
Natural Gas Tankless	1%	1%	1%	1%
Electric Tankless	1%	1%	1%	3%
Heat Pump	0%	.	1%	.

Replacement Water Heater Fuel of Choice	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Electric	52%	55%	44%	62%
Natural Gas	17%	15%	25%	8%
Not Sure	10%	11%	11%	10%
Propane/ LP	7%	6%	7%	9%
Electric Tankless	7%	6%	7%	9%
Natural Gas Tankless	5%	6%	6%	1%
Solar	1%	.	1%	1%
Heat Pump	1%	.	1%	2%

Overall, about seven out of ten members have replaced their water heater in the last five years.

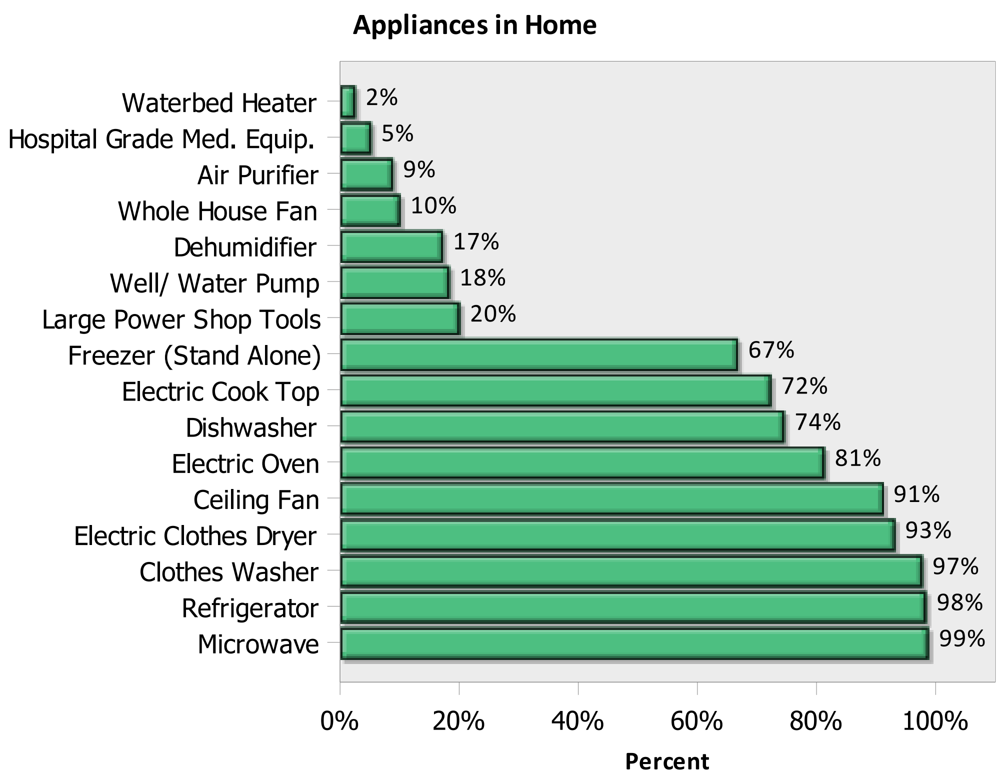
	Fuel Used in Old Water Heater					
Replacement Water Heater Fuel of Choice	*Electric*	*Propane LP*	*Natural Gas*	*Electric Tankless*	*Heat Pump*	*Natural Gas Tankless*
Electric	97%	2%	1%	.	.	.
Electric Tankless	52%	5%	10%	33%	.	.
Heat Pump	44%	.	.	.	56%	.
Propane/ LP	13%	87%	.	.	.	.
Natural Gas	11%	2%	88%	.	.	.
Natural Gas Tankless	7%	.	39%	.	.	54%
Solar	100%	.	.	.	.	.

Members were asked if they needed to replace their primary water heater in the near future, what fuel would they choose. The member was instructed to choose only a fuel that was available at their home. Overwhelmingly, members would pick an electric water heater to replace their existing unit except for members who had Propane or Natural Gas water heaters. Once a fuel source occupies a place in home HVAC or water heating equipment, it is difficult to unseat that fuel in a replacement system.

HOUSEHOLD APPLIANCE PENETRATIONS

Refrigerators, ovens, cooktops, dishwashers and clothes washers and dryers add to the total load profile of a member's home. This section provides insight into the penetration of various domestic appliances in the home.

A. Electric Appliances



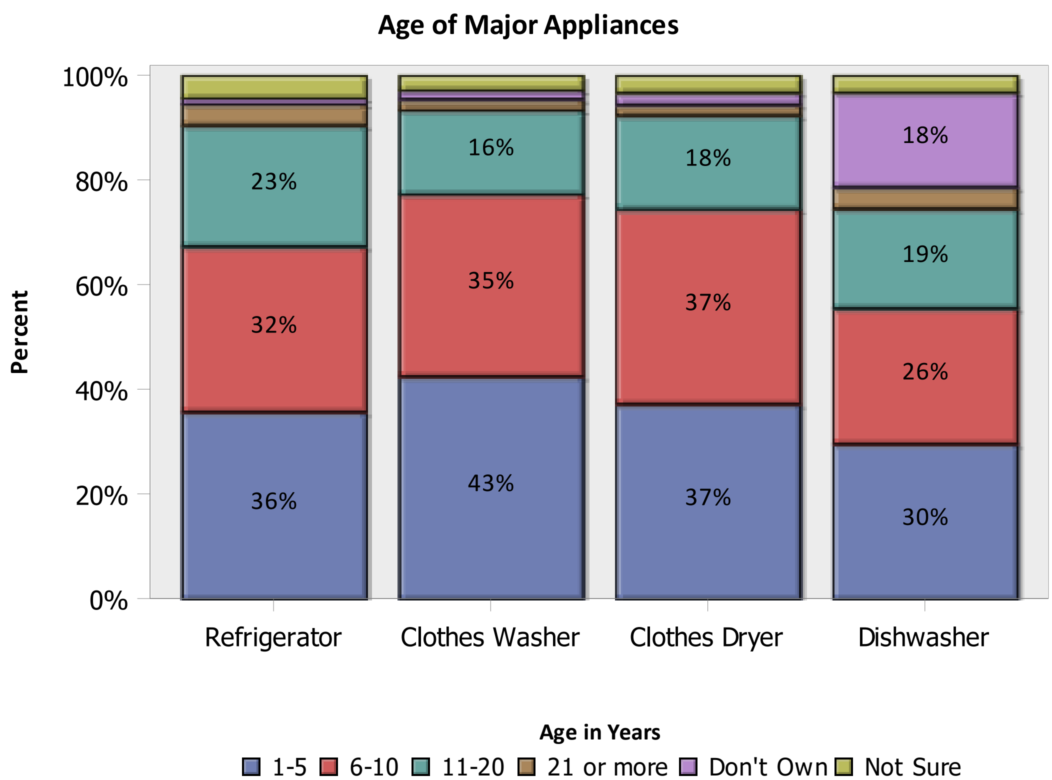
Cooperative members were also asked about their use and ownership of major appliances used for cooking, food storage, dish and clothes washing and drying. Nearly every household utilized a refrigerator, microwave and clothes washer. Electric dryers were prevalent in just over nine out of ten households. Over seven out of ten members indicated owning a dishwasher.

Cooking equipment was found in nearly every home, however, the type of equipment varied. Just over eight out of ten indicated they owned an electric oven while seven out of ten owned an electric cook top.

Freezers were present in two-thirds of homes.

Given the non-rural nature of Big Rivers cooperatives, wells and water pumps were present in nearly two out of ten member homes while other household electric devices such as whole house fans and air purifiers were present in less than one in ten households.

B. Electric Appliances by Age



Roughly one out of four households have refrigerators that are more than ten years old. This percentage is lower for clothes washers, dryers, and dishwashers.

C. Count of Electric Appliances

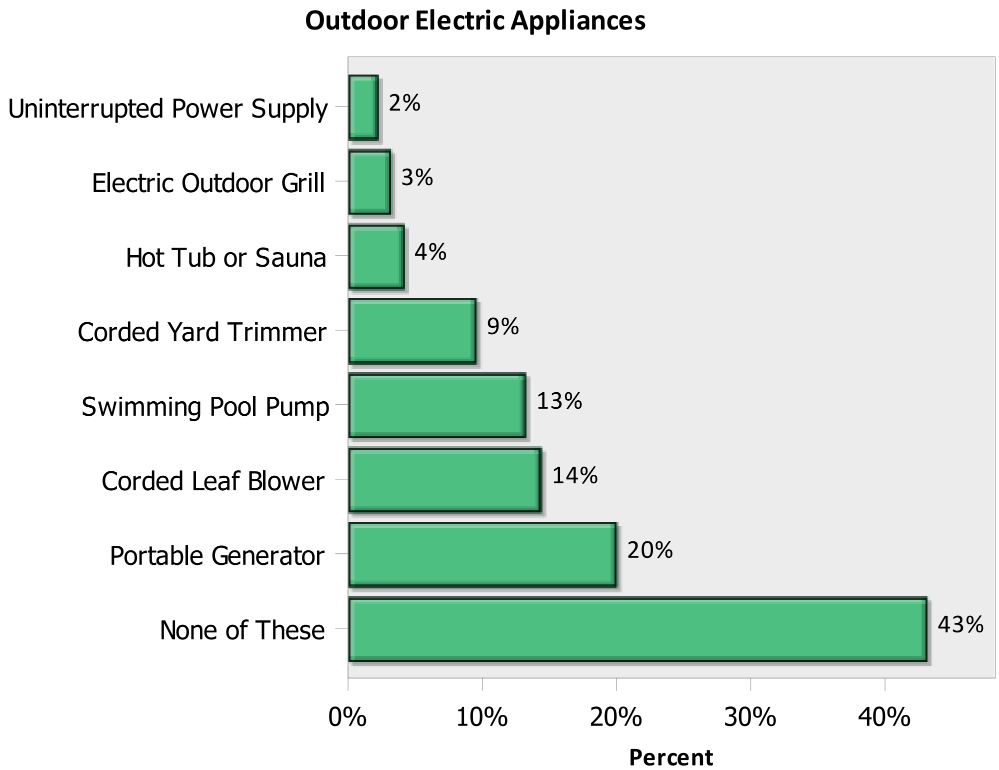
	Count			
Electric Appliances	*Zero(0)*	*One(1)*	*Two(2)*	*Three or more (3+)*
Air Purifier	91%	7%	1%	0%
Ceiling Fan	9%	18%	17%	57%
Clothes Washer	3%	96%	1%	0%
Dehumidifier	83%	16%	1%	0%
Dishwasher	26%	74%	1%	0%
Electric Clothes Dryer	7%	92%	1%	0%
Electric Cook Top	28%	70%	1%	0%
Electric Oven	19%	76%	4%	0%
Freezer (Stand Alone)	33%	56%	9%	2%
Hospital Grade Med. Equip.	95%	4%	0%	0%
Large Power Shop Tools	80%	7%	4%	9%
Microwave	1%	95%	3%	1%
Refrigerator	2%	70%	25%	3%
Waterbed Heater	98%	2%	0%	0%
Well/ Water Pump	82%	17%	0%	0%
Whole House Fan	90%	8%	1%	1%

Members indicating ownership of electric appliances were asked how many of these appliances they had in their home.

Member households own single units of the major appliances listed above with the possible exception of refrigerators where about one-quarter of members indicated owning two or more units.

Members also own multiple ceiling fans in their home. The vast majority owned three or more units.

D. Electric Outdoor Appliances



Outdoor Electric Appliances	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Electric Outdoor Grill	3%	5%	3%	2%
Uninterrupted Power Supply	2%	3%	2%	2%
Hot Tub or Sauna	4%	3%	5%	4%
Corded Yard Trimmer	9%	12%	9%	8%
Swimming Pool Pump	13%	12%	14%	13%
Corded Leaf Blower	14%	15%	15%	12%
Portable Generator	20%	19%	21%	19%
None of These	43%	38%	44%	45%

Cooperative members were also asked about their use and ownership of outdoor electric equipment. High on the list of items used by households were portable generators, used by one out of five households. Corded leaf blowers and swimming pool pumps were present in about one out of seven homes.

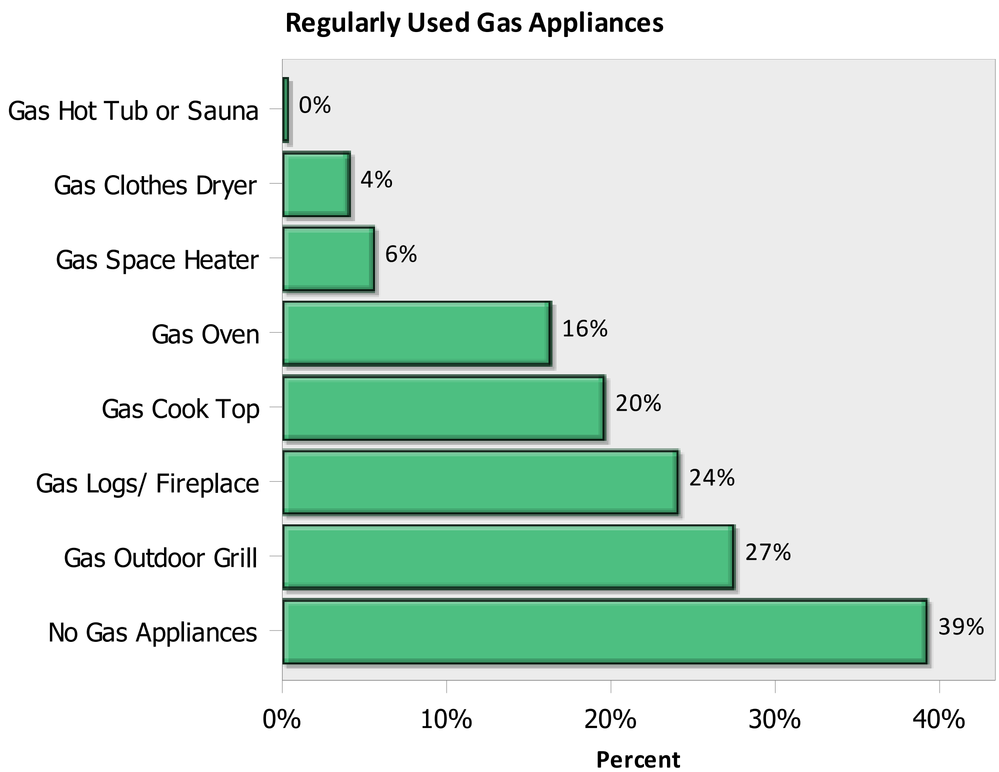
Conversely, lower penetration was experienced for the following electric items: Hot tubs and saunas, uninterrupted power supply, and electric outdoor grills

E. Reasons to Replace Appliances with Energy Efficient Alternative

Most Likely Reason to Replace Appliances	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Necessary (due to age or function)	88%	90%	88%	86%
Recover costs through energy savings in 1-3 years	19%	17%	19%	19%
Finance purchase on my power bill	4%	7%	3%	3%
Plan to replace with more efficient options, regardless	4%	3%	3%	5%

Members overwhelmingly indicated the most likely reason to replace an existing appliance with an energy efficient alternative was necessity due to age or function. About one out of five members would be influenced by the idea of "recovering the cost." Only about 4% of members said they will be doing replacements regardless of age or cost.

F. Other Gas Appliances



Regularly Used Gas Appliances	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Gas Hot Tub or Sauna	0%	0%	0%	0%
Gas Clothes Dryer	4%	4%	6%	2%
Gas Space Heater	6%	6%	4%	7%
Gas Oven	16%	16%	20%	11%
Gas Cook Top	20%	22%	23%	12%
Gas Logs/ Fireplace	24%	28%	24%	20%
Gas Outdoor Grill	27%	25%	32%	21%
No Gas Appliances	39%	38%	32%	51%

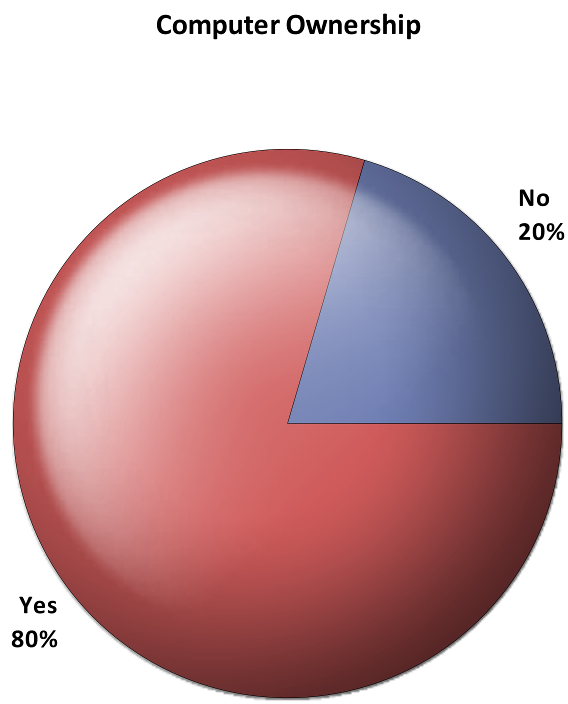
Cooperative members were asked about the gas appliances they regularly used. About four out of ten households said they didn't own any gas appliances. One-fourth of all households regularly use a gas outdoor grill. Roughly one-quarter regularly use their gas fireplace.

The lowest penetration of gas appliances was for: Hot tubs and saunas, gas space heaters, and gas clothes dryers.

HOUSEHOLD ELECTRONICS

As ownership of computing devices continues to grow, so do opportunities for cooperatives to communicate and engage with their membership. This section provides insight into the penetration of home electronics and technology usage.

A. Computer Ownership

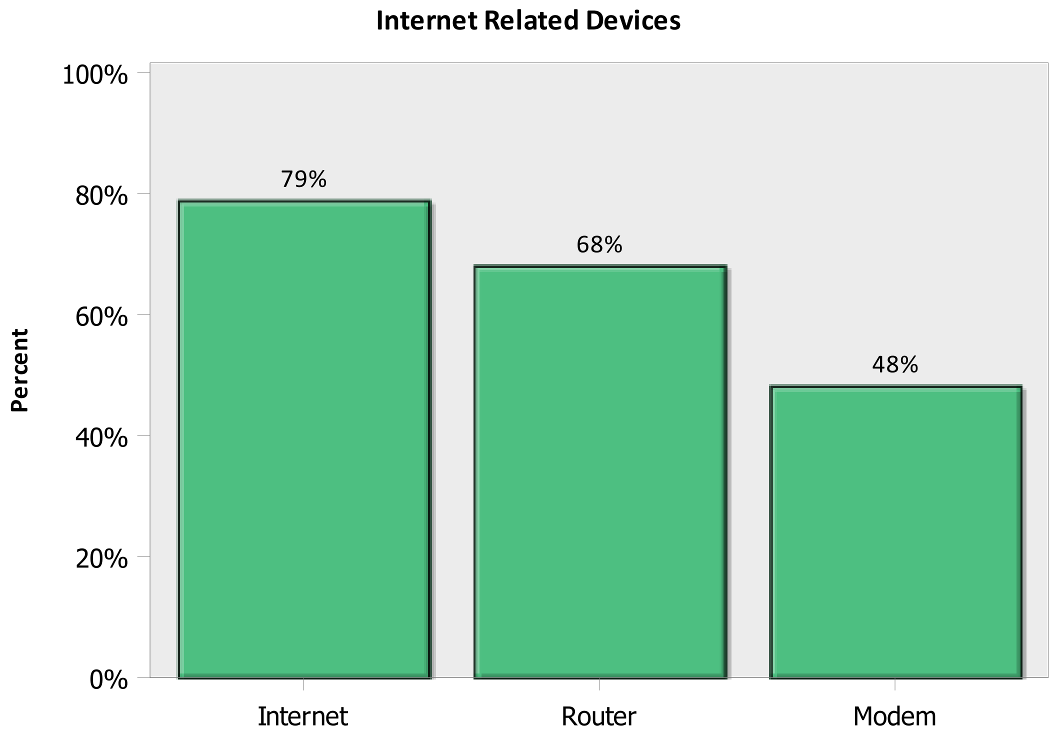


Own Home Computer	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Desktop, Laptop, or Tablet Computer	80%	79%	79%	81%

The vast majority of households own some type of computing device. About 80% of households indicated having some type of computing device (desktop PC, laptop PC or tablet) in the home.

The extremely high incidence of internet access and computing devices provides significant opportunities for Big Rivers' Electric Corporation. Online billing and information portals, electronic communications through email and social media and access to smart home technologies are now all within reach of the typical member household.

B. Online Penetration

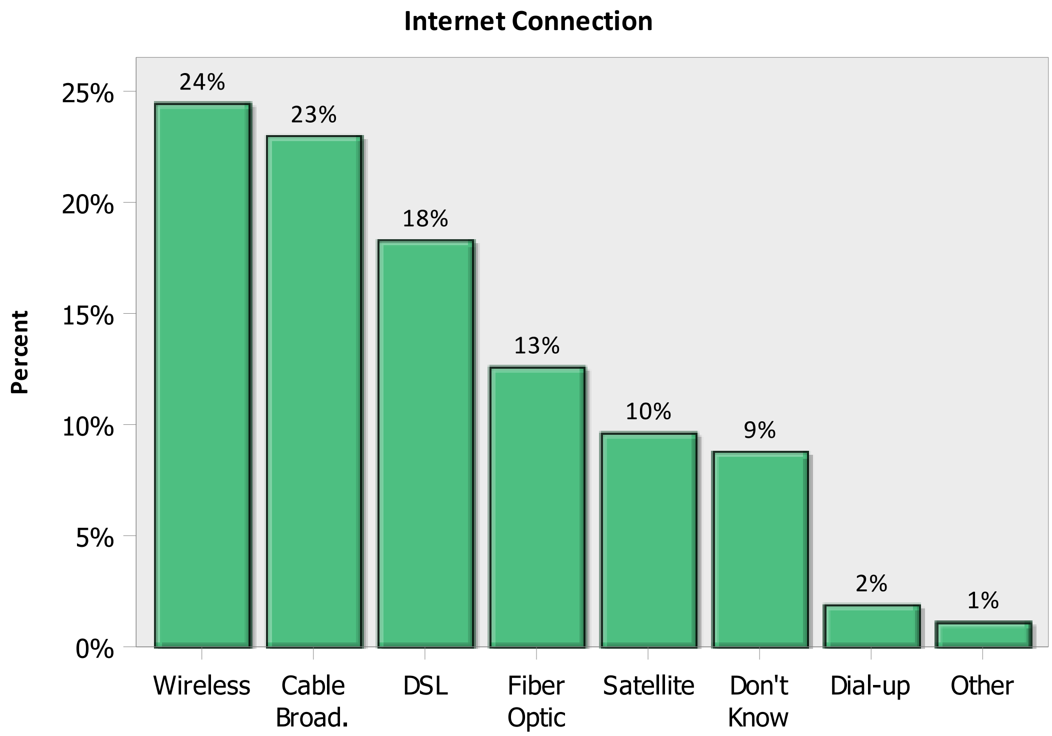


Internet Related Devices	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Internet	78%	79%	78%	79%
Router	68%	69%	67%	69%
Modem	48%	49%	49%	47%

Household penetration of internet access and internet devices is presented above. Nearly eight out of ten homes have access to internet service at home, while nearly two-thirds of members own routers and over four out of ten have modems.

Internet penetration and availability has also grown exponentially during the past decade. A 2019 report published by the Pew Research Center's Internet & American Life Project reported that 90% of American adults use the internet. By comparison, Big Rivers' Electric Corporation members experience slightly lower internet use (80%).

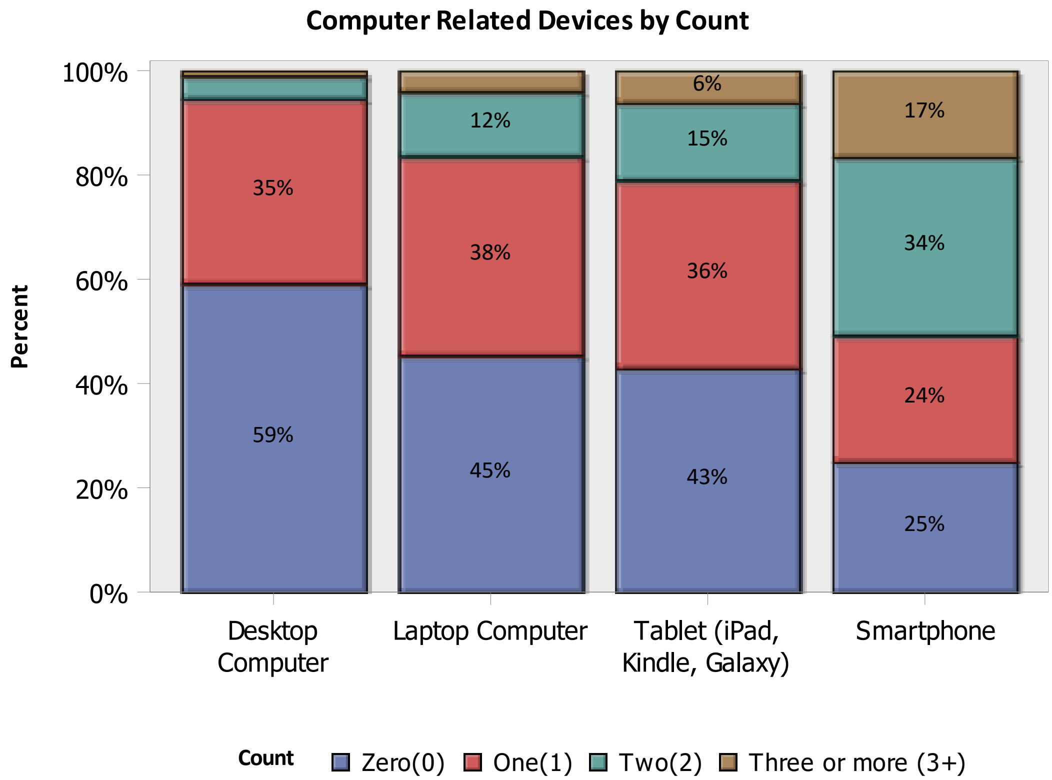
C. Internet Connection



Internet Connection	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
DSL	18%	13%	18%	24%
Cable Broad.	23%	35%	21%	16%
Wireless	24%	19%	31%	19%
Satellite	10%	2%	16%	6%
Fiber Optic	13%	16%	7%	18%
Don't Know	9%	13%	6%	10%
Dial-up	2%	0%	1%	4%
Other	1%	1%	1%	2%

Cable Broadband and wireless are the two most common methods for connecting to the internet. Approximately one out of four members connect wirelessly. Only about two percent of members use a dial-up connection. Meade County members use DSL connections at a much larger rate than other cooperatives.

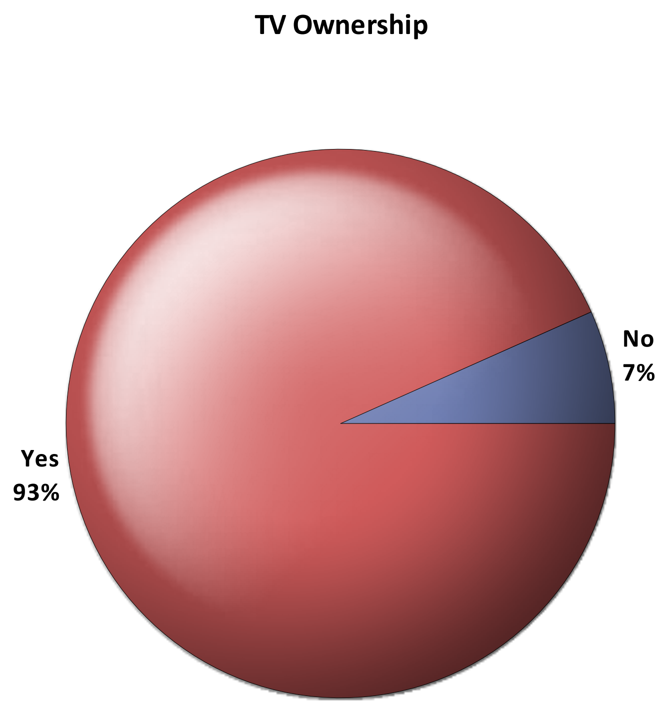
D. Type of Computer Related Items



Tablet computers are more prevalent than desktop and laptop computing devices. About 57% of member household own at least one tablet computer, while only four out of ten members own a desktop computer.

The majority of households are shifting to using smartphones over any other traditional type of computer.

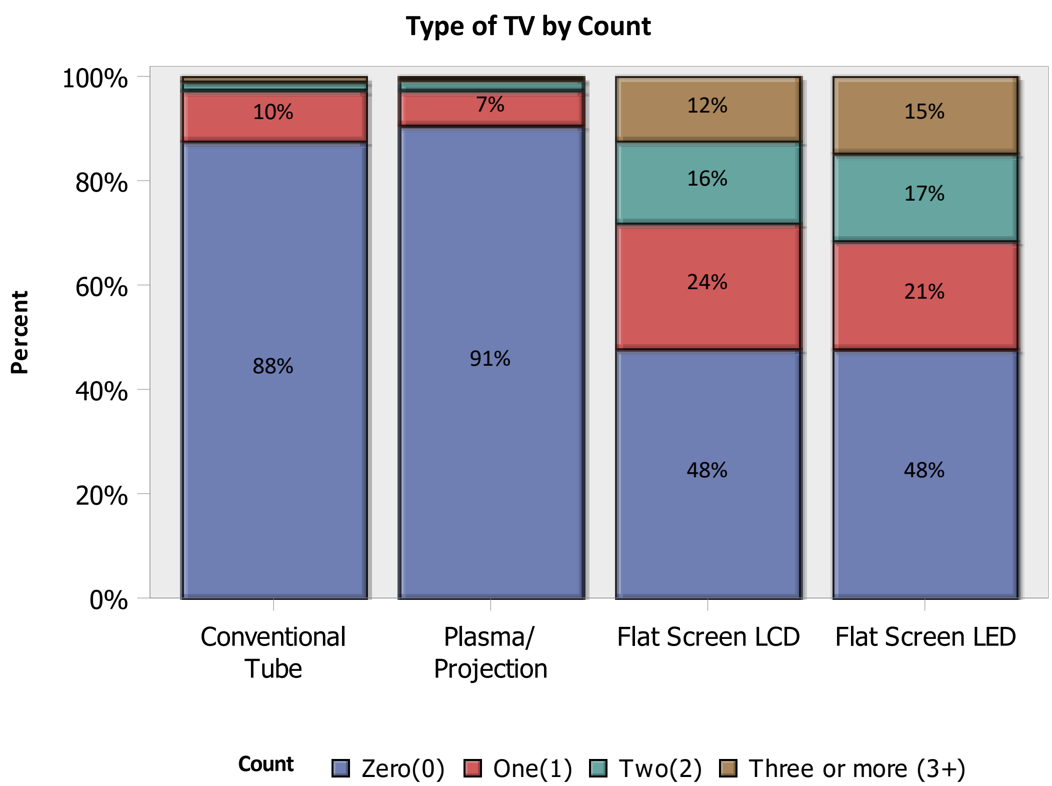
E. Television Ownership



Own a Television	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Tube, Plasma, LCD, or LED TV	93%	93%	93%	94%

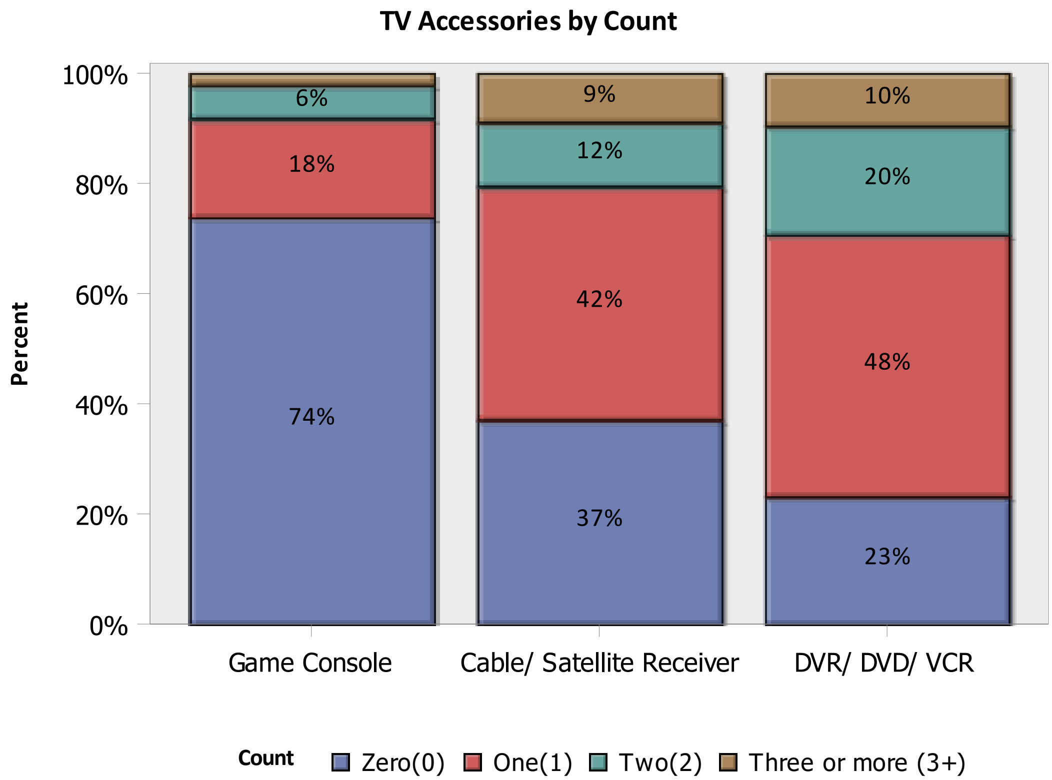
Nearly all households own a television. Well over 90% of households stated they owned at least one television.

F. Type of Television



When it comes to TV's, LCD and LED TVs are the most popular with half of households owning at least one unit. Plasma TVs are the least common with less than one out of ten households owning one.

G. TV Accessory Ownership



DVR/DVD/VCRs are found in about three-quarters of member homes. About one-quarter of households own a game console. About two-thirds own a cable or satellite TV receiver.

H. Rechargeable Devices

	Count			
Rechargeable Devices	*Zero(0)*	*One(1)*	*Two(2)*	*Three or more (3+)*
Full Size Vacuum Cleaner	57%	35%	7%	1%
Power Tools	32%	17%	16%	36%
Lawn equipment	71%	16%	8%	5%

Few households have large rechargeable devices such as lawn equipment. Nearly seven out of ten households own at least one rechargeable power tool, while more than four out of ten households own a full-size rechargeable vacuum cleaner.

I. Electric Vehicles

Own an Electric Vehicle	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Gas/ Electric Hybrid Car	5%	7%	4%	4%
Electric Car	0%	1%	0%	1%
Electric lawn mower	2%	3%	1%	1%

Only two out of one hundred members own electric lawn mowers. Hybrid vehicles are more common at 5%. Electric cars were owned by less than 1% of households.

ENERGY SAVINGS AND CONSERVATION

What energy conservation steps have electric cooperative members taken and what plans do they have for the future? This section outlines opportunities and hurdles cooperatives face in promoting energy efficiency programs to their membership.

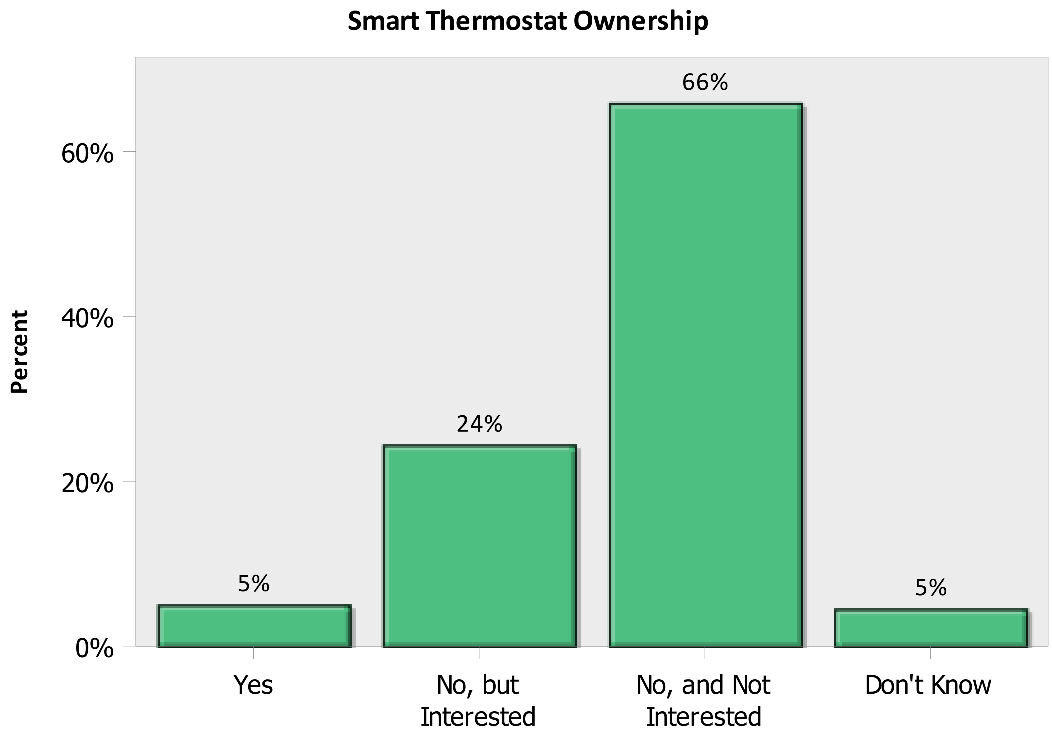
A. Thermostats

Number of Thermostats	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Zero(0)	3%	3%	1%	6%
One(1)	79%	75%	80%	81%
Two(2)	14%	16%	15%	10%
Three or more (3+)	4%	6%	4%	3%

	Number of Thermostats			
Year Home was Built	*Zero(0)*	*One(1)*	*Two(2)*	*Three or more (3+)*
Before 1960	12%	79%	8%	2%
1960 - 1969	4%	80%	12%	5%
1970 - 1979	3%	80%	10%	7%
1980 - 1989	1%	79%	12%	8%
1990 - 1999	1%	79%	18%	3%
2000 - 2009	3%	79%	17%	1%
2010 or after	2%	73%	20%	5%

The majority of homes in Big Rivers' Electric Corporation service areas maintain only one thermostat. Approximately one out of five members indicate using more than one thermostat. It also appears the newer the dwelling, the more likely it is to have more than one thermostat.

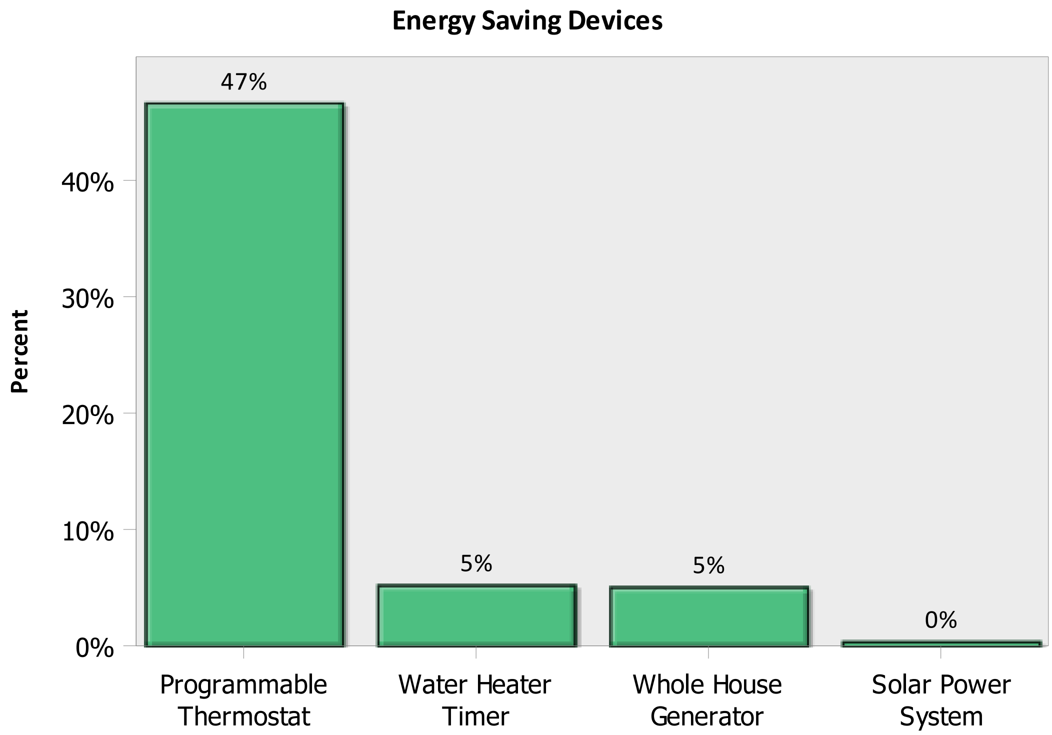
B. Smart Thermostats



Own a Remote Control Smart Thermostat	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Yes	5%	5%	6%	5%
No, but Interested	24%	25%	24%	25%
No, and Not Interested	66%	65%	67%	65%
Don't Know	5%	6%	3%	5%

Only 5% of members stated they owned a smart thermostat such as a Nest or ecobee thermostat that allow you to manage the temperature in your home through a web-enabled device. Roughly one-quarter of members stated they did not own the smart thermostat but were interested in them.

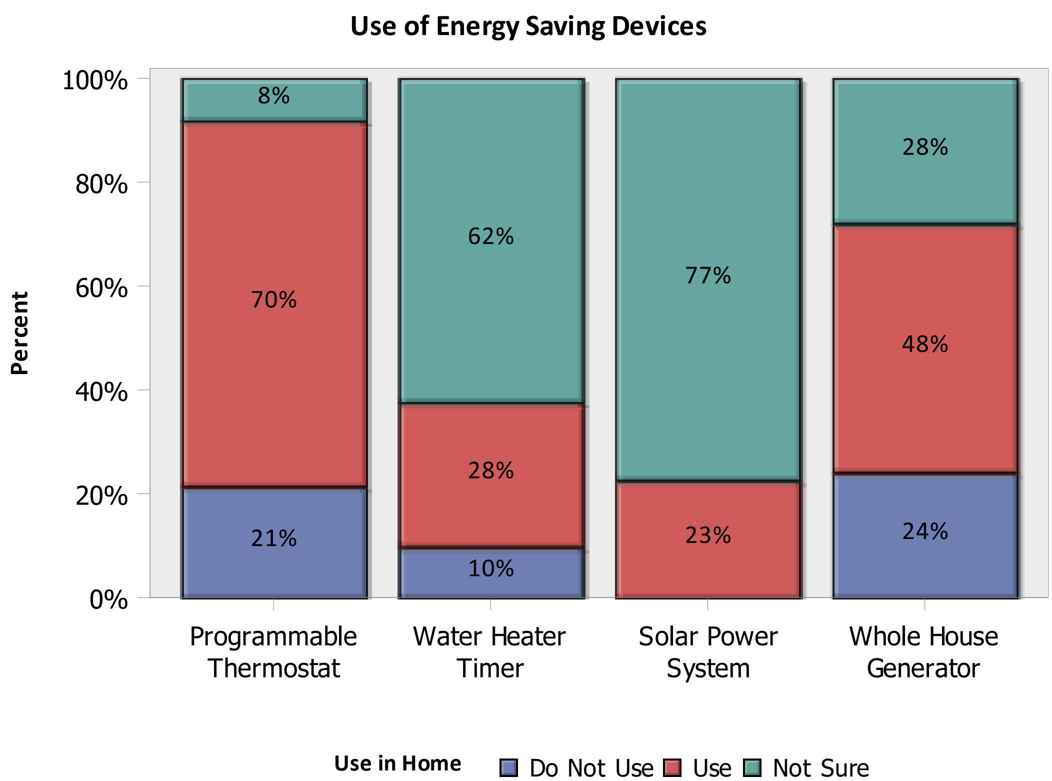
C. Energy Savings



Members were asked to indicate which of the above energy saving items they had at their home. A programmable thermostat was the most commonly found energy saving item.

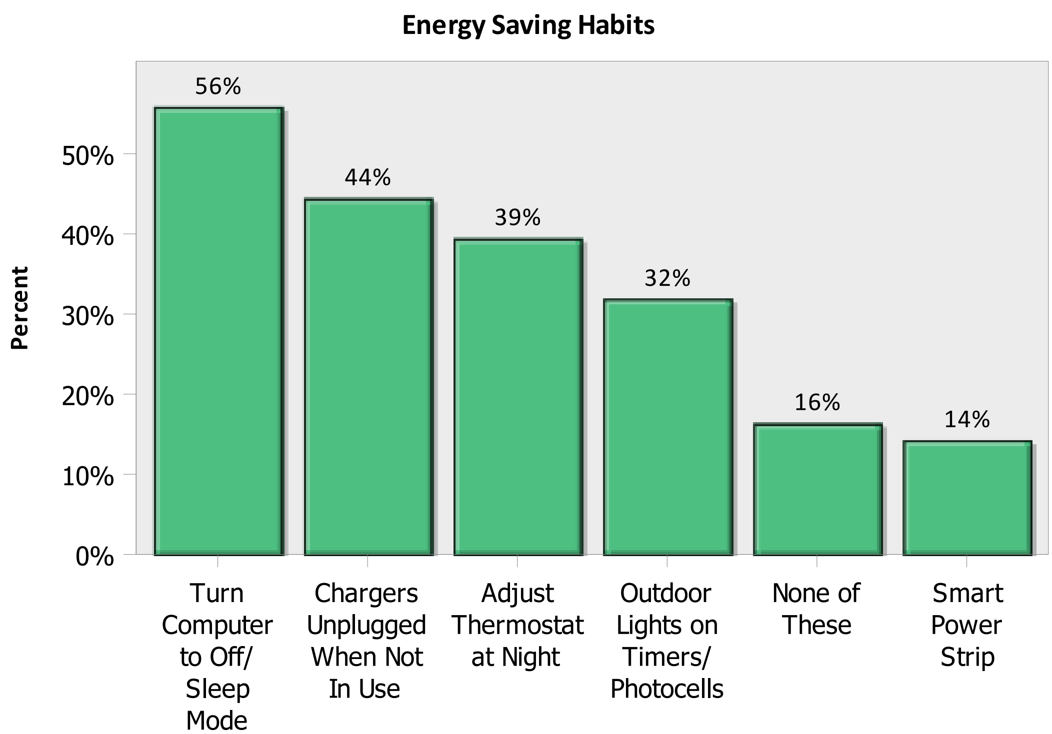
Only a small percentage of members indicated having solar power systems, supplemental generators, or a water heater timer.

D. Energy Saving by Use in Home



Members who said they had an energy saving item in their home were asked if they used the item. A large majority of members, 70%, said they used their programmable thermostat. Whereas, roughly three out of ten members used their water heater timers.

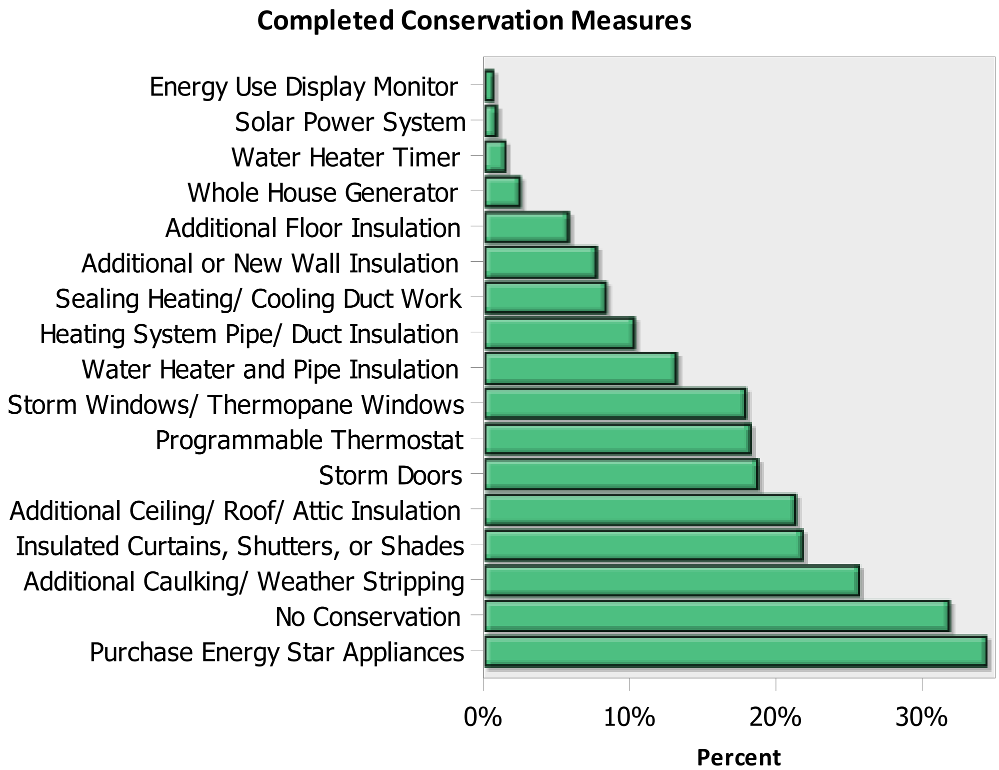
E. Energy Saving Habits



Energy Saving Habits	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Turn Computer to Off/ Sleep Mode	56%	53%	56%	58%
Chargers Unplugged When Not In Use	44%	42%	44%	48%
Adjust Thermostat at Night	39%	45%	38%	38%
Outdoor Lights on Timers/ Photocells	32%	31%	35%	28%
Smart Power Strip	14%	14%	16%	13%
None of These	16%	15%	18%	15%

Members were also asked which of the above energy saving habits they practiced. Over one-half of members stated they turned their computers to off/sleep mode. Less than one-half of members stated they unplug chargers when not in use. About four out of ten members also indicated they adjust their thermostat at night. Approximately one-third stated they have outdoor lights on timers or photocells.

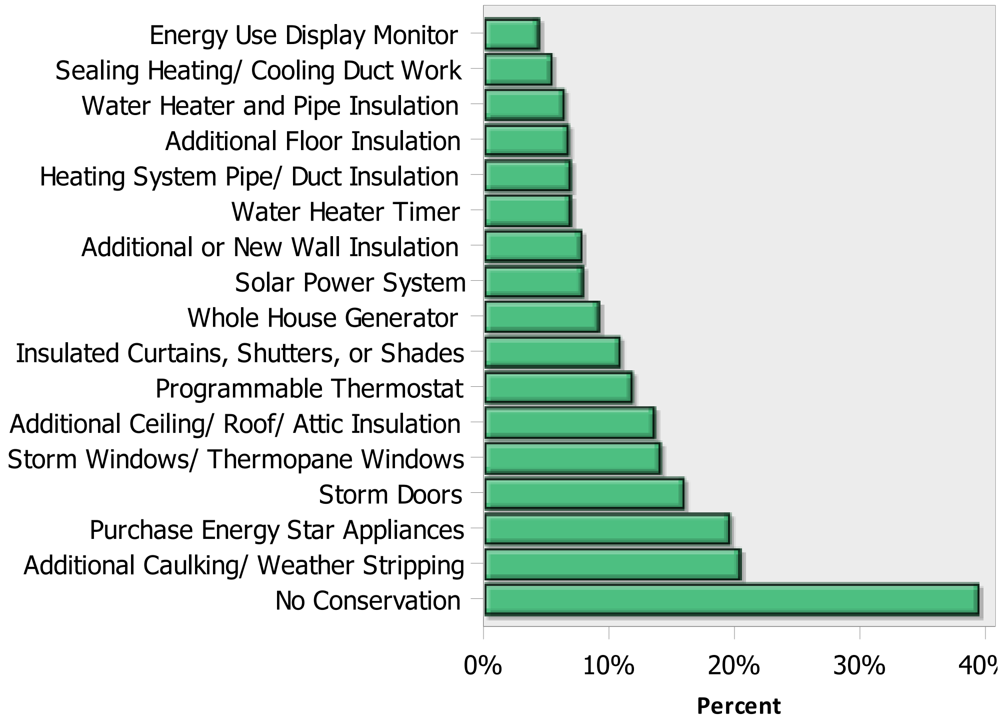
F. Energy Conservation Measures



Overall, the top energy conservation measures done in the last five years are:

- purchasing Energy Star appliances
- installing additional caulking and weather stripping
- using insulated curtains, shutters or shades
- installing additional ceiling, roof, or attic insulation

Future Planned Conservation Measures



Members do not appear as ambitious in committing to conservation measures during the next five years as future participation rates fall short of completion rates undertaken during the past five years. Installing additional caulking/weather stripping and purchasing Energy Star appliances are the top two measures cited for future consideration.

G. Energy Conservation Performed in the Past

Completed Conservation Measures	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Solar Power System	1%	1%	1%	0%
Energy Use Display Monitor	1%	0%	1%	1%
Water Heater Timer	1%	1%	2%	0%
Whole House Generator	2%	3%	1%	4%
Additional Floor Insulation	6%	8%	5%	5%
Sealing Heating/ Cooling Duct Work	8%	8%	8%	8%
Additional or New Wall Insulation	8%	8%	8%	7%
Heating System Pipe/ Duct Insulation	10%	10%	10%	10%
Water Heater and Pipe Insulation	13%	14%	11%	16%
Programmable Thermostat	18%	13%	22%	17%
Storm Windows/ Thermopane Windows	18%	18%	17%	18%
Storm Doors	19%	21%	18%	17%
Additional Ceiling/ Roof/ Attic Insulation	21%	22%	20%	22%
Insulated Curtains, Shutters, or Shades	22%	25%	21%	20%
Additional Caulking/ Weather Stripping	26%	27%	27%	23%
No Conservation	32%	33%	31%	32%
Purchase Energy Star Appliances	34%	33%	35%	35%

In general the three participating cooperatives' memberships have similar habits about performing energy conservation measures.

H. Energy Conservation Planned for the Future

Future Planned Conservation Measures	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Energy Use Display Monitor	4%	3%	4%	6%
Heating System Pipe/ Duct Insulation	7%	8%	5%	9%
Sealing Heating/ Cooling Duct Work	5%	7%	4%	6%
Water Heater and Pipe Insulation	6%	7%	5%	8%
Insulated Curtains, Shutters, or Shades	11%	10%	10%	12%
Water Heater Timer	7%	6%	5%	10%
Additional Floor Insulation	7%	7%	4%	10%
Additional or New Wall Insulation	8%	5%	8%	9%
Solar Power System	8%	6%	8%	9%
Whole House Generator	9%	9%	9%	9%
Programmable Thermostat	12%	10%	12%	14%
Storm Windows/ Thermopane Windows	14%	14%	13%	16%
Additional Ceiling/ Roof/ Attic Insulation	14%	15%	12%	14%
Storm Doors	16%	17%	15%	17%
Purchase Energy Star Appliances	20%	20%	20%	19%
Additional Caulking/ Weather Stripping	20%	22%	22%	17%
No Conservation	39%	36%	41%	40%

Members were asked to indicate which of the above energy conservation items they expected to complete during the next five years. Additional caulking/weather stripping and purchasing of Energy Star appliances was the most popular conservation activity planned for the future. Approximately two out of five members stated they were not inclined to complete conservation activities in the future.

	Conservation Planned for Future Years	
Conservation Done in Past Years	*Conservation Planned*	*No Conversation Planned*
Conservation Done	88%	12%
No Conversation Done	54%	46%

In evaluating adoption of energy conservation measures, members indicating they had taken steps to reduce their energy consumption during the past five years were more likely to indicate they would undertake energy conservation measures in the future. Nearly nine out of ten members who had taken conservation measures in the past five years indicated they planned to initiate more steps in the future. Conversely, only about one-half of members who hadn't taken any steps were inclined to implement conservations measures in the future.

I. Energy Conservation Planned for the Future (continued)

Future Planned Conservation Measures Given No Measures Done in Past Years	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Energy Use Display Monitor	1%	0%	0%	5%
Heating System Pipe/ Duct Insulation	1%	4%	0%	1%
Additional Floor Insulation	1%	2%	1%	0%
Additional or New Wall Insulation	1%	0%	1%	1%
Sealing Heating/ Cooling Duct Work	2%	4%	3%	1%
Water Heater Timer	2%	4%	0%	3%
Insulated Curtains, Shutters, or Shades	2%	6%	1%	1%
Water Heater and Pipe Insulation	1%	2%	0%	3%
Programmable Thermostat	3%	2%	4%	1%
Whole House Generator	2%	0%	3%	3%
Solar Power System	2%	1%	2%	3%
Additional Ceiling/ Roof/ Attic Insulation	3%	6%	4%	1%
Additional Caulking/ Weather Stripping	7%	10%	5%	7%
Storm Doors	4%	9%	3%	1%
Storm Windows/ Thermopane Windows	5%	2%	7%	3%
Purchase Energy Star Appliances	6%	6%	10%	1%
No Conservation	81%	76%	81%	86%

Members indicating they had not completed any energy conservation measures during the past five years were asked to indicate which energy conservation items they expected to complete during the next five years. It appears if nothing has been done in the past, there is a good chance nothing will be done in the future.

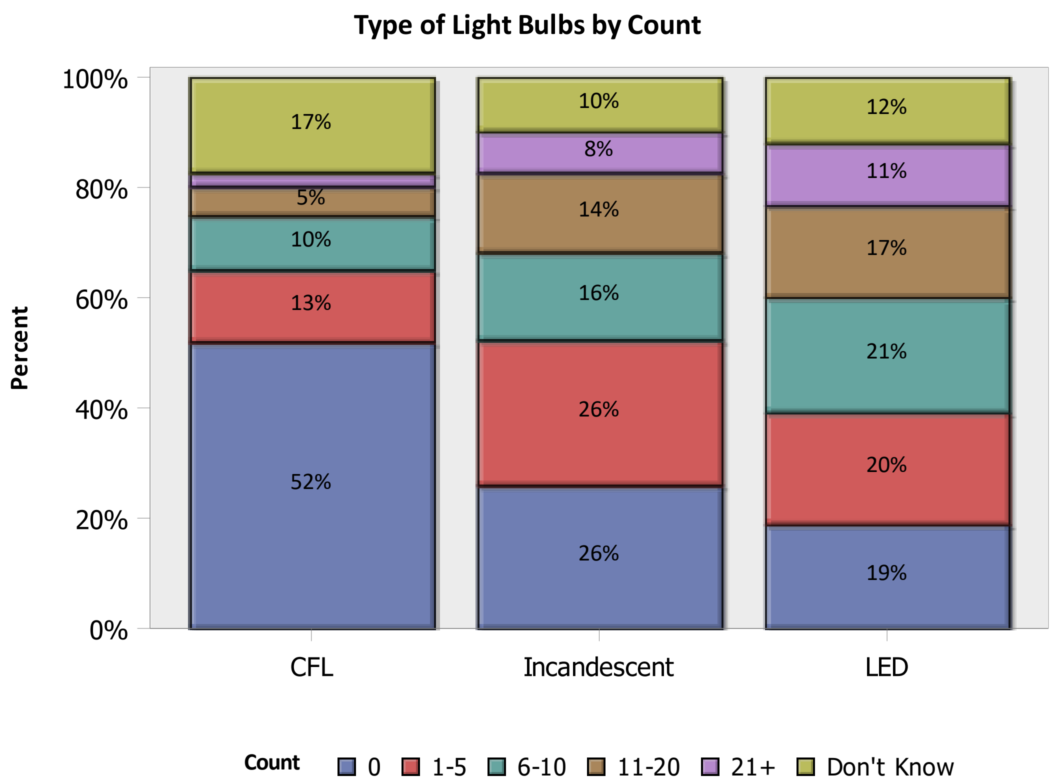
Those inclined to complete future conservation measures indicated purchase of Energy Star appliances and installation of storm windows as the most likely measures.

J. Energy Conservation Reasons to Implement

Reasons to Implement Conservation Measures	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
Necessary (due to age or function)	91%	91%	89%	95%
Receive income tax credits	20%	26%	14%	24%
Recover costs through energy savings in 1-3 years	22%	23%	21%	23%
Finance purchase on my power bill	4%	11%	3%	0%

Members who had not taken any energy conservation measures were asked what it would take to make them complete conservation measures in the future. Doing things out of necessity appears to be the top motivating factor in completing conservation measures. Receiving income tax credits or recovering costs through energy savings within three years does not appear to motivate a significant number of members.

K. Lighting



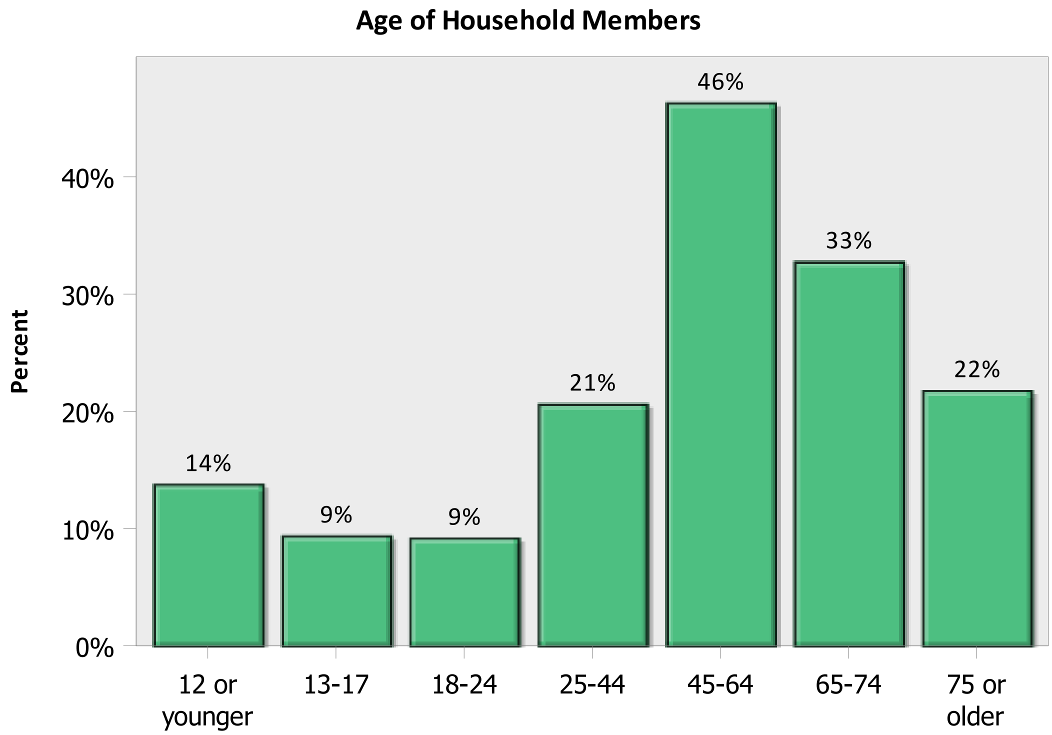
Though still more common than CFL bulbs, incandescent bulbs are declining in overall use. LED bulbs have surpassed incandescent bulbs and appear in greater numbers within members' homes. LEDs are now being used in about seven out of ten homes.

It is common for 10% or more of members to not know what kind of bulbs they use in their homes.

MEMBER DEMOGRAPHICS

Household size can dramatically alter the energy consumption characteristics of a member's home. The following section highlights trends in household size and associated electric usage.

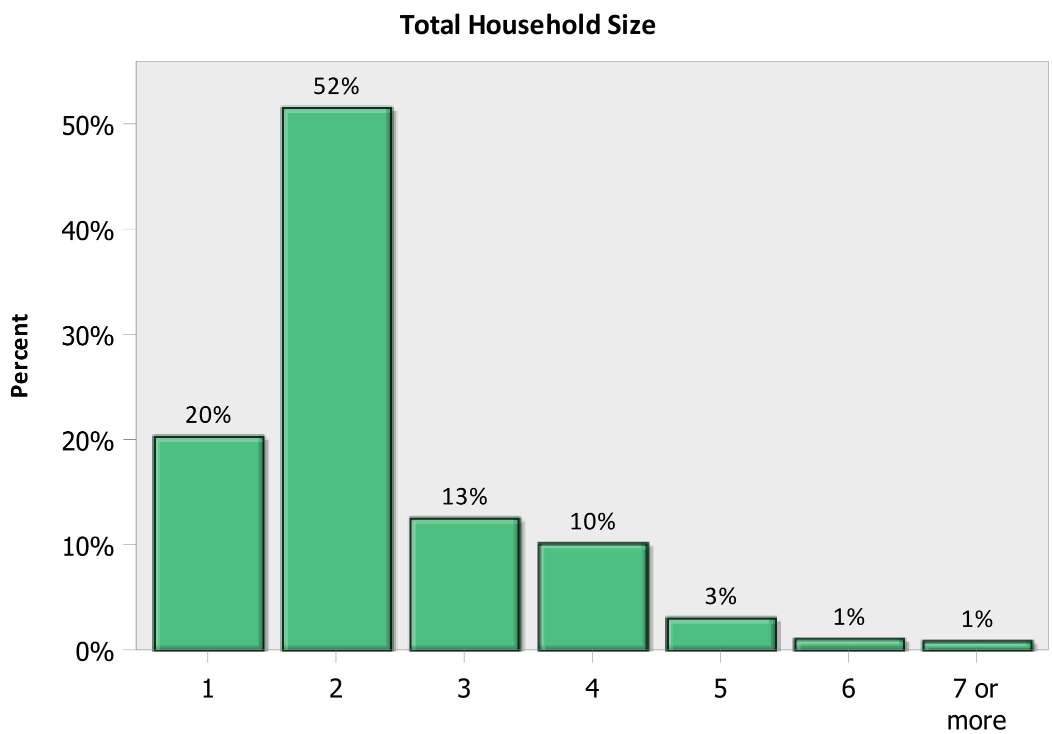
A. Member Age Distribution



Age of Household Members	Count					
	None(0)	*One(1)*	*Two(2)*	*Three(3)*	*Four(4)*	*Five or more(5+)*
Kids (0-12)	86%	7%	5%	1%	0%	0%
Teens (13-17)	91%	7%	2%	0%	0%	0%
Young Adults (18-24)	91%	8%	2%	0%	.	0%
Adults (25-44)	79%	10%	10%	0%	0%	0%
Older Adults (45-64)	54%	19%	27%	0%	0%	.
Senior Adults (65-74)	67%	18%	15%	.	0%	.
Elders (75 or older)	78%	14%	8%	.	.	0%

Just less than one-half of households responding to the survey had at least one family member between the ages of 45 and 64. One-third of households had at least one senior adult (65-74) living in it, while nearly one-fifth of households had a senior 75+ living in it. Young families (households with members between the ages of 25 – 44) represent approximately one out of five households.

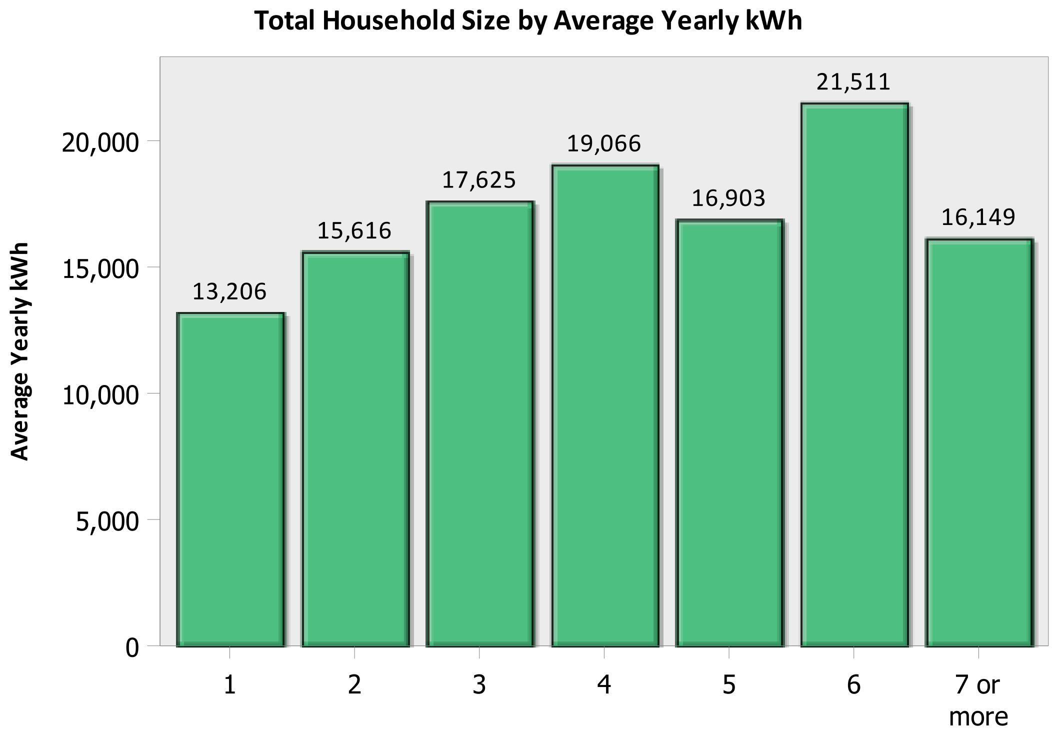
B. Household Size



Total Household Size	*Total*	*Jackson Purchase*	*Kenergy*	*Meade County*
1	20%	25%	20%	17%
2	52%	49%	55%	48%
3	13%	15%	12%	12%
4	10%	8%	10%	12%
5	3%	1%	2%	6%
6	1%	1%	1%	2%
7 or more	1%	.	1%	2%

The average household is occupied by two people as roughly one-half of households contain just two individuals. Meade County households appear to have slightly more members per household than other cooperatives.

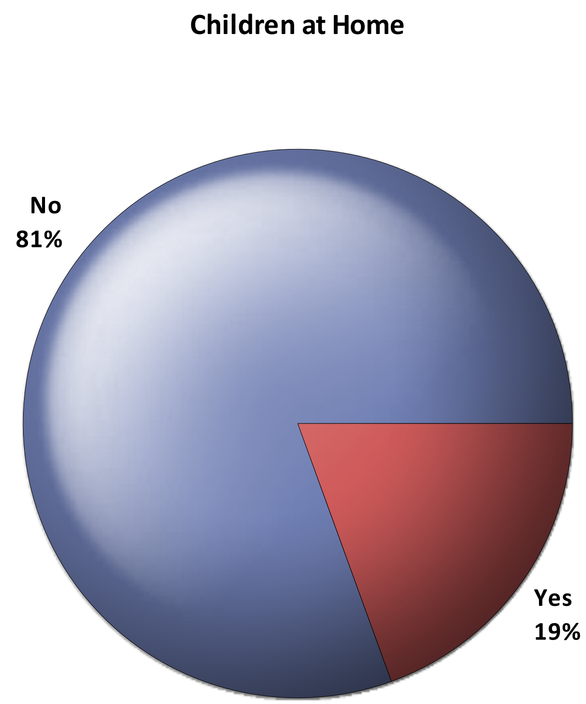
C. kWh Usage by Household Size



There is an 18% increase in the amount of electricity used by a household with two members as compared to a one person household. Electric usage appears to increase with each subsequent increase in family size until 4 members are present.

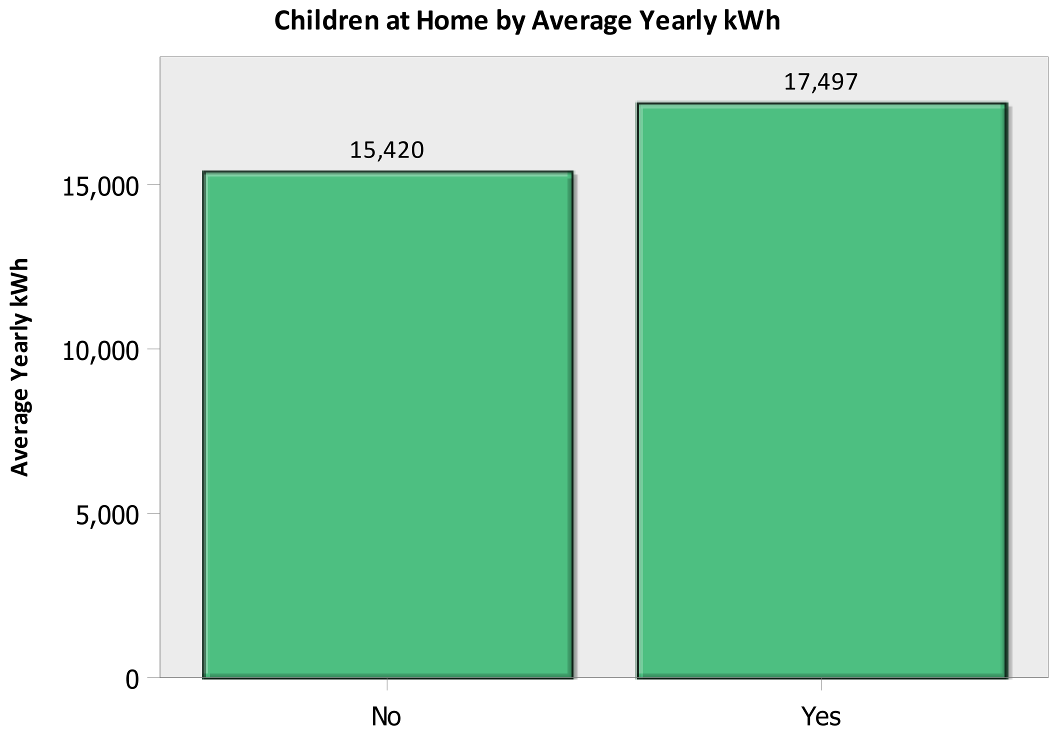
Please note that homes with 5 or more members represent a very small percentage of overall households. The average yearly kWh usage reported for these groups can have a wide confidence interval associated with them. Usage numbers reported for these categories should be viewed with caution.

D. Presence of Children in Home



One out of five members indicated they had at least one child under 18 years of age living at home. The vast majority of members, however, had no children living at their home.

E. kWh Usage by Presence of Children in Home



Survey results indicate households with children use about 13% more electricity than those with no children present. Due to their higher electric consumption, households with children represent an excellent opportunity for promoting energy efficiency and conservation programs.

F. Internet Availability by Household Members

	Internet Present	
Age Group	*Yes*	*No*
Young Adults (18-24)	94%	6%
Adults (25-44)	86%	14%
Older Adults (45-64)	83%	17%
Senior Adults (65-74)	80%	20%
Elders (75 or older)	66%	34%

Access to technology is extremely high for households where at least one person is under 45 years old as nearly nine out of ten indicated access to the internet. Even among older adult (45-64) and senior members (65-74) the internet is available in eight out of ten households. Only among the elder population (75+) does the presence of internet service dip substantially.

	Internet Present	
Children at Home	*Yes*	*No*
No	77%	23%
Yes	88%	12%

Households with children are more likely to have internet access than households without children. Almost nine out of ten households with children indicate internet access.

APPENDIX A – ACCURACY LEVELS

Accuracy Intervals at 95% Confidence Level
Big Rivers Electric Corp.

% Response for Each Category	Average Plus/Minus Range For Confidence Intervals
1-9%	+/- 1.3%
10-19%	+/- 2.1%
20-29%	+/- 2.6%
30-39%	+/- 2.8%
40-49%	+/- 2.9%
50-59%	+/- 2.9%
60-69%	+/- 2.8%
70-79%	+/- 2.6%
80-89%	+/- 2.1%
90-99%	+/- 1.3%

The above table can be used with the percent response for each category presented in the tables or graphs reported for Big Rivers' Electric Corporation. These accuracy intervals are based on a 95% level of confidence and the actual number of surveys completed by electric cooperative members (n=1,108).

For example, if 80% of the surveyed members report living in single-family homes, we can be 95% confident that the actual percent of single-family homes among all members is between 77.9% and 82.1%. Using the chart above, we observe value 80% is located in the 80-89% interval so the confidence interval is calculated by adding and subtracting 2.1% to 80%.

APPENDIX B – SURVEY DOCUMENT & COVER LETTER

Case No. 2020-00299
Attachment for Response to PSC 1-18
Witness: Russell L. Pogue

(E) ABOUT ENERGY SAVINGS

E.6 If you do not currently plan to make any of the above changes in the next five years, which of the following reasons would cause you to adopt one or more of these measures? (Choose all that apply)

○ If it becomes necessary (due to age or function)
○ If I could receive income tax credits for doing so
○ If I could recover the cost through energy savings over the next 1-3 years
○ If I could finance my purchase on my power bill

(F) ABOUT TECHNOLOGY

F.1 Do you have access to the Internet at your home?

○ Yes ○ No ***(SKIP TO F.3)***
○ Don't Know ***(SKIP TO F.3)***

F.2 What is the main way you connect to the Internet? *(Choose ONE)*

○ Dial-up
○ Cable Broadband
○ DSL
○ Satellite
○ Wireless (cellular)
○ Fiber Optic
○ Other ______________________________
○ Don't know

F.3 How many of the following electronics devices do you use in this home?

	None	1	2	3 or more
Desktop computer	○	○	○	○
Laptop	○	○	○	○
Tablet (such as iPad, Kindle, Galaxy)	○	○	○	○
Smart Phone	○	○	○	○
DVR/DVD/VCR	○	○	○	○
Conventional tube TV	○	○	○	○
Plasma/Projection TV	○	○	○	○
Flat Screen LCD TV	○	○	○	○
Flat Screen LED TV	○	○	○	○
Game console	○	○	○	○
Wired Internet router	○	○	○	○
WiFi (wireless) Internet router	○	○	○	○
Modem	○	○	○	○
Cable/Satellite receiver	○	○	○	○

(F) ABOUT TECHNOLOGY

F.4 Please indicate how many of the following RECHARGEABLE devices you use in this home.

	None	1	2	3 or more
Power tools	○	○	○	○
Full size vacuum cleaner	○	○	○	○
Lawn equipment	○	○	○	○

F.5 Do you own any of the following?

Vehicle type	Yes	No	Not Sure
Electric car (such as Chevy Volt / Nissan Leaf)	○	○	○
Gas / Electric hybrid car	○	○	○
Electric lawn mower	○	○	○

(G) ABOUT YOU

G.1 Please select the number of people in each age group who live in your home most of the time.

Age Group	None (0)	One (1)	Two (2)	Three (3)	Four (4)	Five or more
0-12	○	○	○	○	○	○
13-17	○	○	○	○	○	○
18-24	○	○	○	○	○	○
25-44	○	○	○	○	○	○
45-64	○	○	○	○	○	○
65-74	○	○	○	○	○	○
75 +	○	○	○	○	○	○

Thank you! Please return your survey in the enclosed postage paid envelope by September 25, 2019, and be entered to win a $250 gift card.

DO NOT include bill payment in this envelope.

JPEC Your Touchstone Energy® Partner The power of human connections

Complete this survey on the web by going to:
www.KYcooperativesurvey.com
You must use the following code: 1000265

Please use a black or blue pen (no heavy marker or pencil please). Fill the circle in completely as shown:
Correct ● Incorrect ✓ Incorrect ✗

LIVING WITH ELECTRICITY

Please answer all questions about the residence served by your electric co-op. If the property is NOT a residence or vacation property, fill the circle below and return the survey without completing the remaining questions.
○ Not a residence – this address is a:______________________________

(A) ABOUT YOUR HOME

A.1 What is the main use of this home? *(Choose ONE)*

○ Year-round residence
○ Weekend, holiday, vacation residence
○ Winter residence
○ Summer residence
○ Other ______________________________

A.2 Which of the following is the best description of your home? *(Choose ONE)*

○ Single family, detached home (site built)
○ Manufactured home, mobile home or trailer
○ Apartment, duplex, townhome or condominium
○ Kit, pre-fabricated or modular home
○ Other ______________________________

A.3 Do you own or rent your home?

○ Own/buying ○ Rent/lease ○ Other

A.4 How large is the living space of your home? *(Choose ONE)* *(Please do not include garages, unfinished attics, basements, or screened porches)*

○ Less than 1,000 sq. ft.
○ 1,000 – 1,499 sq. ft.
○ 1,500 – 1,999 sq. ft.
○ 2,000 – 2,499 sq. ft.
○ 2,500 - 2,999 sq. ft.
○ 3,000 sq. ft. or more
○ Not sure

A.5 Approximately when was this home built? *(Choose ONE)*

○ Before 1960
○ 1960-1969
○ 1970-1979
○ 1980-1989
○ 1990-1999
○ 2000-2009
○ 2010 or after
○ Not sure

A.6 How many bedrooms and bathrooms do you have in your home?

	None (0)	One (1)	Two (2)	Three (3)	Four (4)	Five or more (5+)
Bedrooms	○	○	○	○	○	○
Full Bathrooms	○	○	○	○	○	○
Half Bathrooms	○	○	○	○	○	○

(B) ABOUT HEATING AND COOLING

B.1 Do you have air conditioning in this home?

	(A) Have in Your Home?	(B) How many units do you have? One (1)	Two (2)	Three +
Central air conditioning	○	○	○	○
Individual room unit(s)	○	○	○	○
Window unit(s)	○	○	○	○
Ductless HVAC / Mini-Split Heat Pump	○	○	○	○

NO air conditioning in this home ○ ⟶ ***(SKIP TO B.3)***

B.2 How old is your main air conditioning system?

○ Less than 5 years
○ 5-10 years
○ 11-15 years
○ More than 15 years
○ Not sure

B.3 What is the main fuel source used to HEAT your home? *(Choose ONE)*

○ Electricity ***(CONTINUE TO B.4)***
○ Natural gas
○ Propane / LP / Bottled Gas
○ Wood
○ Fuel Oil
○ Kerosene
○ Other __________
○ Not sure

SKIP TO B.5

○ No heat ***(SKIP TO B.10)***

B.4 If your main fuel source used is ELECTRICITY, what type of heating equipment do you use? *(Choose ONE)*

○ Standard heat pump
○ Dual fuel heat pump
○ Electric central furnace
○ Electric baseboard
○ Radiant heat
○ Ground / water source heat pump
○ Electric Thermal Storage (ETS)
○ Ductless HVAC / Mini-Split Heat Pump
○ Other __________
○ Not sure

B.5 How old is your main heating system?

○ Less than 5 years
○ 5-10 years
○ 11-15 years
○ More than 15 years
○ Not sure

(B) ABOUT HEATING AND COOLING

B.6 If you have replaced the main heating system in your current home in the past 5 years, what type of fuel did the old system use? *(Choose ONE)*

○ Electricity ○ Natural gas
○ Propane/LP/Bottled Gas ○ Wood
○ Fuel Oil ○ Kerosene
○ Other ____________ ○ Not sure
○ Have Not Replaced

B.7 If you have to replace the main heating system in the near future, what fuel would you choose? Limit your choice to a fuel that is available to you at this location. (*Choose ONE*)

○ Electricity ○ Natural gas
○ Propane/LP/Bottled Gas ○ Wood
○ Fuel Oil ○ Kerosene
○ Other ____________ ○ Not sure

B.8 Aside from your main fuel source, what ADDITIONAL sources of HEAT do you use? *(Please choose ALL that apply)*

○ Electricity ○ Natural gas
○ Propane/LP/Bottled Gas ○ Wood
○ Fuel Oil ○ Kerosene
○ Other ____________ ○ Not sure
○ NO secondary heating system ***(SKIP TO B.10)***

B.9 Can you heat this home entirely with this secondary heating system?

○ Yes ○ No ○ Don't Know

B.10 Do you have a fireplace in your home?

○ Yes ○ No ○ Don't Know

B.11 IF YES, What fuel do you use in your fireplace?

○ Wood ○ Natural gas ○ Propane ○ Other_______

B.12 If natural gas were available in your area, would you consider using it for any of the following? *(Please choose ALL that apply)*

○ Heating your home ○ Cooking ○ Water heating
○ None of these

B.13 How many thermostats do you have in your home?

○ None ○ 1 ○ 2 ○ 3 or more

(C) ABOUT WATER HEATING

C.1 How many water heaters does your home have? (*Choose ONE)*

○ One ○ Two or more ○ None ***(SKIP to D.1)***

C.2 What type of energy does your main water heater use? *(Choose ONE)*

○ Electric ○ Natural gas
○ Electric tankless ○ Natural gas tankless
○ Heat pump water heater ○ Solar
○ Propane/LP/Bottled Gas ○ Not sure

(C) ABOUT WATER HEATING

C.3 What size is your main water heater? *(Choose ONE)*

○ Less than 40 gallons ○ 60 gallons or more
○ 40-60 gallons ○ Not sure

C.4 How old is your main water heater? *(Choose ONE)*

○ Less than 5 years ○ More than 15 years
○ 5-10 years ○ Not sure
○ 11-15 years

C.5 If you have replaced the main water heating system in your current home in the past 5 years, what type of fuel did your old system use? (*Choose ONE)*

○ Electric ○ Natural gas
○ Electric tankless ○ Natural gas tankless
○ Heat pump water heater ○ Solar
○ Propane/LP/Bottled Gas ○ Not sure
○ Have not replaced main water heating system

C.6 If you have to replace the main water heater in the near future, what type would you choose? Limit your choice to a fuel available at this location. (*Choose ONE)*

○ Electric ○ Natural gas
○ Electric tankless ○ Natural gas tankless
○ Heat pump water heater ○ Solar
○ Propane/LP/Bottled Gas ○ Not sure

(D) ABOUT YOUR APPLIANCES

D.1 Please indicate how many of each of these ELECTRIC APPLIANCES are currently used in your home.

Appliance List	Currently used in your home			
Electric oven	○ None	○ 1	○ 2	○ 3 +
Electric cook top	○ None	○ 1	○ 2	○ 3 +
Microwave	○ None	○ 1	○ 2	○ 3 +
Refrigerator	○ None	○ 1	○ 2	○ 3 +
Freezer (stand alone)	○ None	○ 1	○ 2	○ 3 +
Dishwasher	○ None	○ 1	○ 2	○ 3 +
Clothes washer	○ None	○ 1	○ 2	○ 3 +
Electric clothes dryer	○ None	○ 1	○ 2	○ 3 +
Well/water pump	○ None	○ 1	○ 2	○ 3 +
Dehumidifier	○ None	○ 1	○ 2	○ 3 +
Waterbed heater	○ None	○ 1	○ 2	○ 3 +
Ceiling fan	○ None	○ 1	○ 2	○ 3 +
Whole house fan	○ None	○ 1	○ 2	○ 3 +
Air purifier	○ None	○ 1	○ 2	○ 3 +
Large power shop tools	○ None	○ 1	○ 2	○ 3 +
Hospital grade medical equipment	○ None	○ 1	○ 2	○ 3 +

(D) ABOUT YOUR APPLIANCES

D.2 Which of the following ELECTRIC items do you have at your home? (*Please choose ALL that apply*)

○ Swimming pool pump ○ Hot tub or sauna
○ Uninterrupted power supply ○ Electric outdoor grill
○ Corded yard trimmer ○ Portable Generator
○ Corded leaf blower ○ None of these

D.3 Please select which GAS APPLIANCES (natural gas, propane, LP, or bottled gas) you use regularly. (*Please choose ALL that apply*)

○ No gas appliances ○ Gas hot tub or sauna
○ Gas cook top ○ Gas outdoor grill
○ Gas oven ○ Gas space heater
○ Gas clothes dryer ○ Gas logs/Fireplace

D.4 About how old are your appliances? Choose one age for each appliance you own in this home.

	1-5 years	6-10 years	11-20 years	21+ years	Not Sure	Don't Own
Main Refrigerator	○	○	○	○	○	○
Clothes Washer	○	○	○	○	○	○
Clothes Dryer	○	○	○	○	○	○
Dishwasher	○	○	○	○	○	○

D.5 Which of the following makes it more likely that you would replace your appliances with more efficient alternatives? (Choose all that apply)

○ If it becomes necessary (due to age or function)
○ If I could recover the purchase cost through energy savings over the following three years
○ If I could finance my purchase on my power bill
○ I plan to replace with more efficient options over the next few years, regardless of age or cost

(E) ABOUT ENERGY SAVINGS

E.1 Please indicate which of the following ENERGY SAVINGS items you have in your home and whether you use each.

	Do not have	Have, but do not use	Have and use	Not Sure
Programmable thermostat	○	○	○	○
Water heater timer	○	○	○	○
Solar power system (solar panel)	○	○	○	○
Whole house generator	○	○	○	○

E.2 Do you own a Smart Thermostat that you can remotely control temperature by using a device like a PC or iPhone?

○ Yes ○ No, but I am interested in owning one
○ No, and I am not interested in owning one
○ Don't Know

(E) ABOUT ENERGY SAVINGS

E.3 Which of the following energy saving habits do you currently practice? (Choose all that apply)

○ Turn computer(s) to Off/Sleep Mode when not in use
○ Chargers unplugged when not in use
○ Outdoor lighting fixtures on timers or photocells
○ Adjust thermostat at night
○ Smart Power Strip
○ None of the above

E.4 Approximately how many of the following light bulbs do you have in your home?

Type	Zero	1 to 5	6 to 10	11 to 20	21 or more	Don't know
Incandescent (traditional) Bulbs	○	○	○	○	○	○
CFL Bulbs	○	○	○	○	○	○
LED Bulbs	○	○	○	○	○	○

E.5 (A) Which of the following conservation measures have been made to your home in the past 5 years? (B) Which do you plan to make in the next 5 years? *(Please choose all that apply)*

Conservation Measures	(A) Made in past 5 years?	(B) Plan to make next 5 years?
Additional ceiling, roof, or attic insulation	○	○
Additional or new wall insulation	○	○
Additional floor insulation (below lowest floor lived in)	○	○
Storm doors	○	○
Storm windows or thermopane windows	○	○
Insulated curtains, shutters, or shades	○	○
Additional caulking or weather stripping	○	○
Heating system pipe or duct insulation	○	○
Sealing Heating / Cooling duct work	○	○
Water heater and pipe insulation	○	○
Purchased Energy Star appliances	○	○
Programmable thermostat	○	○
Water heater timer	○	○
Solar power system (solar panel)	○	○
Energy use display monitor	○	
Whole house generator	○	
None of the above	○	

c/o Bellomy, 175 Sunnynoll Ct.
Winston-Salem, NC 27106

Members completing the survey – online or by mail – will be entered into a drawing to win one of two $250 gift cards!

Denise Long
15147 Grape Creek Rd
Danville, IL 61834-7804

1000265

Dear Jackson Purchase Energy Member:

Please let me begin by thanking you for being a member of our electric cooperative and for allowing us to be your electric service provider. We are currently reviewing the future electric needs of our members, and are planning today for an adequate supply of power for our membership at the lowest possible prices.

To fairly represent the needs of homes like yours, we are surveying a random sample of members from our cooperative. We are working with Bellomy, a market intelligence firm based in Winston-Salem, NC, to gather this data and would appreciate a few minutes of your time to complete either the enclosed paper survey or our web-based survey. Since only a small but statistically significant number of members has been selected, **your participation is very important**.

There are no right or wrong answers to the items in this survey. Select those answers that apply to your household. Any information you provide will be useful, so please return the survey even if it is incomplete. Of course, your responses will be held in strictest confidence. You will not be personally identified. Rather, the results will be reported in summaries such as group averages, percentages, and other general statistics.

For those members with Internet access, we encourage you to complete this survey online. Please go to:

www.KYcooperativesurvey.com

and use the 7-digit access code to the right of your name above as your password to enter your responses. Using the online survey will help to reduce the overall survey cost.

Or, please use the enclosed prepaid envelope to mail your completed survey form **by September 25, 2019**. If you have any questions or comments, please call Jackson Purchase Energy's Member Service Department at 1-800-633-4044. Thank you for helping us better serve your future electric needs.

Don't forget! Respond now and be entered into a drawing to win one of two $250 gift cards!

Sincerely,

Greg H. Grissom
President and CEO

BIG RIVERS ELECTRIC CORPORATION

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Item 19) ***Refer to the IRP, Chapter 4, Section 4.2, page 81. Explain why BREC considered budgets scenarios that were capped at $1 and $2 million as opposed to evaluating based on a budget that reaches the potential energy efficiency scenario.***

Response) Four potential energy efficiency scenarios were calculated as part of the DSM analysis including Technical, Economic, Achievable, and Program. The $1.0 million and $2.0 million scenarios represent the Program potential scenarios. The 2020 DSM study supporting Big Rivers' 2020 IRP is consistent with previous IRP analysis, which included $1.0 million and $2.0 million scenarios in the Program potential scenarios.

Witness) Russell L. Pogue

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Item 20) ***Refer to the IRP, Chapter 4, section 4.2, page 83, table 4.3. Provide the inputs that BREC used to calculate Total Resource Cost benefit-cost ratio and explain how the ratio is calculated.***

Response) Please see page 1-6 of Appendix B of Big Rivers' 2020 IRP. The Total Resource Cost ("TRC") test evaluates the benefits and costs from the perspective of all utility customers (participants and non-participants) in the utility's service territory.

TRC costs include:

1. Incremental cost of the specific measure,
2. Program costs of offering the specific measure, and
3. Operations and maintenance (O&M) costs associated with implementing the specific measure (if any specifically identified).

TRC benefits include:

1. Avoided capacity costs for Big Rivers,
2. Avoided energy generation costs for Big Rivers, and

3. O&M benefits associated with implementing the specific measure (if any specifically identified).

CONFIDENTIAL Attachment 1 to this responses shows the inputs for the Total Resource Cost Benefit–Cost Ratio for Residential. **CONFIDENTIAL** Attachment 2 to this response show the inputs for the Total Resource Cost Benefit–Cost Ratio for Non–Residential.

The Total Resource Cost Benefit–Cost Ratio is calculated as follows:

1. An annual stream of *benefits* equal to the length of the specific measure life is calculated as the *sum of* (*i*) the annual avoided capacity cost multiplied by the annual peak demand saved, (*ii*) the annual avoided energy cost multiplied by the annual energy saved (including distribution losses), *and* (*iii*) the annual avoided O&M costs (if any).
2. An annual stream of *costs* equal to the length of the specific measure life is calculated as the *sum of* (*i*) the incremental measure cost (paid in year zero), (*ii*) the annual program cost, *and* (*iii*) the annual O&M costs associated with implementing the specific measure (if any).

3. The net present value (NPV) of each stream (costs and benefits) is calculated using the discount rate of 5% in the tables in Attachment 1 and Attachment 2.
4. The NPV of the benefits is divided by the NPV of the costs to determine the benefit-cost ratio.

Witness) Russell L. Pogue

Big Rivers Electric Corporation
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Inputs for Total Resource Cost Benefit–Cost Ratio - Residential

G&T Discount Rate [redacted]

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
G&T Avoided Cost ($/kWh) [1]	[redacted]										
G&T Avoided Cost (Summer kW) [2]	[redacted]										
G&T Avoided Cost (Winter kW) [2]	[redacted]										
Cooperative Retail Avg. Rate ($/kWh) [3]	[redacted]										
Distribution O&M	[redacted]										
Projected O&M Growth Rate [4]	[redacted]										
Distribution Loss Factor (%) [5]	4.40%										
Transmission Loss Factor (%) [5]	2.50%	6.90%									

Notes:

1.- Avoided energy costs were provided for 2020 through 2050 and based on MISO forward curves from ACES.

2.- Avoided capacity costs are estimates based on MISO forward capacity curves (kW-mo) from ACES adjusted by Big Rivers.

3.- Cooperative average retail rates are estimates based on on the weighted average of the Big Rivers' members and are escalated annually at the rate of power supply growth.

4.- Projected O&M growth rate from Big Rivers.

5.- From 2020 Load Forecast

Big Rivers Electric Corporation
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Inputs for Total Resource Cost Benefit–Cost Ratio - Residential

G&T Discount Rate [redacted]

	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
G&T Avoided Cost ($/kWh) [1]	[redacted]									
G&T Avoided Cost (Summer kW) [2]										
G&T Avoided Cost (Winter kW) [2]										
Cooperative Retail Avg. Rate ($/kWh) [3]	[redacted]									
Distribution O&M										
Projected O&M Growth Rate [4]										
Distribution Loss Factor (%) [5]										
Transmission Loss Factor (%) [5]										

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Inputs for Total Resource Cost Benefit–Cost Ratio - Residential

G&T Discount Rate [redacted]

	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
G&T Avoided Cost ($/kWh) [1]	[redacted]									
G&T Avoided Cost (Summer kW) [2]										
G&T Avoided Cost (Winter kW) [2]										
Cooperative Retail Avg. Rate ($/kWh) [3]	[redacted]									
Distribution O&M										
Projected O&M Growth Rate [4]										
Distribution Loss Factor (%) [5]										
Transmission Loss Factor (%) [5]										

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Inputs for Total Resource Cost Benefit–Cost Ratio - Non-Residential

G&T Discount Rate [redacted]

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
G&T Avoided Cost ($/kWh) [1]	[redacted]										
G&T Avoided Cost (Summer kW) [2]											
G&T Avoided Cost (Winter kW) [2]											
Cooperative Retail Avg. Rate ($/kWh) [3]	[redacted]										
Distribution O&M											
Projected O&M Growth Rate [4]											
Distribution Loss Factor (%) [5]	4.40%										
Transmission Loss Factor (%) [5]	2.50%	6.90%									

Notes:

1- Avoided energy costs were provided for 2020 through 2050 and based on MISO forward curves from ACES.

2.- Avoided capacity costs are estimates based on MISO forward capacity curves (kW-mo) from ACES adjusted by Big Rivers.

3.- Cooperative average retail rates are estimates based on on the weighted average of the Big Rivers' members and are escalated annually at the rate of power supply growth.

4.- Projected O&M growth rate from Big Rivers.

5.- From 2020 Load Forecast

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Inputs for Total Resource Cost Benefit–Cost Ratio - Non-Residential

G&T Discount Rate [redacted]

	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
G&T Avoided Cost ($/kWh) [1]	[redacted]									
G&T Avoided Cost (Summer kW) [2]										
G&T Avoided Cost (Winter kW) [2]										
Cooperative Retail Avg. Rate ($/kWh) [3]	[redacted]									
Distribution O&M										
Projected O&M Growth Rate [4]										
Distribution Loss Factor (%) [5]										
Transmission Loss Factor (%) [5]										

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Inputs for Total Resource Cost Benefit–Cost Ratio - Non-Residential

G&T Discount Rate [redacted]

	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
G&T Avoided Cost ($/kWh) [1]	[redacted]									
G&T Avoided Cost (Summer kW) [2]										
G&T Avoided Cost (Winter kW) [2]										
Cooperative Retail Avg. Rate ($/kWh) [3]	[redacted]									
Distribution O&M										
Projected O&M Growth Rate [4]										
Distribution Loss Factor (%) [5]										
Transmission Loss Factor (%) [5]										

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Item 21) ***Refer to the IRP, Chapter 4, Section 4.2, pages 83–84, regarding the cost effectiveness of BREC's Demand-Side Management (DSM) programs.***

a. ***Explain in detail how BREC determines avoided energy and capacity cost projections.***

b. ***Identify and explain the changes in BREC's computation of avoided energy and capacity cost projections as compared to the 2017 IRP.***

Response)

a. Avoided capacity and energy cost data is based on forward curves developed by ACES Power Marketing for the Midcontinent Independent System Operator ("MISO") market. The MISO Zone 6 capacity forecast and energy forecast at MISO Indiana Hub reflect the likely energy and capacity pricing for Big Rivers going forward. Adjustments may be made based on Big Rivers' experience such as bilateral forward capacity sales.

b. Both the avoided costs in Big Rivers' 2020 IRP and Big Rivers' 2017 IRP were based on available forward price curves provided by ACES. In Big

Rivers' 2017 IRP, Big Rivers' management adjusted near term avoided capacity prices based on actual contracted capacity sales in MISO Zone 6.

Witness) Russell L. Pogue

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Item 22) ***Refer to the IRP, Chapter 4, Section 4.2, page 84, regarding the allocation of the DSM incentive budget. Explain how BREC determined the 45/55 percent allocation of the incentive budget between the residential and nonresidential sectors.***

Response) Refer to page 2-12 of Appendix B of Big Rivers' 2020 IRP. The energy and demand savings for the $1.0 and $2.0 million Program Potential Scenarios were calculated by scaling up the residential and non-residential measures in the Achievable Potential at the same rate until the scenario budget is achieved. The resulting sum of incentives for the residential and non-residential results in a 45/55 split. Actual program costs would depend on participation rates among residential and commercial retail members.

Witness) Joshua P. Hoyt

Item 23) ***Refer to the IRP, Chapter 4, Section 4.8, page 89. Explain the barriers that prevent BREC from implementing cost-effective demand response programs.***

Response) Refer to page 5-1 of Appendix B of Big Rivers' 2020 IRP. Barriers to implementing cost-effective demand response programs are listed below.

1. Deployment of Metering Infrastructure –
   i. Advanced metering infrastructure ("AMI"), which allows for measurement and data collection of high frequency time stamped energy use, is not required for time-of use ("TOU") rates because the period and pricing are fixed up-front. Meters would, however, need to be set up and programmed for TOU metering.
   ii. AMI interval metering is required for advanced load management, demand charges, real-time pricing, critical peak pricing, and peak-time rebate programs.
2. The cost of devices that enable greater savings and usage control under the program. For example, some utilities provide free smart thermostats to

customers that enroll in TOU or advanced load management programs to enable load shifting and increase program benefits.

3. Inconvenience, loss of comfort, or even health and safety issues for consumers when reducing air–conditioning or space–heating usage on, very hot or cold days, respectively, or shifting power consuming activities to customer–inconvenient times of the day.
4. Increased customer exposure to volatile wholesale power prices.
5. Higher bills for those customers with higher on–peak consumption that is difficult or impossible to avoid.
6. Administrative burdens associated with rate studies (to design the rates), load management, metering, billing, and back-office functions.

Witness) Joshua P. Hoyt

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Item 24) ***Refer to the IRP, Chapter 4, Section 4.9, page 90. Explain why BREC is evaluating industrial DSM programs when industrial customers can opt out of DSM programs.***

Response) As a potential point of clarification, the 2020 Demand-Side Management Potential Study, defined the "non-residential customers" as "comprised of commercial and industrial loads (C&I) excluding accounts under direct serve agreements,"[1] and so refers to the commercial and industrial loads served by Big Rivers' Members under Big Rivers' Member Rural Delivery Service ("Rural" or "RDS") tariff. Large industrial loads served by Big Rivers' Members under Big Rivers' Large Industrial Customer ("LIC") tariff ("Direct Serve" loads) were not included in the calculation of the potential.

Industrial customers served under the RDS tariff are included in the potential study because, while KRS 278.285(3) allows "individual industrial customers with energy intensive processes to implement cost-effective energy efficiency measures in lieu of" Big Rivers' approved DSM programs, not all Rural industrial customers will

[1] Big Rivers 2020 IRP, Appendix B at page 2-2.

choose to opt out of cost-effective DSM programs. Historically, Big Rivers has never had a commercial customer served under the RDS tariff opt out of DSM programs.

Witness) Russell L. Pogue

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Item 25) ***Refer to the IRP, Chapter 4, generally. Explain whether and how often BREC has commissioned Clearspring Energy Advisors, LLC (Clearspring) to update its evaluation of BREC's DSM program(s). Include in the explanation what programs or reports of preliminary program evaluations, if any, Clearspring is preparing for BREC, beyond the work conducted for the IRP.***

Response) Big Rivers has not commissioned Clearspring to update its evaluation of Big Rivers' DSM program beyond Appendix B within Big Rivers' 2020 IRP.

Witness) Russell L. Pogue

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Item 26) ***Refer to the IRP, Chapter 4, generally. State whether BREC has received any inquiries as to available grants, subsidies, or low-interest loans for energy conservation or energy efficiency that may help those customers remain economically stable or market competitive.***

Response) Big Rivers has received inquiries from commercial members of Big Rivers' Member-Owners. Big Rivers' Energy Service staff provides services supporting manufacturers and small business applications for the United States Department of Agriculture's Rural Energy for America Program ("REAP") grants.

Witness) Russell L. Pogue

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Item 27) ***Refer to the IRP, Chapter 4, generally. Explain whether there has been any change, internally or externally, in the methods of evaluation, quantification, and verification used by BREC for existing or proposed DSM programs. Identify the cost associated with such changes if they exist.***

Response) Big Rivers has not changed the methods of evaluation, quantification or verification for existing or proposed DSM programs. DSM-14 Low-Income Weatherization Support Program – Pilot is the only DSM program Big Rivers currently offers.

Witness) Russell L. Pogue

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Item 28) ***Refer to the IRP, Chapter 4, generally. Explain whether any DSM programs were modeled as a supply-side resource in the Plexos model. If not, explain why.***

Response) DSM programs were not modeled as a supply-side resource in the PLEXOS model because the DSM programs provide small load reductions (*e.g.*, 1-2 MWs). These low (1-2 MWs) load reductions would not change the PLEXOS model's overall results. The DSM programs should be evaluated on their own merit, including whether the programs provide financial benefit to Big Rivers' Member-Owners.

Witness) Russell L. Pogue

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Initial Data Requests
dated February 26, 2021

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Item 29) ***Refer to the IRP, Chapter 5, Section 5.4, page 97.***

a. Provide a copy of Midcontinent Independent System Operator (MISO) CEO John R. Bear's testimony that is referenced on this page.

b. In Section 5.1, page 92, BREC states that the lower wholesale market prices has been advantageous, especially given its generation mix.

(1) Explain how this advantage is impacted as the amount of renewable energy grows within MISO.

(2) Explain the actions that BREC has taken over time that has allowed it to significantly lower the minimum generation limits on its generators and thereby keep its generators running as wholesale prices have fallen.

Response)

a. Please see the attachment to this response, a copy of MISO CEO John R. Bear's October 30, 2019, testimony.

b. (1) As mentioned in Section 5.1 of Big Rivers' 2020 IRP, Big Rivers has been able to significantly lower historical minimum generation limits to minimize losses in the MISO power market during off–peak hours. As renewable energy grows in the MISO footprint, flexibility to respond to changes in load and/or supply will become more valuable in order to maintain reliability.

(2) The primary action that Big Rivers has taken over time that has allowed it to significantly lower the minimum generation limits on its generators has been removing pulverizers from service during off– peak hours. Big Rivers also periodically performs boiler control and combustion tuning to improve efficiencies at minimum load.

Witnesses) Marlene S. Parsley (*a. and b.(1) only*) and
Nathanial A. Berry (*b.(2) only*)

Testimony of John Bear

Chief Executive Officer

Midcontinent Independent System Operator, Inc. (MISO)

Before the House Committee on Energy and Commerce,

Subcommittee on Energy

"Building a 100 Percent Clean Economy:

Solutions for the U.S. Power Sector."

October 30, 2019

Executive Summary

The electric industry is rapidly evolving, shifting to a generation fleet that is more heavily dependent on renewables than ever before. To help prepare for that future, MISO has identified and is studying three overarching trends that are reshaping the industry:

- De-marginalization refers to resources, such as wind and solar, that can provide the next needed, or "marginal" increment of energy at zero or low costs.

- Decentralization involves the shift away from large, central-station power plants to smaller, locally distributed resources.

- Digitalization is the revolution in information and communication technologies that is reshaping nearly everything in our economy, including energy services.

In anticipation of continued change, MISO is working to identify and understand the impact of increased reliance on renewables. Already, we have learned that renewable penetration of 30% would challenge our ability to maintain the planning reserve margin and operate the system within acceptable voltage and thermal limits. Maintaining reliability at the 40% renewable level becomes significantly more complex.

The implications are very real. Today, we face more frequent and less-predictable occurrences of tight operating conditions on the electric grid compared to just a few years ago, and the challenges continue to grow. The approaches that worked in the past will not meet our needs in the future. To ensure system reliability all 8,760 hours of the year, the electricity generating fleet of the future must become even more available, more flexible, and more visible.

Ultimately, the question of achieving 100% clean power does not have a simple "yes" or "no" answer. Renewable energy technologies are advancing rapidly, but none of us knows exactly where we will be technologically more than 30 years from now. Regardless of what the future holds, MISO remains committed to continued reliability and efficiency, and we appreciate the opportunity to help inform the discussion that will shape the path forward.

Introduction

Good morning Committee Chairman Pallone, Ranking Member Walden, Subcommittee Chairman Rush and Ranking Member Upton, and members of the Subcommittee. I am John Bear, Chief Executive Officer of the Midcontinent Independent System Operator, Inc., or MISO. It is a pleasure to be with you today as you consider the future of renewable energy and its impact on our nation, specifically our high voltage electric transmission system. I hope MISO's insights will be useful to your work of shaping U.S. energy policy.

I know this subcommittee is interested in hearing about the implications of the growth of renewable energy, including challenges associated with ensuring reliability, and the infrastructure and the technology innovations that will be necessary as our nation becomes more dependent on renewables. MISO is also concerned about these issues and strives to stay a step ahead of the challenges before us. That's why MISO commits significant resources to researching and assessing future scenarios, and to designing and implementing initiatives that improve our system planning, operations, markets and enable advancing technology.

MISO Overview

Before I share MISO's insights on some of these matters, I would like to provide a little background about our organization.

The Federal Energy Regulatory Commission's (FERC) Order 2000 established Regional Transmission Organizations (RTOs) to be independent entities that plan and operate the electric grid on a regional basis to maintain reliability and maximize efficiency. MISO was the first Independent System Operator to be recognized as an RTO, receiving FERC approval in 2001.

MISO puts a priority on maintaining our independence. We are fuel source and policy neutral, meaning we do not favor, prefer or advocate any particular fuel or policy outcome. That doesn't mean, however, that we are disinterested observers with respect to the topic of this hearing. MISO is a 501(c)(4) not-for-profit social welfare organization with responsibility for ensuring the reliability of the high-voltage electric transmission system and facilitating the delivery of lowest possible cost energy to consumers. The integration of renewables has a direct impact on both the reliability of the system and the value created for customers.

The system that MISO manages includes almost 72,000 miles of high-voltage transmission and over 175,000 MW of generation, which we do not own or maintain but rather exercise functional control over with the consent of the asset owner. Our footprint is the largest in North America in terms of geographical scope, serving about 42 million people across all or parts of 15 states, stretching from the Canadian border to the Gulf of Mexico. Our energy markets are also among the largest in the world, with nearly $30 billion in annual gross market charges. A map of the MISO footprint is provided in the Appendix of this testimony (see Appendix, Figure 1).

Our work to maintain reliability, administer wholesale markets and conduct transmission planning on a regional scale generates substantial benefits. In 2018 alone we created approximately $3.5 billion in savings for the region, and nearly $25 billion since 2007.

Our vast footprint also provides significant diversity in terms of the types of resources, weather patterns, state policies, and notably, perspective and viewpoints across our stakeholder community that are critical to our solving today's complex challenges. MISO has a robust committee-driven stakeholder process in which asset owners, state regulators and other stakeholders provide input and guidance to MISO on a regular and ongoing basis. This is critical to solving today's complex challenges like the one that is the focus of this hearing – the ongoing growth of renewable energy in the power sector.

Portfolio Evolution – Drivers and Implications

The evolution of the generation portfolio is something MISO has been experiencing for some time due to a confluence of factors, including economics, policy and regulation, aging power plants, and customer preferences. In 2005, the MISO region received nearly 80% of its energy from coal-fired units, very little from natural gas, and a negligible amount from renewables. As recently as 2011, we were still receiving about 75% from coal. That percentage recently fell below 50%, with natural gas now providing close to 30% of our energy, and renewables about 8%.

Several data points provide evidence that this shift will continue. States across the country are considering or have announced mandates or aspirational goals for higher renewable energy contributions. Growing corporate and consumer desires for clean energy are affecting utility's future resource plans. Over 80% of the requests we currently have for new resources to connect to the power grid are from renewable generation. The future planning scenarios that MISO develops in collaboration with stakeholders to provide bookends of potential future scenarios indicate a continued transition to higher renewables.

To be prepared for a future that looks very different from the past and present, we must fully understand the change drivers and associated implications. Through this process, we have identified three overarching trends that are reshaping the future of the industry in profound ways. We call these trends the 3Ds:

- De-marginalization refers to resources that can provide the next needed or "marginal" increment of energy at zero or low additional costs, due to their non-existent or very low fuel costs. This includes wind and solar.

- Decentralization involves the shift away from large, central-station power plants to smaller, often variable resources that are located on local, low-voltage electricity distribution networks, such as at homes and businesses.

- Digitalization is the revolution in information and communication technologies and platforms that will continue to disrupt nearly everything in our economy, including energy services.

Recognizing these trends, we launched a study three years ago to identify the "inflection points" at which the existing system would need to undergo significant structural and/or operational changes as it becomes increasingly reliant on intermittent renewables (see Appendix, Figures 2 and 3). Intuitively, we've always known that the growth of intermittent resources like wind and solar would increase the complexity of system planning and operations, and this initiative is providing data that helps us understand the challenges and implications at different penetration levels.

Already we have learned from that study that renewable penetration of 30% would present challenges in terms of our ability to maintain the planning reserve margin and operate the system within acceptable voltage and thermal limits. The study indicates that maintaining grid reliability at the 40% renewable penetration level becomes significantly more complex. In addition to the challenges described at the 30% level, we would encounter the need to balance the system over a very large area to reduce renewable curtailments and regional transmission reliability issues. The system stability issues would drive the need for non-traditional transmission devices like High Voltage Direct Current (HVDC) lines or other advanced technologies. We are currently looking at the implications of a 50% renewable penetration level.

We have also engaged with industry groups from other countries that are grappling with the same challenges related to integrating renewables, and have gained valuable insights from those conversations.

In addition to our study and information gathering, our own experience has also informed our learnings. I outlined previously how the makeup of the generation fleet in our footprint has changed since the launch of our markets in 2005, but that hasn't been the extent of the impacts. Retirements have contributed to declining reserve margins, aging plants to degradation of generating unit performance and availability and increased reliance on variable generation types to system risk.

The implications have been very real. Tight operating conditions, and more specifically the need to utilize emergency procedures to manage reliability risk, used to occur very rarely and only during peak demand periods. We now experience those situations on a much greater periodicity and during the non-peak periods when risk was historically very low. These outcomes, along with our extensive assessment of the holistic challenges associated with the 3D trends, have led to our identification of three key future needs to ensure reliability with the fleet of the future: improved availability, flexibility and visibility.

The path forward to continued reliability

Achieving these needs will require a shift in market processes and protocols. For decades, electricity providers in all 15 states in the MISO region generally used the same basic approach to serve their customers and maintain grid reliability. This approach, which is still largely in use today, includes concepts such as:

- Reserve margins and resource plans that are based on demand in the "peak hour" of the year, which typically occurs on an exceptionally hot and humid summer day when customers run their air conditioners full-tilt;

- Generic capacity credits that do not always reflect actual resource capabilities; and

- Marginal cost pricing, in which wholesale energy prices are based on the costs of the particular resource—such as a coal plant, for example—that provides the marginal, or "next needed," unit of energy.

Today, states in the MISO region are diverging sharply in their energy and environmental policies. Some have adopted aggressive de-carbonization policies, which are prompting utilities within their borders to retire and replace numerous coal and gas resources with intermittent renewables. But other MISO states continue to rely heavily on their legacy fossil resources for various reasons, including reliability concerns, jobs, and a desire to not impose new infrastructure costs on their ratepayers.

In this new era of widely divergent state energy policies, declining reserve margins, and the many implications of the 3D trends discussed above, it is clear that the region's electrical system and its associated wholesale markets require some significant changes. For example:

- We can no longer be confident that the system will be reliable for all 8,760 hours of the year based solely on utilities having enough generation capacity to serve load on the annual peak hour in the summer.

- We can no longer be confident that the region's evolving mix of resources will provide enough, and the right kinds of, critical attributes that are needed to keep the system operating in a reliable, steady state, such as frequency response, voltage control, and black-start capability, among other things.

- We can no longer be confident that the traditional approach of marginal cost pricing will provide adequate financial incentives to prompt utilities and other types of entities to build the kinds of resources—with the right kinds of attributes—that the system needs to keep operating reliably going forward.

- We can no longer be confident that the existing transmission system, which was primarily designed to deliver energy from large, always-on power plants to load centers, can adapt to the new paradigm of smaller, decentralized intermittent renewable resources—including those that are located on state-jurisdictional local distribution networks.

MISO has established three guiding principles to guide and shape our work going forward to ensure reliability in this era of a dramatically evolving system. They are:

1. Reliability Needs and Requirements: Reliability criteria must reflect required attributes in all horizons – "All Hours Matter."

2. Reliability Contribution: Members are responsible for meeting reliability criteria with resources that will be accredited based upon the resource's ability to deliver those attributes.

3. Alignment with Markets and Infrastructure: Market prices must be reflective of underlying system conditions and resources must be appropriately incentivized for the attributes they provide; infrastructure should enable efficient utilization of resources.

As I mentioned previously, MISO is fuel and policy neutral. We do not favor or advocate for any fuel or policy outcome. Instead, we offer our independent and objective analytical analyses to decision- and policymakers to inform their efforts, and then we ensure a reliable implementation of the policies put in place. I hope my testimony helps to highlight that the question of achieving 100% clean power is not one that has a simple “yes” or “no” answer. The U.S. electric grid is often referred to as the most complicated machine humans have ever built, and there will be no shortage of very long and in-depth engineering conversations ahead as the many changes, developments and advances that will be required are explored and cultivated.

While we all know in a general sense that renewable energy technologies are advancing rapidly, none of us has a crystal ball that can tell us exactly where we will be technologically more than 30 years from now. For example, just 15 years ago—half the time we’re talking about for the purposes of this hearing—we still had not perfected energy technologies like fracking and horizontal drilling, which eventually sparked the oil and natural gas boom that completely transformed those industries.

The resource mix is evolving across our footprint in different ways, and at different paces. Our role is to knit together all of these disparate pieces in a way that ensures the continued reliability of the Bulk Electric System and we will continue to work with our diverse stakeholder community to evolve our planning, markets and operations to fulfill that objective. MISO has a unique role in the industry and brings an insightful perspective to the challenges we face. We are committed to continued reliability and efficiency, and we appreciate the opportunity to help inform the discussions that will shape the path forward.

We will keep you informed of our progress, and I look forward to your questions.

APPENDIX

Figure 1: MISO Reliability Footprint

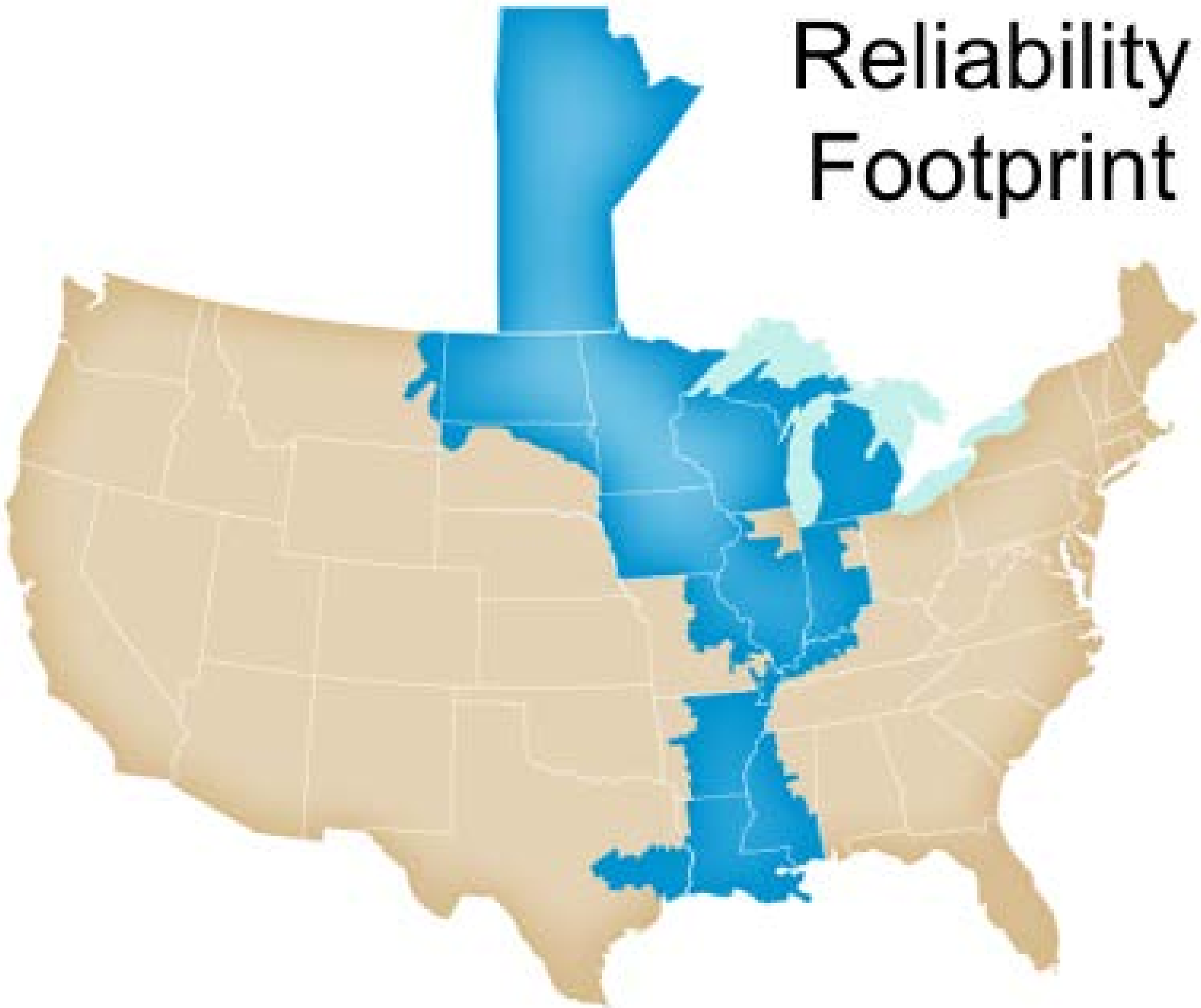
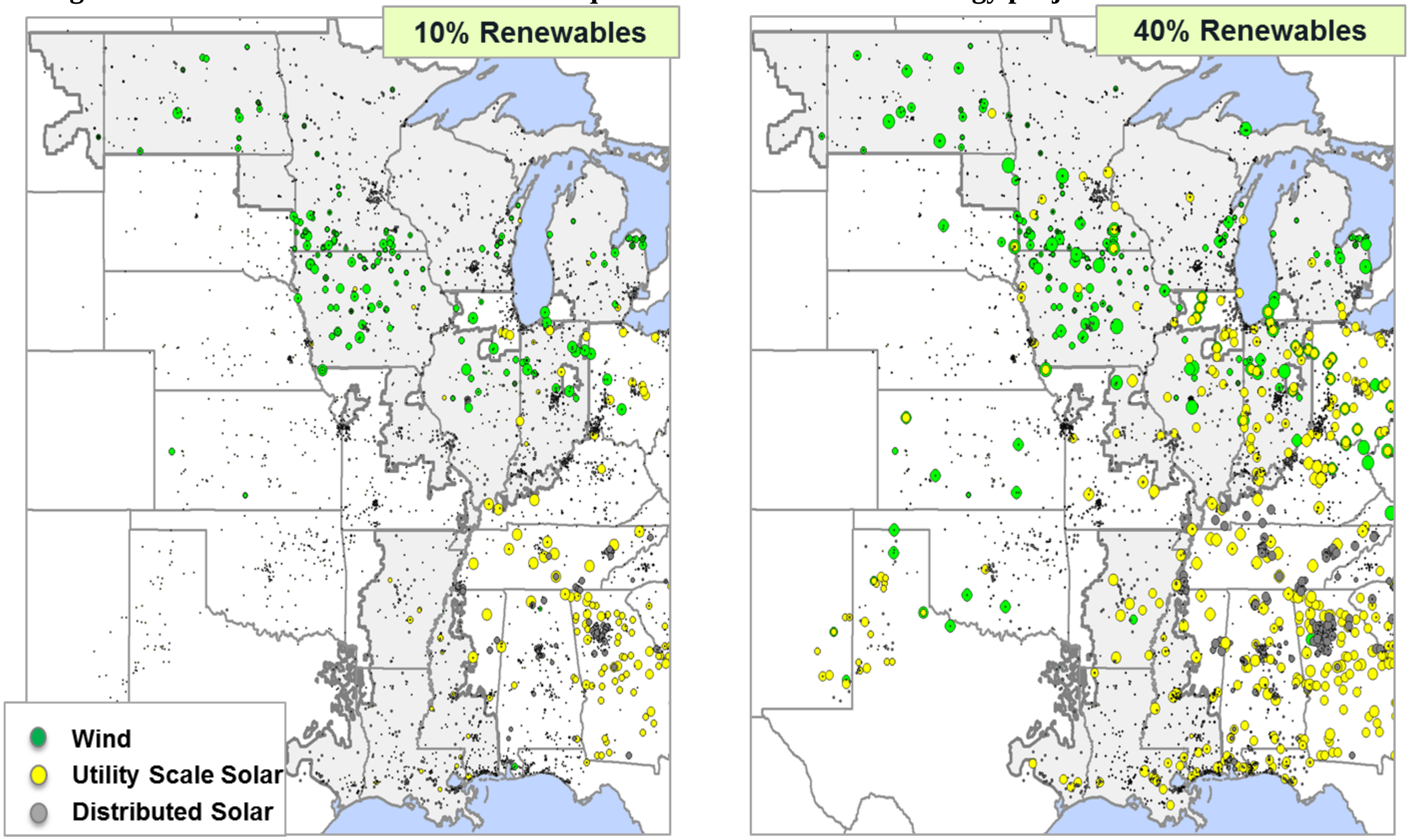


Figure 2: Significant renewable buildout would be required to reach renewable energy projections under certain scenarios.



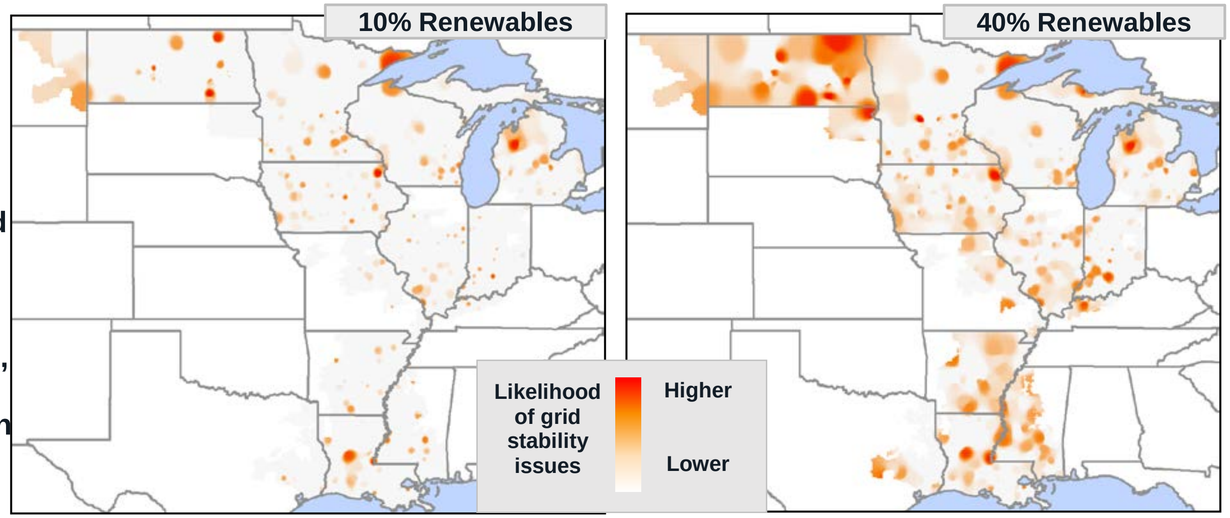
	10% Penetration Level	40% Penetration Level
Wind	1,993 MW	41,521 MW
Utility Solar	1,050 MW	23,125 MW
Distributed Solar	1,276 MW	12,457 MW
Total	4,319 MW	77,103 MW

https://cdn.misoenergy.org/RIIA%20Assumptions%20Doc_v6301579.pdf

Figure 3: Power system stability concerns and integration complexity require improvements to flexibility and visibility.

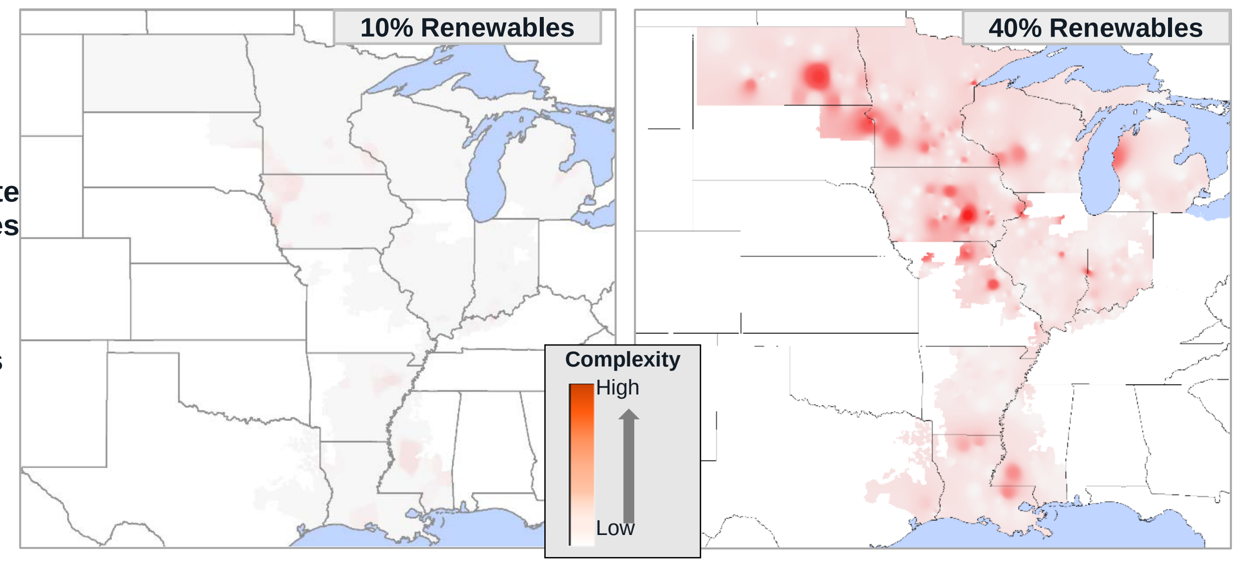
Dynamic Stability

- Stability concerns are driven by the reduction in conventional generation and the increase in inverter based (i.e., wind / solar/ battery) generation
- Additional system reinforcement is needed (e.g., more transmission, keeping more conventional generation online)



Complexity Index

- Integration complexity is measured as the approximate cost of the transmission fixes needed
- By 40% penetration, 18% of renewable energy could be curtailed; transmission fixes could reduce that to 9%



BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's
First Request for Information
dated February 26, 2021

March 19, 2021

Item 30) ***Refer to the IRP, Chapter 5, Section 5.5, page 100. Explain how many customers have requested or are currently working with BREC desiring to build generation for cogeneration purposes or currently have operating cogeneration facilities.***

Response) Currently, one direct serve industrial load has cogeneration capability of 50 MW and one other has expressed intent to add cogeneration capability.

Witness) Mark J. Eacret

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's
First Request for Information
dated February 26, 2021

March 19, 2021

Item 31) ***Refer to the IRP, Chapter 5, Section 5.5.1, page 100.***

a. Provide the current net metering saturation for each Member System.

b. Provide the forecasted net metering saturation by Member System.

Response)

a.

Big Rivers Electric Corporation Member-Owners Current Net Metering Saturation	
Member-Owner	**kW**
Jackson Purchase Energy Corporation	749.3
Meade County Rural Electric Cooperative Corporation	245.8
Kenergy Corp.	3,166.0

b. Neither Big Rivers nor its Member-Owners have forecast the growth of net metering saturation.

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
First Request for Information
dated February 26, 2021

March 19, 2021

Item 32) ***Refer to the IRP, Chapter 5, Section 5.6. On August 31, 2020, the U.S. Environmental Protection Agency (EPA) issued the prepublication final Steam Electric Power Generating Effluent Guidelines and Standards (40 C.F.R. Part 423) (Steam Electric Reconsideration Rule). In 2015, the EPA promulgated a regulation that established effluent limitations guidelines (ELG) and pretreatment standards for wastewater discharges into surface waters and wastewater treatment plants for steam electric power plants. The Steam Electric Reconsideration Rule revises ELG limits for existing facilities and establishes new compliance dates, among other thing.***

a. Explain whether the Steam Electric Reconsideration Rule will materially change or impact the analyses, forecasts, or conclusions in BREC's IRP.

b. If there is a material change or impact to the analyses, forecasts, or conclusions in BREC's IRP, explain what decisions have been or will be made regarding the material change to the IRP and when decisions underlying the changes will be made, including, but not limited to, filing compliance plans related to the material changes.

Response)

a. The Steam Electric Reconsideration Rule will have no material changes to any of the analyses in Big Rivers' 2020 IRP as the provisions of that final rule were generally known and incorporated at the time Big Rivers submitted its 2020 IRP.

b. Not applicable. Please see the response to sub-part a.

Witness) Michael S. Mizell

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's
First Request for Information
dated February 26, 2021

March 19, 2021

Item 33) ***Refer to the IRP, Chapter 6, Section 6.1, pages 110-111. Explain whether BREC is aware of any transmission upgrades that will be necessary to accommodate anticipated new merchant solar generation facilities. Include in the explanation any anticipated operational problems as additional solar generation is connected to BREC's transmission system and brought online.***

Response) At this time, two solar facilities have executed generator interconnection agreements with Big Rivers. Other than the facilities necessary to directly connect the solar facilities, no upgrades to Big Rivers' transmission system are necessary. Big Rivers is not yet aware of any upgrades that will be necessary to accommodate additional merchant solar generation facilities in the future. No operational problems associated with additional solar generation have been identified to-date.

Witness) Christopher S. Bradley

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's
First Request for Information
dated February 26, 2021

March 19, 2021

Item 34) ***Refer to the IRP, Chapter 6, Section 6.1, pages 110-111. Explain how BREC is meeting each of the MISO Transmission Planning guiding principles.***

Response) Participation in the MISO Transmission Expansion Planning process ("MTEP") ensures Big Rivers is meeting each of the MISO Transmission Planning guiding principles. MISO's Business Practice Manual – Transmission Planning (BPM-020), attached hereto, describes the MISO transmission planning process in detail. In addition, Big Rivers prepares a four–year transmission system construction work plan to identify any necessary transmission projects on a "bottom-up" basis. These "bottom-up" projects are submitted to MISO for inclusion in the MTEP.

Witness) Christopher S. Bradley

Manual No. 020

Business Practices Manual
Transmission Planning

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Revision History

Doc Number	Description	Revised by	Effective Date
BPM-020-r23	Updates include the following items: 1) Section 4.5.3.2.1 - Updated FTR Market Administration group name 2) Annual Review Complete 3) Section 7.4.2 – Enhance approach to estimating costs over time in the planning process 4) Updated all hyperlinks throughout	S. Goodwin	DEC-01-2020
BPM-020-r22	Updates include the following items: 1) Clean up Section headings to improve ToC 2) Annual Review Complete	S. Goodwin	MAY-01-2020
BPM-020-r21	Updates include the following item: 1) Section 8 - Variance Analysis, revisions to further explain the Variance Analysis process and incorporate revisions filed in in Docket No. ER20-303-000 2) Revision history table change in the rev20 section, renumber and offer clarity 3) Updated Appendix M to better align the BPM-020 language w/ PRC-023-4	S. Goodwin	FEB-02-2020
BPM-020-r20	Updates include the following items: 1) Revision History Table change in the rev19 section, item No. 3 was clarified. 2) Updated Section 2.8.1, Guiding Principals 3) Appendix J, Cost Allocation	S. Goodwin	AUG-01-2019
BPM-020-r19	Updates include the following items: 1) Updated Section 2.1 on Guiding Principles 2) Updated Section 2.8.1 on MTEP Guiding Principles. 3) Revised project status reporting within Section 4.2 for clarity of milestone responsibility for Eligible Projects and report timing 4) Updated Section 3.3.3 5) Updated Section 4.3.1 for clarity on SSRs 6) Updated Section 4.3.3.2 for clarity on SSRs 7) Annual Review Complete	S. Goodwin	APR-01-2019
BPM-020-r18	Updates include the following items: 1) Updated Hyperlinks to point to new MISO public internet. 2) Aligned Section 4.2.3.1.1 with recent Tariff changes 3) Annual Review Complete	S. Goodwin	MAY-01-2018

BPM-020-r17	Updates include the following items: 1) Appendix L – SOL (IROL) Methodology for the Planning Horizon a. Section L.3 – added language to address Reliability margins in planning horizon. b. Section L.3.6 – added language to explain rationale for 1000 MW criteria c. Section L.3.6 – added language to address T_v in planning horizon 2) Section 4.3.1 – revised language 3) Section 4.3.4.1 – added clarification around P6-1-1 definition 4) Section 4.5.1 – revised language, removing duplicative language in BPM-011 5) Section 5.5.2 – language removed, section reserved for future usage	S. Goodwin	OCT-01-2017
BPM-020-r16	Updates include the following items: 1) Section 4.4 - Long-term Planning 2) Section 6.2 - Generator Retirement and Suspension Studies and System Support Resources (SSR), wholesale replaced with updated language. 3) Other cosmetic formatting	S. Goodwin	DEC-01-2016
BPM-020-r15	Updates include the following items: 1) Section 4.2.3.1 and all subsequent subsections were wholesale replaced with new language 2) New Section 8 added, with all subsection additions	S. Goodwin	SEPT-01-2016
BPM-020-r14	Updates include the following items: 1) Added new TPL-001-4 language throughout 2) Added new Appendix O (rev13) 3) Cosmetic cleanup throughout 4) Refreshed some Figures and Tables 5) Standardized all captions throughout 6) Standardized all bullets throughout 7) Annual Review Complete	M. Tackett / S. Goodwin	JUN-01-2016
BPM-020-r13	Updates include the following items: 1) Delete Section 1.5 2) Rename Section 4 3) Rewrite Section 4 Introduction 4) Add Subsection 4.1.4 5) Rewrite Section 4.3 6) Renumber Subsection 4.3.4 to 6.1 7) Renumber Subsection 4.3.8.4 to 4.5.1 8) Renumber Subsection 4.3.8.5 to 4.5.2 9) Renumber Subsection 4.3.9 to 4.5.3 10) Add New Section 4.5 11) Renumber Section 4.5 to 4.6	M. Tackett/ S. Goodwin	MAY-10-2016

	12) Renumber Section 4.6 to 4.7 13) Rename Section 6 14) Delete Section 6.1 15) Rewrite Appendix K 16) Delete Appendix O 17) Annual Review completed		
BPM-020-r12	Updates include the following items: 1) Annual Review Completed 2) Minor editorial changes in the entire document 3) Section 2.3: Completely rewritten 4) Section 2.4: Completely rewritten 5) Section 6.2: Editorial changes 6) Appendix N: Corrected the reference to Appendix P. 7) Added Appendix P: Methodology for Assessment of Low Voltage Facility Impacts on BES	T. Adu	APR-28-2015
BPM-020-r11	Updates include the following items: 1) Section 4.3.8.4 – Revised section on Baseline Load Deliverability	M. Sutton	NOV-30-2014
BPM-020-r10	Updates include the following items: 1) Annual Review Completed 2) Section 2.4.1.1: Change to BRP Cost Allocation 3) Section 2.4.1.2 I): Change to ITCM GIP Cost Allocation 4) Section 2.8: OMS Committee Role in Transmission Planning section added 5) Section 4.2.3.1: Project Status updates section added 6) Section 6.1: Out-of-Cycle Project Review section revised 7) Section 6.2.6: System Support Resource (SSR) Methodology section added 8) Section 7: Changes to BRP Cost Allocation and updated section references 9) Section 7.1: Moved LODF language to Appendix J and updated language with BRP changes 10) Appendix J.5.1: Moved language to new Appendix O	M. Dantzler	APR-10-2014

BPM-020-r9	Updates include the following items: 1) Annual Review Completed 2) Section 4.3.4: Review of Market Participant Funded Projects section added 3) Appendix J, Section 5.1.1 thru 5.3: Revised language regarding upgrades based on outages during maintenance periods 4) Appendix L: Revised SOL identification methodology 5) Appendix M: Revised to update methodology for new standard PRC-023-2 6) Appendix N: Added new methodology for FAC-013-2: Transfer capability performed in the planning horizon	M. Dantzler	MAY-28-2013
BPM-020-r8	Updates include the following items: 1) Section 4.3.3 – Revised section on Short-term Planning Analysis	M. Dantzler	JAN-17-2013
BPM-020-r7	Updates include the following items: 1) Annual review completed 2) Section 2.4.1.3 – New MEP cost allocation 3) Section 7 – GIP, MEP and MVP cost allocation updates; cost shared projects 4) Remove Section 6 – Generator Interconnection Planning – Duplicate section in BPM-015, owned by the Generator Interconnection Planning Department	M. Dantzler	NOV-19-2012
BPM-020-r6	Updates include the following items: 1) Additional language in Appendix L to clarify communication 2) Add Appendix M: Critical Facility Methodology	A. Dortch	NOV-15-2011
BPM-020-r5	Section 5: Long Term Transmission Services	P. Muncy/ M. Sutton	SEP-22-2011
BPM-020-r4	Updates include the following items: 1) Multi-Value Project Cost Allocation criteria and methodology 2) Shared Network Upgrade methodology 3) Regionally Beneficial Project name change to Market Efficiency Project. Reflects Tariff revisions with an effective date of July 16, 2010.	M. Tackett	MAR-09-2011
BPM-020-r3	1) Appendix J: Additional Language on system reconfiguration and redispatch evaluation for Category C3 events for LODF Calculation 2) Section 2.6.1: Expand on MISO Transmission Provider responsibilities 3) Appendix L: Additional Language on SOL/IROL Methodology	A. Dortch	NOV-20-2010

BPM-20-r2	1) Update to incorporate changes to transmission planning process 2) Update Generator Interconnection section	M. Tackett	OCT-20-2010
BPM-020-r1	1) Annual Review Completed JUN-16-2010	A. Dortch	JUL-08-2009
TP-BPM-002-r1	1) Section 4.3.6: Language Changes in MTEP Contingency Selection Process 2) Section 4.3.7.1: Language Changes in MTEP IROL Identification Process 3) Section 4.3.7.8: New Language describing process for planning for feasibility of LTTR's 4) Appendix J: Additional Language on Implementation Rules for LODF Calculation	J. Webb	JUL-08-2009
TP-BPM-002	Original Posting	S. Goodwin	12-07-2007

Table of Contents

1 Introduction

This introduction to the Midcontinent Independent System Operator, Inc. (MISO) *Business Practices Manual (BPM) for Transmission Planning* includes basic information about this BPM and the other MISO BPMs. The first section (*Section 1.1*) of this Introduction identifies the other BPMs that are available. The second section (*Section 1.2*) is an introduction to this BPM. The third section (*Section 1.3*) identifies other documents in addition to the BPMs, which can be used by the reader as references when reading this BPM.

1.1 Purpose of MISO Business Practices Manuals

The BPMs developed by MISO provide background information, guidelines, Business rules, and processes established by MISO for the operation and administration of the MISO markets, provisions of transmission reliability services, and compliance with the MISO settlements, billing, and accounting requirements. A complete list of MISO BPMs is available for reference through MISO's website. All definitions in this document are as provided in the Tariff, the NERC Glossary of Terms Used in Reliability Standards, or are as defined by this document.

1.2 Purpose of this Business Practices Manual

This *BPM for Transmission Planning* describes MISO's transmission planning process. Also included in this BPM is the former *BPM-013 – Transmission Services.*

1.3 References

Other reference information related to this BPM includes:

- Tariff (Tariff)
- Agreement of the Transmission Facilities Owners to Organize the Midcontinent Independent System Operator, Inc., a Delaware Non-Stock Corporation (MISO Agreement)
- BPM-004 Financial Transmission Rights and Auction Revenue Rights
- BPM-005 Market Settlements
- BPM-011 Resource Adequacy
- BPM-015 Generation Interconnection
- BPM-027 Competitive Transmission Process
- NERC Reliability Standards applicable to transmission planning

1.4 MISO Planning Contacts

For information on MISO planning staff contact details for specific planning functions, contact Client Relations: Client Relations.

2 Overview of Transmission Planning

2.1 MISO Transmission Planning Objectives

MISO regional transmission planning process has as its goal the development of a comprehensive expansion plan that meets both reliability and economic expansion needs. The planning process identifies solutions to reliability issues that arise from the expected dispatch of Network Resources. These solutions include evaluating alternative costs between capital expenditures for transmission expansion projects, and increased operating expenses from re-dispatching Network Resources or other operational actions.

At the start of 2006, the Transmission Provider Board adopted five planning principles to guide MISO regional plan:

- Make the benefits of an economically efficient electricity market available to customers by identifying transmission projects which provide access to electricity at the lowest total electric system cost.
- Develop a transmission plan that meets all applicable NERC and Transmission Owner planning criteria and safeguards local and regional reliability through identification of transmission projects to meet those needs.
- Support state and federal energy policy requirements by planning for access to a changing resource mix.
- Provide an appropriate cost allocation mechanism that ensures that costs of transmission projects are allocated in a manner roughly commensurate with the projected benefits of those projects.
- Analyze system scenarios and make the results available to state and federal energy policy makers and other stakeholders to provide context and to inform choices. Coordinate planning processes with neighbors and work to eliminate barriers to reliable and efficient operations.

Also, it is MISO's goal for the planning process to be fully compliant with the Planning Principles presented in the Federal Energy Regulatory Commission's (FERC) Order Nos. 890 and 890-A. In Order No. 890, FERC identified nine planning principles "that must be satisfied for a transmission provider's planning process to be considered compliant with the Final Rule". MISO has incorporated each of the following principles shown in *Section 2.1.1* below into its planning process, and describes their functions in this Manual.

2.1.1 FERC Order No. 890 Planning Principles

- Coordination
- Openness
- Transparency
- Information Exchange
- Comparability
- Dispute Resolution
- Regional Participation
- Economic Planning Studies
- Cost Allocation for New Projects

2.2 Transmission Planning Functions and Cycles

2.2.1 Planning Functions

The development of the overall MISO Transmission Plan encompasses multiple planning functions addressing different phases and aspects of transmission planning. These functions include:

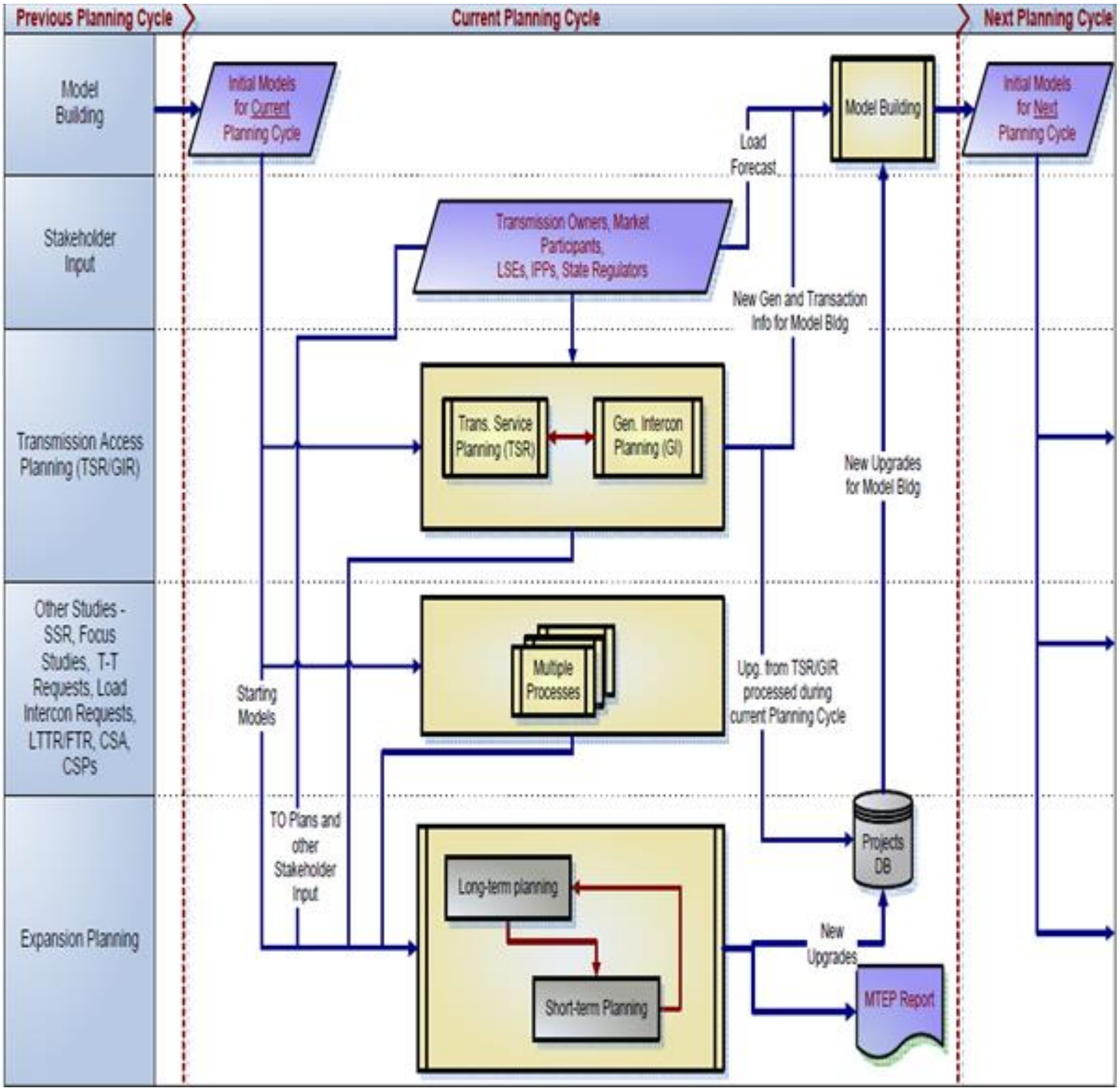
- Model Development
- Cyclical bottom-up and top-down Planning
- Transmission Access Planning
  - Generator Interconnection Planning
  - Transmission Service Planning
- Coordinated Inter-regional Planning (with other RTOs/Regions)
- Non-cyclical Planning Needs
- System Support Resource (SSR) Studies for unit de-commissioning
- Transmission Interconnections
- Load Interconnections
- Focus Studies - Studies initiated during the cyclical planning process that cannot wait until the next planning cycle (e.g., NERC/FERC directives, near-term critical operational issues)

Each of these functions are described in this BPM.

2.2.2 Integration of Planning Functions to Produce MTEP

The various planning functions occur at differing times. For example, the transmission access planning processes occur on a continuous basis in response to customer requests for service. The bottom-up and top-down planning functions repeat on a regular cycle, with an MTEP report produced each twelve (12) Months. Each of these processes informs the other at the commencement of each functions cycle, as shown in *Figure 2.2.2-1* below.

Figure 2.2.2-1: High-level Planning Process Flow Diagram



2.3 Transmission Project Categories and Types

This section describes the categories and types of transmission projects associated with the MISO transmission planning process. There are three distinct categories of transmission projects which include the following:

- Bottom-Up Projects

- Top-Down Projects
- Externally Driven Projects

The specific types of transmission projects include the following:

- Other Projects
- Baseline Reliability Projects
- Market Efficiency Projects
- Multi-Value Projects
- Generation Interconnection Projects
- Transmission Delivery Service Projects
- Market Participant Funded Projects

Table 2.3-1 below illustrates how specific transmission project types map to their parent transmission project categories:

Table 2.3-1: Transmission Project Type-to-Category Mapping

	Bottom-Up Projects	Top-Down Projects	Externally Driven Projects
Other Projects	X		
Baseline Reliability Projects	X		
Market Efficiency Projects		X	
Multi-Value Projects		X	
Generation Interconnection Projects			X
Transmission Delivery Service Projects			X
Market Participant Funded Projects			X

2.3.1 Transmission Project Categories

This section describes the three transmission project categories.

2.3.1.1 Bottom-Up Projects

Bottom-up projects include transmission projects classified as other projects and Baseline Reliability Projects. Bottom-up projects that are ultimately classified as other projects or Baseline Reliability Projects are not cost shared and are generally developed by Transmission Owner(s), via their role as the NERC Transmission Planner (TP), to address localized Transmission Issues and reliability-related Transmission Issues including, but not limited to, compliance with the NERC reliability standards. In its role as the Planning Coordinator (PC), MISO will evaluate all bottom-up projects submitted by Transmission Owner(s) and validate that the projects represent prudent solutions to one or more identified Transmission Issues. In some situations, MISO, as the Planning Coordinator, may also recommend certain bottom-up projects if MISO analysis determines that additional expansion is necessary to comply with the NERC or regional reliability standards. Furthermore, MISO may also recommend alternative solutions to bottom-up projects submitted by Transmission Owner(s), and the expansion planning process will consider those alternative solutions along with the submitted bottom-up projects. Bottom-up projects are produced by the process described in more detail in *Section 4.3* of this BPM. Bottom-up projects have a right-of-first-refusal and are assigned to the applicable Transmission Owner(s) in accordance with Appendix B of the Owners Agreement when approved.

2.3.1.2 Top-Down Projects

Top-down projects include transmission projects classified as Market Efficiency Projects and Multi-Value Projects. Top-down projects include subregional and regional projects developed solely by the MISO planning process in accordance with Attachment FF and with this BPM as well as interregional projects developed jointly with one or more other planning regions in accordance with applicable Joint Operating Agreements or Tariff provisions as appropriate. Regional or subregional top-down projects are developed in a top-down manner by MISO staff working in conjunction with stakeholders to address regional economic and/or public policy Transmission Issues. Regional or subregional top-down projects that are ultimately classified as Market Efficiency Projects or Multi-Value Projects are cost shared per provisions in the Tariff. Interregional top-down projects are developed in a top-down manner by MISO and one or more other planning regions in conjunction with stakeholders to address interregional Transmission Issues. Interregional projects are cost shared per provisions in the Joint Operating Agreement and/or Tariff, first between MISO and the other planning regions, then within MISO based on provisions in Section III of Attachment FF of the Tariff. Top-down projects are produced by the process described in more detail in *Section 4.4* of this BPM. Certain facilities associated with top-down projects may or may not have a right-of-first-refusal and thus will either be assigned to the applicable Transmission Owner(s) in accordance with Appendix B of the Owners Agreement and/or awarded via the provisions of *Section VIII of Attachment FF of the Tariff* and with *BPM-027 – Competitive Transmission Process*.

2.3.1.3 Externally Driven Projects

Externally driven projects are projects driven by needs identified outside of the MISO Transmission Expansion Plan (MTEP) planning process. Externally driven projects typically include New Transmission Access Projects, which are defined in *Module A of the Tariff*, as well as other Network Upgrades that are driven by and benefit a single specific Transmission

Customer or Market Participant. Externally driven projects include Generation Interconnection Projects, which are New Transmission Access Projects developed in accordance with *Attachment X of the Tariff*; Transmission Delivery Service Projects, which are New Transmission Access Projects developed in accordance with Module B of the Tariff; and Market Participant Funded Projects, which are developed pursuant to *Section 6.1* of this BPM. Externally driven projects are generally not cost shared although there are exceptions (e.g., certain Generator Interconnection Projects may be cost shared). Externally driven projects have a Right Of First Refusal (ROFR) and are assigned to the applicable Transmission Owner(s) in accordance with *Appendix B of the Owners Agreement* when approved.

2.3.2 Transmission Project Types

This section describes the eight transmission project types.

2.3.2.1 Other Projects

Other projects represent local transmission projects that address localized Transmission Issues other than the reliability issues addressed by Baseline Reliability Projects, and thus other projects are not projects used to address projected violations of NERC and regional reliability standards. Other projects may include projects to satisfy Transmission Owner and/or state and local planning criteria other than NERC or regional reliability standards, interconnect new Loads, relocate transmission facilities, address aging transmission infrastructure, replace problematic transmission plant, improve operational performance or address other operational issues, address service reliability issues with end-use consumers, improve aesthetics including but not limited to undergrounding overhead transmission facilities, address localized economic issues, and address other miscellaneous localized needs. Other projects are not cost shared through the Tariff and are assigned to the applicable Transmission Owner(s) in accordance with *Appendix B of the Owners Agreement* when approved.

2.3.2.2 Baseline Reliability Projects

Baseline Reliability Projects are defined in *Module A of the Tariff* and described in *Section II of Attachment FF of the Tariff* and represent transmission projects needed to comply with Electric Reliability Organization (i.e., NERC) reliability standards and regional reliability standards. Baseline Reliability Projects are not cost shared through the Tariff and are assigned to the applicable Transmission Owner(s) in accordance with *Appendix B of the Owners Agreement* when approved.

2.3.2.3 Market Efficiency Projects

Market Efficiency Projects are defined in *Module A of the Tariff* and described in *Section II of Attachment FF of the Tariff* and represent transmission projects that address Transmission Issues related to market transmission congestion. Market Efficiency Projects are cost shared projects in accordance with *Section III of Attachment FF of the Tariff*. Specific facilities associated with Market Efficiency Projects may or may not have a right-of-first-refusal depending on the provisions of *Section VIII of Attachment FF of the Tariff*, and thus will either be assigned to the applicable Transmission Owner(s) in accordance with *Appendix B of the Owners Agreement* or incorporated into a Competitive Transmission Project and awarded in accordance with *Section VIII of Attachment FF of the Tariff* when approved.

2.3.2.4 Multi-Value Projects

Multi-Value Projects are defined in *Module A of the Tariff* and described in *Section II of Attachment FF of the Tariff* and represent portfolios of transmission projects that address multiple types of Transmission Issues (e.g., public policy, economic, reliability, etc.) on a region-wide basis. Multi-Value Projects are cost shared projects in accordance with *Section III of Attachment FF of the Tariff*. Specific facilities associated with Multi-Value Projects may or may not have a right-of-first-refusal depending on the provisions of *Section VIII of Attachment FF of the Tariff*, and thus will either be assigned to the applicable Transmission Owner(s) in accordance with *Appendix B of the Owners Agreement* or incorporated into an Competitive Transmission Project and awarded in accordance with *Section VIII of Attachment FF of the Tariff* when approved.

2.3.2.5 Generator Interconnection Projects

Generator Interconnection Projects are New Transmission Access Projects that are defined in *Module A of the Tariff* and described in *Attachment X of the Tariff*. Generation Interconnection Projects represent transmission projects required to facilitate the interconnection of a new Generation Resource to the Transmission System or the upgrade of an existing Generation Resource (e.g., capacity uprate, etc.). These projects include both Direct Assignment Facilities, which are defined in *Module A of the Tariff* and represent facilities necessary to physically interconnect the Generation Resource to the Transmission System when necessary, as well as Network Upgrades required to facilitate reliable delivery of the output of the Generation Resource to ultimate Load. Generation Interconnection Projects are not cost shared through the Tariff except for Network Upgrades operating at 345 kV and above, where ten percent (10%) of such Network Upgrades costs are cost shared on a postage stamp basis. Generator Interconnection Projects are assigned to the applicable Transmission Owner(s) in accordance with Appendix B of the Owners Agreement upon execution of the applicable agreement(s).

NOTE: For interconnection customers interconnecting to American Transmission Company's (ATC LLC) transmission systems and meeting certain eligibility requirements, fifty percent (50%) of the Network Upgrade cost is allocated entirely to the ATC LLC pricing zone and the remaining fifty percent (50%) is allocated to affected pricing zones based on subregional and/or postage-stamp allocation rules described under Attachment FF. A similar treatment is applicable to interconnection customers interconnecting to ITC or METC transmission systems and meeting certain eligibility requirements.

2.3.2.6 Transmission Delivery Service Projects

Transmission Delivery Service Projects are New Transmission Access Projects that are defined in *Module A of the Tariff* and described in Module B of the Tariff and represent Network Upgrades required to facilitate long-term firm point-to-point transmission service requests. Transmission Delivery Service Projects are not cost shared through the Tariff, but instead are charged to the Transmission Customer and may be rolled into base rates in accordance with Attachment N of the Tariff. Transmission Delivery Service Projects are assigned to the applicable Transmission Owner(s) in accordance with Appendix B of the Owners Agreement upon execution of the applicable agreement(s).

2.3.2.7 Market Participant Funded Projects

Market Participant funded projects (MPFPs) are defined as Network Upgrades fully funded by one or more market participants but owned and operated by an incumbent Transmission Owner. These projects apply to those Network Upgrades that are neither currently included in the MTEP Appendix A nor targeted for approval within the current planning cycle.

2.3.2.8 Targeted Market Efficiency Projects

Targeted Market Efficiency Projects are described under Section 9.4 of the MISO-PJM Joint Operating Agreement and are small, low-cost interregional transmission upgrades with short lead times targeted at locations that consistently show congestion limiting the ability of lower-cost generation to reach load.

TMEP criteria include:

- Project is limited to market-to-market flowgates with PJM,
- Cost of the project must be less the $20 million, and
- Project must be in service by the third summer peak period following approval.

Benefits are based on mitigating average market congestion costs of the previous two years and must cover the project's installed capital cost within four years.

2.4 MTEP Project Database and the MTEP Project Appendices

The MTEP project database is the repository for all transmission projects that have been approved and recommended and all transmission projects categorized as bottom-up projects that have been proposed and/or validated per *Section 2.3* of this BPM. The project database contains specific information on each transmission project and specific information on each facility associated with each transmission project including, but not limited to, project scope, facility specifications, cost estimates, project drivers, project assignment, scheduled completion dates, status information, and other pertinent information. Furthermore, the annual MTEP report produced for each planning cycle contains two appendices that list transmission projects included in the MTEP project database. MTEP Appendix A includes all projects that have been approved by the MISO Board of Directors in the current or a previous MTEP planning cycle, but are not yet in service. MTEP Appendix B includes bottom-up projects needed to address reliability or other localized Transmission Issues that have been validated by MISO and are currently the preferred solution, but have not yet been recommended as the final solution. All projects contained in MTEP Appendices A and B are contained within the project database.

2.4.1 MTEP Project Database, Project Table, and Facility Table

The MTEP project database contains all transmission projects that are approved and/or recommended for approval but not yet in service, as well as all projects classified as bottom-up projects that are proposed and/or validated. The project database contains specific data for each individual project in the project database and each individual facility associated with each individual project in the project database. The project database includes all publically available project status update data as described in *Section 4.2.3.1* of this BPM and facility status data for all projects and associated facilities included in the project database. The MTEP project database does not contain a list of solution ideas proposed by stakeholders to address economic or public policy needs as part of the top-down transmission planning processes. Furthermore, the MTEP project database does not contain any externally driven projects where final commitments have not yet been made to pursue the projects via the applicable executed agreements.

The MTEP project database is used to produce a project table and facility table that are posted publically. The project table provides pertinent project-level data associated with projects in Appendices A and B. The MTEP facility table provides pertinent facility-level data associated with projects in Appendices A and B. The project table contains the following data, which is a subset of the project data contained within the project database, for each transmission project in the project database:

2.4.1.1 Project Table Data

- **Planning Review Status**: The Planning Review Status of the project. Available choices are:
  - Submitted for Validation in MTEPyy
  - Submitted for Recommendation in MTEPyy
  - Validated in MTEPyy
  - Recommended in MTEPyy
  - Approved in MTEPyy
  - Not Approved in MTEPyy
  - Withdrawn before Approval in MTEPyy
  - Withdrawn after Approval in MTEPyy

where MTEPyy represents MTEP cycle designation, e.g., MTEP14 is for the 2014 MTEP cycle.

- **MISO Planning Region**: The planning region(s) where the transmission project is located. Available choices are *North*, *Central, East, and South*.
- **Project ID Number**: The assigned ID number for the transmission project.
- **Project Name**: The name of the transmission project.
- **Project Description**: A description of the transmission project.
- **Transmission Issue(s) Addressed (System Need Summary)**: A concise description of Transmission Issue(s) addressed by the transmission project.
- **Impacted Transmission Owner(s)**: The Transmission Owner system(s) to which the new transmission facilities associated with the proposed project will interconnect and/or the Transmission Owner system(s) which contain existing transmission facilities that will be modified or upgraded as part of the transmission project.
- **Impacted States**: The state(s) and/or other applicable jurisdiction(s) where the transmission facilities associated with the proposed transmission project are expected to be located. This information is in the facility table and would be summarized in project level reports.
- **Regulatory ID**: The regulatory ID associated with the project to be used by regulatory authorities for their own tracking purposes.
- **Member Project ID**: The ID assigned to the project by the assigned Transmission Owner or assigned transmission developer.

- **Project Category**: The project category associated with the project. Available choices are *Bottom-Up Project, Top-Down Project,* and *Externally Driven Project*.
- **Project Type**: The project type associated with the project. Available choices for projects classified as Bottom-Up Projects are *Baseline Reliability Project* and *Other Project*. Available choices for projects classified as Top-Down Projects are *Multi-Value Project, Market Efficiency Project, and Targeted Market Efficiency Project.* Available choices for projects classified as Externally Driven Projects are *Generator Interconnection Project – Cost Shared, Generator Interconnection Project – Not Cost Shared*, *Transmission Delivery Service Project*, and *Market Participant Funded Project*.
- **Other Project Sub-Category**: The driver(s) associated with a transmission project classified as an Other Project. Available choices include *Clearance, Condition, Distribution, Local Economic, Local Multiple Benefit, Metering, Operational, Performance, Reconfiguration, Relay, Reliability, Relocation, Replacement,* and *Retirement.*
- **Estimated Project Cost**: The estimated cost of the entire project. This is equal to the sum of the estimated costs of each upgraded and/or new facility associated with the project, where each facility cost is escalated to the expected in service date for that specific facility. This information is at the facility level and will be summarized in project level reports.
- **Projected In Service Date – First Facility**: The projected in service date for the first facility to be upgraded or constructed as part of the transmission project. This information is at the facility level and will be summarized in project level reports.
- **Projected In Service Date – Last Facility**: The projected in service date for the last facility to be upgraded or constructed as part of the transmission project. This information is at the facility level and will be summarized in project level reports.
- **Assigned Transmission Developer**: Indication of the entity (ies) assigned to develop the transmission project and construct and own the associated transmission facilities. For Open Transmission Projects, this field will be populated with the Selected Transmission Developer when determined, and will be blank prior to project award. For Open Transmission Projects where a regulatory process has determined that an existing Transmission Line Facility must be upgraded to include additional transmission circuits and Section VIII of Attachment FF of the tariff requires that this upgrade be jointly developed by the incumbent Transmission Owner and the Selected Transmission Developer, this field will include both the Selected Transmission Developer and the incumbent Transmission Owner(s). For all other transmission

projects, this field will be populated with Transmission Owner(s) that have been assigned to construct the facilities in accordance with Appendix B of the Owners Agreement.

The facilities table contains the following data, which is a subset of the facility data contained within the project database, for each facility associated with each transmission project included in the project database:

2.4.1.2 Facility Table Data

- **Impacted Transmission Owner(s)**: The impacted transmission owner(s) for the specific facility in question.
- **Project ID Number**: The Project ID number associated with the parent project.
- **Facility ID Number**: The assigned ID number associated with the facility in question.
- **Expected ISD**: The expected in service date for the facility in question.
- **Member Project ID**: The ID assigned to the parent project by the assigned Transmission Owner or assigned transmission developer.
- **From Sub**: If a new transmission line or transmission line upgrade, this field represents one of the two substation terminals (where substation terminal could also represent the midpoint of a three terminal transmission line). If substation equipment, a new substation, or a substation upgrade, this field represents the name of the substation.
- **To Sub or Major Equipment Type**: If a new transmission line or transmission line upgrade, this field represents one of the two substation terminals (but not the same terminal specified in "From Sub". If substation equipment, a new substation, or a substation upgrade, this field represents the major equipment type here, for example, transformer, capacitor, reactor, DVAR.
- **Circuit ID**: A unique ID number to track multiple transmission circuits on a common transmission line, multiple transformers or other series equipment between two or more common Buses within a specific substation, or multiple shunt equipment connected to a common Bus within a substation (e.g., capacitor banks, etc.).
- **Max kV**: If a power transformer, this field represents the nominal operating kV of the highest voltage winding. If a multi circuit transmission line with circuits that operate at different voltages, this field represents the nominal operating kV of the highest voltage circuit. Otherwise, this field represents the nominal operating kV associated with the transmission facility.
- **Min kV**: If a power transformer, this field represents the nominal operating kV of the lowest voltage winding (tertiary windings excluded unless electrically connected to transmission facilities). If a multi circuit transmission line with circuits that operate at

different voltages, this field represents the nominal operating kV of the lowest voltage transmission circuit (distribution circuits and communication circuits excluded). Otherwise, this field represents the nominal operating kV associated with the transmission facility.

- **Normal Facility Rating**: The normal continuous MVA or Mvar rating for the summer season.
- **Maximum Facility Rating**: The highest emergency MVA rating associated with the facility for the summer season.
- **Impacted State(s)**: Each state (or other jurisdiction) in which the facility is located or expected to be located.
- **Miles Upgraded**: Associated only with existing transmission line facilities or existing right-of-way. Represents the total number of miles of upgrade made to an existing transmission line facility.
- **Miles New**: Associated only with new transmission line facilities. Represents the total number of miles of new facility construction on new right-of-way.
- **Facility Status**: The current status associated with the transmission facility. Available choices are *Proposed, Planned, Milestone 1, Milestone 2, Milestone 3, Milestone 4: Under Construction, Milestone 5: In service, Under Construction, In Service, and Withdrawn.* This information is at the facility level and will be summarized in project level reports.
- **Estimated Cost**: The *Estimated Cost* of the facility escalated to the expected in service date for the facility.
- **MISO Functional Control**: A binary field that indicates whether or not the facility will be under the functional control of MISO. If "*App H"*, this facility will be placed under the functional control of MISO. If "*App G"*, this facility will not be placed under *MISO Functional Control* and is under an Agency Agreement.

2.4.2 Project Table and Facility Table Status Fields

The project table contains a planning review status field and the facility table includes a facility status field. These fields are discussed in more detail below.

2.4.2.1 Planning Review Status Field

This field represents the status of the projects with regard to planning review activities as follows:

- **Submitted for Validation**: Only bottom-up projects may have a planning review status of *Submitted for Validation*. This status applies to any bottom-up project *te A* by MISO staff or a Transmission Owner that has not yet been validated by MISO.

- **Submitted for Recommendation**: Only bottom-up projects may have a planning review status of *Submitted for Recommendation*. This status applies to any bottom-up project *Submitted for Recommendation* by MISO staff or a Transmission Owner that has not yet been validated by MISO.
- **Validated**: Only bottom-up projects may have a planning review status of *Validated*. This status applies to any bottom-up project that has been *Validated* by MISO to be a prudent solution to an identified Transmission Issue, but has not yet been recommended for approval.
- **Recommended**: This status applies to any transmission project that is being *Recommended* by MISO for approval by the MISO board of directors in the current MTEP cycle, but has not yet been approved by the MISO board of directors.
- **Approved**: This status applies to any transmission project that has been approved for construction by the MISO board of directors.
- **Not Approved**: This status applies to any transmission project that was not successfully validated or recommended by MISO staff. The project's associated facilities would also have a *Withdrawn* facility status.
- **Withdrawn before Approval**: This status applies to any transmission project that has been *Withdrawn before Approval*. The project would remain in the project database with this status. The project's associated facilities would also have a *Withdrawn* facility status.
- **Withdrawn after Approval**: This status applies to any transmission project that has been *Withdrawn after Approval*. The project would remain in the project database with this status. The project's associated facilities would also have a *Withdrawn* facility status.

2.4.2.2 Facility Status Field

This field represents the overall status of a specific facility as follows:

- **Proposed**: Only facilities associated with bottom-up projects may have a facility status of proposed. Facilities associated with bottom-up projects with a Planning Review Status of *Submitted for Validation, Submitted for Recommendation, or Validated* will have a facility status field set to *Proposed*.
- **Planned**: Facilities associated with bottom-up and top-down transmission projects that have a Planning Review Status of *Recommended* but have not yet met cost estimating Milestone 1 pursuant to *Section 4.2.3.1* of this BPM should have a facility status of *Planned*. This status also applies to externally driven projects that have a Planning Review Status of *Recommended* or *Approved* but are not yet *Under Construction*.

- **Milestone 1**: Applies to all bottom-up and top-down transmission projects with facilities that have achieved Milestone 1 pursuant to *Section 4.2.3.1* of this, but have not yet achieved Milestone 2. Milestone 1 is the milestone associated with the completion of the July subregional planning meetings in the current MTEP cycle.
- **Milestone 2**: Applies to bottom-up and top-down transmission projects. Applies to all applicable transmission projects with facilities that have achieved milestone 2 pursuant to *Section 4.2.3.1* of this BPM, but have not yet achieved milestone 3. Milestone 2 is the milestone defined to be just prior to approval of the project by the MISO board of directors.
- **Milestone 3**: Applies to all bottom-up and top-down transmission projects with facilities that have achieved Milestone 3 pursuant to *Section 4.2.3.1* of this BPM, but have not yet achieved Milestone 4. Milestone 3 is the milestone where long lead materials have been ordered.
- **Milestone 4 - Under Construction**: Applies to all bottom-up and top-down transmission projects with facilities that have achieved Milestone 4 pursuant to *Section 4.2.3.1* of this BPM, but have not yet achieved Milestone 5. Milestone 4 is the milestone where construction has commenced.
- **Milestone 5 - In Service**: Applies to all bottom-up and top-down transmission projects with facilities that have achieved Milestone 5 pursuant to *Section 4.2.3.1* of this BPM, which is the milestone where the transmission project has been completed and all associated facilities are *In Service*.
- **Under Construction**: Facilities associated with externally driven projects that are under construction should have a facility status of *Under Construction*.
- **In Service**: Facilities associated with externally driven projects that have been placed in service should have a facility status of *In Service*.
- **Withdrawn**: Facilities that have been withdrawn from projects or are associated with projects that have been cancelled or have a Planning Review Status of *Not Approved,* should have a facility status of *Withdrawn*.

2.4.3 MTEP Appendix A

The MTEP report associated with each MTEP cycle will contain an Appendix A that lists all transmission projects that have been approved in the current MTEP cycle or have been approved in a previous MTEP cycle but are not yet fully implemented (i.e., all facility upgrades and/or new facilities associated with the project are not yet in service). It is important to note that MTEP appendices associated with a specific MTEP cycle are not official until the MISO board approves the MTEP report and associated recommendations. With this in mind, the draft MTEP Appendix A prior to MTEP report approval contains all projects within the transmission project database that have a Planning Review Status of either *Recommended* or *Approved.* In developing the draft MTEP Appendix A, the starting point is MTEP Appendix A from the previous MTEP cycle, which includes all transmission projects with a Planning Review Status of Approved upon approval of the previous MTEP report. Any transmission project included in the previous MTEP Appendix A that has been fully implemented (i.e., all facilities in service) or cancelled will be removed from the current draft MTEP Appendix A. Any transmission project approved since the conclusion of the previous MTEP cycle, including out-of-cycle transmission projects approved since the conclusion of the previous MTEP cycle, which have a current Planning Review Status of Approved, are considered in MTEP Appendix A and will be added to the current draft MTEP Appendix A. Any transmission project recommended for approval since the conclusion of the previous MTEP cycle are not yet included in MTEP Appendix A, but will be added to the draft MTEP Appendix A for consideration by the MISO Board. Upon approval of a specific MTEP report and associated recommendations, all projects in MTEP Appendix A of that MTEP report are considered approved and the Planning Review Status will be set to Approved.

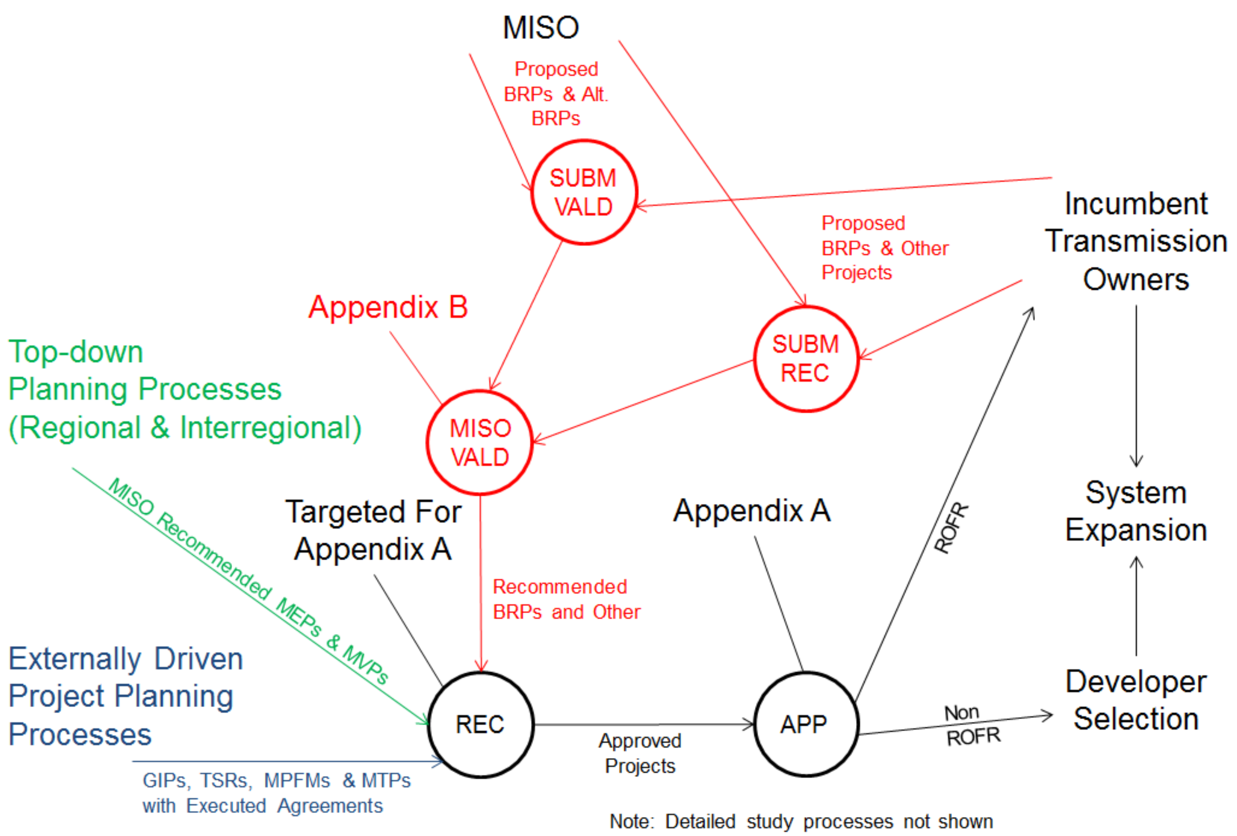
2.4.4 MTEP Appendix B

The MTEP report associated with each MTEP cycle will contain an Appendix B that lists all bottom-up projects that have been validated by MISO as the preferred solution to address an identified need based on current information and forecasts, but where it may be prudent to defer the final recommendation of a solution to a subsequent MTEP cycle (e.g., the preferred project does not yet need a commitment based on anticipated lead time and required in service dates and there is some uncertainty as to the prudence of selecting this project over an alternative project given potential changes in projected future conditions, etc.). MTEP Appendix B is limited to bottom-up projects only (i.e., Baseline Reliability Projects and Other Projects). MTEP Appendix B contains all bottom-up Projects within the transmission project database that have a Planning Review Status of *Validated.* In developing the MTEP Appendix B, the starting point is MTEP Appendix B from the previous MTEP cycle. Any transmission project included in the previous MTEP Appendix B that i) will be recommended for approval in the current MTEP cycle, ii) is determined to no longer be the best or most prudent solution to an identified need, or iii) was previously included to address a specific need or needs that no longer exist will be removed from the current MTEP Appendix B. After this step is completed, any new bottom-up project submitted by a Transmission Owner or MISO in the current MTEP cycle to address an identified need that has been validated by MISO to be the preferred solution based on the most current information and forecasts, but that is not yet ready for recommendation, will be added to the current MTEP Appendix B.

2.4.5 Submission of Bottom-up Projects into the MTEP Project Database

Transmission Owner(s) will submit bottom-up projects into the MTEP project database by September 15th of each year for the MTEP cycle associated with the following calendar year or as out-of-cycle projects in accordance with *Section 6.1* of this BPM. Bottom-up projects, which must be classified as either Baseline Reliability Projects or Other Projects, must be submitted with a Planning Review Status of *Submitted for Validation* or *Submitted for Recommendation*. If the Transmission Owner determines that approval of the submitted transmission project is required in the current MTEP cycle, then the Transmission Owner will specify a Planning Review Status of *Submitted for Recommendation*. If the Transmission Owner determines that approval of the transmission project is not required in the current MTEP cycle, then the Transmission Owner will specify a Planning Review Status of *Submitted for Validation*. If the project is required to comply with NERC TPL standards, the Transmission Owner should designate the submitted project as a Baseline Reliability Project, regardless of the assigned Planning Review Status. *Figure 2.4.5-1* illustrates how bottom-up projects move through the project database and MTEP Appendices from the standpoint of planning review status.

Figure 2.4.5-1: Submission of Top-Down Projects into the MTEP Project Database



2.4.6 Submission of Top-Down Projects into the MTEP Project Database

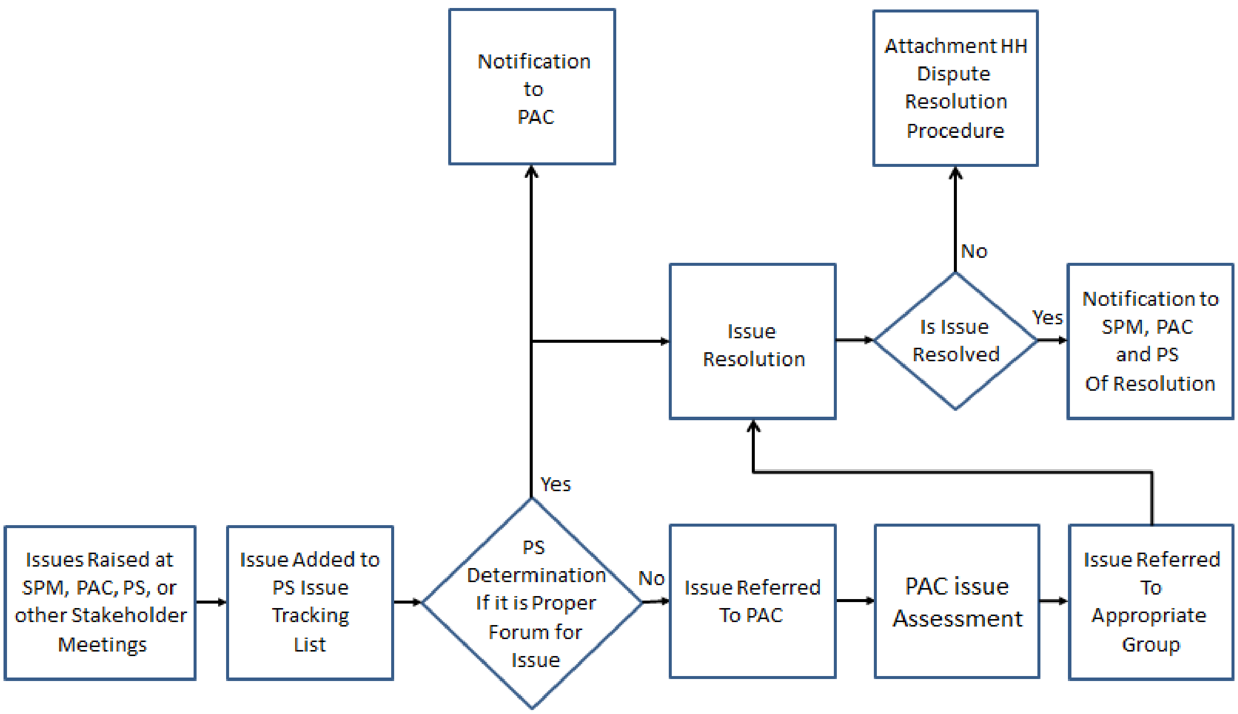
Only MISO staff will submit regional and interregional top-down projects into the MTEP project database at such time when a decision has been made in the planning process to formally recommend the project for approval by the MISO board of directors. All top-down projects will be submitted to the MTEP project database with a Planning Review Status of *Recommended*. No top-down projects will be permitted to have a Planning Review Status of Submitted for Validation, Submitted for Recommendation, or Validated. Top-down projects include interregional, regional, and subregional Market Efficiency Projects and Multi-Value Projects. *Figure 2.4.5-1* illustrates how top-down projects move through the project database and MTEP Appendices from the standpoint of planning review status.

2.4.7 Submission of Externally Driven Projects into the MTEP Project Database

MISO staff or Transmission Owner(s) will submit externally driven projects into the MTEP project database at such time when all conditions, including but not limited to execution of applicable agreements, have been satisfied for formal recommendation of the project for approval by the MISO board of directors. All externally driven projects will be submitted to the MTEP project database with a Planning Review Status of Recommended. No externally driven projects will be permitted to have a Planning Review Status of Submitted for Validation, Submitted for Recommendation, or Validated. *Figure 2.4.5-1* illustrates how externally driven projects move through the project database and MTEP Appendices from the standpoint of planning review status.

2.5 Issues Resolution Process Prior to Tariff Dispute Resolution Procedure (Attachment HH)

Figure 2.5-1: Issues Resolution Process Diagram



During the stakeholder review (i.e., SPM, PS, or PAC) of results and preferred solutions to Appendix B projects or after cost responsibilities for projects to be moved to Appendix A are determined an issue with the project may be raised and at that point the issue will follow the process illustrated in *Figure 2.5-1* above.

After an issue has been raised about a project the next step will be to determine which party is the correct one to address the issue. The Planning Advisory Committee will use the following general guidelines to determine what group addresses the issue:

- High-level policy related issues will be addressed by the PAC
- Technical issues will be directed to the Planning Subcommittee
- Ad Hoc Task Force will be formed for issues that require three (3) or more Days of work from individuals outside the committee structure (i.e. market operations, rate experts, etc.) or additional expertise on planning issues not readily available in the committee.
- Short-term work group may be formed to develop proposals to address an issue and bring that work back to the PAC or PS for consideration.

Once an issue has been referred to the proper working group (including a temporary short-term task force) the issue will be resolved following MISO Governance Process. The process will include the following:

- Working sessions, including research and data gathering will occur for the timeframe necessary to develop a recommendation (motion) for resolution to the issue.
- A motion, based on the outcome of the working sessions, will be presented and seconded.
- Debate will occur on the resolution.
- Committee participants will vote on the resolution.
- That recommendation will be presented to the parent committee(s) (i.e. SPM, PAC, or PS) and MISO. Recommendations are non-binding and will represent the advice of the committee to affected parties.

In the event that affected parties are not satisfied with the recommended resolution or an agreed upon resolution cannot be reached the affected parties may move to the Dispute Resolution Procedure in Attachment HH of the Tariff.

2.6 General Process Responsibilities

2.6.1 Transmission Provider (MISO)

MISO is the NERC Planning Authority for its Member footprint, and performs regional planning in accordance with FERC Planning Principles delineated in Order 890. These Planning Principles provide mechanisms to ensure that the regional planning process is open, transparent, coordinated, includes both reliability and economic planning considerations, and includes mechanisms for equitable cost sharing of expansion costs. MISO, through the regional planning process, integrates the local planning processes of its Member companies and the advice and guidance of stakeholders into a coordinated regional transmission plan and identifies additional expansions as needed to provide for an efficient and reliable transmission system that delivers reliable power supply to connected Load customers, expands trading opportunities, better integrates the grid, alleviates congestion, provides access to diverse energy resources, and enables state and federal energy policy objectives to be met. MISO planning staff will produce regional plan reports no less frequently than biennially, and will make such plans publicly available on the MISO web site.

MISO planning staff is responsible for conducting the regional planning process, including the organization and facilitation of stakeholder meetings and committees that advise the planning staff and the Transmission Provider Board.

In producing the integrated and coordinated regional transmission plan, MISO adheres to the provisions of the tariff and the Business Practices Manuals, including this BPM. MISO planning staff is responsible for establishing the timelines and requirements for, and performing the actions necessary to complete each of the key milestones below in the regional planning process:

- Model development for MISO needs and NERC MOD-032
- Testing models against reliability and economic planning criteria
- Collaborative development of possible solutions to identified issues
- Selection of preferred solution
- Determination of funding and cost responsibility
- Monitoring progress on solution implementation

MISO planning staff is responsible for developing regional planning models and for providing the requirements and timelines for exchange of information with Load Serving Entities (LSE is Tariff defined term), Generation Owners, Transmission Customers, Transmission Owner(s), and neighboring Transmission Entities necessary for model development. Such information includes Load Forecasts and geographic distribution of such forecasts on a transmission substation basis, generating resource commitments, Generator operational and economic performance data, and existing and proposed transmission upgrades. MISO planning staff is responsible for making models available for stakeholder review with appropriate protection of CEII and commercially sensitive data.

MISO planning staff is responsible for developing a Study Plan and arranging for stakeholder meeting(s) with the Subregional Planning Meetings, Planning Subcommittee, and Planning

Advisory Committee for collaborative input and refinement of the planning scope, project definition and purpose, work assignments and responsibility, scheduling, cost analysis, alternatives, and assumptions.

MISO planning staff is responsible for testing regional models to identify performance of the models against national reliability standards, and for identifying opportunities for economic expansions that meet established economic planning criteria, and that are necessary to efficiently meet state and federal energy policy objectives over short, intermediate and long-term planning horizons (1-5, 6-10, 11-20 years). MISO planning staff is responsible for evaluating alternative solutions to identified needs, and for working with Transmission Owner(s) and other stakeholders to identify recommended solutions. Identification of recommended solutions includes consideration of a variety of factors including urgency of need, energy policy mandates, and comparisons amongst alternatives over the planning horizon of initial investment costs, operating performance, robustness of the solution, longevity of the solution provided, and performance against other economic and non-economic metrics as developed with stakeholders.

MISO planning staff evaluates recommended projects for cost allocation in accordance with the Tariff provisions, and for presenting the results of cost allocation calculations to stakeholders for review and comment. MISO planning staff provides projections of annual cost responsibilities by pricing zone associated with cost sharing.

MISO planning staff is responsible for directing the preparation of a preliminary MTEP report proposing new projects, modifications to existing projects and proposing alternative solutions to deficiencies identified in the assessment process, for presenting the highlights of the report to stakeholders, and for distributing the report to stakeholders for written comments.

MISO planning staff is responsible for preparing the final draft of the comprehensive MTEP Plan. MISO planning staff is responsible for presenting the comprehensive MTEP Plan to the Transmission Provider Board (Biennial Plan and annual update reports) for approval. MISO planning staff is then responsible for posting the Transmission Provider Board-certified plan on the MISO website and issuing it to regulatory authorities and other requesting parties and for monitoring and reporting the MISO construction implementation process.

Finally, to the extent assistance is needed by the affected Transmission Owner(s) or designated entities in justifying the need for and obtaining certification of any facilities required by the approved MTEP, MISO shall prepare and present testimony in any proceedings before state or federal courts, regulatory authorities, or other agencies as may be required.

2.6.2 Transmission Owner(s)

In accordance with the ISO Agreement, each Transmission Owner engages in local system planning in order to carry out its responsibility for meeting its respective transmission needs in collaboration with MISO and subject to the requirements of applicable state law or regulatory authority. In meeting its responsibilities under the ISO Agreement, the Transmission Owner(s) may, as appropriate, develop and propose plans involving modifications to any of the Transmission Owner's transmission facilities which are part of the Transmission System. In developing proposed plans, the Transmission Owner(s) will adhere to any applicable state or local regulatory planning processes. Proposed plans developed by the Transmission Owner(s) for potential inclusion in the regional plan are evaluated and discussed with stakeholders through the annual regional planning process as described further in this BPM.

Each Transmission Owner must submit to the Transmission Provider on an annual basis and at a time to be determined by the Transmission Provider, which shall be prior to the beginning of each regional planning cycle, all proposed transmission plans for both transferred and Non-transferred Transmission Facilities. Transmission Owner(s) participate in Subregional Planning Meetings (SPMs) in their respective planning subregions as per the Transmission Provider's meeting schedule, and in regularly scheduled Planning Subcommittee meetings. Transmission Owner(s) may be requested by MISO planning staff to present their proposed projects to stakeholders at SPMs or Planning Subcommittee meetings and discuss the justifications, alternatives, estimated costs, expected service dates, and other aspects of proposed projects with stakeholders. In the alternative, MISO planning staff may present this information to stakeholders, and the Transmission Owner(s) are required to provide representatives that can support these discussions and respond to stakeholder questions about project details.

Transmission Owner(s) are responsible for providing modeling data to MISO as Planning Coordinator per NERC MOD-032 standard. Transmission Owner(s) are responsible for supporting and participating in the development of MISO and Inter-RTO planning models. The Transmission Owner(s) will be responsible for preparing and updating any detailed power system models they may need for their own use, or for meeting modeling requirements of Regional Entities or other planning groups. Transmission Owner(s) are encouraged to use the same, or very nearly the same models for their own planning purposes as developed collaboratively with MISO in order to maintain maximum consistency between planning results obtained from alternative models of the same planning horizon.

Transmission Owner(s) are responsible for applying their expert knowledge of the strengths and weakness of their respective transmission systems to the evaluation of all projects in the MISO Plan affecting their respective transmission systems.

Finally, Transmission Owner(s) are responsible for the good faith implementation including land acquisition, regulatory permitting and construction of Transmission Provider Board-certified expansion projects.

2.6.3 Generation Owners

Generation Owners are responsible for providing modeling data to MISO as the Planning Coordinator in accordance with NERC MOD-032 standard. This data is used by MISO and Transmission Owner(s) for Load flow, short circuit, dynamic stability and other future studies as needs arise. Generation Owners are responsible for meeting regulatory reliability standards and reliability planning clauses in their agreements with Transmission Owner(s) and Service Agreements, as applicable. The facility plans developed with the Generation Interconnection Studies and Generator Agreements will be an essential part of MISO Transmission Owner expansion plans to enable competitive generator markets. Generation Owners are encouraged to participate in the planning process through the stakeholder input and review phases of the planning process.

2.6.4 Load Serving Entities

Load Serving Entities (as defined in *Module A of the Tariff*) are responsible for providing modeling data to MISO as the Planning Coordinator per NERC MOD-032 standard. Load Serving Entities will be responsible for annually making and providing MISO with forecasts of Network Load in accordance with *Section 29.2 and Module E of the Tariff* and MISO's MOD-032 Model Data Requirements & Reporting Procedures. This includes the requirement to provide the amount and location of interruptible Load and the needed Network Resource information. Firm Transmission Service Customers are responsible for identifying POR/POD information as required in the MISO OASIS automation system and Tariff reservation and scheduling requirements. LSEs are encouraged to involve themselves in the MISO planning process by participating in the stakeholder input and review phases of the planning process.

2.6.5 Transmission Customers

Transmission Customers will have the same planning responsibilities as LSEs. Accurate Load Forecasts and assistance in modeling multi-regional Load transfers are an integral requirement in the determination of future system expansion plans. Facility Studies conducted to meet Transmission Customer Long Term Firm Transmission Service request and reservations are a vital part of MISO Transmission Owner expansion plans. Transmission Service Customers are encouraged to involve themselves in the MISO planning process by participating in the stakeholder input and review phases of the planning process.

2.6.6 Other Regional Transmission Operators (RTOs)

The participating RTOs under an inter-RTO cooperation process will be responsible for identifying Network Upgrades through their respective organization procedures and their proposed Integrated Regional Expansion Plans including Generator Interconnection Studies that significantly impact one another. The Joint RTO Transmission Planning Committee and Subcommittees cooperatively determine and facilitate any required Coordination Studies. The affected RTOs use their respective organizational planning procedures (MTEP collaborative process) to complete the coordination studies. The proposed consolidated facilities resulting from the coordination expansion studies are presented to the Joint RTO transmission planning and relevant subcommittees for review. The resulting recommended Inter-RTO coordinated expansion plans are compiled in a report. MISO Inter-RTO coordinated facilities are combined with MISO Intra-MISO expansion plans. The resulting consolidated plan will be submitted for approval to the Transmission Provider Board for certification. After certification by the participating RTOs, construction programs will commence to implement their respective facility responsibilities. The Intra-MISO and Inter-RTO facilities will be constructed as required in the MISO Agreement as well as MISO and Transmission Owner(s) Tariffs. All facility expansions must be effectively coordinated and expeditiously constructed. Further, Inter-RTO facilities require additional Inter-RTO coordination.

2.6.7 Other Stakeholders (Including State Regulatory Commissions)

Stakeholders, including State Regulatory Commissions, provide MISO with critical stakeholder input and review of transmission expansion projects in the MTEP Plan as they are developed and updated. The State Commission inputs related to projections of Load growth, resource requirements, transmission siting authority and environmental concerns assist MISO in the development of realistic transmission expansion projects and alternatives to meet the needs of their citizens as well as neighboring regions. Since all MISO planning meetings are open to all stakeholders, stakeholders are responsible for attending as their interest dictates. Communication avenues such as electronic mail and the MISO website, along with open discussion periods in scheduled meetings, allow stakeholders to effectively participate in the MTEP planning process.

2.7 Treatment of Confidential Data

The Transmission Provider will utilize a Non-Disclosure and Confidentiality Agreement (NDA) to address sharing of Critical Energy Infrastructure Information (CEII) transmission planning information. FTP sites containing such information will require such agreements to be executed to obtain access. Stakeholder meetings at which CEII information will be available will be noticed to email exploders that will require execution of NDAs for inclusion. In the alternative, such meetings will be structured to have separate discussion of issues involving CEII data only with participants that agree to execute the NDA. Confidential information related to economic (e.g., congestion) studies, as well as CEII, is sensitive information which must remain confidential. The Transmission Provider will use generic (publicly available) cost information from industry sources in the economic studies to prevent accidental release of confidential information and promote a truly open process because results of economic studies are available to all interested parties.

2.8 OMS Committee Role in Transmission Planning

The Organization of MISO States (OMS) Committee, as defined in the Owners Agreement and the Tariff, may participate, at its discretion, in the MISO transmission planning process throughout each MTEP planning cycle. Specifically, the OMS Committee may provide input and feedback on the following items:

- Planning Principles
- MTEP Scope
- MTEP Futures
- MTEP Process Issues
- MTEP Final Recommendations

2.8.1 OMS Committee Input on MTEP Guiding Principles Provided by the Transmission Provider Board

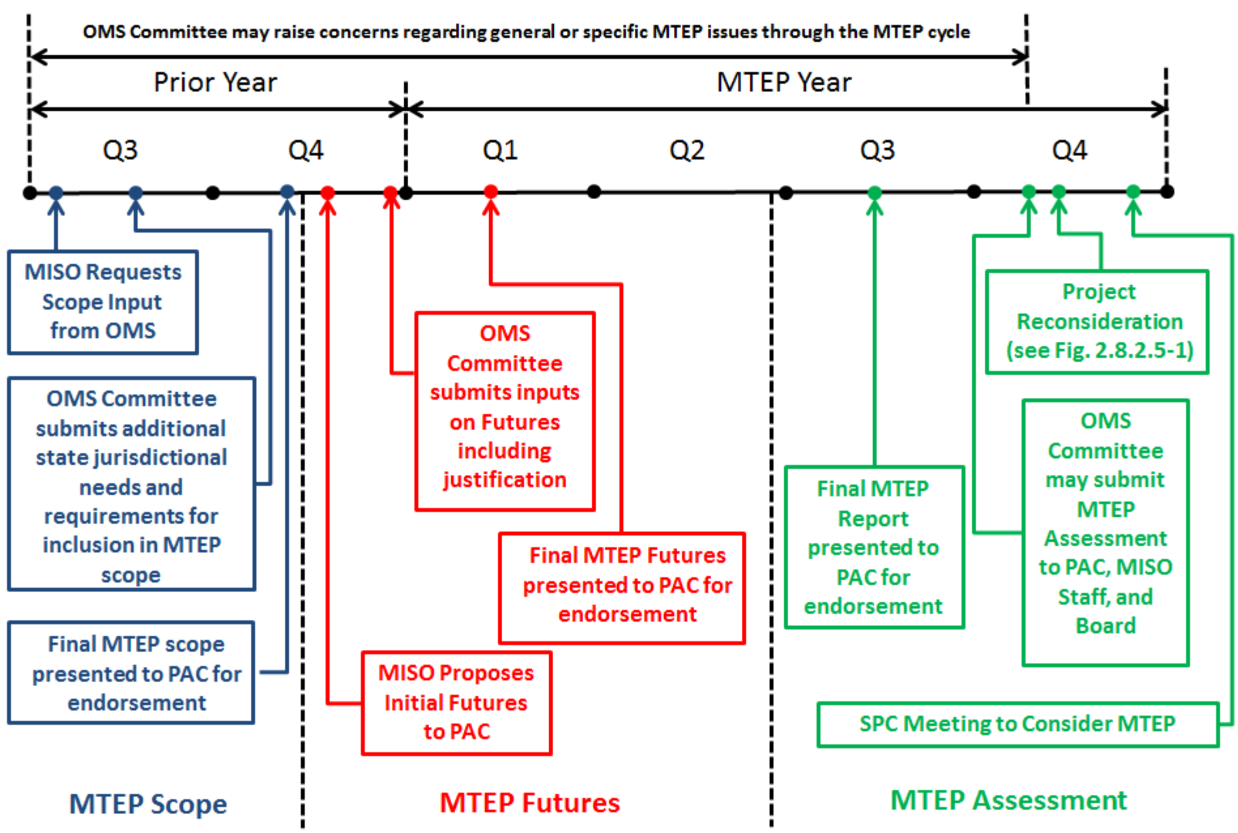
As listed in Section 2.1 of this Transmission Planning Business Practices Manual document, the Transmission Provider Board has adopted MTEP Guiding Principles to guide the transmission planning process. The System Planning Committee (SPC) of the Transmission Provider Board typically reviews these principles every other year and may make adjustments if deemed necessary as circumstances evolve. The OMS Committee will have the opportunity to provide input and feedback to the System Planning Committee of the Transmission Provider Board and to address the SPC in a public meeting every other year regarding the MTEP Guiding Principles provided by the Transmission Provider Board including, but not limited to, recommendations to add, modify, or remove specific MTEP Guiding Principles.

MISO will biennially solicit comments, suggestions, or recommendations regarding the planning principles from the OMS Committee and other sectors of the Planning Advisory Committee (PAC) by a date determined by MISO. MISO will provide the OMS Committee a forty-five (45) day notice of this date. This biennial review process will align with review by the SPC at their February meeting.

2.8.2 OMS Committee Input and Feedback on MTEP

Per Section I.B of Attachment FF of the Tariff, the OMS Committee may submit input into and feedback on each MTEP cycle as illustrated in *Figure 2.8.2-1* and as further described below.

Figure 2.8.2-1: OMS Committee MTEP Input & Feedback Timeline



2.8.2.1 OMS Committee Input on MTEP Scope of Study

Each MTEP cycle begins on June 1 of the year preceding the calendar year designation of the specific MTEP cycle. The scope of study, (Scope) of a specific MTEP cycle, while fixed in part by provisions of the Owners Agreement, Tariff, and Business Practices Manuals, may have additional items added as necessary from cycle-to-cycle. The development of the MTEP scope normally begins with the Subregional Planning Meetings scheduled in June of the year prior to the calendar year designation of the MTEP, and then is rolled up to the Planning Subcommittee in August of that year and finally to the Planning Advisory Committee in September or October of that year where the Planning Advisory Committee will provide feedback and recommendations to MISO. The final scope of a specific MTEP cycle will typically be established by November of the year prior to the calendar year designation of the MTEP cycle.

The OMS Committee may identify items, including additional state jurisdictional needs or requirements, to be included in the scope for a specific MTEP cycle and will forward those items to the Transmission Provider within forty-five (45) Days of the date when MISO requests this information[1]. MISO will typically request this information from the OMS Committee on July 1 of the year prior to the calendar year designation for the MTEP cycle in question so that the OMS Committee may assemble recommendations for MTEP scope items in parallel with the development of scope items via the Subregional Planning Meetings. This allows for MISO to consider MTEP scope recommendations from the Subregional Planning Meetings, the Planning Subcommittee, and the OMS Committee in developing the draft MTEP scope to be submitted to the Planning Advisory Committee at the September or October meeting in the year prior to the calendar year designation for the MTEP in question. MISO will finalize the MTEP scope of study no later than the December PAC meeting.

2.8.2.2 OMS Committee Inputs on Futures

As part of the annual Futures discussions conducted with the Planning Advisory Committee each year, the OMS Committee will have the opportunity to submit suggestions and/or recommendations to MISO regarding the Futures that will be used to support planning analyses, where Futures represent multiple future policy and economic scenarios that drive modeling inputs and assumptions used in the development of the MTEP and related appropriate cost/benefit analyses with respect to certain projects that are not proposed strictly for reliability. Such suggestions and recommendations may address both what Futures will be modeled as well as inputs, parameters and values of the uncertainty variables applied to these Futures. Suggestions

[1] In addition to providing input to the scope of studies for a specific MTEP planning cycle, the OMS Committee and other stakeholders will be able to provide scope input on specific studies and initiatives within the MTEP cycle as they are developed and continue to evolve throughout the cycle.

and recommendations on the proposed futures must be forwarded to MISO within sixty (60) Days after MISO initially proposes the Futures. Suggestions and recommendations on inputs, parameters, values of the uncertainty variables and subsequent modifications, shall be forwarded to MISO within fourteen (14) Days after MISO provides an initial proposal on the values of the uncertainty variables. MISO will present this information as part of the annual Futures discussions conducted with the Planning Advisory Committee. MISO will have the option of incorporating such suggestions and/or recommendations in the development and Application of the MISO selected Futures or of performing supplemental analyses in parallel by applying the assumptions developed from the OMS inputs. In the event the suggestions and/or recommendations requested by OMS are not incorporated into the MISO selected Futures, supplemental OMS analyses shall be provided to the Planning Advisory Committee. Should such requests result in an undue burden on MISO, then MISO will negotiate with the OMS Committee to reach an acceptable compromise that is satisfactory to both parties given the timing, resource, and other constraints imposed on MISO in performing such analyses.

NOTE: In a typical planning year, initial Futures proposals are presented at the September or October Planning Advisory Committee meetings and uncertainty variables are typically detailed at the November and/or December Planning Advisory Committee meetings. Final values for some uncertainty variables cannot be determined until actual modeling begins and it may be necessary to initially provide an approximate value to OMS.

2.8.2.3 Ongoing OMS Committee Feedback on General or Specific MTEP Process Issues

During an ongoing MTEP cycle, the OMS Committee may raise concerns to the MISO staff regarding general or specific issues regarding the MTEP process. The MISO staff will respond to the OMS Committee in a timely manner. If issues cannot be resolved, the OMS Committee may forward concerns to the Planning Advisory Committee and, if requested by the OMS Committee, the Transmission Provider Board, to be considered when taking action to endorse or approve the final MTEP plan. Feedback regarding general or specific issues provided by OMS during an MTEP cycle must be received by the MISO by the latter of sixty (60) Days from when the initial draft of the MTEP report is posted or October 31 of the year corresponding to the calendar year designation of the MTEP, to enable MISO sufficient time to respond to such concerns.

The OMS Committee and other stakeholders may also request, and shall receive from MISO staff as promptly as reasonably possible given analysis timelines and result availability, (a) pricing zone-by-pricing zone cost analyses, and (b) state-by-state, or local resource zone-by-local resource zone project or project portfolio cost and benefit analyses, as appropriate, with respect to any project or project portfolio where the cost allocation is premised in whole or in part on economics, but not including projects proposed strictly for reliability purposes. The analyses furnished shall be of a similar quality to those furnished to transmission owning stakeholders, and shall conform to applicable engineering, economic or other planning standards or practices delineated in NERC standards, the Tariff, and MISO BPMs.

2.8.2.4 OMS Committee Assessment of Overall MTEP Planning Cycle

At the end of an MTEP cycle when the final MTEP plan has been published, but prior to consideration by the Transmission Provider Board, the OMS Committee will have an opportunity to perform, at their discretion, an assessment, in parallel with the assessment performed by the Planning Advisory Committee, of the specific MTEP planning cycle including the overall planning process, models, inputs, and assumptions used within the planning cycle. Should the assessment identify specific concerns, the results of the assessment, including the identified concerns, will be forwarded to the Planning Advisory Committee, the MISO Staff, and the Transmission Provider Board within thirty (30) Days of the date when the final draft of the MTEP report is posted (which is typically in September of each year).

2.8.2.5 OMS Committee Recommendations to Reconsider Specific Project Recommendations

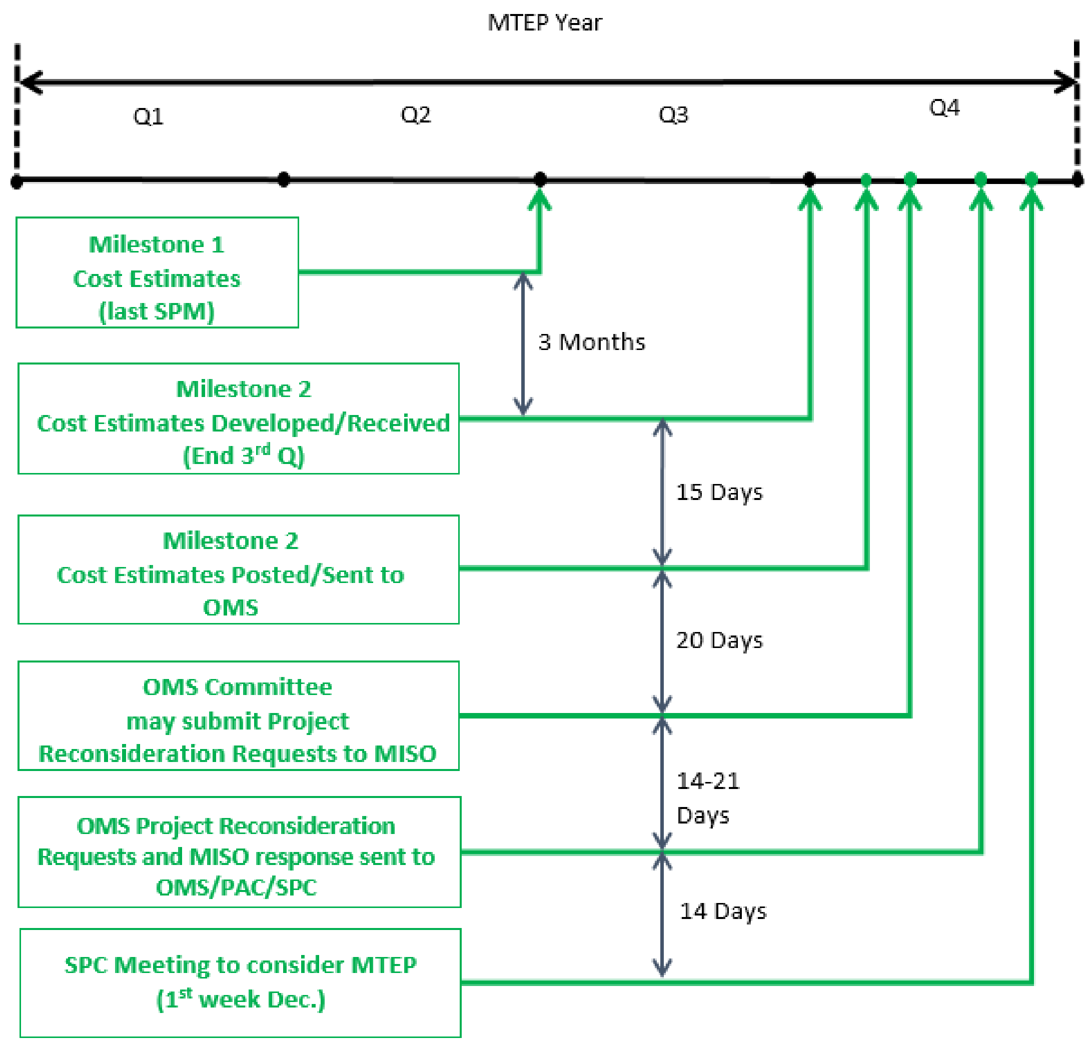
For any project not yet approved by the MISO Board that is eligible to receive regional cost allocation under Attachment FF being recommended for Appendix A, either within a portfolio or individually, and that is not a Generation Interconnection Project, the OMS Committee may, with a sixty-six percent (66%) or greater majority vote by the OMS Board, request such project to be reconsidered by the MISO staff if the OMS Committee actively participated in the planning process for the MTEP cycle or portfolio planning cycle in question and at least one of the following two conditions has been satisfied:

- The proposed project, a proposed alternative to the proposed project, including an alternative combination of facilities for the proposed project, was not vetted within the appropriate planning stakeholder groups (e.g., subregional planning meetings, technical study task forces, technical study review groups, or equivalent stakeholder forum) during the MTEP planning process pursuant to the Order 890 process detailed in Attachment FF of the Tariff;
- The updated cost estimate provided at Milestone 2 for the project has increased by twenty-five percent (25%) or more of the projected costs estimate provided at Milestone 1, where Milestone 1 occurs at the third Subregional Planning Meeting within an MTEP cycle (typically in mid-June) and Milestone 2 is the last quarterly project status update prior to the time the MISO Board is scheduled to meet to consider approval of the MTEP (typically end of September for a December Board approval).

MISO will produce a listing of any projects meeting this cost increase threshold and post it to the MISO website (including a notification to the Planning Advisory Committee) and provide it to the OMS Committee within seven (7) Days of receipt of the quarterly status update.

Should the OMS Committee exercise the option to recommend reconsideration of a project, such request must be forwarded to the MISO Staff, along with an explanation as to why such reconsideration request is being made, within no more than twenty (20) Days of the posting of the Milestone 2 costs and the provision of such cost information to the OMS Committee, where such posting will be made within seven (7) Days of receipt of the last quarterly project status update prior to the scheduled meeting of the System Planning Committee of the Board where consideration will be given to approving the MTEP. MISO staff will review the request and verify that at least one of the two conditions described above for invoking the project reconsideration request is valid. MISO staff will forward the OMS Request along with a good faith attempt to provide a substantive and meaningful response to the OMS Committee, the Planning Advisory Committee, and the System Planning Committee of the Board at least fourteen (14) Days prior to the System Planning Committee meeting to consider approval of the MTEP. MISO will re-convene the Planning Advisory Committee either in person or via conference call to provide an opportunity for the Planning Advisory Committee to make comments on the OMS Request prior to distributing the final MTEP recommendations to the System Planning Committee of the Board. The project reconsideration timeline is illustrated in *Figure 2.8.2.5-1* below.

Figure 2.8.2.5-1: OMS Committee Project Reconsideration Request Timeline



3 Model Development

3.1 Introduction

MISO develops regional planning models which are used by MISO and its members for performing reliability and economic planning studies needed to fulfill various NERC and Tariff compliance obligations. This section describes MISO power flow model development processes through the Model On Demand (MOD) tool as applicable to the various planning functions discussed in this BPM.

3.2 Base Model Development for Planning Studies

The planning functions described below will provide input to the planning model development process through MOD. These planning functions will also specify criteria to output planning models from the MOD as needed to perform the specific planning studies.

- Base Models (PSS®E) for MTEP Reliability Analyses
- Base Models (PSS®E) for MTEP Economic Studies (Additional post processing outside MOD will be needed to prepare PROMOD economic models)
- Base Models (PSS®E) for Generator Interconnection Studies
- Base Models (PSS®E) for Transmission Service Request Studies
- Base Models (PSS®E) for other Non-cyclical planning studies

3.2.1 Model Development Timeline, Key Milestones, and Responsibilities

Figure 3.2.1.4-1 below shows a general overview of the Planning Model Building Development process through MOD. The key process steps are explained below. *Table 3.2.1.4-1* below identifies the planning model development timeline, key milestones, and responsibilities. A detailed schedule for MTEP model development is posted on MISO website at Model Development Schedule.

3.2.1.1 Initiate Base Model Development for the Next Planning Cycle

MISO planning staff in consultation with Planning Subcommittee and Planning Advisory Committee determines the planning study years and seasons for which the base models need to be developed for the next planning cycle. Factors taken into consideration in determining the base model years/seasons include, study horizon used for the previous planning cycle, model years/seasons considered by NERC series models and neighboring coordinated systems, NERC standard compliance requirements, and other specific planning study requirements.

MISO will then request Transmission Owner(s) and other stakeholders to submit model updates in order to build base models for the next planning cycle.

3.2.1.2 Update Models

Before the beginning of the next planning cycle Transmission Owner(s) submit MOD project files to MOD for new reliability projects. Also, Transmission Owner(s) review Appendix A and Appendix B projects model data that are already in MOD from the previous planning cycle and submit corrections and modifications as necessary to the MOD. MISO planning staff will verify these MOD data submittals to make sure that model data match with project and facilities details in Transmission Projects database. Transmission Owner(s) also make any changes or corrections to equipment ratings through the MOD data submittal process.

As described in Subsection 1.3 of MISO Model Data Requirements and Reporting Procedures and in *Section 2.6* of this BPM, Generator Owners (GO) are responsible for submitting modeling data for their existing and future generating facilities with a signed interconnection agreement, Load Serving Entities (LSE) are responsible for providing their scenario Load Forecasts, and TO are responsible for submitting data for their existing and approved transmission facilities.

GO are to coordinate with their interconnected TO in order to ensure that their data is consistent with the TO submitted topology. In alignment with MISO BPM-011 – Resource Adequacy, each LSE is responsible to work with applicable Electric Distribution Companies (EDC) to coordinate the submission of EDC forecast data in areas that have demand and energy that are subject to retail choice. LSE are expected to submit substation Load Forecasts directly to MOD/MISO unless they have made arrangements with their interconnected Transmission Owner to submit data on their behalf. If arrangements have been made, it must be communicated in writing to MISO.

As a best practice, it is desired that TO would also submit modeling data at their disposal for unregistered entities in their footprint. There is no obligation to do so and additionally no compliance repercussions relating to the data provided.

MISO planning staff shall work with Local Balancing Authorities to make changes to transaction and area interchanges based on the transaction data from OASIS and new information available through TSR Study process.

External system in MOD is updated based on the latest NERC series models and also based on any updates available from neighboring coordinated systems.

3.2.1.3 Preliminary Base Model Review

Once the data submittal process is complete, MISO planning staff creates preliminary base models based on the specific model requirements for different planning functions and horizons for stakeholder review. These preliminary models are posted to the MISO Planning Portal and Models ftp site. See the following location for information on accessing secure model sites: Client Relations. The schedule for review and feedback is posted along with the models and typically has the timelines shown in *Table 3.2.1.4-1* below.

3.2.1.4 Develop Base Models for Planning Studies

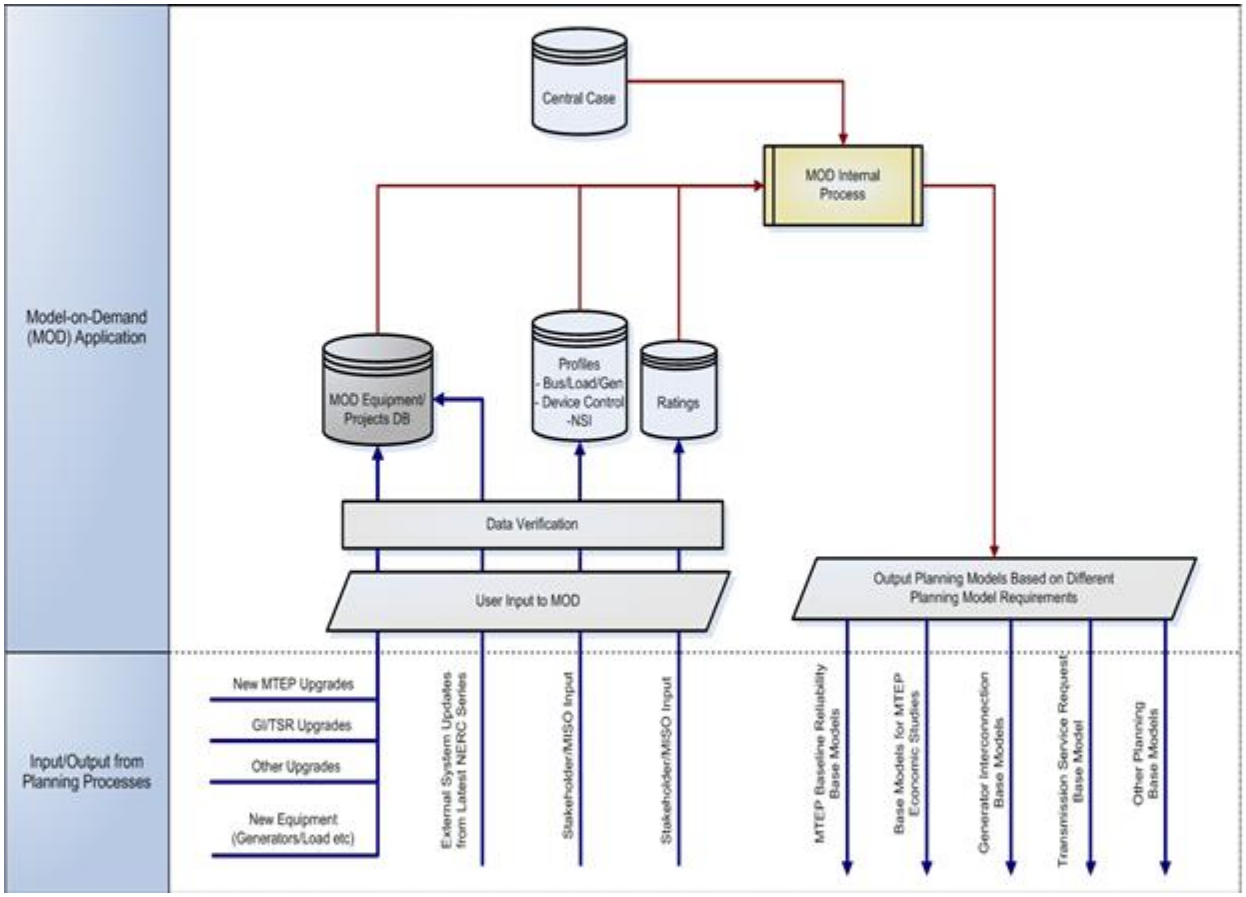
Any additional model updates and corrections needed are submitted through MOD by the appropriate data submitters described above. MISO planning staff then posts the Base Models for different planning functions on the ftp site.

Table 3.2.1.4-1: Model Development Timeline, Key Milestones, and Responsibilities

(Occurs between August and March of each Year on Schedule provided by MISO)

Activity	Responsibility
(A) Initiate base model development for the next planning cycle	
Determine base model study years and seasons for the next planning cycle	MISO planning staff, SPM/PS/PAC
Solicit model update input	MISO staff
(B) Update models	
Submit project files/idevs for new projects	Transmission Owner(s)
Review existing projects in MOD (processed during previous planning cycle) and submit corrections and modifications as necessary	Transmission Owner(s)
Submit equipment rating updates and other model corrections	Transmission Owner(s)
Submit Transmission Owner collected/projected Load Forecast data to MOD on a substation basis	Transmission Owner(s)
Collect Load Forecast data from LSEs/Network Customers – MOD Load Forecast information is compared with Load Forecast data collected from LSEs/Network Customers at the beginning of the planning cycle	MISO planning staff, LSEs
Submit new generator information, unit retirement information (through SSR study process), and generator profile changes to MOD	MISO planning staff, Transmission Owner(s)
Update Transaction data based on information from OASIS and TSR Study process	MISO planning staff
Update the external system from the latest NERC series update and/or updates available from neighboring coordinated systems	MISO planning staff
(C) Preliminary Base Model Review	
Output preliminary base models based on the specific model requirements for different planning functions	MISO planning staff
Post models for review on the MISO Planning/Models ftp site	MISO planning staff
stakeholder review of preliminary models	stakeholders
(D) Develop Base Models for Planning Studies	
Submit additional model updates corrections through MOD based on model review feedback	MISO planning staff, Transmission Owner(s)
Post revised base models on the ftp site	MISO planning staff

Figure 3.2.1.4-1: Planning Model Development - MOD Input/Output



3.2.1.5 Base Models for MTEP Reliability Analyses

MOD will be used to create the starting models to assess near-term (years one through five) and long-term (years six through ten) planning horizons.

3.2.1.5.1 Study Horizon

In general, at the beginning of each planning cycle, the following models will be developed to simulate two year out, five year out and ten year out conditions:

- Two year out summer peak case
- Five year out summer peak case
- Five year out off-peak case
- Ten year out summer peak case

Other study year models may also be developed as necessary depending on specific system conditions that need to be evaluated as part of the planning process described under *Section 4* of this BPM.

3.2.1.5.2 Model Requirements

Section 4.3.5 of this BPM describes the specific model requirement for MTEP reliability planning models. Unless otherwise specified under *Section 4.3.5* of this BPM, the General System Model Criteria described under *Section 3.3* below will be used.

3.2.1.5.3 Model Review

MISO planning staff will create the initial MTEP reliability planning models using MOD and post the starting models on the MISO Planning Portal (MTEP Portal) and MTEP ftp site for stakeholder review. Access to MTEP models requires executing the relevant non-disclosure agreements (NDA) and following the instructions posted on the MISO Access Our Models page, Client Relations.

The timetable for the MTEP model review and approval process will also be posted on the MTEP ftp site at the beginning of each planning cycle.

3.2.1.6 Base Models for MTEP Economic Studies

Based on the defined economic study scope, MOD will be used to create the starting power-flow models for the selected planning study years.

3.2.1.6.1 Study Horizon

Economic models will be developed to simulate five-year-out, ten-year-out and fifteen-year-out economic conditions using the five-year-out and ten-year-our summer peak powerflow cases.

3.2.1.6.2 Model Requirements

Transmission topology data for the economic models are based on the powerflow base models applicable to the chosen economic study year. The Load and generation information source is as described in *Section 4.4.3* of this BPM. See *Section 4.4.3* of this BPM for additional information on data Sources and assumptions used for economic studies.

3.2.1.6.3 Model Review

MISO planning staff will create the initial MTEP economic planning models using MOD and post the starting powerflow models on the MTEP ftp site for stakeholder review. Changes identified through the stakeholder review will be made prior to using the powerflow models for economic studies. The timetable for the MTEP model review and approval process will also be posted on the MTEP ftp site at the beginning of each planning cycle.

3.2.1.7 Base Models for Generator Interconnection Studies

See Appendices E, F, and G for details on GI study functions and model requirements. Unless otherwise noted in those Appendices, the General System Model Criteria described under *Section 3.3* below will be used.

3.2.1.8 Base Models for Transmission Service Request Studies

Section 5.0 of this BPM describes the specific model requirement for TSR study models. Unless otherwise specified under *Section 3.3* of this BPM, the General System Model Criteria described under Section 3.3 below will be used.

3.2.1.9 Base Models for Other Non-cyclical Planning Studies

Section 7.0 of this BPM describes the specific model requirement for other non-cyclical planning studies. Unless otherwise specified under *Section 7* of this BPM, the General System Model Criteria described under *Section 3.3* below will be used.

3.3 General System Model Criteria

3.3.1 Topology Modeling

Topology of the MISO system will reflect the updates from the MISO Transmission Plan, which includes Baseline Reliability and Market Efficiency Projects, and New Transmission Access

Projects. Project status will be reviewed by the MISO planning staff in consultation with the stakeholders before making a determination on including specific future transmission system upgrades in different planning models. Neighboring systems will also be updated based on the data available through the information exchange and coordination arrangement with the neighboring RTOs and regions. The rest of the external system will be updated based on the latest NERC series model information.

3.3.2 Load Modeling

Load will generally be modeled as the most probable (50/50) coincident Load projection for each Transmission Owner service territory, for the study horizon under study. The Load Serving Entity shall provide MISO with Load Forecasts that are comparable with the Load Forecasts data submitted to MISO via the by LSE in other processes. However, there are times when the forecasts may not be identical based on factors such as the treatment of station service Loads. Coincident Loads of each Local Balancing Authority are reflected in the base models for the MISO reliability footprint. The external area Load is modeled as represented in the NERC series models or the neighboring coordinated system used to develop the MOD base models. Conforming and non-conforming Loads need to be differentiated when submitting Load data through MOD. Controllable demand-side management (interruptible Load that can be curtailed, during emergency conditions only) and uncontrollable demand-side management (peak shaving) are identified when submitting Load data to the MOD. Remote Loads (Loads that belong to a company but physically located in another control area) are identified in the inter-area transaction lists submitted through the MOD for proper accounting and modeling. Please refer to the MOD-032 Model Data and reporting Procedures document for more information on submitting Load data for appropriate Load modeling.

3.3.3 Generator Modeling

All existing generators are modeled and the generators that are not part of the Network Resources are modeled off-line unless required to meet public policy, such as renewable energy standards. All existing generators with approved Attachment Y Notices will be modeled offline, beginning on their start date, based on the information provided by the Generator Owners through the System Support Resource study process. Units with approved Attachment Y Notices that have waived their interconnection rights (i.e. retired) will remain offline indefinitely. Units with approved Attachment Y Notices that have not waived their interconnection rights (i.e. suspended) will remain offline for the first 3 years following their start date and after the 3 years they will be available for dispatch. Future generators with a signed Interconnection Agreement are also modeled based on the information available through MISO Generator Interconnection process. If additional generation is needed to serve future Load growth, especially in the case of longer-term models, market resources will be dispatched as available, then proxy generation is modeled based on information available from the interconnection queue and/or through the future generator siting process explained in *Section 4.4* of this BPM. Such proxy generation used in the model are separately identified and documented.

Jointly Owned Units (JOUs) or shared resources are represented in the models either as inter-area transactions or multiple units connected via zero-impedance lines. MISO planning staff will coordinate the appropriate modeling of the JOUs with the respective data submitters for these units. MISO will model resource auction units purchases outside MISO in a similar fashion.

3.3.4 Transactions/Interchanges

The interchanges modeled are derived from the transactions modeled in the latest NERC series models and as updated by Local Balancing Authorities, Transmission Owner(s), and MISO planning staff to reflect new transaction information from OASIS and/or MISO Transmission Service Request study process.

3.3.5 Representation of Lower Voltage Level

The power system models must contain the Bulk Electric System (BES) as typically modeled in NERC series models and required for NERC transmission planning standard compliance. Any sub-BES, lower-voltage transmission may also be modeled as needed to provide additional transmission detail and perform the planning functions described elsewhere in this BPM.

3.3.6 Facilities Ratings in Planning Models

Planning models will be populated with applicable ratings for system intact and contingent conditions. These ratings are developed per FAC-008 and submitted to Model On Demand (MOD) tool for existing and future facilities. Normal ratings are the applicable ratings for system intact conditions and emergency ratings are the applicable ratings for contingent conditions. When producing power flow models from MOD, Rate A will be populated with the normal rating from MOD and rate B will be populated with the emergency rating from MOD for the appropriate seasons.

4 Cyclical Planning Activities

Cyclical planning establishes the transmission expansions that are needed to address both short-term and long-term Transmission Issues that arise on an on-going basis. As such, cyclical planning encompasses a number of sub-processes that link to each other but that have their own associated procedures, schedules, and stakeholder interactions.

4.1 Stakeholder Interactions during Regional Planning Cycle

At each major step of the planning process, the MISO planning staff will engage stakeholders through the following planning groups and through various working groups, task forces and workshops that may be organized by these planning groups.

4.1.1 Subregional Planning Meetings

Subregional Planning Meetings (SPMs) are established under Attachment FF to the Tariff for the purpose of providing an interface to stakeholders on a more localized basis than the centralized stakeholder meetings of the Planning Subcommittee and the Planning Advisory Committee. SPMs are open stakeholder meetings subject to the CEII provisions under the Tariff and as described in *Section 2.7* of this BPM. At a minimum, one SPM will be established for each of the four planning regions established under Attachment FF (North, Central, East and South). The SPMs will occur at the times and for the purposes listed in *Table 4.1.1-1* below associated primarily with the bottom-up planning process described in *Section 4.3* of this BPM.

Table 4.1.1-1: SPM Meetings Schedule

Purpose	Date	Location (Subject to change)
1. Provide additional input to MISO planning staff on stakeholder issues and needs. 2. Discuss pre-planning information and develop MTEP cycle study scope. 3. Review and provide input to planning models. 4. Review and discuss known issues proposed projects and solution ideas.	January	North, Central, East and South (locations to be announced)

Purpose	Date	Location (Subject to change)
1. Review system performance issue identified in initial phase analysis. 2. Discuss possible alternative solutions to issues.	March/April	North, Central, East and South (locations to be announced)
1. Review results of alternative analyses. 2. Comment on proposed preferred solutions.	June/July	North, Central, East and South (locations to be announced)

4.1.2 Planning Subcommittee

The Planning Subcommittee (PS) is also established under Attachment FF and operates under the stakeholder Governance Guides developed by the Committee Restructuring Group. The PS charter is posted on the MISO Planning website. In general, the PS is a stakeholder group of participants interested in MISO planning issues and processes. The PS meets at regular bi-Monthly meetings or as otherwise established under the charter. For the purposes of addressing review and comment on the MTEP regional plan development, the PS will meet at the times and for the purposes listed in *Table 4.1.1-2* below associated primarily with the short-term planning process described in *Section 4.3* of this BPM.

Table 4.1.1-2: PS Meetings Schedule

Purpose	Date[2]	Location (Subject to change)
1. Review and comment on scope of analysis proposed by SPMs. 2. Review and Comments on models. 3. Other regular agenda items as developed by MISO planning staff or participants.	February	Location to be Announced
1. Review MTEP analysis results. 2. Discuss possible alternative solutions to issues. 3. Other regular agenda items as developed by MISO planning staff or participants.	April	Location to be Announced

[2] Reference Committee calendar for specific dates

Purpose	Date[3]	Location (Subject to change)
1. Review MTEP analysis results 2. Other regular agenda items as developed by MISO planning staff or participants.	June	Location to be Announced
1. Comment on proposed preferred solutions. 2. Review preliminary Cost Allocations. 3. Other regular agenda items as developed by MISO planning staff or participants.	August	Location to be Announced
1. Comment on MTEP Report Draft. 2. Other regular agenda items as developed by MISO planning staff or participants.	September	Location to be Announced
1. Input on completed MTEP process. 2. Other regular agenda items as developed by MISO planning staff or participants.	October	Location to be Announced
1. Input on issues and scope for next MTEP. 2. Other regular agenda items as developed by MISO planning staff or participants.	December	Location to be Announced

4.1.3 Planning Advisory Committee

The Planning Advisory Committee (PAC) is established under the Transmission Owner(s) Agreement and Attachment FF and operates under the stakeholder Governance Guides developed by the Committee Restructuring Group. The Planning Advisory Committee is a source of input to the MISO planning staff toward development of the MTEP. Its membership consists of one Member from each of the following stakeholder groups:

- Transmission Owner(s)
- Municipal and cooperative electric utilities and transmission-dependent utilities
- Independent power producers and exempt wholesale generators
- Power marketers and brokers
- Eligible end-use customers
- State regulatory authorities
- Representative of public consumer groups
- Environmental and other stakeholder groups

[3] Reference Committee calendar for specific dates

- Transmission Developers
- Coordinator Sector

The PAC charter is posted on the MISO Planning website. In general, the PAC is a stakeholder group of participants interested in MISO policy issues as they relate to planning. The PAC meets quarterly, or as otherwise established under the charter. The PAC will review the MTEP scope of work developed through the SPM and PS meetings, and will provide input into to development of the assumption sets to be applied in the Long-term planning process. These assumptions include those related to development of planning Futures, Generation Resource forecasts and siting, and transmission plan development. Agenda items to address these issues will be established annually by the PAC in collaboration with MISO planning staff. MISO planning staff will also organize various stakeholder workshops to address long-term planning issues and process.

The PAC provides a final review of each MTEP report and provides its advice to the MISO planning staff, the Advisory Committee, and the Transmission Provider Board.

4.1.4 Expedited Project Review

In accordance with Attachment FF to the tariff, in the event that a Transmission Owner determines that system conditions warrant the urgent development of system enhancements that would be jeopardized unless MISO performs an expedited review of the impacts of the project, MISO shall use a streamlined approval process for reviewing and approving projects proposed by the Transmission Owner(s) so that decisions will be provided to the Transmission Owner within thirty (30) Days of the project's submittal to MISO unless a longer review period is mutually agreed upon.

4.1.4.1 Notification of Need for Expedited Review

When it becomes necessary for a Transmission Owner to request expedited project review, the Transmission Owner will submit the project and corresponding data to MISO using a request form posted on the MISO website: Expedited Project Review Request. Valid requests must include all of the supporting information indicated on the form. MISO will post valid requests within two weeks after receipt.

4.1.4.2 Expedited Review Process

MISO will integrate the expedited review of the project into the Subregional Planning Meetings (SPM) and/or Technical Studies Task Force (TSTF) meetings of the current MTEP cycle. MISO will review the project with stakeholders for impacts on system reliability performance in the same manner as for all other local area projects rolled-up into the current MTEP cycle review. Such reviews include consideration of planning criteria, planning analysis, models, Load Forecasts, and alternatives consistent with the planning process provisions of Attachment FF to the tariff in order to ensure the project does not adversely impact reliability and/or any Baseline Reliability Project, that the project adequately addresses the reliability deficiency.

As with all projects reviewed in the annual cycle, any project undergoing expedited review that would otherwise qualify for regional cost sharing as a Market Efficiency Project (MEP), based upon project cost and voltage threshold criteria, and that would be eligible for competitive development, will be evaluated to see if it would qualify as an MEP except for the urgent need (established by the Transmission Owner). This assessment will be provided for informational purposes if the lead-time and the required in-service date of the project preclude its treatment as an MEP.

4.1.4.3 Inclusion of Project in MTEP

Based upon the completed project review, including input from stakeholders at the SPM/TSTF meeting, MISO will make a determination as to inclusion of the project, or preferred alternative, in the Appendix A of the current MTEP. Once included in the Appendix A it is expected that the Transmission Owner will proceed to implement the project in order to meet its obligations and requirements as provided for in the Transmission Owner's Agreement. The project will be included in the Appendix A list of projects to be presented to the Board of Directors for Certification at the completion of the current annual MTEP cycle. MISO will identify the projects in the MTEP report that have been reviewed on an expedited basis, and will include a report on the number of Expedited Review requests by Transmission Owner.

The results of the completed expedited project review at the SPM/TSTF will be presented at the next available Planning Advisory Committee (PAC) meeting at which the meeting material posting requirements of the stakeholder Governance Guide can be adhered to. Written comments from the PAC on any Expedited Review Projects will be included with other PAC comments on the MTEP at the completion of the annual MTEP cycle. MISO staff will consider the input from the PAC when applying its discretion to determine whether or not to raise the recommendation of the project for inclusion in MTEP to the attention of the System Planning Committee (SPC) of the MISO Board. Stakeholders may also provide advice relative to the project to the SPC and/or the Board in accordance with the protocols of the Advisory Committee.

4.1.4.4 Projects Not Eligible for Expedited Review

Projects that meet tariff criteria to be included in MTEP as an MEP, or that otherwise provide for market efficiency or other needs, and that are not needed to meet the obligations or requirements of the Transmission Owner will not be reviewed on an expedited basis.

4.1.4.5 Expectations of Transmission Owner(s)

The open and transparent planning requirements of Attachment FF to the tariff require that no proposed project of a Transmission Owner that has elected to integrate their local planning processes into the Transmission Provider's processes shall be recommended in the MTEP for implementation until completion of the annual needs analysis carried out in the annual MTEP cycle, except when an expedited review is necessary. Expedited review requests should be exceptions to the normal review process. It is expected that the Transmission Owner will identify the need for projects early enough to be fully vetted in the annual MTEP cycle without the need for expedited review. The Transmission Owner will be expected to present to stakeholders and to MISO at the SPM/TSTF review the reasons why the needs driving the project are urgent and why the project was not identified early enough to be reviewed in the full MTEP review cycle.

4.2 Pre-planning Steps Common to Bottom-up and Top-down Planning

Each MTEP regional planning cycle commences with the assembling of initial information from stakeholders and Transmission Owner(s), and system performance data. This information is used to finalize a scope of work for the current planning cycle. The annual scope of work is generally expected to be consistent from cycle to cycle, but may involve alternative analysis as may be dictated by the information received.

Initial information includes the reporting of data essential for development of system models, the process for which is described in *Section 3* of this BPM.

4.2.1 Assemble Pre-planning Information

The MISO planning staff will collect and assemble information from both internal and external sources that may include but is not limited to:

- Transmission needs identified from Facilities Studies carried out in connection with specific transmission service requests.
- Transmission needs associated with generator interconnection service.
- Transmission needs identified from prior completed short or long-term regional planning processes (i.e. prior MTEP).
- System performance information such as historical incidence of flowgate congestion data, TLR, AFC, any newly identified NCAs, impacts of recently retired generating units or plans for such that have been evaluated in SSR studies.
- Load Forecast and external system information received from the model building process and from Transmission Customers via tariff reporting requirements.
- Transmission needs identified by the Transmission Owner(s) in connection with their local planning analyses.

The first four items listed above are developed by MISO planning staff from internal information. Load Forecast and other modeling data is assembled in the model building process. The reporting and integration of needs identified by the Transmission Owner(s) in their local planning processes are described below.

4.2.2 Integration of Transmission Owner Local Planning Process

The regional planning process must have knowledge of and consider the locally developed plans of all Transmission Owner(s) at the front-end of the regional planning process in order to be able to develop a regional plan in an orderly manner. MISO planning staff solicits this information from Transmission Owner(s) at the front end of the annual planning cycle through a project reporting procedure. The local plans of Transmission Owner(s) are developed through various means, but generally include the following basic steps:

- Solicit input from larger local customers
- Analyze historical distribution Load and trends
- Develop local models
- Apply local planning criteria
- Identify local planning needs, issues, and potential solutions

When the Transmission Owner has developed local planning solutions, those solutions are submitted to the MISO planning staff. This project data is submitted in two forms:

- To Model On Demand for model level data (e.g., script files or idevs that model the project, etc.).
- To the Project Database for descriptions of needs, solutions, alternatives and other project specific data.

This information is solicited by MISO planning staff shortly following the end of the most recently completed MTEP process, and just before the beginning of the next cycle. MISO planning staff assembles this local project information along with the other information described earlier for consideration and review through the MTEP regional planning process at the SPM level. These local planning considerations are assessed and evaluated through the open stakeholder process at SPM forums and integrated into the MTEP regional plan as described further below. For Transmission Owner(s) that have elected under Attachment FF to fully integrate their local planning process with the regional planning processes, the plans developed through local planning processes are included in the beginning of each regional planning cycle as potential alternatives to local system needs identified by the Transmission Owner(s). The regional planning process evaluates, with stakeholder input throughout the cycle, the local plans of these Transmission Owner(s), as one input into the development of the regional plan.

4.2.3 Project Reporting Guidelines

Members who are Transmission Owner(s) are required to report projects developed in their local planning processes and that have an expected in-service date within the MTEP planning horizon. Projects with in-service dates beyond the MTEP planning horizon and up to 10 years from the current year may be submitted for MISO review and tentative inclusion in the MTEP. All transmission voltage Projects with the following criteria must be reported to the Project Database:

- All projects that represent a system topology change (i.e., constructing a new circuit, tapping an existing circuit, removing a circuit from the planning model, or retiring a circuit). All projects that include interconnecting new distribution service from new or existing transmission facilities must report distribution sub taps.
- All new circuit breaker additions to transmission facilities.
- All upgraded circuit breakers that result in changes to a breaker's continuous current-carrying or interrupting capacity.
- All projects that change the electrical characteristics of a circuit (i.e., changes to shunt or series inductors, capacitors, conductor type or performance, switches, current transformers, or wave traps).

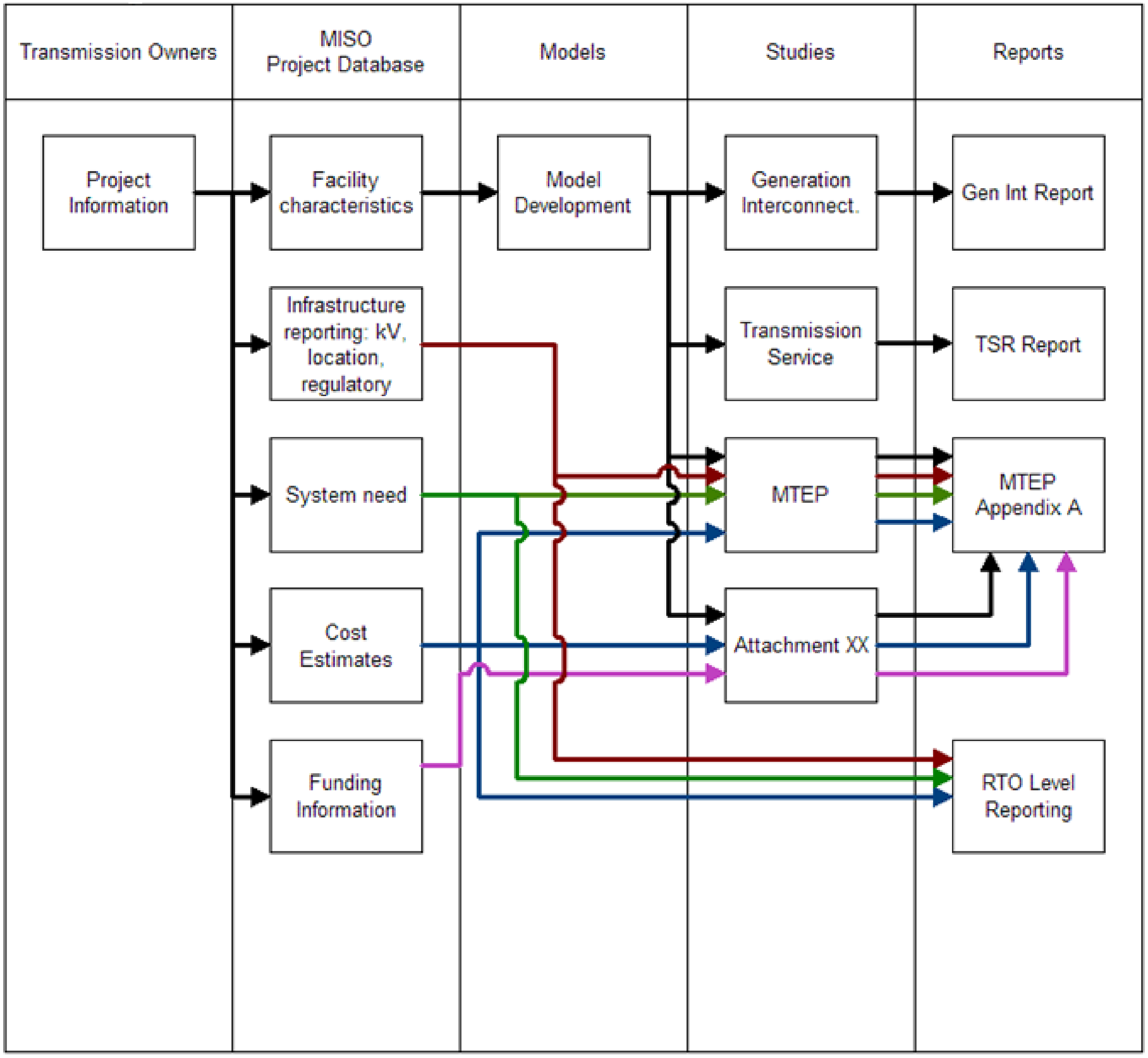
- All projects involving like-for-like replacements with direct costs of $1 million or more.
- All projects that change a circuit rating.
- Generator interconnection projects with signed Interconnection Agreements (provided by MISO planning staff) and Network Upgrades associated with conditionally confirmed transmission service requests (TDSP).
- Members are encouraged (but are not required) to report projects that consist of like-for-like replacements costing less than $1 million, or projects that improve Transmission System operational performance such as SCADA systems, communications, or relaying upgrades.

Project reports are submitted to MISO as part of the MTEP development and update cycle in December, prior to the start of each MTEP regional planning cycle. Project Database updates are reported to the designated MISO planning staff MTEP Appendix A Coordinator. Transmission Owner(s) that have their own FERC approved local planning processes may submit new project proposals and request MISO expedited review and endorsement during other Months within an MTEP cycle as provided for in the Transmission Owner(s) agreement. Other Transmission Owner(s) may only do so on an exception basis due to urgent need to begin development of a local project ahead of the normal regional planning cycle schedule. These expedited reviews are handled via the “Expedited Project Review” procedure described elsewhere in this BPM.

Project data is presently submitted to the Project Database using the MISO Planning Portal web application. The Project and Facility table field definitions are documented in the Planning Portal. Modeling data associated with these projects should also be submitted to the Model On Demand database.

To prepare and submit a required report, the Transmission Owner identifies projects that are planned or under development. Each project is associated with one or more facilities, and this relationship is specified in the Facilities table. The Project table includes a summary of modeling analysis results that support the reliability or economic improvement justification for each project. Detailed analytical results supporting projects is kept in the study Results Database. Project information flow from the Transmission Owner(s) through the MISO planning process and into applicable reports is shown in *Figure 4.2.3-1* below.

Figure 4.2.3-1: MISO Projects Database Information Flow



4.2.3.1 Project Status Updates

In accordance with the MISO Tariff[4], status updates are required to track the progress of a planned transmission project[5]. MISO will request status updates on a quarterly basis via an e-mail sent to the MISO Planning Superlist (which contains the PAC, PSC, and RECBWG lists) no later than fifteen (15) Calendar Days prior to the end of each calendar quarter. Quarterly status updates shall be submitted to MISO fifteen (15) Calendar Days after the end of each calendar quarter[6], except that the Quarterly status update shall be due on the last Calendar Day of the quarter for the quarter which Milestone 2 has been achieved. Such status updates shall be based on the best information available at the time, utilizing the status update template(s) provided by MISO in the respective email request.

In addition to quarterly status updates, MISO, at its sole discretion, may request additional status updates outside the quarterly update cycle. Upon such request, Selected Developers and Transmission Owners are required to provide MISO with the requested status update within ten (10) Business Days, or within a time period mutually agreed upon by MISO and the Selected Developer or Transmission Owner. In providing such status updates, each Selected Developer and Transmission Owner must make a good faith effort to provide MISO with the best information available at that time.

4.2.3.1.1 Requirements for Eligible Project Facilities

Each quarterly status update for facilities identified in an Eligible Project[7] approved after December 1, 2015, shall contain, at a minimum, the information specified in Sections 4.2.3.1.1.I through 4.2.3.1.1.XVI of this BPM:

I. Development status[8] of each facility;
II. Estimated in-service date for each facility, including the identification of any changes;
III. Estimated cost to complete each facility[9];
IV. Estimated total project costs[10] and the identification of any changes from the Baseline Cost Estimate[11];
V. Identification and description of items included in the reported estimated total project cost under *Section 4.2.3.1.1.V* of this BPM, such as allowance for funds used during

4 Attachment FF §I.C.11 of the Tariff
5 i.e. one that is either listed in MTEP Appendix A or is proposed by MISO staff to move to Appendix A in the current planning cycle
6 i.e. March 31, June 30, September 30, and December 31 of each year.
7 'Eligible Project' is defined by the MISO Tariff under Module A.1.E.
8 e.g. 'Proposed', 'Planned', 'Under Construction', 'In-Service', etc.
9 Specified in US $'s for the facility's in-service year
10 Specified as the sum of each facility cost-estimate provided under Section 4.2.3.1.1.IV of this BPM
11 'Baseline Cost Estimate' is defined by the MISO Tariff in Section IX.C.1.1 of Attachment FF

construction ("AFUDC"), construction work in progress ("CWIP"), overhead, contingencies, etc.;

VI. Project expenditures as of the end of the previous calendar quarter[12];

VII. The percentage of the project expenditures provided under *Section 4.2.3.1.1.VII* versus the Baseline Cost Estimate[11] (e.g. expenditures / Baseline Cost Estimate);

VIII. Project schedule depicting the activities for each facility, including the identification of any changes[13];

IX. Design and engineering status[14] for each facility;

X. Status of obtaining necessary regulatory and or environmental permits, certificates, or approvals, including meeting necessary licensing requirements, for each facility;

XI. Status of any necessary land and right-of-way acquisition for each facility[13];

XII. Status of any necessary interconnection agreements for each facility[13];

XIII. Construction status for each facility;

XIV. As applicable, detailed cost estimates for each transmission line facility as follows:
   a. Engineering labor per transmission line facility[9];
   b. Construction labor per transmission line facility[9];
   c. Right-of-way acquisition per transmission line facility[9];
   d. Material procurement per transmission line facility[9]; and
   e. Regulatory or miscellaneous costs per transmission line facility[9].

XV. As applicable, detailed cost estimates for each substation facility as follows:
   a. Engineering labor per substation facility[9];
   b. Construction labor per substation facility[9];
   c. Land acquisition/site property rights per substation facility[9];
   d. Material procurement per substation facility[9]; and
   e. Regulatory or miscellaneous costs for each substation facility[9].

Each quarterly status update indicating a material change or deviation from the MTEP in-service date, Baseline Cost Estimates, or any information submitted in previous status updates, shall also include: an explanation of such change; the cause of, or the reason for, such change; and an assessment of the impact such change may have on the project, including the continued ability to meet the MTEP in-service date and any plans to mitigate such impacts.

In addition to the information required to be included in the quarterly status updates under Sections 4.2.3.1.1.I through 4.2.3.1.1.XVI of this BPM, the information specified in Sections

[12] Specified in US $'s as the sum of each facility's expenditures
[13] May be submitted as one (1) or more attachments to the status update
[14] e.g. 'Not-Started', 'Started', 'Completed', etc.

4.2.3.1.1.XVII through 4.2.3.1.1.XX of this BPM are also required to be submitted to MISO within one hundred and eighty (180) Calendar Days[15] of the date the facilities are energized.

XVI. Final costs to construct the facilities[9];

XVII. Final 'as-built' drawings[16] for each facility;

XVIII. Inspection reports[16] for each facility, if any inspections were performed; and

XIX. Geo-spatial information[16] for each facility (e.g. GIS maps, GPS coordinates, etc.).

4.2.3.1.2 Requirements for Competitive Transmission Facilities

Each quarterly status update for the Competitive Transmission Facilities identified in an Eligible Project shall contain, at a minimum, the information specified in Sections 4.2.3.1.1.I through 4.2.3.1.1.XVI of this BPM and the additional information specified in Sections 4.2.3.1.2.I through 4.2.3.1.2.VI of this BPM:

I. Status of any necessary project financing;

II. The percentage (%) of the total expenditures to date versus the total projected cost schedule provided in the Selected Proposal[17];

III. Whether any rate filings associated with the Competitive Transmission Facilities were made during the previous calendar quarter or are expected to be made during the upcoming calendar quarter;

IV. Disclosure of any changes in the continuing ability of the Selected Developer to meet its obligations under the Selected Developer Agreement, according to the schedules and milestones agreed to therein, including any binding cost caps or cost containment measures that were included in the Selected Proposal;

V. Identification of and an explanation of any changes from the specifications included in the Selected Proposal; and

VI. If any changes are identified in a quarterly status update under *Section 4.2.3.1.3.V* of this BPM, the quarterly status update shall include the Selected Developer's assessment of any impacts on the Competitive Transmission Facilities resulting from such changes.

In addition to the information required to be included in the quarterly status updates under Sections 4.2.3.1.2.I through 4.2.3.1.2.VI of this BPM, the information specified in Sections 4.2.3.1.1.XVII through 4.2.3.1.1.XX of this BPM are also required to be submitted to MISO within one hundred and eighty (180) Calendar Days[18] of the date the facilities are energized.

15 This may be submitted on a different day if both MISO and the Transmission Owner or Selected Developer agrees on a different date.
16 Submitted as one (1) or more attachments to the status update
17 Specified as the sum of expenditures to date of each Competitive Transmission Facility of the Competitive Transmission Project in US $.
18 This may be submitted on a different day if both MISO and the Transmission Owner or Selected Developer agrees on a different date.

4.2.3.1.3 Milestones

Transmission Owners are encouraged to provide updates as frequently as possible, especially after a project's schedule or estimated costs shift by a significant amount. Projects that have not reached or passed a milestone in the last quarter are not required to submit project status updates, although the Transmission Owners must confirm that they have received the request and have no projects that have reached or passed a milestone. Project status updates are required for any projects which have reached and/or passed one of the milestones listed below. If no milestone is reached during the calendar year, then a project status update is required at the end of the year. Transmission Owners must make good faith efforts to provide the best information available concurrent with Milestone 1, 2, 3, and 4 for the quarter immediately following the achievement of Milestone 5.

There are six (6) milestones that shall be utilized in status updates, they are:

- Milestone 1 - Final Subregional Planning Meeting / Expedited Review Submittal;
- Milestone 2 - Pre-project approval;
- Milestone 3 - Long lead materials;
- Milestone 4 - Pre-construction; and
- Milestone 5 - Facility completion.

For typical projects, excluding projects submitted for Expedited Review, Milestone 1 corresponds to the final Subregional Planning Meeting in which a particular project is discussed prior to it being submitted to the MISO Board of Directors for their consideration (typically in June prior to a December approval). For projects submitted for Expedited Review, Milestone 1 will occur at the submission of the Expedited Review request form. The Milestone 1 status update for transmission projects that are to proceed through the MISO Competitive Developer Selection Process will be provided by MISO. For all other transmission projects, the responsible Transmission Owner(s) will provide the status updates.

For all typical (i.e., not projects submitted for Expedited Review) projects, Milestone 2 corresponds to the last quarterly status update prior to the time the MISO Board of Directors is scheduled to meet to consider approval of the project (typically September for a December approval). For all projects submitted for expedited review, Milestone 2 will occur at the Planning Advisory Committee meeting where the project is discussed. For transmission projects that may meet one or more regional cost sharing criterion, MISO will provide the status update for Milestone 2. For all other transmission projects, the assigned Transmission Owner(s) will provide the status update for Milestone 2.

For all projects, Milestone 3 corresponds to the quarter prior to when the Transmission Owner or Selected Developer will place their first order for materials and equipment requiring a long lead time (i.e. materials which require at least 6 Months between their order and receipt).

For all projects, Milestone 4 corresponds to the quarter prior to commencement of physical construction on the facilities associated with the transmission project.

It is recognized that the timing of reporting updates for Milestones 3 and 4 may be significantly in advance of the availability of the most accurate information. For example, ordering of equipment or construction commencement may be scheduled for the end of the next quarter which would necessitate providing an update as much as six (6) Months in advance of that activity. As such, Transmission Owners and Selected Developers are expected to make good faith efforts to provide updated information prior to reaching the Milestones. The Transmission Owner and Selected Developer may provide updated information at the next quarterly request if more accurate information is available. If the Transmission Owners and Selected Developers are unable, due to changes in the expected project schedule, to make this update prior to the Milestones they must provide the information at the next quarterly request.

For all projects, Milestone 5 corresponds to the point when a project is complete, and all capital expenditures for its design, engineering, and construction have occurred.

4.2.3.1.4 Requirements for All Other Transmission Facilities

Transmission Owners must provide status updates for all transmission facilities that were not included in either an Eligible Project, in accordance with *Section 4.2.3.1.1* of this BPM, or a Competitive Transmission Project, in accordance with *Section 4.2.3.1.2* of this BPM, for which they are responsible. These updates must contain, at a minimum, the following data:

I. Most Recent Milestone Achieved;
II. In-service Date;
III. Planning Status (Proposed, Planned, Under Construction, In-Service); and
IV. Total Project Cost Estimate

Additional information is required in status updates for all transmission facilities that meet one or more of the following criteria specified in Sections 4.2.3.1.4.V through 4.2.3.1.4.VII:

V. Estimated facility cost is $50 million or greater;
VI. Transmission facility is regionally cost shared (i.e. has any costs allocated outside of the local pricing zone where the facility is geographically located) within the MISO footprint; or

VII. Transmission facility is cost shared with entities beyond the MISO footprint.

For transmission projects that meet one or more of the criteria listed above in Sections 4.2.3.1.4.V through 4.2.3.1.4.VII of this BPM, the status updates must include the additional information specified in Sections 4.2.3.1.4.VIII through 4.2.3.1.4.XII of this BPM:

VIII. Detailed cost estimates** for each line, broken down as follows:
  a. Engineering labor per facility*
  b. Construction labor per facility
  c. Right-of-way per facility
  d. Material per facility

IX. Detailed cost estimates** for each substation, broken down as follows:
  a. Engineering labor per facility
  b. Construction labor per facility
  c. Site property rights per facility
  d. Material per facility

X. Any regulatory or miscellaneous costs**

XI. Project expenditures to date**

XII. Comments describing current variances

* In this context, a project is a transmission upgrade identified in the MISO planning process and included in the MISO Transmission Expansion Plan (MTEP). Facilities are subset of projects associated with a given project

** Detailed cost information will not be made public, but will be used only to provide information to internal MISO staff. State regulators shall receive information as provided for under the Tariff, pursuant to the appropriate nondisclosure and confidentiality agreements.

4.2.3.1.5 Use of Status Update Information

MISO will use the data provided in the status updates to create an aggregate status report on a quarterly basis, redacting any Confidential Information and Critical Energy Infrastructure Information (CEII) as necessary. Quarterly status reports for the previous calendar quarter will be publicly posted on the MISO website no later than thirty (30) Calendar Days after the respective calendar quarter (e.g. the status updates for the 1st quarter of a given year will be posted on or before April 30th of that year, thirty (30) Days after the 1st quarter ended) Unless required sooner. Posted status reports will not include CEII or Confidential Information; however, they will include, at a minimum, the following information for all projects:

I. Project development status, as reported in the status updates;

II. Original project in-service date, as indicated in the approved MTEP report;
III. Updated project in-service date, as reported in the status updates;
IV. Change in the in-service date from original in-service date (in Months);
V. Change in in-service date since last project status update (in Months);
VI. Original estimated total project cost, as indicated in the approved MTEP report;
VII. Updated estimated total project cost, as reported in the status updates;
VIII. Expenditures to date (in dollars and percent of total estimated project cost);
IX. Change in estimated total project cost since last status update (in percent);
X. Change in estimated total project cost since original estimate indicated in the approved MTEP report (in percent); and
XI. A summary of any comments.

Data provided in the status updates will also be used in presentations given to the MISO Board of Directors and stakeholders. In accordance with the MISO Tariff[19], a presentation will be given to the System Planning Committee of the Board of Directors on a quarterly basis, or as otherwise directed by the MISO Board of Directors. Further informational updates will be provided to the Planning Advisory Committee as specified by the Planning Advisory Committee management plan.

4.2.4 Study Scope Development

Once MISO planning staff assembles pre-planning information, a draft scope of study is prepared by the MISO planning staff and distributed to the SPMs, the PS and the PAC. These stakeholder groups meet on the schedules described above to shape the scope of the current study cycle. In developing the scope of study, the stakeholders and MISO planning staff will consider all of the available pre-planning information as well as any particular service issues raised by stakeholders at these meetings. Stakeholders are invited to solicit written comments and information to help guide the planning analysis before and after stakeholder meetings. MISO Planning staff will endeavor to provide a written reply to all specific stakeholder recommendations for study that are not adopted.

4.3 Bottom-up Planning

Bottom-up transmission expansion planning addresses identification of reliability and localized Transmission Issues and development of solutions in the time frame of one to ten years, with particular focus placed on the next five years. Bottom-up transmission expansion planning is the process used by MISO (the NERC Planning Coordinator or PC) and the Transmission Owner(s)

19 Attachment FF §I.C.11 of the Tariff

(the NERC Transmission Planners or TP) to comply with NERC TPL standards in particular, and other NERC and regional standards applicable to MISO and/or the Transmission Owner(s) when compliance with such standards is achieved entirely or partially through the transmission expansion planning process. Bottom-up transmission expansion planning is also the process used by MISO and the Transmission Owner(s) to i) comply with state and local planning requirements; ii) comply with the Transmission Owner's own planning criteria; iii) and address requirements or needs related to local issues (e.g., requirement to relocate existing transmission facilities, etc.), operational and safety issues (e.g., the need to replace problematic equipment, etc.), infrastructure issues (e.g., the need to replace aging facilities, etc.), and reliability issues outside the scope of the NERC and regional standards (e.g., transmission upgrades to improve end-use customer service reliability, etc.).

As discussed in more detail in *Section 2.3* of this BPM, bottom-up transmission planning produces projects classified as either Baseline Reliability Projects (if such projects are required to comply with NERC standards, particularly NERC TPL 001-4 standards) or "other" projects. Bottom-up transmission projects may be submitted by Transmission Owner(s) (acting in their role as Transmission Planners) for evaluation in the MISO transmission expansion planning process or may be developed directly within the MISO transmission expansion planning process based on ideas developed by MISO stakeholders and/or MISO staff.

4.3.1 Steps in the Bottom-Up Transmission Expansion Planning Process

Key Milestone points in the bottom-up transmission expansion planning process for a particular MTEP cycle are as follows:

- Development of the bottom-up expansion planning scope of work for the current MTEP
- Development of bottom-up planning models as discussed in Section 3 of this BPM
- Identification of projected issues with no system improvements
- Development of alternative solutions to identified issues
- Selection of the best solutions to address identified issues
- Testing the final solution set to ensure the plan is fully compliant with all applicable standards, criteria, and requirements.
- Monitoring progress of solution implementation

4.3.1.1 Identification of Projected Transmission Issues with No System Improvements

Once the MTEP scope has been finalized and the required models have been developed as further discussed in Section 3 of this BPM, simulations of the transmission system will be performed to identify projected violations of i) NERC TPL standards, ii) other NERC and regional standards, iii) state and local jurisdictional requirements, and iv) Transmission Owner planning criteria. Simulations will be performed in accordance with the NERC TPL standards, regional planning standards, and Transmission Owner planning criteria regarding the specific Loading conditions (e.g., summer peak, shoulder peak, light Load, etc.), time horizons (e.g., two-year out forecasted Loads, five-year out forecasted Loads, ten-year out forecasted Loads, etc.) and contingencies to be evaluated. Simulations will analyze, as stipulated in the NERC TPL standards and other applicable standards and planning criteria, i) steady-state performance (thermal loading and steady state voltages), ii) stability (voltage stability and transient angular stability), iii) susceptibility to cascading, and iv) performance during transient conditions (e.g., susceptibility to tripping during stable power swings, ability to ride through transient voltages, etc.).

The issues identification phase will tabulate all projected issues including the specific conditions and/or sensitivities that produced the issues and the specific standards or planning criteria that are violated.

4.3.1.2 Development of Alternative Solutions to Projected Issues

Once issues are identified, the planning process will explore alternative solutions to those issues with the objective of recommending the best overall solutions. Consistent with Attachment FF of the Tariff, both transmission and Non-Transmission Alternatives (NTA) to resolve Transmission Issues will be considered on a comparable basis within the MISO transmission planning process. Non-transmission alternatives include contracted demand response, new or upgraded generators with executed interconnection agreements, and other non-transmission assets (e.g., energy storage not classified as a transmission asset, etc.).

With regard to transmission alternatives, the Transmission Owners Agreement provides MISO with the authority to compel a Transmission Owner to make a good faith effort to construct transmission facilities included in Appendix A of an approved MTEP or, in the case of transmission facilities subject to competitive bidding, the Transmission Owners Agreement provides MISO with the authority to develop and issue RFPs for such transmission facilities. For non-transmission alternatives, the Transmission Owners Agreement and Tariff provide no such authority to MISO. However, in order to provide for the consideration of both transmission and non-transmission alternatives within the overall transmission planning process in accordance with Order 890 and Order 1000, MISO will provide, upon request, information regarding the minimum requirements that must be satisfied for the entire planning horizon by non-transmission alternatives in order to address identified Transmission Issues, and to the extent that a non-transmission alternative is pursued in accordance with the requirements outlined in Attachment FF of the Tariff and this BPM, MISO working with the responsible Transmission Owner will defer, de-scope, or withdraw the transmission project previously proposed to address the Transmission Issue. This process facilitates MISO compliance with FERC Order 890 in a manner that is consistent with MISO's authorities and responsibilities as outlined in the Tariff and the Transmission Owners Agreement.

With regard to non-transmission alternatives, in order to ensure comparability for such non-transmission alternatives, Attachment FF requires adherence to the following:

- For generation alternatives, a Generation Interconnection Agreement must be executed pursuant to Attachment X of the Tariff and in accordance with the requirements of Attachment FF.
- For demand response alternatives, a demand response agreement must be executed between the applicable LSE(s) and end-use customer(s) in accordance with the requirements of Attachment FF.

The scope of transmission alternatives that could address a Transmission Issue include: (i) operational intervention such as redispatch and/or reconfiguration of the transmission system through operator instruction (i.e., system adjustments); (ii) implementation of remedial action schemes subject to applicable standards and approvals; and/or (iii) transmission expansion such as the upgrade of existing facilities or the construction of new transmission facilities. The scope of non-transmission alternatives that could address a Transmission Issue include: (i) contracted demand response; (ii) planned generator interconnections with executed interconnection agreements; and/or (iii) mitigating impacts of any other planned non-transmission assets.

If a non-transmission alternative is pursued and it effectively addresses the applicable Transmission Issue(s) through the execution of applicable agreements within a time period where it is feasible to defer, de-scope, or withdraw a previously proposed transmission project, then the non-transmission alternative may result in the transmission project being deferred, de-scoped, or withdrawn as appropriate based on subsequent analyses by MISO and the responsible Transmission Owner(s) using models that incorporate the non-transmission alternative. To the extent no non-transmission alternative addresses or has been implemented to address a specific Transmission Issue, then consideration will be given to effectiveness, prudency, and robustness of alternative transmission solutions to determine the best transmission solution.

In accordance with their obligations under the NERC TPL standards, NERC Transmission Planners (which are generally Transmission Owners in MISO), will identify issues, investigate alternatives, and develop solutions to be rolled up to the MTEP planning process for consideration. Alternative transmission solutions may be initiated and developed within the MTEP process by MISO staff and/or other stakeholders for consideration as well. In any event, the MTEP process will consider alternative transmission solutions to address each of the identified issues when no effective non-transmission alternative has been identified or successfully implemented.

The development of transmission and non-transmission alternatives is described in the following sections.

4.3.1.2.1 Transmission Alternatives

4.3.1.2.1.1 Planned Redispatch, Reconfiguration, or Load Shed

Planned redispatch, reconfiguration, or load shed is used as an operator initiated and/or controlled adjustment to the system to take corrective action to address a Transmission Issue. Under certain conditions specified within the NERC TPL standards, these actions may include generation redispatch, transmission reconfiguration, or load shed (non-consequential load curtailment).

Planned redispatch, reconfiguration, or load shed may be developed by the Transmission Owners or MISO or proposed by other stakeholders. The process of developing a planned redispatch, reconfiguration, or load shed will include verification that actions are permitted within NERC standards and local planning criteria for the specified system conditions, can be implemented in a timely manner by the system operator within the timeframe allowed as specified by the Transmission Issue, and assess the impact of the next plausible event after a reconfiguration is applied. Further planned redispatch, reconfiguration, or load shed recommended to address Transmission Issues will serve as a component of the aggregate Corrective Action Plans identified in the MTEP to comply with the NERC Standards.
The use of planned redispatch, reconfiguration, or load shed as a planned solution to Transmission Issues shall be summarized at the appropriate SPM. Specific Transmission Issues being addressed by planned redispatch, reconfiguration, or load shed will be reported at the appropriate SPM if they exceed any of the following values:

- Generation Redispatch > 600 MW increment/decrement
- Transmission Reconfiguration > 1 transmission line/transformer opened
- Load Shed > 100 MW

4.3.1.2.1.2 Remedial Action Schemes

A Remedial Action Scheme (RAS) is a NERC defined term[20]. A summary of the NERC definition includes a scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW

[20] NERC Definition: RAS Definition

and Mvar), tripping load, or reconfiguring a System(s). A key distinguishing characteristic of a Remedial Action Scheme is that it is automatic and occurs without any Operator Intervention. Examples of schemes not considered to be a RAS include; non-centrally controlled automatic underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS).

A Remedial Action Scheme could be developed by the Transmission Owners or MISO or proposed by other stakeholders. The process of developing a remedial action scheme will include evaluation of its inadvertent and expected operation considering NERC standards and local planning criteria, verification of its feasibility with the equipment owners impacted by the remedial action scheme, and its impact to the robustness of the system. A Remedial Action Scheme is inherently less robust than transmission expansion solutions and limits the operational flexibility of the system. The use of a RAS should typically be a temporary solution to allow for additional time to develop a more robust permanent solution. To the extent that the Transmission Issues being addressed represent projected violations of the NERC TPL Standard, the remedial action scheme proposed or recommended to address such Transmission Issues will serve as a component of the aggregate Corrective Action Plans identified in the MTEP to comply with the NERC Standards.

4.3.1.2.1.3 Transmission Expansion

Transmission expansion, which includes upgrades to existing transmission facilities and construction of new transmission facilities, represent transmission solutions that are pursued to address Transmission Issues when planned redispatch, reconfiguration, load shed and/or remedial action schemes are not feasible or effective and/or non-transmission alternatives have not been pursued or do not meet the requirements to address the Transmission Issue. Transmission expansion solutions could be developed by the Transmission Owners or MISO or proposed by other stakeholders, and will take the form of transmission projects that address Transmission Issues in the most effective, prudent, and robust manner possible. The process of developing transmission projects will include, when appropriate, evaluation of alternative transmission projects to address a specific Transmission Issue or Transmission Issue set. To the extent that the Transmission Issues being addressed represent projected violations of the NERC TPL Standard, the transmission projects proposed or recommended to address such Transmission Issues will serve as a component of the Corrective Action Plans to facilitate compliance with the NERC TPL Standards (or when applicable, other NERC standards) for the MTEP cycle in question.

4.3.1.2.2 Non-Transmission Alternatives

4.3.1.2.2.1 Contracted Demand Response or Planned Generator Interconnections

Prior to presenting identified issues to stakeholders at an SPM, MISO will confer with the Transmission Owners to determine which projects have drivers or other constraints that cannot be adequately or feasibly addressed by non-transmission alternatives, and will then flag these projects as not compatible with non-transmission alternatives. For all flagged projects, the Transmission Owners and MISO will provide the specific drivers or other constraints that make the project infeasible for consideration of a non-transmission alternative. This information will be provided at an SPM for review by stakeholders. Once identified Transmission Issues and associated project proposals are first presented to stakeholders, if a stakeholder is interested in pursuing a non-transmission alternative to fully or partially address the Transmission Issues being resolved by a non-flagged transmission project, the stakeholder may request that MISO evaluate and communicate information regarding the minimum requirements that must be satisfied by a non-transmission alternative in order to address the Transmission Issue for which the non-flagged transmission project has been proposed. Upon receipt of such a request, MISO will then work with the applicable Transmission Owner to analyze the Transmission Issue to determine such minimum requirements and provide that information to stakeholders. In order to provide the information that could enable development of either targeted demand-side solutions or efficiently located new generation resources, MISO will include information on the optimized bus locations and MW/MVAR amounts of injections and/or withdrawals of real and/or reactive power that would resolve certain identified Transmission Issues along with the deployment duration requirements associated with such injections and withdrawals. This information will be provided on a case-by-case basis where stakeholders express an interest in potentially pursuing demand-side or generation-side alternatives to a proposed transmission project.

MISO will use an optimization tool to determine required injection and/or withdrawal amounts in MW and/or MVAR by bus location for Transmission Issues for which a non-flagged transmission project has been proposed and stakeholders have requested MISO to provide the minimum requirements a non-transmission alternative would need to meet. The analysis will also determine the deployment duration requirements for such non-transmission alternatives. The results of this analysis will be reviewed by the applicable Transmission Owner and will then be posted and discussed along with the applicable identified Transmission Issues and alternative transmission solutions at the applicable SPM(s). Also, results will be included in the MTEP report that will be recommended to the MISO Board of Directors for approval. Stakeholders interested in developing such non-transmission alternatives can use this information to pursue such opportunities. MISO will make data available to stakeholders during the applicable SPMs.

The incorporation of generation and demand response alternatives includes the following steps:

- The load impact optimization tool will be used to determine the minimum amount of demand reduction or generation addition in MW, by bus location, needed to address a Transmission Issue.
  - For demand response non-transmission alternatives, a developer may use the information to develop a demand response non-transmission alternative and then work with the applicable Load Serving Entity, end-use customers, and when required, the responsible Transmission Operator and Transmission Planner, to develop a program and secure an executed demand response contract including development of any necessary operating guides and procedures to ensure the demand response non-transmission alternative effectively eliminates or mitigates the Transmission Issue.
  - For generation non-transmission alternatives, a developer may use the information to adjust siting for a planned future generation resource, and will then proceed through the MISO generation interconnection process to secure a Generation Interconnection Agreement.
- To the extent the Transmission Issue involves reactive power, additional analyses may be performed to determine reactive power injection/withdrawal requirements for non-transmission alternatives.
- Upon execution of a demand response contract, the Load Serving Entity will adjust the load forecast accordingly (i.e., taking into account how the NTA would impact the load forecast) for inclusion in the models for the next MTEP cycle. It is expected that contractual assurance and exit provisions as outlined in Attachment FF of the tariff for demand response initiatives will be incorporated into any such demand response contract prior to adjusting load forecasts in order to ensure that the demand response solution is firm and there is ample time to address the Transmission Issue should the demand response contract desire to terminate. Upon execution of a Generation Interconnection Agreement, the generator will be included in future MTEP study models for the next MTEP cycle and subject to all provisions that govern generators, including the SSR process.

Should subsequent analysis by MISO and the TOs based on modeling adjustments associated with a non-transmission alternative indicate that the Transmission Issue(s) in question has been eliminated or mitigated in the same MTEP cycle in which it was submitted, MISO and the Transmission Owner will evaluate deferring, de-scoping, or withdrawing the previously proposed transmission project as appropriate in the same manner as would be done if other need drivers were eliminated. Where subsequent analysis occurs in the next planning cycle after NTA agreements have been executed and MISO models have been updated to include the impact of the NTA, and the NTA results in mitigation or elimination of the Transmission Issue(s), MISO and the Transmission Owners will confirm mitigation or elimination of the Transmission Issue and then defer, de-scope, or withdraw the proposed transmission project as appropriate, provided that there are no other proposed drivers of the project. However, in some cases, subsequent analysis could be performed by MISO and the Transmission Owners for projects with a Planning Review Status of “Recommended” (i.e., Targeted Appendix A projects) and “Approved” (i.e., Appendix A projects) subject to the feasibility of considering an NTA at that stage of the planning process. Actual decisions to withdraw, de-scope, or defer a transmission project are always made on a case-by-case basis considering all pertinent factors, including such things as other transmission project drivers and the status of the transmission project at the time NTAs are firm.

It is important to note that when consideration is given to deferring, de-scoping, and/or withdrawing a previously proposed transmission project for any reason, consideration will always be given to the following specific factors:

- Other drivers for the original proposed transmission project (e.g., aging and condition, operational flexibility, etc.).
- Impacts on future projects in the MTEP (i.e., impact on the interdependence of multiple transmission projects within MTEP over a period of time).
- Impacts on other Transmission Issues of deferring, de-scoping, or withdrawing the original transmission project given the NTA will be implemented.
- Impact on Transmission System robustness of deferring, de-scoping, or withdrawing the original transmission project given the NTA will be implemented.
- Impact of NTA on NRIS deliverability*.
- Result of no-harm test of NTA*.
- Lead time for NTA vs. required in-service date*
- NTA duration capabilities vs. NTA duration requirements*
- NTA deployment provisions in the executed contract*
- NTA termination provisions in the executed contract*

  *Embedded in the modeling adjustments and subsequent analyses.

4.3.1.3 Selection of the Best Transmission Solutions for Projected Issues

When no non-transmission alternatives are identified or pursued for a specific Transmission Issue or Transmission Issue set, only alternative transmission solutions will be considered. Once the bottom-up planning process has yielded alternative transmission solutions to these identified Transmission Issues, the process will evaluate all solutions and recommend the best solutions. When project lead times require projects to be approved in the current MTEP cycle in order to meet the required in-service date, the planning process will recommend solutions to the MISO Board of Directors via the MTEP, and if the MTEP is approved, those solutions will become transmission projects in Appendix A of the MTEP report in accordance with Section 2.4 of this BPM. When project lead times do not require final commitment to a specific solution in the current MTEP cycle, the best solution at the time will be selected and placed into Appendix B of the MTEP report. Placing transmission solutions in Appendix B ensures there are Corrective Action Plans for projected TPL reliability issues as required by the NERC TPL standards. However, as conditions change, Appendix B projects may be modified, removed, or replaced with other projects when appropriate.

4.3.2 Planning Criteria and Monitored Elements

In accordance with the MISO Transmission Owner(s) Agreement, the MISO Transmission System is to be planned to meet local, regional, and NERC planning standards. The bottom-up planning analysis performed by the MISO planning staff tests the simulated performance of the system against the NERC Standards as well as regional standards and local planning criteria. Studies to determine compliance with local requirements are handled by the individual Transmission Owner(s), unless agreed upon by the affected Transmission Owner and MISO. The branch Loading limits and Bus voltage limits established by a specific Transmission Owner for their own transmission facilities and system are enforced by MISO.

The Transmission Owner has the exclusive authority to establish and modify its local transmission planning criteria at any time. Annually, the Transmission Owner files updates to its local transmission planning criteria as part of the FERC Form 715 filing. In addition, whenever the Transmission Owner updates local transmission planning criteria, the Transmission Owner provides the updated local transmission planning criteria to MISO. As the Transmission Provider, MISO will post the new Transmission Owner criterial on the planning page of the MISO website or provide a link to the Transmission Owner's website. Concurrently, MISO will post a notice on the planning page of MISO's OASIS website indicating MISO has received updated local Transmission Owner's planning criteria.

The effective date of the Transmission Owner's local transmission planning criteria will be the date that the Transmission Owner submits revised criteria to MISO. The Transmission Owner should use best efforts in notifying MISO that the Transmission Owner is in the process of modifying its local transmission planning criteria thirty (30) Days or more, prior to when the Transmission Owner expects to submit the modified criteria to MISO.

Section 4.5 of BPM-015 Generation Interconnection, indicates when Transmission Owner local planning criteria updates will be used in Generation Interconnection studies.

In the event that a modification to a Transmission Owner's local transmission planning criteria conflicts with any provisions of an established MISO Business Practice Manual, in addition to the process in this section, MISO will work directly with the Transmission Owner to discuss and attempt to resolve the differences. If necessary, MISO will convene the applicable MISO stakeholder forum to address the necessary modifications to the Business Practice to enable consistency with the specific Transmission Owner modifications to local transmission planning criteria.

All system elements that constitute the Transmission System of MISO and the MISO Reliability Area, including tie lines to neighboring systems, are monitored in all planning simulations. In addition, first tier non-MISO Member transmission systems are monitored and, when deemed appropriate, specific elements beyond first tier non-MISO Member transmission systems may be monitored as well. For each monitored branch, the Transmission Owner will provide, at a minimum, a Normal Rating and an Emergency Rating, where such ratings are expressed in MVA at the nominal operating voltage. The Normal Rating represents the maximum Load that may be carried by a branch on a continuous basis and the Emergency Rating represents the maximum Load that may be carried by a branch during abnormal system conditions (i.e., one or more system elements out of service due to forced outages, etc.), but not continuously. The Emergency Rating must be greater than or equal to the Normal Rating.

The Transmission Owner may also provide, at their option, a higher emergency rating for any specific monitored branch. The higher emergency rating is expressed in MVA at the nominal operating voltage and also includes a maximum loading duration. The Short-term Emergency Rating represents the maximum Load that may be carried by a branch on an infrequent basis and for a short period of time not to exceed the associated rating duration. In addition to branch ratings, the Transmission Owner will provide upper and lower normal voltage limits and upper and lower emergency voltage limits to be applied to each monitored Bus. These Bus voltage limits may be expressed in kV or per unit of the nominal operating voltage.

Under system intact conditions, branch loading will be monitored against Normal Ratings and Bus voltage will be monitored against normal Bus voltage limits. Under contingent conditions, branch loading will be monitored against Emergency Ratings and Bus voltages will be monitored against emergency Bus voltage limits. For contingent events that are defined by a single contingency or multiple contingencies occurring simultaneously or near simultaneously (e.g., a permanent transmission circuit fault followed by a stuck breaker and the subsequent tripping of a second transmission circuit a few cycles later by a breaker failure relay scheme, etc.), if post contingent steady-state Loading is above the highest applicable rating (Emergency Rating or, if available, higher emergency rating) or post contingent steady-state voltages are outside the emergency Bus voltage thresholds, then a Corrective Action Plan cannot include post contingency manual system adjustments (including curtailment of firm interchange) or post contingency manual non-consequential Load curtailment since such action requires time to implement and would thus result in a violation of Header Note f in Table 1 of TPL-001-4 that prohibits applicable facility ratings from being exceeded on a steady state basis.

However, if a higher emergency rating exists and i) the post contingent steady state Loading is above the Emergency Rating but below the higher emergency rating, ii) the post contingent steady-state voltage magnitudes are within the emergency Bus voltage limits, and iii) Applicable Reliability Standards allow for system adjustments or firm Load curtailment to address the contingency in question, then manual system adjustments or manual firm Load curtailment may be used so long as MISO or the TOs can demonstrate that such manual system adjustments and/or manual firm Load curtailment can be performed within the duration associated with the higher emergency rating that will return the Loading to a level less than or equal to the Emergency Rating within the duration associated with the higher emergency rating in accordance with Header Note e of Table 1 of TPL 001-4. MISO and the TOs will coordinate as to who and how this determination will be made.

4.3.3 Baseline Models - Data Sources and Assumptions

MISO Baseline Reliability study models will typically include power-flow models reflective of two-year out, five-year out, and ten-year out system conditions in accordance with the NERC TPL standards. For two-year out and five-year out conditions, models will be developed both for the system peak demand case and for at least one off-peak case in accordance with the NERC TPL standards. Other variations of these may also be used as appropriate, based on the stakeholder input for a given planning cycle.

4.3.3.1 Topology

The system topology in the bottom-up planning models will reflect the expected system condition for the planning horizon in question. For models used to identify projected system issues with no system improvements, the topology will represent existing facilities, plus system expansions associated with projects with a Planning Review Status of “Approved”, less any facilities where commitments have been made to retire such facilities. For models used to test the final Corrective Action Plan for compliance with Applicable Reliability Standards and Transmission Owner planning criteria, the topology will represent existing facilities; plus all projects with a Planning Review Status of “Approved”, “Recommended”, or “Validated”; less any facilities where commitments have been made to retire such facilities.

Future transmission upgrades are removed from the model if they have a Planning Review Status of “Not Approved” or “Withdrawn”, or if they do not meet the inclusion criteria above. The non-MISO system representation will be based on the latest external system models for the planning horizon.

4.3.3.2 Generation, Load, and Interchanges

All existing generators and future generators with a filed Interconnection Agreement and in-service date prior to the point in time represented by the model will be included in the model. Any additional generation needed to serve future Load growth will be modeled based on input from future generation modeling processes described in *Section 4.4* of this BPM. New information on generators external to the MISO system shall be received through coordinated data exchange with such external entities and they will also be modeled appropriately. All existing generators with approved Attachment Y Notices will be modeled offline, beginning on their start date, based on the information provided by the Generator Owners through the System Support Resource study process, see *Section 6.2* of this BPM. Units with approved Attachment Y Notices that have waived their interconnection rights (i.e., retired) will remain offline indefinitely. Units with approved Attachment Y Notices that have not waived their interconnection rights (i.e., suspended) will remain offline for the first three (3) years following their start date and after the three (3) years they will be available for dispatch.

In any event, sufficient renewable generation will be modeled to meet renewable portfolio standard mandates effective during the applicable planning horizon. The Load Forecast information is ultimately provided by the LSE either directly or through the Transmission Owner. This information is reviewed and compared against Load data from NERC series models and Load Forecast information filed with FERC and State regulatory agencies. Interchange and transaction data are also updated via the model building process which will include any new firm transactions or changes from the Transmission Service planning process.

A firm LBA dispatch is simulated for MISO and external systems for the baseline reliability studies. A firm LBA dispatch requires that firm resources contractually obligated to serve the Load of a particular LSE must be used, and should be economically dispatched to the degree possible subject to generating unit, transmission, and LBA power balance constraints. A security constrained economic dispatch of MISO resources may be used for voltage stability and transient angular stability analyses to ensure market dispatches are secure from a power system stability and cascading outage perspective.

4.3.4 Bottom-up Planning Contingencies

4.3.4.1 Contingencies Evaluated in Support of Annual Reliability Assessments

Regional contingency files are developed by MISO planning staff collaboratively with Transmission Owner(s) and external entities and supplemented by information obtained from stakeholders at SPMs, as appropriate. The list of contingencies will include events described under NERC TPL-001-4 Table 1 plus any applicable local or regional planning standards, criteria or guidelines. NERC TPL contingencies classified as planning events (i.e., denoted by the letter "P" followed by a number) that are violated in planning studies must be mitigated with a Corrective Action Plan. NERC TPL contingencies classified as extreme events must be studied and the results must be evaluated with respect to impact on the system. Should the simulation of an extreme event contingency result in cascading, it is necessary to evaluate possible actions that can be taken to mitigate the impact of the event. Below is a list and description of the NERC TPL contingency categories tested:

- NERC category P0: System intact or no contingency event.
- NERC category P1 (P1-1 through P1-5): Loss of a Single Element due to a Three-phase Fault

  Contingencies include generating units (P1-1); transmission circuits (P1-2); transmission transformers (P1-3); transmission shunt devices (P1-4), where shunt devices include shunt capacitors, shunt reactors, static VAR compensators, and similar shunt devices; and loss of a single pole on an HVDC line (P1-5). Series reactors and series capacitors should be treated as transmission circuits if they have an independent protective zone apart from a transmission circuit or transformer. All Load directly served by the contingent facility should be modeled as interrupted (i.e., consequential Load loss). In addition, all other elements within the protective zone associated with the contingent facility (e.g., shunt reactors, tapped transmission transformers, etc.) should be modeled as interrupted following the contingency. Manual System adjustments and manual non-consequential Load curtailment are not allowed to address issues where post contingent steady-state voltages fall outside of emergency voltage limits. Non-consequential firm Load curtailment and/or curtailment of firm transmission service are not allowed as system adjustments to address branch Loading issues associated with P1 contingencies (except in limited circumstances as detailed in the NERC TPL Footnote 12, and Attachment I).

  Other manual system adjustments (e.g., redispatch, etc.) can only be used on a post contingent basis to address branch Loading issues resulting from P1 contingencies if i) a higher emergency rating is provided for the branch, ii) the post contingent steady state flow on the branch is below the higher emergency rating, and iii) the system adjustments required to reduce branch Loading below the Emergency Rating can be made within the maximum duration associated with the higher emergency rating. In order to ensure a robust system, P1 contingencies for off-peak cases will be simulated both under pre-contingency system intact conditions and pre-contingency N-1 conditions to account for select planned maintenance outages that will occur during off peak periods. The relevant planning event and system impacts shall be available as supporting information for proposed Corrective Action Plans.

- NERC category P2-1: Opening a Line Section without a Fault
  The primary purpose of this contingency is to test the ability of the system to serve Load connected to a transmission circuit from one end with the opposite terminal open. Therefore, these contingencies apply only to network transmission protection zones that include directly connected Loads (primarily transmission circuit protective zones and in rare cases, transformer protective zones where Load may be served from a tertiary winding). These contingencies do not apply to generating units although generator auxiliary Load could be served in the generating unit protective zone. For two-terminal network transmission protection zones that include directly connected Loads, two contingencies are required, one for each terminal open. For a three-terminal network transmission protective zone, three contingencies are required, one for each terminal open. It is not necessary to consider contingencies where two terminals are open on a three-terminal transmission protective zone. Non-consequential firm Load curtailment and/or curtailment of firm transmission service are not allowed as system adjustments to address branch loading or Bus voltage issues associated with P1 contingencies[21].
- NERC category P2-2: Loss of a Bus section due to a Phase-to-ground Fault
  Contingencies include straight Buses and each of the two physical Buses associated with a double Bus configuration (e.g., breaker-and-a-half and/or double-breaker configurations). All Load and shunts served directly by the Bus section should be modeled as interrupted following the fault (i.e., consequential Load loss, etc.). For double-Bus configurations, all network elements that connect to one of the physical Buses directly through a single circuit breaker rather than through a position between two circuit breakers should be modeled as open for the applicable physical Bus contingency. Manual system adjustments and manual non-consequential Load curtailment are not allowed to address issues where post contingent steady-state voltages fall outside of emergency voltage limits. Furthermore, for EHV Bus section P2-2 contingencies, non-consequential firm Load curtailment and/or curtailment of firm transmission service are not allowed as system adjustments to address branch loading issues. For HV Bus section P2-2 contingencies, non-consequential Load curtailment

[21] Except under limited circumstances explained in Footnote 12 and Attachment I of the standard

and/or curtailment of firm transmission service are allowed as system adjustments to address branch loading issues.

However, manual system adjustments or manual firm Load curtailments can only be used on a post contingent basis to address branch Loading issues resulting from P2-2 contingencies if i) a higher emergency rating is provided for the branch, ii) the post contingent steady state flow on the branch is below the higher emergency rating, and iii) the system adjustments or firm Load curtailments required to reduce branch Loading below the Emergency Rating can be made within the maximum duration associated with the higher emergency rating.

- NERC category P2-3: Internal Circuit Breaker Single Phase-to-ground Fault (non-Bus tie circuit breakers only)
  Contingencies include all circuit breakers that are not Bus tie circuit breakers and represent a single phase-to-ground fault within the overlap of the protective zones on each side of the circuit breaker, thus resulting in a loss of both protective zones. All Loads and shunts served directly by each of the two protective zones should be modeled as interrupted following the fault (i.e., consequential Load loss, etc.). Manual System adjustments and manual non-consequential Load curtailment are not allowed to address issues where post contingent steady-state voltages fall outside of emergency voltage limits. Furthermore, for EHV circuit breaker P2-3 contingencies, non-consequential firm Load curtailment and/or curtailment of firm transmission service are not allowed as system adjustments to address branch loading issues. For HV circuit breaker P2-3 contingencies, non-consequential Load curtailment and/or curtailment of firm transmission service are allowed as system adjustments to address branch loading issues.

  However, manual system adjustments or manual firm Load curtailments can only be used on a post contingent basis to address branch Loading issues resulting from P2-3 contingencies if i) a higher emergency rating is provided for the branch, ii) the post contingent steady state flow on the branch is below the higher emergency rating, and iii) the system adjustments or firm Load curtailments required to reduce branch Loading below the Emergency Rating can be made within the maximum duration associated with the higher emergency rating.
- NERC category P2-4: Internal Circuit Breaker Single Phase-to-ground Fault (Bus tie circuit breakers only)
  Contingencies include all circuit breakers that are Bus tie circuit breakers and represent a single phase-to-ground fault within the overlap of the Bus protective zones

on each side of the circuit breaker, thus resulting in a loss of both Buses. All Loads and shunts served directly by each of the two Buses should be modeled as interrupted following the fault (i.e., consequential Load loss, etc.). Manual system adjustments and manual non-consequential Load curtailment are not allowed to address issues where post contingent steady-state voltages fall outside of emergency voltage limits. Non-consequential firm Load curtailment and/or curtailment of firm transmission service are allowed as system adjustments to address branch loading issues associated with P2-4 contingencies.

Manual system adjustments (e.g., redispatch, curtailment of firm transmission service, curtailment of non-consequential Load, etc.) can only be used on a post contingent basis to address branch Loading issues resulting from P2-4 contingencies if i) a higher emergency rating is provided for the branch, ii) the post contingent steady state flow on the branch is below the higher emergency rating, and iii) the system adjustments or firm Load curtailments required to reduce branch Loading below the emergency rating can be made within the maximum duration associated with the higher emergency rating.

- NERC category P3: Loss of a Generating Unit followed by System Adjustments followed by Loss of another Element due to a Three-phase Fault.
  Contingencies include loss of any generating unit followed by allowable system adjustments followed by the loss of any of the following additional elements:
  - P3-1: Generating unit due to a three-phase fault
  - P3-2: Transmission circuit due to a three-phase fault
  - P3-3: Transmission transformer due to a three-phase fault
  - P3-4: Shunt device due to a three-phase fault
  - P3-5: Single pole block of DC line due to a line-to-ground fault

  All Load directly served by the second contingent element and other elements within the protective zone associated with the second contingent element should be modeled as interrupted following the contingency. Manual system adjustments and manual non-consequential Load curtailment subsequent to the second contingency are not allowed to address issues where post contingent steady-state voltages fall outside of emergency voltage limits. Non-consequential firm Load curtailment and/or curtailment of firm transmission service are not allowed as system adjustments to address branch loading issues associated with P3 contingencies.

Other manual system adjustments (e.g., redispatch, etc.) can be used following the loss of the generator to prevent branch loading issues following the loss of the second contingent element.

- NERC category P4 (P4-1 through P4-5): Loss of an Element followed by a Stuck Breaker followed by Loss of an additional Element where the Stuck Breaker is not a Bus-tie Breaker.

  Contingencies include loss of any of the following elements followed by a stuck breaker that triggers the loss of a second element where such stuck breaker is not a Bus-tie breaker (i.e., the two contingent elements are not both Bus sections).
  - P4-1: Generating unit due to a phase-to-ground fault
  - P4-2: Transmission circuit due to a phase-to-ground fault
  - P4-3: Transmission transformer due to a phase-to-ground fault
  - P4-4: Shunt device due to a phase-to-ground fault
  - P4-5: Bus section due to a phase-to-ground fault

All Loads served directly by each of the two contingent elements should be modeled as interrupted following the fault (i.e., consequential Load loss, etc.). In addition, all other elements within the protective zone associated with the contingent elements should be modeled as interrupted following the fault. For dynamic studies, if the circuit breaker consists of independent pole operation (independent mechanisms and trip coils for each pole), the contingency may assume failure of only one pole to trip so long as the failed pole is assumed to be on the faulted phase. Manual system adjustments and manual non-consequential Load curtailment are not allowed to address issues where post contingent steady-state voltages fall outside of emergency voltage limits. Furthermore, for EHV P4-1 through P4-5 contingencies (i.e., the faulted element is an EHV facility as defined above and in the NERC TPL standard), non-consequential firm Load curtailment and/or curtailment of firm transmission service are not allowed as system adjustments to address branch Loading issues. For HV P4-1 through P4-5 contingencies, non-consequential Load curtailment and/or curtailment of firm transmission service are allowed as system adjustments to address branch loading issues.

However, the use of manual system adjustments or manual firm Load curtailments can only be used on a post contingent basis to address branch Loading issues resulting from P4-1 through P4-5 contingencies if i) a higher emergency rating is provided for the branch, ii) the post contingent steady state flow on the branch is below the higher emergency rating, and iii) the system adjustments or firm Load curtailments required to reduce branch Loading below the emergency rating can be made within the maximum duration associated with the higher emergency rating.

- NERC category P4-6: Loss of a Bus section due to a Phase-to-ground Fault followed by a Stuck Breaker followed by Loss of a second Bus where the Stuck Breaker is a Bus-tie Breaker.

  Contingencies include loss of an element followed by a stuck breaker that triggers the loss of a second element where such stuck breaker is a Bus-tie breaker and the contingent elements are both Bus sections. For dynamic studies, if the circuit breaker consists of independent pole operation (independent mechanisms and trip coils for each pole), the contingency may assume failure of only one pole to trip so long as the failed pole is assumed to be on the faulted phase. All Load directly served by all contingent elements should be modeled as interrupted following the fault (i.e., consequential Load loss, etc.). In addition, all other elements within the protective zone associated with all contingent elements should be modeled as interrupted following the fault. Manual system adjustments and manual non-consequential Load curtailment subsequent to the second contingency are not allowed to address issues where post contingent steady-state voltages fall outside of emergency voltage limits. Non-consequential firm Load curtailment and/or curtailment of firm transmission service are allowed as system adjustments to address branch loading issues associated with P4-6 contingencies.

  However, all manual system adjustments (e.g., redispatch, curtailment of firm transmission service, curtailment of non-consequential Load, etc.) can only be used on a post contingent basis to address branch Loading issues resulting from P4-6 contingencies if i) a higher emergency rating is provided for the branch, ii) the post contingent steady state flow on the branch is below the higher emergency rating, and iii) the allowable system adjustments required to reduce branch Loading below the emergency rating can be made within the maximum duration associated with the higher emergency rating.

- NERC category P5 (P5-1 through P5-5): Loss of a Transmission Element due to a Phase-to-ground Fault followed by Failure of a Non-redundant Protective Relay that Triggers Delayed Fault Clearing via Remote Backup Protection on Adjacent Transmission Elements.

  Contingencies include loss of any of the following elements followed by a non-redundant relay failure that triggers the loss of additional elements and delayed fault clearing via remote backup tripping.

  - P5-1: Generating unit due to a phase-to-ground fault
  - P5-2: Transmission circuit due to a phase-to-ground fault
  - P5-3: Transmission transformer due to a phase-to-ground fault
  - P5-4: Shunt device due to a phase-to-ground fault
  - P5-5: Bus section due to a phase-to-ground fault

  All Load directly served by all contingent elements should be modeled as interrupted following the fault (i.e., consequential Load loss, etc.). In addition, all other elements within the protective zone associated with all contingent elements should be modeled as interrupted following the fault. Manual system adjustments and manual non-consequential Load curtailment are not allowed to address issues where post contingent steady-state voltages fall outside of emergency voltage limits. Furthermore, for EHV P5-1 through P5-5 contingencies (i.e., the faulted element is an EHV facility as defined above and in the NERC TPL standard), non-consequential firm Load curtailment and/or curtailment of firm transmission service are not allowed as system adjustments to address branch Loading issues. For HV P5-1 through P5-5 contingencies, non-consequential Load curtailment and/or curtailment of firm transmission service are allowed as system adjustments to address branch loading issues.

  However, manual system adjustments or manual firm Load curtailments can only be used on a post contingent basis to address branch Loading issues resulting from P5-1 through P5-5 contingencies if i) a higher emergency rating is provided for the branch, ii) the post contingent steady state flow on the branch is below the higher emergency rating, and iii) the system adjustments or firm Load curtailments required to reduce branch Loading below the emergency rating can be made within the maximum duration associated with the higher emergency rating.

- NERC category P6 (P6-1 through P6-4): Loss of an Element followed by System Adjustments followed by Loss of another Element due to a Three-phase Fault.
  Contingencies include loss of any element from the list below followed by allowable system adjustments followed by the loss of a second element from the list below:
  - P6-1: Transmission circuit due to a three-phase fault
  - P6-2: Transmission transformer due to a three-phase fault
  - P6-3: Shunt device due to a three-phase fault
  - P6-4: Single pole block of DC line due to a line-to-ground fault

All Load directly served by all contingent elements should be modeled as interrupted following the fault (i.e., consequential Load loss, etc.). In addition, all other elements within the protective zone associated with all contingent elements should be modeled as interrupted following the fault. Manual system adjustments (e.g., redispatch, curtailment of firm transmission service, , etc.) can be used following the loss of the first contingent element to prevent branch loading issues or steady state voltage issues following the loss of the second contingent element.

- NERC category P7 (P7-1 through P7-2): Loss of any Two Transmission Circuits on a Common Structure or Loss of a Bipolar HVDC Circuit. Contingencies include loss of any of the following:
  - P7-1: Two transmission circuits on common structures due to a line-to-ground fault
  - P7-2: Loss of a DC bipolar line for a line-to-ground fault

  All Load directly served by both contingent elements and other elements within the protective zone associated with each contingent element should be modeled as interrupted following the contingency. Manual system adjustments and non-consequential Load curtailment subsequent to the contingency are not allowed to address issues where post contingent steady-state voltages fall outside of emergency voltage limits. Non-consequential firm Load curtailment and/or curtailment of firm transmission service are allowed as system adjustments to address branch loading issues associated with P7 contingencies.

  However, all manual system adjustments (e.g., redispatch, curtailment of firm transmission service, curtailment of non-consequential Load, etc.) can only be used on a post contingent basis to address branch Loading issues resulting from P7 contingencies if i) a higher emergency rating is provided for the branch, ii) the post contingent steady state flow on the branch is below the higher emergency rating, and iii) the allowable system adjustments required to reduce branch Loading below the emergency rating can be made within the maximum duration associated with the higher emergency rating.
- NERC Steady-state and Stability Extreme Event: Category P3 and P6 contingencies without any allowance for system adjustments in between the contingencies.
- NERC Steady-state Extreme Event: Loss of three or more transmission circuits on common structures.

- NERC Steady-state Extreme Event: Loss of all transmission circuits on a common right-of-way.
- NERC Steady-state Extreme Event: Loss of a switching station or substation (loss of one complete voltage level plus all connecting transformers).
- NERC Steady-state Extreme Event: Loss of all generating units at a generating station.
- NERC Steady-state Extreme Event: Loss of a large Load or major Load center, when applicable.
- NERC Steady-state Extreme Event: Loss of two generating stations from a common root cause, when applicable.
- NERC Stability Extreme Event: Category P4 contingencies assuming three-phase fault instead of phase-to-ground fault.
- NERC Stability Extreme Event: Category P5 contingencies assuming three-phase fault instead of phase-to-ground fault.

4.3.4.2 Rationale for Contingencies Selected as More Severe

The NERC TPL standards require that studies are to be performed and evaluated only for those contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information.

MISO applies the following principles in contingency selection:

- When feasible, MISO will evaluate all contingencies for each category in Table 1 of NERC TPL 001-4 for the MISO footprint and all adjacent tier 1 Transmission Planner and/or Planning Coordinator footprints.
- MISO planning staff will rely on the expertise of the planning staffs of MISO Transmission Owner(s) for their input regarding specific contingencies that should be studied when it is not feasible to study all contingencies.
- MISO will consult external Transmission Planners and Planning Coordinators, particularly those representing adjacent tier 1 systems, to determine which external contingencies should be studied when it is not feasible to study all contingencies.
- For contingencies involving the loss of more than one element under two independent triggering events (e.g., P3 and P6 contingencies, etc.), MISO will evaluate an extensive list of contingency combinations to determine the combinations of facilities that have a greater probability of adversely impacting the system or otherwise producing more severe results

Consistent with these contingency selection principles, the following contingencies will be analyzed at a minimum:

- All NERC category P1 contingencies for facilities within MISO or within adjacent Planning Coordinator footprints, including the following:
  - P1-1: Loss of Generator due to 3ϕ fault
  - P1-2: Loss of Transmission Circuit due to 3ϕ fault
  - P1-3: Loss of Transformer due to 3ϕ fault
  - P1-4: Loss of Shunt Device due to 3ϕ fault
  - P1-5: Loss of Single Pole of HVDC Line due to line-to-ground fault
- All NERC category P2 contingencies for facilities within MISO or within adjacent Planning Coordinator footprints, including the following:
  - P2-1: Opening of a Transmission Circuit terminal without a fault
  - P2-2: Loss of Bus section due to ϕ-to-ground fault
  - P2-3: Loss of two Elements due to internal circuit breaker ϕ-to-ground fault
  - P2-4: Loss of two Buses due to internal tie breaker ϕ-to-ground fault
- The set of NERC category P3 contingencies determined to provide the most severe impacts to the system:
  - P3-1: P1-1 followed allowable system adjustments followed by second P1-1
  - P3-2: P1-1 followed by allowable system adjustments followed by P1-2
  - P3-3: P1-1 followed by allowable system adjustments followed by P1-3
  - P3-4: P1-1 followed by allowable system adjustments followed by P1-4
  - P3-5: P1-1 followed by allowable system adjustments followed by P1-5

    It is important to note that it is not necessary to simulate the same two contingent elements (a generator plus another element) in two separate P3 contingencies where the order of contingency occurrence is reversed.
- All NERC category P4 contingencies for facilities within MISO or within adjacent Planning Coordinator footprints, including the following:
  - P4-1: A P1-1 event followed by stuck breaker* followed by breaker failure relay operation**
  - P4-2: A P1-2 event followed by stuck breaker* followed by breaker failure relay operation**
  - P4-3: A P1-3 event followed by stuck breaker* followed by breaker failure relay operation**
  - P4-4: A P1-4 event followed by stuck breaker* followed by breaker failure relay operation**

- P4-5: A P2-2 event followed by stuck breaker*** followed by breaker failure relay operation**
- P4-6: A P2-2 event followed by stuck breaker**** followed by breaker failure relay operation**

  NOTES:
  **In dynamic studies, for circuit breakers with independent pole operated mechanisms, assume only one pole fails to trip, otherwise assume all three poles fail to trip*
  ***Independent contingencies should be conducted for each individual breaker protecting the applicable contingent element (e.g., for a two-terminal transmission line between two ring Buses, there are four breakers protecting the line, two at each terminal, and thus four P1-2 contingencies would be studied for this single facility, etc.).*
  ****P4-5 contingencies apply to Bus faults where the stuck breaker is not a Bus tie breaker.*
  *****P4-6 contingencies apply to Bus faults where the stuck breakers is a Bus tie breaker*

- All NERC category P5 contingencies for facilities within MISO or within adjacent Planning Coordinator footprints where one or more non-redundant protection system components exist, including the following:
  - P5-1: A P1-1 event followed by non-redundant relay component failure* followed by delayed remote clearing
  - P5-2: A P1-2 event followed by non-redundant relay component failure* followed by delayed remote clearing**
  - P5-3: A P1-3 event followed by non-redundant relay component failure* followed by delayed remote clearing**
  - P5-4: A P1-4 event followed by non-redundant relay component failure* followed by delayed remote clearing**
  - P5-5: A P2-2 event followed by non-redundant relay component failure* followed by delayed remote clearing**

  NOTES:
  **Non-redundant relay components include protective relays (21, 87, 50, 51, 67, 59, 32), auxiliary relays (94), lockout relays (86), and communications relays (85). P5 contingencies do not apply to facilities with fully redundant relays at*

all terminals. For a specific facility, a separate P5 contingency must be executed for each distinct impact (e.g., failure of tripping at one terminal vs. the other, etc.). P5 contingencies that have an identical impact to P4 contingencies (e.g., failure of a breaker trip coil, etc.) may reference the results from the corresponding P4 contingency analysis.

***For P5 contingencies on multi-terminal facilities other than Bus sections (P5-2 and P5-3 contingencies), the fault location should be modeled at each terminal that could possibly not trip due to a non-redundant relay component failure. For failure modes that prevent tripping and breaker failure initiation at a single terminal only (e.g., failure of a non-redundant auxiliary tripping relay at one terminal of a line with a DCB protection scheme, etc.), the relay failure should be assumed to occur at the terminal where the fault is simulated. For failure modes that prevent tripping at both terminals (e.g., failure of a non-redundant transformer differential relay for a Bus fault internal to the transformer protective zone but external to the transformer, etc.), a failure of both terminals to trip for a specific event should be simulated. When both terminals fail to trip, remote fault clearing from various lines could be sequential rather than simultaneous, and this should be simulated (e.g., remote backup tripping at the terminal opposite of the fault may clear on zone 3 time instead of zone 2 time, infeed effects may cause sequential tripping of remote backup protection on lines at the terminal opposite of the fault, etc.).*

- The set of NERC category P6 contingencies determined to provide the most severe impacts to the system
  - P6-1: A P1-2 event followed by allowable system adjustments followed by either a P1-2, P1-3, or P1-4 contingency.
  - P6-2: A P1-3 event followed by allowable system adjustments followed by either a P1-2, P1-3, or P1-4 contingency.
  - P6-3: A P1-4 event followed by allowable system adjustments followed by either a P1-2, P1-3, or P1-4 contingency/
  - P6-4: A P1-5 event followed by allowable system adjustments followed by either a P1-2, P1-3, or P1-4 contingency

    It is important to note that it is not necessary to simulate the same two contingent elements in two separate P6 contingencies where the order of contingency occurrence is reversed.

- All NERC category P7-1 contingencies for facilities within MISO or within adjacent Planning Coordinator footprints, where the two contingent transmission circuit share the same structures for a length of one mile or more.
- All NERC category P7-2 contingencies for facilities within MISO or within adjacent Planning Coordinator footprints.
- All NERC steady-state extreme event contingencies involving the loss of three or more transmission circuits on common structures within MISO or an adjacent Planning Coordinator footprint.
- All NERC steady-state extreme event contingencies involving the loss of all transmission circuits on a common right-of-way within MISO or an adjacent Planning Coordinator footprint.
- All NERC steady-state extreme event contingencies involving the loss of a switching station or substation (loss of one complete voltage level plus all connecting transformers) within MISO or an adjacent Planning Coordinator footprint.
- All NERC steady-state extreme event contingencies involving the loss of all generating units at a generating station within MISO or an adjacent Planning Coordinator footprint.
- All NERC steady-state extreme event contingencies involving the loss of a large Load or major Load center within MISO or an adjacent Planning Coordinator footprint where MISO staff working in consultation with applicable Transmission Owner(s) or adjacent Planning Coordinators determine that the probability and impact of such an occurrence are significant.
- NERC steady-state extreme event involving the loss of two generating stations from a common root cause within MISO or an adjacent Planning Coordinator footprint where MISO staff working in consultation with applicable Transmission Owner(s) or adjacent Planning Coordinators determine that the probability and impact of such an occurrence are significant.
- All NERC stability extreme event contingencies defined as MISO P4 contingencies assuming three-phase fault instead of phase-to-ground fault.
- All NERC stability extreme event contingencies defined as MISO P5 contingencies assuming a three-phase fault instead of phase-to-ground fault.

4.3.5 Bottom-up Planning Reliability Testing

Reliability testing of the planned system focuses on ensuring that the Transmission System is reliable in the foreseeable future and complies with national and regional reliability standards (including NERC TPL standards), as well as local and Transmission Owner planning criteria. The Transmission System is analyzed under multiple planning horizons and varying Load conditions.

The planning horizons studied include two-years out, five-years out, and ten-years out. The specific Load cases studied in each specific planning horizon are driven by the NERC TPL standards and may vary from year to year to ensure the planning process considers pertinent future scenarios. Specific Load cases include peak Load cases, shoulder Load cases, and light Load cases. Steady-state analysis is performed on an LBA centric contractual dispatched power-flow model to avoid i) the need to implement a Corrective Action Plan for a problem resulting from the non-firm use of the system or ii) counting on a non-firm transaction from masking a problem that needs a Corrective Action Plan when the system is operated based on a firm contractual dispatch. Steady-state analysis includes both steady-state analysis, as described in *Section 4.3.5.2* of this BPM, and transfer analysis as described in Appendix N of this BPM. Transient angular stability analysis which is described in *Section 4.3.5.3* of this BPM is performed assuming a market-based Security Constrained Economic Dispatch (SCED) to ensure that anticipated non-firm use of the system by the market will not create a risk of transient instability. Should the SCED uncover a transient stability issue, an appropriate limitation or Corrective Action Plan will be considered to address the issue.

4.3.5.1 Steady-State Analysis

Steady-state Contingency Analysis will be performed on the baseline planning models with no system improvements to test the contingencies of various categories described under *Section 4.3.4* of this BPM. Thermal limit and voltage limit violations will be screened based on facility ratings and voltage limits submitted by Transmission Owner(s) as discussed in *Section 4.3.2* of this BPM. To the extent a Transmission Owner does not specify voltage limits, MISO will use the voltage limits in the default criteria outlined in Appendix K of this BPM. In addition, the Transmission Owner may elect to point to the MISO default criteria in Appendix K of this BPM to establish voltage limits for their footprint. Any thermal overloads greater than one-hundred twenty-five percent (125%) of the emergency rating of a Load carrying facility will be flagged and reviewed against applicable Interconnected Reliability Operating Limit (IROL) criteria to determine if an IROL should be created for the facility.

4.3.5.2 Steady-State Voltage Stability Analysis

In addition to contingency analysis, a separate steady-state voltage stability analysis is also performed in order to identify voltage stability limits and power transfer margins. This will help identify areas with voltage instability issues. The appropriate system conditions and areas to study are selected based on the stakeholder and system operator input solicited at the beginning of the planning cycle. Appropriate system conditions are those conditions that align with conditions modeled in TPL-001-4 baseline analysis, TPL-001-4 sensitivity analysis, and/or FAC-013 analysis. The following general study procedures are used for this analysis:

- Specific scenarios are selected for PV and/or QV analyses. Scenarios include transfer levels and interfaces, system conditions (including Load, dispatch, contingencies, and status of reactive resources), and study horizons. The MTEP models are used as the basis for performing the transfer simulations and associated PV and QV analysis.
- For each specific scenario, the study will monitor Bus voltages, reactive reserves at applicable generating units, and flows on applicable branches and interfaces under appropriate system stress conditions (critical contingencies and significant transfer levels).
- For each specific scenario modeled, the study will identify and document transfer limits based on voltage stability margins under PV analysis and areas with exhausted or limited reactive reserves under QV analysis. Voltage stability margins are based on the voltage stability criteria provided by the Transmission Owner or the MISO default voltage stability criteria in Appendix K if the Transmission Owner provides no criteria or points to the MISO criteria.

4.3.5.3 Dynamic Stability Analysis

MISO will perform dynamic stability analysis which includes transient angular stability analysis, transient voltage stability analysis, and other transient voltage analysis (e.g., FIDVR) for the contingencies described in *Section 4.3.4* of this BPM. The contingencies will simulate the initiating fault, generator dynamic response, generation and transmission protection system response, high speed reclosing response when applicable, and subsequent delayed clearing when applicable (P4, P5, and certain extreme event contingencies).

MISO will enforce the damping ratio and critical clearing time margin criteria provided by each Transmission Owner for contingencies in their area, or in the absence of such criteria, will apply the default damping ratio and critical clearing time margin criteria specified in Appendix K of this BPM. For contingencies in multiple Transmission Owner areas, MISO will use the most conservative criteria.

A dynamic study model will monitor Bus voltage magnitudes and phase angles, branch power flows, and apparent impedance trajectories at Load responsive line relay[22] terminals. The dynamic study will calculate damping ratios, identify generating units pulling out of synchronism, simulate tripping of generating units due to power swings or inadequate voltage ride-through

[22] Load responsive relay elements are relay elements that are sensitive to Load currents and power swings as well as short-circuit faults and typically include impedance (distance), overcurrent, and directional overcurrent phase relay elements, but not ground or negative sequence relay elements or differential relay elements.

capability, simulate the tripping of non-faulted transmission lines due to stable or unstable power swings using actual or generic relay models in accordance with the NERC TPL standards, simulate Bus voltage response including fast voltage collapse, transient voltages due to power swings, and/or delayed voltage recovery. MISO will use the generic relay models within PSS®E for dynamic simulation of power swing trips as an initial screening tool, and will then request the actual trip characteristics from the Transmission Owner should a trip be simulated to confirm a power swing trip will actually occur. The clearing times used to simulate protection system response will be determined by Transmission Owner(s) based on worst case breaker clearing times, worst case relay operating times, breaker failure timer settings, remote backup protection timer settings, and the appropriate critical clearing time margin.

4.3.5.4 Results Management

MISO manages results from the MTEP study in a Results database. The results database is populated with results from analysis, comments on results from stakeholders, and mappings of results to projects which have been determined to have resolved the identified system issue.

4.4 Long-term Planning

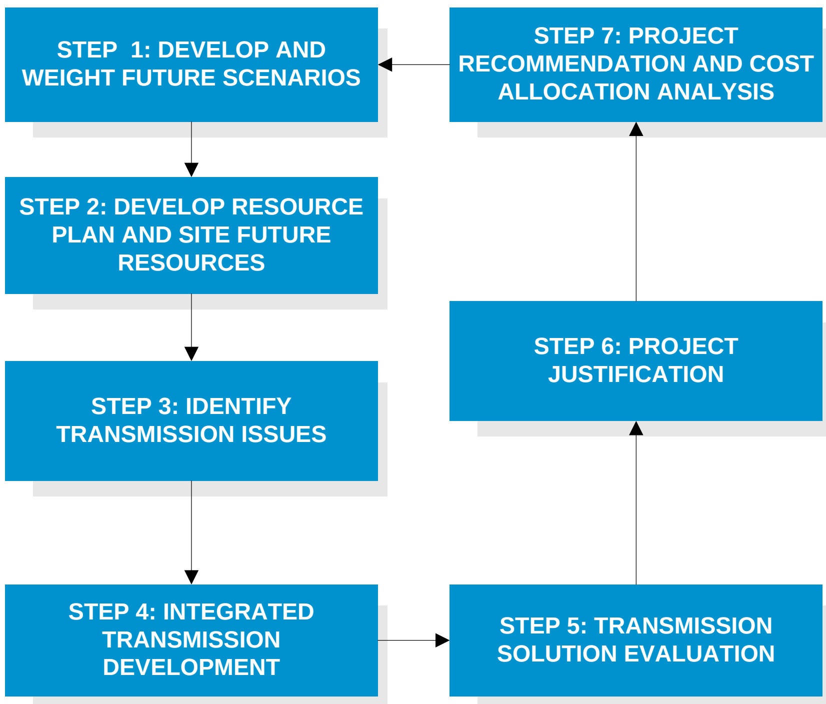
4.4.1 Introduction

The MISO long-term planning process focuses on addressing sub regional, regional, and interregional transmission issues related to historic and future market congestion, long-term economic opportunities and/or public policy compliance in accordance with the provisions of Section C6 of Attachment FF of the MISO Tariff. The objective of the long-term planning process more commonly referred to as the MISO Value-Based Planning process is to develop robust transmission solutions to increase long-term value under a wide range of potential conditions that comply with Federal, State, local and transmission owner reliability standards and public policy mandates. To develop robust transmission solutions, the MISO Value Based Planning Process employs a scenario based approach which considers a range of potential public policies, economic conditions, demand and energy growth rates, fuel prices, as well as other industry trends. Long-term planning is an open and transparent process, compliant with FERC Orders 888, 890 and 1000, which depends upon the collective input of stakeholders and regulators throughout all phases.

4.4.2 Process Steps for Long-term Planning

The MISO Value Based Planning process is shown below in *Figure 4.4.2-1* and the detailed steps are documented in this subsection. While not all steps of the MISO Value Based Planning process will be accomplished during each MTEP cycle, the determination of which step(s) as well as the timeline will be part of the scoping discussions preceding each MTEP cycle. The following sub-sections provide typical timelines for each step; however, actual study timelines may vary.

Figure 4.4.2-1: Long-term Planning Process Diagram



4.4.2.1 Develop and Weight Future Scenarios

By defining a wide range of plausible futures, MISO ensures reliable and efficient grid operations. Future scenario definitions and uncertainty variables are developed for each MTEP cycle with advisement from the Planning Advisory Committee. The Futures development cycle typically begins in January of the year prior the start of the targeted MTEP cycle (e.g. the development of MTEP17 Futures would begin in January 2016). Barring significant changes in policy and economic drivers, Futures scenario definitions will continue to be used for multiple MTEP cycles. While the intent is to use the Future definitions for up to three consecutive MTEP cycles, uncertainty variables within Futures definitions will be evaluated and may be updated annually for relevant changes to policy and economic drivers (e.g. updating the mid-level Henry Hub natural gas price forecast). The determination for what changes/if any to Future definitions and uncertainty variables will occur at the onset of the Futures development process, and will include advisement from the Planning Advisory Committee. In determining final benefit-cost ratios of transmission projects or portfolios, MISO must also remove undue discrimination or the potentially excessive influence of any given assumption or set of assumptions. With this in mind, MISO will develop and assign weighting to the Futures modeled in each MTEP cycle, which will include advisement from Planning Advisory Committee stakeholder sectors. Weights are typically developed after Future definitions are finalized in the June/July timeframe. Weights will be revisited preceding each MTEP cycle; however, barring a change in future definitions weights may remain unchanged from the previous cycle until exceeding the three year limit for Futures definitions.

4.4.2.2 Develop Resource Plan and Site Future Resources

4.4.2.2.1.1 Resource Forecasting

The MISO Generation Interconnection Queue provides initial information into new generation being proposed within the footprint. However, since the Generator Interconnection Queue tends to identify changes within five years or less for new capacity, a resource expansion tool is used to supplement the years beyond that timeframe in order to maintain the load-to-resource balance and Planning Reserve Margin target. Inputs to the resource expansion tool include, but are not limited to a) resource requirements driven by regulatory mandates, state laws and/or federal laws (e.g., State Renewable Portfolio Standards, State implementation plans for EPA compliance, etc.), b) other intelligence on new generation projects and long-range integrated resource plans not yet reflected in the MISO Generation Interconnection Queue, and c) specific input from Generation Developers. Regional Resource Forecasting (RRF) plans, using the preceding steps, are developed for each MTEP Future and are typically available for review in the August/September timeframe.

4.4.2.2.2.2 Generation Siting

Once the future generation from the portfolio assessment process is identified, for transmission planning purposes it must be sited at a physical interconnection point within the study models.

For its long-range planning studies, MISO planning staff forecasts likely sites where new generating resources may be developed at the high-voltage bus level, and presumes that new interconnecting transmission facilities will be constructed as necessary to support generating plants. A number of sources are used to determine likely locations for new generating units including but not limited to the MISO Generator Interconnection Queue, State Integrated Resource Plans, and public announcements. For future generation not yet specifically identified, MISO planning staff will develop assumptions about the new resources location considering distance to fuel sources, distance to load, land designations (e.g. Class 1 lands), and existing infrastructure among others. MISO also considers identified Renewable Energy Zones when determining potential sites for renewable resources. The combined approach endeavors to provide reasonable assumptions regarding fixed-in-place generation to provide a starting point for integrated system reliability and economic enhancement modeling and analysis. In this process, results from completed power flow modeling are used to provide input data to MISO's production cost model. A study horizon of 20 years is to be utilized for long-term planning evaluations to determine project benefits. The long-term planning evaluation process is structured to ensure robustness by utilizing multiple Futures to analyze future impacts in determining the benefit of system expansion projects. These siting assumptions will be provided for stakeholders review and input.

4.4.2.3 Identify Transmission Issues

A key component of MISO Value Based Planning is the identification of Transmission Issues. In most cases, Transmission Issues include economic value opportunities and public policy compliance issues. Economic value opportunities typically include transmission congestion or other market issues where solutions are desired to eliminate costly generation redispatch. This review identifies specific constraints and data associated with those constraints such as shadow prices, binding hours, and binding levels. Once congestion issues are identified, they will be reviewed and shared with stakeholders for feedback. The identified congestion issues are typically available for stakeholders review in December/ January timeframe.

In addition to congestion issues, other types of economic issues, reliability issues and public policy issues may also be considered in the MISO Value Based Planning process. Public policy issues are typically derived from federal, state, and local laws and mandates that govern the maximum or minimum amount of energy or capacity that can be generated by specific types of resources. Also, other economic benefits, such as transmission loss reductions, planning reserve reductions, or the release of "trapped" capacity may be considered in the MISO Value Based Planning process.

4.4.2.4 Integrated Transmission Development

After Transmission Issues are identified, stakeholders will be given the opportunity to submit solutions to these issues. The solution submission window typically opens in January/February timeframe and lasts for six to eight weeks. Solution ideas are used to inform the planning process. MISO, while working with stakeholders, may modify solution ideas throughout the MISO Value Based Planning process.

MISO may also identify its own solution ideas to address Transmission Issues. MISO will continue to work with stakeholders to ensure solutions properly address the Transmission Issues.

4.4.2.5 Transmission Solution Evaluation

The first step in transmission solution development is to convert various solution ideas into proposed projects. Because an integrated transmission plan may consist of multiple non-contiguous facilities to address market congestion or public policy, a determination must be made on how collections of transmission facilities may be combined and tested through an iterative process to compose a project or portfolio. Transmission Issues will be evaluated to determine whether they are decoupled or coupled with each other. Isolated, decoupled issues do not impact others whereas coupled issues represent a group of related regional issues. Solutions to decoupled issues can be evaluated independently as alternatives. Solutions to coupled issues will be evaluated as a collection of facilities to ensure the effectiveness of the transmission plan.

Detailed reliability analysis is required to identify additional issues that may be introduced by the transmission plans developed through economic assessment. Long-term transmission plans may need to be adjusted to ensure system reliability. Reliability analyses will address NERC standards and local planning criteria and may include, but are not limited to, powerflow, transient and voltage stability, and short circuit. Additionally, the reliability assessment determines the reliability-based value contribution of the long-term transmission plans. As value-driven regional expansions are justified, traditionally developed intermediate-term reliability plans may be affected. The combined impact of both reliability and value-based planning strategies must be fully understood in order to further the development of an integrated transmission plan.

Transmission solution evaluation is an iterative process that can take several months to several years to produce an integrated transmission plan. It is necessary that the transmission plan is developed to be effective under the range of Futures studied. Therefore, the proposed transmission plan will be tested under each of the agreed upon Future for economic results (e.g., benefit-to-cost ratios, etc.), reliability performance (e.g., NERC standards, etc.), and public policy performance (e.g., compliance with RPS mandates, etc.). To ensure sufficient coordination with Generation Interconnection, MISO will review all network upgrade facilities that may be identified in ongoing Generation Interconnection studies for impacts on identified system constraints and economic project benefit calculations. Additional sensitivities may also be evaluated such as location and replacement of Regional Resource Forecast (RRF) generation. To the extent issues are uncovered such as reliability violation, incremental congestion, etc., additional adjustments may be needed to the overall transmission plan.

It is important to note that when looking beyond the NERC TPL long-term planning horizon (10 years), it is not necessary that a long-term plan resolve all reliability issues, but to the extent the specific integrated transmission plan causes or aggravates major reliability compliance issues, the MISO Value Based Planning process must work to address such issues through additional projects, project scope changes, or removed projects and evaluate once again pertinent metrics to ensure the best possible plan is developed. In addition, should an economic project inadvertently cause public policy compliance issues such as the inability to meet State Renewable Portfolio Standards, the same type of adjustments and re-evaluation of planning metrics will need to take place.

4.4.2.6 Project Justification

A business case will be created for all projects including an analysis of benefits and costs. Detailed rules on project criteria, benefit metrics and cost determination are provided in *Section 7*of this BPM.

4.4.2.7 Project Recommendation

MISO, with input from stakeholders and considering all analysis performed to determine benefits and costs, will recommend projects to the MISO Board of Directors for approval. This recommendation will be only for those projects that have been shown to meet or exceed all criteria for type of project being recommended. Projects meeting or exceeding all project type criteria will be recommended to the MISO Board of Directors in the last quarter of each MTEP cycle, or as otherwise defined in the MISO Tariff. After Board approval, MISO will determine if any of the qualified projects and facilities to proceed to the developer selection process in accordance with *Attachment FF Section 8* of the Tariff and BPM 027 – Competitive Transmission Process. Incumbent Transmission Owners have an obligation to put forth a good faith effort to construct facilities which do not go through developer selection.

Eligibility for regional cost allocation will be determined for each recommended project pursuant to the rules in *Section 7* of this BPM as well as *Section III.A.2* of Attachment FF of the MISO Tariff.

4.4.3 Data Sources and Assumptions for Long-term Planning Models

Long-term planning models require a detailed transmission topology, generation operating characteristics, as well as economic parameters. MISO, with advisement from the PAC, will determine variable input assumptions using the latest and most appropriate public data sources. The vendor data may be modified in whole or in part with newer or more appropriate data as desired.

The sources of the data provided by the vendor are:

- Federal Energy Regulatory Commission (FERC) Forms 1, 714
- Energy Information Agency Forms (860, 867, 411, 412, 423)
- North American Electric Standards Board (NAESB)
- North American Electric Reliability Council (NERC) Electric Supply and Demand (ES&D) reports
- Generating Availability Data Systems (GADS) Data
- Environmental Protection Agency (CEMS data)
- ISO, OASIS web sites
- Energy company web sites
- State IRPs
- Base MTEP input assumptions will be determined during the MTEP Futures development process as discussed in Section 4.4.2.1 of this BPM.

4.5 Other Cyclical Planning Activities

4.5.1 Baseline Load Deliverability

MISO performs Loss-of-Load Expectation (LOLE) studies primarily within the MTEP context as a "Load Deliverability" study. This study is complimentary to the Baseline Generator Deliverability test discussed below.

- The objective of the MTEP Load Deliverability test is to investigate whether MISO aggregate system and identified Local Resource Zones within the MISO Reliability Authority footprint have sufficient Planning Resources to meet the LOLE reliability criteria identified in section 3.5.2 of the Resource Adequacy BPM[23].

Where the Local Clearing Requirement is greater than the zonal Coincident Peak Demand forecast plus its Planning Reserve Margin and transmission losses and a study is requested by the impacted LSE(s), or applicable regulatory authorities, MISO will evaluate Network Upgrade impacts on limits.

The identified Network Upgrade(s) will be included in the MTEP when a Market Participant or group of Market Participants or other entities agrees to fund the upgrade. The implementation of such a project will be consistent with the Market Participant Funded Projects process, *Section 6.1*

[23] BPM-011 - Resource Adequacy

of this BPM, Other projects consistent with *Section 2.4.1.4* of this BPM, or other applicable tariff provisions and business practices.

4.5.2 Baseline Generator Deliverability

The Generator Deliverability analysis determines the ability of groups of generators in an area to operate at their maximum capability without being limited by transmission constraints, i.e., without being bottled-up. This test is performed as part of the generator interconnection study process on new generators before granting Network Resource (NR) status. The generator is required to fix any transmission constraints limiting deliverability, in order to be treated as a Network Resource. A generator that is certified deliverable, not bottled-up, would be considered deliverable to Load under Module E-1 – Resource Adequacy, of the Tariff.

The deliverability levels of already designated Network Resources may deteriorate over time as a result of Load growth and other changes to the Transmission System. A Baseline Generation Deliverability Study is performed in order to identify and address any new transmission constraints to ensure ongoing deliverability of Network Resources. Also, baseline generator deliverability upgrades represents a reliability need to ensure the continued ability to count on Network Resources nominated to meet reserves.

The Baseline Generator Deliverability analysis is performed using a Summer Peak model and by applying single transmission contingencies to deliverability dispatch patterns. The general generator deliverability study assumptions, as described under *Section 6.1.1.1.9 of BPM-015 – Generation Interconnection*, will be used for the analysis. The generator deliverability will be tested only up to the granted Network Resource levels of the Network Resource units.

4.5.3 Long-term Transmission Rights Feasibility Review

4.5.3.1 Introduction

Auction Revenue Rights (ARRs) are financial instruments that entitle their holders to a share of the revenue generated in the annual Financial Transmission Right (FTR) auction. ARRs are initially allocated to Market Participants based on firm historical usage of the transmission network. Incremental ARRs may be allocated for network upgrades, new and replacement of Network Resources.

Long Term Transmission Rights (LTTRs) are a type of ARRs allocated in Stage 1A or allocated in restoration of the Annual ARR Allocation process that is associated to historical base Load usage of the Transmission System. LTTRs are:

- Allocated in Stage 1A of the ARR allocation.

- Allocated to Market Participants derived from firm historical base Load usage of the Transmission System.
- Guarantee Market participants maintain their previous year LTTR allocated MW amount to the extent it is requested.
- Entitle the holder to a share of the FTR Auction revenue in the form of a stream of revenues or charges based on the clearing price of the ARR path.

The four characteristics of ARRs pertinent to the LTTR include:

- A MW quantity
- A path that is specified in terms of a source and sink. The source may originate from a generation Node, Hub, Load Zone or interface. The sink is always associated with an ARR zone, which is a Hub-type Node. ARR zones are electrical areas defined for the purpose of allocating ARRs based upon locations where a Market Participant serves Load.
- ARR Term (Start and end dates)
- ARR Period (Peak / Off-peak)

ARRs will be allocated once a year, for eight different periods:

- Four Seasons
  - Summer: June, July, August
  - Fall: September, October, November
  - Winter: December, January, February
  - Spring: March, April, May
- Peak and Off-peak Loads

Detailed explanation of FTRs and ARRs can be found in *BPM-004 – Financial Transmission Rights and Auction Revenue Rights.*

This section of the BPM provides the Business practices that incorporate the feasibility of Long–term ARRs into the transmission expansion planning process beginning with the first MTEP annual cycle following completion of the initial establishment of Long-term ARRs.

4.5.3.2 Procedures for Integration of LTTR Feasibility Considerations into the MTEP Process

Both the ARR Allocation process and MTEP Planning process together, should provide to the greatest extent practical, that financial obligations are met in the most economic manner to ensure the feasibility of LTTRs. This may require a repetitive analysis between the ARR allocation process, the FTR Annual Auction (composed of four seasonal cases in both peak and off-peak periods), and the MTEP Planning process due to differences in modeling. The LTTR feasibility study determines the by path cost associated with all LTTR being awarded fully. Transmission System Flowgates limit the ARR allocations. MISO planning staff will use MTEP near-term, intermediate-term and long-term models to determine the benefit of future system improvement projects to alleviate congestion at each of the identified Flowgates. If a future project does alleviate Flowgate congestion, the project will be included in the SFT model to determine improved ARR allocation. It is required that the MTEP process promote the approval and installation of future system transmission improvement projects to ensure the feasibility of first year LTTR allocations into the future. The MTEP process will also assist to explore the economic benefit of an expanding future LTTR market.

4.5.3.2.1 Information Exchange between the ARR Allocation Process and the MTEP Planning

In order to ensure adequate integration of the ARR Allocation and MTEP Planning processes, an information exchange loop will be established between the FTR, Pricing Administration group and MISO planning staff. The following information will be provided to the FTR Market Administration by MISO planning staff in January of each year for their Annual ARR Allocation scheduled in March:

- The list of transmission projects in Appendix A (recommended by Transmission Provider Board) planned to be in service by the next ARR / LTTR allocation period.
- The list of Appendix A and Appendix B transmission upgrade projects proposed for the five-year horizon, and their service dates.

The following information will be provided to the MISO planning staff in April by the FTR Market Administration group at the conclusion of their Annual ARR Allocation:

- A list of curtailed LTTRs in each of the eight allocation cases.
- A list of planned transmission outages included in the ARR Allocation studies, and identification of any planned outages that cause infeasibility
- A list of binding constraints causing LTTR curtailment and the uplift cost associated with fully funding their feasibility.

4.5.3.2.2 Consideration of Problematic Planned Outages in the Planning Process

Planned transmission outages are not generally considered in the MTEP models, since MTEP addresses the five to 10 year planning horizon. This planning horizon extends well beyond the near-term time frame of planned outages. Annual ARR Allocation incorporates planned outages occurring during the study season and lasting at least seven days. To understand the extent to which the planned outage of certain facilities may be critical to ARR feasibility, a list of any planned transmission outages included in the ARR Allocation cases that can be attributed to infeasibility will be provided to the MISO Expansion Planning staff. These transmission outages will be correlated with planned outages evaluated in the MTEP process to determine if there are mitigating solutions that can be applied to theses planned outage conditions in future allocations to eliminate binding. Such mitigations may include planned upgrades from the planning process, or redispatch/reconfiguration options that can be applied in the allocation models.

4.5.3.2.3 Comparison of LTTR allocation binding constraints with Historical or Planning Model Constraints

When an LTTR is determined infeasible in the allocation, the binding constraints causing infeasibility will be reviewed with the MISO planning staff to determine if the constraint is one that has occurred historically in real time, or is projected to occur in planning models. To the extent that the constraint is associated with one appearing in the planning analyses, it is likely that an upgrade has already been identified that will alleviate the constraint. If there is an associated upgrade in MTEP, a review will be made to see if and at what cost the upgrade could be advanced. If no such upgrade has been identified, a review will be conducted to see in what future year a related upgrade may be required as a BRP, and what the cost to advance would be. Finally, if no related constraint can be identified and no future upgrade can be foreseen in the planning models, or can be identified based on existing tariff provisions, the FTR Market Administration group will attempt to determine the cause of the infeasibility in the LTTR allocation process.

4.5.3.3 The ARR Allocation and MTEP Planning Integrated Processes

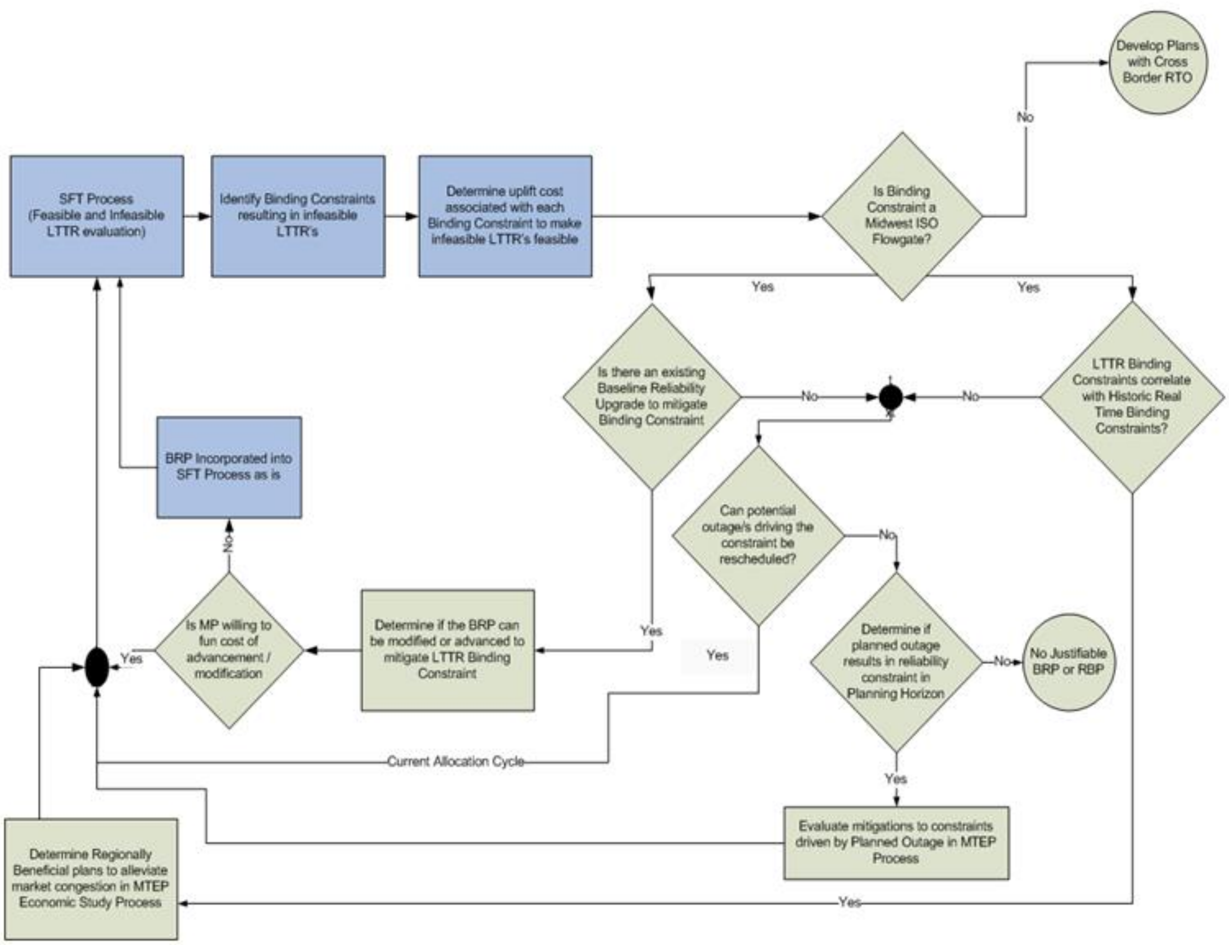
The combined integrated processes of ARR Allocation and MTEP Planning ensure the optimum economic feasibility of LTTRs into future years, as long as the LTTRs continue to be requested. *Figure 4.5.3.3.1-1* provides a guide to these combined integrated processes. The first year ARR/LTTR allocation will determine the allocation of feasible LTTRs. *Figure 4.5.3.3.1-1* is applicable to the second and subsequent year allocations.

4.5.3.3.1 ARR Allocation Process - First Year LTTR Allocations

The FTR Market Administration Group will use the SFT to determine the first year allocation of ARRs/LTTRs. All allocated LTTRs in the first year will be feasible. Factors that limit the LTTR allocations include congestion at Transmission System Flowgates and planned outages. The following information will be provided to the MISO Expansion Planning staff by the FTR Market Administration group at the conclusion of their annual ARR / LTTR allocation:

- A list of curtailed LTTRs in each of the eight allocation cases (i.e. Summer peak and off-peak, Fall peak and off-peak, etc.)
- A list of planned transmission outages included in the ARR allocation studies, and identification of any planned outages that cause infeasibility.
- A list of binding constraints causing LTTR curtailment and the uplift cost associated with fully funding their feasibility. The list of binding constraints should be prioritized to identify the most to the least binding constraint on the allocation.

Figure 4.5.3.3.1-1: AAR Allocation/MTEP Planning Process



4.5.3.3.2 ARR Allocation Process - The Second and Subsequent Year Allocations and Infeasible LTTRs

Every ARR allocated in Stage 1A or Restoration becomes a LTTR. LTTRs have rollover rights, i.e., any LTTRs allocated the first year are guaranteed to be allocated in the second and subsequent years, as long as it is requested. This is true even if the LTTR request is deemed infeasible in next year's ARR allocation. The Restoration stage attempts to allocate a subset of the Stage 1A nominations that had to be curtailed to protect feasibility. In order to restore curtailed nominations, the Restoration Process will assign counter flow ARRs to some Market Participants.

All allocated LTTRs were at some point found to be feasible. LTTR infeasibility will be caused by changes in the ARR allocation cases from one year to the next. Such changes include:

- Network and commercial model updates, including topology changes and model corrections.
- Network topology changes due to the set of planned transmission outages considered in the ARR allocation cases. (Outages with a duration of seven (7) or more Days are included in the allocation cases).
- Changes in loop flow and carved-out assumptions.
- Variation in the nomination patterns:
  - A market participant may choose not to re-nominate existing LTTRs which may cause infeasibility of other LTTRs. This is partly addressed by the fact that all existing LTTRs are eligible for counter flow assignment starting year two of the ARR allocation. However, counter flow will only be assigned to achieve feasibility of eligible base ARR entitlements.
  - Since LTTRs are not treated in the allocation process differently from non-guaranteed nominations, Stage 1A requests that did not exist in the previous allocation may cause the curtailment of LTTRs.
- Expiration of existing rights:
  - Termination of Point-to-Point services or retirement of generating units may lead to the termination of ARR Entitlements and associated LTTRs. This may cause infeasibility, as the terminated LTTRs may provide counter flow to other LTTRs.

The feasibility of the set of outstanding ARRs is required in order to ensure that sufficient FTR Auction revenue is collected to fund ARRs. Since infeasible LTTRs may not be funded from the FTR Auction revenue, their cost is distributed across all LTTR holders, in their LTTR MW share ratio.

Prior to future year's ARRs/LTTRs allocation, the FTR Market Administration Group will update the SFT model with the appropriate MTEP projects applicable to the allocation year. The SFT analysis will determine the feasible LTTRs that can be allocated subject to Flowgate constraint. Impact of planned outages will be considered in the SFT analysis. The MISO planning staff can work with the FTR Market Administration Group with near-term planning MTEP models to assess the impact of planned outages on MISO Flowgates, assess the benefit of rescheduling outages and/or re-dispatch to alleviate the Flowgate congestion. This combined effort between the two groups will provide possible updates to the SFT to ensure the optimum allocation of ARRs/LTTRs.

4.5.3.3.3 MTEP Process - The Second and Subsequent Year Planning Models

As indicated in *Figure 4.5.3.3.1-1*, the MISO planning staff will use the various MTEP models to evaluate Flowgate constraints.

4.5.3.3.3.1 Near-term Planning / 1-2 Year Planning Horizon

As previously mentioned, the MISO planning staff can work with FTR Market Administration Group during the study year SFT analysis to address planned outages/re-dispatch to alleviate Flowgate congestion.

4.5.3.3.3.2 Intermediate-term Planning / 1-10 Year Planning Horizon and Long-term Planning Horizon / 1-20 Year Planning Horizon

MISO planning staff can identify existing MTEP projects or work with the appropriate Transmission Owner to develop future projects required to alleviate Flowgate congestion under MISO control. This will be necessary in the second and subsequent years to ensure the feasibility of first year allocated LTTRs. Regarding Flowgates that are not within MISO control, MISO will need to develop plans with other RTOs as required.

The MISO planning staff will correlate LTTR binding Flowgates with real-time congestion hours. If there is no correlation, there is not likely to be a Market Efficiency Project solution to the LTTR binding constraint.

If there is correlation of LTTR binders with real-time congestion hours, there may be a MEP solution that would resolve the LTTR binding constraints. In this case, the binding Flowgates will be included in the annual process to evaluate the most congested Flowgates. An existing MEP may be modified to include the LTTR related economic benefits or a new MEP project can be developed to alleviate Flowgate congestion. MEPs can be advanced through the MTEP Process based on the project's economic merits. Reliability Based Projects will also need to be evaluated, relative to the LTTR economic related benefits at a Flowgate, to assess if the project's in-service date can be justifiably advanced in the MTEP process. To the extent that a proposed upgrade is an alternative solution to an otherwise identified system issue causing the need for a BRP or a MEP, and such an alternative upgrade would also result in a reduction in the amount of infeasible LTTR cost distribution that is required, such reduction in cost distribution will be considered in the economic comparison of alternatives to the BRP or MEP.

Intermediate-term and long-term BRP and MEP projects would be identified and included in the SFT model in the appropriate year as determined by the project in-service date.

4.6 Interregional Participation

MISO planning staff coordinates transmission expansion studies with adjacent, interconnected transmission providers, Regional Entities, and RTOs. MISO has coordination agreements in place with the PJM RTO (MISO-PJM Coordinated System Plan), Southwest Power Pool (SPP), and Tennessee Valley Authority (TVA). The coordinated agreements call for Coordinated System Plans (CSP) with the other regional planning entities. The primary purpose of these CSPs is to contribute, through coordinated planning, to the on-going reliability and the enhanced operational and economic performance of the systems of the parties.

To accomplish this purpose, the CSP will:

- Integrate the Parties' respective transmission plans, including any market-based additions to system infrastructure (such as generation or merchant transmission projects) and Network Upgrades that were considered.
- Set forth actions to resolve any impacts that may result across the seams between the Parties' systems due to such system additions or Network Upgrades; and
- Describe results of the joint transmission analyses for the combined transmission systems, as well as the procedures, methodologies, and Business rules utilized in preparing and completing the analyses.

The Inter-regional Planning Stakeholder Advisory Committee (IPSAC), which consists of stakeholder and the planning staff of MISO and other neighboring planning regions, will meet at scheduled times to discuss planning issues, concerns, and activities related to CSPs. The IPSAC also exchanges data regarding planning model assumptions for system performance, interface expansions, and network contingencies. The meeting notifications, schedules, and materials of IPSAC meetings are communicated to the stakeholders via Planning Sub-committee and Planning Advisory Committee email exploder lists.

4.7 Dispute Resolution

Disputes involving proposed expansion planning projects are resolved in accordance with Attachment HH (Dispute Resolution Procedures) of MISO's FERC Electric Tariff. Attachment HH includes provisions for dispute resolution through progressive steps consisting of informal negotiation, mediation, and arbitration. It also includes provisions for the formation of MISO's Alternate Dispute Resolution Committee, along with procedures for Expedited Dispute Resolution.

The dispute resolution process begins with a disputing party informing MISO of the subject of a dispute, and designating a representative for further contact. MISO's Client Relations Representative will attempt to resolve the issue with the disputant's representative. If the dispute cannot be resolved at this level, the disputing party notifies MISO and identifies a company officer authorized for further negotiation. MISO likewise designates a company officer, and the two officers attempt to resolve the dispute through informal negotiation.

In the event that the companies' officers cannot resolve the dispute, the matter is presented to the Alternative Dispute Resolution Committee. This Committee (described below) determines if the matter is sent to mediation or arbitration. For mediation, the disputing parties first agree upon a mediator. The mediator meets with the disputants, where each party may present written statements of issues and positions. The mediator evaluates the parties' statements, and provides written, non-binding recommendations to resolve the dispute.

For arbitration, the disputing parties may agree upon a single arbitrator, or a panel of three arbitrators may be selected according to the procedures of Attachment HH. The arbitrators are authorized to hold evidentiary hearings, if needed, as part of a process to discover relevant facts. The arbitrator(s) issue a written decision based on the evidence in the record, the applicable MISO Agreement or Tariff, applicable state and federal standards, and relevant decisions made in prior arbitration proceedings. The decision of the arbitrator(s) is binding, subject to applicable state and federal laws and approvals.

The Alternative Dispute Resolution Committee consists of six representatives selected by the Transmission Provider Board. The Committee is intended to reflect the diversity of MISO, so that Committee members are selected according to the size, type, and geographic location of Owners and Members. No more than one Member on the Committee may be a representative of the same Owner or Member. Among its responsibilities, the Committee is charged with identifying and maintaining a pool of qualified individuals to serve as mediators or arbitrators.

Expedited Dispute Resolution procedures may be applied in disputes involving real-time operation (affecting system security or reliability) or available transmission capacity determinations. Disputes are resolved according to the system described in the preceding text, but disputants proceed through the process on an expedited schedule. In some cases, specific MISO officer positions have authority (from Attachment HH) to negotiate disputes under expedited conditions.

5 Long-term Transmission Service Requests

5.1 Introduction

Requests for transmission service must be evaluated for impacts on system reliability. MISO planning staff is responsible for evaluation of long-term firm transmission service requests with reservation periods of one year or longer, which will be referred to as requests in the planning time horizon. The evaluation process is initiated when a transmission customer submits a qualifying request on MISO OASIS. Certain requests for firm transmission service require power flow network analyses in addition to a flow based analysis, in order to evaluate the system's ability to accommodate the request. The Tariff and other MISO documents identify the procedural requirement of the transmission service reservation process. This document provides information to be used in the performance of network analyses of requests for firm transmission service under the Tariff by MISO, or others performing such analyses on behalf of MISO. Studies may be performed directly by MISO planning staff, or may be performed by others on behalf of MISO under MISO guidance. In all cases, MISO is responsible for the final study results and conclusions, and will have decisional control over the transmission service process.

5.2 Triage

Whenever a long-term transmission service request is submitted on OASIS, Tariff Administrators put the request in "Study" mode which indicates MISO planning staff will further review the request. MISO planning staff runs a daily query that imports the Study TSRs from OASIS and then starts processing them based on queue priority. MISO planning staff then takes appropriate steps to process the transmission service requests based on the type of request as described below.

5.2.1 Processing of "Renewal" Transmission Service Request

MISO planning staff does not restudy renewal transmission service requests. Upon receiving such requests, the MISO planning staff will verify and ensure that the parameters of the renewal TSR matches the parameters of the parent TSR and meet the FERC Order 890 rollover reform requirements as posted on MISO OASIS. The renewal TSR must start immediately following the expiration of the parent TSR. If the renewal meets these requirements, MISO planning staff will request the submittal of two copies of the Specification Sheets which are due within fifteen (15) Calendar Days after MISO makes the request by posting comments on OASIS. If MISO does not receive the specification sheets by the posted due date, MISO will refuse the TSR on OASIS. If MISO receives the specification sheets, then the TSR will be accepted and the customer shall have fifteen (15) Days to confirm the TSR on MISO OASIS. After MISO accepts the TSR, it triggers an automatic timer on MISO OASIS for that particular TSR and customer's failure to confirm the TSR within that fifteen (15) day period will result in an automatic refusal of the TSR, also referred to as "Retracted."

5.2.2 Processing of "Redirect" Transmission Service Request

Upon receiving the redirect request for a particular transmission service request, the TSR group engineers perform MUST (Managing and Utilizing System Transmission) analysis to determine the distribution factors of the new path on the constraints identified in the original request analysis and all the constraints with the new redirected path. If the path has a greater than three percent (>3%) impact on the OTDF or greater than five percent (>5%) impact on the PTDF, then the request for redirect transmission service is denied. If the impact on old constraints and new constraints is less than or equal to the thresholds mentioned above, then the redirect request is accepted. The intent of this check is to ensure that the impact of the redirected path, on any flow gate, is not greater than the original path's impact on the flow gates identified when the original TSR was studied.

If the redirect request meets these requirements, the MISO planning staff will request the submittal of two copies of the Specification Sheets which are due within fifteen (15) Calendar Days after MISO makes the request by posting comments on OASIS. If MISO does not receive the specification sheets by the posted due date, MISO will refuse the redirect TSR on OASIS. If MISO receives the specification sheets, then the redirect TSR will be accepted and the customer shall have fifteen (15) Days to confirm the TSR on MISO OASIS. After MISO accepts the TSR, it triggers an automatic timer on MISO OASIS for that particular TSR and customer's failure to confirm the TSR within that fifteen (15) day period will result in an automatic refusal of the TSR, also referred to as "Retracted."

5.2.3 Processing of "Original" Transmission Service Request

When the customer submits an original long-term transmission service request, MISO engineers determine if a System Impact Study (SIS) is required. MISO will determine whether an SIS is required by reviewing the type of request, the duration of the requested TSR and the flow based analysis results. If the start and end times of the requested transmission service are beyond eighteen (18) Months of the queued date then an SIS is required. If the start and end times of the requested transmission service both fall within eighteen (18) Months of the queued date, then it is up to the discretion of MISO to decide if an SIS is required. If the OASIS Automation tool results indicate significant constraints, which in the engineer's judgment cannot be mitigated during the requested service period, then the request will be refused or counter-offered for a period with no constraints.

If the source for the requested NITS TSR is a MISO aggregate deliverable resource, as identified during the Generation Interconnection NRIS deliverability study or through a market transition deliverability test as a result of a Transmission Owner integration, then the request can be accepted without further analysis for the aggregate deliverable amount. Any incremental MW request above the aggregate deliverable MW amount shall require an SIS.

5.2.4 Application of Rollover Rights for Long-term Firm Service

5.2.4.1 General Principles

Firm transmission service customers with contracts have the right to rollover their service provided the service and the request to roll it over conform to the provisions of *Section 2.2* of the tariff.

5.2.4.2 Original Requests

When a customer requests long-term firm transmission service MISO will evaluate the request for periods beyond the stop date of the request to determine if rollover rights will be available for future periods based on existing firm commitments. If this evaluation determines that sufficient capacity is unavailable to accommodate the request for potential future rollover periods, the Service Agreement will stipulate that the customer will not be permitted to rollover its service beyond the period where sufficient capacity exists. However, the customer has an option to make network upgrades provided it agrees to fund the direct assigned network upgrades, as identified during the Facility Study process, to ensure there is sufficient transmission capacity up until the stop date or beyond the stop date of the TSR.

5.2.4.3 Subsequent Requests

In considering subsequent requests for long-term firm service, MISO will not remove capacity associated with a potential rollover from its OASIS. When evaluating the subsequent requests, MISO will assume that rollover rights will be exercised by all prior confirmed requests that are eligible for rollover rights.

If the new request cannot be accommodated, the new customer will have the option of proceeding with an SIS to determine any upgrades necessary to accommodate the request under the assumption that prior confirmed service will be rolled over.

5.2.4.4 Evaluation or Requests Out of Queue Order

Situations exist where a TSR is analyzed before a higher queue priority competing request if the two requests cover different reservation periods and study time constraints are an issue – i.e., the lower queue request is to start before the higher queue request and not enough time exists to study the requests in queue priority. An example is if two requests are received and transmission capacity is available for each request in their respective time period but not available for both transactions to occur simultaneously in subsequent time periods.

5.3 System Impact Study (SIS) Process

After MISO has made the determination that an SIS is required during the Triage process, MISO starts the SIS process with a few administrative steps outlined below.

5.3.1 System Impact Study Agreement (SISA)

5.3.1.1 Step 1 of SISA

In the first step MISO will send the Transmission Customer an SISA within thirty (30) Days of receiving the request on OASIS. The SISA will also include a good faith estimate of the time to complete the study. The time to complete the study will depend on the number of studies in the queue, and whether certain studies can be done in parallel with each other. The starting study deposit for a typical SIS is $20,000 which is refundable if there are any unused balances after the study is complete. For multi-party studies, the cost of performing study will be distributed proportionately for the group study based on the MW size of each TSR in the group.

5.3.1.2 Step 2 of SISA

In the second step the Transmission Customer is required to execute and send the SISA back to MISO within fifteen (15) Days after MISO initiates the SISA request. The executed SISA must include the initial $20,000 deposit for the study. If MISO does not receive the SISA and the study deposit within fifteen (15) Days from the time MISO makes that request, MISO shall refuse the TSR on OASIS. If the fifteenth (15th) day happens to be either on a weekend or a holiday, then MISO engineers will use 10AM of the next first (1st) Business Day as the deadline to accept the SISA.

5.3.1.3 Step 3 of SISA

In the third and final step, if MISO receives the SISA within fifteen (15) days, then MISO will start the SIS and complete the study within sixty (60) Days from the time the agreement and deposit are received by MISO as defined by Attachment J of the Tariff.

5.3.2 System Impact Study, Technical Overview

Once the customer sends the SISA and the study deposit, MISO starts the actual SIS. Depending on the duration of the Transmission Service request, whether it is a one (1) year request or starting after the first eighteen (18) Months after the queued date, the MISO planning staff will utilize OASIS Automation and off-line network analysis evaluation as appropriate.

5.3.2.1 Flow/Interface Limit Based Analysis

The OASIS Automation tool is a flow based analysis tool that is used to evaluate the impact of the requested transfer on all MISO Flowgates. The tool identifies Available Flowgate Capacity (AFC) on all MISO Flowgates with the impact of the requested transmission service for the next 18 Months. All long-term transmission service requests with stop dates within eighteen (18) Months of the queue date are evaluated using the OASIS Automation tool to ensure that there is enough capacity available during the 18 Month AFC window. While evaluating TSRs using the OASIS automation tool, MISO uses the queue date of the TSR as the first day for the AFC verification for the next 18 Months.

- If the start date and the end date of the TSR are within the next eighteen (18) Months of the queued date, then the OASIS Automation tool results are sufficient to either accept or refuse a TSR, unless MISO planning staff believes that further analysis is required and an offline analysis is warranted.
- If the start and end date of the TSR are beyond eighteen (18) Months of the queued date, then MISO does not use the OASIS Automation tool results. In such scenarios, MISO will rely on the offline analysis only.
- If the start date of the TSR is within the next eighteen (18) Months of the queued date and the end date is beyond the next eighteen (18) Months of the queued date, MISO uses the OASIS Automation tool and the offline analysis.
- If the results of the OASIS Automation tool indicate that there is no capacity available on any MISO Flowgate, then MISO will take appropriate action depending on the term of the requested transmission service as mentioned below.
  - If the start date and the end date of the TSR is within the next eighteen (18) Months of the queued date, and there are negative AFCs on any Flowgate, then MISO will refuse the transmission service.
  - If the start date of the TSR is within the next eighteen (18) Months and the end date is beyond the next 18 Months, then MISO will defer the start date of the TSR until there are no negative AFCs. The offline analysis is required to assess system availability beyond 18 Months. All other associated Module B BPM requirements still apply such that the minimum term of the TSR must be in the increments of one year.

In addition to flow-based limits, there can be interface limits for selling transmission services to or from certain interfaces. Any such interface limits are posted on the MISO OASIS.

Such a limit can be for

- Exporting to a specific POD or Importing from a specific POR;
- Exporting to a group of PODs or importing from a group of PORs

The effective interface limits will be posted on MISO OASIS under OASIS Notices in the following document: *MISO_Subregional_Interface_Limit.pdf*.

5.3.2.2 Network Analysis Concepts

5.3.2.2.1 Model Development

An offline network analysis is used to model the requested transmission service, and the subsequent rollover rights, to determine whether the power can be transferred on the requested path without reliability concerns. Up to three study models may be developed depending on the start and stop dates of the requested service. MISO planning staff will determine the number of models required in consultation with the Ad Hoc Study Group established by MISO planning staff pursuant to *Section 5.5.1* of this BPM.

The first model is developed to simulate the forecasted summer peak conditions within the next eighteen (18) Months of the start date of the TSR and is called the near term case.

The second model is developed to simulate conditions during the rollover period of the request, typically five years and beyond, from the start date of the TSR and is called the out year case.

A third model may be developed to examine other system conditions (off-peak summer conditions, peak winter conditions, etc.) if it is determined by MISO planning staff that the results of this analysis would be beneficial to the TSR analysis. Items that MISO planning staff may consider when determining if a third model would provide sufficient value to justify development include: (To be determined based on input from affected Transmission Owner(s) or the customer).

The base cases for the near term and out year cases are built using the Model on Demand (MOD) base case that is updated on a Monthly basis by the Model Engineering group. MISO planning staff makes several changes to this case to ensure that the case represents the most accurate topology expected to occur during peak conditions, for the near term and out year scenarios. All changes that are modeled in the cases are outlined below:

- All previously queued Original and Renewal TSRs that have a status of Study, Accepted, or Confirmed are modeled in the base cases.
- All MTEP Appendix A projects that are expected to be in service should be included in each of the models that will be utilized for the study.
- All generator interconnection related transmission upgrades that have gone through the MISO queue process and have a signed GIA.
- Remove known counter flow transactions
- Extend existing rollover right transactions—applicable to long-term transactions
- Near term and out year models are built using MISO collaborative series summer Bus, Load, and generator profiles from the Model on Demand (MOD).
- Planning models will be populated with applicable ratings for system intact and contingent conditions. These ratings are developed per FAC-008 and submitted to the MOD tool for existing and future facilities. Normal ratings are the applicable ratings for system intact conditions and emergency ratings are the applicable ratings for contingent conditions. When producing power flow models from MOD, Rate A will be populated with the normal rating from MOD and rate B will be populated with the emergency rating from MOD for the appropriate seasons.

MISO does not model the following information in their study cases for the evaluation of long-term transmission Service requests:

- Short-Term Transmission Service requests (Less than one year)
- Redirected capacity of confirmed Transmission Service Requests (capacity of original request will be modeled). The reason for not modeling redirected paths is because currently the redirect paths do not have rollover rights. If NAESB approves rollovers for redirect requests, MISO will make appropriate changes to the modeling assumptions.
- Preempted Reservations - Network analysis is performed for firm requests only. Before performing analysis for firm requests, non-firm reservations and any preempted firm transactions identified by the Tariff Administrator necessary for OASIS Automation to accept the request will be removed from the model.

- Counter-flows - Counter-flow reservations are identified by OASIS Automation based on the transaction's effect on flowgate flow and not included in the Automation results. Counter-flow reservations in offline studies are not modeled based on engineering judgment and experience.
- Partial Path transactions - A network analysis evaluation will be performed for all long-term firm transmission service requests based on specified source and sink. If service is accepted, but is a known partial path transaction (i.e., true source and sink is not specified) the transaction will not be included in the base model for evaluation of future requests.

5.3.2.2.2 FIRM NITS requests

Requests for NITS must be accompanied by a written Application including all of the information located in Section 29.2 of the Tariff. The Application must be submitted at or near the same time as the OASIS request is made. All requests for Designated Network Resources, whether associated with an initial request for NITS or a subsequent request for a new Designated Network Resource, must include in addition to the information required in the Transaction Specification Sheet of the Application for NITS, the information contained in the form, "MISO Request to Designate a Network Resource."

5.3.2.2.2.1 Review of Pre-existing Network Service or Equivalent

MISO will accept requests for initial NITS from Eligible Customers without a system capacity evaluation if the Network Customer provides adequate information for MISO to determine that the Network Load to be served and the resources designated to supply that Load have been planned for in the development of the Transmission System, and do not include new Load connection points or new resources that have not previously been associated with supply to the Eligible Customers Load responsibility. This will require the following to be demonstrated:

- Loads to be served are from existing connected Load points along with Load Forecast information for those existing Loads. Requests for NITS that include specification of newly connected Load points will require evaluation of transmission capacity.
- Resources designated in the Application that are not owned by the Eligible Customer must have existing transmission service arrangements in place (either as a designated resource in a network service arrangement, or PTP service from the resource to a portion or all of the Load responsibility). If no transmission service was previously required for supply from these designated resources, there must be an existing contract for supply from the resource.

- Resources designated in the Application that are owned by the Eligible Customer must have existing transmission service arrangements in place if the resource is outside of the Local Balancing Authority Area where any of the Load responsibility resides.

If all of the above is verified, Planning will sign the specification sheet, and indicate to the Tariff Administrator that the request for NITS should be accepted.

5.3.2.2.2.1 Procedure for Evaluating NITS or Service from New Designated Resource

If the conditions permitting acceptance of the request for NITS without a system capacity evaluation are not met, MISO planning staff will conduct a network analysis and SIS as necessary, using the same steps as in Sections II and III of this Procedure.

These studies shall be done in an analogous manner to the studies performed for an interconnecting generator that requests to be considered as a competing Network Resource for Load within the Local Balancing Authority Area. The Network Resources and Load responsibility of the Network Customer should all be modeled along with all other Loads and valid resources for the period under study. The Network Resources under evaluation should be modeled as delivering their output to the Load as indicated by the customer and approved by the Ad Hoc Group. Other Designated Network Resources for the Local Balancing Authority, or generators within the study region should be reduced proportional to capacity to balance the capacity of the new generator and maintain the net MISO Interchange. The network should then be tested to determine the ability of the aggregate Designated Network Resources for the Load responsibility to supply the Load under a variety of system conditions within reliability planning standards and criteria consistent with NERC, Regional Entities, and consistently applied Local Balancing Authority Area reliability criteria. These criteria may include among others, the outage of the most critical generator.

5.3.2.3 System Impact Study, Network Analysis Methodology

The ability of all MISO Network Resources (NRs) to be dispatched to their deliverable capacity to serve Network Load, needs to be respected while evaluating a new TSR; therefore, instead of a single, fixed base case dispatch, various different generation dispatch scenarios are considered while evaluating the TSR, which adequately ensure that no NR is restricted due to granted transmission service. TSR evaluation is currently being performed using PSS®MUST software.

5.3.2.3.1 Contingencies to Evaluate

Single line outages of facilities 100 kV and above and pre-defined, multi-element contingencies in the study region would be included in the contingency file. Some areas will be monitored for single line outages of 69 kV and above. All such lists will be consistent with applicable NERC, regional and filed local planning standards and are provided to MISO by its Transmission Owner(s). The study participants, under the direction of MISO, should obtain the relevant lists for the current study, and determine any other conditions to be modeled.

5.3.2.3.2 Monitored Elements

Monitored element files include all facilities 100 kV and above in the study region. Some regions will be monitored for facilities 69 kV and above. In addition, a complete list of MISO and relevant non-MISO flowgates is also included in the monitored file.

5.3.2.3.3 Reliability Margins (TRM/CBM)

MISO will apply the Reliability Margins provided by Transmission Owner(s). Flowgates will be provided with CBM and TRM values to be applied to each flowgate. These values should be consistent with NERC and Regional standards applicable to these quantities. For Application of CBM and TRM in network analyses where ATC is evaluated on a regional basis, the following approach should be used. Transmission Reliability Margin (TRM) will be included as an adjustment to flowgate capability as provided by the Transmission Owner. This may be a MW reduction or a ratings percentage reduction. Capacity Benefit Margin (CBM) will be applied to all sink control areas based on the control area CBM methodology approved by the applicable NERC Regional Reliability Council (RRC). CBM preservation on intervening Local Balancing Authorities will be modeled by reducing the branch ratings on pre-defined flowgates by the designated CBM margin provided for that facility.

5.3.2.3.4 Transfer Simulation Participation Points

Transfers will generally be simulated with a Local Balancing Authority POR/POD transfer (i.e., proportionally increase generation in the source area and decrease generation in the sink area) unless a specific source/sink is known. In certain situations, the transfer may be modeled as generation to Load.

5.3.2.3.5 Pre-Transfer Case and Post-Transfer Case

The pre-transfer case is created by the MISO planning staff as outlined in *Section 5.3.2.2* of this BPM. The post-transfer case is created by adding the capacity of the requested transmission service request to the pre-transfer case.

5.3.2.3.6 DC and AC Contingency Analysis

Based on the established source and sink subsystems, a DC contingency analysis is performed to obtain potential constraint pairs where each pair consists of 1 Monitored Element and 1 Contingency element. A generator sensitivity analysis is performed to obtain potential constraint pairs under worst generation dispatch scenarios. Given the limitations involved in the DC analysis methodology, these results cannot be considered as final. However, they do provide a filtered list of potential constraints that needs to be studied further.

5.3.2.3.7 DC Analysis - Creating pseudo Flowgates using DC Analysis

The following steps takes care of different dispatch pattern of NRs, i.e., all NRs have the right to use transmission service to serve Network Load up to their deliverable level. The transfer analysis is performed under a large number of reasonably worst-case generation dispatch scenarios. The point of creating all these pseudo Flowgates is to identify potential constraints under worst case conditions.

- The impact of each MISO NR unit, in the study region, on each filtered potential constraint is obtained by performing Monitored Sensitivity analysis. This impact is quantified as generator sensitivity factor (GSF, also referred to as ‘DF’).
- Based on the assumption of “80-20 rule”, the probability of all requested capacity being called on, is greater than or equal to twenty percent (20%), i.e., at most fifteen (15) generators can be called on to their P_{max}. Therefore, up to fifteen (15) generators with GSFs greater than five percent (>5%) are dispatched to their P_{max} (maximum deliverable amount) sequentially starting from the highest GSF value. Doing so, results in an increase in generation in the study region. Therefore other generation in the study region should be decreased to keep the NSI of the study region the same.
- These pseudo Flowgates for each filtered potential constraint with its associated 80-20 worst dispatch pattern of NRs are created.

5.3.2.3.8 AC Analysis

Once the flowgate list is created by using the DC analysis under worst case scenarios, as described, the next step is to take these contingencies and then apply them to the study models; the near term and the out year cases.

- Perform AC contingency analysis on the pre-transfer case for near term and out year scenarios. Thermal over loads and voltage violations are saved.
- Perform AC contingency analysis on the post-transfer case for near term and out year scenarios. Thermal over loads and voltage violations are saved.

- The results obtained from the pre-transfer and post-transfer analysis are then compared to determine thermal and voltage constraints due to the study transfer by using the applicable reliability criteria. The cutoff for consideration as a thermal constraint is a five percent (5%) distribution factor of the study transfer on a facility overloaded beyond the applicable rating for system intact conditions, or a three percent (3%) distribution factor of the study transfer on a facility overloaded beyond the applicable rating for a contingency condition. The cutoff for consideration as a voltage constraint is a 0.01 per unit voltage change at a Bus beyond the applicable Bus voltage limits (applies to system intact and contingency conditions).

5.3.2.3.9 SIS Report

MISO shall prepare the SIS report within Tariff guidelines and provide the report to the customer within sixty (60) Days after receiving the SISA and the study deposit. See the appendix B for the SIS report format.

5.3.2.3.10 Ad Hoc Study Group Review and Draft Report

After assimilating all the results from the AC contingency analysis, MISO planning staff prepares a draft report and circulates it to the Ad Hoc Study Group. The goal of providing the report to the Ad Hoc Study Group is primarily to provide comments on the following items:

- Provide comments on the study models developed by the engineers for the near term and out year scenarios
- Provide comments on the overloaded transmission elements and provide mitigation which can include the following
  - Provide correct rating for the equipment
  - Identify existing transmission Operating Guides
  - Identify approved projects that mitigate the thermal constraint
  - Identify any existing Special Protection Schemes (SPS) or Remedial Action Schemes (RAS) that are in place
- Provide comments on the validity of the constraints by looking at the contingencies or provide additional contingencies that should be run to meet their respective Planning principles and practices
- Provide preliminary cost estimates for fixing the overloads on transmission elements.

5.3.2.3.11 Evaluating Constraints and Accepting Transmission Service

After receiving feedback and comments from the Ad Hoc Study Group, the transmission planner will incorporate those comments into the report and post the final report on MISO's OASIS. The report will identify all the constraints that are impacted by the Transmission Service request under study and will provide pertinent information to the customer to ensure that the customer can make an informed decision. There are a few permutations and combinations that can occur and can have a different outcome depending on any of the following conditions.

- External Constraints Only: If the SIS identifies transmission constraints on non-MISO transmission system only, then MISO will assist the transmission customer in coordinating with the non-MISO Transmission Owner(s). The customer must submit the Specification Sheets within fifteen (15) Days after MISO requests the Specification Sheets on OASIS. MISO will provide the customer with all the associated conditions that must be outlined in the Specification Sheets for customer's review. By signing the Specification Sheets, the customer agrees to all the terms and conditions identified in the Specification Sheets. If the external constraint is identified as on the path constraint, then the constraint is ignored and it is not reported upon posting the final report on OASIS. A corresponding study will need to be completed by a non-MISO transmission provider to fulfill obligations for complete path reservation. However, all the procedures mentioned above will be followed if the identified constraint is off the path constraint.
- Internal Constraints Only: If the SIS identifies transmission constraints on MISO Transmission System only, then MISO will give the customer a few choices which are outlined as follows.
  - The SIS report will identify the minimum amount of transmission service that can be granted without any transmission upgrades. If the customer is willing to accept the partial service, then MISO will request the transmission customer to submit the Specification Sheets for the reduced amount. MISO will also check the AFC values for the next eighteen (18) Months to verify when the partial transmission service is available. If there are no negative AFC values for the next eighteen (18) Months then MISO will promptly accept and counteroffer the partial transmission service to start at the requested start time. If there is negative AFC before the start date of the TSR, within the next 18 Months, then MISO will defer the start date of the TSR until there are no negative AFC. Any counteroffers must have an identical value for the first twelve (12) consecutive Months, so if negative AFC is found for any of the first twelve (12) Months of the request the counteroffer will be zero (0) for the first twelve (12) Months. The customer can submit Monthly firm transmission service requests for those Months in the twelve (12) Month period that have positive AFC. If the requested transmission service is NITS, then MISO will also request the transmission customer to submit an eDNR on MISO OASIS within fifteen (15) Days along with the Specification Sheets.

  - The SIS report identifies the upgrades in order to accommodate the full request. Upon posting the final report the customer will be issued a Facility Study agreement and also a request to submit Specification Sheets to accept partial offer as per the SIS report. See the Facility Study section for further details.
- Internal and External Constraints: If the SIS report includes constraints on both MISO system and non-MISO transmission system then MISO will take the same steps as identified and explained in Sections 1 and 2.
- No Constraints: If there are "NO" constraints identified on the Transmission System then the transmission service planning engineers will look at the AFC results and take action accordingly. If there are no AFC and NNL violations within eighteen (18) Months of the queued date of the requested TSR, then MISO planning staff will request the customer to submit Specification Sheets within fifteen (15) days. If it is NITS, then the customer will also be required to submit an eDNR on MISO OASIS along with the Specification Sheets. After the MISO planning staff receives the Specification Sheets and the eDNR information, the MISO planning staff will request the Tariff Administrator to accept the transmission service on OASIS.

A facility will be considered constrained if it becomes overloaded when modeling the transaction, or aggravates an existing overload. The constraint must be impacted by the transaction by a five percent (5%) distribution factor with system intact, or three percent (3%) under contingent conditions. Regardless of the distribution factor, any impacts under 1MW will be ignored.

Table 5.3.2.3.10-1: SIS Impact Results Matrix

Near Term Results	Out Year Results	Status
Clean	Clean	Accepted
Clean	Constraints	Accepted with no rollover rights or Facility Study is offered
Constraints	Clean	MISO planning staff determine what upgrade resolved problem in the near term scenario, then accepts conditional on that upgrade. An option would be provided if the customer can accept the service in the out year time frame without any upgrades.
Constraints	Constraints	MISO planning staff engages Ad Hoc Study Group to resolve constraints

5.4 Facility Study Process

5.4.1 Study Coordination Contacts (Ad Hoc Study Group)

When MISO determines that a Facility Study is needed, it will notify potentially affected Transmission Owner(s) of the need for study. These Transmission Owner(s) should indicate if they believe the proposed request could impact their systems, and if they desire to be part of the Ad Hoc Study Group, as provided in *Section 5.5.1* of this BPM, to evaluate the request.

5.4.2 Tender of Facility Study Agreement

In accordance with the Tariff, MISO will tender a Facility Study agreement to the customer within thirty (30) Days of completion of the SIS. If the Facility Study agreement is not executed within fifteen (15) Days the Application will be terminated and MISO planning staff will notify the Tariff Administrator to refuse the request. The Facility Study agreement will include an estimate of the actual cost to perform the study. This cost estimate will include the cost of work by MISO planning staff and any other participants, including consultants, involved in the coordinated study. The Facility Study agreement will also include a good faith estimate of the time to complete the study. The time to complete the study will depend on the number of studies ahead in the queue, and whether certain studies can be done in parallel with each other. The Tariff requires facilities studies be completed within one-hundred twenty (120) Days of receiving the executed study agreement and deposit.

The study deposit for a Facility Study is $100,000 which is refundable if there are any unused remaining balances after the Facility Study is complete. If the customer requests to stop all Facility Study work because it wishes to withdraw the TSR, then MISO will stop all work and refund the remaining balance.

There are instances when the cost of the actual study is expected to exceed the initial study deposit. In those situations, MISO will request the customer to deposit additional funds to ensure that the Facility Study continues per schedule. If the customer fails to make any additional deposit, MISO will stop all work until the additional deposit is received.

5.4.3 Performing the Facility Study

MISO planning staff will form an Ad Hoc Study Group as provided in *Section 5.5.1* of this BPM. MISO then prepares the study cost estimate, project timeline, and study agreement.

- MISO Planning contacts the impacted area (i.e., Local Balancing Authority where the constraint is located) and, if required, a third party contractor to determine Ad Hoc Study Group membership and cost estimates

- MISO Planning will initiate and coordinate the Ad Hoc Study Group Facility Study process.

The Facility Study report will determine a good faith estimate of the following:

- The cost of direct assignment facilities to be charged to the transmission customer
- The transmission customer's appropriate share of the cost of any required network upgrades
- The time required to complete such construction and initiate the requested service.

After the Facility Study report is complete, it is reviewed by MISO planning staff before it is transmitted to the customer. At this juncture, the transmission customer has the following options.

- It can either opt for a reduced amount of available transmission service, as identified in the SIS report.
- Proceed with a facility construction agreement and agree to fund and build the transmission upgrades for the full requested amount which caused the Facility Study to be performed.
- Withdraw the TSR

5.4.3.1 Specification Sheets

Prior to MISO moving the request to an *Accepted* status, an executed *specification sheet* must be received from the customer. The *specification sheet* gives the details of the service, including the specific source, sink, term of the transaction, amount, and lists any prerequisite conditions that must be met prior to commencement of service, such as Network Upgrades. Once the customer is notified via OASIS, they will have fifteen (15) Calendar Days to provide those forms or the service will be deemed withdrawn and the request will be refused.

5.4.4 Facilities Construction Agreement

When the results of the Facilities Study indicate the need for the Transmission Customer to finance the construction of Network Upgrades, those requirements will be memorialized in a 3-party Facilities Construction Agreement which must be filed at FERC either executed or unexecuted prior to commencement of the transmission service. This agreement will delineate the roles and responsibilities of each party to the agreement.

5.5 Miscellaneous

5.5.1 Ad Hoc Study Group

Under the direction of MISO, the Ad Hoc Study Group will participate in the analysis and reporting of the available transmission capacity to accommodate the transmission service request. The Ad Hoc Study Group will perform, as necessary and in accordance with the provisions of the Tariff, System Impact and Facilities Studies. MISO will form and direct the activities of the Ad Hoc Study Group. It is anticipated that the study group formed to evaluate a transmission service request will be made up of representatives from the source and sink Local Balancing Authorities as well as interested intervening Local Balancing Authorities. It is anticipated that MISO will perform preliminary distribution factor calculations or other analysis to determine the extent of interactions with intervening systems. The Ad Hoc Study Group may also include third party contractors to assist in performing the analyses.

The possible participants in System Impact and subsequent Facilities Studies will include:

- Transmission Customer
- MISO planning staff
- Transmission Owner(s) of facilities potentially impacted by the request
- Adjacent transmission providers/RTO(s)
- Regional or subregional study groups in place in the areas potentially impacted by the request

The role of MISO planning staff will generally be to:

- Establish study time line – Tariff defined
- Prepare the study agreements
- Provide the system models to be used in studies
- Provide the study guidelines by which studies should be performed
- Determine whether an impact study is needed to resolve constraints to accepting service
- Ensure the accuracy of studies, either by MISO planning staff, or on behalf of MISO by contractors or members of the Ad Hoc Study Group
- Coordinate the formation and activities of the Ad Hoc Study Group
- Review any studies performed on behalf of MISO for accuracy and for compliance with the Tariff and applicable standards and procedures
- Provide study results and reports to customer
- Handle billing and payment of study costs

The role of other participants in the studies will generally be to:

- Indicate desire to participate in the Ad Hoc Study Group
- Provide information to MISO to assist in preparing study agreements
- Assist in updating any models used for studies
- Perform studies, or aspects of studies, as requested by, and on behalf of, MISO according to study guidelines of MISO, and applicable standards
- Provide review and comments to MISO of study results with regard to their systems
- Provide study results and reports to MISO
- Respond to MISO questions and assist MISO in responding to customer questions concerning study results

Note: If transmission service is being requested across the border between PJM and MISO, the procedures under "Joint and Common Market," as provided at the following web-link, will be invoked: MISO PJM JOA

If MISO finishes its SIS or the Facility Study before the customer has received the results for the other leg of the transmission service, then MISO will wait to request the transmission service specification sheets until the customer has results from both transmission providers (PJM and MISO). Once the results from PJM's planning department are available, MISO will request the customer to submit the Specification Sheets within fifteen (15) Calendar Days after initiating the request. Customer's failure to submit the Specification Sheets within fifteen (15) Calendar Days will result in the refusal of the TSR on MISO's OASIS.

5.5.2 Reserved

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5.5.3 Group TSR Studies

If multiple customers request TSRs on a common path due to economic or other engineering reasons, MISO shall study all those TSRs in one single group and shall call it a single group study. The cost to perform the System Impact Study and Facility Study shall be prorated based on the individual size of each TSR in the group. The appropriate percentages to calculate the prorate costs to perform the studies shall be shared amongst all the transmission customers at the commencement of the study. The percentage costs for any common upgrades will also be calculated based on the prorate share of the size of the TSR. Any other transmission upgrades costs that are unique to each TSR in the group will be direct assigned to that TSR's customer.

5.5.4 Specification Sheets

Prior to MISO moving the request to an *Accepted* status, an executed Specification Sheet must be received from the customer. The Specification Sheet gives the details of the service, including the specific source, sink, term, amount, and lists any prerequisite conditions that must be met prior to commencement of service, such as Network Upgrades. Once the customer is notified via OASIS, they will have fifteen (15) Calendar Days to provide those forms or the service will be deemed withdrawn and the request will be refused.

5.5.5 Provisional Generator Interconnection Agreements

Point-to-Point transmission service is available for units with provisional interconnection agreements. Network Integrated Transmission Service is not available to units with provisional interconnection agreements.

5.6 Coordination of TSR studies between MHEB, MPC and MISO

This procedure will govern the TSR study coordination for the Long Term Firm Transmission Service Requests on MHEB, MPC and MISO transmission systems where one of the three parties may be an Affected System TSP for the TSR. The entire coordination procedure is documented in Appendix O of this BPM.

5.7 Appropriate Links

OASIS Transmission Studies page. Contains links to the following pages and reports:

- System Impact Studies page which contains links to reports.
- Facility Studies page which contains links to the reports.
  - FERC metrics report links: FERC_Order890_Performance_Metrics
  - AFC procedure links: ATC_Information
  - MISO Network and Point to Point Specification Sheets: MISO_Network_and_Point_to_Point
  - Tariff and Rate Schedules: Long-term Transmission Service Request
  - Transmission Services webpage: Long-term Transmission Service Request

6 Non-Cyclical Planning Studies

6.1 Review of Market Participant Funded Projects

Process for evaluation of Market Participant funded projects (MPFP) is described in this section. Pursuant to Section III.A.2 of Attachment FF of the Tariff, Market Participant funded projects are defined as network upgrades fully funded by one or more market participants but owned and operated by incumbent Transmission Owner(s). This process applies to those network upgrades that are neither currently included in the MISO Transmission Expansion Plan (MTEP) Appendix A nor targeted for approval within the current planning cycle.

- These Market Participant funded projects are not "Merchant Upgrades" which are constructed, owned and operated by Market Participants or Merchant Transmission Owner(s).
- Pursuant to Order 1000, since these network upgrades are not approved as part of a regional planning process for purposes of cost allocation but by nature are directly assigned to the Market Participant, such upgrades are not eligible for elimination of Right of First Refusal (ROFR).

6.1.1 Process Steps

- **Step 1**: all such network upgrades shall be required to be submitted using the MPFP proposal form, which needs to be sent to MISO via electronic mail at the address indicated on the form, by Market Participants by September 15th for inclusion in the MTEP to be approved in December of the following year. Each project will receive a time-stamp date of receipt. Exceptions to the submittal deadline shall be:
  - Allowed where network upgrades are less than $1 million and deemed to not have material impact on the network transmission system by MISO and applicable Transmission Owner(s).
  - Projects that have been proposed as economic projects and have been evaluated in the MCPS process and all appropriate studies have been completed by the 3rd SPM but did not meet MISO's criteria and were, therefore, not selected as Market Efficiency Projects.
- **Step 2**: these projects will follow the same process as TO submitted projects in the MTEP planning cycle.
- **Step 3**: to the extent, prior to commencement of studies, that a proposed network upgrade by the Market Participant is deemed either infeasible or inconsistent with Transmission Owner facility standards, the applicable Transmission Owner(s) shall propose alternative transmission upgrades for market participant funding. These transmission upgrades may be upgrades to the existing system or new facilities.
- **Step 4**: Market Participant and applicable Transmission Owner(s) shall enter into a System Facilities Study Agreement by the first annual regularly scheduled Subregional Planning Meeting (SPM), which is typically held in December. Agreements shall be consistent with Attachment D-2 where all planning, engineering and other study costs associated with the MP request shall be borne by the Market Participant.

- **Step 5**: MISO will present proposed MPFP along with all other proposed MTEP projects at the first annual regularly scheduled SPM.
- **Step 6**: MISO in collaboration with applicable Transmission Owner(s) shall conduct an engineering analysis which would include:
  - Detailed engineering study of appropriate network upgrade needed to mitigate applicable constraint/s and associated estimate costs.
  - A reliability "No-Harm" study to identify detrimental impact to reliability of the existing system if any. Reliability no harm study shall be conducted consistent with NERC Planning Standards, Regional Entity standards, Transmission Owner's Planning Criteria and Tariff and BPM requirements. To the extent, the proposed network upgrades "harm" the reliability of the existing system, additional network upgrades including associated costs shall be developed.
- **Step 7**: Market Participants shall execute Facility Construction Agreement (FCA) with applicable Transmission Owner(s) by the 3rd annual SPM.
  - MISO will notify Market Participant of the final project selection and estimated cost.
- **Step 8**: MISO will communicate the final project selection and estimated cost of the MPFP including any additional necessary upgrades and associated cost at the 3rd SPM including the MPFP in the ongoing MTEP analysis at that time.
- **Step 9**: MISO will evaluate eligible financial rights associated with the final network upgrades in accordance with the Tariff.
- **Step 10**: MISO will include the network upgrades in its current MTEP once the FCAs are in place.

The above outlined process does not in any way preclude individual Market Participants and Transmission Owner(s) mutually agreeing to complete their respective milestones on an accelerated schedule.

6.1.2 Priority of Competing Project Proposals

In the event that multiple Market Participants submit project proposals that are electrically similar, MISO will make a determination in collaboration with the affected Transmission Owner as to whether the projects are effectively the same project[24]. If the projects are determined to be effectively the same project, the priority for the project shall be determined by the time-stamp date of receipt of the MPFP Proposal Form, unless otherwise agreed to by the impacted Market Participants.

[24] Consideration is given to feasibility and compatibility of the multiple proposals and congestion issues addressed by the proposals.

6.2 Generator Retirement and Suspension Studies and System Support Resources (SSR)

6.2.1 Introduction

The Attachment Y program defined in *Section 38.2.7 of the Tariff* provides a mechanism to maintain Transmission System reliability by retaining a Generation Resource as a System Support Resource when the change in status of the generator would result in reliability issues that can only be mitigated with the continued operation of the generator. System Support Resources (SSR) are Generation Resources or Synchronous Condenser Units (SCUs) which are required by MISO to maintain system reliability, if such Generation Resources or SCUs are uneconomic to remain in service and otherwise would be retired or placed into suspension.

MISO in collaboration with the affected Transmission Owners performs an Attachment Y reliability study to assess the impacts of potential generator retirements and suspensions on system performance to determine if violations of NERC or local TO planning criteria occur as a result of the change in status. If reliability issues cannot be resolved with available alternative mitigation plans, the generator is retained and compensated by MISO through an SSR Agreement and costs are paid by the Loads that benefit from the SSR. While the Attachment Y analysis seeks to identify system reinforcements needed to accommodate the retirement/suspension of the generator, SSRs are a last resort measure used as interim mitigation until other transmission upgrades or alternative solutions are available and therefore are not considered to be planning solutions.

6.2.2 Applicability and Notification Requirements

Attachment Y Tariff Notification provisions apply to all Generation Resources as well as units that are interconnected to MISO transmission facilities but pseudo-tied out of MISO market. SSR eligibility will apply to market Generation Resources if the generator has been determined to be required to address reliability issues. Generation Resource Owners are required to submit planned retirements and suspensions to MISO at least twenty-six (26) weeks in advance of the intended change of status for the full capacity or a reduction in capacity of the generator. The Attachment Y Notice must be executed by an officer of the company authorized to make a binding decision and must contain complete information including the change of status dates. Attachment Y Notices are considered definitive decisions and subject to limited rescission rights as provided in the Tariff.

Attachment Y Notices are treated as confidential information and remain confidential until the date of retirement unless the owner publicly releases the information. If reliability issues are identified that cannot be resolved with available mitigation the Attachment Y will no longer be considered confidential and alternatives will be sought in an open stakeholder process.

6.2.3 Study Scope Development

As required by the Tariff, MISO works with affected TOs to define the study parameters for evaluating the impact of the generator change of status and may consider other available studies. The Attachment Y reliability study will include at a minimum thermal and voltage analysis to evaluate steady state system performance. Additional analysis may be included to evaluate system stability and/or import limitations under the expected system conditions. MISO SSR Planning staff consults with MISO Operations staff to consider any additional operational requirements associated with the Attachment Y generator.

Analysis will reflect the conditions expected for the period of the change in status including any relevant topology changes and forecasted Load levels. Generation dispatch will consider any expected changes in generator availability and will be based on security constrained economic commitment and dispatch. Analysis will identify any issues that require mitigation to meet NERC and local planning criteria and include the determination of impact of the Attachment Y unit under study on those issues. SSR need is determined by the presence of unresolved reliability criteria violations where the unit under study meets SSR impact criteria as discussed in *Section 6.2.5* below.

6.2.4 Power Flow Model Preparation

The Attachment Y reliability study cases are derived from MTEP study models to produce a near-term model which represents the initial year of the retirement/suspension of the generation resource or SCU and a mid-term model which represents the longer term outlook as appropriate. The models contain firm transactions appropriate for reliability analysis and are updated to reflect the topology changes associated with MTEP Appendix A and Target Appendix A projects planned to be completed for the study period. The forecasted Load conditions used in the Attachment Y reliability study reflect seasonal conditions such as peak and shoulder Load levels where appropriate. Generation commitment and dispatch is based on Security Constrained Economic Dispatch (SCED) of available Generation Resources. Generation dispatch also considers the operational limitations related to Qualified Facilities (QF) and unit commitment requirements defined in available Operating Guides.

For each study period, two model scenarios are created which represent the “before” and “after” states of the generator/SCU retirement or suspension. The models which represent these two (2) scenarios are created in the following steps:

- **Step 1**: The “after” retirement/suspension model is created first as follows:
  - An approved MTEP series model is selected based on the appropriate seasonal conditions.
  - MTEP Appendix A and Target Appendix A transmission projects are applied/removed to create model topology consistent with the study period.
  - Previously retired and unavailable generators are removed from service and capacity replaced from other available MISO Generation Resources.
  - Generation dispatch prescribed by QF and Operating Guide requirements is manually set.
  - SCED bid input files are updated to excluded the non-dispatchable resources.
  - SCED is applied to the model to dispatch MISO generators.
- **Step 2**: The “before” retirement/suspension model is created from the “after” retirement/suspension model as follows:
  - The study generator(s) is placed in-service and generator output (Pgen) is set to the appropriate Generator Verification Test Capacity (GVTC) value submitted by the resource owner to MISO as per *BPM-011 - Resource Adequacy*.
  - All other generation is scaled down in the MISO market areas, excluding the local area(s) where the study generator is located, by the total amount of the generation under study.

6.2.5 Reliability Evaluation

The Attachment Y reliability study applies NERC and local planning criteria in evaluating the impact of the retirement/suspension on transmission system performance for NERC category P0 conditions and under simulation of NERC category P1-P2 contingent events, selected NERC category P3-P7 events, and planned maintenance plus forced outage events that are included in local planning criteria. The need for the SSR is determined by Transmission System reliability issues where thermal or voltage violations are caused by the removal or reduction of the study generator and cannot be resolved without the use of the SSR Unit. Allowed mitigation measures proposed to address the violations of planning criteria are investigated for effectiveness, and unresolved issues are then documented in justifying the need for the SSR Unit.

The evaluation criteria for the Attachment Y reliability study is further described below:

- The monitored areas include the Transmission Owner area where the Attachment Y generator(s) is located and nearby affected TO areas. Monitored Transmission System facilities include 100 kV and above facilities in the affected areas and 69 kV and above facilities that are under MISO functional control. These monitored facilities also include tie lies to neighboring areas.
- Branch Loading is compared against the normal thermal rating for NERC category P0 conditions (system intact), and against the emergency thermal rating for category P1-P7 contingencies.
- Transmission Bus voltages are evaluated with respect to steady state Bus voltage criteria specified by the Transmission Owner local planning criteria. Generally, pre-contingency voltage limitation is between 1.0 and 1.07 p.u. for 500 kV and above Buses, and between 0.95 and 1.05 p.u. for Buses below 500 kV. Post-contingency voltage limitation is normally between 0.9 and 1.1 p.u., if it is not specified. All 100 kV and above post contingent voltages are assessed after automatic transformer tap change and shunt switching have been performed.
- Under NERC Category P0 conditions and category P1-P7 contingencies, branch thermal violations are only valid if the flow increase on the element in the “after” scenario is equal to or greater than:
  - Five percent (5%) of the “to-be-retired” unit(s) MW amount (i.e., 5% PTDF) for a “base” violation compared with the “before” scenario; or
  - Three percent (3%) of the “to-be-retired” unit(s) MW amount (i.e., 3% OTDF) for a “contingency” violation compared with the “before” scenario.
- Under NERC category P0 conditions and category P1-P7 contingencies, high and low voltage violations are only valid if the change in voltage is greater than one percent (1%) as compared to the “before” scenario.
- Available mitigation may be applied for the valid NERC category P1-P7 thermal and voltage violations described above as allowed by NERC standards.
- Where Transmission Owner planning criteria prescribe requirements for planned outages, analysis of NERC category P3 and P6 events in shoulder conditions will be used to identify reliability issues and assess the need for mitigation.
- Angle/voltage stability studies and import capability will be performed as needed.

- The need for the SSR is determined by the presence of unresolved violations of reliability criteria that can only be alleviated by the SSR generator and where no other mitigation is available. Evaluation of mitigation solutions will consider the use of operating procedures and practices such as equipment switching and post-contingent Load Shedding plans allowed in the operating horizon.

Analysis results are reviewed with the Transmission Owner to validate the findings and identify any immediately available remediation. New or previously planned transmission upgrades needed to address the violations in the near term should be submitted as a MTEP Target Appendix A project for approval in the applicable MTEP planning cycle.

Upon completion of the reliability analysis MISO prepares an initial report containing the detailed study results and conclusion of the analysis which is reviewed and confirmed with the affected Transmission Owner study participants. MISO sends a notification letter to the asset owner to provide an opportunity to withdraw the Attachment Y Notice without further consideration. If the notice is not rescinded within fifteen (15) Business Days, MISO sends a letter with the final Attachment Y study decision.

If no reliability issues are found or if transmission upgrades are planned to be implemented before the retirement or the date of need, or other mitigation options exist, the Attachment Y generator is approved to Retire or Suspend. For any unresolved violations of planning criteria MISO informs the asset owner of the need to pursue a SSR Agreement and posts a public notice of the reliability need for the Attachment Y generator and a public version of the initial report on the MISO OASIS. Additional analysis is performed to identify the Loads subject to SSR cost responsibility.

6.2.6 Alternatives Evaluation

After notifying the asset owner of the SSR need, MISO convenes a public Technical Studies Task Force meeting to review the Attachment Y reliability issues and to seek feasible alternatives to avoid the need for the SSR Agreement in a stakeholder-inclusive process in accordance with *Section D.1.b of Attachment FF - Transmission Expansion Planning Protocol*. MISO works with stakeholders to explore other potential alternatives including generation redispatch, system reconfiguration, new or expedited transmission upgrade projects, new generation resource or SCU installation, remedial action plans, or demand response solutions that are comparable to the SSR Unit.

6.2.7 System Support Resource Agreement

If no feasible alternative is identified, MISO and the Market Participant negotiate and execute an SSR Agreement (Attachment Y-1) to maintain availability of the generator for reliability needs. The SSR Agreement defines the terms of service to permit MISO to dispatch the generator in exchange for compensation for the total cost of service for the generator. The total compensation includes a component of costs filed directly with FERC by the Market Participant and variable compensation component based on the market revenues and charges determined in the market settlements process. MISO files the SSR Agreement along with the associated schedule containing allocation of costs for the SSR Unit for approval by FERC. MISO will conduct a periodic review, at least annually, of the continued need for the SSR. The review will include a reliability analysis of the expected system conditions for the next term of the SSR Agreement and evaluation of any alternatives that can be implemented before the renewal of the agreement.

6.2.8 System Support Resource Agreement Cost Allocation Methodology

6.2.8.1 Overview

MISO SSR Cost Allocation Methodology describes the approach for assigning costs associated with retaining a Generation Resource as an SSR Unit to maintain reliability of the Transmission System. Costs for maintaining the SSR generation are allocated to LSE's that benefit from the operation of the SSR Unit. Analysis is performed to identify the Loads that contribute to constraints identified in the Attachment Y reliability study, and the associated LSE's are assigned a share of the cost responsibility based on their Monthly peak energy withdrawals. The method for cost allocation is filed with the associated SSR Agreement for approval by FERC.

The methodology addresses both thermal and voltage related reliability issues that can be caused by the retirement/suspension of a generation resource. The process for determining the Load impacts requires the calculation of Load distribution factors (DF) and utilizes readily available powerflow analytical tools. The distribution factor is determined for each Load Bus in the MISO system relative to the MISO generation reference which reflects the replacement power for the SSR Unit under study. That is if the SSR Unit were not available the power would be provided by the MISO market generation to serve the system Loads. The SSR Unit avoids the constraints, and thus provides benefit to the Loads contributing to the constraint.

The determination of cost responsibility and allocation of the costs to the Loads requires the analysis of each constraint identified in the Attachment Y reliability study to calculate the distribution factors of MISO Load Buses. The distribution factors are calculated with respect to a MISO-wide generation reference with generator participation based on modeled unit capacity

(P_{max}). This represents the dispatch of MISO market generation to replace the power otherwise provided by the SSR Unit. Load distribution factors for thermal constraints can be calculated by standard linear power flow techniques. Voltage issues require the establishment of proxy interface that represents a constraint for the import of replacement power to the area of voltage decline and requires additional steps to define the interface.

6.2.8.2 Identification of Impacted Load Buses and Associated Elemental Pricing Nodes

6.2.8.2.1 Thermal Constraints

In the case of thermal violations the Load distribution factors are calculated directly by linear power flow analysis to obtain the distribution factor (DF) or shift factor of the constraint flow to the power injection at the Load Bus. This constraint is modeled as an OTDF constraint that includes the impact of the contingent event that was identified to cause the thermal violation. For each constraint identified in the Attachment Y study, distribution factors are calculated using the MISO market Network Model that is the most recent final model available at the time the analysis is performed for the new SSR Agreement or renewal of the contract. A minimum distribution factor cutoff of one percent (1%) is used as a reasonability threshold to eliminate the Buses that have minimal impact. Use of the Network Model allows direct mapping of the Network Model Load Buses to the Elemental Pricing Nodes (EP Nodes) used in settlements.

6.2.8.2.2 Calculation of Load Distribution Factors for Thermal Constraint

For each unresolved thermal constraint identified in the Attachment Y study, linear power flow analysis is performed to determine how much impact Load Buses in the MISO system have on the constraints that are caused or made worse by the SSR Unit.

- **Step 1:** Using the quarterly MISO market Network Model, the Load distribution factors are calculated with respect to the MISO aggregate market generation reference using DC powerflow analysis to determine the change in flow of the monitored thermal constraint due to the MW Load at each Bus.
  - Define subsystem for distribution factor reference (include MISO generation Buses)
  - Define subsystems for individual Load Buses in MISO footprint
  - Create monitor list of constraints using thermal monitored facilities and contingent elements
  - Using Network Model base case, run DC powerflow analysis to calculate distribution factors of Load Buses in MISO footprint for each constraint identified

- **Step 2:** Load Buses with distribution factors that exceed one percent (1%) minimum threshold are selected and mapped to the corresponding Elemental Pricing Nodes using the MISO Commercial Model
  - Analysis results are filtered to retain all Load Buses with distribution factors above one percent (1%)
  - Using the MISO Commercial Model data, Elemental Pricing Node names are mapped to the associated Load Buses
- **Step 3:** Elemental Pricing Nodes are ranked in descending order according to their Load distribution factors
- **Step 4:** Load distribution factors are summed to obtain a total
- **Step 5:** Eighty percent of the total of the distribution factors is calculated as the cutoff threshold above which Loads are selected for cost allocation
- **Step 6:** Elemental Pricing Nodes with the same Load distribution factors at the eighty percent cutoff threshold are included for cost allocation

6.2.8.2.3 Voltage Constraints

For voltage violations and voltage stability issues, the Loads in voltage constrained area contribute to the voltage decline or voltage collapse condition. Load Buses that contributed to the voltage issues are first identified by steady state or voltage stability studies and further evaluated using modal analysis traditionally used to identify participating Buses at the point of instability. More detailed examination of the transmission network is necessary to identify the weak interfaces where the system would separate to avoid further propagation of a voltage collapse event. The boundary of the area susceptible to the voltage violations or potential voltage collapse is defined as a proxy interface of transmission facilities that completely encloses the voltage constrained area and thus all Loads within the area are considered equal contributors the voltage issues (distribution factor is ~1.0).

Once the proxy interface has been defined, the MISO market Network Model that is the most recent final quarterly model available at the time of the analysis for the new or renewed SSR Agreement is used to allow mapping of the Load Buses to the corresponding EP Nodes. Since all Load Buses that are within the bounded area have the same distribution factor, all Loads will be allocated a portion of the SSR costs. Use of the Network Model allows direct mapping of the Network Model Load Buses to the Elemental Pricing Nodes (EP Nodes) used in settlements.

6.2.8.2.4 Determination of Voltage Constraint Proxy

For each voltage violation constraint or voltage stability constraint identified in the Attachment Y study, the boundary of the voltage constrained are is determined by the location of the Buses with voltage violations or Buses participating in voltage collapse. Examination of the transmission network topology is used to determine the appropriate interface to establish a boundary around the affected voltage constrained area.

- **Step 1:** Using the Attachment Y study model, Buses with voltage violations are identified
- **Step 2:** Using the Attachment Y study model, voltage stability assessment (P-V analysis) scenario is defined to simulate transfers to replace Attachment Y generation with other MISO market generation.
  - Create sink subsystem for the generator under study (include SSR Units)
  - Define all areas specified in the Attachment Y study as monitored areas
  - Enable modal analysis and include Attachment Y study areas for monitoring
- **Step 3:** Voltage stability analysis is performed to determine the point of instability for each contingency
- **Step 4:** At the stability limit, modal analysis is performed to indicate the Buses participating in the voltage collapse for the mode with the lowest eigenvalue (near zero).
- **Step 5:** Using the set of Buses with voltage violations or participating in voltage collapse, the boundary of the voltage constrained area is determined and a corresponding interface is defined by transmission elements that fully enclose the area
  - The interface is determined by weak transmission system and lower kV lines that are likely to separate the voltage constrained area from the rest of the interconnection following a disturbance
  - The voltage constrained area is the minimum area enclosed by the interface that includes the identified Buses and the SSR generator
- **Step 6:** The voltage proxy constraint is defined by the interface of the voltage constrained area

6.2.8.2.5 Calculation of Load Distribution Factors for Proxy Voltage Constraint

- **Step 1:** Using the quarterly MISO market Network Model, the Load distribution factors are calculated with respect to the MISO aggregate market generation reference using DC powerflow analysis to determine the change in flow of the monitored voltage proxy constraint due to the MW Load at each Bus

- Define subsystem for distribution factor reference (include MISO generation Buses)
- Define subsystems for individual Load Buses in MISO footprint
- Using Network Model base case, run DC powerflow analysis to calculate distribution factors of Load Buses in MISO footprint for each proxy constraint identified

* **Step 2:** Load Buses with distribution factors that exceed one percent (1%) minimum threshold are selected and mapped to the corresponding Elemental Pricing Nodes using the MISO Commercial Model
  - Analysis results are filtered to retain all Load Buses with distribution factors above one percent (1%)
  - Using the MISO Commercial Model data, map the Elemental Pricing Node names to the associated Load Buses

6.2.8.3 Calculation of Cost Allocation Shares

6.2.8.3.1 Determination of the Impacted Load Zone Commercial Pricing Nodes

Using the quarterly MISO Commercial Model, the Elemental Pricing Nodes that are associated with the impacted Load Buses are used to identify the Load Zone Commercial Pricing Nodes for the current billing Month.

6.2.8.3.2 Identification of the coincident peak Actual Energy Withdrawal for Billing Month for Impacted Load Zone Commercial Pricing Nodes

For each Load Zone Commercial Pricing Node identified in the previous step, MISO determines the Monthly_PEAK $_{\text{CP NODE}}$, which is the hourly Actual Energy Withdrawal volume during the billing Month based on the coincident peak hour across all Impacted Load Zone Commercial Pricing Nodes.

6.2.8.3.3 Determination of the portion of the Load Zone Commercial Pricing Node benefiting from the SSR for the billing Month

To determine the Elemental Pricing Node Volume (EPN _MW), using the Peak Hour in the billing Month for a Load Zone Commercial Pricing Node, the Daily Load Weighting Factor (DLWF)[25] for each Elemental Pricing Node associated with the Load Zone Commercial Pricing Node is multiplied by the Monthly_PEAK.

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[25] The Daily Load Weighting Factor is a daily calculation of the ratio of the EPNode Load to the total Load for the parent CPNode Load as determined by real time data, and is used to estimate the EPNode fraction for the purpose of settling the prices in the market settlements process. This calculation is performed seven (7) Days prior to the market day from data supplied by the State Estimator, which is "[a] software program used by the Transmission Provider to create a real time assessment of the condition of the Transmission Provider Region." Tariff Section 1.S.

Equation 6.2.8.3.3-1: Elemental Pricing Node Volume

$$EPN\_MW = Monthly\_PEAK_{\ CP\ NODE} \times DLWF_{EP\ NODE}$$

For each impacted Load EPNode, the distribution factors are summed for all constraints identified by the Transmission Provider to determine the aggregate Load distribution factor (EPN_LDF).

Equation 6.2.8.3.3-2: Aggregate Load Distribution Factor

$$EPN\_LDF = \Sigma\, DF_{CONSTRAINT}$$

The Elemental Pricing Node Volume is multiplied by the aggregate Load distribution factor (EPN_LDF) for each Elemental Pricing Node, to determine the Elemental Node Impact Volume (EPN_IMP_MW).

Equation 6.2.8.3.3-3: Elemental Node Impact Volume

$$EPN\_IMP\_MW = EPN\_MW \times EPN\_LDF$$

The EPN_IMP_MW is summed for all Elemental Pricing Nodes for the Load Zone Commercial Pricing Node for a total Load Zone Commercial Pricing Node Impact Volume (IMP_MW).

Equation 6.2.8.3.3-4: Commercial Pricing Node Impact Volume

$$IMP\_MW_{CP\ NODE} = \Sigma\, EPN\_IMP\_MW$$

6.2.8.3.4 Determination of the Cost Share for the Load Zone Commercial Pricing Node

A Commercial Pricing Node’s percentage Share (CPN_SHARE) for a SSR Agreement is equal to the IMP_MW for that Load Zone Commercial Pricing Node divided by the total IMP_MW for all Load Zone Commercial Pricing Nodes that benefit from the SSR Unit(s).

Equation 6.2.8.3.4-1: Commercial Pricing Nodes Percentage Share

$$\mathrm{CPN\_SHARE_{SSR} = IMP\_MW_{CP\ NODE} / \Sigma\ IMP\_MW_{CP\ NODE}}$$

6.2.8.3.5 Determination of the Sum of the Load Zone Commercial Pricing Node shares by LSE

Sum the CPN_SHARE by Asset Owner, which represents the LSE, to determine the total LSE percentage Share (LSE_SHARE) for the SSR Agreement.

Equation 6.2.8.3.5-1: Commercial Pricing Nodes Percentage Sum

$$LSE\_SHARE_{SSR} = \Sigma\ CPN\_SHARE_{SSR}$$

6.2.8.3.6 Determine the Net Charge or Credit Assigned to Each LSE

The net charge or credit for each LSE (SSR_AMT_{LSE}) is obtained by multiplying the LSE_SHARE_{SSR} by the net charge or credit calculated for the SSR Agreement ($TOTAL\_AMT_{SSR}$).

Equation 6.2.8.3.6-1: LSE Net Charge

$$SSR\_AMT_{LSE} = LSE\_SHARE_{SSR} \times TOTAL\_AMT_{SSR}$$

6.2.8.4 Example of SSR Cost Allocation

Table 6.2.8.4-1: List of Elemental Pricing Nodes that Impact SSR Constraint

Node	Constraint	Distribution Factor
EP-1	A	0.05
EP-2	A	0.1
EP-3	A	0.08
EP-4	A	0.25
EP-5	A	0.06
EP-6	A	0.15
EP-7	A	0.18
EP-8	A	0.07
EP-9	A	0.3
EP-10	A	0.5
EP-1	B	0.08
EP-2	B	0.1
EP-3	B	0.07
EP-4	B	0.15
EP-5	B	0.18
EP-6	B	0.06
EP-7	B	0.05
EP-8	B	0.3
EP-9	B	0.25
EP-10	B	0.5
EP-1	C	0.05

EP-2	C	0.5
EP-3	C	0.15
EP-4	C	0.06
EP-5	C	0.07
EP-6	C	0.25
EP-7	C	0.3
EP-8	C	0.08
EP-9	C	0.18
EP-10	C	0.1

Table 6.2.8.4-2: Calculation of Cost Shares by Commercial Pricing Node

EP-Node	CP-Node	Weighting Factor	CP-Node Demand*	EP-CP Demand	Aggregate DF	Aggregate Impact	% cost Allocation
EP-1	CP-1	0.2	100	20	0.18	3.6	0.173652983
EP-2	CP-2	0.2	2000	400	0.7	280	13.50634316
EP-3	CP-3	0.2	1500	300	0.3	90	4.341324586
EP-4	CP-4	0.2	3000	600	0.46	276	13.3133954
EP-5	CP-5	0.2	1000	200	0.31	62	2.990690271
EP-5	CP-6	0.2	5000	1000	0.31	310	14.95345135
EP-6	CP-6	0.2	5000	1000	0.46	460	22.18899233
EP-7	CP-7	0.2	250	50	0.53	26.5	1.278278906
EP-8	CP-8	0.2	1800	360	0.45	162	7.814384255
EP-9	CP-9	0.2	500	100	0.73	73	3.521296609
EP-10	CP-10	0.2	1000	200	1.1	220	10.61212677
EP-10	CP-11	0.2	500	100	1.1	110	5.306063383
Total Impact						2073.1	100

*** CP Node Demand = Monthly coincident peak**

6.2.9 Interconnection Service and Rescission Rights

Generation Resources that are approved to Suspend operation retain interconnection service while the unit is under suspension. The owner of the resource may rescind or modify the dates of the suspension notice at any time. Generator suspension is limited to a maximum of thirty-six (36) Months in a five (5) year period, and failure to return from the generator suspension will result in termination of the interconnection service. Generation Resources that are approved to Retire will lose interconnection service as of the date of the retirement or the end of an SSR Agreement. The owner of the resource may rescind the retirement notice until the time that MISO approves the retirement or terminates the SSR Agreement.

6.2.10 Attachment Y-2 Non-binding Informational Studies

Owners of Generation Resources may submit an Attachment Y-2 request to MISO to perform reliability assessment of the impact of a potential retirement or suspension of their resource without a definitive plan to cease operation. The cost for the study is paid by the requesting owner.

MISO will consult with the affected Transmission Owner(s) and perform reliability analysis as described in the aforementioned *Section 6.2.5*, above. The results of the Attachment Y-2 study will be provided to the requesting owner upon completion to aid in Business decisions but will not constitute approval of the change in status or result in an SSR Agreement. Any subsequent definitive decision to Retire or Suspend operation requires the owner to submit a new Attachment Y Notice at least twenty-six (26) weeks in advance of the intended change of status. However, the results from the Attachment Y-2 study may be used to evaluate the subsequent Attachment Y Notice.

7 Cost Allocation Process

Attachment FF, Section III of MISO's EMT presents the Designation of Cost Responsibility for MTEP Projects, which describes the project cost allocation process to all Market Participants and Transmission Customers. The provisions and requirements of the cost allocation process are summarized in the following sections of this Business Practice Manual. Readers and users of this Manual are advised, however that the authoritative document for project cost allocation remains the Tariff.

7.1 Baseline Reliability Projects

All costs for Baseline Reliability expansion projects are recovered through Attachment O by the Transmission Owner(s) developing such projects.

7.2 Generation Interconnection Projects

Generation Interconnection Projects are Network Upgrades associated with interconnection of new, or increase in generating capacity of existing, generation under *Attachments X to the Tariff*. These projects are driven by interconnection study procedures and agreements. Interconnection Customer is responsible for one-hundred percent (100%) of the costs of Network Upgrades rated below 345 kV and ninety percent (90%) of the costs of Network Upgrades rated at 345 kV and above (with the remaining ten percent (10%) being recovered on a system-wide basis.

7.3 Transmission Delivery Service Projects

Facilities for Transmission Service projects are designated as Direct Assignment or Network Upgrades. Transmission expansion project costs that are designated to Direct Assignment Facilities are allocated to the specific Transmission Customer requesting the service. Costs for Network Upgrade projects are rolled into the MISO facilities rate base until the Transmission Owner is allowed to recover the costs in its own facilities rates.

7.4 Market Efficiency Projects

A Market Efficiency Project can be proposed by MISO, Transmission Owner(s), ITC(s), Market Participant(s), or regulatory authorities and shown to provide market efficiency benefits to one or more Market Participant(s), but not determined to be a Multi-Value Project, and provides sufficient market efficiency benefits to justify inclusion into the MTEP.

The Tariff establishes that an MEP may be eligible for cost sharing as an MTEP transmission expansion project if it has a rated voltage of 345 kV or above, has total project costs of five million dollars ($5 million) or more, and can demonstrate regional benefit metric, multiple future scenarios, and multi-year analysis as described in *Sections 7.4.1 and 7.4.2* below.

Twenty percent (20%) of the cost for a Market Efficiency Project is allocated to all Transmission Customers through a system-wide rate. The remaining eighty percent (80%) of the project cost is allocated to all Transmission Customers in each of MISO's Cost Allocation Zones (see Attachment WW of the Tariff). The cost allocated to each of these zones is based on the relative benefit each receives from the project, as determined by the economic benefit analysis process described in *Sections 7.4.1 and 7.4.2* below. Also, a key provision of the cost allocation method is the "No Loss" provision. This "No Loss" provision is intended to protect customers in a zone from being allocated costs where they may not benefit from the project. Zones that are not shown to receive net benefits from the Market Efficiency Project will be excluded from the allocation of the eighty percent (80%) component of project cost.

If MISO planning staff determines that a specific project meets the criteria of both a Baseline Reliability Project and a Market Efficiency Project, the project cost is allocated using the Market Efficiency Project allocation procedures.

7.4.1 Economic Benefit Metric

The criteria to determine whether a project should be included as a Market Efficiency Project is based on multiple future scenarios and multi-year analysis guided by input from all stakeholders. Adjusted production cost (APC) savings will be calculated as the difference in total production cost of the Resources in each Cost Allocation Zone, adjusted for import costs and export revenues, with and without the proposed Market Efficiency Project as part of the Transmission System. Project APC benefit evaluations will include benefits for the first 20 years of project life after the projected in-service date, with a maximum planning horizon of 25 years from the approval year. The total APC benefit shall be determined by calculating the present value of annual APC benefits for the multiple future scenarios and multi-year evaluations. The weighted futures, no loss (WFNL) metric for each Cost Allocation Zone shall be calculated using the weighted APC savings determined for each future scenario included in the analysis.

7.4.2 Market Efficiency Project Benefit and Cost Evaluation Methodology

Project benefit evaluations will include benefits for the first 20 years of project life after the projected in-service date, with a maximum planning horizon of 25 years from the approval year. The annual benefit for a proposed Market Efficiency Project will be determined as the sum of the WFNL values for each Cost Allocation Zone. The total project benefit will be determined by calculating the present value of annual benefits for the multiple future scenarios and multi-year evaluations.

The costs applied in the benefit to cost ratio will be the present value, over the same period for which the project benefits are determined, of the annual Network Upgrade Charges for the project as determined in accordance with the formula in Attachment GG for the Transmission Owner constructing the proposed Market Efficiency Project. If the Transmission Owner developing the project is unknown during the planning process (i.e., if the project is eligible for the Competitive Transmission Process), MISO will estimate costs applied in the benefit to cost ratio using professional judgment informed by publicly available information.

The present value calculation for both the annual benefits and annual costs will apply a discount rate representing the after-tax weighted average cost of capital of the Transmission Owner(s) that make up the MISO Transmission System.

A benefit to cost ratio test will be used to evaluate a proposed Market Efficiency Project. Only projects that meet a benefit to cost ratio of 1.25 or greater will be included in the MTEP as a Market Efficiency Project and be eligible for regional cost sharing.

The benefits of the project and the cost allocations as a percentage of project cost will be determined one time at the time that the project is presented to the MISO Board for approval. Estimated Project Cost will be used to estimate the benefit to cost ratio and the eligibility for cost sharing at the time of project approval. To the extent that the Commission approves the collection of costs in rates for Construction Work in Progress (CWIP) for a constructing Transmission Owner, costs will be allocated and collected prior to completion of the project.

7.5 Multi-Value Projects

The revised Tariff filing of July 15, 2010 incorporated a new type of cost shared project designated as a Multi-Value Project (MVP). An MVP is one or more Network Upgrades that address a common set of Transmission Issues, satisfy one or more of the criteria listed in *Section 7.5.1* of this BPM, and satisfy all of the conditions listed in *Section 7.5.2* of this BPM. The primary purpose of the MVP is to enable cost sharing of projects that are regional in nature and developed to enable compliance with public policy requirements, which include state and federal laws and regulations, and/or to provide economic value, defined as the difference between financially quantifiable benefits related to the provision of transmission service and the project costs.

7.5.1 Multi-Value Project Criteria

All Multi-Value Projects must satisfy one or more of the criteria outlined below:

7.5.1.1 Multi-Value Project - Criterion 1

An MVP must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirements that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the Transmission System to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.

7.5.1.2 Multi-Value Project - Criterion 2

An MVP must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher where the Total MVP Benefit -to-Cost ratio is described in *Section 4.3.9* of this BPM. The reduction of production costs and the associated reduction of LMPs resulting from a transmission congestion relief project are not additive, and are considered a single type of economic value since LMP savings are a subset of production cost savings. The specific types of economic value that may be considered are listed in *Section 7.5.3* of this BPM.

7.5.1.3 Multi-Value Project - Criterion 3

An MVP must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity reliability standard and must provide economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs. That is, the total MVP Benefit-to-Cost Ratio, as discussed in *Section 4.3.9* of this BPM, must be greater than 1.0.

7.5.2 Multi-Value Project Conditions

All Multi-Value Projects must satisfy all of the following conditions listed below:

- Must be evaluated as part of a portfolio of projects, as designated in the transmission expansion planning process, whose benefits are spread broadly across the footprint.
- Facilities associated with the transmission project must not be in service, under construction, or approved for construction by the Transmission Provider Board prior to July 16, 2010 or the date the constructing Transmission Owner becomes a signatory Member of the ISO Agreement, whichever is later.
- The transmission project must be evaluated through the MISO planning process and approved for construction by the Transmission Provider Board prior to the start of

construction, where construction does not include preliminary site and route selection activities.

- The transmission project must not contain any transmission facilities listed in Attachment FF-1 of the Tariff.
- The total capital cost of the transmission project must be greater than or equal to the lesser of $20,000,000.00 or five percent (5%) of the constructing Transmission Owner's net transmission plant as reported in Attachment O of the Tariff at the time the transmission project is approved in an MTEP.
- The transmission project must include, but not necessarily be limited to, the construction or improvement of transmission facilities operating at voltages above 100 kV. A transformer is considered to operate above 100 kV when at least two sets of transformer terminals operate at voltages above 100 kV.
- Network Upgrades driven solely by an Interconnection Request, as defined in *Attachment X of the Tariff*, or a Transmission Service request will not be considered MVPs.

7.5.3 Multi-Value Projects - Types of Economic Benefits

The following specific types of economic benefits may be considered when qualifying a project as a Multi-Value Project under Criterion 2 or Criterion 3:

- Production cost savings where production costs include generator startup, hourly generator no-Load, generator energy and generator Operating Reserve costs. Production cost savings can be realized through reductions in both transmission congestion and transmission energy losses. Production cost savings can also be realized through reductions in Operating Reserve requirements within specific Reserve Zones and, in some cases, reductions in overall Operating Reserve requirements for the entire MISO.
- Capacity cost savings due to a reduction of system losses during the system peak demand. Capacity cost savings are generated by reducing the overall resource adequacy requirements by an amount equal to the product of the reduced system loss level during the projected system peak demand and one plus the projected Planning Reserve Margin. The economic value of this reduction will be set equal to the projected value of the Cost of New Entry (CONE).
- Capacity cost savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion. These reductions are typically possible due to relief of transmission congestion and may be determined through execution of Loss of Load Expectation studies.

- Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future due to pursuit of a specific MVP.
- Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the Transmission System and directly related to providing Transmission Service. Financially quantifiable benefits not directly related to providing Transmission Service, such as economic development benefits and other types of benefits not directly related to providing Transmission Service, cannot be considered in qualifying a project for MVP status.

7.5.4 Multi-Value Projects - Other Provisions

The following provisions also apply to Multi-Value Projects:

7.5.4.1 Multi-Value Projects - Project Type Designation Rule

Should a project qualify as an MVP and also qualify as either a BRP, MEP, or both, the project will be designated as an MVP and not as a BRP or MEP.

7.5.4.2 Multi-Value Projects - Like-for-Like Capital Replacement

Should a project be required to facilitate like-for-like capital replacements of plant originally installed as part of an MVP where replacement is i) due to aging, failure, damage or relocation requirements and ii) not the result of negligence by the constructing Transmission Owner, that project will be considered an MVP. The minimum project cost limitation for MVPs described in *Section 7.5.2* of this BPM will not apply to the like-for-like capital replacement projects described in this Section.

7.5.5 Multi-Value Projects - Cost Allocation

7.5.5.1 Multi-Value Projects - Qualification of Facilities for Cost Sharing

Subject to the conditions outlined in *Section 7.5.2* of this BPM, any facility associated with an MVP will qualify for cost sharing subject to the following rules:

- Facilities must be considered Network Upgrades and may include any lower voltage facilities that may be needed to relieve applicable reliability criteria violations that are projected to occur as a direct result of the development of the MVP.
- Any Network Upgrade cost associated with constructing an underground or underwater transmission line above and beyond the cost of a feasible alternative overhead transmission line that provides comparable regional benefits will not qualify for cost sharing.

- Any DC transmission line and associated terminal equipment will not qualify for cost sharing when scheduling and dispatch of the DC transmission line is not turned over to the MISO markets, real-time control of the DC transmission line is not turned over to the MISO automatic generation control system and/or the DC transmission line is operated in a manner that requires specific users to subscribe for DC transmission service.

7.5.5.2 Multi-Value Projects - Allocation of Eligible Costs

One-hundred percent (100%) of the eligible annual revenue requirements of the MVPs shall be allocated on a system-wide basis to Transmission Customers that withdraw energy, including both Loads internal to the MISO footprint and External Transactions sinking outside the MISO footprint, excluding transactions that sink in PJM. Also, Load serviced under a Grandfather Agreement is excluded from charges for MVPs. The allocation of costs will be in proportion to the metered energy in MWh withdrawn from the Transmission System for internal Loads or the energy in MWh scheduled for External Transactions. Eligibility of annual revenue requirements for cost sharing is in accordance with *Section 7.5.5.1* of this BPM. These annual revenue requirements will be recovered through a MVP Usage Charge which is described in more detail in *BPM-005 – Market Settlements*. Revenues collected through this charge will be distributed to the Transmission Owner(s) in accordance with the ISO agreement.

7.6 Targeted Market Efficiency Projects

Targeted Market Efficiency Projects are interregionally cost allocated with PJM under Section 9.4 of the MISO-PJM Joint Operating Agreement. The MISO share of the project cost is allocated to benefitting Transmission Pricing Zones in accordance with Attachment FF of the MISO Tariff.

7.7 Project Completion Reporting Guidelines – for Cost Shared Projects

Transmission Owner(s) shall report the MTEP approved cost shared projects (i.e., BRP[26], GIP, MEP, TMEP and MVP) upon completion and commissioning of those projects to MISO. This information will be used to verify that only the costs of approved cost shared projects and facilities are charged to other pricing zones through Attachment GG (BRP, GIP, TMEP and MEP) and Attachment MM (MVP) revenue requirement and rates calculations. Also, the information will be

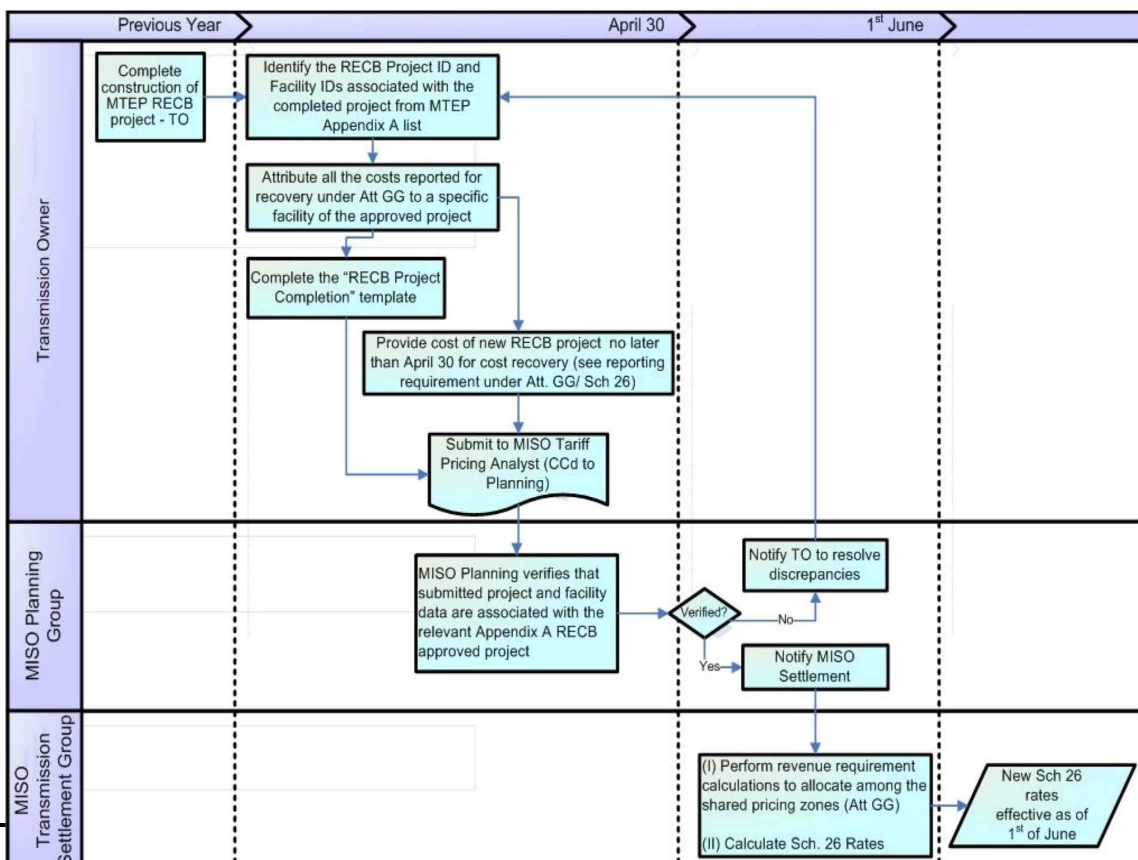
[26] Applies to Baseline Reliability Projects approved by the MISO Board of Directors for cost sharing before MTEP13.

used for the purpose of tracking costs and in-service dates of approved MTEP cost shared projects.

This reporting requirement supplements the annual reporting requirements under Attachment GG and Attachment MM of the Tariff for calculating and collecting the charges associated with Network Upgrades of cost shared projects and for distributing the revenues associated with such charges. *Figure 7.7-1* below shows a high-level process flow diagram with a time-line and associated responsibilities.

A reporting template along with the appropriate contact and submittal information is posted on the Planning page of the MISO web site (MISO Planning). This template shall also be used for reporting Construction Work In Progress (CWIP) costs associated with MTEP-approved cost shared projects for cost recovery through Attachment GG and Attachment MM of the Tariff by Transmission Owner(s) with FERC approval for recovery of CWIP costs.

Figure 7.7-1: Process Flow for Reporting MTEP Cost Shared Project Costs for Recovery under Attachment GG and MM of the Tariff



Note: (1) For certain Transmission Owner(s) (ATC LLC, ITC/METC) who have forward-looking formula rates, the Schedule 26 rates' effective date will be January 1st, requiring a Nov 30th Attachment GG reporting date to MISO. Also, the project costs could include MTEP cost shared project costs projected for the following year.

8 Variance Analysis

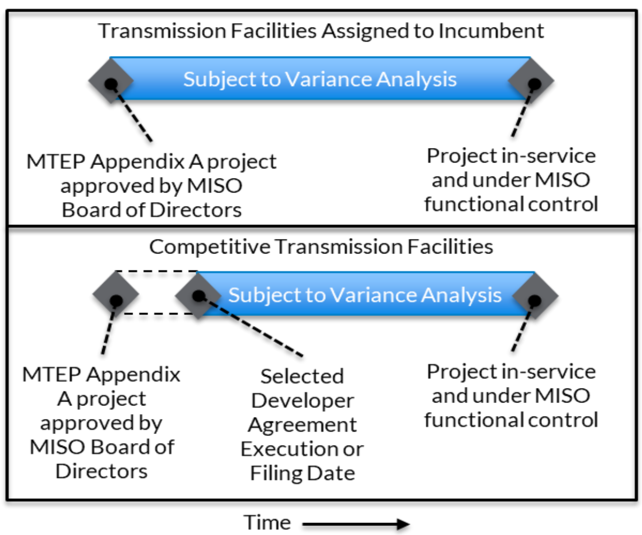
After a MTEP is approved by the MISO Board of Directors, certain circumstances or events may arise that could potentially have a material impact on approved facilities, triggering MISO's Variance Analysis process. Variance Analysis is the additional analysis performed by MISO to understand the reasons for such circumstances or events and to evaluate the potential impacts that these circumstances or events may have on the applicable project and the Transmission System.

8.1 Applicability and Scope

MISO's Variance Analysis process is applicable to Eligible Projects and the facilities that comprise such projects approved by the MISO Board of Directors for inclusion in Appendix A of the MTEP after December 1, 2015, in accordance with the MISO Tariff under *Section IX.A of Attachment FF*.

Eligible Projects and their component facilities are subject to the Variance Analysis process at different times depending on whether their development is assigned to incumbent Transmission Owner(s) or awarded through the Competitive Transmission Process.

Figure 8.1-1: Eligible Project Lifecycle and When Subject to Variance Analysis



MISO monitors the quarterly facility status updates submitted by Transmission Owners and/or Selected Developers, and other available information to determine if a ground may exist to conduct Variance Analysis for an Eligible Project or one of its individual facilities.

8.2 Variance Analysis Process

The process that will be utilized by MISO to perform a Variance Analysis is detailed in this *Section 8* of BPM-020 and governed by the MISO Tariff in *Section IX of Attachment FF*..

8.2.1 Three Phase Variance Analysis

Variance Analysis is a sequential, methodical, three-phase process that is based on identifying and confirming Variance Analysis grounds (phase 1), conducting analysis to determine the appropriate outcome (phase 2), and implementation of the outcome selected (phase 3).

Figure 8.2.1-1: Overview of Three-Phase Variance Analysis Process

There are four main grounds that may trigger the commencement of Variance Analysis. These four grounds are specified in the MISO Tariff in *Section IX.C of Attachment FF*. Phase 1 is the process for confirming whether one or more identified grounds for commencing Variance Analysis exist.

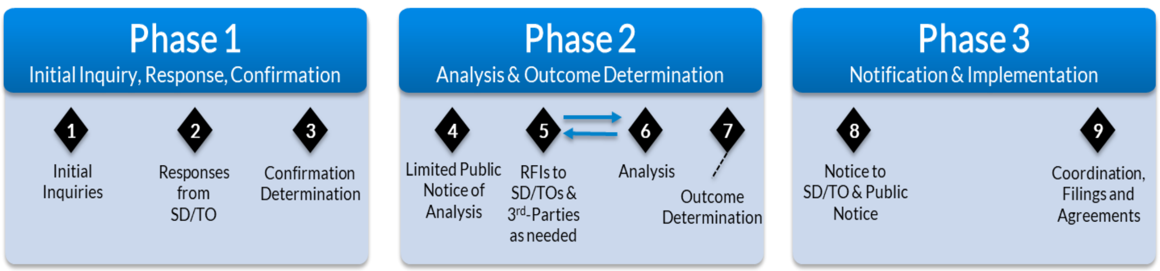
There are four types of outcomes of the Variance Analysis process. These outcomes are described in the MISO Tariff under *Section IX.E of Attachment FF*. Phase 2 involves a process of data collection and analysis for the purpose of selecting the appropriate outcome for confirmed Variance Analysis grounds.

The results of the Variance Analysis process depend on the outcome selected and whether the project is a Competitive Transmission Project (requiring a Selected Developer Agreement) or assigned to the incumbent Transmission Owner(s). Phase 3 consists of implementing the outcome that was selected in phase 2.

8.2.2 Activities and Milestones

Generally, the Variance Analysis process consists of approximately nine activities and milestones.

Figure 8.2.2-1: Nine Key Activities and Milestones in Variance Analysis Process

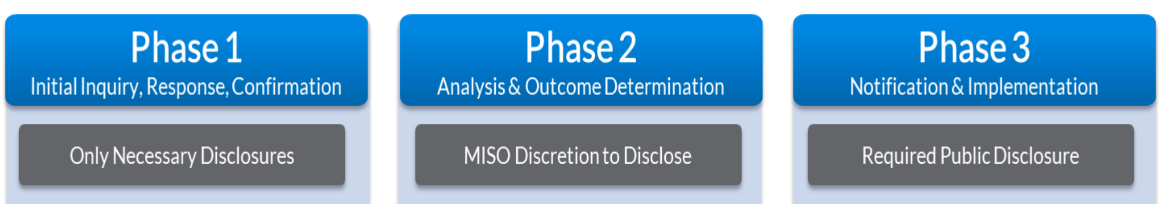


The nine activities and milestones shown in Figure 8.2.2-1 are the tactical steps to move through the process from one phase to the next. The order and timing of key activities and milestones may be tailored to the needs of individual projects or instances of Variance Analysis. For example, in more complex Variance Analyses. MISO may determine that subsequent inquiries and further responses from the applicable Selected Developer or Transmission Owner are required. The applicable Selected Developer or Transmission Owner will be given an opportunity to be heard during the process at an appropriate, mutually-agreed, time.

8.2.3 Confidentiality Requirements of Variance Analysis by Phase

The specific confidentiality provisions applicable to the Variance Analysis process are described by the MISO Tariff in *Section IX.F of Attachment FF*.

Figure 8.2.3-1: Overview of Confidentiality Requirements by Phase



As illustrated in Figure 8.2.3-1, confidentiality requirements are most restrictive in phase 1 and ease at the end of phase 3. In phase 1, public disclosure of whether Variance Analysis has commenced is not permitted. In phase 2, MISO has discretion to postpa limited public notice stating only that Variance Analysis has commenced for a particular facility or project and the grounds found to exist. In phase 3, MISO is required to post a public notice of the Variance Analysis outcome that was selected. MISO is permitted by its Tariff to disclose that Variance

Analysis has commenced to third parties if it is necessary to request information in phases 1 and 2 to establish the existence of ground(s) or to collect information to evaluate possible outcomes.

8.2.4 Duration of Variance Analysis phases

The durations of phases 1, 2, and 3 of Variance Analysis are neither defined nor limited by the MISO Tariff or this BPM. This allows Variance Analysis to be effectively applied to broad range of scenarios.

8.2.5 Governance of Variance Analysis

The Competitive Transmission Executive Committee has the exclusive and final authority to oversee and implement Variance Analysis, including the decision to implement any of the appropriate Variance Analysis outcomes. Specific provisions applicable to the governance of Variance Analysis can be found in the MISO Tariff in *Section IX.B of Attachment FF*.

8.2.6 Phase 1: Initial Inquiry, Response, Confirmation

Variance Analysis will commence with an initial inquiry (or inquiries) when MISO determines that one or more of the grounds for Variance Analysis[27] may exist in accordance with the MISO Tariff in *Section IX.D of Attachment FF*. Upon such determination, MISO will send an email notification to the applicable Selected Developer(s) or Transmission Owner(s) that Variance Analysis has been triggered. This email notification will be sent to the primary and secondary contact persons that the Selected Developer(s) or Transmission Owner(s) have on file with MISO through their project status reporting submissions that are required in accordance with *Section 4.2.3.1* of this BPM and shall include a brief description of MISO's concerns. This initial inquiry is represented as activity/milestone #1 in Figure 8.2.2-1.

In accordance with the MISO Tariff in *Section IX.D.1 of Attachment FF*, the applicable Selected Developer(s) or Transmission Owner(s) shall have an opportunity to state its position on whether the grounds for triggering a Variance Analysis described in the initial inquiry notification exist and what Variance Analysis outcome it believes is appropriate for the respective situation. Supporting facts and documentation shall be submitted by the applicable Selected Developer(s) or Transmission Owner(s) to MISO as part of the Selected Developer(s) or Transmission Owner(s) response. Submission of this response or responses on position and the supporting facts and documentation are represented as activity/milestone #2 in Figure 8.2.2-1.

Based upon a consideration of the Selected Developer(s) or Transmission Owner(s) response(s) and any other relevant information, MISO will determine whether it continues to believe grounds

[27] The grounds for Variance Analysis are specified by the MISO Tariff in *Section IX.C of Attachment FF*

for triggering Variance Analysis exist. Should MISO determine that the grounds for Variance Analysis do not exist, it shall terminate the instance of Variance Analysis. If MISO continues to believe that reasonable grounds for Variance Analysis still exist, it will confirm that the grounds exist and commence Phase 2 of Variance Analysis. MISO will notify the applicable Selected Developer(s) or Transmission Owner(s) of its determination by email through their respective primary and secondary contact persons on file with MISO through their project status reporting submissions required in accordance with *Section 4.2.3.1* of this BPM. Confirmation that grounds exist or that they do not exist and that, therefore, Variance Analysis should be terminated are both represented by activity/milestone #3 in Figure 8.2.2-1.

8.2.7 Phase 2: Analysis and Outcome Determination

At the beginning of phase 2, in accordance with the MISO Tariff in *Section IX.F of Attachment FF*, MISO may elect, but is not required, to provide limited public notice that Variance Analysis has commenced once it has confirmed that one or more grounds exist. This public notice will be posted on the MISO website.[28] Public notice that Variance Analysis has commenced is represented as activity/milestone #4 in Figure 8.2.2-1.

Once MISO confirms grounds for Variance Analysis exist, MISO will further evaluate the circumstances, events, and relevant facts associated with the Variance Analysis scope in accordance with the provisions specified by the MISO Tariff in *Section IX.D.2 of Attachment FF*. MISO will collect information through Request for Information requests sent to the Selected Developer(s) or Transmission Owner(s) or third parties, followed by analysis, a cycle which may be repeated as many times as necessary before advancing to phase 3. The repeatable data collection and analysis process is represented as activities/milestones #5 and #6 in Figure 8.2.2-1.

Upon completion of its analysis, the CTEC may make a determination as to which Variance Analysis outcome to apply in accordance with the MISO Tariff, as described in *Sections IX.D.2 and IX.D.2.1 of Attachment FF*. The possible outcomes of a Variance Analysis are specified by the MISO Tariff under *Section IX.E of Attachment FF*. Further selection considerations for each individual outcome are listed in the MISO Tariff under *Sections IX.E.1, IX.E.2, IX.E.3, and IX.E.4 of Attachment FF*. The ultimate outcome determination that marks the end of phase 2 is represented as activity/milestone #7 in Figure 8.2.2-1.

[28] https://www.misoenergy.org/planning/planning/

8.2.8 Phase 3: Notification and Implementation

In accordance with *Section IX.D.3 of Attachment FF* to the MISO Tariff, MISO will inform the applicable Selected Developer(s), Transmission Owner(s), and any other affected parties of the selected Variance Analysis outcome. Such notification will be sent by email to the respective primary and secondary contact persons on file with MISO through their project status reporting submissions required in accordance with *Section 4.2.3.1* of this BPM. Public notice will be posted on the MISO website, as soon as practicable after notifying the applicable Selected Developer(s) or Transmission Owner(s) and any other affected parties of the Variance Analysis outcome. The posting shall include the reason(s) the respective Variance Analysis outcome was selected. Both the notifications to affected parties and the public postings shall be appropriately redacted in order to protect any Critical Energy Infrastructure Information (CEII) and any Confidential Information not needed to explain why Variance Analysis was triggered or why a particular outcome was selected in accordance with *Section IX.D.3.B of Attachment FF* to the MISO Tariff. The notice provided to applicable Selected Developer(s), Transmission Owner(s), and any other affected parties, in addition to the public notice posted to the website are represented together as activity/milestone #8 in Figure 8.2.2-1.

In accordance with the MISO Tariff in *Section IX.D.3 of Attachment FF*, MISO will implement the approved Variance Analysis outcome in coordination with the applicable incumbent Transmission Owner(s), Selected Developer(s), and any other affected parties. If the approved Variance Analysis outcome includes a mitigation plan that alters the schedule, cost, design, or scope of a Competitive Transmission Facility under a Selected Developer Agreement, MISO and the applicable Selected Developer(s) shall amend the Selected Developer Agreement in accordance with the MISO Tariff. If the approved Variance Analysis outcome includes a Reassignment or the Cancellation of a Competitive Transmission Facility, MISO will file a Notice of Termination with the FERC in accordance with the provisions specified in *Section IX.D.3.E of Attachment FF* to the MISO Tariff. The implementation of the selected Variance Analysis outcome, including but not limited to coordination among affected parties and the filing of agreements and notices, is represented as activity/milestone #9 in Figure 8.2.2-1.

8.3 Project Financial Security Impacts due to Variance Analysis

The potential impacts on a Selected Developer's Project Financial Security as a result of a Variance Analysis are specified in the MISO Tariff under *Section IX.H of Attachment FF*.

8.4 Dispute Resolution Provisions for Variance Analysis

Disputes associated with the Variance Analysis process shall be addressed in accordance with the provisions specified in the MISO Tariff under *Section IX.G of Attachment FF*.

Appendix A Reserved

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Appendix B TSR Planning Guideline No. 1.2 – SIS Report Format

Purpose

To provide guidelines for consistent reporting of System Impact Studies associated with requests for long-term firm transmission service under the Tariff.

Introduction

This guideline is to be followed by MISO planning staff, Transmission Owner(s), or Third Parties when reporting results of an SIS in order to provide consistency in the reporting of results for such studies.

Report Outline

The SIS report shall include the following information:

Executive Summary

This section lists:

- Type of service requested
- Whether or not service can be granted at this time
  - Profile of service, if applicable
  - List of milestones for the profile
  - List (or point to a list) of transmission system constraints
  - Cost to resolve the constraints to service
  - If there is existing SPS to mitigate the constraints, then the MW reduction of the existing SPS does not exceed its maximum allowable run back with additional transfer.

Description of Request

The OASIS request information identifying the transaction

Criteria, Methodology, and Assumptions

A detailed statement of criteria used, including any specific Regional or local criteria applied. The study scope and a description of how the study was conducted, including the cases, scenarios, critical assumptions, and modeling of the new or modified facilities

Analysis Results

A summary of results of any thermal, voltage, and stability analyses conducted indicating the impact of the request on system performance. Analysis output will be retained and be available for review.

Preliminary Estimate if Direct Assignment or Network Upgrades Required

A listing of any Direct Assignment or Network Upgrade facilities preliminarily determined to be necessary to accommodate the request. A good faith estimate of the customer cost responsibility for such facilities will be determined in a subsequent Facilities Study

Appendix C TSR Planning Guideline No. 1.3 – FS Report Format

Purpose

To provide guidelines for consistent reporting of Facility Studies associated with requests for long-term firm transmission service under the Tariff.

Introduction

This guideline is to be followed by MISO planning staff, Transmission Owner(s), or Third Parties when reporting results of a Facility Study in order to provide consistency in the reporting of results of such studies.

Report Outline

The Facility Study report shall include the following information:

Description of Request

The OASIS request information identifying the transaction.

Criteria, Methodology, and Assumptions

A detailed statement of criteria used, including any specific Regional or local criteria applied. The study scope and a description of how the study was conducted, including the cases, scenarios, critical assumptions, and modeling of the new or modified facilities. A description of the new/upgrade facilities.

Good Faith Estimate

A detailed statement of the cost of any Direct Assignment Facilities to be charged to the Transmission Customer, the Transmission Customer's appropriate share of the cost of any required Network Upgrades, and the time required to complete such construction and initiate the requested service.

Appendix D Long-term Firm Transmission Service Requests – Process Overview

Figure D-1: Long Term Transmission Service Requests Process Overview (Steps 1-11)

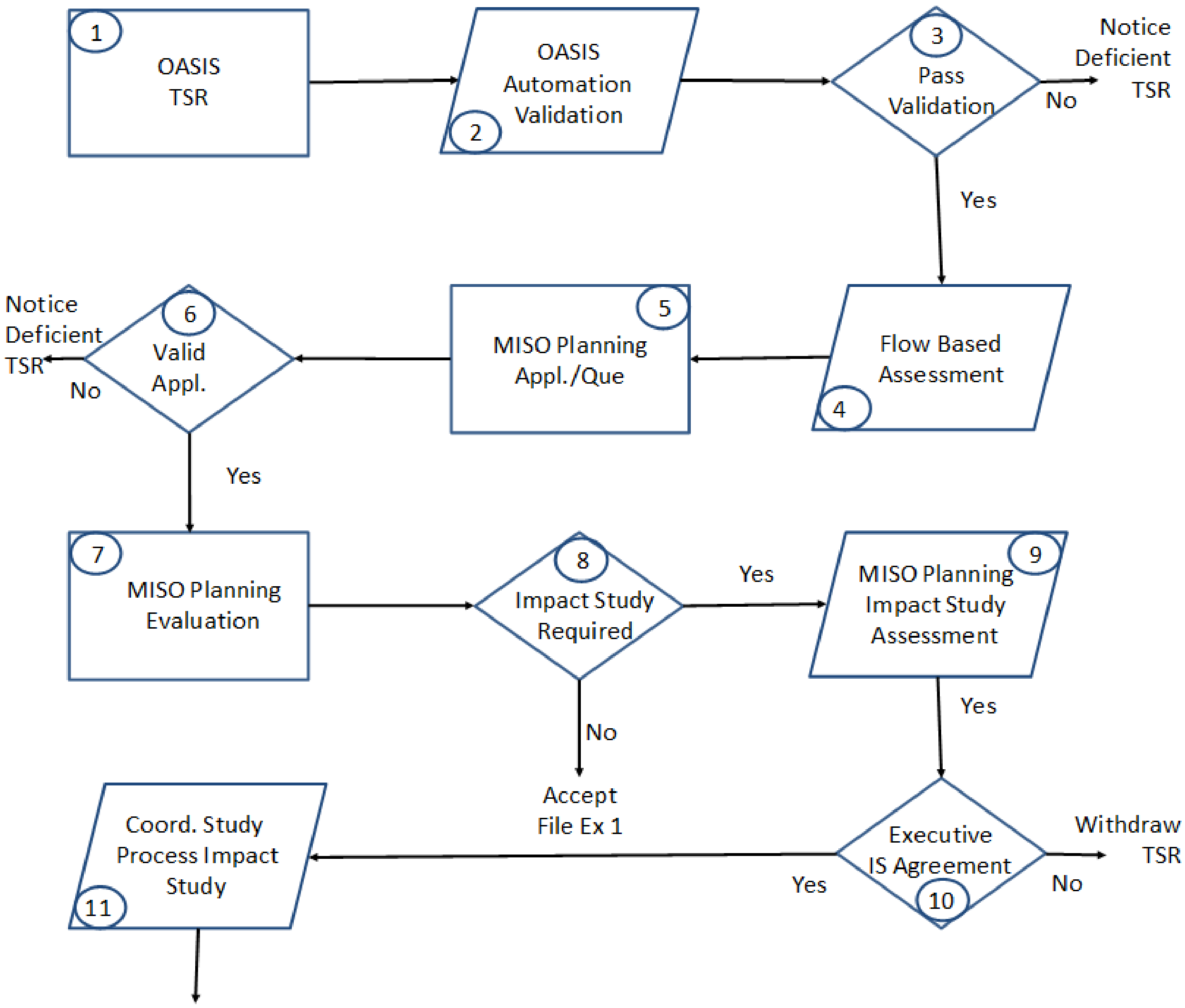
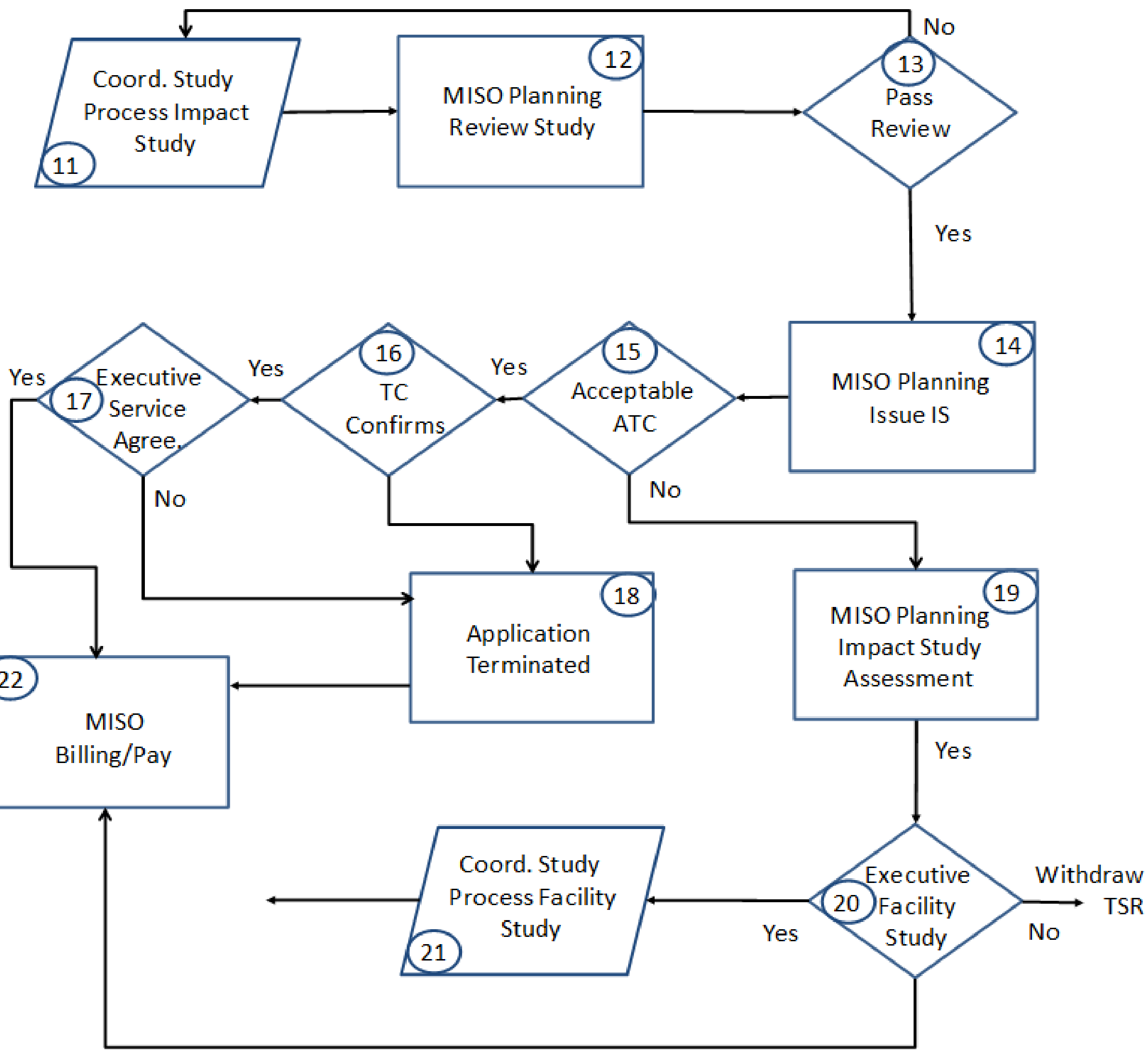


Figure D-2: Long Term Transmission Service Requests Process Overview (Steps 11-22)



Appendix E Reserved

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Appendix F Reserved

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Appendix G Reserved

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Appendix J Implementation Rules for LODF Calculation

J.1 Line Outage Distribution Factor (LODF)

The LODF method determines the impact of a new facility planned as part of an expansion project on other, existing components for a defined region. LODF equals the change in flow on a facility due to the outage of a new project facility and is absolute value of facility flow change divided by flow on new project facility prior to outage. Where a project consists of multiple facilities, each new project facility is outaged for its effect on the MISO system facilities.

As an example, consider a new project facility with a post-project powerflow of 100 MW. An existing MISO facility has pre-project flow of 200 MW and a post-project flow of 180 MW. The existing circuit flow change is 20 MW between the cases. The LODF for the existing circuit is 20 percent, as calculated:

Equation J.1-1: LODF Calculation

$$\frac{ABS(200\ MW - 180\ MW)}{100\ MW} = 20\%$$

MISO calculates Line Outage Distribution Factor of the proposed expansion project for each existing component within the MISO footprint rated at 100 kV and above. In the event that a component's LODF is less than one percent (1%) e.g., the monitored component's power flow changes by less than one percent with the addition of the proposed expansion project, the component is excluded from further cost allocation calculations.

The LODF is then applied to each affected existing component according to the mileage rating of the component. A cost allocation value, called the "Sum of Absolute Value of LODF-Mile" (LODF-Mile), is calculated by multiplying the LODF times the mileage, for each component affected by a given expansion project. Transmission Owner(s) are expected to provide line length (in miles) for all transmission system components. Where the component mileage is not available, MISO planning staff estimates mileage using model impedance values and typical impedance per mile rates for similar components. Transformers are given a designated mileage rating of one mile.

J.2 Calculating LODF for Complex Projects

When there is a complex system reconfiguration, a project boundary flow is used to calculate LODFs for the project facilities using *Equation J.2-1 below*. The project boundary flow is the equivalent to pre-outage flow for single new project facility. The project boundary flow is calculated by drawing a boundary around the project area and calculating net flow for pre-project and post-project models. The difference in project boundary flows is the divisor used for LODF calculations. The before and after project case flows difference are calculated for all MISO facilities.

As an example, consider a project with difference in project boundary flows of 100 MW. A MISO facility has pre-project flow of 200 MW and a post-project flow of 180 MW. The existing circuit flow change is 20 MW between the cases. The LODF for the existing circuit is twenty percent (20%), as calculated:

Equation J.2-1: LODF Calculation

$$\frac{ABS(200\ MW - 180\ MW)}{100\ MW} = 20\%$$

J.3 General LODF Methodology and Thresholds

- Use "Sum of Absolute value of LODF-Mile" method to develop subregional cost allocation percent. This metric is calculated by multiplying the LODF times the mileage, for each component affected by a given expansion project. All MISO Transmission Facilities are monitored.
- LODF cutoff rate: one percent (1%), if a monitored branch does not respond by one percent (1%) of the project line flow, its impact is ignored
- Mileage: Line length is provided in the applicable powerflow model or is reported by Transmission Owner for monitored branches. If not reported, it will be calculated through model impedance and typical values for impedance/mile. Transformers are set to be one mile.
- Only facilities with both terminal 100 kV and above are considered for allocation in the computation.
- The Transmission Pricing Zone (TPZ) of a monitored facility will be approximated by the model control area in the applicable powerflow model, subject to review by the impacted Transmission/Facility Owners(s)
- Tie-lines: Percent ownership as reported by Transmission Owner(s). Otherwise the default owner is control area of non-metered Bus terminal in model.
- LODF for Projects consisting of multiple branch additions or upgrades will be determined by breaking the project up into its separate branches, and determining the LODF allocation for the cost of each branch. This will avoid masking of proximity effects of the new project (which is the principle of the LODF) where individual

branches of a project may have counter-impacts that net to a small impact on nearby facilities. When the LODF is calculated for one of the branches of a multiple branch project, each of the other branches of the project is included in the model, however, the LODF contribution on other branches of the new project are not counted.

- Where a monitored line is a Remote Line not in the owner's pricing zone the LODF impacts on the Remote Line will be added to the LODF impacts of all other lines of the pricing zone that the Remote Line is in, see Section J.5 below.

J.4 Models and Applicable Topology

- The applicable MTEP planning horizon model is used for all project LODF calculations. For example, if a five-year-out model is being used for MTEP, and a project is first identified as a required Generator Interconnection Project from a pricing zone which used LODF cost allocation in that MTEP process, the five-year-out model will be used even though the project may have a three-year-out service date. This avoids the need to develop many different models for LODF determination.
- Both Appendix A and Target Appendix A Projects will be included in the MTEP planning horizon model, per the requirements of the MTEP model building process. •
  Existing HVDC lines will be modeled as fixed flow with flow controlled to the level set for normal system conditions with the new facility.
- Existing Phase Angle Regulators will be modeled as fixed flow with flow controlled to the level set for normal system conditions with the new facility.

J.5 Project Specific Methodology

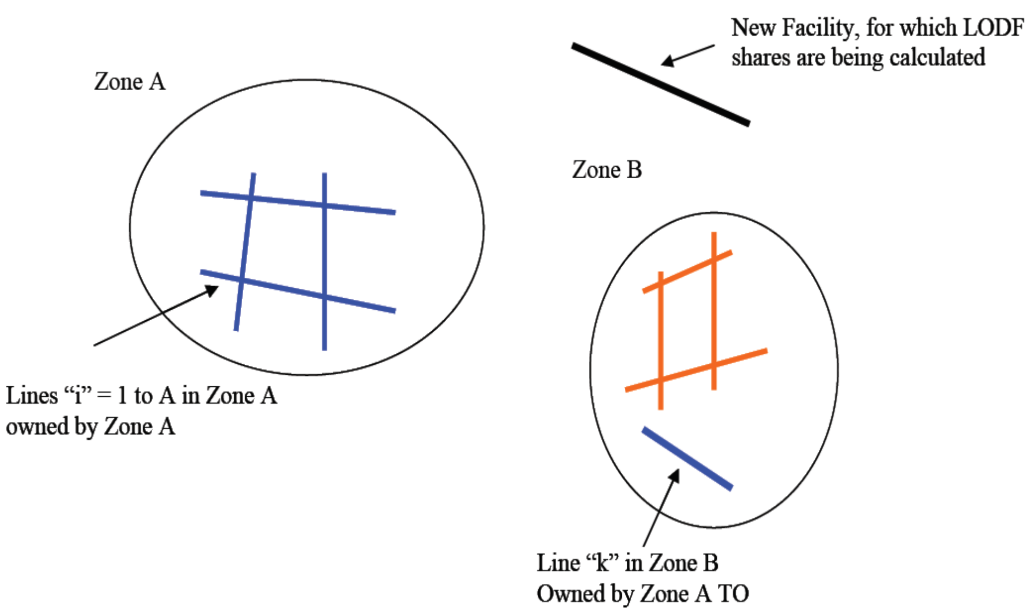
- A reconductored line can be simulated as the original line with a parallel pseudo line. LODF will be computed by taking out the parallel line. Alternatively, comparison of line flows between the base system and the change system will be used to develop LODF values.
- Rebuilds involving conversion (removal) of a low voltage facility to a high voltage facility (addition) will compare line flows between the base system and the change system to develop LODF values.
- A series inductor or capacitor will use the same approach as for reconductored lines.
- Looped lines will be treated as any other line. A looped (non-radial) line is a networked extension of an existing line to a new substation.
- Terminal upgrades (including bus sections, switches, circuit breakers, protection devices): If equipment is stand alone, the LODF calculation is not required because there is no impedance change.

- For shunt-connected devices (capacitors, SVCs, reactors), the LODF calculation is not required because there is no impedance change.

J.6 Treatment of Monitored Lines Outside of the Owner's Zone

This is the "Location" or "Load Based" approach. This will include in the Zone B share the flow impacts of all lines in a Zone B, regardless of line ownership.

Figure J.5-1: Example Showing Location Matters Not Ownership



$$\text{Share}_{\text{Zone B}} = \frac{\sum^{B} \text{LODF}_{j} + \text{LODF}_{k}}{\text{LODF}_{sys}}$$

J.7 Cost Allocation Considerations

- For a project or facility that does not alter system impedance (e.g. circuit breaker or terminal equipment), all costs will be one-hundred percent (100%) local.
- For projects consisting of facilities at multiple voltages, each facility will be evaluated for postage-stamp eligibility based on its voltage class.
- Costs of 345 kV or higher voltage substation facilities that are installed as a part of a new transformer installation for transformers with high side voltages of 345 kV or higher and low side voltages of 344 kV or lower, and that are needed only to support a new transformer installation shall be lumped with the cost of the transformer and given the same cost allocation treatment as for the transformer. As an example, a new 345 kV Bus and circuit breakers needed to install a new 345/138 kV transformer would not be postage-stamped, but would be allocated according to the LODF of the transformer serving the 138 kV system. Costs of related 345 kV equipment such as a line extension to the new 345 kV class substation will be treated on a case-by-case basis depending on the intended future plans for additional networked lines to be installed at the substation. Costs of 345 kV Bus and circuit breakers related to new

line installations at the same time as the transformer installation will be treated as 345 kV facilities and given the postage-stamped treatment.

- Projects or facilities driven solely by contingency loss of, or design violations of, facilities of 69 kV and below will not be cost shared.
- Cost of shunt-connected devices (capacitors, SVCs, reactors) required for Load-serving steady-state voltage control or voltage quality will NOT be shared, unless such devices are also needed to remedy stability or to increase transfer capability for reliability purposes (import capability or generator deliverability). Stability and reliability-transfer-related shunts will have costs shared ten percent (10%) Postage-Stamp with the remaining 90% assigned locally for shunts connected to 345 kV and above (LODF = 1 for local branches, 0 for others), and one-hundred percent (100%) assigned locally for below 345 kV.
- Cost of terminal upgrades, including Bus sections, switches, circuit breakers and other protection devices, that are an integral part and necessary to integrate a project involving a line or transformer addition or enhancement are lumped with and allocated as per the allocation percentages for the related branch facilities.
- The costs of upgrades to existing circuit breakers or other interrupting devices that are needed due to increased interrupting duty or continuous loading capability requirements will be allocated one-hundred percent (100%) local.

Appendix K Default MISO Planning Criteria

The NERC TPL-001-4 planning standards require the Planning Coordinator and Transmission Planning to establish certain planning criteria (TPL-001-4 Requirement R5 and R6). Transmission Planners are responsible for developing planning criteria and methodologies for their own footprints in accordance with the TPL standards. As the Planning Coordinator, the standard MISO practice will be to use the planning criteria developed by each Transmission Planner for issues within the footprint of that Transmission Planner, or if issues extend across multiple Transmission Planner footprints, the most conservative of the planning criteria developed by each applicable Transmission Planner. In cases where the Transmission Planner does not develop specific planning criteria, MISO, as the Planning Coordinator, will use the default planning criteria contained within this attachment. Furthermore, Transmission Owner(s) may point to the MISO default planning criteria as their own planning criteria in lieu of developing their own such criteria and methodologies if they so choose.

Figure K-1: Default Planning Criteria

Steady State Voltage (Pursuant to TPL-001-4 Requirement R5):	
Normal Low Voltage Limit (p.u.)	0.95
Normal High Voltage Limit (p.u.)	1.05
Emergency Low Voltage Limit (p.u.)	0.9
Emergency High Voltage Limit (p.u.)	1.1
Post Contingency Maximum Voltage Deviation (p.u.)	0.2
Transient Voltage: Generator Low Voltage Ride-Through Capability* (Pursuant to TPL-001-4 Requirement R5)	
0.00 to 0.15 seconds (p.u.)	0
0.15 to 0.30 seconds (p.u.)	0.45
0.30 to 2.00 seconds (p.u.)	0.65
2.00 to 3.00 seconds (p.u.)	0.75
Beyond 3.00 seconds (p.u.)	0.9
Transient Voltage: Generator High Voltage Ride-Through Capability* (Pursuant to TPL-001-4 Requirement R5)	
0.00 to 0.20 seconds (p.u.)	1.2
0.20 to 0.50 seconds (p.u.)	1.175
0.50 to 1.00 seconds (p.u.)	1.15
Beyond 1.00 seconds (p.u.)	1.1
Transient Voltage: Load Low Voltage Recovery Limits (Pursuant to TPL-001-4 Requirement R5)	
0.00 to 20.00 seconds after fault clearing (p.u.)	0.7
Beyond 20.00 seconds after fault clearing (p.u.)	0.9
Stability Criteria (Pursuant to TPL-001-4 Requirement R6):	

Transient Voltage: Load Low Voltage Recovery Limits (Pursuant to TPL-001-4 Requirement R5)	
Angular Transient Stability Minimum Damping Ratio (ζ)	0.03
Angular Transient Stability Critical Clearing Time Margin (cycles)	1
Voltage Stability Maximum Transfer Limit (% of transfer at nose of PV curve)	90
Cascading Outage Definition (Pursuant to TPL-001-4 Requirement R6):	
Number of inadvertent elements tripping: If Total Load Loss ≤ 1000 MW*	3 or more
Number of inadvertent elements tripping: If Total Load Loss > 1000 MW*	1 or more

**Note 1: Based on Attachment 2 of NERC PRC-024.*

***Note 2: The number of BES line and/or transformer circuits that were tripped due to circuit overloads or power swings subsequent to the elements tripped by the protection system to clear the contingency fault.*

****Note 3: Total Load loss does not include consequential Load loss from elements tripping to clear the fault.*

Appendix L SOL (IROL) Methodology for the Planning Horizon

L.1 Definitions

MISO establishes SOLs and IROLs for the Planning Horizons. The provided SOLs (including the subset of SOLs that are IROLs) shall include the identification of the subset of multiple contingencies (if any) from Reliability Standard TPL-001-4 which result in stability limits. The SOL/IROL Limits attained from Steady State, Voltage Stability, and Transient Stability analyses for the MTEP planning horizon is posted to two secure locations: The MISO Extranet Reliability Authority page and the MISO ftp site.

Instructions for access for the Extranet Reliability Authority are found at: Extranet Access Form

Instructions for access for the MTEP ftp site are found at: MTEP FTP Access Form

The methodology for developing SOLs and IROLs for the Planning Horizon is described in this document.

L.1.1 Applicability of SOLs for the Planning Horizon

This methodology is applicable for developing SOLs used in the planning horizon.

L.1.2 Relationship of SOLs and Facility Ratings

SOLs in the planning horizon are described as the most limiting facility rating considering its design thermal or voltage rating together with the system conditions at which the limit is reached or exceeded when applying the TPL standards under base system conditions and simulating transfers consistent with FAC-013. The SOL condition shall not produce any facility Loading or voltage condition that exceeds the most limiting element that determines the Facility Rating.

L.1.3 Relationship of SOLs and IROLs

By definition, IROLs are a subset of SOLs that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System. Therefore, IROLs in the planning horizon are described as the system condition(s) (system or area demand level and facility contingency conditions) consistent with the NERC TPL standards, and simulating transfers consistent with FAC-013, for which instability, uncontrolled separation, or Cascading Outages are projected to occur.

L.2 Determination of SOL Conditions in the Planning Horizon

Near and longer term planning addresses identification of needs and solutions in the time frame of one to ten years, with particular focus on the first five (5) years. Screening reliability analyses are performed in the six to ten year period to identify possible issues that may require longer lead-time solutions, as required by the NERC standards.

Baseline reliability analysis provides an independent assessment of the reliability of the currently planned MISO Transmission System for the near-term planning horizon (e.g., within the next five years). This is accomplished through a series of evaluations of the near-term system with Planned (committed) and Proposed transmission system upgrades, as identified in the expansion planning process, to ensure that they are sufficient and necessary to meet NERC and regional planning standards for reliability. This assessment is accomplished through a combination of steady-state power flow, dynamic and first contingency transfer capability (FCITC) analyses of the transmission system performed by MISO staff and reviewed in an open stakeholder process.

Regional contingency files are developed by MISO Staff collaboratively with Transmission Owner and regional study group input. The list of contingencies will include events described under NERC TPL-001-4 or any applicable local or RRO planning criteria or guidelines. Below is a list of typical contingency categories tested. The extent that SOLs affect BES performance is determined using the following contingency criteria:

L.2.1 Pre Contingency State

The transmission system is modeled under NERC category P0 conditions (e.g. system intact) using both steady-state and dynamic stability analysis. Potential planning criteria violations (thermal overload and low or high voltage conditions) are identified using Transmission Owner’s design criteria limits. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to the system topology such as applicable planned facility outages in the planning horizon.

L.2.2 Post Contingency State

The transmission system is modeled under NERC category P1 through P7 conditions (e.g., loss of single or multiple Bulk Electric System elements, respectively) using both steady-state and dynamic stability analyses and under NERC category P1 using Transfer Capability analyses. Planning criteria violations (thermal overload and low or high voltage conditions) are identified using Transmission Owner's design criteria limits. Following the single Contingencies—(R2.2.1) Single line to ground or three-phase fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device or (R2.2.2) the loss of any generator, line, transformer, or shunt device without a Fault or a (R2.2.3) Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system—the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur. For Transfer Capability analysis, dynamic and voltage stability studies shall be conducted at the established FCITC limit for NERC category P1 contingent conditions and to the extent either dynamic or voltage instability is identified at the FCITC limit, a lower stable FCITC will be calculated. An SOL shall be established on the constrained element based on its pre-contingent flow at the stable FCITC limit.

L.2.3 Single Contingency System Response

For the near-term planning horizon, any potential criteria violations under NERC category P1 conditions are thoroughly analyzed. This analysis identifies possible corrective measures to prevent or mitigate potential violations, including operating procedures, construction of new transmission facilities, power flow switching strategies, generator re-dispatch, or controlled interruption to local Network Customers within the Faulted Facility affected area. The planning process also determines that appropriate preventative or mitigation measures can be put in place before the need is expected to occur in the planning horizon.

L.2.4, L.2.5, L.2.6, L.2.6.1 Multiple Contingency System Response

For the near-term planning horizon, modeled criteria violations under NERC category P2 through P7 conditions are evaluated for their potential to result in Cascading Outages or uncontrolled separation. This analysis identifies possible corrective measures to prevent or mitigate Cascading Outages or uncontrolled separation, including construction of new transmission facilities, power flow switching strategies, generator re-dispatch, or controlled load interruption or curtailment of firm transfers. The planning process also determines appropriate preventative or mitigation measures can be put in place before the end of the planning horizon.

L.3 Baseline Models

The MISO Baseline Reliability study models will typically include power-flow models reflective of five-year out and ten-year out system conditions. Other variations of these may also be used as appropriate based on the stakeholder input for a given planning cycle. The determination of SOLs and IROLs in the Planning Horizon establishes limits that are based on a representation of the actual transmission system capability. Reliability margins are not applied in the SOL/IROL analysis. The MISO SOL methodology consists of each of the following elements:

L.3.1 Topology

The system topology in the Baseline Reliability Plan models will reflect the expected system condition for the planning horizon. This will include documented future transmission projects within the MISO Transmission System. The Baseline Reliability Plan models shall include at least the entire MISO's Planning Authority area as well as any critical modeling details from other Planning Authority areas deemed necessary to impact the Facility or Facilities under study. The following general criteria will be used to model future transmission projects:

- Planned projects with Expected In Service Date before the MTEP study horizon year (before July 1 for summer peak cases);
- Projects with Regulatory Approvals;
- Projects with system needs documented by a MISO study (i.e., a previous MTEP study, a Generator Interconnection study, a Transmission Service study, or a Coordinated Seasonal Assessment);
- Planned projects based on Conditionally Confirmed TSR upgrades;
- Upgrades related to Generator Interconnection requests with signed Interconnection Agreements;
- Projects which are not subject to cost sharing.

Future transmission upgrades are removed from the model if they have Withdrawn Planning Status, or if they do not meet the inclusion criteria above. The non-MISO system representation will be based on the latest external system for the planning horizon.

L.3.2 Contingencies

Regional contingency files are developed by MISO Staff collaboratively with Transmission Owner and regional study group input. The list of contingencies will include events described under NERC TPL-001-4, or any applicable local or Regional Entity planning criteria or guidelines. Below is a list of typical contingency categories tested.

- NERC category P0: is system intact or no contingency event.
- All Category P1: faulted events for systems under MISO operational control. Generally, greater than 100 kV, but includes some 69 kV. Category P1 includes single generator, transmission circuit and transformer outages. It also includes single pole block of DC lines.
- NERC category P2 through P7 faulted events: The more severe events will be studied per the standards. All events will be documented and studied over

study cycle. Transmission Owner(s) and MISO staff will document NERC category P2 through P7 coverage.

L.3.3 Granularity of Models

The MTEP base models include all networked transmission system elements rated 100 kV and above. Additionally, the base model includes certain 69 kV elements that have been identified by Member Transmission Owner(s) as potentially significant for local system reliability studies.

L.3.4 Remedial Action Plans

The MISO base model for evaluating SOLs includes analysis of known Special Protection Systems and Remedial Action Plans.

L.3.5 Generation, Load, and Interchange

All existing generators and future generators with a filed Interconnection Agreement will be modeled. Any additional generation needed to serve future Load growth will be modeled based on input from future generation modeling processes described in *Section 4.4* of this BPM. New information on generators in the external system through coordinated data exchange with other external entities will also be modeled. Retirement of existing generators will also be updated based on the information available through the System Support Resource study process, see *Section 6.2* of this BPM. The Load Forecast information is based on the stakeholder input in the model building process. This information is reviewed and compared against Load flow data from NERC series models, Load Forecast information as filed with FERC and State regulatory agencies. Interchange and transaction data are also updated via the model building process which will include any new transactions or changes from the Transmission Service Planning process.

L.3.6 Criteria for determining when violating an SOL qualifies as an IROL

In the annual MTEP planning study, for multiple contingencies, the following criterion applies in determination of SOLs which qualify as IROLs:

- **MTEP Steady State Analysis**: After performing the steady state analysis to determine each SOL, additional analysis will be performed to identify thermal overloads in excess of SOL demonstrated to result in cascading loss of Load in excess of 1000 MW. Monitoring of MISO facilities shall be performed at the following facility rating thresholds (consistent with PRC-023):

- If the Facility Rating is based on a Loading duration of up to and including four hours, the circuit loading threshold is one-hundred fifteen percent (115%) of the Facility Rating.
- If the Facility Rating is based on a Loading duration greater than four and up to and including eight hours, the circuit Loading threshold is one-hundred twenty percent (120%) of the Facility Rating.
- If the Facility Rating is based on a Loading duration of greater than eight hours, the circuit loading threshold is one-hundred thirty percent (130%) of the Facility Rating.

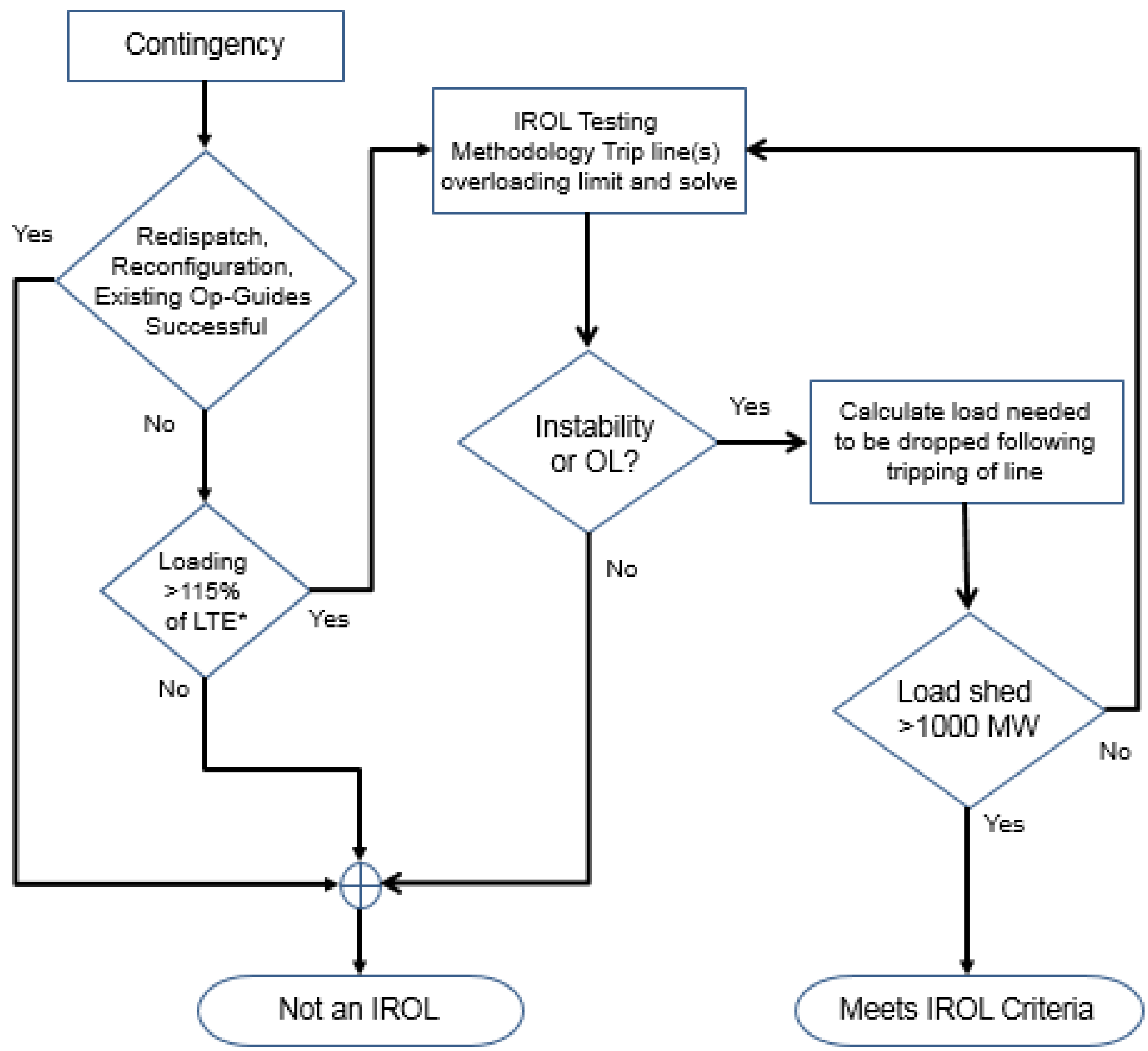
To the extent facility rating thresholds established by MISO Transmission Owner(s) (for purposes of IROL identification) are lower than the above thresholds, MISO will use TOs rating thresholds.

By NERC definition, an IROL is a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System. To the extent that an applicable contingency causes post contingency flow greater than the aforementioned facility emergency ratings above, the cascading test (*Figure L.3.6-1)* will be used to determine the amount of load lost on the system for the event. If the amount of firm load loss is greater than 1000 MW it will be classified as an IROL.

The 1000 MW load loss limit was selected to define the IROL threshold since it is consistent with what operations uses, and more generally, while it may cause significant regional impact, from the standpoint of interconnection-wide impacts it seems a reasonable limit.

The cascading test methodology is shown below and is performed using the Loading duration threshold to identify a cascading condition for the determination of an IROL.

Figure L.3.6-1: General Process for Cascading Analysis



***Use one-hundred fifteen percent (115%) of LTE unless Transmission Provider has supplied another Loading level to use**

- **MTEP Transient Stability Analysis**: After performing the transient stability analysis to determine each SOL, additional analysis will be performed to determine instabilities identified for multiple contingencies resulting in cascading loss of Load in excess of 1000 MW.

- **Near Term Transfer Capability based studies**: The following studies shall be conducted to determine IROLs based on transfer studies. Transfers to be studied shall be established pursuant to FAC-013 Transfer Capability Methodology documented in Appendix N of this BPM. The most limiting transfer IROL limit with cascading loss of Load impact in excess of 1000 MW shall be established for each studied transfer path where this limit is lower than the established FCITC SOL limit. These limits shall be based on the following studies and designated as IROL, and both the monitored and contingent elements associated with each limit shall be designated as an IROL limited facilities.
  - **Thermal Study**: Steady State testing using multiple contingencies performed while monitoring MISO facilities at the following facility rating thresholds (consistent with PRC-023):
    - If the Facility Rating is based on a Loading duration of up to and including four hours, the circuit loading threshold is one-hundred fifteen percent (115%) of the Facility Rating.
    - If the Facility Rating is based on a Loading duration greater than four and up to and including eight hours, the circuit Loading threshold is one-hundred twenty percent (120%) of the Facility Rating.
    - If the Facility Rating is based on a Loading duration of greater than eight hours, the circuit loading threshold is one-hundred thirty percent (130%) of the Facility Rating.

To the extent facility rating thresholds established by MISO Transmission Owner(s) (for purposes of IROL identification) are lower than the above thresholds, MISO will use TOs rating thresholds.

Potential IROL limit shall be established if the above thresholds are exceeded at transfer levels below the SOL FCITC transfer limit and cascading loss of Load is determined to be in excess of 1000 MW. Both the monitored and contingency elements associated with the limit shall be designated as potential IROL limited facilities.

- **Steady State Voltage Stability**: Voltage stability analysis shall also be simulated for each of the thermal transfers to assess IROLs from a reactive capability standpoint. To the extent voltage instability limit (with loss of Load in excess of 1000 MW) is identified to be lower than the thermal transfer IROL limit, the lower IROL shall be established on an interface associated with the transfer path. Both the monitored and contingency elements associated with the instability shall be designated as IROL limited facilities.

- **Transient Stability**: Transient stability analysis shall be conducted on the transfer study case. The transfer at the lower of the two IROL limits established either through thermal or voltage stability study shall be incorporated in this study case. To the extent instability (with loss of Load in excess of 1000 MW) is identified for simulated applicable disturbances, a lower IROL limit at the transfer point where no voltage, thermal or transient instabilities are identified shall be established. Both the monitored and contingency elements associated with the instability shall be designated as IROL limited facilities.

To the extent that any IROLs are the result of system topology changes introduced through future planned upgrades as determined by Transmission Owner(s), MISO shall also document an applicable future date against these associated IROLs. These dates would align with the in-service dates for the associated future projects.

MISO, as a Planning Coordinator, does not develop IROL T_v; however, MISO applies a default value of thirty (30) minutes for all IROLs identified in the Planning Horizon based on the maximum value specified in the NERC definition of IROL T_v. MISO's SOL and IROL determination in the Planning Horizon is intended to provide an indication of potential reliability impacts in future system conditions that may require monitoring and further evaluation for operational concerns. The assessment does not include a detailed analysis for developing operating actions needed to mitigate the risks of SOL and IROL exceedances and therefore, MISO does not develop T_v for the IROLs identified in the Planning Horizon.

L.4 Issuance of Documentation

This SOL Methodology, and any change to it, will be issued to the following entities prior to the effectiveness of the change.

L.4.1 Adjacent Planning Authority

Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the SOL Methodology.

L.4.2 Reliability Coordinator and Transmission Operator

Each Reliability Coordinator (MISO) and Transmission Operator that operates any portion of the MISO's Planning Authority Area.

L.4.3 Transmission Planner

Each Transmission Planner that plans a portion of the MISO Planning Authority Area.

L.5 Documented Response Time

If a recipient of this SOL Methodology provides documented technical comments on the methodology, the MISO will provide a documented response to that recipient within forty-five (45) Calendar Days of receipt of those comments. The response will indicate whether a change will be made to the SOL Methodology and, if no change will be made, the reasoning behind the decision.

L.6 Data Retention Period

The MISO shall keep all superseded portions of this SOL Methodology for twelve (12) Months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three (3) years.

Appendix M Planning Horizon PRC-023 Applicable Facility Identification Procedure

M.1 Requirement Six (R6)

Pursuant to requirement R6, MISO shall conduct an annual assessment once every calendar year, with no more than fifteen (15) months between assessments. MISO shall utilize the MISO Transmission Expansion Plan (MTEP) study and MISO Master Flowgate list as part of the annual assessment. PRC-023 Attachment B Criteria shall determine the circuits in MISO area, for which Transmission Owner(s), Generation Owners and Distribution Providers must adhere to PRC-023, Requirements R1 through R5 in order to prevent its phase protective relay settings from limiting transmission system Loadability, while maintaining reliable protection of the BES for all fault conditions. Circuits evaluated are transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, or circuits operated below 100 kV that have been classified as part of the BES.

M.1.1 PRC-023 Attachment B Criteria

MISO shall identify these circuits once a year pursuant to the criteria documented below that is consistent with each sub criterion within Attachment B of PRC-023. If inputs under Attachment B sub requirements are developed more frequently than once a year or revised within a year MISO shall review and may update the circuit list if needed.

- **M.1.1.1: Criterion B1** - Upon completion of MISO's reliability assessment, MISO shall annually incorporate the most current permanent flowgates within MISO Planning Coordinator footprint that are part of the MISO Master Flowgate list in establishing its initial facility list. In subsequent assessment years, MISO will update the facility list determined pursuant to this criteria based on additions or deletions to the permanent flowgate list annually.
- **M.1.1.2**: **Criterion B2** - MISO will incorporate circuits which are monitored facilities of an IROL into its facility list following completion of its annual reliability assessment. The methodology used in determining these IROLs established pursuant to FAC-010 and FAC-014 is documented in Appendix L of this BPM.
- **M.1.1.3**: **Criterion B3** - Consistent with NUC-001-2, MISO maintains mutually agreed upon Nuclear Plant Operating Agreements which include Nuclear Plant Interface Requirements (NPIRs) with Generator Owners and applicable Transmission Planners within its footprint. MISO shall incorporate

the circuits that form a path to supply off-site power to nuclear plants as established within applicable NPIRs in its facility list annually.

- **M.1.1.4**: **Criterion B4** - Circuits included on the facility list shall be identified through the following sequence of power flow analyses performed by the planning coordinator for the one-to-five year planning horizon. In order to monitor thermal loading, MISO shall utilize facility rating thresholds consistent with the following sub requirements:
    a. Simulate double contingency combinations, without manual system adjustments in between the two contingent events.
        - The contingency pairing for NERC TPL category P6 events is intended to simulate contingencies that produce the most severe impact. Due to the large footprint of MISO, groups are developed to represent facilities in closer proximity and are representative of the MISO Local Resource Zones. All BES contingency combinations within a group are simulated. Contingencies in adjacent groups are paired by operating voltage and generation capacity thresholds.

    b. For facilities operated between 100 kV and 200 kV (and facilities less than 100 kV that have been classified as part of the BES), evaluate the post-contingency loading based upon the Facility Rating assigned to that circuit, in consultation with the Facility Owner and included in the MISO Transmission Expansion Plan base models.
    c. Where more than one applicable rating exists, the rating based on the loading duration nearest four hours will be used.
    d. Rating based on loading duration assumed:
        - If the Facility Rating is based on a load duration of up to and including four hours, the circuit load threshold is one-hundred fifteen percent (115%) of the Facility Rating.
        - If the Facility Rating is based on a load duration greater than four and up to and including eight hours, the circuit load threshold is one-hundred twenty percent (120%) of the Facility Rating.
        - If the Facility Rating is based on a load duration of greater than eight hours, the circuit load threshold is one-hundred thirty percent (130%) of the Facility Rating.

- To the extent facility rating thresholds established by MISO Transmission Owner(s) (for purposes of IROL identification) are lower than the outlined thresholds, MISO will use the lower rating thresholds.

e. MISO will exclude radially operated circuits and generation Step Up transformers, which are used exclusively for exporting energy from a BES generation unit or plant.

- **M.1.1.5**: **Criterion B5** - MISO conducts technical studies annually as part of its reliability assessment to determine additional facilities other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- **M.1.1.6**: **Criterion B6** - The MISO shall supplement the list of circuits developed pursuant to sub requirements B1 through B5 above with additional facilities identified by the MISO Transmission Owner(s). MISO will solicit its Transmission Owner(s) for this list once a year before establishing its annual facility list.

M.1.2 Requirement R6.1

MISO shall annually (once every calendar year, with no more than fifteen (15) months between assessments) develop and maintain a list of circuits that meet any of the criterion detailed in Requirement R6 that would be subject to Requirements R1 through R5 listed in PRC-023. This list shall be created annually and will include identification of the first calendar year for which the circuit meets any of the criterion described in Requirement R6. The list will be available on the MISO extranet site, which can be accessed via the link below.

- MISO Extranet - PRC-023 List

M.1.3 Requirement R6.2

MISO shall make the list of circuits available at least once every calendar year, to all appropriate Regional Entities, Reliability Coordinators, Transmission Owner(s), Generator Owners, and Distribution Providers. The initial list of circuits shall be posed within thirty (30) calendar days of its establishment. If any change is made to the list of circuits, a new list shall be posted within thirty (30) calendar days of any such change. The list of circuits shall be posted in PDF format.

Expansion Planning shall also send a notification to all appropriate Regional Entities, Reliability Coordinators, Transmission Owner(s), Generator Owners, and Distribution Providers within thirty (30) calendar days of posting of the initial list or an updated list.

Transmission Owner(s) of circuits[i] to which the relay loadability standard (PRC-023) shall apply, as referenced by MISO Transmission Asset Management - Expansion Planning will also be identified in the published list.

Appendix N Transfer Capability Methodology

Pursuant to NERC Reliability Standard FAC-013, MISO documents its Transfer Capability Methodology applicable to the Near-Term Transmission Planning Horizon within this Appendix N of this BPM. MISO conducts its Near-Term (Years one through five) planning assessment based on powerflow simulations representative of various system conditions in five year out MISO Transmission Expansion Plan (MTEP) models. System conditions modeled in these models are normal base transfers representative of network operated to supply projected customer demands and projected Firm Transmission Services at forecasted system demands and consistent with applicable NERC Transmission Planning standards. By using these base MTEP models to conduct Transfer Capability analyses pursuant to the methodology documented below, MISO thus establishes Transfer Capability as an incremental above these base transfer levels.

N.1 Transfer Capability Methodology

This Appendix N constitutes MISO's documented methodology, which it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability methodology). This methodology includes the following information:

N.1.1 Transfer Selection Criteria

Prior to commencement of its annual MTEP Transmission Planning studies, MISO will develop a list of transfers to be assessed and the transfer analysis parameters to be used for the studies in collaboration with its planning stakeholders. A First Contingency Incremental Transfer Capability (FCITC) for each studied transfer path shall be established based on the most limiting of the Steady State or Voltage Stability and Transient Stability verification analyses. These transfers will be selected based on the following criteria:

- **Demand Forecast**: Transfers simulating increases in demand shall be conducted on MTEP five year out Summer Peak case.
  - Within its footprint where demand forecasts have historically exceeded their previously forecasted 50/50 forecast more than once, MISO will test increase in demand up to but not limited to respective current 90/10 demand forecast in the Near-Term planning horizon.
  - Where supported by local regulatory agency requests on study of new customer demands above projected Load Forecast, specific increased demand transfers will be included within MTEP scope upon review of planning stakeholders.
- **Economic Exchange of power between systems**: Transfers simulating increases in economic power transactions may result from various conditions.

These conditions based on stakeholder input and review of historic and projected system uses will be simulated in MTEP five (5) year out off-peak or light load cases as applicable. Conditions to test economic transfers shall be based on:

  - Increase in low cost renewable generation in specified regions within the MISO footprint.
  - Increase in other low cost generation in specified regions depending on shifts in projected fuel prices.
  - When supported by local Load Serving Entities (LSEs) and Generation Owners (GOs), specific economic transfers will be included within MTEP scope, upon review of planning stakeholders.

- **Historic and Projected Transmission Usage**: Transfers simulating historic and projected transmission usage not otherwise incorporated under economic transfers will be developed on the following basis and studied in peak or off-peak base cases as applicable:
  - Where review of flows on critical interfaces monitored in real time and same facilities within applicable MTEP cases is determined to be measurably different, MISO will establish transfers to simulate flows consistent with historic flows. Projected system flows may be established where planned generation and load additions are determined to increase historic flows.
    - Critical Interfaces to be reviewed shall be established within each MTEP scope based on real time operations feedback.
    - Flows shall be deemed measurably different where planning case interface flow is more than five percent (5%) lower than historic flows on the same interface.
- **Generation Forecast**: Transfers simulating reduced generation in specified systems where requested by Generation Owners will be included within MTEP scope upon review of planning stakeholders.

In support of the standard, there will typically be approximately three to five models built annually for performing transfer analysis, unless stakeholders agree otherwise. Planning horizon transfer simulation models created shall be developed using, but not limited to, the criteria outlined in N1.1.

N.1.2 System Operating Limits (SOL)

Transfer capabilities shall respect all System Operating Limits (SOLs) defined in MISO's SOL/IROL methodology, as documented within Appendix L of this BPM.

N.1.3 Planning Practice Consistency

Assumptions and criteria used to perform transfer capability assessments shall be performed consistent with MISO's planning practices as documented in this BPM.

N.1.4 Assumptions and Criteria

Each of the assumptions and criteria used in performing the assessment outlined in requirements R1.4.1 through R1.4.7 shall be addressed as follows:

N.1.4.1 Generator Dispatch

Generation dispatch reflected in base MTEP cases is derived from a regional tiered merit order list. Future planned committed generation or generators with signed interconnection agreements are also included in the model. All existing generators with approved Attachment Y Notices will be modeled offline, beginning on their start date, based on the information provided by the Generator Owners through the System Support Resource study process. Units with approved Attachment Y Notices that have waived their interconnection rights (i.e., retired) will remain offline indefinitely. Units with approved Attachment Y Notices that have not waived their interconnection rights (i.e., suspended) will remain offline for the first three (3) years following their start date and after the three (3) years they will be available for dispatch. Additional details on MTEP model generation dispatch is documented under *Section 4.3.3.2* of this BPM.

N.1.4.2 Transmission System Topology

Projected transmission system topology in the five year planning horizon including but not limited to long term planned Transmission Outages, additions, and retirements are reflected in MTEP base cases. Please refer to *Appendix L: MISO SOL – IROL Methodology* of this BPM in compliance with FAC-010 and *Section R3.1* for additional details on system topology.

N.1.4.3 System Demand

Load demand in MTEP base cases is based on the most probable (50/50) coincident load projection for each Transmission Owner service territory for the study horizon being analyzed. The external area load is modeled as represented in the applicable ERAG cases. Load is modeled as a net of indirect demand-side management programs. Modeling of system demand consistent with MOD standards is reflected within MTEP base cases. Additional details on MTEP load modeling is documented under *Section 3.3.2* of this BPM.

N.1.4.4Current approved and projected Transmission Uses

MTEP base cases reflect projected firm transmission uses between MISO system and adjacent non-MISO systems as derived from applicable ERAG models. Transfers will be simulated so as to not exceed MISO aggregate interchange with outside areas. Where transfers are established to increase flows to simulate projected transmission uses, MISO will establish known interfaces monitored in real time to establish transfer paths.

N.1.4.5 Parallel Path (loop flow) Adjustments

Because it is recognized that transfers occur on all transmission paths that are part of the ac interconnected system, in establishing transfer capability, MISO will monitor and recognize neighboring or adjacent interconnected system limits.

N.1.4.6 Contingencies

All single-event contingencies (NERC category P1, P2, and P7) will be applied in testing transfer capability. In addition select single-event contingencies plus a single element maintenance outage will also be simulated in establishing transfer capability for off-peak conditions. Consideration of this select list of single-event contingencies plus a single element maintenance outage ensures that the more significant maintenance outages are accounted for in establishing transfer capability, but these types of contingencies will only be simulated in transfers studied in off-peak cases where maintenance outages are most likely. These single-event contingencies plus a maintenance outage will be selected based on the results of past MTEP planning studies.

Please refer to *Section R3.2* from *Appendix L: MISO SOL – IROL Methodology* of this BPM in compliance with FAC-010 for additional details on contingencies simulated.

N.1.4.7 Monitored Facilities

In addition to all BES elements monitored in MISO and adjacent seams areas, select Low Voltage facilities shall also be monitored. Low Voltage facilities identified pursuant to MISO Low Voltage Monitoring criteria documented in Appendix P of this BPM shall be included in monitored facility list.

N.1.5 Adjustment of Generation, Load or Both in Transfer Simulations

Generation dispatch used in simulating transfers shall be consistent with MISO planning practices of using a tiered regional merit order. At the Exporting (or Sending) area, higher cost Network Resources (NRs) shall be dispatched up to the limit of generating capacity prior to dispatching Energy Resources (ERs). A merit order based on generation costs derived from Ventyx© Powerbase data used in MTEP base case modeling shall be employed in selection of cheaper generation capacity within NRs and ERs. Similarly, higher cost generation in the importing area will be reduced to accommodate needed transfer levels. This will be accomplished by assigning participation factors to generators based on cost.

Where increases in demand are to be simulated in transfers, load at applicable stations will be increased maintaining respective modeled power factors.

N.2 Issuance of Methodology by PC

A notice of issuance of Transfer Capability Methodology shall be sent out in accordance with *Sections R2.1 and R2.2* of this Appendix N as shown below.

N.2.1 Distribution of Transfer Capability Methodology

MISO will distribute its Transfer Capability Methodology to Planning Coordinators adjacent to or overlapping the MISO footprint. MISO will also distribute its Transfer Capability Methodology to each Transmission Planning Registered Entity within the MISO footprint. The most current list (at the time of communication) of PCs and TPs are listed on NERC registration site will be used.

N.2.2 Distribution to Other Entities

MISO will additionally distribute its Transfer Capability Methodology to each functional entity that has a reliability-related need for the Transfer Capability Methodology and submits a request for that methodology within thirty (30) Calendar Days of receiving that written request.

N.3 Response to comments

If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, MISO shall provide a documented response to that recipient within forty-five (45) Calendar Days of receipt of those comments. MISO shall indicate in its comments whether a change will be made to the Transfer Capability methodology and, if no change will be made to the Transfer Capability Methodology, the reason why.

The Transfer Capability studies shall be performed annually. The determination of list of transfers will be completed by the end of first quarter of each year. In order to conduct transfer assessment, consistent with current methodology and allow sufficient time to conduct assessment, only revisions to Transfer Capability methodology made before the end of first quarter of each year shall apply to current year planning assessment. Revisions made after first quarter of each year shall apply to subsequent year assessments.

N.4 Annual assessment of Transfer Capability

As noted above, MISO shall conduct an assessment of Transfer Capability on an annual basis. Simulations in support of the assessment shall include at least one year in the Near-Term Transmission Planning Horizon with the year typically being the five (5) year out planning year.

N.5 Availability of Study Results

MISO shall make the documented Transfer Capability assessment results available within forty-five (45) Calendar Days of completion of the assessment to the recipients of its Transfer Capability methodology pursuant to *Sections R2.1 and R2.2* from this Appendix N of this BPM.

Additionally, any functional entity that has a reliability related need for MISO Transfer Analysis assessment results and makes a written request for those results after the completion of the assessment, MISO will make available to that entity the results of its assessment within forty-five (45) Calendar Days of receipt of the request. In MISO's determination of whether the functional entity has a reliability related need, to the extent the requesting entity does not have applicable confidentiality privileges, MISO will make available limited publicly available assessment results not subject to confidential information.

N.6 Availability of Study Related Data

Any entity receiving the results of MISO's Transfer Analysis assessment requesting supporting data for the assessment results will be provided supporting data within forty-five (45) Calendar Days of receipt of request, subject to MISO legal and regulatory obligations regarding the disclosure of confidential and/or sensitive information.

Appendix O Coordination of Studies between MHEB, MPC, and MISO

The procedure will govern the TSR study coordination for the Long Term Firm Transmission Service Requests on MHEB, MPC and MISO transmission systems where one of the three parties may be an Affected System TSP for the TSR. The entire coordination procedure is documented in Appendix O of this BPM.

O.1 Purpose

The purpose of this coordination procedure is to coordinate Long Term Firm Transmission Service Requests where one of the three parties may be an Affected System. Each party will implement this procedure through Business Practices under each party's respective tariff(s).

O.2 Scope

A TSR is deemed within scope for this agreement as follows:

- MH will be considered an Affected System for TSRs requested under the MPC or Tariffs if the TSR has a POR or a POD from the following list:
  - ALTE, ALTW, CE, DPC, GRE, LES, MDU, MEC, MGE, MHEB, MP, MPC, MPW, NPPD, NSP, ONTW, OPPD, OTP, SMP, SPC, WAPA, WEC, WPS
- MPC will be considered an Affected System for TSRs requested under the MH or Tariffs if the TSR has a POR or a POD from the following list:
  - GRE, MDU, MHEB, MP, MPC, NSP, ONTW, OTP, SPC, WAPA
- MISO will be considered an Affected System for all TSRs requested under the MPC or MH tariff

A TSR that is deemed in scope will be subject to the coordination procedures below. If the TSR is not deemed in scope, it is not subject to the coordination procedures below.

O.3 Definitions

Affected System – a non-Host TSP whose transmission system may be reasonably expected to experience a non-trivial loading impact due to a TSR on a Host TSP's transmission system.

Affected System Upgrades – upgrades required to the Confirmed Affected System transmission system to accommodate the Host TSP TSR. The need for the Affected System

Upgrade will be identified in the impact study and further defined in the Affected System facilities study.

Confirmed Affected System – an Affected System that has been confirmed through either the Host TSP or the Affected System impact analysis that the Affected System has an impacted facility due to a TSR on a Host TSP's transmission system as shown in the Host TSP impact study report.

Host TSP – MH, MPC, or MISO that receives the TSR

Long Term Firm Transmission Service Request (TSR) – a request for long term firm transmission service across the TSP's transmission system under the respective party's tariff (MISO's tariff, MPC's Open Access Transmission Tariff (OATT), or MH's OATT)

Neighboring TSP(s) – MH, MPC, and/or MISO that does not receive the TSR. General reference to any or all of the parties to this coordination language.

as defined by the Tariff
Remedial Action Scheme – as defined by NERC standards

POR/POD – as defined by the Tariff

Transmission Service Provider or TSP – as defined by NERC standards

O.4 Procedure

MISO, MH, and MPC have agreed to the following process by which Long Term Firm Transmission Service Request studies are conducted to determine the impacts of TSRs on each other's transmission systems. Coordination with Affected Systems is required by the parties' respective tariffs. This joint coordination of TSR studies serves to clarify the process by which that coordination is conducted for MISO, MH, and MPC.

O.4.1 Notice

The Host TSP will provide notice of new TSRs which fall within the aforementioned scope in *Section O.2* to the Affected System(s) once the TSR customer has signed an impact study agreement. The Host TSP will send an email with details of the associated TSR so that the Neighboring TSP can begin including the TSR in their models. The Host TSP will include the

Affected Systems in the ad-hoc study group for a Host TSP TSR impact study. This notice shall be provided regardless of whether the Affected System is also a Host TSP.

O.4.2 Impact Study Obligations

There are two coordination scenarios to consider for a TSR:

- When two or more of the parties are Host TSPs, and
- When only one of the parties is a Host TSP

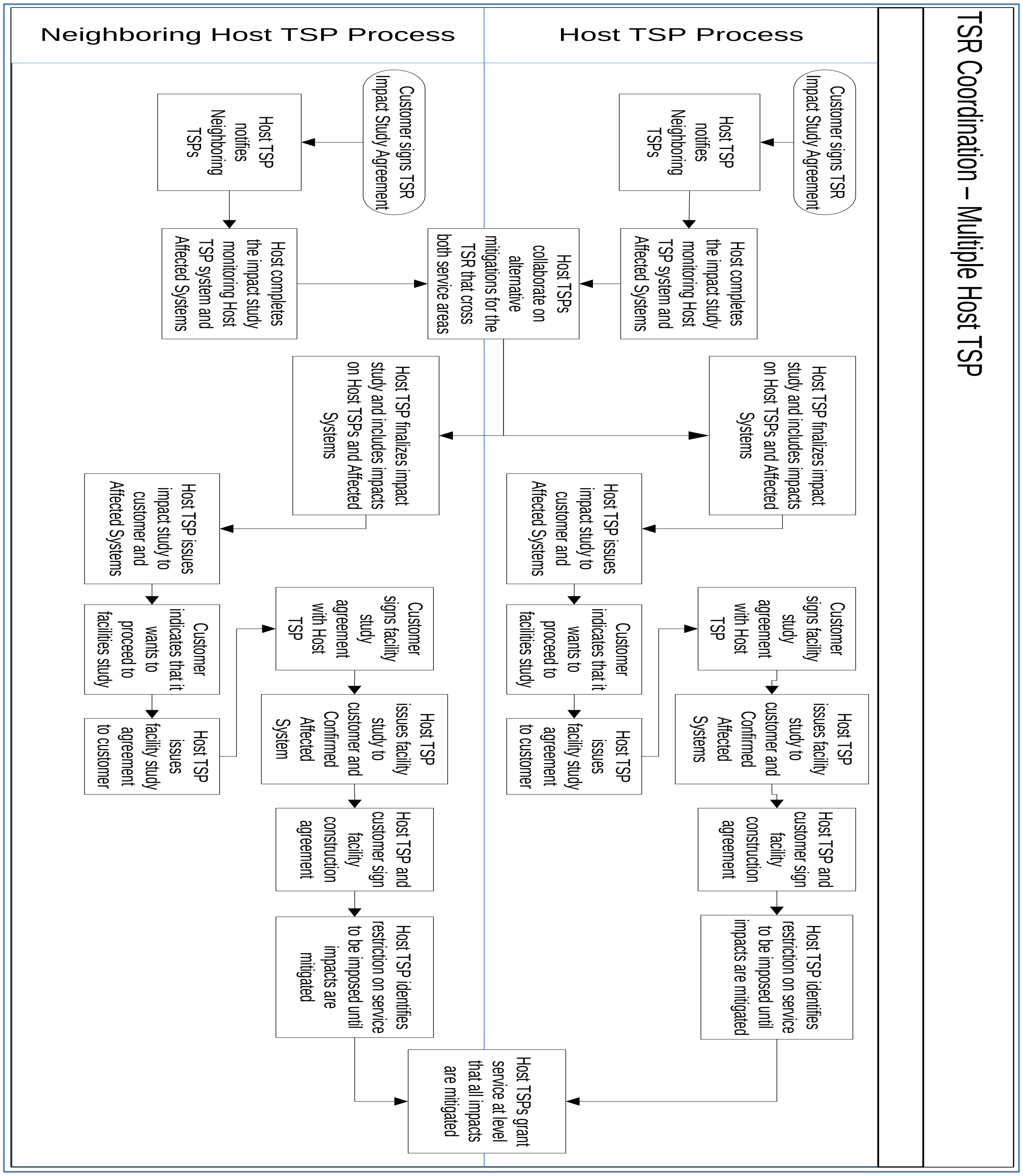
O.4.2.1 Process for a TSR that has more than one of the Neighboring TSPs as Host TSPs

The first scenario occurs when the transmission of energy from the source to the sink identified in a TSR is dependent on transmission service from two or more TSPs which are parties in this coordination procedure. In this scenario the study to evaluate the impact of the TSR on the Host TSP's transmission system will be completed by each Host TSP as per the Host TSP's tariff, Business Practices, and study methodology.

If one of the Neighboring TSPs is a non-Host TSP, the non-Host TSP will be deemed an Affected System by each Host TSP and all associated provisions related to Affected Systems coordination will apply, as stated in the second scenario below.

Process diagrams are included to provide clarity. If a conflict arises between the process diagram and the text in this procedure, the text shall rule.

Figure O.4.2.1-1: Process diagram of TSR Coordination – Multiple Host TSP



O.4.2.2 Process for Affected System Coordination

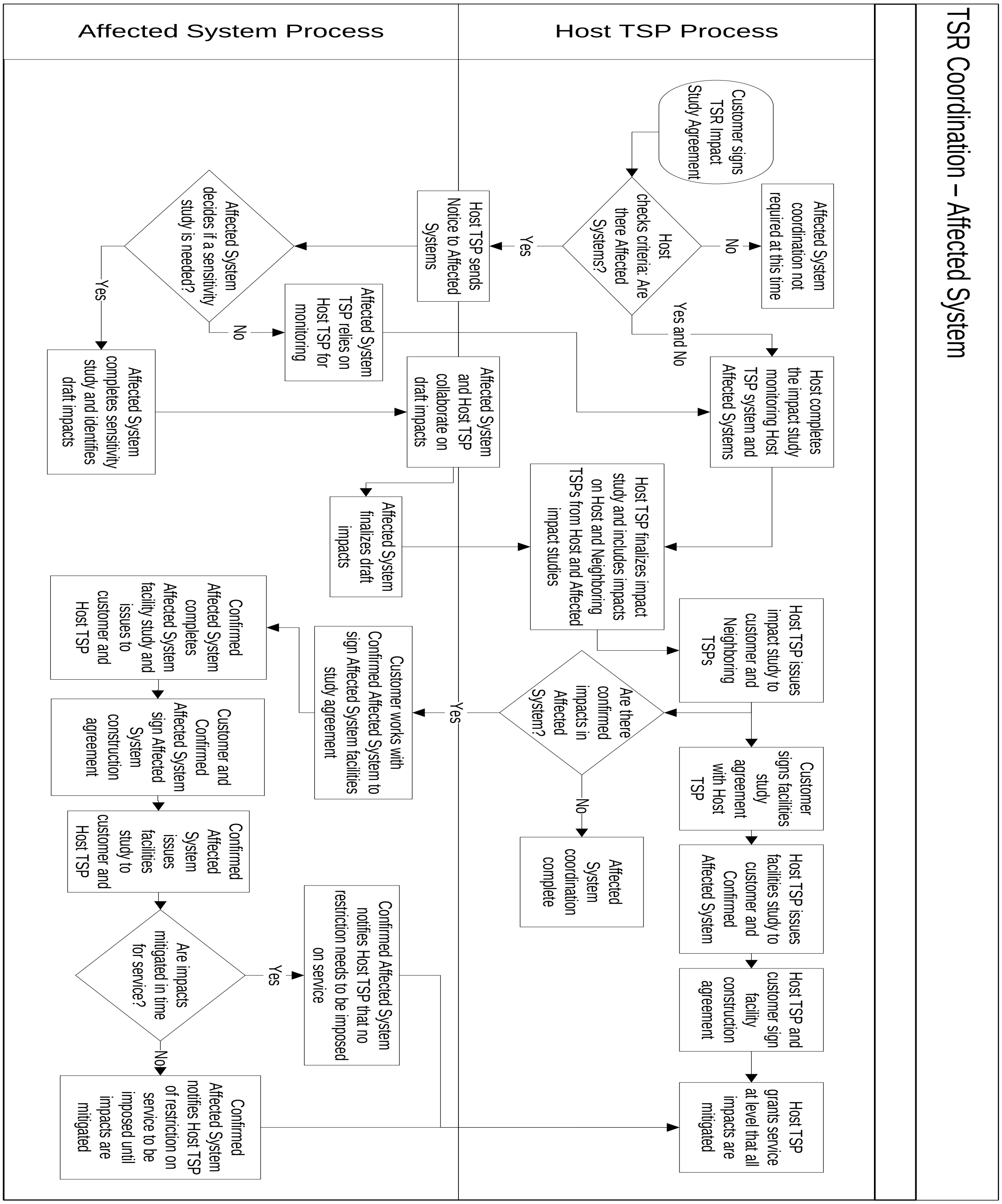
The second scenario occurs when the transmission of energy from the source to the sink identified in a TSR is dependent on transmission service from only one of the TSPs party to this coordination procedure. This scenario also covers treatment of a non-Host TSP when there is a TSR coordinated between two Host TSPs. If a Neighboring TSP is deemed an Affected System in accordance with scope section, *Section O.2* of this BPM, the Host TSP will include the Affected System(s) in the coordinated study process by providing Affected Systems with an opportunity to perform a sensitivity impact study on their own transmission system to be included in the Host TSP's impact study report. The Host TSP shall forward to the Affected System(s) the information necessary for the Affected System(s) to study the impact of the TSR on their respective transmission systems.

The Host TSP will accept study results from the Affected System(s) regarding the impact of the TSR on the Affected System's transmission system until a date ten (10) Calendar Days before the Host TSP's impact study is due to the TSR customer, provided that the Affected System will be allowed a minimum of forty-five (45) Calendar Days to complete their sensitivity study, unless otherwise agreed to. If the Host TSP determines that the study process is extended due to the complexity of the project, the same extension will be granted to the Affected System(s). Sensitivity studies conducted by Affected System(s) will use the methodology and criteria of the Affected System conducting the study.

The Affected System may either perform its own sensitivity study on the impact of the TSR on its transmission system for inclusion in the Host TSP's study report or may defer to the Host TSP's analysis for monitoring of its own transmission system. If the Affected System decides to perform its own sensitivity study, the time requirements for providing the results of the study to the Host TSP shall be as described above. If the Affected System's policies allow for the sharing of study models, a Customer can apply to obtain the study models from the Affected System by executing the required confidentiality agreements.

Process diagrams are included to provide clarity. If a conflict arises between the process diagram and the text in this procedure, the text shall rule.

Figure O.4.2.2-1: Process diagram of TSR Coordination – Affected System



O.4.2.3 General Impact Study Obligations

During the course of the TSR impact study for both scenarios, the Host TSP will monitor the Affected Systems' transmission systems and provide the draft results of potential impacts to the Affected Systems. When the Host TSP performs the impact study, the Host TSP will use reasonable efforts to monitor the affected system and:

- The MISO transmission owner study and reinforcement criteria will apply to the monitoring of MISO transmission facilities;
- The MPC study and reinforcement criteria will apply to the monitoring of MPC transmission facilities; and
- The MH study and reinforcement criteria will apply to the monitoring of MH transmission facilities.

If available, the Affected System will provide service limitation policies to the Customer upon request.

Potential impacts on the Neighboring TSP's transmission systems will be included in the Host TSP's impact study report along with any information regarding the validity of the impacts. Each Host TSP will coordinate with its Neighboring TSPs to develop alternatives to mitigate identified impacts. The Host TSP will include the following details provided by the Confirmed Affected System(s) in the Host TSP's impact study report:

- The minimum amount of transmission service that can be granted without Affected System Upgrades,
- A preliminary description of the required Affected System Upgrades,
- an estimated planning level cost, and
- Preliminary estimate of the in-service date of the system reinforcement

The Host TSP will refer the TSR customer to the Confirmed Affected System to begin the associated facilities study agreement process and construction of Affected System Upgrades for network reinforcements required on that transmission system.
The Host TSP will promptly share the study reports with the Affected Systems upon completion.

O.4.3 Mitigating Host TSP TSR on the Confirmed Affected System's Transmission System

If the transmission customer proceeds to the facilities study stage with the Host TSP (or to a service agreement if no facilities studies are necessary), notice will be provided by the Host TSP to any Confirmed Affected Systems. The tariff and Business Practices of an Affected System will apply to the identification and construction of Affected System Upgrades and/or implementation of other mitigation measures to address impacts to the Confirmed Affected System identified in the impact study.

The Host TSP and Confirmed Affected System will promptly share Facility Study reports with each other upon completion.

Transmission service will only be granted by the Host TSP up to the amount at which there are no transmission constraints identified by the studies on the transmission systems of the Confirmed Affected System(s). Partial transmission service may be granted if the Confirmed Affected System is not constrained at that level of service. The requested amount of transmission service can only be granted once all identified constraints on the system (MISO, MH, and MPC) have been mitigated.

If Confirmed Affected System(s) constraints are addressed through the use of alternative measures in lieu of constructing facilities, or as an interim measure while facilities are under construction, firm transmission service will not be granted beyond the amount permitted by the Confirmed Affected System's Business Practices.

O.5 Application and Governing Agreements

This coordination procedure applies to Manitoba Hydro (MH), Minnkota Power Cooperative (MPC), and the Midcontinent Independent System Operator (MISO). This procedure is effective as of the date this procedure is signed.

O.5.1 Governing Agreement for MPC and MISO Coordination

This coordination procedure is established between MPC and MISO pursuant to *Sections 9.1 and 14.1* of the MISO-MPC Coordination Agreement.

O.5.2 Governing Agreement for MH and MISO Coordination

This coordination procedure is established between MH and MISO pursuant to *Section 5.4* of the MISO-MH Coordination Agreement.

O.5.3 Governing Agreement for MPC and MH Coordination

This coordination procedure is established between MPC and MH pursuant to *Sections 9.011, 9.02, and 9.022* of the Interconnection, Facilities and Coordinating Agreement respecting Ridgeway-Shannon 230 kV Interconnection.

Appendix P Methodology for Assessment of Low Voltage Facility Impacts on BES

P.1 Purpose

The assessment of impacts from low voltage sub-100kV facilities on the Bulk Electric System is intended to identify facilities that pose a reliability risk and should be monitored/managed in MISO operations and planning processes. MISO planning analysis is performed to simulate contingent events that can cause overloads on the lower voltage system and subsequent tripping of facilities that result in BES overloads or system instability. This screening analysis is performed periodically (2-3 year cycle) to produce a list of the low voltage facilities that are candidates for monitoring and management by MISO. For each study cycle, the scope of the effort will be reviewed with the stakeholder community to allow opportunity to update elements of the study methodology and the assumptions included in the analysis.

P.2 Model Selection

The impact analysis will use existing MTEP models in order to expedite the model preparation work. Since these models have been reviewed and updated for use in the MTEP TPL compliance analysis, the models will require minimal modifications for use. Models will be posted for stakeholder review and will include a near term summer peak and a mid-term shoulder peak case that are intended to reflect the variations in dispatch associated with different types of Generation Resources such as higher wind conditions.

P.3 Monitoring and Contingency Set

All model elements 40kV and higher in all MISO areas and first tier external areas will be monitored for screening. All 100 kV and higher branches in MISO and first tier areas will be included in the contingency set. N-1-1 contingencies are generated from the combinations of the elements included in the contingency set.

P.4 Contingency Screening

An initial contingency analysis run is performed on the contingent events to identify any pre-existing BES overloads that will be used later in differentiating new overloads from impacts on pre-existing (post-contingent) violations.

P.5 Cascading Analysis

The contingency process uses a customized script to implement event processing by the analytical engine which calculates the resulting post-contingent flows. This tool checks for subsequent loading exceeding one-hundred percent (100%) of emergency rating for low voltage facilities and one-hundred twenty-five percent (125%) for BES facilities or voltages outside of limits of the monitored facilities.

The process then tests any low voltage facility that is overloaded one-hundred percent (100%) by removing it from service, along with any BES facility loaded above one-hundred twenty-five percent (125%), and attempts a power flow solution. If the power flow does not solve, the low voltage facility that was tested is flagged as a potential stability issue. If the power flow does solve, further overloads are checked to determine if a BES overload occurs, low voltages below 0.7 p.u. exist, or if the trip of the low voltage facilities causes cascading overloads on the remaining low voltage circuits. BES overloads are compared against the pre- overloads existing (not caused by the low voltage facility trip). If a new BES overload exists, the low voltage facility is flagged as having a BES impact. Any pre-existing overload is checked to determine if the change in flow is greater than five percent (>5%). The analysis continues by tripping further overloaded low voltage facilities as well as any BES facility that is greater than one-hundred twenty-five percent (>125%) of the emergency rating. If a subsequent unsolved power flow case, low voltages below 0.7 p.u. exist or BES overload occurs, the low voltage facility is flagged as having a BES impact.

Low voltage facilities are further analyzed to determine if the LODF of the BES contingency elements on the low voltage facility exceeds three percent (3%). If the LODF is less than three percent (<3%) the low voltage facility is excluded from the candidate list.

P.6 Post Analysis Review and Available Mitigation Plan

The results from the analysis are posted to the MISO planning ftp site for review and validation by Asset Owners. For results that are determined to be invalid (incorrect ratings/contingency definitions, etc.), the facilities are removed from consideration. Facilities with a documented operating action (reconfiguration) will be monitored but not managed. Facilities that do not have a documented mitigation plan will be evaluated to determine if market dispatch will be effective in managing congestion.

P.7 Dispatch Responsiveness

Dispatch responsiveness tests each candidate low voltage facilities without a mitigation plan to determine if MISO generation can be effectively used to manage the flow on the facility. Analysis of the facilities in the immediate and surrounding areas is performed to determine all contingent elements that have a three percent (3%) LODF on the low voltage candidate facility. The contingency elements are combined to produce double contingency events which are used to calculate the generator sensitivities for all MISO generators on the associated low voltage facility/contingent event. Generator sensitivities with at least a one and half percent (1.5%) impact on the candidate facility are used to determine the units to consider in re-dispatch. The total impact of dispatch is calculated as the sum of all the MISO dispatchable generation with at least one and half percent (1.5%) sensitivity multiplied by the modeled P_{max} of the units.

P.8 Candidate Selection

Facilities where the total impact of the generation dispatch is greater than twenty-five percent (25%) are then selected for congestion management. If total impact of the generation dispatch responsiveness does not meet the threshold of twenty-five percent (25%) of the low voltage facility emergency rating, an operating guide will be needed to manage the risk of overload.

P.9 Treatment in MISO Operations and Planning Processes

Candidate facilities meet the selection criteria for BES impacts will be monitored in MISO Operations and Planning Processes. If a candidate facility has met the Dispatch Responsiveness test and has not operational mitigation plan, it will be included for congestion management. Otherwise the facility will be monitored in security analysis to provide awareness of the potential reliability issues that may require mitigating actions. Candidate facilities will be monitored in MISO MTEP planning analysis for overloads and, if overloaded, will be analyzed further to determine if tripping of the facility causes an impact on the BES Transmission System. MISO will plan for BES Transmission System upgrades necessary to address the BES issues but will not plan for upgrades to non-transferred low voltage facilities. However, a facility owner may choose to pursue a more cost effective alternative low voltage transmission solution if it eliminates the risks to the BES Transmission System.

Figure P.9-1: Overall Process Steps

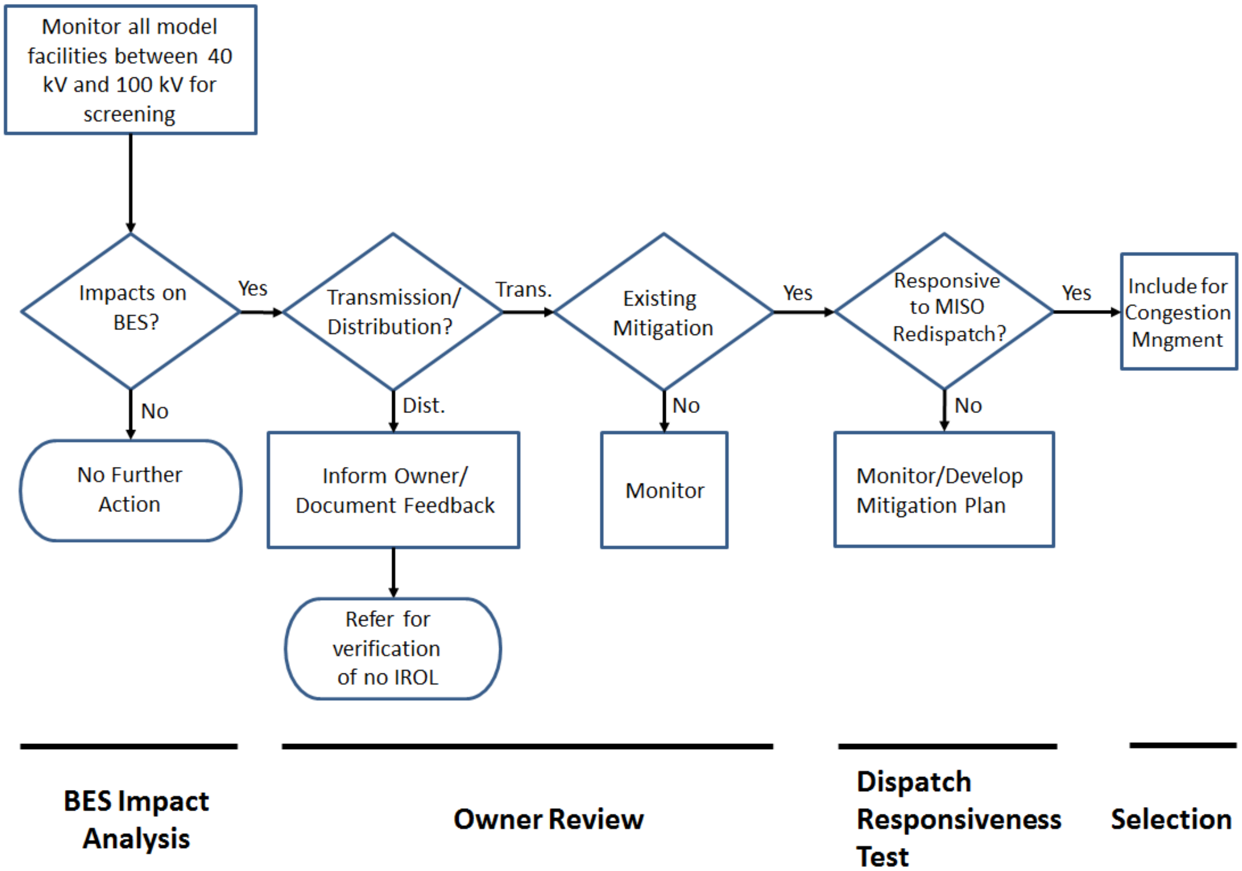


Figure P.9-2: BES Impact Analysis

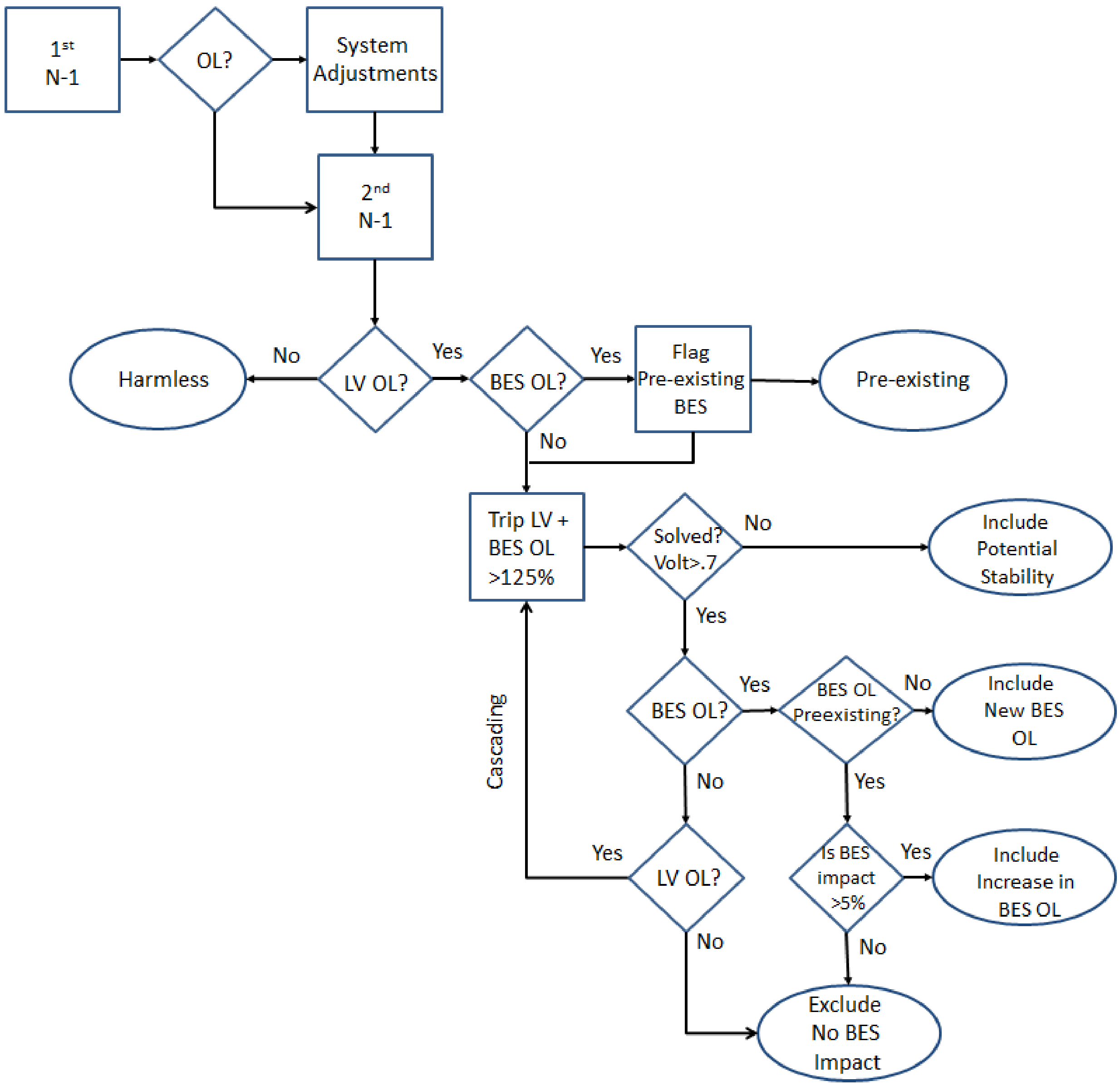
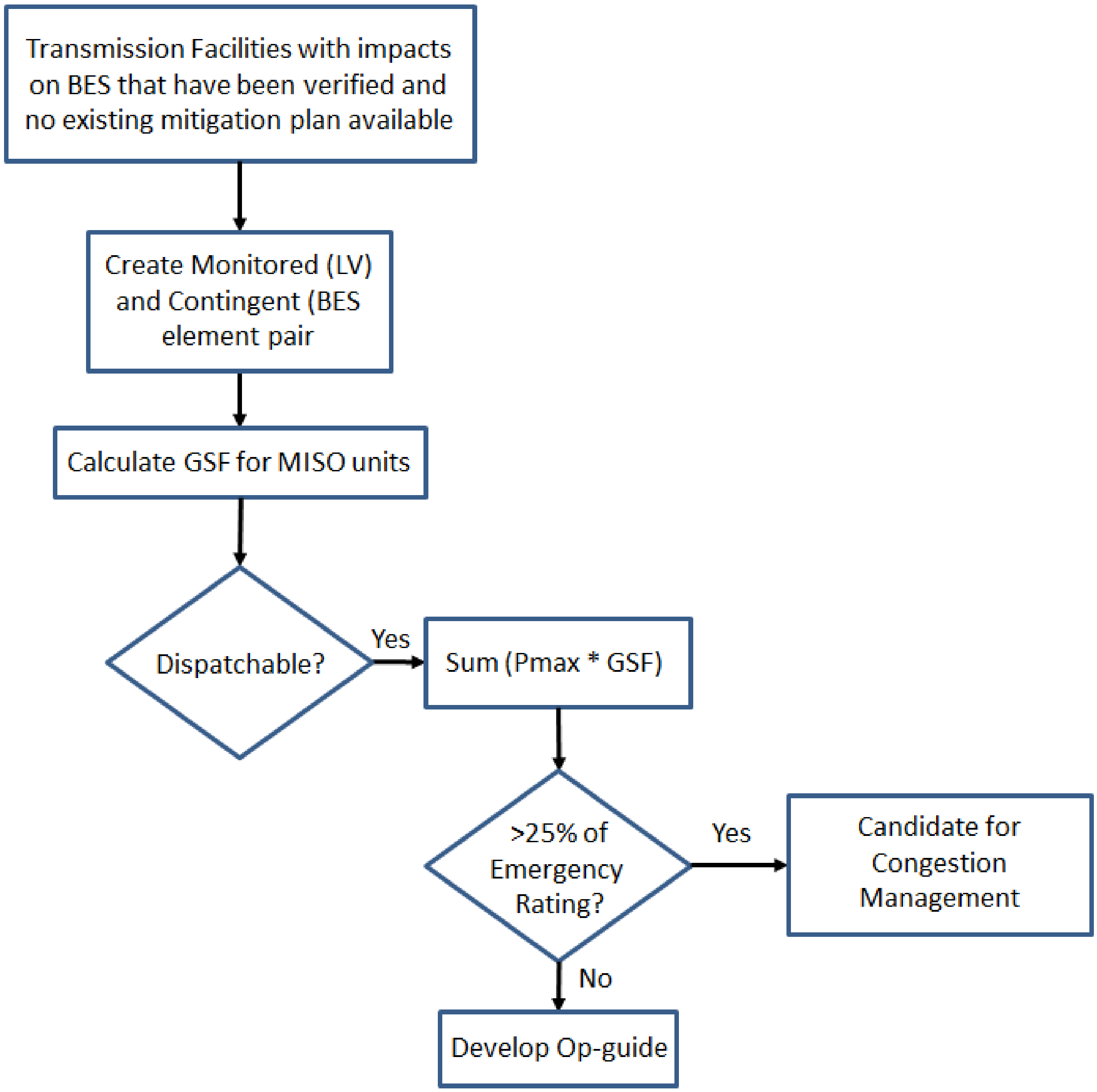


Figure P.9-3: Dispatch Responsiveness Test



P.10 Example of Impact Analysis on the MISO BES

- **Example 1:** *New BES overload caused by low voltage facility trip*
  - Contingency *Black-Orange 345 kV line No. 1* & Contingency *Red-Grey 138 kV line No. 2*
  - 1st N-1 contingency (Op. 10), open *Black–Orange 345 kV line No. 1*
  - No violations after 1st N-1 contingency
  - 2nd N-1 contingency (Op. 24), open *Red-Grey 138 kV line No. 1*
  - Violations after 2nd N-1 contingency
  - Voltage Violation, voltage level on the *East 138 kV Bus* is 0.88 p.u. (<0.9 by 0.02).
  - Thermal Violation, loading on the *West Sub M-West Sub N 69 kV line No. 1* is 54 MVA (114.9%, 47 MVA)
  - A 69 kV facility overload caused by the initial contingencies that are tripped in the subsequent cascading test.
  - **Step 1**: Remove the *West Sub M-West Sub N 69 kV line No. 1*
    - Voltage Violation, voltage level on the *East Sub Q 138 kV Bus* is 0.84 p.u. (<0.9 by 0.06)
    - Voltage Violation, voltage level on the *East Sub P 69 kV Bus* is 0.89 p.u. (<0.9 by 0.01)
    - Thermal Violation, loading on the *East Sub A-East Sub B 138 kV line No. 1* is 234 MVA (101.7%, 230 MVA)

New BES overloads results from the trip of the LV facility so cascading test is terminated. The new BES overload resulting from the low voltage facility trip passes impact criteria and the low voltage facility of the *West Sub M-West Sub N 69 kV line No. 1* is evaluated for LODF impact. LODF for the contingent element *Black–Orange 345 kV line No. 1* on the *West Sub M-West Sub N 69 kV line No. 1* facility is greater than three percent (>3%) so facility is included as candidate for monitoring.

- **Example 2:** incremental overload greater than five percent (>5%) of pre-existing BES overload
  - 'Contingency *Red-Blue 345 kV line No. 1* & Contingency *Yellow-Green 138 kV line No. 2*
  - 1st N-1 contingency (Op. 1), Open the *Red-Blue 345 kV line No. 1*
  - No violations after 1st N-1 Contingency (Op. 1)
  - 2nd N-1 contingency (Op. 17), Open the *Yellow-Green 138 kV line No. 1*
  - Violations after 2nd N-1 contingency:

- Voltage Violation, voltage level on the *East Sub Q 138 kV Bus* is 0.89 p.u. (<0.9 by 0.01)
- Thermal Violation, loading on the *East Sub A-East Sub B 138 kV line No. 1* is 240 MVA (104.3%, 230 MVA)
- Thermal Violation, loading on the *West Sub C-West Sub D 69 kV line No. 1* is 38 MVA (108.6%, 35 MVA)

Since *East Sub A-East Sub B 138 kV line No. 1* is a BES overload as a result of the initial BES contingencies this is flagged as pre-existing and not caused by the subsequent trip of the low voltage facility in subsequent steps. However, the 69 kV facility overload caused by the initial contingencies is tripped in the subsequent cascading test.

- **Step 1**: Remove the *West Sub C-West Sub D 69 kV line No. 1*
  - Voltage Violation, voltage level on the *East Sub Q 138 kV Bus* is 0.86 p.u. (<0.9 by 0.04)
  - Voltage Violation, voltage level in the *East Sub R 69 kV Bus* is 0.87 p.u.(<0.9 by 0.03)
  - Thermal Violation, loading on the *East Sub A-East Sub B 138 kV line No. 1* is 252 MVA (109.6%, 230 MVA)

No new BES overloads result from the trip of the LV facility and no further overloading occurs on the 69 kV facilities so the cascading test is ended. However, since the overload on the *East Sub A-East Sub B 138 kV line No. 1* is further increased by five percent (5%), this passes the impact criteria and the low voltage facility of the *West Sub C-West Sub D 69 kV line No. 1* is evaluated for LODF impact. LODF for the contingent element *Yellow-Green 138 kV line No. 1* on the *West Sub C-West Sub D 69 kV line No. 1* facility is greater than three percent (>3%) so facility is included as candidate for monitoring.

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's
First Request for Information
dated February 26, 2021

March 19, 2021

Item 35) ***Refer to the IRP, Chapter 6, Section 6.1, pages 110-111. Explain the actions that BREC has taken to reduce transmission losses. Include in the explanation the percent losses assumed in the forecasts and whether this has been reduced since the last IRP filing.***

Response) As a normal course of business, Big Rivers considers losses when specifying transformers and determining conductor sizes. However, actual losses can be impacted by many factors such as the system configuration, generation dispatch, parallel flows, *etc*. Losses included in the load forecast and Big Rivers' 2020 IRP are intended to reflect recently experienced actual losses. Losses were estimated at 2.3% in Big Rivers' 2017 IRP, and were 2.5% in our 2020 IRP.

Witness) Christopher S. Bradley

BIG RIVERS ELECTRIC CORPORATION

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2020 INTEGRATED RESOURCE PLAN OF
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March 19, 2021

Item 36) ***Refer to the IRP, Chapter 6, Section 6.2, page 111. Explain the factors affecting BREC's transfer capability and the extent to which they are controllable.***

Response) The transmission topology, generation dispatch, regional power flows and other factors all impact transfer capability. On a real–time basis, Big Rivers' ability to impact transfer capability is limited. Big Rivers has worked with MISO and neighboring utilities to develop operating guidelines that relieve real-time congestion when implemented. These operating guidelines may result in an increased transfer capability. Participation in MISO's MTEP process provides Big Rivers and others the opportunity to identify and evaluate projects that may provide long–term transfer capability improvements.

Witness) Christopher S. Bradley

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Item 37) ***Refer to the IRP, Chapter 8, page 134. Explain what is meant by the risk tolerance of the board.***

Response) Big Rivers' Board has established Big Rivers' mission to safely deliver competitive and reliable wholesale power and cost-effective shared services desired by its Member-Owners. The Big Rivers' six-member Board of Directors is comprised of two representatives from each Member-Owner. The Board strives to achieve its' mission by approving an annual strategic plan that emphasizes safety, excellence, integrity, teamwork, Member-Owners and community service, respect for employees, and environmental consciousness. Among other duties, Big Rivers' Board approves an Enterprise Risk Management Policy directing Big Rivers' management regarding risk management objectives; risk governance structure and responsibilities; and scope of business activities, associated risk management guidelines, and risk management policies. An example of risk management in the scope of business activities is Big Rivers' Board's preference to own economic generation resources to serve native load and to diversify the portfolio of generation resources to reduce the risk of reliance on a specific fuel source.

Witness) Mark J. Eacret

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March 19, 2021

Item 38) ***Refer to the IRP, Chapter 8 Section 8.1 page 134.***

a. Explain why retirement costs were modeled at zero expense.

b. Explain whether MISO constraints are modeled, and if so, identify those constraints.

Response)

a. The retirement costs were modeled at zero expense because they are a sunk cost, with the only difference being the time value of money between any differences in retirement dates as referenced on page 141 of Big Rivers' 2020 IRP.

b. There are no MISO constraints being modeled in the PLEXOS models. The constraints referenced in the statement on page 134 are the input and modeling constraints that are further explained in Section 8.2.1 – Base Case Inputs/Constraints on pages 148-155.

Witness) Paul G. Smith

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March 19, 2021

Item 39) ***Refer to the IRP, Chapter 8, Section 8.1, pages 134–135, and Section 8.2.2, page 155. Provide a more detailed explanation of the ST Plan functions and how it relates to the LT Plan optimal solution. Include in the explanation whether the ST Plan solution ever indicates that a selected LT Plan solution may not be optimal, and if so, explain how that might occur.***

Response) Only the LT Plan will solve for a least–cost solution that include changes in capacity (additions and subtractions). The ST Plan (*a.k.a.*, ST Schedule) provides revenue and cost output for a known portfolio (no changes in capacity are solved). The ST Plan does not provide a least–cost solution as it only solves for the dispatch of the known portfolio. Both the LT Plan and ST Plan provide hourly granularity in their analysis, but since the LT Plan is evaluating multiple options surrounding capacity changes to solve for a least–cost solution, the LT Plan model is much more complex and can take a very long time to solve.

To mitigate long model run times, the LT Plan has the ability to modify the hourly duration curve by a time period (day, week, month, quarter or year) and number of blocks in each duration curve. For example, if the "week" time period is selected with the number of blocks set as "two", the hourly values would be the same for each 3.5 days. If the duration curve settings are too lax and if different capacity options have close economics, the LT Plan least–cost solution could be different from if every hour was modeled.

In Big Rivers' 2020 IRP models, the LT Plan duration curve has a time period of one day with four blocks in each duration curve (modeled in six–hour blocks). The Preliminary LT Plan had the least–cost solution including exiting the SEPA[1] contract and adding more Natural Gas Combined Cycle ("NGCC") capacity. Big Rivers evaluated multiple portfolio options in the ST Plan and determined retaining the SEPA contract provided the optimal solution. In reviewing the output of each model, the LT Plan's setting of six–hour blocks was determined to not accurately reflect the four–hour daily minimum SEPA dispatch.

Witness) Duane E. Braunecker

[1] SEPA = Southeastern Power Administration.

Item 40) ***Refer to the IRP, Chapter 8, Section 8.1.1, page 136.***

a. ***Explain whether there were any additional scenarios run where additional ELG costs beyond those included in the 2019–2033 Long Term Financial Plan were required for the Green Station to be compliant and which rendered the Green Station uneconomic. If so, explain the results of the analysis, and if not, explain why not.***

b. ***Explain what additional ELG compliance costs beyond those included in the 2019–2033 Long Term Financial Plan might be incurred that would render Green Station uneconomic and how much tolerance is there before that point would be reached.***

c. ***If additional ELG compliance costs could render the Green Station uneconomic, then potentially, other units in MISO Region 6 or beyond could face similar fates. Explain whether BREC is aware of any studies within MISO Region 6 or beyond regarding the effects of CCR and ELG compliance that could affect forecasted energy and capacity prices and, if so, explain how those forecasted compliance cost effects could affect BREC.***

d. ***Explain whether BREC has preliminarily explored the option of converting the Green Station to natural gas fired and why potentially constructing a NGCC at Sebree is more cost-effective.***

e. ***If the Green Station were to be idled or retired, explain whether that would present problems satisfying nonmember contract obligations, and if not, explain how those contracts would be honored through the forecast period.***

Response)

a. There were no additional scenarios run for Green Station where additional ELG costs were included, beyond those included in the 2019–2033 Long–Term Financial Plan. Big Rivers is not aware of any additional ELG compliance costs for Green Station beyond the dry bottom ash requirement. Those costs were included in the 2019–2033 Long–Term Financial Plan and PLEXOS models. Since, Big Rivers is not aware of any additional ELG compliance cost for Green Station, there are no scenarios to be run.

b. Please see Big Rivers' response to sub–part a. Also, for clarification, the dry bottom ash requirement (additional ELG compliance cost for Green Station) was found to render the Green Station units uneconomic at current market expectations.

c. Big Rivers is unaware of any studies within MISO Zone 6 or beyond regarding the effects of CCR and ELG compliance on forecasted energy and capacity prices.

d. Big Rivers has studied converting the Green Station units to natural gas and found that constructing a Natural Gas Combined Cycle ("NGCC") plant is more cost effective due to the lower heat rate of a NGCC unit. In order to achieve a cost effective heat rate, the NGCC unit needs to be at least 600 MW capacity. However, as Big Rivers explains in its application in Case No. 2020-00079,[1] converting Green Station to natural gas is the best short-

[1] *In the Matter of: Electronic Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity Authorizing the Conversion of Green Station Units to Natural Gas-Fired Units and an Order Approving the Establishment of a Regularity Asset, Ky. P.S.C. Case No. 2021-00079* (March 1, 2021).

term option for alleviating a capacity deficit while Big Rivers pursues partners for the longer-term NGCC option.

e. If Green Station were idled without a replacement resource, nonmember contractual obligations could be satisfied with MISO market purchases of capacity and energy. For a complete discussion regarding Big Rivers' proposed project for a replacement resource – the conversion of the Green Station units to burn natural gas, which mitigates the inherent risk of MISO market purchases – see Big Rivers' application recently filed before the Commission in Case No. 2021-00079.

Witnesses) Nathanial A. Berry (*a., b., and d. only*) and
Mark J. Eacret (*c. and e. only*)

Item 41) ***Refer to the IRP, Chapter 8, Section 8.1.1 and 8.1.2, pages 137–141.***

a. ***Explain whether the cost of moving and installing the FGD scrubber from Coleman to Wilson and any degradation in MW output from operating the scrubber were included in the Wilson cost assumptions and, if not, why not.***

b. ***Explain the circumstances under which BREC would choose to exit the SEPA contract and how that capacity and energy would be replaced.***

c. ***Explain how BREC would make up the capacity and energy provided through the SEPA contract should it elect to exit the contract.***

d. ***Provide the capacity values MISO assigns to utility scale solar generation facilities over the forecast period.***

e. ***Explain all of the modeling parameters/assumptions supporting the generation option of a partnership with several other counterparties in a new 592 MW natural gas combined-cycle (NGCC)***

unit, including whether the new unit is located at either the Coleman or Sebree sites.

f. ***Explain why a partnership is necessary and the modeling option.***

g. ***Explain how a 237 MW natural gas combustion turbine (NGCT) was selected as an option and the circumstances of BREC needing that amount of peaking capacity.***

h. ***For both the NGCC and NGCT generation options, explain whether firm pipeline transportation cost was included as part of the option cost regardless of whether the commodity was purchased on a firm or spot basis.***

i. ***Explain whether the PPA – Block market purchases are modeled as long-term or short-term purchases and the rationale for the assumption.***

j. ***Explain why the PPA was marketed at only 10 MW increments.***

k. ***Explain why additional renewable energy generation options were not included for planning purposes.***

Response)

a. The costs of relocating the FGD scrubber from Coleman to Wilson are not included in Big Rivers' 2020 IRP PLEXOS models due to the start date being 2024. The FGD scrubber installation will be completed in the spring of 2022. The lower variable costs due to the scrubber location (market gypsum and market fly ash sales) and the five MW higher auxiliary power (417 MW to 412 MW) were included in the IRP models.

b. Big Rivers would exit the SEPA contract if it were beneficial to its Member-Owners. The energy and capacity would be replaced with a more economic option either by another generation resource, or by purchasing from the market or another party.

c. Please see response to sub–part b.

d. For the Base Case, Big Rivers utilized the current MISO Business Practice Manual to calculate the solar firm capacity utilizing the projected solar load profile. An annual 0.5% capacity degradation was modeled. Please see table below showing the projected firm capacity for each solar facility.

Big Rivers Electric Corporation Projected Solar Firm Capacity (MWs)			
Year	**Henderson**	**McCracken**	**Meade**
2024	116.14	49.43	31.10
2025	115.34	49.13	30.90
2026	114.54	48.83	30.70
2027	113.74	48.53	30.50
2028	112.94	48.23	30.30
2029	112.14	47.93	30.10
2030	111.34	47.63	29.90
2031	110.54	47.33	29.70
2032	109.74	47.03	29.50
2033	108.94	46.73	29.30
2034	108.14	46.43	29.10
2035	107.34	46.13	28.90
2036	106.54	45.83	28.70
2037	105.74	45.53	28.50
2038	104.94	45.23	28.30
2039	104.14	44.93	28.10
2040	130.34	44.63	27.90
2041	102.54	44.33	27.70
2042	101.74	44.03	27.50
2043	100.94	43.73	27.30

e. The 592 MW NGCC unit was modeled with the option to be built at the Sebree site or the Coleman site. Table 8.5 on page 147 of Big Rivers' 2020 IRP provided the fixed O&M cost and build cost for each site, with the Coleman site having higher build cost projection and much higher gas service cost. The LT Plan model can select the NGCC – Sebree or NGCC – Coleman options at 10 MW increments, which have the same cost, up to the full size of the unit. Big Rivers' optimal plan includes 90 MW of the NGCC unit located at Sebree which would require partners for the other 500 MW.

f. The 592 MW NGCC unit is just too large for Big Rivers' needs and its goal of diversifying its generation portfolio. Big Rivers just spent the last seven (7) years right sizing its portfolio to balance its generation and load. Big Rivers has no desire to voluntarily place the Company back in that position. A smaller NGCC unit would not have the economies of scale of the larger NGCC unit; therefore, the need for Big Rivers to find partners arises.

g. The 237 MW size for the NGCT was chosen because that was the size of the unit in the EIA[1] data where the cost and operational data was obtained.

h. Both the NGCC and NGCT generation options have gas line transportation costs included. For the firm gas models, the pipeline transportation costs are treated as a fixed cost as pipeline costs occur whether gas is being

[1] EIA = United States Department of Energy's Energy Information Administration.

consumed or not. For the spot gas models, the pipeline transportation costs are a variable cost and are added to the spot gas price as a delivery charge.

i. The PPA – Block market purchases were modeled so that any increment of 10 MWs (up to 800 MWs) could be acquired for any time frame at the market projections. The LT Plan models are capable of modifying the PPA – Block size either larger or smaller for shorter or longer durations if the PPA – Block unit provides a least-cost solution.

j. The 10 MW increment for the PPA – Block market was chosen because it was a size that is small enough for meaningful model results and large enough to not cause very long LT Plan model run (solve) times.

k. Other sources of renewable energy options, such as wind, are not economically feasible for Big Rivers at this point in time.

Witness) Duane E. Braunecker

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Item 42) ***Refer to the IRP, Chapter 8, Section 8.1.1, page 138. Explain and provide a table showing the amount of time annually each of BREC's generation units' cost are at or below the MISO market price and hence economically dispatched, and the amount of time these units are above the market price and hence ramped down to minimum levels for the last three years. Include in the explanation whether the units are considered "must run" for transmission system support in Region 6 and how this affects the decision to run the units at higher levels even if the unit variable cost is greater than the market clearing energy price.***

Response) In accordance with the MISO Resource Adequacy provisions in tariff Section 69A.5, each day Big Rivers submits a self-schedule or offer in the Day-Ahead energy and operating reserve market, except to the extent that the resource is unavailable. MISO's required offers consist of startup, no load and incremental energy costs.

MISO's market clearing engines use these offers to commit resources and clear the energy and operating reserve markets in an optimal manner to produce the lowest–cost power, subject to physical limitations, reliability requirements and good utility practice. MISO's clearing engines include simultaneously co-optimized Security Constrained Unit Commitment ("SCUC") and Security Constrained Economic Dispatch ("SCED") algorithms[1]. The Day-Ahead SCED algorithm is used to clear and price the Day Ahead Energy and Operating Reserve Market and is executed sequentially for each individual hour in the Day Ahead market subsequent to the execution of the Day Ahead SCUC algorithm. MISO uses calculators to generate real-time ex-ante prices prior to the end of the 5-minute dispatch interval and ex-post prices to generate five-minute real-time ex-post prices.

After-the-fact calculations of generation units' costs below hourly market price are not the only determinant of dispatch, just as unit cost above the market price is not the only driver of units being ramped to minimum. As mentioned above, MISO's SCUC and SCED algorithms consider physical limitations of both the transmission system and the availability of the particular generator in determining the requested dispatch level of each generator. Generator availability is influenced by periodic

[1] See MISO Business Practice Manual BPM-002-Energy and Operating Reserve Markets available on MISO website https://www.misoenergy.org/legal/business-practice-manuals/

maintenance, testing, and other operational issues which occur from time to time. Big Rivers must consider physical limitations such as number of starts for a unit over its' lifetime when considering unit commitment, and sometimes keeping a unit running at a minimal loss for a short period, such as overnight, is ultimately to the Member's benefit rather than cycling a unit off and on daily. Unit testing requirements, fuel inventory levels, and system congestion issues might also drive a decision to run a unit out of economic order. Regarding whether MISO considers the units "must run" for transmission support, as a Market Participant submitting offers of generation, Big Rivers would not be explicitly aware that MISO's commitment or dispatch of a unit was due to transmission reliability issues rather than economics, except if MISO commits a unit at below cost and supplements the generator with make whole payments.

The table in the attachment to this response presents the percentage of hours that the Locational Marginal Price at each coal unit exceeded the average annual fuel cost during hours in which the unit was not on outage. During those hours, the units were always submitted to MISO on Economic dispatch. Note that the 2020 figures in the table were impacted by low LMP's during the depths of the COVID pandemic.

Witness) Marlene S. Parsley

Big Rivers Electric Corporation
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Percentage of Hours Generating Above and Below Market, Idle, and on Outage

	Green 1				Green 2				Wilson			
	LMP>Cost	LMP<Cost	Idle	Outage	LMP>Cost	LMP<Cost	Idle	Outage	LMP>Cost	LMP<Cost	Idle	Outage
2018	52.4%	35.8%	1.6%	10.1%	58.7%	38.0%	0.8%	2.5%	40.5%	27.3%	1.0%	31.2%
2019	38.2%	40.7%	9.7%	11.5%	34.7%	38.0%	23.2%	4.1%	40.7%	43.9%	7.4%	8.0%
2020	21.0%	39.9%	36.9%	2.2%	13.3%	19.8%	64.1%	3.1%	30.7%	50.6%	8.0%	10.7%

Item 43) ***Refer to the IRP, Chapter 8, Section 8.2, Table 8.7, page 154, and Appendix A, Load Forecast Study, Tables "Total Native System Energy Summary" and "Historical and Projected CP Demands," pages 35 and 41, respectively.***

a. Explain why the energy and peak numbers do not match between the tables.

b. The forecast periods shown between the tables are different. Explain what period covers the forecast period in the IRP.

c. Explain whether nonmember load obligations and or transmission losses are included in the Base Case forecast shown in Table 8.7, and if not, explain why not.

d. Also, refer to the Load Forecast Study, Native System Weather Scenarios table, page 51. For the Base Case, explain why winter forecast amounts do not match those in the Historical and Projected CP Demands table on page 43.

Response)

a. Please see Big Rivers' response to sub–part c.

b. The load forecast covers the period from the present through 2039. In the PLEXOS IRP models, the twenty (20) year period beginning with 2024 through 2043 was chosen. The 2024 start was chosen to allow for capacity additions as they are not likely to be able to be completed before 2024; the 2043 end was chosen because it represents the end of Big Rivers' all requirements contracts with its Member-Owners.

c. Non-Member load obligations and transmission losses are not included in the Base Case forecast shown in Table 8.7. Big Rivers believes that long-term resources are not the most cost-efficient approach to fulfill Non-Member load obligations. The OMU and Nebraska contracts will end in [redacted] and KYMEA contract expires in [redacted].[1]

[1] OMU = Owensboro Municipal Utilities; Nebraska contracts are with the Cities of Wakefield and Wayne, Nebraska, and with the Northeast Nebraska Public Power District; KYMEA = Kentucky Municipal Energy Association.

As discussed in Big Rivers' Application in Case No. 2021-00079,[2] converting the two generating units at its Green Station to burn natural gas will not only meet Big Rivers' short-term needs, but also allow Big Rivers to retain flexibility in the resource options to meet its long-term needs.

Transmission losses were not included in the PLEXOS IRP models because the PLEXOS IRP models work exactly the way the MISO market works. For energy, MW volumes are equal throughout the MISO footprint, *i.e.*, 1 MW of generation at one node (location) equals 1 MW of load at the load node (location). MISO accounts for the losses (transmission) in the Locational Market Price ("LMP") pricing which is accounted in PLEXOS with the LMP price inputs. For peak demand, the transmission losses are accounted for in the reserve margins requirements in MISO and the inputs being used in PLEXOS.

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[2] See *In the Matter of: 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. P.S.C. Case No. 2021-00079.

d. There is no direct comparison between these two tables for winter peak. "Native System Weather Scenarios" on page 51 shows the Big Rivers system winter peak. "Historical and Projected CP Demands" on page 43 shows the Rural system winter peak in column "Rural System CP". Column "Total Annual CP" in table "Historical and Projected CP Demands" on page 43 only represents the winter peak during years 2015, 2018, and 2019 when the annual peak was a winter peak. For all other years, the base winter values derived on page 51 are a sum of the winter Rural system CP, winter Direct Serve CP, and winter transmission losses.

Witnesses) Duane E. Braunecker (*a., b. and c. only*),
Matthew S. Sekeres (*d. only*) and
Steven A. Fenrick (*d. only*)

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Item 44) ***Refer to the IRP, Chapter 8, Section 8.1, pages 134–135, and Section 8.2.2 pages 155–156. The least cost LT Plan, in part, calls for idling both Green coal units and adding 90 MW of a new 592 MW NGCC unit at Sebree in 2024.***

a. Confirm that BREC does intend to idle both Green units and provide the anticipated date when the units will be idled.

b. Explain whether there are or have been any discussions with potential partners in a joint venture to construct a NGCC unit or units at the Sebree Station, and if so, the status of those discussions. Include in the discussion whether 2024 is the date the ST Plan and LT Plan estimate that the NGCC unit will be operational, and if not, provide when BREC estimates the unit will be operational.

c. Provide a table for the entire forecast period from 2020–2043 showing the timeline for the capacity additions and idling the Green or Reid Stations for each of the ST Plan scenarios annually.

Response)

a. In order to meet Effluent Limitation Guidelines ("ELGs") and have the Green Station ash pond closed by October 2023, the Green coal units are scheduled to be idled by June 2022. Since the filing of Big Rivers' 2020 IRP in September 2020, Big Rivers separately has filed an application seeking the Commission's approval, among other things, to convert the Green units to burn natural gas, which would lower the inherent risk of securing capacity through the MISO market, as well as providing additional benefits fully discussed in Big Rivers' recently filed Application in Case No. 2021-00079.[1]

b. Yes, Big Rivers has had discussions with potential partners on a joint venture for a NGCC unit. So far, interested parties have been non-committal, and taken a wait–and–see approach. In the PLEXOS models, the anticipated start date for the NGCC unit was January 2024. As time

[1] *See In the Matter of: 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,* P.S.C. Case No. 2021-00079, Application (filed March 1, 2021).

progresses without committed partners and build plans, the NGCC start date continues to push out.

c. The PLEXOS ST Plan model does not solve for capacity additions/subtractions as the portfolios (capacity changes) were inputs for the ST Plan. Also, the Big Rivers 2020 IRP PLEXOS models started in year 2024, the year all capacity changes were made for the duration of the horizon (2024 to 2043). The firm capacity for each short term plan portfolio can be seen in the tables located in Appendix G, Short Term Plan, pages G-7 to G-9. The table attached to this response summarizes the capacity changes for the short term plan portfolios.

Witnesses) Nathanial A. Berry (*a. and c.*)
Mark J. Eacret (*b.*)

Big Rivers Electric Corporation Short Term Plan Capacity Changes (2024-2043)						
Portfolio	**Wilson**	**Green**	**Reid CT**	**SEPA**	**Solar**	**NGCC**
Status Quo (Wilson, RCT, SEPA, Green)	Run	Run	Run	Run	None	None
+ Solar	Run	Run	Run	Run	260 MW	None
+ Solar, Green Idled	Run	Idled	Run	Run	260 MW	None
+ Solar, Green and Reid CT Idled, Exit SEPA, + 330 NGCC Sebree	Run	Idled	Idled	Exit	260 MW	330 MW
+ Solar, Green Idled, + 90 NGCC Sebree	Run	Idled	Run	Run	260 MW	90 MW
+ Solar, Green and Reid CT Idled, + 150 NGCC Sebree	Run	Idled	Idled	Run	260 MW	150 MW
+ Solar, Green Idled and Exit SEPA, + 260 NGCC Sebree	Run	Idled	Run	Run	260 MW	260 MW

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Item 45) ***Refer to the IRP, Chapter 8, Section 8.2.2, pages 155–156, and Load Forecast Study, Section 5, pages 49–53. Explain how the LT Plan and ST Plan optimal results are affected by the four various weather and economic scenarios.***

Response) Big Rivers elected to use the base load forecast for the PLEXOS models (LT Plan and ST Plan) due to the minimal effect the four various weather and economic scenarios would have on the results. Big Rivers' optimal (least–cost) plan included idling the Green coal units and partnering in 90 MW of a 592 MW NGCC unit. In the LT Plan models, the four various weather and economic scenarios would not change the least–cost solution, and only the MW amount of the NGCC unit would vary by the difference in the various load forecasts (*i.e.*, higher amount of NGCC for loads higher than the base forecast and lower amount of NGCC for loads less than the base forecast). For the ST Plan models, the optimal results will not be affected by the weather and economic scenarios.

Witness) Duane E. Braunecker

Item 46) ***Refer to the IRP, Appendix A, Load Forecast Study, Section 2.1.1, pages 17–18, and Section 7.1, pages 57–58.***

a. Provide an overview of the economic and demographic conditions currently and what is projected over the forecast period for BREC and the Member Systems.

b. Provide a more complete explanation of how county level demographic and economic data from Woods & Poole, Inc. was tailored to fit each Member System's specific service territory.

c. Provide an explanation of why the number of residential consumers begin declining in 2028.

Response)

a. Please see Big Rivers' 2020 IRP, Appendix A, Load Forecast Study, page 59, which provides a description of the economic drivers and forecasted growth trajectory of each driver. Please refer to the **CONFIDENTIAL** Excel file provided in response to Item 10 of the Commission Staff's First Request for Information for the full–time-series of values.

b. Each Member System supplied reports containing either total accounts by county or, if available, residential class accounts by county. The Member Systems also supplied estimates for the percentage of the account totals provided that would be considered primary households. By multiplying these two inputs, Clearspring created estimates for the number of primary households serviced by each Member System in each county. Then, by dividing the number of primary households serviced by the total number of households in the county (obtained by Woods & Poole), Clearspring arrived at estimates for the total percentage of each county served by each Member System. Each county level economic and demographic variable used from Woods & Poole was then built up from the county level as a 'sum product' of each county total multiplied by each percentage of the county served. Please see Big Rivers' response to Item 49b. and Item 49c. for the Commission Staff's First Request for Information for a numerical illustration of this process.

c. The Residential consumer forecast projections are directly derived from the households projected by Woods & Poole for each Member System's service territory. Woods & Poole does not disclose their proprietary models, so it is difficult to provide quantifiable impacts of each contributing factor. The Woods & Poole population forecast is dependent on employment opportunities and historical population growth in each geographic region. While population forecasts do not exactly match households, the population forecasts would reflect a similar trajectory to households.

Witnesses) Matthew S. Sekeres and
Steven A. Fenrick

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Item 47) ***Refer to the IRP, Appendix A, Load Forecast Study, Section 2.1.1, pages 17, 19, and 62, and Appendix, pages 89, 93, and 97. AC saturation, AC efficiency, electric heat saturation, and heating efficiency are the only data relating to the effects of appliance and equipment efficiency gains that would affect load growth.***

a. Provide any studies which compare and contrast the efficacy of straight econometric models and statistically adjusted end use (SAE) models.

b. Explain why BREC chose to forego use of SAE models in its residential and commercial class load forecasts.

c. Explain the source of the AC and heating efficiency data.

d. Explain the meaning of AC and heating efficiency.

e. Explain why greater use of the data in the end use survey was not incorporated into the models.

Response)

a. A recent research paper produced by the Lawrence Berkeley National Laboratory ("LBNL") titled *Load Forecasting in Electric Utility Integrated Resource Planning* examined the results of utilities that employed the econometric and SAE approaches. In examining the LBNL calculations on forecasting errors, there are no significant advantages in forecasting accuracy to employing SAE models versus econometric methods when forecasting energy loads. According to the LBNL study, the econometric approach did have considerably lower errors in regard to forecasting peak demand average annual growth rates. The econometric approach is more widely used within the electric utility forecasting industry and provides a more transparent understanding of the specific variables and their impacts to calculate the forecast. In the LBNL research, Clearspring noticed that the two utilities that used SAE models exclusively were much larger in size than the utilities that used the econometric approach. In Clearspring's load forecasting experience, larger utilities with more load diversity tend to be easier to forecast accurately in terms of average percent error. Despite this advantage in the LBNL sample, the SAE method is not conclusively better in terms of percent errors than the econometric approach and, in some cases, performs worse. To Clearspring's knowledge, there is no evidence that a SAE model will produce a more accurate forecast than a well-specified econometric model and the econometric method is our preferred approach. Clearspring's forecasts did incorporate end-use components such as heating and air conditioning survey saturations and efficiency projections and empirically estimated the impacts of those end-use components econometrically. The LBNL study can be found at the following link: https://emp.lbl.gov/publications/load-forecasting-electric-utility

b. Please see Big Rivers' response to sub-part a.

c. The source of the data is the United States Department of Energy's Energy Information Administration ("EIA") Annual Energy Outlook ("AEO") report. For the 2020 data and forecasts, these data can be found in the 2020 edition of the AEO report, Table 21 titled, "Residential Sector Equipment

Stock and Efficiency, and Distributed Generation". Efficiency data used prior to 2020 were gathered from AEO reports of those specific years. The link to the 2020 AEO report can be found here: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=30-AEO2020&sourcekey=0

d. The inclusion of the efficiency measures into the models is to capture the impacts on residential electricity use when residential end-use appliances become more efficient over time and require lower inputs of electricity per output delivered by the appliance. The stock of AC units and heating units is projected to become more efficient during the forecast period and the impact on residential use per consumer is estimated and incorporated into the load forecast.

The EIA AEO uses the measure of SEER for capturing AC efficiency. The EIA defines SEER as, *"Seasonal Energy Efficiency Ratio: The total cooling of a central unitary air conditioner or a unitary heat pump in Btu during its normal annual usage period for cooling divided by the total electric energy input in watt-hours during the same period."*

The EIA AEO uses the measure of HSPF for capturing residential space heating efficiency. The EIA defines HSPF as, *"Heating Seasonal Performance Factor: The total heating output of a heat pump in Btu during its normal annual usage period for heating divided by total electric input in watt-hours during the same period."*

e. According to the EIA's Office of Energy Consumption and Efficiency Statistics, May 2018 Table CE5.3a, space heating and air conditioning are two of the three largest sources of end–use consumption in the East South Central region of the United States. The other large source would be electric water heating. Electric space heating average annual kWh use per household is estimated at 3,991 kWhs. Air conditioning is estimated at 2,640 kWhs and electric water heating at 3,476 kWhs. Clearspring attempted to include electric water heater saturations into the modeling, but it produced incorrectly signed coefficients. This is likely due to the high correlation (*i.e.*, multicollinearity) with electric space heating in residences. The next closest end–use source is pool pumps at 1,329 kWhs but the low saturation levels in Big Rivers' service territory, plus end–use survey data only being collected on pool pumps since 2017, limits the usefulness of including this variable. The next highest end–use is lighting at 1,200 kWhs. While household lighting load has diminished with the advent and incorporation of LEDs, Clearspring did not have a strong survey-derived variable to incorporate and forecast the efficiency gains from this end-use.

While an advantage of the econometric approach is that it explicitly estimates the impacts of variables on electricity use per consumer, there is a limit to the number of variables that can and should be included due to concerns over forecast accuracy, multicollinearity, and available degrees of freedom. Clearspring included two of the three largest end–uses available through Big Rivers' residential end-use appliance survey data and combined those with forecasted efficiency gains from the EIA.

Witnesses) Matthew S. Sekeres and
Steven A. Fenrick

Item 48) ***Refer to the IRP, Appendix A, Load Forecast Study, Section 2.1.1, pages 17, 19, and 62, and Appendix, pages 89, 93, and 97.***

a. ***On pages 18–19, when comparing the historical periods in the graphs, the number of customers is increasing and the use per consumer shows substantial variability with a downward trend. However, the use per consumer projection is virtually flat.***

(1) Referring also to pages 21 and 25, the number of GCI and LCI consumers increases and holds steady respectively. Explain why the number of residential consumers declines beginning in 2028.

(2) Provide an explanation of what is driving the variability and pronounced negative trend in the historical use per customer observations.

(3) Provide an explanation of why the projected use per consumer is virtually flat and, essentially, a slightly negative trend line from the last historical data point.

b. ***Provide a table showing both the weather normalized and actual data used to calculate the use per customer for 2008–2019.***

c. Explain the residential class price variable and identify the components of the residential price and the alternate fuel price including variable units. Include in the explanation why that variable appears to be the only variable that is in log form.

d. Explain the January through December variables in the models.

e. Explain the rationale for and the advantages of forecasting residential load growth directly versus as the product of forecast consumers and use per consumer and whether a comparison was conducted to demonstrate the efficacy of this method.

Response)

a.

(1) Please see Big Rivers' response to Item 46, sub–part c, of the Commission Staff's First Request for Information for a description of the residential consumer forecast. There are many reasons why GCI and LCI consumer growth rates would not, or should not be expected to, match a residential consumer growth rate on the same system.

Residential consumers represent the number of households in the region. This can deviate from population trajectories due to fluctuations in the system–wide people–per–household or changes in the population of group living facilities, *e.g.*, prisons, retirement homes, college dormitories and military barracks. Population can further deviate from employment due to shifts in the working age population or average age of retirement. Changes in workforce productivity over time can also have an impact on commercial consumer values. Even though households are remaining mostly flat during the final decade of the forecast period, population is growing by a very minimal amount with additional increases to employment and GRP driving additional commercial growth.

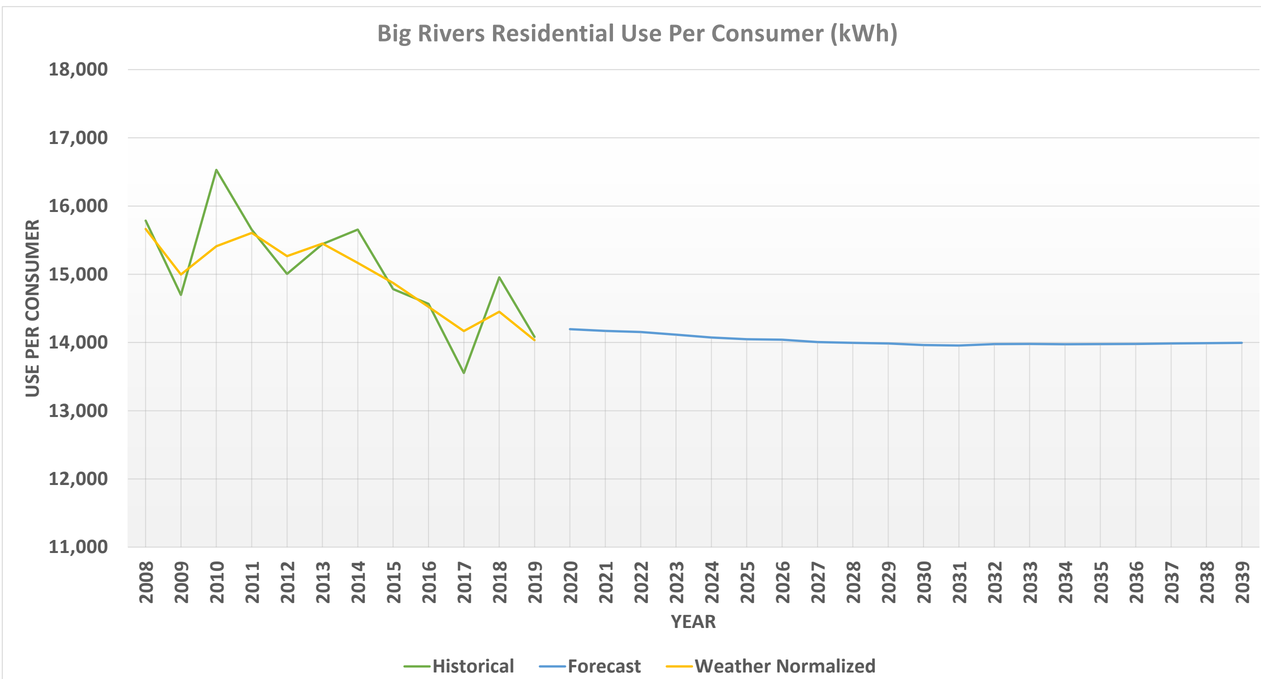
In the ten (10) years before the forecast, *i.e.*, 2009-2019, Residential consumers grew by a total of 2.9%. In the twenty (20) years before the forecast, *i.e.*, 1999-2019, Residential consumers grew by 13.4%. In this same time periods, GCI consumers grew by 20.4% over ten (10) years and 79.8% over twenty (20) years.

(2) The variability and decline in historical Residential use per consumer is explained by increases in appliance efficiency, changes in electricity and alternate fuel prices, and weather.

(3) Further increases to appliance efficiencies place the Residential use per consumer values on a declining trajectory during the early years of the forecast period. During the later years of the forecast period, the marginal efficiency gain is less with each year and is balanced by the upward pressure on usage caused by a decrease in the relative cost of electricity.

b. Please see the table and the graph which follow.

Big Rivers Electric Corporation 2020 Integrated Resource Plan Clearspring – Data for Use–per–Customer Calculation		
Year	**Actual Residential Use Per Consumer (kWhs)**	**Weather Normalized Residential Use Per Consumer (kWhs)**
2008	15,786	15,664
2009	14,696	14,996
2010	16,531	15,411
2011	15,653	15,608
2012	15,006	15,266
2013	15,443	15,450
2014	15,654	15,168
2015	14,783	14,872
2016	14,565	14,521
2017	13,553	14,168
2018	14,955	14,450
2019	14,083	14,033



c. The residential price variable has a numerator that is calculated based on residential revenue adjusted in 2019 dollars divided by residential kWh sales. The denominator is the alternative fuel price index. This alternative fuel price index is constructed by combining the 2019 adjusted prices for natural gas and propane using a Törnqvist-Theil price index that is a popular indexing method when combining time trends of multiple price elements. Please see the following link to the OECD Glossary of Statistical Terms for a description: https://stats.oecd.org/glossary/detail.asp?ID=2711. Big Rivers' end–use appliance surveys were used as the appliance shares in weighting the changes in prices over time from natural gas and propane, respectively. The alternative fuel prices were gathered from the United States Department of Energy's Energy Information Administration. The price variable was logged to provide a price elasticity estimate. A price elasticity indicates the percentage of electricity reduction per percentage in the price ratio of the electricity price to the alternative fuels.

The following equations summarize the residential class price variable.

$$Price\ Variable = \frac{Residential\ Electricity\ Price}{Alternative\ Fuel\ Price\ Index}$$

$$Residential\ Electricity\ Price = \frac{\left(\frac{Residential\ Revenue}{CPI_{2019=1.00}}\right)}{Residential\ kWh\ Sales}$$

$$Alternative\ Fuel\ Price\ Index = \ Alternative\ Fuel\ Price\ Index_{t-1} * \exp[(\frac{(Sat\ \%_{NG})}{(Sat\ \%_{NG} + Sat\ \%_{Prop})}) * \ln\left(\frac{Real\ Price_t^{NG}}{Real\ Price_{t-1}^{NG}}\right) + (\frac{(Sat\ \%_{Prop})}{(Sat\ \%_{NG} + Sat\ \%_{Prop})}) * \ln\left(\frac{Real\ Price_t^{Prop}}{Real\ Price_{t-1}^{Prop}}\right)],$$

where the Alternative Fuel Price Index is set to 1.00 in 1999.

d. These are intercept terms estimated specifically for each month. Given that Clearspring's models are based on monthly data, it is best to include monthly intercepts that capture the use–per–consumer monthly patterns and differences. For various behavioral reasons due to weather, school/work schedules, and other items, consumer electricity use will be different based on the differing months of the year. Including these binary variables as intercept terms increases the accuracy of the monthly models by capturing and estimating these differences.

e. To clarify, Clearspring forecasted numbers of consumers and use–per–consumer separately and then took the product of those two forecasts. This is the preferred approach as the models can isolate the separate causes and provide better forecasts of the two separate components of use–per–consumer and consumer counts.

Witnesses) Matthew S. Sekeres and
Steven A. Fenrick

Item 49) ***Refer to the IRP, Appendix A, Load Forecast Study, Section 2.1.1, page 18.***

a. ***Further explain how the various weights, which were based on the number of Residential customers served by each Member System were derived and which economic and demographic variables, were modified with the weights.***

b. ***Provide a numerical example to illustrate the process of modifying county level data to fit within a member's service territory.***

c. ***Provide a list of economic and demographic variables taken from Woods & Poole Economics, Inc., and if known, explain how the county level data was derived.***

Response)

a. Please see Big Rivers' response to Item 46, sub–part b. of the Commission First Request for Information for the description of how the county weights were derived. The list of modeling variables using this weighting technique includes households, GRP, total employment, and total retail sales. All remaining modeling variables that were used do not use this technique because the source data are not at the county level.

b. The following is a hypothetical example to illustrate the county weighting process.

i. A Member System submits account values by county for their residential class.

ii. A Member System submits an estimate for the percentage of accounts submitted that represent primary household accounts.

iii. Clearspring calculates the households served by county.

iv. Clearspring compares households served to total households in the county obtained from Woods & Poole Economics, Inc. ("Woods & Poole").

v. All other county level variables are aggregated using the percentage of each county served.

The table on the following page further illustrates this process.

Big Rivers Electric Corporation
2020 Integrated Resource Plan
Clearspring County Weighting Process Illustration

Step		County X	County Y	County Z
i.				
	Residential Accounts in County	3,000	2,000	1,000
ii.				
	Percentage Estimate of Primary Households in County	90%	90%	90%
iii.				
	Residential Accounts Served [a]	3,000	2,000	1,000
	Primary Household Multiplier [b]	90%	90%	90%
	Primary Households Served [a **x** b]	2,700	1,800	900
iv.				
	Primary Households Served [a]	2,700	1,800	900
	Total Households in County (from Woods & Poole) [b]	10,000	5,000	5,000
	Percent of County Served [a **/** b]	27%	36%	18%
v.				
	Total Employment in County (from Woods & Poole) [a]	12,000	6,000	4,000
	Percent of County Served [b]	27%	36%	18%
	Employment Served [a **x** b] [1]	3,240	2,160	720

[1] Total Member System Employment Served is 6,120 = 3,240 + 2,160 +720.

c. The modeling variables used from Woods & Poole are households, GRP, total employment, and total retail sales. Woods & Poole cites the historical sources for these variables as follows:

i. Households – United States Census Bureau,
ii. GRP – United States Department of Commerce, Bureau of Economic Analysis,
iii. Employment – United States Department of Commerce, Bureau of Economic Analysis, and
iv. Retail Sales – Census of Retail Trade (United States Department of Commerce, Bureau of the Census).

Woods & Poole develops economic and demographic forecasts for Untied States economic regions, and then applies those forecasts to state and county-level forecasts using a proprietary four–stage forecasting and allocation methodology. The methodology is described in detail in Woods & Poole's documentation accompanying the forecasts.

Witnesses) Matthew S. Sekeres and
Steven A. Fenrick

Item 50) ***Refer to the IRP, Appendix A, Load Forecast Study, Section 2.2.1.1, page 22, and Appendix pages 90, 94, and 98.***

a. ***Explain the region encompassed by the GRP variable prior to being modified to fit each member's service territory.***

b. ***Explain how the GRP variable was modified to fit each member's service territory.***

c. ***Explain why a retail sales variable was not used in the JPEC General C&I Consumer Model on page 90 and the meaning of the January 1990–July 2015 variable.***

d. ***Explain the January–December variables in the use per consumer models.***

e. ***Explain the components that make up the C&I price variable.***

f. ***Explain whether the data is weather normalized and provide a comparison of the historical use per customer on a weather normalized and actual basis.***

g. Referring to the graph on page 23, the historical data shows a significant decline in use per consumer while the projection is essentially a flat trend line from the last historical data point. Explain the rationale for such a flat projection.

h. Presumably, small commercial and industrial consumers use appliances and equipment that will experience efficiency gains over the forecast period. Explain why BREC does not include these consumers in its end use surveys.

i. Provide a copy of the 2019 residential end use survey and the results of the survey, and explain how the survey results are utilized by each Member System.

Response)

a. The GRP variable was developed by Woods & Poole, Inc. at the county level.

b. The GRP variable was designed to fit each Member–Owner's service territory using the county weighting process described in Big Rivers' response to Item 49, sub–part b. of the Commission Staff's First Request for Information.

c. When the retail sales variable is included in the GCI Consumer Model for Jackson Purchase Energy Corporation, the parameter estimate is incorrectly signed. It is negative when it is expected to be positive. For this reason, Clearspring did not include the variable in the model.

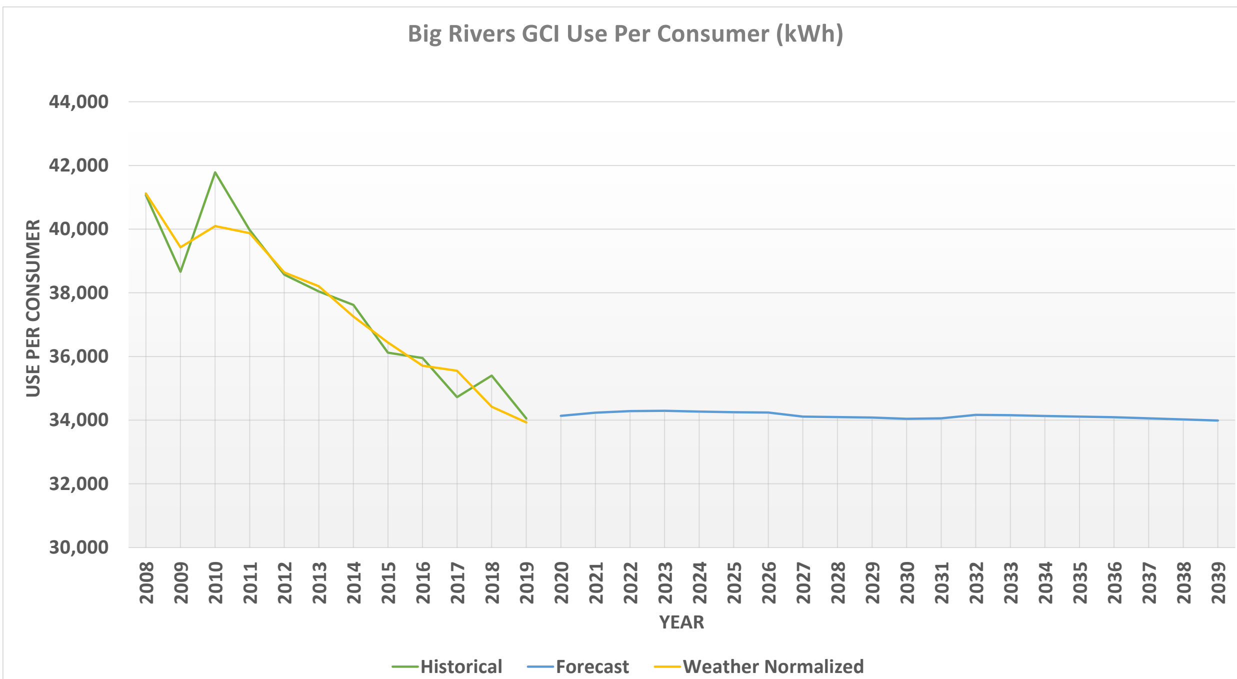
Jackson Purchase Energy Corporation appears to have gone through an account reclassification ending around July 2015 that involves residential accounts being reclassified as GCI over the preceding months. This variable is included to capture the sudden shift in consumers during that period.

d. These are intercept terms estimated specifically for each month. Given that Clearspring's models are based on monthly data, it is best to include monthly intercepts that capture monthly patterns and differences in the use per consumer. For various reasons due to weather, commercial work schedules, and other items, consumer electricity use will be different based on the differing months of the year. Including these binary variables as intercept terms increases the accuracy of the monthly models by capturing and estimating these differences.

e. The historical C&I prices are calculated as total GCI revenue divided by total GCI sales. Projected growth rates are derived using both Big Rivers' wholesale price forecasts and regional retail commercial rate projections from the Unites States Department of Energy's Energy Information Administration.

f. The reference for this question appears to be consumer values. Consumer values are not weather normalized. It is assumed that weather does not have any impact on consumer values. A weather normalization for GCI use–per–consumer is provided in the table and graph on the following pages.

Big Rivers Electric Corporation 2020 Integrated Resource Plan Clearspring – Data for GCI Use–per–Customer Calculation		
Year	**Actual GCI Use Per Consumer (kWhs)**	**Weather Normalized GCI Use Per Consumer (kWhs)**
2008	41,068	41,122
2009	38,661	39,427
2010	41,782	40,098
2011	39,971	39,873
2012	38,572	38,638
2013	38,044	38,208
2014	37,617	37,252
2015	36,121	36,441
2016	35,959	35,709
2017	34,721	35,549
2018	35,398	34,419
2019	34,050	33,930



g. Much of the historical drop in GCI use–per–consumer is attributable to various account reclassifications. Meade County Rural Electric Cooperative Corporation experienced an account reclassification in 2013 moving their largest customers from GCI into the LCI category. Jackson

Purchase Energy Corporation likely experienced an account reclassification from residential to GCI around 2014-2015. Both of these reclassifications would be one–time shifts in usage that would contribute to lowering the GCI use–per–consumer values in the past but not cause additional reductions in the future. Other historical reductions are attributable to increases in the GCI electricity price, and some of the more extreme weather years, such as 2010, also have considerable reductions due to weather conditions.

h. The diversity of the C&I market creates complexities that would be extremely difficult to capture in a universal survey instrument. Schools, restaurants, lodging, office buildings, manufacturing, agriculture, *etc.*, have varied activities and end–use profiles. Trying to capture information from these accounts would be nearly impossible through a single survey. Big Rivers' survey contractor provides surveying services for more than 100 cooperatives nationwide and has never performed a commercial saturation survey. Big Rivers and its Member-Owners assign staff to evaluate individual facilities for energy efficiency opportunities at the request of those retail commercial members.

i. The saturation survey is integral to each of the Member–Owners' load forecast analysis. Specifically, the survey results for each Member System are used in the models to estimate heating and cooling electric load sensitivities to cold and warm temperatures.

Witnesses) Matthew S. Sekeres (*a. through g. only*),
Steven A. Fenrick (*a. through g. only*), and
Russell L. Pogue (*h. and i. only*)

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's
First Request for Information
dated February 26, 2021

March 19, 2021

Item 51) ***Refer to the IRP, Appendix A, Load Forecast Study, Section 7.1, page 58.***

a. ***For each Member System, explain which weather station data was used as a data source.***

b. ***Provide a detailed explanation of the following:***

(1) What weather data was collected;

(2) How each variable was calculated; and

(3) How each variable was customized for each Member System's service territory.

c. ***Explain why a 15–year period was used as the basis for weather normalization as opposed to a 20–year or 30–year period.***

d. ***Explain how the data was weather normalized.***

Response)

a. The weather for Jackson Purchase Energy Corporation was gathered from the National Weather Service at Paducah, Kentucky, with a backup station from Murray, Kentucky in the case of missing data.

The weather for Kenergy, Corp. was gathered from Owensboro, Kentucky with a backup station from Henderson, Kentucky in the case of missing data.

The weather for Meade County Rural Electric Cooperative Corporation was gathered from Louisville, Kentucky with a backup station from Brandenburg, Kentucky in the case of missing data.

b.

(1) Daily minimum, maximum, and mean temperatures were collected for each Member–Owner's system.

(2) Refer to the models displayed in Big Rivers' 2020 IRP, Appendix A, Load Forecast Study, pages 89-100.

<u>Energy Model Weather Variables</u>

"Cooling Degree Days" ("CDD") are calculated by taking the daily average temperature and subtracting a 65 degree base. If the average daily temperature is under 65 then the CDD value for the day is zero. Monthly CDD values are a sum of the daily CDD values.

"Heating Degree Days" ("HDD") are calculated by taking a 65 degree base and subtracting the daily average temperature. If the average daily temperature is over 65 then the HDD value for the day is zero. Monthly HDD values are a sum of the daily HDD values.

<u>Load Factor Model Weather Variables</u>

"Cooling Degree Days on Peak Day" is a modified CDD variable calculated using the maximum daily temperature and a base of 75 degrees. This variable is not aggregated to a monthly total and only represents the conditions on the system peak day.

"Heating Degree Days on Peak Day" is a modified HDD variable calculated using the minimum daily temperature and a base of 55 degrees. This variable is not aggregated to a monthly total and only represents the conditions on the system peak day.

"Cooling Degree Days During Remainder of Month" represents the same CDD variable as in the energy models except with the CDD value on the peak day of the month removed.

"Heating Degree Days During Remainder of Month" represents the same HDD variable as in the energy models except with the HDD value on the peak day of the month removed.

(3) The weather variables contained custom values for each Member's system due to the different weather station assignments described in Big Rivers' response to sub–part a.

c. Refer to Big Rivers' 2020 IRP, Appendix A, Load Forecast Study, pages 70-72. Clearspring ran an analysis looking at the differences in the weather inputs using 10–year and 20–year averages. The differences from choosing a different time frame are small and, from an energy perspective, would largely cancel out. A 10–year selection would lead to slightly higher CDD but slightly lower HDD values, mostly canceling any net energy impact. Similarly, a 20–year selection would lead to slightly lower CDD but higher HDD values, mostly canceling any net energy impact.

Additionally, selecting longer time frames carries with it some data issues. An increased amount of weather data would need to be taken from secondary or even tertiary weather stations. These data elements would be needed to create the peak day weather variables in the load factor models.

d. Forecast data in the load forecast study are inherently weather normalized by using a 15–year average historical value for the weather input in each model.

Historical data are weather normalized through the following process:

(1) Create a historical dataset of each weather sensitive model prediction using the actual observed historical weather.

(2) Create a historical dataset of each weather sensitive model prediction using the same 15–year average weather inputs that are used in the forecast period.

(3) Recreate a history with the actual observed usage plus the results to step (2) minus the results to step (1).

(4) Adjust for any remaining iterative changes associated with the new totals such as changes to distribution or transmission losses.

Witnesses) Matthew S. Sekeres and
Steven A. Fenrick

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's
First Request for Information
dated February 26, 2021

March 19, 2021

Item 52) ***Refer to the IRP, Appendix A, Load Forecast Study, Section 2.2.2, pages 24–25.***

a. ***Explain what customer (in terms of load and energy use) is projected to come online in 2020 and what consumer load is leaving (in terms of annual load and energy use) the system in 2022.***

b. ***Explain how the addition of anticipated load in 2020 and the multiplier effects of that new addition were incorporated into service member models and the decision parameters regarding when an anticipated new load can be added to the load forecast. Include in the discussion whether the effects of the new load were incorporated into the residential and small commercial and industrial class models. If so, explain how the effects were incorporated.***

c. ***Explain how the anticipated loss of load in 2022 and the multiplier effects of that anticipated loss were incorporated into service member models. Provide the decision parameters regarding when an anticipated loss can be subtracted from the load forecast.***

Include in the discussion whether the effects of the lost load were incorporated into the residential and small commercial and industrial class models. If so, explain how the effects were incorporated.

d. Provide a copy of each final forecast report presented to each member system along with any handouts and any other presentation materials.

Response)

a. The answer to both of these questions is the same customer. The load coming online in 2020 in the LCI class was projected to begin in April 2020 and gradually ramp up until it is [redacted]. It is projected at a total of [redacted] and [redacted]. This is the construction load for the new Direct Serve customer, and as such, the removal of the LCI load [redacted] directly coincides with the addition of the Direct Serve customer in [redacted].

b. The addition of the LCI load in April 2020 and the transition to the full facility under Direct Serve [redacted] both required modifications to the econometric model drivers for Residential and GCI. Additionally, feedback was incorporated from Members' system staff regarding both the load and timing of the additions. Total employment, GRP, households, and sales modeling variables were all adjusted to reflect these two new loads. Please refer to the **CONFIDENTIAL** Excel file provided in response to Item 10 of the Commission Staff's First Request for Information for exact modeling variable modifications. These four variables are broken down into the values provided by Woods and Poole, Inc. (columns V, Y, AB, and AE in the **CONFIDENTIAL** Excel file) and the modifications made to these four variables associated with these two new customer loads (columns U, X, AA, and AD of the **CONFIDENTIAL** Excel file).

c. The removal of this load under LCI represents a transition for this service location to the Direct Serve class. Refer to Big Rivers' responses to sub–parts a. and b. for more information.

d. The Load Forecast Reports for Big Rivers' Member-Owners[1] are provided as Attachment 1, Attachment 2, and Attachment 3 to this response.

Witnesses) Matthew S. Sekeres and
Steven A. Fenrick

[1] Big Rivers' Member-Owners are Jackson Purchase Energy Corporation, Kenergy Corp., and Meade County Rural Electric Cooperative Corporation.

LOAD FORECAST

2020

Big Rivers
ELECTRIC CORPORATION

Case No. 2020-00299
Attachment 1 for Response to PSC 1-52d
Witnesses: Matthew S. Sekeres and Steven A. Fenrick

2020 Jackson Purchase Energy Corporation Load Forecast Study

Developed in partnership with

Big Rivers Electric Corporation

and

Jackson Purchase Energy Corporation

June 12, 2020

Prepared By:

Clearspring Energy Advisors LLC

1050 Regent St., Suite L3

Madison, WI 53715

608.442.8668

Confidentiality Statement

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1 INTRODUCTION AND SYSTEM SUMMARY

1.1 PROJECT OVERVIEW

The 2020 Big Rivers Electric Corporation ("Big Rivers") electric load forecast has been created from the bottom up. That is, forecast models have been developed for each of the three distribution systems served by Big Rivers. Each distribution member forecast is conducted separately, and each distribution member has reviewed and approved the load forecast applicable to its system.

Clearspring Energy Advisors, LLC (Clearspring) was selected by Big Rivers and its members to prepare this 2020 electric load forecast. The forecasting process relies heavily on internal system data, third-party demographic and economic data, and insight from cooperative staff that are most familiar with the end-uses and trends in the service territory. An emphasis has been placed on strong coordination between Big Rivers, the three member systems, and Clearspring in preparing this study to ensure accurate and useful load forecast results.

The forecast team members include the following individuals.

Name	Company	Role
Marlene Parsley	Big Rivers Electric Corporation	Project Manager
Russ Pogue	Big Rivers Electric Corporation	DSM Study
Jeff Williams	Jackson Purchase Energy Corporation	CFO – VP Finance, Accounting & Member Services
Scott Ribble	Jackson Purchase Energy Corporation	
Matt Sekeres	Clearspring Energy Advisors	Lead Consultant
Steve Fenrick	Clearspring Energy Advisors	Econometric Model Development
Josh Hoyt	Clearspring Energy Advisors	DSM Study

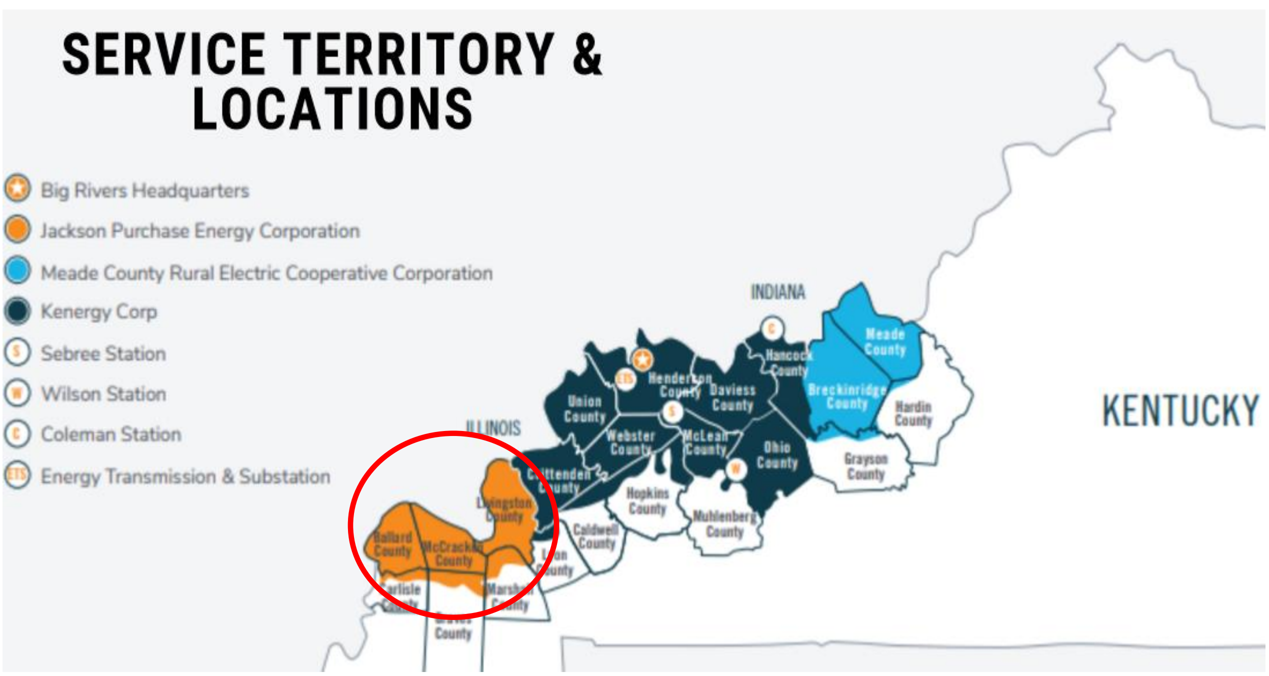
The forecast results meet the requirements of and will be used in USDA Rural Utilities Service ("RUS") loan applications, the forecast will be a key input into an Integrated Resource Plan ("IRP") being completed by Big Rivers under the direction of the Kentucky Public Service Commission ("Commission"), and the forecast will be used for planning and financial projections.

1.2 Member Information

The three distribution cooperatives are Jackson Purchase Energy Corporation, Kenergy Corporation, and Meade County Rural Electric Cooperative Corporation. These three Big Rivers members serve more than 118,000 residential households, businesses, and farms in western Kentucky. This report details the load forecast for Jackson Purchase Energy Corporation ("JPEC").

JPEC served approximately 30,000 members in 2019 and maintains 2,970 miles of power line. The service territory of JPEC is circled below.

Service Territory



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1.3 FORECAST SUMMARY

The forecast study develops a forecast for individual retail classes. The forecasted retail classes are:

- Residential,
- General Commercial and Industrial ("GCI"),
- Large Commercial and Industrial ("LCI"),
- Irrigation,
- Street & Highway, and
- Direct Serve sales.

The Residential, GCI, LCI, Irrigation, and Street and Highway classes along with distribution and own losses make up the Rural system requirements. Direct Serve sales are aggregated with the Rural system to provide total system requirements. JPEC's retail class sales forecast is the product of the consumer forecast and the use per consumer forecast for each class. JPEC's total sales forecast is constructed by summing the individual retail class sales forecasts.

The table below provides JPEC's Rural energy requirements, Direct Serve energy requirements, Rural peak demand coincident to Big Rivers, Direct Serve sum of individual non-coincident peak (NCP) and Rural system load factor for the last five historical years (2015-2019) and the forecasts for the next 20 years. Throughout this load forecast study, 2019 is considered a historical data year even though due to timeline considerations November and December of 2019 often contain estimated data.

System Summary

JPEC System Totals					
Year	Total Rural Energy Requirements (MWh)	Direct Serve Energy Requirements (MWh)	Rural System Coincident Peak Demand (MW)	Direct Serve Sum of Individual NCP (MW)	Rural System Coincident Peak Load Factor
2015	665,040	5,844	147.8	3.2	51.4%
2016	661,559	6,889	144.0	3.3	52.3%
2017	628,392	5,156	148.9	3.1	48.2%
2018	664,405	866	145.0	1.8	52.3%
2019	633,355	390	123.2	1.7	58.7%
2020	657,825	2,137	142.1	1.2	52.7%
2021	662,525	2,137	143.0	1.2	52.9%
2022	666,559	2,137	144.2	1.2	52.8%
2023	668,982	2,137	144.5	1.2	52.8%
2024	670,668	2,137	144.8	1.2	52.7%
2025	672,693	2,137	145.1	1.2	52.9%
2026	675,011	2,137	145.4	1.2	53.0%
2027	674,899	2,137	145.3	1.2	53.0%
2028	676,704	2,137	145.6	1.2	52.9%
2029	678,260	2,137	145.9	1.2	53.1%
2030	678,909	2,137	145.9	1.2	53.1%
2031	680,535	2,137	146.2	1.2	53.1%
2032	684,011	2,137	146.9	1.2	53.0%
2033	685,263	2,137	147.1	1.2	53.2%
2034	685,957	2,137	147.2	1.2	53.2%
2035	686,844	2,137	147.4	1.2	53.2%
2036	687,688	2,137	147.5	1.2	53.1%
2037	688,434	2,137	147.6	1.2	53.2%
2038	688,992	2,137	147.7	1.2	53.2%
2039	689,629	2,137	147.8	1.2	53.2%
Average Annual Growth Rates					
Previous 10 Years	-0.10%	-30.65%	-1.83%	-11.51%	1.76%
Previous 5 Years	-1.57%	-39.87%	-4.77%	-10.82%	3.37%
Next 5 Years	1.15%	40.51%	3.28%	-7.07%	-2.12%
Next 10 Years	0.69%	18.54%	1.70%	-3.60%	-1.00%
Next 20 Years	0.43%	8.87%	0.92%	-1.82%	-0.49%

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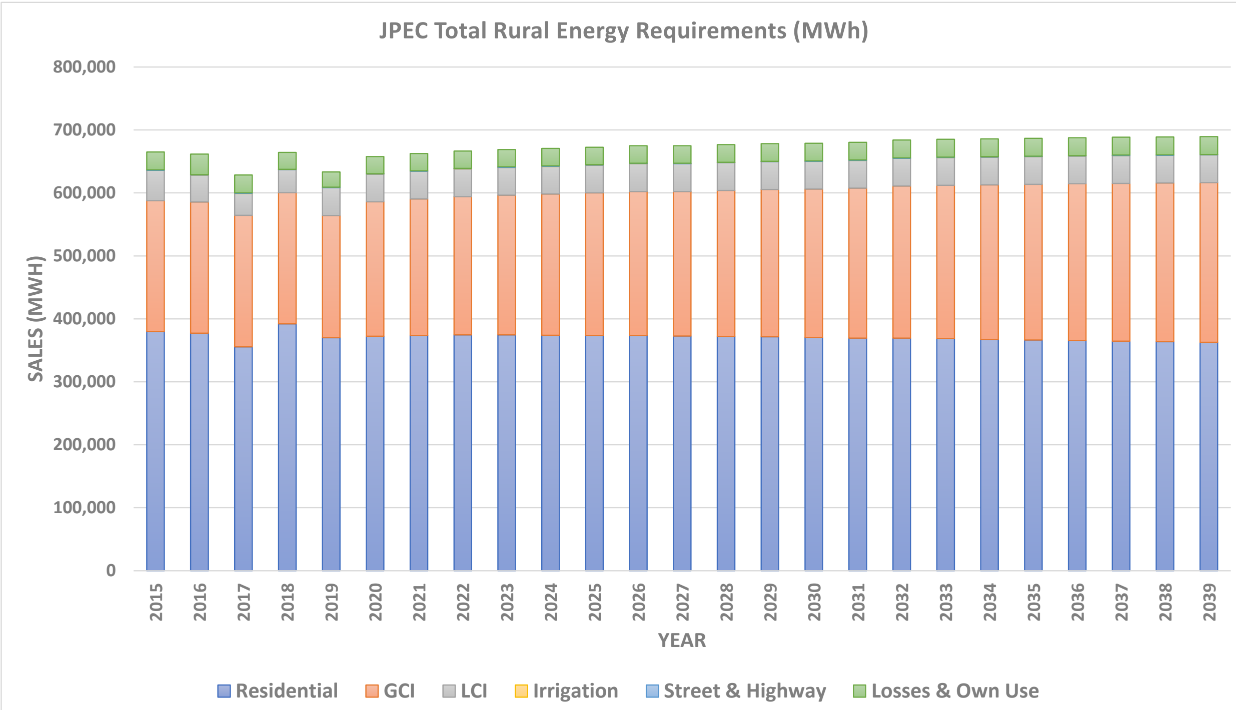
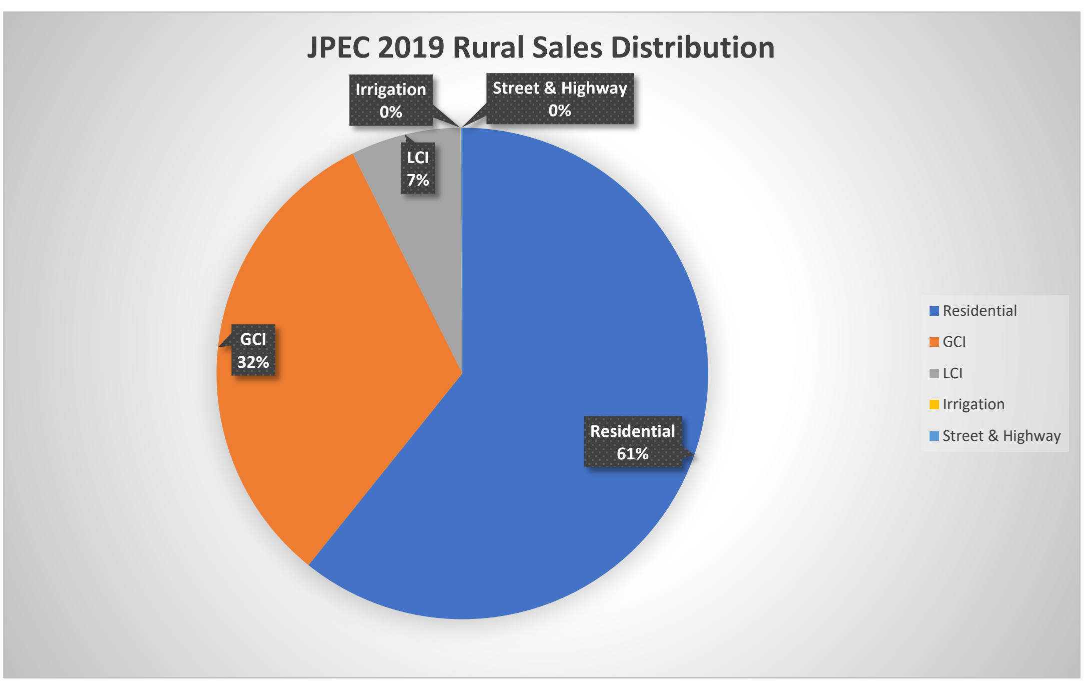
The following graph provides the cooperative's total system Rural energy requirements forecast.

Rural Energy Requirements



The figure below provides the cooperative's Rural sales distribution by class for 2019.

2019 Sales by Class Distribution



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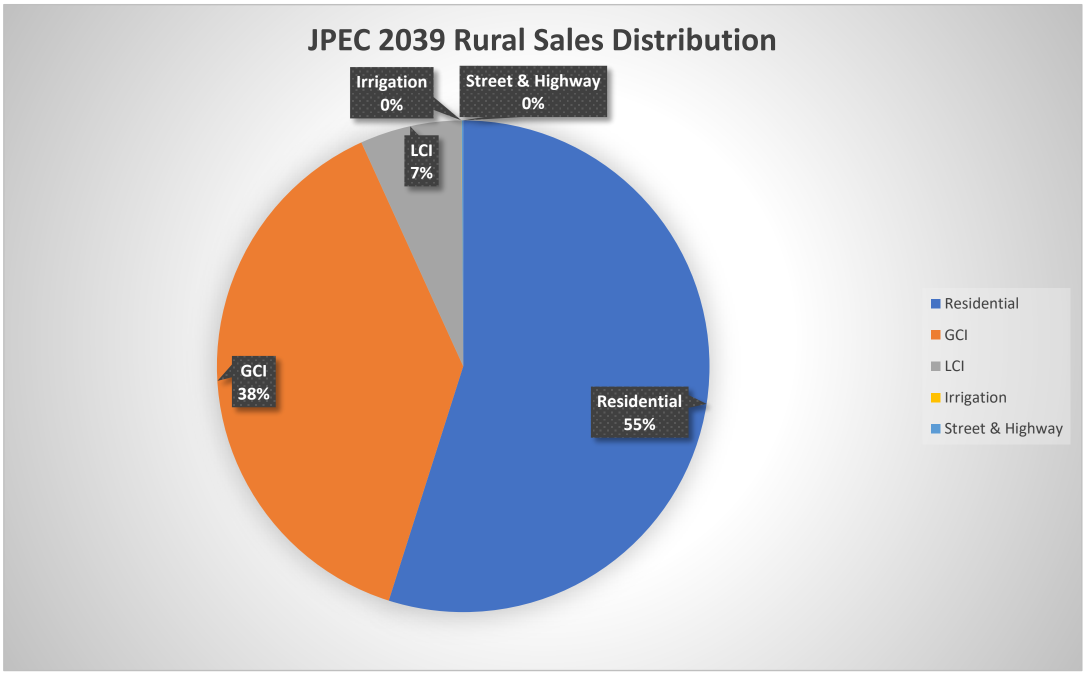
The figure below provides the cooperative's Rural sales forecasted distribution by class for 2039.

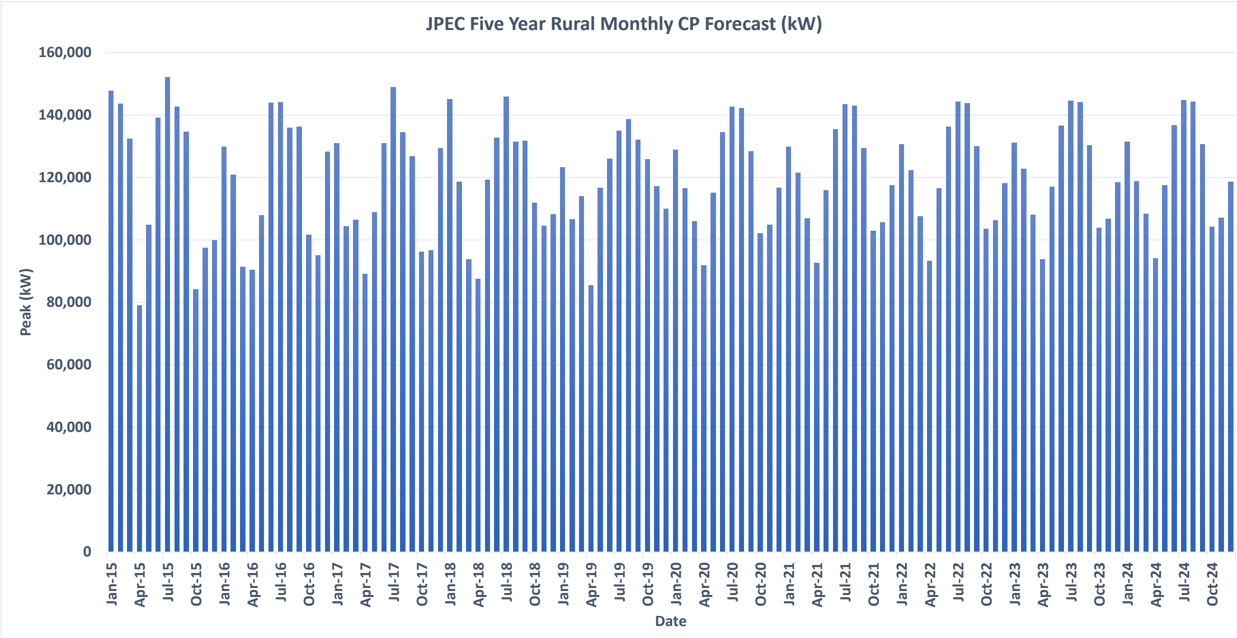
2039 Sales by Class Distribution



1.3.1 Monthly Peak Forecast

Monthly load factors have been econometrically modeled for each system. The load factor models are used in conjunction with the energy forecasts to calculate peak monthly peak demands. The monthly Rural peak demand forecast (coincident with Big Rivers) for the prior and next five years is presented in the following figure.

Monthly Rural Peak Forecast

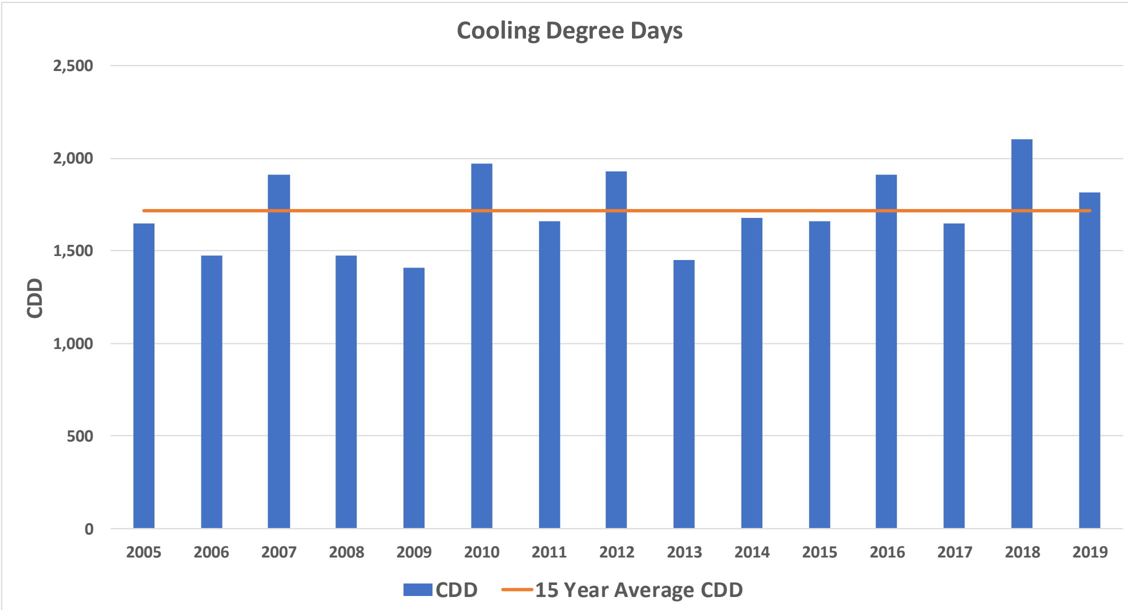


1.4 2019 Weather Conditions

There contains an assumption of a "normal" weather scenario for the forecasts for each class. Clearspring Energy compiled historical weather observations to enable the estimation of weather impacts onto sales and peak loads. Weather variables such as cooling degree days (CDD), heating degree days (HDD), and peak temperatures were gathered using weather stations within each service territory. Paducah, KY was used as the primary weather station to gather data for JPEC. In the cases of missing historical data at Paducah, a variety of backup stations were used to fill in missing data.

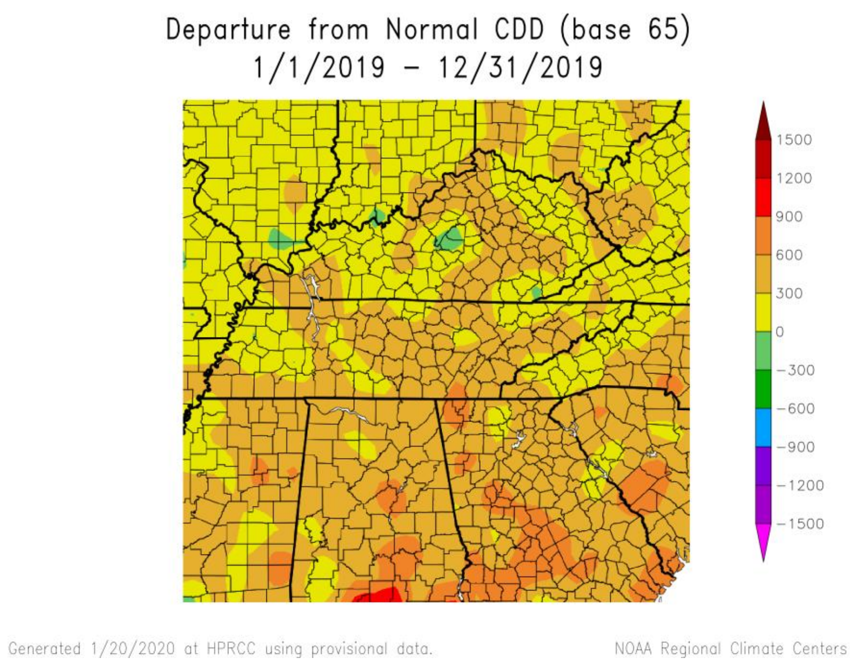
The figure below displays the last fifteen years of CDDs for JPEC along with the 15-year average CDD.

Cooling Degree Days for Last 15 Years



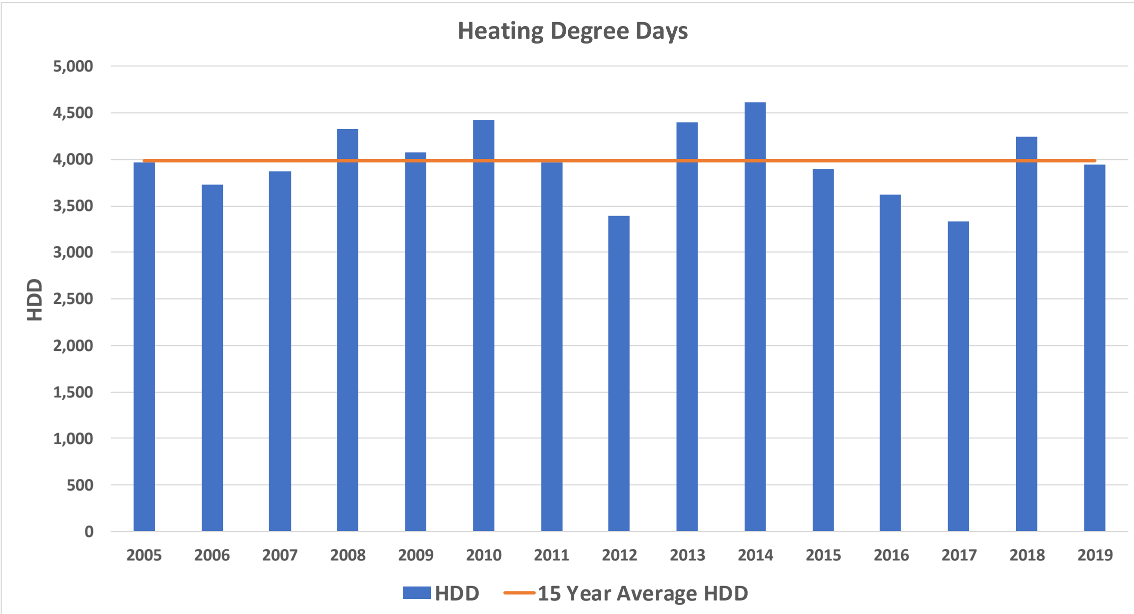
The figure below provides the CDD deviation in 2019 from a 30-year normal amount for the entire state of Kentucky.

Kentucky 2019 CDD Deviations



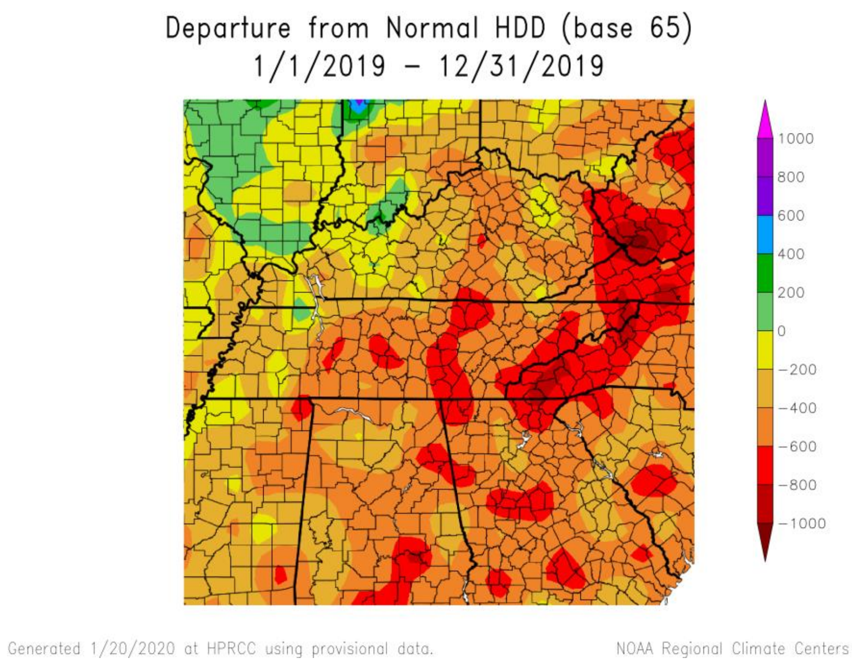
The figure below displays the last fifteen years of HDDs for JPEC along with the 15-year average HDD.

Heating Degree Days for Last 15 Years



The figure below provides the HDD deviation in 2019 from a 30-year normal amount for the entire state of Kentucky.

Kentucky 2019 HDD Deviations



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1.5 Forecast Process Summary

Clearspring developed econometric models in order to forecast Residential energy per consumer, General C&I (GCI) consumers, GCI use per consumer, and the Rural system's monthly load factors. A growth index using projections for the number of households was used to forecast Residential consumers. Historical weather and economic data was gathered from various sources to estimate the impacts of variables onto the corresponding category. Normalized weather and forecasted economic variables are then combined with the parameter estimates of the models to calculate forecasted values.

Forecasts for the LCI and Direct Serve commercial loads have been prepared judgmentally based on input from the cooperatives and historical value. Judgment and trend analysis are used to project Irrigation, Street and Highway, own use, and distribution losses. The forecasts have been provided to Big Rivers and the member systems and have been approved by each.

2 Energy Forecast Results

2.1 Residential Class

The Residential sales forecast is comprised of a forecast for Residential use per consumer and a forecast for Residential retail members. The product of the two disaggregated forecasts equals the Residential sales forecast.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of Residential customers, Residential use per consumer, and Residential energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are also provided.

Historical and Projected Residential Consumers, Use per Consumer, and Sales

JPEC Residential Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (kWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	25,347		14,990		379,943	
2016	25,380	0.13%	14,869	-0.81%	377,370	-0.68%
2017	25,632	1.00%	13,873	-6.70%	355,608	-5.77%
2018	25,578	-0.21%	15,323	10.45%	391,939	10.22%
2019	25,516	-0.24%	14,503	-5.35%	370,062	-5.58%
2020	25,606	0.35%	14,548	0.31%	372,513	0.66%
2021	25,735	0.50%	14,524	-0.16%	373,782	0.34%
2022	25,819	0.33%	14,512	-0.09%	374,682	0.24%
2023	25,875	0.22%	14,474	-0.26%	374,518	-0.04%
2024	25,911	0.14%	14,435	-0.27%	374,024	-0.13%
2025	25,930	0.08%	14,412	-0.16%	373,714	-0.08%
2026	25,937	0.03%	14,407	-0.04%	373,677	-0.01%
2027	25,934	-0.01%	14,369	-0.26%	372,657	-0.27%
2028	25,921	-0.05%	14,359	-0.07%	372,202	-0.12%
2029	25,895	-0.10%	14,347	-0.08%	371,528	-0.18%
2030	25,858	-0.14%	14,323	-0.17%	370,374	-0.31%
2031	25,812	-0.18%	14,316	-0.05%	369,523	-0.23%
2032	25,757	-0.22%	14,340	0.17%	369,342	-0.05%
2033	25,695	-0.24%	14,341	0.01%	368,491	-0.23%
2034	25,627	-0.26%	14,338	-0.02%	367,438	-0.29%
2035	25,556	-0.28%	14,340	0.01%	366,473	-0.26%
2036	25,483	-0.29%	14,344	0.03%	365,533	-0.26%
2037	25,409	-0.29%	14,352	0.06%	364,674	-0.24%
2038	25,336	-0.29%	14,358	0.04%	363,774	-0.25%
2039	25,265	-0.28%	14,365	0.05%	362,929	-0.23%
Average Annual Growth Rates						
Previous 10 Years	-0.20%		-0.27%		-0.47%	
Previous 5 Years	-0.14%		-1.66%		-1.80%	
Next 5 Years	0.31%		-0.09%		0.21%	
Next 10 Years	0.15%		-0.11%		0.04%	
Next 20 Years	-0.05%		-0.05%		-0.10%	

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2.1.1 Residential Consumer Forecast

Household growth estimates for each county within JPEC's service territory are used to project the number of Residential members in future years. The following table provides the historical and projected data used to forecast Residential consumers. Actual county level consumer data was provided for 2019. County distributions prior to 2019 have been estimated.

Historical and Projected Residential Consumers By County

JPEC Residential Consumers							
Year	Residential Accounts by County						
	Ballard	Carlisle	Graves	Livingston	Marshall	McCracken	
	Percentage of County Served						
	58.8%	18.5%	10.9%	100.0%	25.4%	32.7%	**Total**
2000	2,261	433	1,906	4,605	3,873	10,730	**23,808**
2001	2,302	441	1,941	4,689	3,944	10,926	**24,242**
2002	2,339	448	1,972	4,763	4,006	11,099	**24,627**
2003	2,357	452	1,987	4,800	4,037	11,185	**24,817**
2004	2,377	455	2,004	4,841	4,072	11,281	**25,030**
2005	2,405	461	2,028	4,899	4,121	11,416	**25,329**
2006	2,432	466	2,050	4,953	4,166	11,541	**25,607**
2007	2,448	469	2,064	4,986	4,194	11,619	**25,781**
2008	2,473	474	2,085	5,036	4,236	11,735	**26,038**
2009	2,472	474	2,084	5,035	4,235	11,733	**26,033**
2010	2,474	474	2,086	5,039	4,238	11,742	**26,053**
2011	2,474	474	2,086	5,039	4,239	11,742	**26,054**
2012	2,464	472	2,077	5,018	4,221	11,693	**25,944**
2013	2,455	470	2,070	5,000	4,206	11,651	**25,852**
2014	2,440	467	2,057	4,970	4,180	11,580	**25,694**
2015	2,407	461	2,029	4,902	4,123	11,424	**25,347**
2016	2,410	462	2,032	4,909	4,129	11,438	**25,380**
2017	2,434	466	2,052	4,958	4,170	11,552	**25,632**
2018	2,429	465	2,048	4,947	4,161	11,528	**25,578**
2019	2,423	464	2,043	4,935	4,151	11,500	**25,516**
2020	2,428	465	2,050	4,946	4,170	11,547	**25,606**
2021	2,435	465	2,061	4,962	4,198	11,614	**25,735**
2022	2,437	465	2,068	4,969	4,218	11,661	**25,819**
2023	2,437	465	2,073	4,971	4,234	11,695	**25,875**
2024	2,436	464	2,076	4,969	4,246	11,720	**25,911**
2025	2,433	463	2,078	4,964	4,256	11,736	**25,930**
2026	2,429	461	2,079	4,958	4,263	11,747	**25,937**
2027	2,424	460	2,079	4,951	4,268	11,753	**25,934**
2028	2,418	458	2,078	4,941	4,272	11,753	**25,921**
2029	2,412	457	2,076	4,930	4,273	11,748	**25,895**
2030	2,405	455	2,072	4,917	4,273	11,737	**25,858**
2031	2,397	453	2,069	4,903	4,270	11,721	**25,812**
2032	2,389	451	2,064	4,887	4,266	11,700	**25,757**
2033	2,380	448	2,058	4,872	4,261	11,676	**25,695**
2034	2,371	446	2,052	4,855	4,254	11,649	**25,627**
2035	2,362	444	2,046	4,838	4,247	11,619	**25,556**
2036	2,354	442	2,039	4,822	4,239	11,588	**25,483**
2037	2,345	440	2,033	4,806	4,230	11,556	**25,409**
2038	2,336	437	2,026	4,790	4,222	11,524	**25,336**
2039	2,329	435	2,019	4,775	4,214	11,493	**25,265**
Average Annual Growth Rates							
Previous 10 Years	-0.20%	-0.20%	-0.20%	-0.20%	-0.20%	-0.20%	**-0.20%**
Previous 5 Years	-0.14%	-0.14%	-0.14%	-0.14%	-0.14%	-0.14%	**-0.14%**
Next 5 Years	0.11%	-0.01%	0.33%	0.14%	0.45%	0.38%	**0.31%**
Next 10 Years	-0.04%	-0.16%	0.16%	-0.01%	0.29%	0.21%	**0.15%**
Next 20 Years	-0.20%	-0.32%	-0.06%	-0.16%	0.07%	0.00%	**-0.05%**

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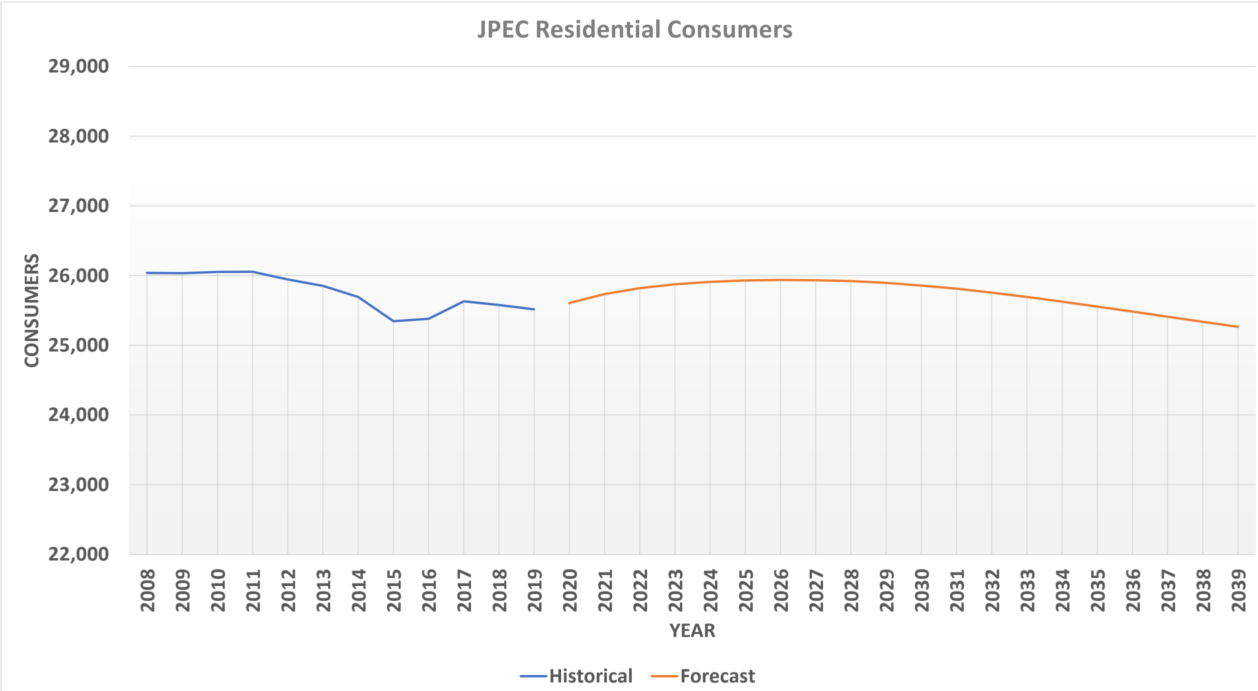
The following figure provides the historical and projected Residential consumers.

Residential Consumers



2.1.2 Residential Use per Consumer Forecast

The Residential use per consumer forecast is estimated using an econometric model that relates certain explanatory variables to Residential use per consumer. The model employs a monthly dataset with 154 observations from January 2007 to October 2019. The model uses price of electricity, alternate fuel prices, cooling and heating degree days, appliance saturation levels, and appliance efficiencies. Explanatory variable values are projected in future years using demographic and economic projections and weather normalized values. The Residential use per consumer model is provided in the table below.

Residential Use Per Consumer Model

JPEC Residential Use Per Consumer Model

Sample: 2007 - 2019
Total Observations: 154

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	6.555083	0.051571	127.1073	0
February	6.471421	0.0465	139.1691	0
March	6.494198	0.037785	171.8732	0
April	6.395643	0.030825	207.4807	0
May	6.52232	0.034815	187.3398	0
June	6.629714	0.042908	154.5117	0
July	6.692348	0.04857	137.7881	0
August	6.689342	0.046313	144.4377	0
September	6.605444	0.037123	177.9347	0
October	6.422282	0.029883	214.9132	0
November	6.438005	0.038993	165.1081	0
December	6.556474	0.044827	146.261	0
Log(Residential Price/Alternate Fuel Price)	-0.066133	0.011283	-5.861178	0
Cooling Degree Days*(AC Saturation)*(1/AC Efficiency)	0.014177	0.000883	16.0548	0
Heating Degree Days*Electric Heat Saturation*(1/Heating Efficiency)	0.015707	0.001259	12.47104	0

Weighted Statistics

Adjusted R-squared: 0.9412

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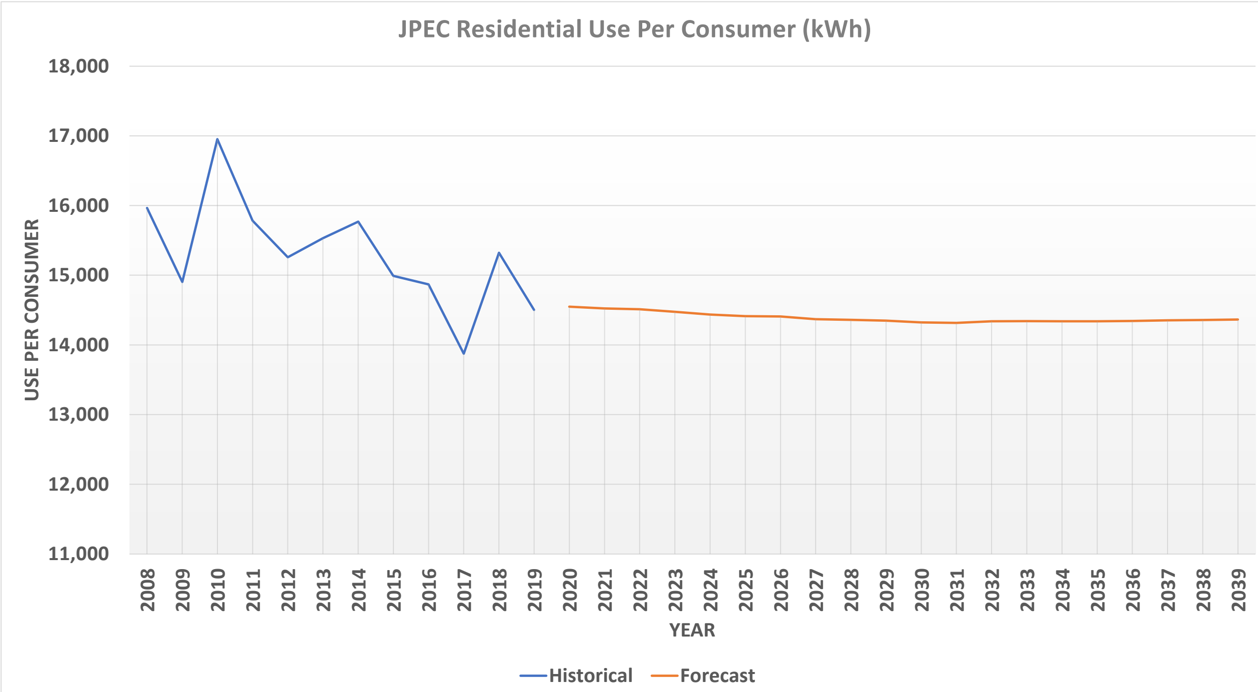
The following figure provides the historical and projected Residential use per consumer for JPEC.

Residential Use Per Consumer



2.2 Commercial and Industrial Class

The total commercial and industrial class is divided into three distinct sub classes. Certain large commercial and industrial consumers that are directly served off the transmission system are deemed as Direct Serve consumers and these consumers are individually forecasted based on input from the member system, Big Rivers, or the Direct Serve consumer itself. The Direct Serve sales are aggregated to the total system requirements separately from the Rural system load. The second commercial and industrial class is the Large C&I (LCI) class. This class consists of the remainder of consumers over 1,000 kVA that do not qualify as Direct Serve consumers. The rest of the commercial and industrial retail members are placed and forecasted within the General C&I (GCI) class.

2.2.1 General Commercial and Industrial (GCI) Class

The GCI class is defined as the total commercial and industrial loads minus the Direct Serve and LCI loads. Given the importance of the GCI class, Clearspring Energy used econometric modeling to project both the GCI consumer counts and the GCI use per consumer for JPEC.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of GCI customers, GCI use per consumer, and GCI energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table for GCI consumers, use per consumer, and sales.

Historical and Projected GCI Consumers, Use per Consumer, and Sales

JPEC General C&I Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (kWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	4,001		51,952		207,862	
2016	4,226	5.63%	49,280	-5.14%	208,270	0.20%
2017	4,355	3.05%	47,934	-2.73%	208,762	0.24%
2018	4,437	1.88%	46,998	-1.95%	208,524	-0.11%
2019	4,498	1.37%	43,166	-8.15%	194,154	-6.89%
2020	4,557	1.32%	46,810	8.44%	213,323	9.87%
2021	4,601	0.97%	47,064	0.54%	216,559	1.52%
2022	4,648	1.01%	47,233	0.36%	219,527	1.37%
2023	4,691	0.94%	47,324	0.19%	222,015	1.13%
2024	4,735	0.93%	47,332	0.02%	224,126	0.95%
2025	4,779	0.93%	47,369	0.08%	226,377	1.00%
2026	4,823	0.91%	47,409	0.08%	228,637	1.00%
2027	4,866	0.89%	47,178	-0.49%	229,549	0.40%
2028	4,907	0.86%	47,222	0.09%	231,735	0.95%
2029	4,948	0.83%	47,271	0.10%	233,900	0.93%
2030	4,988	0.80%	47,251	-0.04%	235,677	0.76%
2031	5,026	0.76%	47,374	0.26%	238,088	1.02%
2032	5,062	0.72%	47,730	0.75%	241,602	1.48%
2033	5,096	0.68%	47,811	0.17%	243,655	0.85%
2034	5,129	0.64%	47,840	0.06%	245,373	0.71%
2035	5,160	0.61%	47,902	0.13%	247,189	0.74%
2036	5,190	0.57%	47,967	0.14%	248,939	0.71%
2037	5,218	0.54%	48,009	0.09%	250,513	0.63%
2038	5,245	0.52%	48,034	0.05%	251,949	0.57%
2039	5,271	0.49%	48,074	0.08%	253,405	0.58%
Average Annual Growth Rates						
Previous 10 Years	3.94%		-2.78%		1.05%	
Previous 5 Years	4.66%		-5.34%		-0.93%	
Next 5 Years	1.03%		1.86%		2.91%	
Next 10 Years	0.96%		0.91%		1.88%	
Next 20 Years	0.80%		0.54%		1.34%	

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2.2.1.1 GCI Consumer Forecast

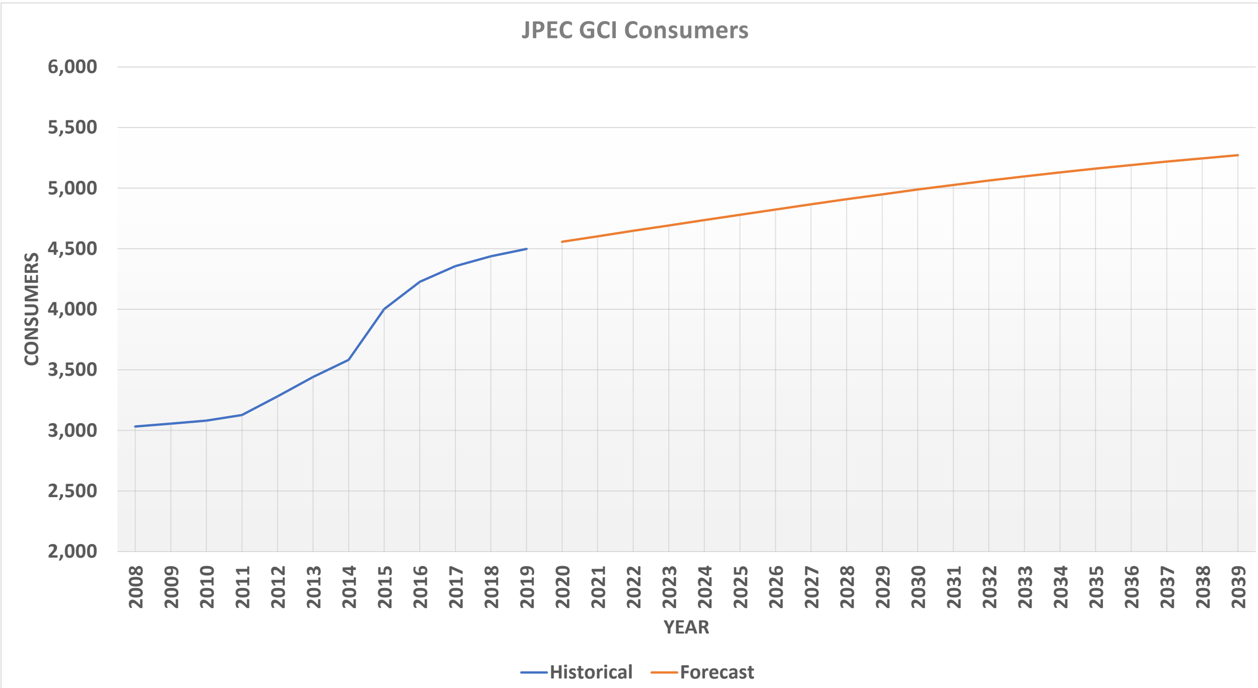
The GCI consumer forecast is estimated using an econometric model that relates explanatory variables to the GCI consumer count. The model uses GRP within the counties served by JPEC. Explanatory variable values are projected in future years using economic projections. The GCI consumer model is provided in the table below.

GCI Consumer Model

JPEC General C&I Consumer Model				
Sample: 1999 - 2019 Total Observations: 250				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
GRP	2.262405	0.009413	240.3562	0
January 1999 - July 2015	-1180.094	21.57386	-54.70017	0
Weighted Statistics				
Adjusted R-squared: 0.926993				

The following figure provides the historical and projected JPEC GCI consumers.

GCI Consumers



2.2.1.2 GCI Use per Consumer Forecast

The GCI use per consumer forecast is estimated using an econometric model that relates certain explanatory variables to the GCI use per consumer. The model uses electricity price, employment per consumer, cooling degree days, and heating degree days within the counties served by JPEC. Explanatory variable values are projected in future years using demographic and economic projections and weather normalized values. The GCI use per consumer model is provided in the table below.

GCI Use per Consumer Model

JPEC General C&I Use Per Consumer Model

Sample: 1999 - 2019
Total Observations: 250

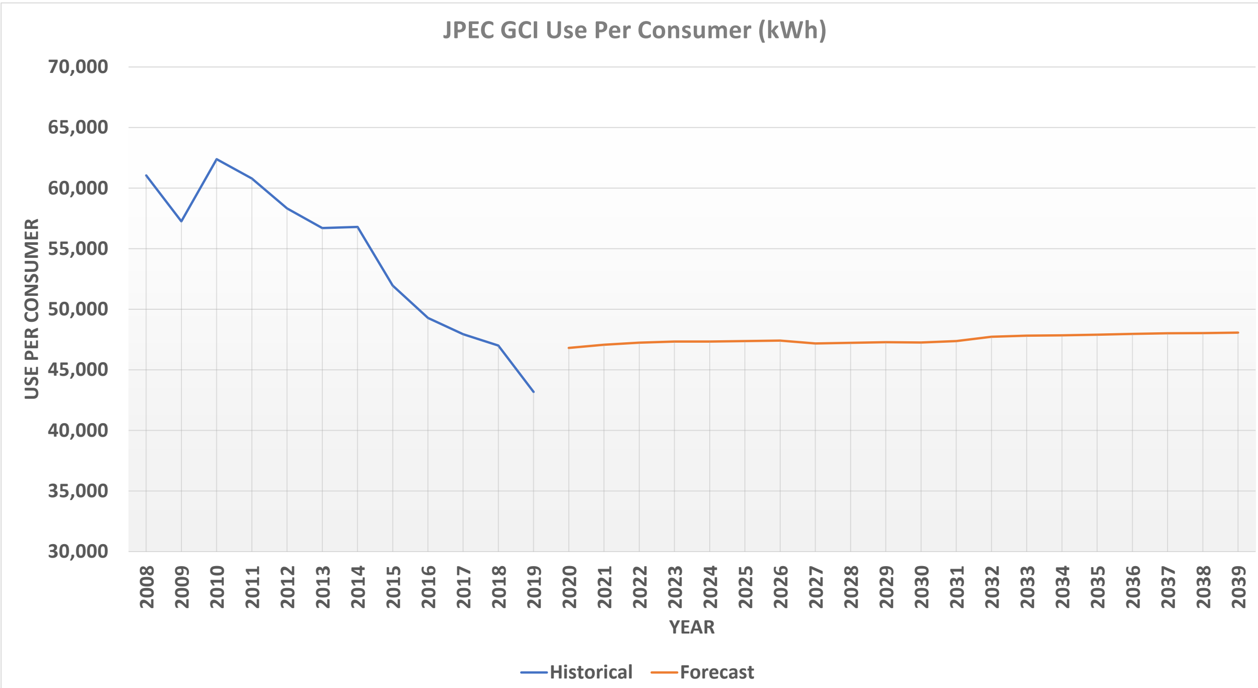
Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	8.600848	0.281849	30.5158	0
February	8.522346	0.280138	30.42194	0
March	8.546241	0.276151	30.94766	0
April	8.560973	0.269839	31.72619	0
May	8.626614	0.270179	31.9293	0
June	8.614929	0.268555	32.07879	0
July	8.649323	0.269833	32.05432	0
August	8.660487	0.269027	32.19186	0
September	8.644216	0.266897	32.38786	0
October	8.617445	0.274983	31.33808	0
November	8.563895	0.277375	30.87484	0
December	8.586087	0.281162	30.53791	0
Log(C&I Electricity Price)	-0.183357	0.054165	-3.385128	0.0008
Cooling Degree Days	0.00061	0.0000953	6.401003	0
Heating Degree Days	0.000201	0.000052	3.856308	0.0001
Log(Total Employment/C&I Consumers)	0.178616	0.036983	4.829628	0
January 1999 - July 2015	0.102737	0.02041	5.033621	0

Weighted Statistics

Adjusted R-squared: 0.796959

The following figure provides the historical and projected GCI use per consumer for JPEC.

GCI Use per Consumer



2.2.2 Large Commercial and Industrial (LCI) Class

The Large C&I (LCI) class consists of the remainder of consumers over 1,000 kVA that do not qualify as Direct Serve consumers. In 2019 the JPEC LCI class contained 8 consumers. The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of LCI consumers, LCI use per consumer, and LCI energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table for LCI consumers, use per consumer, and sales.

Historical and Projected LCI Consumers, Use per Consumer, and Sales

JPEC Large C&I Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (MWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	8		6,020		48,159	
2016	7	-9.38%	5,893	-2.11%	42,725	-11.28%
2017	5	-25.29%	6,450	9.46%	34,940	-18.22%
2018	6	10.77%	6,090	-5.59%	36,537	4.57%
2019	8	38.89%	5,288	-13.16%	44,070	20.62%
2020	9	8.00%	4,897	-7.41%	44,070	0.00%
2021	9	0.00%	4,897	0.00%	44,070	0.00%
2022	9	0.00%	4,897	0.00%	44,070	0.00%
2023	9	0.00%	4,897	0.00%	44,070	0.00%
2024	9	0.00%	4,897	0.00%	44,070	0.00%
2025	9	0.00%	4,897	0.00%	44,070	0.00%
2026	9	0.00%	4,897	0.00%	44,070	0.00%
2027	9	0.00%	4,897	0.00%	44,070	0.00%
2028	9	0.00%	4,897	0.00%	44,070	0.00%
2029	9	0.00%	4,897	0.00%	44,070	0.00%
2030	9	0.00%	4,897	0.00%	44,070	0.00%
2031	9	0.00%	4,897	0.00%	44,070	0.00%
2032	9	0.00%	4,897	0.00%	44,070	0.00%
2033	9	0.00%	4,897	0.00%	44,070	0.00%
2034	9	0.00%	4,897	0.00%	44,070	0.00%
2035	9	0.00%	4,897	0.00%	44,070	0.00%
2036	9	0.00%	4,897	0.00%	44,070	0.00%
2037	9	0.00%	4,897	0.00%	44,070	0.00%
2038	9	0.00%	4,897	0.00%	44,070	0.00%
2039	9	0.00%	4,897	0.00%	44,070	0.00%
Average Annual Growth Rates						
Previous 10 Years	2.65%		-2.14%		0.45%	
Previous 5 Years	-1.71%		-0.50%		-2.20%	
Next 5 Years	1.55%		-1.53%		0.00%	
Next 10 Years	0.77%		-0.77%		0.00%	
Next 20 Years	0.39%		-0.38%		0.00%	

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2.2.3 Direct Serve Class

The Direct Serve class contains consumers that are directly served from the transmission system. The sales forecasts are based on manager and staff knowledge and input from each cooperative. JPEC's Direct Serve class contained one consumer in 2019.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of Direct Serve customers, Direct Serve use per consumer, and Direct Serve energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table for Direct Serve consumers, use per consumer, and sales.

Historical and Projected Direct Serve Consumers, Use per Consumer, and Sales

JPEC Direct Serve Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (MWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	1		5,844		5,844	
2016	1	0.00%	6,889	17.89%	6,889	17.89%
2017	1	0.00%	5,156	-25.16%	5,156	-25.16%
2018	1	0.00%	866	-83.21%	866	-83.21%
2019	1	0.00%	390	-54.93%	390	-54.93%
2020	1	0.00%	2,137	447.67%	2,137	447.67%
2021	1	0.00%	2,137	0.00%	2,137	0.00%
2022	1	0.00%	2,137	0.00%	2,137	0.00%
2023	1	0.00%	2,137	0.00%	2,137	0.00%
2024	1	0.00%	2,137	0.00%	2,137	0.00%
2025	1	0.00%	2,137	0.00%	2,137	0.00%
2026	1	0.00%	2,137	0.00%	2,137	0.00%
2027	1	0.00%	2,137	0.00%	2,137	0.00%
2028	1	0.00%	2,137	0.00%	2,137	0.00%
2029	1	0.00%	2,137	0.00%	2,137	0.00%
2030	1	0.00%	2,137	0.00%	2,137	0.00%
2031	1	0.00%	2,137	0.00%	2,137	0.00%
2032	1	0.00%	2,137	0.00%	2,137	0.00%
2033	1	0.00%	2,137	0.00%	2,137	0.00%
2034	1	0.00%	2,137	0.00%	2,137	0.00%
2035	1	0.00%	2,137	0.00%	2,137	0.00%
2036	1	0.00%	2,137	0.00%	2,137	0.00%
2037	1	0.00%	2,137	0.00%	2,137	0.00%
2038	1	0.00%	2,137	0.00%	2,137	0.00%
2039	1	0.00%	2,137	0.00%	2,137	0.00%
Average Annual Growth Rates						
Previous 10 Years	0.00%		-30.65%		-30.65%	
Previous 5 Years	0.00%		-39.87%		-39.87%	
Next 5 Years	0.00%		40.51%		40.51%	
Next 10 Years	0.00%		18.54%		18.54%	
Next 20 Years	0.00%		8.87%		8.87%	

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2.3 Street and Highway Class

Given the small proportion of the Street and Highway class in total sales, the forecast for this class was calculated manually rather than through econometric modeling. The most recent consumer values were held constant through the forecast and the prior twelve months of usage were used to derive monthly energy forecasts for the forecast period.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of Street and Highway consumers, Street and Highway use per consumer, and Street and Highway energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table for Street and Highway consumers, use per consumer, and sales.

Historical and Projected Street & Highway Consumers, Use per Consumer, and Sales

JPEC Street & Highway Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (kWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	3		203,037		626	
2016	4	40.54%	145,844	-28.17%	632	0.95%
2017	5	3.85%	139,532	-4.33%	628	-0.65%
2018	6	24.07%	111,140	-20.35%	621	-1.17%
2019	7	22.39%	92,254	-16.99%	630	1.59%
2020	9	31.71%	75,766	-17.87%	682	8.17%
2021	9	0.00%	75,766	0.00%	682	0.00%
2022	9	0.00%	75,766	0.00%	682	0.00%
2023	9	0.00%	75,766	0.00%	682	0.00%
2024	9	0.00%	75,766	0.00%	682	0.00%
2025	9	0.00%	75,766	0.00%	682	0.00%
2026	9	0.00%	75,766	0.00%	682	0.00%
2027	9	0.00%	75,766	0.00%	682	0.00%
2028	9	0.00%	75,766	0.00%	682	0.00%
2029	9	0.00%	75,766	0.00%	682	0.00%
2030	9	0.00%	75,766	0.00%	682	0.00%
2031	9	0.00%	75,766	0.00%	682	0.00%
2032	9	0.00%	75,766	0.00%	682	0.00%
2033	9	0.00%	75,766	0.00%	682	0.00%
2034	9	0.00%	75,766	0.00%	682	0.00%
2035	9	0.00%	75,766	0.00%	682	0.00%
2036	9	0.00%	75,766	0.00%	682	0.00%
2037	9	0.00%	75,766	0.00%	682	0.00%
2038	9	0.00%	75,766	0.00%	682	0.00%
2039	9	0.00%	75,766	0.00%	682	0.00%
Average Annual Growth Rates						
Previous 10 Years	8.58%		-7.85%		0.05%	
Previous 5 Years	17.90%		-14.80%		0.45%	
Next 5 Years	5.66%		-3.86%		1.58%	
Next 10 Years	2.79%		-1.95%		0.79%	
Next 20 Years	1.39%		-0.98%		0.39%	

2.4 Irrigation Class

Given the small proportion of the Irrigation class in total sales, the forecast for this class was calculated manually rather than through econometric modeling. The most recent consumer values were held constant through the forecast and the prior twelve months of usage were used to derive monthly energy forecasts for the forecast period.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of Irrigation customers, Irrigation use per consumer, and Irrigation energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table for Irrigation consumers, use per consumer, and sales.

Historical and Projected Irrigation Consumers, Use per Consumer, and Sales

JPEC Irrigation Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (kWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	4		15,428		62	
2016	4	0.00%	12,760	-17.29%	51	-17.29%
2017	4	0.00%	25,437	99.35%	102	99.35%
2018	5	12.50%	15,618	-38.60%	70	-30.93%
2019	5	11.11%	21,652	38.63%	108	54.04%
2020	5	0.00%	21,652	0.00%	108	0.00%
2021	5	0.00%	21,652	0.00%	108	0.00%
2022	5	0.00%	21,652	0.00%	108	0.00%
2023	5	0.00%	21,652	0.00%	108	0.00%
2024	5	0.00%	21,652	0.00%	108	0.00%
2025	5	0.00%	21,652	0.00%	108	0.00%
2026	5	0.00%	21,652	0.00%	108	0.00%
2027	5	0.00%	21,652	0.00%	108	0.00%
2028	5	0.00%	21,652	0.00%	108	0.00%
2029	5	0.00%	21,652	0.00%	108	0.00%
2030	5	0.00%	21,652	0.00%	108	0.00%
2031	5	0.00%	21,652	0.00%	108	0.00%
2032	5	0.00%	21,652	0.00%	108	0.00%
2033	5	0.00%	21,652	0.00%	108	0.00%
2034	5	0.00%	21,652	0.00%	108	0.00%
2035	5	0.00%	21,652	0.00%	108	0.00%
2036	5	0.00%	21,652	0.00%	108	0.00%
2037	5	0.00%	21,652	0.00%	108	0.00%
2038	5	0.00%	21,652	0.00%	108	0.00%
2039	5	0.00%	21,652	0.00%	108	0.00%
Average Annual Growth Rates						
Previous 10 Years	-5.17%		-7.62%		-12.39%	
Previous 5 Years	4.56%		-8.69%		-4.52%	
Next 5 Years	0.00%		0.00%		0.00%	
Next 10 Years	0.00%		0.00%		0.00%	
Next 20 Years	0.00%		0.00%		0.00%	

2.5 Total Energy

The total energy requirements are calculated by taking the sales forecasts for each class, detailed in the previous sections of this report, and adding distribution losses and own use. Distribution losses are estimated using a three-year historical average percent. This percent is computed after any Direct Sale loads are removed since these loads are no loss loads.

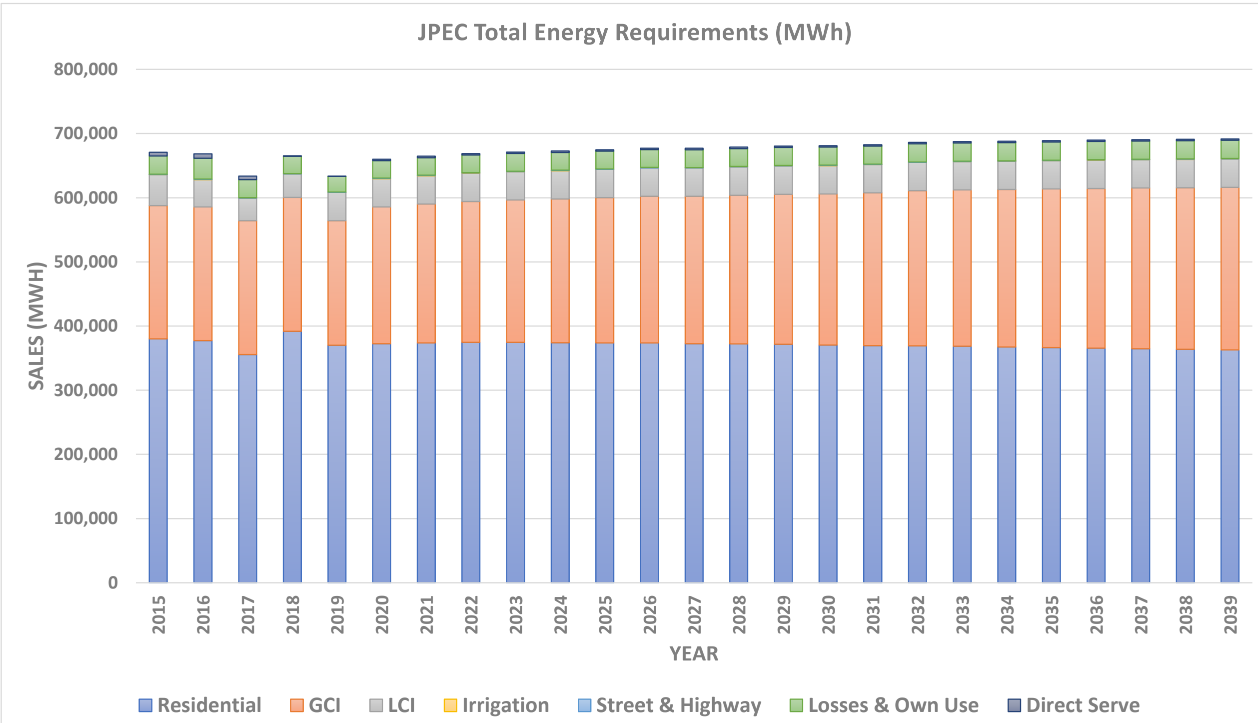
The following table provides the historical and forecast components of total energy requirements. The last five historical years are provided (2015 to 2019) along with the next twenty years of forecasts for each component. This includes Rural energy sales, Direct Serve sales, the estimated DSM impacts in forecasted years, and line losses. It is assumed that any impacts of prior DSM programs are captured indirectly through the historical energy and peak data used as an input to the modeling process. The DSM column provided in the table below is intended to capture any additional impacts from DSM spending in the future. For the base case forecast the additional DSM impact has been set to zero. Alternate scenarios have been quantified for Big Rivers and provided in Excel that detail the impacts of one million and two million DSM spending scenarios. These scenario impacts are derived directly from the Big Rivers DSM study completed in 2020.

Total System Energy Summary

JPEC Total System Energy Summary						
Year	Rural System Energy Sales (MWh)	Direct Serve Energy Sales (MWh)	DSM Impact (MWh)	Total System Energy Sales (MWh)	Line Losses (% of Rural Energy)	Total Energy Requirements (MWh)
2015	636,652	5,844	0	642,495	4.24%	670,884
2016	629,047	6,889	0	635,937	4.89%	668,448
2017	600,039	5,156	0	605,195	4.48%	633,548
2018	637,691	866	0	638,557	3.99%	665,271
2019	609,025	390	0	609,415	3.81%	633,745
2020	630,696	2,137	0	632,833	4.10%	659,963
2021	635,202	2,137	0	637,339	4.10%	664,662
2022	639,070	2,137	0	641,207	4.10%	668,697
2023	641,393	2,137	0	643,530	4.10%	671,119
2024	643,009	2,137	0	645,147	4.10%	672,806
2025	644,951	2,137	0	647,088	4.10%	674,830
2026	647,174	2,137	0	649,311	4.10%	677,149
2027	647,066	2,137	0	649,203	4.10%	677,036
2028	648,797	2,137	0	650,934	4.10%	678,842
2029	650,289	2,137	0	652,426	4.10%	680,397
2030	650,911	2,137	0	653,049	4.10%	681,046
2031	652,471	2,137	0	654,608	4.10%	682,672
2032	655,805	2,137	0	657,942	4.10%	686,148
2033	657,005	2,137	0	659,143	4.10%	687,400
2034	657,671	2,137	0	659,809	4.10%	688,094
2035	658,522	2,137	0	660,659	4.10%	688,981
2036	659,331	2,137	0	661,469	4.10%	689,825
2037	660,047	2,137	0	662,184	4.10%	690,571
2038	660,583	2,137	0	662,720	4.10%	691,130
2039	661,194	2,137	0	663,331	4.10%	691,766
Average Annual Growth Rates						
Previous 10 Years	0.05%	-30.65%	0.00%	-0.19%	-3.08%	-0.33%
Previous 5 Years	-1.55%	-39.87%	0.00%	-1.69%	-0.35%	-1.70%
Next 5 Years	1.09%	40.51%	0.00%	1.15%	1.45%	1.20%
Next 10 Years	0.66%	18.54%	0.00%	0.68%	0.72%	0.71%
Next 20 Years	0.41%	8.87%	0.00%	0.42%	0.36%	0.44%

The following graph provides the class components that comprise the total energy requirements for JPEC.

Total Energy Forecast



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3 PEAK DEMAND

3.1 COINCIDENT PEAK DEMAND

The Rural system coincident peak demand (Rural CP) is measured based on JPEC's demand coincident with the Big Rivers' total system peak. Clearspring Energy econometrically modeled JPEC's Rural coincident load factor using a monthly dataset. The predicted load factor is combined with the Rural energy forecast to forecast the Rural coincident peak demand. The Rural load factor model uses temperature on the peak day each month, cooling degree days, heating degree days, appliance saturations, and appliance efficiencies. The Rural CP load factor model is provided in the table below.

Rural CP Load Factor Model

JPEC Load Factor Model

Sample: 2007 - 2019
Total Observations: 154

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	0.657717	0.029229	22.50207	0
February	0.690955	0.024563	28.13002	0
March	0.668066	0.021476	31.10736	0
April Cold Peaking	0.701504	0.017757	39.50476	0
April Hot Peaking	0.659123	0.021667	30.42063	0
May	0.591251	0.015673	37.72414	0
June	0.609293	0.021739	28.02783	0
July	0.60305	0.024117	25.00528	0
August	0.600394	0.022935	26.17772	0
September	0.606743	0.021043	28.83319	0
October Cold Peaking	0.732852	0.015114	48.48963	0
October Hot Peaking	0.626334	0.025267	24.78835	0
November	0.680741	0.020149	33.78508	0
December	0.695933	0.027604	25.21132	0
Cooling Degree Days on Peak Day*(AC Saturation)*(1/AC Efficiency)	-0.086523	0.015833	-5.464825	0
Heating Degree Days on Peak Day*Electric Heating Saturation*(1/Heating Efficiency)	-0.085747	0.014716	-5.826914	0
Cooling Degree During Remainder of Month*(AC Saturation)*(1/AC Efficiency)	0.004952	0.000601	8.240219	0
Heating Degree During Remainder of Month*Electric Heating Saturation*(1/Heating Efficiency)	0.004441	0.000788	5.636105	0

Weighted Statistics

Adjusted R-squared: 0.711106

The following table provides the last five years of historical data and the next 20 years of forecasted data for the winter, summer, and annual peaks for JPEC's Rural system. The table also provides the annual coincident peak contribution for the Direct Serve class and the total JPEC coincident peak contribution. The Direct Serve coincident peak contribution was forecasted using a three year average of historical values for the class. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table below.

Historical and Projected CP Demands

JPEC Coincident Peak (kW)					
Year	Rural Summer CP	Rural Winter CP	Rural Annual CP	Direct Serve Annual CP	Total Annual CP
2015	152,076	147,777	147,777	1,647	149,424
2016	144,033	129,764	144,033	1,733	145,767
2017	148,902	130,891	148,902	16	148,918
2018	145,856	145,041	145,041	38	145,079
2019	138,722	123,172	123,172	32	123,205
2020	142,147	128,901	142,147	245	142,392
2021	143,015	129,843	143,015	245	143,260
2022	144,204	130,639	144,204	245	144,449
2023	144,544	131,086	144,544	245	144,788
2024	144,752	131,366	144,752	245	144,997
2025	145,051	131,708	145,051	245	145,296
2026	145,432	132,106	145,432	245	145,677
2027	145,307	132,039	145,307	245	145,552
2028	145,604	132,330	145,604	245	145,849
2029	145,856	132,570	145,856	245	146,101
2030	145,922	132,631	145,922	245	146,167
2031	146,208	132,874	146,208	245	146,453
2032	146,896	133,470	146,896	245	147,141
2033	147,116	133,648	147,116	245	147,361
2034	147,221	133,723	147,221	245	147,466
2035	147,373	133,837	147,373	245	147,618
2036	147,519	133,949	147,519	245	147,764
2037	147,650	134,050	147,650	245	147,894
2038	147,741	134,115	147,741	245	147,986
2039	147,848	134,195	147,848	245	148,093
Average Annual Growth Rates					
Previous 10 Years	-0.72%	-1.83%	-1.83%	-33.96%	-1.96%
Previous 5 Years	-0.42%	-4.77%	-4.77%	-55.21%	-4.98%
Next 5 Years	0.85%	1.30%	3.28%	49.85%	3.31%
Next 10 Years	0.50%	0.74%	1.70%	22.41%	1.72%
Next 20 Years	0.32%	0.43%	0.92%	10.64%	0.92%

3.2 NON-COINCIDENT PEAK DEMAND

Rural NCP is forecasted monthly using an average of historical coincident factors examining the ratio between past coincident and non-coincident peaks. The Rural NCP value represents the single highest cooperative Rural load amount of the year regardless of the time it occurred. Direct Serve NCP is also forecasted using judgement and input from cooperative staff. The following table provides the last five years of historical data and the next 20 years of forecasted data for the Rural CP, Rural NCP, and Direct Serve NCP for JPEC's total system. Growth rates for the prior 5 years and projected growth rates for the next 5, 10, and 20 years are also provided in the table below.

Historical and Projected Demands

JPEC Peak (kW)						
Year	Total CP	% Change per Year in Total CP	Rural NCP	% Change per Year in Rural NCP	Direct Serve NCP	% Change per Year in Direct Serve NCP
2015	149,424		152,076		3,229	
2016	145,767	-2.45%	146,095	-3.93%	3,332	3.18%
2017	148,918	2.16%	148,902	1.92%	3,148	-5.51%
2018	145,079	-2.58%	146,742	-1.45%	1,793	-43.05%
2019	123,205	-15.08%	139,022	-5.26%	1,733	-3.31%
2020	142,392	15.57%	144,189	3.72%	1,201	-30.70%
2021	143,260	0.61%	145,069	0.61%	1,201	0.00%
2022	144,449	0.83%	145,815	0.51%	1,201	0.00%
2023	144,788	0.23%	146,162	0.24%	1,201	0.00%
2024	144,997	0.14%	146,376	0.15%	1,201	0.00%
2025	145,296	0.21%	146,682	0.21%	1,201	0.00%
2026	145,677	0.26%	147,071	0.27%	1,201	0.00%
2027	145,552	-0.09%	146,943	-0.09%	1,201	0.00%
2028	145,849	0.20%	147,247	0.21%	1,201	0.00%
2029	146,101	0.17%	147,505	0.18%	1,201	0.00%
2030	146,167	0.05%	147,575	0.05%	1,201	0.00%
2031	146,453	0.20%	147,869	0.20%	1,201	0.00%
2032	147,141	0.47%	148,576	0.48%	1,201	0.00%
2033	147,361	0.15%	148,804	0.15%	1,201	0.00%
2034	147,466	0.07%	148,916	0.08%	1,201	0.00%
2035	147,618	0.10%	149,075	0.11%	1,201	0.00%
2036	147,764	0.10%	149,229	0.10%	1,201	0.00%
2037	147,894	0.09%	149,367	0.09%	1,201	0.00%
2038	147,986	0.06%	149,466	0.07%	1,201	0.00%
2039	148,093	0.07%	149,581	0.08%	1,201	0.00%
Average Annual Growth Rates						
Previous 10 Years	-1.96%		-0.69%		-11.51%	
Previous 5 Years	-4.98%		-2.44%		-10.82%	
Next 5 Years	3.31%		1.04%		-7.07%	
Next 10 Years	1.72%		0.59%		-3.60%	
Next 20 Years	0.92%		0.37%		-1.82%	

4 ALTERNATIVE SYSTEM FORECASTS AND UNCERTAINTY ANALYSIS

While the projections summarized in previous sections should be viewed as the most probable outcome, it is important to remember that energy loads can be influenced by factors that are inherently difficult to predict, such as weather and the economy. Forecasting attempts to model reality and identify the primary drivers of growth and change. Each forecast has an inherent error tolerance between which actual observed outcomes are likely to fall. Therefore, it is important to develop flexible plans for meeting future energy needs based on a range of forecast outcomes.

The study includes scenario analyses that show how the forecasts change under assumed variations in future weather and economic growth paths. The alternate growth scenarios that have been explored are:

1. Extreme weather with normal economic growth
2. Mild weather with normal economic growth
3. High economic growth with normal weather
4. Low economic growth with normal weather

4.1 WEATHER SCENARIOS

Weather is one of the critical components to explain year-to-year variation in load. Because of this, extreme and mild weather scenarios were developed for the forecast period. The Residential use per consumer and GCI use per consumer monthly energy models use cooling degree days and heating degree days. For the creation of the mild and extreme energy scenarios these two variables were altered to a fifteen-year historical annual maximum and minimum value. These annual extremes were then redistributed across each month based on an average monthly distribution of cooling degree days and heating degree days. The Rural peak load factor model also contains cooling degree days and heating degree days for the month. Additionally, the load factor model captures peak day weather conditions. The extreme and mild weather scenarios alter the load factor model to use monthly weather conditions consistent with the energy models and change the peak day conditions to the most extreme or mild found in the last fifteen years of history for each

given month. The peak values displayed are a maximum of each monthly scenario value for the given season and therefore can occur in a different month than the base case forecast. Forecasts are provided in Excel that detail each scenario by month.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the mild, base, and extreme weather scenarios. The forecasts are for the Rural system.

Rural System Weather Scenarios

JPEC Rural System Weather Scenarios									
Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Mild	Base	Extreme	Mild	Base	Extreme	Mild	Base	Extreme
2015		665,040			147,777			152,076	
2016		661,559			129,764			144,033	
2017		628,392			130,891			148,902	
2018		664,405			145,041			145,856	
2019		633,355			123,172			138,722	
2020	626,258	657,825	695,249	117,709	128,901	140,228	132,454	142,147	160,712
2021	630,955	662,525	699,918	118,626	129,843	141,188	133,347	143,015	161,511
2022	635,016	666,559	703,889	119,410	130,639	141,989	135,062	144,204	162,166
2023	637,627	668,982	706,044	119,902	131,086	142,382	135,486	144,544	162,307
2024	639,512	670,668	707,457	120,233	131,366	142,601	135,778	144,752	162,324
2025	641,698	672,693	709,258	120,618	131,708	142,892	136,144	145,051	162,463
2026	644,139	675,011	711,402	121,048	132,106	143,251	136,579	145,432	162,716
2027	644,232	674,899	711,021	121,043	132,039	143,113	136,528	145,307	162,423
2028	646,152	676,704	712,669	121,368	132,330	143,363	136,870	145,604	162,616
2029	647,821	678,260	714,071	121,644	132,570	143,561	137,162	145,856	162,772
2030	648,611	678,909	714,539	121,752	132,631	143,569	137,275	145,922	162,735
2031	650,325	680,535	716,047	122,027	132,874	143,776	137,590	146,208	162,955
2032	653,802	684,011	719,511	122,624	133,470	144,364	138,278	146,896	163,633
2033	655,125	685,263	720,669	122,829	133,648	144,511	138,519	147,116	163,803
2034	655,901	685,957	721,260	122,934	133,723	144,553	138,649	147,221	163,857
2035	656,848	686,844	722,069	123,071	133,837	144,640	138,818	147,373	163,972
2036	657,739	687,688	722,852	123,201	133,949	144,731	138,976	147,519	164,089
2037	658,518	688,434	723,556	123,314	134,050	144,817	139,115	147,650	164,202
2038	659,115	688,992	724,067	123,393	134,115	144,865	139,217	147,741	164,273
2039	659,783	689,629	724,663	123,486	134,195	144,932	139,333	147,848	164,362

Direct Serve load is assumed to not be influenced by weather and is held constant to the base case forecast for the weather ranges. The extreme and mild ranges with the Direct Serve class included are shown below.

Total System Weather Scenarios

JPEC Total System Weather Scenarios									
Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Mild	Base	Extreme	Mild	Base	Extreme	Mild	Base	Extreme
2015		670,884			149,424			153,690	
2016		668,448			129,796			145,767	
2017		633,548			132,543			148,918	
2018		665,271			145,079			145,878	
2019		633,745			123,205			138,738	
2020	628,396	659,963	697,386	117,953	129,146	140,473	132,699	142,392	160,957
2021	633,092	664,662	702,056	118,871	130,088	141,433	133,592	143,260	161,756
2022	637,153	668,697	706,026	119,654	130,883	142,234	135,307	144,449	162,411
2023	639,764	671,119	708,181	120,146	131,331	142,627	135,731	144,788	162,552
2024	641,649	672,806	709,595	120,478	131,611	142,846	136,022	144,997	162,569
2025	643,835	674,830	711,395	120,862	131,953	143,137	136,389	145,296	162,708
2026	646,276	677,149	713,539	121,292	132,351	143,495	136,823	145,677	162,961
2027	646,369	677,036	713,159	121,288	132,283	143,358	136,773	145,552	162,668
2028	648,289	678,842	714,806	121,613	132,574	143,608	137,114	145,849	162,861
2029	649,959	680,397	716,208	121,889	132,814	143,805	137,407	146,101	163,017
2030	650,748	681,046	716,676	121,997	132,876	143,814	137,520	146,167	162,980
2031	652,462	682,672	718,184	122,271	133,119	144,021	137,834	146,453	163,199
2032	655,939	686,148	721,648	122,869	133,714	144,608	138,523	147,141	163,878
2033	657,263	687,400	722,806	123,074	133,893	144,756	138,764	147,361	164,048
2034	658,038	688,094	723,397	123,179	133,968	144,797	138,893	147,466	164,101
2035	658,985	688,981	724,206	123,316	134,082	144,884	139,063	147,618	164,216
2036	659,876	689,825	724,989	123,446	134,194	144,976	139,221	147,764	164,334
2037	660,655	690,571	725,693	123,559	134,295	145,061	139,360	147,894	164,447
2038	661,252	691,130	726,204	123,638	134,359	145,110	139,462	147,986	164,517
2039	661,921	691,766	726,800	123,731	134,440	145,177	139,578	148,093	164,606

4.2 Economic Scenarios

Another critical component of a long-term load forecast is the underlying economic variables within the service territory. Two scenarios have been developed: low economic growth and high economic growth. To create the economic scenarios, economic variables within each econometrically modeled class are altered by an additional plus or minus 1.0% per year relative to the base case forecast. The altered variables include electricity price, GRP, and employment. The forecast for Residential consumers, LCI, Irrigation, and Street and Highway are not modeled econometrically and are therefore directly modified by 1.0% per year relative to the base case forecast to create the high and low economic ranges.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the low, base, and high economic scenarios.

Rural System Economic Scenarios

JPEC Rural System Economic Scenarios									
Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Low	Base	High	Low	Base	High	Low	Base	High
2015		665,040			147,777			152,076	
2016		661,559			129,764			144,033	
2017		628,392			130,891			148,902	
2018		664,405			145,041			145,856	
2019		633,355			123,172			138,722	
2020	653,918	657,825	661,740	128,784	128,901	129,019	141,107	142,147	143,189
2021	651,335	662,525	673,766	128,305	129,843	131,386	140,402	143,015	145,640
2022	648,019	666,559	685,238	127,667	130,639	133,628	140,129	144,204	148,310
2023	643,082	668,982	695,152	126,678	131,086	135,534	138,884	144,544	150,262
2024	637,408	670,668	704,374	125,521	131,366	137,278	137,511	144,752	152,091
2025	632,032	672,693	714,020	124,421	131,708	139,100	136,221	145,051	154,026
2026	626,902	675,011	724,055	123,369	132,106	140,995	135,004	145,432	156,063
2027	619,511	674,899	731,531	121,882	132,039	142,401	133,320	145,307	157,564
2028	613,873	676,704	741,141	120,726	132,330	144,203	132,023	145,604	159,532
2029	607,988	678,260	750,547	119,521	132,570	145,961	130,682	145,856	161,464
2030	601,283	678,909	759,006	118,154	132,631	147,531	129,176	145,922	163,201
2031	595,432	680,535	768,620	116,949	132,874	149,315	127,862	146,208	165,196
2032	591,153	684,011	780,426	116,047	133,470	151,511	126,892	146,896	167,665
2033	584,926	685,263	789,772	114,778	133,648	153,248	125,513	147,116	169,615
2034	578,220	685,957	798,529	113,421	133,723	154,874	124,037	147,221	171,445
2035	571,674	686,844	807,566	112,098	133,837	156,555	122,601	147,373	173,339
2036	565,090	687,688	816,608	110,774	133,949	158,243	121,159	147,519	175,237
2037	558,426	688,434	825,586	109,441	134,050	159,926	119,706	147,650	177,127
2038	551,613	688,992	834,392	108,081	134,115	161,575	118,222	147,741	178,981
2039	544,866	689,629	843,345	106,734	134,195	163,252	116,752	147,848	180,865

The Direct Serve class is not modeled using econometric modeling. As such, the load is increased by an additional 1.0% per year relative to the base case in the high scenario. In the low scenario the Direct Serve class is decreased by 1.0% per year relative to the base case. The high and low ranges with the Direct Serve class included are shown below.

Total System Economic Scenarios

JPEC Total System Economic Scenarios									
Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Low	Base	High	Low	Base	High	Low	Base	High
2015		670,884			149,424			153,690	
2016		668,448			129,796			145,767	
2017		633,548			132,543			148,918	
2018		665,271			145,079			145,878	
2019		633,745			123,205			138,738	
2020	656,044	659,963	663,889	129,028	129,146	129,264	141,350	142,392	143,435
2021	653,440	664,662	675,936	128,548	130,088	131,633	140,643	143,260	145,889
2022	650,102	668,697	687,430	127,906	130,883	133,878	140,367	144,449	148,561
2023	645,143	671,119	697,365	126,915	131,331	135,786	139,120	144,788	150,516
2024	639,448	672,806	706,608	125,756	131,611	137,533	137,744	144,997	152,347
2025	634,051	674,830	716,276	124,654	131,953	139,358	136,452	145,296	154,285
2026	628,899	677,149	726,332	123,599	132,351	141,255	135,233	145,677	156,324
2027	621,487	677,036	733,830	122,110	132,283	142,663	133,546	145,552	157,827
2028	615,828	678,842	743,461	120,951	132,574	144,467	132,247	145,849	159,798
2029	609,921	680,397	752,888	119,744	132,814	146,228	130,903	146,101	161,732
2030	603,195	681,046	761,368	118,375	132,876	147,801	129,395	146,167	163,472
2031	597,322	682,672	771,004	117,167	133,119	149,587	128,079	146,453	165,469
2032	593,023	686,148	782,831	116,262	133,714	151,785	127,106	147,141	167,940
2033	586,774	687,400	792,198	114,991	133,893	153,524	125,725	147,361	169,893
2034	580,046	688,094	800,977	113,631	133,968	155,154	124,246	147,466	171,725
2035	573,479	688,981	810,035	112,306	134,082	156,837	122,807	147,618	173,622
2036	566,874	689,825	819,099	110,979	134,194	158,527	121,363	147,764	175,522
2037	560,188	690,571	828,099	109,644	134,295	160,212	119,908	147,894	177,415
2038	553,354	691,130	836,926	108,281	134,359	161,864	118,421	147,986	179,272
2039	546,585	691,766	845,900	106,932	134,440	163,544	116,949	148,093	181,158

5 Weather Normalized Values

Weather-sensitive electricity loads comprise a large portion of electricity end-uses. Weather conditions vary and will cause electricity sales and peak demands to increase during more extreme periods or decrease during milder periods. In this section, we provide estimates of energy and peak demands for JPEC during the last ten years with the assumption that temperatures had been at their 15-year normal amounts in each year.

The weather normalized values are calculated using the econometric models that identified weather as a driver of electricity sales. These are the Residential use per consumer and the GCI use per consumer models. Additionally, the load factor model (used to project peak demands) also includes temperature variables. The weather impacts of the deviation from the actual weather to the weather normalized weather are estimated using these models. The weather impacts are then added (or subtracted) to the actual load in that year to determine the weather normalized energy or peak demand.

The following table provides the last ten years of historical data for JPEC's Rural system. The normalized peak values displayed are a maximum of each monthly normalized value for the given season and therefore frequently occur in a different month than the actual value. Monthly normalized values are provided in Excel that detail the weather normalized values for each monthly peak day.

Rural System Weather Normalized

JPEC Rural System Weather Normalization						
Year	Energy (MWh)		Winter CP Demand (kW)		Summer CP Demand (kW)	
	Actual	Normalized	Actual	Normalized	Actual	Normalized
2010	701,841	667,526	143,361	134,538	160,441	148,843
2011	676,059	675,572	133,690	124,098	160,920	154,502
2012	663,607	665,929	125,246	136,778	158,592	141,509
2013	670,360	675,993	126,111	126,624	139,485	147,521
2014	685,357	670,073	157,275	144,706	141,668	140,681
2015	665,040	667,536	147,777	139,910	152,076	148,326
2016	661,559	657,993	129,764	123,945	144,033	142,338
2017	628,392	648,058	130,891	137,894	148,902	144,306
2018	664,405	640,687	145,041	134,008	145,856	140,362
2019	633,355	630,459	123,172	124,555	138,722	139,759

The following table provides the last ten years of historical data for JPEC's total system.

Total System Weather Normalized

JPEC Total System Weather Normalization						
Year	Energy (MWh)		Winter CP Demand (kW)		Summer CP Demand (kW)	
	Actual	Normalized	Actual	Normalized	Actual	Normalized
2010	716,681	682,366	145,343	136,633	160,463	150,760
2011	683,764	683,277	135,509	125,944	162,746	156,327
2012	668,864	671,186	125,267	136,799	158,614	141,531
2013	676,355	681,987	126,138	126,651	141,267	149,303
2014	690,322	675,038	159,073	146,504	141,684	142,571
2015	670,884	673,380	149,424	141,557	153,690	148,342
2016	668,448	664,882	129,796	125,656	145,767	144,072
2017	633,548	653,214	132,543	139,546	148,918	144,322
2018	665,271	641,553	145,079	134,045	145,878	140,383
2019	633,745	630,849	123,205	124,588	138,738	139,775

6 FORECAST METHODOLOGY

The load forecast process began by discussions with Clearspring Energy to solicit feedback from representatives of each member system as well as Big Rivers. The forecasting team issued an information request to each member system requesting monthly energy data by rate class, historical or anticipated changes in load on the system, large consumer energy and peak demand data, and retail price forecasts. Big Rivers provided historical demand data used as the basis to forecast load factors and peak demands.

In addition to this data, Clearspring Energy collected a variety of additional data to develop the load forecast. This included county-level historical socioeconomic data from Woods & Poole Economics, Inc., historical alternative fuel price data and energy efficiency indexes from the Energy Information Administration (EIA), monthly and daily weather data from the Midwest Regional Climate Center (MRCC) and High Plains Regional Climate Center (HPRCC), and appliance and end-use saturations for each member system based off historical end-use surveys conducted by Big Rivers. The most recent survey was conducted in 2019.

6.1 DATABASE SETUP AND ANALYSES

Upon receipt of the associated member systems' data, Big Rivers' data and data obtained from external sources, Clearspring Energy reviewed the data for accuracy and adequacy for use in the study. An electronic database with consumer and energy sales by rate class and demand data was developed using Microsoft Excel™.

County-level economic and demographic data was gathered and added to the energy database. Weighted averages were calculated using customized member system county weights based on the service territory of each member system. The appropriate weights are calculated using the number of Residential consumers served for each member system by county.

Weather variables were also calculated and added to the database. Appropriate customized weather station data was used based on the service territory location of each member system. Historical fifteen-year averages of the selected weather variables were calculated and used as the basis for the normal weather expectation in future years and in the weather normalization results.

All price information is adjusted for inflation using an inflation adjustment from the Congressional Budget Office (CBO).

Data Category	Data Source
Energy, Demand, Customers, and Electricity Price	Big Rivers and its three member systems
Economic & Demographic	Woods & Poole Economics, Inc.
Weather	Midwest Regional Climate Center High Plains Regional Climate Center
Alternative Fuel Prices and Appliance Energy Efficiency	Energy Information Administration
End-Use Appliance Saturations	Big Rivers Survey Reports

6.2 Model Development

Clearspring estimated econometric models to forecast Residential use per consumer, GCI consumers, GCI use per consumer, and the load factor. A separate model was developed for each member system and for each component. A growth index using household forecasts was used to escalate Residential consumers.

Forecasts for the LCI and Direct Serve commercial consumers were prepared judgmentally based on input from the cooperatives. Due to their relatively small size, trend analysis was used to project the Street and Highway and Irrigation classes.

Econometric parameters were estimated using the ordinary least squares (OLS) approach to regression analysis employed by the EViews™ version 10 econometric software package. Heteroskedasticity adjusted standard errors were calculated for statistical significance testing of the included variables. The models were selected based on theoretical and statistical validity as well as the reasonableness of the forecast results generated.

The statistical validity of each variable included in the model needed to pass two key criterion to be included in the model. A simple but important standard is that the coefficient of each explanatory variable must have a logical sign. For example, energy sales will generally increase during periods of colder or hotter weather (i.e., these variables should have positive coefficients). Conversely,

energy sales generally decrease with increasing electricity prices (i.e., the coefficient of this variable should be negative).

The second criterion is the fact that each explanatory variable has a statistically significant influence on the dependent variable. The statistical significance of an explanatory variable is measured by the t-statistic. The specific value of a particular t-statistic required for statistical significance depends on both the degrees of freedom (the number of data points less the number of variables) of the equations and desired level of confidence in the estimated coefficients. In general, however, the t-statistic should have a magnitude of at least 1.645 for a 90 percent level of confidence.

Another validity criterion that we took into consideration are examinations of the equation residuals (the difference between the actual historical and estimated historical values). In a good equation, the residuals are randomly distributed and of approximately constant magnitude, in absolute terms. This indicates that there is no obvious pattern in the data that has not been explained by the equation.

The models developed must also pass a test of reasonableness. Models must make intuitive sense to the members of the forecasting team and the forecasts that result must be plausible given reasonable assumptions of growth factors.

6.3 FORECAST DEVELOPMENT

Using the econometric equations developed as part of the modeling process, monthly forecasts were created for each of the member systems. The modeled classes are calculated using the estimated equations along with forecasted values for those variables that enter into the estimated equation.

The amount of energy required by each system (ultimately provided by Big Rivers) is greater than the sum of the retail energy sales. System own-use and energy losses are forecast for each member system. Energy losses are forecasted as a percentage of total system energy requirements based on historical loss data.

Three monthly demand values are determined for each of the member distribution cooperatives. The individual Direct Serve consumer non-coincident peaks, the distribution cooperative's Rural non-coincident peak demand, and its contribution to the Big Rivers monthly coincident peak (CP).

Clearspring developed a load factor econometric model to forecast the Rural coincident peak load factor which we then use to calculate the peak demand forecasts for each of the three member systems.

Preliminary forecasts were distributed to the respective member systems and Big Rivers for their review and input. The member systems offered suggestions for revisions to the forecasts and these revisions were incorporated.

6.4 Changes in Methodology From 2017 Load Forecast

The 2020 research was conducted by Clearspring Energy Advisors, LLC whereas the 2017 research was conducted by GDS Associates, Inc ("GDS"). Clearspring has reviewed the past load forecast report and other documents and lists the known methodological changes that we are aware of based on this review of the prior consultants' research. We note that it is often precarious to assume what the exact research of another consultant consisted of. We offer the list with the caveat that we may be incorrect in interpreting the exact methodological approach used by GDS.

1. Clearspring uses "weighted" economic and demographic variables that are weighted based on the calculated consumer counts in each county served by each member system. We believe that GDS did not calculate the variables based on weighted consumer counts but used unweighted variables.
2. GDS used a Statistical Adjusted End-Use (SAE) modeling approach. Clearspring uses econometric modeling to directly estimate the impacts of variables that influence use per consumer or consumer counts.
3. Clearspring directly models the electricity price in relationship to an alternative price fuel index (comprised of natural gas and propane prices). We are not aware of GDS directly inserting alternative fuel prices into the analysis.
4. Clearspring calculates the price elasticity based on the relative impact of the electricity price and the alternative fuel index. This price elasticity is estimated directly in the econometric model. Conversely, GDS did not use their SAE modeling but, rather, estimated the price elasticity with a separate econometric model that did not account for other possible drivers of electricity use.

5. Clearspring uses a 15-year weather normal for the base case load forecasts, whereas GDS used a 20-year weather normal.
6. Different weather station mappings were used.
7. Clearspring uses daily high/low temperature values for the load factor econometric model used to forecast peak demands. GDS appears to use hourly values to forecast peak demands.
8. GDS makes some references to using trended energy amounts in models. It is unclear exactly what that means but there are likely differences in the methods used to allocate energy to each specific month.

7 APPENDIX

The following table provides the details on the consumers, sales, and use per consumer for each class for JPEC's system. The prior five years and the forecasted year values are provided in the table. Both historical and forecasted growth rates for each class are also provided.

Jackson Purchase Energy Corporation															
RESIDENTIAL	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	25,347	25,380	25,632	25,578	25,516	25,606	25,735	25,819	25,875	25,911	25,930	25,937	25,934	25,921	25,895
SALES-MWH	379,943	377,370	355,608	391,939	370,062	372,513	373,782	374,682	374,518	374,024	373,714	373,677	372,657	372,202	371,528
USE PER CONSUMER-kWH	14,990	14,869	13,873	15,323	14,503	14,548	14,524	14,512	14,474	14,435	14,412	14,407	14,369	14,359	14,347
GENERAL C&I	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	4,001	4,226	4,355	4,437	4,498	4,557	4,601	4,648	4,691	4,735	4,779	4,823	4,866	4,907	4,948
SALES-MWH	207,862	208,270	208,762	208,524	194,154	213,323	216,559	219,527	222,015	224,126	226,377	228,637	229,549	231,735	233,900
USE PER CONSUMER-kWH	51,952	49,280	47,934	46,998	43,166	46,810	47,064	47,233	47,324	47,332	47,369	47,409	47,178	47,222	47,271
LARGE C&I	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	8	7	5	6	8	9	9	9	9	9	9	9	9	9	9
SALES-MWH	48,159	42,725	34,940	36,537	44,070	44,070	44,070	44,070	44,070	44,070	44,070	44,070	44,070	44,070	44,070
USE PER CONSUMER-kWH	6,019,886	5,893,043	6,450,435	6,089,574	5,288,380	4,896,648	4,896,648	4,896,648	4,896,648	4,896,648	4,896,648	4,896,648	4,896,648	4,896,648	4,896,648
IRRIGATION	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	4	4	4	5	5	5	5	5	5	5	5	5	5	5	5
SALES-MWH	62	51	102	70	108	108	108	108	108	108	108	108	108	108	108
USE PER CONSUMER-kWH	15,428	12,760	25,437	15,618	21,652	21,652	21,652	21,652	21,652	21,652	21,652	21,652	21,652	21,652	21,652
STREET & HIGHWAY	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	3	4	5	6	7	9	9	9	9	9	9	9	9	9	9
SALES-MWH	626	632	628	621	630	682	682	682	682	682	682	682	682	682	682
USE PER CONSUMER-kWH	203,037	145,844	139,532	111,140	92,254	75,766	75,766	75,766	75,766	75,766	75,766	75,766	75,766	75,766	75,766
RURAL TOTAL	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	29,363	29,621	30,001	30,031	30,034	30,186	30,359	30,490	30,589	30,669	30,732	30,783	30,823	30,851	30,866
SALES-MWH	636,652	629,047	600,039	637,691	609,025	630,696	635,202	639,070	641,393	643,009	644,951	647,174	647,066	648,797	650,289
USE PER CONSUMER-kWH	21,682	21,236	20,000	21,234	20,278	20,894	20,923	20,960	20,968	20,966	20,986	21,024	20,993	21,030	21,068
OWNUSE-MWH	185	179	173	185	179	180	181	182	182	183	183	184	184	184	184
PURCHASES-MWH	665,040	661,559	628,392	664,405	633,355	657,825	662,525	666,559	668,982	670,668	672,693	675,011	674,899	676,704	678,260
LOSSES-MWH	28,204	32,332	28,180	26,529	24,151	26,950	27,142	27,308	27,407	27,476	27,559	27,654	27,649	27,723	27,787
LOSSES (%)	4.2%	4.9%	4.5%	4.0%	3.8%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%
DIRECT SERVE	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
SALES-MWH	5,844	6,889	5,156	866	390	2,137	2,137	2,137	2,137	2,137	2,137	2,137	2,137	2,137	2,137
USE PER CONSUMER-kWH	5,843,850	6,889,161	5,155,580	865,807	390,236	2,137,207	2,137,207	2,137,207	2,137,207	2,137,207	2,137,207	2,137,207	2,137,207	2,137,207	2,137,207
SYSTEM TOTAL WITH DIRECT SERVE	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	29,364	29,622	30,002	30,032	30,035	30,187	30,360	30,491	30,590	30,670	30,733	30,784	30,824	30,852	30,867
SALES-MWH	642,495	635,937	605,195	638,557	609,415	632,833	637,339	641,207	643,530	645,147	647,088	649,311	649,203	650,934	652,426
USE PER CONSUMER-kWH	21,880	21,468	20,172	21,263	20,290	20,964	20,993	21,029	21,037	21,035	21,055	21,093	21,062	21,099	21,136
OWNUSE-MWH	185	179	173	185	179	180	181	182	182	183	183	184	184	184	184
PURCHASES-MWH	670,884	668,448	633,548	665,271	633,745	659,963	664,662	668,697	671,119	672,806	674,830	677,149	677,036	678,842	680,397
LOSSES-MWH	28,204	32,332	28,180	26,529	24,151	26,950	27,142	27,308	27,407	27,476	27,559	27,654	27,649	27,723	27,787
LOSSES (%)	4.2%	4.8%	4.4%	4.0%	3.8%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%
ANNUAL PEAK	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
RURAL CP - kW	147,777	144,033	148,902	145,041	123,172	142,147	143,015	144,204	144,544	144,752	145,051	145,432	145,307	145,604	145,856
DIRECT SERVE CP - kW	1,647	1,733	16	38	32	245	245	245	245	245	245	245	245	245	245
TOTAL CP - kW	149,424	145,767	148,918	145,079	123,205	142,392	143,260	144,449	144,788	144,997	145,296	145,677	145,552	145,849	146,101
RURAL NCP - kW	152,076	146,095	148,902	146,742	139,022	144,189	145,069	145,815	146,162	146,376	146,682	147,071	146,943	147,247	147,505
DIRECT SERVE SUM OF INDIVIDUAL NCP - kW	3,229	3,332	3,148	1,793	1,733	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201

Case No. 2020-00299

Attachment 1 for Response to PSC 1-52d

Witnesses: Matthew S. Sekeres and Steven A. Fenrick

Jackson Purchase Energy Corporation											Last 10 Yrs	Last 5 Yrs	Next 5 Yrs	Next 10 Yrs	Next 20 Yrs
RESIDENTIAL	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	25,858	25,812	25,757	25,695	25,627	25,556	25,483	25,409	25,336	25,265	-0.2%	-0.1%	0.3%	0.1%	0.0%
SALES-MWH	370,374	369,523	369,342	368,491	367,438	366,473	365,533	364,674	363,774	362,929	-0.5%	-1.8%	0.2%	0.0%	-0.1%
USE PER CONSUMER-kWH	14,323	14,316	14,340	14,341	14,338	14,340	14,344	14,352	14,358	14,365	-0.3%	-1.7%	-0.1%	-0.1%	0.0%
GENERAL C&I	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	4,988	5,026	5,062	5,096	5,129	5,160	5,190	5,218	5,245	5,271	3.9%	4.7%	1.0%	1.0%	0.8%
SALES-MWH	235,677	238,088	241,602	243,655	245,373	247,189	248,939	250,513	251,949	253,405	1.0%	-0.9%	2.9%	1.9%	1.3%
USE PER CONSUMER-kWH	47,251	47,374	47,730	47,811	47,840	47,902	47,967	48,009	48,034	48,074	-2.8%	-5.3%	1.9%	0.9%	0.5%
LARGE C&I	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	9	9	9	9	9	9	9	9	9	9	2.6%	-1.7%	1.6%	0.8%	0.4%
SALES-MWH	44,070	44,070	44,070	44,070	44,070	44,070	44,070	44,070	44,070	44,070	0.5%	-2.2%	0.0%	0.0%	0.0%
USE PER CONSUMER-kWH	4,896,648	4,896,648	4,896,648	4,896,648	4,896,648	4,896,648	4,896,648	4,896,648	4,896,648	4,896,648	-2.1%	-0.5%	-1.5%	-0.8%	-0.4%
IRRIGATION	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	5	5	5	5	5	5	5	5	5	5	-5.2%	4.6%	0.0%	0.0%	0.0%
SALES-MWH	108	108	108	108	108	108	108	108	108	108	-12.4%	-4.5%	0.0%	0.0%	0.0%
USE PER CONSUMER-kWH	21,652	21,652	21,652	21,652	21,652	21,652	21,652	21,652	21,652	21,652	-7.6%	-8.7%	0.0%	0.0%	0.0%
STREET & HIGHWAY	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	9	9	9	9	9	9	9	9	9	9	8.6%	17.9%	5.7%	2.8%	1.4%
SALES-MWH	682	682	682	682	682	682	682	682	682	682	0.1%	0.5%	1.6%	0.8%	0.4%
USE PER CONSUMER-kWH	75,766	75,766	75,766	75,766	75,766	75,766	75,766	75,766	75,766	75,766	-7.9%	-14.8%	-3.9%	-1.9%	-1.0%
RURAL TOTAL	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	30,869	30,861	30,841	30,814	30,779	30,740	30,696	30,650	30,604	30,559	0.3%	0.5%	0.4%	0.3%	0.1%
SALES-MWH	650,911	652,471	655,805	657,005	657,671	658,522	659,331	660,047	660,583	661,194	0.0%	-1.6%	1.1%	0.7%	0.4%
USE PER CONSUMER-kWH	21,086	21,142	21,264	21,322	21,368	21,423	21,479	21,535	21,585	21,637	-0.3%	-2.0%	0.7%	0.4%	0.3%
OWNUSE-MWH	184	184	184	184	184	183	183	183	182	182	1.2%	-1.4%	0.4%	0.3%	0.1%
PURCHASES-MWH	678,909	680,535	684,011	685,263	685,957	686,844	687,688	688,434	688,992	689,629	-0.1%	-1.6%	1.2%	0.7%	0.4%
LOSSES-MWH	27,814	27,880	28,023	28,074	28,102	28,139	28,173	28,204	28,227	28,253	-3.2%	-1.9%	2.6%	1.4%	0.8%
LOSSES (%)	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	-3.1%	-0.3%	1.4%	0.7%	0.4%
DIRECT SERVE	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	1	1	1	1	1	1	1	1	1	1	0.0%	0.0%	0.0%	0.0%	0.0%
SALES-MWH	2,137	2,137	2,137	2,137	2,137	2,137	2,137	2,137	2,137	2,137	-30.7%	-39.9%	40.5%	18.5%	8.9%
USE PER CONSUMER-kWH	2,137,207	2,137,207	2,137,207	2,137,207	2,137,207	2,137,207	2,137,207	2,137,207	2,137,207	2,137,207	-30.7%	-39.9%	40.5%	18.5%	8.9%
SYSTEM TOTAL WITH DIRECT SERVE	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	30,870	30,862	30,842	30,815	30,780	30,741	30,697	30,651	30,605	30,560	0.3%	0.5%	0.4%	0.3%	0.1%
SALES-MWH	653,049	654,608	657,942	659,143	659,809	660,659	661,469	662,184	662,720	663,331	-0.2%	-1.7%	1.1%	0.7%	0.4%
USE PER CONSUMER-kWH	21,155	21,211	21,332	21,390	21,436	21,491	21,548	21,604	21,654	21,706	-0.5%	-2.2%	0.7%	0.4%	0.3%
OWNUSE-MWH	184	184	184	184	184	183	183	183	182	182	1.2%	-1.4%	0.4%	0.3%	0.1%
PURCHASES-MWH	681,046	682,672	686,148	687,400	688,094	688,981	689,825	690,571	691,130	691,766	-0.3%	-1.7%	1.2%	0.7%	0.4%
LOSSES-MWH	27,814	27,880	28,023	28,074	28,102	28,139	28,173	28,204	28,227	28,253	-3.2%	-1.9%	2.6%	1.4%	0.8%
LOSSES (%)	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	-2.9%	-0.2%	1.4%	0.7%	0.3%
ANNUAL PEAK	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
RURAL CP - kW	145,922	146,208	146,896	147,116	147,221	147,373	147,519	147,650	147,741	147,848	-1.8%	-4.8%	3.3%	1.7%	0.9%
DIRECT SERVE CP - kW	245	245	245	245	245	245	245	245	245	245	-34.0%	-55.2%	49.8%	22.4%	10.6%
TOTAL CP - kW	146,167	146,453	147,141	147,361	147,466	147,618	147,764	147,894	147,986	148,093	-2.0%	-5.0%	3.3%	1.7%	0.9%
RURAL NCP - kW	147,575	147,869	148,576	148,804	148,916	149,075	149,229	149,367	149,466	149,581	-0.7%	-2.4%	1.0%	0.6%	0.4%
DIRECT SERVE SUM OF INDIVIDUAL NCP - kW	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	-11.5%	-10.8%	-7.1%	-3.6%	-1.8%

LOAD FORECAST

2020

Big Rivers
ELECTRIC CORPORATION

Case No. 2020-00299
Attachment 2 for Response to PSC 1-52d
Witnesses: Matthew S. Sekeres and Steven A. Fenrick

2020 Kenergy Corporation Load Forecast Study

Developed in partnership with

Big Rivers Electric Corporation

and

Kenergy Corporation

June 8, 2020

Prepared By:

Clearspring Energy Advisors LLC

1050 Regent St., Suite L3

Madison, WI 53715

608.442.8668

Confidentiality Statement

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1 Introduction and System Summary

1.1 Project Overview

The 2020 Big Rivers Electric Corporation ("Big Rivers") electric load forecast has been created from the bottom up. That is, forecast models have been developed for each of the three distribution systems served by Big Rivers. Each distribution member forecast is conducted separately, and each distribution member has reviewed and approved the load forecast applicable to its system.

Clearspring Energy Advisors, LLC (Clearspring) was selected by Big Rivers and its members to prepare this 2020 electric load forecast. The forecasting process relies heavily on internal system data, third-party demographic and economic data, and insight from cooperative staff that are most familiar with the end-uses and trends in the service territory. An emphasis has been placed on strong coordination between Big Rivers, the three member systems, and Clearspring in preparing this study to ensure accurate and useful load forecast results.

The forecast team members include the following individuals.

Name	Company	Role
Marlene Parsley	Big Rivers Electric Corporation	Project Manager
Russ Pogue	Big Rivers Electric Corporation	DSM Study
Steve Thompson	Kenergy Corporation	Vice President of Finance
Travis Siewert	Kenergy Corporation	Manager of General Accounting
Matt Sekeres	Clearspring Energy Advisors	Lead Consultant
Steve Fenrick	Clearspring Energy Advisors	Econometric Model Development
Josh Hoyt	Clearspring Energy Advisors	DSM Study

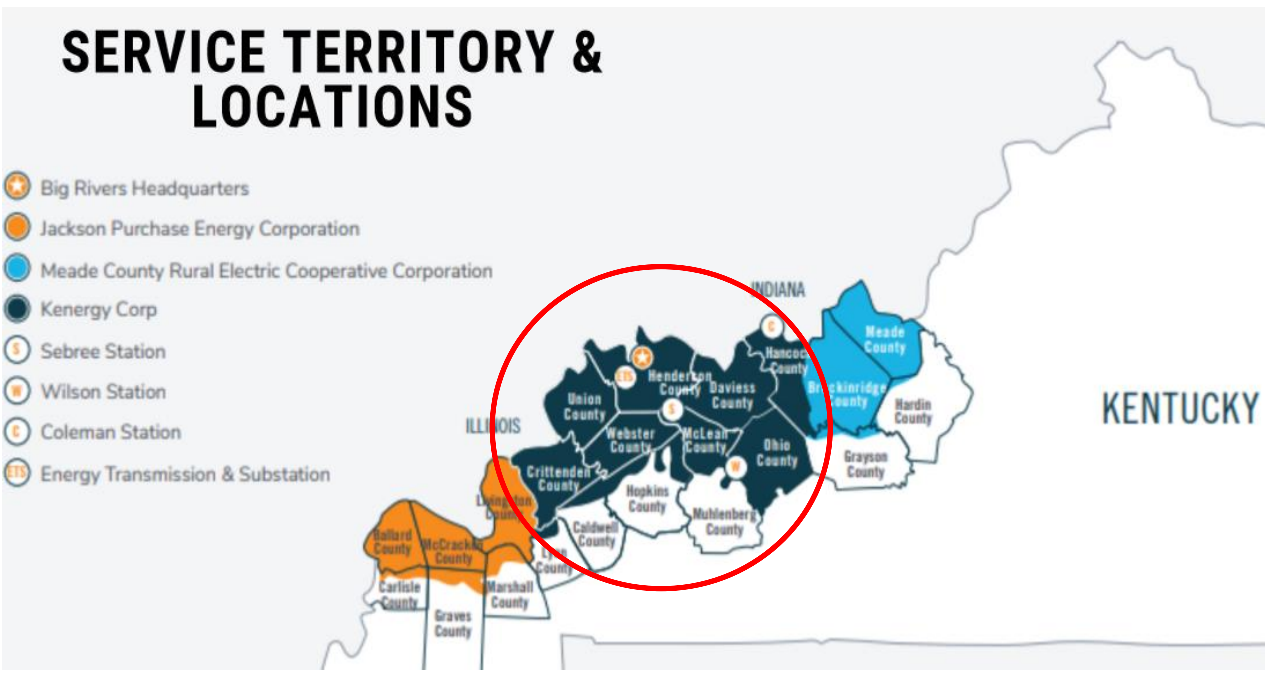
The forecast results meet the requirements of and will be used in USDA Rural Utilities Service ("RUS") loan applications, the forecast will be a key input into an Integrated Resource Plan ("IRP") being completed by Big Rivers under the direction of the Kentucky Public Service Commission (“Commission”), and the forecast will be used for planning and financial projections.

1.2 Member Information

The three distribution cooperatives are Jackson Purchase Energy Corporation, Kenergy Corporation, and Meade County Rural Electric Cooperative Corporation. These three Big Rivers members serve more than 118,000 residential households, businesses, and farms in western Kentucky. This report details the load forecast for Kenergy Corporation (“Kenergy”).

Kenergy served approximately 58,000 members in 2019 and maintains over 7,100 miles of power line. The service territory of Kenergy is circled below.

Service Territory



1.3 Forecast Summary

The forecast study develops a forecast for individual retail classes. The forecasted retail classes are:

- Residential,

- General Commercial and Industrial ("GCI"),
- Large Commercial and Industrial ("LCI"),
- Street & Highway, and
- Direct Serve sales.

The Residential, GCI, LCI, and Street and Highway classes along with distribution and own losses make up the Rural system requirements. Direct Serve sales are aggregated with the Rural system to provide total system requirements. Kenergy's retail class sales forecast is the product of the consumer forecast and the use per consumer forecast for each class. Kenergy's total sales forecast is constructed by summing the individual retail class sales forecasts.

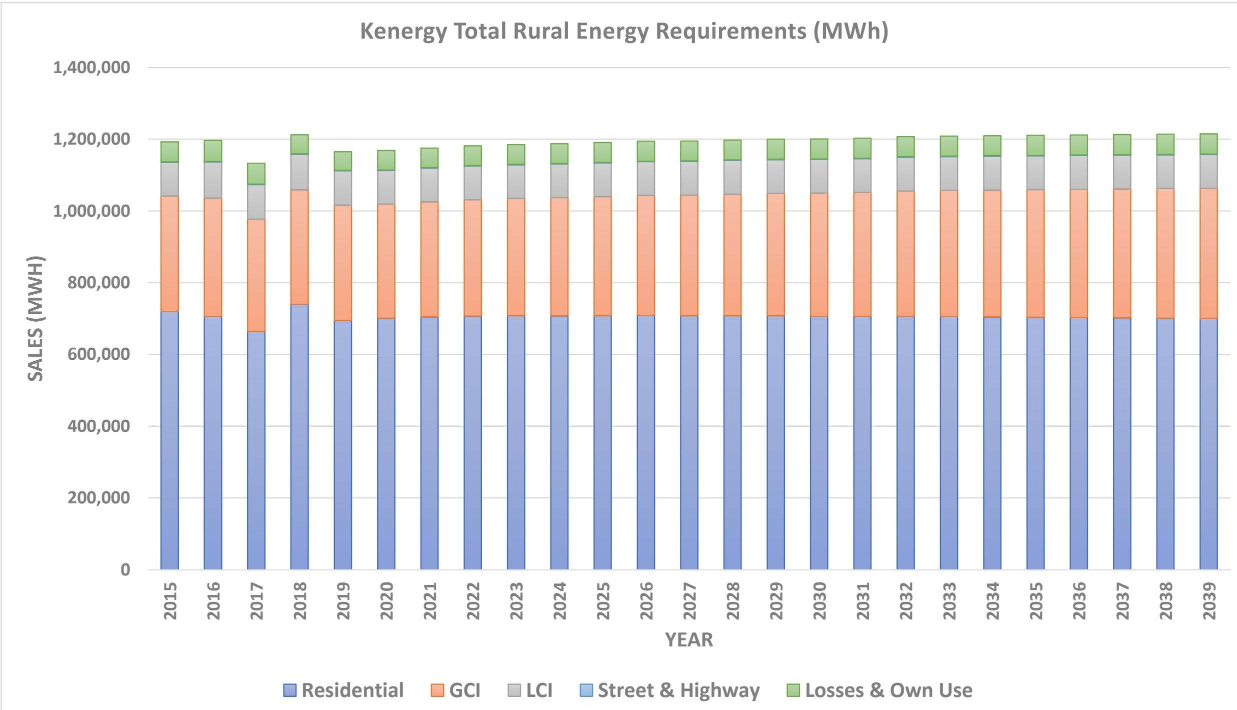
The table below provides Kenergy's Rural energy requirements, Direct Serve energy requirements, Rural peak demand coincident to Big Rivers, Direct Serve sum of individual non-coincident peak (NCP) and Rural system load factor for the last five historical years (2015-2019) and the forecasts for the next 20 years. Throughout this load forecast study, 2019 is considered a historical data year even though due to timeline considerations November and December of 2019 often contain estimated data.

System Summary

Kenergy System Totals					
Year	Total Rural Energy Requirements (MWh)	Direct Serve Energy Requirements (MWh)	Rural System Coincident Peak Demand (MW)	Direct Serve Sum of Individual NCP (MW)	Rural System Coincident Peak Load Factor
2015	1,192,608	7,653,848	282.4	1,026.1	48.2%
2016	1,196,513	6,015,387	252.1	730.8	54.0%
2017	1,132,856	6,033,800	260.9	735.0	49.6%
2018	1,212,570	6,327,349	272.9	891.2	50.7%
2019	1,165,073	7,220,918	243.2	938.4	54.7%
2020	1,168,414	7,026,368	246.3	842.0	54.0%
2021	1,175,466	7,026,368	247.7	842.0	54.2%
2022	1,181,432	7,026,368	247.9	842.0	54.4%
2023	1,184,956	7,026,368	248.6	842.0	54.4%
2024	1,187,470	7,026,368	249.1	842.0	54.3%
2025	1,190,502	7,026,368	249.7	842.0	54.4%
2026	1,194,276	7,026,368	250.4	842.0	54.4%
2027	1,194,968	7,026,368	250.6	842.0	54.4%
2028	1,197,732	7,026,368	251.2	842.0	54.3%
2029	1,200,013	7,026,368	251.6	842.0	54.4%
2030	1,200,985	7,026,368	251.9	842.0	54.4%
2031	1,202,995	7,026,368	252.3	842.0	54.4%
2032	1,207,253	7,026,368	253.2	842.0	54.3%
2033	1,208,937	7,026,368	253.6	842.0	54.4%
2034	1,209,959	7,026,368	253.9	842.0	54.4%
2035	1,211,071	7,026,368	254.1	842.0	54.4%
2036	1,212,117	7,026,368	254.3	842.0	54.3%
2037	1,213,197	7,026,368	254.6	842.0	54.4%
2038	1,214,050	7,026,368	254.8	842.0	54.4%
2039	1,215,002	7,026,368	255.0	842.0	54.4%
Average Annual Growth Rates					
Previous 10 Years	0.18%	-0.54%	-1.40%	-0.75%	1.60%
Previous 5 Years	-1.24%	-3.19%	-4.74%	-1.93%	3.67%
Next 5 Years	0.38%	-0.54%	0.48%	-2.15%	-0.15%
Next 10 Years	0.30%	-0.27%	0.34%	-1.08%	-0.05%
Next 20 Years	0.21%	-0.14%	0.24%	-0.54%	-0.03%

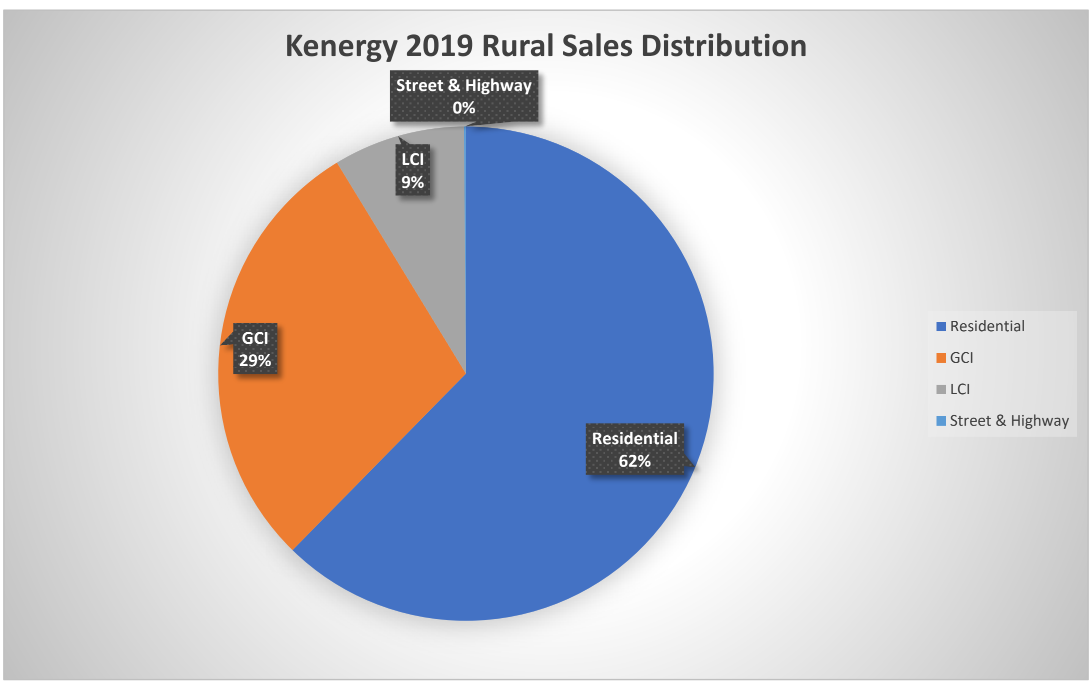
The following graph provides the cooperative's total system Rural energy requirements forecast.

Rural Energy Requirements



The figure below provides the cooperative's Rural sales distribution by class for 2019.

2019 Sales by Class Distribution



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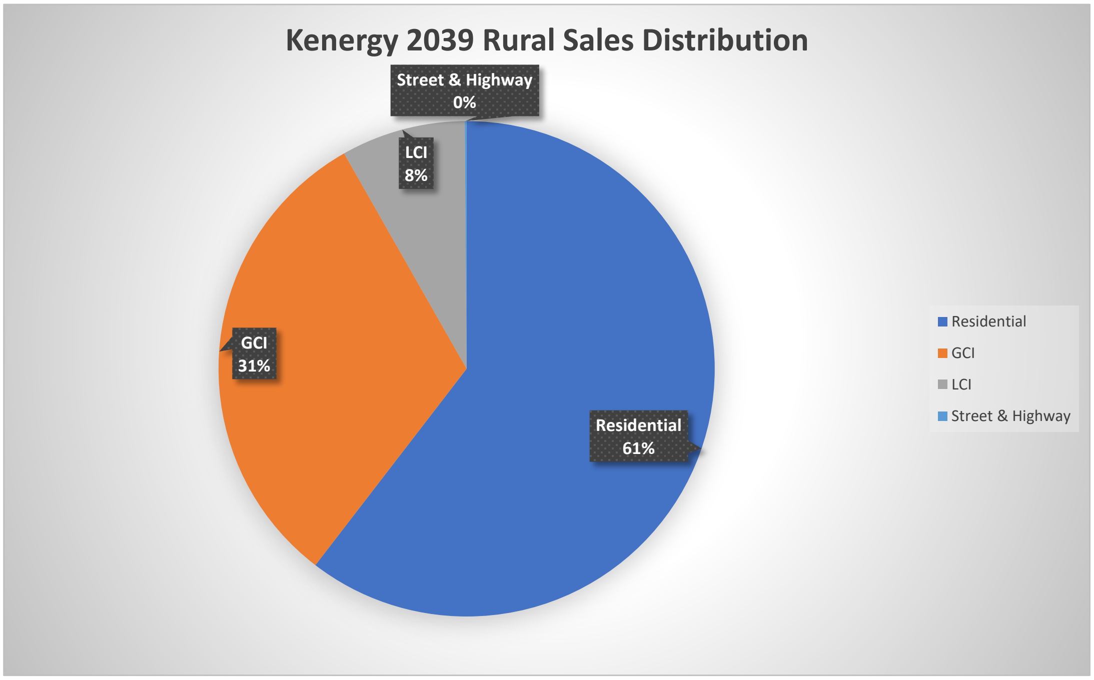
The figure below provides the cooperative's Rural sales forecasted distribution by class for 2039.

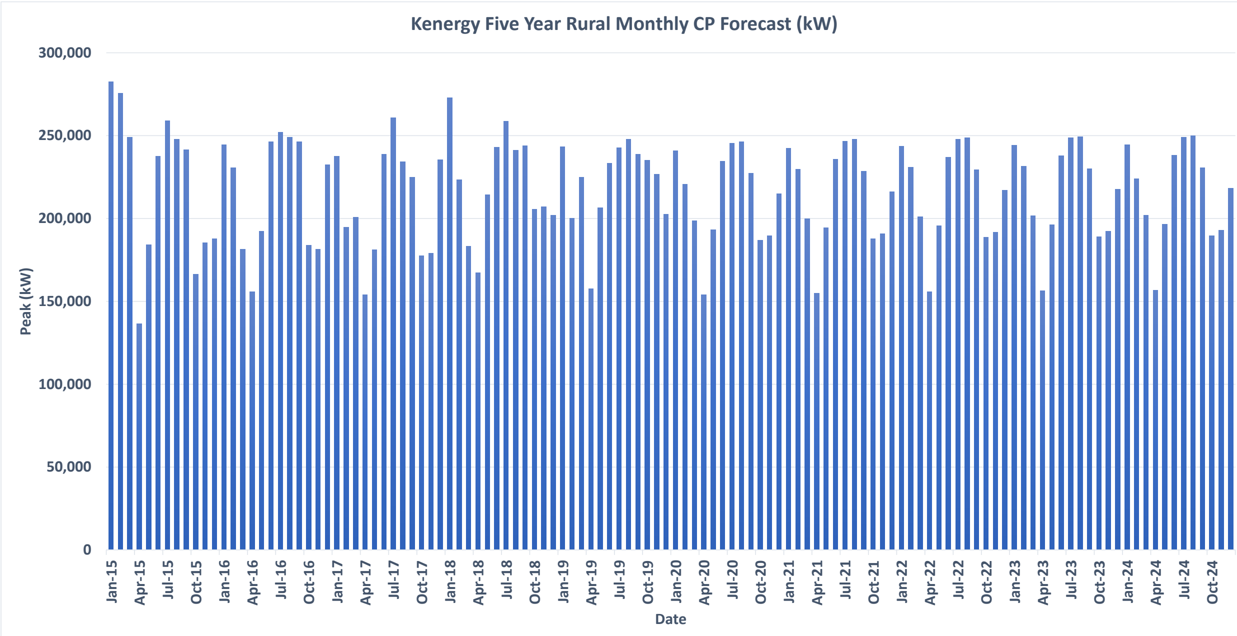
2039 Sales by Class Distribution



1.3.1 Monthly Peak Forecast

Monthly load factors have been econometrically modeled for each system. The load factor models are used in conjunction with the energy forecasts to calculate peak monthly peak demands. The monthly Rural peak demand forecast (coincident with Big Rivers) for the prior and next five years is presented in the following figure.

Monthly Rural Peak Forecast

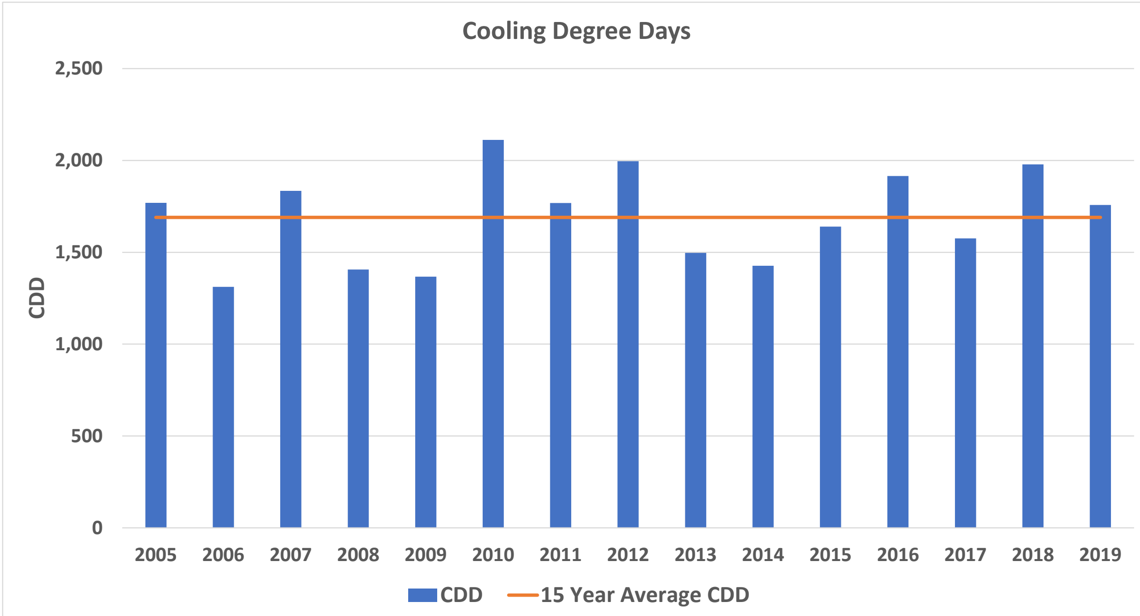


1.4 2019 Weather Conditions

There contains an assumption of a "normal" weather scenario for the forecasts for each class. Clearspring Energy compiled historical weather observations to enable the estimation of weather impacts onto sales and peak loads. Weather variables such as cooling degree days (CDD), heating degree days (HDD), and peak temperatures were gathered using weather stations within each service territory. Owensboro, KY was used as the primary weather station to gather data for Kenergy. In the cases of missing historical data at Owensboro, a variety of backup stations were used to fill in missing data.

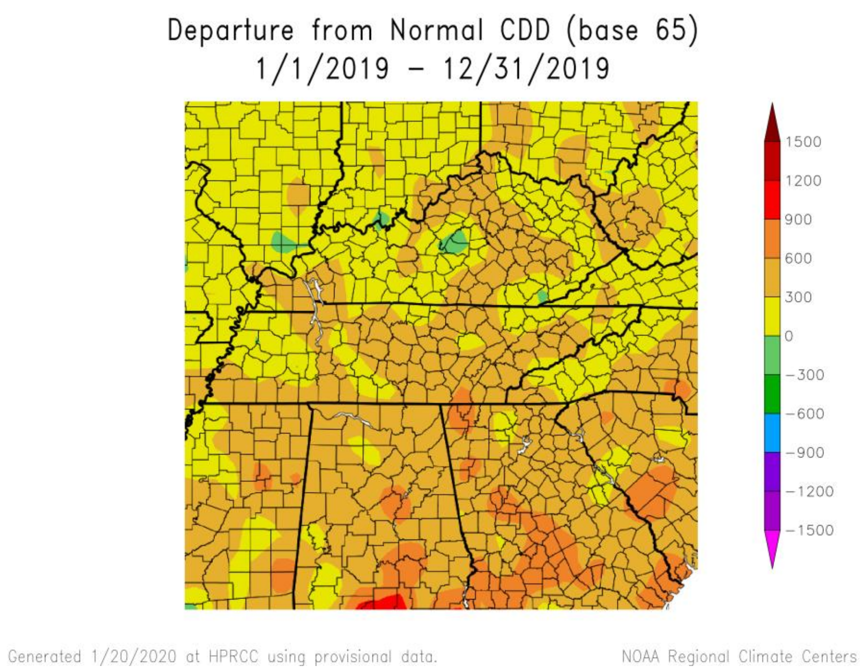
The figure below displays the last fifteen years of CDDs for Kenergy along with the 15-year average CDD.

Cooling Degree Days for Last 15 Years



The figure below provides the CDD deviation in 2019 from a 30-year normal amount for the entire state of Kentucky.

Kentucky 2019 CDD Deviations



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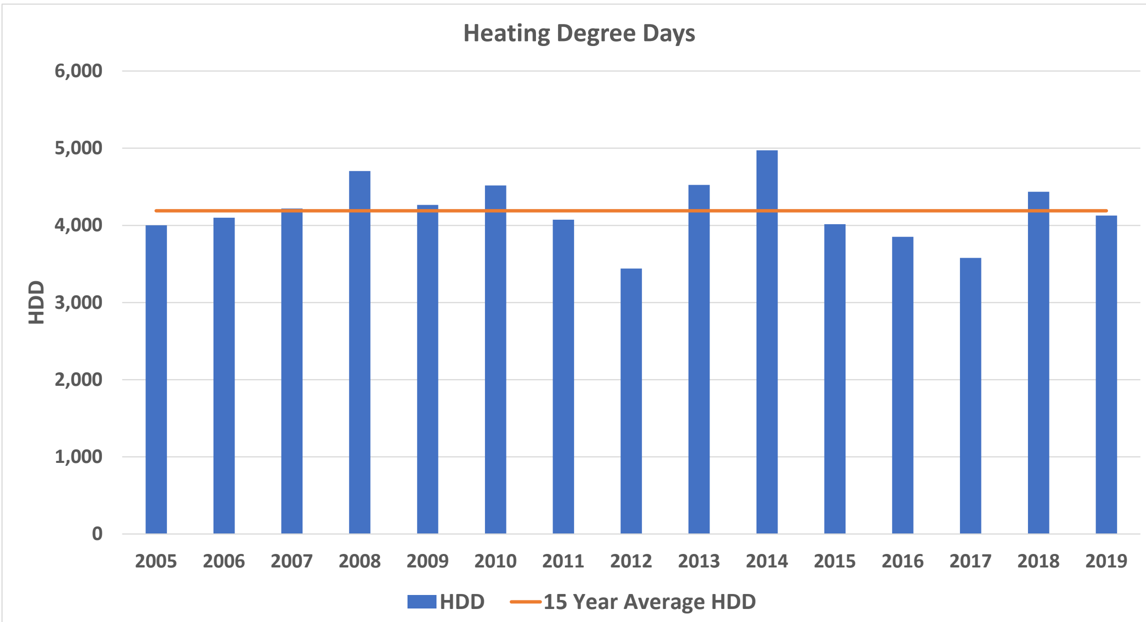
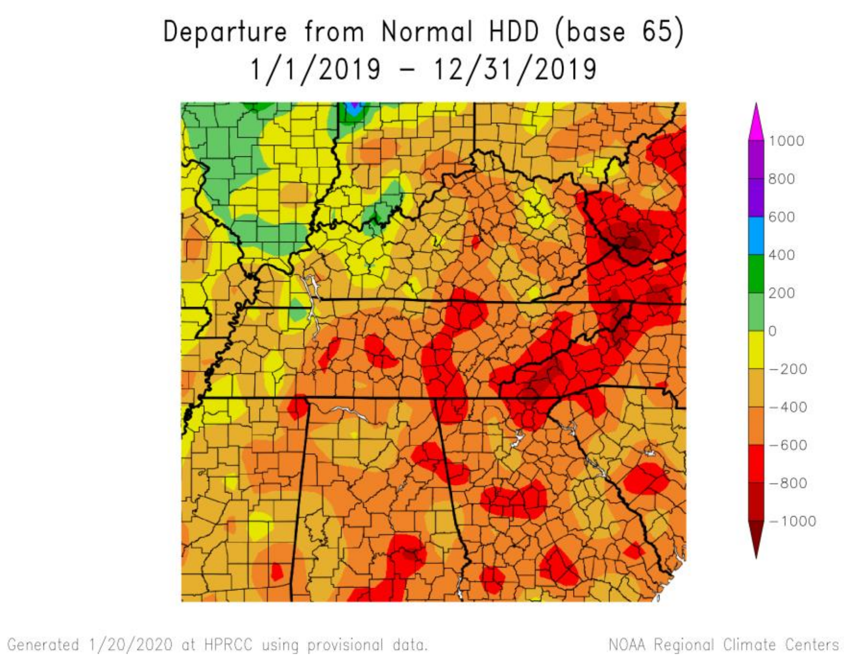
The figure below displays the last fifteen years of HDDs for Kenergy along with the 15-year average HDD.

Heating Degree Days for Last 15 Years



The figure below provides the HDD deviation in 2019 from a 30-year normal amount for the entire state of Kentucky.

Kentucky 2019 HDD Deviations



1.5 FORECAST PROCESS SUMMARY

Clearspring developed econometric models in order to forecast Residential energy per consumer, General C&I (GCI) consumers, GCI use per consumer, and the Rural system's monthly load factors. A growth index using projections for the number of households was used to forecast Residential consumers. Historical weather and economic data was gathered from various sources to estimate the impacts of variables onto the corresponding category. Normalized weather and forecasted economic variables are then combined with the parameter estimates of the models to calculate forecasted values.

Forecasts for the LCI and Direct Serve commercial loads have been prepared judgmentally based on input from the cooperatives and historical value. Judgment and trend analysis are used to project Street and Highway, own use, and distribution losses. The forecasts have been provided to Big Rivers and the member systems and have been approved by each.

2 ENERGY FORECAST RESULTS

2.1 Residential Class

The Residential sales forecast is comprised of a forecast for Residential use per consumer and a forecast for Residential retail members. The product of the two disaggregated forecasts equals the Residential sales forecast.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of Residential customers, Residential use per consumer, and Residential energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are also provided.

Historical and Projected Residential Consumers, Use per Consumer, and Sales

Kenergy Residential Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (kWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	45,587		15,799		720,243	
2016	45,905	0.70%	15,383	-2.64%	706,144	-1.96%
2017	46,348	0.97%	14,331	-6.84%	664,218	-5.94%
2018	46,561	0.46%	15,898	10.93%	740,207	11.44%
2019	46,662	0.22%	14,880	-6.40%	694,305	-6.20%
2020	46,755	0.20%	15,000	0.81%	701,335	1.01%
2021	47,047	0.62%	14,979	-0.14%	704,720	0.48%
2022	47,254	0.44%	14,967	-0.08%	707,240	0.36%
2023	47,408	0.33%	14,931	-0.24%	707,857	0.09%
2024	47,527	0.25%	14,892	-0.26%	707,796	-0.01%
2025	47,616	0.19%	14,871	-0.14%	708,107	0.04%
2026	47,682	0.14%	14,872	0.00%	709,109	0.14%
2027	47,730	0.10%	14,836	-0.24%	708,096	-0.14%
2028	47,759	0.06%	14,830	-0.04%	708,247	0.02%
2029	47,765	0.01%	14,822	-0.05%	707,964	-0.04%
2030	47,749	-0.03%	14,800	-0.15%	706,687	-0.18%
2031	47,716	-0.07%	14,796	-0.03%	706,000	-0.10%
2032	47,666	-0.10%	14,828	0.21%	706,767	0.11%
2033	47,602	-0.13%	14,833	0.04%	706,072	-0.10%
2034	47,531	-0.15%	14,832	-0.01%	704,971	-0.16%
2035	47,451	-0.17%	14,835	0.02%	703,949	-0.15%
2036	47,366	-0.18%	14,840	0.03%	702,910	-0.15%
2037	47,281	-0.18%	14,848	0.06%	702,047	-0.12%
2038	47,197	-0.18%	14,855	0.04%	701,096	-0.14%
2039	47,116	-0.17%	14,862	0.05%	700,225	-0.12%
Average Annual Growth Rates						
Previous 10 Years	0.34%		-0.50%		-0.16%	
Previous 5 Years	0.59%		-2.31%		-1.73%	
Next 5 Years	0.37%		0.02%		0.39%	
Next 10 Years	0.23%		-0.04%		0.20%	
Next 20 Years	0.05%		-0.01%		0.04%	

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2.1.1 Residential Consumer Forecast

Household growth estimates for each county within Kenergy's service territory are used to project the number of Residential members in future years. The following table provides the historical and projected data used to forecast Residential consumers. Actual county level consumer data was provided for 2019. County distributions prior to 2019 have been estimated.

Historical and Projected Residential Consumers By County

Kenergy Residential Consumers															
Year	Residential Accounts by County														
	Caldwell	Crittenden	Daviess	Hancock	Henderson	Hopkins	Ohio	Union	Webster	McLean	Lyon	Muhlenburg	Breckenridge	Livingston	
	Percentage of County Served														
	17.7%	46.0%	41.4%	100.0%	30.6%	15.4%	25.4%	25.8%	39.3%	52.6%	38.2%	0.0%	0.0%	0.3%	**Total**
2000	1,024	1,883	17,911	3,517	6,242	3,155	2,608	1,540	2,200	2,148	1,415	4	1	12	**43,661**
2001	1,036	1,905	18,116	3,557	6,313	3,192	2,638	1,558	2,226	2,173	1,431	4	1	12	**44,161**
2002	1,045	1,921	18,269	3,587	6,366	3,218	2,660	1,571	2,244	2,191	1,444	4	1	12	**44,534**
2003	1,055	1,939	18,447	3,622	6,428	3,250	2,686	1,586	2,266	2,212	1,458	4	1	12	**44,967**
2004	1,069	1,966	18,698	3,671	6,516	3,294	2,723	1,608	2,297	2,242	1,477	4	1	13	**45,580**
2005	1,056	1,941	18,467	3,626	6,435	3,253	2,689	1,588	2,269	2,215	1,459	4	1	13	**45,016**
2006	1,042	1,916	18,222	3,578	6,350	3,210	2,654	1,567	2,239	2,185	1,440	4	1	12	**44,420**
2007	1,050	1,930	18,361	3,605	6,399	3,235	2,674	1,579	2,256	2,202	1,451	4	1	12	**44,758**
2008	1,056	1,942	18,476	3,628	6,439	3,255	2,691	1,589	2,270	2,216	1,460	4	1	13	**45,039**
2009	1,058	1,945	18,506	3,633	6,449	3,260	2,695	1,591	2,273	2,219	1,462	4	1	13	**45,111**
2010	1,060	1,949	18,543	3,641	6,462	3,267	2,700	1,595	2,278	2,224	1,465	4	1	13	**45,201**
2011	1,062	1,953	18,581	3,648	6,475	3,273	2,706	1,598	2,283	2,228	1,468	4	1	13	**45,294**
2012	1,061	1,951	18,554	3,643	6,466	3,269	2,702	1,596	2,279	2,225	1,466	4	1	13	**45,229**
2013	1,062	1,953	18,582	3,648	6,475	3,274	2,706	1,598	2,283	2,229	1,468	4	1	13	**45,297**
2014	1,063	1,954	18,588	3,649	6,477	3,275	2,707	1,599	2,283	2,229	1,469	4	1	13	**45,310**
2015	1,069	1,966	18,701	3,672	6,517	3,295	2,723	1,608	2,297	2,243	1,478	4	1	13	**45,587**
2016	1,077	1,980	18,831	3,697	6,562	3,318	2,742	1,620	2,313	2,258	1,488	4	1	13	**45,905**
2017	1,087	1,999	19,013	3,733	6,626	3,350	2,769	1,635	2,336	2,280	1,502	4	1	13	**46,348**
2018	1,092	2,008	19,101	3,750	6,656	3,365	2,782	1,643	2,347	2,291	1,509	4	1	13	**46,561**
2019	1,094	2,012	19,143	3,758	6,671	3,372	2,788	1,646	2,351	2,296	1,512	4	1	13	**46,662**
2020	1,095	2,012	19,209	3,763	6,683	3,375	2,796	1,645	2,350	2,293	1,515	4	1	13	**46,755**
2021	1,101	2,019	19,369	3,782	6,723	3,391	2,817	1,650	2,356	2,298	1,523	4	1	13	**47,047**
2022	1,104	2,022	19,494	3,796	6,751	3,401	2,833	1,651	2,357	2,299	1,528	4	1	13	**47,254**
2023	1,106	2,023	19,598	3,805	6,771	3,407	2,846	1,651	2,356	2,297	1,532	4	1	13	**47,408**
2024	1,107	2,022	19,687	3,811	6,785	3,410	2,857	1,649	2,354	2,293	1,534	4	1	13	**47,527**
2025	1,107	2,021	19,763	3,815	6,795	3,411	2,866	1,647	2,349	2,289	1,536	4	1	13	**47,616**
2026	1,107	2,019	19,829	3,817	6,802	3,410	2,873	1,644	2,344	2,283	1,537	4	1	13	**47,682**
2027	1,106	2,016	19,887	3,819	6,805	3,408	2,879	1,640	2,338	2,277	1,538	4	1	13	**47,730**
2028	1,105	2,012	19,937	3,819	6,805	3,403	2,884	1,636	2,331	2,270	1,538	4	1	13	**47,759**
2029	1,103	2,008	19,976	3,818	6,802	3,398	2,888	1,631	2,324	2,262	1,538	4	1	13	**47,765**
2030	1,101	2,003	20,005	3,815	6,795	3,390	2,890	1,626	2,315	2,254	1,538	4	1	13	**47,749**
2031	1,098	1,997	20,026	3,812	6,786	3,381	2,890	1,620	2,306	2,245	1,537	4	1	13	**47,716**
2032	1,095	1,991	20,039	3,808	6,773	3,371	2,890	1,614	2,297	2,235	1,536	4	1	13	**47,666**
2033	1,091	1,985	20,046	3,802	6,758	3,359	2,889	1,608	2,287	2,225	1,534	4	1	13	**47,602**
2034	1,087	1,978	20,048	3,797	6,742	3,347	2,887	1,602	2,277	2,215	1,533	4	1	13	**47,531**
2035	1,083	1,972	20,046	3,792	6,724	3,334	2,884	1,595	2,266	2,205	1,531	4	1	13	**47,451**
2036	1,079	1,965	20,041	3,786	6,705	3,321	2,881	1,589	2,256	2,194	1,530	4	1	13	**47,366**
2037	1,075	1,959	20,034	3,781	6,686	3,308	2,878	1,583	2,246	2,185	1,529	4	1	13	**47,281**
2038	1,071	1,954	20,027	3,776	6,667	3,294	2,875	1,576	2,237	2,175	1,528	4	1	13	**47,197**
2039	1,066	1,948	20,021	3,772	6,647	3,280	2,871	1,571	2,227	2,166	1,528	4	1	13	**47,116**
Average Annual Growth Rates															
Previous 10 Years	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%	**0.34%**
Previous 5 Years	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	**0.59%**
Next 5 Years	0.22%	0.10%	0.56%	0.28%	0.34%	0.22%	0.49%	0.04%	0.02%	-0.02%	0.28%	0.08%	0.39%	0.09%	**0.37%**
Next 10 Years	0.08%	-0.02%	0.43%	0.16%	0.20%	0.08%	0.35%	-0.09%	-0.12%	-0.15%	0.17%	-0.08%	0.27%	-0.03%	**0.23%**
Next 20 Years	-0.13%	-0.16%	0.22%	0.02%	-0.02%	-0.14%	0.15%	-0.23%	-0.27%	-0.29%	0.05%	-0.30%	0.14%	-0.18%	**0.05%**

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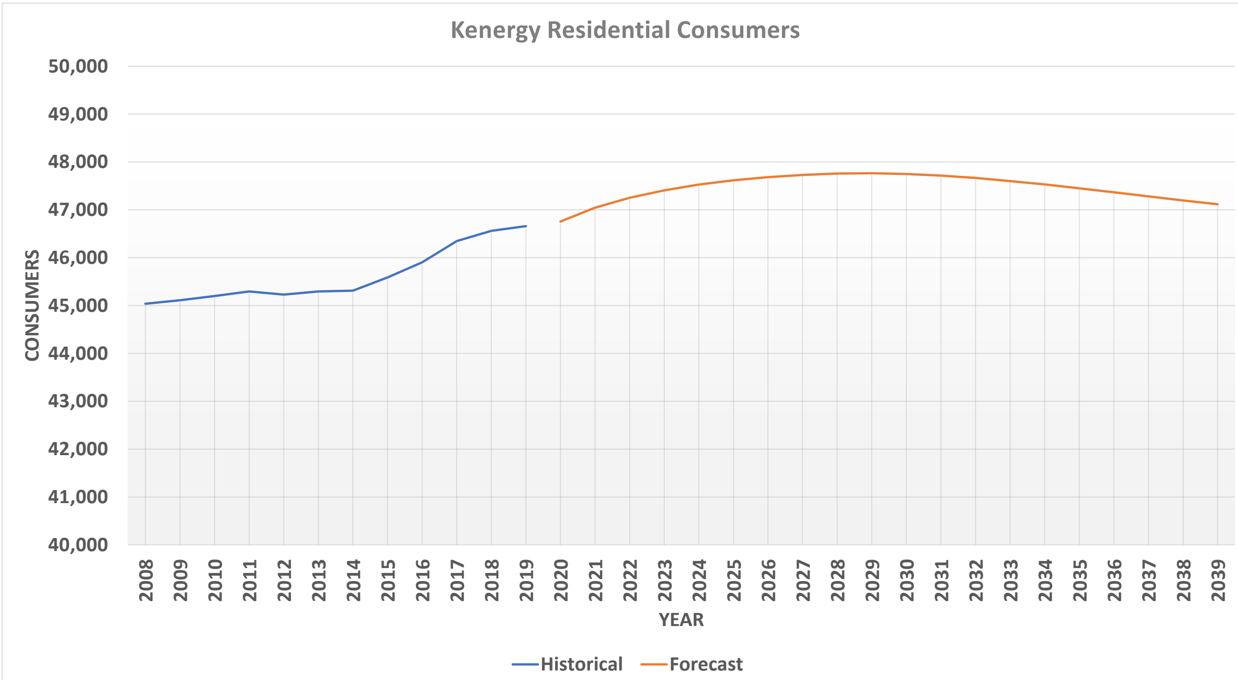
The following figure provides the historical and projected Residential consumers.

Residential Consumers



2.1.2 Residential Use per Consumer Forecast

The Residential use per consumer forecast is estimated using an econometric model that relates certain explanatory variables to Residential use per consumer. The model employs a monthly dataset with 154 observations from January 2007 to October 2019. The model uses price of electricity, alternate fuel prices, cooling and heating degree days, appliance saturation levels, and appliance efficiencies. Explanatory variable values are projected in future years using demographic and economic projections and weather normalized values. Preliminary model results were reviewed by cooperative staff and modifications were made if necessary where staff had specific knowledge of the service territory and conditions. The Residential use per consumer model is provided in the table below.

Residential Use Per Consumer Model

Kenergy Residential Use Per Consumer Model

Sample: 2007 - 2019

Total Observations: 154

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	6.614538	0.051025	129.6343	0
February	6.585116	0.053226	123.7206	0
March	6.631454	0.045352	146.2217	0
April	6.555139	0.047973	136.642	0
May	6.618776	0.038003	174.1632	0
June	6.680367	0.043713	152.8245	0
July	6.784962	0.044501	152.4661	0
August	6.801286	0.043024	158.0823	0
September	6.728907	0.044558	151.013	0
October	6.544728	0.042725	153.1825	0
November	6.450676	0.041616	155.0059	0
December	6.558418	0.049587	132.26	0
Log(Residential Price/Alternate Fuel Price)	-0.070507	0.013307	-5.298569	0
Cooling Degree Days*(AC Saturation)*(1/AC Efficiency)	0.010761	0.000612	17.574	0
Heating Degree Days*Electric Heat Saturation*(1/Heating Efficiency)	0.011193	0.000849	13.18324	0

Weighted Statistics

Adjusted R-squared: 0.922044

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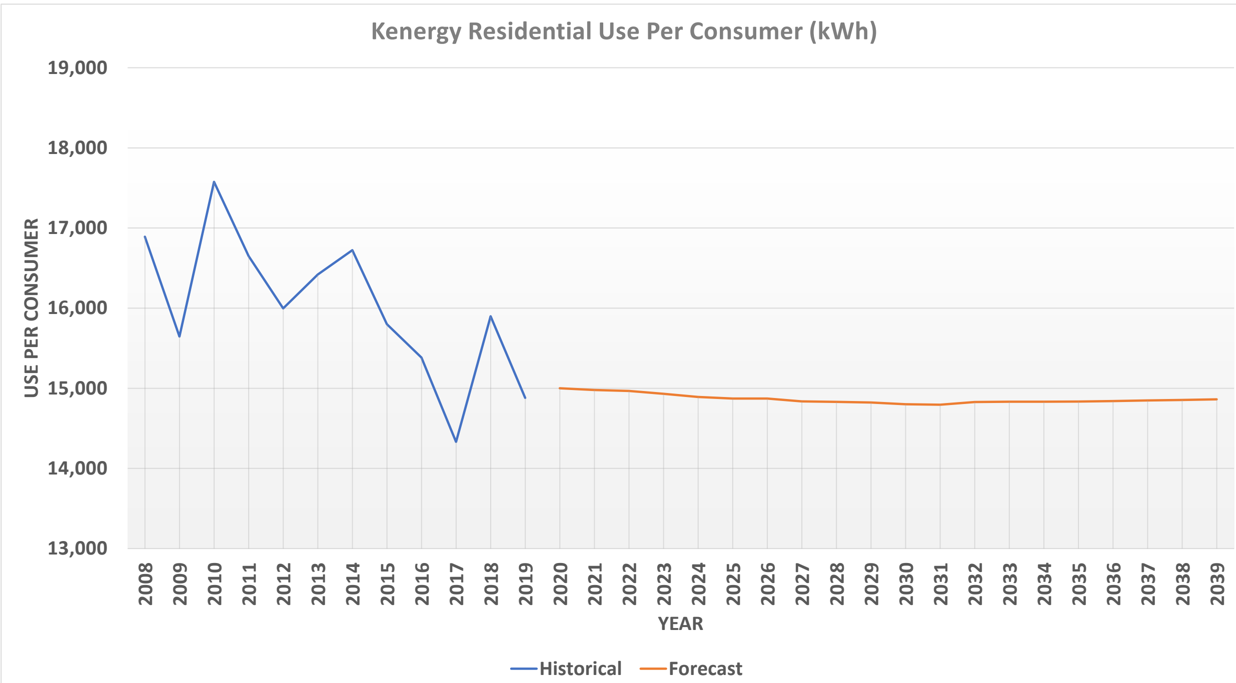
The following figure provides the historical and projected Residential use per consumer for Kenergy.

Residential Use Per Consumer



2.2 Commercial and Industrial Class

The total commercial and industrial class is divided into three distinct sub classes. Certain large commercial and industrial consumers that are directly served off the transmission system are deemed as Direct Serve consumers and these consumers are individually forecasted based on input from the member system, Big Rivers, or the Direct Serve consumer itself. The Direct Serve sales are aggregated to the total system requirements separately from the Rural system load. The second commercial and industrial class is the Large C&I (LCI) class. This class consists of the remainder of consumers over 1,000 kW that do not qualify as Direct Serve consumers. The rest of the commercial and industrial retail members are placed and forecasted within the General C&I (GCI) class.

2.2.1 General Commercial and Industrial (GCI) Class

The GCI class is defined as the total commercial and industrial loads minus the Direct Serve and LCI loads. Given the importance of the GCI class, Clearspring Energy used econometric modeling to project both the GCI consumer counts and the GCI use per consumer for Kenergy.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of GCI customers, GCI use per consumer, and GCI energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table for GCI consumers, use per consumer, and sales.

Historical and Projected GCI Consumers, Use per Consumer, and Sales

Kenergy General C&I Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (kWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	10,693		30,072		321,546	
2016	10,798	0.99%	30,556	1.61%	329,950	2.61%
2017	10,844	0.42%	28,887	-5.46%	313,235	-5.07%
2018	10,939	0.88%	29,148	0.91%	318,840	1.79%
2019	11,142	1.86%	28,928	-0.76%	322,306	1.09%
2020	11,503	3.24%	27,615	-4.54%	317,646	-1.45%
2021	11,613	0.96%	27,640	0.09%	320,985	1.05%
2022	11,736	1.06%	27,621	-0.07%	324,153	0.99%
2023	11,855	1.01%	27,574	-0.17%	326,892	0.85%
2024	11,973	1.00%	27,506	-0.25%	329,346	0.75%
2025	12,092	0.99%	27,450	-0.20%	331,925	0.78%
2026	12,210	0.97%	27,398	-0.19%	334,521	0.78%
2027	12,327	0.96%	27,273	-0.46%	336,189	0.50%
2028	12,443	0.94%	27,219	-0.20%	338,674	0.74%
2029	12,558	0.93%	27,165	-0.20%	341,132	0.73%
2030	12,672	0.91%	27,093	-0.26%	343,334	0.65%
2031	12,785	0.89%	27,057	-0.13%	345,939	0.76%
2032	12,897	0.87%	27,079	0.08%	349,238	0.95%
2033	13,008	0.86%	27,026	-0.20%	351,540	0.66%
2034	13,117	0.84%	26,958	-0.25%	353,616	0.59%
2035	13,226	0.83%	26,893	-0.24%	355,700	0.59%
2036	13,335	0.82%	26,828	-0.24%	357,738	0.57%
2037	13,442	0.81%	26,754	-0.27%	359,631	0.53%
2038	13,549	0.79%	26,674	-0.30%	361,398	0.49%
2039	13,654	0.78%	26,598	-0.29%	363,176	0.49%
Average Annual Growth Rates						
Previous 10 Years	1.48%		-0.72%		0.75%	
Previous 5 Years	1.19%		-1.28%		-0.11%	
Next 5 Years	1.45%		-1.00%		0.43%	
Next 10 Years	1.20%		-0.63%		0.57%	
Next 20 Years	1.02%		-0.42%		0.60%	

2.2.1.1 GCI Consumer Forecast

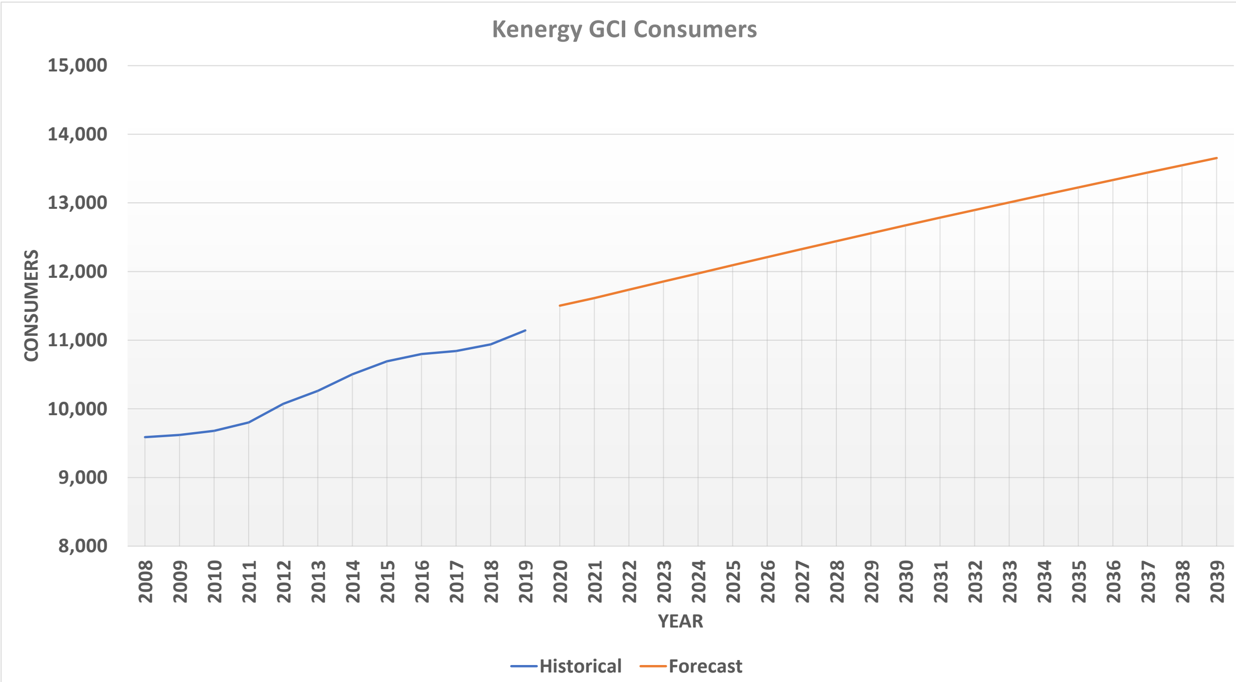
The GCI consumer forecast is estimated using an econometric model that relates explanatory variables to the GCI consumer count. The model uses GRP and total retail sales within the counties served by Kenergy. Explanatory variable values are projected in future years using economic projections. The GCI consumer model is provided in the table below.

GCI Consumer Model

Kenergy General C&I Consumer Model				
Sample: 1999 - 2019 Total Observations: 250				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
GRP	1.363354	0.23916	5.700593	0
Total Retail Sales	2.918014	0.739225	3.947394	0.0001
Weighted Statistics				
Adjusted R-squared: 0.559381				

The following figure provides the historical and projected Kenergy GCI consumers.

GCI Consumers



2.2.1.2 GCI Use per Consumer Forecast

The GCI use per consumer forecast is estimated using an econometric model that relates certain explanatory variables to the GCI use per consumer. The model uses electricity price, employment per consumer, cooling degree days, and heating degree days within the counties served by Kenergy. Explanatory variable values are projected in future years using demographic and economic projections and weather normalized values. Preliminary model results were reviewed by cooperative staff and modifications were made if necessary where staff had specific knowledge of the service territory and conditions. The GCI use per consumer model is provided in the table below.

GCI Use per Consumer Model

Kenergy General C&I Use Per Consumer Model

Sample: 1999 - 2019
Total Observations: 250

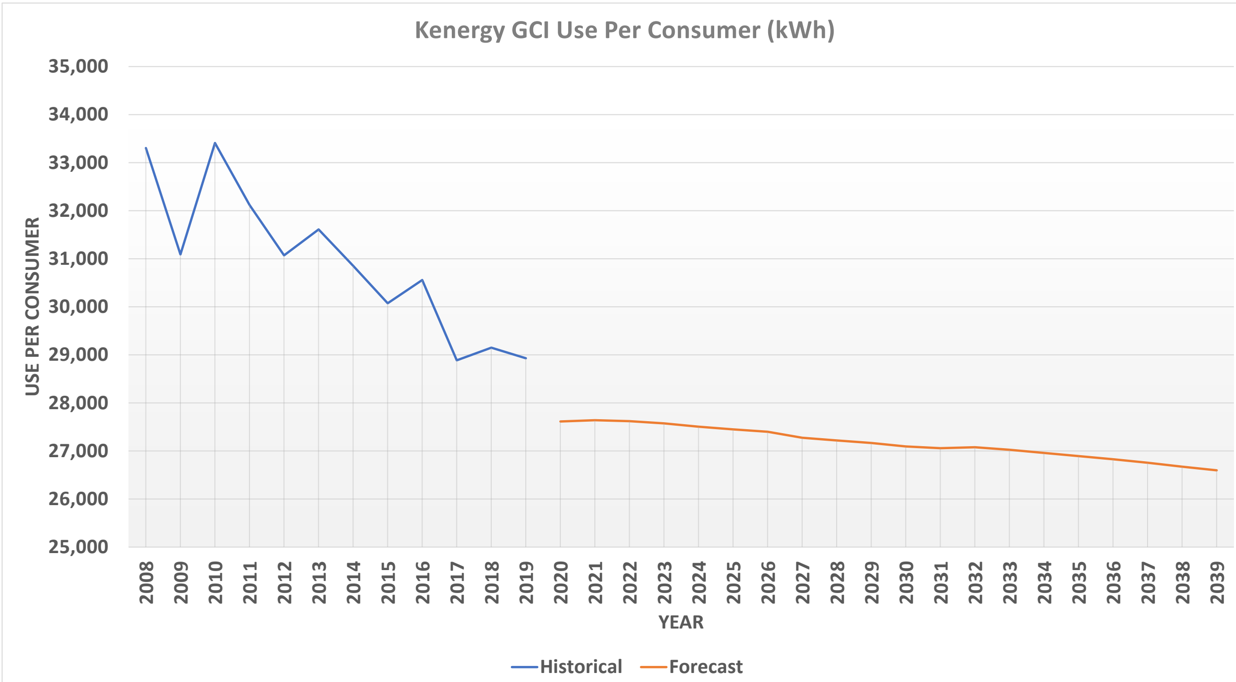
Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	11.05862	0.206038	53.67269	0
February	10.95246	0.202846	53.99397	0
March	11.01351	0.201787	54.57994	0
April	11.01615	0.201731	54.60801	0
May	11.21571	0.19844	56.51943	0
June	11.33681	0.198407	57.13918	0
July	11.32223	0.20008	56.58848	0
August	11.26737	0.200495	56.19772	0
September	11.22473	0.199892	56.15399	0
October	11.21241	0.199678	56.15239	0
November	11.2425	0.20106	55.91619	0
December	11.24374	0.205601	54.68706	0
Log(C&I Electricity Price)	-0.080253	0.036195	-2.217223	0.0276
Cooling Degree Days	0.000892	0.0000848	10.51386	0
Heating Degree Days	0.000511	0.0000577	8.843284	0
Log(Total Employment/C&I Consumers)	0.727082	0.030415	23.90546	0

Weighted Statistics

Adjusted R-squared: 0.895253

The following figure provides the historical and projected GCI use per consumer for Kenergy.

GCI Use per Consumer



2.2.2 Large Commercial and Industrial (LCI) Class

The Large C&I (LCI) class consists of the remainder of consumers over 1,000 kW that do not qualify as Direct Serve consumers. In 2019 the Kenergy LCI class contained 12 consumers. The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of LCI consumers, LCI use per consumer, and LCI energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table for LCI consumers, use per consumer, and sales.

Historical and Projected LCI Consumers, Use per Consumer, and Sales

Kenergy Large C&I Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (MWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	15		6,241		93,619	
2016	15	-2.22%	6,830	9.44%	100,178	7.01%
2017	13	-9.66%	7,250	6.15%	96,066	-4.10%
2018	13	-1.89%	7,603	4.87%	98,843	2.89%
2019	12	-5.77%	7,810	2.71%	95,667	-3.21%
2020	12	-2.04%	7,822	0.16%	93,867	-1.88%
2021	12	0.00%	7,822	0.00%	93,867	0.00%
2022	12	0.00%	7,822	0.00%	93,867	0.00%
2023	12	0.00%	7,822	0.00%	93,867	0.00%
2024	12	0.00%	7,822	0.00%	93,867	0.00%
2025	12	0.00%	7,822	0.00%	93,867	0.00%
2026	12	0.00%	7,822	0.00%	93,867	0.00%
2027	12	0.00%	7,822	0.00%	93,867	0.00%
2028	12	0.00%	7,822	0.00%	93,867	0.00%
2029	12	0.00%	7,822	0.00%	93,867	0.00%
2030	12	0.00%	7,822	0.00%	93,867	0.00%
2031	12	0.00%	7,822	0.00%	93,867	0.00%
2032	12	0.00%	7,822	0.00%	93,867	0.00%
2033	12	0.00%	7,822	0.00%	93,867	0.00%
2034	12	0.00%	7,822	0.00%	93,867	0.00%
2035	12	0.00%	7,822	0.00%	93,867	0.00%
2036	12	0.00%	7,822	0.00%	93,867	0.00%
2037	12	0.00%	7,822	0.00%	93,867	0.00%
2038	12	0.00%	7,822	0.00%	93,867	0.00%
2039	12	0.00%	7,822	0.00%	93,867	0.00%
Average Annual Growth Rates						
Previous 10 Years	0.63%		0.97%		1.61%	
Previous 5 Years	-4.08%		4.42%		0.16%	
Next 5 Years	-0.41%		0.03%		-0.38%	
Next 10 Years	-0.21%		0.02%		-0.19%	
Next 20 Years	-0.10%		0.01%		-0.09%	

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2.2.3 Direct Serve Class

The Direct Serve class contains consumers that are directly served from the transmission system. The sales forecasts are based on manager and staff knowledge and input from each cooperative. Kenergy's Direct Serve class contained 22 consumers in 2019.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of Direct Serve customers, Direct Serve use per consumer, and Direct Serve energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table for Direct Serve consumers, use per consumer, and sales.

Historical and Projected Direct Serve Consumers, Use per Consumer, and Sales

Kenergy Direct Serve Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (MWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	21		364,469		7,653,848	
2016	21	0.00%	286,447	-21.41%	6,015,387	-21.41%
2017	21	0.00%	287,324	0.31%	6,033,800	0.31%
2018	22	3.97%	289,802	0.86%	6,327,349	4.87%
2019	22	0.76%	328,224	13.26%	7,220,918	14.12%
2020	22	0.00%	319,380	-2.69%	7,026,368	-2.69%
2021	22	0.00%	319,380	0.00%	7,026,368	0.00%
2022	22	0.00%	319,380	0.00%	7,026,368	0.00%
2023	22	0.00%	319,380	0.00%	7,026,368	0.00%
2024	22	0.00%	319,380	0.00%	7,026,368	0.00%
2025	22	0.00%	319,380	0.00%	7,026,368	0.00%
2026	22	0.00%	319,380	0.00%	7,026,368	0.00%
2027	22	0.00%	319,380	0.00%	7,026,368	0.00%
2028	22	0.00%	319,380	0.00%	7,026,368	0.00%
2029	22	0.00%	319,380	0.00%	7,026,368	0.00%
2030	22	0.00%	319,380	0.00%	7,026,368	0.00%
2031	22	0.00%	319,380	0.00%	7,026,368	0.00%
2032	22	0.00%	319,380	0.00%	7,026,368	0.00%
2033	22	0.00%	319,380	0.00%	7,026,368	0.00%
2034	22	0.00%	319,380	0.00%	7,026,368	0.00%
2035	22	0.00%	319,380	0.00%	7,026,368	0.00%
2036	22	0.00%	319,380	0.00%	7,026,368	0.00%
2037	22	0.00%	319,380	0.00%	7,026,368	0.00%
2038	22	0.00%	319,380	0.00%	7,026,368	0.00%
2039	22	0.00%	319,380	0.00%	7,026,368	0.00%
Average Annual Growth Rates						
Previous 10 Years	0.47%		-1.01%		-0.54%	
Previous 5 Years	0.93%		-4.09%		-3.19%	
Next 5 Years	0.00%		-0.54%		-0.54%	
Next 10 Years	0.00%		-0.27%		-0.27%	
Next 20 Years	0.00%		-0.14%		-0.14%	

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2.3 Street and Highway Class

Given the small proportion of the Street and Highway class in total sales, the forecast for this class was calculated manually rather than through econometric modeling. The most recent consumer values were held constant through the forecast and the prior twelve months of usage were used to derive monthly energy forecasts for the forecast period.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of Street and Highway consumers, Street and Highway use per consumer, and Street and Highway energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table for Street and Highway consumers, use per consumer, and sales.

Historical and Projected Street & Highway Consumers, Use per Consumer, and Sales

Kenergy Street & Highway Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (kWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	91		19,216		1,750	
2016	93	2.10%	17,592	-8.45%	1,636	-6.52%
2017	94	0.63%	16,873	-4.08%	1,579	-3.48%
2018	96	2.40%	15,076	-10.65%	1,445	-8.51%
2019	94	-2.43%	14,967	-0.72%	1,399	-3.14%
2020	93	-0.53%	14,987	0.14%	1,394	-0.40%
2021	93	0.00%	14,987	0.00%	1,394	0.00%
2022	93	0.00%	14,987	0.00%	1,394	0.00%
2023	93	0.00%	14,987	0.00%	1,394	0.00%
2024	93	0.00%	14,987	0.00%	1,394	0.00%
2025	93	0.00%	14,987	0.00%	1,394	0.00%
2026	93	0.00%	14,987	0.00%	1,394	0.00%
2027	93	0.00%	14,987	0.00%	1,394	0.00%
2028	93	0.00%	14,987	0.00%	1,394	0.00%
2029	93	0.00%	14,987	0.00%	1,394	0.00%
2030	93	0.00%	14,987	0.00%	1,394	0.00%
2031	93	0.00%	14,987	0.00%	1,394	0.00%
2032	93	0.00%	14,987	0.00%	1,394	0.00%
2033	93	0.00%	14,987	0.00%	1,394	0.00%
2034	93	0.00%	14,987	0.00%	1,394	0.00%
2035	93	0.00%	14,987	0.00%	1,394	0.00%
2036	93	0.00%	14,987	0.00%	1,394	0.00%
2037	93	0.00%	14,987	0.00%	1,394	0.00%
2038	93	0.00%	14,987	0.00%	1,394	0.00%
2039	93	0.00%	14,987	0.00%	1,394	0.00%
Average Annual Growth Rates						
Previous 10 Years	2.07%		-3.24%		-1.23%	
Previous 5 Years	2.66%		-7.29%		-4.82%	
Next 5 Years	-0.11%		0.03%		-0.08%	
Next 10 Years	-0.05%		0.01%		-0.04%	
Next 20 Years	-0.03%		0.01%		-0.02%	

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2.4 Total Energy

The total energy requirements are calculated by taking the sales forecasts for each class, detailed in the previous sections of this report, and adding distribution losses and own use. Distribution losses are estimated using a three-year historical average percent. This percent is computed after any Direct Sale loads are removed since these loads are no loss loads.

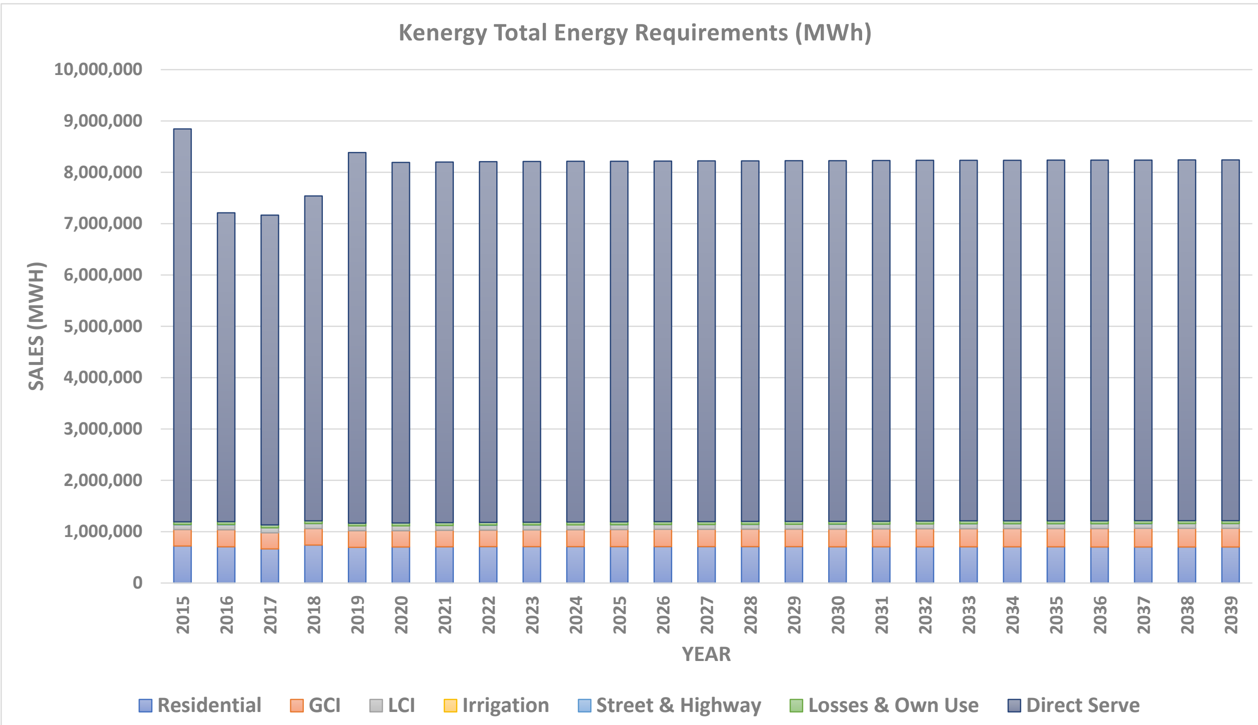
The following table provides the historical and forecast components of total energy requirements. The last five historical years are provided (2015 to 2019) along with the next twenty years of forecasts for each component. This includes Rural energy sales, Direct Serve sales, the estimated DSM impacts in forecasted years, and line losses. It is assumed that any impacts of prior DSM programs are captured indirectly through the historical energy and peak data used as an input to the modeling process. The DSM column provided in the table below is intended to capture any additional impacts from DSM spending in the future. For the base case forecast the additional DSM impact has been set to zero. Alternate scenarios have been quantified for Big Rivers and provided in Excel that detail the impacts of one million and two million DSM spending scenarios. These scenario impacts are derived directly from the Big Rivers DSM study completed in 2020.

Total System Energy Summary

Kenergy Total System Energy Summary						
Year	Rural System Energy Sales (MWh)	Direct Serve Energy Sales (MWh)	DSM Impact (MWh)	Total System Energy Sales (MWh)	Line Losses (% of Rural Energy)	Total Energy Requirements (MWh)
2015	1,137,157	7,653,848	0	8,791,006	4.65%	8,846,457
2016	1,137,908	6,015,387	0	7,153,295	4.85%	7,211,900
2017	1,075,098	6,033,800	0	7,108,898	4.90%	7,166,656
2018	1,159,333	6,327,349	0	7,486,682	4.19%	7,539,919
2019	1,113,677	7,220,918	0	8,334,595	4.21%	8,385,991
2020	1,114,242	7,026,368	0	8,140,610	4.44%	8,194,781
2021	1,120,966	7,026,368	0	8,147,333	4.44%	8,201,834
2022	1,126,653	7,026,368	0	8,153,021	4.44%	8,207,799
2023	1,130,010	7,026,368	0	8,156,378	4.44%	8,211,323
2024	1,132,403	7,026,368	0	8,158,771	4.44%	8,213,838
2025	1,135,293	7,026,368	0	8,161,660	4.44%	8,216,870
2026	1,138,891	7,026,368	0	8,165,259	4.44%	8,220,643
2027	1,139,546	7,026,368	0	8,165,913	4.44%	8,221,335
2028	1,142,182	7,026,368	0	8,168,549	4.44%	8,224,100
2029	1,144,357	7,026,368	0	8,170,724	4.44%	8,226,381
2030	1,145,281	7,026,368	0	8,171,649	4.44%	8,227,352
2031	1,147,199	7,026,368	0	8,173,567	4.44%	8,229,363
2032	1,151,266	7,026,368	0	8,177,633	4.44%	8,233,621
2033	1,152,873	7,026,368	0	8,179,240	4.44%	8,235,304
2034	1,153,848	7,026,368	0	8,180,216	4.44%	8,236,326
2035	1,154,910	7,026,368	0	8,181,278	4.44%	8,237,439
2036	1,155,908	7,026,368	0	8,182,276	4.44%	8,238,484
2037	1,156,939	7,026,368	0	8,183,307	4.44%	8,239,564
2038	1,157,754	7,026,368	0	8,184,122	4.44%	8,240,418
2039	1,158,662	7,026,368	0	8,185,030	4.44%	8,241,369
Average Annual Growth Rates						
Previous 10 Years	0.23%	-0.54%	0.00%	-0.44%	-1.52%	-0.45%
Previous 5 Years	-1.12%	-3.19%	0.00%	-2.93%	-3.30%	-2.93%
Next 5 Years	0.33%	-0.54%	0.00%	-0.43%	1.04%	-0.41%
Next 10 Years	0.27%	-0.27%	0.00%	-0.20%	0.52%	-0.19%
Next 20 Years	0.20%	-0.14%	0.00%	-0.09%	0.26%	-0.09%

The following graph provides the class components that comprise the total energy requirements for Kenergy.

Total Energy Forecast



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3 PEAK DEMAND

3.1 COINCIDENT PEAK DEMAND

The Rural system coincident peak demand (Rural CP) is measured based on Kenergy's demand coincident with the Big Rivers' total system peak. Clearspring Energy econometrically modeled Kenergy's Rural coincident load factor using a monthly dataset. The predicted load factor is combined with the Rural energy forecast to forecast the Rural coincident peak demand. The Rural load factor model uses temperature on the peak day each month, cooling degree days, heating degree days, appliance saturations, and appliance efficiencies. The Rural CP load factor model is provided in the table below.

Rural CP Load Factor Model

Kenergy Load Factor Model				
Sample: 2007 - 2019 Total Observations: 154				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	0.652034	0.023963	27.20968	0
February	0.679921	0.022638	30.03493	0
March	0.648822	0.01715	37.83232	0
April Cold Peaking	0.680085	0.015563	43.69874	0
April Hot Peaking	0.687651	0.019987	34.40458	0
May	0.60156	0.013883	43.33197	0
June	0.594472	0.016098	36.92744	0
July	0.59567	0.01599	37.2529	0
August	0.590477	0.016007	36.88807	0
September	0.598327	0.016549	36.15449	0
October Cold Peaking	0.725742	0.016679	43.51174	0
October Hot Peaking	0.62122	0.020181	30.78215	0
November	0.67773	0.016807	40.325	0
December	0.683866	0.02341	29.21206	0
Cooling Degree Days on Peak Day*(AC Saturation)*(1/AC Efficiency)	-0.082488	0.013899	-5.935027	0
Heating Degree Days on Peak Day*Electric Heating Saturation*(1/Heating Efficiency)	-0.068364	0.008904	-7.677592	0
Cooling Degree During Remainder of Month*(AC Saturation)*(1/AC Efficiency)	0.00506	0.000622	8.129419	0
Heating Degree During Remainder of Month*Electric Heating Saturation*(1/Heating Efficiency)	0.003299	0.000433	7.62205	0
Weighted Statistics				
Adjusted R-squared: 0.691088				

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The following table provides the last five years of historical data and the next 20 years of forecasted data for the winter, summer, and annual peaks for Kenergy's Rural system. The table also provides the annual coincident peak contribution for the Direct Serve class and the total Kenergy coincident peak contribution. The Direct Serve coincident peak contribution was forecasted using an average of historical load factors for that class. It is important to note that load for three of the Direct Serve consumers are included in the Direct Serve energy and Direct Serve non-coincident peak (NCP) forecasts but are not included in the coincident peak forecasts. This includes load for two smelters that are served by Kenergy but do not contribute to Big Rivers energy obligations, and load for Domtar which is listed separately on the Big Rivers forecast due to a partial requirement up to their tariff amount. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table below.

Historical and Projected CP Demands

Kenergy Coincident Peak (kW)					
Year	Rural Summer CP	Rural Winter CP	Rural Annual CP	Direct Serve Annual CP	Total Annual CP
2015	258,844	282,422	282,422	105,791	388,213
2016	252,137	244,652	252,137	104,017	356,153
2017	260,886	237,617	260,886	99,362	360,248
2018	258,518	272,902	272,902	80,492	353,394
2019	247,670	243,217	243,217	102,899	346,116
2020	246,286	240,846	246,286	111,856	358,142
2021	247,668	242,296	247,668	111,856	359,524
2022	247,905	243,529	247,905	108,798	356,703
2023	248,579	244,129	248,579	108,798	357,378
2024	249,064	244,488	249,064	108,798	357,862
2025	249,672	244,954	249,672	108,798	358,470
2026	250,446	245,585	250,446	108,798	359,244
2027	250,580	245,574	250,580	108,798	359,378
2028	251,163	246,002	251,163	108,798	359,961
2029	251,649	246,334	251,649	108,798	360,447
2030	251,867	246,392	251,867	108,798	360,665
2031	252,313	246,670	252,313	108,798	361,111
2032	253,236	247,428	253,236	108,798	362,034
2033	253,610	247,661	253,610	108,798	362,408
2034	253,853	247,760	253,853	108,798	362,651
2035	254,105	247,900	254,105	108,798	362,903
2036	254,344	248,033	254,344	108,798	363,142
2037	254,586	248,193	254,586	108,798	363,385
2038	254,778	248,310	254,778	108,798	363,576
2039	254,988	248,445	254,988	108,798	363,786
Average Annual Growth Rates					
Previous 10 Years	-0.37%	-1.40%	-1.40%	1.68%	-0.59%
Previous 5 Years	-0.10%	-4.74%	-4.74%	-0.85%	-3.67%
Next 5 Years	0.11%	0.10%	0.48%	1.12%	0.67%
Next 10 Years	0.16%	0.13%	0.34%	0.56%	0.41%
Next 20 Years	0.15%	0.11%	0.24%	0.28%	0.25%

3.2 Non-Coincident Peak Demand

Rural NCP is forecasted monthly using an average of historical coincident factors examining the ratio between past coincident and non-coincident peaks. The Rural NCP value represents the single highest cooperative Rural load amount of the year regardless of the time it occurred. Direct Serve NCP is also forecasted using judgement and input from cooperative staff. Excel deliverables showing each Direct Serve consumer individually by month have been provided to Kenergy and Big Rivers. The table below displays the single highest monthly Direct Serve NCP value for each year. The following table provides the last five years of historical data and the next 20 years of forecasted data for the Rural CP, Rural NCP, and Direct Serve NCP for Kenergy's total system. Growth rates for the prior 5 years and projected growth rates for the next 5, 10, and 20 years are also provided in the table below.

Historical and Projected Demands

Kenergy Peak (kW)						
Year	Total CP	% Change per Year in Total CP	Rural NCP	% Change per Year in Rural NCP	Direct Serve NCP	% Change per Year in Direct Serve NCP
2015	388,213		282,422		1,026,058	
2016	356,153	-8.26%	254,824	-9.77%	730,803	-28.78%
2017	360,248	1.15%	263,055	3.23%	734,976	0.57%
2018	353,394	-1.90%	272,902	3.74%	891,152	21.25%
2019	346,116	-2.06%	249,712	-8.50%	938,439	5.31%
2020	358,142	3.47%	248,475	-0.50%	842,014	-10.28%
2021	359,524	0.39%	249,869	0.56%	842,014	0.00%
2022	356,703	-0.78%	251,026	0.46%	842,014	0.00%
2023	357,378	0.19%	251,659	0.25%	842,014	0.00%
2024	357,862	0.14%	252,104	0.18%	842,014	0.00%
2025	358,470	0.17%	252,674	0.23%	842,014	0.00%
2026	359,244	0.22%	253,417	0.29%	842,014	0.00%
2027	359,378	0.04%	253,515	0.04%	842,014	0.00%
2028	359,961	0.16%	254,062	0.22%	842,014	0.00%
2029	360,447	0.13%	254,511	0.18%	842,014	0.00%
2030	360,665	0.06%	254,689	0.07%	842,014	0.00%
2031	361,111	0.12%	255,095	0.16%	842,014	0.00%
2032	362,034	0.26%	256,006	0.36%	842,014	0.00%
2033	362,408	0.10%	256,383	0.15%	842,014	0.00%
2034	362,651	0.07%	256,629	0.10%	842,014	0.00%
2035	362,903	0.07%	256,884	0.10%	842,014	0.00%
2036	363,142	0.07%	257,125	0.09%	842,014	0.00%
2037	363,385	0.07%	257,370	0.10%	842,014	0.00%
2038	363,576	0.05%	257,564	0.08%	842,014	0.00%
2039	363,786	0.06%	257,776	0.08%	842,014	0.00%
Average Annual Growth Rates						
Previous 10 Years	-0.59%		-1.14%		-0.75%	
Previous 5 Years	-3.67%		-4.23%		-1.93%	
Next 5 Years	0.67%		0.19%		-2.15%	
Next 10 Years	0.41%		0.19%		-1.08%	
Next 20 Years	0.25%		0.16%		-0.54%	

4 ALTERNATIVE SYSTEM FORECASTS AND UNCERTAINTY ANALYSIS

While the projections summarized in previous sections should be viewed as the most probable outcome, it is important to remember that energy loads can be influenced by factors that are inherently difficult to predict, such as weather and the economy. Forecasting attempts to model reality and identify the primary drivers of growth and change. Each forecast has an inherent error tolerance between which actual observed outcomes are likely to fall. Therefore, it is important to develop flexible plans for meeting future energy needs based on a range of forecast outcomes.

The study includes scenario analyses that show how the forecasts change under assumed variations in future weather and economic growth paths. The alternate growth scenarios that have been explored are:

1. Extreme weather with normal economic growth
2. Mild weather with normal economic growth
3. High economic growth with normal weather
4. Low economic growth with normal weather

4.1 WEATHER SCENARIOS

Weather is one of the critical components to explain year-to-year variation in load. Because of this, extreme and mild weather scenarios were developed for the forecast period. The Residential use per consumer and GCI use per consumer monthly energy models use cooling degree days and heating degree days. For the creation of the mild and extreme energy scenarios these two variables were altered to a fifteen-year historical annual maximum and minimum value. These annual extremes were then redistributed across each month based on an average monthly distribution of cooling degree days and heating degree days. The Rural peak load factor model also contains cooling degree days and heating degree days for the month. Additionally, the load factor model captures peak day weather conditions. The extreme and mild weather scenarios alter the load factor model to use monthly weather conditions consistent with the energy models and change the peak day conditions to the most extreme or mild found in the last fifteen years of history for each

given month. The peak values displayed are a maximum of each monthly scenario value for the given season and therefore can occur in a different month than the base case forecast. Forecasts are provided in Excel that detail each scenario by month.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the mild, base, and extreme weather scenarios. The forecasts are for the Rural system.

Rural System Weather Scenarios

Kenergy Rural System Weather Scenarios									
Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Mild	Base	Extreme	Mild	Base	Extreme	Mild	Base	Extreme
2015		1,192,608			282,422			258,844	
2016		1,196,513			244,652			252,137	
2017		1,132,856			237,617			260,886	
2018		1,212,570			272,902			258,518	
2019		1,165,073			243,217			247,670	
2020	1,098,023	1,168,414	1,250,501	211,946	240,846	274,569	229,613	246,286	280,842
2021	1,104,941	1,175,466	1,257,675	213,314	242,296	276,099	231,001	247,668	282,200
2022	1,110,839	1,181,432	1,263,685	214,493	243,529	277,376	226,423	247,905	283,293
2023	1,114,600	1,184,956	1,266,885	215,172	244,129	277,859	227,231	248,579	283,669
2024	1,117,375	1,187,470	1,269,054	215,626	244,488	278,082	227,847	249,064	283,865
2025	1,120,597	1,190,502	1,271,827	216,164	244,954	278,442	228,557	249,672	284,240
2026	1,124,477	1,194,276	1,275,442	216,835	245,585	279,004	229,403	250,446	284,838
2027	1,125,433	1,194,968	1,275,797	216,934	245,574	278,849	229,648	250,580	284,739
2028	1,128,301	1,197,732	1,278,415	217,408	246,002	279,205	230,287	251,163	285,183
2029	1,130,688	1,200,013	1,280,550	217,792	246,334	279,464	230,826	251,649	285,542
2030	1,131,818	1,200,985	1,281,318	217,924	246,392	279,420	231,106	251,867	285,621
2031	1,133,896	1,202,995	1,283,233	218,243	246,670	279,639	231,583	252,313	285,985
2032	1,138,060	1,207,253	1,287,585	218,977	247,428	280,415	232,485	253,236	286,913
2033	1,139,782	1,208,937	1,289,213	219,238	247,661	280,605	232,877	253,610	287,234
2034	1,140,859	1,209,959	1,290,161	219,372	247,760	280,655	233,139	253,853	287,424
2035	1,141,996	1,211,071	1,291,237	219,534	247,900	280,764	233,401	254,105	287,641
2036	1,143,046	1,212,117	1,292,273	219,679	248,033	280,878	233,642	254,344	287,862
2037	1,144,099	1,213,197	1,293,380	219,837	248,193	281,039	233,877	254,586	288,106
2038	1,144,937	1,214,050	1,294,249	219,954	248,310	281,152	234,066	254,778	288,293
2039	1,145,863	1,215,002	1,295,227	220,086	248,445	281,288	234,270	254,988	288,502

Direct Serve load is assumed to not be influenced by weather and is held constant to the base case forecast for the weather ranges. The extreme and mild ranges with the Direct Serve class included are shown below. Note that there are three Direct Serve consumers included in the energy totals that do not contribute to the Big Rivers CP values provided on this table.

Total System Weather Scenarios

Kenergy Total System Weather Scenarios									
Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Mild	Base	Extreme	Mild	Base	Extreme	Mild	Base	Extreme
2015		8,846,457			388,213			353,972	
2016		7,211,900			347,603			356,153	
2017		7,166,656			339,136			360,248	
2018		7,539,919			353,394			351,128	
2019		8,385,991			346,116			356,234	
2020	8,124,391	8,194,781	8,276,868	314,853	343,753	377,476	341,469	358,142	389,641
2021	8,131,308	8,201,834	8,284,043	316,220	345,203	379,005	342,857	359,524	390,999
2022	8,137,207	8,207,799	8,290,052	317,399	346,435	380,282	335,222	356,703	392,091
2023	8,140,968	8,211,323	8,293,253	318,078	347,036	380,765	336,029	357,378	392,467
2024	8,143,742	8,213,838	8,295,421	318,532	347,395	380,988	336,645	357,862	392,664
2025	8,146,965	8,216,870	8,298,194	319,070	347,861	381,349	337,355	358,470	393,038
2026	8,150,845	8,220,643	8,301,809	319,742	348,491	381,911	338,201	359,244	393,637
2027	8,151,801	8,221,335	8,302,164	319,840	348,480	381,755	338,446	359,378	393,537
2028	8,154,669	8,224,100	8,304,782	320,315	348,908	382,111	339,086	359,961	393,981
2029	8,157,056	8,226,381	8,306,918	320,698	349,241	382,370	339,624	360,447	394,340
2030	8,158,186	8,227,352	8,307,686	320,831	349,298	382,327	339,904	360,665	394,420
2031	8,160,264	8,229,363	8,309,600	321,149	349,576	382,545	340,381	361,111	394,784
2032	8,164,428	8,233,621	8,313,953	321,883	350,335	383,321	341,284	362,034	395,711
2033	8,166,149	8,235,304	8,315,580	322,144	350,567	383,511	341,675	362,408	396,032
2034	8,167,226	8,236,326	8,316,529	322,279	350,666	383,561	341,937	362,651	396,222
2035	8,168,364	8,237,439	8,317,604	322,441	350,807	383,670	342,199	362,903	396,440
2036	8,169,413	8,238,484	8,318,640	322,585	350,939	383,784	342,441	363,142	396,660
2037	8,170,466	8,239,564	8,319,748	322,743	351,100	383,945	342,676	363,385	396,905
2038	8,171,304	8,240,418	8,320,617	322,860	351,216	384,058	342,864	363,576	397,092
2039	8,172,231	8,241,369	8,321,594	322,992	351,351	384,195	343,068	363,786	397,301

4.2 Economic Scenarios

Another critical component of a long-term load forecast is the underlying economic variables within the service territory. Two scenarios have been developed: low economic growth and high economic growth. To create the economic scenarios, economic variables within each econometrically modeled class are altered by an additional plus or minus 1.0% per year relative to the base case forecast. The altered variables include electricity price, GRP, employment, and total retail sales. The forecast for Residential consumers, LCI, and Street and Highway are not modeled econometrically and are therefore directly modified by 1.0% per year relative to the base case forecast to create the high and low economic ranges.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the low, base, and high economic scenarios.

Rural System Economic Scenarios

Kenergy Rural System Economic Scenarios									
Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Low	Base	High	Low	Base	High	Low	Base	High
2015		1,192,608			282,422			258,844	
2016		1,196,513			244,652			252,137	
2017		1,132,856			237,617			260,886	
2018		1,212,570			272,902			258,518	
2019		1,165,073			243,217			247,670	
2020	1,161,721	1,168,414	1,175,116	240,633	240,846	241,060	244,543	246,286	248,031
2021	1,156,277	1,175,466	1,194,716	239,508	242,296	245,091	243,291	247,668	252,060
2022	1,149,648	1,181,432	1,213,378	238,144	243,529	248,936	241,118	247,905	254,727
2023	1,140,565	1,184,956	1,229,662	236,148	244,129	252,160	239,149	248,579	258,078
2024	1,130,468	1,187,470	1,244,992	233,912	244,488	255,152	236,989	249,064	261,251
2025	1,120,827	1,190,502	1,260,953	231,775	244,954	258,269	234,939	249,672	264,570
2026	1,111,833	1,194,276	1,277,802	229,786	245,585	261,578	233,036	250,446	268,088
2027	1,099,945	1,194,968	1,291,432	227,196	245,574	264,217	230,533	250,580	270,936
2028	1,089,950	1,197,732	1,307,370	225,011	246,002	267,338	228,439	251,163	274,284
2029	1,079,483	1,200,013	1,322,866	222,736	246,334	270,370	226,250	251,649	277,544
2030	1,067,825	1,200,985	1,336,985	220,212	246,392	273,112	223,818	251,867	280,523
2031	1,057,079	1,202,995	1,352,326	217,886	246,670	276,108	221,586	252,313	283,770
2032	1,048,264	1,207,253	1,370,296	215,978	247,428	279,659	219,762	253,236	287,576
2033	1,037,171	1,208,937	1,385,442	213,604	247,661	282,635	217,453	253,610	290,779
2034	1,025,502	1,209,959	1,399,894	211,116	247,760	285,468	215,029	253,853	293,846
2035	1,013,907	1,211,071	1,414,510	208,665	247,900	288,359	212,611	254,105	296,937
2036	1,002,253	1,212,117	1,429,108	206,209	248,033	291,252	210,182	254,344	300,026
2037	990,624	1,213,197	1,443,807	203,776	248,193	294,187	207,755	254,586	303,132
2038	978,808	1,214,050	1,458,296	201,309	248,310	297,082	205,285	254,778	306,191
2039	967,071	1,215,002	1,472,961	198,858	248,445	300,010	202,830	254,988	309,284

The Direct Serve class is not modeled using econometric modeling. As such, the load is increased by an additional 1.0% per year relative to the base case in the high scenario. In the low scenario the Direct Serve class is decreased by 1.0% per year relative to the base case. The high and low ranges with the Direct Serve class included are shown below.

Total System Economic Scenarios

Kenergy Total System Economic Scenarios									
Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Low	Base	High	Low	Base	High	Low	Base	High
2015		8,846,457			388,213			353,972	
2016		7,211,900			347,603			356,153	
2017		7,166,656			339,136			360,248	
2018		7,539,919			353,394			351,128	
2019		8,385,991			346,116			356,234	
2020	8,150,051	8,194,781	8,239,521	343,453	343,753	344,052	355,653	358,142	360,632
2021	8,074,344	8,201,834	8,329,385	341,299	345,203	349,112	353,282	359,524	365,780
2022	7,997,451	8,207,799	8,418,310	338,907	346,435	353,986	347,106	356,703	366,336
2023	7,918,104	8,211,323	8,504,858	335,881	347,036	358,240	344,048	357,378	370,775
2024	7,837,743	8,213,838	8,590,451	332,616	347,395	362,260	340,801	357,862	375,036
2025	7,757,839	8,216,870	8,676,676	329,450	347,861	366,407	337,663	358,470	379,443
2026	7,678,581	8,220,643	8,763,788	326,432	348,491	370,744	334,672	359,244	384,049
2027	7,596,430	8,221,335	8,847,682	322,813	348,480	374,412	331,080	359,378	387,984
2028	7,516,171	8,224,100	8,933,884	319,599	348,908	378,562	327,899	359,961	392,421
2029	7,435,440	8,226,381	9,019,644	316,294	349,241	382,624	324,622	360,447	396,769
2030	7,353,518	8,227,352	9,104,027	312,742	349,298	386,394	321,102	360,665	400,836
2031	7,272,509	8,229,363	9,189,631	309,387	349,576	390,419	317,782	361,111	405,171
2032	7,193,430	8,233,621	9,277,865	306,449	350,335	395,000	314,870	362,034	410,065
2033	7,112,073	8,235,304	9,363,274	303,047	350,567	399,004	311,473	362,408	414,356
2034	7,030,141	8,236,326	9,447,991	299,530	350,666	402,867	307,961	362,651	418,511
2035	6,948,282	8,237,439	9,532,870	296,050	350,807	406,787	304,455	362,903	422,690
2036	6,866,365	8,238,484	9,617,731	292,565	350,939	410,709	300,938	363,142	426,867
2037	6,784,471	8,239,564	9,702,694	289,103	351,100	414,673	297,423	363,385	431,061
2038	6,702,392	8,240,418	9,787,447	285,606	351,216	418,597	293,865	363,576	435,207
2039	6,620,391	8,241,369	9,872,376	282,126	351,351	422,554	290,322	363,786	439,388

5 WEATHER NORMALIZED VALUES

Weather-sensitive electricity loads comprise a large portion of electricity end-uses. Weather conditions vary and will cause electricity sales and peak demands to increase during more extreme periods or decrease during milder periods. In this section, we provide estimates of energy and peak demands for Kenergy during the last ten years with the assumption that temperatures had been at their 15-year normal amounts in each year.

The weather normalized values are calculated using the econometric models that identified weather as a driver of electricity sales. These are the Residential use per consumer and the GCI use per consumer models. Additionally, the load factor model (used to project peak demands) also includes temperature variables. The weather impacts of the deviation from the actual weather to the weather normalized weather are estimated using these models. The weather impacts are then added (or subtracted) to the actual load in that year to determine the weather normalized energy or peak demand.

The following table provides the last ten years of historical data for Kenergy's Rural system. The normalized peak values displayed are a maximum of each monthly normalized value for the given season and therefore frequently occur in a different month than the actual value. Monthly normalized values are provided in Excel that detail the weather normalized values for each monthly peak day.

Rural System Weather Normalized

Kenergy Rural System Weather Normalization						
Year	Energy (MWh)		Winter CP Demand (kW)		Summer CP Demand (kW)	
	Actual	Normalized	Actual	Normalized	Actual	Normalized
2010	1,270,263	1,199,746	261,869	250,621	275,926	246,933
2011	1,214,795	1,207,461	248,534	239,690	268,831	271,747
2012	1,192,208	1,204,726	230,936	251,579	277,689	245,885
2013	1,221,667	1,222,206	242,793	245,852	246,568	255,251
2014	1,240,267	1,214,127	309,978	270,960	248,934	252,026
2015	1,192,608	1,201,323	282,422	270,456	258,844	256,468
2016	1,196,513	1,190,890	244,652	243,514	252,137	252,911
2017	1,132,856	1,174,049	237,617	253,408	260,886	257,291
2018	1,212,570	1,179,704	272,902	250,552	258,518	258,089
2019	1,165,073	1,164,968	243,217	236,693	247,670	257,319

The following table provides the last ten years of historical data for Kenergy's total system.

Total System Weather Normalized

Kenergy Total System Weather Normalization						
Year	Energy (MWh)		Winter CP Demand (kW)		Summer CP Demand (kW)	
	Actual	Normalized	Actual	Normalized	Actual	Normalized
2010	9,353,885	9,283,367	359,384	349,113	367,583	340,979
2011	9,452,290	9,444,957	350,539	335,757	367,317	370,233
2012	9,784,359	9,796,877	330,546	351,189	370,516	351,965
2013	9,818,249	9,818,788	340,519	340,118	346,232	354,915
2014	9,731,881	9,705,741	417,360	378,342	351,698	360,076
2015	8,846,457	8,855,172	388,213	376,247	353,972	360,175
2016	7,211,900	7,206,277	347,603	346,175	356,153	356,928
2017	7,166,656	7,207,849	339,136	354,927	360,248	356,653
2018	7,539,919	7,507,052	353,394	331,045	351,128	350,699
2019	8,385,991	8,385,886	346,116	339,591	356,234	365,884

6 FORECAST METHODOLOGY

The load forecast process began by discussions with Clearspring Energy to solicit feedback from representatives of each member system as well as Big Rivers. The forecasting team issued an information request to each member system requesting monthly energy data by rate class, historical or anticipated changes in load on the system, large consumer energy and peak demand data, and retail price forecasts. Big Rivers provided historical demand data used as the basis to forecast load factors and peak demands.

In addition to this data, Clearspring Energy collected a variety of additional data to develop the load forecast. This included county-level historical socioeconomic data from Woods & Poole Economics, Inc., historical alternative fuel price data and energy efficiency indexes from the Energy Information Administration (EIA), monthly and daily weather data from the Midwest Regional Climate Center (MRCC) and High Plains Regional Climate Center (HPRCC), and appliance and end-use saturations for each member system based off historical end-use surveys conducted by Big Rivers. The most recent survey was conducted in 2019.

6.1 DATABASE SETUP AND ANALYSES

Upon receipt of the associated member systems' data, Big Rivers' data and data obtained from external sources, Clearspring Energy reviewed the data for accuracy and adequacy for use in the study. An electronic database with consumer and energy sales by rate class and demand data was developed using Microsoft Excel™.

County-level economic and demographic data was gathered and added to the energy database. Weighted averages were calculated using customized member system county weights based on the service territory of each member system. The appropriate weights are calculated using the number of Residential consumers served for each member system by county.

Weather variables were also calculated and added to the database. Appropriate customized weather station data was used based on the service territory location of each member system. Historical fifteen-year averages of the selected weather variables were calculated and used as the basis for the normal weather expectation in future years and in the weather normalization results.

All price information is adjusted for inflation using an inflation adjustment from the Congressional Budget Office (CBO).

Data Category	Data Source
Energy, Demand, Customers, and Electricity Price	Big Rivers and its three member systems
Economic & Demographic	Woods & Poole Economics, Inc.
Weather	Midwest Regional Climate Center High Plains Regional Climate Center
Alternative Fuel Prices and Appliance Energy Efficiency	Energy Information Administration
End-Use Appliance Saturations	Big Rivers Survey Reports

6.2 Model Development

Clearspring estimated econometric models to forecast Residential use per consumer, GCI consumers, GCI use per consumer, and the load factor. A separate model was developed for each member system and for each component. A growth index using household forecasts was used to escalate Residential consumers.

Forecasts for the LCI and Direct Serve commercial consumers were prepared judgmentally based on input from the cooperatives. Due to their relatively small size, trend analysis was used to project the Street and Highway class.

Econometric parameters were estimated using the ordinary least squares (OLS) approach to regression analysis employed by the EViews™ version 10 econometric software package. Heteroskedasticity adjusted standard errors were calculated for statistical significance testing of the included variables. The models were selected based on theoretical and statistical validity as well as the reasonableness of the forecast results generated.

The statistical validity of each variable included in the model needed to pass two key criterion to be included in the model. A simple but important standard is that the coefficient of each explanatory variable must have a logical sign. For example, energy sales will generally increase during periods of colder or hotter weather (i.e., these variables should have positive coefficients). Conversely,

energy sales generally decrease with increasing electricity prices (i.e., the coefficient of this variable should be negative).

The second criterion is the fact that each explanatory variable has a statistically significant influence on the dependent variable. The statistical significance of an explanatory variable is measured by the t-statistic. The specific value of a particular t-statistic required for statistical significance depends on both the degrees of freedom (the number of data points less the number of variables) of the equations and desired level of confidence in the estimated coefficients. In general, however, the t-statistic should have a magnitude of at least 1.645 for a 90 percent level of confidence.

Another validity criterion that we took into consideration are examinations of the equation residuals (the difference between the actual historical and estimated historical values). In a good equation, the residuals are randomly distributed and of approximately constant magnitude, in absolute terms. This indicates that there is no obvious pattern in the data that has not been explained by the equation.

The models developed must also pass a test of reasonableness. Models must make intuitive sense to the members of the forecasting team and the forecasts that result must be plausible given reasonable assumptions of growth factors.

6.3 Forecast Development

Using the econometric equations developed as part of the modeling process, monthly forecasts were created for each of the member systems. The modeled classes are calculated using the estimated equations along with forecasted values for those variables that enter into the estimated equation.

The amount of energy required by each system (ultimately provided by Big Rivers) is greater than the sum of the retail energy sales. System own-use and energy losses are forecast for each member system. Energy losses are forecasted as a percentage of total system energy requirements based on historical loss data.

Three monthly demand values are determined for each of the member distribution cooperatives. The individual Direct Serve consumer non-coincident peaks, the distribution cooperative's Rural non-coincident peak demand, and its contribution to the Big Rivers monthly coincident peak (CP).

Clearspring developed a load factor econometric model to forecast the Rural coincident peak load factor which we then use to calculate the peak demand forecasts for each of the three member systems.

Preliminary forecasts were distributed to the respective member systems and Big Rivers for their review and input. The member systems offered suggestions for revisions to the forecasts and these revisions were incorporated.

6.4 Changes in Methodology From 2017 Load Forecast

The 2020 research was conducted by Clearspring Energy Advisors, LLC whereas the 2017 research was conducted by GDS Associates, Inc ("GDS"). Clearspring has reviewed the past load forecast report and other documents and lists the known methodological changes that we are aware of based on this review of the prior consultants' research. We note that it is often precarious to assume what the exact research of another consultant consisted of. We offer the list with the caveat that we may be incorrect in interpreting the exact methodological approach used by GDS.

1. Clearspring uses "weighted" economic and demographic variables that are weighted based on the calculated consumer counts in each county served by each member system. We believe that GDS did not calculate the variables based on weighted consumer counts but used unweighted variables.
2. GDS used a Statistical Adjusted End-Use (SAE) modeling approach. Clearspring uses econometric modeling to directly estimate the impacts of variables that influence use per consumer or consumer counts.
3. Clearspring directly models the electricity price in relationship to an alternative price fuel index (comprised of natural gas and propane prices). We are not aware of GDS directly inserting alternative fuel prices into the analysis.
4. Clearspring calculates the price elasticity based on the relative impact of the electricity price and the alternative fuel index. This price elasticity is estimated directly in the econometric model. Conversely, GDS did not use their SAE modeling but, rather, estimated the price elasticity with a separate econometric model that did not account for other possible drivers of electricity use.

5. Clearspring uses a 15-year weather normal for the base case load forecasts, whereas GDS used a 20-year weather normal.
6. Different weather station mappings were used.
7. Clearspring uses daily high/low temperature values for the load factor econometric model used to forecast peak demands. GDS appears to use hourly values to forecast peak demands.
8. GDS makes some references to using trended energy amounts in models. It is unclear exactly what that means but there are likely differences in the methods used to allocate energy to each specific month.

7 APPENDIX

The following table provides the details on the consumers, sales, and use per consumer for each class for Kenergy's system. The prior five years and the forecasted year values are provided in the table. Both historical and forecasted growth rates for each class are also provided.

Kenergy Corporation															
RESIDENTIAL	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	45,587	45,905	46,348	46,561	46,662	46,755	47,047	47,254	47,408	47,527	47,616	47,682	47,730	47,759	47,765
SALES-MWH	720,243	706,144	664,218	740,207	694,305	701,335	704,720	707,240	707,857	707,796	708,107	709,109	708,096	708,247	707,964
USE PER CONSUMER-kWH	15,799	15,383	14,331	15,898	14,880	15,000	14,979	14,967	14,931	14,892	14,871	14,872	14,836	14,830	14,822
GENERAL C&I	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	10,693	10,798	10,844	10,939	11,142	11,503	11,613	11,736	11,855	11,973	12,092	12,210	12,327	12,443	12,558
SALES-MWH	321,546	329,950	313,235	318,840	322,306	317,646	320,985	324,153	326,892	329,346	331,925	334,521	336,189	338,674	341,132
USE PER CONSUMER-kWH	30,072	30,556	28,887	29,148	28,928	27,615	27,640	27,621	27,574	27,506	27,450	27,398	27,273	27,219	27,165
LARGE C&I	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	15	15	13	13	12	12	12	12	12	12	12	12	12	12	12
SALES-MWH	93,619	100,178	96,066	98,843	95,667	93,867	93,867	93,867	93,867	93,867	93,867	93,867	93,867	93,867	93,867
USE PER CONSUMER-kWH	6,241,235	6,830,320	7,250,281	7,603,271	7,809,534	7,822,260	7,822,260	7,822,260	7,822,260	7,822,260	7,822,260	7,822,260	7,822,260	7,822,260	7,822,260
IRRIGATION	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SALES-MWH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
USE PER CONSUMER-kWH															
STREET & HIGHWAY	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	91	93	94	96	94	93	93	93	93	93	93	93	93	93	93
SALES-MWH	1,750	1,636	1,579	1,445	1,399	1,394	1,394	1,394	1,394	1,394	1,394	1,394	1,394	1,394	1,394
USE PER CONSUMER-kWH	19,216	17,592	16,873	15,076	14,967	14,987	14,987	14,987	14,987	14,987	14,987	14,987	14,987	14,987	14,987
RURAL TOTAL	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	56,385	56,811	57,298	57,609	57,909	58,363	58,765	59,095	59,368	59,606	59,813	59,997	60,161	60,306	60,428
SALES-MWH	1,137,157	1,137,908	1,075,098	1,159,333	1,113,677	1,114,242	1,120,966	1,126,653	1,130,010	1,132,403	1,135,293	1,138,891	1,139,546	1,142,182	1,144,357
USE PER CONSUMER-kWH	20,168	20,030	18,763	20,124	19,231	19,092	19,076	19,065	19,034	18,998	18,981	18,983	18,941	18,940	18,938
OWNUSE-MWH	0	554	2,196	2,409	2,314	2,336	2,352	2,366	2,377	2,386	2,395	2,402	2,409	2,414	2,419
PURCHASES-MWH	1,192,608	1,196,513	1,132,856	1,212,570	1,165,073	1,168,414	1,175,466	1,181,432	1,184,956	1,187,470	1,190,502	1,194,276	1,194,968	1,197,732	1,200,013
LOSSES-MWH	55,451	58,051	55,562	50,827	49,083	51,835	52,148	52,413	52,569	52,680	52,815	52,982	53,013	53,136	53,237
LOSSES (%)	4.6%	4.9%	4.9%	4.2%	4.2%	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%
DIRECT SERVE	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	21	21	21	22	22	22	22	22	22	22	22	22	22	22	22
SALES-MWH	7,653,848	6,015,387	6,033,800	6,327,349	7,220,918	7,026,368	7,026,368	7,026,368	7,026,368	7,026,368	7,026,368	7,026,368	7,026,368	7,026,368	7,026,368
USE PER CONSUMER-kWH	364,468,972	286,446,994	287,323,813	289,802,237	328,223,546	319,380,344	319,380,344	319,380,344	319,380,344	319,380,344	319,380,344	319,380,344	319,380,344	319,380,344	319,380,344
SYSTEM TOTAL WITH DIRECT SERVE	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	56,406	56,832	57,319	57,630	57,931	58,385	58,787	59,117	59,390	59,628	59,835	60,019	60,183	60,328	60,450
SALES-MWH	8,791,006	7,153,295	7,108,898	7,486,682	8,334,595	8,140,610	8,147,333	8,153,021	8,156,378	8,158,771	8,161,660	8,165,259	8,165,913	8,168,549	8,170,724
USE PER CONSUMER-kWH	155,851	125,868	124,023	129,909	143,871	139,430	138,592	137,914	137,336	136,829	136,402	136,045	135,684	135,401	135,166
OWNUSE-MWH	0	554	2,196	2,409	2,314	2,336	2,352	2,366	2,377	2,386	2,395	2,402	2,409	2,414	2,419
PURCHASES-MWH	8,846,457	7,211,900	7,166,656	7,539,919	8,385,991	8,194,781	8,201,834	8,207,799	8,211,323	8,213,838	8,216,870	8,220,643	8,221,335	8,224,100	8,226,381
LOSSES-MWH	55,451	58,051	55,562	50,827	49,083	51,835	52,148	52,413	52,569	52,680	52,815	52,982	53,013	53,136	53,237
LOSSES (%)	0.6%	0.8%	0.8%	0.7%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
ANNUAL PEAK	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
RURAL CP - kW	282,422	252,137	260,886	272,902	243,217	246,286	247,668	247,905	248,579	249,064	249,672	250,446	250,580	251,163	251,649
DIRECT SERVE CP - kW	105,791	104,017	99,362	80,492	102,899	111,856	111,856	108,798	108,798	108,798	108,798	108,798	108,798	108,798	108,798
TOTAL CP - kW	388,213	356,153	360,248	353,394	346,116	358,142	359,524	356,703	357,378	357,862	358,470	359,244	359,378	359,961	360,447
RURAL NCP - kW	282,422	254,824	263,055	272,902	249,712	248,475	249,869	251,026	251,659	252,104	252,674	253,417	253,515	254,062	254,511
DIRECT SERVE SUM OF INDIVIDUAL NCP - kW	1,026,058	730,803	734,976	891,152	938,439	842,014	842,014	842,014	842,014	842,014	842,014	842,014	842,014	842,014	842,014

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Kenergy Corporation											Last 10 Yrs	Last 5 Yrs	Next 5 Yrs	Next 10 Yrs	Next 20 Yrs
RESIDENTIAL	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	47,749	47,716	47,666	47,602	47,531	47,451	47,366	47,281	47,197	47,116	0.3%	0.6%	0.4%	0.2%	0.0%
SALES-MWH	706,687	706,000	706,767	706,072	704,971	703,949	702,910	702,047	701,096	700,225	-0.2%	-1.7%	0.4%	0.2%	0.0%
USE PER CONSUMER-kWH	14,800	14,796	14,828	14,833	14,832	14,835	14,840	14,848	14,855	14,862	-0.5%	-2.3%	0.0%	0.0%	0.0%
GENERAL C&I	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	12,672	12,785	12,897	13,008	13,117	13,226	13,335	13,442	13,549	13,654	1.5%	1.2%	1.5%	1.2%	1.0%
SALES-MWH	343,334	345,939	349,238	351,540	353,616	355,700	357,738	359,631	361,398	363,176	0.8%	-0.1%	0.4%	0.6%	0.6%
USE PER CONSUMER-kWH	27,093	27,057	27,079	27,026	26,958	26,893	26,828	26,754	26,674	26,598	-0.7%	-1.3%	-1.0%	-0.6%	-0.4%
LARGE C&I	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	12	12	12	12	12	12	12	12	12	12	0.6%	-4.1%	-0.4%	-0.2%	-0.1%
SALES-MWH	93,867	93,867	93,867	93,867	93,867	93,867	93,867	93,867	93,867	93,867	1.6%	0.2%	-0.4%	-0.2%	-0.1%
USE PER CONSUMER-kWH	7,822,260	7,822,260	7,822,260	7,822,260	7,822,260	7,822,260	7,822,260	7,822,260	7,822,260	7,822,260	1.0%	4.4%	0.0%	0.0%	0.0%
IRRIGATION	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-
SALES-MWH	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-
USE PER CONSUMER-kWH											-	-	-	-	-
STREET & HIGHWAY	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	93	93	93	93	93	93	93	93	93	93	2.1%	2.7%	-0.1%	-0.1%	0.0%
SALES-MWH	1,394	1,394	1,394	1,394	1,394	1,394	1,394	1,394	1,394	1,394	-1.2%	-4.8%	-0.1%	0.0%	0.0%
USE PER CONSUMER-kWH	14,987	14,987	14,987	14,987	14,987	14,987	14,987	14,987	14,987	14,987	-3.2%	-7.3%	0.0%	0.0%	0.0%
RURAL TOTAL	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	60,526	60,606	60,668	60,715	60,753	60,782	60,806	60,828	60,851	60,875	0.6%	0.7%	0.6%	0.4%	0.3%
SALES-MWH	1,145,281	1,147,199	1,151,266	1,152,873	1,153,848	1,154,910	1,155,908	1,156,939	1,157,754	1,158,662	0.2%	-1.1%	0.3%	0.3%	0.2%
USE PER CONSUMER-kWH	18,922	18,929	18,977	18,988	18,992	19,001	19,010	19,020	19,026	19,033	-0.3%	-1.8%	-0.2%	-0.2%	-0.1%
OWNUSE-MWH	2,423	2,427	2,429	2,431	2,432	2,434	2,435	2,436	2,436	2,437	-	-	0.6%	0.4%	0.3%
PURCHASES-MWH	1,200,985	1,202,995	1,207,253	1,208,937	1,209,959	1,211,071	1,212,117	1,213,197	1,214,050	1,215,002	0.2%	-1.2%	0.4%	0.3%	0.2%
LOSSES-MWH	53,280	53,369	53,558	53,633	53,678	53,728	53,774	53,822	53,860	53,902	-1.3%	-4.5%	1.4%	0.8%	0.5%
LOSSES (%)	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%	-1.5%	-3.3%	1.0%	0.5%	0.3%
DIRECT SERVE	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	22	22	22	22	22	22	22	22	22	22	0.5%	0.9%	0.0%	0.0%	0.0%
SALES-MWH	7,026,368	7,026,368	7,026,368	7,026,368	7,026,368	7,026,368	7,026,368	7,026,368	7,026,368	7,026,368	-0.5%	-3.2%	-0.5%	-0.3%	-0.1%
USE PER CONSUMER-kWH	319,380,344	319,380,344	319,380,344	319,380,344	319,380,344	319,380,344	319,380,344	319,380,344	319,380,344	319,380,344	-1.0%	-4.1%	-0.5%	-0.3%	-0.1%
SYSTEM TOTAL WITH DIRECT SERVE	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	60,548	60,628	60,690	60,737	60,775	60,804	60,828	60,850	60,873	60,897	0.6%	0.7%	0.6%	0.4%	0.2%
SALES-MWH	8,171,649	8,173,567	8,177,633	8,179,240	8,180,216	8,181,278	8,182,276	8,183,307	8,184,122	8,185,030	-0.4%	-2.9%	-0.4%	-0.2%	-0.1%
USE PER CONSUMER-kWH	134,961	134,814	134,744	134,667	134,598	134,551	134,516	134,484	134,447	134,407	-1.0%	-3.6%	-1.0%	-0.6%	-0.3%
OWNUSE-MWH	2,423	2,427	2,429	2,431	2,432	2,434	2,435	2,436	2,436	2,437	-	-	0.6%	0.4%	0.3%
PURCHASES-MWH	8,227,352	8,229,363	8,233,621	8,235,304	8,236,326	8,237,439	8,238,484	8,239,564	8,240,418	8,241,369	-0.4%	-2.9%	-0.4%	-0.2%	-0.1%
LOSSES-MWH	53,280	53,369	53,558	53,633	53,678	53,728	53,774	53,822	53,860	53,902	-1.3%	-4.5%	1.4%	0.8%	0.5%
LOSSES (%)	0.6%	0.6%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	-0.9%	-1.6%	1.8%	1.0%	0.6%
ANNUAL PEAK	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
RURAL CP - kW	251,867	252,313	253,236	253,610	253,853	254,105	254,344	254,586	254,778	254,988	-1.4%	-4.7%	0.5%	0.3%	0.2%
DIRECT SERVE CP - kW	108,798	108,798	108,798	108,798	108,798	108,798	108,798	108,798	108,798	108,798	1.7%	-0.8%	1.1%	0.6%	0.3%
TOTAL CP - kW	360,665	361,111	362,034	362,408	362,651	362,903	363,142	363,385	363,576	363,786	-0.6%	-3.7%	0.7%	0.4%	0.2%
RURAL NCP - kW	254,689	255,095	256,006	256,383	256,629	256,884	257,125	257,370	257,564	257,776	-1.1%	-4.2%	0.2%	0.2%	0.2%
DIRECT SERVE SUM OF INDIVIDUAL NCP - kW	842,014	842,014	842,014	842,014	842,014	842,014	842,014	842,014	842,014	842,014	-0.7%	-1.9%	-2.1%	-1.1%	-0.5%

LOAD FORECAST

2020

Big Rivers
ELECTRIC CORPORATION

Case No. 2020-00299
Attachment 3 for Rresponse to PSC 1-52d
Witnesses: Matthew S. Sekeres and Steven A. Fenrick

2020 Meade County RECC Load Forecast Study

Developed in partnership with

Big Rivers Electric Corporation

and

Meade County RECC

June 12, 2020

Prepared By:

Clearspring Energy Advisors LLC

1050 Regent St., Suite L3

Madison, WI 53715

608.442.8668

Confidentiality Statement

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1 INTRODUCTION AND SYSTEM SUMMARY

1.1 PROJECT OVERVIEW

The 2020 Big Rivers Electric Corporation ("Big Rivers") electric load forecast has been created from the bottom up. That is, forecast models have been developed for each of the three distribution systems served by Big Rivers. Each distribution member forecast is conducted separately, and each distribution member has reviewed and approved the load forecast applicable to its system.

Clearspring Energy Advisors, LLC (Clearspring) was selected by Big Rivers and its members to prepare this 2020 electric load forecast. The forecasting process relies heavily on internal system data, third-party demographic and economic data, and insight from cooperative staff that are most familiar with the end-uses and trends in the service territory. An emphasis has been placed on strong coordination between Big Rivers, the three member systems, and Clearspring in preparing this study to ensure accurate and useful load forecast results.

The forecast team members include the following individuals.

Name	Company	Role
Marlene Parsley	Big Rivers Electric Corporation	Project Manager
Russ Pogue	Big Rivers Electric Corporation	DSM Study
Anna Swanson	Meade County RECC	Vice President of Accounting & Finance
David Poe	Meade County RECC	V.P. Operations and Engineering
Mike French	Meade County RECC	System Engineer
Matt Sekeres	Clearspring Energy Advisors	Lead Consultant
Steve Fenrick	Clearspring Energy Advisors	Econometric Model Development
Josh Hoyt	Clearspring Energy Advisors	DSM Study

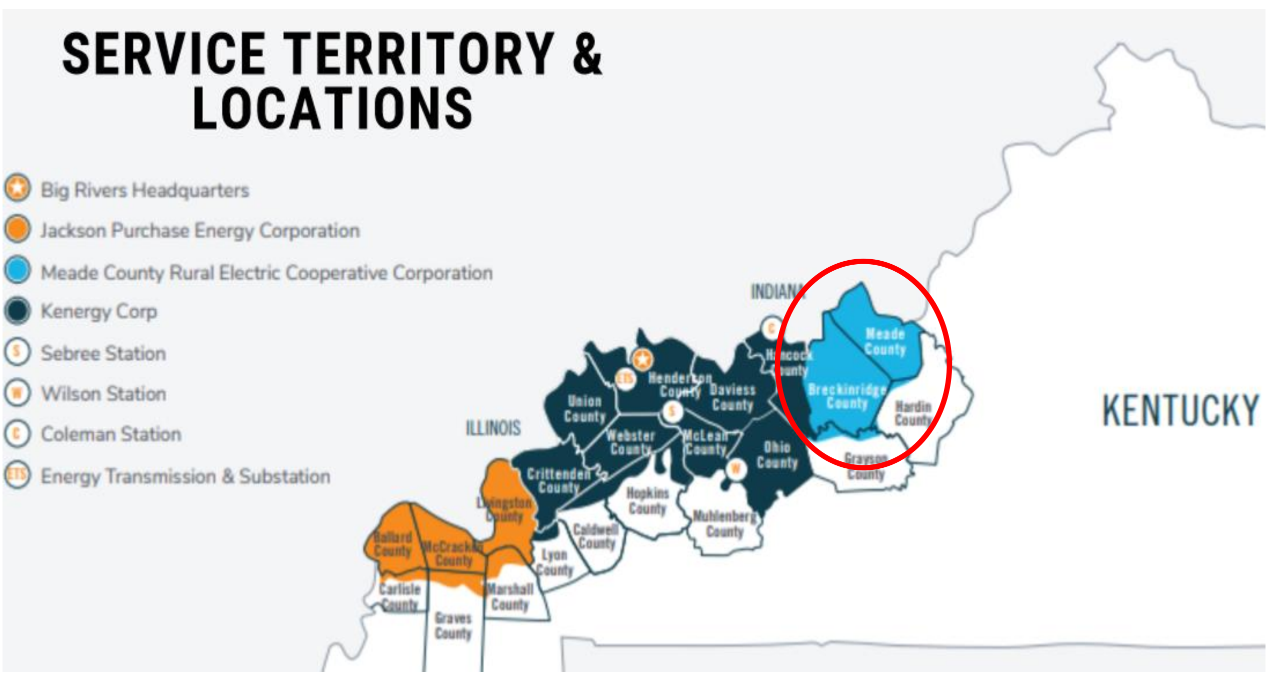
The forecast results meet the requirements of and will be used in USDA Rural Utilities Service ("RUS") loan applications, the forecast will be a key input into an Integrated Resource Plan ("IRP") being completed by Big Rivers under the direction of the Kentucky Public Service Commission ("Commission"), and the forecast will be used for planning and financial projections.

1.2 Member Information

The three distribution cooperatives are Jackson Purchase Energy Corporation, Kenergy Corporation, and Meade County Rural Electric Cooperative Corporation. These three Big Rivers members serve more than 118,000 residential households, businesses, and farms in western Kentucky. This report details the load forecast for Meade County RECC ("MCRECC").

MCRECC served approximately 30,000 members in 2019. The service territory of MCRECC is circled below.

Service Territory



1.3 Forecast Summary

The forecast study develops a forecast for individual retail classes. The forecasted retail classes are:

- Residential,
- General Commercial and Industrial ("GCI"),
- Large Commercial and Industrial ("LCI"),
- Street & Highway, and
- Direct Serve sales.

The Residential, GCI, LCI, and Street and Highway classes along with distribution and own losses make up the Rural system requirements. Direct Serve sales are aggregated with the Rural system to provide total system requirements. MCRECC's retail class sales forecast is the product of the consumer forecast and the use per consumer forecast for each class. MCRECC's total sales forecast is constructed by summing the individual retail class sales forecasts.

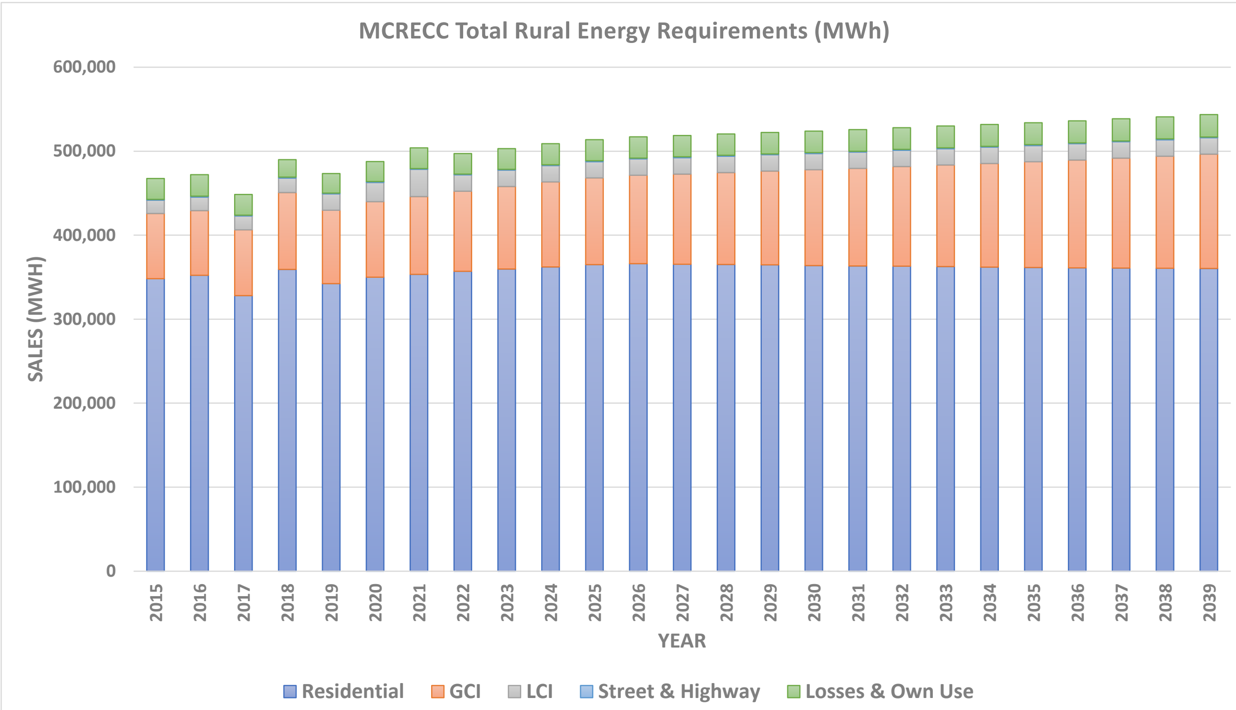
The table below provides MCRECC's Rural energy requirements, Direct Serve energy requirements, Rural peak demand coincident to Big Rivers, Direct Serve sum of individual non-coincident peak (NCP) and Rural system load factor for the last five historical years (2015-2019) and the forecasts for the next 20 years. Throughout this load forecast study, 2019 is considered a historical data year even though due to timeline considerations November and December of 2019 often contain estimated data.

System Summary

MCRECC System Totals					
Year	Total Rural Energy Requirements (MWh)	Direct Serve Energy Requirements (MWh)	Rural System Coincident Peak Demand (MW)	Direct Serve Sum of Individual NCP (MW)	Rural System Coincident Peak Load Factor
2015	467,555	0	136.4	0.0	39.1%
2016	471,965	0	90.5	0.0	59.4%
2017	448,590	0	94.5	0.0	54.2%
2018	490,014	0	138.8	0.0	40.3%
2019	473,343	0	124.5	0.0	43.4%
2020	487,757	0	95.5	0.0	58.1%
2021	504,013	0	98.5	0.0	58.4%
2022	497,146	1,051,200	97.4	200.0	58.2%
2023	503,090	1,051,200	98.5	200.0	58.3%
2024	508,849	1,054,080	99.6	200.0	58.2%
2025	513,690	1,051,200	100.4	200.0	58.4%
2026	517,123	1,051,200	101.0	200.0	58.4%
2027	518,638	1,051,200	101.2	200.0	58.5%
2028	520,540	1,054,080	101.6	200.0	58.3%
2029	522,355	1,051,200	101.9	200.0	58.5%
2030	523,927	1,051,200	102.2	200.0	58.5%
2031	525,718	1,051,200	102.6	200.0	58.5%
2032	527,976	1,051,200	103.0	200.0	58.4%
2033	529,917	1,051,200	103.4	200.0	58.5%
2034	531,850	1,051,200	103.8	200.0	58.5%
2035	533,933	1,051,200	104.2	200.0	58.5%
2036	536,146	1,051,200	104.6	200.0	58.3%
2037	538,527	1,051,200	105.1	200.0	58.5%
2038	540,978	1,051,200	105.6	200.0	58.5%
2039	543,566	1,051,200	106.1	200.0	58.5%
Average Annual Growth Rates					
Previous 10 Years	0.41%	-	-0.62%	-	1.04%
Previous 5 Years	-0.69%	-	-3.50%	-	2.91%
Next 5 Years	1.46%	-	-4.37%	-	6.04%
Next 10 Years	0.99%	-	-1.98%	-	3.03%
Next 20 Years	0.69%	-	-0.80%	-	1.50%

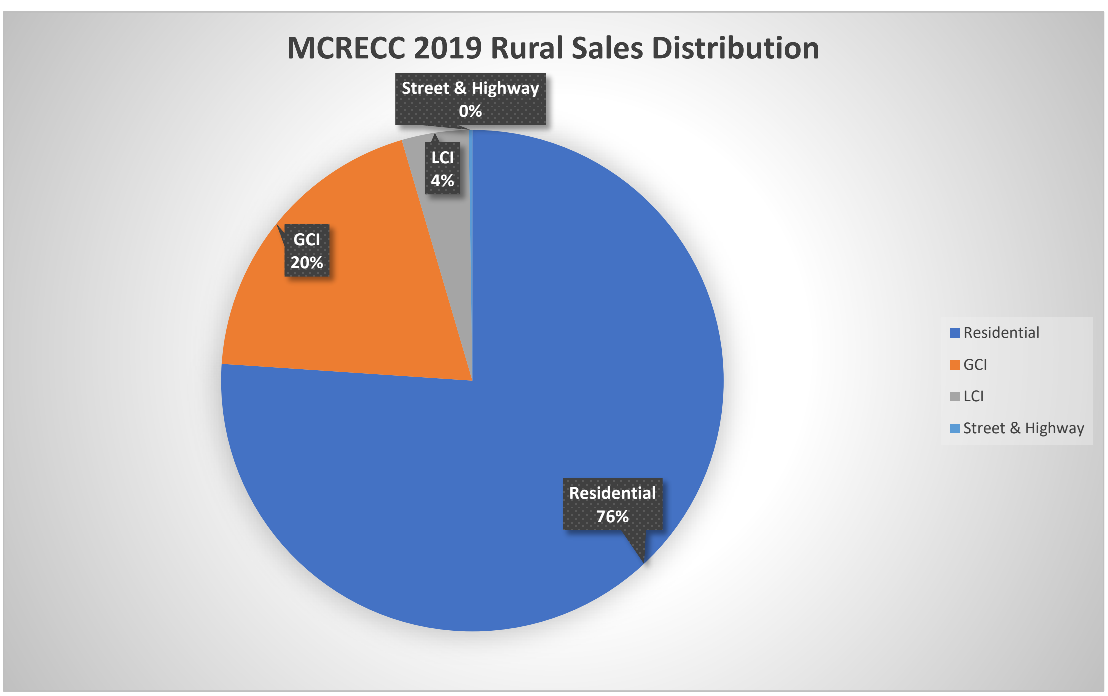
The following graph provides the cooperative's total system Rural energy requirements forecast.

Rural Energy Requirements



The figure below provides the cooperative's Rural sales distribution by class for 2019.

2019 Sales by Class Distribution



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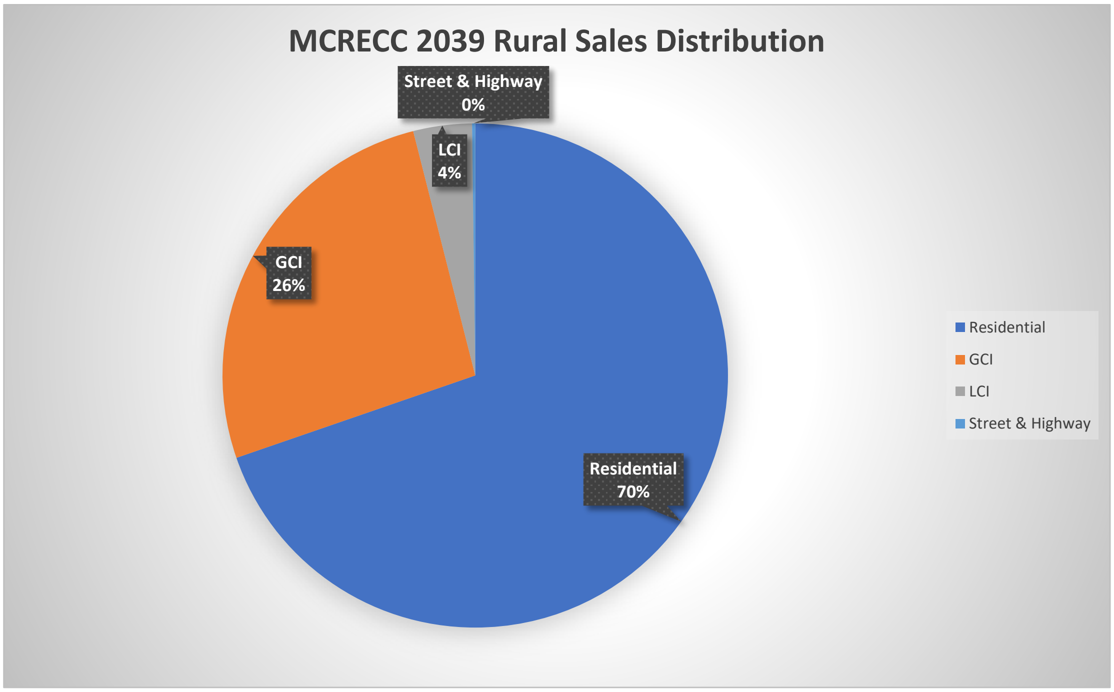
The figure below provides the cooperative's Rural sales forecasted distribution by class for 2039.

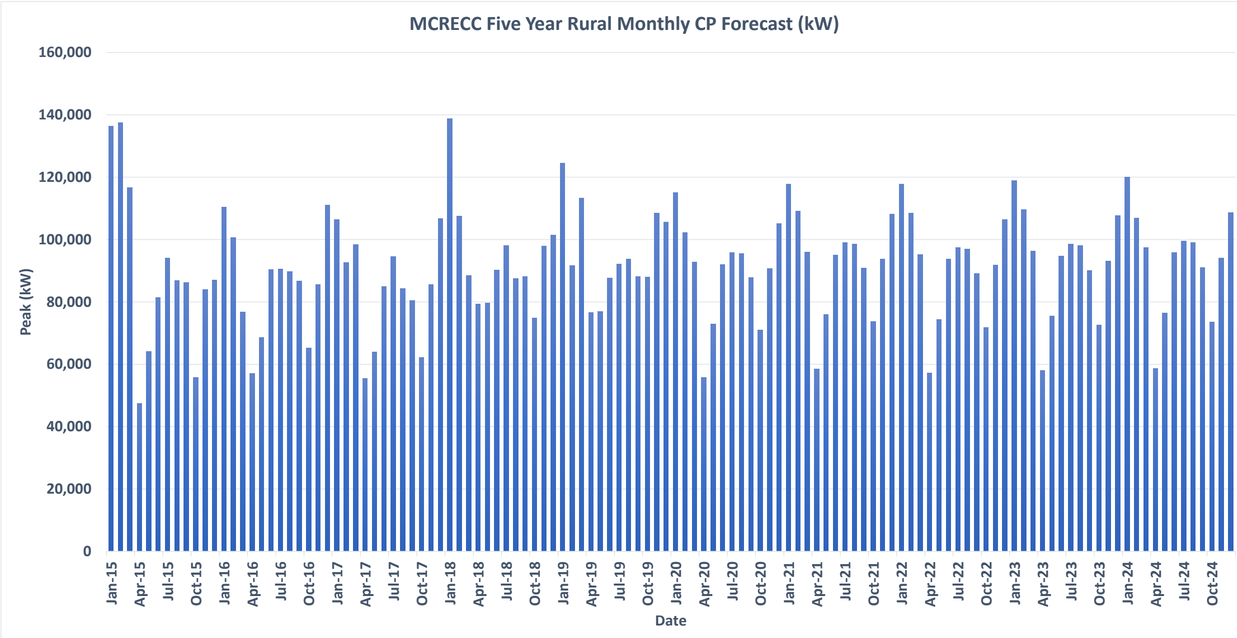
2039 Sales by Class Distribution



1.3.1 Monthly Peak Forecast

Monthly load factors have been econometrically modeled for each system. The load factor models are used in conjunction with the energy forecasts to calculate peak monthly peak demands. The monthly Rural peak demand forecast (coincident with Big Rivers) for the prior and next five years is presented in the following figure.

Monthly Rural Peak Forecast



1.4 2019 Weather Conditions

There contains an assumption of a "normal" weather scenario for the forecasts for each class. Clearspring Energy compiled historical weather observations to enable the estimation of weather impacts onto sales and peak loads. Weather variables such as cooling degree days (CDD), heating degree days (HDD), and peak temperatures were gathered using weather stations within each service territory. Louisville, KY was used as the primary weather station to gather data for MCRECC. In the cases of missing historical data at Louisville, a variety of backup stations were used to fill in missing data.

The figure below displays the last fifteen years of CDDs for MCRECC along with the 15-year average CDD.

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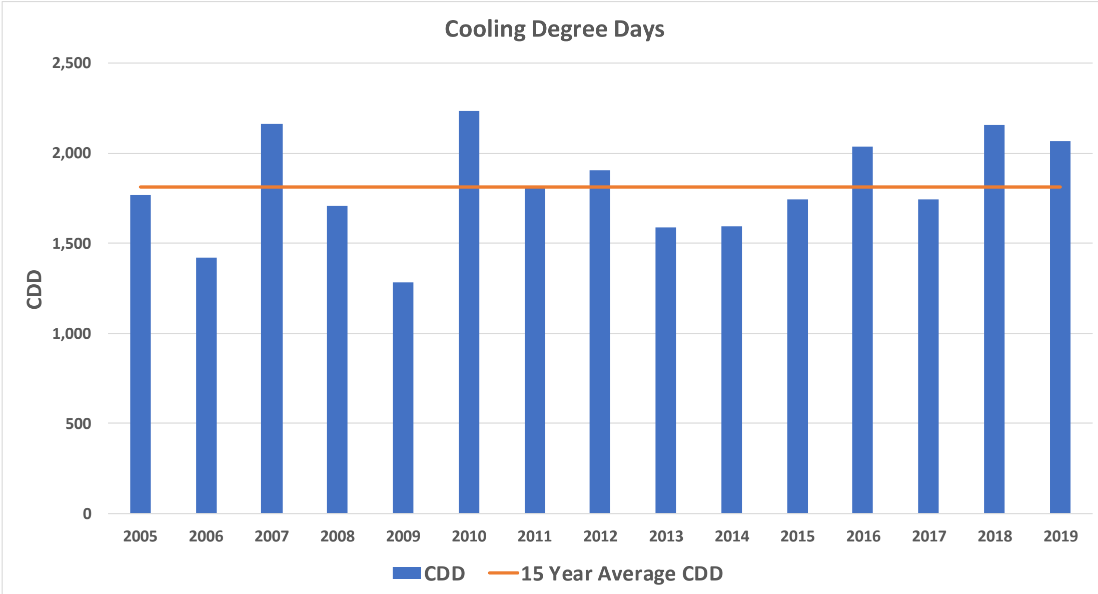
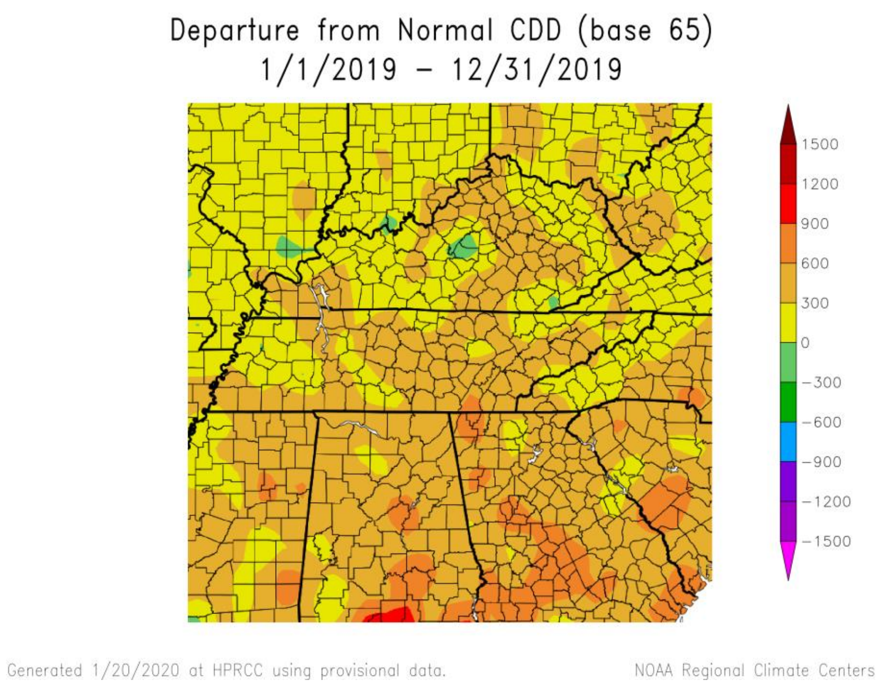
Cooling Degree Days for Last 15 Years



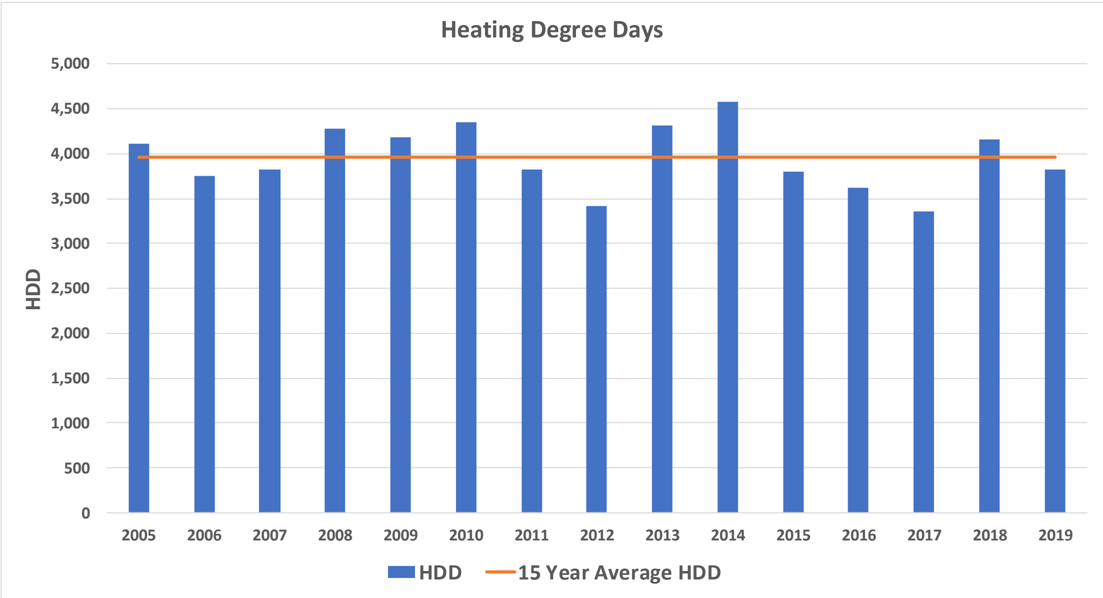
The figure below provides the CDD deviation in 2019 from a 30-year normal amount for the entire state of Kentucky.

Kentucky 2019 CDD Deviations



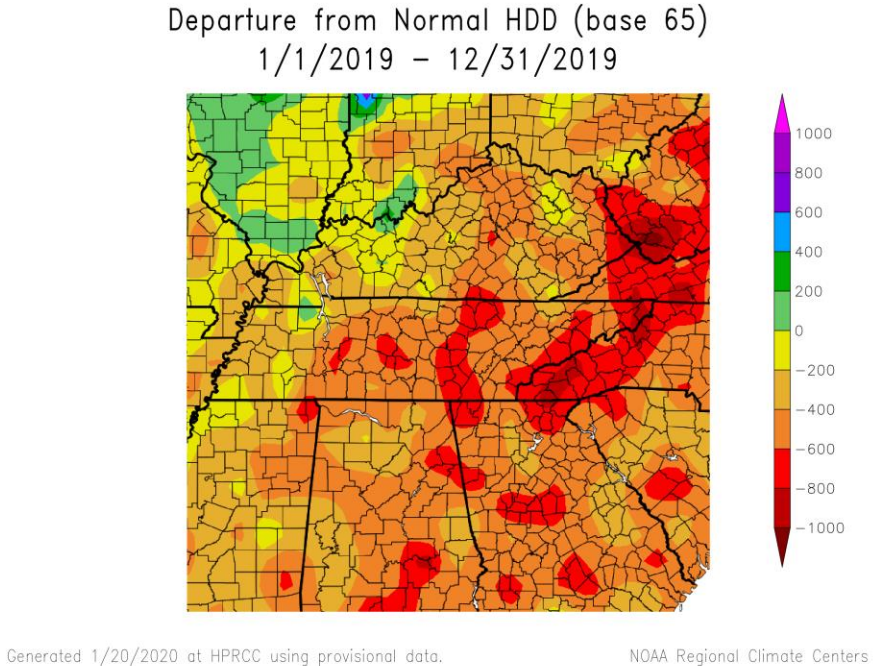
The figure below displays the last fifteen years of HDDs for MCRECC along with the 15-year average HDD.

Heating Degree Days for Last 15 Years



The figure below provides the HDD deviation in 2019 from a 30-year normal amount for the entire state of Kentucky.

Kentucky 2019 HDD Deviations



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1.5 FORECAST PROCESS SUMMARY

Clearspring developed econometric models in order to forecast Residential energy per consumer, General C&I (GCI) consumers, GCI use per consumer, and the Rural system's monthly load factors. A growth index using projections for the number of households was used to forecast Residential consumers. Historical weather and economic data was gathered from various sources to estimate the impacts of variables onto the corresponding category. Normalized weather and forecasted economic variables are then combined with the parameter estimates of the models to calculate forecasted values.

Forecasts for the LCI and Direct Serve commercial loads have been prepared judgmentally based on input from the cooperatives and historical values. Judgment and trend analysis are used to project Street and Highway, own use, and distribution losses. The forecasts have been provided to Big Rivers and the member systems and have been approved by each.

2 ENERGY FORECAST RESULTS

2.1 Residential Class

The Residential sales forecast is comprised of a forecast for Residential use per consumer and a forecast for Residential retail members. The product of the two disaggregated forecasts equals the Residential sales forecast.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of Residential customers, Residential use per consumer, and Residential energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are also provided.

Historical and Projected Residential Consumers, Use per Consumer, and Sales

MCRECC Residential Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (kWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	27,038		12,877		348,157	
2016	27,298	0.96%	12,908	0.24%	352,360	1.21%
2017	27,471	0.63%	11,941	-7.49%	328,042	-6.90%
2018	27,584	0.41%	13,022	9.05%	359,192	9.50%
2019	27,713	0.47%	12,355	-5.12%	342,387	-4.68%
2020	27,953	0.86%	12,524	1.37%	350,066	2.24%
2021	28,263	1.11%	12,500	-0.19%	353,285	0.92%
2022	28,594	1.17%	12,485	-0.12%	356,981	1.05%
2023	28,897	1.06%	12,450	-0.28%	359,772	0.78%
2024	29,178	0.97%	12,417	-0.27%	362,302	0.70%
2025	29,443	0.91%	12,393	-0.19%	364,881	0.71%
2026	29,574	0.44%	12,379	-0.11%	366,082	0.33%
2027	29,593	0.06%	12,348	-0.25%	365,417	-0.18%
2028	29,603	0.03%	12,333	-0.13%	365,079	-0.09%
2029	29,603	0.00%	12,317	-0.13%	364,616	-0.13%
2030	29,593	-0.03%	12,296	-0.17%	363,877	-0.20%
2031	29,573	-0.07%	12,285	-0.09%	363,302	-0.16%
2032	29,548	-0.09%	12,289	0.04%	363,126	-0.05%
2033	29,518	-0.10%	12,284	-0.04%	362,603	-0.14%
2034	29,486	-0.11%	12,278	-0.05%	362,024	-0.16%
2035	29,453	-0.11%	12,275	-0.02%	361,540	-0.13%
2036	29,420	-0.11%	12,275	0.00%	361,129	-0.11%
2037	29,389	-0.11%	12,278	0.02%	360,829	-0.08%
2038	29,361	-0.10%	12,280	0.02%	360,544	-0.08%
2039	29,337	-0.08%	12,283	0.02%	360,337	-0.06%
Average Annual Growth Rates						
Previous 10 Years	0.66%		-0.38%		0.28%	
Previous 5 Years	0.64%		-2.11%		-1.48%	
Next 5 Years	1.04%		0.10%		1.14%	
Next 10 Years	0.66%		-0.03%		0.63%	
Next 20 Years	0.29%		-0.03%		0.26%	

2.1.1 Residential Consumer Forecast

Household growth estimates for each county within MCRECC's service territory are used to project the number of Residential members in future years. The following table provides the historical and projected data used to forecast Residential consumers. Actual county level consumer data was provided for 2019. County distributions prior to 2019 have been estimated.

Historical and Projected Residential Consumers By County

MCRECC Residential Consumers							
Year	Residential Accounts by County						
	Breckinridge	Meade	Grayson	Ohio	Hardin	Hancock	
	Percentage of County Served						
	100.0%	80.0%	11.3%	9.2%	0.1%	0.3%	**Total**
2000	10,683	9,451	1,269	926	51	11	**22,391**
2001	10,912	9,654	1,296	946	52	12	**22,873**
2002	11,066	9,790	1,315	959	53	12	**23,195**
2003	11,269	9,970	1,339	977	54	12	**23,621**
2004	11,526	10,197	1,369	999	55	12	**24,159**
2005	11,704	10,354	1,391	1,014	56	12	**24,532**
2006	11,928	10,552	1,417	1,034	57	13	**25,001**
2007	12,144	10,743	1,443	1,053	58	13	**25,453**
2008	12,313	10,893	1,463	1,067	59	13	**25,808**
2009	12,376	10,949	1,470	1,073	59	13	**25,940**
2010	12,506	11,064	1,486	1,084	60	13	**26,213**
2011	12,596	11,144	1,497	1,092	60	13	**26,402**
2012	12,644	11,186	1,502	1,096	61	13	**26,503**
2013	12,703	11,238	1,509	1,101	61	14	**26,625**
2014	12,809	11,332	1,522	1,110	61	14	**26,847**
2015	12,900	11,412	1,533	1,118	62	14	**27,038**
2016	13,024	11,522	1,547	1,129	62	14	**27,298**
2017	13,106	11,595	1,557	1,136	63	14	**27,471**
2018	13,160	11,643	1,564	1,141	63	14	**27,584**
2019	13,222	11,697	1,571	1,146	63	14	**27,713**
2020	13,345	11,790	1,583	1,156	64	14	**27,953**
2021	13,509	11,918	1,593	1,165	65	14	**28,263**
2022	13,684	12,060	1,599	1,171	65	14	**28,594**
2023	13,846	12,190	1,605	1,177	65	14	**28,897**
2024	13,998	12,311	1,609	1,181	66	14	**29,178**
2025	14,141	12,425	1,612	1,185	66	14	**29,443**
2026	14,219	12,472	1,615	1,188	66	14	**29,574**
2027	14,240	12,464	1,617	1,190	67	14	**29,593**
2028	14,257	12,453	1,618	1,192	67	14	**29,603**
2029	14,270	12,438	1,619	1,194	67	14	**29,603**
2030	14,278	12,418	1,620	1,195	67	14	**29,593**
2031	14,281	12,395	1,620	1,195	67	14	**29,573**
2032	14,282	12,370	1,619	1,195	68	14	**29,548**
2033	14,280	12,342	1,619	1,194	68	14	**29,518**
2034	14,279	12,314	1,618	1,194	68	14	**29,486**
2035	14,276	12,285	1,617	1,193	68	14	**29,453**
2036	14,273	12,257	1,617	1,191	68	14	**29,420**
2037	14,271	12,229	1,616	1,190	68	14	**29,389**
2038	14,271	12,203	1,616	1,189	68	14	**29,361**
2039	14,273	12,179	1,616	1,187	68	14	**29,337**
Average Annual Growth Rates							
Previous 10 Years	0.66%	0.66%	0.66%	0.66%	0.66%	0.66%	**0.66%**
Previous 5 Years	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	**0.64%**
Next 5 Years	1.15%	1.03%	0.48%	0.61%	0.79%	0.39%	**1.04%**
Next 10 Years	0.77%	0.62%	0.30%	0.41%	0.59%	0.21%	**0.66%**
Next 20 Years	0.38%	0.20%	0.14%	0.18%	0.36%	0.05%	**0.29%**

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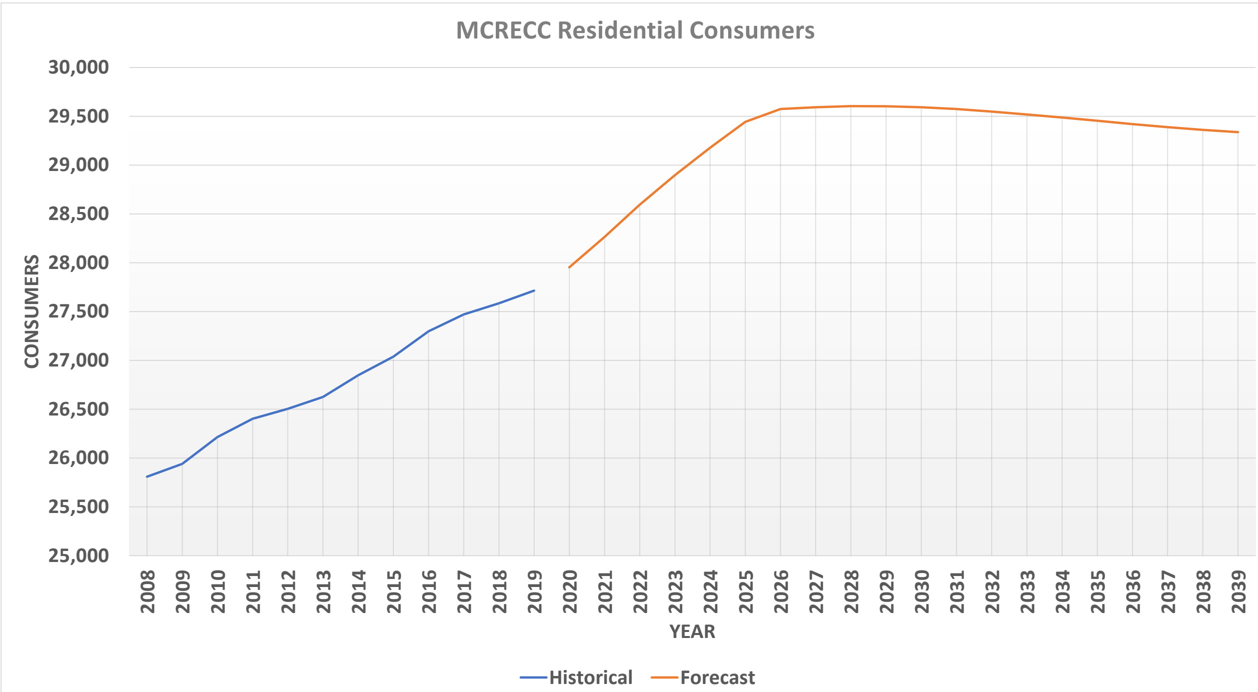
Witnesses: Matthew S. Sekeres and Steven A. Fenrick

The following figure provides the historical and projected Residential consumers.

Residential Consumers



2.1.2 Residential Use per Consumer Forecast

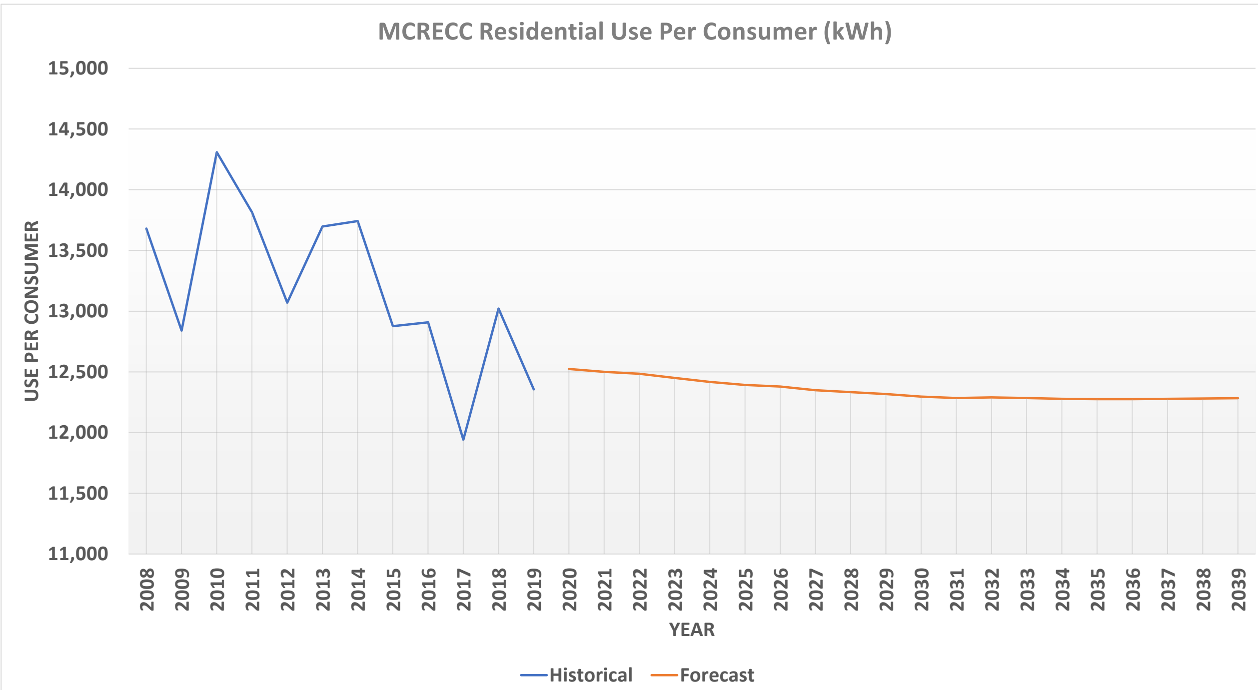
The Residential use per consumer forecast is estimated using an econometric model that relates certain explanatory variables to Residential use per consumer. The model employs a monthly dataset with 154 observations from January 2007 to October 2019. The model uses price of electricity, alternate fuel prices, cooling and heating degree days, appliance saturation levels, and appliance efficiencies. Explanatory variable values are projected in future years using demographic and economic projections and weather normalized values. The Residential use per consumer model is provided in the table below.

Residential Use Per Consumer Model

MCRECC Residential Use Per Consumer Model				
Sample: 2007 - 2019 Total Observations: 154				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	6.502017	0.032406	200.6445	0
February	6.442692	0.029824	216.0239	0
March	6.463045	0.025399	254.4629	0
April	6.344359	0.021936	289.2233	0
May	6.403802	0.021567	296.9234	0
June	6.477804	0.028175	229.9153	0
July	6.53239	0.028028	233.0685	0
August	6.501135	0.029804	218.1295	0
September	6.418795	0.023509	273.0325	0
October	6.356149	0.02102	302.3865	0
November	6.425176	0.024297	264.4417	0
December	6.511993	0.028191	230.9937	0
Log(Residential Price/Alternate Fuel Price)	-0.037951	0.006605	-5.745857	0
Cooling Degree Days*(AC Saturation)*(1/AC Efficiency)	0.012035	0.000577	20.86585	0
Heating Degree Days*Electric Heat Saturation*(1/Heating Efficiency)	0.010624	0.00039	27.22624	0
Weighted Statistics				
Adjusted R-squared: 0.977587				

The following figure provides the historical and projected Residential use per consumer for MCRECC.

Residential Use Per Consumer



2.2 Commercial and Industrial Class

The total commercial and industrial class is divided into three distinct sub classes. Certain large commercial and industrial consumers that are directly served off the transmission system are deemed as Direct Serve consumers and these consumers are individually forecasted based on input from the member system, Big Rivers, or the Direct Serve consumer itself. The Direct Serve sales are aggregated to the total system requirements separately from the Rural system load. The second commercial and industrial class is the Large C&I (LCI) class. This class consists of the top 10 commercial and industrial consumers (Direct Serve excluded), with one additional consumer coming online in 2020 and expected to remain on the system through 2021. The rest of the commercial and industrial retail members are placed and forecasted within the General C&I (GCI) class.

2.2.1 General Commercial and Industrial (GCI) Class

The GCI class is defined as the total commercial and industrial loads minus the Direct Serve and LCI loads. Given the importance of the GCI class, Clearspring Energy used econometric modeling to project both the GCI consumer counts and the GCI use per consumer for MCRECC.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of GCI customers, GCI use per consumer, and GCI energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table for GCI consumers, use per consumer, and sales.

Historical and Projected GCI Consumers, Use per Consumer, and Sales

MCRECC General C&I Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (kWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	2,111		36,754		77,603	
2016	2,086	-1.23%	36,856	0.28%	76,862	-0.96%
2017	2,092	0.29%	37,455	1.63%	78,337	1.92%
2018	2,108	0.78%	43,412	15.90%	91,502	16.80%
2019	2,092	-0.74%	41,731	-3.87%	87,303	-4.59%
2020	2,128	1.71%	42,259	1.26%	89,922	3.00%
2021	2,192	3.00%	42,259	0.00%	92,620	3.00%
2022	2,257	3.00%	42,259	0.00%	95,399	3.00%
2023	2,325	3.00%	42,259	0.00%	98,261	3.00%
2024	2,395	3.00%	42,259	0.00%	101,208	3.00%
2025	2,443	2.02%	42,251	-0.02%	103,233	2.00%
2026	2,492	1.99%	42,257	0.01%	105,297	2.00%
2027	2,542	2.01%	42,253	-0.01%	107,403	2.00%
2028	2,593	1.99%	42,256	0.01%	109,551	2.00%
2029	2,645	2.01%	42,253	-0.01%	111,742	2.00%
2030	2,697	1.99%	42,256	0.01%	113,977	2.00%
2031	2,751	2.00%	42,254	0.00%	116,257	2.00%
2032	2,806	2.00%	42,255	0.00%	118,582	2.00%
2033	2,863	2.00%	42,254	0.00%	120,953	2.00%
2034	2,920	2.00%	42,255	0.00%	123,372	2.00%
2035	2,978	2.00%	42,254	0.00%	125,840	2.00%
2036	3,038	2.00%	42,255	0.00%	128,357	2.00%
2037	3,098	2.00%	42,254	0.00%	130,924	2.00%
2038	3,160	2.00%	42,255	0.00%	133,542	2.00%
2039	3,224	2.00%	42,255	0.00%	136,213	2.00%
Average Annual Growth Rates						
Previous 10 Years	0.21%		-1.07%		-0.87%	
Previous 5 Years	-0.31%		1.51%		1.19%	
Next 5 Years	2.74%		0.25%		3.00%	
Next 10 Years	2.37%		0.12%		2.50%	
Next 20 Years	2.19%		0.06%		2.25%	

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2.2.1.1 GCI Consumer Forecast

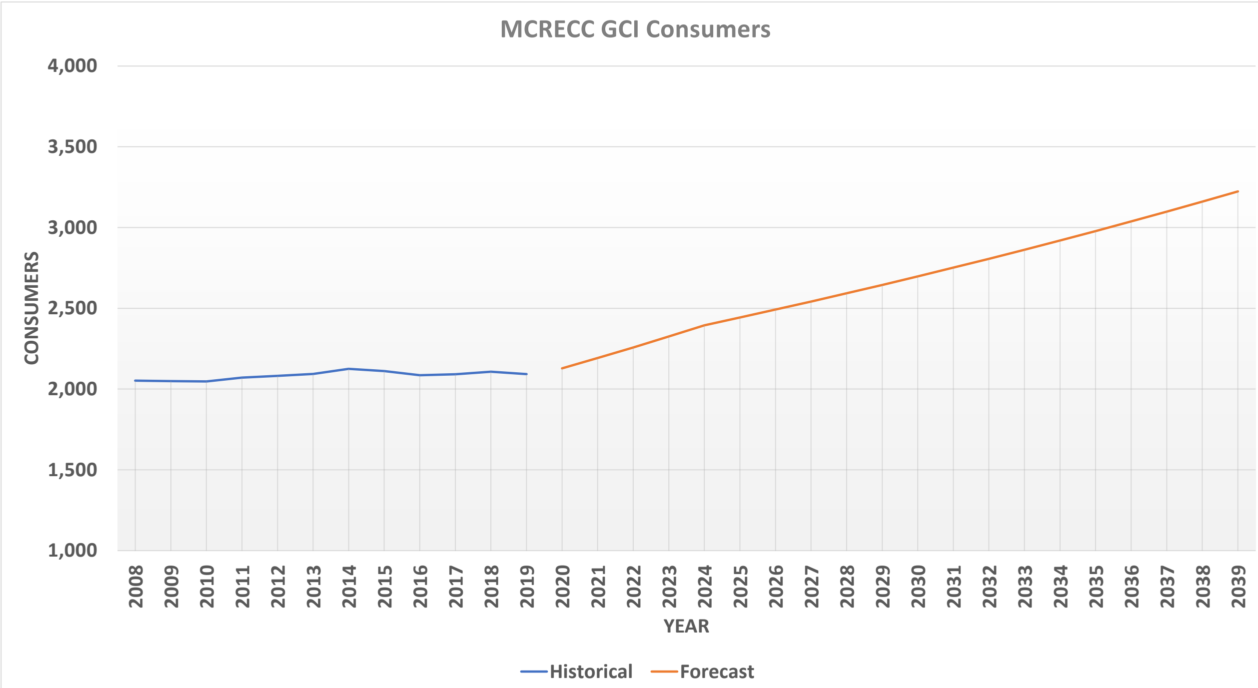
The GCI consumer forecast is estimated using an econometric model that relates explanatory variables to the GCI consumer count. The model uses GRP and total retail sales within the counties served by MCRECC. Explanatory variable values are projected in future years using economic projections. Preliminary model results were reviewed by cooperative staff and modifications were made if necessary where staff had specific knowledge of the service territory and conditions. The GCI consumer model is provided in the table below.

GCI Consumer Model

MCRECC General C&I Consumer Model				
Sample: 1999 - 2019 Total Observations: 250				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
GRP	2.015144	0.225529	8.935168	0
Total Retail Sales	1.943915	0.398097	4.883025	0
Weighted Statistics				
Adjusted R-squared: 0.259195				

The following figure provides the historical and projected MCRECC GCI consumers.

GCI Consumers



2.2.1.2 GCI Use per Consumer Forecast

The GCI use per consumer forecast is estimated using an econometric model that relates certain explanatory variables to the GCI use per consumer. The model uses electricity price, employment per consumer, cooling degree days, and heating degree days within the counties served by MCRECC. Explanatory variable values are projected in future years using demographic and economic projections and weather normalized values. Preliminary model results were reviewed by cooperative staff and modifications were made if necessary where staff had specific knowledge of the service territory and conditions. The GCI use per consumer model is provided in the table below.

GCI Use per Consumer Model

MCRECC General C&I Use Per Consumer Model

Sample: 1999 - 2019

Total Observations: 250

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	10.06521	0.348749	28.86087	0
February	10.05561	0.347507	28.93638	0
March	10.09085	0.344394	29.30033	0
April	10.11935	0.349425	28.96004	0
May	10.225	0.347119	29.45672	0
June	10.23109	0.346896	29.49327	0
July	10.24525	0.348128	29.42953	0
August	10.25894	0.349417	29.36012	0
September	10.22784	0.346684	29.50194	0
October	10.26088	0.346634	29.60148	0
November	10.19701	0.347028	29.38384	0
December	10.12429	0.349255	28.98822	0
Log(C&I Electricity Price)	-0.202295	0.077951	-2.595147	0.0101
Cooling Degree Days	0.000622	0.0000764	8.148743	0
Heating Degree Days	0.000328	0.0000497	6.610873	0
Log(Total Employment/C&I Consumers)	0.530934	0.088259	6.015658	0
2013 Forward	-0.125527	0.023921	-5.247572	0

Weighted Statistics

Adjusted R-squared: 0.789073

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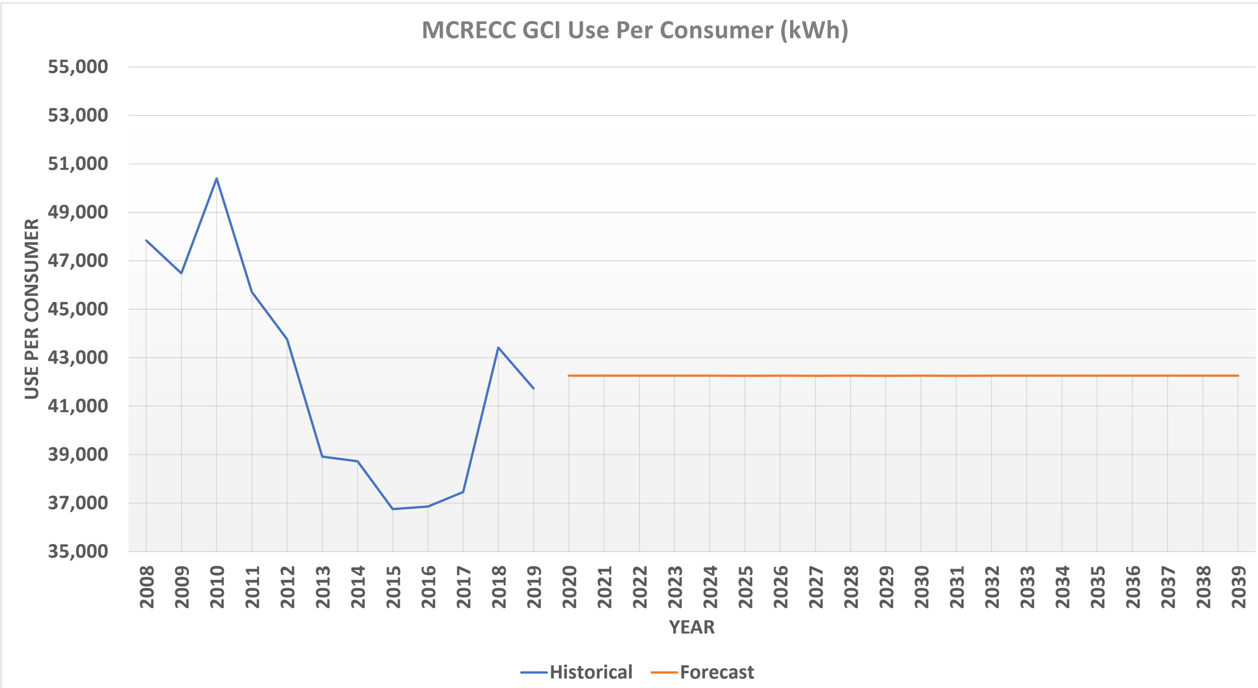
The following figure provides the historical and projected GCI use per consumer for MCRECC.

GCI Use per Consumer



2.2.2 Large Commercial and Industrial (LCI) Class

The Large C&I (LCI) class consists of the top 10 commercial and industrial consumers (Direct Serve excluded), with one additional consumer coming online in 2020 and expected to remain on the system through 2021. The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of LCI consumers, LCI use per consumer, and LCI energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table for LCI consumers, use per consumer, and sales.

Historical and Projected LCI Consumers, Use per Consumer, and Sales

MCRECC Large C&I Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (MWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	10		1,590		15,902	
2016	10	0.00%	1,610	1.22%	16,096	1.22%
2017	10	0.00%	1,643	2.05%	16,427	2.05%
2018	10	0.00%	1,733	5.49%	17,328	5.49%
2019	10	0.00%	1,937	11.81%	19,374	11.81%
2020	11	7.50%	2,125	9.67%	22,841	17.89%
2021	11	2.33%	2,945	38.61%	32,396	41.83%
2022	10	-9.09%	1,937	-34.21%	19,374	-40.19%
2023	10	0.00%	1,937	0.00%	19,374	0.00%
2024	10	0.00%	1,937	0.00%	19,374	0.00%
2025	10	0.00%	1,937	0.00%	19,374	0.00%
2026	10	0.00%	1,937	0.00%	19,374	0.00%
2027	10	0.00%	1,937	0.00%	19,374	0.00%
2028	10	0.00%	1,937	0.00%	19,374	0.00%
2029	10	0.00%	1,937	0.00%	19,374	0.00%
2030	10	0.00%	1,937	0.00%	19,374	0.00%
2031	10	0.00%	1,937	0.00%	19,374	0.00%
2032	10	0.00%	1,937	0.00%	19,374	0.00%
2033	10	0.00%	1,937	0.00%	19,374	0.00%
2034	10	0.00%	1,937	0.00%	19,374	0.00%
2035	10	0.00%	1,937	0.00%	19,374	0.00%
2036	10	0.00%	1,937	0.00%	19,374	0.00%
2037	10	0.00%	1,937	0.00%	19,374	0.00%
2038	10	0.00%	1,937	0.00%	19,374	0.00%
2039	10	0.00%	1,937	0.00%	19,374	0.00%
Average Annual Growth Rates						
Previous 10 Years	-		-		-	
Previous 5 Years	7.65%		4.39%		12.38%	
Next 5 Years	0.00%		0.00%		0.00%	
Next 10 Years	0.00%		0.00%		0.00%	
Next 20 Years	0.00%		0.00%		0.00%	

2.2.3 Direct Serve Class

The Direct Serve class contains consumers that are directly served from the transmission system. The sales forecasts are based on manager and staff knowledge and input from each cooperative. MCRECC's Direct Serve class contained zero consumers in 2019. One Direct Serve consumer is expected to come online in 2022.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of Direct Serve customers, Direct Serve use per consumer, and Direct Serve energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table for Direct Serve consumers, use per consumer, and sales.

Historical and Projected Direct Serve Consumers, Use per Consumer, and Sales

MCRECC Direct Serve Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (MWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	0		0		0	
2016	0		0		0	
2017	0		0		0	
2018	0		0		0	
2019	0		0		0	
2020	0		0		0	
2021	0		0		0	
2022	1		1,051,200		1,051,200	
2023	1	0.00%	1,051,200	0.00%	1,051,200	0.00%
2024	1	0.00%	1,054,080	0.27%	1,054,080	0.27%
2025	1	0.00%	1,051,200	-0.27%	1,051,200	-0.27%
2026	1	0.00%	1,051,200	0.00%	1,051,200	0.00%
2027	1	0.00%	1,051,200	0.00%	1,051,200	0.00%
2028	1	0.00%	1,054,080	0.27%	1,054,080	0.27%
2029	1	0.00%	1,051,200	-0.27%	1,051,200	-0.27%
2030	1	0.00%	1,051,200	0.00%	1,051,200	0.00%
2031	1	0.00%	1,051,200	0.00%	1,051,200	0.00%
2032	1	0.00%	1,051,200	0.00%	1,051,200	0.00%
2033	1	0.00%	1,051,200	0.00%	1,051,200	0.00%
2034	1	0.00%	1,051,200	0.00%	1,051,200	0.00%
2035	1	0.00%	1,051,200	0.00%	1,051,200	0.00%
2036	1	0.00%	1,051,200	0.00%	1,051,200	0.00%
2037	1	0.00%	1,051,200	0.00%	1,051,200	0.00%
2038	1	0.00%	1,051,200	0.00%	1,051,200	0.00%
2039	1	0.00%	1,051,200	0.00%	1,051,200	0.00%
Average Annual Growth Rates						
Previous 10 Years	-		-		-	
Previous 5 Years	-		-		-	
Next 5 Years	-		-		-	
Next 10 Years	-		-		-	
Next 20 Years	-		-		-	

2.3 Street and Highway Class

Given the small proportion of the Street and Highway class in total sales, the forecast for this class was calculated manually rather than through econometric modeling. The Street and Highway forecast was held to the prior twelve months of usage and consumer levels.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of Street and Highway consumers, Street and Highway use per consumer, and Street and Highway energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table for Street and Highway consumers, use per consumer, and sales.

Historical and Projected Street & Highway Consumers, Use per Consumer, and Sales

MCRECC Street & Highway Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (kWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	6		175,482		1,053	
2016	6	0.00%	173,945	-0.88%	1,044	-0.88%
2017	6	0.00%	173,811	-0.08%	1,043	-0.08%
2018	6	0.00%	174,346	0.31%	1,046	0.31%
2019	6	0.00%	174,119	-0.13%	1,045	-0.13%
2020	6	0.00%	174,119	0.00%	1,045	0.00%
2021	6	0.00%	174,119	0.00%	1,045	0.00%
2022	6	0.00%	174,119	0.00%	1,045	0.00%
2023	6	0.00%	174,119	0.00%	1,045	0.00%
2024	6	0.00%	174,119	0.00%	1,045	0.00%
2025	6	0.00%	174,119	0.00%	1,045	0.00%
2026	6	0.00%	174,119	0.00%	1,045	0.00%
2027	6	0.00%	174,119	0.00%	1,045	0.00%
2028	6	0.00%	174,119	0.00%	1,045	0.00%
2029	6	0.00%	174,119	0.00%	1,045	0.00%
2030	6	0.00%	174,119	0.00%	1,045	0.00%
2031	6	0.00%	174,119	0.00%	1,045	0.00%
2032	6	0.00%	174,119	0.00%	1,045	0.00%
2033	6	0.00%	174,119	0.00%	1,045	0.00%
2034	6	0.00%	174,119	0.00%	1,045	0.00%
2035	6	0.00%	174,119	0.00%	1,045	0.00%
2036	6	0.00%	174,119	0.00%	1,045	0.00%
2037	6	0.00%	174,119	0.00%	1,045	0.00%
2038	6	0.00%	174,119	0.00%	1,045	0.00%
2039	6	0.00%	174,119	0.00%	1,045	0.00%
Average Annual Growth Rates						
Previous 10 Years	0.00%		0.09%		0.09%	
Previous 5 Years	0.00%		-0.15%		-0.15%	
Next 5 Years	0.00%		0.00%		0.00%	
Next 10 Years	0.00%		0.00%		0.00%	
Next 20 Years	0.00%		0.00%		0.00%	

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2.4 Total Energy

The total energy requirements are calculated by taking the sales forecasts for each class, detailed in the previous sections of this report, and adding distribution losses and own use. Distribution losses are estimated using a three-year historical average percent. This percent is computed after any Direct Sale loads are removed since these loads are no loss loads.

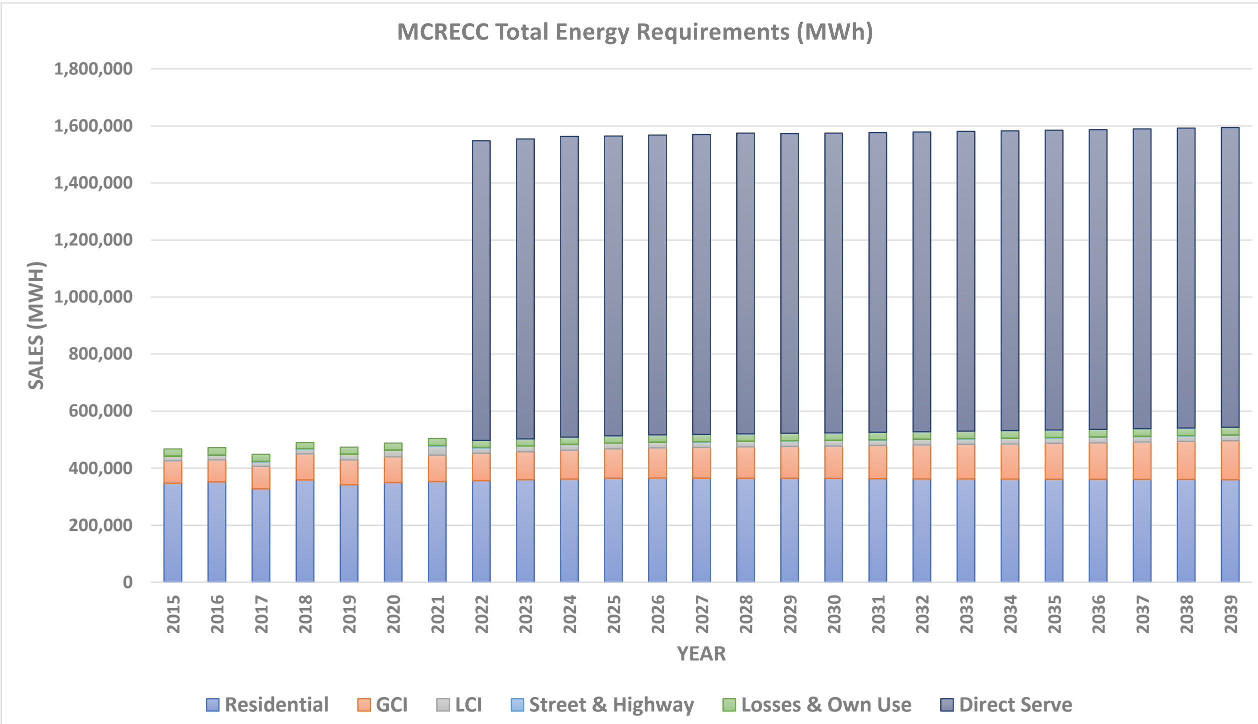
The following table provides the historical and forecast components of total energy requirements. The last five historical years are provided (2015 to 2019) along with the next twenty years of forecasts for each component. This includes Rural energy sales, Direct Serve sales, the estimated DSM impacts in forecasted years, and line losses. It is assumed that any impacts of prior DSM programs are captured indirectly through the historical energy and peak data used as an input to the modeling process. The DSM column provided in the table below is intended to capture any additional impacts from DSM spending in the future. For the base case forecast the additional DSM impact has been set to zero. Alternate scenarios have been quantified for Big Rivers and provided in Excel that detail the impacts of one million and two million DSM spending scenarios. These scenario impacts are derived directly from the Big Rivers DSM study completed in 2020.

Total System Energy Summary

MCRECC Total System Energy Summary						
Year	Rural System Energy Sales (MWh)	Direct Serve Energy Sales (MWh)	DSM Impact (MWh)	Total System Energy Sales (MWh)	Line Losses (% of Rural Energy)	Total Energy Requirements (MWh)
2015	442,716	0	0	442,716	5.16%	467,555
2016	446,363	0	0	446,363	5.27%	471,965
2017	423,849	0	0	423,849	5.39%	448,590
2018	469,069	0	0	469,069	4.15%	490,014
2019	450,110	0	0	450,110	4.79%	473,343
2020	463,874	0	0	463,874	4.78%	487,757
2021	479,346	0	0	479,346	4.78%	504,013
2022	472,799	1,051,200	0	1,523,999	4.78%	1,548,346
2023	478,452	1,051,200	0	1,529,652	4.78%	1,554,290
2024	483,929	1,054,080	0	1,538,009	4.78%	1,562,929
2025	488,532	1,051,200	0	1,539,732	4.78%	1,564,890
2026	491,799	1,051,200	0	1,542,999	4.78%	1,568,323
2027	493,239	1,051,200	0	1,544,439	4.78%	1,569,838
2028	495,049	1,054,080	0	1,549,129	4.78%	1,574,620
2029	496,777	1,051,200	0	1,547,977	4.78%	1,573,555
2030	498,273	1,051,200	0	1,549,473	4.78%	1,575,127
2031	499,977	1,051,200	0	1,551,177	4.78%	1,576,918
2032	502,127	1,051,200	0	1,553,327	4.78%	1,579,176
2033	503,975	1,051,200	0	1,555,175	4.78%	1,581,117
2034	505,815	1,051,200	0	1,557,015	4.78%	1,583,050
2035	507,799	1,051,200	0	1,558,999	4.78%	1,585,133
2036	509,905	1,051,200	0	1,561,105	4.78%	1,587,346
2037	512,172	1,051,200	0	1,563,372	4.78%	1,589,727
2038	514,506	1,051,200	0	1,565,706	4.78%	1,592,178
2039	516,969	1,051,200	0	1,568,169	4.78%	1,594,766
Average Annual Growth Rates						
Previous 10 Years	0.47%	-	0.00%	0.47%	-0.86%	0.41%
Previous 5 Years	-0.57%	-	0.00%	-0.57%	-2.00%	-0.69%
Next 5 Years	1.46%	-	0.00%	27.86%	-0.06%	26.99%
Next 10 Years	0.99%	-	0.00%	13.15%	-0.03%	12.76%
Next 20 Years	0.69%	-	0.00%	6.44%	-0.02%	6.26%

The following graph provides the class components that comprise the total energy requirements for MCRECC.

Total Energy Forecast



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3 PEAK DEMAND

3.1 COINCIDENT PEAK DEMAND

The Rural system coincident peak demand (Rural CP) is measured based on MCRECC's demand coincident with the Big Rivers' total system peak. Clearspring Energy econometrically modeled MCRECC's Rural coincident load factor using a monthly dataset. The predicted load factor is combined with the Rural energy forecast to forecast the Rural coincident peak demand. The Rural load factor model uses temperature on the peak day each month, cooling degree days, heating degree days, appliance saturations, and appliance efficiencies. The Rural CP load factor model is provided in the table below.

Rural CP Load Factor Model

MCRECC Load Factor Model

Sample: 2007 - 2019
Total Observations: 154

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	0.63496	0.019625	32.35468	0
February	0.671053	0.019148	35.04466	0
March	0.628937	0.013808	45.54862	0
April Cold Peaking	0.629017	0.011065	56.84797	0
April Hot Peaking	0.748793	0.023472	31.90101	0
May	0.636076	0.026591	23.92087	0
June	0.617738	0.025053	24.65735	0
July	0.618232	0.02604	23.74132	0
August	0.609817	0.026399	23.09969	0
September	0.614158	0.024352	25.22	0
October Cold Peaking	0.65492	0.010088	64.91917	0
October Hot Peaking	0.65788	0.024236	27.14475	0
November	0.643386	0.012405	51.86569	0
December	0.63915	0.016121	39.64587	0
Cooling Degree Days on Peak Day*(AC Saturation)*(1/AC Efficiency)	-0.112885	0.017785	-6.347315	0
Heating Degree Days on Peak Day*Electric Heating Saturation*(1/Heating Efficiency)	-0.097711	0.00623	-15.68304	0
Cooling Degree During Remainder of Month*(AC Saturation)*(1/AC Efficiency)	0.005567	0.000627	8.883967	0
Heating Degree During Remainder of Month*Electric Heating Saturation*(1/Heating Efficiency)	0.004775	0.000341	14.00279	0

Weighted Statistics

Adjusted R-squared: 0.776379

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The following table provides the last five years of historical data and the next 20 years of forecasted data for the winter, summer, and annual peaks for MCRECC's Rural system. The table also provides the annual coincident peak contribution for the Direct Serve class and the total MCRECC coincident peak contribution. The Direct Serve coincident peak contribution was forecasted with input from MCRECC and Big Rivers. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table below.

Historical and Projected CP Demands

MCRECC Coincident Peak (kW)					
Year	Rural Summer CP	Rural Winter CP	Rural Annual CP	Direct Serve Annual CP	Total Annual CP
2015	94,070	136,353	136,353	0	136,353
2016	90,521	110,353	90,521	0	90,521
2017	94,481	106,464	94,481	0	94,481
2018	98,175	138,799	138,799	0	138,799
2019	93,779	124,505	124,505	0	124,505
2020	95,513	115,070	95,513	0	95,513
2021	98,535	117,754	98,535	0	98,535
2022	97,449	117,746	97,449	198,000	295,449
2023	98,516	118,962	98,516	198,000	296,516
2024	99,559	120,116	99,559	198,000	297,559
2025	100,413	121,272	100,413	198,000	298,413
2026	101,001	122,103	101,001	198,000	299,001
2027	101,246	122,344	101,246	198,000	299,246
2028	101,592	122,489	101,592	198,000	299,592
2029	101,917	122,781	101,917	198,000	299,917
2030	102,215	122,878	102,215	198,000	300,215
2031	102,553	123,142	102,553	198,000	300,553
2032	102,996	123,433	102,996	198,000	300,996
2033	103,377	123,723	103,377	198,000	301,377
2034	103,767	123,949	103,767	198,000	301,767
2035	104,184	124,272	104,184	198,000	302,184
2036	104,632	124,591	104,632	198,000	302,632
2037	105,114	124,995	105,114	198,000	303,114
2038	105,610	125,385	105,610	198,000	303,610
2039	106,132	125,829	106,132	198,000	304,132
Average Annual Growth Rates					
Previous 10 Years	0.36%	-0.62%	-0.62%	-	-0.62%
Previous 5 Years	0.70%	-3.50%	-3.50%	-	-3.50%
Next 5 Years	1.20%	-0.72%	-4.37%	-	19.04%
Next 10 Years	0.84%	-0.14%	-1.98%	-	9.19%
Next 20 Years	0.62%	0.05%	-0.80%	-	4.57%

3.2 NON-COINCIDENT PEAK DEMAND

Rural NCP is forecasted monthly using an average of historical coincident factors examining the ratio between past coincident and non-coincident peaks. The Rural NCP value represents the sum of each substation peak value for each month. Direct Serve NCP is also forecasted using judgement and input from cooperative staff. The following table provides the last five years of historical data and the next 20 years of forecasted data for the Rural CP, Rural NCP, and Direct Serve NCP for MCRECC's total system. Growth rates for the prior 5 years and projected growth rates for the next 5, 10, and 20 years are also provided in the table below.

Historical and Projected Demands

MCRECC Peak (kW)						
Year	Total CP	% Change per Year in Total CP	Rural NCP	% Change per Year in Rural NCP	Direct Serve NCP	% Change per Year in Direct Serve NCP
2015	136,353		0		0	
2016	90,521	-33.61%	122,386	#DIV/0!	0	#DIV/0!
2017	94,481	4.38%	125,414	2.47%	0	#DIV/0!
2018	138,799	46.91%	141,738	13.02%	0	#DIV/0!
2019	124,505	-10.30%	128,374	-9.43%	0	#DIV/0!
2020	95,513	-23.29%	127,167	-0.94%	0	#DIV/0!
2021	98,535	3.16%	131,633	3.51%	0	#DIV/0!
2022	295,449	199.84%	130,125	-1.15%	200,000	#DIV/0!
2023	296,516	0.36%	131,467	1.03%	200,000	0.00%
2024	297,559	0.35%	132,743	0.97%	200,000	0.00%
2025	298,413	0.29%	134,021	0.96%	200,000	0.00%
2026	299,001	0.20%	134,939	0.69%	200,000	0.00%
2027	299,246	0.08%	135,206	0.20%	200,000	0.00%
2028	299,592	0.12%	135,365	0.12%	200,000	0.00%
2029	299,917	0.11%	135,689	0.24%	200,000	0.00%
2030	300,215	0.10%	135,795	0.08%	200,000	0.00%
2031	300,553	0.11%	136,088	0.22%	200,000	0.00%
2032	300,996	0.15%	136,409	0.24%	200,000	0.00%
2033	301,377	0.13%	136,729	0.23%	200,000	0.00%
2034	301,767	0.13%	136,979	0.18%	200,000	0.00%
2035	302,184	0.14%	137,336	0.26%	200,000	0.00%
2036	302,632	0.15%	137,689	0.26%	200,000	0.00%
2037	303,114	0.16%	138,135	0.32%	200,000	0.00%
2038	303,610	0.16%	138,566	0.31%	200,000	0.00%
2039	304,132	0.17%	139,057	0.35%	200,000	0.00%
Average Annual Growth Rates						
Previous 10 Years	-0.62%		-		-	
Previous 5 Years	-3.50%		-		-	
Next 5 Years	19.04%		0.67%		-	
Next 10 Years	9.19%		0.56%		-	
Next 20 Years	4.57%		0.40%		-	

4 Alternative System Forecasts and Uncertainty Analysis

While the projections summarized in previous sections should be viewed as the most probable outcome, it is important to remember that energy loads can be influenced by factors that are inherently difficult to predict, such as weather and the economy. Forecasting attempts to model reality and identify the primary drivers of growth and change. Each forecast has an inherent error tolerance between which actual observed outcomes are likely to fall. Therefore, it is important to develop flexible plans for meeting future energy needs based on a range of forecast outcomes.

The study includes scenario analyses that show how the forecasts change under assumed variations in future weather and economic growth paths. The alternate growth scenarios that have been explored are:

1. Extreme weather with normal economic growth
2. Mild weather with normal economic growth
3. High economic growth with normal weather
4. Low economic growth with normal weather

4.1 Weather Scenarios

Weather is one of the critical components to explain year-to-year variation in load. Because of this, extreme and mild weather scenarios were developed for the forecast period. The residential use per consumer and GCI use per consumer monthly energy models use cooling degree days and heating degree days. For the creation of the mild and extreme energy scenarios these two variables were altered to a fifteen-year historical annual maximum and minimum value. These annual extremes were then redistributed across each month based on an average monthly distribution of cooling degree days and heating degree days. The Rural peak load factor model also contains cooling degree days and heating degree days for the month. Additionally, the load factor model captures peak day weather conditions. The extreme and mild weather scenarios alter the load factor model to use monthly weather conditions consistent with the energy models and change the peak day conditions to the most extreme or mild found in the last fifteen years of history for each

given month. The peak values displayed are a maximum of each monthly scenario value for the given season and therefore can occur in a different month than the base case forecast. Forecasts are provided in Excel that detail each scenario by month.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the mild, base, and extreme weather scenarios. The forecasts are for the Rural system.

Rural System Weather Scenarios

MCRECC Rural System Weather Scenarios									
Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Mild	Base	Extreme	Mild	Base	Extreme	Mild	Base	Extreme
2015		467,555			136,353			94,070	
2016		471,965			110,353			90,521	
2017		448,590			106,464			94,481	
2018		490,014			138,799			98,175	
2019		473,343			124,505			93,779	
2020	454,867	487,757	520,459	95,147	115,070	135,299	86,403	95,513	113,739
2021	470,947	504,013	536,873	97,716	117,754	138,075	89,393	98,535	116,967
2022	463,860	497,146	530,211	97,542	117,746	138,215	85,791	97,449	115,398
2023	469,747	503,090	536,192	98,682	118,962	139,472	86,874	98,516	116,392
2024	475,443	508,849	541,993	99,765	120,116	140,667	87,926	99,559	117,378
2025	480,236	513,690	546,865	100,842	121,272	141,873	88,795	100,413	118,167
2026	483,705	517,123	550,250	101,631	122,103	142,723	89,423	101,001	118,660
2027	485,380	518,638	551,588	101,940	122,344	142,867	89,739	101,246	118,767
2028	487,394	520,540	553,363	102,153	122,489	142,921	90,135	101,592	119,013
2029	489,310	522,355	555,063	102,489	122,781	143,146	90,503	101,917	119,250
2030	490,984	523,927	556,520	102,650	122,878	143,157	90,839	102,215	119,470
2031	492,843	525,718	558,227	102,949	123,142	143,367	91,204	102,553	119,754
2032	495,121	527,976	560,452	103,258	123,433	143,622	91,653	102,996	120,175
2033	497,093	529,917	562,352	103,563	123,723	143,878	92,041	103,377	120,534
2034	499,042	531,850	564,256	103,807	123,949	144,072	92,431	103,767	120,915
2035	501,118	533,933	566,336	104,126	124,272	144,386	92,840	104,184	121,339
2036	503,300	536,146	568,569	104,432	124,591	144,708	93,270	104,632	121,810
2037	505,623	538,527	571,000	104,800	124,995	145,137	93,723	105,114	122,333
2038	508,010	540,978	573,505	105,156	125,385	145,552	94,190	105,610	122,875
2039	510,525	543,566	576,158	105,556	125,829	146,031	94,678	106,132	123,446

Direct Serve load is assumed to not be influenced by weather and is held constant to the base case forecast for the weather ranges. The extreme and mild ranges with the Direct Serve class included are shown below.

Total System Weather Scenarios

MCRECC Total System Weather Scenarios									
Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Mild	Base	Extreme	Mild	Base	Extreme	Mild	Base	Extreme
2015		467,555			136,353			94,070	
2016		471,965			110,353			90,521	
2017		448,590			106,464			94,481	
2018		490,014			138,799			98,175	
2019		473,343			124,505			93,779	
2020	454,867	487,757	520,459	95,147	115,070	135,299	86,403	95,513	113,739
2021	470,947	504,013	536,873	97,716	117,754	138,075	89,393	98,535	116,967
2022	1,515,060	1,548,346	1,581,411	275,742	295,946	316,415	283,791	295,449	313,398
2023	1,520,947	1,554,290	1,587,392	276,882	297,162	317,672	284,874	296,516	314,392
2024	1,529,523	1,562,929	1,596,073	277,965	298,316	318,867	285,926	297,559	315,378
2025	1,531,436	1,564,890	1,598,065	279,042	299,472	320,073	286,795	298,413	316,167
2026	1,534,905	1,568,323	1,601,450	279,831	300,303	320,923	287,423	299,001	316,660
2027	1,536,580	1,569,838	1,602,788	280,140	300,544	321,067	287,739	299,246	316,767
2028	1,541,474	1,574,620	1,607,443	280,353	300,689	321,121	288,135	299,592	317,013
2029	1,540,510	1,573,555	1,606,263	280,689	300,981	321,346	288,503	299,917	317,250
2030	1,542,184	1,575,127	1,607,720	280,850	301,078	321,357	288,839	300,215	317,470
2031	1,544,043	1,576,918	1,609,427	281,149	301,342	321,567	289,204	300,553	317,754
2032	1,546,321	1,579,176	1,611,652	281,458	301,633	321,822	289,653	300,996	318,175
2033	1,548,293	1,581,117	1,613,552	281,763	301,923	322,078	290,041	301,377	318,534
2034	1,550,242	1,583,050	1,615,456	282,007	302,149	322,272	290,431	301,767	318,915
2035	1,552,318	1,585,133	1,617,536	282,326	302,472	322,586	290,840	302,184	319,339
2036	1,554,500	1,587,346	1,619,769	282,632	302,791	322,908	291,270	302,632	319,810
2037	1,556,823	1,589,727	1,622,200	283,000	303,195	323,337	291,723	303,114	320,333
2038	1,559,210	1,592,178	1,624,705	283,356	303,585	323,752	292,190	303,610	320,875
2039	1,561,725	1,594,766	1,627,358	283,756	304,029	324,231	292,678	304,132	321,446

4.2 ECONOMIC SCENARIOS

Another critical component of a long-term load forecast is the underlying economic variables within the service territory. Two scenarios have been developed: low economic growth and high economic growth. To create the economic scenarios, economic variables within each econometrically modeled class are altered by an additional plus or minus 1.0% per year relative to the base case forecast. The altered variables include electricity price, GRP, employment, and total retail sales. The forecast for Residential consumers, LCI, and Street and Highway are not modeled econometrically and are therefore directly modified by 1.0% per year relative to the base case forecast to create the high and low economic ranges.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the low, base, and high economic scenarios.

Rural System Economic Scenarios

MCRECC Rural System Economic Scenarios									
Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Low	Base	High	Low	Base	High	Low	Base	High
2015		467,555			136,353			94,070	
2016		471,965			110,353			90,521	
2017		448,590			106,464			94,481	
2018		490,014			138,799			98,175	
2019		473,343			124,505			93,779	
2020	484,870	487,757	490,649	114,967	115,070	115,172	94,808	95,513	96,220
2021	495,511	504,013	512,540	116,370	117,754	119,141	96,726	98,535	100,350
2022	483,206	497,146	511,156	115,071	117,746	120,431	94,657	97,449	100,256
2023	483,505	503,090	522,813	114,974	118,962	122,970	94,618	98,516	102,442
2024	483,546	508,849	534,381	114,802	120,116	125,468	94,543	99,559	104,623
2025	482,594	513,690	545,129	114,614	121,272	127,990	94,265	100,413	106,632
2026	480,258	517,123	554,472	114,090	122,103	130,204	93,728	101,001	108,372
2027	476,112	518,638	561,808	113,021	122,344	131,786	92,868	101,246	109,755
2028	472,313	520,540	569,601	111,850	122,489	133,283	92,102	101,592	111,251
2029	468,427	522,355	577,334	110,828	122,781	134,933	91,315	101,917	112,732
2030	464,320	523,927	584,827	109,619	122,878	136,382	90,504	102,215	114,186
2031	460,404	525,718	592,596	108,573	123,142	138,011	89,729	102,553	115,694
2032	456,885	527,976	600,940	107,541	123,433	139,686	89,044	102,996	117,327
2033	453,094	529,917	608,946	106,518	123,723	141,353	88,305	103,377	118,894
2034	449,297	531,850	616,969	105,435	123,949	142,959	87,576	103,767	120,476
2035	445,625	533,933	625,201	104,444	124,272	144,675	86,868	104,184	122,098
2036	442,061	536,146	633,617	103,444	124,591	146,398	86,187	104,632	123,761
2037	438,633	538,527	642,266	102,520	124,995	148,220	85,533	105,114	125,471
2038	435,259	540,978	651,036	101,581	125,385	150,037	84,891	105,610	127,206
2039	431,988	543,566	660,012	100,690	125,829	151,921	84,267	106,132	128,979

The Direct Serve class is not modeled using econometric modeling. As such, the load is increased by an additional 1.0% per year relative to the base case in the high scenario. In the low scenario the Direct Serve class is decreased by 1.0% per year relative to the base case. The high and low ranges with the Direct Serve class included are shown below.

Total System Economic Scenarios

MCRECC Total System Economic Scenarios									
Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Low	Base	High	Low	Base	High	Low	Base	High
2015		467,555			136,353			94,070	
2016		471,965			110,353			90,521	
2017		448,590			106,464			94,481	
2018		490,014			138,799			98,175	
2019		473,343			124,505			93,779	
2020	484,870	487,757	490,649	114,967	115,070	115,172	94,808	95,513	96,220
2021	495,511	504,013	512,540	116,370	117,754	119,141	96,726	98,535	100,350
2022	1,507,665	1,548,346	1,589,096	289,559	295,946	302,344	287,542	295,449	303,371
2023	1,497,452	1,554,290	1,611,266	287,680	297,162	306,665	285,523	296,516	307,537
2024	1,489,741	1,562,929	1,636,346	285,726	298,316	310,945	283,468	297,559	311,698
2025	1,475,517	1,564,890	1,654,606	283,756	299,472	315,249	281,210	298,413	315,687
2026	1,462,669	1,568,323	1,674,461	281,449	300,303	319,244	278,693	299,001	319,407
2027	1,448,012	1,569,838	1,692,309	278,598	300,544	322,609	275,853	299,246	322,770
2028	1,436,345	1,574,620	1,713,729	275,645	300,689	325,888	273,107	299,592	326,246
2029	1,419,302	1,573,555	1,728,859	272,842	300,981	329,320	270,340	299,917	329,707
2030	1,404,683	1,575,127	1,746,864	269,851	301,078	332,550	267,549	300,215	333,141
2031	1,390,255	1,576,918	1,765,145	267,023	301,342	335,961	264,794	300,553	336,629
2032	1,376,224	1,579,176	1,784,001	264,209	301,633	339,418	262,129	300,996	340,242
2033	1,361,921	1,581,117	1,802,519	261,404	301,923	342,867	259,410	301,377	343,789
2034	1,347,612	1,583,050	1,821,054	258,539	302,149	346,256	256,701	301,767	347,351
2035	1,333,429	1,585,133	1,839,797	255,765	302,472	349,754	254,013	302,184	350,953
2036	1,319,352	1,587,346	1,858,726	252,983	302,791	353,258	251,352	302,632	354,596
2037	1,305,412	1,589,727	1,877,887	250,278	303,195	356,863	248,718	303,114	358,286
2038	1,291,526	1,592,178	1,897,168	247,557	303,585	360,461	246,096	303,610	362,001
2039	1,277,743	1,594,766	1,916,656	244,883	304,029	364,127	243,492	304,132	365,754

5 WEATHER NORMALIZED VALUES

Weather-sensitive electricity loads comprise a large portion of electricity end-uses. Weather conditions vary and will cause electricity sales and peak demands to increase during more extreme periods or decrease during milder periods. In this section, we provide estimates of energy and peak demands for MCRECC during the last ten years with the assumption that temperatures had been at their 15-year normal amounts in each year.

The weather normalized values are calculated using the econometric models that identified weather as a driver of electricity sales. These are the Residential use per consumer and the GCI use per consumer models. Additionally, the load factor model (used to project peak demands) also includes temperature variables. The weather impacts of the deviation from the actual weather to the weather normalized weather are estimated using these models. The weather impacts are then added (or subtracted) to the actual load in that year to determine the weather normalized energy or peak demand.

The following table provides the last ten years of historical data for MCRECC's Rural system. The normalized peak values displayed are a maximum of each monthly normalized value for the given season and therefore frequently occur in a different month than the actual value. Monthly normalized values are provided in Excel that detail the weather normalized values for each monthly peak day.

Rural System Weather Normalized

MCRECC Rural System Weather Normalized						
Year	Energy (MWh)		Winter CP Demand (kW)		Summer CP Demand (kW)	
	Actual	Normalized	Actual	Normalized	Actual	Normalized
2010	509,286	472,922	127,271	114,316	103,588	91,640
2011	480,251	481,648	119,700	118,084	97,064	95,288
2012	465,662	479,154	100,287	116,531	105,088	90,919
2013	482,894	480,259	115,173	115,472	86,400	92,983
2014	489,939	473,712	148,770	121,995	90,553	91,188
2015	467,555	470,936	136,353	121,768	94,070	90,586
2016	471,965	472,166	110,353	107,242	90,521	92,643
2017	448,590	466,797	106,464	112,319	94,481	91,282
2018	490,014	476,197	138,799	123,719	98,175	93,761
2019	473,343	468,866	124,505	115,381	93,779	89,542

The following table provides the last ten years of historical data for MCRECC's total system.

Total System Weather Normalized

MCRECC Total System Weather Normalized						
Year	Energy (MWh)		Winter CP Demand (kW)		Summer CP Demand (kW)	
	Actual	Normalized	Actual	Normalized	Actual	Normalized
2010	509,286	472,922	127,271	114,316	103,588	91,640
2011	480,251	481,648	119,700	118,084	97,064	95,288
2012	465,662	479,154	100,287	116,531	105,088	90,919
2013	482,894	480,259	115,173	115,472	86,400	92,983
2014	489,939	473,712	148,770	121,995	90,553	91,188
2015	467,555	470,936	136,353	121,768	94,070	90,586
2016	471,965	472,166	110,353	107,242	90,521	92,643
2017	448,590	466,797	106,464	112,319	94,481	91,282
2018	490,014	476,197	138,799	123,719	98,175	93,761
2019	473,343	468,866	124,505	115,381	93,779	89,542

6 FORECAST METHODOLOGY

The load forecast process began by discussions with Clearspring Energy to solicit feedback from representatives of each member system as well as Big Rivers. The forecasting team issued an information request to each member system requesting monthly energy data by rate class, historical or anticipated changes in load on the system, large consumer energy and peak demand data, and retail price forecasts. Big Rivers provided historical demand data used as the basis to forecast load factors and peak demands.

In addition to this data, Clearspring Energy collected a variety of additional data to develop the load forecast. This included county-level historical socioeconomic data from Woods & Poole Economics, Inc., historical alternative fuel price data and energy efficiency indexes from the Energy Information Administration (EIA), monthly and daily weather data from the Midwest Regional Climate Center (MRCC) and High Plains Regional Climate Center (HPRCC), and appliance and end-use saturations for each member system based off historical end-use surveys conducted by Big Rivers. The most recent survey was conducted in 2019.

6.1 DATABASE SETUP AND ANALYSES

Upon receipt of the associated member systems' data, Big Rivers' data and data obtained from external sources, Clearspring Energy reviewed the data for accuracy and adequacy for use in the study. An electronic database with consumer and energy sales by rate class and demand data was developed using Microsoft Excel™.

County-level economic and demographic data was gathered and added to the energy database. Weighted averages were calculated using customized member system county weights based on the service territory of each member system. The appropriate weights are calculated using the number of residential consumers served for each member system by county.

Weather variables were also calculated and added to the database. Appropriate customized weather station data was used based on the service territory location of each member system. Historical fifteen-year averages of the selected weather variables were calculated and used as the basis for the normal weather expectation in future years and in the weather normalization results.

All price information is adjusted for inflation using an inflation adjustment from the Congressional Budget Office (CBO).

Data Category	Data Source
Energy, Demand, Customers, and Electricity Price	Big Rivers and its three member systems
Economic & Demographic	Woods & Poole Economics, Inc.
Weather	Midwest Regional Climate Center High Plains Regional Climate Center
Alternative Fuel Prices and Appliance Energy Efficiency	Energy Information Administration
End-Use Appliance Saturations	Big Rivers Survey Reports

6.2 Model Development

Clearspring estimated econometric models to forecast Residential use per consumer, GCI consumers, GCI use per consumer, and the load factor. A separate model was developed for each member system and for each component. A growth index using household forecasts was used to escalate Residential consumers.

Forecasts for the LCI and Direct Serve commercial consumers were prepared judgmentally based on input from the cooperatives. Due to their relatively small size, trend analysis was used to project the Street and Highway class.

Econometric parameters were estimated using the ordinary least squares (OLS) approach to regression analysis employed by the EViews™ version 10 econometric software package. Heteroskedasticity adjusted standard errors were calculated for statistical significance testing of the included variables. The models were selected based on theoretical and statistical validity as well as the reasonableness of the forecast results generated.

The statistical validity of each variable included in the model needed to pass two key criterion to be included in the model. A simple but important standard is that the coefficient of each explanatory variable must have a logical sign. For example, energy sales will generally increase during periods of colder or hotter weather (i.e., these variables should have positive coefficients). Conversely,

energy sales generally decrease with increasing electricity prices (i.e., the coefficient of this variable should be negative).

The second criterion is the fact that each explanatory variable has a statistically significant influence on the dependent variable. The statistical significance of an explanatory variable is measured by the t-statistic. The specific value of a particular t-statistic required for statistical significance depends on both the degrees of freedom (the number of data points less the number of variables) of the equations and desired level of confidence in the estimated coefficients. In general, however, the t-statistic should have a magnitude of at least 1.645 for a 90 percent level of confidence.

Another validity criterion that we took into consideration are examinations of the equation residuals (the difference between the actual historical and estimated historical values). In a good equation, the residuals are randomly distributed and of approximately constant magnitude, in absolute terms. This indicates that there is no obvious pattern in the data that has not been explained by the equation.

The models developed must also pass a test of reasonableness. Models must make intuitive sense to the members of the forecasting team and the forecasts that result must be plausible given reasonable assumptions of growth factors.

6.3 Forecast Development

Using the econometric equations developed as part of the modeling process, monthly forecasts were created for each of the member systems. The modeled classes are calculated using the estimated equations along with forecasted values for those variables that enter into the estimated equation.

The amount of energy required by each system (ultimately provided by Big Rivers) is greater than the sum of the retail energy sales. System own-use and energy losses are forecast for each member system. Energy losses are forecasted as a percentage of total system energy requirements based on historical loss data.

Three monthly demand values are determined for each of the member distribution cooperatives. The individual Direct Serve consumer non-coincident peaks, the distribution cooperative's Rural non-coincident peak demand, and its contribution to the Big Rivers monthly coincident peak (CP).

Clearspring developed a load factor econometric model to forecast the Rural coincident peak load factor which we then use to calculate the peak demand forecasts for each of the three member systems.

Preliminary forecasts were distributed to the respective member systems and Big Rivers for their review and input. The member systems offered suggestions for revisions to the forecasts and these revisions were incorporated.

6.4 CHANGES IN METHODOLOGY FROM 2017 LOAD FORECAST

The 2020 research was conducted by Clearspring Energy Advisors, LLC whereas the 2017 research was conducted by GDS Associates, Inc ("GDS"). Clearspring has reviewed the past load forecast report and other documents and lists the known methodological changes that we are aware of based on this review of the prior consultants' research. We note that it is often precarious to assume what the exact research of another consultant consisted of. We offer the list with the caveat that we may be incorrect in interpreting the exact methodological approach used by GDS.

1. Clearspring uses "weighted" economic and demographic variables that are weighted based on the calculated consumer counts in each county served by each member system. We believe that GDS did not calculate the variables based on weighted consumer counts but used unweighted variables.
2. GDS used a Statistical Adjusted End-Use (SAE) modeling approach. Clearspring uses econometric modeling to directly estimate the impacts of variables that influence use per consumer or consumer counts.
3. Clearspring directly models the electricity price in relationship to an alternative price fuel index (comprised of natural gas and propane prices). We are not aware of GDS directly inserting alternative fuel prices into the analysis.
4. Clearspring calculates the price elasticity based on the relative impact of the electricity price and the alternative fuel index. This price elasticity is estimated directly in the econometric model. Conversely, GDS did not use their SAE modeling but, rather, estimated the price elasticity with a separate econometric model that did not account for other possible drivers of electricity use.

5. Clearspring uses a 15-year weather normal for the base case load forecasts, whereas GDS used a 20-year weather normal.
6. Different weather station mappings were used.
7. Clearspring uses daily high/low temperature values for the load factor econometric model used to forecast peak demands. GDS appears to use hourly values to forecast peak demands.
8. GDS makes some references to using trended energy amounts in models. It is unclear exactly what that means but there are likely differences in the methods used to allocate energy to each specific month.

7 APPENDIX

The following tables provide the details on the consumers, sales, and use per consumer for each class for MCRECC's system. The prior five years and the forecasted year values are provided in the tables. Both historical and forecasted growth rates for each class are also provided.

Meade County Rural Electric Cooperative Corporation															
RESIDENTIAL	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	27,038	27,298	27,471	27,584	27,713	27,953	28,263	28,594	28,897	29,178	29,443	29,574	29,593	29,603	29,603
SALES-MWH	348,157	352,360	328,042	359,192	342,387	350,066	353,285	356,981	359,772	362,302	364,881	366,082	365,417	365,079	364,616
USE PER CONSUMER-kWH	12,877	12,908	11,941	13,022	12,355	12,524	12,500	12,485	12,450	12,417	12,393	12,379	12,348	12,333	12,317
GENERAL C&I	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	2,111	2,086	2,092	2,108	2,092	2,128	2,192	2,257	2,325	2,395	2,443	2,492	2,542	2,593	2,645
SALES-MWH	77,603	76,862	78,337	91,502	87,303	89,922	92,620	95,399	98,261	101,208	103,233	105,297	107,403	109,551	111,742
USE PER CONSUMER-kWH	36,754	36,856	37,455	43,412	41,731	42,259	42,259	42,259	42,259	42,259	42,251	42,257	42,253	42,256	42,253
LARGE C&I	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	10	10	10	10	10	11	11	10	10	10	10	10	10	10	10
SALES-MWH	15,902	16,096	16,427	17,328	19,374	22,841	32,396	19,374	19,374	19,374	19,374	19,374	19,374	19,374	19,374
USE PER CONSUMER-kWH	1,590,215	1,609,623	1,642,673	1,732,845	1,937,443	2,124,726	2,945,088	1,937,443	1,937,443	1,937,443	1,937,443	1,937,443	1,937,443	1,937,443	1,937,443
IRRIGATION	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SALES-MWH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
USE PER CONSUMER-kWH															
STREET & HIGHWAY	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
SALES-MWH	1,053	1,044	1,043	1,046	1,045	1,045	1,045	1,045	1,045	1,045	1,045	1,045	1,045	1,045	1,045
USE PER CONSUMER-kWH	175,482	173,945	173,811	174,346	174,119	174,119	174,119	174,119	174,119	174,119	174,119	174,119	174,119	174,119	174,119
RURAL TOTAL	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	29,165	29,400	29,578	29,708	29,821	30,097	30,471	30,867	31,238	31,589	31,902	32,082	32,151	32,211	32,263
SALES-MWH	442,716	446,363	423,849	469,069	450,110	463,874	479,346	472,799	478,452	483,929	488,532	491,799	493,239	495,049	496,777
USE PER CONSUMER-kWH	15,180	15,182	14,330	15,789	15,094	15,413	15,731	15,317	15,316	15,319	15,313	15,330	15,342	15,369	15,398
OWNUSE-MWH	728	721	574	617	560	592	599	607	614	621	627	631	632	633	634
PURCHASES-MWH	467,555	471,965	448,590	490,014	473,343	487,757	504,013	497,146	503,090	508,849	513,690	517,123	518,638	520,540	522,355
LOSSES-MWH	24,111	24,882	24,167	20,328	22,674	23,292	24,068	23,740	24,024	24,299	24,530	24,694	24,766	24,857	24,944
LOSSES (%)	5.2%	5.3%	5.4%	4.1%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%
DIRECT SERVE	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1
SALES-MWH	0	0	0	0	0	0	0	1,051,200	1,051,200	1,054,080	1,051,200	1,051,200	1,051,200	1,054,080	1,051,200
USE PER CONSUMER-MWH								1,051,200	1,051,200	1,054,080	1,051,200	1,051,200	1,051,200	1,054,080	1,051,200
SYSTEM TOTAL WITH DIRECT SERVE	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	29,165	29,400	29,578	29,708	29,821	30,097	30,471	30,868	31,239	31,590	31,903	32,083	32,152	32,212	32,264
SALES-MWH	442,716	446,363	423,849	469,069	450,110	463,874	479,346	1,523,999	1,529,652	1,538,009	1,539,732	1,542,999	1,544,439	1,549,129	1,547,977
USE PER CONSUMER-kWH	15,180	15,182	14,330	15,789	15,094	15,413	15,731	49,371	48,966	48,686	48,262	48,095	48,036	48,091	47,978
OWNUSE-MWH	728	721	574	617	560	592	599	607	614	621	627	631	632	633	634
PURCHASES-MWH	467,555	471,965	448,590	490,014	473,343	487,757	504,013	1,548,346	1,554,290	1,562,929	1,564,890	1,568,323	1,569,838	1,574,620	1,573,555
LOSSES-MWH	24,111	24,882	24,167	20,328	22,674	23,292	24,068	23,740	24,024	24,299	24,530	24,694	24,766	24,857	24,944
LOSSES (%)	5.2%	5.3%	5.4%	4.1%	4.8%	4.8%	4.8%	1.5%	1.5%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
ANNUAL PEAK	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
RURAL CP - kW	136,353	90,521	94,481	138,799	124,505	95,513	98,535	97,449	98,516	99,559	100,413	101,001	101,246	101,592	101,917
DIRECT SERVE CP - kW	0	0	0	0	0	0	0	198,000	198,000	198,000	198,000	198,000	198,000	198,000	198,000
TOTAL CP - kW	136,353	90,521	94,481	138,799	124,505	95,513	98,535	295,449	296,516	297,559	298,413	299,001	299,246	299,592	299,917
RURAL NCP - kW		122,386	125,414	141,738	128,374	127,167	131,633	130,125	131,467	132,743	134,021	134,939	135,206	135,365	135,689
DIRECT SERVE SUM OF INDIVIDUAL NCP - kW	0	0	0	0	0	0	0	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000

Case No. 2020-00299
Attachment 3 for Rresponse to PSC 1-52d
Witnesses: Matthew S. Sekeres and Steven A. Fenrick

Meade County Rural Electric Cooperative Corporation											Last 10 Yrs	Last 5 Yrs	Next 5 Yrs	Next 10 Yrs	Next 20 Yrs
RESIDENTIAL	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	29,593	29,573	29,548	29,518	29,486	29,453	29,420	29,389	29,361	29,337	0.7%	0.6%	1.0%	0.7%	0.3%
SALES-MWH	363,877	363,302	363,126	362,603	362,024	361,540	361,129	360,829	360,544	360,337	0.3%	-1.5%	1.1%	0.6%	0.3%
USE PER CONSUMER-kWH	12,296	12,285	12,289	12,284	12,278	12,275	12,275	12,278	12,280	12,283	-0.4%	-2.1%	0.1%	0.0%	0.0%
GENERAL C&I	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	2,697	2,751	2,806	2,863	2,920	2,978	3,038	3,098	3,160	3,224	0.2%	-0.3%	2.7%	2.4%	2.2%
SALES-MWH	113,977	116,257	118,582	120,953	123,372	125,840	128,357	130,924	133,542	136,213	-0.9%	1.2%	3.0%	2.5%	2.2%
USE PER CONSUMER-kWH	42,256	42,254	42,255	42,254	42,255	42,254	42,255	42,254	42,255	42,255	-1.1%	1.5%	0.3%	0.1%	0.1%
LARGE C&I	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	10	10	10	10	10	10	10	10	10	10	-	7.7%	0.0%	0.0%	0.0%
SALES-MWH	19,374	19,374	19,374	19,374	19,374	19,374	19,374	19,374	19,374	19,374	-	12.4%	0.0%	0.0%	0.0%
USE PER CONSUMER-kWH	1,937,443	1,937,443	1,937,443	1,937,443	1,937,443	1,937,443	1,937,443	1,937,443	1,937,443	1,937,443	-	4.4%	0.0%	0.0%	0.0%
IRRIGATION	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-
SALES-MWH	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-
USE PER CONSUMER-kWH											-	-	-	-	-
STREET & HIGHWAY	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	6	6	6	6	6	6	6	6	6	6	0.0%	0.0%	0.0%	0.0%	0.0%
SALES-MWH	1,045	1,045	1,045	1,045	1,045	1,045	1,045	1,045	1,045	1,045	0.1%	-0.2%	0.0%	0.0%	0.0%
USE PER CONSUMER-kWH	174,119	174,119	174,119	174,119	174,119	174,119	174,119	174,119	174,119	174,119	0.1%	-0.2%	0.0%	0.0%	0.0%
RURAL TOTAL	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	32,306	32,341	32,370	32,396	32,422	32,447	32,474	32,503	32,537	32,577	0.6%	0.6%	1.2%	0.8%	0.4%
SALES-MWH	498,273	499,977	502,127	503,975	505,815	507,799	509,905	512,172	514,506	516,969	0.5%	-0.6%	1.5%	1.0%	0.7%
USE PER CONSUMER-kWH	15,424	15,460	15,512	15,557	15,601	15,650	15,702	15,758	15,813	15,869	-0.2%	-1.1%	0.3%	0.2%	0.3%
OWNUSE-MWH	635	636	637	637	638	638	639	639	640	641	-8.3%	-8.9%	2.1%	1.3%	0.7%
PURCHASES-MWH	523,927	525,718	527,976	529,917	531,850	533,933	536,146	538,527	540,978	543,566	0.4%	-0.7%	1.5%	1.0%	0.7%
LOSSES-MWH	25,019	25,104	25,212	25,305	25,397	25,497	25,602	25,716	25,833	25,957	-0.5%	-2.7%	1.4%	1.0%	0.7%
LOSSES (%)	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	-0.9%	-2.0%	-0.1%	0.0%	0.0%
DIRECT SERVE	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-
SALES-MWH	1,051,200	1,051,200	1,051,200	1,051,200	1,051,200	1,051,200	1,051,200	1,051,200	1,051,200	1,051,200	-	-	-	-	-
USE PER CONSUMER-MWH	1,051,200	1,051,200	1,051,200	1,051,200	1,051,200	1,051,200	1,051,200	1,051,200	1,051,200	1,051,200	-	-	-	-	-
SYSTEM TOTAL WITH DIRECT SERVE	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	32,307	32,342	32,371	32,397	32,423	32,448	32,475	32,504	32,538	32,578	0.6%	0.6%	1.2%	0.8%	0.4%
SALES-MWH	1,549,473	1,551,177	1,553,327	1,555,175	1,557,015	1,558,999	1,561,105	1,563,372	1,565,706	1,568,169	0.5%	-0.6%	27.9%	13.1%	6.4%
USE PER CONSUMER-kWH	47,961	47,962	47,985	48,003	48,022	48,046	48,072	48,098	48,119	48,136	-0.2%	-1.1%	26.4%	12.3%	6.0%
OWNUSE-MWH	635	636	637	637	638	638	639	639	640	641	-8.3%	-8.9%	2.1%	1.3%	0.7%
PURCHASES-MWH	1,575,127	1,576,918	1,579,176	1,581,117	1,583,050	1,585,133	1,587,346	1,589,727	1,592,178	1,594,766	0.4%	-0.7%	27.0%	12.8%	6.3%
LOSSES-MWH	25,019	25,104	25,212	25,305	25,397	25,497	25,602	25,716	25,833	25,957	-0.5%	-2.7%	1.4%	1.0%	0.7%
LOSSES (%)	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	-0.9%	-2.0%	-20.2%	-10.5%	-5.3%
ANNUAL PEAK	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
RURAL CP - kW	102,215	102,553	102,996	103,377	103,767	104,184	104,632	105,114	105,610	106,132	-0.6%	-3.5%	-4.4%	-2.0%	-0.8%
DIRECT SERVE CP - kW	198,000	198,000	198,000	198,000	198,000	198,000	198,000	198,000	198,000	198,000	-	-	-	-	-
TOTAL CP - kW	300,215	300,553	300,996	301,377	301,767	302,184	302,632	303,114	303,610	304,132	-0.6%	-3.5%	19.0%	9.2%	4.6%
RURAL NCP - kW	135,795	136,088	136,409	136,729	136,979	137,336	137,689	138,135	138,566	139,057	-	-	0.7%	0.6%	0.4%
DIRECT SERVE SUM OF INDIVIDUAL NCP - kW	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	-	-	-	-	-

BIG RIVERS ELECTRIC CORPORATION

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BIG RIVERS ELECTRIC CORPORATION
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dated February 26, 2021

March 19, 2021

Item 53) ***Refer to the IRP, Appendix A, Load Forecast Study, Section 2.5, pages 33 and 35.***

a. ***Explain whether the Own Use column in the table is inclusive of each Member System's use plus BREC's use.***

b. ***Explain whether the Distribution Losses column contains losses for the Member Systems only.***

c. ***Explain whether the Transmission Losses column contains losses for BREC only.***

Response)

a. The Own Use column does not include Big Rivers' use.

b. The Distribution Losses column contains Big Rivers' Members' Systems distribution losses only.

c. Transmission Losses in the Total Native System Energy Summary table for the historical period through 2019 are based on actual loss factors as calculated for Big Rivers' system. For the forecast period beginning 2020 forward, the loss factor is held constant at the 2020 rate.

Witnesses) Matthew S. Sekeres (*a. and b. only*),
Steven A. Fenrick (*a. and b. only*), and
Marlene S. Parsley (*c. only*)

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Item 54) ***Refer to the IRP, Appendix A, Load Forecast Study, Section 2.5, page 34. Explain why only a portion of the Domtar energy use contributes to BREC's energy requirements. Include in the discussion whether and to what degree Domtar affects BREC's peak load demand requirements.***

Response) Only the Firm Power Billing Demand for Domtar is included in Big Rivers' energy requirements and load forecast according to the retail electric service agreement between Kenergy and Domtar. This amount can be adjusted monthly between 15 MW and 35 MW.

Witness) Marlene S. Parsley

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Item 55) ***Refer to the IRP, Appendix A, Load Forecast Study, Section 3, Table "Big Rivers Total System Energy Summary (MWh)," page 41. For the years 2022 and beyond in the forecast period, explain whether the direct and multiplier effects of the additional jobs created by the expansion of the direct serve load was accounted for in the Total Rural Requirements forecast, and if so, explain how.***

Response) Please see Big Rivers' response to Item 52 of Commission Staff's First Request for Information for a discussion on the Direct Serve addition.

Witnesses) Matthew S. Sekeres and
Steven A. Fenrick

Item 56) ***Refer to the IRP, Appendix A, Load Forecast Study, Section 3, Table Big Rivers Coincident Peak (kW), page 43, and Table Total System NCP (kW), page 45.***

a. ***For planning purposes through the forecast period, explain whether BREC's reserve margin is greater than what is required to be maintained by MISO at any time during a planning year.***

b. ***For table "Big Rivers Coincident Peak (kW)," explain why the Rural Annual CP column contains the greater Rural Winter CP amounts but is inconsistent in taking the greater amounts between Rural Summer and Rural Winter CP amounts in the forecast period.***

c. ***Explain the causes for BREC's Rural System CP to change from winter to summer peaking beginning in year 2037.***

d. ***Provide an update to the "Table Big Rivers Coincident Peak (kW)" and to the "Table Total System NCP (kW)" by including the amount of BREC's generating capacity, the amount required to fulfill MISO obligations, and the resulting reserve margin in each year of the***

forecast. In addition, include the annual balance for the years included in the Long Term Plan, 2040-2043.

Response)

a. MISO planning reserve margin requirements have typically been 8% to 9%, the transmission losses have been around 2%, and the Big Rivers–to–MISO NCP to CP factor has been in the -3% to -5% range. This totals to MISO planning reserve margin requirements to be in the 8% to 10% range when modeling generation capacity as firm capacity ("MISO UCAP") which lowers the generation max capacity (MISO ICAP) by the forced outage rate.

In Big Rivers' 2020 IRP models, the LT Plan (Capacity Planning) model had requirements to solve for a least–cost plan while maintaining capacity reserve requirements between 8% and 10%, and Big Rivers modeled the generation resources with firm capacity or MISO UCAP. In the LT Plan, Big Rivers wanted to determine if purchasing from the market provided a least–cost solution so the PPA – Block was modeled to represent market purchase. For planning purposes, the LT Plan is solving and maintaining Big Rivers' capacity reserve margin at what is projected for meeting MISO's requirements.

For Big Rivers' 2020 IRP optimal plan, the ST Plan model was used which does not solve for capacity changes. The capacity changes were provided as inputs for the ST Plan and Big Rivers. In the optimal plan, 90 MW of the NGCC unit was chosen and was not modified throughout the 20–year planning cycle. Table 8.10 in Big Rivers' 2020 IRP shows the Reserve Capacity Margin is decreasing throughout the period; the Reserve Capacity Margin is at 12% in 2024 and reduces to 7% by 2043. This change is due to both Big Rivers' load increasing and Big Rivers' generation resources (solar degradation by 0.5% annually) decreasing through the period.

b. The Rural Annual CP column is not intended to display the highest monthly Rural CP value. This column is included to capture the CP contribution of the Rural system to Big Rivers' annual peak. The Big Rivers system has Direct Serve loads and transmission losses to factor in when determining the annual peak amount and month. Because of this, the Rural system highest CP, if determined in isolation, would not always match the Rural system contribution to Big Rivers' annual CP. The monthly forecast table located in Big Rivers' 2020 IRP, Appendix A, Load Forecast Study, page 88 may be helpful when trying to examine seasonal versus annual contributions.

c. The summer and winter Rural CP projections are very similar through the forecast. The subtle shift from winter to summer peak reflects a strength of the monthly modeling process in picking up shifts in class compositions over time. Residential load has historically been more concentrated in the winter and Commercial loads have been more concentrated in the summer. The gradual increase in summer peak relative to winter is a result of the Commercial class growth rates being higher relative to Residential.

d. Please see the attachment for this response.

Witnesses) Duane E. Braunecker (*a. only*)

Matthew S. Sekeres (*b. and c. only*)

Steven A. Fenrick (*b. and c. only*)

Marlene S. Parsley (*d. only*)

Big Rivers Electric Corporation
Case No. 2020-00299

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	1,193	**39%**	306	1,184	**1%**
2024	493,376	495,970	493,376	322,043	20,908	836,327	815	65	880	917	**5%**	210	1,091	**-16%**
2025	495,136	497,935	495,136	322,043	20,953	838,132	817	65	883	915	**4%**	311	1,193	**-23%**
2026	496,879	499,794	496,879	322,043	20,998	839,920	819	66	884	914	**4%**	311	1,196	**-24%**
2027	497,133	499,957	497,133	322,043	21,005	840,180	819	66	885	913	**3%**	100	985	**-7%**
2028	498,359	500,820	498,359	322,043	21,036	841,438	820	66	886	911	**3%**	100	986	**-8%**
2029	499,422	501,685	499,422	322,043	21,063	842,528	821	66	887	910	**3%**		887	**3%**
2030	500,004	501,900	500,004	322,043	21,078	843,125	822	67	888	909	**3%**		888	**2%**
2031	501,074	502,687	501,074	322,043	21,106	844,223	823	67	889	908	**2%**		889	**2%**
2032	503,128	504,331	503,128	322,043	21,158	846,330	825	67	891	906	**2%**		891	**2%**
2033	504,103	505,032	504,103	322,043	21,183	847,329	826	67	892	905	**2%**		892	**1%**
2034	504,841	505,432	504,841	322,043	21,202	848,086	827	67	893	904	**1%**		893	**1%**
2035	505,663	506,010	505,663	322,043	21,223	848,929	828	67	894	902	**1%**		894	**1%**
2036	506,495	506,574	506,495	322,043	21,245	849,782	829	67	895	901	**1%**		895	**1%**
2037	507,349	507,238	507,349	322,043	21,266	850,659	829	67	896	900	**1%**		896	**0%**
2038	508,129	507,810	508,129	322,043	21,286	851,459	830	67	897	898	**0%**		897	**0%**
2039	508,968	508,470	508,968	322,043	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 + 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

Item 57) ***Refer to the IRP, Appendix A, Load Forecast Study, Section 3, pages 42–43; Section 7.4, page 61; and Appendix, page 92, 96, and 100.***

a. ***Explain each of the variables in the Load Factor Models.***

b. ***Explain why April and October have both Cold and Hot Peaking categories.***

c. ***Explain whether nonmember requirements are included in the peak demand calculations, and if not, why not.***

d. ***Is it correct to interpret the historical data in the table on page 43 as:***

(1) The total annual CP is the actual BREC peak demand for a given year.

(2) That either the greater of the Rural Summer CP or the Winter CP occurred at the same time as the actual BREC system peak demand.

(3) That the Direct Serve CP and transmission losses both occurred at the time of the actual BREC system peak demand.

(4) That the Rural Summer CP and the Rural Winter CP is the sum of the actual individual Member System peak demands.

e. Explain whether the data has been weather normalized.

f. Explain whether Distribution losses are inherent in the Seasonal Rural CP calculation. If not, explain why it is appropriate to include Transmission losses.

Response)

a. Refer to Big Rivers' response to Item 48, sub-part d. of the Commission Staff's First Request for Information for the description of the January through December variables. One difference in the peak models is the introduction of April and October as either "Cold Peaking" or "Hot Peaking." April and October are shoulder months and can peak throughout history on a hot day within the month ("April Hot Peaking" and "October Hot Peaking") or a cold day in the month ("April Cold Peaking" and "October Cold Peaking"). Whether the system peaked on a hot or cold day during these months drives unique load factor characteristics for each Member-

Owners' system. These are binary variables to capture this difference. Throughout the forecast period, each of these months are projected as hot peaking months ("April Hot Peaking" and "October Hot Peaking" equal one; "April Cold Peaking" and October Cold Peaking" equal zero.).

Please see Big Rivers' response to Item 47, sub–part d. of the Commission Staff's First Request for Information for an explanation of the efficiency portion of the variables. Also, see Big Rivers' response to Item 51, sub–part b.(2) for definitions of the weather-related portions of the variables. The saturation portions of the variables represent the percentage of consumers that has either air conditioning ("AC Saturation") or electric heat ("Electric Heating Saturation").

b. Please see Big Rivers' response to sub–part a.

c. Please see Big Rivers' response to Item 43, sub–part c. of the Commission's First Request for Information.

d.

(1) This does not include any non-member loads, and actual peak values may vary slightly due to variance in transmission losses.

(2) No. The annual Big Rivers system peak demand does not necessarily occur at the greater of the Rural Summer CP and Rural Winter CP. The inclusion of the Direct Serve CP in the Big Rivers' totals can cause the annual peak for Big Rivers to occur during a different season than the Rural peak.

(3) The Direct Serve CP is the value at the time of the actual Big Rivers system peak. The transmission losses are an estimated value at the Big Rivers system peak.

(4) The Rural Summer CP and the Rural Winter CP are the sum of the actual individual Rural Member System CP demands. Direct Serve customers are not included in the Rural values.

e. The historical data displayed on the referenced table in Big Rivers' 2020 IRP, Appendix A, Load Forecast Study, page 43, are actual data. They are not weather normalized. The weather normalized peak data are shown in Big Rivers' 2020 IRP, Appendix A, Load Forecast Study, page 70.

f. Distribution losses are included in the Rural CP calculations.

Witnesses) Matthew S. Sekeres and
Steven A. Fenrick

BIG RIVERS ELECTRIC CORPORATION

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Item 58) ***Refer to the IRP, Appendix A, Load Forecast Study, Section 5, page 51.***

a. Explain the basis for the plus and minus one percent variation applied to the economic variables in 2020.

b. Explain whether the one percent variation was applied each forecast year for the economic variables.

c. Explain whether the initial source for the forecast economic variables also included any alternative economic variable forecasts, and if so, why those alternate forecasts were not used in BREC's analyses.

Response)

a. These economic scenarios are designed to represent realistic economic conditions that cooperatives such as Big Rivers and its Member-Owners might face. The scenarios illustrate the impacts of a one percent variation in the economic conditions, and the magnitude of load impacts resulting from a one percent variation in either direction.

b. An additional one percent variation was applied each year (a total of one percent in 2020, two percent in 2021, three percent in 2022, *etc.*).

c. Other than some limited ranges on some of the alternative fuel price data, none of the demographic or economic variables had any alternative forecasts from the source data. Clearspring determined it would not be useful to show scenarios based on the limited ranges provided since there were no corresponding alternative scenarios for any remaining variables.

Witnesses) Matthew S. Sekeres and
Steven A. Fenrick

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Item 59) ***Refer to the IRP, Appendix A, Load Forecast Study, Section 7.5, page 62. Explain whether BREC considered using a short-term SAE model and a long-term econometric model, and then blending the two into one forecast.***

Response) No, Big Rivers did not consider using either of these models and blending them into a single forecast. Please see Big Rivers' response to Item 47, sub–part a. of the Commission Staff's First Request for Information for further details regarding the econometric approach and the SAE approach.

Witnesses) Matthew S. Sekeres and
Steven A. Fenrick

Item 60) ***Explain whether BREC prepared this IRP to meet its system and nonmember commitments or required MISO obligations regarding energy and capacity.***

Response) Big Rivers prepared its 2020 IRP to meet its' native load demand and energy obligations, including Planning Reserve Margins that are required due to Big Rivers' MISO membership. Big Rivers did not include nonmember load obligations in the Base Case.

Witness) Marlene S. Parsley

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Item 61) ***Explain whether any behind the meter supply-side resources were modeled, and if so, what these were.***

Response) There were no behind the meter supply-side resources modeled in PLEXOS nor in the 2020 Long Term Load Forecast.

Witness) Mark J. Eacret

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Item 62) ***Provide a table illustrating the energy forecast and generation supply. If the energy forecast is greater than the existing load, explain how the shortage will be covered.***

Response) The annual energy positions from 2024 to 2043 are shown in the tables of Appendix G, Short Term Plan, pages G-4 to G-6. The table on the following page summarizes Big Rivers' optimal plan, with a January 2024 anticipated start date for the Natural Gas Combined Cycle ("NGCC") unit, as fully explained in Big Rivers' response to Item 44 of the Commission Staff's First Request for Information. Big Rivers is a MISO member; therefore, all of Big Rivers load will be purchased in MISO and all of Big Rivers' generation will be offered and sold into MISO. Any energy shortages will be covered within the Big Rivers' purchases in MISO. Projected MISO purchases will be hedged to protect Member Owners from price volatility.

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Big Rivers Electric Corporation Annual Energy Position, MWhs			
Green Idled + Solar + 90 MW NGCC Sebree			
Year	Generation (a)	Native Load (b)	Energy Position (c) = (a) =- (b)
2024	[redacted]		
2025			
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
2035			
2036			
2037			
2038			
2039			
2040			
2041			
2042			
2043			
Average			

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Witness) Mark J. Eacret

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Item 63) ***Provide a table illustrating the annual demand forecast, generation capacity forecast, and the resulting reserve margin over the entire forecast period through 2043. If the demand forecast is greater than existing capacity or the forecasted generation additions and the resulting reserve margin falls below minimum levels at any time (seasonally or annually), explain how any shortages in either energy or capacity will be covered.***

Response) Please see Table 8.10 Generation and Capacity Reserve Margin on page 160 of Big Rivers' 2020 IRP. If Big Rivers is short on capacity, it would need to purchase the required capacity either from third parties or in the MISO market. Subsequent to submitting its 2020 IRP, Big Rivers submitted an application seeking a Certificate of Public Convenience and Necessity to convert its generating units at Green Station to burn natural gas and to minimize its reliance on the MISO capacity market.[1]

[1] *See In the Matter of: 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*

MISO's planning year is from June through May and there is no seasonal market. Any energy shortages are discussed in Big Rivers' response to Item 62 of the Commission Staff's First Request for Information.

Witness) Mark J. Eacret

Gas-Fired Units and an Order Approving the Establishment of a Regulatory Asset, P.S.C. Case No. 2021-00079.