6.4 PERFORMANCE MEASURES

A summary tabulation of the expected value of all performance measures is provided in Table 29 below. Detailed results behind this summary tabulation are attached in Appendix D, Economic Impact for Each Alternative Resource Plan HC.

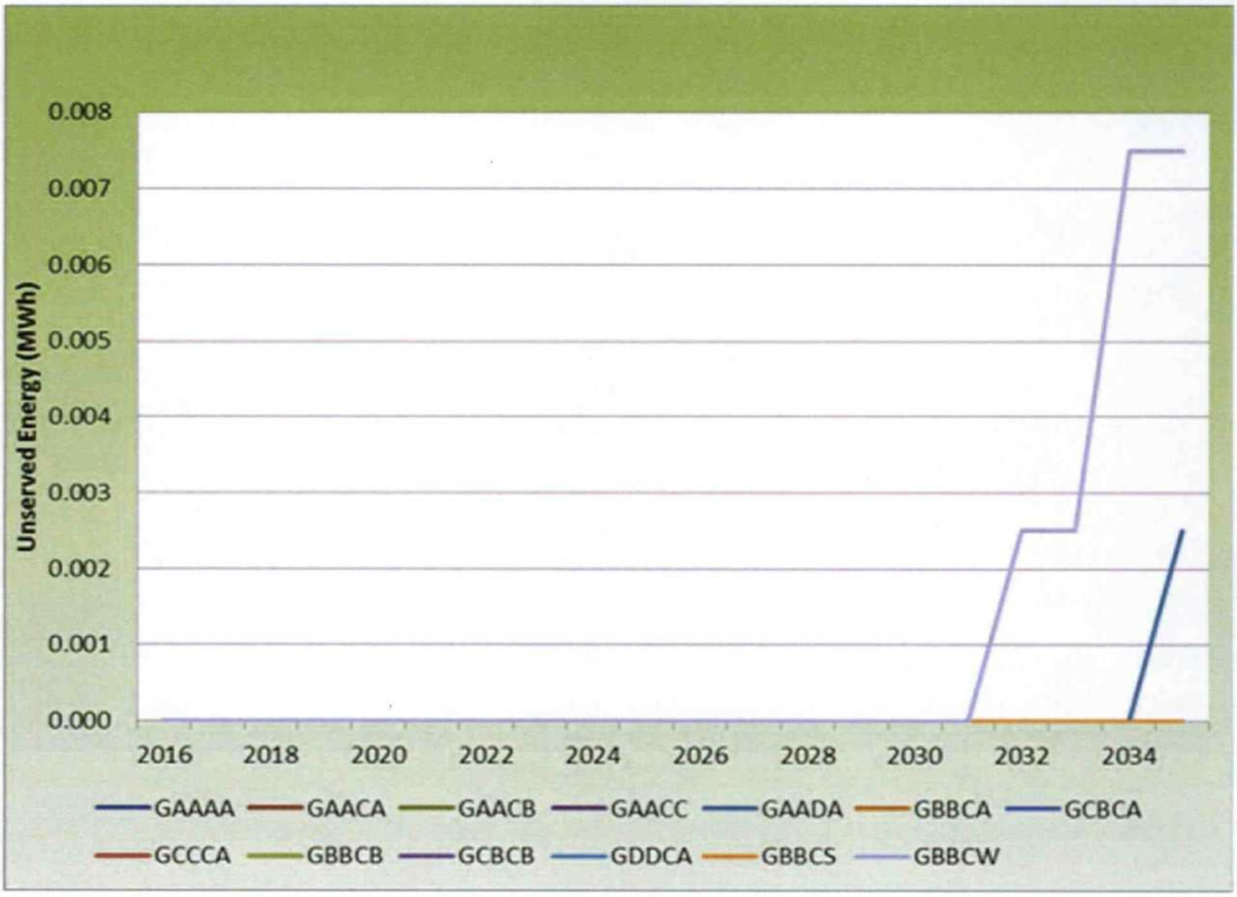
Table 29: Expected Value of Performance Measures ** Highly Confidential **

Plan	NPVRR ($MM)	Levelized Annual Rates ($/KW-hr)	Maximum Rate Increase
GBBCS	10,382	[redacted]	[redacted]
GBBCA	10,389	[redacted]	[redacted]
GAACA	10,447	[redacted]	[redacted]
GAACC	10,511	[redacted]	[redacted]
GCBCA	10,524	[redacted]	[redacted]
GBBCW	10,529	[redacted]	[redacted]
GDDCA	10,629	[redacted]	[redacted]
GCBCB	10,660	[redacted]	[redacted]
GAADA	10,688	[redacted]	[redacted]
GBBCB	10,698	[redacted]	[redacted]
GAACB	10,756	[redacted]	[redacted]
GCCCA	10,947	[redacted]	[redacted]
GAAAA	11,476	[redacted]	[redacted]

6.5 UNSERVED ENERGY

The expected value of unserved energy for all GMO Alternative Resource Plans is provided in Table 30 below.

Table 30: Expected Value of Unserved Energy



6.6 JOINT-PLANNING KCP&L/GMO RESOURCE PLANS

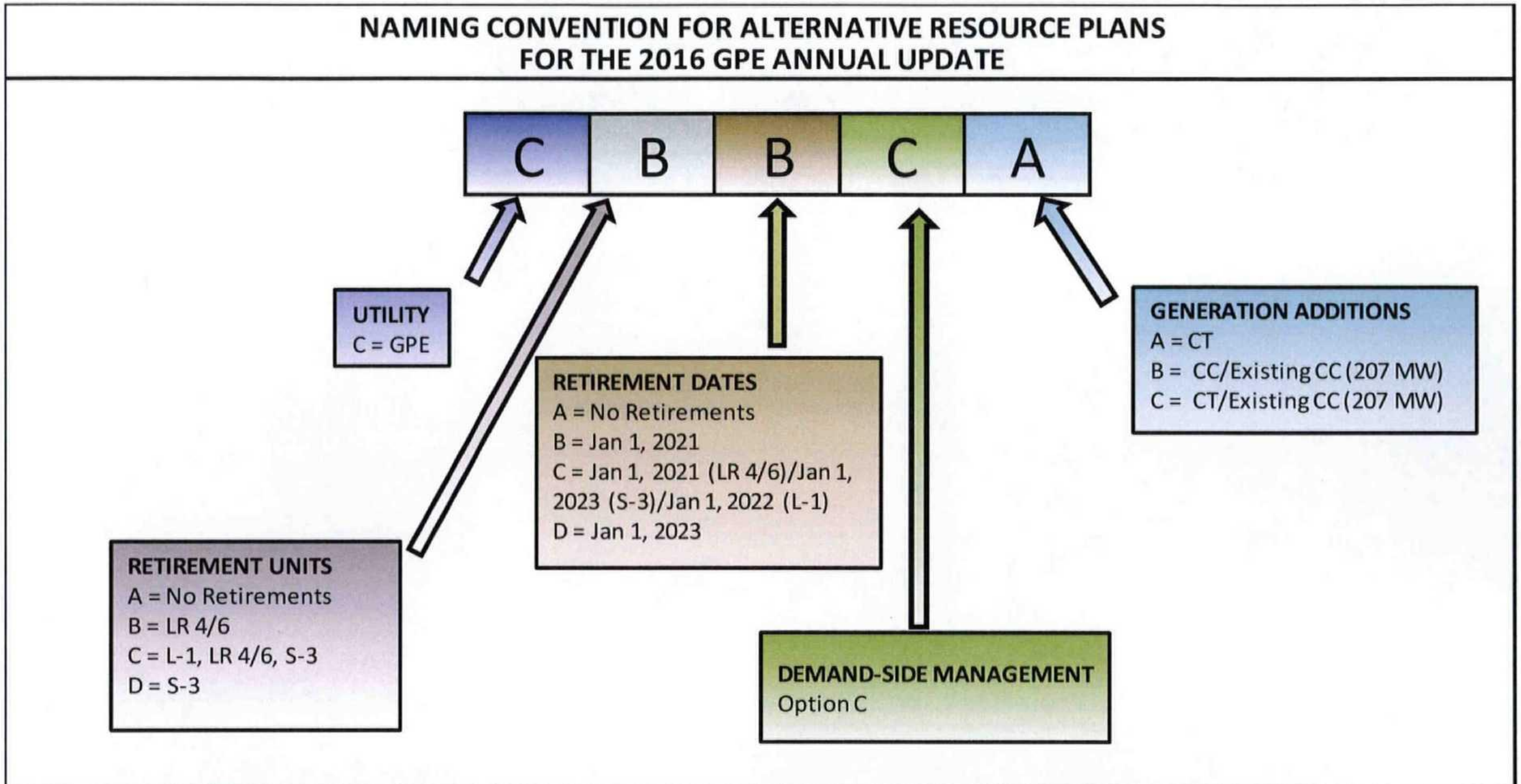
KCP&L also considers it prudent resource planning to develop and analyze alternative resource plans that are based upon KCP&L and GMO combining resources. Evaluating alternative resource plans on a joint planning basis can provide a platform to determine if joint planning "serves the public interest" as mandated in 4 CSR 240-22.010 Policy Objectives.

The joint-planning Alternative Resource Plans were developed to reflect combinations of the KCP&L and GMO Alternative Resource Plans. For example, combined company plan CBBCA is the combination of KCP&L alternative resource plan KAACA (no retirements/DSM Option C) and GMO alternative resource plan GBBCA (retire Lake Road 4/6 by 2021/DSM Option C).

The NPVRR for each joint-planning Alternative Resource Plan was determined under the same 18 scenarios analyzed for the stand alone companies. For example, electricity market prices, natural gas prices, CO_2 allowance prices, etc. were unchanged from the stand-alone company scenarios.

The plan-naming convention utilized for the joint-planning Alternative Resource Plans developed is shown in Table 31. The Alternative Resource Plans were developed using various capacities of supply-side resources and demand-side resources. In total, five joint-planning Alternative Resource Plans were developed for the integrated resource analysis for the 2016 Annual Update. An overview of the Alternative Resource Plans is shown in Table 32 below.

Table 31: Joint-Planning Alternative Resource Plan Naming Convention



Definitions:

L-1 - LaCygne-1	**LR 4/6 - Lake Road 4/6**	**CT - Combustion Turbine**
S-3 - Sibley -3		**CC - Combined Cycle**

Table 32: Overview of Joint-Planning Resource Plans

Plan Name	DSM Level	Cease Burning Coal	Year to Cease Burning Coal	Renewable Additions		Generation Addition (if needed)
CBBCA	Option C	Sibley-1 Sibley-2	2019	Solar: 2016 - 8 MW 2026 - 12 MW	Wind: 2016 - 350 MW 2017 - 260 MW	n/n
		Lake Road 4/6	2021 (convert to NG in 2016)			
CCCCA	Option C	Sibley-1 Sibley-2	2019	Solar: 2016 - 8 MW 2026 - 12 MW	Wind: 2016 - 350 MW 2017 - 260 MW	414 MW CT in 2023 207 MW CT in 2033
		Lake Road 4/6	2021 (convert to NG in 2016)			
		LaCygne-1	2022			
		Sibley-3	2023			
CCCCB	Option C	Sibley-1 Sibley-2	2019	Solar: 2016 - 8 MW 2026 - 12 MW	Wind: 2016 - 350 MW 2017 - 260 MW	Add 207 MW Existing CC in 2017 207 MW CC in 2023 207 MW CC in 2033
		Lake Road 4/6	2021 (convert to NG in 2016)			
		LaCygne-1	2022			
		Sibley-3	2023			
CCCCC	Option C	Sibley-1 Sibley-2	2019	Solar: 2016 - 8 MW 2026 - 12 MW	Wind: 2016 - 350 MW 2017 - 260 MW	Add 207 MW Existing CC in 2017 207 MW CT in 2023 207 MW CT' in 2033
		Lake Road 4/6	2021 (convert to NG in 2016)			
		LaCygne-1	2022			
		Sibley-3	2023			
CDDCA	Option C	Sibley-3	2023	Solar: 2016 - 8 MW 2026 - 12 MW	Wind: 2016 - 350 MW 2017 - 260 MW	207 MW CT in 2035

Results for each of the joint-planning Alternative Resource Plans are shown in Table 33 below.

Table 33: Joint-Planning Twenty-Year Net Present Value Revenue Requirement

Rank (L-H)	Plan	NPVRR ($mm)	Delta
1	CDDCA	$31,712	$0
2	CBBCA	$31,748	$37
3	CCCCA	$31,969	$257
4	CCCCC	$32,067	$355
5	CCCCB	$32,123	$411

The joint-planning Alternative Resource Plan (ARP), CDDCA, provided the lowest Net Present Value Revenue Requirement (NPVRR). This plan consists of retirement of Sibley-3 by 2023 in addition to Sibley-1, Sibley-2, and Montrose Units 1, 2, and 3. The next lowest NPVRR plan was CBBCA, which is the combination of the KCP&L and GMO Preferred Plans, and consisting of retirement of Lake Road 4/6 by 2021 in addition to Sibley-1, Sibley-2, and Montrose Units 1, 2, and 3. The NPVRR difference between these two plans is $37 Million over the 20-year planning period out of a total NPVRR of ~$32 Billion.

Table 34 and Table 35 show the expected value of NPVRR for the joint plans with and without CO_2 restrictions. The "Without" CO_2 restrictions shows the expected value over the nine scenarios that have $0 CO_2 emission allowance cost. The "With" CO_2 restrictions shows the expected value over the nine scenarios that include the Company's non-zero CO_2 emission allowance forecast. Under the scenarios with CO_2 restrictions, the plan that includes retirement of Sibley 3 is the lowest cost plan. Under scenarios without CO_2 restrictions, the lowest cost plan includes continued operation at Sibley 3. Given the results of the joint plans, no changes to the GMO or KCP&L Preferred Plans were warranted.

Table 34: Joint Plan Results With CO_2 Restrictions

Total Revenue Requirement - EV 9EPs (CO_2 - YES)						
Rank (L-H)	Plan	NPVRR ($mm)	Delta	Retirements	Additions	DSM level
1	CDDCA	$33,088	$0	S-3 2023	207MW CTs in 2035	C
2	CBBCA	$33,220	$133	LR 4/6 2021	None	C
3	CCCCA	$33,246	$158	LR 4/6 2021, L-1 2022, S-3 2023	CTs: 414MW 2023, 207MW 2033	C
4	CCCCB	$33,324	$236	LR 4/6 2021, L-1 2022, S-3 2023	Existing CC 207MW 2017, CCs: 207MW 2023, 207MW 2033	C
5	CCCCC	$33,335	$247	LR 4/6 2021, L-1 2022, S-3 2023	Existing CC 207MW 2017, CTs: 207MW 2023, 207MW 2033	C

Table 35: Joint Plan Results Without CO_2 Restrictions

Total Revenue Requirement - EV 9EPs (CO_2 - NO)						
Rank (L-H)	Plan	NPVRR ($mm)	Delta	Retirements	Additions	DSM level
1	CBBCA	$30,767	$0	LR 4/6 2021	None	C
2	CDDCA	$30,794	$28	S-3 2023	207MW CTs in 2035	C
3	CCCCA	$31,118	$351	LR 4/6 2021, L-1 2022, S-3 2023	CTs: 414MW 2023, 207MW 2033	C
4	CCCCC	$31,222	$455	LR 4/6 2021, L-1 2022, S-3 2023	Existing CC 207MW 2017, CCs: 207MW 2023, 207MW 2033	C
5	CCCCB	$31,322	$555	LR 4/6 2021, L-1 2022, S-3 2023	Existing CC 207MW 2017, CCs: 207MW 2023, 207MW 2033	C

A summary tabulation of the expected value of all performance measures is provided in Table 36 below. Detailed results behind this summary tabulation are attached in Appendix D.

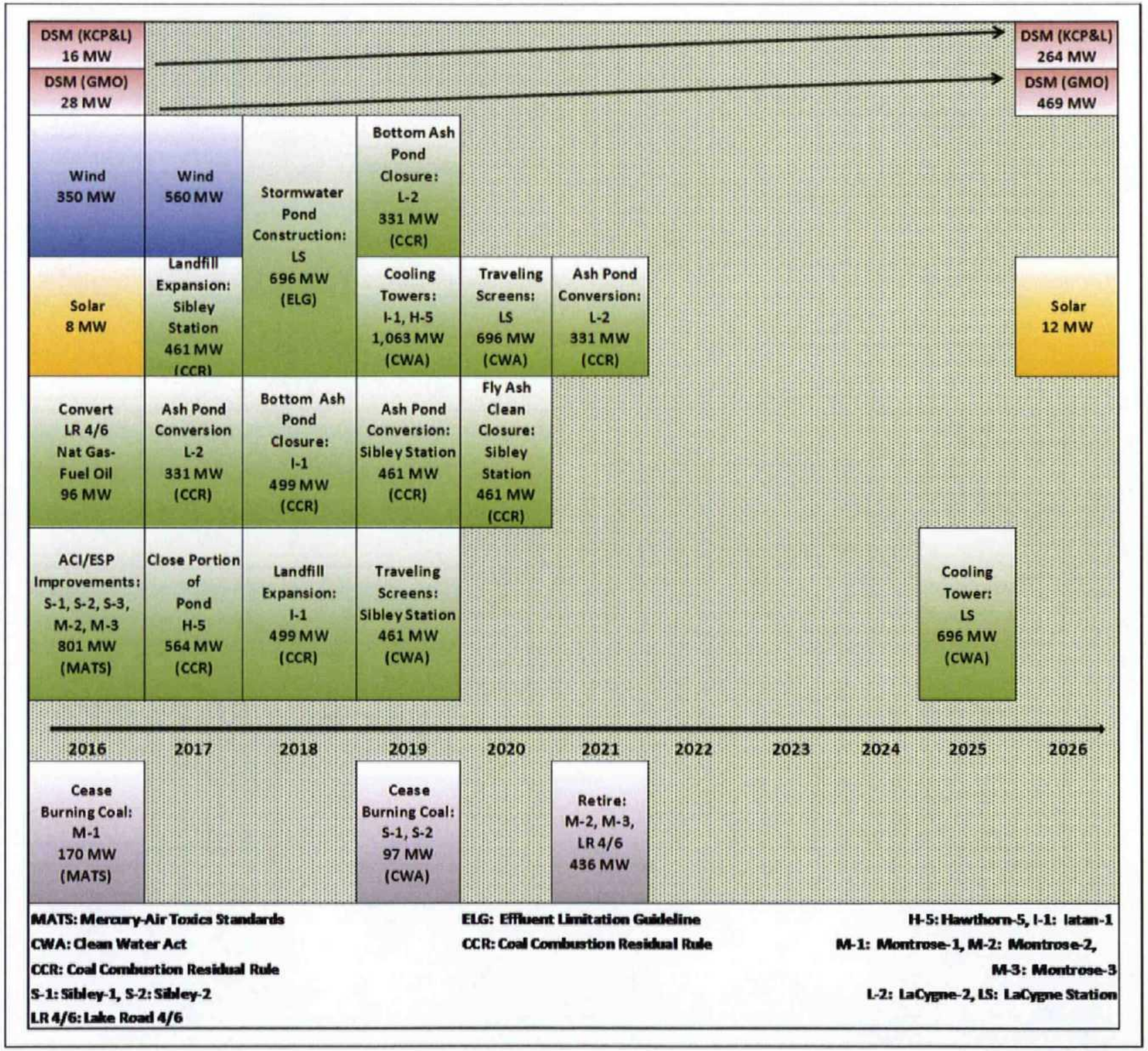
Table 36: Joint-Planning Expected Value of Performance Measures ** Highly Confidential **

Plan	NPVRR ($MM)	Levelized Annual Rates ($/KW-hr)	Maximum Rate Increase
CDDCA	31,712	[redacted]	
CBBCA	31,748		
CCCCA	31,969		
CCCCC	32,067		
CCCCB	32,123		

HC

The Joint-Planning Alternative Resource Plan that reflects the combination of the KCP&L Preferred Plan, KAACA and GMO's Preferred Plan, GBBCA is Alternative Resource Plan CBBCA. This plan is comprised of the following components for years 2016 – 2026 and shown in Figure 5 below. The joint-planning additions shown are equivalent to the stand-alone KCP&L and GMO Alternative Resource Plans, KAACA and GBBCA, respectively..

Figure 5: 2016 Joint-Planning Alternative Resource Plan CBBCA - Years 2016 through 2026


DSM (KCP&L) 16 MW
DSM (GMO) 28 MW
DSM (KCP&L) 264 MW
DSM (GMO) 469 MW
Wind 350 MW
Wind 560 MW
Stormwater Pond Construction: LS 696 MW (ELG)
Bottom Ash Pond Closure: L-2 331 MW (CCR)
Solar 8 MW
Landfill Expansion: Sibley Station 461 MW (CCR)
Cooling Towers: I-1, H-5 1,063 MW (CWA)
Traveling Screens: LS 696 MW (CWA)
Ash Pond Conversion: L-2 331 MW (CCR)
Solar 12 MW
Convert LR 4/6 Nat Gas-Fuel Oil 96 MW
Ash Pond Conversion L-2 331 MW (CCR)
Bottom Ash Pond Closure: I-1 499 MW (CCR)
Ash Pond Conversion: Sibley Station 461 MW (CCR)
Fly Ash Clean Closure: Sibley Station 461 MW (CCR)
ACI/ESP Improvements: S-1, S-2, S-3, M-2, M-3 801 MW (MATS)
Close Portion of Pond H-5 564 MW (CCR)
Landfill Expansion: I-1 499 MW (CCR)
Traveling Screens: Sibley Station 461 MW (CWA)
Cooling Tower: LS 696 MW (CWA)
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
Cease Burning Coal: M-1 170 MW (MATS)
Cease Burning Coal: S-1, S-2 97 MW (CWA)
Retire: M-2, M-3, LR 4/6 436 MW
MATS: Mercury-Air Toxics Standards
CWA: Clean Water Act
CCR: Coal Combustion Residual Rule
S-1: Sibley-1, S-2: Sibley-2
LR 4/6: Lake Road 4/6
ELG: Effluent Limitation Guideline
CCR: Coal Combustion Residual Rule
H-5: Hawthorn-5, I-1: Iatan-1
M-1: Montrose-1, M-2: Montrose-2,
M-3: Montrose-3
L-2: LaCygne-2, LS: LaCygne Station

The Joint-Planning Alternative Resource Plan for the 20-year planning period is shown in Table 37 below:

Table 37: Joint-Planning Alternative Resource Plan

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2016	0	350	8	44	170	6627
2017	0	560		109		6827
2018	0			179		6827
2019	0			241	97	6741
2020	0			334		6775
2021	0			420	436	6366
2022	0			500		6366
2023	0			578		6381
2024	0			650		6319
2025	0			695		6319
2026	0		12	733		6321
2027	0			763		6321
2028	0			793		6321
2029	0			822		6321
2030	0			847		6321
2031	0			867		6321
2032	0			886		6321
2033	0			905		6321
2034	0			924		6321
2035	0			939		6321

6.7 JOINT-PLANNING ECONOMIC IMPACT

The economic impact by year of the Joint-Planning Alternative Resource Plan CBBCA is represented in Table 38 below. The economic impact of all plans can be found in Appendix D.

Table 38: Joint-Planning Alternative Resource Plan - Economic Impact ** Highly Confidential **

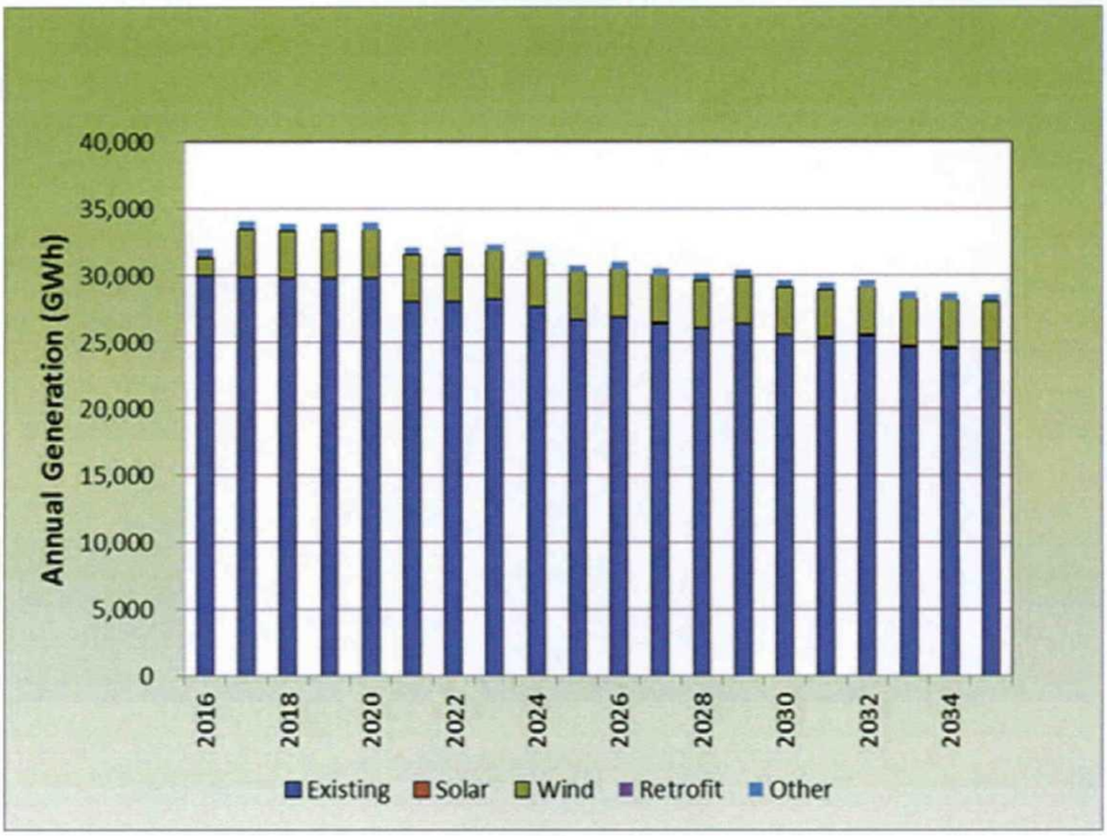
Year	Revenue Requirement ($MM)	Levelized Annual Rates ($/kW-hr)	Rate Increase
2016	2,655	[redacted]	
2017	2,715		
2018	2,787		
2019	2,969		
2020	3,025		
2021	3,080		
2022	3,170		
2023	3,235		
2024	3,290		
2025	3,380		
2026	3,423		
2027	3,498		
2028	3,534		
2029	3,579		
2030	3,652		
2031	3,693		
2032	3,762		
2033	3,864		
2034	3,917		
2035	3,993		

HC

6.8 JOINT-PLANNING ANNUAL GENERATION

The expected value of annual generation of the Joint-Planning Alternative Resource Plan CBBCA is represented in Table 39 below. The annual generation of all Combined-Company plans can be found in Appendix C, Generation and Emissions for Each Alternative Resource Plan.

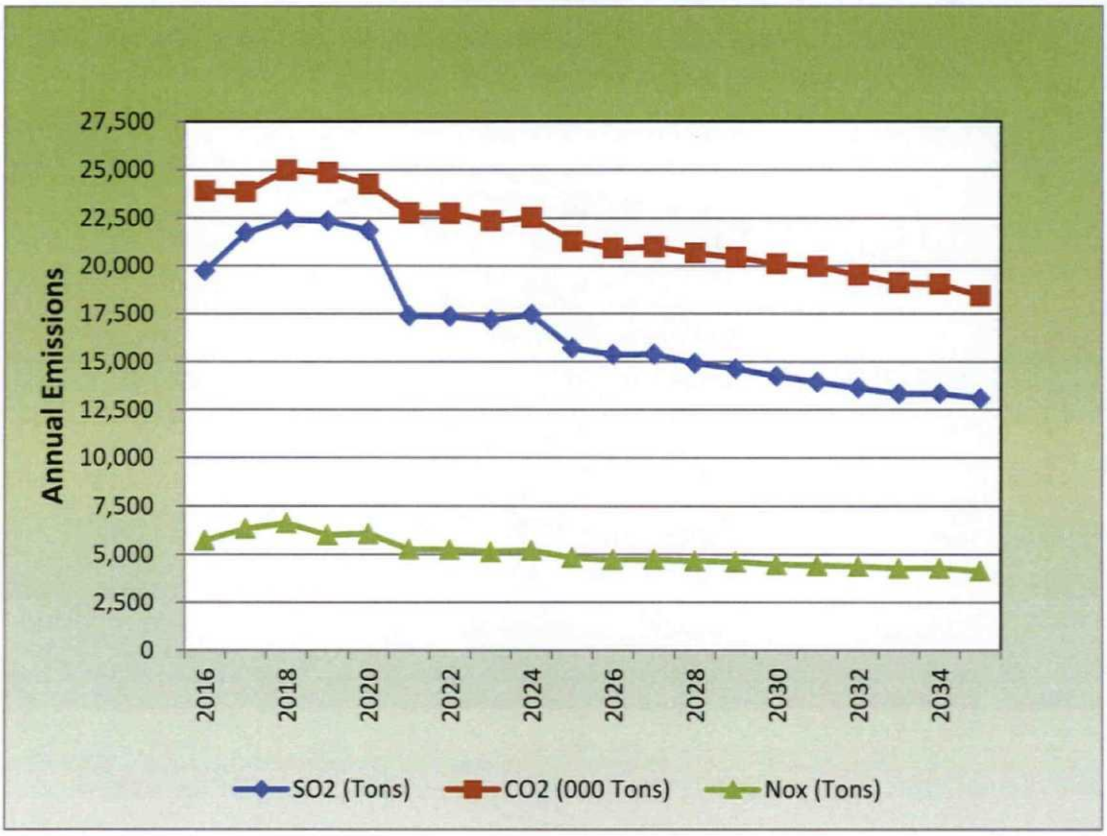
Table 39: Joint-Planning Alternative Resource Plan CBBCA Annual Generation



6.9 JOINT-PLANNING ANNUAL EMISSIONS

The expected value of annual emissions of the Joint-Planning Alternative Resource Plan CBBCA is represented in Table 40 below. The annual emissions of all Joint-Planning plans can be found in Appendix C.

Table 40: Joint-Planning Alternative Resource Plan CBBCA Annual Emissions



SECTION 7: RESOURCE ACQUISITION STRATEGY

7.1 2016 ANNUAL UPDATE PREFERRED PLAN

The 2016 Annual Update Preferred Plan for the 20-year planning period is shown in Table 41 below.

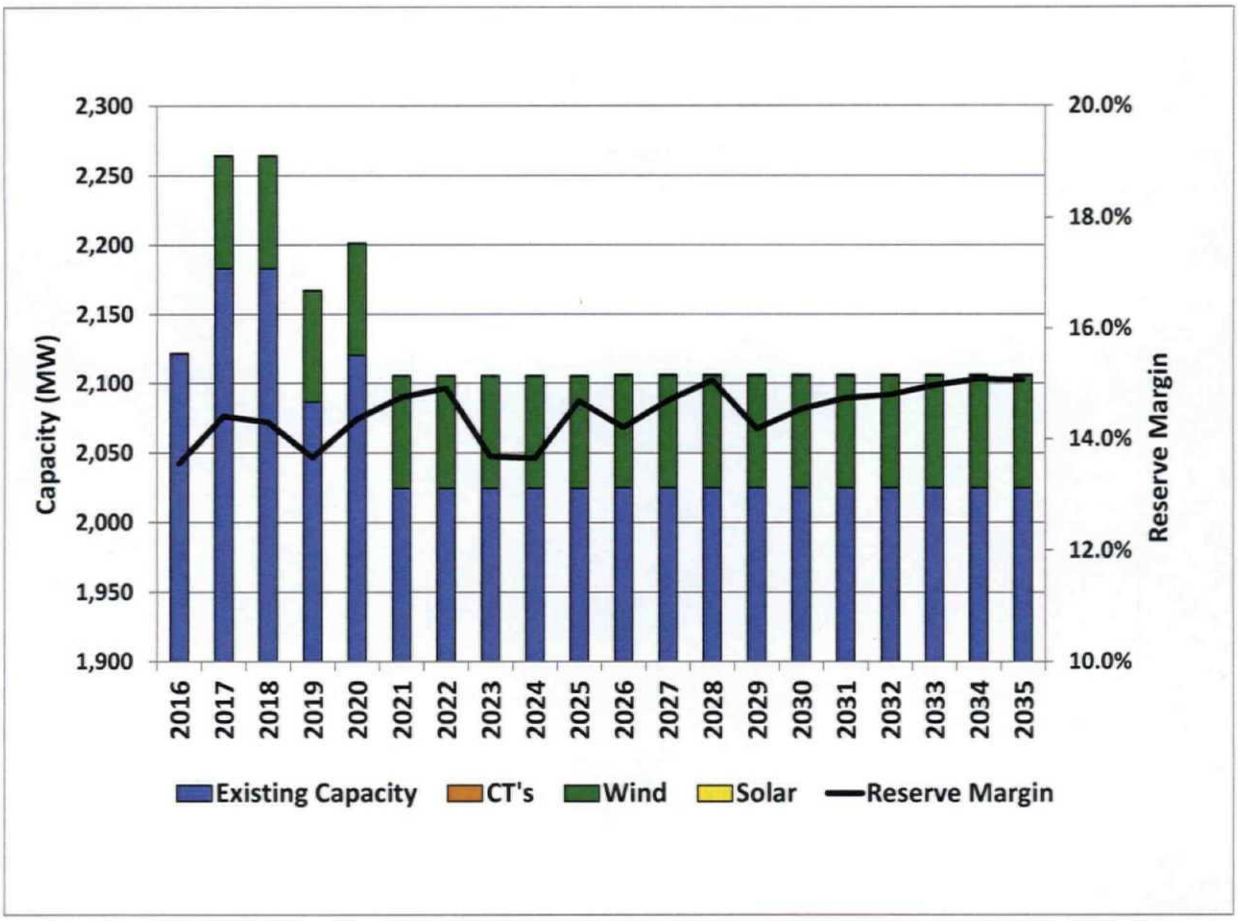
Table 41: 2016 Annual Update Preferred Plan

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2016	0		5	28		2121
2017	0	260		66		2183
2018	0			99		2183
2019	0			136	97	2086
2020	0			192		2120
2021	0			249	96	2024
2022	0			307		2024
2023	0			364		2024
2024	0			420		2024
2025	0			445		2024
2026	0		5	469		2025
2027	0			491		2025
2028	0			512		2025
2029	0			532		2025
2030	0			549		2025
2031	0			565		2025
2032	0			581		2025
2033	0			596		2025
2034	0			610		2025
2035	0			624		2025

7.1.1 PREFERRED PLAN COMPOSITION

The capacity composition by supply-side resource and reserve margin for the Preferred Plan is provided in Table 42 below:

Table 42: Preferred Plan Capacity Composition



Based in part upon current Missouri RPS rule requirements, the Preferred Plan includes 10 MW of solar additions and 310 MW of wind additions over the twenty-year planning period. It should be noted that the solar resource addition in 2016 is expected to consist of ownership in 2 MW Commercial and Industrial rooftop installations and 3 MW of a central station solar facility located at Greenwood, Missouri. The 260 MW wind addition is planned for 2017. DSM resources consist of a suite of eight residential and eight commercial programs three of which are demand response programs, two are educational programs, and eleven energy efficiency programs. The Preferred Plan reflects Sibley Units 1 and 2 ceasing to burn coal in 2019 and the 96 MW Lake Road 4/6 converting to natural gas in 2016 and then retiring by 2021. The environmental drivers that contributed to discontinuing coal use, and the Lake Road 4/6 retirement, include Mercury and Air Toxics Standards Rule, Ozone National Ambient Air Quality Standards (NAAQS), PM NAAQS, Clean Water Act Section 316(a) and (b), Effluent Guidelines, Coal Combustion Residuals Rule, and Clean Power Plan. These rules will be monitored by GMO to determine if the decision to cease burning coal and to retire Lake Road 4/6 in the projected retirement year continues to be prudent.

7.1.2 PREFERRED PLAN ECONOMIC IMPACT

The expected value of economic impact by year of the Preferred Plan is represented in Table 43 below. The economic impact of all plans can be found in Appendix D.

Table 43: Preferred Plan Economic Impact ** Highly Confidential **

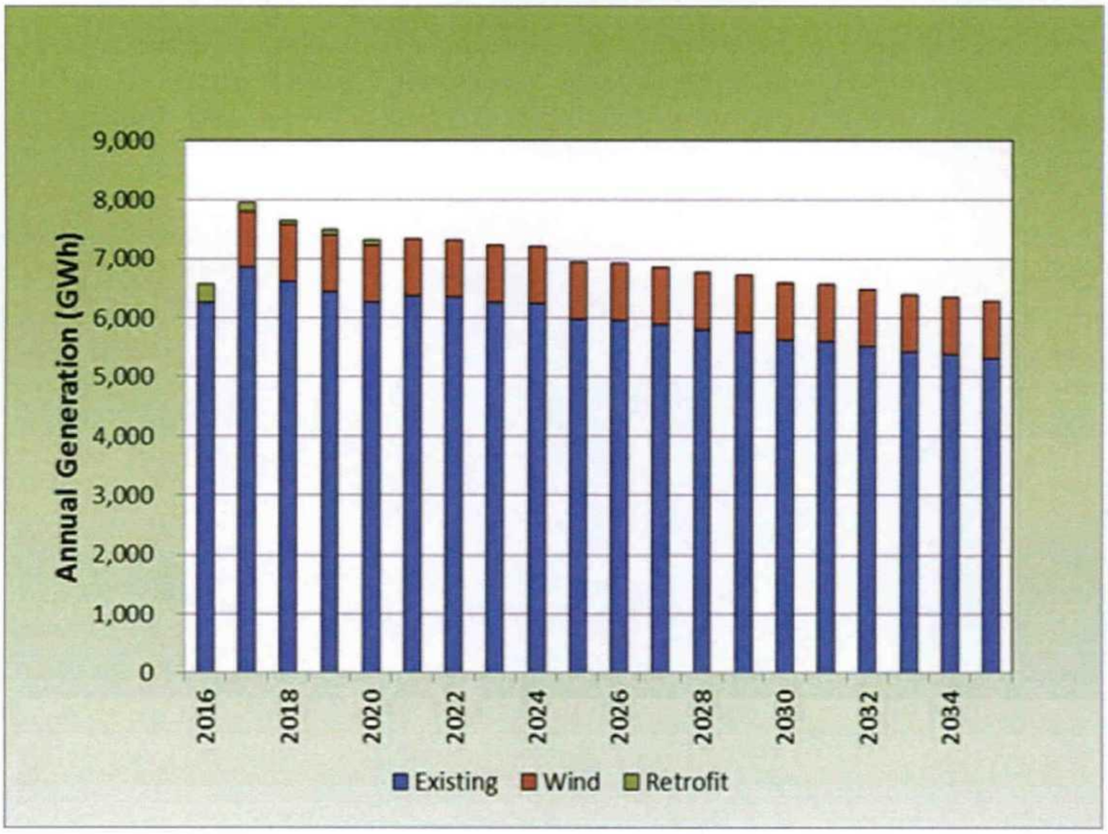
Year	Revenue Requirement ($MM)	Levelized Annual Rates ($/kW-hr)	Rate Increase
2016	846	[redacted]	
2017	855		
2018	890		
2019	949		
2020	977		
2021	991		
2022	1,030		
2023	1,077		
2024	1,100		
2025	1,116		
2026	1,140		
2027	1,159		
2028	1,164		
2029	1,198		
2030	1,214		
2031	1,230		
2032	1,275		
2033	1,302		
2034	1,315		
2035	1,357		

HC

7.1.3 PREFERRED PLAN ANNUAL GENERATION

The expected value of annual generation for the preferred plan is shown in Table 44 below. The annual generation for all plans is included in Appendix C.

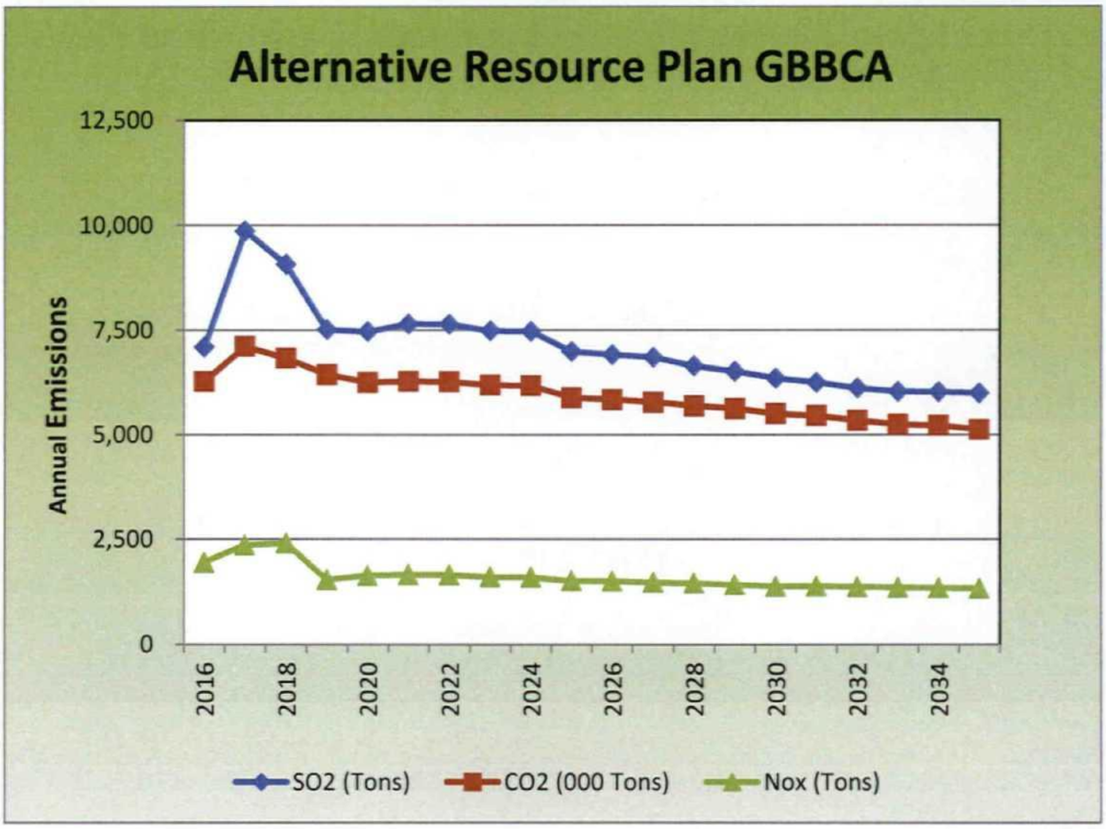
Table 44: Preferred Plan Annual Generation



7.1.4 PREFERRED PLAN ANNUAL EMISSIONS

The expected value of annual emissions for the Preferred Plan is shown in Table 45 below. The annual generation for all plans is included in Appendix C.

Table 45: Preferred Plan Annual Emissions



7.1.5 PREFERRED PLAN DISCUSSION

The Preferred Plan was not the lowest cost plan from a Net Present Value of Revenue Requirement (NPVRR) perspective. One Alternative Resource Plan (ARP), GBBCS, had a slightly lower NPVRR than the Preferred Plan. This ARP varies from the Preferred Plan GBBCA by excluding the 10 MW of solar additions that the Preferred Plan includes. Because GMO feels it is prudent to further diversity its generation portfolio for compliance of future federal environmental regulations, as well as gain experience in constructing and operating an utility-scale solar facility, the Preferred Plan, GBBCA, which includes 3 MW of a utility-scale solar facility at Greenwood, Missouri and 7 MW of commercial solar additions, continues to be the Preferred Plan.

The Preferred Plan also meets the fundamental planning objectives as required by Rule 22.010(2) to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies.

7.2 CRITICAL UNCERTAIN FACTORS

The Critical Uncertain Factors for the 2016 Annual Update are identical to those in the 2015 Triennial IRP. The Company determined three risks to be critical uncertain factors that would be used in the risk sensitivities of the integrated analysis; load growth, natural gas prices and CO_2 credit prices. The probabilities for both load growth and natural gas are the same as used on all filings since the 2012 Triennial IRP – with Mid 50% and High and Low states at 25% weighted probabilities. For CO_2, the decision states are now modeled as a 40% probability there will be a CO_2 credit market and 60% probability that no CO_2 credit market will exist. The weighted endpoint probability is the product these three weighted probabilities

The Critical Uncertain Factors identified were incorporated into a decision tree representation of the risks that will impact the performance of the alternative resource plans. A graphical representation of the decision tree risks is provided in Figure 6 below:

Figure 6: Critical Uncertain Factors With Decision Tree Probabilities

Endpoint	Load Growth	Natural Gas	CO_2	Endpoint Probability
1	High	High	Yes	2.5%
2	High	High	No	3.8%
3	High	Mid	Yes	5.0%
4	High	Mid	No	7.5%
5	High	Low	Yes	2.5%
6	High	Low	No	3.8%
7	Mid	High	Yes	5.0%
8	Mid	High	No	7.5%
9	Mid	Mid	Yes	10.0%
10	Mid	Mid	No	15.0%
11	Mid	Low	Yes	5.0%
12	Mid	Low	No	7.5%
13	Low	High	Yes	2.5%
14	Low	High	No	3.8%
15	Low	Mid	Yes	5.0%
16	Low	Mid	No	7.5%
17	Low	Low	Yes	2.5%
18	Low	Low	No	3.8%

The company performed an analysis to address the impact of the critical uncertain factors on Preferred Plan selection. This analysis ranks how plans perform relative to the representation of the eighteen endpoint tree. The results of the analysis are represented in the following tables.

7.2.1 CRITICAL UNCERTAIN FACTOR: HIGH LOAD GROWTH

HIGH LOAD GROWTH											
HIGH GAS				MID GAS				LOW GAS			
CO2 YES		CO2 NO		CO2 YES		CO2 NO		CO2 YES		CO2 NO	
Endpoint	1	Endpoint	2	Endpoint	3	Endpoint	4	Endpoint	5	Endpoint	6
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
GBBCS	11,283	GBBCS	10,356	GBBCS	11,190	GBBCS	10,262	GCBCA	11,080	GBBCS	10,160
GBBCA	11,288	GBBCA	10,362	GBBCA	11,196	GBBCA	10,268	GBBCS	11,085	GBBCA	10,167
GAACA	11,349	GAACA	10,421	GCBCA	11,233	GAACA	10,327	GBBCA	11,091	GAACA	10,225
GAACC	11,362	GAACC	10,481	GAACA	11,257	GBBCW	10,385	GAACA	11,152	GBBCW	10,244
GCBCA	11,374	GBBCW	10,521	GAACC	11,290	GAACC	10,411	GDDCA	11,189	GAACC	10,332
GDDCA	11,483	GCBCA	10,644	GDDCA	11,343	GCBCA	10,493	GCBCB	11,194	GCBCA	10,333
GBBCW	11,505	GBBCB	10,674	GCBCB	11,363	GAADA	10,557	GAACC	11,206	GAADA	10,418
GCBCB	11,511	GAADA	10,688	GBBCW	11,374	GBBCB	10,577	GBBCW	11,232	GDDCA	10,442
GBBCB	11,614	GAACB	10,733	GBBCB	11,513	GDDCA	10,601	GBBCB	11,388	GCBCB	10,452
GAADA	11,662	GDDCA	10,750	GAADA	11,538	GCBCB	10,617	GAADA	11,401	GBBCB	10,467
GAACB	11,672	GCBCB	10,767	GAACB	11,571	GAACB	10,636	GAACB	11,446	GAACB	10,525
GCCCA	11,822	GCCCA	11,111	GCCCA	11,652	GCCCA	10,930	GCCCA	11,470	GCCCA	10,743
GAAAA	12,310	GAAAA	11,439	GAAAA	12,251	GAAAA	11,379	GAAAA	12,177	GAAAA	11,311

7.2.2 CRITICAL UNCERTAIN FACTOR: LOW LOAD GROWTH

LOW LOAD GROWTH

HIGH GAS

CO2 YES		CO2 NO	
Endpoint	13	Endpoint	14
PLAN	NPVRR	PLAN	NPVRR
GBBCS	10,708	GBBCS	9,868
GBBCA	10,713	GBBCA	9,874
GAACA	10,771	GAACA	9,931
GCBCA	10,776	GAACC	9,993
GAACC	10,783	GBBCW	10,027
GDDCA	10,881	GCBCA	10,122
GBBCW	10,928	GAADA	10,174
GCBCB	10,929	GBBCB	10,188
GBBCB	11,035	GDDCA	10,221
GAADA	11,070	GAACB	10,246
GAACB	11,093	GCBCB	10,273
GCCCA	11,210	GCCCA	10,576
GAAAA	11,731	GAAAA	10,955

MID GAS

CO2 YES		CO2 NO	
Endpoint	15	Endpoint	16
PLAN	NPVRR	PLAN	NPVRR
GBBCS	10,655	GBBCS	9,816
GBBCA	10,661	GBBCA	9,823
GCBCA	10,679	GAACA	9,880
GAACA	10,719	GBBCW	9,936
GAACC	10,752	GAACC	9,965
GDDCA	10,785	GCBCA	10,019
GCBCB	10,821	GAADA	10,090
GBBCW	10,838	GDDCA	10,119
GBBCB	10,972	GBBCB	10,134
GAADA	10,989	GCBCB	10,168
GAACB	11,030	GAACB	10,192
GCCCA	11,085	GCCCA	10,445
GAAAA	11,710	GAAAA	10,936

LOW GAS

CO2 YES		CO2 NO	
Endpoint	17	Endpoint	18
PLAN	NPVRR	PLAN	NPVRR
GCBCA	10,569	GBBCS	9,758
GBBCS	10,588	GBBCA	9,765
GBBCA	10,594	GAACA	9,823
GAACA	10,653	GBBCW	9,840
GDDCA	10,674	GCBCA	9,908
GCBCB	10,692	GAACC	9,930
GAACC	10,707	GAADA	9,998
GBBCW	10,735	GDDCA	10,008
GBBCB	10,886	GCBCB	10,048
GAADA	10,893	GBBCB	10,066
GAACB	10,944	GAACB	10,124
GCCCA	10,947	GCCCA	10,308
GAAAA	11,674	GAAAA	10,911

7.2.3 CRITICAL UNCERTAIN FACTOR: HIGH NATURAL GAS PRICES

HIGH NATURAL GAS PRICES

HIGH LOAD

CO2 YES		CO2 NO	
Endpoint	1	Endpoint	2
PLAN	NPVRR	PLAN	NPVRR
GBBCS	11,283	GBBCS	10,356
GBBCA	11,288	GBBCA	10,362
GAACA	11,349	GAACA	10,421
GAACC	11,362	GAACC	10,481
GCBCA	11,374	GBBCW	10,521
GDDCA	11,483	GCBCA	10,644
GBBCW	11,505	GBBCB	10,674
GCBCB	11,511	GAADA	10,688
GBBCB	11,614	GAACB	10,733
GAADA	11,662	GDDCA	10,750
GAACB	11,672	GCBCB	10,767
GCCCA	11,822	GCCCA	11,111
GAAAA	12,310	GAAAA	11,439

MID LOAD

CO2 YES		CO2 NO	
Endpoint	7	Endpoint	8
PLAN	NPVRR	PLAN	NPVRR
GBBCS	10,978	GBBCS	10,096
GBBCA	10,983	GBBCA	10,102
GAACA	11,042	GAACA	10,161
GCBCA	11,054	GAACC	10,222
GAACC	11,054	GBBCW	10,257
GDDCA	11,161	GCBCA	10,360
GBBCW	11,198	GAADA	10,412
GCBCB	11,201	GBBCB	10,416
GBBCB	11,306	GDDCA	10,463
GAADA	11,346	GAACB	10,474
GAACB	11,365	GCBCB	10,503
GCCCA	11,493	GCCCA	10,819
GAAAA	12,002	GAAAA	11,181

LOW LOAD

CO2 YES		CO2 NO	
Endpoint	13	Endpoint	14
PLAN	NPVRR	PLAN	NPVRR
GBBCS	10,708	GBBCS	9,868
GBBCA	10,713	GBBCA	9,874
GAACA	10,771	GAACA	9,931
GCBCA	10,776	GAACC	9,993
GAACC	10,783	GBBCW	10,027
GDDCA	10,881	GCBCA	10,122
GBBCW	10,928	GAADA	10,174
GCBCB	10,929	GBBCB	10,188
GBBCB	11,035	GDDCA	10,221
GAADA	11,070	GAACB	10,246
GAACB	11,093	GCBCB	10,273
GCCCA	11,210	GCCCA	10,576
GAAAA	11,731	GAAAA	10,955

7.2.4 CRITICAL UNCERTAIN FACTOR: LOW NATURAL GAS PRICES

LOW NATURAL GAS PRICES

	CO2 YES		CO2 NO	
HIGH LOAD	Endpoint	5	Endpoint	6
	PLAN	NPVRR	PLAN	NPVRR
	GCBCA	11,080	GBBCS	10,160
	GBBCS	11,085	GBBCA	10,167
	GBBCA	11,091	GAACA	10,225
	GAACA	11,152	GBBCW	10,244
	GDDCA	11,189	GAACC	10,332
	GCBCB	11,194	GCBCA	10,333
	GAACC	11,206	GAADA	10,418
	GBBCW	11,232	GDDCA	10,442
	GBBCB	11,388	GCBCB	10,452
	GAADA	11,401	GBBCB	10,467
	GAACB	11,446	GAACB	10,525
	GCCCA	11,470	GCCCA	10,743
	GAAAA	12,177	GAAAA	11,311

	CO2 YES		CO2 NO	
MID LOAD	Endpoint	11	Endpoint	12
	PLAN	NPVRR	PLAN	NPVRR
	GCBCA	10,808	GBBCS	9,946
	GBBCS	10,820	GBBCA	9,953
	GBBCA	10,827	GAACA	10,011
	GAACA	10,886	GBBCW	10,029
	GDDCA	10,914	GCBCA	10,103
	GCBCB	10,927	GAACC	10,118
	GAACC	10,940	GAADA	10,193
	GBBCW	10,968	GDDCA	10,207
	GBBCB	11,121	GCBCB	10,237
	GAADA	11,130	GBBCB	10,254
	GAACB	11,179	GAACB	10,311
	GCCCA	11,190	GCCCA	10,506
	GAAAA	11,909	GAAAA	11,097

	CO2 YES		CO2 NO	
LOW LOAD	Endpoint	17	Endpoint	18
	PLAN	NPVRR	PLAN	NPVRR
	GCBCA	10,569	GBBCS	9,758
	GBBCS	10,588	GBBCA	9,765
	GBBCA	10,594	GAACA	9,823
	GAACA	10,653	GBBCW	9,840
	GDDCA	10,674	GCBCA	9,908
	GCBCB	10,692	GAACC	9,930
	GAACC	10,707	GAADA	9,998
	GBBCW	10,735	GDDCA	10,008
	GBBCB	10,886	GCBCB	10,048
	GAADA	10,893	GBBCB	10,066
	GAACB	10,944	GAACB	10,124
	GCCCA	10,947	GCCCA	10,308
	GAAAA	11,674	GAAAA	10,911

7.2.5 CRITICAL UNCERTAIN FACTOR: CO_2 - YES

CO_2 YES CREDIT PRICES

HIGH LOAD

HIGH GAS		MID GAS		LOW GAS	
Endpoint	1	Endpoint	3	Endpoint	5
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
GBBCS	11,283	GBBCS	11,190	GCBCA	11,080
GBBCA	11,288	GBBCA	11,196	GBBCS	11,085
GAACA	11,349	GCBCA	11,233	GBBCA	11,091
GAACC	11,362	GAACA	11,257	GAACA	11,152
GCBCA	11,374	GAACC	11,290	GDDCA	11,189
GDDCA	11,483	GDDCA	11,343	GCBCB	11,194
GBBCW	11,505	GCBCB	11,363	GAACC	11,206
GCBCB	11,511	GBBCW	11,374	GBBCW	11,232
GBBCB	11,614	GBBCB	11,513	GBBCB	11,388
GAADA	11,662	GAADA	11,538	GAADA	11,401
GAACB	11,672	GAACB	11,571	GAACB	11,446
GCCCA	11,822	GCCCA	11,652	GCCCA	11,470
GAAAA	12,310	GAAAA	12,251	GAAAA	12,177

MID LOAD

HIGH GAS		MID GAS		LOW GAS	
Endpoint	7	Endpoint	9	Endpoint	11
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
GBBCS	10,978	GBBCS	10,906	GCBCA	10,808
GBBCA	10,983	GBBCA	10,912	GBBCS	10,820
GAACA	11,042	GCBCA	10,937	GBBCA	10,827
GCBCA	11,054	GAACA	10,971	GAACA	10,886
GAACC	11,054	GAACC	11,004	GDDCA	10,914
GDDCA	11,161	GDDCA	11,044	GCBCB	10,927
GBBCW	11,198	GCBCB	11,075	GAACC	10,940
GCBCB	11,201	GBBCW	11,089	GBBCW	10,968
GBBCB	11,306	GBBCB	11,226	GBBCB	11,121
GAADA	11,346	GAADA	11,244	GAADA	11,130
GAACB	11,365	GAACB	11,284	GAACB	11,179
GCCCA	11,493	GCCCA	11,348	GCCCA	11,190
GAAAA	12,002	GAAAA	11,962	GAAAA	11,909

LOW LOAD

HIGH GAS		MID GAS		LOW GAS	
Endpoint	13	Endpoint	15	Endpoint	17
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
GBBCS	10,708	GBBCS	10,655	GCBCA	10,569
GBBCA	10,713	GBBCA	10,661	GBBCS	10,588
GAACA	10,771	GCBCA	10,679	GBBCA	10,594
GCBCA	10,776	GAACA	10,719	GAACA	10,653
GAACC	10,783	GAACC	10,752	GDDCA	10,674
GDDCA	10,881	GDDCA	10,785	GCBCB	10,692
GBBCW	10,928	GCBCB	10,821	GAACC	10,707
GCBCB	10,929	GBBCW	10,838	GBBCW	10,735
GBBCB	11,035	GBBCB	10,972	GBBCB	10,886
GAADA	11,070	GAADA	10,989	GAADA	10,893
GAACB	11,093	GAACB	11,030	GAACB	10,944
GCCCA	11,210	GCCCA	11,085	GCCCA	10,947
GAAAA	11,731	GAAAA	11,710	GAAAA	11,674

7.2.6 CRITICAL UNCERTAIN FACTOR: CO_2 - NO

CO_2 NO CREDIT PRICES

HIGH LOAD

HIGH GAS		MID GAS		LOW GAS	
Endpoint	2	Endpoint	4	Endpoint	6
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
GBBCS	10,356	GBBCS	10,262	GBBCS	10,160
GBBCA	10,362	GBBCA	10,268	GBBCA	10,167
GAACA	10,421	GAACA	10,327	GAACA	10,225
GAACC	10,481	GBBCW	10,385	GBBCW	10,244
GBBCW	10,521	GAACC	10,411	GAACC	10,332
GCBCA	10,644	GCBCA	10,493	GCBCA	10,333
GBBCB	10,674	GAADA	10,557	GAADA	10,418
GAADA	10,688	GBBCB	10,577	GDDCA	10,442
GAACB	10,733	GDDCA	10,601	GCBCB	10,452
GDDCA	10,750	GCBCB	10,617	GBBCB	10,467
GCBCB	10,767	GAACB	10,636	GAACB	10,525
GCCCA	11,111	GCCCA	10,930	GCCCA	10,743
GAAAA	11,439	GAAAA	11,379	GAAAA	11,311

MID LOAD

HIGH GAS		MID GAS		LOW GAS	
Endpoint	8	Endpoint	10	Endpoint	12
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
GBBCS	10,096	GBBCS	10,025	GBBCS	9,946
GBBCA	10,102	GBBCA	10,032	GBBCA	9,953
GAACA	10,161	GAACA	10,089	GAACA	10,011
GAACC	10,222	GBBCW	10,146	GBBCW	10,029
GBBCW	10,257	GAACC	10,174	GCBCA	10,103
GCBCA	10,360	GCBCA	10,236	GAACC	10,118
GAADA	10,412	GAADA	10,307	GAADA	10,193
GBBCB	10,416	GDDCA	10,339	GDDCA	10,207
GDDCA	10,463	GBBCB	10,341	GCBCB	10,237
GAACB	10,474	GCBCB	10,378	GBBCB	10,254
GCBCB	10,503	GAACB	10,400	GAACB	10,311
GCCCA	10,819	GCCCA	10,666	GCCCA	10,506
GAAAA	11,181	GAAAA	11,143	GAAAA	11,097

LOW LOAD

HIGH GAS		MID GAS		LOW GAS	
Endpoint	14	Endpoint	16	Endpoint	18
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
GBBCS	9,868	GBBCS	9,816	GBBCS	9,758
GBBCA	9,874	GBBCA	9,823	GBBCA	9,765
GAACA	9,931	GAACA	9,880	GAACA	9,823
GAACC	9,993	GBBCW	9,936	GBBCW	9,840
GBBCW	10,027	GAACC	9,965	GCBCA	9,908
GCBCA	10,122	GCBCA	10,019	GAACC	9,930
GAADA	10,174	GAADA	10,090	GAADA	9,998
GBBCB	10,188	GDDCA	10,119	GDDCA	10,008
GDDCA	10,221	GBBCB	10,134	GCBCB	10,048
GAACB	10,246	GCBCB	10,168	GBBCB	10,066
GCBCB	10,273	GAACB	10,192	GAACB	10,124
GCCCA	10,576	GCCCA	10,445	GCCCA	10,308
GAAAA	10,955	GAAAA	10,936	GAAAA	10,911

7.2.7 CRITICAL UNCERTAIN FACTORS – SUMMARY AND EVALUATION

This summary table, Table 46, provides the expected value for NPVRR across the eighteen endpoint tree by plan and the value for NPVRR for the mid-load, mid-gas and no-CO_2 scenario, Endpoint 9.

Table 46: Alternative Resource Plan NPVRRs

Expected Value	EV		Endpoint	9	
PLAN	NPVRR	DELTA	PLAN	NPVRR	DELTA
GBBCS	10,382	-	GBBCS	10,906	-
GBBCA	10,389	6	GBBCA	10,912	6
GAACA	10,447	65	GCBCA	10,937	31
GAACC	10,511	129	GAACA	10,971	65
GCBCA	10,524	141	GAACC	11,004	98
GBBCW	10,529	146	GDDCA	11,044	139
GDDCA	10,629	246	GCBCB	11,075	169
GCBCB	10,660	278	GBBCW	11,089	183
GAADA	10,688	306	GBBCB	11,226	320
GBBCB	10,698	316	GAADA	11,244	339
GAACB	10,756	374	GAACB	11,284	378
GCCCA	10,947	565	GCCCA	11,348	442
GAAAA	11,476	1,094	GAAAA	11,962	1,056

Table 47 below provides the Alternative Resource Plan that had the lowest NPVRR for each endpoint scenario.

Table 47: Endpoint/Lowest NPVRR Alternative Resource Plan

EP	Plan	NPVRR	Conditional Probability
1	GBBCS	11,283	2.5%
2	GBBCS	10,356	3.8%
3	GBBCS	11,190	5.0%
4	GBBCS	10,262	7.5%
5	GCBCA	11,080	2.5%
6	GBBCS	10,160	3.8%
7	GBBCS	10,978	5.0%
8	GBBCS	10,096	7.5%
9	GBBCS	10,906	10.0%
10	GBBCS	10,025	15.0%
11	GCBCA	10,808	5.0%
12	GBBCS	9,946	7.5%
13	GBBCS	10,708	2.5%
14	GBBCS	9,868	3.8%
15	GBBCS	10,655	5.0%
16	GBBCS	9,816	7.5%
17	GCBCA	10,569	2.5%
18	GBBCS	9,758	3.8%

The sum of the joint probabilities and the count of the number of times an Alternative Resource Plan is the low cost scenario endpoint is as follows:

Table 48: Cumulative Probabilities of Lowest NPVRR Plans

Plan	Conditional Probability	Count
GBBCS	90.0%	15
GCBCA	10.0%	3

7.3 IMPLEMENTATION PLAN

The Implementation Plan provided in the 2015 Triennial IRP has not materially changed. However, the option for 50 MW wind generation at Gray County was not exercised due to the expected transmission upgrade cost. The 2017 wind generation additions consist of an additional 200 MW of wind and renewal of a 60 MW wind PPA. Both of these wind resources were disclosed in the 2015 Triennial IRP and are still part of the current Implementation Plan. Also, the Implementation Plan includes solar resource additions in 2016 consisting of ownership in 2 MW Commercial and Industrial rooftop installations and a 3 MW central station solar facility. The 3 MW company-owned solar facility will be located at the Greenwood Energy Center and has been granted a Certificate of Public Convenience and Necessity in Case No. EA-2015-0256.

The Demand-Side Management program schedule has been updated and the current schedule is provided in Table 49 below.

7.3.1 DEMAND-SIDE MANAGEMENT SCHEDULE

The current schedule for planned DSM programs is shown in Table 49 below:

Table 49: DSM Program Schedule

Program Name	DSM Type	New or Existing	Segment	Program Implemented	Annual Report	EM&V Completed and draft report available
Home Lighting Rebate	Energy Efficiency	New	Residential	Apr., 2016*	90-days following Plan Year	1-Yr following Plan Year
Home Appliance Recycling Rebate	Energy Efficiency	New	Residential	Apr., 2016*	90-days following Plan Year	1-Yr following Plan Year
Home Energy Report	Energy Efficiency	New	Residential	Apr., 2016*	90-days following Plan Year	1-Yr following Plan Year
Online Home Energy Audit	Educational	New	Residential	Apr., 2016*	90-days following Plan Year	1-Yr following Plan Year
Whole House Efficiency	Energy Efficiency	New	Residential	Apr., 2016*	90-days following Plan Year	1-Yr following Plan Year
Income-Eligible Multi-Family	Energy Efficiency	New	Residential	Apr., 2016*	90-days following Plan Year	1-Yr following Plan Year
Income-Eligible Weatherization**	Energy Efficiency	New	Residential	Apr., 2016*	90-days following Plan Year	1-Yr following Plan Year
Residential Programmable Thermostat	Demand Response	New	Residential	Apr., 2016*	90-days following Plan Year	1-Yr following Plan Year
Business Energy Efficiency Rebate - Standard	Energy Efficiency	New	C&I	Apr., 2016*	90-days following Plan Year	1-Yr following Plan Year
Business Energy Efficiency Rebate - Custom	Energy Efficiency	New	C&I	Apr., 2016*	90-days following Plan Year	1-Yr following Plan Year
Strategic Energy Management	Energy Efficiency	New	C&I	Apr., 2016*	90-days following Plan Year	1-Yr following Plan Year
Block Bidding	Energy Efficiency	New	C&I	Apr., 2016*	90-days following Plan Year	1-Yr following Plan Year
Online Business Energy Audit	Educational	New	C&I	Apr., 2016*	90-days following Plan Year	1-Yr following Plan Year
Small Business Direct Install	Energy Efficiency	New	C&I	Apr., 2016*	90-days following Plan Year	1-Yr following Plan Year
Commercial Programmable Thermostat	Demand Response	New	C&I	Apr., 2016*	90-days following Plan Year	1-Yr following Plan Year
Demand Response Incentive	Demand Response	New	C&I	Apr., 2016*	90-days following Plan Year	1-Yr following Plan Year
*On February 24, 2016, the Commission voted in favor of the Company's MEEIA cycle 2 plan. The Company is awaiting an Order from the Commission.						
**1-year only						

SECTION 8: SPECIAL CONTEMPORARY ISSUES

From the Commission Order, EO-2016-0038, the following Special Contemporary Resource Planning Issues are addressed as follows:

8.1 IMPACTS OF EMERGING ENERGY EFFICIENCY TECHNOLOGIES

Review the impact of foreseeable emerging energy efficiency technologies throughout the 20-year planning period.

Response:

In 2015, GMO engaged the Applied Energy Group (AEG) to conduct a Demand Side Management (DSM) Resource Potential Study which will be completed in 2017 and will be used in developing the 2018 Triennial IRP. This question gets at the heart of what the overall purpose of the DSM potential study is, which is the review and analysis of all possible impacts from demand-side resources, especially emerging technologies, programs, and initiatives that will have incremental effects on the planning cycle in years to come. The DSM potential study will include the effects of improved and emerging technologies expected over the 20-year IRP planning horizon. The following sections describe the processes AEG incorporates in tracking, reviewing, and analyzing the impacts of emerging energy efficiency technologies

AEG's Continuous In-House Research of Emerging Technologies

AEG is constantly monitoring the trends and feasibility of technologies that are available on the market as well as those expected to be on the market in the coming years (e.g. super-efficient air conditioners, cutting-edge LED lighting technologies, heat pump water heaters, heat pump clothes dryers, behavioral programs, combined heat and power initiatives, the effects of codes and standards, electric vehicles, etc).

AEG staff are currently active participants in several formalized and ongoing stakeholder processes to review, analyze, and package the latest measure assumptions for use in utility

DSM programs; including as members of the Pacific Northwest's Regional Technical Forum, the California Technical Forum, and the Illinois TRM Technical Advisory Committee. AEG participation in each of these groups, as well as ongoing work with utility and government clients around the country, allows them to stay on the cutting edge in terms of emerging technologies and technologies that are new to the market. The AEG measure-development approach and LoadMAP model allow for technologies to enter program portfolios whenever they become viable and cost-effective throughout the multi-year time horizon.

Measure Development in General

As a centralized and consistent source to use across all of the planning, implementation, and evaluation consulting projects, AEG has developed and maintained a Database of Energy Efficiency Measures (DEEM) since 2004. DEEM is a comprehensive database that includes highly-detailed information on thousands of DSM measures and emerging technologies applicable to residential, commercial, and industrial customer segments. The key data points it contains which can be used to support analysis include:

- Unit energy and peak demand savings
- Measure replacement and installation costs (capital cost, incremental cost, annual operating and maintenance costs, etc.)
- Measure life
- Baseline characteristics (early retirement, normal replacement, applicable codes & standards)
- Non-energy benefits (water savings, health improvements, productivity gains, increased comfort, etc.)
- Applicability (market sector, geographic region, etc.)
- An AEG-internal measurement of data source quality, based on publication/review process, calculations, thoroughness, and other factors

DEEM is updated continually to reflect the most recent source material and state-of-the-art technological advancements. Each database entry is meticulously referenced to document the original source containing the measure information. Key sources compiled and assembled inside DEEM include:

- U.S. Department of Energy National Laboratories (PNNL, ORNL, NREL)
- U.S. Energy Information Administration (Annual Energy Outlook)
- State and regional technical reference manuals (TRM)
- Northwest Power & Conservation Council's Regional Technical Forum (RTF) workbooks
- California's Database for Energy Efficient Resources (DEER)
- RSMeans Cost Data Books
- Building simulation data
- AEG and third-party evaluation and market research reports

Use of Emerging Technologies in the DSM Potential Study

The definition of "emerging technology" when identifying and including specific measures in DSM potential studies is that a technology or practice is known and quantifiable, but is somewhere early on the adoption curve. While more time may be required to prove a measure's effects through evaluations, billing analysis, and other appropriate methods; if estimates of the measure parameters discussed above can be developed with sufficient quality for the purposes of resource planning, they will be included in the analysis. This may mean a given emerging technology is in the labs (e.g. higher lumen-per-watt evolutions of LED lamps), common in other countries but not yet the U.S. (e.g. heat pump clothes dryers), or is being piloted by utility programs before mainstream adoption has occurred (e.g. smart, internet-enabled thermostats).

This categorization frequently includes subjectivity, however, as sometimes hard and fast rules cannot be applied. This is why AEG conducts a thorough review process with both its clients and its client's external stakeholders. The measure list is distributed and discussed to ensure that all parties have been able to provide input and suggestions toward appropriately characterizing the portfolio of DSM resources.

As with any forecasting activity, assumptions and landscapes will change on an ongoing basis, and should be revisited regularly. Refreshing and revising DSM potential studies every 2 to 4 years allows these changes to be incorporated such that resource acquisition plans can be adjusted accordingly.

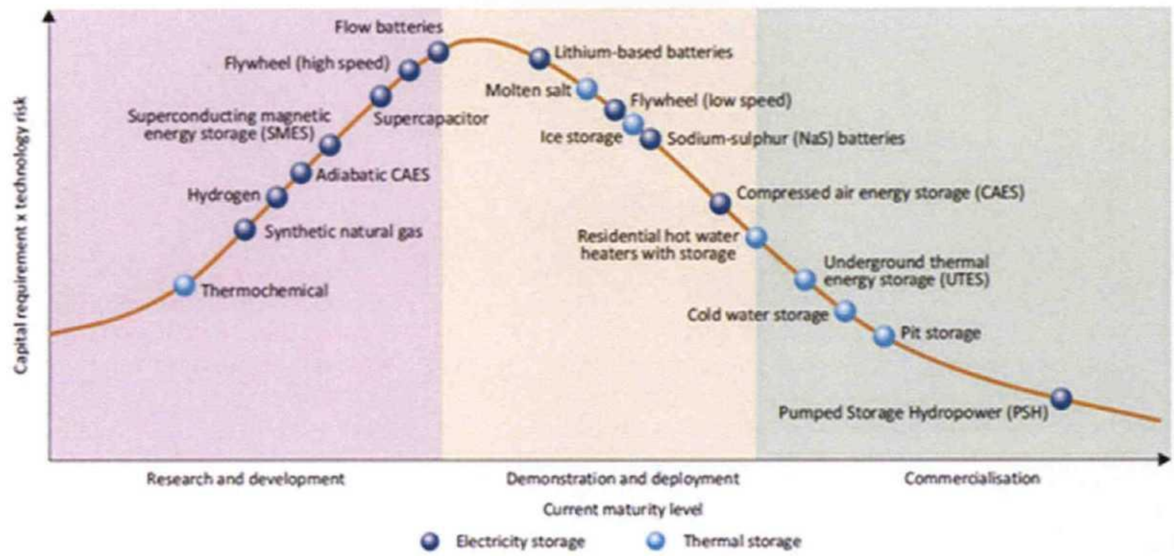
8.2 IMPACTS OF EMERGING ENERGY STORAGE TECHNOLOGIES

Review the impact of foreseeable emerging energy storage technologies throughout the 20-year planning period.

Response: Energy Storage Technologies and Future Potential Needs

The International Energy Agency's (IEA) '2014 Technology Roadmap: Energy Storage' incorporated the following depiction of the maturity of emerging electricity and thermal energy storage technologies. This diagram, Figure 7, shows that GMO's 2015 Triennial IRP screening incorporated the three most mature electric storage technologies; pumped storage hydropower (PSH), compressed air energy storage (CAES), and sodium-sulfur (NaS) batteries. The diagram also identified flywheels, lithium based and flow batteries as electric storage technologies that have emerged from the research and development stage and are progressing toward commercialization. Since this study has been published, lithium based and flow batteries have continued to make significant progress along this maturity curve and are rapidly becoming commercially viable.

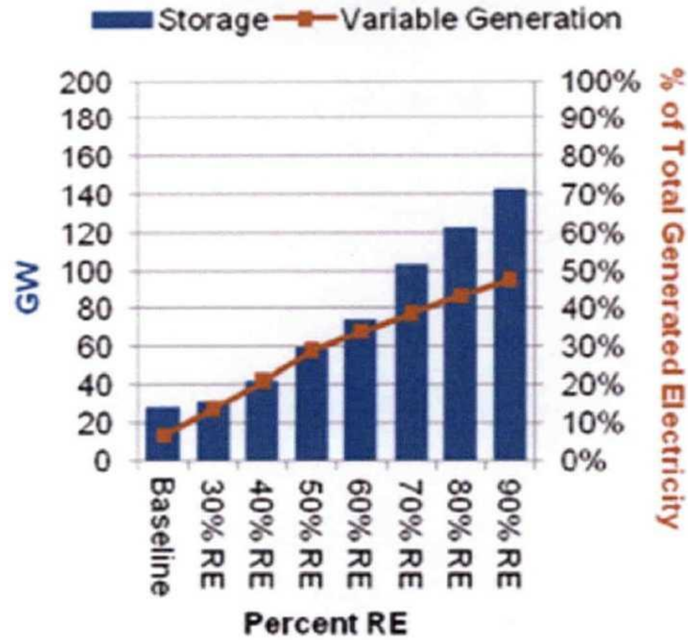
Figure 7: Maturity of Energy Storage Technologies



Source: Decourt, B. and R. Debarre (2013), "Electricity storage", *Factbook*, Schlumberger Business Consulting Energy Institute, Paris, France and Paksoy, H. (2013), "Thermal Energy Storage Today" presented at the IEA Energy Storage Technology Roadmap Stakeholder Engagement Workshop, Paris, France, 14 February.

The National Renewable Energy Laboratory (NREL) 2012 "Renewable Electricity Futures Study" projects that the total installed electricity storage capacity in the US could grow to between 103 GW and 152 GW in 2050. By 2050, storage capacity was estimated at 28 GW in the Low-Demand Baseline scenario, 31 GW in the 30% RE scenario, 74 GW in the 60% RE scenario, and 142 GW in the 90% RE scenario. Figure 8, illustrates how the magnitude of storage will grow as variable generation as a percent of total electric generation increases. Based on these NREL projections, minimal additional electricity storage would be required for bulk energy services in the 30% renewable energy scenario. With the combined KCP&L/GMO preferred resource plan, current projections are that renewable generation will not exceed 20% of our energy production portfolio throughout the planning period, significantly below the 30% level.

Figure 8: Storage Capacity in 2050



The KCP&L SmartGrid Demonstration project incorporated the demonstration and operational testing of the lithium-ion battery storage technology in a 1.0 MW/1.0 MWh Bulk Energy Storage System (BESS) and a 6.0 kW/11.2 kWh Premise Energy Storage System (PESS). GMO will continue to track the development and costs of these technologies, as well as the potential to use energy storage with renewable integration, for future resource planning.

Energy Storage – The Falling Cost of Storage

The energy storage technologies included in the 2015 IRP Supply Side Resource prescreening process were compressed air energy storage (CAES), pumped hydro, and sodium sulfur (NaS) batteries. Due to their relatively high cost (the NaS Battery ranked 20th in both the Technology Ranking by Nominal Utility Cost and Probable Environmental Cost analysis), along with the early development stage and limited commercial utility application, these energy storage technologies were not passed on to the integrated resource analysis.

Several recent studies are projecting significant reductions in the cost of battery energy storage technology by 2020. In 2014, the Brattle Group published the findings of a study they performed for Oncor in a report titled "The Value of Distributed Electricity Storage in Texas". This report cites several studies that project the installed cost of battery energy storage will drop to $350/kWh by 2020, with the battery only component of the cost of being $200/kWh. The study also indicated that battery only costs could reach $110 /kWh if the low cost GigaFactory production projections by Tesla Motors, Inc. are realized.

More recently, in October 2015, Goldman Sachs published an Equity Research document entitled 'The Great Battery Race – Framing the next frontier in clean technology – Electrical Energy Storage' in which they projected that battery pack costs will approach $125 - $200 per kWh by 2020, further validating the drop in battery storage costs projected by Brattle Group in the Oncor study.

The Oncor study used an installed cost of $350/kWh for energy storage systems configured with 3.0 MWh of energy storage for each MW of capacity. Based on the Oncor cost projections, a lithium battery storage system configured similarly (1.0 MW/6.0 MWh ratio) to the NaS system evaluated in the 2015 IRP would have a projected installed cost of $1,650/kW, approximately half that of the NaS battery cost of $3,549/kW.

These and other electricity storage technologies will continue to be monitored and evaluated for their economic viability and impact on future resource plans.

Energy Storage as a Supply-Side Resource

In 2014, the Brattle Group published the findings of a study they performed for Oncor in a report titled "The Value of Distributed Electricity Storage in Texas". This study incorporated the significant reduction in battery storage projected to be achieved by 2020. The following excerpts summarize the findings of the Oncor study:

> *"Our analysis shows that deploying electricity storage on distribution systems across Texas could provide substantial net benefits to the state. ...*

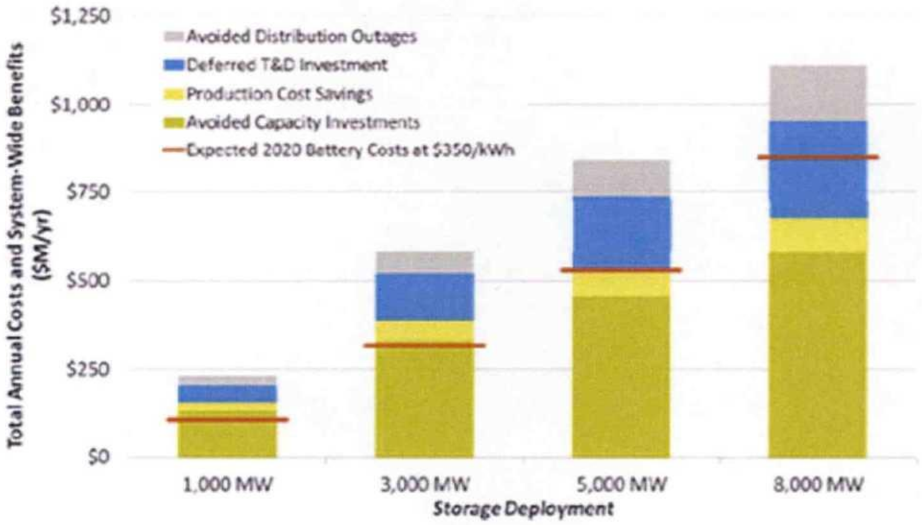
"Our analysis assumes that the storage deployment plan will be developed to capture as much benefits as possible by integrating value from increasing customer reliability, improving the T&D systems, and transacting in the wholesale power markets. ..."

"However, while beneficial from an integrated, system-wide perspective, an efficient scale of storage deployment would not be reached if deployed solely by merchant developers in the wholesale market, by retail customers, or only for capturing T&D benefits."

These findings are consistent with many other industry benefit cost assessments in that they show that, for the foreseeable future, to be economically viable, storage systems must be deployed in a manner by which they can achieve multiple value streams. Figure 9 illustrates the levelized annual cost and benefit component estimated in the study. In each scenario, the benefits derived from Avoided Capacity Investments make up the bulk of the resulting benefits.

Through KCP&L's SmartGrid Demonstration experience, GMO learned that care must be taken to ensure that the kW and kWh components are 'sized' properly for any specific application. A properly 'sized' energy storage component as a percentage of energy capacity varies considerably by application. For some ancillary services applications like frequency regulation, an energy storage system may only require 1.0 MWh or less of energy storage for each MW of capacity. While others like Energy Time Shift or Arbitrage may require 6-8 MWh of energy storage for each MW of capacity.

Figure 9: Value of Distributed Electric Storage in Texas Findings



<u>Energy Storage as a Demand Side Resource</u>

Increasingly customers are investigating the potential of premise sighted storage often stemming from reliability/resiliency issues and concerns about the loss of utility power for extended periods. The DOE/EPRI 2013 'Electricity Storage Handbook in Collaboration with NRECA' and the DOE Smart Grid Computational Tool have identified the following potential benefit areas of electric energy storage systems when installed behind the customer meter, often in conjunction with solar PV generation systems.

Customer Energy Management Services Benefit Areas

- Power Quality
- Power Reliability & Resiliency
- Retail Energy Time Shift (/TOU)
- Demand Charge Management
- Renewable Energy Time Shift (w/TOU)
- DR Program Participation

Utility Benefit Areas of Demand Side Electric Storage

- Electric Supply Capacity (Peak Shaving)
- Optimized Generation Operation
- Distribution Upgrade Deferral
- Distribution Voltage Support

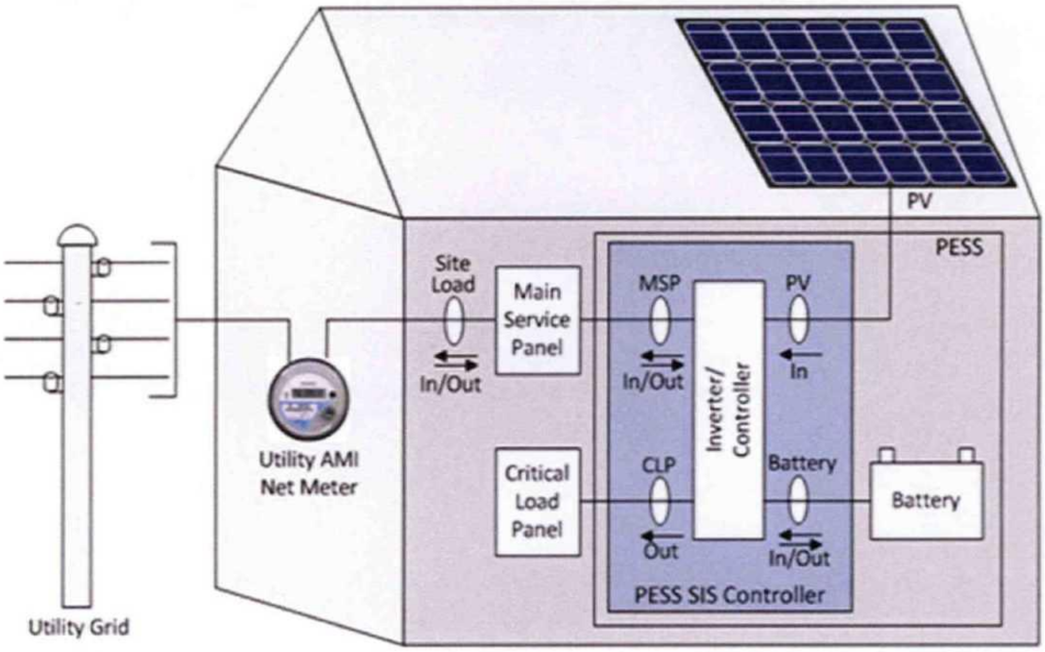
Electricity storage can be used for any of the benefit areas listed above, but it is rare for a single area to generate sufficient revenue to justify its investment. However, the flexibility of storage can be leveraged to provide multiple or stacked benefits to the customer and utility, with a single storage system that captures several revenue streams and becomes economically viable. How these services can be stacked depends on the location of the system within the grid and the storage technology used.

As part of the SmartGrid Demonstration Project, KCP&L incorporated a consumer Premise Energy Storage System (PESS) was installed at the SmartGrid Demonstration House in conjunction with the 2.82 kW solar PV array. The PESS consists of an 11.7 kWh lithium-ion battery with a unique hybrid inverter/converter rated for 6.0 kW discharge. The PESS was configured as illustrated in Figure 10 and was used to demonstrate and quantify the benefits derived from three typical end-use functions:

- Time-of-Use Energy Cost Management
- Renewable Energy Time Shift
- Electric Service Reliability

The analysis of these operational demonstrations was published in the 'KCP&L Green Impact Zone SmartGrid Demonstration Project Final Technical Report, version 2.0, dated May 22, 2015. This report is attached to this Annual Update as Appendix C.

Figure 10: PESS Installation at SmartGrid Demonstration House



The installed cost of the SmartGrid Demonstration PESS was approximately $25,000 or $4,165/kW ($2,135/kWh) of electric energy storage capacity. As battery energy storage costs drop, demand side storage systems like the SmartGrid Demonstration PESS become more economically viable. In Morgan Stanley's 2014 'Blue Paper on Solar Power & Energy Storage' they project that by 2020 the total installed cost of a similarly configured PESS at $8,625 cost, but could go as low as $4,260. At these cost points, if the proper pricing programs are available and by leveraging multiple benefit streams, PESS may become an economical investment for some customers. It will depend largely on the value the individual customer places on continuity of electric supply during electric grid power outages.

GMO will continue to monitor demand side energy storage costs and trends and will incorporate these technologies and systems in future demand side potential studies.

8.3 ENVIRONMENTAL CAPITAL AND OPERATING COSTS FOR COAL-FIRED GENERATING UNITS

Analyze and document the future capital and operating costs faced by each GMO coal-fired generating unit in order to comply with the following environmental standards:

(1) **Clean Air Act New Source Review provisions:** The Company reviews proposed generation projects and permits these projects, as necessary, to comply with rule.

(2) **1-hour Sulfur Dioxide National Ambient Air Quality Standard:** See Table 50, Table 51, and Table 52.

(3) **National Ambient Air Quality Standards for ozone and fine particulate matter:** See Table 50, Table 51, and Table 52.

(4) Cross-State Air Pollution Rule, including the anticipated 2016 update to the rule to incorporate interstate transport requirements for the 2008 ozone National Ambient Air Quality Standard:

The Company will comply through a combination of trading allowances within or outside its system in addition to changes in operations as necessary.

(5) **Clean Air Interstate Rule:** This rule has been superseded by the Cross-State Air Pollution Rule.

(6) **Mercury and Air Toxics Standards:** See Table 50, Table 51, and Table 52.

(7) **Clean Water Act Section 316(b) Cooling Water Intake Standards:** See Table 50, Table 51, and Table 52.

(8) **Clean Water Act Steam Electric Effluent Limitation Guidelines:** See Table 50, Table 51, and Table 52.

(9) **Coal Combustion Waste rules:** See Table 50, Table 51, and Table 52.

(10) **Clean Air Act Section 111(d) Greenhouse Gas standards for existing sources:** See "Clean Power Plan" discussion below.

(11) **Clean Air Act Regional Haze Requirements:** The Company is in compliance with this rule.

Table 50: Environmental Capital Cost Estimates ** Highly Confidential **

Environmental Retrofit Technology Capital Costs (2015 $ x Millions)	Lake Road 4/6	Sibley 1	Sibley 2	Sibley 3	Iatan 1 [1]
MATS/Activated Carbon Injection	[redacted]				
MATS/ESP Rebuild					
PM and SO_2 NAAQS/Scrubber/BH					
CWA 316(b)/Fish-Friendly Screens					
CWA 316(a)/Cooling Tower					
ELG-CCR/Ash Conversion					

Notes
NA = Not Applicable
Equipment Installed
R = Retired before Rule is promulgated
MATS = Mercury and Air Toxics Standard
NAAQS = National Ambient Air Quality Standards
ELG = Effluent Limitation Guidelines
CCR = Coal Combustion Residual Rules
CWA = Clean Water Act
[1] GMO's Share

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Table 51: Environmental Fixed O&M Estimates ** Highly Confidential **

Environmental Retrofit Technology Fixed O&M ($/kW - 2015 $)	Lake Road 4/6	Sibley 1	Sibley 2	Sibley 3	Iatan 1
MATS/Activated Carbon Injection	[redacted]				
MATS/ESP Rebuild					
PM and SO_2 NAAQS/Scrubber/BH					
CWA 316(b)/Fish-Friendly Screens					
CWA 316(a)/Cooling Tower					
ELG-CCR/Ash Conversion					

Notes
NA = Not Applicable
Equipment Installed
R=Retired before Rule is promulgated
MATS = Mercury and Air Toxics Standard
NAAQS = National Ambient Air Quality Standards
ELG = Effluent Limitation Guidelines
CCR = Coal Combustion Residual Rules
CWA = Clean Water Act

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Table 52: Environmental Variable O&M Estimates ** Highly Confidential **

Environmental Retrofit Technology Variable O&M ($/MWh - 2015 $)	Lake Road 4/6	Sibley 1	Sibley 2	Sibley 3	Iatan 1
MATS/Activated Carbon Injection	[redacted]				
MATS/ESP Rebuild					
PM and SO_2 NAAQS/Scrubber/BH					
CWA 316(b)/Fish-Friendly Screens					
CWA 316(a)/Cooling Tower					
EGL-CCR/Ash Conversion					

Notes
NA = Not Applicable
✓ Equipment Installed
R=Retired before Rule is promulgated
MATS = Mercury and Air Toxics Standard
NAAQS = National Ambient Air Quality Standards
ELG = Effluent Limitation Guidelines
CCR = Coal Combustion Residual Rules
CWA = Clean Water Act

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(12) **Clean Power Plan:** Issued by the EPA in August 2015, the Clean Power Plan ("CPP") regulations seek to reduce CO_2 emissions from certain power plants by 32% from 2005 levels by 2030. It does so by imposing CO_2 reduction obligations on existing power plants based on what EPA identified as the "Best System of Emission Reductions". States are expected to develop State Implementation Plans ("SIPs") that will ensure that the state meets its CO_2 reduction obligations. Reductions are to start in 2022 with further reductions phased in through 2030. States may choose a mass-based or rate-based compliance structure. A mass-based structure sets state CO_2 emission targets in terms of total tons emitted from covered resources. A rate-based structure sets state targets based on pounds of CO_2 emitted per MWh generated. The CPP requires initial SIPs to be submitted to the EPA by September 2016, with final SIPs due by September 2018. On February 9, 2016, the Supreme Court issued a stay of the CPP until legal challenges can be addressed. Some states have indicated that no further work will be done on SIP development until the stay is lifted.

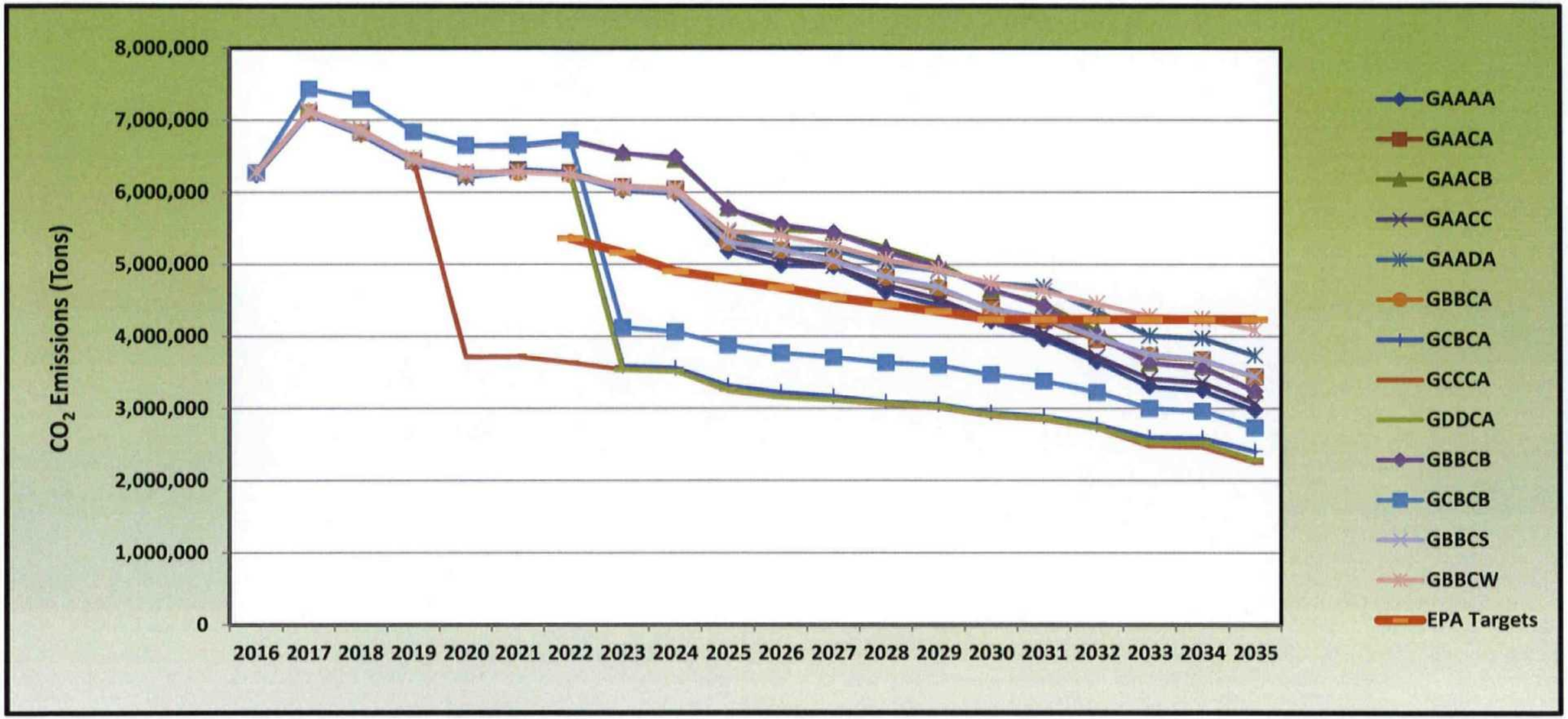
GMO has attempted to analyze the potential CPP impacts on its resource plans. Since the CPP State Implementation Plans have yet to be developed and approved, a number of important assumptions were required to perform this analysis. These assumptions include:

- A mass-based compliance structure
- When CO_2 emission allowances are allocated, the allocations are based on a utility's share of 2012 emissions relative to state total emissions from covered resources
- No emission allowance set-asides for new renewable generation, new non-renewable generation or energy efficiency programs
- A CO_2 emission allowance trading market is established
- Regional wholesale electric market prices based on CO_2 emission allowances applied to covered resources

GMO CPP Analysis Results – CO_2 emissions

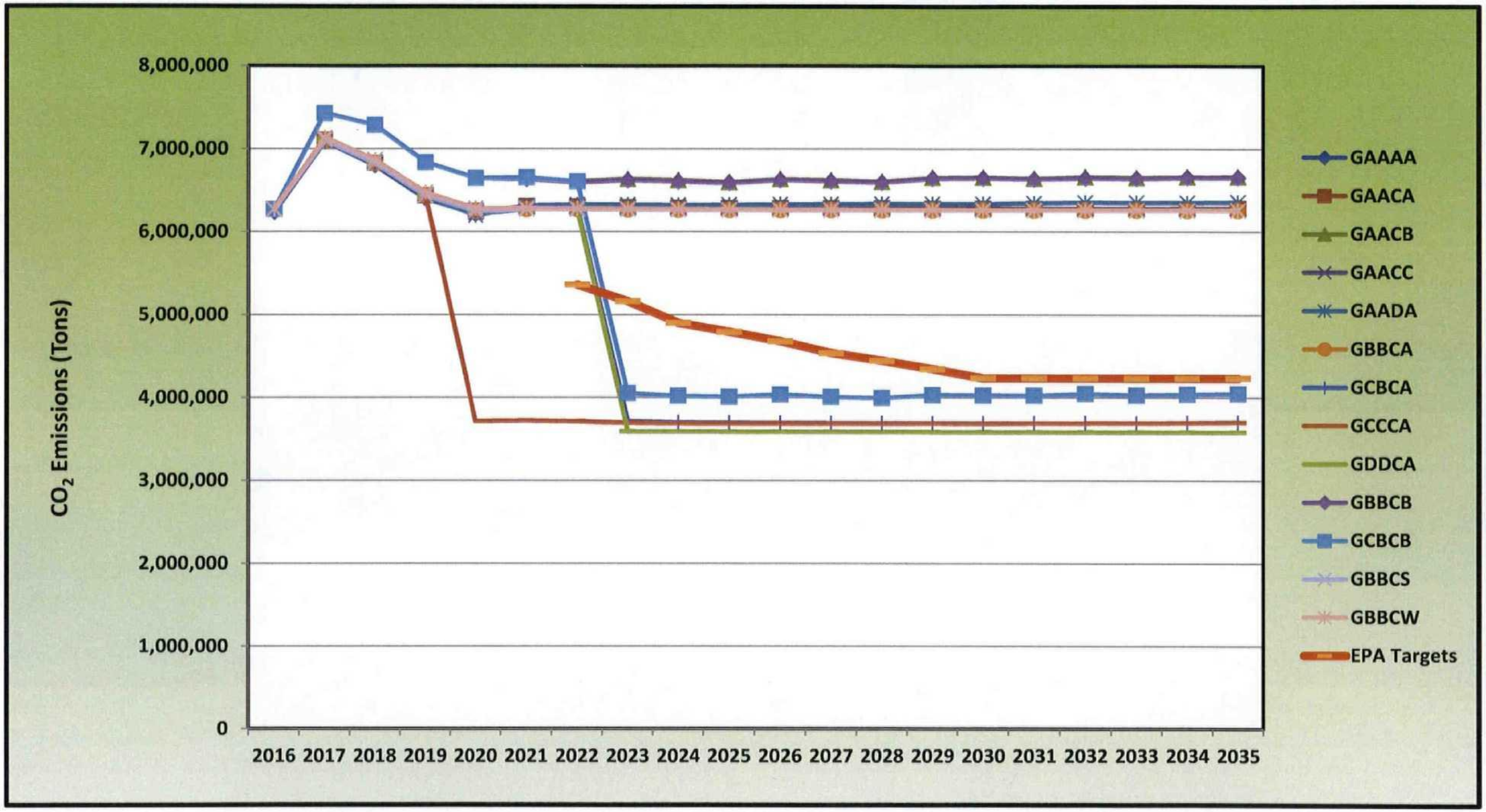
The following chart shows the expected value of CO_2 produced each year (in tons) for each GMO alternative resource plan modeled. This is the expected value over the nine scenarios that include CO_2 emission costs. The chart also shows the assumed amount of CO_2 emission allowances allocated to GMO (labeled "EPA Targets"). Note that projected CO_2 emissions for several of the alternative resource plans modeled indicate that GMO would have CO_2 emissions in excess of the estimated EPA targets for the first several years. The cost associated with these emissions has been included in the NPVRR results. As the projected natural gas prices and CO_2 emissions allowance price increase in the later years of the 20-year analysis period, the change in the economic dispatch of GMO's generation portfolio would reduce CO_2 emissions to levels below the CPP targets. Based on the NPVRR results from the 13 GMO alternative resource plans modeled, no additional coal plant retirements are indicated.

Table 53: Projected Annual CO_2 Emissions With CO_2 Restrictions



For comparison purposes, the following chart shows the expected value of CO_2 produced each year (in tons) for each of the GMO alternative resource plans modeled under the 9 scenarios without CO_2 costs applied. Note that for several alternative resource plans, the annual projected CO_2 emissions exceed the CPP targets in all years. The three alternative resource plans with projected CO_2 emissions below the EPA targets include retirement of Sibley Unit 3.

Table 54: Projected Annual CO_2 Emissions Without CO_2 Restrictions



Estimated CPP Cost Impact

Based on analysis to date, the 20-year net present value of CPP compliance costs for GMO range from ** [redacted] **. The upper end of the range represents the case where emission allowances are auctioned by Missouri and Kansas rather than allocated to the utilities.

Economic dispatch including an explicit CO_2 cost on GMO's covered resources shows a significant increase in gas generation as compared to historic operation. Given this increase in gas generation, the alternative resource plans modeled include additional cost for GMO's gas turbine fleet for increased O&M and year-round firm gas service.

This analysis is based on several major assumptions that could ultimately be proved incorrect. For example, the assumed state CO_2 emission allowances allocation could be different from what GMO has assumed in this analysis. Given the Supreme Court CPP stay, it is uncertain as to when Missouri and Kansas will develop their SIPs specifying how the emission allowance would be allocated, if allocated at all. In addition, it appears that the CO_2 emission forecast used in this analysis may result in a regional shift of coal-based generation to gas-based generation greater than that required to meet the CPP mass-based CO_2 targets. Given this, more work is needed to refine the CO_2 emission allowance forecast. Results of this additional work will be provided in the next IRP annual update.

In addition to actions previously taken by the company to reduce CO_2 emissions related to retail load, (renewable generation additions, DSM program development and implementation, coal use reductions, plant efficiency improvements, etc.) current modeling indicates additional CO_2 reduction would come from increased existing combustion turbine utilization. Existing combustion turbines are not "covered resources" so their CO_2 emissions do not count towards the state's CO_2 limits. While this shift in generation to existing combustion turbine resource would be permissible under the current CPP, EPA did not anticipate such a shift. As such, actual national CO_2 levels could exceed EPA's intended targets under such a scenario.

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8.4 TRANSMISSION GRID IMPACTS

Analyze and document the cost of any transmission grid upgrades or additions needed to address transmission grid reliability, stability, or voltage support impacts that could result from the retirement of any existing GMO coal-fired generating unit in the time period established in the IRP process.

Response: The GMO coal units identified for potential retirement in the IRP plan are Sibley Units 1, and 2, and Lake Road 4/6. The transmission grid impact of retirement of these small units should be minimal. Retirement of any of the larger GMO coal fired generators would necessitate the replacement of that supply with some other resource. It is not possible to identify all the necessary transmission upgrades that might be associated with retirement of a specific generating unit without knowing the specific location of the replacement generation. From the transmission perspective, the most advantageous location for replacement generation is the site of the retired generation where the transmission capacity utilized by the retired generation would be available for new resources.

8.5 DISTRIBUTED GENERATION POTENTIAL

Analyze and document the range of potential levels of distributed generation in GMO's service territory for the 20-year planning horizon and the potential impacts of each identified level of distributed generation, and in particular distributed solar generation, on GMO's preferred resource plan. The potential impacts should quantify both the amount of electrical energy the distributed generation is expected to provide to the grid and the amount of electrical energy that the distributed generation customers are expected to consume on site that will offset the amount that the company would normally provide to those customers.

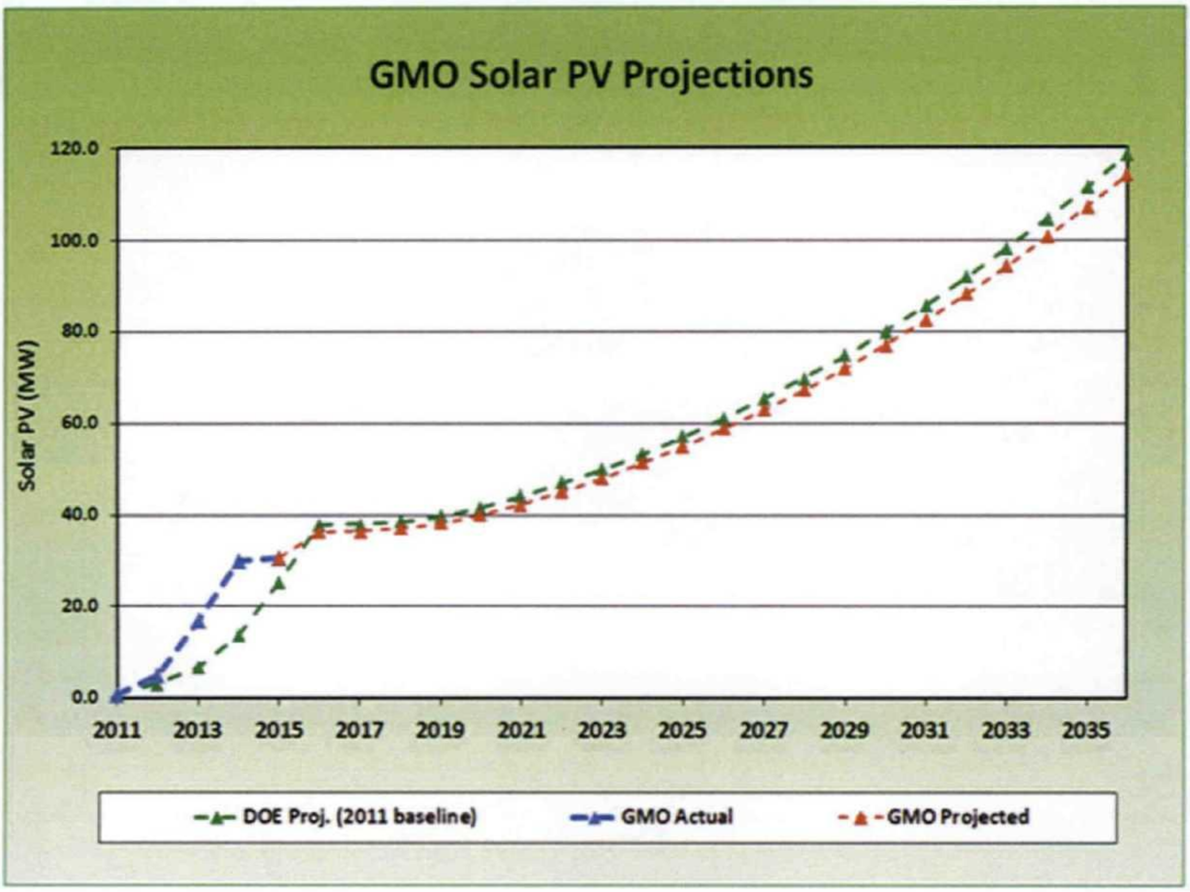
Response: There is a substantial amount of uncertainty regarding distributed solar PV generation over a 20 year planning horizon. Nearly 100% of GMO's existing distributed solar generation is attributed to the Missouri law in which GMO paid up to $2.00/watt in rebates for customer installed solar generation. Pursuant to that Missouri law, a one-time rebate cap was established not to exceed \$50M. Those funds were all committed in November of 2013 and have since been exhausted. Distributed solar generation installations as a result of the rebates realized its peak in 2013 and 2014, with approximately 12 MW of installed capacity per year. Subsequent to the rebate less than 1MW of solar generation was installed in 2015.

As of 2015 year end, GMO customers had 30.65 MW of distributed solar generation installed producing an estimated 44.3 GWH (@ 16.5% load factor) of which 19.8 GWH were exported to the grid and the remaining 24.5 GWH being consumed onsite by the customer.

The GMO load forecast includes the projected impact of distributed solar generation throughout the 20 year planning horizon. The end-use level load forecasts were developed using both primary PV data collected by GMO and secondary data and projections of PV adoption produced by the U.S. Department of Energy (DOE) for the West North Central Region of the U.S. DOE updates its projections at least once a year and we use the most recently available projections whenever we update our models.

Table 55 illustrates the level of distributed solar PV generation included in the current load forecast relative to the DOE forecasted growth for the region.

Table 55: GMO Solar PV Projections



Due to the uncertainty of future PV adoption rates without rebates and other incentives, GMO is participating in a 2016 EPRI supplemental research project, 'Forecasting Residential Solar Photovoltaic Adoption', which seeks to develop methods for forecasting PV adoption GMO will continue to track the development and cost of distributed generation and use the results of this EPRI project as well as the intake of Net Metering applications for future resource planning.

Distributed Combined Heat & Power Generation (CHP)

In the DSM Resource Potential Study conducted by Navigant for the GMO service territory in preparation for the 2015 Triennial IRP filing, Navigant conducted an analysis of CHP systems to identify opportunities for this technology. Navigant evaluated the cost effectiveness of CHP systems driven by a range of prime movers, system configurations, and usage levels. Steam turbines and gas turbines were the only technologies to pass the TRC test. Navigant found that no systems passed a participant test without incentives. However, Navigant found that when incentives on par with those offered elsewhere in the U.S. were included, the system that passed the TRC screen also passed the participant test. With incentives, Navigant determined that, for the GMO service area, 22.1 MW of capacity reduction from CHP was realistically achievable over a 20 year planning horizon.

While GMO did not incorporate a specific CHP incentive program for the 2016-2018 MEEIA implementation cycle, CHP projects will be considered in the Business Energy Efficiency Rebate – Custom Program. KCP&L and the implementation contractor will work with customers interested in CHP to determine project costs, cost-effectiveness, tax credits, and financing options.

In 2015, KCP&L engaged the Applied Energy Group (AEG) to conduct a Demand Side Management (DSM) Resource Potential Study which will be used in developing the 2018 Triennial IRP. AEG will reevaluate the potential for CHP technologies as a distributed generation resource.

Other Distributed Generation Technologies

GMO monitors the economic viability and potential impact other emerging distributed generation technologies (wind, bio, fuel cells, etc.). Currently we do not project that any other distributed generation technologies will be adopted at a significant enough level to have a measurable impact throughout the 20 year planning horizon.

8.6 ENERGY EFFICIENCY FINANCING

Review the options available to GMO for providing customer financing for energy efficiency measures. Discuss GMO's current, near term (next three years) and long-term activities and plans for providing customer financing for energy efficiency measures.

Response:

While GMO has offered customer financing options in the past, GMO currently has no programs in place to provide direct customer financing for energy efficiency measures. The current Customer Information System is not designed to support this financing process functionality which would limit the implementation of such options across both service territories. The Company is, however, currently in development of a new combined CIS platform that could potentially handle such processes. If the ongoing exploration and program evaluation indicates this offering is advantageous, the financing option will be investigated further.

In Q4 2015, GMO hosted several residential customer panelist discussions and surveys across the service territory. One of the questions inquired about interest in on-bill financing for residential HVAC systems. Of the 784 panelists who completed the survey, only about 25% expressed interest. Those who were interested were mainly-college educated, 35-84 years old, employed full time with a 'mid-level' income. These results align with those of the American Council for an Energy-Efficient Economy (ACEEE) research on utility financing. ACEEE found that "homeowner financing programs historically draw low participation rates and tend to attract educated and higher income-level homeowners who are the least in need of financing opportunities. Financing for those who are most in need, people with low or fixed incomes and poor credit, has had low success" http://aceee.org/topics/energy-efficiency-financing.

Note that while GMO not currently offer a financing option, there are other financing opportunities and funding sources available to the Company's customer base and encourages customers to explore these options. In fact, options like PACE or local, State or

Federal funding have been promoted on the GMO Energy Efficiency website. Some examples of potential financing options are:

- Energy Service Company (ESCO) financing
- Manufacturer direct financing for various energy efficient appliances
- Local Distributors and Contractors loans through private outside lenders
- Property-Assessed Clean Energy Programs (PACE) –financing Energy Efficiency and Renewables on commercial private property; to be repaid over 10-20 years through property assessments and paid as addition to the property tax bills. They are in the process of evaluating the option of offering to residential customers as well.
- Energy Loan Program (Sponsored by the DOE) – Available to public schools, colleges, city/county gov. buildings, public water and wastewater treatment facilities and public/private non-profit hospitals; 2016 FY interest rate set at 2.75%.

In the near-term, GMO will continue to monitor the marketplace and performance of the MEEIA programs. If the Company determines that additional financing options are needed to meet the Company's goals, the Company will then consider additional financing options including a deeper assessment of the new CIS platform functionality and the possibility of incorporating this mechanism into the program.

Long-term, GMO will continue as discussed above, and will keep current on market trends and how/if the Company needs to adjust the current program offerings, including the offering of a customer financing option.

8.7 CLEAN POWER PLAN COMPLIANCE

Describe how the preferred plan of the Company's last and current annual or triennial Integrated Resource Plans (IRPs) positions the utility for full or partial compliance with the U.S. Environmental Protection Agency's (EPA) Clean Power Plan (CPP) under Section 111(d) of the Clean Air Act, as released in final form on August 3, 2015. Please include in this regard:

(1). An evaluation of how renewable energy, energy efficiency and other demand-side resources (including combined heat and power) deployed by the Company after January 1, 2013 could contribute to compliance;

Since Missouri and Kansas would likely adopt a mass-based CPP compliance structure, actions previously taken by the company that reduce CO_2 emissions related to retail load, (renewable generation additions, DSM program development, etc.) would only indirectly contribute to CPP compliance. These activities would not create CO_2 credits like they would under a rate-based compliance structure.

(2). An evaluation of how renewable energy and energy efficiency and other demand-side resources (including combined heat and power) deployed by the Company after the submission of a final State Implementation Plan could qualify under EPA's proposed Clean Energy Investment Program (CEIP);

There are no current plans to add renewable resources that would qualify under the CEIP. The integrated analysis indicated that new wind resources added in this period would not be economic. Any energy efficiency measures that might qualify under the CEIP would not create CO_2 credits the Company could use for CPP compliance under a mass-based compliance structure.

(3). A description of additional investments (in fiscal, capacity, and energy terms by year) which will be required by the Company to meet the targets in the CPP under scenarios including: a statewide rate-based or mass-based emissions goal; a "trading-ready" approach; and participation in the CEIP;

Based on many assumptions that are subject to change, no significant investments are required for CPP compliance. The Company currently anticipates minor investments to allow for potential year-round operation of gas-fired generation.

(4). The barriers to achieving these additional investments;

At this time, the Company does not anticipate any barriers to achieve these minor investments.

(5). The price of carbon used by the Company in the analyses above; and

The carbon forecasts used by the Company are provided in Section 3 above.

(6). An indication of the Company's preferences regarding various compliance options under a state implementation plan.

The Company prefers a mass-based approach without offsets and a carbon trading market.

8.8 SOLAR ASSESSMENT

Describe any assessment of the value of solar (VOS) performed or used by the Company specifically for its Missouri service territory.

Response:

The current Missouri laws established with HB142 are built on a Net Metering model, therefore a VOS study has not been considered.

8.9 TRANSMISSION GRID IMPACTS

Analyze and document the cost of any transmission grid upgrades or additions needed to address transmission grid reliability, stability, or voltage support impacts that could result from the retirement of any existing GMO coal-fired generating unit.

Response: See response to Special Contemporary Issue (12)8.4 above.

8.10 GENERATION COST AND PERFORMANCE DATA

Analyze and document cost and performance information sufficient to fairly analyze and compare utility scale wind and solar resources, including distributed generation, to other supply-side alternatives.

Response: Utilizing cost and operating data obtained from Electric Power Research Institute Technical Assessment Guide (EPRI-TAG®), the Energy Information Administration, and recently obtained market intelligence, an analysis comparing supply-side resources including utility solar, utility scale wind and distributed generation options is provided in Table 56 below:

Table 56: Supply Side Technology Analysis ** Highly Confidential **

[redacted]

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8.11 IMPACT OF EMERGING ENERGY EFFICIENCY TECHNOLOGIES

Analyze the impact of emerging energy efficiency technologies throughout the planning period.

Response: See response to Special Contemporary Issue 8.1 above.