Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
2019-2020 Planning Reserve Margin (PRM) Study											
Installed Capacity (ICAP) (MW)	20,794	14,439	11,394	12,382	8,699	19,835	24,228	11,529	24,492	6,096	[A]
Unforced Capacity (UCAP) (MW)	19,762	13,629	10,863	11,012	7,766	18,529	22,171	10,823	22,509	5,061	[B]
Adjustment to UCAP {1d in 10yr} (MW)	702	1,038	-12	702	2,342	1,731	2,674	-273	811	2,025	[C]
LRR (UCAP) (MW)	20,464	14,667	10,851	11,713	10,108	20,259	24,845	10,550	23,320	7,086	[D]=[B]+[C]
Peak Demand (MW)	17,780	12,629	9,391	9,415	8,079	17,584	21,208	7,770	20,693	4,814	[E]
LRR UCAP per-unit of LRZ Peak Demand	**115.1%**	**116.1%**	**115.6%**	**124.4%**	**125.1%**	**115.2%**	**117.2%**	**135.8%**	**112.7%**	**147.2%**	[F]=[D]/[E]

Table 6-1: Planning Year 2019-2020 LRZ Local Reliability Requirements

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
2022-2023 Planning Reserve Margin (PRM) Study											
Installed Capacity (ICAP) (MW)	20,976	15,211	11,600	13,115	8,721	20,540	22,924	11,617	25,612	6,096	[A]
Unforced Capacity (UCAP) (MW)	19,942	14,364	11,064	11,717	7,787	19,196	21,224	10,910	23,542	5,061	[B]
Adjustment to UCAP {1d in 10yr} (MW)	1,091	479	90	223	2,380	1,348	3,177	-195	391	1,974	[C]
LRR (UCAP) (MW)	21,032	14,843	11,154	11,940	10,167	20,544	24,401	10,715	23,933	7,036	[D]=[B]+[C]
Peak Demand (MW)	18,303	12,761	9,648	9,394	8,119	17,827	21,038	7,990	20,763	4,839	[E]
LRR UCAP per-unit of LRZ Peak Demand	**114.9%**	**116.3%**	**115.6%**	**127.1%**	**125.2%**	**115.2%**	**116.0%**	**134.1%**	**115.3%**	**145.4%**	[F]=[D]/[E]

Table 6-2: Planning Year 2022-2023 LRZ Local Reliability Requirements

FILED
June 17, 2021
INDIANA UTILITY
REGULATORY COMMISSION

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
2024-2025 Planning Reserve Margin (PRM) Study											
Installed Capacity (ICAP) (MW)	20,976	15,211	11,600	13,115	8,721	20,540	23,188	11,617	25,612	6,096	[A]
Unforced Capacity (UCAP) (MW)	19,942	14,364	11,064	11,717	7,787	19,196	21,446	10,910	23,542	5,061	[B]
Adjustment to UCAP {1d in 10yr} (MW)	1,313	578	261	114	2,487	1,181	2,323	-220	711	2,010	[C]
LRR (UCAP) (MW)	21,255	14,942	11,324	11,831	10,274	20,377	23,769	10,690	24,253	7,072	[D]=[B]+[C]
Peak Demand (MW)	18,519	12,837	9,809	9,287	8,173	17,663	20,982	8,055	20,999	4,875	[E]
LRR UCAP per-unit of LRZ Peak Demand	**114.8%**	**116.4%**	**115.5%**	**127.4%**	**125.7%**	**115.4%**	**113.3%**	**132.7%**	**115.5%**	**145.1%**	[F]=[D]/[E]

Table 6-3: Planning Year 2024-2025 LRZ Local Reliability Requirements

Weather Year Time of Peak Demand (ESTHE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
1988	8/1/88 16:00	8/1/88 16:00	8/1/88 16:00	7/31/88 16:00	8/16/88 16:00	8/15/88 17:00	7/9/88 17:00	7/6/88 18:00	7/19/88 15:00	8/15/88 15:00	7/2/88 18:00
1989	7/10/89 16:00	7/9/89 18:00	7/9/89 18:00	7/10/89 19:00	7/10/89 17:00	7/10/89 19:00	7/10/89 16:00	6/26/89 16:00	8/27/89 16:00	12/24/89 9:00	8/27/89 16:00
1990	7/3/90 17:00	7/3/90 18:00	8/27/90 16:00	7/3/90 16:00	9/6/90 16:00	9/6/90 16:00	7/9/90 17:00	8/28/90 15:00	7/10/90 16:00	8/6/90 16:00	8/27/90 18:00
1991	7/19/91 16:00	7/18/91 17:00	7/18/91 15:00	7/17/91 18:00	7/6/91 18:00	8/2/91 17:00	8/2/91 17:00	7/19/91 16:00	7/24/91 16:00	8/20/91 18:00	8/2/91 16:00
1992	8/10/92 16:00	8/9/92 17:00	8/10/92 18:00	7/8/92 16:00	7/2/92 15:00	7/2/92 16:00	7/14/92 16:00	8/27/92 15:00	7/16/92 17:00	8/10/92 16:00	7/11/92 17:00
1993	8/27/93 15:00	8/11/93 16:00	8/24/93 16:00	8/22/93 19:00	7/17/93 17:00	7/27/93 16:00	7/25/93 16:00	8/27/93 15:00	7/28/93 15:00	8/19/93 16:00	8/20/93 17:00
1994	7/6/94 14:00	6/14/94 19:00	6/15/94 16:00	7/19/94 18:00	7/5/94 18:00	7/5/94 17:00	7/20/94 15:00	6/18/94 18:00	8/14/94 16:00	8/14/94 16:00	1/19/94 9:00
1995	7/13/95 17:00	7/13/95 17:00	7/13/95 17:00	7/12/95 16:00	7/13/95 17:00	7/13/95 16:00	7/13/95 16:00	7/13/95 17:00	7/14/95 16:00	8/16/95 16:00	8/31/95 16:00
1996	8/6/96 17:00	8/6/96 17:00	6/29/96 17:00	7/18/96 17:00	7/18/96 18:00	7/18/96 17:00	7/19/96 17:00	8/7/96 15:00	7/1/96 15:00	2/5/96 7:00	7/3/96 16:00
1997	7/16/97 16:00	7/16/97 18:00	7/16/97 17:00	7/26/97 20:00	7/27/97 17:00	7/26/97 17:00	7/27/97 15:00	7/16/97 16:00	7/22/97 15:00	8/31/97 17:00	7/25/97 16:00
1998	7/20/98 16:00	7/13/98 18:00	6/25/98 16:00	7/20/98 18:00	7/20/98 16:00	7/20/98 17:00	7/19/98 17:00	6/25/98 16:00	7/7/98 15:00	8/28/98 17:00	8/28/98 17:00

1999	7/30/99 15:00	7/25/99 15:00	7/30/99 15:00	7/25/99 17:00	7/19/99 0:00	7/26/99 19:00	7/30/99 15:00	7/30/99 14:00	7/28/99 15:00	8/5/99 16:00	8/20/99 18:00
2000	8/15/00 16:00	8/14/00 19:00	7/17/00 17:00	8/31/00 19:00	8/29/00 16:00	8/17/00 18:00	9/2/00 16:00	8/9/00 15:00	8/29/00 18:00	8/30/00 16:00	8/30/00 17:00
2001	8/9/01 15:00	8/7/01 16:00	8/9/01 17:00	7/31/01 18:00	7/23/01 17:00	7/23/01 17:00	8/7/01 16:00	8/8/01 16:00	7/12/01 15:00	1/4/01 8:00	7/20/01 17:00
2002	7/2/02 16:00	7/6/02 18:00	8/1/02 15:00	7/20/02 19:00	7/9/02 17:00	8/1/02 16:00	8/3/02 15:00	7/3/02 16:00	7/30/02 16:00	8/7/02 17:00	7/10/02 16:00
2003	8/21/03 16:00	8/24/03 17:00	8/21/03 16:00	7/26/03 18:00	8/21/03 16:00	8/21/03 18:00	8/27/03 17:00	8/21/03 16:00	7/29/03 16:00	1/24/03 7:00	7/17/03 17:00
2004	7/13/04 16:00	6/7/04 18:00	6/8/04 17:00	7/20/04 17:00	7/13/04 16:00	7/13/04 16:00	1/31/04 4:00	7/22/04 15:00	7/14/04 15:00	8/1/04 17:00	7/24/04 16:00
2005	7/24/05 17:00	7/17/05 17:00	7/24/05 16:00	7/25/05 17:00	7/24/05 17:00	7/24/05 17:00	7/25/05 16:00	7/24/05 18:00	7/27/05 15:00	8/20/05 17:00	8/21/05 15:00
2006	7/31/06 17:00	7/31/88 17:00	7/31/06 15:00	7/19/06 18:00	7/31/06 18:00	8/2/06 17:00	7/31/06 16:00	8/3/06 15:00	8/10/06 18:00	8/15/06 18:00	8/15/06 17:00
2007	8/1/07 17:00	8/10/07 17:00	8/2/07 16:00	7/17/07 15:00	8/15/07 18:00	8/15/07 17:00	8/7/07 16:00	7/31/07 18:00	8/14/07 16:00	8/21/07 15:00	8/14/07 18:00
2008	7/17/08 15:00	7/11/08 18:00	7/7/08 17:00	8/3/08 16:00	7/20/08 16:00	7/20/08 17:00	8/23/08 15:00	8/24/08 12:00	7/22/08 15:00	8/6/08 18:00	7/22/08 16:00
2009	6/25/09 16:00	6/22/09 19:00	6/25/09 16:00	7/24/09 18:00	8/9/09 17:00	8/9/09 16:00	1/16/09 4:00	6/25/09 16:00	7/11/09 19:00	7/2/09 16:00	7/11/09 17:00
2010	8/3/10 18:00	8/8/10 18:00	8/20/10 14:00	7/17/10 18:00	8/10/10 17:00	8/3/10 16:00	8/13/10 16:00	9/1/10 15:00	7/21/10 15:00	8/1/10 17:00	8/2/10 16:00
2011	7/20/11 16:00	7/18/11 17:00	7/20/11 16:00	7/20/11 16:00	9/1/11 16:00	8/2/11 18:00	7/20/11 16:00	7/2/11 16:00	8/3/11 16:00	8/18/11 16:00	8/31/11 17:00
2012	7/6/12 17:00	7/31/88 17:00	7/13/95 17:00	7/25/12 17:00	7/6/12 18:00	7/24/12 18:00	7/5/12 17:00	7/6/12 17:00	7/30/12 17:00	8/16/12 17:00	7/3/12 16:00
2013	7/17/13 17:00	8/27/13 15:00	8/27/13 17:00	7/18/13 17:00	9/10/13 16:00	8/31/13 17:00	8/31/13 15:00	7/19/13 14:00	7/18/13 16:00	8/7/13 16:00	8/9/13 16:00
2014	7/22/14 16:00	7/21/14 17:00	7/7/14 16:00	7/22/14 16:00	8/24/14 16:00	7/26/14 15:00	1/24/14 9:00	7/22/14 16:00	7/14/14 16:00	1/8/14 3:00	8/24/14 17:00
2015	7/29/15 16:00	8/14/15 16:00	8/14/15 17:00	7/13/15 16:00	9/2/15 16:00	9/9/15 16:00	7/29/15 16:00	7/29/15 16:00	7/28/15 15:00	8/12/15 16:00	7/21/15 15:00
2016	7/20/16 15:00	6/25/16 15:00	8/11/16 14:00	7/20/16 14:00	9/7/16 15:00	9/7/16 16:00	9/8/16 16:00	9/7/16 14:00	7/22/16 15:00	8/23/16 15:00	8/3/16 15:00
2017	7/20/17 16:00	7/6/17 17:00	9/25/17 15:00	7/20/17 16:00	7/12/17 14:00	7/20/17 14:00	9/22/17 15:00	9/25/17 15:00	7/21/17 16:00	8/20/17 15:00	7/20/17 16:00

Table 6-4: Time of Peak Demand for all 30 weather years

Appendix A: Comparison of Planning Year 2018 to 2019

Multiple study sensitivity analyses were performed to compute changes in the PRM target on an UCAP basis, from the 2018-2019 planning year to the 2019-2020 planning year. These sensitivities included one-off incremental changes of input parameters to quantify how each change affected the PRM result independently. Note the impact of the incremental PRM changes from 2018 to 2019 in the waterfall chart of Figure A-1; see Section A.1 Waterfall Chart Details for an explanation.

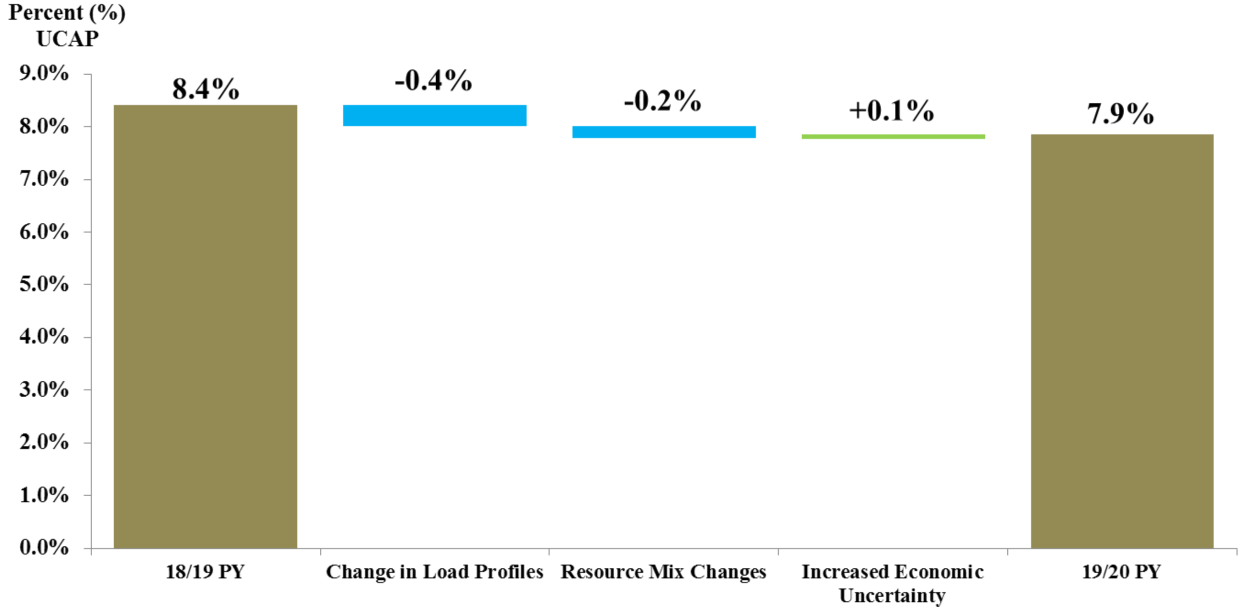


Figure A-1: Waterfall Chart of 2018 PRM UCAP to 2019 PRM UCAP

A.1 Waterfall Chart Details

A.1.1 Load

The MISO Coincident Peak Demand decreased from the 2018-2019 planning year, which was driven by the updated actual load forecasts submitted by the LSEs. The reduction was mainly driven by reduction in anticipated load growth and changes in diversity. The monthly load profiles submitted by LSE's resulted in more peaked load shapes compared to the 2018-2019 PY. This caused a 0.4 percentage point decrease to the PRM.

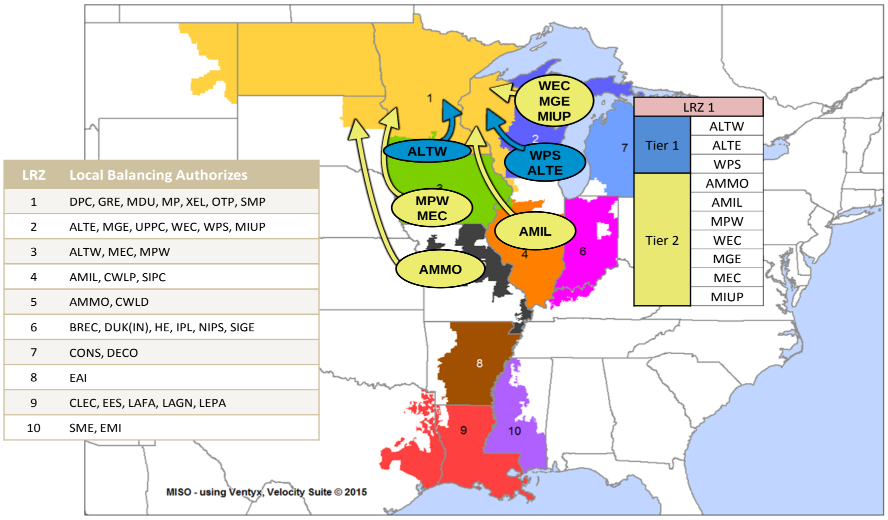
An increase of economic load uncertainty, detailed in Section 4.3.2, in the 2019-2020 planning year resulted in a 0.1 percentage point increase in the PRM UCAP. The modeling of economic load uncertainty effectively increases the risk associated with high peak loads, thus resulting in larger adjustment to UCAP for the same MISO peak load. Upon incorporating the increased adjustment into the equations of Section 4.5.1 of the report, the mathematical calculations result in a higher PRM in percentage.

A.1.2 Units

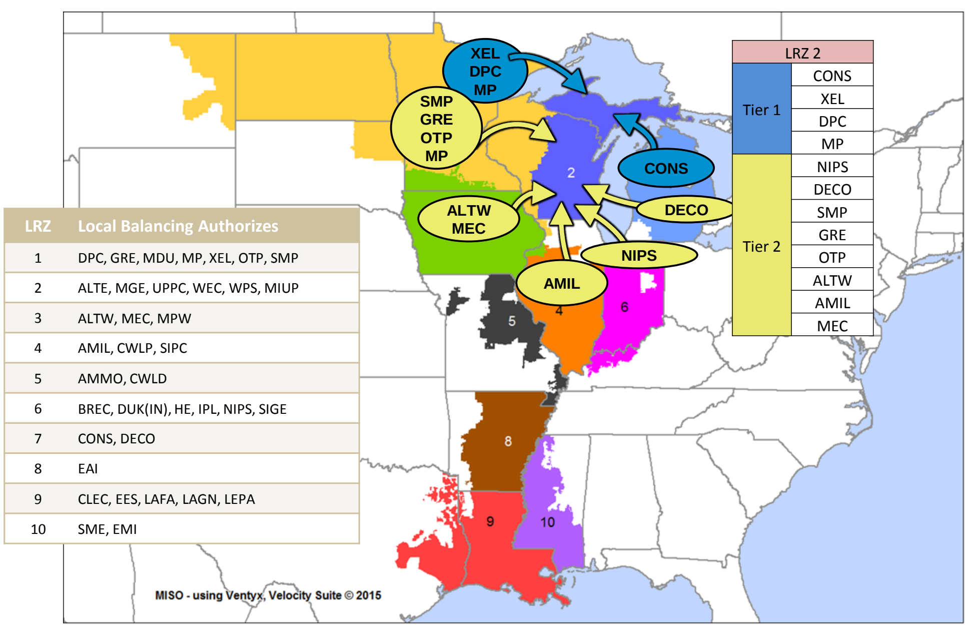
Changes from 2018-2019 planning year values are due to changes in Generation Verification Test Capacity (GVTC); EFORd or equivalent forced outage rate demand with adjustment to exclude events outside management control (XEFORd); new units; retirements; suspensions; and changes in the resource mix. The MISO fleet weighted average forced outage rate increased from 9.16 percent to 9.28 percent from the previous study to this study. An increase in unit outage rates will generally lead to an increase in reserve margin in order to cover the increased risk of loss of load. Although the MISO-wide average EFORd increased slightly for the 2019-2020 PY, new units and retirements led to a resource mix that improved reliability overall.

Appendix B: Capacity Import Limit source subsystem definitions (Tiers 1 & 2)

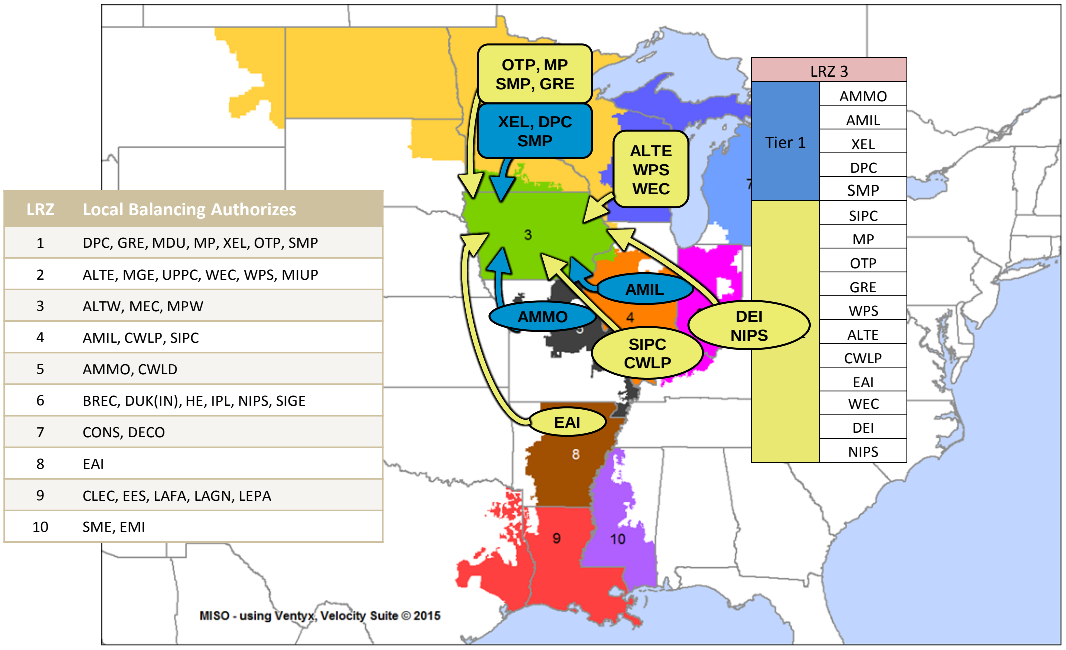
MISO Local Resource Zone 1



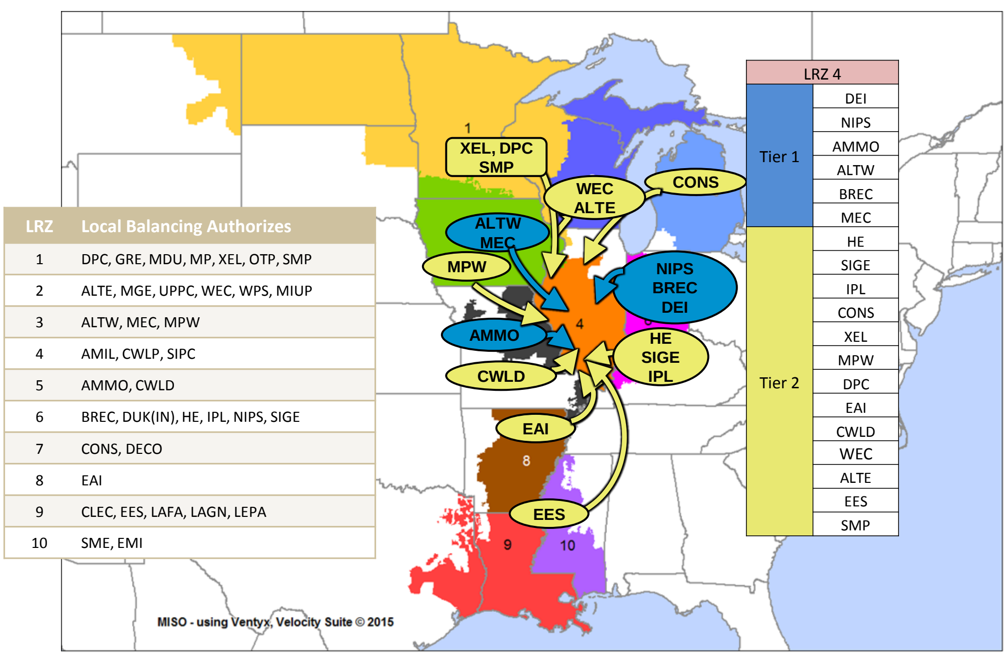
MISO Local Resource Zone 2



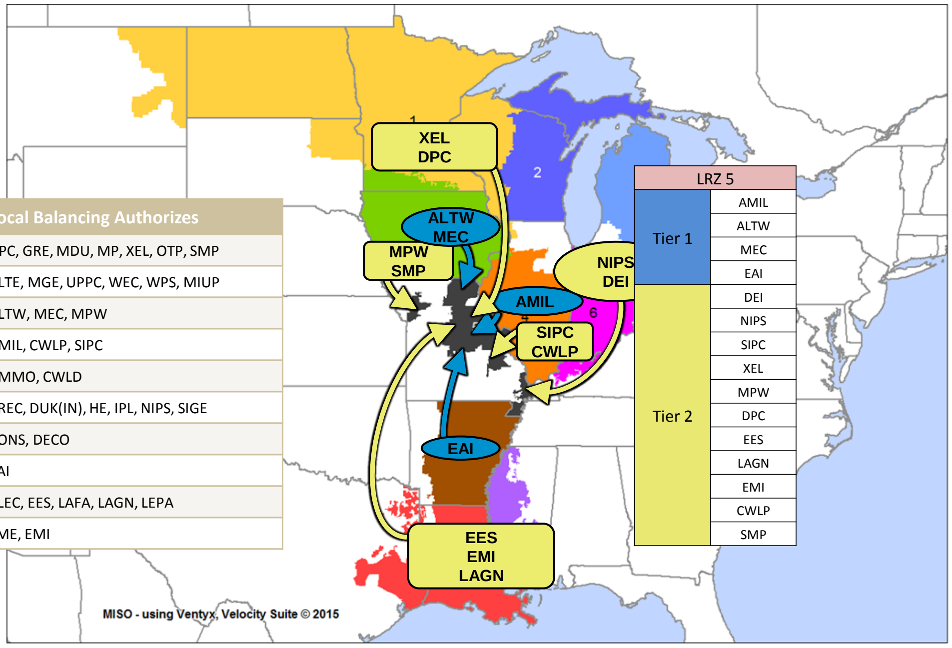
MISO Local Resource Zone 3



MISO Local Resource Zone 4



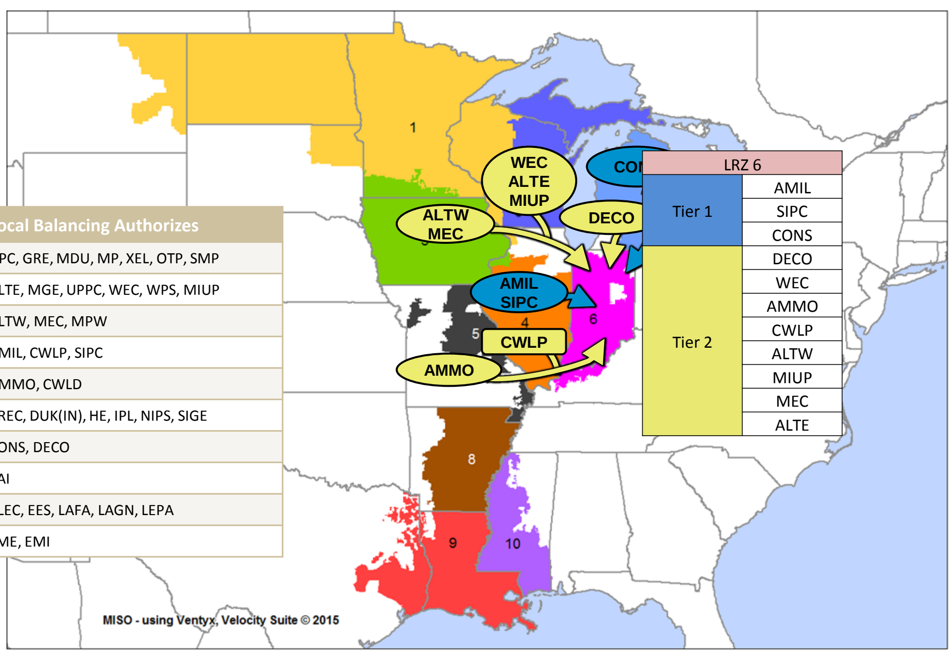
MISO Local Resource Zone 5



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	SME, EMI

LRZ 5	
Tier 1	AMIL
	ALTW
	MEC
	EAI
Tier 2	DEI
	NIPS
	SIPC
	XEL
	MPW
	DPC
	EES
	LAGN
	EMI
	CWLP
	SMP

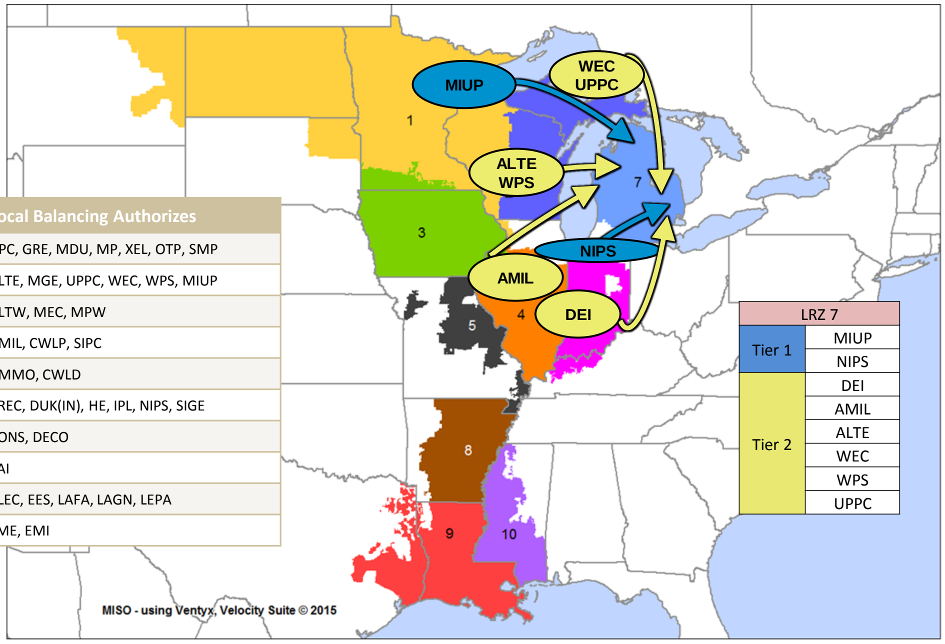
MISO Local Resource Zone 6



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	SME, EMI

LRZ 6	
Tier 1	AMIL
	SIPC
	CONS
Tier 2	DECO
	WEC
	AMMO
	CWLP
	ALTW
	MIUP
	MEC
	ALTE

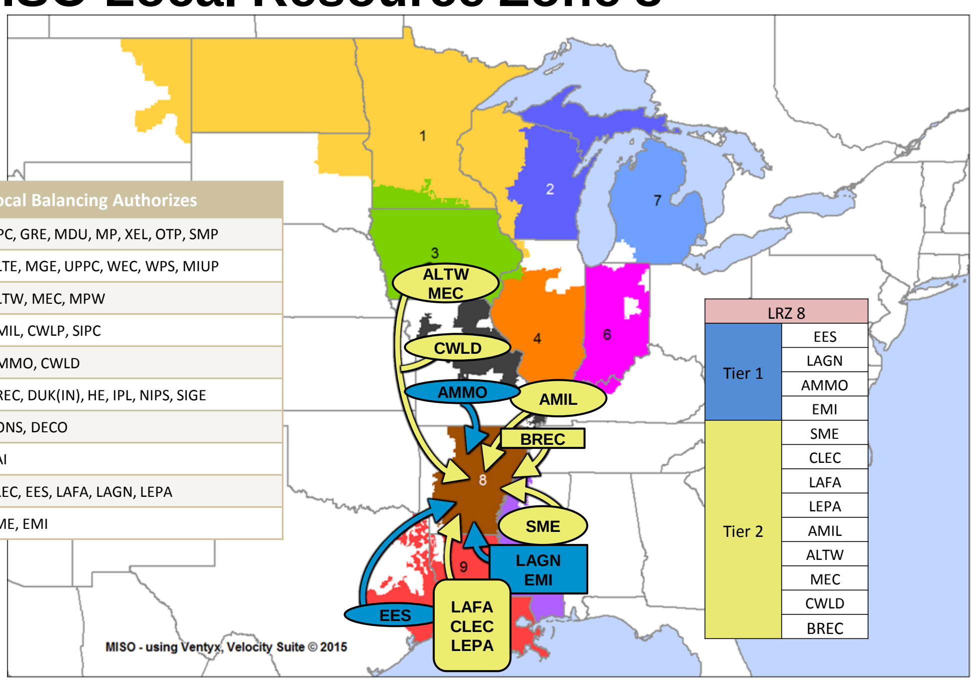
MISO Local Resource Zone 7



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	SME, EMI

LRZ 7	
Tier 1	MIUP
	NIPS
Tier 2	DEI
	AMIL
	ALTE
	WEC
	WPS
	UPPC

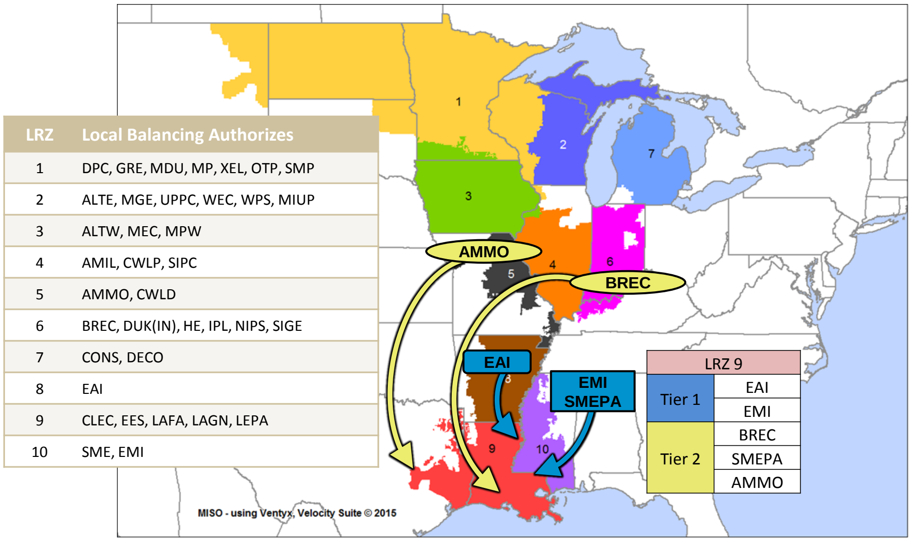
MISO Local Resource Zone 8



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	SME, EMI

LRZ 8	
Tier 1	EES
	LAGN
	AMMO
	EMI
Tier 2	SME
	CLEC
	LAFA
	LEPA
	AMIL
	ALTW
	MEC
	CWLD
	BREC

MISO Local Resource Zone 9

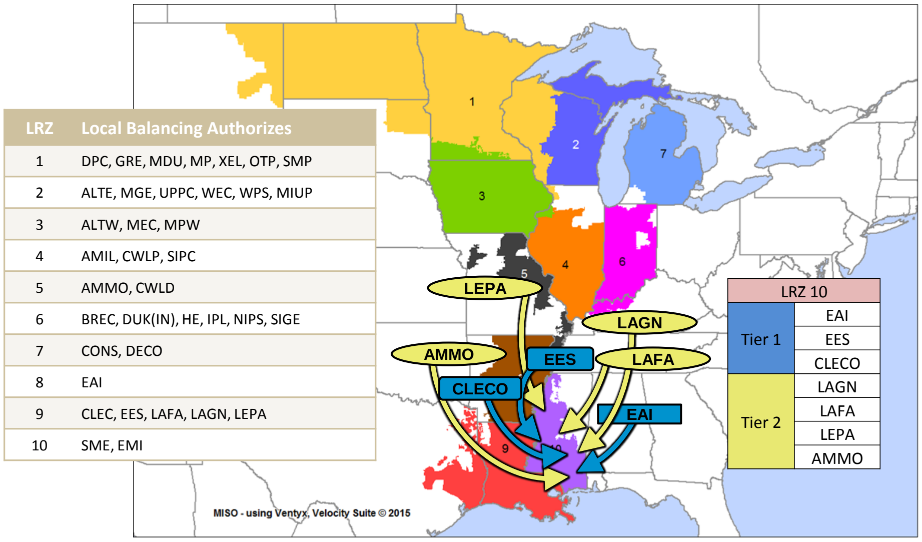


LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	SME, EMI

LRZ 9	
Tier 1	EAI
	EMI
Tier 2	BREC
	SMEPA
	AMMO

* BRAZ, DERS, EES-EMI, and BCA now modeled in EES power flow area

MISO Local Resource Zone 10



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	SME, EMI

LRZ 10	
Tier 1	EAI
	EES
	CLECO
Tier 2	LAGN
	LAFA
	LEPA
	AMMO

Appendix C: Compliance Conformance Table

Requirements under: Standard BAL-502-RF-03	Response
R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The Planning Year 2019 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2019 through May 2020 and beyond. Analysis of Planning Year 2019 is in Sections 5.1 and 6.1 Analysis of Future Years 2020-2028 is in Sections 5.3 and 6.1
R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).	Section 4.5 of this report outlines the utilization of LOLE in the reserve margin determination. "These metrics were determined by a probabilistic LOLE analysis such that the LOLE for the planning year was one day in 10 years, or 0.1 day per year."
R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.	Section 4.3 of this report. "Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE or shedding of firm load."
R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).	Section 4.5.1 of this report. "The minimum amount of capacity above the 50/50 net internal MISO Coincident Peak Demand required to meet the reliability criteria was used to establish the PRM values."
R1.2 Be performed or verified separately for each of the following planning years.	Covered in the segmented R1.2 responses below.
R1.2.1 Perform an analysis for Year One.	In Sections 5.1 and 6.1, a full analysis was performed for planning year 2019.
R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.	Sections 5.3 and 6.1 show a full analysis was performed for future planning years 2022 and 2024.
R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.	Analysis was performed.
R1.3 Include the following subject matter and documentation of its use:	Covered in the segmented R1.3 responses below.

R1.3.1 Load forecast characteristics: • Median (50:50) forecast peak load • Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts). • Load diversity. • Seasonal Load variations. • Daily demand modeling assumptions (firm, interruptible). • Contractual arrangements concerning curtailable/Interruptible Demand.	Median forecasted load – In Section 4.3 of this report: "The average monthly loads of the predicted load shapes were adjusted to match each LRZ's Module E 50/50 monthly zonal peak load forecasts for each study year." Load Forecast Uncertainty – A detailed explanation of the weather and economic uncertainties are given in Sections 4.3.1 and 4.3.2. Load Diversity/Seasonal Load Variations — In Section 4.3 of this report: "For the 2019-2020 LOLE analysis, a load training process utilizing neural net software was used to create a neural-net relationship between historical weather and load data. This relationship was then applied to 30 years of hourly historical weather data in order to create 30 different load shapes for each LRZ in order to capture both load diversity and seasonal variations." Demand Modeling Assumptions/Curtailable and Interruptible Demand — All Load Modifying Resources must first meet registration requirements through Module E. As stated in Section 4.2.7: "Each demand response program was modeled individually with a monthly capacity and was limited to the number of times each program can be called upon as well as limited by duration."
R1.3.2 Resource characteristics: • Historic resource performance and any projected changes • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area. • Resource planned outage schedules, deratings, and retirements. • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration. • Criteria for including planned resource additions in the analysis.	Section 4.2 details how historic performance data and seasonal ratings are gathered, and includes discussion of future units and the modeling assumptions for intermittent capacity resources. A more detailed explanation of firm capacity purchases and sales is in Section 4.4.
R1.3.3 Transmission limitations that prevent the delivery of generation reserves	Annual MTEP deliverability analysis identifies transmission limitations preventing delivery of generation reserves. Additionally, Section 3 of this report details the transfer analysis to capture transmission constraints limiting capacity transfers.
R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis	Inclusion of the planned transmission addition assumptions is detailed in Section 3.2.3.
R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.	Section 4.4 provides the analysis on the treatment of external support assistance and limitations.

R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel. • Common mode outages that affect resource availability. • Environmental or regulatory restrictions of resource availability. • Any other demand (Load) response programs not included in R1.3.1. • Sensitivity to resource outage rates. • Impacts of extreme weather/drought conditions that affect unit availability. • Modeling assumptions for emergency operation procedures used to make reserves available. • Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.	Fuel availability, environmental restrictions, common mode outage and extreme weather conditions are all part of the historical availability performance data that goes into the unit's EFORd statistic. The use of the EFORd values is covered in Section 4.2. The use of demand response programs are mentioned in Section 4.2. The effects of resource outage characteristics on the reserve margin are outlined in Section 4.5.2 by examining the difference between PRM ICAP and PRM UCAP values.
R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included	Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 3 treats worst-case theoretical outages by Perform First Contingency Total Transfer Capability (FCTTC) analysis for each LRZ, by modeling NERC Category P0 (system intact) and Category P1 (N-1) contingencies.
R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis	MISO internal resources are among the quantities documented in the tables provided in Sections 5 and 6.
R1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis	MISO load is among the quantities documented in the tables provided in Sections 5 and 6.
R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.	In Sections 5 and 6, the peak load and estimated amount of resources for planning years 2019, 2022, and 2024 are shown. This includes the detail for each transmission constrained sub-area.
R2.1 This documentation shall cover each of the years in Year One through ten.	Section 5.3 and Table 5-4 shows the three calculated years, and in-between years estimated by interpolation. Estimated transmission limitations may be determined through a review of the 2019 LOLE study transfer analysis shown in Section 3 of this report, along with the results from previous LOLE studies.
R2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	Section 5.3 and Table 5-4 shows the three calculated years underlined.
R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.	The 2019 LOLE Study Report documentation is posted on November 1 prior to the planning year.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2.	In Sections 5 and 6, the difference between the needed amount and the projected planning reserves for planning years 2019, 2022, and 2024 are shown the adjustments to ICAP and UCAP in Table 5-1, Table 5-3, Table 6-1, Table 6-2, and Table 6-3.

Appendix D: Acronyms List Table

CEL	Capacity Export Limit
CIL	Capacity Import Limit
CPNode	Commercial Pricing Node
DF	Distribution Factor
EFORd	Equivalent Forced Outage Rate demand
ELCC	Effective Load Carrying Capability
ERZ	External Resource Zone
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GADS	Generator Availability Data System
GLT	Generation Limited Transfer
GVTC	Generation Verification Test Capacity
ICAP	Installed Capacity
LBA	Local Balancing Authority
LCR	Local Clearing Requirement
LFE	Load Forecast Error
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRR	Local Reliability Requirement
LRZ	Local Resource Zones
LSE	Load Serving Entity
MARS	Multi-Area Reliability Simulation
MECT	Module E Capacity Tracking
MISO	Midcontinent Independent System Operator
MOD	Model on Demand
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt hours
NERC	North American Electric Reliability Corp.
PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PRM ICAP	PRM Installed Capacity

PRM UCAP	PRM Unforced Capacity
PRMR	Planning Reserve Margin Requirement
PSS E	Power System Simulator for Engineering
RCF	Reciprocal Coordinating Flowgate
RPM	Reliability Pricing Model
SERVM	Strategic Energy & Risk Valuation Model
SPS	Special Protection Scheme
TARA	Transmission Adequacy and Reliability Assessment
UCAP	Unforced Capacity
XEFORd	Equivalent forced outage rate demand with adjustment to exclude events outside management control
ZIA	Zonal Import Ability
ZEA	Zonal Export Ability

Attachment 6.1 Vectren Electric 2018-2020 DSM Plan

Vectren South 2018-2020 Electric Energy Efficiency Plan

Prepared by:
Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana Inc. (Vectren South)

4/7/2017

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List of Acronyms & Abbreviations

Acronym	Description
AEG	Applied Energy Group
ARCA	Appliance Recycling Centers of America Inc.
BAS	Building Automation System
BTU	Building Tune-Up
BYOT	Bring Your Own Thermostat
C&I	Commercial and Industrial
CAC	Central Air Conditioning
CFL	Compact Fluorescent Lamp
CVR	Conservation Voltage Reduction
DLC	Direct Load Control
DR	Demand Response
DSM	Demand Side Management
EAD	Energy Design Assistance
EAP	Energy Assistance Program
ECM	Electronically Commutated Motors
EE	Energy Efficiency
EISA	Energy Independence and Security Act
EM&V	Evaluation, Measurement and Verification
ES	ENERGY STAR
HEA	Home Energy Assessment & Weatherization
HERS	Home Efficiency Rating System
HVAC	Heating, Ventilation and Air Conditioning
IQW	Income Qualified & Weatherization
IRP	Integrated Resource Plan
IURC	Indiana Utility Regulatory Commission
kW/kWh	Kilowatt, Kilowatt hour
LED	Light Emitting Diode
MISO	Midcontinent Independent Transmission System Operator, Inc.
MPS	Market Potential Study
MW,MWh	Megawatt, Megawatt hour
NEF	National Energy Foundation
NPV	Net Present Value
O&M	Operations and Maintenance
PCT	Participant Cost Test
RFQ	Request for Qualification
RIM	Ratepayer Impact Measure
RNC	Residential New Construction
TRM	Technical Reference Manual
UCT	Utility Cost Test

1. Introduction

Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South") provides energy delivery services to approximately 144,000 electric customers and 111,000 natural gas customers located in Southwestern Indiana. Vectren South is a direct, wholly owned subsidiary of Vectren Utility Holdings, Inc. and an indirect subsidiary of Vectren Corporation ("Vectren"), headquartered in Evansville, IN. This Vectren South 2018-2020 Electric Demand Side Management (DSM) Plan ("2018-2020 Plan" or "Plan") describes the details of the electric Energy Efficiency (EE) and Demand Response (DR) programs Vectren South plans to offer in its service territory in 2018-2020.

Vectren South is proposing a 2018-2020 Plan designed to cost effectively reduce energy use by approximately 1% of eligible retail sales each year over the three-year plan. The EE savings goals are consistent with Vectren South's 2016 Integrated Resource Plan ("2016 IRP"), reasonably achievable and cost effective. The Plan includes program budgets, including the direct and indirect costs of energy efficiency programs. The 2018-2020 Plan recommends electric EE and DR programs for the residential and commercial & industrial (C&I) sectors in Vectren South's service territory. Where appropriate, it also describes opportunities for coordination with some of Vectren South's gas EE programs to leverage the best total EE and DR opportunities for customers and to share costs of delivery. Vectren South utilizes a portfolio of DSM programs to achieve demand reductions and energy savings, thereby providing reliable electric service to its customers. Vectren's DSM programs have been approved by the Indiana Utility Regulatory Commission ("Commission" or "IURC") and implemented pursuant to various IURC orders over the years.

2. Vectren South DSM Strategy

Energy efficiency remains at the core of Vectren's culture as the utility strives to partner with customers to help them use energy wisely. The company's tagline, Live Smart, originated from Vectren's turn toward energy efficiency in 2006 with the emergence natural gas energy efficiency programs, and then that effort was bolstered when electric energy efficiency programs were launched in 2010. Vectren employees receive regular communication on the progress toward the company's annual energy efficiency goals and rely on their workforce to serve as ambassadors in driving participation in its energy efficiency programs. One of the utility's goals is to "Be a leader in customer conservation and energy efficiency," and Vectren proactively works with its oversight boards in each state it serves to assemble progressive, cost-effective programs that work toward achieving that objective.

The preferred portfolio of Vectren South's recently filed 2016 Integrated Resource Plan ("2016 IRP") includes EE programs for all customer classes and sets an annual savings target of 1% of retail sales for 2018-2020. The framework for the 2018 - 2020 Plan was modeled at a savings level of 1% of retail sales adjusted for an opt-out rate of 73% eligible load, as provided for in Indiana Code § 8-1-8.5-10 ("Section 10"). The load forecast also includes an ongoing level of EE related to codes and standards embedded in the load forecast projections. Ongoing EE and DR programs are also important given the integration of Vectren South's natural gas and electric EE and DR programs.

A. Integration with Vectren South Gas

Opportunities exist to gain both natural gas and electric savings from some EE programs and measures. In these instances, energy savings will be captured by the respective utility. For the programs where integration opportunities exist, Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric. Below is a list of programs that Vectren South has identified as integrated:

- Residential Prescriptive
- Residential New Construction
- Home Energy Assessment & Weatherization
- Income Qualified Weatherization
- Energy Efficient Schools
- Residential Behavioral Savings
- Commercial and Industrial (C&I) Custom
- Small Business Direct Install
- C&I New Construction
- Building Tune-up
- Multi-Family Retrofit

B. Vectren Oversight Board

The Vectren Oversight Board (VOB) provides input into the planning and evaluation of Vectren South's EE programs. The VOB was formed in 2010 pursuant to the Final Order issued in Cause No. 43427 and included the Indiana Office of the Utility Consumer Counselor (OUCC) and Vectren South as voting members. The Citizens Action Coalition (CAC) was added as a voting member of the VOB in 2013 pursuant to the Final Order issued in Cause No. 44318. In 2014, the Vectren South Electric Oversight Board merged with the Vectren South Gas Oversight Board and Vectren North Gas Oversight to form one governing body, the VOB. Vectren and the VOB have worked collaboratively over the last several years and Vectren requests to continue the current voting structure.

3. Vectren South Planning Process

Vectren South has offered a variety of EE programs since April 2010 and has engaged in a similar planning process each time a new portfolio is presented to the Commission for approval.

The 2018-2020 Plan was developed in conjunction with the 2016 IRP planning process and therefore the 2016 IRP served as a key input into the 2018-2020 Plan. As such, this process aligns with Indiana Code § 8-1-8.5-10 ("Section 10"), which requires that EE goals be consistent with an electricity supplier's IRP.

Consistent with the 2016 IRP preferred portfolio, the framework for the 2018 - 2020 Plan was modeled at a savings level of 1% of retail sales with opt-out assumptions incorporated. Once the level of EE programs to be offered from 2018 through 2020 was established, Vectren South engaged in a process to develop the 2018-2020 Plan. The objective of the planning process was to develop a plan based upon market-specific information for Vectren South's territory, which could be successfully implemented utilizing realistic assessments of achievable market potential.

The program design used an Electric Market Potential Study (MPS) for guidance to validate that the plan estimates were reasonable. While building from the bottom up with estimates from program implementers to help determine participation, this comparison to the MPS allowed the planning team to determine if the results were reasonable.

In 2013, Vectren South engaged EnerNOC, Inc., to conduct an MPS and Action Plan. For this effort, EnerNOC evaluated electric energy efficiency resources in the residential, commercial, and industrial sectors for the years 2015-2019. The study included a detailed, bottom-up assessment of the Vectren South market in the Evansville metropolitan area to deliver a projection of baseline electric energy use, forecasts of the energy savings achievable through efficiency measures, and program designs and strategies to optimally deliver those savings. The study assessed various tiers of technical, economic and achievable potential by sector, customer type and measure.

Given this Plan 2018 through 2020, and the most recent MPS ended in 2019, Vectren South, with VOB approval, engaged Applied Energy Group (AEG), previously EnerNOC, to refresh the MPS for 2018 and 2019 and to extend the analysis to include 2020. Several key data elements of the analysis were updated as part of this effort, specifically:

- Load forecast, which is approximately 4% lower in 2018-2020 than the load forecast used for those years in the original analysis
- The impact of large customer opt-outs on the market potential for the commercial and industrial (C&I) sectors, where 73% of eligible C&I load has elected to opt out of energy efficiency programs and the accompanying surcharge that would otherwise appear on their bill
- LED lighting measures cost and performance data
- Vectren South EE Program performance and budgets
- Projections of avoided energy, capacity, and transmission and distribution (T&D) infrastructure costs
- Vectren South retail rates, discount rates, and line losses

In addition, vendors and other implementation partners who operate the current programs were involved in the planning process by providing suggestions for program changes and enhancements. The vendors and partners also provided technical information about measures to include recommended incentives, estimated participation and estimated implementation costs. This data provided a foundation for the 2018-2020 Plan based on actual experience within Vectren South's territory. These companies also bring their experience operating programs for other utilities. Once the draft version of the 2018-2020 Plan was developed, Vectren South solicited feedback from the VOB for consideration in the final design.

Other sources of program information were also considered. Current evaluations and the Indiana Technical Resource Manual (TRM) were used for adjustments to inputs. In addition, best practices were researched and reviewed to gain insights into the program design of successful EE and DR programs implemented by other utility companies.

VOB feedback was incorporated into the planning process, as applicable.

4. Cost Effectiveness Analysis

Vectren South's last step of the planning process was the cost benefit analysis. Vectren South retained Dr. Richard Stevie, Vice President of Forecasting with Integral Analytics, to complete the cost benefit modeling. Utilizing DSMore, the measures and programs were analyzed for cost effectiveness. The DSMore tool is nationally recognized and used in many states across the country to determine cost-effectiveness. Developed and licensed by Integral Analytics based in Cincinnati, OH, the DSMore cost-effectiveness modeling tool takes hourly prices and hourly energy savings from the specific measures/technologies being considered for the EE program, and then correlates both to weather. This tool looks at more than 30 years of historic weather variability to get the full weather variances appropriately modeled. In turn, this allows the model to capture the low probability, but high consequence weather events and apply appropriate value to them. Thus, a more accurate view of the value of the efficiency measure can be captured in comparison to other alternative supply options.

The outputs of DSMore include all the California Standard Practice Manual results including Total Resource Cost (TRC), Utility Cost Test (UCT), Participant Cost Test (PCT) and Ratepayer Impact Measure (RIM) tests. Inputs into the model include the following: participation rates, incentives paid, energy savings of the measure, life of the measure, implementation costs, and administrative costs, incremental costs to the participant of the high efficiency measure, and escalation rates and discount rates. Vectren South considers the results of each test and ensures that the portfolio passes the TRC test as it includes the total costs and benefits to both the utility and the consumer. The model includes a full range of economic perspectives typically used in EE and DSM analytics. The perspectives include:

- Total Resource Cost Test - shows the combined perspective of the utility and the participating customers. This test compares the level of benefits associated with the reduced energy supply costs to utility programs and participant costs.
- Utility Cost Test - shows the value of the program considering only avoided utility supply cost (based on the next unit of generation) in comparison to program costs.
- Participant Cost Test - shows the value of the program from the perspective of the utility’s customer participating in the program. The test compares the participant’s bill savings over the life of the EE/DR program to the participant’s cost of participation.
- Ratepayer Impact Measure Test - shows the impact of a program on all utility customers through impacts in average rates. This perspective also includes the estimates of revenue losses, which may be experienced by the utility as a result of the program.

The cost effectiveness analysis produces two types of resulting metrics:

- Net Benefits (dollars) = NPV $\sum$ benefits – NPV $\sum$ costs
- Benefit Cost Ratio = NPV $\sum$ benefits ÷ NPV $\sum$ costs

Cost effectiveness analysis is performed using each of the four primary tests. The results of each test reflect a distinct perspective and have a separate set of inputs demonstrating the treatment of costs and benefits. A summary of benefits and costs included in each cost effectiveness test can be found in Appendix A.

5. 2018 - 2020 Plan Objectives and Impact

The framework for the 2018-2020 Plan aligns with the preferred portfolio as filed in the 2016 IRP and was designed to reach a reduction in sales of approximately 1% of eligible retail sales with opt-out assumptions incorporated. Table 1 below provides an overview of energy savings and demand impacts, participation and budget by the residential and C&I sectors and for the total portfolio. Table 2 provides an overview of budget and energy savings by program and by year.

Table 1: 2018-2020 Portfolio Summary of Participation, Impacts & Budget

Residential

Program Year	Participants/ Measures	Annual Energy Savings kWh	Annual Demand Savings kW	Direct Program Budget	First Year Cost/Kwh*
2018	327,374	21,520,612	5,782	$4,663,152	$0.22
2019	347,909	22,025,627	6,021	$4,865,148	$0.22
2020	217,427	19,294,127	5,977	$4,649,484	$0.24

Commercial & Industrial

Program Year	Participants/ Measures	Annual Energy Savings kWh	Annual Demand Savings kW	Direct Program Budget	First Year Cost/Kwh*
2018	7,252	15,135,729	1,648	$3,387,238	$0.22
2019	6,211	16,043,561	1,585	$3,568,128	$0.22
2020	7,638	17,053,515	1,773	$3,720,882	$0.22

Portfolio Participation, Impacts & Budget

Program Year	Participants/ Measures	Annual Energy Savings kWh	Annual Demand Savings kW	Res & C&I Direct Program Budget	Indirect Portfolio Level Budget	Other Costs Budget	Portfolio Total Budget Including Indirect & Other	First Year Cost/Kwh*
2018	334,626	36,656,341	7,430	$8,050,391	$937,436	$500,000	$9,487,827	$0.23
2019	354,120	38,069,188	7,607	$8,433,276	$960,110	$200,000	$9,593,386	$0.23
2020	225,065	36,347,642	7,750	$8,370,366	$960,225	$200,000	$9,530,591	$0.24

*Cost per kWh includes program and indirect costs for budget. First year costs are calculated by dividing total cost by total savings and do not include carry forward costs related to smart thermostat, BYOT and CVR programs.

Table 2: Vectren South 2018 - 2020 Plan Overview by Program

	Total Budget ($)			Total Savings (kWh)			Total Demand (kW)		
Residential Programs	**2018**	**2019**	**2020**	**2018**	**2019**	**2020**	**2018**	**2019**	**2020**
Residential Lighting	$ 942,125	$ 930,451	$ 691,256	7,610,617	8,340,595	6,075,005	942	1,029	791
Residential Prescriptive	$ 635,925	$ 681,609	$ 694,362	1,747,547	1,918,174	1,979,280	1,558	1,775	1,910
Residential New Construction	$ 85,345	$ 87,132	$ 88,940	187,038	187,038	187,038	118	118	118
Home Energy Assessment & Weatherization	$ 526,473	$ 533,934	$ 541,669	863,991	863,991	863,991	192	192	192
Income Qualified Weatherization	$ 841,848	$ 899,806	$ 958,593	959,988	1,046,148	1,130,945	459	499	540
Food Bank - LED Bulb Distribution	$ 174,141	$ 175,308	$ -	1,401,264	1,401,264	-	149	149	0
Energy Efficient Schools	$ 131,696	$ 136,805	$ 119,995	899,706	937,194	645,216	53	53	53
Residential Behavioral Savings	$ 305,622	$ 285,585	$ 286,545	6,470,000	5,970,000	5,600,000	1,351	1,248	1,153
Appliance Recycling	$ 174,759	$ 180,648	$ 186,532	913,771	894,534	884,915	121	118	117
Smart Thermostat Program	$ 97,639	$ 98,222	$ 98,798	-	-	-	-	-	-
CVR Residential	$ 118,786	$ 114,907	$ 230,134	-	-	1,461,047	-	-	263
SmartDLC - Wifi DR/DLC Change-out	$ 517,759	$ 562,148	$ 606,532	466,690	466,690	466,690	600	600	600
BYOT (Bring Your Own Thermostat)	$ 111,036	$ 178,592	$ 146,128	-	-	-	240	240	240
Residential Subtotal	**$ 4,663,152**	**$4,865,148**	**$4,649,484**	**21,520,612**	**22,025,627**	**19,294,127**	**5,782**	**6,021**	**5,977**
C&I Programs	**2018**	**2019**	**2020**	**2018**	**2019**	**2020**	**2018**	**2019**	**2020**
Commercial Prescriptive	$ 729,398	$ 655,370	$ 731,330	4,999,125	4,501,186	5,002,621	378	325	369
Commercial Custom	$ 1,019,072	$ 1,022,184	$ 1,160,256	5,000,000	5,000,000	5,500,000	476	476	524
Small Business Direct Install	$ 1,149,640	$ 1,182,037	$ 1,173,133	4,032,934	3,905,372	3,900,306	667	645	567
Commercial New Construction	$ 214,536	$ 386,092	$ 222,628	502,080	1,835,413	502,080	108	120	108
Building Tune-up	$ 130,880	$ 182,074	$ 261,266	500,000	700,000	1,000,000	1	1	1
Multi-Family Retrofit	$ 34,880	$ 35,074	$ 35,266	101,590	101,590	115,853	18	18	18
CVR Commercial	$ 108,834	$ 105,297	$ 137,003	-	-	1,032,655	-	-	186
Commercial Subtotal	**$ 3,387,238**	**$3,568,128**	**$3,720,882**	**15,135,729**	**16,043,561**	**17,053,515**	**1,648**	**1,585**	**1,773**
Residential & Commercial Subtotal	**$ 8,050,391**	**$8,433,276**	**$8,370,366**	**36,656,341**	**38,069,188**	**36,347,642**	**7,430**	**7,607**	**7,750**
Portfolio Level Costs Subtotal*	$ 937,436	$ 960,110	$ 960,225						
Other Costs Subtotal**	$ 500,000	$ 200,000	$ 200,000						
DSM Portfolio Total including Other Costs	**$ 9,487,827**	**$9,593,386**	**$9,530,591**	**36,656,341**	**38,069,188**	**36,347,642**	**7,430**	**7,607**	**7,750**

*Portfolio level costs include: Contact Center, Online Audit, Outreach & Education, and Evaluation.

**Other Costs include Market Potential Study and Emerging Markets.

A. Plan Savings

The planned savings goal for 2018-2020 was calculated based on a percentage of forecasted weather normalized electric sales for 2018 to 2020 with a target of 1% of eligible retail sales. The forecast is consistent with Vectren South's 2016 IRP sales forecast. Goals are based on gross energy savings with opt-out assumptions incorporated. Table 3 demonstrates the portfolio, residential and C&I energy savings targets at the 1% eligible retail sales level. Table 4 demonstrates the portfolio energy and demand savings by program and by year.

Table 3: Vectren South 2018 - 2020 Plan Portfolio Summary Planned Energy Savings

Portfolio Summary	kWh Savings			kW Savings		
	2018	**2019**	**2020**	**2018**	**2019**	**2020**
Residential Total	21,520,612	22,025,627	19,294,127	5,782	6,021	5,977
Commercial & Industrial Total	15,135,729	16,043,561	17,053,515	1,648	1,585	1,773
Portfolio Total	36,656,341	38,069,188	36,347,642	7,430	7,607	7,750

Table 4: Vectren South 2018 - 2020 Plan Portfolio Planned Energy Savings

Residential	**2018 kWh**	**2018 kW**	**2019 kWh**	**2019 kW**	**2020 kWh**	**2020 kW**
Residential Lighting	7,610,617	942	8,340,595	1,029	6,075,005	791
Residential Prescriptive	1,747,547	1,558	1,918,174	1,775	1,979,280	1,910
Residential New Construction	187,038	118	187,038	118	187,038	118
Home Energy Assessment & Weatherization	863,991	192	863,991	192	863,991	192
Income Qualified Weatherization	959,988	459	1,046,148	499	1,130,945	540
Food Bank - LED Bulb Distribution	1,401,264	149	1,401,264	149	0	0
Energy Efficient Schools	899,706	53	937,194	53	645,216	53
Residential Behavioral Savings	6,470,000	1,351	5,970,000	1,248	5,600,000	1,153
Appliance Recycling	913,771	121	894,534	118	884,915	117
Smart Thermostat Program	-	-	-	-	-	-
CVR Residential	-	-	-	-	1,461,047	263
SmartDLC - Wifi DR/DLC Change-out	466,690	600	466,690	600	466,690	600
BYOT (Bring Your Own Thermostat)	-	240	-	240	-	240
Residential Total	**21,520,612**	**5,782**	**22,025,627**	**6,021**	**19,294,127**	**5,977**
Commercial & Industrial	**2018 kWh**	**2018 kW**	**2019 kWh**	**2019 kW**	**2020 kWh**	**2020 kW**
Commercial Prescriptive	4,999,125	378	4,501,186	325	5,002,621	369
Commercial Custom	5,000,000	476	5,000,000	476	5,500,000	524
Small Business Direct Install	4,032,934	667	3,905,372	645	3,900,306	567
Commercial New Construction	502,080	108	1,835,413	120	502,080	108
Building Tune-up	500,000	1	700,000	1	1,000,000	1
Multi-Family Retrofit	101,590	18	101,590	18	115,853	18
CVR Commercial	-	-	-	-	1,032,655	186
Commercial & Industrial Total	**15,135,729**	**1,648**	**16,043,561**	**1,585**	**17,053,515**	**1,773**
Portfolio Total	**36,656,341**	**7,430**	**38,069,188**	**7,607**	**36,347,642**	**7,750**

B. Plan Budget

The total planned program budget includes the direct and indirect costs of implementing Vectren South's electric energy efficiency programs. In addition, a budget for other costs are being requested as described below.

Direct program costs include three main categories: vendor implementation, program incentives and administration costs. The program budgets were built based upon multiple resources. Program budgets were discussed with program implementers as a basis for the development of this plan. Vendor implementation budgets were estimated using historical data and estimates provided by the current vendors. This helps to assure that the estimates are realistic for successful delivery. Program incentives were calculated by assigning measures with appropriate incentive values based upon existing program incentives, evaluation results and vendor recommendations. Lastly, administrative costs are comprised of internal costs for Vectren South's management and oversight of the programs. Administrative costs were allocated back to programs based on the percent of savings these programs represent as well as estimated staff time spent on programs.

Indirect costs are costs that are not directly tied to a single program, but rather support multiple programs or the entire portfolio. These include: Contact Center, Online Audit, Outreach & Education, and Evaluation, Measurement and Verification (EM&V). These costs are budgeted at the portfolio level.

Other costs are also being requested in the 2018-2020 filed plan. Vectren South requests approval of a budget to include a Market Potential Study for 2020 and beyond and funding for Emerging Markets, which is discussed later in the Plan. Emerging Markets funding allows Vectren's EE portfolio to offer leading-edge program designs for next-generation technologies, services, and engagement strategies to growing markets in the Vectren South territory. This funding will not be used to support existing measures or programs, but rather support new program development or new measures within an existing program. Tables 5 through 8 below list the summary budgets by year, program and category.

Table 5: Vectren South 2018 – 2020 Summary Budgets by Year

Residential	2018	2019	2020	Total Budget
Residential Lighting	$942,125	$930,451	$691,256	$2,563,832
Residential Prescriptive	$635,925	$681,609	$694,362	$2,011,896
Residential New Construction	$85,345	$87,132	$88,940	$261,417
Home Energy Assessment & Weatherization	$526,473	$533,934	$541,669	$1,602,076
Income Qualified Weatherization	$841,848	$899,806	$958,593	$2,700,247
Food Bank - LED Bulb Distribution	$174,141	$175,308	$0	$349,449
Energy Efficient Schools	$131,696	$136,805	$119,995	$388,496
Residential Behavioral Savings	$305,622	$285,585	$286,545	$877,752
Appliance Recycling	$174,759	$180,648	$186,532	$541,939
Smart Thermostat Program	$97,639	$98,222	$98,798	$294,659
CVR Residential	$118,786	$114,907	$230,134	$463,827
SmartDLC - Wifi DR/DLC Change-out	$517,759	$562,148	$606,532	$1,686,439
BYOT (Bring Your Own Thermostat)	$111,036	$178,592	$146,128	$435,756
Residential Total	**$4,663,152**	**$4,865,148**	**$4,649,484**	**$14,177,784**
Commercial & Industrial	**2018**	**2019**	**2020**	**Total Budget**
Commercial Prescriptive	$729,398	$655,370	$731,330	$2,116,098
Commercial Custom	$1,019,072	$1,022,184	$1,160,256	$3,201,512
Small Business Direct Install	$1,149,640	$1,182,037	$1,173,133	$3,504,810
Commercial New Construction	$214,536	$386,092	$222,628	$823,256
Building Tune-up	$130,880	$182,074	$261,266	$574,220
Multi-Family Retrofit	$34,880	$35,074	$35,266	$105,220
CVR Commercial	$108,834	$105,297	$137,003	$351,134
Commercial & Industrial Total	**$3,387,238**	**$3,568,128**	**$3,720,882**	**$10,676,248**
Total Direct Program Costs	**$8,050,391**	**$8,433,276**	**$8,370,366**	**$24,854,032**
Indirect Portfolio Level Costs	**2018**	**2019**	**2020**	**Total Budget**
Contact Center	$63,000	$63,000	$63,000	$189,000
Online Audit	$36,444	$39,806	$42,911	$119,161
Outreach & Education	$410,000	$410,000	$410,000	$1,230,000
Evaluation	$427,992	$447,304	$444,314	$1,319,610
Indirect Portfolio Level Costs Subtotal	**$937,436**	**$960,110**	**$960,225**	**$2,857,771**
Total Portfolio	**$8,987,827**	**$9,393,386**	**$9,330,591**	**$27,711,803**
Other Costs	**2018**	**2019**	**2020**	**Total Budget**
Emerging Markets	$200,000	$200,000	$200,000	$600,000
Market Potential Study	$300,000	$0	$0	$300,000
Other Costs Subtotal	**$500,000**	**$200,000**	**$200,000**	**$900,000**
DSM Portfolio Total including Other Costs	**$9,487,827**	**$9,593,386**	**$9,530,591**	**$28,611,803**

Table 6: Vectren South 2018 Summary Budgets by Category

Residential	Administrative	Implementation	Incentives	Total Budget
Residential Lighting	$ 94,072	$ 225,000	$ 623,053	$ 942,125
Residential Prescriptive	$ 5,880	$ 219,860	$ 410,185	$ 635,925
Residential New Construction	$ 17,639	$ 39,856	$ 27,850	$ 85,345
Home Energy Assessment & Weatherization	$ 47,036	$ 479,437	$ -	$ 526,473
Income Qualified Weatherization	$ 35,277	$ 806,571	$ -	$ 841,848
Food Bank - LED Bulb Distribution	$ 35,277	$ 138,864	$ -	$ 174,141
Energy Efficient Schools	$ 44,096	$ 87,600	$ -	$ 131,696
Residential Behavioral Savings	$ 29,398	$ 276,224	$ -	$ 305,622
Appliance Recycling	$ 11,759	$ 115,500	$ 47,500	$ 174,759
Smart Thermostat Program	$ 17,639	$ 40,000	$ 40,000	$ 97,639
CVR Residential	$ 2,940	$ 115,846	$ -	$ 118,786
SmartDLC - Wifi DR/DLC Change-out	$ 11,759	$ 484,000	$ 22,000	$ 517,759
BYOT (Bring Your Own Thermostat)	$ 47,036	$ 26,000	$ 38,000	$ 111,036
Residential Subtotal	**$ 399,806**	**$ 3,054,758**	**$1,208,588**	**$ 4,663,152**

Commercial & Industrial	Administrative	Implementation	Incentives	Total Budget
Commercial Prescriptive	$ 29,398	$ 200,000	$ 500,000	$ 729,398
Commercial Custom	$ 94,072	$ 325,000	$ 600,000	$ 1,019,072
Small Business Direct Install	$ 2,940	$ 321,700	$ 825,000	$ 1,149,640
Commercial New Construction	$ 47,036	$ 102,500	$ 65,000	$ 214,536
Building Tune-up	$ 5,880	$ 100,000	$ 25,000	$ 130,880
Multi-Family Retrofit	$ 5,880	$ 10,000	$ 19,000	$ 34,880
CVR Commercial	$ 2,940	$ 105,894	$ -	$ 108,834
Commercial Subtotal	**$ 188,144**	**$ 1,165,094**	**$2,034,000**	**$ 3,387,238**
Residential & Commercial Subtotal	**$ 587,950**	**$ 4,219,853**	**$3,242,588**	**$ 8,050,391**

Indirect Costs		Total Budget
Contact Center		$ 63,000
Online Audit		$ 36,444
Outreach & Education		$ 410,000
Evaluation		$ 427,992
DSM Portfolio Total		**$ 8,987,827**

Other Costs		Total Budget
Emerging Markets		$ 200,000
Market Potential Study		$ 300,000
Other Costs Subtotal		**$ 500,000**
DSM Portfolio Total including Other Costs		**$ 9,487,827**

Table 7: Vectren South 2019 Summary Budgets by Category

Residential	Administrative	Implementation	Incentives	Total Budget
Residential Lighting	$ 97,184	$ 225,000	$ 608,267	$ 930,451
Residential Prescriptive	$ 6,074	$ 226,800	$ 448,735	$ 681,609
Residential New Construction	$ 18,222	$ 41,060	$ 27,850	$ 87,132
Home Energy Assessment & Weatherization	$ 48,592	$ 485,342	$ -	$ 533,934
Income Qualified Weatherization	$ 36,444	$ 863,362	$ -	$ 899,806
Food Bank - LED Bulb Distribution	$ 36,444	$ 138,864	$ -	$ 175,308
Energy Efficient Schools	$ 45,555	$ 91,250	$ -	$ 136,805
Residential Behavioral Savings	$ 30,370	$ 255,215	$ -	$ 285,585
Appliance Recycling	$ 12,148	$ 122,000	$ 46,500	$ 180,648
Smart Thermostat Program	$ 18,222	$ 40,000	$ 40,000	$ 98,222
CVR Residential	$ 3,037	$ 111,870	$ -	$ 114,907
SmartDLC - Wifi DR/DLC Change-out	$ 12,148	$ 506,000	$ 44,000	$ 562,148
BYOT (Bring Your Own Thermostat)	$ 48,592	$ 84,000	$ 46,000	$ 178,592
Residential Subtotal	**$ 413,032**	**$ 3,190,764**	**$1,261,352**	**$ 4,865,148**

Commercial & Industrial	Administrative	Implementation	Incentives	Total Budget
Commercial Prescriptive	$ 30,370	$ 200,000	$ 425,000	$ 655,370
Commercial Custom	$ 97,184	$ 325,000	$ 600,000	$ 1,022,184
Small Business Direct Install	$ 3,037	$ 319,000	$ 860,000	$ 1,182,037
Commercial New Construction	$ 48,592	$ 112,500	$ 225,000	$ 386,092
Building Tune-up	$ 6,074	$ 141,000	$ 35,000	$ 182,074
Multi-Family Retrofit	$ 6,074	$ 10,000	$ 19,000	$ 35,074
CVR Commercial	$ 3,037	$ 102,260	$ -	$ 105,297
Commercial Subtotal	**$ 194,368**	**$ 1,209,760**	**$2,164,000**	**$ 3,568,128**
Residential & Commercial Subtotal	**$ 607,400**	**$ 4,400,524**	**$3,425,352**	**$ 8,433,276**

Indirect Costs		Total Budget
Contact Center		$ 63,000
Online Audit		$ 39,806
Outreach & Education		$ 410,000
Evaluation		$ 447,304
DSM Portfolio Total		**$ 9,393,386**

Other Costs		Total Budget
Emerging Markets		$ 200,000
Market Potential Study		$ -
Other Costs Subtotal		**$ 200,000**
DSM Portfolio Total including Other Costs		**$ 9,593,386**

Table 8: Vectren South 2020 Summary Budgets by Category

Residential	Administrative	Implementation	Incentives	Total Budget
Residential Lighting	$ 100,256	$ 150,000	$ 441,000	$ 691,256
Residential Prescriptive	$ 6,266	$ 234,111	$ 453,985	$ 694,362
Residential New Construction	$ 18,798	$ 42,292	$ 27,850	$ 88,940
Home Energy Assessment & Weatherization	$ 50,128	$ 491,541	$ -	$ 541,669
Income Qualified Weatherization	$ 37,596	$ 920,997	$ -	$ 958,593
Food Bank - LED Bulb Distribution	$ -	$ -	$ -	$ -
Energy Efficient Schools	$ 46,995	$ 73,000	$ -	$ 119,995
Residential Behavioral Savings	$ 31,330	$ 255,215	$ -	$ 286,545
Appliance Recycling	$ 12,532	$ 128,000	$ 46,000	$ 186,532
Smart Thermostat Program	$ 18,798	$ 40,000	$ 40,000	$ 98,798
CVR Residential	$ 40,729	$ 189,405	$ -	$ 230,134
SmartDLC - Wifi DR/DLC Change-out	$ 12,532	$ 528,000	$ 66,000	$ 606,532
BYOT (Bring Your Own Thermostat)	$ 50,128	$ 42,000	$ 54,000	$ 146,128
Residential Subtotal	**$ 426,088**	**$ 3,094,561**	**$1,128,835**	**$ 4,649,484**
Commercial & Industrial	**Administrative**	**Implementation**	**Incentives**	**Total Budget**
Commercial Prescriptive	$ 31,330	$ 250,000	$ 450,000	$ 731,330
Commercial Custom	$ 100,256	$ 400,000	$ 660,000	$ 1,160,256
Small Business Direct Install	$ 3,133	$ 345,000	$ 825,000	$ 1,173,133
Commercial New Construction	$ 50,128	$ 107,500	$ 65,000	$ 222,628
Building Tune-up	$ 6,266	$ 205,000	$ 50,000	$ 261,266
Multi-Family Retrofit	$ 6,266	$ 10,000	$ 19,000	$ 35,266
CVR Commercial	$ 3,133	$ 133,870	$ -	$ 137,003
Commercial Subtotal	**$ 200,512**	**$ 1,451,370**	**$2,069,000**	**$ 3,720,882**
Residential & Commercial Subtotal	**$ 626,600**	**$ 4,545,931**	**$3,197,835**	**$ 8,370,366**
Indirect Costs				**Total Budget**
Contact Center				$ 63,000
Online Audit				$ 42,911
Outreach & Education				$ 410,000
Evaluation				$ 444,314
DSM Portfolio Total				**$ 9,330,591**
Other Costs				**Total Budget**
Emerging Markets				$ 200,000
Market Potential Study				$ -
Other Costs Subtotal				**$ 200,000**
DSM Portfolio Total including Other Costs				**$ 9,530,591**

C. Cost Effectiveness Results

The total portfolio for the Vectren South programs passes the TRC and UCT test for both the Residential and Commercial & Industrial sectors. Table 9 below confirms that all programs pass the TRC at greater than one. In completing the cost effectiveness testing, Vectren South used 7.29% as the weighted average cost of capital (WACC) as approved by the Commission on April 27, 2011 in Cause No. 43839. For the 2018 - 2020 Plan, Vectren South utilized the avoided costs from the 2016 IRP.

Table 9: Vectren South 2018-2020 Plan Cost Effectiveness Results without Performance Incentive

Residential	TRC	UCT	RIM	Participant	TRC NPV $	UCT NPV $	Lifetime Cost/kWh	1st Year Cost/kWh
Residential Lighting	4.20	6.19	0.86	5.18	$ 11,354,267	$ 12,498,117	$0.01	$0.12
Residential Prescriptive	1.28	2.68	0.99	1.04	$ 1,113,799	$ 3,153,088	$0.05	$0.36
Residential New Construction	1.25	2.02	0.79	1.39	$ 98,697	$ 248,511	$0.06	$0.47
Home Energy Assessment & Weatherization	1.19	1.19	0.48	n/a	$ 277,622	$ 277,622	$0.06	$0.62
Income Qualified Weatherization	1.30	1.30	0.59	n/a	$ 752,131	$ 752,131	$0.08	$0.86
Food Bank - LED Bulb Distribution	8.42	8.42	0.88	n/a	$ 2,503,138	$ 2,503,138	$0.01	$0.12
Energy Efficient Schools	3.28	3.28	0.53	n/a	$ 829,622	$ 829,622	$0.02	$0.16
Residential Behavioral Savings	1.54	1.54	0.50	n/a	$ 440,606	$ 440,606	$0.04	$0.05
Appliance Recycling	1.19	1.02	0.36	n/a	$ 83,146	$ 12,513	$0.05	$0.20
Smart Thermostat Program	-	-	-	n/a	$ (162,984)	$ (275,015)	n/a	n/a
CVR Residential	1.59	1.59	0.66	n/a	$ 580,613	$ 580,613	$0.07	$0.16
SmartDLC - Wifi DR/DLC Change-out	1.90	1.75	0.92	n/a	$ 1,301,580	$ 1,181,234	$0.10	$1.11
BYOT (Bring Your Own Thermostat)	2.80	1.92	1.92	n/a	$ 498,223	$ 370,438	n/a	n/a
Residential Portfolio	**2.18**	**2.64**	**0.76**	**4.06**	**$19,670,459**	**$22,572,616**	**$0.04**	**$0.21**
Commercial & Industrial	**TRC**	**UCT**	**RIM**	**Participant**	**TRC NPV $**	**UCT NPV $**	**Lifetime Cost/kWh**	**1st Year Cost/kWh**
Commercial Prescriptive	1.63	3.68	0.51	2.70	$ 2,811,420	$ 5,291,462	$0.02	$0.15
Commercial Custom	2.05	3.27	0.52	3.59	$ 5,003,931	$ 6,772,616	$0.02	$0.21
Small Business Direct Install	5.34	2.38	0.53	24.51	$ 6,333,499	$ 4,520,941	$0.03	$0.30
Commercial New Construction	2.01	1.69	0.45	9.55	$ 652,266	$ 530,199	$0.03	$0.29
Building Tune-up	1.09	1.13	0.34	9.35	$ 46,816	$ 67,027	$0.04	$0.26
Multi-Family Retrofit	3.99	2.28	0.53	24.86	$ 167,808	$ 125,751	$0.03	$0.33
CVR Commercial	1.30	1.30	0.55	n/a	$ 219,929	$ 219,929	$0.07	$0.13
Commercial & Industrial Total	**2.21**	**2.69**	**0.51**	**4.57**	**$15,235,668**	**$17,527,926**	**$0.02**	**$0.22**
Indirect Portfolio Level Costs					$ (2,666,479)	$ (2,666,479)		
Total Portfolio	**2.01**	**2.40**	**0.61**	**4.31**	**$32,239,647**	**$37,434,062**	**$0.03**	**$0.24**

First year costs are calculated by diving total cost by total savings and do not include carry forward costs related to smart thermostat, BYOT and CVR programs.

Table 9.1: Vectren South 2018-2020 Plan Cost Effectiveness Results including Performance Incentive

Including Performance Incentive	TRC	UCT	RIM	Participant	TRC NPV $	UCT NPV $	Lifetime Cost/kWh	1st Year Cost/kWh
Total Portfolio	**1.80**	**2.11**	**0.59**	**4.31**	**$28,624,007**	**$33,818,421**	**$0.04**	**$0.27**

*Utility Performance Incentive does not include IQW, 2016 Smart Tstat, or CVR.

6. New or Modified Program Initiatives

Vectren South's 2018-2020 filing largely extends the existing momentum of the portfolio of programs from 2016-2017 while applying the lessons learned from Vectren's program experience and evaluations as well as making refinements to key data and assumptions as described in this document.

Below is a summary which outlines notable changes for the 2018-2020 Plan from previous filings. More in depth details on the following topics can be found within the Program Descriptions portion of this document.

A. Residential Lighting

All programs within this filing will utilize light emitting diode (LED) lighting technologies per evaluation recommendations. This shift began in 2016 and the 2017 portfolio, as a whole, shifted focus from Compact Fluorescent Lamp (CFL) lamps to LED bulbs where performance, price and market readiness have all improved dramatically in recent years.

Additionally, new light bulbs standards are proposed to go into effect in 2020 due to the Energy Independence and Security Act (EISA). As proposed, this legislation would change the baseline and available savings for general service bulbs. The future of the 2020 EISA legislation is uncertain, thus Vectren will include LED bulbs in the plan for all three years. The incorporation of LED bulbs in 2020 is with the understanding that the measure's inclusion is pending regulatory outcomes.

There is still significant opportunity in the residential lighting market and thus Vectren plans to continue this offering as long as the market and legislation will allow. Lighting programs are consistently highly cost-effective and critical to the advancement of increased efficiency.

B. LED Food Bank

The LED Food Bank program was first offered in 2016 to help meet goals and serve the IQW population. This program will be part of the standard portfolio offering in 2018-2019 (2020 is not included due to EISA uncertainty). The program has been well received by food banks and pantries and Vectren South expects to see continued participation in 2018 and 2019.

C. Residential Prescriptive

Starting in 2018, duct sealing measure within the residential prescriptive program will require a small co-pay of $50 by the customer. The purpose of the duct sealing measure change is to increase participation and promotion of deeper retrofit measures in homes.

D. Smart Thermostat Program Expansion

In 2016, Vectren South conducted a field study designed to analyze the EE and DR benefits associated with smart thermostats. Between the months of April and May 2016, Vectren South installed approximately 2,000 smart thermostats (1,000 Honeywell and 1,000 Nest) in customer homes. The program is currently under evaluation to measure effectiveness. Vectren South anticipates continuing to pay incentives to these 2,000 customers, who are currently enrolled in Vectren South's Summer Cycler program. In addition, and as a result of the field study, Vectren South anticipates expanding its Smart Thermostat program by offering the following two new programs during 2018 through 2020: (1) DLC Change-out program and (2) Bring Your Own Thermostat (BYOT) program. A description of these new programs is included.

E. Commercial & Industrial Prescriptive

Based upon input from the VOB during the planning process, Vectren South added several agricultural measures to the prescriptive measure offering list including:

- Livestock Waterer
- Agriculture - Poultry Farm LED Lighting
- VSD Milk Pump
- High Volume Low Speed Fans
- High Speed Fans (Ventilation and Circulation)
- Dairy Plate Cooler
- Heat Mat (Single, ~14x60")
- Automatic Milker Take Off
- HE Diary Scroll Compressor
- Heat Reclaimer (No Pre-cooler Installed)

F. Commercial & Industrial Targeted Outreach

Vectren South's Commercial & Industrial Programs will seek out higher participation levels from schools, civic/government buildings and non-profit organizations and through a concentrated outreach approach. The concerted outreach will directly engage these segments to inform them of energy-saving opportunities and the available rebates through existing programs. Additional consideration can be provided to align program engagement with peak times to undertake energy efficiency projects: for schools, this means helping them schedule projects to be completed during summer vacations; for government institutions, this means planning around their fiscal cycles.

With this targeted outreach approach, Vectren South plans to assist 30 schools, 15 governmental buildings and 60 non-profit organizations in 2018-2020. Schools will likely receive support through the Prescriptive and Custom programs, while civic/government buildings and non-profit organizations may qualify for the Small Business Energy Savings program benefits.

G. Multi-Family Retrofit

The Multi-Family Retrofit program was offered as a small pilot starting in 2017 and will continue to be available to the Commercial & Industrial sector in 2018-2020. This program was initiated to continue to serve the multi-family sector as the integrated Multi-Family Direct Install program was discontinued in 2017 due to market saturation.

H. Emerging Markets

The Emerging Markets funding allows Vectren South's DSM portfolio to offer leading-edge program designs for next-generation technologies, services, and engagement strategies to growing markets in the Vectren South territory. Incentives promoted through this program may range from innovative rebate offerings to engineering and trade ally assistance to demand-control services that encourage early adoption of new, efficient technologies in high-impact market sectors. Depending on the development of certain technologies and growth areas in the service territory, a wide variety of projects and services are eligible. Because this program will focus on innovative new approaches and leading the DSM market, the exact list of measures cannot be set at this time. However, potential measures and services include: new technologies, such as Advanced Lighting Controls; new strategies for achieving significant energy savings, such as midstream incentives, contractor bids to provide energy efficiency projects, and targeting high-impact market sectors; and integrated DSM (iDSM) approaches, such as demand response, combined energy efficiency and demand response measures, and load shifting. This funding will not be used to support existing measures or programs, but rather support new program development or new measures within an existing program

7. Program Descriptions

A. Residential Lighting

The Residential Lighting Program is a market-based residential EE program designed to reach residential customers through retail outlets. The program consists of a buy-down strategy that provides incentives to consumers to facilitate the purchase of EE lighting products. The overall program goal is to increase the penetration of ENERGY STAR qualified lighting products based on the most up-to-date standards. As of 2017, the Residential Lighting program shifted 100% to LED bulbs.

There is still significant opportunity in the residential lighting market and thus Vectren plans to continue this offering as long as the market and legislation will allow. Lighting programs are consistently highly cost-effective and critical to the advancement of increased efficiency.

The future of the 2020 EISA legislation is uncertain, thus Vectren will include LED bulbs in the plan for all three years. The incorporation of LED bulbs in 2020 is with the understanding that the measure's inclusion is pending regulatory outcomes and uses conservative estimates.

Table 11: Residential Lighting Program Budget & Energy Savings Targets

Market	Program	2018	2019	2020	Total Program
Residential	**Residential Lighting**				
	Number of Measures	222,863	246,086	163,416	632,365
	Energy Savings kWh	7,610,617	8,340,595	6,075,005	22,026,217
	Peak Demand kW	942.2	1,028.9	791.4	2,762.4
	Total Program Budget $	942,125	930,451	691,256	2,563,832
	Per Participant Avg Energy Savings (kWh)*	34.1	33.9	37.2	34.8
	Per Participant Avg Demand Savings (kW)*				0.004
	Weighted Avg Measure Life*				15
	Net To Gross Ratio				67%

Eligible Customers

Any customer of a participating retailer in Vectren South's electric territory.

Marketing Plan

The program is designed to reach residential customers through retail outlets. Proposed marketing efforts include point of purchase promotional activities, the use of utility bill inserts and customer emails, utility web site and social media promotions and coordinated advertising with selected manufacturers and retail outlets.

Barriers/Theory

The program addresses the market barriers by empowering customers to take advantage of new lighting technologies through education and availability in the marketplace; accelerating the adoption of proven energy efficient technologies through incentives to lower price; and working with retailers to allow them to sell more high efficient products.

Initial Measures, Products and Services

The measures will include a variety of ENERGY STAR qualified lighting products currently available at retailers in Indiana, including LED bulbs, fixtures and ceiling fans.

Program Delivery

Vectren South will oversee the program and partner with Ecova to deliver the program.

Evaluation, Measurement and Verification

The implementation contractor will verify the paperwork of the participating retail stores. They will also spot check stores to assure that the program guidelines are being followed. A third party evaluator will evaluate the program using standard EM&V protocols.

B. Residential Prescriptive

Program Description

The program, also called Residential Efficient Products, is designed to incent customers to purchase energy efficient equipment by covering part of the incremental cost. The program also offers home weatherization rebates to residential customers for attic insulation, wall insulation and duct sealing. If a product vendor or contractor chooses to do so, the rebates can be presented as an "instant discount" to Vectren South residential customers on their invoice.

Table 12: Budget & Energy Savings Targets

Market	Program	2018	2019	2020	Total Program
Residential	**Residential Prescriptive**				
	Number of Measures	4,093	6,445	6,595	17,133
	Energy Savings kWh	1,747,547	1,918,174	1,979,280	5,645,001
	Peak Demand kW	1,558.1	1,775.2	1,910.2	5,243.5
	Total Program Budget $	635,925	681,609	694,362	4,037
	Per Participant Avg Energy Savings (kWh)*				329.5
	Per Participant Avg Demand Savings (kW)*				0.306
	Weighted Avg Measure Life*				17
	Net To Gross Ratio				52%

Eligible Customers

Any residential customer located in the Vectren South electric service territory. For the equipment rebates, the applicant must reside in a single-family home or multi-family complex with up to 12 units. Only single-family homes are eligible for insulation and duct sealing remediation measures.

Marketing Plan

The marketing plan includes program specific materials that will target contractors, trade allies, distributors, manufacturers, industry organizations and appropriate retail outlets in the Heating, Ventilation and Air Conditioning (HVAC) industry. Marketing outreach medium include targeted direct marketing, direct contact by vendor personnel, trade shows and trade associations. Vectren will also use web banners, bill inserts, customer emails, social media outreach, press releases and mass market advertising. Program marketing will direct customers and contractors to the Vectren South website or call center for additional information.

Barriers/Theory

The initial cost is one of the key barriers. Customers do not always understand the long-term benefits of the energy savings from efficient alternatives. Trade allies are also often reluctant to sell the higher cost items as they do not want to be the high cost bidder. Incentives help address the initial cost issue and provide a good reason for Trade Allies to promote these higher efficient options.

Initial Measures, Products and Services

Details of the measures, savings, and incentives can be found in Appendix B. Measures included in the program will change over time as baselines change, new technologies become available and customer needs are identified.

Program Delivery

Vectren South will oversee the program and will partner with CLEAResult to deliver the program.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

As part of the Quality Assurance/Quality Control process, the vendor will provide 100% paper verification that the equipment/products purchased meet the program efficiency standards and a field verification of 5% of the measures installed. A third party evaluator will review the program using appropriate EM&V protocols.

C. Residential New Construction

Program Description

The Residential New Construction (RNC) program produces long-term energy savings by encouraging the construction of single-family homes, duplexes, or end-unit townhomes with only one shared wall that are inspected and evaluated through the Home Efficiency Rating System (HERS). Builders can select from two rebate tiers for participation. Gold Star homes must achieve a HERS rating of 61 to 65. Platinum Star homes must meet a HERS rating of 60 or less.

The RNC Program provides incentives and encourages home builders to construct homes that are more efficient than current building codes and address the lost opportunities in this customer segment by promoting EE at the time the initial decisions are being made. The Residential New Construction Program will work closely with builders, educating them on the benefits of energy efficient new homes. Homes may feature additional insulation, better windows, and higher efficiency appliances. The homes should also be more efficient and comfortable than standard homes constructed to current building codes.

Table 13: Program Budget & Energy Savings Targets

Market	Program	2018	2019	2020	Total Program
Residential	**Residential New Construction**				
	Number of Homes	139	139	139	417
	Energy Savings kWh	187,038	187,038	187,038	561,114
	Peak Demand kW	118.0	118.0	118.0	354.0
	Total Program Budget $	85,345	87,132	88,940	261,417
	Per Participant Avg Energy Savings (kWh)*				1345.6
	Per Participant Avg Demand Savings (kW)*				0.849
	Weighted Avg Measure Life*				25
	Net To Gross Ratio				50%

Eligible Customers

Any customer or home builder constructing an eligible home in the Vectren South service territory.

Marketing Plan

In order to move the market toward an improved home building standard, education will be required for home builders, architects and designers as well as customers buying new homes. A combination of in-person meetings with these market participants as well as other educational methods will be necessary.

Barriers/Theory

The Residential New Construction program addresses the primary barriers of first cost as well as builder and customer knowledge. First cost is addressed by program incentives to help reduce the cost of the EE upgrades. The program provides opportunities for builders and developers to gain knowledge and skills concerning EE building practices and coaches them on application of these skills. The HERS rating system allows customers to understand building design and construction improvements through a rating system completed by professionals.

Incentive Strategy

Program incentives are designed to be paid to both all-electric and combination homes that have natural gas heating. It is important to note that the program is structured such that an incentive will not be paid for an all-electric home that has natural gas available to the home site. Incentives can be paid to either the home builder or the customer/account holder. Incentives will be based on the rating tier qualification. For all-electric homes, where Vectren South natural gas service is not available, the initial incentives will be:

Tier	HERS Rating	Total Incentive
Platinum	60 or less	$800
Gold	61 to 65	$700

For homes with central air conditioning and Vectren South natural gas space heating, the electric portion of the incentive will be:

Tier	HERS Rating	Total Incentive	Gas Portion	Electric Portion
Platinum	60 or less	$800	$600	$200
Gold	61 to 65	$700	$525	$175

Program Delivery

Vectren South will oversee the program and will partner with CLEAResult to deliver the program.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory.

Evaluation, Measurement and Verification

Field inspections will occur at least once during construction and upon completion by a certified HERS Rater. As part of the Quality Assurance/Quality Control process, the vendor will provide 100% paper verification that the equipment/products purchased meet the program efficiency standards. A third party evaluator will evaluate the program using standard EM&V protocols.

D. Home Energy Assessments & Weatherization

Program Description

The Home Energy Assessment and Weatherization Program will be offered jointly by Vectren South Gas and Electric. This program targets a hybrid phased approach that combines helping customers analyze and understand their energy use via an on-site energy assessment, providing direct installation of energy efficient measures including low-flow water fixtures, LED bulbs and thermostats, as well as provide deeper retrofit measures.

- Phase 1 - Assessors will perform a walk-through assessment of the home, collecting data for use in identifying cost-effective energy efficient improvements and appropriate direct install measures. Audit report provided to customer onsite will showcase deeper retrofit measure opportunities within the home.

- Phase 2 - If the home is eligible for air sealing and/or duct sealing, the Assessor will provide the information to the customer for scheduling the Phase 2 appointment via the online scheduling portal for a co-pay of $50. Customers who choose to install attic insulation will be referred to the Residential Energy Efficient Rebate Program.

Customers can schedule an assessment appointment in one of the following two ways: (1) by visiting vectren.com/saveenergy to schedule an appointment through self-booking tool; or (2) calling the call center to speak with a program representative. Customers who opt to receive email notifications will receive confirmation and appointment reminders prior to the assessment.

Table 14: Home Energy Assessments & Weatherization Budget & Energy Savings Targets

Market	Program	2018	2019	2020	Total Program
Residential	**Home Energy Assessment & Weatherization**				
	Number of Homes	1,210	1,210	1,210	3,630
	Energy Savings kWh	863,991	863,991	863,991	2,591,973
	Peak Demand kW	191.6	192.0	192.0	575.6
	Total Program Budget $	526,473	533,934	541,669	1,602,076
	Per Participant Avg Energy Savings (kWh)*				714.0
	Per Participant Avg Demand Savings (kW)*				0.159
	Weighted Avg Measure Life*				12
	Net To Gross Ratio				98%

Eligible Customers

Vectren South residential customers with electric service at a single-family residence, provided the home was not built within the past five years and has not had an audit within the last three years. Additionally, the home should be owner-occupied (or renter where occupants have the electric service in their name).

Marketing Plan

Proposed marketing efforts include utilizing direct mailers, email blasts, Vectren South online audit tools, bill inserts, social media outreach, as well as other outreach and education efforts and promotional campaigns throughout the year to ensure participation levels are maintained.

Barriers/Theory

The primary barrier addressed through this program is customer education and awareness. Often customers do not understand what opportunities exist to reduce their home energy use. This program not only informs the customer but helps them start down the path of energy savings by directly installing low-cost measures. The program is also a "gateway" to other Vectren South gas and electric programs.

Initial Measures, Products and Services

The direct install measures available for installation at no cost include:

- Kitchen & Bathroom Aerators
- Filter Whistle
- LED bulbs
- Low Flow Showerhead
- Pipe Wrap
- Water Heater Temperature Setback
- Wi-fi Thermostat

For customers who elect to move forward with Phase 2, Duct Sealing and Air Sealing are available for a $50 co-pay.

Program Delivery

Vectren South will oversee the program and will partner with CLEAResult to deliver the program.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

To assure compliance with program guidelines, field visits with auditors will occur as well as spot check verifications of measure installations. A third party evaluator will evaluate the program using standard EM&V protocols.

E. Income Qualified Weatherization

Program Description

The Income Qualified Weatherization program is designed to produce long-term energy and demand savings in the residential market. The program is designed to provide weatherization upgrades to low-income homes that otherwise would not have been able to afford the energy saving measures. The program provides direct installation of energy-saving measures and educates consumers on ways to reduce energy consumption. Customers eligible through the Income Qualified Weatherization Program will have opportunity to receive deeper retrofit measures including refrigerators, attic insulation, duct sealing, and air infiltration reduction. This year, we will engage with the manufactured homes population and offer the same measures offered to single family homes.

Collaboration and coordination between gas and electric low-income programs along with state and federal funding is recommended to provide the greatest efficiencies among all programs. The challenge of meeting the goals set for this program have centered on health and safety as well as customer cancellations and scheduling. Vectren South is committed to finding innovative solutions to these areas. A health and safety budget has been established, and we continue to work on improving methods of customer engagement with various confirmations via phone and email reminders prior to the appointment.

Table 15: Income Qualified Weatherization Budget & Energy Savings Targets

Market	Program	2018	2019	2020	Total Program
Residential	**Income Qualified Weatherization**				
	Number of Homes	475	500	525	1,500
	Energy Savings kWh	959,988	1,046,148	1,130,945	3,137,081
	Peak Demand kW	458.8	499.4	540.2	1,498.4
	Total Program Budget $	841,848	899,806	958,593	2,700,247
	Per Participant Avg Energy Savings (kWh)*				2091.4
	Per Participant Avg Demand Savings (kW)*				0.999
	Weighted Avg Measure Life*				14
	Net To Gross Ratio				100%

Eligible Customers

The Residential Low Income Weatherization Program targets single-family and manufactured homeowners and tenants who have electric service in their name with Vectren South and a total household income up to 200% of the federally-established poverty level.

Marketing Plan

Vectren South will provide a list to the implementation contractor of high consumption customers who have received Energy Assistance Program (EAP) funds within the past 12 months to help prioritize those customers who will benefit most from the program. This will also help in any direct marketing activities to specifically target those customers.

Barriers/Theory

Lower-income homeowners do not have the money to make even simple improvements to lower their energy usage and often live in homes with the most need for EE improvements. They may also lack the knowledge, experience, or capability to do the work. Health and safety can also be at risk for low-income homeowners, as their homes typically are not as “tight”, and indoor air quality can be compromised. In order to increase participation and eligibility, Vectren South has incorporated a Health and Safety budget of $250 per home. This program provides those customers with basic improvements to help them start saving energy without needing to make the investment themselves.

Initial Measures, Products and Services

Measures available for installation will vary based on the home and include:

- LED bulbs/lamps
- Low flow kitchen and bath aerators
- Low flow showerheads
- Pipe wrap
- Filter whistles
- Infiltration reduction
- Attic insulation
- Duct repair, seal and insulation
- Refrigerator replacement
- Programmable/Smart thermostat
- Smart power strips

Program Delivery

Vectren South will oversee the program and will partner with CLEAResult to deliver the program.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

To assure quality installations, 5% of the installations will be field inspected. A third party evaluator will evaluate the program using standard EM&V protocols.

F. LED Food Bank

Program Description

The food bank program provides LED bulbs to food pantries in Vectren South's electric service territory. This program targets hard to reach, low income customers in the Vectren South electric territory. All food pantry recipients must provide proof of income qualification to receive the food baskets.

The program implementer purchases bulbs from a manufacturer and bulbs are shipped in bulk to the partner food bank. Food banks then distribute the bulbs to the respective food pantries in its network. Pantries include bulbs when assembling food packages and bulbs are provided to food recipients.

Table 16: LED Food Bank Budget & Energy Savings Targets

Market	Program	2018	2019	2020	Total Program
Residential	**Food Bank - LED Bulb Distribution**				
	Number of Measures	50,496	50,496	0	100,992
	Energy Savings kWh	1,401,264	1,401,264	0	2,802,528
	Peak Demand kW	148.8	148.8	0.0	297.6
	Total Program Budget $				349,449
	Per Participant Avg Energy Savings (kWh)*				27.8
	Per Participant Avg Demand Savings (kW)*				0.003
	Weighted Avg Measure Life*				15
	Net To Gross Ratio				100%

Eligible Customers

Any participant visiting a food pantry in Vectren South's electric territory.

Marketing Plan

The program will be marketed directly to food banks in the Vectren South electric service territory as well as other channels identified by the implementation contractor.

Barriers/Theory

Lower-income homeowners do not have the money to make even simple improvements to lower their energy usage and often live in homes with the most need for EE improvements. They may also lack the knowledge, experience, or capability to do the work. This program also addresses the barrier of education and awareness of EE opportunities. Working through food banks, participants receive LED bulbs and are educated about opportunities to save energy.

Initial Measures, Products and Services

Each participating food pantry will place a bundle of four (4) LED bulbs in food packages.

Program Delivery

Vectren South will oversee the program and will partner with CLEAResult and the Tri-State Area Food Bank to deliver the program.

Evaluation, Measurement and Verification

A third party evaluator will evaluate the program using standard EM&V protocols. A postcard will be provided to each participant to help acquire necessary information for EM&V. The postcard will be a postage paid reply card and 'drop box' will also be provided for customers to voluntarily supply their information for verification.

G. Energy Efficient Schools

Program Description

The Energy Efficient Schools Program is designed to impact students by teaching them how to conserve energy and to produce cost effective electric savings by influencing students and their families to focus on the efficient use of electricity.

The program consists of a school education program for 5th grade students attending schools served by Vectren South. To help in this effort, each child that participates will receive a take-home energy kit with various energy saving measures for their parents to install in the home. The kits, along with the in-school teaching materials, are designed to make a lasting impression on the students and help them learn ways to conserve energy.

Table 17: Energy Efficient Schools Budget & Energy Savings Targets

Market	Program	2018	2019	2020	Total Program
Residential	**Energy Efficient Schools**				
	Number of Kits	2,400	2,500	2,600	7,500
	Energy Savings kWh	899,706	937,194	645,216	2,482,115
	Peak Demand kW	52.8	52.8	52.8	158.4
	Total Program Budget $	131,696	136,805	119,995	388,496
	Per Participant Avg Energy Savings (kWh)*				330.9
	Per Participant Avg Demand Savings (kW)*				0.021
	Weighted Avg Measure Life*				10
	Net To Gross Ratio				100%

Eligible Customers

The program will be available to selected 5th grade students/schools in the Vectren South electric service territory.

Marketing Plan

The program will be marketed directly to elementary schools in Vectren South electric service territory as well as other channels identified by the implementation contractor. A list of the eligible schools will be provided by Vectren South to the implementation contractor for direct marketing to the schools via email, phone, and mail (if necessary) to obtain desired participation levels in the program.

Barriers/Theory

This program addresses the barrier of education and awareness of EE opportunities. Working through schools, both students and families are educated about opportunities to save. As well, the families receive energy savings devices they can install to begin their savings.

Initial Measures, Products and Services

The kits for students will include:

- Low flow showerhead
- Low flow kitchen aerator
- Low flow bathroom aerator (2)
- LED bulbs (2)
- LED nightlight
- Filter whistle

Program Delivery

Vectren South will oversee the program and will partner with National Energy Foundation (NEF) to deliver the program.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

Classroom participation will be tracked. A third party evaluator will evaluate the program using standard EM&V protocols.

H. Residential Behavior Savings

Program Description

The Residential Behavioral Savings Program motivates behavior change and provides relevant, targeted information to the consumer through regularly scheduled direct contact via mailed and emailed home energy reports. The report and web portal include a comparison against a group of similarly sized and equipped homes in the area, usage history comparisons, goal setting tools, and progress trackers. The Home Energy Report program anonymously compares customers' energy use with that of other customers with similar home size and demographics. Customers can view the past 12 months of their energy usage and compare and contrast their energy consumption and costs with others in the same neighborhood. Once a consumer understands better how they use energy, they can then start conserving energy.

Program data and design was provided by OPower, the implementation vendor for the program. OPower provides energy usage insight that drives customers to take action by selecting the most relevant information for each particular household, which ensures maximum relevancy and high response rate to recommendations.

Table 18: Residential Behavior Savings Program Budget & Energy Savings Targets

Market	Program	2018	2019	2020	Total Program
Residential	**Residential Behavioral Savings**				
	Number of Participants	41,348	38,203	35,298	114,849
	Energy Savings kWh	6,470,000	5,970,000	5,600,000	18,040,000
	Peak Demand kW	1,351	1,248	1,153	3,752
	Total Program Budget $	305,622	285,585	286,545	877,752
	Per Participant Avg Energy Savings (kWh)*				157.1
	Per Participant Avg Demand Savings (kW)*				0.033
	Weighted Avg Measure Life*				1
	Net To Gross Ratio				100%

Eligible Customers

Residential customers who receive electric service from Vectren South are eligible to participate in this integrated natural gas and electric EE program.

Barriers/Theory

The Residential Behavioral Savings program provides residential customers with better energy information through personalized reports delivered by mail, email and an integrated web portal to help them put their energy usage in context and make better energy usage decisions. Behavioral science research has demonstrated that peer-based comparisons are highly motivating ways to present information. The program will leverage a dynamically created comparison group for each residence and compare it to other similarly sized and located households.

Implementation & Delivery Strategy

The program will be delivered by OPower and include energy reports and a web portal. Customers typically receive between 4 to 6 reports annually and monthly emailed reports. These reports provide updates on energy consumption patterns compared to similar homes and provide energy savings strategies to reduce energy use. They also promote other Vectren South programs to interested customers. The web portal is an interactive system for customers to perform a self-audit, monitor energy usage over time, access energy savings tips and be connected to other Vectren South gas and electric programs.

Program Delivery

Vectren South will oversee the program and partner with OPower to deliver the program.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

A third party evaluator will complete the evaluation of this program and work with Vectren South to select the participant and non-participant groups.

I. Appliance Recycling

Program Description

The Residential Appliance Recycling program encourages customers to recycle their old inefficient refrigerators and freezers in an environmentally safe manner. The program recycles operable refrigerators and freezers so the appliance no longer uses electricity, and keeps 95% of the appliance out of landfills. An older refrigerator can use up to three times the amount of energy as new efficient refrigerators. An incentive of $50 will be provided to the customer for each operational unit picked up.

Table 19: Appliance Recycling Budget & Energy Savings Targets

Market	Program	2018	2019	2020	Total Program
Residential	**Appliance Recycling**				
	Number of Measures	950	930	920	2,800
	Energy Savings kWh	913,771	894,534	884,915	2,693,219
	Peak Demand kW	120.7	118.1	116.8	355.6
	Total Program Budget $	174,759	180,648	186,532	541,939
	Per Participant Avg Energy Savings (kWh)*				961.9
	Per Participant Avg Demand Savings (kW)*				0.127
	Weighted Avg Measure Life*				8
	Net To Gross Ratio				54%

Eligible Customers

Any residential customer with an operable secondary refrigerator or freezer receiving electric service from Vectren South.

Marketing Plan

The program will be marketed through a variety of mediums, including the use of utility bill inserts and customer emails, press releases, retail campaigns coordinated with appliance sales outlets as well as the potential for direct mail, web and social and mass media promotional campaigns.

Barriers/Theory

Many homes have second refrigerators and freezers that are very inefficient. Customers are not aware of the high energy consumption of these units. Customers also often have no way to move and dispose of the units, so they are kept in homes past their usefulness. This program educates customers about the waste of these units and provides a simple way for customers to dispose of the units.

Program Delivery

Vectren South will work directly with Appliance Recycling Centers of America Inc. (ARCA), to implement this program.

Evaluation, Measurement and Verification

Recycled units will be logged and tracked to assure proper handling and disposal. The utility will monitor the activity for disposal. Customer satisfaction surveys will also be used to understand the customer experience with the program. A third party evaluator will evaluate the program using standard EM&V protocols.

J. Smart Thermostat Program

Program Description

In 2016, Vectren South conducted a field study designed, in part, to analyze the different approaches to DR that are available through smart thermostats. Between the months of April and May, Vectren South installed approximately 2,000 smart thermostats (1,000 Honeywell and 1,000 Nest) in customer homes. Vectren South leveraged these thermostats to manage DR events during the summer in an effort to evaluate the reduction in peak system loads. These smart devices are connected to Wi-Fi and reside on the customer's side of the electric meter and are used to communicate with customer's air conditioning systems. The program provides Vectren South with increased customer contact opportunities and the ability to facilitate customers' shift of their energy usage to reduce peak system loads. Vectren South will not install additional thermostats pursuant to this program; however, incentives will continue to be paid to participating customers.

Table 20: Smart Thermostat Program Budget & Energy Savings Targets

Market	Program	2018	2019	2020	Total Program
Residential	**Smart Thermostat Program**				
	Number of Measures	0	0	0	0
	Energy Savings kWh				
	Peak Demand kW	0	0	0	0
	Total Program Budget $	97,639	98,222	98,798	294,659
	Per Participant Avg Energy Savings (kWh)*				0.0
	Per Participant Avg Demand Savings (kW)*				0.000
	Weighted Avg Measure Life*				15
	Net To Gross Ratio				100%

*No additional kWh or demand savings will be recorded.

Incentive Strategy

The program budget is for incentives for existing customers to participate in the Demand Response events for 2018-2020.

Program Delivery

Vectren South will oversee the program.

Evaluation, Measurement and Verification

A third party evaluator will evaluate the program using standard EM&V protocols.

K. Smart DLC – Wi-Fi/DLC Switchout Program

Program Description

Since 1992, Vectren South has operated a Direct Load Control (DLC) program called Summer Cycler that reduces residential and small commercial air-conditioning and water heating electricity loads during summer peak hours. While this technology still helps lower peak load demand for electricity, this aging technology will be phased out over time. Vectren's Summer Cycler program has served Vectren and its customers well for more than two decades, but emerging technology is now making the program obsolete.

By installing connected devices in customer homes rather than using one-way signal switches, Vectren will be able to provide its customer base deeper energy savings opportunities and shift future energy focus to customer engagement rather than traditional program goals and rules. The most recent Vectren electric DSM evaluation has demonstrated that smart thermostats outperform standard programmable thermostats and are a practical option to transition into future customer engagement strategies.

Smart thermostat installations are also a feasible solution to multiple utility and customer quandaries. Past Vectren evaluations have discovered that its customers program less than half of all programmable thermostats installed, hindering potential savings and acting a disincentive for customers to become involved in how their home uses energy. This issue is coupled with the uncertainty of whether standard DLC switches in the field are in working order and the fact that the switches cannot record or yield any savings data. With these issues mitigated, utility management burden is reduced, customer engagement and satisfaction is increased, and Vectren will be able to obtain better home usage data for creation and implementation of future DSM programs.

If approved by the Commission, Vectren South anticipates replacing DLC switches with smart thermostats over time, as the benefits associated with this emerging technology far outweigh the benefits associated with DLC switches. In 2018, Vectren South will begin its phase out of the Summer Cycler program by removing approximately 1,000 Sumer Cycler devices and replacing them with Wi-Fi thermostats that utilize demand response technology. Customers will receive a professionally installed Wi-Fi thermostat at no additional cost and a monthly bill credit of $5 during the months of June to September. The current monthly credit for Summer Cycler is also $5; therefore the annual bill credit by customer does not change.

By replacing the Summer Cycler devices, Vectren South will eliminate the annual inspection and maintenance ("I&M costs") for the Summer Cycler program, and thus offer a more reliable DR program. Long-term, Vectren South will almost eliminate the annual ongoing inspection and maintenance cost. By replacing 1,000 switches each year, Vectren continues to have resources to manage peak demand for electricity during the summer months.

Table 22: SmartDLC – Wi-Fi/DLC Switchout Program& Energy Savings Targets

Market	Program	2018	2019	2020	Total Program
Residential	**SmartDLC - Wifi DR/DLC Changeout**				
	Number of Participants	1,000	1,000	1,000	3,000
	Energy Savings kWh	466,690	466,690	466,690	1,400,070
	Peak Demand kW	600.0	600.0	600.0	1,800.0
	Total Program Budget $	517,759	562,148	606,532	1,686,439
	Per Participant Avg Energy Savings (kWh)*				466.7
	Per Participant Avg Demand Savings (kW)*				0.600
	Weighted Avg Measure Life*				15
	Net To Gross Ratio				100%

Eligible Customers

Customers in the Vectren South territory who currently participate in the DLC Summer Cycler program and have access to Wi-Fi.

Marketing Plan

Proposed marketing efforts include utilizing direct mailers, email blasts, Vectren South online audit tools, bill inserts as well as other outreach and education efforts and promotional campaigns throughout the year to ensure participation levels are maintained.

Incentive Strategy

Customers will receive a professionally installed Wi-Fi thermostat at no additional cost and a monthly bill credit of $5 during the months of June to September.

Program Delivery

Vectren South will oversee the program.

Evaluation, Measurement and Verification

A third party evaluator will evaluate the program using standard EM&V protocols.

L. Bring Your Own Thermostat (BYOT)

Program Description

The Bring Your Own Thermostat ("BYOT") program is a further expansion of the residential smart thermostat initiative. BYOT allows customers to purchase their own device from multiple vendors and participate in DR with Vectren South and other load curtailing programs managed through the utility. Taking advantage of two-way communicating smart thermostats, the BYOT program can help reduce acquisition costs for load curtailment programs and improve customer satisfaction.

Table 23: BYOT Program Budget & Energy Savings Targets

Market	Program	2018	2019	2020	Total Program
Residential	**BYOT (Bring Your Own Thermostat)**				
	Number of Participants	400	400	400	1,200
	Energy Savings kWh				
	Peak Demand kW	240.0	240.0	240.0	720.0
	Total Program Budget $	111,036	178,592	146,128	435,756
	Per Participant Avg Energy Savings (kWh)*				0.0
	Per Participant Avg Demand Savings (kW)*				0.600
	Weighted Avg Measure Life*				15
	Net To Gross Ratio				100%

Eligible Customers

Residential single or multi-family customers in the Vectren South territory with access to Wi-Fi and who own a qualifying compatible Wi-Fi thermostat that operates the central air-conditioning cooling system.

Marketing Plan

Proposed marketing efforts include utilizing direct mailers, email blasts, Vectren South online audit tools, bill inserts as well as other outreach and education efforts and promotional campaigns throughout the year to ensure participation levels are maintained.

Incentive Strategy

Customers will receive a one-time enrollment incentive of $75 and a bill credit of $5 during the months of June to September. The enrollment incentive will be provided in the first year to new enrollees only.

Program Delivery

Vectren South will oversee the program.

Evaluation, Measurement and Verification

A third party evaluator will evaluate the program using standard EM&V protocols.

M. Conservation Voltage Reduction - Residential and Commercial and Industrial

Program Description

Conservation Voltage Reduction (CVR) is a technology that reduces energy usage and peak demand through automated monitoring and control of voltage levels provided on distribution circuits. End use customers realize lower energy and demand consumption when CVR is applied to the distribution circuit from which they are served.

A distribution circuit facilitates electric power transfer from an electric substation to utility meters located at electric customer premises. Electric power customers employ end-use electric devices (loads) that consume electrical power. At any point along a single distribution circuit, voltage levels vary based upon several parameters, mainly including, but not exclusive of, the actual electrical conductors that comprise the distribution circuit, the size and location of electric loads along the circuit, the type of end-use loads being served, the distance of loads from the power source, and losses incurred inherent to the distribution circuit itself. All end-use loads require certain voltage levels to operate and standards exist to regulate the levels of voltage delivered by utilities. In Indiana, Vectren South is required to maintain a steady state +/- 5% of the respective baseline level as specified by ANSI C84.1 (120 volt baseline yields acceptable voltage range of 114 volts to 126 volts).

Historically, utilities including Vectren South have set voltage levels near the upper limit at the distribution circuit source (substation) and have applied voltage support devices such as voltage regulators and capacitors along the circuit to assure that all customers are provided voltages within the required range. This basic design economically met the requirements by utilizing the full range (+/- 5%) of allowable voltages while only applying independent voltage support where needed. This basic design has worked well for many years. However, in the 1980's, utilities recognized that loads on the circuits would actually consume less energy if voltages in the lower portion of the acceptable range were provided. In fact, many utilities, including Vectren South, established emergency operating procedures to lower voltage at distribution substations by 5% during power shortage conditions.

The recent focus on EE and the availability of technology that allows monitoring and tighter control of circuit voltage conditions has led to development of automated voltage control schemes which coordinate the operation of voltage support devices and allow more customers on the circuit to be served at voltages in the lower portion of the acceptable range.

Once applied, a step change in energy and demand consumption by customers is realized, dependent upon where customer loads are located within the voltage zones, the load characteristics of the circuit, and how end-use loads respond to the voltage reduction. The resultant energy and demand consumption reduction persist at the new levels as long as tighter voltage bandwidth operation is applied. As a result, ongoing energy and demand savings persists for the duration of the life of the CVR equipment and as long as the equipment is maintained and operated in the voltage bandwidth mode.

With Commission approval, Vectren South will capitalize the costs to implement the CVR program and seek to recover through the annual Demand Side Management Adjustment (DSMA) mechanism the carrying costs and depreciation expense associated with the implementation along with annual, ongoing Operation and Maintenance (O&M) expense, a representative share of Vectren South's DSM support staff and administration costs and related EM&V cost. The budget below is reflective of this request.

Table 21: Conservation Voltage Reduction Energy Savings Targets

Market	Program	2018	2019	2020	Total Program
Residential	**CVR Residential**				
	Number of Participants			5,324	5,324
	Energy Savings kWh			1,461,047	1,461,047
	Peak Demand kW			263	263
	Total Program Budget $	118,786	114,907	230,134	463,827
	Per Participant Avg Energy Savings (kWh)*				274.4
	Per Participant Avg Demand Savings (kW)*				0.049
	Weighted Avg Measure Life*				15
	Net To Gross Ratio				100%

Market	Program	2018	2019	2020	Total Program
Commercial & Industrial	**CVR Commercial**				
	Number of Participants			558	558
	Energy Savings kWh			1,032,655	1,032,655
	Peak Demand kW			185.9	185.9
	Total Program Budget $	108,834	105,297	137,003	351,134
	Per Participant Avg Energy Savings (kWh)*				1850.6
	Per Participant Avg Demand Savings (kW)*				0.333
	Weighted Avg Measure Life*				15
	Net To Gross Ratio				100%

Program Delivery

Vectren South will oversee the program and will partner with an implementer to deliver the program. One unit installation will be completed in 2017, and as an expansion of this program, one additional unit will be installed in 2020.

Eligible Customers

Vectren South has identified substations that will benefit from the CVR program. For this program, one substation will be installed in 2020.

Barriers/Theory

CVR is both a DR and an EE program. First, it seeks to cost effectively deploy new technology to targeted distribution circuits, in part to reduce the peak demand experienced on Vectren South's electrical power supply system. The voltage reduction stemming from the CVR program operates to effectively reduce consumption during the times in which system peaks are set and as a result directly reduces peak demand. CVR also cost effectively reduces the level of ongoing energy consumption by end-use devices located on the customer side of the utility meter as many end-use devices consume less energy with lower voltages consistently applied. Like an equipment maintenance service program, the voltage optimization allows the customer’s equipment to operate at optimum levels which saves energy without requiring direct customer intervention or change.

Initial Measures, Products and Services

Vectren South will install the required communication and control equipment on the appropriate circuits from the substation. No action is required of the customers.

N. Commercial and Industrial Prescriptive

Program Description

The Commercial & Industrial (C&I) Prescriptive Program is designed to provide financial incentives on qualifying products to produce greater energy savings in the C&I market. The rebates are designed to promote lower electric energy consumption, assist customers in managing their energy costs, and build a sustainable market around EE.

Program participation is achieved by offering incentives structured to cover a portion of the customer's incremental cost of installing prescriptive efficiency measures.

Table 24: Commercial & Industrial Prescriptive Budget & Energy Savings Targets

Market	Program	2018	2019	2020	Total Program
Commercial & Industrial	**Commercial Prescriptive**				
	Number of Measures	7,024	5,981	6,856	19,861
	Energy Savings kWh	4,999,125	4,501,186	5,002,621	14,502,932
	Peak Demand kW	378.2	325.4	369.0	1,072.6
	Total Program Budget $	729,398	655,370	731,330	2,116,098
	Per Participant Avg Energy Savings (kWh)*				730.2
	Per Participant Avg Demand Savings (kW)*				0.054
	Weighted Avg Measure Life*				14
	Net To Gross Ratio				87%

Eligible Customers

Any eligible participating commercial or industrial customer receiving Vectren South electric service.

Marketing Plan

Proposed marketing efforts include trade ally outreach, trade ally meetings, direct mail, face-to-face meetings with customers, marketing campaigns and bonuses, web-based marketing, and coordination with key account executives.

Barriers/Theory

Customers often have the barrier of higher first cost for EE measures, which precludes them from purchasing the more expensive EE alternative. They also lack information on high-efficiency alternatives. Trade allies often run into the barrier of not being able to promote more EE alternatives because of first cost or lack of knowledge. Trade allies also gain credibility with customers for their EE claims when a measure is included in a utility prescriptive program. Through the program the Trade allies can promote EE measures directly to their customers encouraging them to purchase more efficient equipment while helping customers get over the initial cost barrier.

Initial Measures, Products and Services

Measures will include high efficient lighting and lighting controls, HVAC equipment including variable frequency drives, commercial kitchen equipment including electronically commutated motors (ECMs), and miscellaneous items including compressed air equipment.

Note that measures included in the program will change over time as baselines change, new technologies become available and customer needs are identified. Detailed measure listings, participation and incentives are in Appendix B.

Implementation & Delivery Strategy

The program will be delivered primarily through the trade allies working with their customers. Vectren South and its implementation partners will work with the trade allies to make them aware of the offerings and help them promote the program to their customers. The implementation partner will provide training and technical support to the trade allies to become familiar with the EE technologies offered through the program. The program will be managed by the same implementation provider as the Commercial & Industrial Custom program so that customers can seamlessly receive assistance and all incentives can be efficiently processed through a single procedure.

Incentive Strategy

Incentives are provided to customers to reduce the difference in first cost between the lower efficient technology and the high efficient option. There is no fixed incentive percentage amount based on the difference in price because some technologies are newer and need higher amounts. Others have been available in the marketplace longer and do not need as much to motivate customers. Incentives will be adjusted to respond to market activity and bonuses may be available for limited time, if required, to meet goals.

Program Delivery

Vectren South will oversee the program partner Nexant to deliver the program.

Evaluation, Measurement and Verification

Site visits will be made on 5% of the installations, as well as all projects receiving incentive greater than $20,000, to verify the correct equipment was installed. Standard EM&V protocols will be used for the third party evaluation of the program.

O. Commercial and Industrial Custom

Program Description

The Commercial & Industrial (C&I) Custom Program promotes the implementation of customized energy saving measures at qualifying customer facilities. Incentives promoted through this program serve to reduce the cost of implementing energy saving projects and upgrading to high-efficiency equipment. Due to the nature of a custom EE program, a wide variety of projects are eligible.

Table 25: Commercial & Industrial Custom Budget & Energy Savings Targets

Market	Program	2018	2019	2020	Total Program
Commercial & Industrial	**Commercial Custom**				
	Number of Measures	50	50	55	155
	Energy Savings kWh	5,000,000	5,000,000	5,500,000	15,500,000
	Peak Demand kW	476.0	476.0	524.0	1,476.0
	Total Program Budget $	1,019,072	1,022,184	1,160,256	3,201,512
	Per Participant Avg Energy Savings (kWh)*				100000.0
	Per Participant Avg Demand Savings (kW)*				9.523
	Weighted Avg Measure Life*				15
	Net To Gross Ratio				100%

Eligible Customers

Any participating commercial or industrial customer receiving electric service from Vectren South.

Marketing Plan

Proposed marketing efforts include coordination with key account representatives to leverage the contacts and relationships they have with the customers. Direct mail, media outreach, trade shows, marketing campaigns and bonuses, trade ally meetings, and educational seminars could also be used to promote the program.

Barriers/Theory

Applications of some specific EE technologies are unique to that customer's application or process. The energy savings estimates for these measures are highly variable and cannot be assessed without an engineering estimation of that application; however, they offer a large opportunity for energy savings. To promote the installation of these high efficient technologies or measures, the Commercial & Industrial Custom program will provide incentives based on the kWh saved as calculated by the engineering analysis. To assure savings, these projects will require program engineering reviews and pre approvals. The custom energy assessments offered will help remove customer barriers regarding opportunity identification and determining energy savings potential.

Initial Measures, Products and Services

All technologies or measures that save kWh qualify for the program. Facility energy assessments will be offered to customers who are eligible and encouraged to implement multiple EE measures. Detailed measure listings, participation and incentives are in Appendix B.

Implementation & Delivery Strategy

The implementation partner will work collaboratively with Vectren South staff to recruit and screen customers for receiving facility energy assessments. The implementation partner will also provide engineering field support to customers and trade allies to calculate the energy savings. Customers or trade allies with a proposed project will complete an application form with the energy savings calculations for the project. The implementation team will review all calculations and where appropriate complete site visits to assess and document pre-installation conditions. Customers will be informed and funds will be reserved for the project. Implementation engineering staff will review the final project information as installed and verify the energy savings. Incentives are then paid on the verified savings.

The implementation partner will work collaboratively with Vectren South staff to recruit and screen customers for receiving facility energy assessments, technical assistance and energy management education. The program will seek to gain customer commitment towards setting up an energy management process and implementing multiple EE improvements. The implementation partner will help customers achieve agreed upon milestones in support for their commitment.

Incentive Strategy

Incentives will be calculated on a per kWh basis. The initial kWh rate will be $0.12/kWh and is paid based on the first year annual savings reduction. Rates may change over time and vary with some of the special initiatives. Incentives will not pay more than 50% of the project cost nor provide incentives for projects with paybacks less than 12 months. Vectren South will offer a cost share on facility energy assessments that will cover up to 100% of the assessment cost.

Program Delivery

Vectren South will oversee the program partner Nexant to deliver the program.

Evaluation, Measurement and Verification

Given the variability and uniqueness of each project, all projects will be pre-approved. Pre and post visits to the site to verify installation and savings will be performed as defined by the program implementation partner. Monitoring and verification may occur on the largest projects. A third party evaluator will be used for this project and use standard EM&V protocols.

P. Small Business Direct Install

Program Description

The Small Business Direct Install Program provides value by directly installing EE products such as high efficiency lighting, pre-rinse sprayers, refrigeration controls, electrically-commutated motors, smart thermostats and vending machine controls. The program helps businesses identify and install cost effective energy saving measures by providing an on-site energy assessment customized for their business.

Table 26: Small Business Direct Install Budget & Energy Savings Targets

Market	Program	2018	2019	2020	Total Program
Commercial & Industrial	**Small Business Direct Install**				
	Number of Projects	146	142	127	415
	Energy Savings kWh	4,032,934	3,905,372	3,900,306	11,838,612
	Peak Demand kW	667.0	645.0	567.0	1,879.0
	Total Program Budget $	1,149,640	1,182,037	1,173,133	3,504,810
	Per Participant Avg Energy Savings (kWh)*				28526.8
	Per Participant Avg Demand Savings (kW)*				4.528
	Weighted Avg Measure Life*				15
	Net To Gross Ratio				95%

Eligible Customers

Any participating Vectren South business customer with a maximum peak energy demand of less than 400 kW.

Marketing Plan

The Small Business Direct Install Program will be marketed primarily through in-network trade ally outreach. The program implementer will provide trade ally-specific marketing collateral to support trade allies as they connect with customers.

The program will provide targeted marketing efforts as needed to individual customer segments (e.g., hospitality, grocery stores, and retail) to increase participation in under-performing segments, including direct customer outreach and enhanced incentive campaigns. Additional program marketing may occur through direct mail, trade associations, local business organizations, marketing campaigns and bonuses, educational seminars, and direct personal communication from Vectren South staff and third-party contractors.

Barriers/Theory

Small business customers generally do not have the knowledge, time or money to invest in EE upgrades. This program assists these small businesses with direct installation and turn-key services to get measures installed at no or low out-of-pocket cost.

There is an implementation contractor in place providing suggested additions and changes to the program based on results and local economics.

Implementation & Delivery Strategy

Trade Ally Network: Trained trade ally energy advisors will provide energy assessments to business customers with less than 400 kW of annual peak demand. The program implementer will issue an annual Request for Qualification (RFQ) to select the trade allies with the best ability to provide high-quality and cost-effective service to small businesses, and provide training to Small Business Energy Solutions trade allies on the program process, with an emphasis on improving energy efficiency sales.

Energy Assessment: Trade allies will walk through small businesses and record site characteristics and energy efficiency opportunities at no cost to the customer. They will provide an energy assessment report that will detail customer-specific opportunities, costs, energy savings, incentives, and simple payback periods. The trade ally will then review the report with the customer, presenting the program benefits and process, while addressing any questions.

Initial Measures, Products and Services

Details of the measures, savings, and incentives can be found in Appendix B. The program will have two types of measures provided. The first are measures that will be installed at no cost to the customer. Some available measures will include, but are not limited to the following:

- LEDs: 8-12W
- LEDs: MR16 track light
- LEDs: > 12 W flood light
- Wifi-enabled thermostats
- Programmable thermostats
- Pre-rinse sprayers
- Faucet aerators

The second types of measures require the customer to pay a portion of the labor and materials. Some available measures will include, but are not limited to the following:

- Interior LED lighting (replacing incandescent, high bays and linear fluorescents)
- High-efficiency linear fluorescent lighting
- Linear fluorescent delamping
- LED exit signs
- Exterior LED lighting
- ECMs in refrigeration equipment

- Anti-sweat heater controls
- LED lighting for display cases

Incentive Strategy

In addition to the no-cost measures identified during the audit, the program will also pay a cash incentive on every recommended improvement identified through the assessment. Incentive rates may change over time and vary with special initiatives.

Program Delivery

Vectren South will oversee the program partner Nexant to deliver the program.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas and electric EE program in its combined natural gas and electric service territory.

Evaluation, Measurement and Verification

On-site verification will be provided for the first three projects completed by each trade ally, in addition to the program standard 5% of all completed projects and all projects receiving incentives greater than $20,000. These verifications allow the program to validate energy savings, in addition to providing an opportunity to ensure the trade allies are providing high-quality customer services and the incentivized equipment satisfies program requirements. A third party evaluator will evaluate the program using standard EM&V protocols.

Q. Commercial & Industrial New Construction

Program Description

The Commercial and Industrial New Construction Program provides value by promoting EE designs with the goal of developing projects that are more energy efficient than current Indiana building code. This program applies to new construction and major renovation projects. Major renovation is defined as the replacement of at least two systems within an existing space (e.g. lighting, HVAC, controls, building envelope). The program provides incentives as part of the facility design process to explore opportunities in modeling EE options to craft an optimal package of investments. The program also offers customers the opportunity to receive prescriptive or custom rebates toward eligible equipment in order to reduce the higher capital cost for the EE solutions.

Table 27: Commercial & Industrial New Construction Budget & Energy Savings Targets

Market	Program	2018	2019	2020	Total Program
Commercial & Industrial	**Commercial New Construction**				
	Number of Projects	18	20	18	56
	Energy Savings kWh	502,080	1,835,413	502,080	2,839,573
	Peak Demand kW	108.0	120.0	108.0	336.0
	Total Program Budget $	214,536	386,092	222,628	823,256
	Per Participant Avg Energy Savings (kWh)*				50706.7
	Per Participant Avg Demand Savings (kW)*				6.000
	Weighted Avg Measure Life*				10
	Net To Gross Ratio				100%

Eligible Customers

Any commercial or industrial customer who receives or intends to receive electric service from Vectren South.

Marketing Plan

The Commercial & Industrial New Construction Program will be marketed through trade ally meetings, trade association training, marketing campaigns and bonuses, educational seminars, and direct personal communication from Vectren South staff and third party contractors.

Barriers/Theory

There are three primary barriers addressed by the C&I New Construction program. The first is knowledge. For commercial and industrial buildings it is the knowledge and experience of the design team including the owner, architect, lighting and HVAC engineers, general contractor and others. This team may not understand new technologies and EE options that could be considered. The second barrier is cost. There is a cost during the design phase of the project in modeling EE options to see what can cost-effectively work within the building. The program provides design team incentives to help reduce the design cost for the consideration of EE upgrades. The third barrier is the first cost of the high efficiency upgrades in equipment and materials. The program provides prescriptive or custom rebates toward eligible equipment to help reduce this first cost.

Implementation & Delivery Strategy

The new construction program is designed as a proactive, cost-effective way to achieve energy efficiency savings and foster economic growth. Typically, program participants face time and cost constraints throughout the project that make it difficult to invest in sustainable building practices. Participants need streamlined and informed solutions that are specific to their projects and locations. This scenario is particularly true for small to medium-sized new construction projects, where design fees and schedules provide for a very limited window of opportunity.

To help overcome the financial challenge for small-medium size projects, we offer a Standard Energy Design Assistance (EDA). EDA targets buildings that are less than 100,000 square feet, but is also available for larger new buildings that are beyond the schematic design phase or are on an accelerated schedule. Commercial and industrial projects for buildings greater than 100,000 square feet still in the conceptual design phase qualify for Vectren South’s Enhanced EDA incentives. The Vectren South implementation partner staff expert will work with the design team through the conceptual design, schematic design and design development processes providing advice and counsel on measures that should be considered and EE modeling issues. Incentives will be paid after the design team submits completed construction documents for review to verify that the facility design reflects the minimum energy savings requirements.

For those projects that are past the phase where EDA can be of benefit, the C&I New Construction program offers the opportunity to receive prescriptive or custom rebates towards eligible equipment.

Incentive Strategy

Incentives are provided to help offset some of the expenses for the design team’s participation in the EDA process with the design team incentive. The design team incentive is a fixed amount based on the new/renovated conditioned square footage and is paid when the proposed EE projects associated with the construction documents exceed a minimum energy savings threshold. The program also offers customers the opportunity to receive prescriptive or custom rebates toward eligible equipment in order to reduce the higher capital cost for the EE solutions. Program specific savings and incentive include:

Facility Size – Square Feet	Design Team Incentives	Minimum Savings
Small <25,000	$750	25,000 kWh
Medium 25,000 - 100,000	$2,250	75,000 kWh
Large >100,000	$3,750	150,000 kWh
Enhance Large >100,000	$5,000	10% beyond code

Program Delivery

Vectren South will oversee the program and partner with Nexant to deliver the program.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas and electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

All construction documents will be reviewed and archived. A third party evaluator will evaluate the program using standard EM&V protocols.

R. Commercial Building Tune-Up

Program Description

The Building Tune-Up (BTU) program provides a targeted, turnkey, and cost-effective retrocommissioning solution for small- to mid-sized customer facilities.

It is designed as a comprehensive customer solution that will identify, validate, quantify, and encourage the installation of both operational and capital measures. The majority of these measures will be no- or low-cost with low payback periods and will capture energy savings from a previously untapped source: building automation systems.

Table 28: Building Tune-Up Budget & Energy Savings Targets

Market	Program	2018	2019	2020	Total Program
Commercial & Industrial	**Building Tune-up**				
	Number of Projects	10	14	20	44
	Energy Savings kWh	500,000	700,000	1,000,000	2,200,000
	Peak Demand kW	1.0	1.0	1.0	3.0
	Total Program Budget $	130,880	182,074	261,266	574,220
	Per Participant Avg Energy Savings (kWh)*				50000.0
	Per Participant Avg Demand Savings (kW)*				0.068
	Weighted Avg Measure Life*				7
	Net To Gross Ratio				100%

Eligible Customers

Applicants must be both an active Vectren South electric customer on a qualifying commercial rate and an active natural gas General Service customer on Rate 120 or 125. The program will target customers with buildings between 50,000 square feet and 150,000 square feet.

Marketing Plan

The BTU Program will be marketed primarily through in-network service provider outreach and direct personal communication from Vectren South staff and third-party contractors. The program implementer will provide service provider specific-marketing collateral to support these companies as they connect with customers.

The program will provide targeted marketing efforts to recruit quality participants. Additional program marketing may occur through direct mailing, trade associations, marketing campaigns and bonuses, local business organizations, and educational seminars.

Barriers/Theory

The program will typically target customers with buildings between 50,000 square feet and 150,000 square feet. Customers in this size range face unique barriers to energy efficiency. For example, although they are large enough to have a Building Automation System (BAS), they are usually too small to have a dedicated facility manager or staff with experience achieving operational efficiency. Also, most retrocommissioning service companies prefer larger projects and their services often are too expensive for small-to-midsized customers. We have specifically tailored the incentive structure and program design to eliminate these barriers. The BTU program is designed as a comprehensive customer solution that will identify, validate, quantify, and encourage the installation of both operational and capital measures eligible for incentive offerings.

Implementation & Delivery Strategy

The BTU program is designed to encourage high levels of implementation by customers seeking to optimize the operation of their existing HVAC system. Key elements of the program approach are:

- Service Provider Network: Service providers play a key role in program marketing and outreach. Their existing relationships with building owners and knowledge of customer facilities give them an easy starting point to begin program marketing efforts. For this reason, recruiting quality providers, training them on program processes, and making the BTU program profitable for them are key strategies that drive program participation. The program implementer will issue an annual RFQ to select those service providers with the best ability to provide high-quality and cost-effective services.

- Fully Funded Service Offering: The BTU program fully funds the investigation of opportunities by the program implementer and service providers. The program also provides a cash incentive on implemented improvements.

- Customer Commitment: BTU program participants are required to commit to a spending minimum to implement a group, or “bundle,” of agreed-upon energy saving measures. This bundle of measures will have a collective estimated simple payback of 1.5 years or less based upon energy savings identified, which ensures that it benefits customers as well as the program.

- Technical Services: The program will provide the following technical services to successfully implement each BTU project:

Application Phase: Each application will be screened to verify that the customer's facility has enough energy savings potential for the BTU study. After being accepted into the program, the customer will sign the Customer Agreement to spend the minimum amount of money on a bundle of measures with a simple payback of 1.5 years or less. This agreement ensures that both the customer and Vectren South will achieve energy savings from the project.

Investigation and Implementation Phase: During the investigation and implementation phase, the program implementer and the customers' preferred in-network service provider will perform a BTU study to identify and install measures for the customer. They will generate a study report to summarize findings from the investigation and present the results to the customer. The customer will select the bundle of measures to install that meet the program minimum and payback requirements, and work with their service provider to install the selected measures.

Verification Phase: The program implementer revisits the customer's facility as needed. If any of the measures were incorrectly installed, the service provider works with the customer to fix it. The implementer and service provider calculate the final estimated energy savings from the BTU project and share those results with both the customer and Vectren South, thus ensuring that the most accurate energy savings estimate is reported.

Initial Measures, Products and Services

The BTU program will specifically target measures that provide no- and low-cost operational savings. Customized measures will be identified for each building, these could include:

- Scheduling air handling units
- Optimizing economizer and outdoor air control
- Reducing/resetting duct static pressure
- Resetting chilled water temperature

Most measures involve optimizing the building automation system (BAS) settings but the program will also investigate related capital measures, like controls, operations, processes, and HVAC.

Incentive Strategy

The BTU program fully funds the investigation of opportunities by the program implementer and service provider. The program also provides a cash incentive on implemented improvements.

Program Delivery

Vectren South will oversee the program and partner with Nexant to deliver the program.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas and electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

A third party evaluator will evaluate the program using standard EM&V protocols.

S. Multi-Family Retrofit

Program Description

The Multi-Family Retrofit Program provides value by directly installing EE products such as high efficiency lighting, water-saving measures, thermostats, and vending machine controls into multi-family common areas. The program helps multi-family facilities identify and install cost-effective energy-saving measures by providing an on-site energy assessment customized for their business.

Table 29: Multi-Family Retrofit Budget & Energy Savings Targets

Market	Program	2018	2019	2020	Total Program
Commercial & Industrial	**Multi-Family Retrofit**				
	Number of Projects	4	4	4	12
	Energy Savings kWh	101,590	101,590	115,853	319,033
	Peak Demand kW	18.0	18.0	18.0	54.0
	Total Program Budget $	34,880	35,074	35,266	105,220
	Per Participant Avg Energy Savings (kWh)*				26586.1
	Per Participant Avg Demand Savings (kW)*				4.500
	Weighted Avg Measure Life*				15
	Net To Gross Ratio				100%

Eligible Customers

Applicants must be both an active Vectren South electric customer on a qualifying commercial rate and an active natural gas General Service customer on Rate 120 or 125.

Marketing Plan

The Multi-Family Retrofit Program will be marketed primarily through in-network trade ally outreach. The program implementer will provide trade ally-specific marketing collateral to support trade allies as they connect with customers.

The program will provide targeted marketing efforts as needed to increase participation, including direct customer outreach and enhanced incentive campaigns.

Additional program marketing may occur through direct mail, trade associations, local business organizations, marketing campaigns and bonuses, educational seminars, and direct personal communication from Vectren South staff and third-party contractors.

Barriers/Theory

Multi-family landlords generally do not have the knowledge, time or money to invest in EE upgrades. This program assists these customers with direct installation and turn-key services to get measures installed at no or low out-of-pocket cost.

There is an implementation contractor in place providing suggested additions and changes to the program based on results and local economics.

Implementation & Delivery Strategy

Trade Ally Network: Trained trade ally energy advisors will provide energy assessments to customers. The program implementer will issue an annual RFQ to select the trade allies with the best ability to provide high-quality and cost-effective service to customers, and provide training to trade allies on the program process, with an emphasis on improving energy efficiency sales.

Energy Assessments: Trade allies will walk through the multi-family common areas and record site characteristics and energy efficiency opportunities at no cost to the customer. They will provide an energy assessment report that will detail customer-specific opportunities, costs, energy savings, incentives, and simple payback periods. The trade ally will then review the report with the customer, presenting the program benefits and process, while addressing any questions.

Initial Measures, Products and Services

The program will have two types of measures provided. The first are measures that will be installed at no cost to the customer. They will include but are not limited to the following:

- LEDs: 8-12W
- LEDs: MR16 track light
- LEDs: > 12 W flood light
- Wi-fi enabled thermostats
- Programmable thermostats
- Pre-rinse sprayers
- Faucet aerators

The second types of measures require the customer to pay a portion of the labor and materials. These measures include:

- Interior LED lighting (replacing incandescent, high bays and linear fluorescents)
- High-efficiency linear fluorescent lighting
- Linear fluorescent delamping
- Electronically commutated motors (ECM)
- Anti-sweat heater controls
- LED exit signs
- Exterior LED lighting

Incentive Strategy

In addition to the no-cost measures identified during the audit, the program will also pay a cash incentive for all recommended improvements identified through the assessment.

Program Delivery

Vectren South will oversee the program and will partner with Nexant to deliver the program.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas and electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

On-site verification will be provided for the first three projects completed by each trade ally, in addition to the program standard 5% of all completed projects and all projects receiving incentives greater than $20,000. These verifications allow the program to validate energy savings, in addition to providing an opportunity to ensure the trade allies are providing high-quality customer services and the incentivized equipment satisfies program requirements. A third party evaluator will evaluate the program using standard EM&V protocols.

8. Program Administration

As in previous years, Vectren South will continue to serve as the program administrator for the 2018-2020 Plan. Vectren South will utilize third party program implementers to deliver specific programs or program components where specialty expertise is required. Contracting directly with specialty vendors avoids an unnecessary layer of management, oversight and expense that occurs when utilizing a third-party administration approach.

Program administration costs are allocated at the program level and include costs associated with program support and internal labor. Program support includes costs associated with outside consulting and annual license and maintenance fees for DSMore, Data Management, and Esource. Based upon the EE and DR programs proposed in the 2018 - 2020 Plan, Vectren South is proposing to maintain the staffing levels that were previously approved to support the portfolio. The major responsibilities associated with these FTEs are as follows:

- **Portfolio Management and Implementation -** Oversees the overall portfolio and staff necessary to support program administration. Serves as primary contact for regulatory and oversight of programs.
- **Reporting and Analysis -** Responsible for all aspects of program reporting including, budget analysis/reporting, scorecards and filings.
- **Outreach and Education -** Serves as contact to trade allies regarding program awareness. Also serves as point of contact for residential and commercial/industrial customers to assist with responding to program inquiries.
- **Research and Evaluation -** Works with the selected EM&V Administrator and facilitates measurement and verification efforts, assists with program reporting/tracking.

9. Support Services

Support services are considered indirect costs which support the entire portfolio and include: Contact Center, Online Audit, Outreach & Education, and Evaluation, Measurement and Verification (EM&V). These costs are budgeted at the portfolio level.

Table 30: Portfolio Level Costs by Year

Indirect Portfolio Level Costs	2018	2019	2020
Contact Center	$63,000	$63,000	$63,000
Online Audit	$36,444	$39,806	$42,911
Outreach & Education	$410,000	$410,000	$410,000
Evaluation	$427,992	$447,304	$444,314
Total Indirect Portfolio Level Costs	**$937,436**	**$960,110**	**$960,225**

A. Contact Center

The Vectren Contact Center, called the Energy Efficiency Advisory Team, fields referrals from the company's general call center and serves as a resource for interested customers. A toll-free number is provided on all outreach and education materials. Direct calls are initial contacts from customers or market providers coming through the dedicated toll free number printed on all Vectren South's energy efficiency materials. Transferred calls are customers that have spoken with a Vectren Contact Center representative and have either asked or been offered a transfer to an Energy Efficiency Advisor who is trained to respond to energy efficiency questions or conduct the on-line energy audit.

These customer communication channels provide support mechanisms for Vectren South customers to receive the following services:

- Provide general guidance on energy saving behaviors and investments using customer specific billing data via the on-line tool (bill analyzer and energy audit).
- Respond to questions about the residential and general service programs.
- Facilitate the completion of and provide a hard copy report from the online audit tool for customers without internet access or who have difficulty understanding how to use the tool.
- Respond to inquiries about rebate fulfillment status.

B. Online Audit

The Online Energy Audit tool is a customer engagement and messaging tool that uses actual billing data from a customer's energy bills to pinpoint ways to save energy in their home. Data collected drives account messaging through providing tips and rebates relevant to that customer's situation. Additionally, data collected from the online energy audit is used to validate neighbor comparison data, which illustrates how the customer's monthly energy use compares to their neighbors and is designed to inspire customers to try and save more energy than their efficient neighbors. This tool provides the online ability and means to communicate, cross promote, and educate customers about energy efficiency and Vectren's energy efficiency programs. The Online Energy Audit tool provides tools and messaging to educate customers and provide suggestions, tips, and advice on energy usage.

C. Outreach & Education

Vectren South's Customer Outreach and Education program serves to raise awareness and drive customer participation as well as educate customers on how to manage their energy bills. The program includes the following goals as objectives:

- Build awareness;
- Educate consumers on how to conserve energy and reduce demand;
- Educate customers on how to manage their energy costs and reduce their bill;
- Communicate support of customer EE needs; and
- Drive participation in the EE and DR programs.

The marketing approach includes paid media as well as web-based tools to help analyze bills, energy audit tools, EE and DSM program education and information. Informational guides and sales promotion materials for specific programs are included in this budget.

This effort is the key to achieving greater energy savings by convincing the families and businesses making housing/facility, appliance and equipment investments to opt for greater EE. The first step in convincing the public and businesses to invest in EE is to raise their awareness.

It is essential that a broad public education and outreach campaign not only raise awareness of what consumers can do to save energy and control their energy bills, but also prime them for participation in the various EE and DR programs.

Vectren South will oversee outreach and education for the programs and work closely with implementation partners to provide consistent messaging across different program outreach and education efforts. Vectren South will utilize the services of communication and EE experts to deliver the EE and DR message.

The Outreach budget also includes funds for program development and staff training. Examples of these costs include memberships to EE related organizations, outreach for home/trade shows and travel and training related to EE associated staff development.

D. Evaluation

Vectren South will work with an independent third party evaluator, selected by the VOB, to conduct an evaluation of DSM programs approved as part of its 2018-2020 Plan. The evaluation will include standard EM&V analyses, such as a process, impact, and/or market effects evaluation of Vectren South's portfolio of DSM programs. Gas impacts will be calculated for all of Vectren South's integrated gas programs. EM&V costs are based on 5% of the budget and allocated at the portfolio level.

10. Other Costs

Other costs being requested in the 2018-2020 filed plan include a Market Potential Study and funding for Emerging Markets.

Table 31: Other Costs by Year

Other Costs	2018	2019	2020
Emerging Markets	$200,000	$200,000	$200,000
Market Potential Study	$300,000	$0	$0
Total	**$500,000**	**$200,000**	**$200,000**

A. Emerging Markets

The Emerging Markets funding allows Vectren's DSM portfolio to offer leading-edge program designs for next-generation technologies, services, and engagement strategies to growing markets in the Vectren territory. The budget will be $200,000 each year for 2018-2020 and will not be used to support existing programs, but rather support new program development or new measures within an existing program.

Incentives promoted through this program may range from innovative rebate offerings to engineering and trade ally assistance to demand-control services that encourage early adoption of new, efficient technologies in high-impact market sectors. Depending on the development of certain technologies and growth areas in the service territory, a wide variety of projects and services are eligible.

To offset the risks of oversaturation of common prescriptive measures and redefined prescriptive baselines, this program will bring to market next generation technologies and energy-saving strategies that have significant savings and cost-effectiveness potential. As new technologies develop towards lower costs and higher efficiency, their market penetration and energy-savings potential will increase. This program will allow Vectren to be on the forefront of emerging technologies to understand the market disruption a new product may cause, test strategies for capturing their energy-saving opportunities, and plan for future program savings growth. This offering will supplement the other DSM programs that do not easily fit into other program offerings. Additionally, growing segments of Vectren South electric customers may require tailored offerings to accommodate their needs in order to participate.

Because this program will focus on innovative new approaches and leading the DSM market, the exact list of measures cannot be set at this time. However, potential measures and services include: new technologies, such as Advanced Lighting Controls; new strategies for achieving significant energy savings, such as midstream incentives, contractor bids to provide energy efficiency projects, and targeting high-impact market sectors; and integrated DSM (iDSM) approaches, such as demand response, combined energy efficiency and demand response measures, and load shifting.

Emerging technologies and measures will be reviewed and may be offered using this funding as long as they do not fall into a current program offering. Innovative engagement and incentivizing approaches may also be used as a tool to provide reduced costs to new systems, equipment and/or services to help reduce peak demand and electric usage. This program also allows Vectren to take steps toward an integrated Demand Side Management approach to address both energy efficiency and demand response together.

B. Market Potential Study

Vectren South is requesting $300,000 to complete a full blown Market Potential Study (MPS) for the years of 2020 and beyond, which is scheduled for 2018. Vectren will issue a Request for Quote to select a consultant to perform this work.

11. Conclusion

Vectren South has developed a 2018-2020 Electric Energy Efficiency Plan that is aligned with the 2016 Integrated Resource Plan and is reasonably achievable and cost effective. The cost effectiveness analysis was performed for 2018-2020 using the DSMore model – a nationally recognized economic analysis tool that is specifically designed to evaluate the cost effectiveness of implementing energy efficiency and demand response programs.

Program costs were determined by referencing 2016 program delivery costs, based on prior contracts and performance in the field and consultation with the program vendors that will deliver the DSM Plan. Energy and demand savings were primarily determined by using recent EM&V results and the IN TRM version 2.2. For measures that were not addressed in the IN TRM or EM&V, Vectren South used Technical Resource Manual resources from nearby states or vendor input. Vectren South utilized the avoided costs from Figure 10.13 in the 2016 IRP.

Based on this information, Vectren South requests IURC approval of this 2018-2020 DSM Plan as well as the costs associated with Emerging Markets and the Market Potential study for 2020 and beyond.

12. Appendix A: Cost Effectiveness Tests Benefits & Costs Summary

Test	Benefits	Costs
Participant Cost Test	• Incentive payments • Annual bill savings • Applicable tax credits	• Incremental technology/equipment costs • Incremental installation costs
Utility Cost Test (Program Administrator Cost Test)	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs
Rate Impact Measure Test	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs • Lost revenue due to reduced energy bills
Total Resource Cost Test	• Avoided energy costs • Avoided capacity costs • Applicable participant tax credits	• All program costs (not including incentive costs) • Incremental technology/equipment costs (whether paid by the participant or the utility)

13. Appendix B: Program Measure Detail

Program	Measure	Measure Life	Average Savings per Unit (kWh)	Demand per Unit (KW)	2018 Participation	2019 Participation	2020 Participation	Avg Incentive Paid Per Unit	Average Incremental Cost	2018 kWh Savings	2019 kWh Savings	2020 kWh Savings
Residential Programs												
Residential Lighting	Standard Units		27.75	0.00	146,465	164,424	80,000		$ 3	4,064,403	4,562,766	2,220,000
Residential Lighting	Specialty Units		44.00	0.01	62,698	67,962	69,716		$ 4	2,758,712	2,990,328	3,067,504
Residential Lighting	LED Fixtures		57.48	0.01	13,700	13,700	13,700		$ 20	787,501	787,501	787,501
Total Residential Lighting					**222,863**	**246,086**	**163,416**			**7,610,617**	**8,340,595**	**6,075,005**
Residential Prescriptive	Air Source Heat Pump 16 SEER	18	1,154.92	0.30	52	52	52	$ 300	$ 870	60,056	60,056	60,056
Residential Prescriptive	Air Source Heat Pump 18 SEER	18	1,625.77	0.35	9	9	9	$ 500	$ 870	14,632	14,632	14,632
Residential Prescriptive	Attic Insulation - Elec Heated	25	3,382.75	0.30	13	13	13	$ 450	$ 500	43,976	43,976	43,976
Residential Prescriptive	Attic Insulation - Gas Heated South (Electric)	25	339.71	0.30	36	36	36	$ 450	$ 500	12,229	12,229	12,229
Residential Prescriptive	Central Air Conditioner 16 SEER	18	294.63	0.35	644	644	644	$ 200	$ 400	189,745	189,745	189,745
Residential Prescriptive	Central Air Conditioner 18 SEER	18	573.88	0.33	76	76	76	$ 400	$ 800	43,615	43,615	43,615
Residential Prescriptive	Dual Fuel Air Source Heat Pump 16 SEER	18	767.06	0.34	0	0	0	$ 300	$ 1,000	0	0	0
Residential Prescriptive	Duct Sealing Electric Heat Pump - South	20	829.21	0.44	7	7	7	$ 350	$ 400	5,804	5,804	5,804
Residential Prescriptive	Duct Sealing Electric Resistive Furnace - South	20	1,351.93	0.40	0	0	0	$ 350	$ 400	0	0	0
Residential Prescriptive	Duct Sealing Gas Heating with A/C - South (Electric)	20	228.61	0.40	77	77	77	$ 175	$ 200	17,603	17,603	17,603
Residential Prescriptive	Ductless Heat Pump 17 SEER 9.5 HSPF	18	3,847.40	0.29	2	2	2	$ 500	$ 1,667	7,695	7,695	7,695
Residential Prescriptive	Ductless Heat Pump 19 SEER 9.5 HSPF	18	3,919.89	0.40	7	7	7	$ 500	$ 2,333	27,439	27,439	27,439
Residential Prescriptive	Ductless Heat Pump 21 SEER 10.0 HSPF	18	3,924.75	0.29	2	2	2	$ 500	$ 2,833	7,850	7,850	7,850
Residential Prescriptive	Ductless Heat Pump 23 SEER 10.0 HSPF	18	4,032.45	0.31	11	11	11	$ 500	$ 3,333	44,357	44,357	44,357
Residential Prescriptive	Duel Fuel Air Source Heat Pump 18 SEER	18	1,498.67	0.13	0	0	0	$ 500	$ 1,667	0	0	0
Residential Prescriptive	ECM HVAC Motor	20	384.72	0.10	1,107	1,107	1,107	$ 100	$ 97	425,884	425,884	425,884
Residential Prescriptive	Heat Pump Water Heater	10	2,291.38	0.31	2	2	2	$ 300	$ 1,000	4,583	4,583	4,583
Residential Prescriptive	Nest On-Line Store (Electric)	15	466.69	0.90	300	350	400	$ 75	$ 39	140,007	163,342	186,676
Residential Prescriptive	Nest On-Line Store (Dual)	15	377.71	0.90	900	1,000	1,100	$ 15	$ 175	339,939	377,710	415,481
Residential Prescriptive	Pool Heater	10	666.87	0.00	1	1	1	$ 1,000	$ 3,333	667	667	667
Residential Prescriptive	Wifi Thermostat - South (Electric)	15	405.09	0.00	264	264	264	$ 10	$ 21	106,944	106,944	106,944
Residential Prescriptive	Smart Programmable Thermostat - South (Electric)	15	412.19	0.00	428	428	428	$ 15	$ 39	176,417	176,417	176,417
Residential Prescriptive	Variable Speed Pool Pump	15	1,173.00	1.72	18	18	18	$ 300	$ 750	21,114	21,114	21,114
Residential Prescriptive	Wall Insulation - Elec Heated	25	1,158.34	0.04	5	5	5	$ 450	$ 500	5,792	5,792	5,792
Residential Prescriptive	Wall Insulation - Gas Heated - South (Electric)	25	60.29	0.04	32	32	32	$ 450	$ 500	1,929	1,929	1,929
Residential Prescriptive	AC Tune Up	5	75.64	0.12	0	644	644	$ 50	$ 64	0	48,710	48,710
Residential Prescriptive	ASHP Tune Up	5	284.99	0.12	0	22	22	$ 50	$ 64	0	6,270	6,270
Residential Prescriptive	Air Purifier	9	492.70	0.06	100	100	100	$ 25	$ 70	49,270	49,270	49,270
Residential Prescriptive	Furnace Tune Up	2	35.51	0.00	0	1,536	1,536	$ -	$ -	0	54,543	54,543
Total Residential Prescriptive					**4,093**	**6,445**	**6,595**			**1,747,547**	**1,918,174**	**1,979,280**
Residential New Construction	Gold Star: HERS Index Score ≤ 65 - EH	25	954.15	0.64	0	0	0	$ 700	$ 2,504	0	0	0
Residential New Construction	Gold Star: HERS Index Score ≤ 65 - Gas Heated	25	954.15	0.64	22	22	22	$ 175	$ 1,573	20,991	20,991	20,991
Residential New Construction	Platinum Star: HERS Index Score ≤ 60 - EH	25	1,419.20	0.89	1	1	1	$ 800	$ 3,079	1,419	1,419	1,419
Residential New Construction	Platinum Star: HERS Index Score ≤ 60-Gas Heated	25	1,419.20	0.89	116	116	116	$ 200	$ 1,778	164,627	164,627	164,627
Total Residential New Construction					**139**	**139**	**139**			**187,038**	**187,038**	**187,038**

Program	Measure	Measure Life	Average Savings per Unit (kWh	Demand per Unit (KW)	2018 Participation	2019 Participation	2020 Participation	Avg Incentive Paid Per Unit	Average Incremental Cost	2018 kWh Savings	2019 kWh Savings	2020 kWh Savings
HEA & Weatherization	Water Heater Temperature Setback - Elec DHW	4	86.40	0.01	15	15	15		$ 7	1,296	1,296	1,296
HEA & Weatherization	Wifi Thermostat - South (Electric)	15	405.09	0.00	399	399	399		$ 21	161,631	161,631	161,631
HEA & Weatherization	Exterior LED Lamp	15	91.98	0.00	1,210	1,210	1,210		$ 8	111,296	111,296	111,296
HEA & Weatherization	Duct Sealing Gas Heating with A/C	15	228.61	0.40	64	64	64		$ 200	14,631	14,631	14,631
HEA & Weatherization	Duct Sealing Electric Heat Pump	15	829.21	0.44	8	8	8		$ 400	6,634	6,634	6,634
HEA & Weatherization	Duct Sealing Electric Resistive Furnace	15	1,351.93	0.40	4	4	4		$ 400	5,408	5,408	5,408
HEA & Weatherization	Air Sealing Gas Furnace w/ CAC	15	140.27	0.39	258	258	258		$ 100	36,190	36,190	36,190
HEA & Weatherization	Air Sealing Heat Pump	15	1,501.47	0.28	30	30	30		$ 200	45,044	45,044	45,044
HEA & Weatherization	Air Sealing Electric Furnace w/ CAC	15	4,687.85	0.92	15	15	15		$ 200	70,318	70,318	70,318
HEA & Weatherization	AC Tune Up	5	75.64	0.12	0	0	0		$ 175	0	0	0
HEA & Weatherization	ASHP Tune Up	5	284.99	0.12	0	0	0		$ 350	0	0	0
HEA & Weatherization	Furnace Tune Up	2	35.51	0.00	0	0	0		$ -	0	0	0
Total HEA & Weatherization					**15,158**	**15,158**	**15,158**			**863,991**	**863,991**	**863,991**
	Number of Homes				1,210	1,210	1,210					
Income Qualified Weatherization	Water Heater Temperature Setback - Gas DHW	4	-34.20	0.00	0	0	0		$ 7	0	0	0
Income Qualified Weatherization	Attic Insulation - Electric Resistance Heated	25	828.28	0.03	24	25	26		$ 1,413	19,879	20,707	21,535
Income Qualified Weatherization	Attic Insulation - Gas Heated (Electric)	25	138.64	0.14	238	250	263		$ 706	32,997	34,661	36,463
Income Qualified Weatherization	Audit Recommendations - dual (Electric)	1	67.87	0.01	475	500	525		$ 26	32,239	33,936	35,633
Income Qualified Weatherization	Audit Recommendations - Electric Only	1	67.87	0.01	0	0	0		$ 106	0	0	0
Income Qualified Weatherization	Bathroom Aerator 1.0 gpm - Elec DHW	10	12.03	0.00	145	153	160		$ 1	1,744	1,841	1,925
Income Qualified Weatherization	9W LED	15	18.66	0.00	2,170	2,284	2,399		$ 3	40,501	42,628	44,775
Income Qualified Weatherization	LED 5W Globe	15	10.37	0.00	93	98	102		$ 9	964	1,016	1,058
Income Qualified Weatherization	LED R30 Dimmable	15	52.98	0.01	365	385	404		$ 12	19,337	20,396	21,403
Income Qualified Weatherization	Exterior LED Lamps	15	91.98	0.00	285	300	315		$ 7	26,214	27,594	28,974
Income Qualified Weatherization	Filter Whistle	15	54.72	0.00	190	200	210		$ 2	10,397	10,944	11,491
Income Qualified Weatherization	Kitchen Flip Aerator 1.5 gpm - Elec DHW	10	120.03	0.01	42	44	47		$ 1	5,041	5,281	5,641
Income Qualified Weatherization	LED Nightlight	16	13.64	0.00	887	933	980		$ 3	12,095	12,723	13,364
Income Qualified Weatherization	Low Flow Showerhead 1.5 gpm - Elec DHW	5	299.86	0.01	89	93	98		$ 3	26,688	27,887	29,386
Income Qualified Weatherization	Pipe Wrap - Elec DHW (per home)	15	148.16	0.02	42	44	47		$ 2	6,223	6,519	6,964
Income Qualified Weatherization	Wifi Thermostat - South (Electric)	15	405.19	0.00	262	276	290		$ 25	106,160	111,832	117,505
Income Qualified Weatherization	Refrigerator Replacement	8	441.56	0.07	63	67	70		$ 580	27,818	29,584	30,909
Income Qualified Weatherization	Smart Power Strips	4	23.00	0.00	570	600	630		$ 35	13,110	13,800	14,490
Income Qualified Weatherization	Smart Thermostat (Electric)	15	412.19	0.00	47	49	52		$ 125	19,373	20,197	21,434
Income Qualified Weatherization	Water Heater Temperature Setback - Elec DHW	4	86.40	0.01	135	142	150		$ 7	11,664	12,269	12,960
Income Qualified Weatherization	Duct Sealing Gas Heating with A/C	15	228.61	0.40	303	319	335		$ 225	69,270	72,928	76,585
Income Qualified Weatherization	Duct Sealing Electric Heat Pump	15	829.21	0.44	36	38	39		$ 450	29,852	31,510	32,339
Income Qualified Weatherization	Duct Sealing Electric Resistive Furnace	15	1,351.93	0.40	18	19	20		$ 450	24,335	25,687	27,039
Income Qualified Weatherization	Air Sealing Gas Furnace w/ CAC	15	140.27	0.39	303	319	335		$ 100	42,502	44,746	46,990
Income Qualified Weatherization	Air Sealing Heat Pump	15	1,501.47	0.28	36	38	39		$ 200	54,053	57,056	58,557
Income Qualified Weatherization	Air Sealing Electric Furnace w/ CAC	15	4,687.85	0.92	18	19	20		$ 200	84,381	89,069	93,757
Income Qualified Weatherization	AC Tune Up	5	75.64	0.12	0	0	0		$ 200	0	0	0
Income Qualified Weatherization	ASHP Tune Up	5	284.99	0.12	0	0	0		$ 400	0	0	0
Income Qualified Weatherization	9W LED	15	18.66	0.00	766	919	1,072		$ 3	14,297	17,152	20,008
Income Qualified Weatherization	LED 5W Globe	15	10.37	0.00	45	54	64		$ 9	467	560	664
Income Qualified Weatherization	LED R30 Dimmable	15	52.98	0.01	179	215	251		$ 12	9,483	11,390	13,297
Income Qualified Weatherization	Wifi Thermostat - South (Electric)	15	405.19	0.00	29	35	40		$ 25	11,751	14,182	16,208
Income Qualified Weatherization	Site Visit and DI - dual (Electric)	1	0.00	0.00	100	120	140		$ 23	0	0	0
Income Qualified Weatherization	9W LED	15	18.66	0.00	1,250	1,500	1,750		$ 3	23,330	27,996	32,662
Income Qualified Weatherization	LED 5W Globe	15	10.37	0.00	114	136	159		$ 9	1,182	1,410	1,649
Income Qualified Weatherization	LED R30 Dimmable	15	52.98	0.01	250	300	350		$ 12	13,244	15,893	18,542
Income Qualified Weatherization	Bathroom Aerator 1.0 gpm - Electric DHW	10	12.03	0.00	23	28	32		$ 1	277	337	385
Income Qualified Weatherization	Kitchen Flip Aerator 1.5 gpm - Electric DHW	10	120.03	0.01	11	13	15		$ 1	1,320	1,560	1,800
Income Qualified Weatherization	Low Flow Showerhead 1.5 gpm - Electric DHW	5	299.86	0.01	29	35	40		$ 3	8,696	10,495	11,994
Income Qualified Weatherization	Wifi Thermostat - South (Electric)	15	405.19	0.00	72	87	101		$ 25	29,174	35,252	40,924
Income Qualified Weatherization	Duct Sealing Gas Heating with A/C	15	114.31	0.20	213	255	298		$ 225	24,347	29,148	34,063
Income Qualified Weatherization	Duct Sealing Electric Heat Pump	15	414.61	0.22	13	15	18		$ 450	5,390	6,219	7,463
Income Qualified Weatherization	Duct Sealing Electric Resistive Furnace	15	675.96	0.20	25	30	35		$ 450	16,899	20,279	23,659
Income Qualified Weatherization	Air Sealing Gas Furnace w/ CAC	15	70.14	0.19	213	255	298		$ 100	14,939	17,884	20,900

Program	Measure	Measure Life	Average Savings per Unit (kWh)	Demand per Unit (KW)	2018 Participation	2019 Participation	2020 Participation	Avg Incentive Paid Per Unit	Average Incremental Cost	2018 kWh Savings	2019 kWh Savings	2020 kWh Savings
Income Qualified Weatherization	Air Sealing Heat Pump	15	1,501.47	0.28	36	38	39		$ 200	54,053	57,056	58,557
Income Qualified Weatherization	Air Sealing Electric Furnace w/ CAC	15	4,687.85	0.92	18	19	20		$ 200	84,381	89,069	93,757
Income Qualified Weatherization	AC Tune Up	5	75.64	0.12	0	0	0		$ 200	0	0	0
Income Qualified Weatherization	ASHP Tune Up	5	284.99	0.12	0	0	0		$ 400	0	0	0
Income Qualified Weatherization	9W LED	15	18.66	0.00	766	919	1,072		$ 3	14,297	17,152	20,008
Income Qualified Weatherization	LED 5W Globe	15	10.37	0.00	45	54	64		$ 9	467	560	664
Income Qualified Weatherization	LED R30 Dimmable	15	52.98	0.01	179	215	251		$ 12	9,483	11,390	13,297
Income Qualified Weatherization	Wifi Thermostat - South (Electric)	15	405.19	0.00	29	35	40		$ 25	11,751	14,182	16,208
Income Qualified Weatherization	Site Visit and DI - dual (Electric)	1	0.00	0.00	100	120	140		$ 23	0	0	0
Income Qualified Weatherization	9W LED	15	18.66	0.00	1,250	1,500	1,750		$ 3	23,330	27,996	32,662
Income Qualified Weatherization	LED 5W Globe	15	10.37	0.00	114	136	159		$ 9	1,182	1,410	1,649
Income Qualified Weatherization	LED R30 Dimmable	15	52.98	0.01	250	300	350		$ 12	13,244	15,893	18,542
Income Qualified Weatherization	Bathroom Aerator 1.0 gpm - Electric DHW	10	12.03	0.00	23	28	32		$ 1	277	337	385
Income Qualified Weatherization	Kitchen Flip Aerator 1.5 gpm - Electric DHW	10	120.03	0.01	11	13	15		$ 1	1,320	1,560	1,800
Income Qualified Weatherization	Low Flow Showerhead 1.5 gpm - Electric DHW	5	299.86	0.01	29	35	40		$ 3	8,696	10,495	11,994
Income Qualified Weatherization	Wifi Thermostat - South (Electric)	15	405.19	0.00	72	87	101		$ 25	29,174	35,252	40,924
Income Qualified Weatherization	Duct Sealing Gas Heating with A/C	15	114.31	0.20	213	255	298		$ 225	24,347	29,148	34,063
Income Qualified Weatherization	Duct Sealing Electric Heat Pump	15	414.61	0.22	13	15	18		$ 450	5,390	6,219	7,463
Income Qualified Weatherization	Duct Sealing Electric Resistive Furnace	15	675.96	0.20	25	30	35		$ 450	16,899	20,279	23,659
Income Qualified Weatherization	Air Sealing Gas Furnace w/ CAC	15	70.14	0.19	213	255	298		$ 100	14,939	17,884	20,900
Income Qualified Weatherization	Air Sealing Heat Pump	15	750.74	0.14	13	15	18		$ 200	9,760	11,261	13,513
Income Qualified Weatherization	Air Sealing Electric Furnace w/ CAC	15	2,343.93	0.46	25	30	35		$ 200	58,598	70,318	82,037
Income Qualified Weatherization	Mobile Home Audit (Dual)	1	0.00	0.00	213	255	298		$ 26	0	0	0
Income Qualified Weatherization	Mobile Home Audit (Electric)	1	0.00	0.00	38	45	53		$ 106	0	0	0
Total Income Qualified Weatherization					**10,457**	**11,537**	**12,623**			**959,988**	**1,046,148**	**1,130,945**
	Number of Homes				475	500	525					
Foodbank	**9W LED**	**15**	**27.75**	**0.00**	**50,496**	**50,496**	**0**		**$ 3**	**1,401,264**	**1,401,264**	**0**
Energy Efficient Schools	15-watt LED x1	15	39.33		2,400	2,500				94,403	98,336	0
Energy Efficient Schools	11-watt LED	15	43.69		2,400	2,500				104,863	109,232	0
Energy Efficient Schools	11-watt LED	15	43.69		2,400	2,500				104,863	109,232	0
Energy Efficient Schools	Showerheads	5	122.64		2,400	2,500	2,600			294,330	306,594	318,864
Energy Efficient Schools	Kitchen aerators	10	55.83		2,400	2,500	2,600			133,987	139,569	145,152
Energy Efficient Schools	Bathroom aerators	10	20.04		2,400	2,500	2,600			48,094	50,098	52,102
Energy Efficient Schools	Bathroom aerators	10	20.04		2,400	2,500	2,600			48,094	50,098	52,102
Energy Efficient Schools	Filter Whistle	5	22.60		2,400	2,500	2,600			54,240	56,500	58,760
Energy Efficient Schools	LED Night Light	16	7.01		2,400	2,500	2,600			16,833	17,534	18,236
Total Energy Efficient Schools					**2,400**	**2,500**	**2,600**			**899,706**	**937,194**	**645,216**
Residential Behavorial Savings		**1**	**157.08**		**41,348**	**38,203**	**35,298**			**6,470,000**	**5,970,000**	**5,600,000**
Appliance Recycling	Refrigerator Recycling	8	1,000.09	0.14	760	744	736	$ 50		760,068	744,067	736,066
Appliance Recycling	Freezer Recycling	8	808.96	0.10	190	186	184	$ 50		153,702	150,467	148,849
Total Appliance Recycling					**950**	**930**	**920**			**913,771**	**894,534**	**884,915**
Smart Thermostat Program (Incentive)		15			2,000	2,000	2,000	$ 20				
												Savings
Conservation Voltage Reduction - Residential		**15**										**1,461,047**
Smart DLC - Wifi DR/DLC Changeout		**15**	**466.69**	**0.90**	**1,000**	**1,000**		**$ 20**		**466,690**	**466,690**	**466,690**
BYOT (Bring Your Own Thermostat)		**15**		**0.90**	**300**	**300**	**300**	**$ 20**				
Sub-Total Residential										**21,520,612**	**22,025,627**	**19,294,126**

Program	Measure	Measure Life	Average Savings per Unit (kWl	Demand per Unit (KW)	2018 Participati on	2019 Participati on	2020 Participatio n	Avg Incentive Paid Per Unit	Average Incremental Cost	2018 kWh Savings	2019 kWh Savings	2020 kWh Savings
C&I Prescriptive	Lighting Power Density Reduction	15	0.9	0.0002	4	3	4	15754.5	-	4	3	4
C&I Prescriptive	LED Decoratives	10	147.0	0.0460	2231	1892	2170	10	20.62	327,957	278,124	318,990
C&I Prescriptive	T12/T8 4 Lamp 4' To LED Panel	15	288.0	0.0755	1069	907	1040	40	91.64	307,872	261,216	299,520
C&I Prescriptive	T12/T8 3 Lamp 4' To LED Panel	15	261.0	0.0485	578	491	563	40	81.80	150,858	128,151	146,943
C&I Prescriptive	T12/T8 2 Lamp 4' To LED Panel	15	226.0	0.0350	513	435	499	40	37.41	115,938	98,310	112,774
C&I Prescriptive	T12/T8 Lamp 4' to LED Tube (includes U-tube)	15	105.0	0.0174	398	338	388	5	22.85	41,790	35,490	40,740
C&I Prescriptive	Fixture Mounted Occupancy Sensor	8	150.1	0.0182	360	305	350	15	125.00	54,035	45,780	52,534
C&I Prescriptive	High Bay HID to LED 175W+	16	780.2	0.2351	293	249	285	90	340.61	228,610	194,279	222,368
C&I Prescriptive	Bonus Incentive - Electric	0	-	-	259	750	0	50	-	-	-	-
C&I Prescriptive	1000W HID to Exterior LED	15	3,143.7	-	250	212	244	200	330.07	785,916	666,457	767,054
C&I Prescriptive	T12/T8 48" 1 Lamp To Delamp (includes U-tubes)	11	116.0	0.0460	202	171	196	5	15.02	23,439	19,842	22,743
C&I Prescriptive	251-400W Post Fixture LED	15	1,122.0	-	148	126	144	120	543.96	166,063	141,378	161,574
C&I Prescriptive	<= 175W Parking Garage or Canopy Fixture to LED	15	524.6	0.0194	94	80	91	50	240.34	49,314	41,970	47,740
C&I Prescriptive	251-400W Parking Garage or Canopy Fixture to LED	15	1,360.7	0.0693	90	76	87	120	257.23	122,466	103,416	118,384
C&I Prescriptive	<= 175W Wallpack to LED	15	583.4	0.0148	86	73	84	50	227.82	50,170	42,586	49,004
C&I Prescriptive	176-250W Wallpack to LED	15	873.6	-	67	57	65	65	316.05	58,534	49,798	56,787
C&I Prescriptive	Occupancy Sensor - Wall Mounted <500W	8	420.4	0.0114	65	55	63	20	42.00	27,324	23,120	26,483
C&I Prescriptive	251-400W Wallpack to LED 75W+	15	1,438.2	-	56	48	55	120	354.13	80,538	69,033	79,100
C&I Prescriptive	T12 or T8 2-Lamp 8-Foot to LED Panel or Kit	15	217.5	0.0457	46	39	45	40	175.56	10,005	8,483	9,788
C&I Prescriptive	T12 96" 4 Lamp To T8 96" 4 Lamp	15	348.4	0.1018	34	29	33	12	202.04	11,846	10,104	11,497
C&I Prescriptive	<= 175W Post Fixture LED	16	556.7	-	33	28	32	50	278.89	18,371	15,588	17,814
C&I Prescriptive	2 Lamp 4ft T12 to 2 Lamp 4ft HPT8	15	46.1	0.0228	28	24	28	6	47.68	1,290	1,105	1,290
C&I Prescriptive	176-250W Post Fixture LED	15	988.8	-	28	24	27	65	398.61	27,686	23,731	26,697
C&I Prescriptive	T12 6' To Refrigerated Display Case Lighting 6' LED - Cooler	8.1	496.9	0.0494	27	23	26	30	137.14	13,418	11,430	12,921
C&I Prescriptive	Fluorescent Exit Sign To LED Exit Sign	16	92.3	0.0106	23	19	22	30	24.91	2,124	1,754	2,031
C&I Prescriptive	176-250W Parking Garage or Canopy Fixture to LED	15	916.1	-	19	16	19	65	295.80	17,405	14,657	17,405
C&I Prescriptive	T8 5' To Refrigerated Display Case Lighting 5' LED - Cooler	8.1	332.5	0.0500	17	15	17	15	150.00	5,652	4,987	5,652
C&I Prescriptive	Cooler - Walk-In Electronically Commutated (EC) Motor	15	357.0	0.0500	13	11	13	35	50.00	4,641	3,927	4,641
C&I Prescriptive	Occupancy Sensor - Ceiling Mounted <500w	8	604.2	0.0144	10	8	9	20	66.00	6,042	4,834	5,438
C&I Prescriptive	Split System Unitary Air Conditioner <65,000 BtuH	15	638.9	0.0682	10	8	9	120	282.11	6,389	5,111	5,750
C&I Prescriptive	T12/T8 U-Tube 2 Lamp 2' To LED Panel	15	185.0	0.0267	8	7	8	30	179.14	1,480	1,295	1,480
C&I Prescriptive	T12 48" 4 Lamp To T8 48" 28W 4 Lamp	15	240.1	0.0440	8	7	8	14	36.19	1,921	1,681	1,921
C&I Prescriptive	Wifi Thermostat - Electric Only	15	4,720.3	-	8	7	16	100	200.00	37,763	33,042	75,526
C&I Prescriptive	Programmable Thermostat - Electric Only	15	4,720.3	-	8	7	16	100	200.00	37,763	33,042	75,526
C&I Prescriptive	Occupancy Sensor - Ceiling Mounted 500W+	8	176.7	0.0617	7	6	7	40	66.00	1,237	1,060	1,237
C&I Prescriptive	T12/T8 1 Lamp 4' To LED Panel	15	129.4	0.0436	7	6	7	30	83.42	906	776	906
C&I Prescriptive	2 Lamp 8ft T12 to 4 Lamp 4ft HPT8	15	41.1	0.0110	7	6	7	25	132.19	288	247	288
C&I Prescriptive	ENERGY STAR Commercial Ice Machine < 500 lb/day harvest rate	9	230.4	0.0338	5	5	5	100	296.00	1,152	1,152	1,152
C&I Prescriptive	Delamp 2' T12	11	36.4	0.0200	5	4	5	2.5	-	182	146	182
C&I Prescriptive	VFD Supply Fan <100hp	15	35,640.0	0.0149	4	3	4	900	10,915.00	142,560	106,920	142,560
C&I Prescriptive	Interior 1000W HID to LED	16	898.6	0.0199	4	3	4	110	-	3,594	2,696	3,594
C&I Prescriptive	2x2 Panel	15	144.0	0.0377	4	3	4	20	45.82	576	432	576
C&I Prescriptive	Split System Unitary Air Conditioner 65,000-135,000 BtuH	15	1,689.3	0.0424	3	2	3	240	666.67	5,068	3,379	5,068
C&I Prescriptive	ENERGY STAR Commercial Hot Holding Cabinets Full Size	12	5,256.0	0.8100	3	2	3	420	1,110.00	15,768	10,512	15,768
C&I Prescriptive	Split System Unitary Air Conditioner 135,000-240,000 BtuH	15	4,865.3	0.0442	2	2	2	600	1,100.00	9,731	9,731	9,731
C&I Prescriptive	ENERGY STAR CEE Tier 2 Window\Sleeve\Room AC < 14,000 BTUH	15	232.2	0.2248	1	1	1	20	-	232	232	232
C&I Prescriptive	ENERGY STAR CEE Tier 2 Window\Sleeve\Room AC >= 14,000 BTUH	15	363.3	0.4430	1	1	1	22	-	363	363	363
C&I Prescriptive	Split System Unitary Air Conditioner 240,000-760,000 BtuH	15	27,827.4	0.2015	1	1	1	1200	2,000.00	27,827	27,827	27,827
C&I Prescriptive	Split System Unitary Air Conditioner >760,000 BtuH	15	81,970.0	2.8190	1	1	1	1050	-	81,970	81,970	81,970
C&I Prescriptive	ENERGY STAR Window\Sleeve\Room AC < 14,000 BTUH	15	189.8	0.1628	1	1	1	12	-	190	190	190
C&I Prescriptive	ENERGY STAR Window\Sleeve\Room AC >= 14,000 BTUH	15	293.3	0.3208	1	1	1	14	-	293	293	293
C&I Prescriptive	ENERGY STAR CEE Tier 1 Window\Sleeve\Room AC < 14,000 BTUH	15	189.8	0.1135	1	1	1	16	-	190	190	190
C&I Prescriptive	ENERGY STAR CEE Tier 1 Window\Sleeve\Room AC >= 14,000 BTUH	15	293.3	0.2237	1	1	1	18	-	293	293	293
C&I Prescriptive	Electric Chiller - Air cooled, with condenser	20	9,606.6	0.0031	1	1	1	1500	-	9,607	9,607	9,607
C&I Prescriptive	Electric Chiller Tune-up - Air cooled, without condenser	5	8,153.0	0.0013	1	1	1	400	-	8,153	8,153	8,153

Program	Measure	Measure Life	Average Savings per Unit (kWh)	Demand per Unit (KW)	2018 Participation	2019 Participation	2020 Participation	Avg Incentive Paid Per Unit	Average Incremental Cost	2018 kWh Savings	2019 kWh Savings	2020 kWh Savings
C&I Prescriptive	Electric Chiller Tune-up - Water Cooled, Centrifugal	5	21,430.9	0.0002	1	1	1	1600	-	21,431	21,431	21,431
C&I Prescriptive	Electric Chiller Tune-up - Water Cooled, Rotary Screw	5	5,073.1	0.0425	1	1	1	1600	1,790.00	5,073	5,073	5,073
C&I Prescriptive	Chilled Water Reset Control	10	173.0	0.0133	1	1	1	1.5	-	173	173	173
C&I Prescriptive	Electric Chiller - Air cooled, without condenser	20	2,923.7	0.0013	1	1	1	500	-	2,924	2,924	2,924
C&I Prescriptive	Electric Chiller - Water Cooled, Rotary Screw <150 tons	20	5,814.1	0.0011	1	1	1	1500	-	5,814	5,814	5,814
C&I Prescriptive	Electric Chiller - Water Cooled, Rotary Screw 150-300 tons	20	17,632.9	0.0000	1	1	1	4500	-	17,633	17,633	17,633
C&I Prescriptive	Electric Chiller - Water Cooled, Rotary Screw >300 tons	20	33,449.4	0.0003	1	1	1	9000	-	33,449	33,449	33,449
C&I Prescriptive	Electric Chiller - Water Cooled, Centrifugal <150 tons	20	6,969.9	0.0033	1	1	1	1500	-	6,970	6,970	6,970
C&I Prescriptive	Electric Chiller - Water Cooled, Centrifugal 150-300 tons	20	17,438.9	0.0006	1	1	1	4500	-	17,439	17,439	17,439
C&I Prescriptive	Electric Chiller - Water Cooled, Centrifugal >300 tons	20	18,656.4	0.0416	1	1	1	9000	13,833.00	18,656	18,656	18,656
C&I Prescriptive	Electric Chiller Tune-up - Air cooled, with condenser	5	9,222.3	0.0015	1	1	1	400	-	9,222	9,222	9,222
C&I Prescriptive	Central Lighting Control	8	224.7	0.0270	1	1	1	30	-	225	225	225
C&I Prescriptive	Daylight Dimming Control <500w	8	337.1	0.0135	1	1	1	20	-	337	337	337
C&I Prescriptive	Occupancy Sensor - Wall Mounted 500W+	8	344.9	0.0270	1	1	1	40	-	345	345	345
C&I Prescriptive	Daylight Dimming Control 500W+	8	674.2	0.0270	1	1	1	40	-	674	674	674
C&I Prescriptive	Fixture Mounted daylight dimming control	8	168.6	0.0068	1	1	1	15	-	169	169	169
C&I Prescriptive	Switching Control for Multi-Level Lighting 500W+	8	168.6	0.0068	1	1	1	30	-	169	169	169
C&I Prescriptive	ENERGY STAR Griddles	12	6,995.7	1.3416	1	1	1	550	-	6,996	6,996	6,996
C&I Prescriptive	ENERGY STAR Combination Oven	12	18,431.7	3.5348	1	1	1	1000	-	18,432	18,432	18,432
C&I Prescriptive	ENERGY STAR Convection Oven	12	3,234.8	0.6204	1	1	1	350	-	3,235	3,235	3,235
C&I Prescriptive	ENERGY STAR Commercial Dishwasher - Door Type, High Temp	15	14,143.0	0.6889	1	1	1	1100	-	14,143	14,143	14,143
C&I Prescriptive	ENERGY STAR Commercial Dishwasher - Door Type, Low Temp	15	12,135.0	0.5911	1	1	1	1000	-	12,135	12,135	12,135
C&I Prescriptive	ENERGY STAR Commercial Dishwasher - Multi-Tank Conveyor, High Temp	20	34,153.0	1.6635	1	1	1	2700	-	34,153	34,153	34,153
C&I Prescriptive	ENERGY STAR Commercial Dishwasher - Multi-Tank Conveyor, Low Temp	20	17,465.0	0.8507	1	1	1	1400	-	17,465	17,465	17,465
C&I Prescriptive	ENERGY STAR Commercial Dishwasher - Single Tank Conveyor, High Temp	20	19,235.0	0.9369	1	1	1	1500	-	19,235	19,235	19,235
C&I Prescriptive	ENERGY STAR Commercial Ice Machine >=500 and <1000 lb/day harvest rate	9	702.4	0.1100	1	1	1	175	1,485.00	702	702	702
C&I Prescriptive	ENERGY STAR Commercial Dishwasher - Single Tank Conveyor, Low Temp	20	11,384.0	0.5545	1	1	1	900	-	11,384	11,384	11,384
C&I Prescriptive	ENERGY STAR Commercial Dishwasher - Under Counter, High Temp	10	7,471.0	0.3639	1	1	1	600	-	7,471	7,471	7,471
C&I Prescriptive	ENERGY STAR Commercial Dishwasher - Under Counter, Low Temp	10	1,213.0	0.0591	1	1	1	100	-	1,213	1,213	1,213
C&I Prescriptive	ENERGY STAR Commercial Ice Machine >=1000 lb/day harvest rate	9	1,227.5	0.1898	1	1	1	250	-	1,227	1,227	1,227
C&I Prescriptive	ENERGY STAR Commercial Hot Holding Cabinets Half Size	12	1,795.8	0.2755	1	1	1	150	-	1,796	1,796	1,796
C&I Prescriptive	ENERGY STAR Commercial Hot Holding Cabinets Three Quarter Size	12	2,825.1	0.4334	1	1	1	230	-	2,825	2,825	2,825
C&I Prescriptive	ENERGY STAR Commercial Fryer	12	1,526.2	0.2195	1	1	1	80	-	1,526	1,526	1,526
C&I Prescriptive	ENERGY STAR Commercial Steam Cookers	12	2,200.0	0.4400	1	1	1	200	-	2,200	2,200	2,200
C&I Prescriptive	Air Source Heat Pump <65,000 BtuH	15	555.3	0.0136	1	1	1	120	221.67	555	555	555
C&I Prescriptive	Air Source Heat Pump≥65,000 Btu/h and <135,000 Btu/h	15	492.0	-	1	1	1	240	-	492	492	492
C&I Prescriptive	Air Source Heat Pump≥135,000 Btu/h and <240,000 Btu/h	15	1,350.0	-	1	1	1	600	-	1,350	1,350	1,350
C&I Prescriptive	Air Source Heat Pump≥240,000 Btu/h and <760,000 Btu/h	15	6,949.0	-	1	1	1	1200	-	6,949	6,949	6,949
C&I Prescriptive	Water Source Heat Pump <17,000Btu/hr	15	160.0	0.0500	1	1	1	30	-	160	160	160
C&I Prescriptive	Water Source Heat Pump >=17,000Btu/hr - 65,000Btu/hr	15	596.6	0.0475	1	1	1	120	-	597	597	597
C&I Prescriptive	Water Source Heat Pump >65,000Btu/hr and <135,000Btu/hr	15	1,193.2	0.0463	1	1	1	240	-	1,193	1,193	1,193
C&I Prescriptive	Ground Source Heat Pump <135,000 Btu/hr	15	1,322.4	-	1	1	1	30	-	1,322	1,322	1,322
C&I Prescriptive	Ground Water Source Heat Pump <135,000 Btu/hr	15	41,712.0	0.0350	1	1	1	240	-	41,712	41,712	41,712
C&I Prescriptive	High Bay HID to LED <175W	16	303.5	0.0067	1	1	1	35	-	303	303	303
C&I Prescriptive	T12 or T8 1-Lamp 8-Foot to LED Panel or Kit	15	118.0	0.0228	1	1	1	40	-	118	118	118
C&I Prescriptive	T12/T8 Lamp 8' to LED Tube	15	210.0	-	1	1	1	10	-	210	210	210
C&I Prescriptive	Clothes Washer ENERGY STAR/CEE Tier 1	11	541.5	-	1	1	1	50	-	542	542	542
C&I Prescriptive	Pellet Dryers duct insulation	5	297.7	0.0450	1	1	1	30	-	298	298	298
C&I Prescriptive	Clothes Washer CEE Tier 2	11	541.5	-	1	1	1	60	-	542	542	542
C&I Prescriptive	Clothes Washer CEE Tier 3	11	541.5	-	1	1	1	70	-	542	542	542
C&I Prescriptive	Smart Strip Plug Outlet	8	23.6	-	1	1	1	8	-	24	24	24
C&I Prescriptive	Plug Load Occupancy sensor with Smart Strip	8	169.0	-	1	1	1	20	-	169	169	169
C&I Prescriptive	Compressed Air Engineered Nozzles (1/8")	15	429.8	0.1631	1	1	1	5	-	430	430	430
C&I Prescriptive	Compressed Air Engineered Nozzles (1/4")	15	1,346.6	0.5111	1	1	1	8	-	1,347	1,347	1,347
C&I Prescriptive	VFD compressor	15	31,875.0	0.0011	1	1	1	5625	-	31,875	31,875	31,875
C&I Prescriptive	Barrel Wraps (Inj Mold Only)	5	983.3	0.0306	1	1	1	30	-	983	983	983

Program	Measure	Measure Life	Average Savings per Unit (kWh	Demand per Unit (KW)	2018 Participation	2019 Participation	2020 Participation	Avg Incentive Paid Per Unit	Average Incremental Cost	2018 kWh Savings	2019 kWh Savings	2020 kWh Savings
C&I Prescriptive	Electric Chiller Tune-up - Water Cooled, Centrifugal	5	21,430.9	0.0002	1	1	1	1600	-	21,431	21,431	21,431
C&I Prescriptive	T12/T8 96" 1 Lamp To Delamp	11	157.2	0.0684	1	1	1	10	-	157	157	157
C&I Prescriptive	Incandescent Traffic Signal To LED Traffic Signal Round 8" Red	10	298.7	0.0341	1	1	1	30	-	299	299	299
C&I Prescriptive	Incandescent Traffic Signal To LED Traffic Signal Pedestrian 12"	10	946.1	0.1080	1	1	1	50	-	946	946	946
C&I Prescriptive	Packaged Terminal Air Conditioner (PTAC) <7000 BtuH	15	138.0	0.2284	1	1	1	35	-	138	138	138
C&I Prescriptive	Packaged Terminal Air Conditioner (PTAC) 7,000-15,000 BtuH	15	1,702.4	0.9600	1	1	1	70	35.00	1,702	1,702	1,702
C&I Prescriptive	Packaged Terminal Air Conditioner (PTAC) >15,000 BtuH	15	506.0	0.7715	1	1	1	105	-	506	506	506
C&I Prescriptive	Packaged Terminal Heat Pump (PTHP) <7,000 BtuH	15	395.4	0.3945	1	1	1	35	48.97	395	395	395
C&I Prescriptive	Packaged Terminal Heat Pump (PTHP) 7,000 - 15,000 BtuH	15	385.0	0.1000	1	1	1	70	-	385	385	385
C&I Prescriptive	Packaged Terminal Heat Pump (PTHP) > 15,000 BtuH	15	639.8	0.1133	1	1	1	105	-	640	640	640
C&I Prescriptive	Cooler <15 vol	12	3,671.3	0.0593	1	1	1	375	-	3,671	3,671	3,671
C&I Prescriptive	T12 6' To Refrigerated Display Case Lighting 6' LED - Cooler With Connected Motion Sensor	8.1	825.7	0.0856	1	1	1	45	-	826	826	826
C&I Prescriptive	T12 6' To Refrigerated Display Case Lighting 6' LED - Freezer	8.1	622.5	0.0923	1	1	1	30	-	622	622	622
C&I Prescriptive	T12 6' To Refrigerated Display Case Lighting 6' LED - Freezer With Connected Motion Sensor	8.1	890.2	0.0923	1	1	1	45	-	890	890	890
C&I Prescriptive	T8 5' To Refrigerated Display Case Lighting 5' LED - Cooler With Connected Motion Sensor	8.1	475.4	0.0493	1	1	1	25	-	475	475	475
C&I Prescriptive	T8 5' To Refrigerated Display Case Lighting 5' LED - Freezer	8.1	358.4	0.0531	1	1	1	15	-	358	358	358
C&I Prescriptive	T8 5' To Refrigerated Display Case Lighting 5' LED - Freezer With Connected Motion Sensor	8.1	512.5	0.0531	1	1	1	25	-	513	513	513
C&I Prescriptive	Cooler - Reach-In Electronically Commutated (EC) Motor	15	328.0	0.0330	1	1	1	35	-	328	328	328
C&I Prescriptive	Freezer - Reach-In Electronically Commutated (EC) Motor	15	411.0	0.0350	1	1	1	45	-	411	411	411
C&I Prescriptive	Cooler 15-30 vol	12	14,411.1	0.0500	1	1	1	1650	164.00	14,411	14,411	14,411
C&I Prescriptive	Freezer - Walk-In Electronically Commutated (EC) Motor	15	532.0	0.0360	1	1	1	45	-	532	532	532
C&I Prescriptive	Cooler Anti-Sweat Heater Controls	12	614.5	-	1	1	1	50	-	615	615	615
C&I Prescriptive	Freezer Anti-Sweat Heater Controls	12	1,302.5	-	1	1	1	100	-	1,303	1,303	1,303
C&I Prescriptive	Refrigerated Case Covers	5	157.5	-	1	1	1	10	-	158	158	158
C&I Prescriptive	Cooler - Glass Door 30-50 vol	12	38,943.5	0.0800	1	1	1	3000	164.00	38,944	38,944	38,944
C&I Prescriptive	Cooler - Glass Door >50 vol	12	91,487.5	0.1000	1	1	1	7000	249.00	91,488	91,488	91,488
C&I Prescriptive	Freezer - Glass Door <15 vol	12	5,837.7	0.0800	1	1	1	750	142.00	5,838	5,838	5,838
C&I Prescriptive	Freezer - Glass Door 15-30 vol	12	26,061.0	0.0900	1	1	1	4500	166.00	26,061	26,061	26,061
C&I Prescriptive	Freezer - Glass Door 30-50 vol	12	164,834.0	0.4400	1	1	1	8000	166.00	164,834	164,834	164,834
C&I Prescriptive	Freezer - Glass Door >50 vol	12	715,400.0	0.7667	1	1	1	35000	407.00	715,400	715,400	715,400
C&I Prescriptive	T12 48" 1 Lamp To T5 46" 1 Lamp	15	25.3	0.0100	1	1	1	4	-	25	25	25
C&I Prescriptive	175 - 250W HID To T5 46" 2 Lamp HO	15	377.7	0.1049	1	1	1	45	-	378	378	378
C&I Prescriptive	175 - 250W HID To T5 46" 3 Lamp HO	15	167.5	0.0465	1	1	1	40	-	168	168	168
C&I Prescriptive	400W HID To T5 46" 4 Lamp HO	15	702.9	0.1952	1	1	1	85	-	703	703	703
C&I Prescriptive	400W HID To T5 46" 6 Lamp HO	15	318.6	0.0885	1	1	1	50	-	319	319	319
C&I Prescriptive	1000W HID To T5 46" 10 Lamp HO	15	1,652.2	0.4587	1	1	1	115	-	1,652	1,652	1,652
C&I Prescriptive	1000W HID To T5 46" 12 Lamp HO	15	1,215.3	0.3374	1	1	1	105	-	1,215	1,215	1,215
C&I Prescriptive	T12 48" 2 Lamp To T5 46" 2 Lamp	15	18.4	0.0073	1	1	1	6	-	18	18	18
C&I Prescriptive	T12 48" 3 Lamp To T5 46" 3 Lamp	15	43.7	0.0173	1	1	1	8	-	44	44	44
C&I Prescriptive	T12 48" 4 Lamp To T5 46" 4 Lamp	15	36.8	0.0146	1	1	1	12	-	37	37	37
C&I Prescriptive	HID 75W-100W To T5 Garage 1 Lamp	15	301.7	0.1104	1	1	1	8	-	302	302	302
C&I Prescriptive	HID 101W-175W To T5 Garage 2 Lamp	15	275.4	0.1008	1	1	1	12	-	275	275	275
C&I Prescriptive	HID 176W+ To T5 Garage 3 Lamp	15	367.2	0.1344	1	1	1	16	-	367	367	367
C&I Prescriptive	Up to 175W HID To T5 46" 2 Lamp HO	15	239.8	0.0666	1	1	1	35	-	240	240	240
C&I Prescriptive	Up to 175W HID To T5 46" 3 Lamp HO	15	88.7	0.0246	1	1	1	30	-	89	89	89
C&I Prescriptive	Up to 175W HID to T8VHO 48" 3 Lamp	15	197.1	0.0547	1	1	1	35	-	197	197	197
C&I Prescriptive	T12 48" 1 Lamp To T8 48" 25W 1 Lamp	15	48.3	0.0192	1	1	1	8	-	48	48	48
C&I Prescriptive	T12 48" 2 Lamp To T8 48" 25W 2 Lamp	15	71.3	0.0283	1	1	1	10	-	71	71	71
C&I Prescriptive	T12 48" 3 Lamp To T8 48" 25W 3 Lamp	15	123.5	0.0490	1	1	1	12	-	123	123	123
C&I Prescriptive	T12 48" 4 Lamp To T8 48" 25W 4 Lamp	15	146.0	0.0579	1	1	1	16	-	146	146	146
C&I Prescriptive	1 Lamp 4ft T12 to 1 Lamp 4ft HPT8	15	41.4	0.0164	1	1	1	4	-	41	41	41
C&I Prescriptive	3 Lamp 4ft T12 to 3 Lamp 4ft HPT8	15	96.6	0.0383	1	1	1	8	-	97	97	97
C&I Prescriptive	4 Lamp 4ft T12 to 4 Lamp 4ft HPT8	15	110.4	0.0438	1	1	1	12	-	110	110	110
C&I Prescriptive	T12 96" 1 Lamp To T8 96" 1 Lamp	15	39.1	0.0155	1	1	1	6	-	39	39	39
C&I Prescriptive	T12 96" 2 Lamp To T8 96" 2 Lamp	15	32.2	0.0128	1	1	1	8	-	32	32	32
C&I Prescriptive	176-250W HID to T8VHO 48" 4 Lamp	15	266.1	0.0739	1	1	1	50	-	266	266	266
C&I Prescriptive	1 Lamp 8ft T12 to 2 Lamp 4ft HPT8	15	62.1	0.0246	1	1	1	20	-	62	62	62

Program	Measure	Measure Life	Average Savings per Unit (kWh	Demand per Unit (KW)	2018 Participation	2019 Participation	2020 Participation	Avg Incentive Paid Per Unit	Average Incremental Cost	2018 kWh Savings	2019 kWh Savings	2020 kWh Savings
C&I Prescriptive	Electric Chiller Tune-up - Water Cooled, Centrifugal	5	21,430.9	0.0002	1	1	1	1600	-	21,431	21,431	21,431
C&I Prescriptive	T12/T8 96" 1 Lamp To Delamp	11	157.2	0.0684	1	1	1	10	-	157	157	157
C&I Prescriptive	400W HID to T8VHO 4ft 6 Lamp	15	762.0	0.2116	1	1	1	85	-	762	762	762
C&I Prescriptive	400W HID to T8VHO 4ft 8 Lamp	15	558.4	0.1550	1	1	1	60	-	558	558	558
C&I Prescriptive	MH 1000W To T8VHO 48" 8 Lamp (2 fixtures)	15	1,655.5	0.4596	1	1	1	125	-	1,655	1,655	1,655
C&I Prescriptive	T12 48" 1 Lamp To T8 48" 28W 1 Lamp	15	45.3	0.0180	1	1	1	6	-	45	45	45
C&I Prescriptive	T12 48" 2 Lamp To T8 48" 28W 2 Lamp	15	57.5	0.0228	1	1	1	8	-	57	57	57
C&I Prescriptive	T12 48" 3 Lamp To T8 48" 28W 3 Lamp	15	103.7	0.0411	1	1	1	10	-	104	104	104
C&I Prescriptive	Vending Machine Occ Sensor - Refrigerated Beverage	5	1,611.8	-	1	1	1	50	-	1,612	1,612	1,612
C&I Prescriptive	Snack Machine Controller (Non-refrigerated vending)	5	342.5	-	1	1	1	25	-	343	343	343
C&I Prescriptive	Vending Machine Occ Sensor - Refrigerated Glass Front Cooler	5	1,208.9	-	1	1	1	50	-	1,209	1,209	1,209
C&I Prescriptive	VFD Return Fan <100hp	15	60,000.0	-	1	1	1	900	-	60,000	60,000	60,000
C&I Prescriptive	VFD Tower Fan <100hp	15	19,220.0	-	1	1	1	900	-	19,220	19,220	19,220
C&I Prescriptive	VFD CW Pump <100hp	15	26,800.0	-	1	1	1	900	-	26,800	26,800	26,800
C&I Prescriptive	VFD HW Pump <100hp	15	88,620.0	0.9790	1	1	1	900	-	88,620	88,620	88,620
C&I Prescriptive	VFD CHW Pump <100hp	15	74,020.0	0.3900	1	1	1	900	-	74,020	74,020	74,020
C&I Prescriptive	Heat Pump Water Heater 10-50 MBH	10	3,534.0	0.5000	1	1	1	500	-	3,534	3,534	3,534
C&I Prescriptive	Window Film	10	3.7	0.0010	1	1	1	1	-	4	4	4
C&I Prescriptive	Pre-Rinse Sprayer - Electric	5	3,727.2	-	1	1	1	50	-	3,727	3,727	3,727
C&I Prescriptive	Livestock Waterer	10	266.1	0.5250	1	1	1	110	787.50	266	266	266
C&I Prescriptive	Agriculture - Poultry Farm LED Lighting	7	292.0	0.0500	1	1	1	10	30.00	292	292	292
C&I Prescriptive	VSD Milk Pump	15	33.9	0.0116	1	1	1	5	4,000.00	34	34	34
C&I Prescriptive	High Volume Low Speed Fans	10	8,543.0	3.1000	1	1	1	1000	4,180.00	8,543	8,543	8,543
C&I Prescriptive	High Speed Fans (Ventilation and Ciculation)	7	625.0	0.1980	1	1	1	50	150.00	625	625	625
C&I Prescriptive	Dairy Plate Cooler	15	76.2	0.0163	1	1	1	8	-	76	76	76
C&I Prescriptive	Heat Mat (Single, ~14x60")	5	657.0	-	1	1	1	65	225.00	657	657	657
C&I Prescriptive	Automatic Milker Take Off	15	556.0	0.1165	1	1	1	5	-	556	556	556
C&I Prescriptive	HE Diary Scroll Compressor	12	279.5	0.0689	1	1	1	250	-	279	279	279
C&I Prescriptive	Heat Reclaimer (No Precooler Installed)	14	152.7	-	1	1	1	5	-	153	153	153
C&I Prescriptive	Prescriptive Other	15								132,109	99,082	132,110
Total C&I Prescriptive					**7,024**	**5,981**	**6,856**			**4,999,125**	**4,501,186**	**5,002,621**
Small Business Direct Install (SBDI)	Lamp & Ballast Retrofit: 1-Lamp 4' T12 to HP, 28W or 25W T8	15	64.0	0.0171	80	77	68	12	51	5,122	4,930	4,353
Small Business Direct Install (SBDI)	Lamp & Ballast Retrofit: 2-Lamp 4' T12 to HP, 28W or 25W T8	15	85.4	0.0228	119	116	102	15	56	10,158	9,902	8,707
Small Business Direct Install (SBDI)	Lamp & Ballast Retrofit: 3-Lamp 4' T12 to HP, 28W or 25W T8	15	104.1	0.0383	2	2	1	20	70	208	208	104
Small Business Direct Install (SBDI)	Lamp & Ballast Retrofit: 4-Lamp 4' T12 to HP, 28W or 25W T8	15	116.5	0.0390	159	154	136	24	78	18,523	17,940	15,843
Small Business Direct Install (SBDI)	Lamp & Ballast Retrofit: 1-Lamp 8' T12 to 2-Lamp 4' or 1-Lamp 8' HP, 28W or 25W T8 w/ reflector	15	153.9	0.0246	2	2	1	20	93	308	308	154
Small Business Direct Install (SBDI)	Lamp & Ballast Retrofit: 2-Lamp 8' T12 to 4-Lamp 4' or 2-Lamp 8' HP, 28W or 25W T8 w/ reflector	15	59.3	0.0230	192	185	164	25	108	11,381	10,966	9,721
Small Business Direct Install (SBDI)	Lamp & Ballast Retrofit: 1-Lamp 8' T12 to 2-Lamp 4' or 1-Lamp 8' HP, 28W or 25W T8	15	110.7	0.0246	2	2	1	22	88	221	221	111
Small Business Direct Install (SBDI)	Lamp & Ballast Retrofit: 2-Lamp 8' T12 to 4-Lamp 4' or 2-Lamp 8' HP, 28W or 25W T8	15	41.6	0.0208	256	248	218	27	103	10,653	10,320	9,072
Small Business Direct Install (SBDI)	400W HID to High Bay Fluorescent 6-Lamp 4' HP, 28W or 25W T8	7	703.4	0.2116	2	2	1	125	300	1,407	1,407	703
Small Business Direct Install (SBDI)	250W HID to High Bay Fluorescent 4-Lamp 4' HP, 28W or 25W T8	7	519.9	0.1778	2	2	1	90	255	1,040	1,040	520
Small Business Direct Install (SBDI)	Delamping with Lamp & Ballast Retrofit: 4-Lamp 4' T12 to 3-Lamp 4' HP, 28W or 25W T8	15	211.2	0.0648	2	2	1	35	75	422	422	211
Small Business Direct Install (SBDI)	Delamping with Lamp & Ballast Retrofit: 4-Lamp 4' T12 to 2-Lamp 4' HP, 28W or 25W T8	15	264.9	0.0876	2	2	1	45	75	530	530	265
Small Business Direct Install (SBDI)	Delamping with Lamp & Ballast Retrofit: 3-Lamp 4' T12 to 2-Lamp 4' HP, 28W or 25W T8	15	199.8	0.0611	2	2	1	35	57	400	400	200
Small Business Direct Install (SBDI)	Delamping with Lamp & Ballast Retrofit: 2-Lamp 4' T12 to 1-Lamp 4' HP, 28W or 25W T8	15	137.3	0.0246	2	2	1	25	50	275	275	137
Small Business Direct Install (SBDI)	Delamping with Lamp & Ballast Retrofit: 4-Lamp 8' T12 to 4-Lamp 4' or 2-Lamp 8' HP, 28W or 25W T8	15	360.0	0.1368	2	2	1	60	105	720	720	360
Small Business Direct Install (SBDI)	Delamping with Lamp & Ballast Retrofit w/Reflector: 4-Lamp 4' T12 to 3-Lamp 4' HP, 28W or 25W T8	15	247.1	0.0716	2	2	1	35	90	494	494	247
Small Business Direct Install (SBDI)	Delamping with Lamp & Ballast Retrofit w/Reflector: 4-Lamp 4' T12 to 2-Lamp 4' HP, 28W or 25W T8	15	341.5	0.0910	1152	1115	984	60	58.51	393,353	380,719	335,989
Small Business Direct Install (SBDI)	Delamping with Lamp & Ballast Retrofit w/Reflector: 3-Lamp 4' T12 to 2-Lamp 4' HP, 28W or 25W T8	15	225.7	0.0675	2	2	1	40	88	451	451	226
Small Business Direct Install (SBDI)	Delamping with Lamp & Ballast Retrofit w/Reflector: 2-Lamp 4' T12 to 1-Lamp 4' HP, 28W or 25W T8	15	149.2	0.0404	2	2	1	25	57	298	298	149
Small Business Direct Install (SBDI)	Delamping with Lamp & Ballast Retrofit w/Reflector: 2-Lamp 8' T12 to 2-Lamp 4' or 1-Lamp 8' HP, 28W or 25W T8	15	275.9	0.0631	2	2	1	50	110	552	552	276
Small Business Direct Install (SBDI)	Delamping with Lamp & Ballast Retrofit w/Reflector: 4-Lamp 8' T12 to 4-Lamp 4' or 2-Lamp 8' HP, 28W or 25W T8	15	505.3	0.1368	2	2	1	90	140	1,011	1,011	505
Small Business Direct Install (SBDI)	Lamp & Ballast Retrofit: 1-Lamp 4' T12/T8 to 4' LED Tube	15	112.9	0.0232	80	77	68	18	80	9,036	8,697	7,680
Small Business Direct Install (SBDI)	Lamp & Ballast Retrofit: 2-Lamp 4' T12/T8 to 4' LED Tube	15	74.4	-	2	2	1	25	100	149	149	74
Small Business Direct Install (SBDI)	Lamp & Ballast Retrofit: 3-Lamp 4' T12/T8 to 4' LED Tube	15	81.8	-	2	2	1	25	120	164	164	82
Small Business Direct Install (SBDI)	Lamp & Ballast Retrofit: 4-Lamp 4' T12/T8 to 4' LED Tube	15	314.3	0.0645	437	423	374	50	140	137,340	132,940	117,541
Small Business Direct Install (SBDI)	Lamp & Ballast Retrofit: 1-Lamp 8' T12/T8 to 2-Lamp 4' or 1-Lamp 8' LED Tube	15	171.9	0.0353	675	654	577	30	132	116,013	112,404	99,170
Small Business Direct Install (SBDI)	Lamp & Ballast Retrofit: 2-Lamp 8' T12/T8 to 4-Lamp 4' or 2-Lamp 8' LED Tube	15	214.5	0.0433	40	39	34	40	175	8,580	8,366	7,293

Program	Measure	Measure Life	Average Savings per Unit (kWh)	Demand per Unit (KW)	2018 Participation	2019 Participation	2020 Participation	Avg Incentive Paid Per Unit	Average Incremental Cost	2018 kWh Savings	2019 kWh Savings	2020 kWh Savings
Small Business Direct Install (SBDI)	Delamping with Lamp & Ballast Retrofit: 4-Lamp 4' T12/T8 to 3-Lamp 4' LED Tube	15	190.4	-	2	2	1	30	130	381	381	190
Small Business Direct Install (SBDI)	Delamping with Lamp & Ballast Retrofit: 4-Lamp 4' T12/T8 to 2-Lamp 4' LED Tube	15	353.6	0.0726	80	77	68	60	120	28,285	27,225	24,042
Small Business Direct Install (SBDI)	Delamping with Lamp & Ballast Retrofit: 3-Lamp 4' T12/T8 to 2-Lamp 4' LED Tube	15	158.1	-	2	2	1	30	100	316	316	158
Small Business Direct Install (SBDI)	Delamping with Lamp & Ballast Retrofit: 2-Lamp 4' T12/T8 to 1-Lamp 4' LED Tube	15	213.5	-	2	2	1	40	75	427	427	214
Small Business Direct Install (SBDI)	Delamping with Lamp & Ballast Retrofit: 4-Lamp 8' T12/T8 to 4-Lamp 4' or 2-Lamp 8' LED Tube	15	364.8	-	2	2	1	65	250	730	730	365
Small Business Direct Install (SBDI)	Delamping with Lamp & Ballast Retrofit w/Reflector: 2-Lamp 2' T12 U-tube to 2-Lamp 2' HP, 28W or 25W T8	15	108.0	0.0329	2	2	1	19	89	216	216	108
Small Business Direct Install (SBDI)	400W HID to High Bay LED ≤250W	15	589.9	0.1797	172	166	147	220	480	101,461	97,921	86,714
Small Business Direct Install (SBDI)	250W HID to High Bay LED ≤100W	15	716.6	0.1778	2	2	1	160	460	1,433	1,433	717
Small Business Direct Install (SBDI)	LED Exit Sign Fixture with Battery Backup	16	87.2	0.0077	641	621	548	60	88	55,923	54,178	47,810
Small Business Direct Install (SBDI)	4-Lamp 4' T12/T8 to LED Panel	15	286.6	-	2	2	1	50	155	573	573	287
Small Business Direct Install (SBDI)	3-Lamp 4' T12/T8 to LED Panel	15	214.9	-	2	2	1	40	145	430	430	215
Small Business Direct Install (SBDI)	2-Lamp 4' T12/T8 to LED Panel	15	93.3	-	2	2	1	40	135	187	187	93
Small Business Direct Install (SBDI)	ENERGY STAR® LED lamps 40W Equivalent	15	64.3	0.0293	279	270	238	12	33	17,951	17,372	15,313
Small Business Direct Install (SBDI)	ENERGY STAR® LED lamps 60W Equivalent	15	120.8	0.0337	913	884	780	22	7.38	110,272	106,769	94,208
Small Business Direct Install (SBDI)	ENERGY STAR® LED lamps 75W+ Equivalent	15	179.2	0.0536	2	2	1	32	35	358	358	179
Small Business Direct Install (SBDI)	ENERGY STAR® LED downlights - 40W Equivalent	15	94.3	0.0285	2	2	1	18	52	189	189	94
Small Business Direct Install (SBDI)	ENERGY STAR® LED downlights - 60W Equivalent	15	132.3	0.0371	5	5	4	27	57	661	661	529
Small Business Direct Install (SBDI)	ENERGY STAR® LED downlights - 75W+ Equivalent	15	205.3	0.0412	398	385	340	35	39	81,698	79,029	69,792
Small Business Direct Install (SBDI)	Delamp 1 lamp 8ft T12 lamp and ballast	10	278.1	-	2	2	1	50	34	556	556	278
Small Business Direct Install (SBDI)	Delamp 2 lamp 8ft T12 lamp and ballast	10	417.2	-	2	2	1	75	36	834	834	417
Small Business Direct Install (SBDI)	Delamp 4 lamp 8ft T12 lamp and ballast	10	834.3	-	2	2	1	75	38	1,669	1,669	834
Small Business Direct Install (SBDI)	Vending Machine Occ Sensor - Refrigerated Glass Front Cooler	5	1,208.9	-	2	2	1	200	178	2,418	2,418	1,209
Small Business Direct Install (SBDI)	Vending Machine Occ Sensor - Refrigerated Beverage	5	1,602.5	-	2	2	1	250	208	3,205	3,205	1,602
Small Business Direct Install (SBDI)	Occupancy Sensors - Ceiling Mount (must control 350 watts)	8	299.3	0.0630	5	5	4	60	170	1,496	1,496	1,197
Small Business Direct Install (SBDI)	Occupancy Sensors - Wall Mount (must control at least 200 watts)	8	250.2	0.0108	2	2	1	40	115	500	500	250
Small Business Direct Install (SBDI)	Occupancy Sensors - Fixture Mount (must control at least 100 watts)	8	154.6	0.0054	2	2	1	25	37	309	309	155
Small Business Direct Install (SBDI)	Exterior Wallpack: 175W HID to LED	15	470.4	0.0251	972	941	830	100	225.5	457,246	442,663	390,447
Small Business Direct Install (SBDI)	Exterior Wallpack: 176 W-250 W HID to LED	15	639.2	0.1236	172	166	147	115	310	109,946	106,111	93,965
Small Business Direct Install (SBDI)	Exterior Wallpack: 251 W-400 W HID to LED	15	1,066.7	0.0900	2	2	1	185	600	2,133	2,133	1,067
Small Business Direct Install (SBDI)	Exterior Canopy: less than 175W HID to LED	15	470.4	0.0251	632	612	540	100	190.4	297,304	287,896	254,025
Small Business Direct Install (SBDI)	Exterior Canopy: 176 W-250 W HID to LED	15	639.2	0.1236	132	128	113	115	272	84,377	81,820	72,232
Small Business Direct Install (SBDI)	Exterior Canopy: 251 W-400 W HID to LED	15	1,066.7	0.0900	2	2	1	185	600	2,133	2,133	1,067
Small Business Direct Install (SBDI)	Exterior Flood: less than 175W HID to LED	15	470.4	0.0251	778	753	664	100	188.33	365,985	354,224	312,357
Small Business Direct Install (SBDI)	Exterior Flood: 176 W-250 W HID to LED	15	639.2	0.1236	146	141	125	115	310	93,326	90,130	79,903
Small Business Direct Install (SBDI)	Exterior Flood: 251 W-400 W HID to LED	15	1,066.7	0.0900	2	2	1	185	600	2,133	2,133	1,067
Small Business Direct Install (SBDI)	Exterior Pole Mount: less than 175W HID to LED	15	470.4	0.0251	680	658	581	100	187.5	319,884	309,535	273,313
Small Business Direct Install (SBDI)	Exterior Pole Mount: 176 W-250 W HID to LED	15	639.2	0.1236	146	141	125	115	310	93,326	90,130	79,903
Small Business Direct Install (SBDI)	Exterior Pole Mount: 251 W-400 W HID to LED	15	1,066.7	0.0900	2	2	1	185	600	2,133	2,133	1,067
Small Business Direct Install (SBDI)	Exterior Pole Mount: 1000W HID to LED	15	3,536.6	0.6745	2	2	1	500	615	7,073	7,073	3,537
Small Business Direct Install (SBDI)	Exterior Other: less than 175W HID to LED	15	470.4	0.0251	534	517	456	100	63.75	251,203	243,206	214,510
Small Business Direct Install (SBDI)	Exterior Other: 176 W-250 W HID to LED	15	639.2	0.1236	119	116	102	115	140	76,067	74,150	65,200
Small Business Direct Install (SBDI)	Exterior Other: 251 W-400 W HID to LED	15	1,066.7	0.0900	2	2	1	185	600	2,133	2,133	1,067
Small Business Direct Install (SBDI)	EC (electronically commutated) Motor, Reach-in Refrigerator	15	325.0	0.0320	2	2	1	70	159	650	650	325
Small Business Direct Install (SBDI)	EC (electronically commutated) Motor, Reach-in Freezer	15	409.0	0.0340	2	2	1	90	159	818	818	409
Small Business Direct Install (SBDI)	EC (electronically commutated) Motor, Walk-in Refrigerator	15	354.0	0.0486	355	343	303	70	137	125,670	121,422	107,262
Small Business Direct Install (SBDI)	EC (electronically commutated) Motor, Walk-in Freezer	15	528.0	0.0560	4	4	3	90	180	2,112	2,112	1,584
Small Business Direct Install (SBDI)	Anti-Sweat Heater Controls - Refrigerator	12	540.0	-	2	2	1	110	300	1,080	1,080	540
Small Business Direct Install (SBDI)	Anti-Sweat Heater Controls - Freezer	12	1,277.0	-	2	2	1	220	360	2,554	2,554	1,277
Small Business Direct Install (SBDI)	Strip Curtain - Walk in Refrigerator	6	13.2	0.0500	35	34	30	2.25	14.5	462	448	396
Small Business Direct Install (SBDI)	Strip Curtain - Walk in Freezer	6	92.9	0.3400	35	34	30	15	14.5	3,253	3,160	2,788
Small Business Direct Install (SBDI)	Refrigerated Display Case Lighting 5' T12/T8 to LED - Refrigerator	8.1	332.0	0.0493	2	2	1	55	180	664	664	332
Small Business Direct Install (SBDI)	Refrigerated Display Case Lighting 5' T12/T8 to LED - Freezer	8.1	358.0	0.0856	2	2	1	55	180	716	716	358
Small Business Direct Install (SBDI)	Refrigerated Display Case Lighting 6' T12/T8 to LED - Refrigerator	8.1	450.0	0.0531	2	2	1	70	200	900	900	450
Small Business Direct Install (SBDI)	Refrigerated Display Case Lighting 6' T12/T8 to LED - Freezer	8.1	498.0	0.0923	2	2	1	70	200	996	996	498
Small Business Direct Install (SBDI)	Programmable Thermostat - Single Point - Electric Only	15	2,037.5	-	272	263	464	250	5	554,200	535,863	945,400
Small Business Direct Install (SBDI)	Programmable Thermostat - Multi Point - Electric Only	15	4,658.0	-	2	2	2	325	10	9,316	9,316	9,316
Small Business Direct Install (SBDI)	"Smart" Wi-Fi Thermostat - Single Point - Electric Only	15	2,037.5	-	2	2	2	400	50	4,075	4,075	4,075
Small Business Direct Install (SBDI)	"Smart" Wi-Fi Programmable Thermostat - Multi Point - Electric Only	15	4,658.0	-	2	2	2	450	100	9,316	9,316	9,316
Small Business Direct Install (SBDI)	Pre-Rinse Sprayer - Electric	5	3,727.2	-	2	2	1	100	0	7,454	7,454	3,727
Small Business Direct Install (SBDI)	Faucet Aerator - Electric	10	391.0	-	0	0	0	50	0	-	-	-
Small Business Direct Install (SBDI)	2x2 Fluorescent Fixture to LED Panel	15	144.0	0.0377	7	7	6	20	45.82	1,008	1,008	864
Total SBDI					**10,808**	**10,465**	**9,429**			**4,032,934**	**3,905,372**	**3,900,306**

Program	Measure	Measure Life	Average Savings per Unit (kWh)	Demand per Unit (KW)	2018 Participation	2019 Participation	2020 Participation	Avg Incentive Paid Per Unit	Average Incremental Cost	2018 kWh Savings	2019 kWh Savings	2020 kWh Savings
Multifamily Retrofit	Pre-Rinse Sprayer - Electric	5	3,727.2	-	0	0	0	100	0	-	-	-
Multifamily Retrofit	Faucet Aerator - Electric	10	391.0	-	1	1	1	50	0	391	391	391
Multifamily Retrofit	Exterior Pole Mount: 1000W HID to LED	15	3,536.6	0.6745	1	1	1	500	615	3,537	3,537	3,537
Multifamily Retrofit	Exterior Wallpack: 251 W-400 W HID to LED	15	1,066.7	0.0900	1	1	1	185	600	1,067	1,067	1,067
Multifamily Retrofit	Exterior Canopy: 251 W-400 W HID to LED	15	1,066.7	0.0900	1	1	1	185	600	1,067	1,067	1,067
Multifamily Retrofit	Exterior Flood: 251 W-400 W HID to LED	15	1,066.7	0.0900	1	1	1	185	600	1,067	1,067	1,067
Multifamily Retrofit	Exterior Pole Mount: 251 W-400 W HID to LED	15	1,066.7	0.0900	1	1	1	185	600	1,067	1,067	1,067
Multifamily Retrofit	Exterior Other: 251 W-400 W HID to LED	15	1,066.7	0.0900	1	1	1	185	600	1,067	1,067	1,067
Multifamily Retrofit	400W HID to High Bay LED ≤250W	15	589.9	0.1797	1	1	1	220	480	590	590	590
Multifamily Retrofit	250W HID to High Bay LED ≤100W	15	716.6	0.1778	0	0	0	160	460	-	-	-
Multifamily Retrofit	Exterior Wallpack: 176 W-250 W HID to LED	15	639.2	0.1236	4	4	4	115	310	2,557	2,557	2,557
Multifamily Retrofit	Exterior Canopy: 176 W-250 W HID to LED	15	639.2	0.1236	4	4	4	115	272	2,557	2,557	2,557
Multifamily Retrofit	Exterior Flood: 176 W-250 W HID to LED	15	639.2	0.1236	4	4	4	115	310	2,557	2,557	2,557
Multifamily Retrofit	Exterior Pole Mount: 176 W-250 W HID to LED	15	639.2	0.1236	4	4	4	115	310	2,557	2,557	2,557
Multifamily Retrofit	Exterior Other: 176 W-250 W HID to LED	15	639.2	0.1236	4	4	4	115	140	2,557	2,557	2,557
Multifamily Retrofit	Anti-Sweat Heater Controls - Freezer	12	1,277.0	-	0	0	0	220	360	-	-	-
Multifamily Retrofit	Exterior Wallpack: 175W HID to LED	15	470.4	0.0251	14	14	14	100	225.5	6,586	6,586	6,586
Multifamily Retrofit	Exterior Canopy: less than 175W HID to LED	15	470.4	0.0251	14	14	14	100	190.4	6,586	6,586	6,586
Multifamily Retrofit	Exterior Flood: less than 175W HID to LED	15	470.4	0.0251	14	14	14	100	188.33	6,586	6,586	6,586
Multifamily Retrofit	Exterior Pole Mount: less than 175W HID to LED	15	470.4	0.0251	14	14	14	100	187.5	6,586	6,586	6,586
Multifamily Retrofit	Exterior Other: less than 175W HID to LED	15	470.4	0.0251	14	14	14	100	63.75	6,586	6,586	6,586
Multifamily Retrofit	400W HID to High Bay Fluorescent 6-Lamp 4' HP, 28W or 25W T8	7	703.4	0.2116	1	1	1	125	300	703	703	703
Multifamily Retrofit	Anti-Sweat Heater Controls - Refrigerator	12	540.0	-	0	0	0	110	300	-	-	-
Multifamily Retrofit	250W HID to High Bay Fluorescent 4-Lamp 4' HP, 28W or 25W T8	7	519.9	0.1778	0	0	0	90	255	-	-	-
Multifamily Retrofit	Delamping with Lamp & Ballast Retrofit: 4-Lamp 8' T12/T8 to 4-Lamp 4' or 2-Lamp 8' LED Tube	15	364.8	-	0	0	0	65	250	-	-	-
Multifamily Retrofit	Vending Machine Occ Sensor - Refrigerated Beverage	5	1,602.5	-	0	0	0	250	208	-	-	-
Multifamily Retrofit	Refrigerated Display Case Lighting 6' T12/T8 to LED - Refrigerator	8.1	450.0	0.0531	0	0	0	70	200	-	-	-
Multifamily Retrofit	Refrigerated Display Case Lighting 6' T12/T8 to LED - Freezer	8.1	498.0	0.0923	0	0	0	70	200	-	-	-
Multifamily Retrofit	EC (electronically commutated) Motor, Walk-in Refrigerator	15	354.0	0.0486	0	0	0	70	137	-	-	-
Multifamily Retrofit	EC (electronically commutated) Motor, Walk-in Freezer	15	528.0	0.0560	0	0	0	90	180	-	-	-
Multifamily Retrofit	Refrigerated Display Case Lighting 5' T12/T8 to LED - Refrigerator	8.1	332.0	0.0493	0	0	0	55	180	-	-	-
Multifamily Retrofit	Refrigerated Display Case Lighting 5' T12/T8 to LED - Freezer	8.1	358.0	0.0856	0	0	0	55	180	-	-	-
Multifamily Retrofit	Vending Machine Occ Sensor - Refrigerated Glass Front Cooler	5	1,208.9	-	0	0	0	200	178	-	-	-
Multifamily Retrofit	Lamp & Ballast Retrofit: 2-Lamp 8' T12/T8 to 4-Lamp 4' or 2-Lamp 8' LED Tube	15	214.5	0.0433	2	2	2	40	175	429	429	429
Multifamily Retrofit	Occupancy Sensors - Ceiling Mount (must control 350 watts)	8	299.3	0.0630	1	1	1	60	170	299	299	299
Multifamily Retrofit	EC (electronically commutated) Motor, Reach-in Refrigerator	15	325.0	0.0320	0	0	0	70	159	-	-	-
Multifamily Retrofit	EC (electronically commutated) Motor, Reach-in Freezer	15	409.0	0.0340	0	0	0	90	159	-	-	-
Multifamily Retrofit	4-Lamp 4' T12/T8 to LED Panel	15	286.6	-	0	0	0	50	155	-	-	-
Multifamily Retrofit	Lamp & Ballast Retrofit: 1-Lamp 8' T12/T8 to 2-Lamp 4' or 1-Lamp 8' LED Tube	15	171.9	0.0353	21	21	21	30	132	3,609	3,609	3,609
Multifamily Retrofit	3-Lamp 4' T12/T8 to LED Panel	15	214.9	-	0	0	0	40	145	-	-	-
Multifamily Retrofit	Delamping with Lamp & Ballast Retrofit w/Reflector: 4-Lamp 8' T12 to 4-Lamp 4' or 2-Lamp 8' HP, 28W or 25W T8	15	505.3	0.1368	0	0	0	90	140	-	-	-
Multifamily Retrofit	Lamp & Ballast Retrofit: 4-Lamp 4' T12/T8 to 4' LED Tube	15	314.3	0.0645	14	14	14	50	140	4,400	4,400	4,400
Multifamily Retrofit	2-Lamp 4' T12/T8 to LED Panel	15	93.3	-	0	0	0	40	135	-	-	-
Multifamily Retrofit	Delamping with Lamp & Ballast Retrofit: 4-Lamp 4' T12/T8 to 3-Lamp 4' LED Tube	15	190.4	-	0	0	0	30	130	-	-	-
Multifamily Retrofit	Lamp & Ballast Retrofit: 3-Lamp 4' T12/T8 to 4' LED Tube	15	81.8	-	0	0	0	25	120	-	-	-
Multifamily Retrofit	Delamping with Lamp & Ballast Retrofit: 4-Lamp 4' T12/T8 to 2-Lamp 4' LED Tube	15	353.6	0.0726	3	3	3	60	120	1,061	1,061	1,061
Multifamily Retrofit	Occupancy Sensors - Wall Mount (must control at least 200 watts)	8	250.2	0.0108	0	0	0	40	115	-	-	-
Multifamily Retrofit	Delamping with Lamp & Ballast Retrofit w/Reflector: 2-Lamp 8' T12 to 2-Lamp 4' or 1-Lamp 8' HP, 28W or 25W T8	15	275.9	0.0631	1	1	1	50	110	276	276	276
Multifamily Retrofit	Lamp & Ballast Retrofit: 2-Lamp 8' T12 to 4-Lamp 4' or 2-Lamp 8' HP, 28W or 25W T8 w/ reflector	15	59.3	0.0230	1	1	1	25	108	59	59	59
Multifamily Retrofit	Delamping with Lamp & Ballast Retrofit: 4-Lamp 8' T12 to 4-Lamp 4' or 2-Lamp 8' HP, 28W or 25W T8	15	360.0	0.1368	0	0	0	60	105	-	-	-
Multifamily Retrofit	Lamp & Ballast Retrofit: 2-Lamp 8' T12 to 4-Lamp 4' or 2-Lamp 8' HP, 28W or 25W T8	15	41.6	0.0208	1	1	1	27	103	42	42	42
Multifamily Retrofit	Delamping with Lamp & Ballast Retrofit w/Reflector: 4-Lamp 4' T12 to 2-Lamp 4' HP, 28W or 25W T8	15	341.5	0.0910	35	35	35	60	58.51	11,951	11,951	11,951
Multifamily Retrofit	Lamp & Ballast Retrofit: 2-Lamp 4' T12/T8 to 4' LED Tube	15	74.4	-	0	0	0	25	100	-	-	-
Multifamily Retrofit	Delamping with Lamp & Ballast Retrofit: 3-Lamp 4' T12/T8 to 2-Lamp 4' LED Tube	15	158.1	-	0	0	0	30	100	-	-	-
Multifamily Retrofit	"Smart" Wi-Fi Programmable Thermostat - Multi Point - Electric Only	15	4,658.0	-	0	0	0	450	100	-	-	-

Program	Measure	Measure Life	Average Savings per Unit (kWh)	Demand per Unit (KW)	2018 Participation	2019 Participation	2020 Participation	Avg Incentive Paid Per Unit	Average Incremental Cost	2018 kWh Savings	2019 kWh Savings	2020 kWh Savings
Multifamily Retrofit	Lamp & Ballast Retrofit: 1-Lamp 8' T12 to 2-Lamp 4' or 1-Lamp 8' HP, 28W or 25W T8 w/ reflector	15	153.9	0.0246	1	1	1	20	93	154	154	154
Multifamily Retrofit	Delamping with Lamp & Ballast Retrofit w/Reflector: 4-Lamp 4' T12 to 3-Lamp 4' HP, 28W or 25W T8	15	247.1	0.0716	1	1	1	35	90	247	247	247
Multifamily Retrofit	Delamping with Lamp & Ballast Retrofit w/Reflector: 2-Lamp 2' T12 U-tube to 2-Lamp 2' HP, 28W or 25W T8	15	108.0	0.0329	1	1	1	19	89	108	108	108
Multifamily Retrofit	Lamp & Ballast Retrofit: 1-Lamp 8' T12 to 2-Lamp 4' or 1-Lamp 8' HP, 28W or 25W T8	15	110.7	0.0246	0	0	0	22	88	-	-	-
Multifamily Retrofit	Delamping with Lamp & Ballast Retrofit w/Reflector: 3-Lamp 4' T12 to 2-Lamp 4' HP, 28W or 25W T8	15	225.7	0.0675	1	1	1	40	88	226	226	226
Multifamily Retrofit	LED Exit Sign Fixture with Battery Backup	16	87.2	0.0077	1	1	1	60	88	87	87	87
Multifamily Retrofit	Lamp & Ballast Retrofit: 1-Lamp 4' T12/T8 to 4' LED Tube	15	112.9	0.0232	3	3	3	18	80	339	339	339
Multifamily Retrofit	Lamp & Ballast Retrofit: 4-Lamp 4' T12 to HP, 28W or 25W T8	15	116.5	0.0390	1	1	1	24	78	116	116	116
Multifamily Retrofit	Delamping with Lamp & Ballast Retrofit: 4-Lamp 4' T12 to 3-Lamp 4' HP, 28W or 25W T8	15	211.2	0.0648	0	0	0	35	75	-	-	-
Multifamily Retrofit	Delamping with Lamp & Ballast Retrofit: 4-Lamp 4' T12 to 2-Lamp 4' HP, 28W or 25W T8	15	264.9	0.0876	0	0	0	45	75	-	-	-
Multifamily Retrofit	Delamping with Lamp & Ballast Retrofit: 2-Lamp 4' T12/T8 to 1-Lamp 4' LED Tube	15	213.5	-	0	0	0	40	75	-	-	-
Multifamily Retrofit	Lamp & Ballast Retrofit: 3-Lamp 4' T12 to HP, 28W or 25W T8	15	104.1	0.0383	0	0	0	20	70	-	-	-
Multifamily Retrofit	Delamping with Lamp & Ballast Retrofit: 3-Lamp 4' T12 to 2-Lamp 4' HP, 28W or 25W T8	15	199.8	0.0611	0	0	0	35	57	-	-	-
Multifamily Retrofit	Delamping with Lamp & Ballast Retrofit w/Reflector: 2-Lamp 4' T12 to 1-Lamp 4' HP, 28W or 25W T8	15	149.2	0.0404	1	1	1	25	57	149	149	149
Multifamily Retrofit	ENERGY STAR® LED downlights - 60W Equivalent	15	132.3	0.0371	1	1	1	27	57	132	132	132
Multifamily Retrofit	ENERGY STAR® LED downlights - 75W+ Equivalent	15	205.3	0.0412	12	12	12	35	39	2,463	2,463	2,463
Multifamily Retrofit	Lamp & Ballast Retrofit: 2-Lamp 4' T12 to HP, 28W or 25W T8	15	85.4	0.0228	4	4	4	15	56	341	341	341
Multifamily Retrofit	ENERGY STAR® LED downlights - 40W Equivalent	15	94.3	0.0285	1	1	1	18	52	94	94	94
Multifamily Retrofit	Lamp & Ballast Retrofit: 1-Lamp 4' T12 to HP, 28W or 25W T8	15	64.0	0.0171	3	3	3	12	51	192	192	192
Multifamily Retrofit	Delamping with Lamp & Ballast Retrofit: 2-Lamp 4' T12 to 1-Lamp 4' HP, 28W or 25W T8	15	137.3	0.0246	0	0	0	25	50	-	-	-
Multifamily Retrofit	"Smart" Wi-Fi Thermostat - Single Point - Electric Only	15	2,037.5	-	0	0	0	400	50	-	-	-
Multifamily Retrofit	2x2 Fluorescent Fixture to LED Panel	15	144.0	0.0377	1	1	1	20	45.82	144	144	144
Multifamily Retrofit	Delamp 4 lamp 8ft T12 lamp and ballast	10	834.3	-	0	0	0	75	38	-	-	-
Multifamily Retrofit	Occupancy Sensors - Fixture Mount (must control at least 100 watts)	8	154.6	0.0054	0	0	0	25	37	-	-	-
Multifamily Retrofit	Delamp 2 lamp 8ft T12 lamp and ballast	10	417.2	-	0	0	0	75	36	-	-	-
Multifamily Retrofit	ENERGY STAR® LED lamps 60W Equivalent	15	120.8	0.0337	28	28	28	22	7.38	3,382	3,382	3,382
Multifamily Retrofit	ENERGY STAR® LED lamps 75W+ Equivalent	15	179.2	0.0536	1	1	1	32	35	179	179	179
Multifamily Retrofit	Delamp 1 lamp 8ft T12 lamp and ballast	10	278.1	-	0	0	0	50	34	-	-	-
Multifamily Retrofit	ENERGY STAR® LED lamps 40W Equivalent	15	64.3	0.0293	9	9	9	12	33	579	579	579
Multifamily Retrofit	Strip Curtain - Walk in Refrigerator	6	13.2	0.0500	0	0	0	2.25	14.5	-	-	-
Multifamily Retrofit	Strip Curtain - Walk in Freezer	6	92.9	0.3400	0	0	0	15	14.5	-	-	-
Multifamily Retrofit	Programmable Thermostat - Multi Point - Electric Only	15	4,658.0	-	0	0	0	325	10	-	-	-
Multifamily Retrofit	Programmable Thermostat - Single Point - Electric Only	15	2,037.5	-	7	7	14	250	5	14,263	14,261.50	28,525
Total Multifamily Retrofit					**255**	**255**	**262**			**101,590**	**101,589**	**115,853**
CVR Commercial		**15**	**1,850.6**	**0.3330**			**558**					**1,032,656**
Total C&I										**15,135,729**	**16,043,561**	**17,053,516**
Portfolio Total										**36,656,341**	**38,069,187**	**36,347,642**

Attachment 6.2 2019 DSM Market Potential Study

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

prepared for

VECTREN ENERGY DELIVERY OF INDIANA

*2020-2025 Integrated **Electric** DSM Market Potential Study & Action Plan*

January
2019

FINAL REPORT

prepared by
GDS ASSOCIATES INC
EMI CONSULTING

EXECUTIVE SUMMARY

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VOLUME I *Electric DSM Market Potential Study*

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VOLUME II *Electric Action Plan*

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VOLUME III *Electric Appendices*

Electric ***DSM Market Potential Study***

Electric ***Action Plan***

Executive Summary

OBJECTIVES & SCOPE

This project included a demand-side management (DSM) Market Potential Study and Action Plan for Vectren Energy Delivery of Indiana ("Vectren"). The study included assessments of electric energy efficiency and demand response potential. The results of the potential study were leveraged to develop a DSM Action Plan for Vectren's 2020-2025 planning horizon. This report provides the results of the electric energy efficiency and demand response potential analysis.

The energy efficiency potential study assessed potential by customer segment (residential, commercial, and industrial – with and without opt-out customers). The effort included several preliminary tasks to assess the Vectren market and develop foundational assumptions about the customer base, sales forecasts, and savings opportunities to order to then assess the overall energy efficiency potential in the Vectren services territories.

APPROACH SUMMARY

The GDS team used a bottom-up approach to estimate energy efficiency potential in the residential sector. Bottom-up approaches begin with characterizing the eligible equipment stock, estimating savings and screening for cost-effectiveness first at the measure level, then summing savings at the end-use and service area levels. In the commercial and industrial sectors, GDS utilized the bottom-up modeling approach to first estimate measure-level savings and costs as well as cost-effectiveness, and then applied cost-effective measure savings to all applicable shares of energy load. The demand response potential assessment was conducted in a similar manner as the energy efficiency potential assessment. Below is the summary of the Maximum Achievable Potential (MAP), Realistic Achievable Potential (RAP) and Program Potential. More detail can be found in Section 1 of Volume I, Market Potential Study.

- ***Achievable Potential*** is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:
- ***Maximum Achievable Potential*** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- ***Realistic Achievable Potential*** estimates achievable potential with Vectren paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.
- ***Program Potential*** refers to the efficiency potential possible given specific program funding levels and designs; in this study program potential is addressed by the DSM Action Plan, which further addresses issues such as market dynamics (net versus gross impacts), timeframe differences, proxy versus specific program delivery approaches, and budget realities.

RESULTS

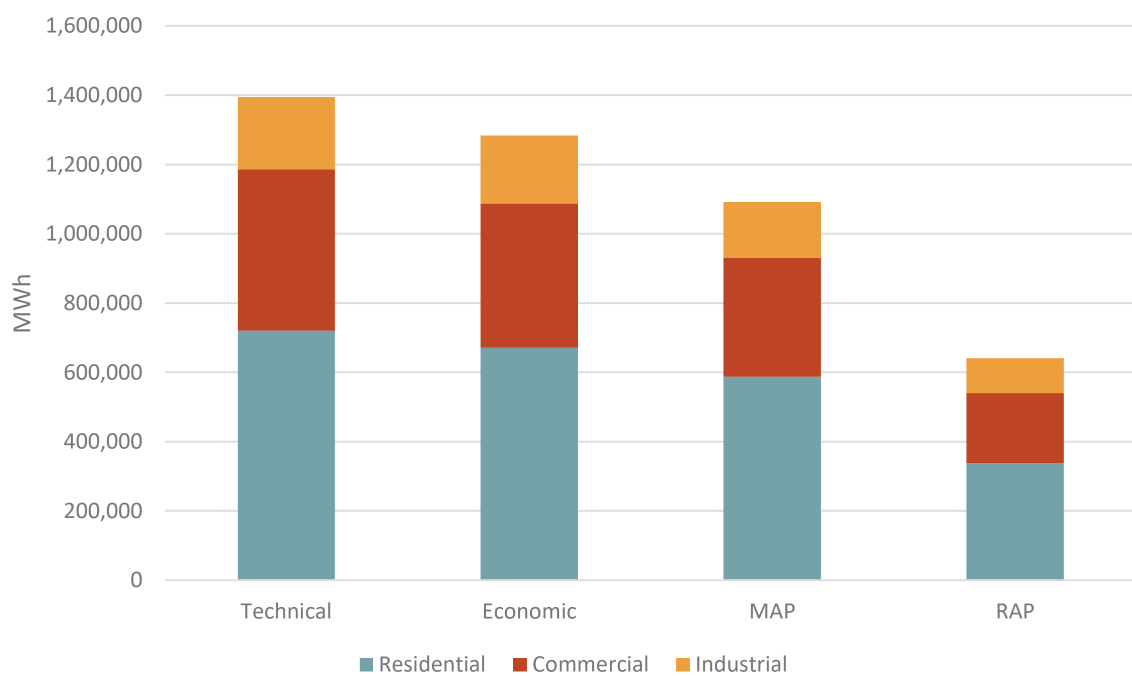
Table ES-1 summarizes the electric energy-efficiency savings for all measures at the different levels of potential relative to the baseline forecast. This provides cumulative annual technical, economic, MAP and RAP, and program potential energy savings, in total MWh and as a percentage of the sector-level sales forecast. Note that the steps of measure bundling, program design and program delivery refine the RAP results later into the Program Potential. The cumulative RAP increases to 9% cumulative annual savings over the next six years. The RAP savings estimates have a large residential sector low-income component.[1] Approximately 65% of the residential sector budget addresses the low-income market segment, with about 27% of the RAP savings are attributable to this segment.

TABLE ES-1 INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY (NET OF LARGE CUSTOMER OPT-OUT LOAD)

	2020	2021	2022	2023	2024	2025
MWh						
Technical	179,992	209,578	199,765	194,021	182,130	169,589
Economic	167,372	192,143	183,629	179,315	168,500	156,910
MAP	91,970	135,273	134,335	135,296	133,380	126,777
RAP	57,005	69,699	66,105	67,277	68,583	67,330
Program	47,451	49,716	44,565	45,375	43,309	43,244
Forecasted Sales[2]	3,340,248	3,345,466	3,360,838	3,378,011	3,402,115	3,414,693
Energy Savings (as % of Forecast)						
Technical	5.4%	6.3%	5.9%	5.7%	5.4%	5.0%
Economic	5.0%	5.7%	5.5%	5.3%	5.0%	4.6%
MAP	2.8%	4.0%	4.0%	4.0%	3.9%	3.7%
RAP	1.7%	2.1%	2.0%	2.0%	2.0%	2.0%
Program	1.4%	1.5%	1.3%	1.3%	1.3%	1.3%

Figure ES-1 provides the electric technical, economic, and achievable potential, by sector, by the end of the 20-year timeframe for the study (2020-2039). The residential sector contributes about half of the overall realistic achievable potential. Program potential only extends through 2025 and is not included in the figure below.

FIGURE ES-1 TWENTY (20)-YEAR CUMULATIVE ANNUAL ELECTRIC ENERGY EFFICIENCY POTENTIAL – ALL SECTORS COMBINED (NET OF LARGE CUSTOMER OPT-OUT LOAD)



[1] Low income households were characterized as homes that have household incomes at or below 200% of federal poverty guidelines. Based on data from the American Community 5-Year Public Use Microdata Set (PUMS), GDS used household income and number of people per household to identify the percent of the population at or below 200% of federal poverty guidelines for the Vectren South service area. 21% of single-family households and 48% of multifamily households were identified to meet the criteria.

[2] The forecasted sales here exclude opt-out customers. See Tables 1-2 through 1-5 for a comparison of the results with and without opt-out customers included in the analysis. Unless otherwise noted, the results in the report exclude opt-out sales and opt-out savings potential.

Measure-Level Realistic Achievable Potential (Net of Opt-Outs)

Table ES-2 provides the incremental RAP for each year by sector. The incremental annual savings potential ranges from 57 GWh to nearly 70 GWh. These results exclude load and savings attributed to large customers that have opted out of energy efficiency programs.

TABLE ES-2 INCREMENTAL ELECTRIC MEASURE LEVEL REALISTIC ACHIEVABLE POTENTIAL – BY SECTOR (2020-2025)

Incremental Annual MWh	2020	2021	2022	2023	2024	2025
Sector						
Residential	41,177	50,889	44,349	42,814	42,014	38,952
Commercial	10,311	12,122	13,911	15,609	16,770	17,811
Industrial	5,517	6,688	7,846	8,854	9,799	10,567
Total	57,005	69,699	66,105	67,277	68,583	67,330
Forecasted Sales (Net of Opt-Outs)	3,340,248	3,345,466	3,360,838	3,378,011	3,402,115	3,414,693
Incremental Annual Savings %						
Sector						
Residential	2.9%	3.5%	3.1%	2.9%	2.9%	2.6%
Commercial	0.8%	1.0%	1.1%	1.2%	1.3%	1.4%
Industrial	0.9%	1.0%	1.2%	1.4%	1.5%	1.6%
% of Forecasted Sales	1.7%	2.1%	2.0%	2.0%	2.0%	2.0%

Table ES-3 provides the cumulative RAP for each year across the 2020-2025 timeframe. The cumulative annual savings potential ranges from 57 GWh to nearly 309 GWh. These results assume that opt-out industrial customers do not provide any savings potential.

TABLE ES-3 CUMULATIVE ELECTRIC MEASURE LEVEL REALISTIC ACHIEVABLE POTENTIAL – BY SECTOR (2020-2025)

Cumulative Annual MWh	2020	2021	2022	2023	2024	2025
Sector						
Residential	41,177	84,538	105,533	134,072	159,025	184,648
Commercial	10,311	21,974	35,168	49,609	64,869	80,454
Industrial	5,517	11,982	19,336	27,377	35,449	43,566
Total	57,005	118,494	160,037	211,059	259,344	308,667
Forecasted Sales (Net of Opt-Outs)	3,340,248	3,345,466	3,360,838	3,378,011	3,402,115	3,414,693
Cumulative Annual Savings %						
Sector						
Residential	2.9%	5.9%	7.3%	9.2%	10.8%	12.5%
Commercial	0.8%	1.8%	2.8%	4.0%	5.1%	6.3%
Industrial	0.9%	1.9%	3.0%	4.2%	5.5%	6.7%
% of Forecasted Sales	1.7%	3.5%	4.8%	6.2%	7.6%	9.0%

Table ES-4 provides the annual budgets in the RAP scenario. The total RAP budgets across all sectors ranges from $24 million to $35 million during the 2020-2025 timeframe.

TABLE ES-4 ANNUAL BUDGETS (2020-2025) IN THE RAP SCENARIO ($ IN MILLIONS)

RAP Budgets	2020	2021	2022	2023	2024	2025
Energy Efficiency						
Incentives	$16.2	$21.1	$22.8	$24.0	$24.8	$24.6
Admin	$4.8	$6.2	$6.4	$6.6	$7.0	$7.0
Energy Efficiency Sub-Total	$21.0	$27.3	$29.2	$30.6	$31.8	$31.6
Demand Response / CVR						
Incentives	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Admin	$1.4	$1.7	$2.1	$1.6	$1.0	$0.9
Demand Response / CVR Sub-Total	$1.4	$1.7	$2.1	$1.6	$1.0	$0.9
Indirect[3]	$1.4	$1.8	$1.7	$1.9	$2.0	$2.1
Total						
Total Costs	$23.8	$30.8	$33.0	$34.0	$34.8	$34.5

Measure-Level Realistic Achievable Potential (Including Opt-Outs)

Table ES-5 provides the incremental RAP for each year across the 2020-2025 timeframe, with sales and savings estimates from opt-out customers included. The incremental annual savings potential ranges from 72 GWh to 97 GWh. The incremental RAP increases by approximately 15 to 30 GWh across the timeframe, compared to the results with opt-out customers excluded.

TABLE ES-5 INCREMENTAL ELECTRIC REALISTIC ACHIEVABLE POTENTIAL – BY SECTOR (2020-2025)

Incremental Annual MWh	2020	2021	2022	2023	2024	2025
Sector						
Residential	41,177	50,889	44,349	42,814	42,014	38,952
Commercial	11,578	13,618	15,630	17,541	18,846	20,006
Industrial	19,324	23,576	27,883	31,695	35,218	38,149
Total	72,080	88,082	87,862	92,050	96,078	97,106
Forecasted Sales	5,163,888	5,174,499	5,196,938	5,221,660	5,253,393	5,273,051
Sector						
Residential	2.9%	3.5%	3.1%	2.9%	2.9%	2.6%
Commercial	0.8%	1.0%	1.1%	1.2%	1.3%	1.4%
Industrial	0.8%	1.0%	1.2%	1.3%	1.5%	1.6%
% of Forecasted Sales	1.4%	1.7%	1.7%	1.8%	1.8%	1.8%

Table ES-6 provides the cumulative RAP for each year across the 2020-2025 timeframe, with sales and savings estimates from opt-out customers included. The cumulative annual savings potential ranges from 72 GWh to 426 GWh. The cumulative annual RAP increases by more than 100 GWh across the 2020-2025 timeframe, compared to the results with opt-out customers excluded.

[3] Indirect costs represent costs that are not specifically attributed to individual programs and can include additional outreach, evaluation, and program planning activities.

TABLE ES-6 CUMULATIVE ELECTRIC REALISTIC ACHIEVABLE POTENTIAL – BY SECTOR (2020-2025)

Cumulative Annual MWh	2020	2021	2022	2023	2024	2025
Sector						
Residential	41,177	84,538	105,533	134,072	159,025	184,648
Commercial	11,578	24,685	39,512	55,740	72,884	90,391
Industrial	19,324	41,785	67,208	94,837	123,025	151,326
Total	72,080	151,009	212,254	284,649	354,935	426,364
Forecasted Sales	5,163,888	5,174,499	5,196,938	5,221,660	5,253,393	5,273,051
Sector						
Residential	2.9%	5.9%	7.3%	9.2%	10.8%	12.5%
Commercial	0.8%	1.8%	2.8%	4.0%	5.1%	6.3%
Industrial	0.8%	1.8%	2.9%	4.0%	5.2%	6.4%
% of Forecasted Sales	1.4%	2.9%	4.1%	5.5%	6.8%	8.1%

DEMAND SAVINGS

The study also included an assessment of peak demand savings potential. Table ES-7 below provides the overall peak demand savings from energy efficiency, demand response, and CVR potential. The demand response potential assumes the energy efficiency peak demand reductions take precedent, and thereby reduce the baseline peak demand which can be further reduced by demand response.

TABLE ES-7 CUMULATIVE PEAK DEMAND SAVINGSPOTENTIAL – MAP AND RAP (2020-2025)

MW	2020	2021	2022	2023	2024	2025
MAP						
Energy Efficiency	12	28	43	58	72	85
Demand Response	22	61	103	121	124	123
CVR	0.4	0.4	0.4	1.1	1.1	1.1
Total	34	90	147	180	197	209
RAP						
Energy Efficiency	8	16	23	31	38	45
Demand Response	7	19	37	47	51	51
CVR	0.4	0.4	0.4	1.1	1.1	1.1
Total	15	35	60	79	90	98

ACTION PLAN

The results of the potential study were leveraged to develop a DSM Action Plan for the 2020-2025 timeframe. The achievable potential identified by the potential study formed the basis of the development of program potential, which further accounts for budgetary and market considerations. Furthermore, the Vectren Electric DSM Action Plan was developed as an integrated effort with the Vectren Gas DSM Action Plan, in order to optimize program design, budget, and cost-effectiveness considerations. Table ES-8 provides the incremental program potential for each year across the 2020-2025 timeframe. The incremental annual savings potential ranges from 43,244 MWh to 49,716 MWh.

TABLE ES-8 INCREMENTAL ELECTRIC PROGRAM POTENTIAL – BY SECTOR (2020-2025)

Incremental Annual MWh	2020	2021	2022	2023	2024	2025
Sector						
Residential	22,880	24,682	18,353	17,461	16,186	16,349
Commercial and Industrial	24,571	25,034	26,212	27,914	27,124	26,895
Total	47,451	49,716	44,565	45,375	43,309	43,244
Forecasted Sales (Net of Opt-Outs)	3,340,248	3,345,466	3,360,838	3,378,011	3,402,115	3,414,693
Incremental Annual Savings %						
Sector						
Residential	1.6%	1.7%	1.3%	1.2%	1.1%	1.1%
Commercial and Industrial	1.3%	1.3%	1.4%	1.5%	1.4%	1.4%
Incremental Annual Savings %						
% of Forecasted Sales	1.4%	1.5%	1.3%	1.3%	1.3%	1.3%

Table ES-9 provides the cumulative Program Potential for each year across the 2020-2025 timeframe. The cumulative annual savings potential rises from 47,451 MWh to 273,660 MWh.

TABLE ES-9 CUMULATIVE ELECTRIC PROGRAM POTENTIAL – BY SECTOR (2020-2025)

Cumulative MWh	2020	2021	2022	2023	2024	2025
Sector						
Residential	22,880	47,562	65,915	83,376	99,562	115,911
Commercial and Industrial	24,571	49,605	75,817	103,730	130,854	157,749
Total	47,451	97,167	141,732	187,107	230,416	273,660
Forecasted Sales (Net of Opt-Outs)	3,340,248	3,345,466	3,360,838	3,378,011	3,402,115	3,414,693
Cumulative Annual Savings %						
Sector						
Residential	1.6%	3.3%	4.5%	5.7%	6.8%	7.9%
Commercial and Industrial	1.3%	2.6%	4.0%	5.5%	6.8%	8.2%
% of Forecasted Sales	1.4%	2.9%	4.2%	5.5%	6.8%	8.0%

Table ES-10 provides the annual budgets in the DSM Action Plan. The portfolio-level budgets range from $10.3 million to $11.2 million during the 2020-2025 timeframe.

TABLE ES-10 DSM ACTION PLAN ANNUAL BUDGETS (2020-2025)

Annual Budgets	2020	2021	2022	2023	2024	2025
Residential						
Incentives	$1.3	$1.4	$1.3	$1.1	$1.2	$1.2
Admin	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4
Implementation	$3.5	$3.8	$3.8	$3.8	$3.9	$4.0
Residential Sub-total	**$5.2**	**$5.5**	**$5.4**	**$5.3**	**$5.5**	**$5.6**
Commercial and Industrial						
Incentives	$2.4	$2.5	$2.5	$2.4	$2.4	$2.3
Admin	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
Implementation	$1.3	$1.4	$1.4	$1.5	$1.6	$1.6
Commercial and Industrial Sub-total	**$3.9**	**$4.0**	**$4.1**	**$4.1**	**$4.2**	**$4.1**
Non-Sector Specific Costs						
Indirect	$0.5	$0.5	$0.5	$0.5	$0.6	$0.6
Evaluation	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
Other	$0.2	$0.5	$0.2	$0.2	$0.5	$0.2
Total						
DSM Portfolio Total	**$10.3**	**$11.1**	**$10.8**	**$10.7**	**$11.2**	**$11.0**

COST-EFFECTIVENESS

For planning purposes, each of the recommended programs must pass the Utility Cost Test (UCT) and the Total Resource Cost (TRC) tests, except for Income-Qualified Programs which do not need to meet cost-effectiveness tests in order to promote a greater social good. The cost-effectiveness results are reported for the UCT and the TRC tests. Each program is assessed separately to determine relative benefits and costs (in contrast to assessing each individual measure). The definitions for the four standard tests most commonly used in EE program design are described below.

- ***Total Resource Cost test (TRC).*** The benefits in this test are the lifetime avoided energy costs and avoided capacity costs. The costs in this test are the incremental measure costs plus all administrative costs spent by the program administrator.
- ***Utility Cost Test (UCT).*** The benefits in this test are the lifetime avoided energy costs and avoided capacity costs, the same as the TRC benefits. The costs in this test are the program administrator's incentive costs and administrative costs.
- ***Participant Cost Test (PCT).*** The benefits in this test are the lifetime value of retail rate savings (which is another way of saying "lost utility revenues"). The costs in this test are those seen by the participant; in other words: the incremental measure costs minus the value of incentives paid out.
- ***Rate Impact Measure test (RIM).*** The benefits of the RIM test are the same as the TRC benefits. The RIM costs are the same as the UCT, except for the addition of lost revenue. This test attempts to show the effects that EE programs will have on rates, which is almost always to raise them on a per unit basis. Thus, costs typically outweigh benefits from the point of view of this test, but the assumption is that absolute energy use decreases to a greater extent than per-unit rates are increased — resulting in lower average utility bills.

Table ES-11 provides the cost-benefit ratios for each of the major cost-effectiveness tests as well as the TRC Net Benefits by program and sector. Cost-benefit screening was performed using DSMore.

TABLE ES-11 VECTREN RECOMMENDED ACTION PLAN COST-EFFECTIVENESS SUMMARY

Program	TRC Ratio	TRC NET Benefits	UCT Ratio	PCT Ratio	RIM Ratio
Res Lighting	3.27	$9,339,929	5.38	4.99	0.69
Res HEA	2.24	$1,690,395	2.24		0.64
Res IQW	1.07	$507,171	1.14	9.65	0.66
Res Schools	4.79	$2,469,620	4.79		0.71
Res Behavior	1.82	$1,503,965	1.82		0.61
Res Appliance Recycling	2.50	$1,700,461	2.07		0.63
Res CVR	2.38	$1,909,353	2.38		0.78
Res Food Bank	8.29	$1,535,163	8.29		0.70
Res HEMS	1.01	$11,100	1.01		0.47
Direct Load Control	4.07	$10,016,215	3.06		2.28
Res New Construction	1.14	$91,580	1.98	1.28	0.75
Res Prescriptive	1.41	$3,069,767	1.91	2.01	0.77
Res Portfolio ALL E	2.12	$33,844,720	2.35	4.90	0.81
CI Prescriptive	3.06	$49,412,426	6.22	2.97	0.92
CI Custom	3.11	$20,261,839	6.46	3.45	0.77
CI Small Business	1.74	$4,065,481	2.49	3.09	0.53
CI CVR	2.55	$1,538,199	2.55		0.86
CI Portfolio ALL	**2.88**	**$75,277,946**	**5.43**	**3.13**	**0.82**
Total Portfolio ALL	***2.33***	***$102,456,927***	***3.25***	***3.56***	***0.79***

VOLUME I

2020-2025 Integrated Electric DSM Market Potential Study

prepared for

VECTREN
Live Smart

JANUARY 2019

1 Introduction

1.1 BACKGROUND & STUDY SCOPE

This Market Potential Study was conducted to support the development of a DSM Action Plan for Vectren. The study included primary market research and a comprehensive review of current programs, historical savings, and projected energy savings opportunities to develop estimates of technical, economic, and achievable potential. Separate estimates of electric energy efficiency and demand response potential were developed. The effort was highly collaborative, as the GDS Team worked closely alongside Vectren, as well as the Vectren Oversight Board, to produce reliable estimates of future saving potential, using the best available information and best practices for developing market potential saving estimates.

1.2 TYPES OF POTENTIAL ESTIMATED

The scope of this study distinguishes three types of energy efficiency potential: (1) technical, (2) economic, and (3) achievable.

- ***Technical Potential*** is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is constrained only by factors such as technical feasibility and applicability of measures.
- ***Economic Potential*** refers to the subset of the technical potential that is economically cost-effective as compared to conventional supply-side energy resources. Economic potential follows the same adoption rates as technical potential. Like technical potential, the economic scenario ignores market barriers to ensuring actual implementation of efficiency. Finally, economic potential only considers the costs of efficiency measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration) that would be necessary to capture them. This study uses the Utility Cost Test (UCT) to assess cost-effectiveness.
- ***Achievable Potential*** is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:
- ***Maximum Achievable Potential*** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- ***Realistic Achievable Potential*** estimates achievable potential with Vectren paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.
- ***Program Potential*** refers to the efficiency potential possible given specific program funding levels and designs; in this study program potential is addressed by the DSM Action Plan, which further addresses issues such as market dynamics (net versus gross impacts), timeframe differences, proxy versus specific program delivery approaches, and budget realities.

1.3 STUDY LIMITATIONS

As with any assessment of energy efficiency potential, this study necessarily builds on various assumptions and data sources, including the following:

- Energy efficiency measure lives, savings, and costs
- Projected penetration rates for energy efficiency measures
- Projections of electric and natural gas avoided costs
- Future known changes to codes and standards

- Vectren load forecasts and assumptions on their disaggregation by sector, segment, and end use
- End-use saturations and fuel shares

While the GDS team has sought to use the best and most current available data, there are often reasonable alternative assumptions which would yield slightly different results.

1.4 ORGANIZATION OF REPORT

The remainder of this report is organized in seven sections as follows:

Section 2 Methodology details the methodology used to develop the estimates of technical, economic, and achievable energy efficiency and demand response potential savings.

Section 3 Market Characterization provides an overview of the Vectren service areas and a brief discussion of the forecasted energy sales by sector.

Section 4 Residential Energy Efficiency Potential provides a breakdown of the technical, economic, and achievable potential in the residential sector.

Section 5 Commercial Energy Efficiency Potential provides a breakdown of the technical, economic, and achievable potential in the commercial sector.

Section 6 Industrial Energy Efficiency Potential provides a breakdown of the technical, economic, and achievable potential in the industrial sector.

Section 7 Demand Response Potential provides a breakdown of the technical, economic, and achievable potential demand response by program type.

Appendices for the DSM Market Potential are included in Volume III of this report. MPS appendices include a discussion of sources used for the analysis, detailed measure level assumptions by customer segment, nonresidential sector potential savings (including opt-out customers), and detailed demand response results.

2 Methodology

This section describes the overall methodology utilized to assess the electric energy efficiency and demand response potential in the Vectren service area. The main objectives of this Market Potential Study were to estimate the technical, economic, MAP and RAP of energy efficiency and demand response in the Vectren electric (Vectren South) service territory; and to quantify these estimates of potential in terms of MWh and MW savings, for each level of energy efficiency and demand response potential.

The development of the DSM Action Plan, and associated savings during the 2020-2025 timeframe, are discussed in Volume II of this report.

2.1 OVERVIEW OF APPROACH

For the residential sector, GDS took a bottom-up approach to the modeling, whereby measure-level estimates of costs, savings, and useful lives were used as the basis for developing the technical, economic, and achievable potential estimates. The measure data was used to build-up the technical potential, by applying the data to each relevant market segment. The measure data allowed for benefit-cost screening to assess economic potential, which was in turn used as the basis for achievable potential, which took into consideration incentives and estimates of annual adoption rates.

For the commercial and industrial sectors, GDS took a bottom-up modeling approach to first estimate measure-level savings and costs as well as cost-effectiveness, and then applied cost-effective measure savings to all applicable shares of energy load. Disaggregated forecast data served as the foundation for the development of the energy efficiency potential estimates. The creation of the disaggregation involved two steps. First, GDS looked at actual customer groupings based on NAICS code and then calibrated our top down load allocation based these codes to determine whether the customer was captured in the load forecast. Second, GDS determined the appropriate industry for industrial customers and the building type for commercial customers.

2.2 MARKET CHARACTERIZATION

The initial step in the analysis was to gather a clear understanding of the current market segments by fuel type in the Vectren service area. The GDS team coordinated with Vectren to gather utility sales and customer data and existing market research to define appropriate market sectors, market segments, vintages, saturation data and end uses for each fuel type. This information served as the basis for completing a forecast disaggregation and market characterization of both the residential and nonresidential sectors.

2.2.1 Forecast Disaggregation

In the residential sector, GDS calibrated its building energy modeling simulations with Vectren's sales forecasts.[4] This process began with the construction of building energy models, using the BEopt™ (Building Energy Optimization)[5] software, which were specified in accordance with the most currently available data describing the residential building stock in the Vectren South service area. Models were constructed for both single-family and multifamily homes, as well as various types of heating and cooling equipment and fuel types. Key characteristics defining these models include conditioned square footage, typical building envelope conditions such as insulation levels and representative appliance and HVAC efficiency levels. The simulations yielded estimated energy consumption for each building prototype, including estimates of each key end use. These end use estimates were then multiplied by the estimated proportion of customers that applied to each end use, to calculate an estimated service territory total consumption for each end use. For example, when completing this process for the Vectren South electric potential analysis, the simulated heat

[4] Vectren's sales forecast in all sectors excludes the impact of future DSM savings. Excluding future DSM savings prevents under-estimating energy efficiency savings potential.
[5] BEopt can be used to analyze both new construction and existing home retrofits, as well as single-family detached and multi-family buildings, through evaluation of single building designs, parametric sweeps, and cost-based optimizations.

pump electric heating consumption was multiplied by the proportion of homes that rely on heat pumps for their electric heating needs, to calculate the total heat pump electric heating load in the Vectren South service territory.

The simulation process required several iterations. GDS collaborated with Vectren to verify and modify certain assumptions about the market characteristics, such as the heating fuel and equipment types. GDS adjusted its assumptions about key market characteristics and revised its BEopt models to calibrate its building energy models to within 1% of forecasted sales in 2020.

In the commercial and industrial sectors, disaggregated forecast data provides the foundation for the development of energy efficiency potential estimates. GDS disaggregated the nonresidential sector for Vectren into building or industry types using Vectren's commercial and industrial customer database and 2017 monthly sales data. GDS supplemented the Vectren customer database with a third-party dataset (purchased from InfoUSA) that provided additional SIC/NAICS code data by business.[6] This disaggregation involved two steps. First, the GDS team used rate codes to determine whether the customer was captured in either Vectren's commercial or industrial load forecast. Next, GDS determined the appropriate industry for industrial customers and the building type for commercial customers. We used the following information, either from Vectren's customer data or third-party dataset, to determine the appropriate building or industry type. Using these fields, GDS assigned customers Vectren's non-residential data sets to one of the commercial or industrial segments listed in Table 2-1.

TABLE 2-1 NON-RESIDENTIAL SEGMENTS

COMMERCIAL	INDUSTRIAL	
☑ Education	☑ Chemicals	☑ Paper
☑ Food Sales	☑ Fabricated Metals	☑ Plastics and Rubber
☑ Food Service	☑ Food and Agriculture	☑ Primary Metals
☑ Health Care	☑ Machinery	☑ Transportation Equipment
☑ Hospital	☑ Mining	☑ Wood
☑ Large Office	☑ Nonmetallic Mineral	
☑ Large Retail		
☑ Lodging		
☑ Mercantile		
☑ Office		
☑ Public Assembly		
☑ Warehouse		

GDS further disaggregated sales for each of the segments into end uses. For commercial segments, GDS primarily used Vectren's 2016 end-use forecast planning models supplemented with updated EIA 2012 Commercial Building Energy Consumption Survey (CBECS) data for the East South-Central Census region. This information was used to determine energy use intensities, expressed in kWh per square foot, for each end use within each segment.[7] We then used data compiled from metering studies, Evaluation, Measurement and Verification (EM&V), and engineering algorithms to further disaggregate energy intensities into more granular end uses and technologies. For the industrial sector, the analysis relied on the EIA's Manufacturing Energy Consumption survey to disaggregate industry-specific estimates of consumption into end uses.[8]

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[6] The Vectren dataset classifies businesses by Standard Industrial Classification (SIC) code, a four-digit standardized code, that has largely been replaced by the North American Industry Classification System (NAICS) code. The GDS Team converted the Vectren SIC codes to NAICS codes, then mapped NAICS/SIC codes to building and industry types considered in this study.
[7] U.S. Energy Information Agency. *Commercial Buildings Energy Consumption Survey (CBECS)*. May 20, 2016. https://www.eia.gov/consumption/commercial/. Although the Vectren service area officially resides in the East-North Central Census region, Vectren's long-term load forecast uses the East-South Central Census region as a more accurate representation of the Vectren service area.
[8] U.S. EIA. *Manufacturing Energy Consumption Survey (MECS) 2010.* March 2013. https://www.eia.gov/consumption/manufacturing/data/2010/.

Table 2-2 lists the electric end-uses considered in the forecast disaggregation and subsequent potential assessment.

TABLE 2-2 ELECTRIC END USES

RESIDENTIAL	COMMERCIAL	INDUSTRIAL
☑ Behavioural	☑ Cooking	☑ Agriculture
☑ Clothes Washer/Dryer	☑ Cooling	☑ Computers & Office Equipment
☑ Dishwasher	☑ Lighting	☑ CHP
☑ Electronics	☑ Office Equipment	☑ Lighting
☑ Hot Water	☑ Refrigeration	☑ Machine Drive
☑ HVAC Equipment	☑ Space Heating	☑ Process Heating
☑ HVAC Shell	☑ Ventilation	☑ Process Cooling
☑ Lighting	☑ Water Heating	☑ Space Cooling
☑ Pool/Spa		☑ Space Heating
		☑ Ventilation
		☑ Water Heating

2.2.2 Eligible Opt-Out Customers

In Indiana, commercial or industrial customers with a peak load greater than 1MW are eligible to opt out of utility-funded electric energy efficiency programs. In the Vectren service area, approximately 67% of C&I customers are eligible to opt-out. Of eligible customers, nearly 76% have chosen to opt-out. As a result, only 49% of total C&I sales have not presently opted out of funding Vectren's energy efficiency programs.[9]

FIGURE 2-1 OPT-OUT SALES BY C&I SECTOR

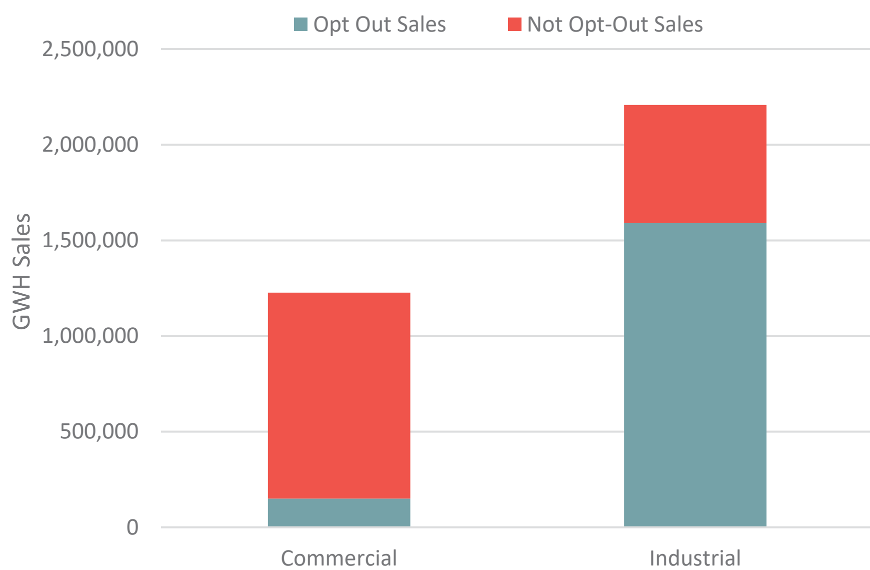

Figure 2-1 shows the total sales for the commercial and industrial sectors, as well as the sales, by sector, that have currently opted out of paying the charge levied to support utility-administered energy efficiency programs. The portion of sales that have not opted out include both ineligible load (i.e. does not meet the 1 MW monthly peak requirement) as well as eligible load that has not yet opted out.

The main body of this report focuses on the electric energy efficiency potential savings in the commercial and industrial sectors excluding sales from opt-out customers. Appendix E and Appendix F provide the respective results of commercial and industrial sector potential in a scenario that includes savings from Vectren's opt-out customers.

2.2.3 Building Stock/Equipment Saturation

To assess the potential electric energy efficiency savings available, estimates of the current saturation of baseline equipment and energy efficiency measures are necessary.

[9] These percentages were calculated based on the 2017 Vectren non-residential customer data and 2017 billing history.

2.2.3.1 Residential Sector

For the residential sector, GDS relied on several primary research efforts. The electric measure analysis was largely informed by a 2016 baseline survey of Vectren South customers. Nearly 500 responses to this survey provided a strong basis for many of the Vectren South electric measure baseline and efficient saturation estimates. A 2015 CFL and LED baseline study helped inform the saturation estimates for the lighting end use. A 2017 electric baseline thermostat survey of Vectren customers was leveraged to better characterize the increased prominence of smart and Wi-Fi-enabled thermostats.

EIA Residential Energy Consumption Survey (RECS) data from 2015 helped fill in data gaps that could not be directly informed by Vectren primary research. Other data sources included ENERGY STAR unit shipment data, Vectren evaluation reports, and baseline studies from other states. The ENERGY STAR unit shipment data filled data gaps related to the increased saturation of energy efficient equipment across the U.S. in the last decade.

2.2.3.2 Commercial Sector

For the ***commercial sector***, data collected through on-site visits as part of this study was leveraged to develop remaining factors for many of the measures. GDS coordinated with Vectren and the Oversight Board to develop a research plan, sampling plan, and a survey questionnaire used to collect data.

The study included primary onsite research with 38 of Vectren's commercial customers across all building types considered in the study.[10] The on-site data collection included facility operation schedules and building characteristics, HVAC equipment type and efficiency levels, lighting fixture inventories, control systems and strategies, and related electric consuming equipment characteristics.

The survey data was used to inform two main assumptions for the potential study, the Base Case and the Remaining factors. The Base Case Factor is the fraction of the end use energy that is applicable for the efficient technology in a given market segment. Survey data was used to determine fractional energy use for most measures in the study. The survey data provided counts for equipment and energy usage levels for the lighting, heating, cooling, water heating, motors and refrigeration end-uses. For example, T8 lighting used 88% of the energy for interior fluorescent lamps and fixtures for the surveyed buildings. The remaining usage was a combination of T12s, T5s and LED linear tube lighting. In total, 60% of the base case allocations came directly from the survey data and the other 40% came from regional potential study data from other Indiana Utilities or from GDS estimates based upon past study experience.

The remaining factor is the fraction of applicable kWh sales that are associated with equipment that has not yet been converted to the energy efficiency measure. It can also be defined as one minus the fraction of the market segment that already have the energy-efficiency measure installed, or one minus the market saturation for the measures. The commercial survey data was used to determine the remaining factors for 60% of all measures in the study. For example, the survey found that 24% of linear fluorescent lamps have already been converted to LEDs. The remaining factor for this measure is 76%. The latest ENERGY STAR shipment data report also provided remaining factors for several measures. The other remaining factors are either 100% for emerging technologies measures or estimates are based on GDS past study experience.

2.2.3.3 Industrial Sector

For the ***industrial sector***, Vectren survey data was leveraged to determine the remaining factors for several end-uses, including motors, interior and exterior lighting and fixture measures. GDS was able to approximate the percentage of remaining standard efficiency motors from the survey data (approximately 67% appear to be standard efficiency), as well as the approximate percentage of remaining constant speed motors (non-VFD) for the industrial survey group (approximately 65% constant speed). GDS was also able to determine a percentage of remaining fluorescent tube

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[10] The full survey dataset was provided to Vectren as a deliverable.

fixture lighting and HID fixture lighting (non-LED) to be approximately 90% from the industrial survey responses. Other industrial process remaining factors were determined based on remaining factors used in previous studies, which were determined from baseline studies in other jurisdictions, the U.S. EIA 2013 Industrial Model Documentation Report, or GDS engineering estimates.

2.2.4 Remaining Factor

The remaining factor is the proportion of a given market segment that is not yet efficient and can still be converted to an efficient alternative. If is by definition, the inverse of the saturation of an energy efficient measure, prior to any adjustments. For this study we made two key adjustments to recognize that the energy efficient saturation does not necessarily always fully represent the state of market transformation. In other words, while a percentage of installed measures may already be efficient, this does not preclude customers from backsliding, or reverting to standard technologies, or otherwise less efficient alternatives in the future, based on considerations like measure cost and availability and customer preferences (e.g. historically, some customers have disliked CFL light quality, and have reverted to incandescent and halogen bulbs after the CFLs burn out).

For measures categorized as market opportunity (i.e. replace-on-burnout), we assumed that 50% of the instances in which an efficient measure is already installed, the burnout or failure of those measures would be eligible for inclusion in the estimate of future savings potential. Essentially this adjustment implies that we are assuming that 50% of the market is transformed, and no future savings potential exists, whereas the remaining 50% of the market is not transformed and could backslide without the intervention of a Vectren program and an incentive. Similarly, for retrofit measures, we assumed that only 10% of the instances in which an efficient measure is already installed, the burnout or failure of those measures would be eligible for inclusion in the estimate of future savings potential. This recognizes the more proactive nature of retrofit measures, as the implementation of these measures are more likely to be elective in nature, compared to market opportunity measures, which are more likely to be needs-based. We recognize the uncertainty in these assumptions, but we believe these are appropriate assumptions, as they recognize a key component of the nature of customer decision making.

2.3 MEASURE CHARACTERIZATION

2.3.1 Measure Lists

The study's sector-level energy efficiency measure lists were informed by a range of sources including the Indiana TRM, current Vectren program offerings, and commercially viable emerging technologies, among others. Measure list development was a collaborative effort in which GDS developed draft lists that were shared with Vectren and the Stakeholders. The final measure lists ultimately included in the study reflected the informed comments and considerations from the parties that participated in the measure list review process.

In total, GDS analyzed 538 measure types for Vectren South – Electric. Some measures save both electric and natural gas. For those measures, the savings of both fuels were included in the benefit-cost screening.[11] Many measures were included in the study as multiple permutations to account for different specific market segments, such as different building types, efficiency levels, and replacement options. GDS developed a total of 4,155 measure permutations for this study. Each permutation was, screened for cost-effectiveness according to the Utility Cost Test (UCT). The parameters for cost-effectiveness under the UCT are discussed in detail later in Section 2.4.3.

[11] Because electric and natural gas results are presented in separate reports, costs were apportioned between electric and gas based on the relative amount of savings from each fuel type.

TABLE 2-3 NUMBER OF MEASURES EVALUATED

	# of Measures	Total # of Measure Permutations	# with UCT ≥ 1
Vectren South – Electric			
Residential	185	636	449
Commercial	219	2,190	1,890
Industrial	165	1,464	1,424
Total	550	4,155	3,681

2.3.2 Emerging Technologies

GDS considered several specific emerging technologies as part of analyzing future potential. In the residential sector, these technologies include several smart technologies, including smart appliances, smart water heater (WH) tank controls, smart window coverings, smart ceiling fans, heat pump dryers and home automation/home energy management systems. In the non-residential sector, specific emerging technologies that were considered as part of the analysis include strategic energy management, advance lighting controls, advanced rooftop controls, cloud-based energy information systems ("EIS"), high performance elevators, and escalator motor controls. While this is likely not an exhaustive list of possible emerging technologies over the next twenty years it does consider many of the known technologies that are available today but may not yet have widespread market acceptance and/or product availability.

In addition to these specific technologies, GDS acknowledges that there could be future opportunities for new technologies as equipment standards improve and market trends occur. While this analysis does not make any explicit assumption about unknown future technologies, the methodology assumes that subsequent equipment replacement that occurs over the course of the 20-year study timeframe, and at the end of the initial equipment's useful life, will continue to achieve similar levels of energy savings, relative to improved baselines, at similar incremental costs.

2.3.3 Assumptions and Sources

A significant amount of data is needed to estimate the electric savings potential for individual energy efficiency measures or programs across the residential and nonresidential customer sectors. GDS utilized data specific to Vectren when it was available and current. GDS used the most recent Vectren evaluation report findings (as well as Vectren program planning documents), 2015 Indiana Technical Reference Manual (IN TRM), the Illinois TRM, and the Michigan Energy Measures Database (MEMD) to a large amount of the data requirements. Evaluation report findings and the Indiana TRM were leveraged to the extent feasible – additional data sources were only used if these first two sources either did not address a certain measure or contained outdated information. The BEopt simulation modeling results formed the basis for most heating and cooling end use measure savings. The National Renewable Energy Laboratory (NREL) Energy Measures Database also served as a key data source in developing measure cost estimates. Additional source documents included American Council for an Energy-Efficient Economy (ACEEE) research reports covering topics like emerging technologies.

Measure Savings: GDS relied on existing Vectren evaluation report findings and the 2015 IN TRM to inform calculations supporting estimates of annual measure savings as a percentage of base equipment usage. For custom measures and measures not included in the IN TRM, GDS estimated savings from a variety of sources, including:

- Illinois TRM, MEMD, and other regional/state TRMs
- Building energy simulation software (BEopt) and engineering analyses
- Secondary sources such as the ACEEE, Department of Energy (DOE), Energy Information Administration (EIA), ENERGY STAR©, and other technical potential studies

Measure Costs: Measure costs represent either incremental or full costs. These costs typically include the incremental cost of measure installation, when appropriate based on the measure definition. For purposes of this study, nominal measure costs held constant over time.[12] One exception is an assumed decrease in costs for light emitting diode (LED) bulbs over the study horizon. LED bulb consumer costs have been declining rapidly over the last several years and future cost projections indicate a continued decrease in bulb costs.[13] GDS' treatment of LED bulb costs, LED lighting efficacy, and the impacts of the Energy Independence and Security Act ("EISA") are discussed in greater detail in Section 2.3.5, "Review of LED Lighting Assumptions."

GDS obtained measure cost estimates primarily from the Vectren program planning databases, and the 2015 IN TRM. GDS used the following data sources to supplement the IN TRM:

- Illinois TRM, MEMD, and other regional/state TRMs
- Secondary sources such as the ACEEE, ENERGY STAR, and National Renewable Energy Lab (NREL)
- Program evaluation and market assessment reports completed for utilities in other states

Measure Life: Measure life represents the number of years that energy using equipment is expected to operate. GDS obtained measure life estimates from the 2015 IN TRM and Vectren program planning databases, and used the following data sources for measures not in the IN TRM:

- Illinois TRM, MEMD, and other regional/state TRMs
- Manufacturer data
- Savings calculators and life-cycle cost analyses

All measure savings, costs, and useful life assumption sources are documented in Appendices B-D.

2.3.4 Treatment of Codes and Standards

Although this analysis does not attempt to predict how energy codes and standards will change over time, the analysis does account for the impacts of several known improvements to federal codes and standards. Although not exhaustive, key adjustments include[14]:

- The baseline efficiency for air source heat pumps (ASHP) is anticipated to improve to 14 SEER/8.2 HSPF[15] in 2015. As the existing stock of ASHPs was estimated to turn over and allowing for a sell-through period, the baseline efficiency was assumed to be the new federal standard, beginning in FY18.
- In 2015, the DOE makes amended standards effective for residential water heaters that required updated energy factors (EF) depending on the type of water heater and the rated storage volume. For electric storage water heaters with a volume greater than 55 gallons, the standards effectively require heat pumps for electric storage products. For storage tank water heaters with a volume of 55 gallons or less, the new standard (EF=0.948) becomes essentially the equivalent of today's efficient storage tank water heaters. [16]
- In March 2015, the DOE amended the standards for residential clothes washers. The new standards will require the Integrated Modified Energy Factor (MEF) (ft^3/kWh/cycle) to meet certain thresholds based on the machine configurations. The ENERGY STAR specifications for residential clothes washers will also be amended to increase the efficiency of units that can earn the ENERGY STAR label. Version 7.0 of the ENERGY STAR specification is scheduled to go into effect in March 2015. These amended federal and ENERGY STAR standards have been factored into the study.

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[12] GDS reviewed the deemed measure cost assumptions included in the Illinois TRM from 2012 (v1) through 2018 (v7). Where a direct comparison of cost was applicable, GDS found no change in measure cost across 80% of residential and nonresidential measures. In a similar search of the Michigan Energy Measure Database (MEMD) from 2011 to 2018, GDS again found that most of incremental measure costs in 2018 were either the same or higher than the recorded incremental measure cost in 2011.

[13] LED Incremental Cost Study Overall Final Report. The Cadmus Group. February 2016

[14] Key adjustments for LED screw-in lighting are addressed separately later in this section.

[15] SEER: Seasonal Energy Efficiency Ratio; HSPF: Heating Seasonal Performance Factor.

[16] Ultimately, GDS did not incorporate the requirements for large capacity water heaters into the analysis due to recent legislation that allows grid-enabled water heaters to remain at lower efficiency levels.

- In line with the phase-in of 2005 EPAct regulations, the baseline efficiency for general service linear fluorescent lamps was moved from the T12 light bulb to a T8 light bulb effective June 1, 2016.
- New U.S. Department of Energy (DOE) standards require that all general service fluorescent lamps (GSFL) manufactured after Jan. 26, 2018, meet increased efficacy standards, or lumens per watt, to encourage the adoption of high-efficiency lighting products. In the T8 category, most lamps pass the standards. However, these are primarily reduced-wattage (e.g., 25W, 28W) lamps. The basic-grade 32W lamps do not comply. The standard provides a loophole which excludes fluorescent tubes with a color rendering index (CRI) of 87 or higher. Even with that loophole, there will be fewer T8 lamps to choose from going forward and it is likely that the move to linear LEDs will accelerate.

2.3.5 Review of LED Lighting Assumptions

Recognizing that there remains significant uncertainty regarding the future potential of residential screw-in lighting, GDS reviewed the latest lighting-specific program designs and consulted with industry peers to develop critical assumptions regarding the future assumed baselines for LED screw base omnidirectional, specialty/decorative, and reflector/directional lamps over the study timeframe.

EISA Impacts. LED screw base omnidirectional and decorative lamps are impacted by the EISA 2007 regulation backstop provision, which requires all non-exempt lamps to be 45 lumens/watt, beginning in 2020. Based on this current legislation, the federal baseline in 2020 will be roughly equivalent to a CFL bulb. However, in January 2017, the Department of Energy expanded the scope of the standard to include directional and specialty bulb but stated that they may delay enforcement based on ongoing dialog with industry stakeholders. Although there is uncertainty surrounding EISA and the backstop provision, the Market Potential Study assumes the backstop provision for standard (A-lamp) screw-in bulbs will take effect beginning in 2022. The analysis assumes the expanded definition of general service lamps to include specialty and reflector sockets will impact those sockets beginning in 2023.

LED Bulb Costs. Based on EIA Technology Forecast Report, LED bulb costs were assumed to decrease over the analysis period. LED bulb costs ranged between $3 (standard) and $8.60 (reflector) in 2020, decreasing to $2-$3 by 2039. Incentives were modeled as a % of incremental cost, resulting in decreasing incentives over the analysis timeframe as well.

LED Lighting Efficacy. Using the same EIA Technical Forecast Report, LED efficacy was also assumed to improve over the analysis timeframe. By 2040, the LED wattage of a bulb equivalent to a 60W incandescent will improve from 8W (today's typical LED) down to 4W.

2.3.6 Net to Gross (NTG)

All estimates of technical, economic, and achievable potential, as well as measure level cost-effectiveness screening were conducted in terms of gross savings to reflect the absence of program design considerations in these phases of the analysis. The impacts of free-riders (participants who would have installed the high efficiency option in the absence of the program) and spillover customers (participants who install efficiency measures due to program activities, but never receive a program incentive) are considered in the DSM Action Plan component of this study.

2.4 ENERGY EFFICIENCY POTENTIAL

This section reviews the types of potential analyzed in this report, as well as some key methodological considerations in the development of technical, economic, and achievable potential.

2.4.1 Types of Potential

Potential studies often distinguish between several types of energy efficiency potential: technical, economic, achievable, and program. However, because there are often important definitional issues between studies, it is important to understand the definition and scope of each potential estimate as it applies to this analysis.

The first two types of potential, technical and economic, provide a theoretical upper bound for energy savings from energy efficiency measures. Still, even the best-designed portfolio of programs is unlikely to capture 100% of the technical or economic potential. Therefore, achievable potential attempts to estimate what savings may realistically be achieved through market interventions, when it can be captured, and how much it would cost to do so. Figure 2-2 illustrates the types of energy efficiency potential considered in this analysis. Program potential, in the form of the DSM Action Plan, is discussed in Volume II of the report.

FIGURE 2-2 TYPE OF ENERGY EFFICIENCY POTENTIAL[17]

Not Technically Feasible	TECHNICAL POTENTIAL			
Not Technically Feasible	Not Cost-Effective	ECONOMIC POTENTIAL		
Not Technically Feasible	Not Cost-Effective	Market Barriers	MAXIMUM ACHIEVABLE POTENTIAL	
Not Technically Feasible	Not Cost-Effective	Market Barriers	Partial Incentives	REALISTIC ACHIEVABLE POTENTIAL

2.4.2 Technical Potential

Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility and applicability of measures. Under technical potential, GDS assumed that 100% of new construction and market opportunity measures are adopted as those opportunities become available (e.g., as new buildings are constructed they immediately adopt efficiency measures, or as existing measures reach the end of their useful life). For retrofit measures, implementation was assumed to be resource constrained and that it was not possible to install all retrofit measures all at once. Rather, retrofit opportunities were assumed to be replaced incrementally until 100% of stock was converted to the efficient measure over a period of no more than 15 years.

2.4.2.1 Competing Measures and Interactive Effects Adjustments

GDS prevents double-counting of savings, and accounts for competing measures and interactive savings effects, through three primary adjustment factors:

Baseline Saturation Adjustment. Competing measure shares may be factored into the baseline saturation estimates. For example, nearly all homes can receive insulation, but the analysis has created multiple measure permutations to account for varying impacts of different heating/cooling combinations and have applied baseline saturations to reflect proportions of households with each heating/cooling combination.

Applicability Factor Adjustment. Combined measures into measure groups, where total applicability factor across measures is set to 100%. For example, homes cannot receive a programmable thermostat, connected thermostat, and smart thermostat. In general, the models assign the measure with the most savings the greatest applicability factor in the measure group, with competing measures picking up any remaining share.

Interactive Savings Adjustment. As savings are introduced from select measures, the per-unit savings from other measures need to be adjusted (downward) to avoid over-counting. The analysis typically prioritizes market opportunity

[17] Reproduced from "Guide to Resource Planning with Energy Efficiency." November 2007. US Environmental Protection Agency (EPA). Figure 2-1.

equipment measures (versus retrofit measures that can be installed at any time). For example, the savings from a smart thermostat are adjusted down to reflect the efficiency gains of installing an efficient air source heat pump. The analysis also prioritizes efficiency measures relative to conservation (behavioral) measures.

2.4.3 Economic Potential

Economic potential refers to the subset of the technical potential that is economically cost-effective (based on screening with the Utility Cost Test) as compared to conventional supply-side energy resources.

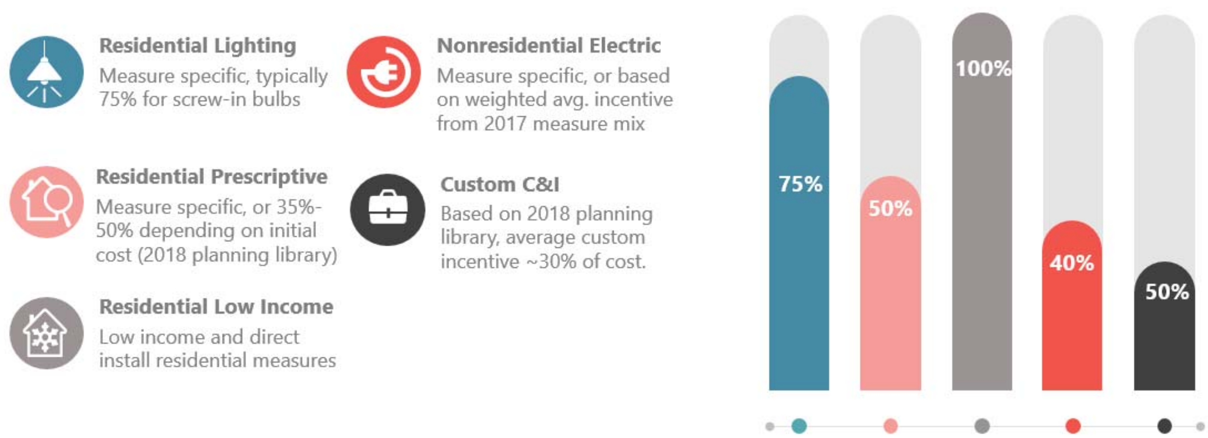
2.4.3.1 Utility Cost Test and Incentive Levels

The economic potential assessment included a screen for cost-effectiveness using the Utility Cost Test (UCT) at the measure level. In the Vectren South territory, the UCT considers both electric and natural gas savings as benefits, and utility incentives and direct install equipment expenses as the cost. Consistent with application of economic potential according to the National Action Plan for Energy Efficiency, the measure level economic screening does not consider non-incentive/measure delivery costs (e.g. admin, marketing, evaluation etc.) in determining cost-effectiveness.[18]

Apart from the low-income segment of the residential sector, all measures were required to have a UCT benefit-cost ratio greater than 1.0 to be included in economic potential and all subsequent estimates of energy efficiency potential. Low-income measures were not required to be cost-effective; all low-income specific measures are included in the economic and achievable potential estimates.

For both the calculation of the measure-level UCT, as well as the determination of RAP, historical incentive levels (as a % of incremental measure cost) were calculated for current measure offerings. Figure 2-3 describes the incentive levels by key market segment within the residential and nonresidential sectors.

FIGURE 2-3 INCENTIVES BY SECTOR AND MARKET SEGMENT



GDS relied on Vectren's measure planning library and supporting DSM Operating Plan appendices to map current measure offerings to their historical incentive levels.[19] For study measures that did not map directly to a current offering, GDS calculated the weighted average incentive level (based on 2017 participation) by sector and/or program and applied these "typical" incentive levels to the new measures.

[18] National Action Plan for Energy Efficiency: Understanding Cost-Effectiveness of Energy Efficiency Programs. Note: Non-incentive delivery costs are included in the assessment of achievable potential and the DSM Action Plan.
[19] The measure planning library was leveraged primarily for determining current incentive levels rather than for developing estimates of future costs or savings potential.

- In the residential sector, lighting incentive levels were assumed to represent 75% of the measure cost. Remaining residential incentive levels were either 50% of the incremental measure cost, or 35% of the measure cost (for more expensive measures).
- Low income and direct install measures received incentives equal to 100% of the measure cost
- In the non-residential sector, prescriptive incentives were 50% of the measure cost, and custom measures received incentives equal to 30% of the measure cost 3
- In the MAP scenario, all incentives were set to 100% of the incremental measure cost.

2.4.3.2 Avoided Costs

Avoided energy supply costs are used to assess the value of energy savings. Avoided cost values for electric energy, electric capacity, and avoided transmission and distribution (T&D) were provided by Vectren as part of an initial data request. Electric energy is based on an annual system marginal cost. For years outside of the avoided cost forecast timeframe, future year avoided costs are escalated by the rate of inflation.

2.4.4 Achievable Potential

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:

- ***Maximum Achievable Potential*** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- ***Realistic Achievable Potential*** estimates achievable potential with Vectren paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

2.4.4.1 Market Adoption Rates

GDS assessed achievable potential on a measure-by-measure basis. In addition to accounting for the natural replacement cycle of equipment in the achievable potential scenario, GDS estimated measure specific maximum adoption rates that reflect the presence of possible market barriers and associated difficulties in achieving the 100% market adoption assumed in the technical and economic scenarios.

The initial step was to assess the long-term market adoption potential for energy efficiency technologies. Due to the wide variety of measures across multiple end-uses, GDS employed varied measure and end-use-specific ultimate adoption rates versus a singular universal market adoption curve. These long-term market adoption estimates were based on either Vectren-specific Willingness to Participate (WTP) market research or publicly available DSM research including market adoption rate surveys and other utility program benchmarking. These surveys included questions to residential homeowners and nonresidential facility managers regarding their perceived willingness to purchase and install energy efficient technologies across various end uses and incentive levels.

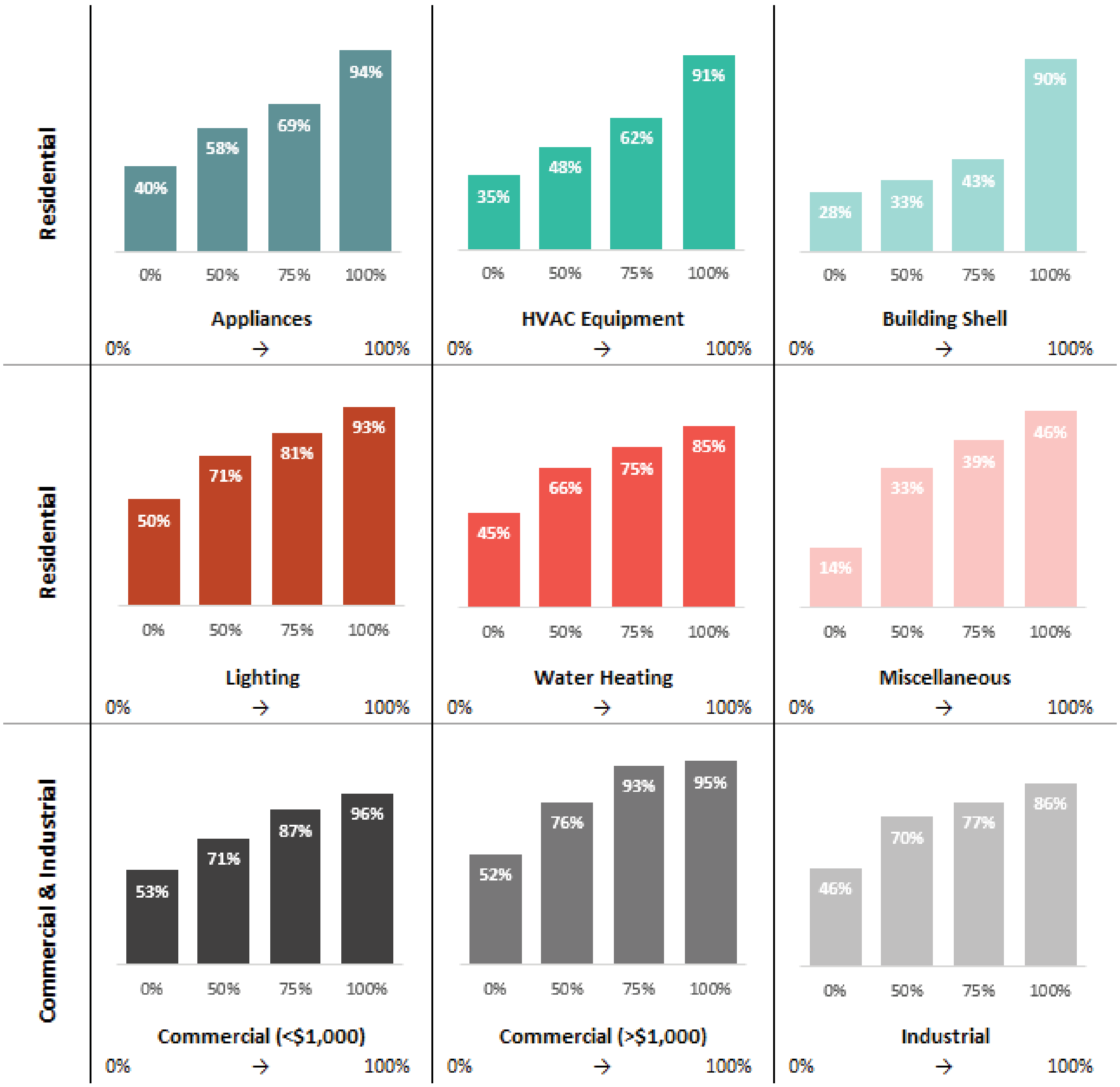
GDS utilized likelihood and willingness-to-participate data to estimate the long-term (20-year) market adoption potential for both the maximum and realistic achievable scenarios.[20] Table 2-4 presents the long-term market adoption rates at varied incentive levels used for both the residential and nonresidential sectors. When incentives are assumed to represent 100% of the measure cost (maximum achievable), the long-term market adoption ranged by sector and

[20] For the MAP Scenario, the long-term adoption rate was reached by Year15 (or earlier) and annual participation remained flat in the final five years of the analysis. In the RAP scenario, the analysis assumes the maximum adoption rate is reached over a period of 20-years or less.

end-use from 46% to 96%. For the RAP scenario, the incentive levels also varied by measure resulting in measure-specific market adoption rates.

TABLE 2-4 LONG-TERM MARKET ADOPTION RATES AT DISCRETE INCENTIVE LEVELS

(based on Willingness-to-Participate Survey Results)



GDS then estimated initial year adoption rates by reviewing the current saturation levels of efficient technologies and (if necessary) calibrating the estimates of 2020 annual potential to recent historical levels achieved by Vectren's current DSM portfolio. This calibration effort ensures that the forecasted achievable potential in 2020 is realistic and attainable. GDS then assumed a non-linear ramp rate from the initial year market adoption rate to the various long-term market adoption rates for each specific end-use.

One caveat to this approach is that the ultimate long-term adoption rate is generally a simple function of incentive levels and payback. There are other factors that may influence a customer's willingness to purchase an energy efficiency measure. For example, increased marketing and education programs can have a critical impact on the success of energy efficiency programs. Other benefits, such as increased comfort or safety and reduced maintenance costs could also factor into a customer's decision to purchase and install energy efficiency measures. To acknowledge these impacts, GDS considered the participant spillover and non-participant spillover rates (identified in prior Vectren evaluations) that demonstrate the impacts that efficiency program and their marketing/education components can have on increased technology adoption. GDS used these spillover rates to increase the long-term adoption rates (typically by 5%-7%) at each incentive level.

2.4.4.2 Non-Incentive Costs

Consistent with National Action Plan for Energy Efficiency (NAPEE) guidelines[21], utility non-incentive costs were included in the overall assessment of cost-effectiveness at the realistic achievable potential scenario. 2020 direct measure/program non-incentive costs were calibrated to recent 2016-2018 historical levels and set at $0.045 per first year kWh saved for residential lighting, $0.01 per first year kWh saved for residential behavior, $0.145 for the remaining residential measures, and $0.07 per first year kWh saved in the non-residential sectors. Non-incentive costs were then escalated annually at the rate of inflation%. [22]

In addition to non-incentive costs attributed directly to programs and measures, the analysis also included indirect program delivery that are not specifically attributed to individual programs and can include additional outreach, evaluation, and program planning activities. These costs were calibrated to 2015-2018 historical levels of $0.024 per first year kWh, escalated 5% annually.[23]

2.5 DEMAND RESPONSE AND CVR POTENTIAL

This section provides an overview of the demand response and conservation voltage reduction ("CVR") potential methodology. Summary results of the demand response analysis are provided in Section 7. Additional results details are provided in Appendix G.

2.5.1 Demand Response Program Options

Table 2-5 provides a brief description of the demand response (DR) program options considered and identifies the eligible customer segment for each demand response program that was considered in this study. This includes direct load control (DLC) and rate design options.

TABLE 2-5 DEMAND RESPONSE PROGRAM OPTIONS AND ELIGIBLE MARKETS

DR Program Option	Program Description	Eligible Markets
DLC AC (Switch)	The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle)	Residential and Non-Residential Customers
DLC AC (Thermostat)	The system operator can remotely raise the AC's thermostat set point during peak load conditions, lowering AC load.	Residential and Non-Residential Customers

[21] National Action Plan for Energy Efficiency (2007). Guide for Conducting Energy Efficiency Potential Studies. Prepared by Optimal Energy. This study notes that economic potential only considers the cost of efficiency measures themselves, ignoring programmatic costs. Conversely, achievable potential should consider the non-measures costs of delivering programs. Pg. 2-4.

[22] As noted earlier in the report, measure costs and utility incentives were not escalated over the 20-year analysis timeframe to keep those costs constant in nominal dollars.

[23] The historic compound average annual growth rate (CAGR) over the same time is 22.6%. GDS used a more conservative escalation rate based on an expected slower growth rate in the future.

DR Program Option	Program Description	Eligible Markets
DLC Pool Pumps	The swimming pool pump is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours.	Residential Customers
DLC Water Heaters	The water heater is remotely shut off by the system operator for periods normally ranging from 2 to 8 hours.	Residential and Non-Residential Customers
Critical Peak Pricing with Enabling Technology	A retail rate in which an extra-high price for electricity is provided during a limited number of critical periods (e.g. 100 hours) of the year. Market-based prices are typically provided on a day-ahead basis, or an hour-ahead basis. Includes enabling technology that connects technologies within building. Only for customers with AC.	Residential and Non-Residential Customers
Critical Peak Pricing without Enabling Technology	A retail rate in which an extra-high price for electricity is provided during a limited number of critical periods (e.g. 100 hours) of the year. Market-based prices are typically provided on a day-ahead basis, or an hour-ahead basis.	Residential and Non-Residential Customers
Real Time Pricing	A retail rate in which customers pay electricity supply rates that vary by the hour.	Non-Residential Customers
Peak Time Rebates	A program where customers are rewarded if they reduce electricity consumption during peak times with monetary rebates.	Residential and Non-Residential Customers
Time of Use Rates	A retail rate in which customers are charged higher rates for the energy they use during specific peak demand times.	Residential and Non-Residential Customers

Double-counting savings from demand response programs that affect the same end uses is a common issue that must be addressed when calculating the demand response savings potential. For example, a direct load control (DLC) program of air conditioning and a rate program both assume load reduction of the customers' air conditioners. For this reason, it is typically assumed that customers cannot participate in programs that affect the same end uses. As Vectren has offered a DLC program for many years, it was assumed that participation in this offering be prioritized before rate-based DR options. The order of the rest of the programs is based on savings where programs with higher savings per customer are prioritized.

2.5.2 Demand Response Potential Assessment Approach Overview

The analysis of DR, where possible, closely followed the approach outlined for energy efficiency. The framework for assessing the cost-effectiveness of demand response programs is based *on A Framework for Evaluating the Cost-Effectiveness of Demand Response, prepared for the National Forum on the National Action Plan (NAPA) on Demand Response*.[24] Additionally, GDS reviewed the May 2017 National Standard Practice Manual published by the National Efficiency Screening Project.[25] GDS utilized this guide to define avoided ancillary services and energy and/or capacity price suppression benefits.

The demand response analysis was conducted using the GDS Demand Response Model. The Model determines the estimated savings for each demand response program by performing a review of all benefits and cost associated with each program. GDS developed the model such that the value of future programs could be determined and to help facilitate demand response program planning strategies. The model contains approximately 50 required inputs for each program including: expected life, coincident peak ("CP") kW load reductions, proposed rebate levels, program related expenses such as vendor service fees, marketing and evaluation cost and on-going O&M expenses. This model and future program planning features can be used to standardize the cost-effectiveness screening process between Vectren departments interested in the deployment of demand response resources.

The UCT was used to determine the cost-effectiveness of each demand response program. Benefits are based on avoided demand, energy (including load shifting), wholesale cost reductions and T&D costs. Costs include incremental program equipment costs (such as control switches or smart thermostats), fixed program capital costs (such as the cost of a central controller), program administrative, marketing, and evaluation costs. Incremental equipment program costs are included for both new and replacement units (such as control switches) to account for units that are replaced at the end of their useful life.

The demand response analysis includes estimates of technical, economic, and achievable potential. Achievable potential is broken into maximum and RAP in this study:

MAP represents an estimate of the maximum cost-effective demand response potential that can be achieved over the 15-year study period. For this study, this is defined as customer participation in demand response program options that reflect a "best practices" estimate of what could eventually be achieved. MAP assumes no barriers to effective delivery of programs.

RAP represents an estimate of the amount of demand response potential that can be realistically achieved over the 20-year study period. For this study, this is defined as achieving customer participation in demand response program options that reflect a realistic estimate of what could eventually be achieved assuming typical or "average" industry experience. RAP is a discounted MAP, by considering program barriers that limit participation, therefore reducing savings that could be achieved.

Last, the analysis evaluated direct load control of thermostat potential under two possible conditions: 1) a Bring Your Own Thermostat ***(BYOT) scenario*** where the customer provides their own thermostat and are monetarily incentivized; and 2) a ***utility incentivized scenario*** where the utility provides the smart thermostat and provides a smaller monetary incentive. These options are described in more detail in Appendix G.

2.5.3 Avoided Costs

Demand response avoided costs were consistent with those utilized in the energy efficiency potential analysis and were provided by Vectren. The primary benefit of demand responses is avoided generation capacity, resulting from a

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[24] Study was prepared by Synapse Energy Economics and the Regulatory Assistance Project, February 2013.
[25] National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, May 18, 2017, Prepared by The National Efficiency Screening Project

reduction in the need for new peaking generation capacity. Demand response can also produce energy related benefits. If the demand response option is considered "load shifting", such as direct load control of electric water heating, the consumption of energy is shifted from the control period to the period immediately following the period of control. For this study, GDS assumed that the energy is shifted with no loss of energy. If the program is not considered to be "load shifting" the measure is turned off during peak control hours, and the energy is saved altogether. Demand response programs can also potentially delay the construction of new transmission and distribution lines and facilities, which is reflected in avoided T&D costs.

2.5.4 Demand Response Program Assumptions

This section briefly discusses the general assumptions and sources used to complete the demand response potential analysis. Appendix G provides additional detail by program and sector related to load reduction, program costs, and projected participation.

Load Reduction: Demand reductions were based on load reductions found in Vectren's existing demand response programs, and various secondary data sources including the FERC and other industry reports, including demand response potential studies. DLC and thermostat-based DR options were typically calculated based on a per-unit kW demand reduction whereas rate-based DR options were typically assumed to reduce a percentage of the total facility peak load.

Useful Life: The useful life of a smart thermostat is assumed to be 15 years . Load control switches have a useful life of 15 years. This life was used for all direct load control measures in this study.

Program Costs: One-time program development costs included in the first year of the analysis for new programs. No program development costs are assumed for programs that already exist. Each new program includes an evaluation cost, with evaluation cost for existing programs already being included in the administration costs. It was assumed that there would be a cost of $50[26] per new participant for marketing for the DLC programs. Marketing costs are assumed to be 33.3% higher for MAP. All program costs were escalated each year by the general rate of inflation assumed for this study.

Saturation: The number of control units per participant was assumed to be 1 for all direct load control programs using switches (such as water heaters and air conditioning switches), because load control switches can control up to two units. However, for controllable thermostats, some participants have more than one thermostat. The average number of residential thermostats per single family home was assumed to be 1.72 thermostats.

2.5.5 DR Program Adoption Levels

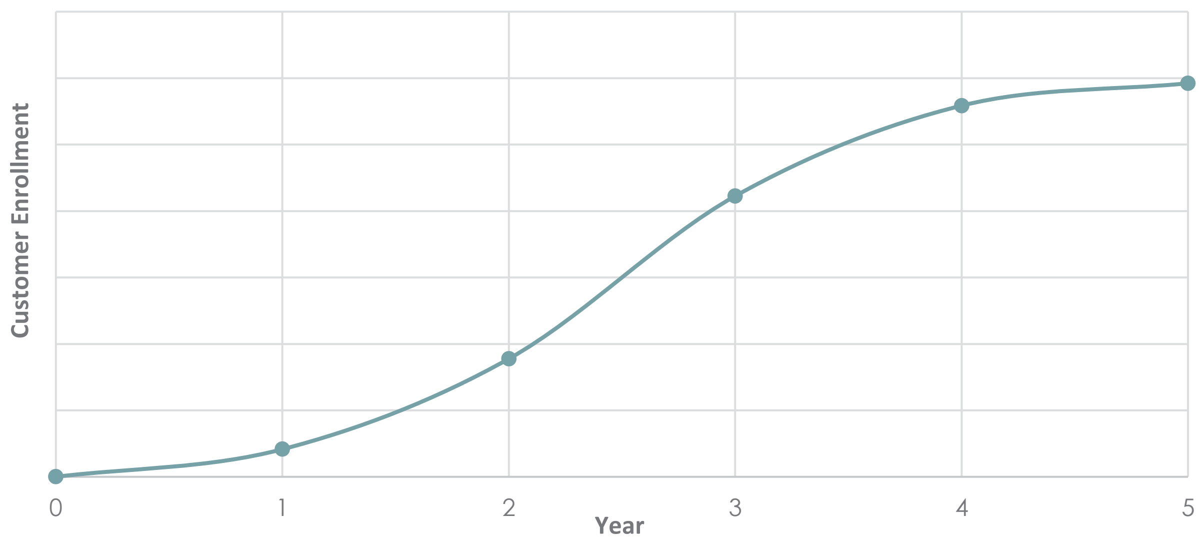
Long-term program adoption levels (or "steady state" participation) represent the enrollment rate once the fully achievable participation has been reached. GDS reviewed industry data and program adoption levels from several utility DR programs. The main sources of participant rates are several studies completed by the Brattle Group. Additional detail about participation rates and sources are shown in Appendix G. As noted earlier in this section, for direct load control programs, MAP participation rates rely on industry best adoption rates and RAP participation rates are based on industry average adoption levels. For the rate programs, the MAP steady-state participation rates assumed programs were opt-out based and RAP participation assumed opt-in status.

Customer participation in new demand response programs is assumed to reach the steady state take rate over a five-year period. The path to steady state customer participation follows an "S-shaped" curve, in which participation growth accelerates over the first half of the five-year period, and then slows over the second half of the period (see Figure 2-

[26] TVA Potential Study Volume III: Demand Response Potential, Global Energy Partners, December 2011

4). Existing programs have already gone through this ramp-up period, so they were escalated linearly to the final participation rate.

FIGURE 2-4 ILLUSTRATION OF S-SHAPED MARKET ADOPTION CURVE



2.5.6 Conservation Voltage Reduction (CVR)

GDS evaluated CVR as a demand response program capable of providing avoided energy and demand cost benefits through reduction of voltages along circuits fed by two different substations. CVR has been demonstrated by Vectren in an existing application at the Buckwood substation. Vectren plans to expand its CVR program to the East Side substation in 2020 and the Broadview substation in 2023. GDS has modeled the potential of CVR as reflecting the East Side and Broadview implementations only.

Energy and demand impacts were estimated by GDS using a combination of data sources, including the EM&V analysis of the Buckwood pilot program, an engineering report prepared by Power Systems Engineering, and data summarizing the customer counts by sector and energy sales volumes for each of the three substations. When CVR is implemented, energy savings are achieved for the hours of reduction, and Vectren indicated they intend to continue to operate CVR for a number of hours throughout the year, leading to energy savings and demand savings for the expanded program. The East Side substation is projected to save 2.63% of its residential and 4.71% of its C&I annual energy sales through application of CVR. Analysis by Power Systems Engineering indicates that the Broadview substation would achieve greater potential energy savings relative to East Side, achieving a 3.25% reduction of residential energy sales and 4.86% of C&I energy sales. Table 2-6 shows these impact details.

TABLE 2-6 CVR IMPACTS BY SUBSTATION

Substation	East Side	Broadview
Residential		
Total Energy Sales (kWh)	55,586,807	53,397,685
% Savings Assumed from CVR	2.63%	3.25%
CVR Energy Savings (kWh)	1,461,047	1,733,455
CVR Demand Savings (kW)	263	312
Commercial & Industrial		
Total Energy Sales (kWh)	21,922,082	43,766,990
% Savings Assumed from CVR	4.71%	4.86%
CVR Energy Savings (kWh)	1,032,655	2,127,540
CVR Demand Savings (kW)	186	383

Substation	East Side	Broadview
Substation Total		
Total Energy Sales (kWh)	77,508,888	97,164,675
% Savings Assumed from CVR	3.22%	3.97%
CVR Energy Savings (kWh)	2,493,702	3,860,995
CVR Demand Savings (kW)	449	695

Two sources of program costs are included in the cost effectiveness screening for CVR: implementation costs and administrative costs. Incentives are not necessary as voltage reduction is achieved without requiring participation or consent from customers and without sacrificing quality of service. Implementation costs are annualized based on a carrying cost factor that includes 30-years of straight-line depreciation, 4.0% interest for debt, and 3.2% for O&M.

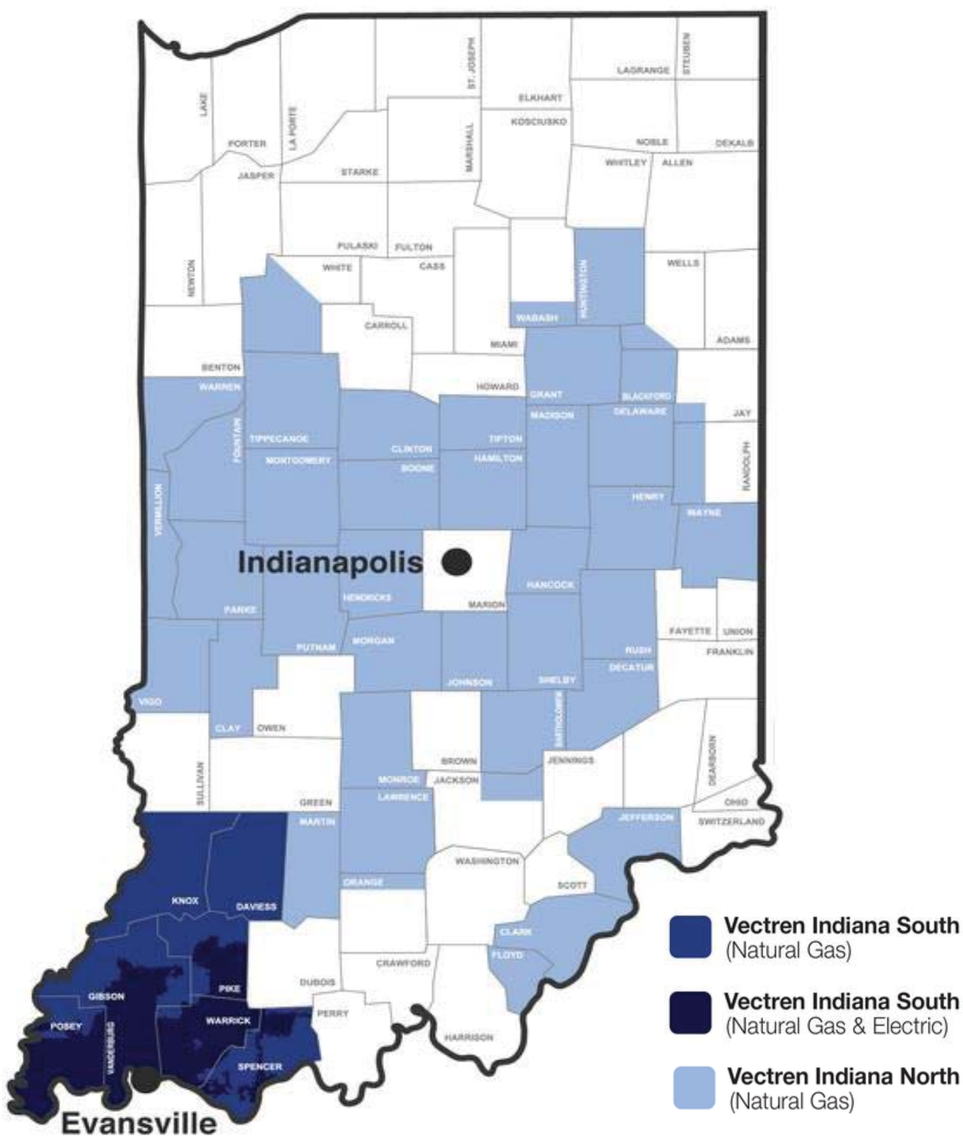
3 Market Characterization

Developing a market characterization in the context of utility electric consumption among each sector is a key foundational element to market potential studies. A market characterization describes how energy is used among the various end-uses and building types that are the subject of the potential study. This section provides a brief overview of the sales and customer forecasts for Vectren's electric customers. It also includes a more detailed breakdown of the end-use and building type consumption, along with an overview of how these segmentations were developed.

3.1 VECTREN INDIANA SERVICE AREAS

This study assessed the electric energy efficiency potential for Vectren South. Figure 3-1 provides the overall Vectren South and Vectren North territories in Indiana.

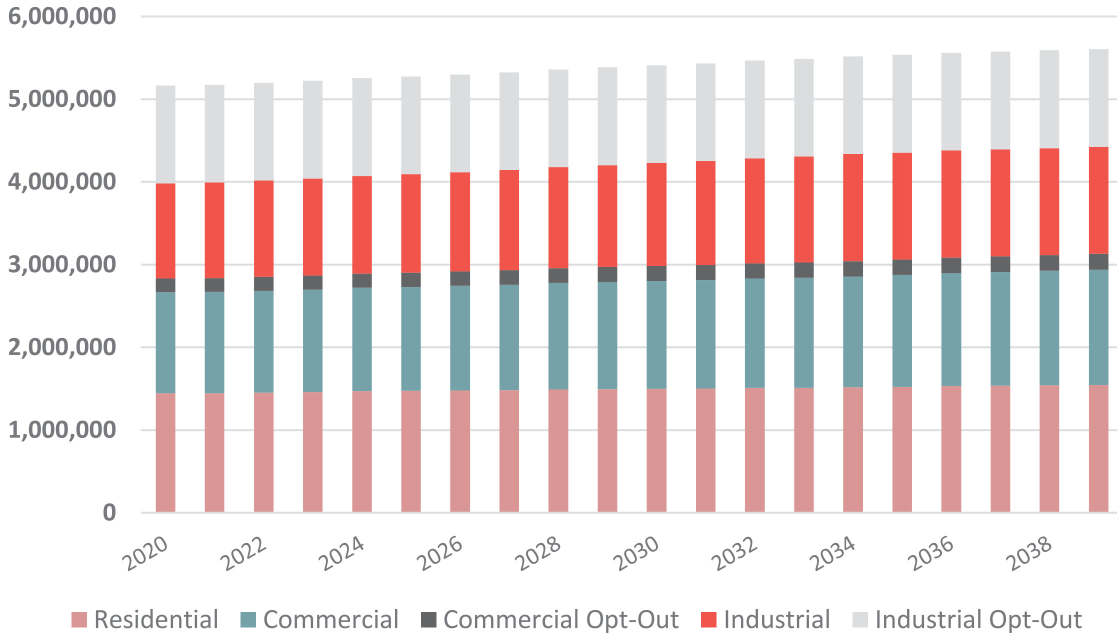
FIGURE 3-1 VECTREN SERVICE TERRITORY MAP



3.2 LOAD FORECASTS

Figure 3-2 provides the electric sales by sector across the 2020-2039 timeframe. Sales are forecasted to gradually increase from 5.2 million MWh to 5.6 million MWh from 2020 to 2039. The sales figure shows commercial and industrial sales break outs of the sales projections for opt-out customers.

FIGURE 3-2 20-YEAR ELECTRIC SALES (MWH) FORECAST BY SECTOR

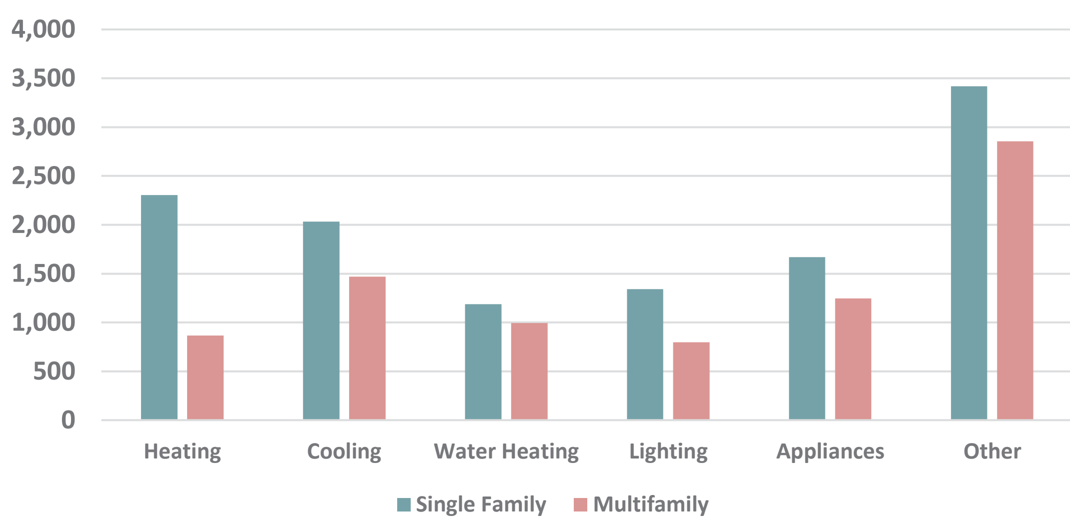


3.3 SECTOR LOAD DETAIL

3.3.1 Residential Sector

The residential electric calibration effort led to a housing-type specific end-use intensity breakdown as shown below in Figure 3-3. Overall, we estimated single-family consumption to be just shy of 12,000 kWh per year, and multifamily homes to be about 8,200 kWh per year. The "Other" end use is the leading end-use among both housing types. This reflects the increasing prominence of electronics and other plug in devices.

FIGURE 3-3 RESIDENTIAL ELECTRIC END-USE BREAKDOWN BY HOUSING TYPE



3.3.2 Commercial Sector

Figure 3-4 provides a breakdown of commercial electric sales by building type. Mercantile (25%) and Office (20%) are the leading contributors of stand-alone building types to the total commercial electric sales.[27]

FIGURE 3-4 COMMERCIAL ELECTRIC SALES BREAKDOWN BY BUILDING TYPE

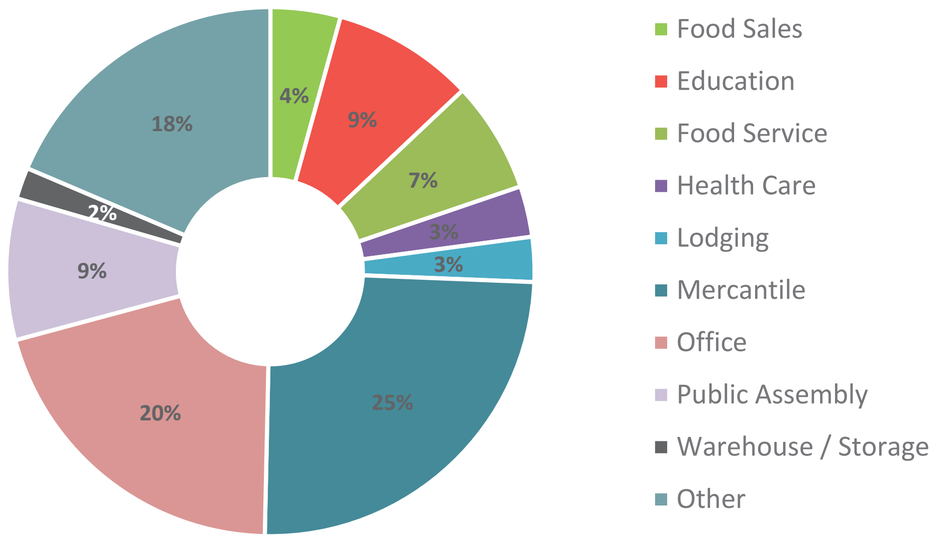
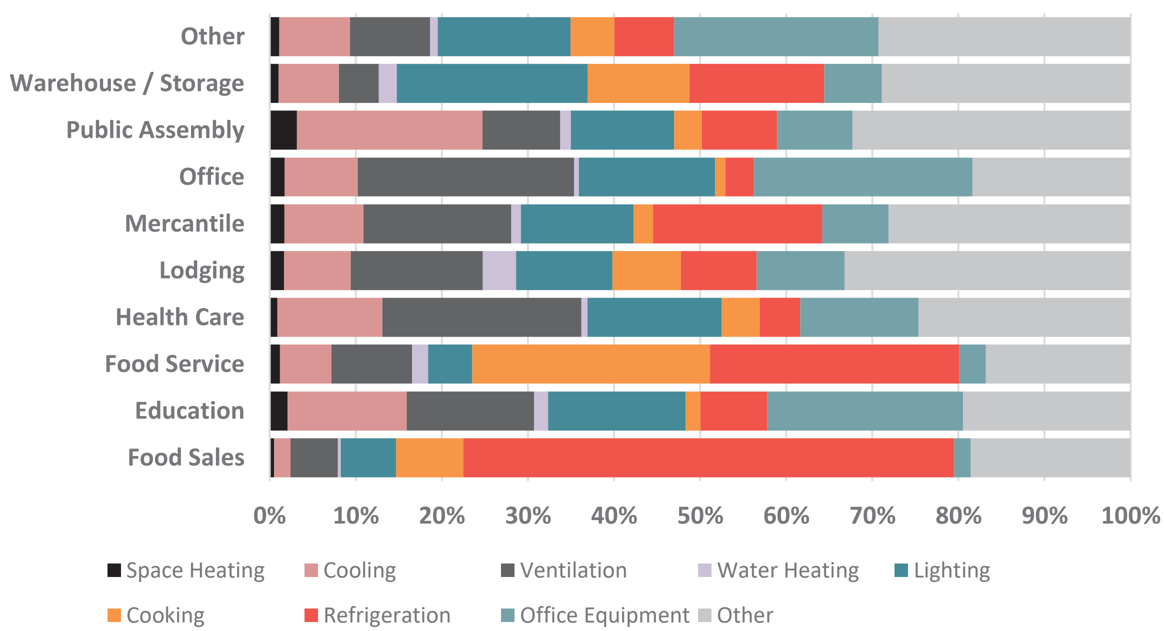


Figure 3-5 provides an illustration of the leading end-uses across all building types in the commercial sector. Ventilation, lighting, and refrigeration are prominent across most of the building types.

FIGURE 3-5 COMMERCIAL ELECTRIC END-USE BREAKDOWN BY BUILDING TYPE



[27] "Other" building types include buildings that engage in several different activities, a majority of which are commercial (e.g. retail space), though the single largest activity may be industrial or agricultural; "other" also includes miscellaneous buildings that do not fit into any other category.

3.3.3 Industrial Sector

Figure 3-6 provides a breakdown of industrial electric sales by industry type. Food (20%) and Plastics & Rubber (15%) are the leading industry types contributing to industrial electric sales.

FIGURE 3-6 INDUSTRIAL ELECTRIC INDUSTRY TYPE BREAKDOWN[28]

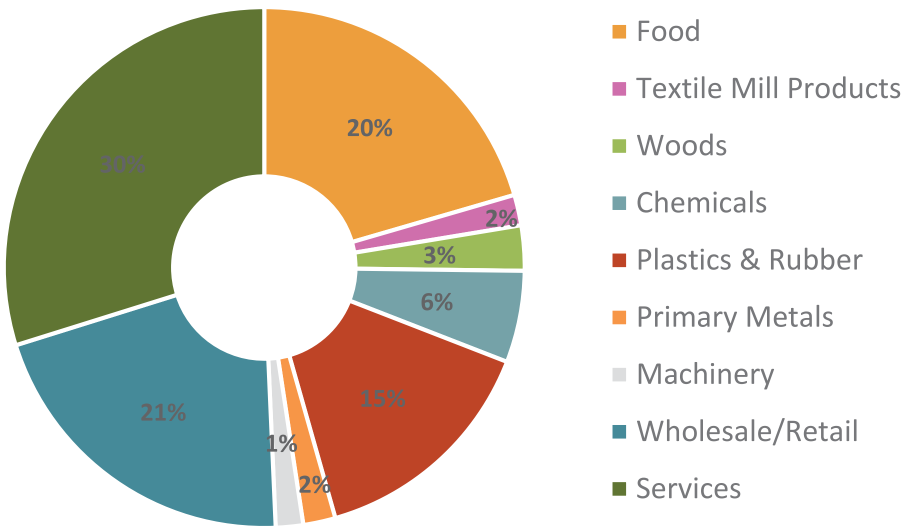
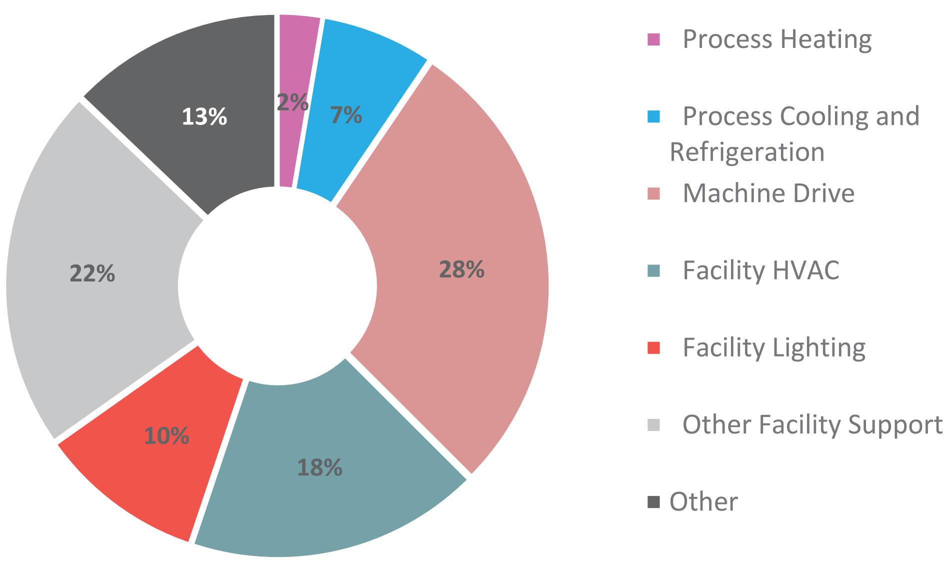


Figure 3-7 provides a breakdown of the industrial electric sales end use. Machine Drive (28%) and Facility HVAC (18%) are the leading end-uses.

FIGURE 3-7 INDUSTRIAL ELECTRIC END-USE BREAKDOWN



[28] "Wholesale/Retail" and "Services" industrial types include industrial buildings that devote a minority percentage of floor space to commercial activities like wholesale and retail trade, and construction, healthcare, education and accommodation & food service. Automotive related industries are divided between plastics, rubber, and machinery based on their NAICS codes.

4 Residential Energy Efficiency Potential

This section provides the potential results for technical, economic, MAP and RAP for the residential sector. Results are broken down by fuel type as well as end use. The cost-effectiveness results and budgets for the RAP scenario are also provided.

4.1 SCOPE OF MEASURES & END USES ANALYZED

There were 185 total unique electric measures included in the analysis. Table 4-1 provides the number of measures by end-use and fuel type (the full list of residential measures is provided in Appendix B). The measure list was developed based on a review of current Vectren programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 4-1 RESIDENTIAL ENERGY EFFICIENCY MEASURES – BY END USE AND FUEL TYPE

End-Use	Number of Unique Measures
Appliances	26
Audit	6
Behavioral	9
HVAC Equipment	41
Lighting	15
Miscellaneous	6
New Construction	4
Plug Loads	9
HVAC Shell	55
Water Heating	14

4.2 RESIDENTIAL ELECTRIC POTENTIAL

Figure 4-1 provides the technical, economic, MAP and RAP results for the 6-year, 10-year, and 20-year timeframes. The 6-year technical potential is 35.0% of forecasted sales, and the economic potential is 32.3% of forecasted sales. The 6-year MAP is 24.0% and the RAP is 12.5%.

FIGURE 4-1 RESIDENTIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF RESIDENTIAL SALES)

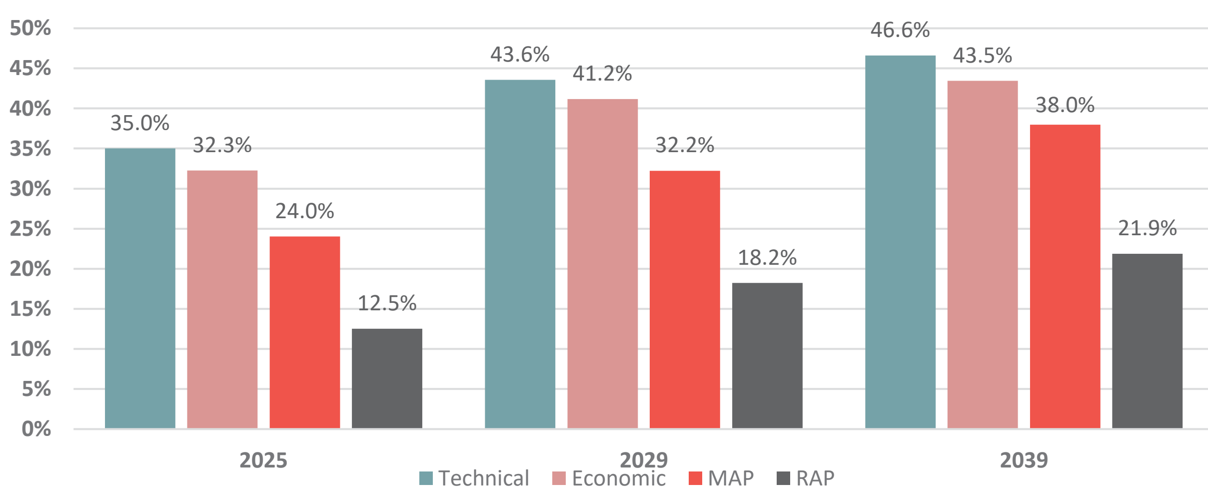


Table 4-2 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The RAP increases to more than 12% cumulative annual savings over the next six years.

TABLE 4-2 RESIDENTIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2020	2021	2022	2023	2024	2025
MWh						
Technical	114,516	242,109	325,265	410,315	460,483	515,889
Economic	106,549	222,594	297,135	376,090	422,227	475,305
MAP	53,840	136,061	192,386	253,741	306,917	353,855
RAP	41,177	84,538	105,533	134,072	159,025	184,648
Forecasted Sales	1,443,774	1,444,794	1,451,508	1,458,672	1,469,169	1,473,649
Energy Savings (as % of Forecast)						
Technical	7.9%	16.8%	22.4%	28.1%	31.3%	35.0%
Economic	7.4%	15.4%	20.5%	25.8%	28.7%	32.3%
MAP	3.7%	9.4%	13.3%	17.4%	20.9%	24.0%
RAP	2.9%	5.9%	7.3%	9.2%	10.8%	12.5%

Table 4-3 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 2.6% to 3.5% per year over the next six years.

TABLE 4-3 RESIDENTIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2020	2021	2022	2023	2024	2025
MWh						
Technical	114,516	136,960	120,797	111,329	99,306	86,829
Economic	106,549	124,856	110,653	103,092	92,493	81,164
MAP	53,840	90,090	82,609	79,096	75,741	68,596
RAP	41,177	50,889	44,349	42,814	42,014	38,952
Forecasted Sales	1,443,774	1,444,794	1,451,508	1,458,672	1,469,169	1,473,649
Energy Savings (as % of Forecast)						
Technical	7.9%	9.5%	8.3%	7.6%	6.8%	5.9%
Economic	7.4%	8.6%	7.6%	7.1%	6.3%	5.5%
MAP	3.7%	6.2%	5.7%	5.4%	5.2%	4.7%
RAP	2.9%	3.5%	3.1%	2.9%	2.9%	2.6%

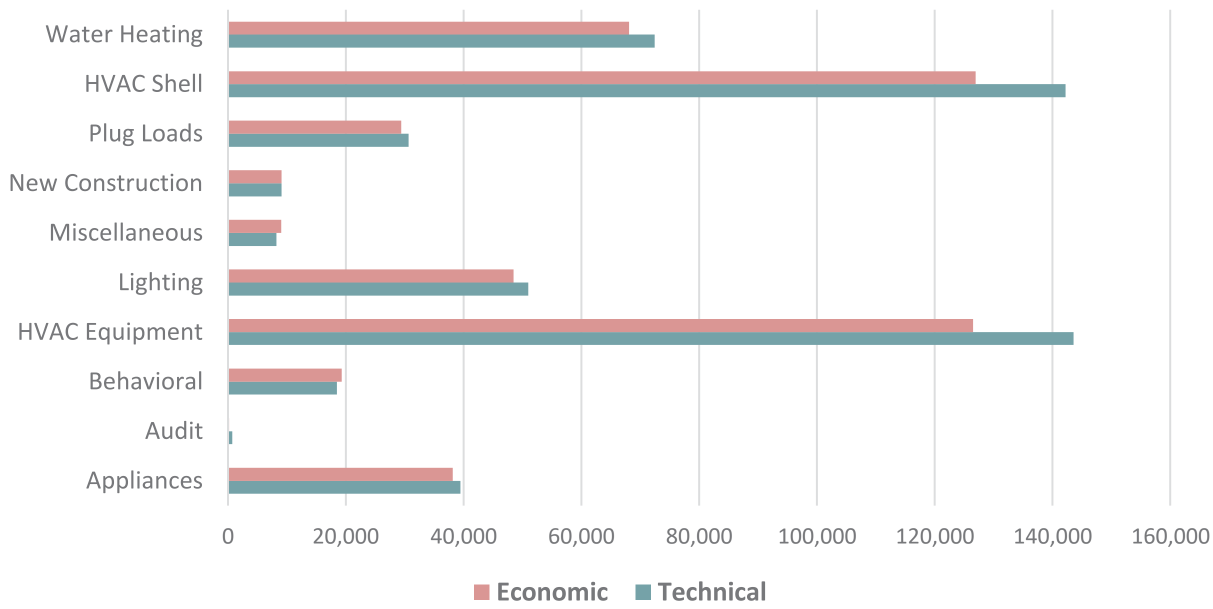
Technical & Economic Potential

Table 4-4 provides cumulative annual technical and economic potential results from 2020-2025. Figure 4-2 shows a comparison of the technical and economic potential (6-year) by end use. The HVAC Shell and HVAC Equipment are by far the leading end-uses among technical and economic potential.

TABLE 4-4 TECHNICAL AND ECONOMIC RESIDENTIAL ELECTRIC POTENTIAL

	2020	2021	2022	2023	2024	2025
Energy (MWh)						
Technical	114,516	242,109	325,265	410,315	460,483	515,889
Economic	106,549	222,594	297,135	376,090	422,227	475,305
Peak Demand (MW)						
Technical	18.9	39.3	55.4	70.1	80.0	90.1
Economic	16.7	34.2	48.2	61.1	70.1	79.3

FIGURE 4-2 6-YEAR TECHNICAL AND ECONOMIC RESIDENTIAL ELECTRIC POTENTIAL – BY END-USE



Maximum Achievable Potential

Figure 4-3 illustrates the cumulative annual MAP results by end use across the 2020-2025 timeframe. Like technical and economic potential, HVAC Shell and HVAC Equipment are the leading end uses. Water Heating, Lighting and Appliances also have significant maximum achievable potential.

FIGURE 4-3 RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) MAP POTENTIAL BY END-USE

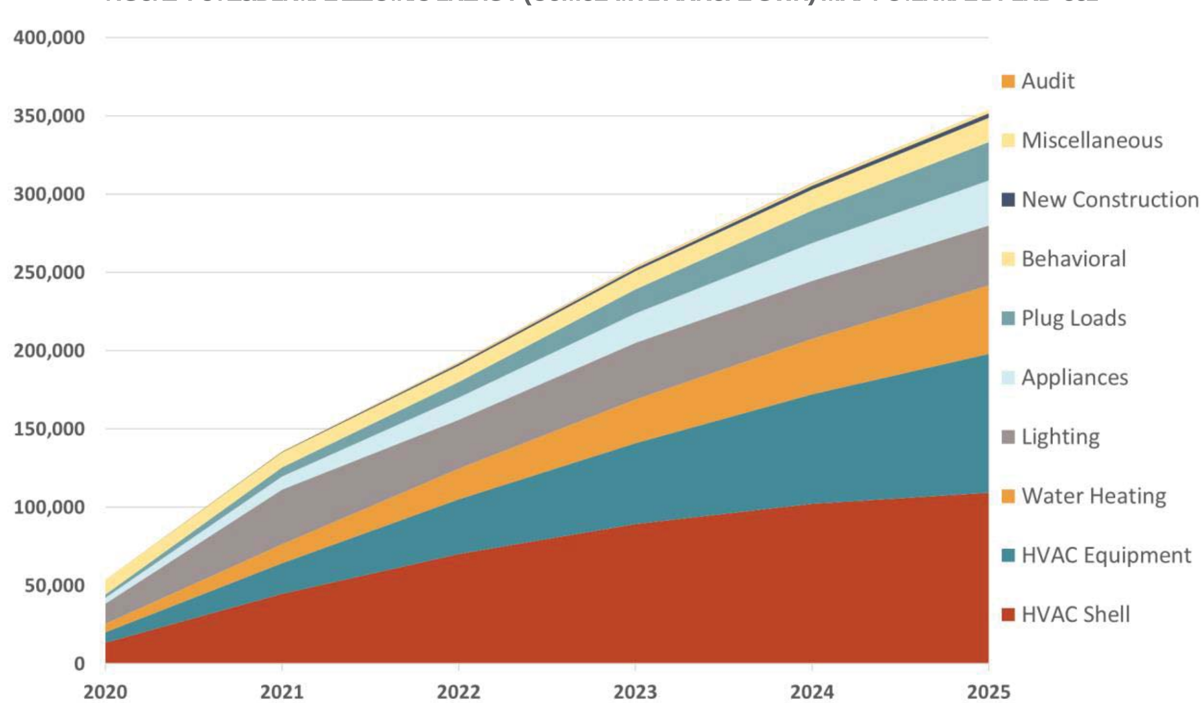


Table 4-5 provides the incremental and cumulative annual MAP across the 2020-2025 timeframe. The incremental MAP potential peaks in 2021 and declines slightly from 2022-2025 as the EISA backstop provision reduces lighting potential and the HVAC Shell end use declines after much of the retrofit measures have been exhausted quickly in the MAP scenario.

TABLE 4-5 RESIDENTIAL ELECTRIC MAP BY END-USE

End Use	2020	2021	2022	2023	2024	2025
Incremental Annual MWh						
Appliances	3,722	4,817	5,313	5,351	5,133	4,722
Audit	61	119	146	167	180	187
Behavioral[29]	9,042	8,056	8,175	8,344	8,597	9,884
HVAC Equipment	6,596	13,003	15,440	17,537	18,995	19,707
Lighting	13,134	21,487	13,717	11,990	10,085	6,389
Miscellaneous[30]	161	215	278	348	421	490
New Construction	255	345	473	587	677	849
Plug Loads	2,023	3,604	4,433	5,085	6,946	6,181
HVAC Shell	13,402	31,486	26,946	21,471	16,065	11,427
Water Heating	5,444	6,957	7,689	8,217	8,642	8,759
Total	**53,840**	**90,090**	**82,609**	**79,096**	**75,741**	**68,596**
% of Forecasted Sales	**3.7%**	**6.2%**	**5.7%**	**5.4%**	**5.2%**	**4.7%**
Incremental Annual MW						
Total	7.4	12.7	12.0	11.4	10.9	10.2
% of Forecasted Demand	1.7%	2.9%	2.7%	2.6%	2.4%	2.3%
Cumulative Annual MWh[31]						
Appliances	3,722	8,540	13,780	19,046	24,047	28,656
Audit	61	119	146	167	180	187
Behavioral	9,042	9,526	10,557	11,781	13,440	15,404
HVAC Equipment	6,596	19,544	34,785	51,794	70,076	88,670
Lighting	13,134	34,830	31,327	36,243	36,889	38,538
Miscellaneous	161	376	655	1,003	1,423	1,914
New Construction	255	600	1,072	1,659	2,337	3,186
Plug Loads	2,023	5,626	10,059	15,144	20,912	24,448
HVAC Shell	13,402	44,560	70,192	89,281	102,002	109,345
Water Heating	5,444	12,339	19,814	27,624	35,612	43,506
Total	**53,840**	**136,061**	**192,386**	**253,741**	**306,917**	**353,855**
% of Forecasted Sales	**3.7%**	**9.4%**	**13.3%**	**17.4%**	**20.9%**	**24.0%**
Cumulative Annual MW						
Total	7.4	19.1	28.6	37.7	45.7	53.0
% of Forecasted Demand	1.7%	4.3%	6.4%	8.4%	10.2%	11.7%

Realistic Achievable Potential

Figure 4-4 illustrates the cumulative annual RAP results by end use across the 2020-2025 timeframe. Like maximum achievable potential, HVAC Shell and HVAC Equipment are the leading end uses. Water Heating, Lighting and Appliances also have significant realistic achievable potential.

[29] The behavioral end-use includes home energy reports and home energy management systems (HEMs).
[30] Miscellaneous consists of pool heater, efficient pool pumps, motors and timers, and well pumps.
[31] Audit measures and most Behavioral measures have a one-year assumed measure life. For this reason, Audit savings are the same for both incremental and cumulative annual, and there is only a minor difference between incremental and cumulative annual savings for Behavioral measures.

FIGURE 4-4 RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) RAP POTENTIAL BY END-USE

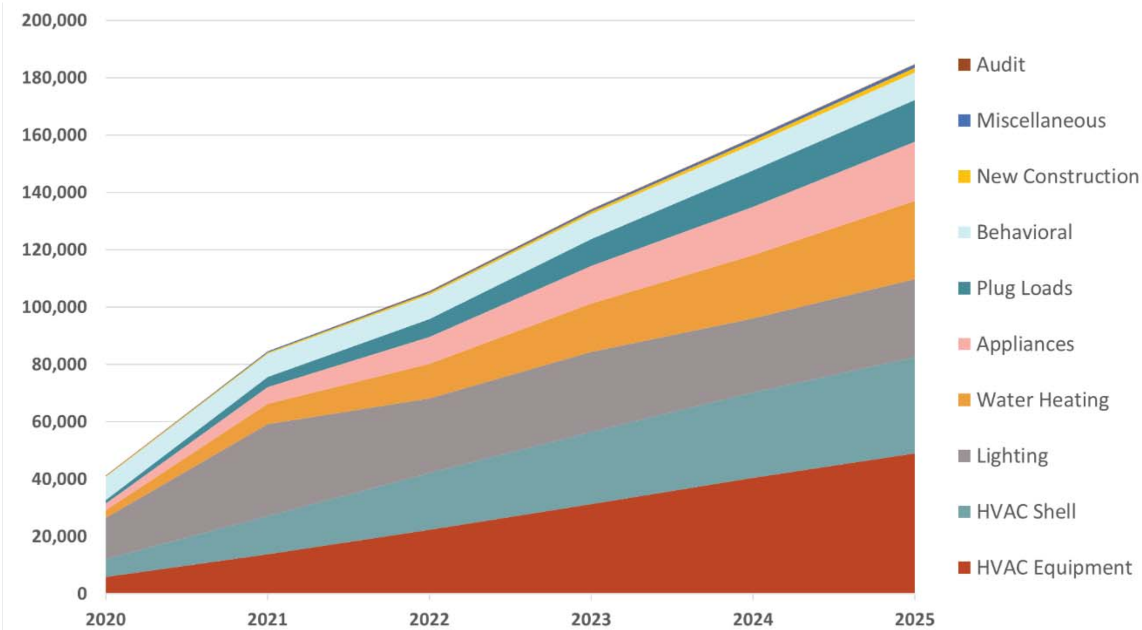


Table 4-6 provides the incremental and cumulative annual RAP across the 2020-2025 timeframe. Lighting and behavioral savings are leading end-uses of incremental RAP in the early years, and HVAC Shell, HVAC Equipment, and Water Heating increase throughout the six-year timeframe.

TABLE 4-6 RESIDENTIAL ELECTRIC RAP BY END-USE

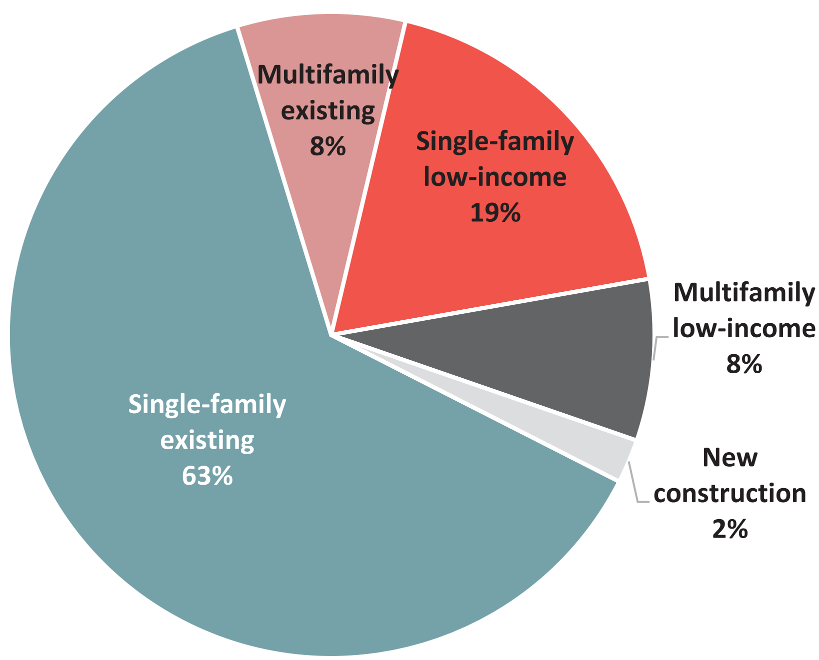
End Use	2020	2021	2022	2023	2024	2025
Incremental Annual MWh						
Appliances	2,364	3,363	3,692	3,844	3,902	3,794
Audit	39	78	93	108	121	131
Behavioral[32]	8,061	7,657	7,661	7,651	7,698	8,093
HVAC Equipment	5,848	7,985	8,594	9,039	9,321	9,579
Lighting	14,292	17,399	9,794	7,875	6,298	3,575
Miscellaneous[33]	128	153	176	200	226	252
New Construction	184	209	244	263	272	314
Plug Loads	1,267	2,394	2,688	2,922	3,799	3,433
HVAC Shell	6,246	7,198	6,529	5,752	4,960	4,234
Water Heating	2,748	4,454	4,880	5,160	5,417	5,547
Total	**41,177**	**50,889**	**44,349**	**42,814**	**42,014**	**38,952**
% of Forecasted Sales	**2.9%**	**3.5%**	**3.1%**	**2.9%**	**2.9%**	**2.6%**
Incremental Annual MW						
Total	5.5	6.9	6.5	6.4	6.3	6.1
% of Forecasted Demand	1.2%	1.6%	1.5%	1.4%	1.4%	1.3%

[32] The behavioral end-use includes home energy reports and home energy management systems (HEMs).
[33] Miscellaneous consists of pool heater, efficient pool pumps, motors and timers, and well pumps.

End Use	2020	2021	2022	2023	2024	2025
Cumulative Annual MWh[34]						
Appliances	2,364	5,727	9,388	13,177	16,990	20,708
Audit	39	78	93	108	121	131
Behavioral	8,061	8,159	8,496	8,768	9,179	9,711
HVAC Equipment	5,848	13,820	22,375	31,268	40,402	49,002
Lighting	14,292	31,875	26,081	27,825	25,847	27,162
Miscellaneous	128	281	456	657	882	1,135
New Construction	184	393	636	899	1,171	1,485
Plug Loads	1,267	3,661	6,349	9,270	12,634	14,534
HVAC Shell	6,246	13,364	19,709	25,173	29,755	33,555
Water Heating	2,748	7,180	11,950	16,926	22,045	27,226
Total	**41,177**	**84,538**	**105,533**	**134,072**	**159,025**	**184,648**
% of Forecasted Sales	**2.9%**	**5.9%**	**7.3%**	**9.2%**	**10.8%**	**12.5%**
Cumulative Annual MW						
Total	5.5	11.5	15.8	20.4	24.8	28.9
% of Forecasted Demand	1.2%	2.6%	3.6%	4.6%	5.5%	6.4%

Figure 4-5 illustrates a market segmentation of the RAP in the residential sector by 2025. Nearly two-thirds of the RAP is associated with single-family existing homes that are not low-income, whereas the total low-income potential is nearly 30% of the RAP.[35]

FIGURE 4-5 2025 RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL) RAP POTENTIAL BY MARKET SEGMENT



[34] Audit measures and most Behavioral measures have a one-year assumed measure life. For this reason, Audit savings are the same for both incremental and cumulative annual, and there is only a minor difference between incremental and cumulative annual savings for Behavioral measures.
[35] The low-income measures in the RAP analysis did not have to pass the UCT.

RAP Benefits & Costs

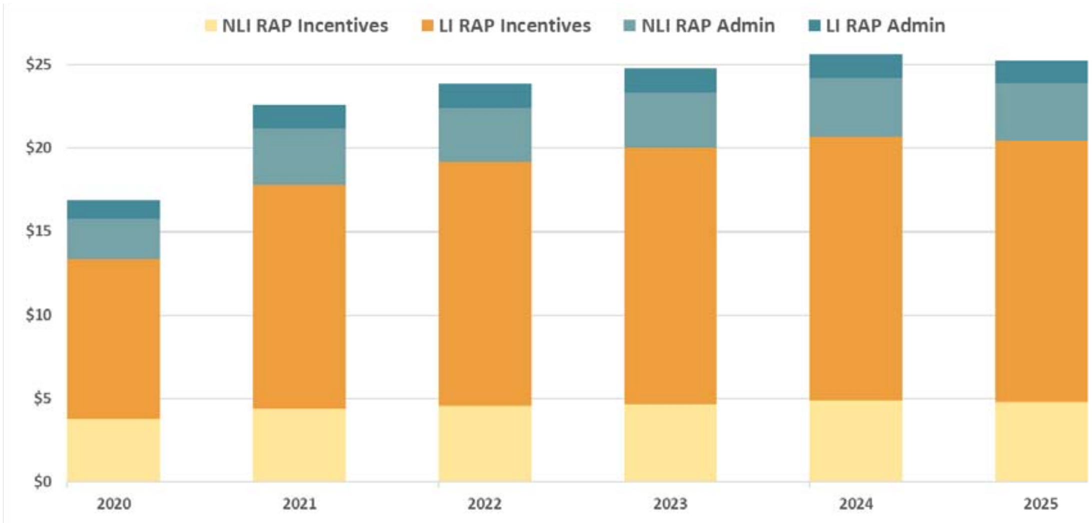
Table 4-7 provides the net present value benefits and cost, as calculated using the UCT, across the 2020-2025 timeframe for the RAP scenario. The overall UCT ratio is 1.1. However, if low-income measures were removed, the overall UCT ratio would be nearly 2.0.

TABLE 4-7 RESIDENTIAL NPV BENEFITS & COSTS RAP BY END-USE ($ IN MILLIONS)

End Use	NPV Benefits	NPV Costs	UCT Ratio
Overall Results			
Appliances	$24.8	$24.1	1.03
Audit	$0.1	$2.8	0.04
Behavioral	$10.9	$5.1	2.14
HVAC Equipment	$88.5	$107.3	0.82
Lighting	$27.3	$11.7	2.33
Miscellaneous	$5.1	$1.3	3.95
New Construction	$3.1	$0.7	4.11
Plug Loads	$12.8	$11.2	1.15
HVAC Shell	$42.0	$52.8	0.80
Water Heating	$36.7	$17.8	2.06
Total	$251.3	$234.8	1.07
Excluding Low-Income			
Appliances	$18.0	$10.0	1.80
Audit	$0.0	$0.0	0.00
Behavioral	$10.9	$5.1	2.14
HVAC Equipment	$62.8	$27.4	2.29
Lighting	$25.4	$10.4	2.44
Miscellaneous	$5.1	$1.3	3.95
New Construction	$3.1	$0.7	4.11
Plug Loads	$12.6	$9.8	1.29
HVAC Shell	$17.2	$13.8	1.25
Water Heating	$34.5	$17.0	2.02
Total	$189.5	$95.4	1.99

Figure 4-6 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2020-2025 timeframe. These budgets are further divided into low-income ("LI") and not low-income ("NLI") components. The low-income incentive portion of the budget ranges from 57% to 62% of the total budget from 2020 to 2025. RAP budgets rise to about $25 million after four years.

FIGURE 4-6 ANNUAL BUDGETS FOR RESIDENTIAL RAP ($ IN MILLIONS)



5 Commercial Energy Efficiency Potential

This section provides the potential results for technical, economic, MAP and RAP for the commercial sector. Results are broken down by end use. The cost-effectiveness results and budgets for the RAP scenario are also provided.

5.1 SCOPE OF MEASURES & END USES ANALYZED

There were 222 total electric measures included in the analysis. Table 5-1 provides the number of measures by end-use and fuel type (the full list of commercial measures is provided in Appendix C). The measure list was developed based on a review of current Vectren programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 5-1 COMMERCIAL ENERGY EFFICIENCY MEASURES – BY FUEL TYPE

End-Use	Number of Unique Measures
Space Heating	32
Cooling	76
Ventilation	8
Water Heating	14
Lighting	26
Cooking	7
Refrigeration	23
Office Equipment	14
Behavioral	3
Other	19

5.2 COMMERCIAL ELECTRIC POTENTIAL

Figure 5-1 provides the technical, economic, MAP and RAP results for the 6-year, 10-year, and 20-year timeframes. The 6-year technical potential is 22.1% of forecasted sales, and the economic potential is 20.0% of forecasted sales. The 6-year MAP is 14.8% and the RAP is 6.3%.

FIGURE 5-1 COMMERCIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF COMMERCIAL SALES)

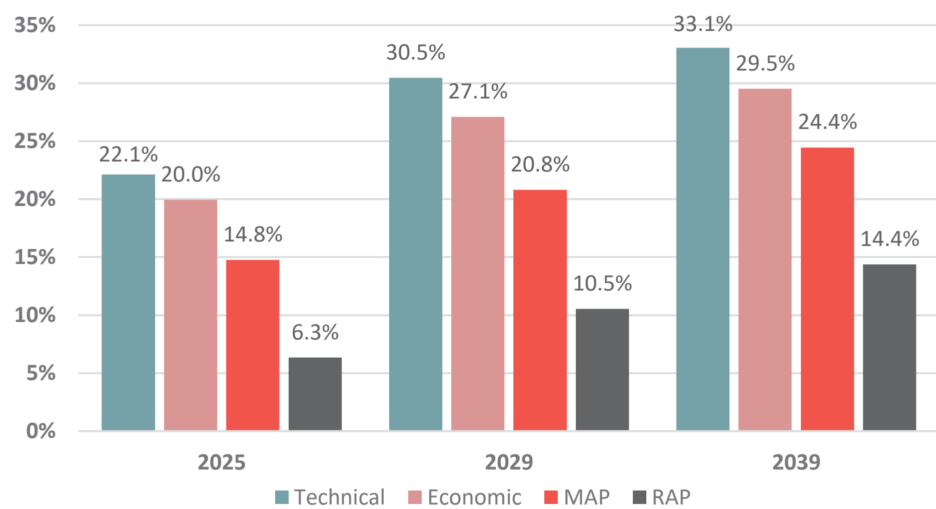


Table 5-2 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The RAP reaches 6.3% after six years.

TABLE 5-2 COMMERCIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2020	2021	2022	2023	2024	2025
MWh						
Technical	44,537	90,258	139,200	189,608	237,091	280,925
Economic	41,327	83,264	127,773	173,145	215,118	253,284
MAP	26,345	55,895	88,639	123,072	156,473	187,460
RAP	10,311	21,974	35,168	49,609	64,869	80,454
Forecasted Sales	1,235,560	1,237,950	1,244,360	1,251,998	1,263,383	1,269,201
Energy Savings (as % of Forecast)						
Technical	3.6%	7.3%	11.2%	15.1%	18.8%	22.1%
Economic	3.3%	6.7%	10.3%	13.8%	17.0%	20.0%
MAP	2.1%	4.5%	7.1%	9.8%	12.4%	14.8%
RAP	0.8%	1.8%	2.8%	4.0%	5.1%	6.3%

Table 5-3 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 0.8% to 1.4% per year over the next six years.

TABLE 5-3 COMMERCIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2020	2021	2022	2023	2024	2025
MWh						
Technical	44,537	48,599	52,397	54,755	54,631	55,436
Economic	41,327	44,816	47,926	49,670	49,022	49,453
MAP	26,345	30,503	34,404	37,095	37,636	38,255
RAP	10,311	12,122	13,911	15,609	16,770	17,811
Forecasted Sales	1,235,560	1,237,950	1,244,360	1,251,998	1,263,383	1,269,201
Energy Savings (as % of Forecast)						
Technical	3.6%	3.9%	4.2%	4.4%	4.3%	4.4%
Economic	3.3%	3.6%	3.9%	4.0%	3.9%	3.9%
MAP	2.1%	2.5%	2.8%	3.0%	3.0%	3.0%
RAP	0.8%	1.0%	1.1%	1.2%	1.3%	1.4%

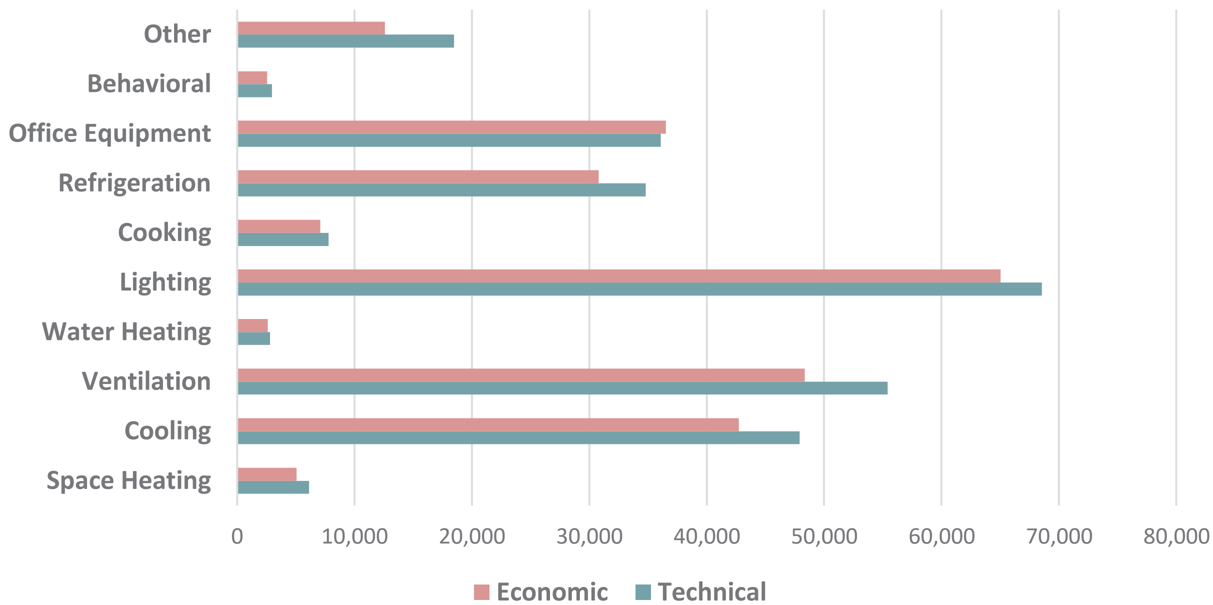
Technical & Economic Potential

Table 5-4 provides cumulative annual technical and economic potential results from 2020-2025. Figure 5-2 shows a comparison of the technical and economic potential (6-year) by end use. Lighting, Ventilation, and Cooling are the leading stand-alone end uses among technical and economic potential.

TABLE 5-4 TECHNICAL & ECONOMIC COMMERCIAL ELECTRIC POTENTIAL

	2020	2021	2022	2023	2024	2025
Energy (MWh)						
Technical	44,537	90,258	139,200	189,608	237,091	280,925
Economic	41,327	83,264	127,773	173,145	215,118	253,284
Peak Demand (MW)						
Technical	6	12	18	24	30	35
Economic	4	9	14	19	23	28

FIGURE 5-2 6-YEAR TECHNICAL AND ECONOMIC COMMERCIAL ELECTRIC POTENTIAL – BY END-USE



Maximum Achievable Potential

Figure 5-3 illustrates the cumulative annual MAP results by end use across the 2020-2025 timeframe. Like technical and economic potential, Lighting, Ventilation, and Cooling are the leading end uses. Refrigeration and Office Equipment also have significant maximum achievable potential.

FIGURE 5-3 COMMERCIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) MAP POTENTIAL BY END-USE

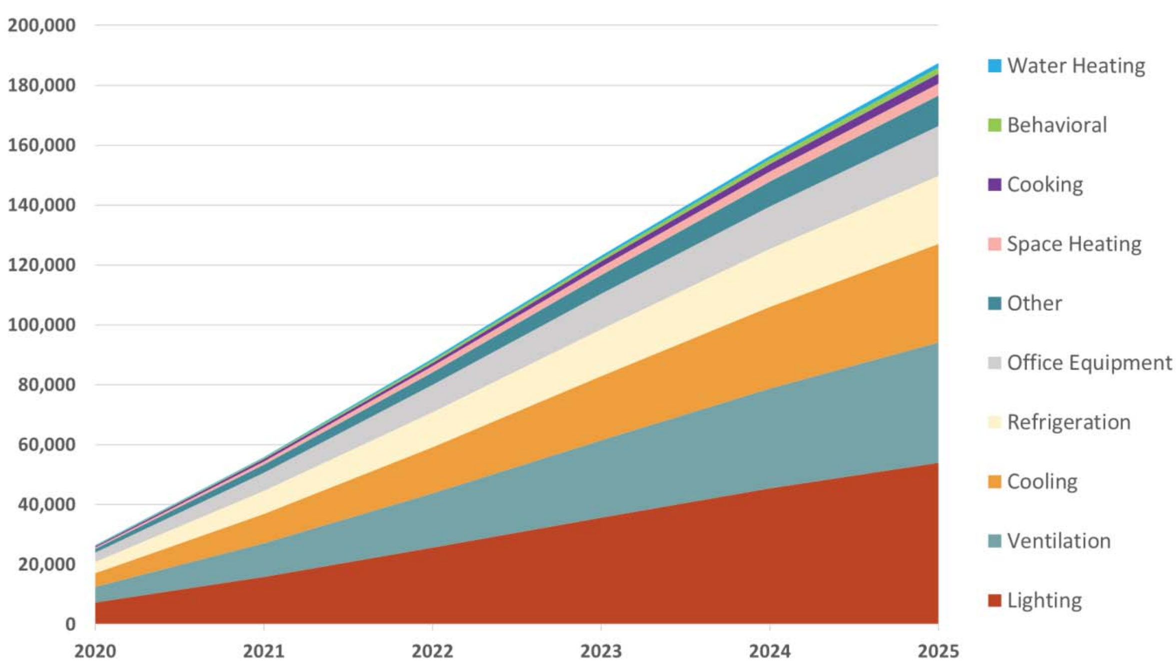


Table 5-5 provides the incremental and cumulative annual MAP across the 2020-2025 timeframe. The incremental MAP ranges from 2.1% to 3.0% of forecasted sales across the six-year timeframe. Cumulative annual MAP rises to 14.8% by 2025.

TABLE 5-5 COMMERCIAL ELECTRIC MAP BY END-USE

End Use	2020	2021	2022	2023	2024	2025
Incremental Annual MWh						
Space Heating	567	663	729	740	699	619
Cooling	4,588	5,218	5,739	6,375	6,441	6,118
Ventilation	5,063	6,071	7,004	7,569	7,496	6,806
Water Heating	140	183	228	268	301	336
Lighting	7,338	8,570	9,628	10,120	9,750	8,608
Cooking	292	390	495	600	696	780
Refrigeration	3,843	4,502	4,993	5,237	5,245	6,009
Office Equipment	3,157	3,002	2,882	2,853	2,956	4,530
Behavioral	201	264	533	676	1,045	1,277
Other	1,156	1,641	2,175	2,657	3,006	3,173
Total	26,345	30,503	34,404	37,095	37,636	38,255
% of Forecasted Sales	2.1%	2.5%	2.8%	3.0%	3.0%	3.0%
Incremental Annual MW						
Total	2.1	2.5	2.9	3.0	3.1	2.9
% of Forecasted Demand	0.7%	0.8%	0.9%	1.0%	1.0%	1.0%
Cumulative Annual MWh						
Space Heating	567	1,230	1,959	2,699	3,398	4,017
Cooling	4,588	9,806	15,545	21,516	27,457	32,979
Ventilation	5,063	11,134	18,138	25,707	33,203	40,009
Water Heating	140	323	551	819	1,120	1,441
Lighting	7,338	15,908	25,535	35,656	45,406	54,014
Cooking	292	683	1,178	1,777	2,474	3,254
Refrigeration	3,843	7,617	11,630	15,621	19,368	22,748
Office Equipment	3,157	6,159	9,040	11,893	14,152	16,551
Behavioral	201	452	769	1,161	1,648	2,219
Other	1,156	2,583	4,294	6,222	8,249	10,228
Total	26,345	55,895	88,639	123,072	156,473	187,460
% of Forecasted Sales	2.1%	4.5%	7.1%	9.8%	12.4%	14.8%
Cumulative Annual MW						
Total	2.1	4.6	7.3	10.3	13.2	16.0
% of Forecasted Demand	0.7%	1.5%	2.4%	3.4%	4.4%	5.3%

Realistic Achievable Potential

Figure 5-4 illustrates the cumulative annual RAP results by end use across the 2020-2025 timeframe. Like maximum achievable potential, Lighting, Ventilation, and Cooling are the leading end uses. Refrigeration and Office Equipment also have significant realistic achievable potential.

FIGURE 5-4 COMMERCIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) RAP POTENTIAL BY END-USE

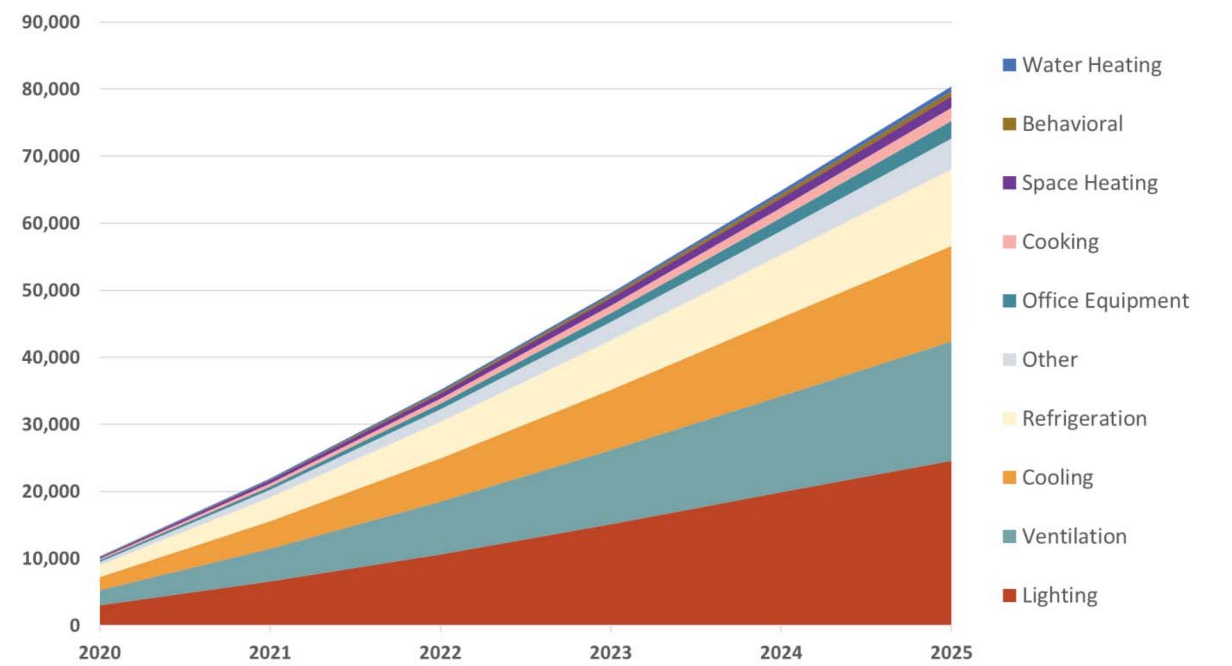


Table 5-6 provides the incremental and cumulative annual RAP across the 2020-2025 timeframe. The incremental RAP ranges from 0.8% to 1.4% of forecasted sales across the six-year timeframe. Cumulative annual RAP rises to 6.3% by 2025.

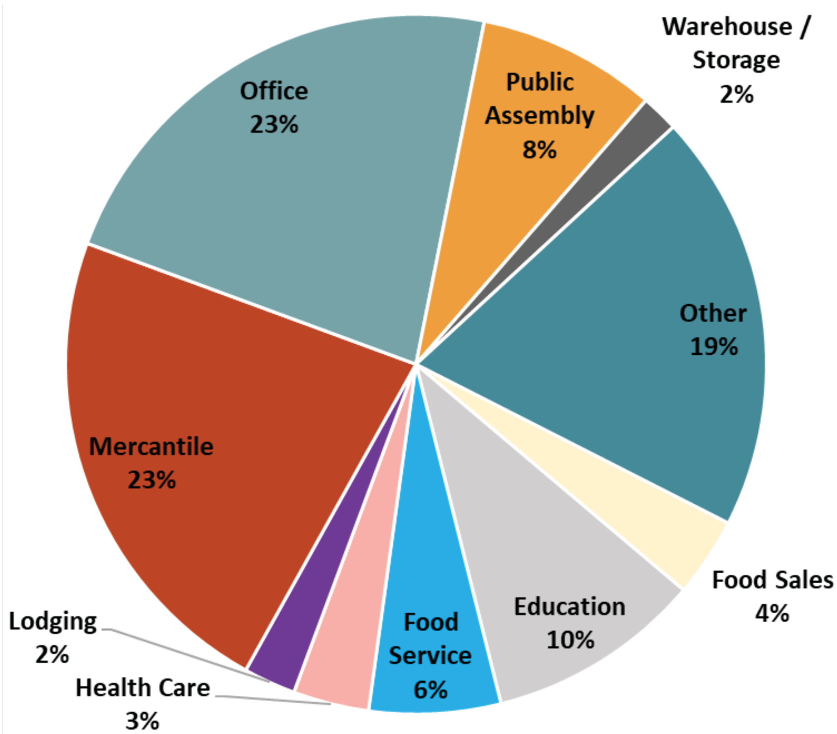
TABLE 5-6 COMMERCIAL ELECTRIC RAP BY END-USE

End Use	2020	2021	2022	2023	2024	2025
Incremental Annual MWh						
Space Heating	240	271	297	311	314	308
Cooling	1,955	2,170	2,379	2,738	2,852	2,874
Ventilation	2,232	2,616	2,951	3,231	3,377	3,387
Water Heating	77	97	117	137	156	180
Lighting	3,016	3,565	4,067	4,470	4,718	4,750
Cooking	198	247	299	352	404	455
Refrigeration	1,809	2,097	2,361	2,574	2,744	3,268
Office Equipment	220	280	364	463	571	701
Behavioral	57	80	169	227	353	456
Other	507	700	907	1,106	1,282	1,433
Total	10,311	12,122	13,911	15,609	16,770	17,811
% of Forecasted Sales	0.8%	1.0%	1.1%	1.2%	1.3%	1.4%
Incremental Annual MW						
Total	0.9	1.0	1.3	1.9	2.9	4.6
% of Forecasted Demand	0.3%	0.3%	0.4%	0.6%	1.0%	1.5%
Cumulative Annual MWh						
Space Heating	240	511	808	1,119	1,433	1,741
Cooling	1,955	4,125	6,504	9,030	11,641	14,251
Ventilation	2,232	4,848	7,799	11,029	14,406	17,793
Water Heating	77	174	291	428	584	756

End Use	2020	2021	2022	2023	2024	2025
Lighting	3,016	6,581	10,648	15,117	19,835	24,585
Cooking	198	444	743	1,095	1,499	1,954
Refrigeration	1,809	3,530	5,407	7,380	9,403	11,423
Office Equipment	220	500	864	1,327	1,898	2,599
Behavioral	57	133	240	381	556	774
Other	507	1,127	1,864	2,702	3,614	4,577
Total	10,311	21,974	35,168	49,609	64,869	80,454
% of Forecasted Sales	0.8%	1.8%	2.8%	4.0%	5.1%	6.3%
Cumulative Annual MW						
Total	0.9	1.9	3.1	4.3	5.7	7.0
% of Forecasted Demand	0.3%	0.6%	1.0%	1.4%	1.9%	2.3%

Figure 5-5 illustrates a market segmentation of the RAP in the commercial sector by 2025. Mercantile, Office, and Education are the leading building types.

FIGURE 5-5 2025 COMMERCIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL) RAP POTENTIAL BY MARKET SEGMENT



RAP Benefits & Costs

Table 5-7 provides the net present value benefits and cost, as calculated using the UCT, across the 2020-2025 timeframe for the RAP scenario. Lighting and Cooking are the most cost-effective end-uses, and Cooling also provides significant NPV benefits.

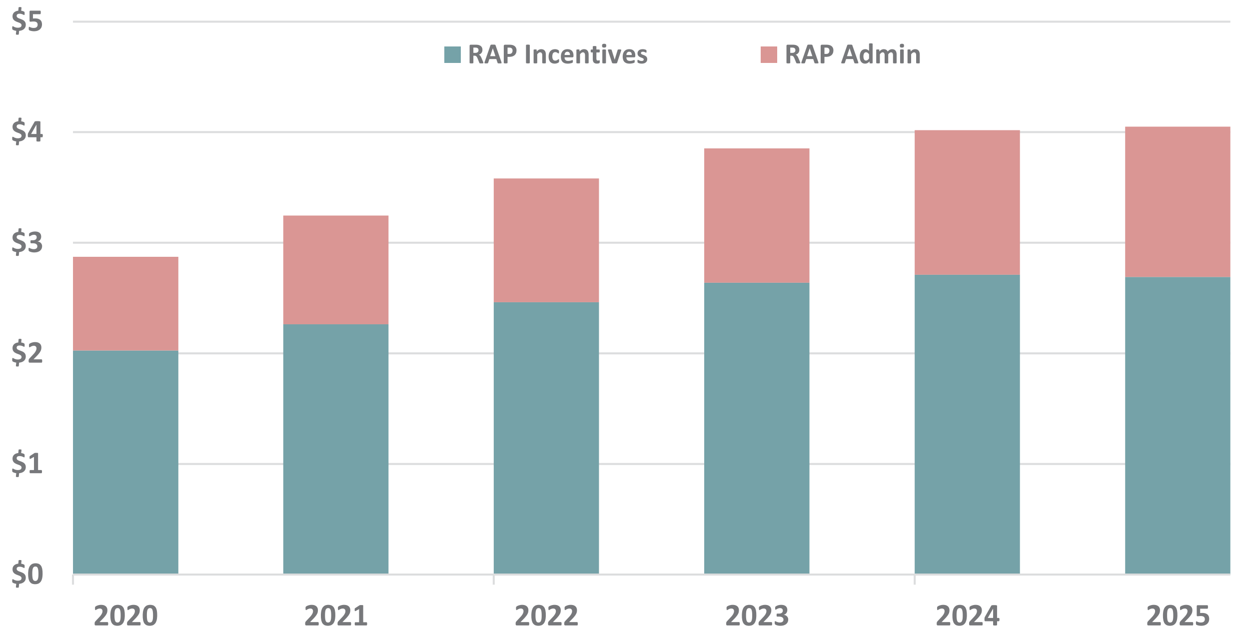
TABLE 5-7 COMMERCIAL NPV BENEFITS & COSTS RAP BY END-USE ($ IN MILLIONS)

End Use	NPV Benefits	NPV Costs	UCT Ratio
Space Heating	$0.62	$1.12	0.55
Cooling	$9.94	$3.09	3.21
Ventilation	$7.94	$5.05	1.57
Water Heating	$0.21	$0.08	2.60

End Use	NPV Benefits	NPV Costs	UCT Ratio
Lighting	$11.03	$6.03	1.83
Cooking	$0.69	$0.34	2.06
Refrigeration	$3.45	$1.33	2.59
Office Equipment	$0.88	$0.48	1.85
Behavioral	$0.11	$0.08	1.33
Other	$1.95	$0.53	3.67
Total	**$36.8**	**$18.1**	**2.03**

Figure 5-6 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2020-2025 timeframe. The incentives rise from $2.0 million to $2.7 million, and overall budgets rise from $2.9 million to $4.1 million by 2025.

FIGURE 5-6 ANNUAL BUDGETS FOR COMMERCIAL RAP ($ IN MILLIONS)



5.3 COMMERCIAL POTENTIAL INCLUDING OPT-OUT CUSTOMERS

Table 5-8 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast, excluding opt-out customers. This is the same information provided in Section 5.2. The cumulative annual energy savings across the 20-year study timeframe are also shown in the far-right column. Table 5-9 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast, including opt-out customers. The cumulative annual energy savings across the 20-year study timeframe are also shown in the far-right column.

The 20-year RAP is 17.8 GWh excluding opt-out customers. This figure rises to 20.0 GWh with opt-out customers included.

TABLE 5-8 COMMERCIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY – EXCLUDING OPT-OUT CUSTOMERS

	2020	2021	2022	2023	2024	2025	2039 (cumulative)
MWh							
Technical	44,537	48,599	52,397	54,755	54,631	55,436	465,610
Economic	41,327	44,816	47,926	49,670	49,022	49,453	415,838
MAP	26,345	30,503	34,404	37,095	37,636	38,255	344,315
RAP	10,311	12,122	13,911	15,609	16,770	17,811	202,365
Forecasted Sales	1,235,560	1,237,950	1,244,360	1,251,998	1,263,383	1,269,201	1,408,342
Technical	3.6%	3.9%	4.2%	4.4%	4.3%	4.4%	33.1%
Economic	3.3%	3.6%	3.9%	4.0%	3.9%	3.9%	29.5%
MAP	2.1%	2.5%	2.8%	3.0%	3.0%	3.0%	24.4%
RAP	0.8%	1.0%	1.1%	1.2%	1.3%	1.4%	14.4%

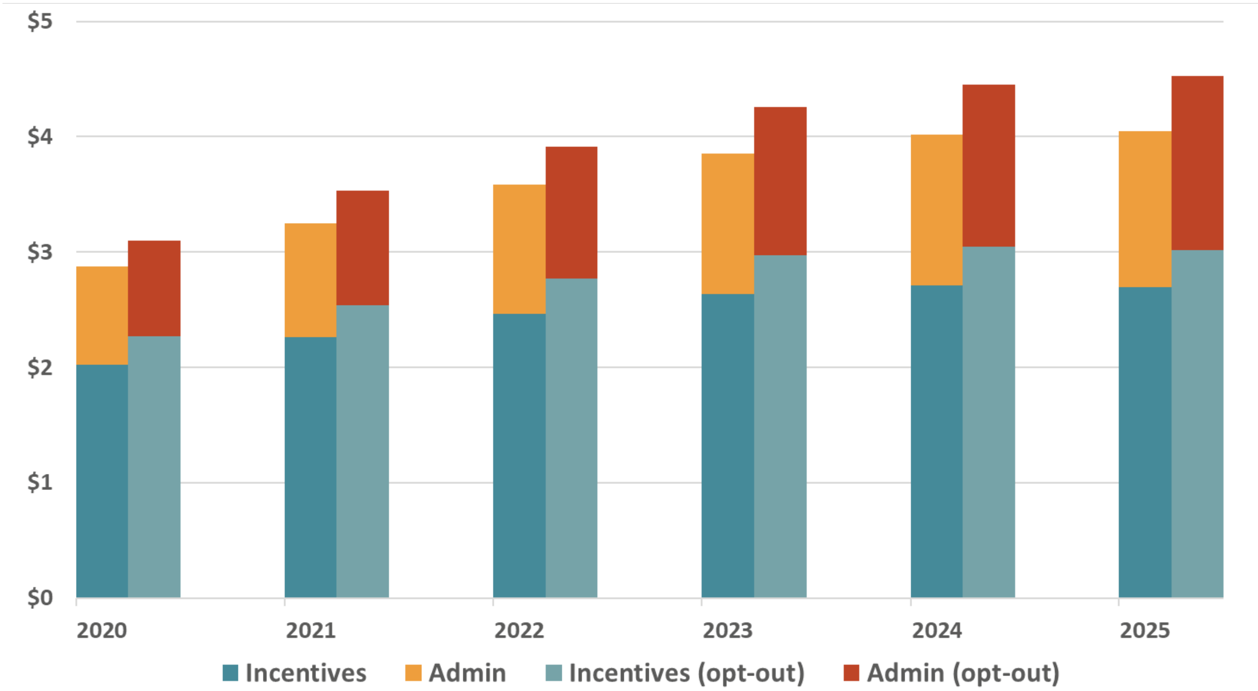
TABLE 5-9 COMMERCIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY – INCLUDING OPT-OUT CUSTOMERS[36]

	2020	2021	2022	2023	2024	2025	2039 (cumulative)
MWh							
Technical	50,170	54,751	59,038	61,705	61,577	62,517	524,715
Economic	46,545	50,469	53,966	55,928	55,202	55,716	468,265
MAP	29,659	34,334	38,719	41,744	42,354	43,062	387,577
RAP	11,578	13,618	15,630	17,541	18,846	20,006	227,568
Forecasted Sales	1,390,224	1,392,929	1,400,166	1,408,787	1,421,633	1,428,202	1,585,207
Technical	3.6%	3.9%	4.2%	4.4%	4.3%	4.4%	33.1%
Economic	3.3%	3.6%	3.9%	4.0%	3.9%	3.9%	29.5%
MAP	2.1%	2.5%	2.8%	3.0%	3.0%	3.0%	24.4%
RAP	0.8%	1.0%	1.1%	1.2%	1.3%	1.4%	14.4%

Figure 5-7 provides the budget for the RAP scenario, with and without opt-out customers. The budget is broken into incentive and admin budgets for each year of the 2020-2025 timeframe. The overall budgets without opt-out customers rise from $2.9 million to $4.1 million by 2025. The budgets with opt-out customers included increase from $3.1 million to $4.5 million by 2025.

[36] Due to limited number of commercial opt-out customers and minor changes in building segmentation, savings as a percentage of sales is negligible out to three decimal places.

FIGURE 5-7 ANNUAL BUDGETS FOR COMMERCIAL RAP ($ IN MILLIONS) – WITH AND WITHOUT OPT-OUT CUSTOMERS



6 Industrial Energy Efficiency Potential

This section provides the potential results for technical, economic, MAP and RAP for the industrial sector. Results are broken down by end use. The cost-effectiveness results and budgets for the RAP scenario are also provided. The results in this section exclude the savings and sales forecast associated with opt-out customers

6.1 SCOPE OF MEASURES & END USES ANALYZED

There were 165 total unique electric measures included in the analysis. Table 6-1 provides number of measures by end-use (the full list of industrial measures is provided in Appendix D). The measure list was developed based on a review of current Vectren programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 6-1 INDUSTRIAL ENERGY EFFICIENCY MEASURES – BY FUEL TYPE

End-Use	Number of Unique Measures
Computers & Office Equipment	6
Water Heating	6
Ventilation	7
Space Cooling	22
Space Heating	16
Cooking	7
Refrigeration	25
Lighting	20
Other	7
Machine Drive	21
Process Heating and Cooling	12
Agriculture	16

6.2 INDUSTRIAL ELECTRIC POTENTIAL

Figure 6-1 provides the technical, economic, MAP and RAP results for the 6-year, 10-year, and 20-year timeframes. The 6-year technical potential is 20.6% of forecasted sales, and the economic potential is 19.3% of forecasted sales. The 6-year MAP is 14.0% and the RAP is 6.7%.

FIGURE 6-1 INDUSTRIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF INDUSTRIAL SALES)

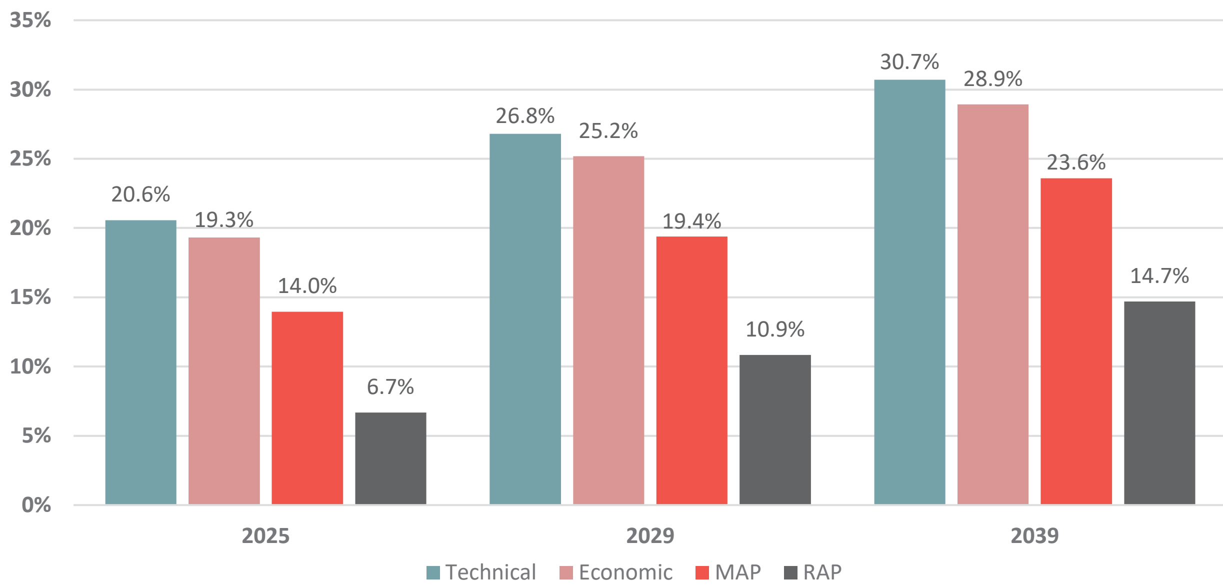


Table 6-2 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The RAP reaches 6.7% after six years.

TABLE 6-2 INDUSTRIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2020	2021	2022	2023	2024	2025
MWh						
Technical	20,939	44,360	69,559	95,219	115,910	133,986
Economic	19,496	41,369	65,048	89,324	108,808	125,853
MAP	11,785	25,996	42,270	59,617	76,091	90,989
RAP	5,517	11,982	19,336	27,377	35,449	43,566
Forecasted Sales	640,023	641,915	644,247	646,702	649,006	651,371
Energy Savings (as % of Forecast)						
Technical	3.3%	6.9%	10.8%	14.7%	17.9%	20.6%
Economic	3.0%	6.4%	10.1%	13.8%	16.8%	19.3%
MAP	1.8%	4.0%	6.6%	9.2%	11.7%	14.0%
RAP	0.9%	1.9%	3.0%	4.2%	5.5%	6.7%

Table 6-3 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 0.9% to 1.6% per year over the next six years.

TABLE 6-3 INDUSTRIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2020	2021	2022	2023	2024	2025
MWh						
Technical	20,939	24,019	26,570	27,937	28,192	27,324
Economic	19,496	22,471	25,050	26,553	26,985	26,293
MAP	11,785	14,679	17,322	19,105	20,003	19,927
RAP	5,517	6,688	7,846	8,854	9,799	10,567
Forecasted Sales	640,023	641,915	644,247	646,702	649,006	651,371
Energy Savings (as % of Forecast)						
Technical	3.3%	3.7%	4.1%	4.3%	4.3%	4.2%
Economic	3.0%	3.5%	3.9%	4.1%	4.2%	4.0%
MAP	1.8%	2.3%	2.7%	3.0%	3.1%	3.1%

	2020	2021	2022	2023	2024	2025
MWh						
RAP	0.9%	1.0%	1.2%	1.4%	1.5%	1.6%

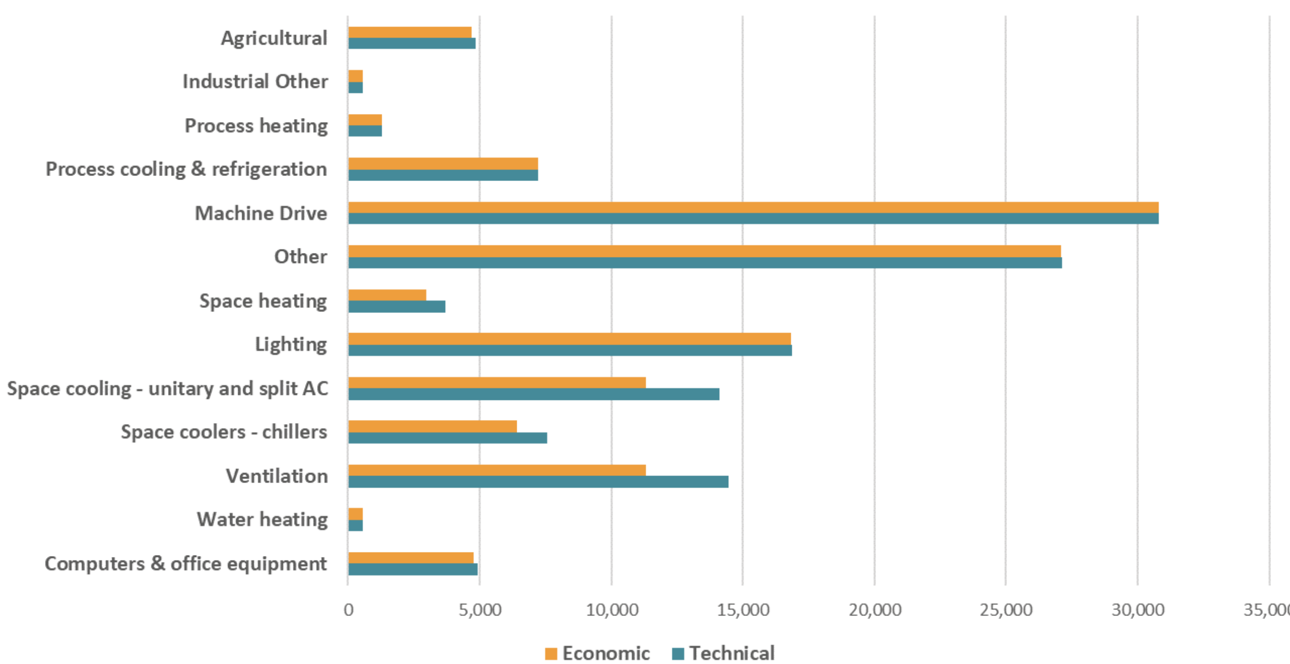
Technical & Economic Potential

Table 6-4 provides cumulative annual technical and economic potential results from 2020-2025. Figure 6-2 shows a comparison of the technical and economic potential (6-year) by end use. Machine drive, Lighting, and Ventilation are the leading stand-alone end uses among technical and economic potential.

TABLE 6-4 TECHNICAL AND ECONOMIC INDUSTRIAL ELECTRIC POTENTIAL

	2020	2021	2022	2023	2024	2025
Energy (MWh)						
Technical	20,939	44,360	69,559	95,219	115,910	133,986
Economic	19,496	41,369	65,048	89,324	108,808	125,853
Peak Demand (MW)						
Technical	5	10	15	21	25	29
Economic	4	9	14	19	24	27

FIGURE 6-2 YEAR TECHNICAL AND ECONOMIC INDUSTRIAL ELECTRIC POTENTIAL – BY END-USE



Maximum Achievable Potential

Figure 6-3 illustrates the cumulative annual MAP results by end use across the 2020-2025 timeframe. Like technical and economic potential, Machine Drive, Lighting, and Ventilation are the leading end uses. Space cooling and process cooling & refrigeration also have significant maximum achievable potential.

FIGURE 6-3 INDUSTRIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) MAP POTENTIAL BY END-USE

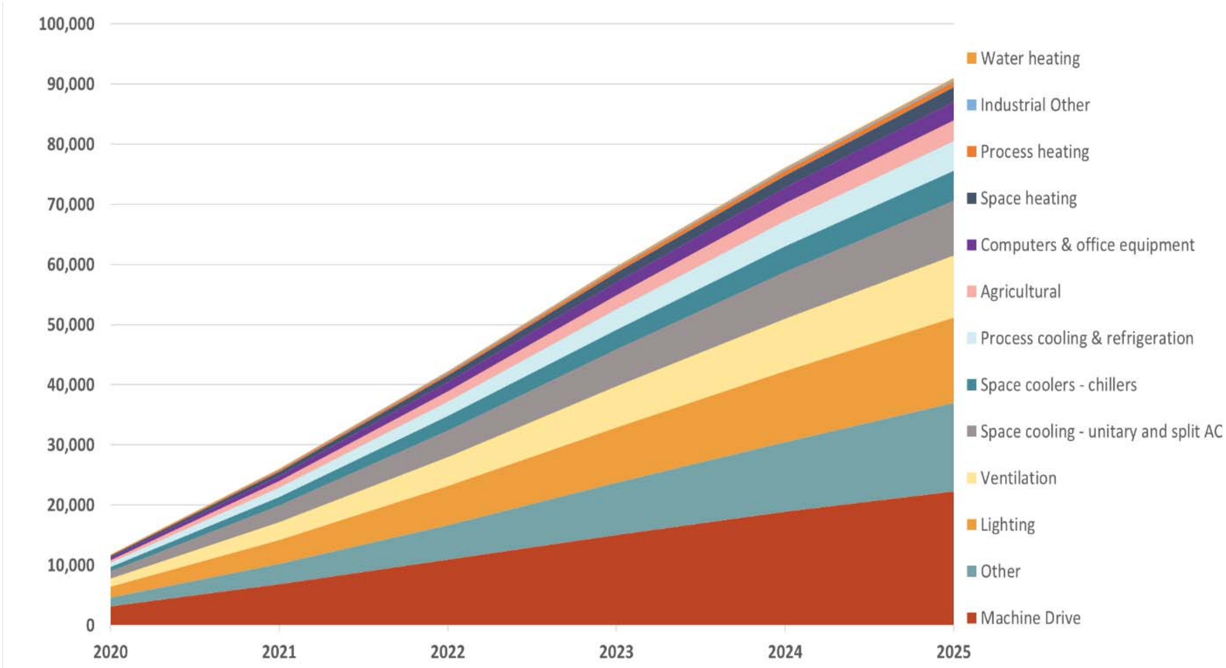


Table 6-5 provides the incremental and cumulative annual MAP across the 2020-2025 timeframe. The incremental MAP ranges from 1.8% to 3.1% of forecasted sales across the six-year timeframe. Cumulative annual MAP rises to 14.0% by 2025.

TABLE 6-5 INDUSTRIAL ELECTRIC MAP BY END-USE

End Use	2020	2021	2022	2023	2024	2025
Incremental Annual MWh						
Computers & office equipment	385	494	596	678	736	867
Water heating	40	41	44	49	55	60
Ventilation	1,311	1,626	1,898	2,011	1,926	1,675
Space coolers - chillers	677	808	912	949	971	886
Space cooling - unitary and split AC	1,271	1,503	1,696	1,768	1,814	1,631
Lighting	1,797	2,238	2,662	2,951	3,008	2,839
Space heating	328	390	444	464	480	435
Other	1,466	1,909	2,391	2,877	3,392	3,930
Machine Drive	3,166	3,928	4,588	5,017	5,150	5,093
Process cooling & refrigeration	681	931	1,165	1,362	1,511	1,617
Process heating	122	169	217	259	290	306
Industrial Other	47	56	64	73	83	93
Agricultural	494	587	644	645	588	495
Total	11,785	14,679	17,322	19,105	20,003	19,927
% of Forecasted Sales	1.8%	2.3%	2.7%	3.0%	3.1%	3.1%
Incremental Annual MW						
Total	3	3	4	4	4	4
% of Forecasted Demand	2.3%	2.8%	3.3%	3.7%	3.8%	3.8%

End Use	2020	2021	2022	2023	2024	2025
Cumulative Annual MWh						
Computers & office equipment	385	878	1,474	2,153	2,630	3,056
Water heating	40	82	126	175	230	288
Ventilation	1,311	2,932	4,819	6,813	8,712	10,350
Space coolers - chillers	677	1,483	2,392	3,335	4,237	4,964
Space cooling - unitary and split AC	1,271	2,760	4,425	6,133	7,727	9,090
Lighting	1,797	3,972	6,492	9,204	11,859	14,223
Space heating	328	715	1,151	1,603	2,029	2,398
Other	1,466	3,374	5,764	8,638	11,542	14,682
Machine Drive	3,166	6,853	10,906	15,038	18,913	22,274
Process cooling & refrigeration	681	1,497	2,405	3,333	4,203	4,961
Process heating	122	271	443	625	801	956
Industrial Other	47	97	148	199	248	296
Agricultural	494	1,081	1,725	2,370	2,958	3,450
Total	11,785	25,996	42,270	59,617	76,091	90,989
% of Forecasted Sales	1.8%	4.0%	6.6%	9.2%	11.7%	14.0%
Cumulative Annual MW						
Total	3	6	9	13	17	20
% of Forecasted Demand	2.3%	5.0%	8.2%	11.6%	14.6%	17.4%

Realistic Achievable Potential

Figure 6-4 illustrates the cumulative annual RAP results by end use across the 2020-2025 timeframe. Like maximum achievable potential, Machine Drive, Lighting, and Ventilation are the leading end uses. Space cooling and process cooling & refrigeration also have significant realistic achievable potential.

FIGURE 6-4 INDUSTRIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) RAP POTENTIAL BY END-USE

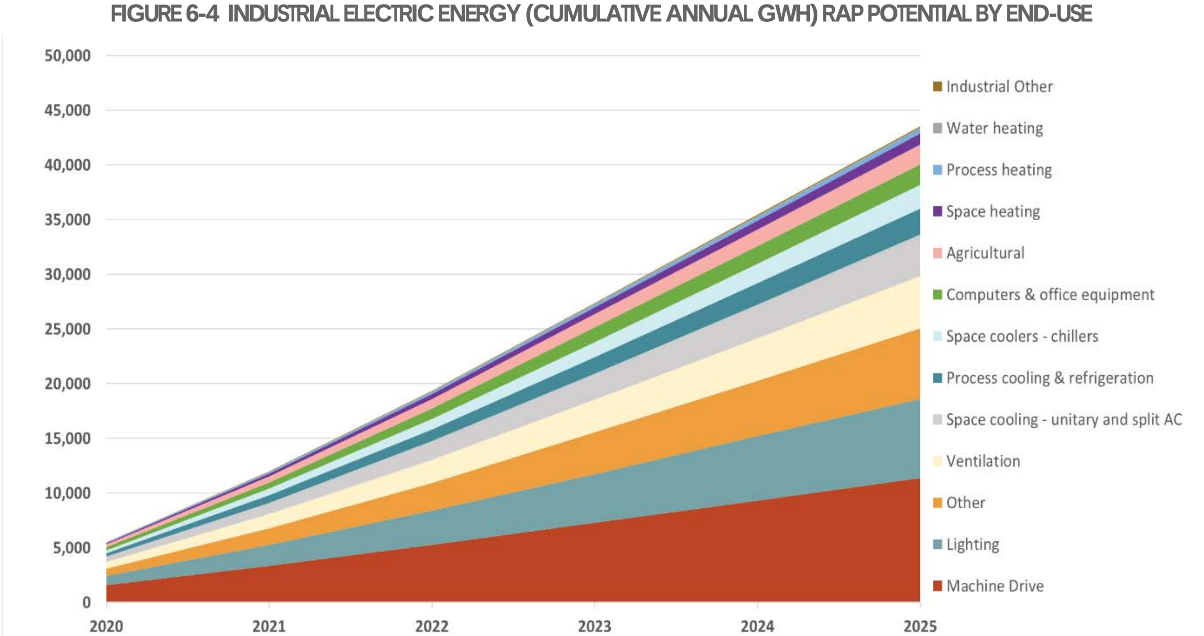


Table 6-6 provides the incremental and cumulative annual RAP across the 2020-2025 timeframe. The incremental RAP ranges from 0.9% to 1.6% of forecasted sales across the six-year timeframe. Cumulative annual RAP rises to 6.7% by 2025.

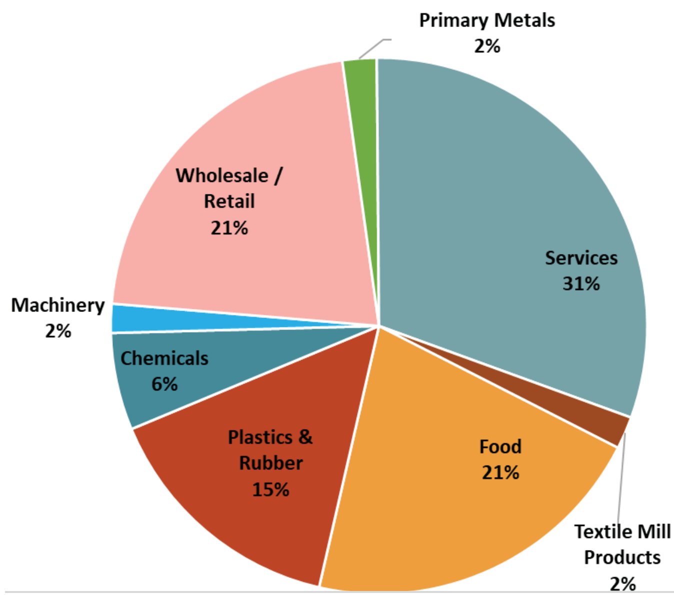
TABLE 6-6 INDUSTRIAL ELECTRIC RAP BY END-USE

End Use	2020	2021	2022	2023	2024	2025
Incremental Annual MWh						
Computers & office equipment	263	316	367	415	457	544
Water heating	9	12	16	20	25	29
Ventilation	599	713	818	883	915	911
Space coolers - chillers	271	323	372	406	453	465
Space cooling - unitary and split AC	477	570	655	711	801	815
Lighting	892	1,083	1,268	1,419	1,532	1,592
Space heating	125	150	173	189	213	218
Other	649	834	1,046	1,269	1,502	1,772
Machine Drive	1,575	1,881	2,183	2,456	2,683	2,888
Process cooling & refrigeration	326	421	517	619	724	826
Process heating	56	75	95	116	136	156
Industrial Other	13	17	23	29	36	44
Agricultural	262	292	312	323	321	307
Total	5,517	6,688	7,846	8,854	9,799	10,567
% of Forecasted Sales	0.9%	1.0%	1.2%	1.4%	1.5%	1.6%
Incremental Annual MW						
Total	1	1	2	2	2	2
% of Forecasted Demand	1.1%	1.3%	1.5%	1.7%	1.9%	2.0%
Cumulative Annual MWh						
Computers & office equipment	263	579	945	1,360	1,623	1,873
Water heating	9	21	37	57	82	110
Ventilation	599	1,311	2,124	3,000	3,904	4,799
Space coolers - chillers	271	593	964	1,367	1,790	2,177
Space cooling - unitary and split AC	477	1,041	1,683	2,372	3,081	3,783
Lighting	892	1,948	3,157	4,478	5,863	7,253
Space heating	125	273	443	627	817	1,007
Other	649	1,484	2,530	3,798	5,051	6,463
Machine Drive	1,575	3,334	5,252	7,275	9,335	11,358
Process cooling & refrigeration	326	694	1,093	1,516	1,948	2,373
Process heating	56	121	195	276	361	445
Industrial Other	13	27	44	63	84	107
Agricultural	262	554	867	1,189	1,511	1,817
Total	5,517	11,982	19,336	27,377	35,449	43,566
% of Forecasted Sales	0.9%	1.9%	3.0%	4.2%	5.5%	6.7%

End Use	2020	2021	2022	2023	2024	2025
Cumulative Annual MW						
Total	1	3	4	6	8	9
% of Forecasted Demand	1.1%	2.3%	3.7%	5.3%	6.8%	8.4%

Figure 6-5 illustrates a market segmentation of the RAP in the industrial sector by 2025. Food, plastics & rubber and chemicals are the leading market segments.

FIGURE 6-5 2025 INDUSTRIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL) RAP POTENTIAL BY MARKET SEGMENT[37]



RAP Benefits & Costs

Table 6-7 provides the net present value benefits and cost, as calculated using the UCT, across the 2020-2025 timeframe for the RAP scenario. Machine Drive is the most cost-effective end-use, and Facility Lighting provides the greatest NPV benefits.

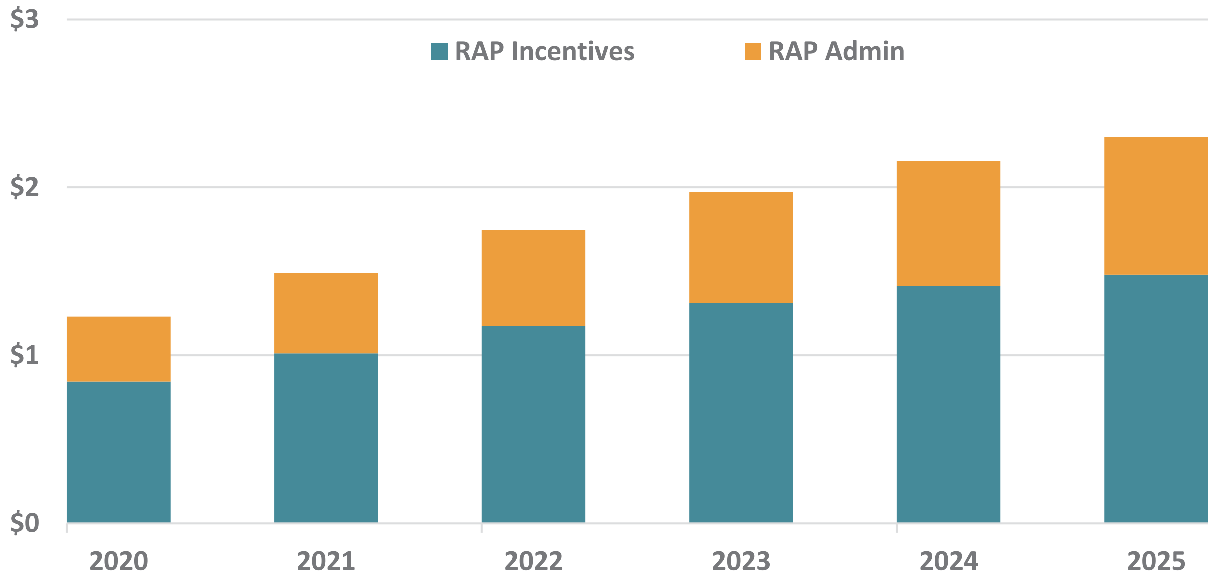
TABLE 6-7 INDUSTRIAL NPV BENEFITS AND COSTS RAP BY END-USE ($ IN MILLIONS)

End Use	NPV Benefits	NPV Costs	UCT Ratio
Machine Drive	$7.4	$1.3	5.90
Facility HVAC	$5.9	$1.4	4.18
Facility Lighting	$9.9	$3.7	2.64
Other Facility Support	$2.9	$1.2	2.45
Process Cooling and Refrigeration	$1.3	$0.4	3.64
Process Heating	$0.2	$0.0	4.59
Other	$3.6	$1.2	3.04
Total	$31.2	$9.2	3.40

[37] "Wholesale/Retail" and "Services" industrial types include industrial buildings that devote a minority percentage of floor space to commercial activities like wholesale and retail trade, and construction, healthcare, education and accommodation & food service. Automotive related industries are divided between plastics, rubber, and machinery based on their NAICS codes.

Figure 6-6 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2020-2025 timeframe. The incentives rise from $0.8 million to $1.5 million, and overall budgets rise from $1.2 million to $2.3 million by 2025.

FIGURE 6-6 ANNUAL BUDGETS FOR INDUSTRIAL RAP ($ IN MILLIONS)



6.3 INDUSTRIAL POTENTIAL INCLUDING OPT-OUT CUSTOMERS

Table 6-8 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast, excluding opt-out customers. This is the same information provided in Section 6.2. The cumulative annual energy savings across the 20-year study timeframe are also shown in the far-right column. Table 6-9 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast, including opt-out customers.[38] The cumulative annual energy savings across the 20-year study timeframe are also shown in the far-right column.

The 20-year RAP is 14.7%, excluding opt-out customers. This figure drops to 13.5%, with opt-out customers included. Though the savings as a percentage of sales decreases, the energy savings of the RAP rises from 100,008 MWh to 334,101 MWh when the opt-out customers are included in the analysis.

TABLE 6-8 INDUSTRIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY – EXCLUDING OPT-OUT CUSTOMERS

	2020	2021	2022	2023	2024	2025	2039 (cumulative)
MWh							
Technical	20,939	24,019	26,570	27,937	28,192	27,324	208,784
Economic	19,496	22,471	25,050	26,553	26,985	26,293	196,720
MAP	11,785	14,679	17,322	19,105	20,003	19,927	160,447
RAP	5,517	6,688	7,846	8,854	9,799	10,567	100,008
Forecasted Sales	640,023	641,915	644,247	646,702	649,006	651,371	679,928
Energy Savings (as % of Forecast)							
Technical	3.3%	3.7%	4.1%	4.3%	4.3%	4.2%	30.7%
Economic	3.0%	3.5%	3.9%	4.1%	4.2%	4.0%	28.9%
MAP	1.8%	2.3%	2.7%	3.0%	3.1%	3.1%	23.6%
RAP	0.9%	1.0%	1.2%	1.4%	1.5%	1.6%	14.7%

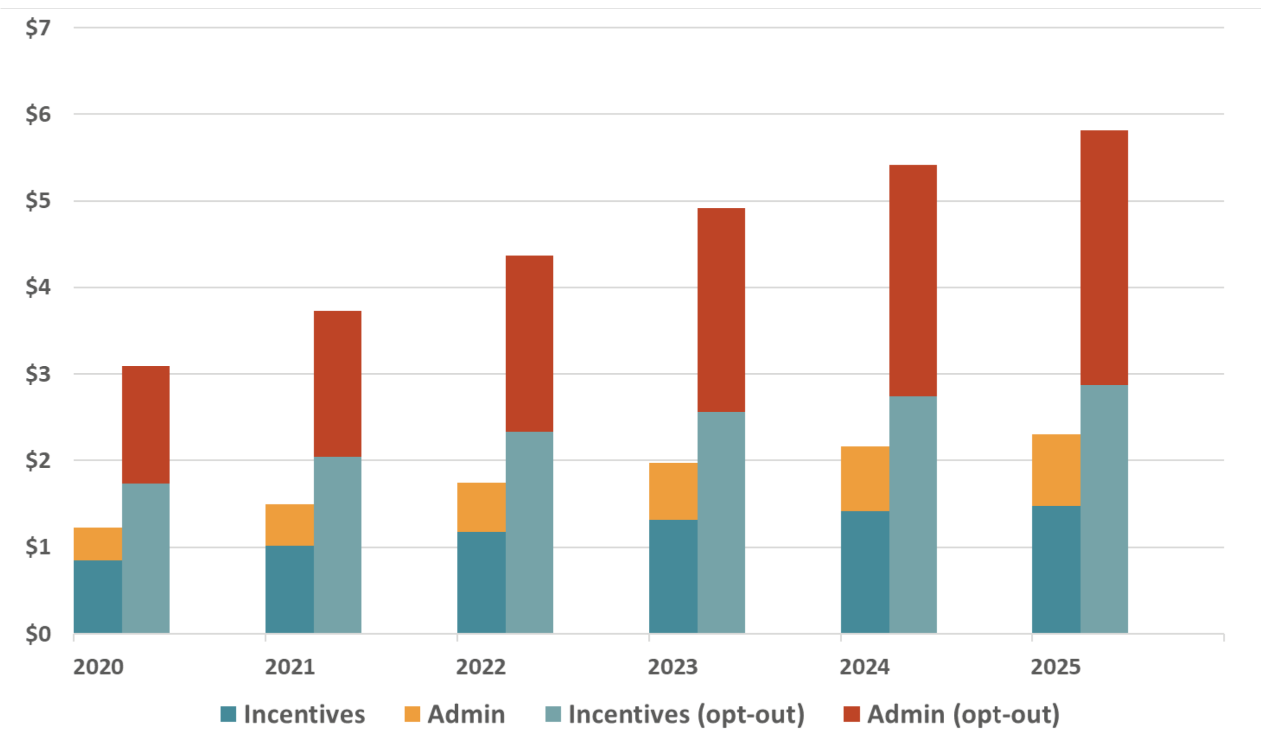
[38] Note the increase in the forecasted sales with opt-out customers included.

TABLE 6-9 INDUSTRIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY – INCLUDING OPT-OUT CUSTOMERS

	2020	2021	2022	2023	2024	2025	2039 (cumulative)
MWh							
Technical	66,750	78,664	89,185	95,702	97,760	95,516	688,359
Economic	63,335	74,992	85,566	92,390	94,842	92,995	659,191
MAP	41,085	51,432	61,105	67,856	71,118	70,784	521,639
RAP	19,324	23,576	27,883	31,695	35,218	38,149	334,101
Forecasted Sales	2,329,890	2,336,776	2,345,264	2,354,201	2,362,591	2,371,200	2,475,157
Energy Savings (as % of Forecast)							
Technical	2.9%	3.4%	3.8%	4.1%	4.1%	4.0%	27.8%
Economic	2.7%	3.2%	3.6%	3.9%	4.0%	3.9%	26.6%
MAP	1.8%	2.2%	2.6%	2.9%	3.0%	3.0%	21.1%
RAP	0.8%	1.0%	1.2%	1.3%	1.5%	1.6%	13.5%

Figure 6-8 provides the budget for the RAP scenario, with and without opt-out customers. The budget is broken into incentive and admin budgets for each year of the 2020-2025 timeframe. The overall budgets without opt-out customers rise from $1.2 million to $2.3 million by 2025. The budgets with opt-out customers included increase from $3.1 million to $5.8 million by 2025.

FIGURE 6-7 ANNUAL BUDGETS FOR INDUSTRIAL RAP ($ IN MILLIONS) – WITH AND WITHOUT OPT-OUT CUSTOMERS



7 Demand Response and CVR Potential

This section provides the results of the technical, economic, MAP and RAP potential for the demand response analysis. Results are broken down by sector and program. The cost-effectiveness results and budgets for the MAP and RAP scenarios are also provided. Section 2.5 provides a description of the demand response methodology. Additional demand response results details are provided in Appendix G.

This section also provides the results of the CVR analysis. Energy and peak demand savings are provided, along with estimated budget requirements and the program benefits and costs.

7.1 TOTAL DEMAND RESPONSE POTENTIAL

Table 7-1 shows the technical, economic, and achievable (MAP and RAP) cumulative annual potential for the 2020-2025 timeframe. Achievable potential includes a participation rate to estimate the realistic number of customers that are expected to participate in each cost-effective demand response program option. These values are at the customer meter. The MAP assumes the maximum participation that would happen in the real-world, while the realistically achievable potential (RAP) discounts MAP by considering barriers to program implementation that could limit the amount of savings achieved.

TABLE 7-1 SUMMARY OF TECHNICAL, ECONOMIC, AND ACHIEVABLE POTENTIAL[39]

Potential Level	2020 Savings (MW)	2021 Savings (MW)	2022 Savings (MW)	2023 Savings (MW)	2024 Savings (MW)	2025 Savings (MW)
Technical	399	368	333	312	304	300
Economic	367	348	322	306	299	295
MAP	23	64	110	131	138	139
RAP	7	20	38	49	53	55

Table 7-2 and Table 7-3 show the achievable potential savings for the 2020-2025 timeframe. Only those programs that were found to be cost-effective are included. Critical Peak Pricing (with Enabling Technologies) are the leading programs in both the commercial and residential sectors.

TABLE 7-2 MAP SAVINGS BY PROGRAM

	Program	2020 Savings (MW)	2021 Savings (MW)	2022 Savings (MW)	2023 Savings (MW)	2024 Savings (MW)	2025 Savings (MW)
Residential	DLC AC Thermostat (Utility Incentivized)	2	3	5	7	8	10
	DLC AC Thermostat (BYOT)	2	3	5	7	8	10
	Critical Peak Pricing (with Enabling Technologies)	8	24	49	64	68	68
	Critical Peak Pricing (without Enabling Technologies)	4	11	17	19	19	18
	Peak Time Rebates	5	10	10	6	5	4
	Total	18	49	82	96	99	100

[39] The results in Table 7-1 do not account for any interactions with energy efficiency. In other words, the results are independent of the energy efficiency potential. Table 7-2 and Table 7-3 provide the DR total both without and with accounting for the interactions between energy efficiency potential and demand response potential. The "with energy efficiency interaction" results assume that energy efficiency potential comes first, then demand response.

	Program	2020 Savings (MW)	2021 Savings (MW)	2022 Savings (MW)	2023 Savings (MW)	2024 Savings (MW)	2025 Savings (MW)
Commercial	DLC AC Thermostat (Utility Incentivized)	0	1	1	1	1	2
	DLC AC Thermostat (BYOT)	0	1	1	1	1	2
	Critical Peak Pricing (with Enabling Technologies)	4	11	23	31	33	33
	Critical Peak Pricing (without Enabling Technologies)	1	2	3	3	3	3
	Time of Use Rate	0	1	1	1	1	1
	Total	5	15	28	36	38	39
Residential & Commercial Total (without energy efficiency interaction)		23	64	110	131	138	139
Residential & Commercial Total (with energy efficiency interaction)		22	61	103	121	124	123

TABLE 7-3 RAP SAVINGS BY PROGRAM

	Program	2020 Savings (MW)	2021 Savings (MW)	2022 Savings (MW)	2023 Savings (MW)	2024 Savings (MW)	2025 Savings (MW)
Residential	DLC AC Thermostat (Utility Incentivized)	1	2	3	3	4	5
	DLC AC Thermostat (BYOT)	1	2	3	3	4	5
	Critical Peak Pricing (with Enabling Technologies)	2	6	12	16	18	18
	Critical Peak Pricing (without Enabling Technologies)	1	3	5	7	7	7
	Peak Time Rebates	1	3	6	8	8	8
	Time of Use Rate	1	2	3	3	4	4
	Residential Total	5	16	30	38	41	42
Commercial	DLC AC Thermostat (Utility Incentivized)	0	0	0	0	0	1
	DLC AC Thermostat (BYOT)	0	0	0	0	0	1
	Critical Peak Pricing (with Enabling Technologies)	1	3	7	9	10	10
	Critical Peak Pricing (without Enabling Technologies)	0	1	1	2	2	2
	Commercial Total	1	4	8	11	12	12
Residential & Commercial Total (without energy efficiency interaction)		7	20	38	49	53	55
Residential & Commercial Total (with energy efficiency interaction)		7	19	37	47	51	51

Benefits & Costs

Table 7-4 and Table 7-5 show the MAP and RAP budget requirement (for only cost-effective programs) across the 2020-2025 timeframe that would be required to achieve the cumulative annual potential for each of the thermostat scenarios. GDS assumed that the Utility Incentivized Scenario would be combined with the existing energy efficiency smart thermostat program, so those customers would already have thermostats installed. Therefore, there would be no additional incentives or equipment costs for those customers. For the BYOT program, GDS assumed there would be a $75 one-time credit[40] for each new participant. The current and future hardware and software cost of a Demand Response Management System and the cost of non-equipment incentives are included in these budgets.

TABLE 7-4 SUMMARY OF MAP BUDGET REQUIREMENTS

	Utility Incentivized	BYOT
2020	$2,603,899	$2,903,578
2021	$3,795,482	$4,142,869
2022	$3,491,247	$3,886,512
2023	$1,824,460	$2,267,934
2024	$795,194	$1,286,975
2025	$524,919	$1,065,077

TABLE 7-5 SUMMARY OF RAP BUDGET REQUIREMENTS

	Utility Incentivized	BYOT
2020	$1,214,023	$1,366,348
2021	$1,519,553	$1,695,871
2022	$1,874,090	$2,074,485
2023	$1,218,690	$1,443,328
2024	$687,836	$936,763
2025	$517,151	$790,398

Table 7-6 and Table 7-7 show the MAP and RAP residential net present values of the total benefits, costs, and savings, along with the UCT ratio for each program for the length of the study. The study period is 2020 to 2034 for MAP (15 years) and 2020 to 2039 for RAP (20 years). Two scenarios were looked at for the demand response study: control of air conditioners by smart thermostats where the utility provides the thermostat (utility incentivized), or where the customer provides their own thermostat (BYOT).

TABLE 7-6 MAP NPV BENEFITS, COSTS, AND UCT RATIOS FOR EACH DEMAND RESPONSE PROGRAM

	Program	NPV Benefits	NPV Costs	UCT Ratio
Residential	DLC AC Thermostat (Utility Incentivized)	$17,194,723	$1,983,943	8.67
	DLC AC Thermostat (BYOT)	$17,194,723	$8,202,189	2.10
	DLC AC Switch	$444,312	$981,072	0.45
	DLC Water Heaters	$70,254	$909,399	0.08
	DLC Pool Pumps	$3,606	$932,923	0.00
	Critical Peak Pricing (with Enabling Technologies)	$71,995,462	$4,229,589	17.02
	Critical Peak Pricing (without Enabling Technologies)	$22,495,433	$3,296,084	6.82

[40] Vectren South 2018 Electric DSM Operating Plan

	Program	NPV Benefits	NPV Costs	UCT Ratio
	Peak Time Rebates	$7,465,909	$2,061,985	3.62
	Time of Use Rates	$827,243	$1,655,665	0.50
Commercial	DLC AC Thermostat (Utility Incentivized)	$2,808,364	$740,617	3.79
	DLC AC Thermostat (BYOT)	$2,808,364	$1,217,479	2.31
	DLC AC Switch	$7,448	$888,343	0.01
	DLC Water Heaters	$238	$887,382	0.00
	Critical Peak Pricing (with Enabling Technologies)	$36,360,268	$1,072,797	33.89
	Critical Peak Pricing (without Enabling Technologies)	$3,959,266	$804,905	4.92
	Real Time Pricing	$166,288	$627,540	0.26
	Peak Time Rebates	$327,957	$818,521	0.40
	Time of Use Rates	$960,336	$826,947	1.16

TABLE 7-7 RAP NPV BENEFITS, COSTS, AND UCT RATIOS FOR EACH DEMAND RESPONSE PROGRAM

	Program	NPV Benefits	NPV Costs	UCT Ratio
Residential	DLC AC Thermostat (Utility Incentivized)	$13,414,527	$1,347,251	9.96
	DLC AC Thermostat (BYOT)	$13,414,527	$5,676,540	2.36
	DLC AC Switch	$161,139	$1,085,281	0.15
	DLC Water Heaters	$24,158	$1,058,798	0.02
	DLC Pool Pumps	$703	$1,101,271	0.00
	Critical Peak Pricing (with Enabling Technologies)	$23,447,290	$1,299,760	18.04
	Critical Peak Pricing (without Enabling Technologies)	$10,175,975	$1,383,206	7.36
	Peak Time Rebates	$11,651,211	$1,567,503	7.43
	Time of Use Rates	$5,036,926	$1,623,212	3.10
Commercial	DLC AC Thermostat (Utility Incentivized)	$1,332,037	$752,800	1.77
	DLC AC Thermostat (BYOT)	$1,332,037	$957,031	1.39
	DLC AC Switch	$305	$1,051,229	0.00
	DLC Water Heaters	$41	$1,051,193	0.00
	Critical Peak Pricing (with Enabling Technologies)	$13,997,560	$706,486	19.81
	Critical Peak Pricing (without Enabling Technologies)	$2,562,131	$697,914	3.67
	Real Time Pricing	$715,458	$745,708	0.96
	Peak Time Rebates	$437,224	$855,727	0.51
	Time of Use Rates	$725,868	$803,613	0.90

7.2 CVR POTENTIAL

Tables 7-8 and 7-9 show the respective incremental and cumulative annual CVR potential for the first six years of the study. Energy (MWh) and peak demand (kW) savings estimates are included in the tables.

TABLE 7-8. CVR INCREMENTAL ANNUAL POTENTIAL

	2020	2021	2022	2023	2024	2025
Projected MWh Savings	2,494	0	0	3,861	0	0
Projected kW Savings	449	0	0	695	0	0

TABLE 7-9. CVR CUMULATIVE ANNUAL POTENTIAL

	2020	2021	2022	2023	2024	2025
Projected MWh Savings	2,494	2,494	2,494	6,355	6,355	6,355
Projected kW Savings	449	449	449	1,144	1,144	1,144

Table 7-10 shows the annual budget requirements to run the CVR program with the East Side and Broadview substations. The capital cost of the East Side substation is $1,350,000, and initial equipment and software costs of the Broadview station is $1,550,000. The implementation costs for the East Side substation are $139,748 per year, and $163,225 for the Broadview substation (starting in 2023). Administrative costs are assumed to be $40,000 for the entire CVR program in 2020 and escalates by 1.5% per year thereafter.

TABLE 7-10. ANNUAL CVR BUDGET REQUIREMENTS

	CVR Budget
2020	$179,748
2021	$180,348
2022	$180,957
2023	$344,810
2024	$345,437
2025	$346,074

Table 3-9 shows the NPV benefits and costs associated with the CVR program across the 20-yr timeframe of the study. The UCT ratio is 1.38.

TABLE 7-11. NPV BENEFITS, COSTS, AND UCT RATIO FOR CVR PROGRAM

Program	NPV Benefits	NPV Costs	UCT Ratio
CVR	$4,687,972	$3,407,160	1.38

VOLUME II

2020-2025 Integrated Electric Action Plan

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Live Smart

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1 Summary of Results

1.1 VECTREN'S ACTION PLAN

The Market Potential Study serves as the basis for developing Vectren's Action Plan. The Action Plan is designed to extract the insights and data from the Market Potential Study and translate them into opportunities to deliver to customers. The Action Plan provides guidance to mobilize the results of the Market Potential Study research and design program initiatives that provide a pathway to advance efforts that are reasonable and relevant in developing Vectren's portfolio. The following section lays out the process, principles, and elements of Vectren's portfolio of programs. A summary of the results for the proposed portfolio is also provided.

1.2 GUIDING PLANNING PRINCIPLES IN DEVELOPING ACTION PLAN OFFERINGS

Vectren's Energy Efficiency Action Plan was developed in accordance with a number of guiding principles and considerations. The process was built on using the most recent Market Potential Study as the foundation, and was then designed to incorporate industry best standards, implementer experiences, and projected changes in the market (such as codes and standards) in order to translate the insights and knowledge from the Market Potential Study into actionable energy efficiency programs for Vectren's planning purposes and customers.

A review of the key planning guidelines and considerations used to frame the Action Plan follows:

TABLE 1-1 KEY PLANNING GUIDELINES IN DEVELOPING THE ACTION PLAN

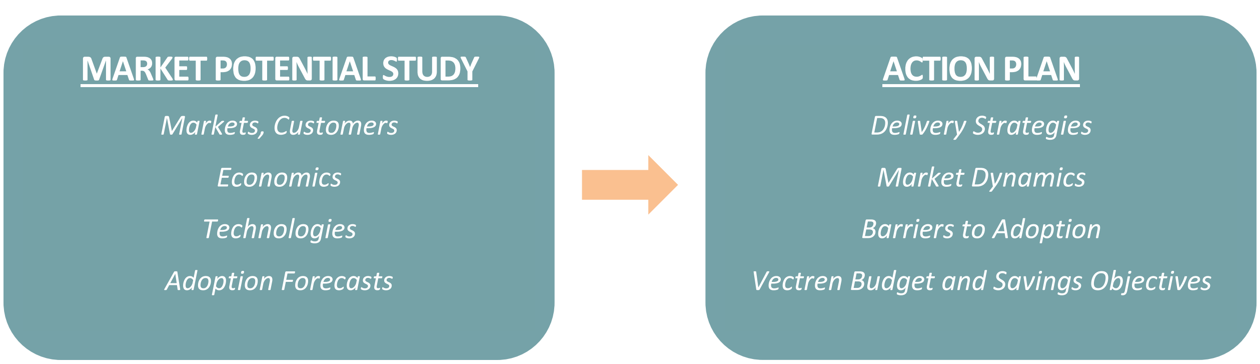
Plan Consideration	Description
Market Coverage	Consideration was given to crafting a portfolio of programs that offers opportunities for savings across all of Vectren's customer groups. This includes residential (single, multifamily and income qualified) as well as commercial and industrial markets.
Direct Link to the Market Potential Study	The Action Plan is directly linked to the Market Potential Study by using its market and cost data. It is acknowledged that there are differences between market and achievable potential due to market dynamics (net versus gross impacts), timeframe differences, proxy versus specific program delivery approaches, and budget realities. Wherever possible, the Market Potential Study serves as a primary reference source making it easier for Vectren to return to the Market Potential Study for added insights as conditions in the market change.
Leveraging Current Program Efforts	Efforts were directed at leveraging existing Vectren offerings to take advantage of market and trade ally understanding, to utilize existing market relationships, retain the relevant elements of programs already working well, and to continue promotional efforts (where relevant).
Introduce New Measures and Concepts	The approach actively looked at incorporating new, applicable measures deemed cost effective and suitable for Vectren's portfolio. This included the introduction of selected new measures in the existing prescriptive-type programs.
Cost Effectiveness Analysis	For planning purposes, each of the recommended programs must pass the Utility Cost Test (UCT) and the Total Resource Cost (TRC) tests, except for Income-Qualified Programs which do not need to meet cost-effectiveness tests in order to promote a greater social good. The cost-effectiveness results are reported for the UCT and the TRC tests. Each program is assessed separately to determine relative benefits and costs (in contrast to assessing each individual measure).
Income-Qualified Programs	Because income-qualified programs are not required to be cost-effective, the Market Potential Study did not screen out measures for income qualified programs based on any cost-effectiveness tests. The team used alternate guidelines for determining which measures would be included in the program. The team chose a "quality over quantity" approach and provided more services to each individual customer than in previous program years. To ensure that income-qualified programs did not overwhelm other energy efficiency program priorities, the team ensured that the overall program budget did not vastly exceed previous program budgets.
C&I Custom Program	Because the C&I Custom program utilizes engineering estimates for each project, customers can submit a wide range of projects through the program. Typically, C&I customers submit large projects through the program to provide an economy of scale for the company taking the time to

Plan Consideration	Description
	complete program paperwork. The Market Potential Study, however, includes all measures that C&I customers may submit through the program no matter the size of the project. Due to this project sizing difference, the Market Potential Study estimates significantly higher savings than the team believed was achievable through the program. The team adjusted C&I Custom program participation and savings based on feedback from implementers and historical program participation.
Adoption Forecasts	Forecasts of customer adoption were reviewed and applied from the Market Potential Study in combination with the historical participation from Vectren's programs. Information was also captured from actual VEDI program experience from evaluation reporting, reliance on "like-utility" estimates in offering similar programs and discussions with implementers.
Impact of Codes and Standards	The savings presented in the Action Plan considers upcoming changes to the baseline. The residential lighting program serves as a good example, where the baseline is changing in 2020 due to the Energy Independence Security Act (EISA). Since 2010, first CFLs and then LEDs have claimed significant shares of the U.S. light bulb market. As a result, the energy efficiency of the average new light bulb sold in the U.S. has increased significantly. That means the savings that energy efficiency programs can claim for helping to install an efficient LED has decreased. Starting in 2020, LED (or equivalent lights) become the standard alternative, directly impacting the amount of savings available for customers changing out their bulbs. The elimination of savings from LED lighting is included in the Vectren portfolio starting in 2021-2022. A similar situation is evident in looking at savings estimates from electrically commutated motors (ECM) as part of furnaces. The standards for ECM motors are scheduled to increase in July 2019, resulting in a loss of reportable energy savings starting in 2020 from the measure.
Program Costs and Budgets	A budget that characterizes the estimated costs for delivering programs to customers is presented for each program. The costs include all participant incentive, planning, evaluation and implementation costs forecast for each year of program operation.
Electric and Natural Gas Integration	As a combination utility, some of Vectren's programs offer savings addressing both electric and natural gas reductions. Programs such as new construction, behavioral savings, multifamily, and income-qualified weatherization all include electric and gas savings. These programs follow the need to split program costs across fuel types while the cost-effectiveness results include benefits of electric and gas reductions. This effort was directed at areas of the Vectren service territory which offer both fuel types to customers. The specific impacts of these programs are provided in the individual program write-ups.

1.3 VECTREN ENERGY EFFICIENCY ACTION PLAN BACKGROUND

The development of the Action Plan is designed to translate the insights and information from the broader Market Potential Study analysis into discrete and specific offerings for Vectren's customers. The Market Potential Study and the Action Plan are related and share common values, but the Action Plan provides more detail, specificity and mobilization strategies.

The Action Plan outlines recommended electric programs for 2020-2025, a shorter timeframe than the potential research. The Action Plan lays outs how to achieve the savings uncovered in the potential study research, shifting the broad and high-level forecast of savings opportunities in the Market Potential Study results into specific and actionable savings opportunities. An illustrative view between the Market Potential Study and the Action Plan elements follows:

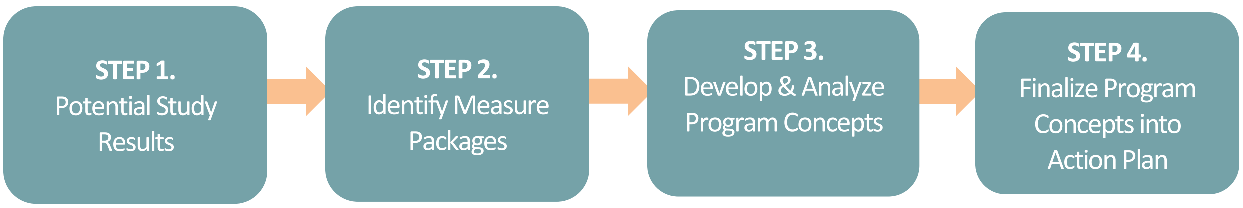


1.4 VECTREN ENERGY EFFICIENCY ACTION PLAN FRAMEWORK

The effort to develop Vectren's energy efficiency programs, for their planning purposes, follows a grounded and sequential process. The process was built on applying the recent market potential analytics as a starting point and, from there, developing program offerings that cost-effectively meet Vectren's planning and program objectives. An illustrative review of the process follows.

1.4.1 Approach

Our approach was based on conducting a series of sequential activities that take the top measures from the potential analyses and develop more detailed and defined concepts to better reflect likely delivery strategies and actual experience. This included packaging measures into programs to analyze and forecast adoption, economic impacts, and savings estimates. This approach is consistent with similar energy efficiency potential efforts and is detailed in the Guide for Conducting Energy Efficiency Potential Studies, prepared by the National Action Plan for Energy Efficiency (2007). These activities are discussed in more detail below.



1.4.2 Action Plan Activities

Step 1. Potential Study Results

The starting point for developing the programs in the Vectren Action Plan was the recently-completed Market Potential Study. This study provided a current assessment of the energy efficiency opportunities available in Vectren service territory and was built on the utility's most recent sales information, market characterization, and forecast of adoption using a number of scenarios and data on measure penetration, costs, energy savings, and overall economics. A key input used for the Action Plan was the identification of the relative savings impacts and cost and benefits for a large array of possible measures that were considered for the Vectren portfolio.

The focus on identifying relevant measures for further consideration in the Vectren portfolio was based on looking at the forecast impacts from both the Total Resource Cost (TRC) and the Utility Cost Test (UCT). Measures which passed either test were reviewed and screened to determine their applicability, market rationale, and viability to be packaged into programs for subsequent examination. The project team, working with Vectren, coordinated multiple meetings with staff and implementers to assist in our understanding of current and proposed DSM initiatives, details of Indiana and Vectren-specific markets, and the suitability of efficiency measures given the utility's customer base. For example, there were a number of retail consumer-related products that passed the relevant screening—such as energy efficient laptops, printers, SMART televisions, and monitors—but are not typically handled through utility intervention. Instead they are part of national standards and market efforts. The result was a list of 413 measures, deemed to be the most reasonable and relevant for further consideration by Vectren.

Step 2. Identify Measure Packages

Using the data and results of the MPS, relevant measures were bundled into packages to better reflect targeted end uses, typical trade ally involvement in customer transactions, and common delivery strategies. The combined packages of measures were designed to advance the analysis efforts and optimally spread delivery costs across a range of technologies. The packages were developed through discussions with Vectren staff, review of prior utility offerings and discussions with Vectren's implementors.

Step 3. Develop and Analyze Program Concepts

Measure packages were then combined into program concepts, designed to reflect program implementation. The concepts were developed through a series of interviews with Vectren's program implementers. These discussions were designed to capture their insights and suggestions as what works best in Vectren's market based on their experiences. Discussions were also conducted with Vectren staff to get a sense of prior offerings, to better understand program delivery experiences. Finally, effort was also directed at incorporating practices and findings from other utility experiences in Indiana and in the region. The results of this step provided inputs to the Action Plan modeling including: energy savings, program costs, participation and incentives. These elements are all key inputs into modeling the stream of benefits and costs and determine cost effectiveness.

Step 4. Finalize Offerings in Action Plan

The final program concepts and relevant information were incorporated into Vectren's Action Plan document. The Action Plan provides the key information for required to implement desired programs.

A review of the key Action Plan data elements and sources follows:

TABLE 1-2 ACTION PLAN DATA ELEMENTS

Action Plan Content	Description
Energy Savings	Each program contains savings estimates for kWh, kW, and therms developed from the Market Potential Study analysis. Additional sources for the savings estimates include: the Indiana TRM, prior evaluation results from VEDI, prior DSM filings, and discussions with relevant implementers.
Technology Costs	Technology cost was obtained from the Market Potential Study analysis. Additional sources included prior evaluation results from VEDI and prior DSM filings.
Estimated Useful Lifetime	Estimates of useful lifetime (EUL) were based on the Market Potential Study analytics and the Indiana Measure Library. For programs with multiple measures, the program EUL was calculated using a weighted average of the number of each measure implemented.
Incentive Strategy	The specific incentive strategy including type (rebate, loan, POS reduction, manufacturer payment), and amount was determined from discussions with Vectren. There is a good history from prior VEDI DSM efforts to detail incentive strategy and amounts to move the market. The cost economics from the Participant Test were also used to gauge impacts.
Annual Adoption	Forecasts of customer adoption from the Market Potential Study were reviewed and adjustments were applied based on historical participation in Vectren's programs, upcoming changes in codes and standards, actual performance reported in VEDI evaluation reporting, and "like-utility" estimates in offering similar programs.
NTG Impacts	NTG estimates from past evaluation studies were used for existing programs. Benchmarking against other Indiana utilities or "like utilities" was used for new initiatives. Discussions with implementers were also included.
Program Costs	Program budgets were developed using historical program cost data and past VEDI evaluations. Discussions with relevant implementation contractors also provided insight regarding typical utility management requirements and related costs.
Benefit-Cost Impacts	Each program concept also includes the impact of the relative costs and benefits for each initiative. The results include the forecast of benefit-costs from various perspectives: Participant test, Rate Impact test, Utility Cost test, and Total Resource Cost test.

2 Overview of Vectren's Energy Efficiency Portfolio

The following section outlines the portfolio of programs developed by Vectren, EMI Consulting, and GDS (referred to hereafter as "the team"). The section begins with a high-level summary of the recommended programs and then provides detailed participation estimates for each year of the Action Plan.

2.1 RECOMMENDED VECTREN ENERGY EFFICIENCY PROGRAM PORTFOLIO

The following table presents the recommended Vectren proposed portfolio. A more detailed program-by-program write-up is also provided in Section 3 to define each program's overall design and incorporate relevant technology and market data to permit modeling of load impacts, budgets, and cost-effectiveness.

TABLE 2-1 SUMMARY OF DRAFT 2020-2025 ENERGY EFFICIENCY PROGRAMS

Programs	Continuation from Previous Plan	New or Expanded Offering	Pilot Program	Participant Unit	Gas/Electric Integrated Savings
Residential Lighting	X			Bulb	
Residential Prescriptive	X	X		Equipment / Appliance / Service	X
Residential New Construction	X			Home	X
Income Qualified Weatherization	X			Home	X
Energy Efficient Schools	X			Kit	X
Residential Behavioral Savings	X	X		Home	X
Appliance Recycling	X	X		Refrigerator/ Freezer	
Home Energy Assessment	X			Home	X
Food Bank	X	X		Bulb	X
CVR Residential	X			NA	
Home Energy Management Systems		X	X	Home	X
Smart Cycle (DLC Change Out)	X			Thermostat	
Bring Your Own Thermostat	X			Thermostat	
Commercial Prescriptive	X	X		Equipment / Appliance / Service	X
Commercial Custom	X	X		Project	X
Small Business	X	X		Project	X
CVR C&I	X			NA	

2.2 SUMMARY OF ENERGY EFFICIENCY IMPACTS

An overall summary of results reflecting savings and costs is shown in Table 2-2 below. These results present an aggregation of all the programs, as well as the results by portfolio (Residential and Commercial/Industrial).

TABLE 2-2 VECTREN INDIANA ELECTRIC DSM 2020-2025 SAVINGS- ALL PROGRAMS

Year	New Participants in Year	Energy Savings in MWh Savings in Year	Summer kW Savings	Incentives, 000$	Program Costs, 000$	Indirect and Other Costs, 000$	Budget, 000$
2020	345,916	47,451	10,758	3,731	5,342	1,207	10,279
2021	382,684	49,716	10,653	3,814	5,724	1,547	11,085
2022	216,286	44,565	10,262	3,787	5,714	1,251	10,752
2023	135,923	45,375	10,907	3,551	5,867	1,253	10,670
2024	137,955	43,309	10,405	3,565	6,063	1,570	11,198
2025	138,078	43,244	10,683	3,563	6,116	1,279	10,959
Total	**1,356,842**	**273,660**	**63,667**	**22,011**	**34,826**	**8,107**	**64,944**

TABLE 2-3 VECTREN INDIANA ELECTRIC DSM 2020-2025 SAVINGS- RESIDENTIAL

Year	New Participants in Year	Energy Savings in MWh Savings in Year	Summer kW Savings	Incentives, 000$	Program Costs, 000$	Indirect and Other Costs, 000$	Budget, 000$
2020	302,908	22,880	5,784	1,321	3,860	582	5,763
2021	333,657	24,682	5,569	1,358	4,185	768	6,312
2022	162,737	18,353	4,926	1,316	4,118	515	5,949
2023	80,062	17,461	5,215	1,103	4,166	482	5,752
2024	81,637	16,186	4,879	1,166	4,297	587	6,050
2025	83,617	16,349	5,216	1,236	4,356	483	6,076
Total	**1,044,618**	**115,911**	**31,588**	**7,502**	**24,983**	**3,418**	**35,902**

TABLE 2-4 VECTREN INDIANA ELECTRIC DSM 2020-2025 SAVINGS- COMMERCIAL AND INDUSTRIAL

Year	New Participants in Year	Energy Savings in MWh Savings in Year	Summer kW Savings	Incentives, 000$	Program Costs, 000$	Indirect and Other Costs, 000$	Budget, 000$
2020	43,008	24,571	4,975	2,410	1,482	625	4,516
2021	49,027	25,034	5,084	2,456	1,539	779	4,773
2022	53,549	26,212	5,336	2,471	1,596	736	4,803
2023	55,861	27,914	5,691	2,447	1,700	771	4,919
2024	56,318	27,124	5,526	2,399	1,766	983	5,148
2025	54,461	26,895	5,467	2,327	1,760	795	4,883
Total	**312,224**	**157,749**	**32,079**	**14,510**	**9,843**	**4,689**	**29,042**

2.3 PORTFOLIO TARGETS BY YEAR

The following tables present the portfolio participation, savings, and costs targets by each program year.

TABLE 2-5 2020 PORTFOLIO TARGETS

	Participants	Total kWh Savings	Total kW (Demand)	Admin.	Implementation	Incentives	Total Budget
Residential							
Residential Lighting	239,866	8,088,914	905.24	$101,000	$186,419	$463,014	$750,433
Residential Prescriptive	7,966	2,465,148	691.22	$40,400	$347,608	$632,065	$1,020,073
Residential New Construction	86	188,624	121.46	$5,050	$50,000	$16,775	$71,825
Home Energy Assessment	300	519,393	55.48	$5,050	$240,000	-	$245,050
Income Qualified Weatherization	539	778,285	443.32	$20,200	$1,275,176	-	$1,295,376
Energy Efficient Schools	2,600	1,149,200	136.50	$20,200	$113,589	-	$133,789
Residential Behavioral Savings	49,000	7,049,208	1,574.28	$40,400	$323,803	-	$364,203
Appliance Recycling	1,251	1,179,811	171.20	$40,400	$143,657	$61,000	$245,057
CVR Residential	-	1,461,047	430	$30,300	$218,023	-	$248,323
Smart Cycle (DLC Change Out)	1,000	-	1,015.00	$20,200	$516,000	$96,000	$632,200
BYOT (Bring Your Own Thermostat)	300	-	240.00	$20,200	$22,280	$52,280	$94,760
Food Bank	-	-	-	-	-	-	-
Home Energy Management Systems	-	-	-	$10,100	$70,000	-	$80,100
Residential Subtotal	**302,908**	**22,879,629**	**5,783.70**	**$353,500**	**$3,506,555**	**$1,321,134**	**$5,181,189**
Commercial & Industrial (C&I)							
Commercial Prescriptive	42,431	14,490,335	3,807.71	$55,550	$622,327	$1,370,010	$2,047,886
Commercial Custom	196	6,107,234	740.00	$60,600	$344,162	$491,537	$896,299
Small Business	381	2,940,932	213.00	$5,050	$215,618	$548,167	$768,835
CVR Commercial	-	1,032,656	214	$30,300	$148,233	-	$178,533
Commercial & Industrial Subtotal	**43,008**	**24,571,158**	**4,974.71**	**$151,500**	**$1,330,340**	**$2,409,714**	**$3,891,554**
Indirect Costs							
Contact Center							$63,000
Online Audit							$42,911
Outreach							$410,000
Portfolio Costs Subtotal							**$515,911**
Subtotal (Before Evaluation)							**$9,588,653**
Evaluation							$490,728
DSM Portfolio Total							**$10,079,381**
Other Costs							
Emerging Markets							$200,000
Market Potential Study							-
Other Costs Subtotal							**$200,000**
DSM Portfolio Total including Other Costs							**$10,279,381**

Note: The team did not factor in the Energy Independence and Security Act (EISA) backstop provision until 2022. The team assumed that Vectren would continue to pilot the Home Energy Management Systems program through 2020.

TABLE 2-6 2021 PORTFOLIO TARGETS

	Participants	Total kWh Savings	Total kW (Demand)	Admin.	Implementation	Incentives	Total Budget
Residential							
Residential Lighting	262,832	8,704,288	875.28	$102,616	$189,402	$455,001	$747,018
Residential Prescriptive	8,276	2,618,629	661.70	$41,046	$353,169	$645,510	$1,039,726
Residential New Construction	77	168,932	108.81	$5,131	$57,249	$15,025	$77,405
Home Energy Assessment	350	605,959	64.72	$5,131	$258,000	-	$263,131
Income Qualified Weatherization	566	823,215	467.28	$20,523	$1,293,527	-	$1,314,050
Energy Efficient Schools	2,600	1,149,200	136.50	$20,523	$117,253	-	$137,776
Residential Behavioral Savings	49,000	7,049,208	1,574.28	$20,523	$328,984	-	$349,507
Appliance Recycling	1,344	1,285,473	172.83	$41,046	$159,415	$66,625	$267,086
CVR Residential	-	-	-	$30,785	$197,378	-	$228,163
Smart Cycle (DLC Change Out)	1,000	198,000	1,015	$20,523	$536,000	$116,000	$672,523
BYOT (Bring Your Own Thermostat)	300	-	240.00	$20,523	$30,280	$60,280	$111,083
Food Bank	6,312	1,564,332	172.21	$20,523	$92,517	-	$113,041
Home Energy Management Systems	1,000	515,000	80.00	$10,262	$212,900	-	$223,162
Residential Subtotal	**333,657**	**24,682,235**	**5,568.60**	**$359,156**	**$3,826,074**	**$1,358,441**	**$5,543,671**
Commercial & Industrial (C&I)							
Commercial Prescriptive	48,449	15,981,655	4,131.23	$56,439	$682,432	$1,424,756	$2,163,627
Commercial Custom	196	6,107,234	740.00	$61,570	$349,669	$491,537	$902,775
Small Business	382	2,944,615	213.00	$5,131	$219,172	$539,573	$763,876
CVR Commercial	-	-	-	$30,785	$133,547	-	$164,332
Commercial & Industrial Subtotal	**49,027**	**25,033,504**	**5,084.23**	**$153,924**	**$1,384,820**	**$2,455,867**	**$3,994,610**
Indirect Costs							
Contact Center							$64,008
Online Audit							$43,598
Outreach							$416,560
Portfolio Costs Subtotal							**$524,166**
Subtotal (Before Evaluation)							**$10,062,446**
Evaluation							$522,653
DSM Portfolio Total							**$10,585,099**
Other Costs							
Emerging Markets							$200,000
Market Potential Study							$300,000
Other Costs Subtotal							**$500,000**
DSM Portfolio Total including Other Costs							**$11,085,099**

Note: Participation and savings spike in 2021 due to: high Residential Prescriptive participation estimated by the Market Potential Study, the start of the Home Energy Management Systems program, the inclusion of the Food Bank program, and a final surge in participation in the Residential Lighting program estimated by the Market Potential Study.

TABLE 2-7 2022 PORTFOLIO TARGETS

	Participants	Total kWh Savings	Total kW (Demand)	Admin.	Implementation	Incentives	Total Budget
Residential							
Residential Lighting	91,708	3,259,915	255.83	$104,258	$144,380	$346,846	$595,484
Residential Prescriptive	8,303	2,722,283	737.22	$41,703	$358,820	$680,160	$1,080,683
Residential New Construction	75	164,892	106.37	$5,213	$53,186	$14,675	$73,074
Home Energy Assessment	420	727,151	77.67	$5,213	$263,225	-	$268,438
Income Qualified Weatherization	594	869,076	492.09	$20,852	$1,312,171	-	$1,333,023
Energy Efficient Schools	2,600	670,800	93.60	$20,852	$92,229	-	$113,080
Residential Behavioral Savings	49,000	7,049,208	1,574.28	$20,852	$334,248	-	$355,099
Appliance Recycling	1,425	1,360,636	184.89	$41,703	$171,385	$70,500	$283,589
CVR Residential	-	-	-	$31,277	$190,034	-	$221,311
Smart Cycle (DLC Change Out)	1,000	198,000	1,015	$20,852	$556,000	$136,000	$712,852
BYOT (Bring Your Own Thermostat)	300	-	240.00	$20,852	$38,280	$68,280	$127,412
Food Bank	6,312	816,353	69.09	$20,852	$18,800	-	$39,651
Home Energy Management Systems	1,000	515,000	80.00	$10,426	$219,900	-	$230,326
Residential Subtotal	**162,737**	**18,353,314**	**4,926.04**	**$364,902**	**$3,752,658**	**$1,316,461**	**$5,434,021**
Commercial & Industrial (C&I)							
Commercial Prescriptive	52,971	17,154,963	4,383.05	$57,342	$733,558	$1,448,274	$2,239,173
Commercial Custom	196	6,107,234	740.00	$62,555	$355,263	$491,537	$909,355
Small Business	382	2,949,771	213.00	$5,213	$222,721	$530,824	$758,758
CVR Commercial	-	-	-	$31,277	$128,261	-	$159,538
Commercial & Industrial Subtotal	**53,549**	**26,211,968**	**5,336.05**	**$156,387**	**$1,439,803**	**$2,470,635**	**$4,066,825**
Indirect Costs							
Contact Center							$65,032
Online Audit							$44,295
Outreach							$423,225
Portfolio Costs Subtotal							**$532,552**
Subtotal (Before Evaluation)							**$10,033,398**
Evaluation							$518,856
DSM Portfolio Total							**$10,552,254**
Other Costs							
Emerging Markets							$200,000
Market Potential Study							-
Other Costs Subtotal							**$200,000**
DSM Portfolio Total including Other Costs							**$10,752,254**

Note: Savings and participation are down in 2022 as the team assumed that the EISA backstop provision would remove downstream standard screw-in lighting incentives from all programs except for direct installations.

TABLE 2-8 2023 PORTFOLIO TARGETS

	Participants	Total kWh Savings	Total kW (Demand)	Admin.	Implementation	Incentives	Total Budget
Residential							
Residential Lighting	12,231	807,282	19.16	$105,926	$32,756	$78,689	$217,370
Residential Prescriptive	8,140	2,793,920	812.09	$42,370	$364,561	$707,135	$1,114,066
Residential New Construction	73	160,852	103.94	$5,296	$50,202	$14,325	$69,824
Home Energy Assessment	504	872,581	93.20	$5,296	$267,437	-	$272,733
Income-Qualified Weatherization	623	917,290	518.75	$21,185	$1,331,114	-	$1,352,299
Energy-Efficient Schools	2,600	670,800	93.60	$21,185	$98,274	-	$119,460
Residential Behavioral Savings	49,000	7,049,208	1,574.28	$21,185	$339,596	-	$360,781
Appliance Recycling	1,435	1,366,149	188.46	$42,370	$174,745	$70,750	$287,865
CVR Residential	-	1,461,047	430	$31,778	$270,252	-	$302,029
Smart Cycle (DLC Change Out)	1,000	198,000	1,015	$21,185	$576,000	$156,000	$753,185
BYOT (Bring Your Own Thermostat)	300	-	240.00	$21,185	$46,280	$76,280	$143,745
Food Bank	3,156	649,158	46.71	$21,185	$9,550	-	$30,735
Home Energy Management Systems	1,000	515,000	80.00	$10,593	$234,900	-	$245,493
Residential Subtotal	**80,062**	**17,461,286**	**5,215.19**	**$370,741**	**$3,795,666**	**$1,103,179**	**$5,269,586**
Commercial & Industrial (C&I)							
Commercial Prescriptive	55,283	17,821,076	4,524.43	$58,259	$769,435	$1,434,660	$2,262,354
Commercial Custom	196	6,107,234	740.00	$63,556	$360,948	$491,537	$916,040
Small Business	382	2,952,715	213.00	$5,296	$226,003	$521,287	$752,586
CVR Commercial		1,032,656	214	$31,778	$184,861	-	$216,639
Commercial & Industrial Subtotal	**55,861**	**27,913,681**	**5,691.43**	**$158,889**	**$1,541,248**	**$2,447,483**	**$4,147,620**
Indirect Costs							
Contact Center							$66,073
Online Audit							$45,004
Outreach							$429,997
Portfolio Costs Subtotal							**$541,073**
Subtotal (Before Evaluation)							**$9,958,279**
Evaluation							$512,192
DSM Portfolio Total							**$10,470,471**
Other Costs							
Emerging Markets							$200,000
Market Potential Study							-
Other Costs Subtotal							**$200,000**
DSM Portfolio Total including Other Costs							**$10,670,471**

Note: The team assumed that the EISA backstop provision would remove downstream specialty screw-in lighting incentives from all programs except for direct installations.

TABLE 2-9 2024 PORTFOLIO TARGETS

	Participants	Total kWh Savings	Total kW (Demand)	Admin.	Implementation	Incentives	Total Budget
Residential							
Residential Lighting	14,089	977,297	19.66	$107,621	$38,416	$92,287	$238,324
Residential Prescriptive	7,892	2,860,501	889.35	$43,048	$370,394	$732,410	$1,145,582
Residential New Construction	71	156,812	101.51	$5,381	$48,144	$13,975	$67,500
Home Energy Assessment	504	840,768	89.03	$5,381	$271,716	-	$277,097
Income-Qualified Weatherization	653	967,302	546.35	$21,524	$1,350,360	-	$1,371,884
Energy-Efficient Schools	2,600	670,800	93.60	$21,524	$106,392	-	$127,916
Residential Behavioral Savings	49,000	7,049,208	1,574.28	$21,524	$345,029	-	$366,554
Appliance Recycling	1,372	1,300,910	183.54	$43,048	$168,946	$67,325	$279,320
CVR Residential	-	-	-	$32,286	$315,241	-	$347,528
Smart Cycle (DLC Change Out)	1,000	198,000	1,015	$21,524	$596,000	$176,000	$793,524
BYOT (Bring Your Own Thermostat)	300	-	240.00	$21,524	$54,280	$84,280	$160,084
Food Bank	3,156	649,158	46.71	$21,524	$9,703	-	$31,227
Home Energy Management Systems	1,000	515,000	80.00	$10,762	$245,940	-	$256,702
Residential Subtotal	**81,637**	**16,185,755**	**4,879.02**	**$376,673**	**$3,920,561**	**$1,166,277**	**$5,463,511**
Commercial & Industrial (C&I)							
Commercial Prescriptive	55,739	18,058,503	4,572.95	$59,191	$791,792	$1,394,674	$2,245,657
Commercial Custom	196	6,107,234	740.00	$64,572	$366,723	$491,537	$922,832
Small Business	383	2,957,870	213.00	$5,381	$229,663	$512,537	$747,582
CVR Commercial	-	-	-	$32,286	$216,561	-	$248,848
Commercial & Industrial Subtotal	**56,318**	**27,123,608**	**5,525.95**	**$161,431**	**$1,604,739**	**$2,398,748**	**$4,164,919**
Indirect Costs							
Contact Center							$67,130
Online Audit							$45,724
Outreach							$436,877
Portfolio Costs Subtotal							**$549,730**
Subtotal (Before Evaluation)							**$10,178,160**
Evaluation							$520,077
DSM Portfolio Total							**$10,698,237**
Other Costs							
Emerging Markets							$200,000
Market Potential Study							$300,000
Other Costs Subtotal							**$500,000**
DSM Portfolio Total including Other Costs							**$11,198,237**

Note: The team assumed that lighting direct installations would decrease from the previous year due to EISA.

TABLE 2-10 2025 PORTFOLIO TARGETS

	Participants	Total kWh Savings	Total kW (Demand)	Admin.	Implementation	Incentives	Total Budget
Residential							
Residential Lighting	15,913	1,146,410	274.12	$109,343	$44,005	$105,714	$259,061
Residential Prescriptive	8,136	2,974,980	961.29	$43,737	$376,320	$767,435	$1,187,492
Residential New Construction	70	154,792	100.29	$5,467	$46,909	$13,800	$66,176
Home Energy Assessment	504	790,845	83.15	$5,467	$276,063	-	$281,530
Income-Qualified Weatherization	685	1,018,544	575.34	$21,869	$1,369,913	-	$1,391,782
Energy-Efficient Schools	2,600	670,800	93.60	$21,869	$117,023	-	$138,891
Residential Behavioral Savings	49,000	7,049,208	1,574.28	$21,869	$350,550	-	$372,418
Appliance Recycling	1,253	1,180,913	171.99	$43,737	$155,651	$61,050	$260,438
CVR Residential	-	-	-	$32,803	$282,073	-	$314,876
Smart Cycle (DLC Change Out)	1,000	198,000	1,015	$21,869	$616,000	$196,000	$833,869
BYOT (Bring Your Own Thermostat)	300	-	240.00	$21,869	$62,280	$92,280	$176,429
Food Bank	3,156	649,158	46.71	$21,869	$9,858	-	$31,727
Home Energy Management Systems	1,000	515,000	80.00	$10,934	$266,980	-	$277,914
Residential Subtotal	**83,617**	**16,348,650**	**5,215.76**	**$382,700**	**$3,973,626**	**$1,236,279**	**$5,592,604**
Commercial & Industrial (C&I)							
Commercial Prescriptive	53,882	17,825,085	4,513.77	$60,139	$797,128	$1,331,794	$2,189,060
Commercial Custom	196	6,107,234	740.00	$65,606	$372,590	$491,537	$929,733
Small Business	383	2,963,026	213.00	$5,467	$233,383	$503,787	$742,637
CVR Commercial	-	-	-	$32,803	$193,019	-	$225,821
Commercial & Industrial Subtotal	**54,461**	**26,895,345**	**5,466.77**	**$164,014**	**$1,596,120**	**$2,327,118**	**$4,087,252**
Indirect Costs							
Contact Center							$68,204
Online Audit							$46,456
Outreach							$443,867
Portfolio Costs Subtotal							**$558,526**
Subtotal (Before Evaluation)							**$10,238,382**
Evaluation							$520,203
DSM Portfolio Total							**$10,758,585**
Other Costs							
Emerging Markets							$200,000
Market Potential Study							-
Other Costs Subtotal							**$200,000**
DSM Portfolio Total including Other Costs							**$10,958,585**

Note: The team assumed that lighting direct installations would decrease from the previous year due to EISA.

3 Program Concepts

This section provides an overview of each program, organized by the following topic areas: 1) Background, 2) Relationship to Vectren's Market Potential Study, 3) Methods and Associated Risks, and 4) Technology and Program Data.

3.1 RESIDENTIAL LIGHTING

3.1.1 Background

The Residential Lighting Program remains an upstream program designed to reach Vectren customers through retail outlets. The program is aimed at encouraging Vectren customers to install more energy-efficient bulbs in their homes. The program consists of a buy-down strategy at the point of purchase, so it is seamless to the participant. Any customer of a participating retailer in Vectren South's electric territory is eligible for the program.

Vectren will oversee the program and work with a partner organization on delivery. The implementation contractor will verify the paperwork of the participating retail stores and spot check stores to assure that the program guidelines are being followed.

The measures will include a variety of ENERGY STAR-qualified lighting products currently available at retailers in Indiana including:

- Standard units
- Specialty units
- LED fixtures
- Exterior lighting controls

3.1.2 Relationship to Vectren's Market Potential Study

The team cross-referenced measures from the Market Potential Study with measures included in the Residential Lighting Program. As measures from the Residential Lighting Program also appear in other Vectren residential programs, the team also compared the rate of sales in other programs to the Residential Lighting Program. From this analysis, the team estimated that measures from the Residential Lighting Program have market potential well above Action Plan participation estimates.

3.1.3 Program Considerations

The program, as designed, takes the Energy Independence and Security Act (EISA) policies into account. A backstop efficiency ruling is slated to take effect in 2020 and will shift the baseline efficiency of most screw-in LED bulbs from halogens to CFLs. Though there is speculation about the timeline and likelihood of this regulation taking effect, the team conservatively assumed the EISA backstop for standard LED bulbs would take effect in 2020 and the EISA backstop for specialty bulbs would take effect in 2021. The team also assumed that non-compliant products would still be sold for up to one year after the regulations take effect, as suggested by the Uniform Methods Project.[41] Therefore, the Residential Lighting Program will discontinue standard LED incentives beginning in 2022 and for specialty lighting products in 2023.

3.1.4 Technology and Program Data

The following table provides summary of the Residential Lighting Program energy impacts and budget.

[41] https://www.nrel.gov/docs/fy18osti/70472.pdf

TABLE 3-1 RESIDENTIAL LIGHTING – IMPACTS AND BUDGET

	2020	2021	2022	2023	2024	2025
Number of Participants	239,866	262,832	91,708	12,231	14,089	15,913
Energy Savings (kWh)	8,088,914	8,704,288	3,259,915	807,282	977,297	1,146,410
Summer Peak Demand Savings (kW)	905	875	256	19	20	274
Total Program Budget	$750,433	$747,018	$595,484	$217,370	$238,324	$259,061
Per Participant Energy Savings (kWh)	34	33	36	66	69	72
Per Participant Demand Savings (kW)	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01	0.02
Per Participant Average Incentive	$2	$2	$4	$6	$7	$7
Weighted Average Measure Life	15	15	14	9	9	9
Incremental Technology Cost	$4	$4	$6	$26	$26	$26
Net-to-Gross Ratio	84%	79%	76%	84%	84%	84%

Note: Number of participants, energy savings, and demand savings estimates based primarily on Market Potential Study results. Program budget estimate based on current schedule of work and projected rising costs from Vectren Program Cost and Measure Data spreadsheet. Per unit savings estimates based on the Market Potential Study results. Per participant energy savings, per participant demand savings, and incremental technology cost weighted by participant. Weighted average measure life and net to gross ratio weighted by kWh.

3.2 RESIDENTIAL PRESCRIPTIVE

3.2.1 Background

The Residential Prescriptive Program is designed to incent customers to purchase energy efficient equipment by covering part of the incremental cost. The program also offers home weatherization rebates to residential customers for attic and wall insulation. If a product vendor or contractor chooses to do so, they can present rebates as an "instant discount" to Vectren's residential customers on their invoice. Vectren will oversee the program and work with an implementation partner on delivery.

Any residential customer located in the Vectren South electric service territory is eligible to participate in the program. For the equipment rebates, the applicant must reside in a single-family home or multi-family complex with up to 12 units. Only single-family homes are eligible for insulation measures.

Measures included in the program will change over time as baselines change, new technologies become available, and customer needs are identified. Measures include:

- ASHP Tune Ups
- Air Purifiers
- Air Source Heat Pumps
- Attic Insulation
- Central Air Conditioners
- Duct Sealing
- Ductless Heat Pumps
- Duel Fuel Air Source Heat Pumps
- ENERGY STAR Electric Clothes Washers (new in 2020)
- ENEGY STAR Dehumidifiers, Electric Clothes Dryers and Room Air Conditioners (new in 2020)
- Heat Pump Water Heaters

- Nest On-Line Store Thermostats
- Wi-Fi Thermostats
- Smart/CEE Tier3 Clothes Washers (new in 2020)
- Smart Programmable Thermostats
- Variable Speed Pool Pumps
- Wall Insulation
- Air Conditioning Tune Ups

3.2.2 Relation to Vectren's Market Potential Study

The team cross-referenced measures from the Market Potential Study with measures included in the existing Residential Prescriptive Program. As measures from the Residential Prescriptive Program also appear in other Vectren residential programs, the team also compared the rate of sales in other programs to the Residential Prescriptive Program. From this analysis, the team found that several Residential Prescriptive Program measures had already reached the full RAP estimated in the Market Potential Study (such as attic insulation), and the team capped future participation at the rates estimated by the potential study.

3.2.3 Program Considerations

A major change to the electric Residential Prescriptive program is the removal of the ECM HVAC motor and pool heaters measure due to changes in standards, low NTG, and low benefit-cost testing.

There are many measures are new to the program, including: dehumidifiers, clothes washers, clothes dryers, room air conditioners, water heaters, and tankless water heaters. The team provided escalating estimates for participation for these measures over the duration of the Action Plan.

3.2.4 Technology and Program Data

The following table provides summary of the Residential Prescriptive Program energy impacts and budget.

TABLE 3-2 RESIDENTIAL PRESCRIPTIVE – IMPACTS AND BUDGET (ELECTRIC)

	2020	2021	2022	2023	2024	2025
Number of Participants	7,966	8,276	8,303	8,140	7,892	8,136
Energy Savings kWh	2,465,148	2,618,629	2,722,283	2,793,920	2,860,501	2,974,980
Peak Demand kW	691	662	737	812	889	961
Total Program Budget	$1,020,073	$1,039,726	$1,080,683	$1,114,066	$1,145,852	$1,187,492
Per Participant Energy Savings (kWh)	309	316	328	343	362	366
Per Participant Demand Savings (kW)	0.09	0.08	0.09	0.10	0.11	0.12
Per Participant Average Incentive	$79	$78	$82	$87	$93	$94
Weighted Average Measure Life	13	13	14	14	14	14
Incremental Technology Cost	$148	$146	$160	$174	$191	$199
Net-to-Gross Ratio	50%	51%	51%	52%	53%	53%

Note: Number of participants, energy savings, and demand savings estimates based primarily on Market Potential Study results. Program budget estimate based on current schedule of work and projected rising costs from Vectren Program Cost and Measure Data spreadsheet. Per unit savings estimates based on the Market Potential Study results. Per participant energy savings, per participant demand savings, and incremental technology cost weighted by participant. Weighted average measure life and net to gross ratio weighted by kWh.

3.3 RESIDENTIAL NEW CONSTRUCTION

3.3.1 Background

The Residential New Construction (RNC) program will produce long-term electric and gas savings by encouraging the construction of single-family homes, duplexes, or end-unit townhomes with only one shared wall that are inspected and evaluated through the Home Efficiency Rating System (HERS). Two incentive levels have been defined by the HERS Index score the house achieves. As of 2018, Gold Star homes must achieve a HERS rating of 61 to 63. Platinum Star homes must meet a HERS rating of 60 or less.

Any customer or home builder constructing a home and meeting the program specifications in the Vectren South electric service territory is eligible to participate in the program. Program incentives are designed to be paid to both all-electric and combination homes that have natural gas heating and water heating. It is important to note that the program is structured such that an incentive will not be paid for an all-electric home that has natural gas available to the home site. Incentives can be paid to either the home builder or the customer/account holder. Incentives are based on the rating tier qualification. As part of the Quality Assurance/Quality Control process, the HERS Assessment is completed by a certified third party HERS Rater. As part of the Quality Assurance/Quality Control process, the vendor provided 100% paper verification that the equipment/products purchased meet the program efficiency standards.

3.3.2 Relation to Vectren's Market Potential Study

The Market Potential Study indicated that the market for the Residential New Construction Program is shrinking in Vectren South and is expanding in Vectren North. The team used previous program participation to calibrate rates from the Market Potential Study.

3.3.3 Program Considerations

The housing market is sensitive to market conditions and unforeseen economic circumstances may impact this program in the future.

3.3.4 Technology and Program Data

The following table provides summary of the Residential New Construction Program energy impacts and budget.

TABLE 3-3 RESIDENTIAL NEW CONSTRUCTION – IMPACTS AND BUDGET

	2020	2021	2022	2023	2024	2025
Number of Homes	86	77	75	73	71	70
Energy Savings kWh	188,624	168,932	164,892	160,852	156,812	154,792
Peak Demand kW	121	109	106	104	102	100
Total Program Budget	$71,825	$77,405	$73,074	$69,824	$67,500	$66,176
Per Participant Energy Savings (kWh)	2,193	2,194	2,199	2,203	2,209	2,211
Per Participant Demand Savings (kW)	1.41	1.41	1.42	1.42	1.43	1.43
Per Participant Average Incentive	$195	$195	$196	$196	$197	$197
Weighted Average Measure Life	25	25	25	25	25	25
Incremental Technology Cost	$2,352	$2,353	$2,361	$2,370	$2,379	$2,384
Net-to-Gross Ratio	50%	50%	50%	50%	50%	50%
Note: Participant and energy savings estimates based primarily on Market Potential Study results. Program budget estimate based on current schedule of work and projected rising costs from Vectren Program Cost and Measure Data spreadsheet. Per						

	2020	2021	2022	2023	2024	2025
unit savings estimates based on the Market Potential Study results. Per participant energy savings, per participant demand savings, and incremental technology cost weighted by participant. Weighted average measure life and net to gross ratio weighted by kWh.						

3.4 HOME ENERGY ASSESSMENT

3.4.1 Background

The Home Energy Assessment (HEA) Program is offered jointly by Vectren South Gas and Electric. This program provides customers with an on-site energy assessment, providing direct installation of energy-efficient measures including high efficiency water fixtures, LED bulbs and smart thermostats. Assessors will perform a walk-through assessment of the home, collecting data for use in identifying cost-effective energy-efficient improvements and appropriate direct install measures. Assessors will then provide an audit report to the customer while assessors are onsite to outline other retrofit opportunities within the home.

Vectren South residential customers with electric service at a single-family residence, provided the home was not built within the past five years and has not had an audit within the last three years, are eligible to participate in the program. Additionally, the home should either be owner-occupied or, if renter-occupied, where occupants have the electric service in their name.

The direct install measures available for installation at no cost include:

- Audit & Education
- Kitchen & Bathroom Aerators
- Filter Whistle
- LED bulbs
- High efficiency Showerhead
- Pipe Wrap
- Water Heater Temperature Setback
- Smart Thermostat

3.4.2 Relation to Vectren's Market Potential Study

The team cross-referenced measures from the Market Potential Study with measures included in the Home Energy Assessment Program. As measures from the Home Energy Assessment program also appear in other Vectren residential programs, the team also compared the rate of sales in other programs to the Home Energy Assessment Program. From this analysis, the team estimated that measures from the Home Energy Assessment Program have market potential well above Action Plan participation estimates.

3.4.3 Program Considerations

The impact of the EISA backstop was considered in the inclusion of LED bulbs in the Home Energy Assessment program and affects the program beginning in 2024. Because of the direct install nature of the program, it was assumed that inefficient lighting will continue to be present in customer homes throughout the timeframe of the Action Plan. Thus, inefficient lighting found in customer homes would be eligible for replacement, though fewer inefficient bulbs would be found in customer homes after 2023.

3.4.4 Technology and Program Data

The following table provides summary of the Home Energy Assessment Program energy impacts and budget.

TABLE 3-4 HOME ENERGY ASSESSMENT – IMPACTS AND BUDGET

	2020	2021	2022	2023	2024	2025
Number of Participants	300	350	420	504	504	504
Energy Savings kWh	519,393	605,959	727,151	872,581	840,768	790,845
Peak Demand kW	55	65	78	93	89	83
Total Program Budget	$245,050	$263,131	$268,438	$272,733	$277,097	$281,530
Per Participant Energy Savings (kWh)	1,731	1,731	1,731	1,731	1,668	1,569
Per Participant Demand Savings (kW)	0.18	0.18	0.18	0.18	0.18	0.16
Weighted Average Measure Life	13	13	13	13	13	13
Net-to-Gross Ratio	101%	101%	101%	101%	101%	101%

Note: Number of participants estimated based on interview with the current program implementer, JE Shekell. Per unit savings estimated based on 2018 Operating Plan. Program costs estimated based on current SOW and projected rising costs described by JE Shekell. Kwh and kw savings estimated by dividing total savings by total participants. Incremental technology cost estimated by summing the incremental cost of each piece of equipment and divided by number of participants. Weighted average measure life and net to gross ratio weighted by kWh.

3.5 INCOME-QUALIFIED WEATHERIZATION

3.5.1 Background

The Income-Qualified Weatherization Program (IQW) is designed to provide direct install measures and weatherization upgrades to low-income homes that otherwise would not have been able to afford the energy saving measures. The program provides direct installation of energy-saving measures and educates consumers on ways to reduce energy consumption. Eligible customers will have opportunity to receive deeper retrofit measures including refrigerators, attic insulation, duct sealing, and air infiltration reduction. Vectren will oversee the program and partner with an implementation contractor to deliver the program. A list of high consumption customers who have received Energy Assistance Program (EAP) funds within the past 12 months will be used to help prioritize those customers. In addition to utilizing the EAP List, implementers will utilize census data to target low-income areas within Vectren territory.In future years, the IQW program will shift focus to providing a more quality and in-depth approach. The focus will be to provide deeper retrofit measures where needed to fewer participants, thus reaping greater savings and benefits to the customer.

Collaboration and coordination between gas and electric low-income programs along with state and federal funding is recommended to provide the greatest efficiencies among all programs. The challenge of meeting the goals set for this program have centered on health and safety as well as customer cancellations and scheduling. Vectren is committed to finding innovative solutions to these areas. A health and safety (H&S) budget has been established and we continue to work on improving methods of customer engagement with various confirmations via phone and email reminders prior to the appointment. Vectren will look for ways to do more of a qualitative approach within this program to ensure the maximum savings is reached and H&S issues are addressed appropriately.

Measures available for installation will vary based on the home and include:

- LED bulbs/lamps (interior/exterior)
- High Efficiency Showerheads (Standard or Handheld)
- High efficiency faucet aerators
- Filter whistles
- Infiltration reduction
- Attic insulation

- Duct repair, seal and insulation
- Refrigerator replacement
- Smart thermostats
- Water Heater Temperature Setback

3.5.2 Relation to Vectren's Market Potential Study

The team cross-referenced measures from the Market Potential Study with measures included in IQW. As measures from IQW also appear in other Vectren residential programs, the team also compared the rate of sales in other programs to IQW. From this analysis, the team estimated that measures from IQW have market potential well above Action Plan participation estimates.

3.5.3 Program Considerations

Measures for the Income-Qualified Weatherization Program do not need to be cost-effective at the program level and therefore the Market Potential Study did not screen measures based on a cost-effectiveness test. The team chose measures that they felt would provide the most value to customers. The team chose a "quality over quantity" approach and provided more services to each individual customer than in previous program years. To ensure that the program did not overwhelm other energy efficiency program priorities, the team ensured that the overall program budget did not vastly exceed previous program budgets. The team dropped smart power strips from the program as they had a very low cost-effectiveness score and seemed to provide less value than other measures.

The impact of the EISA backstop was considered in the inclusion of income-qualified LED bulbs in the program beginning in 2024. It was assumed that inefficient lighting will continue to be present in customer homes throughout the timeframe of the Action Plan. Thus, inefficient lighting found in customer homes would be eligible for replacement, though fewer inefficient bulbs would be found in customer homes after 2023.

3.5.4 Technology and Program Data

The following table provides summary of IQW energy impacts and budget.

TABLE 3-5 INCOME-QUALIFIED WEATHERIZATION – IMPACTS AND BUDGET

	2020	2021	2022	2023	2024	2025
Number of Participants	539	566	594	623	653	685
Energy Savings kWh	778,285	823,215	869,076	917,290	967,302	1,018,544
Peak Demand kW	443	467	492	519	546	575
Total Program Budget	$1,295,376	$1,314,050	$1,333,023	$1,352,299	$1,371,884	$1,391,782
Per Participant Energy Savings (kWh)	1,444	1,454	1,463	1,472	1,481	1,487
Per Participant Demand Savings (kW)	0.82	0.83	0.83	0.83	0.84	0.84
Weighted Average Measure Life	16	16	16	16	16	16
Incremental Technology Cost	$809	$822	$833	$850	$867	$880
Net-to-Gross Ratio	100%	100%	100%	100%	100%	100%

Note: Energy savings, and demand savings estimates primarily based on the Market Potential Study results and 2018 Operating Plan estimates and projected rising costs from 2018-20 filed Energy Efficiency Plan and Vectren Program Cost and Measure Data spreadsheet. Number of participants based on historical program participation. Per participant energy and demand savings calculated by dividing total savings by participation. Weighted average measure life and net to gross weighted by kWh. Incremental cost calculated by summing the incremental cost of each piece of equipment and divided by number of participants.

3.6 ENERGY-EFFICIENT SCHOOLS

3.6.1 Background

The Energy-Efficient Schools Program is designed to produce cost-effective electric and gas savings by educating students and their families about conservation and the efficient use of electricity. The program consists of a school education program for fifth grade students attending schools served by Vectren South. To help in this effort, each child that participates will receive a take-home energy kit with various energy-saving measures for their parents to install in the home. The kits, along with the in-school teaching materials, are designed to make a lasting impression on the students and help them learn ways to conserve energy. Selected fifth grade students/schools in the Vectren South electric service territory are eligible for the program.

The kits for students will include:

- High efficiency showerheads
- High efficiency kitchen aerators
- High efficiency bathroom aerators
- LED bulbs
- LED nightlights
- Filter whistles

3.6.2 Relation to Vectren's Market Potential Study

Though the Market Potential Study estimated savings, only customers with enrolled fifth grade students will participate in the program. As such, the Market Potential Study did not serve as a useful estimate for future Energy-Efficient Schools Program participation. The team relied on previous participation and discussions with the implementer to arrive at useful estimates.

3.6.3 Program Considerations

The team assumed that previous participation is a good indicator of future participation and, in consultation with the implementer, assumed that the program had a little room to grow from the 2018-2020 filed Energy Efficiency plan. The Energy-Efficient Schools Program will discontinue standard LED incentives beginning in 2022 to account for the EISA backstop.

3.6.4 Technology and Program Data

The following table provides summary of the Energy-Efficient Schools Program energy impacts and budget.

TABLE 3-6 ENERGY-EFFICIENT SCHOOLS – IMPACTS AND BUDGET

	2020	2021	2022	2023	2024	2025
Number of Participants	2,600	2,600	2,600	2,600	2,600	2,600
Energy Savings kWh	1,149,200	1,149,200	670,800	670,800	670,800	670,800
Peak Demand kW	137	137	94	94	94	94
Total Program Budget	$133,789	$137,776	$113,080	$119,460	$127,916	$138,891
Per Participant Demand Savings (kWh)	442	442	258	258	258	258
Per Participant Demand Savings (kW)	0.05	0.05	0.04	0.04	0.04	0.04
Weighted Average Measure Life	12	12	10	10	10	10

	2020	2021	2022	2023	2024	2025
Net-to-Gross Ratio	100%	100%	100%	100%	100%	100%

Note: Number of participants, energy savings, and demand savings estimates primarily based on the 2018-20 filed Energy Efficiency Plan. and the 2018 Operating Plan. Program costs primarily based on current SOW and projected rising costs from 2018-20 filed Energy Efficiency Plan and Vectren Program Cost and Measure Data spreadsheet. Per participant energy savings and demand savings calculated by dividing total savings by total participation. Weighted measure life and net to gross ratio are weighted by kWh.

3.7 RESIDENTIAL BEHAVIOR SAVINGS

3.7.1 Background

The Residential Behavioral Savings Program (RBS) motivates behavior change and provides relevant, targeted information to the consumer through regularly scheduled, direct contact via mailed and emailed home energy reports. The measures for this program consist of a Home Energy Report and web portal, which anonymously compares customers' energy use with that of other customers with similar-sized home and demographics, usage history comparisons, goal setting tools, and progress trackers. Customers can view the past twelve months of their energy usage and compare and contrast their energy consumption and costs with others in the same neighborhood. The logic for the program is that once a consumer understands better how they use energy, they can then start conserving energy. Residential customers who receive electric service from Vectren South are eligible for this integrated natural gas and electric EE program.

The program will be delivered by an implementation vendor and include energy reports and a web portal. Customers typically receive between 4-6 reports annually. Additionally, customers receive monthly emails. These reports provide updates on energy consumption patterns compared to similar homes and provide energy savings strategies to reduce energy use. These reports can also promote other Vectren programs to interested customers. The web portal is an interactive system for customers to perform a self-audit, monitor energy usage over time, access energy saving tips, and be connected to other Vectren South gas and electric programs. A third-party evaluator will complete the evaluation of this program.

In 2021, Vectren plans on introducing a new targeted income cohort of participants into the program. Vectren will work with the implementation contractor and the third-party evaluator to determine a participant and non-participant group for this new cohort.

3.7.2 Relation to Vectren's Market Potential Study

The team assumed that restrictions stipulated within the current RBS implementation contract would continue through the timeframe of the Action Plan. As specified by the contract, Vectren can increase the number of treatment customers to the original contracted amount (49,000). The team ensured that this 49,000-participant estimate was below the estimate provided by the Market Potential Study.

3.7.3 Program Considerations

The team assumed that past program performance is a reasonable indicator of future performance. As the third-party evaluator estimates savings for RBS using a billing analysis, the savings resulting from the program may shift from year to year, depending on the behavior of the program participants in any given year. The program also faces the risk of customers losing interest in the program and no longer attempting to curb their energy usage.

3.7.4 Technology and Program Data

The following table provides summary of RBS energy impacts and budget.

TABLE 3-7 RESIDENTIAL BEHAVIOR SAVINGS – IMPACTS AND BUDGET

	2020	2021	2022	2023	2024	2025
Number of Participants	49,000	49,000	49,000	49,000	49,000	49,000
Energy Savings kWh	7,049,208	7,049,208	7,049,208	7,049,208	7,049,208	7,049,208
Peak Demand kW	1,574	1,574	1,574	1,574	1,574	1,574
Total Program Budget	$364,203	$349,507	$355,099	$360,781	$366,554	$372,418
Per Participant Energy Savings (kWh)	144	144	144	144	144	144
Per Participant Demand Savings (kW)	0.03	0.03	0.03	0.03	0.03	0.03
Weighted Average Measure Life	1	1	1	1	1	1
Net-to-Gross Ratio	100%	100%	100%	100%	100%	100%

Note: Number of participants, energy savings, and demand savings estimates primarily based on the 2018-20 filed Energy Efficiency Plan. and the 2018 Operating Plan. Program costs primarily based on current SOW and projected rising costs from 2018-20 filed Energy Efficiency Plan and Vectren Program Cost and Measure Data spreadsheet. Per participant energy savings and demand savings calculated by dividing total savings by total participation. Weighted measure life and net to gross ratio are weighted by kWh.

3.8 APPLIANCE RECYCLING

3.8.1 Background

The Residential Appliance Recycling Program encourages customers to recycle their old inefficient refrigerators, freezers, and air conditioners in an environmentally safe manner. The program recycles these appliances so that they no longer use electricity and it keeps 95% of the appliance out of landfills.

Any residential customer with an operable secondary refrigerator, freezer, or air conditioner unit receiving electric service from Vectren South is eligible to participate in the program.

Vectren works directly with an implementer to administer this program. Recycled units are logged and tracked to assure proper handling and disposal. The utility monitors the activity for disposal. Customer satisfaction surveys are also used to understand the customer experience with the program.

Measures include:

- Refrigerator recycling
- Freezer recycling
- Room air conditioner recycling (new in 2020)

3.8.2 Relation to Vectren's Market Potential Study

The team cross-referenced measures from the Market Potential Study with measures included in the Appliance Recycling Program. From this analysis, the team estimated that measures from the Appliance Recycling Program have market potential well above Action Plan participation estimates.

3.8.3 Program Considerations

After reviewing the results of the Market Potential Study and conducting an interview with the current program implementer, the team decided to add room air conditioner recycling to the program. Based on the Market Potential Study, the team also projected growth in the Appliance Recycling Program in the region over the span of the Action Plan.

3.8.4 Technology and Program Data

The following table provides summary of the Appliance Recycling Program energy impacts and budget.

TABLE 3-8 APPLIANCE RECYCLING – IMPACTS AND BUDGET

	2020	2021	2022	2023	2024	2025
Number of Participants	1,251	1,344	1,425	1,435	1,372	1,253
Energy Savings kWh	1,179,811	1,285,473	1,360,636	1,366,149	1,300,910	1,180,913
Peak Demand kW	171	173	185	188	184	172
Total Program Budget	$245,057	$267,086	$283,589	$287,865	$279,320	$260,438
Per Participant Energy Savings (kWh)	943	956	955	952	948	942
Per Participant Demand Savings (kW)	0.14	0.13	0.13	0.13	0.13	0.14
Per Participant Average Incentive	$49	$50	$49	$49	$49	$49
Weighted Average Measure Life	8	8	8	8	8	8
Net-to-Gross Ratio	71%	71%	71%	71%	71%	71%

Note: Number of participants, energy savings, and demand savings estimated primarily based on the Market Potential Study and 2018 Operating Plan. Program costs estimated using the Market Potential Study, the current SOW, and projected rising costs from 2018-20 filed Energy Efficiency Plan and Program Cost and Participant Data spreadsheet. Per unit savings estimated based on 2018 Operating Plan. weighted average measure life and net to gross ratio weighted by kWh. Per participant incentive and incremental technology cost weighted by participant.

3.9 FOOD BANK

3.9.1 Background

The Food Bank Program provides LED bulbs and high efficiency showerheads to food pantries in Vectren South's electric service territory. This program targets hard-to-reach, low-income customers in the Vectren South electric territory. All food pantry recipients must provide proof of income qualification to receive the food baskets.

Each participating food pantry will place a bundle of four LED bulbs and a single high efficiency showerhead in food packages. The program implementer purchases equipment from a manufacturer and the equipment is shipped in bulk to the partner food bank. Food banks then distribute the equipment to the respective food pantries in its network. Pantries include equipment when assembling food packages and equipment is provided to food recipients. Any customer visiting a food pantry in Vectren South's electric territory is eligible to participate in the program.

Measures include:

- LED bulbs
- High efficiency showerheads (new in 2021)

3.9.2 Relation to Vectren's Market Potential Study

Though the Market Potential Study estimated savings resulting from income-qualified measures, only a small portion of income-qualified customers will become food pantry recipients. As such, the Market Potential Study did not serve as a useful estimate for future Food Bank Program participation.

3.9.3 Program Considerations

Vectren expressed interest in continuing a Food Bank program after the EISA backstop was implemented. The team examined possible new measures and determined that showerheads could provide significant energy savings for food pantry recipients. The team used savings values from other income-qualified programs as a proxy for savings from the Food Bank Program.

3.9.4 Technology and Program Data

The following table provides summary of the Food Bank Program energy impacts and budget.

TABLE 3-9 FOOD BANK – IMPACTS AND BUDGET

	2020	2021	2022	2023	2024	2025
Number of Participants	-	6,312	6,312	3,156	3,156	3,156
Energy Savings kWh	-	1,564,332	816,353	649,158	649,158	649,158
Peak Demand kW	-	172	69	47	47	47
Total Program Budget	-	$113,041	$39,651	$30,735	$31,227	$31,727
Per Participant Energy Savings (kWh)	-	248	129	206	206	206
Per Participant Demand Savings (kW)	-	0.03	0.01	0.01	0.01	0.01
Weighted Average Measure Life	-	11	11	7	5	5
Net-to-Gross Ratio	-	100%	100%	100%	100%	100%

Note: Number of participants, energy savings, and demand savings estimated based on 2018 Operating Plan. Program costs estimated based on current SOW, projected rising costs from 2018-20 filed Energy Efficiency Plan, and Vectren Program Cost and Measure Data spreadsheet. Per unit energy savings and per unit demand savings calculated by dividing total savings by the total number of participants. Weighted average measure life and net to gross ratio weighted by kWh. Incremental technology cost calculated by summing the incremental cost of each piece of equipment and dividing by the total number of participants.

3.10 HOME ENERGY MANAGEMENT SYSTEMS

3.10.1 Background

The Home Energy Management Systems (HEMS) program is a behavioral program that provides real time energy usage data to encourage customers to take action to reduce energy consumption. The objectives of this program include:

- Motivate customers to save energy by increasing customer awareness and engagement around energy consumption and their utility bill
- Increase customer knowledge of and participation in Company programs including, but not limited to, energy efficiency programs and advanced data analytics
- Deliver energy and demand savings

The HEMS program will be piloted using advanced metering infrastructure (AMI) data to communicate energy usage to customers. The platform will utilize a smart phone application to communicate with customers about their home energy usage and provide suggestions for ways customers can save energy. To enhance customer engagement, participants in the program will receive a smart thermostat at no cost, if they do not currently have one installed in their home. Pending EM&V Report results, the program will potentially be rolled out to additional participants.

Given a successful pilot and positive EM&V Report results of the HEMS program, Vectren plans to scale the program to include additional features. The additional features would allow customers to install a device that provides real-time home energy usage data.

All Vectren South electric customers are eligible to participate in this program.

3.10.2 Relation to Vectren's Market Potential Study

The Market Potential Study provided estimates on various smart home technologies including home energy management systems. The program model is very specific and initially only relies on a phone application, the energy management systems estimate in the Market Potential Study may not accurately reflect the total market size available to the Home Energy Management Systems Program.

The team relied on savings estimates from the implementation contractor. The team compared estimates provided by the implementation contractor to the estimated savings presented in the Market Potential Study and found that the implementation contractor estimates were well within the bounds of the Market Potential Study estimates.

3.10.3 Program Considerations

The team utilized savings estimates provided by a HEMS vendor as well as publicly available evaluation documents of home energy management systems. The vendor indicated that they had evaluation-verified savings estimates, although the evaluation results were not currently public. The team acknowledges that savings estimates provided by the implementing contractor are susceptible to bias and, thus, chose a conservative estimate to provide counterbalance.

3.10.4 Technology and Program Data

The following table provides summary of the Home Energy Management Systems Program energy impacts and budget.

TABLE 3-10 HOME ENERGY MANAGEMENT SYSTEMS – IMPACTS AND BUDGET

	2020	2021	2022	2023	2024	2025
Number of Participants	-	1,000	1,000	1,000	1,000	1,000
Energy Savings kWh	-	515,000	515,000	515,000	515,000	515,000
Peak Demand kW	-	80	80	80	80	80
Total Program Budget	$80,100	$223,162	$230,326	$245,493	$256,702	$277,914
Per Participant Energy Savings (kWh)	-	515	515	515	515	515
Per Participant Demand Savings (kW)	-	0.08	0.08	0.08	0.08	0.08
Weighted Average Measure Life	-	6	6	6	6	6
Net-to-Gross Ratio	-	100%	100%	100%	100%	100%

Note: Number of participants, energy savings, demand savings, and program costs estimated based on interviews with the implementer. The team assumed the same weighted average measure life as the current behavioral program. The net to gross ratio is weighted by kWh.

The following table provides summary of the cumulative participants in the Home Energy Management Systems Program over the course of the Action Plan.

TABLE 3-10 HOME ENERGY MANAGEMENT SYSTEMS – PARTICIPANTS AND CUMULATIVE PARTICIPANTS

	2020	2021	2022	2023	2024	2025
Number of Participants	-	1,000	1,000	1,000	1,000	1,000
Cumulative Number of Participants	-	1,000	2,000	3,000	4,000	5,000

3.11 BRING YOUR OWN THERMOSTAT

3.11.1 Background

The Bring Your Own Thermostat Program (BYOT) is a further expansion of the Residential Smart/Wi-Fi thermostat initiative approved in 2016. BYOT allows customers who have or will purchase their own thermostat from multiple potential vendors to participate in demand response (DR) and other load curtailing programs managed through the utility. The program allows the utility to avoid the costs of hardware, installation, and maintenance associated with traditional load control methods.

By taking advantage of two-way communicating smart Wi-Fi thermostats, BYOT programs can help utilities reduce acquisition costs for load curtailment programs and improve customer satisfaction. Through the use of smart/Wi-Fi enabled thermostats, the utility can remotely verify how many customers are connected to the network at any given time and determine which thermostats are participating in DR events.

Any residential customer who receives electric service from Vectren South at a single-family residence is eligible to participate in the program. Customers will receive a one-time enrollment incentive of $75 and a bill credit of $5 during the months of June through September. The enrollment incentive, the amount which was determined based on research of other utility BYOT programs, will be provided in the first year to new enrollees only.

3.11.2 Relation to Vectren's Market Potential Study

The Market Potential Study indicated that there is substantial room in the market for this program.

3.12 SMART CYCLE

3.12.1 Background

Since 1992, Vectren South has operated a Direct Load Control (DLC) program called Summer Cycler that reduces residential and small commercial air-conditioning and water heating electricity loads during summer peak hours.

The Smart Cycle program will replace traditional DLC switches with smart thermostats over time, as the benefits associated with smart thermostats far outweigh the benefits associated with DLC switches. Smart thermostats provide an alternative to traditional residential load control switches as well as enhance the way customers manage and understand their home energy use. By installing connected devices in customer homes rather than using one-way signal switches, Vectren will be able to provide its customer base with deeper energy savings opportunities and shift future energy focus to customer engagement rather than traditional program goals and rules. The most recent Vectren electric DSM evaluation has demonstrated that smart thermostats outperform standard programmable thermostats and are a practical option to transition into future customer engagement strategies.

Customers in the Vectren South territory who currently participate in the DLC Summer Cycler Program and have access to Wi-Fi are eligible for the program. Customers receive a professionally-installed Wi-Fi thermostat at no additional cost and a monthly bill credit of $5 during the months of June through September. The current monthly credit for Summer Cycler is also $5; therefore, the annual bill credit by customer does not change.

3.12.2 Relation to Vectren's Market Potential Study

The Market Potential Study indicates that there is market potential well above Action Plan participation estimates in this program.

3.13 COMMERCIAL AND INDUSTRIAL PRESCRIPTIVE

3.13.1 Background

The Commercial & Industrial (C&I) Prescriptive Program is designed to provide financial incentives on qualifying products to produce greater energy savings in the C&I market. The rebates are designed to promote lower electric energy consumption, assist customers in managing their energy costs, and build a sustainable market around energy efficiency (EE). Program participation is achieved by offering incentives structured to cover a portion of the customer's incremental cost of installing prescriptive efficiency measures. Any participating commercial or industrial customer receiving electric service from Vectren South is eligible to participate in the program.

Top performing measures include:

- High-efficiency lighting and lighting controls
- HVAC equipment such as air conditioners, air-source heat pumps, chillers, boilers, and furnaces

New measures will include:

- Smart thermostats
- Refrigerator strip curtains
- High-efficiency hand dryers
- Efficient low-temperature compressors for refrigerators
- Refrigeration tune-ups
- Duct sealing

The full list of measures can be found in the measure library in Appendix K.

The program is delivered primarily through trade allies. Vectren South and its implementation partners work with the trade allies to make them aware of the offerings and help them promote the program to their customers. The implementation partner will provide training and technical support to the trade allies to become familiar with the EE technologies offered through the program. The program will be managed by the same implementation provider as the C&I Custom Program so that customers can seamlessly receive assistance and all incentives can be efficiently processed through a single procedure.

Incentives are provided to customers to reduce the difference in first cost between the lower-efficiency technology and the high-efficiency option. There is no fixed incentive percentage amount based on the difference in price because some technologies are newer and need higher amounts. Others have been available in the marketplace longer and do not need as much incentive to motivate customers. To verify the correct equipment was installed, site visits will be made on 5% of the installations, as well as all projects receiving incentive greater than $20,000.

3.13.2 Relation to Vectren's Market Potential Study

The team cross-referenced measures from the Market Potential Study with measures included in the C&I Prescriptive Program. As measures from the C&I Prescriptive Program also appear in the Small Business Program, the team also compared the rate of sales in this program to the C&I Prescriptive Program. From this analysis, the team estimated that most measures from the C&I Prescriptive Program have market potential well above Action Plan participation estimates. For a select few measures (high-bay and low-bay LED lighting, refrigerated LEDs, commercial dishwashers, and 90% TE boilers sized at or above 1,000 MBH), the Market Potential Study provided a lower estimate of future participants than previously experienced by the program. The team capped participation at the total number of participants estimated in the potential study for these measures.

3.13.3 Program Considerations

Advances in technology pose a risk to estimates for the C&I Prescriptive Program, although the size, scope, and directionality of that impact are difficult to define. The team developed estimates to address the largest risks to program savings: overall participation and NTG. The team modeled previous NTG estimates and tried to fit Action Plan NTGs to the trend of these historical NTG estimates.

Due to low cost-effectiveness scores in the Market Potential Study, the team dropped plug load sensors, smart power strips, window film, 90% AFUE boilers sized at less than 400 MBH, gas convection ovens, gas griddles, fluorescent lighting, and steam boilers.

3.13.4 Technology and Program Data

The following table provides summary of the C&I Prescriptive Program energy impacts and budget.

TABLE 3-11 COMMERCIAL AND INDUSTRIAL PRESCRIPTIVE – IMPACTS AND BUDGET

	2020	2021	2022	2023	2024	2025
Number of Participants	42,431	48,449	52,971	55,283	55,739	53,882
Energy Savings kWh	14,490,335	15,981,655	17,154,963	17,821,076	18,058,503	17,825,085
Peak Demand kW	3,808	4,131	4,383	4,524	4,573	4,514
Total Program Budget	$2,047,886	$2,163,627	$2,239,173	$2,262,354	$2,245,657	$2,189,060
Per Participant Energy Savings (kWh)	342	330	324	322	324	330
Per Participant Demand Savings (kW)	0.09	0.08	0.08	0.08	0.08	0.08
Per Participant Average Incentive	$32	$29	$27	$26	$25	$25
Weighted Average Measure Life	15	15	15	15	14	14
Incremental Technology Cost	$91	$85	$79	$74	$70	$66
Net-to-Gross Ratio	80%	80%	80%	80%	80%	80%

Note: Number of participants, energy savings, and demand savings estimates based primarily on Market Potential Study results and on estimates from Market Potential Study and 2017 EM&V report. Program budget estimate based on current schedule of work and projected rising costs from Vectren Program Cost and Measure Data spreadsheet. Per unit savings estimates based on the Market Potential Study results. Per participant energy savings, per participant demand savings, and incremental technology cost weighted by participant. Linear LED lighting incentives and incremental costs are discounted by 33% from 2020 to 2025 based on findings from the DOE's Energy Savings Forecast of Solid-State Lighting in General Illumination Applications 2016 report. Weighted average measure life and net to gross ratio weighted by kWh.

3.14 COMMERCIAL AND INDUSTRIAL CUSTOM

3.14.1 Background

The C&I Custom Program promotes the implementation of customized energy-saving projects at qualifying customer facilities. Incentives promoted through this program serve to reduce the cost of implementing energy-reducing projects and upgrading to high-efficiency equipment. Due to the nature of Vectren's custom program, a wide variety of projects are eligible, including conventional custom retrofit projects, new construction (Commercial New Construction) projects, and major renovation (Building Tune-Up) projects. Beginning in 2020, Vectren will pilot a Strategic Energy Management component, an Advanced Lighting Controls component, and a Midstream HVAC component. As the design of the pilots will depend on Vectren-specific market research into C&I customers, the team did not establish the precise program design of the pilots nor the precise incentive structure.

Any participating commercial or industrial customer receiving electric service from Vectren South is eligible to participate in the C&I Custom Program. In addition to this requirement, the Building Tune-Up component also requires buildings to be at least 50,000 square feet. For the pilot components, the implementer will target a small group of participants to test the viability of the concept in Vectren territory.

3.14.1.1 Conventional Custom Projects

Similar to previous program years, customers may propose new custom retrofit projects. Customers or trade allies with a proposed project complete an application form with the energy savings calculations for the project. The implementation team reviews all calculations and, where appropriate, completes site visits to assess and document pre-installation conditions. The implementer then informs that their project has been pre-approved and their funds are reserved for the project. Implementation engineering staff review the final project information as installed and verify the energy savings. Incentives are then paid on the verified savings. Given the variability and uniqueness of each project, all projects are pre-approved. Pre- and post-installation visits to the site to verify installation and savings are performed as defined by the program implementation partner. Monitoring and verification may occur on the largest projects. This component provides incentives based on the kWh saved as calculated by the engineering analysis.

3.14.1.2 Commercial New Construction

The Commercial New Construction (CNC) component promotes energy-efficient designs with the goal of developing projects that are more energy efficient than current Indiana building code. This program applies to new construction and major renovation projects. Major renovation is defined as the replacement of at least two systems within an existing space (e.g., lighting, HVAC, controls, building envelope). The program provides incentives as part of the facility design process to explore opportunities in modeling EE options to craft an optimal package of investments. The program also offers customers the opportunity to receive prescriptive or custom rebates toward eligible equipment in order to reduce the higher capital cost for an energy efficient solution.

To help overcome financial challenge of designing energy-efficient new construction projects, Vectren offers a Standard Energy Design Assistance (“EDA”). This provides additional engineering expertise during the design phase to identify energy-saving opportunities. C&I projects for buildings greater than 100,000 square feet still in the conceptual design phase qualify for Vectren South’s Enhanced EDA incentives which include energy modeling. The Vectren South implementation partner staff expert works with the design team through the conceptual design, schematic design, and design development processes, providing advice and counsel on measures that should be considered and EE modeling issues. Incentives are paid after the design team submits completed construction documents for review to verify that the facility design reflects the minimum energy savings requirements.

CNC provides incentives to help offset some of the expenses for the design team’s participation in the EDA process with the design team incentive. The design team incentive is a fixed amount based on the new/renovated conditioned square footage and is paid when the proposed EE projects associated with the construction documents exceed a minimum energy savings threshold. The program also offers customers the opportunity to receive prescriptive or custom rebates toward eligible equipment in order to reduce the higher capital cost for the EE solutions.

3.14.1.3 Building Tune-Up (BTU)

The BTU component provides a targeted, turnkey, and cost-effective retro-commissioning solution for small- to mid-sized customer facilities. It is designed as a comprehensive customer solution that will identify, validate, quantify, and encourage the installation of both operational and capital measures. The majority of these measures will be no- or low-cost with low payback periods and will capture energy savings from a previously untapped source: building automation systems.

The BTU component is designed to encourage high levels of implementation by customers seeking to optimize the operation of their existing HVAC system. BTU typically targets customers with buildings between 50,000 square feet and 150,000 square feet. Facility energy assessments are offered to customers who are eligible and motivated to implement multiple energy efficiency measures. BTU specifically targets measures that provide no- and low-cost operational savings. Most measures involve optimizing the building automation system (BAS) settings, but the program also investigates related capital measures, like controls, operations, processes, and HVAC. The implementation partner works collaboratively with Vectren South staff to recruit and screen customers for receiving facility energy assessments.

The following table describes the specific savings requirements related to each incentive:

TABLE 3-12 INCENTIVE SAVINGS REQUIREMENTS

Facility Size – Square Feet	Design Team Incentives	Minimum Savings
Small <25,000	$750	25,000 kWh
Medium 25,000 - 100,000	$2,250	75,000 kWh
Large >100,000	$3,750	150,000 kWh
Enhance Large >100,000	$5,000	10% beyond code

3.14.1.4 Strategic Energy Management Pilot

The Strategic Energy Management Pilot (SEM) is a guided operations and maintenance program with benchmarking and regular follow-up meetings to chart customer performance. The implementer will recruit customers to participate in the program and achieve energy savings for their facilities. The implementer will then measure their performance over time (usually a period of 6 months or a year) using energy billing data to determine the amount of energy savings the customer achieved and provide incentives to the customer accordingly. Depending on market research, the SEM pilot may also include cohorts of participants and inter-cohort and intra-cohort competition. Vectren may require the SEM pilot to fit Department of Energy (DOE) 50,001 Ready specifications. This DOE program model attempts to standardize programs across states and jurisdictions to give companies with facilities in more than one utility jurisdiction the opportunity to participate in SEM programs using similar qualification criteria and with similar program applications.

3.14.1.5 Advanced Lighting Controls Pilot

The Advanced Lighting Controls Pilot (ALC) will incentivize networked lighting control systems that include daylighting and/or occupancy sensors in the lighting fixtures. Like conventional custom projects, engineers will review project applications to establish conventional energy savings. Unlike the conventional custom projects, ALC projects may also include additional estimates for reduced hours-of-use or hours of lower energy use resulting from daylighting and/or occupancy sensors in the networked lighting.

3.14.1.6 Midstream HVAC Pilot

The Midstream HVAC Pilot will provide incentives to actors at the distributor level (firms positioned between the manufacturer and the end user). The pilot will provide incentives for HVAC equipment such as package units, heat pumps, room AC, split systems, and chillers.

Through midstream HVAC incentives, the program aims to influence the equipment that distributors stock, fine-tune incentives to fit desired program outcomes, and address the needs of the replace-on-burnout market. Because distributors have a large influence on the HVAC equipment that C&I customers eventually install, the pilot will be able to encourage distributors to supply more energy-efficient options. Midstream HVAC incentives can be more easily adjusted, as C&I customers receive the discount at the time of equipment purchase, not after a lengthy application process. Because C&I customers receive a discount at the time of purchase, the pilot may influence more quick-fire purchasing decisions such as replace-on-burnout purchases. C&I customers will not be encumbered by a lengthy application process to replace their defunct HVAC equipment.

3.14.2 Relation to Vectren's Market Potential Study

The Market Potential Study identified room in C&I markets, but due to the unique nature of each custom program project, it is difficult to compare Market Potential Study opportunity to Action Plan estimates.

3.14.3 Program Considerations

The team assumed that average participation rates from the C&I Custom Program would produce a rough estimate of participation for the program in the future. Due to the wide variations in program savings and number of participating projects over the years, this estimate has a very wide error bound.

3.14.4 Technology and Program Data

The following table provides summary of the C&I Custom Program energy impacts and budget.

TABLE 3-13 COMMERCIAL AND INDUSTRIAL CUSTOM – IMPACTS AND BUDGET

	2020	2021	2022	2023	2024	2025
Number of Participants	196	196	196	196	196	196
Energy Savings kWh	6,107,234	6,107,234	6,107,234	6,107,234	6,107,234	6,107,234
Peak Demand kW	740	740	740	740	740	740
Total Program Budget	$896,299	$902,775	$909,355	$916,040	$922,832	$929,733
Per Participant Energy Savings (kWh)	31,159	31,159	31,159	31,159	31,159	31,159
Per Participant Demand Savings (kW)	3.78	3.78	3.78	3.78	3.78	3.78
Per Participant Average Incentive	$2,508	$2,508	$2,508	$2,508	$2,508	$2,508
Weighted Average Measure Life	16	16	16	16	16	16
Incremental Technology Cost	$26,185	$26,185	$26,185	$26,185	$26,185	$26,185
Net-to-Gross Ratio	100%	100%	100%	100%	100%	100%

Note: Number of participants, energy savings, and program costs estimated based on program estimates for the 2015-2017 energy efficiency scorecards. Demand savings estimated based on the 2018 Operating Plan. Weighted average measure life and net to gross ratio weighted by kWh.

3.15 SMALL BUSINESS ENERGY SOLUTIONS

3.15.1 Background

The Small Business Energy Solutions Program (SBES) provides value by directly installing EE products such as high-efficiency lighting, pre-rinse sprayers, refrigeration controls, electrically-commutated motors, smart thermostats, and vending machine controls. The program helps small businesses and multi-family customers identify and install cost-effective energy-saving measures by providing an onsite energy assessment customized for their business.
Any participating Vectren South business customer with a maximum peak energy demand of less than 400 kW is eligible to participate in the program. Additionally, multi-family building owners with Vectren general electric service may qualify for the program, including apartment buildings, condominiums, cooperatives, duplexes, quadraplexes, townhomes, nursing homes, and retirement communities.

Trained trade ally energy advisors provide energy assessments to business customers with less than 400 kW peak demand and to multi-family buildings. The program implementer issues an annual Request for Qualification (RFQ) to select the trade allies with the best ability to provide high-quality and cost-effective service to small businesses and provide training to SBES trade allies on the program process, with an emphasis on improving energy efficiency sales.

Trade allies walk through small businesses and record site characteristics and energy efficiency opportunities at no cost to the customer. They provide an energy assessment report that details customer-specific opportunities, costs, energy savings, incentives, and simple payback periods. The trade ally then reviews the report with the customer, presenting the program benefits and process, while addressing any questions.

The program has two types of measures provided. The first type of measures are installed at no cost to the customer. They include, but are not limited to, the following:

- LEDs
- Wifi-enabled thermostats
- Programmable thermostats
- High efficiency pre-rinse sprayers
- Faucet aerators
- Weather stripping (exterior door)

The second types of measures require the customer to pay a portion of the labor and materials. These measures include:

- Interior LED lighting
- Exterior LED lighting
- EC Motors
- Anti-sweat heater controls
- Refrigerated LED lighting and case covers
- Lighting control
- Vending machine control
- Smart thermostats

In addition to the no-cost measures identified during the audit, the program also pays a cash incentive on every recommended and implemented improvement identified through the assessment. Incentive rates may change over time and vary with special initiatives.

Onsite verification is provided for the first three projects completed by each trade ally, in addition to the program standard of 5% of all completed projects and all projects receiving incentives greater than $20,000. These verifications allow the program to validate energy savings, in addition to providing an opportunity to ensure trade allies provide high-quality customer services and the incentivized equipment satisfies program requirements.

3.15.2 Relation to Vectren's Market Potential Study

The Market Potential Study identified savings for the overall C&I sectors but provided less-specific estimates for the small business sector. As participation in the program is small, the team assumed that historic participation trends would continue through the timeline of the action plan.

3.15.3 Program Considerations

The team reviewed estimates for the impact of the EISA backstop in other jurisdictions and found that the EISA backstop will have a much smaller impact on C&I programs compared to residential programs. This research also indicated that small businesses will face a larger impact from the backstop as their lighting characteristics more closely resemble the residential market. Because of this impact, the team assumed decreasing participation in lighting measures impacted by the EISA backstop after 2021.

The team dropped fluorescent lighting from the program as the technology will be superseded by linear LEDs and savings from LEDs are much more substantial.

3.15.4 Technology and Program Data

The following table provides summary of SBES energy impacts and budget.

TABLE 3-14 SMALL BUSINESS ENERGY SOLUTIONS – IMPACTS AND BUDGET

	2020	2021	2022	2023	2024	2025
Number of Participants	381	382	382	382	383	383
Energy Savings kWh	2,940,932	2,944,615	2,949,771	2,952,715	2,957,870	2,963,026
Peak Demand kW	213	213	213	213	213	213
Total Program Budget	$768,835	$763,876	$758,758	$752,586	$747,582	$742,637
Per Participant Energy Savings (kWh)	7,719	7,708	7,722	7,730	7,723	7,736
Per Participant Demand Savings (kW)	0.56	0.56	0.56	0.56	0.56	0.56
Per Participant Average Incentive	$1,439	$1,412	$1,390	$1,365	$1,338	$1,315
Weighted Average Measure Life	15	15	15	15	15	15
Incremental Technology Cost	$312	$311	$310	$310	$309	$308
Net-to-Gross Ratio	91%	91%	91%	91%	91%	91%

Note: Number of participants, energy savings, and demand savings estimated based on the 2018 Operating Plan. Program costs estimated using the current program SOW and projected rising costs from 2018-20 filed Energy Efficiency Plan and Vectren Program Cost and Measure Data spreadsheet. Per participant average incentive and incremental technology cost estimated by summing the values for each piece of equipment and dividing by the number of participants. Linear LED lighting incentives and incremental costs are discounted by 33% from 2020 to 2025 based on findings from the DOE's Energy Savings Forecast of Solid-State Lighting in General Illumination Applications 2016 report. Weighted average measure life and net to gross ratio are weighted by kWh.

3.16 CONSERVATION VOLTAGE REDUCTION

3.16.1 Background

Conservation Voltage Reduction (CVR) achieves energy conservation through automated monitoring and control of voltage levels provided on distribution circuits. End use customers realize lower energy and demand consumption when CVR is applied to the distribution circuit from which they are served.

CVR is both a DR and an EE program. It targets distribution circuits, in part to reduce the peak demand experienced on Vectren's electrical power supply system. The voltage reduction stemming from the CVR program operates to effectively reduce consumption during the times in which system peaks are set and as a result directly reduces peak demand. CVR also cost-effectively reduces the level of ongoing energy consumption by end-use devices located on the customer side of the utility meter, as many end-use devices consume less energy with lower voltages consistently applied. Like an equipment maintenance service program, the voltage optimization allows the customer's equipment to operate at optimum levels which saves energy without requiring direct customer intervention or change.

Delivery of the CVR Program will be achieved through the installation of control logic, telecommunication equipment, and voltage control equipment in order to control the voltage bandwidth on CVR circuits within voltage compliance levels required by the Indiana Utility Regulatory Commission.

3.16.2 Program Considerations

The team assumed similar participation in conservation voltage reduction as in previous years.

VOLUME III

APPENDICES

2020-2025 Integrated Electric DSM Market Potential Study & Action Plan

prepared for

VECTREN
Live Smart

JANUARY 2019

VOLUME III *Electric Appendices*

Electric DSM Market Potential Study

Electric Action Plan

APPENDIX A *DSM Market Potential Study Sources*

This appendix catalogs many of the data sources used in this study, grouped by major activity. In general, GDS attempted to utilize Vectren-specific data, where available. When Vectren-specific data was not available or reliable, GDS leveraged secondary data from nearby or regional sources.

A.1 MARKET RESEARCH

Market research studies were used to understand home and business characteristics and equipment stock characteristics. Vectren supplied GDS with several residential market research studies, and GDS conducted primary research in the small commercial sector to gather additional equipment and efficiency characteristics.

- ***Vectren Residential Market Research Studies:*** The electric measure analysis was largely informed by a 2016 baseline survey of Vectren South customers. Nearly 500 responses to this survey provided a strong basis for many of the Vectren South electric measure baseline and efficient saturation estimates. A 2015 CFL and LED baseline study helped inform the saturation estimates for the lighting end use. A 2017 electric baseline thermostat survey of Vectren customers was leveraged to better characterize the increased prominence of smart and Wi-Fi-enabled thermostats.
- ***Vectren Commercial Primary Market Research:*** GDS collected data in 38 commercial facilities to better understand electric and natural gas equipment saturation and efficiency characteristics.
- ***Industrial Surveys***: Vectren survey data was leveraged to determine the remaining factors for several end-uses, including motors, interior and exterior lighting and fixture measures.
- ***EIA/DOE Industrial Data:*** Including the DOE Industrial Electric Motor Systems Market Opportunities Report, the DOE Assessment of the Market for Compressed Air Efficiency Services, and EIA Industrial Demand Module of the National Energy Modeling System.
- ***US American Community Survey:*** Public Use Microdata Survey data was used to estimate the percent of low-income households (using annual household income and number of people per household) in the Vectren South and North territories.
- ***Energy Star Shipment Data:*** Energy Star shipment data provides a detailed historical estimate of the percent of shipped equipment/appliances that meet ENERGY STAR standards. Over the long-term, this serves as a proxy for the percent of the market that could be considered energy efficient.

A.2 FORECAST CALIBRATION

The forecast calibration effort was used to create a detailed segmentation of Vectren's load forecast and ensure that estimated savings would not overstate future potential. Vectren supplied GDS with the most recent load forecast.

- ***Vectren Load Forecast:*** The 2016 Long-Term Electric Energy and Demand load forecast consists of the most recent ITRON load forecast completed for VEDI for 2016-2036. The natural gas forecast was provided directly from Vectren for the North and South territories from 2017 to 2027. Future years were escalated by a compound average annual growth rate.
- ***Vectren Commercial and Industrial Customer Forecast:*** The 2017 historical commercial and industrial data utilized rate codes and existing NAICS code to segment historical sales by commercial building type and/or industry type.
- ***InfoUSA***: GDS utilized a third-party dataset that provided additional commercial and industrial business information, including NAICS codes, to supplement the building/industry types codes supplied by Vectren
- ***EIA Commercial Building Energy Consumption Survey:*** GDS updated the ITRON load forecast to utilize more recent information for the East South-Central region from the EIA 2012 CBECS survey.

- *EIA Manufacturing Energy Consumption Survey:* GDS used the 2014 study to further refine the industrial load forecast by end-use.
- *BEopt:* GDS developed residential building prototypes from the market research effort to develop detailed consumption estimates by end-use and calibrated these models to Vectren's residential load forecasts.

A.3 ENERGY EFFICIENCY MEASURE DATA

The energy efficiency measure analysis developed per unit savings, cost, and useful life assumptions for each energy efficiency measure in the residential, commercial, and industrial sectors. Preference was given to Vectren-specific evaluated savings and/or deemed savings/algorithms in the Indiana TRM.

- *2017 Vectren EM&V Report (Cadmus):* For the development of savings estimates of measures already offered by Vectren, GDS either used the estimates from the most recent evaluation reports or used the evaluation methodology to develop forward looking savings projections.
- *Indiana TRM v2.2:* In the absence of evaluation data, GDS attempted to leverage the Indiana TRM. Assumptions and algorithms were based off the IN TRM to the extent practical.
- *Vectren Operating Plan:* Historical incentive estimates and in some cases, incremental measure costs, were based on the Vectren Operating Plans.
- *Other TRMs:* In some cases, TRM's or deemed measure databases from other states were more applicable than the IN TRM due to more currently available estimates and the more appropriate use of updated federal standards. The Illinois TRM and the Michigan Energy Measures Database were the primary non-Indiana TRMs used.
- *Other Secondary Sources:* In some cases, following the source hierarchy listed above was not enough to develop savings estimates. In these cases, GDS leveraged other secondary research documents such as ACEEE emerging technology reports.

A.4 DEMAND RESPONSE / CVR MEASURE ANALYSIS

The DR/CVR analysis developed per unit savings, cost, and useful life assumptions for select demand response programs, and included assumptions regarding future CVR potential from two additional substations.

- *Vectren programs / 2012 FERC DR Survey:* Demand reductions were based on load reductions found in Vectren's existing demand response programs, and various secondary data sources including the FERC and other industry reports, including demand response potential studies.
- *Indiana TRM v2.2:* In the absence of evaluation data, GDS attempted to leverage the Indiana TRM. Assumptions and algorithms were based off the IN TRM to the extent practical.
- *Comverge:* Comverge provided an estimate of the load control switch useful life.
- *Nest and Ecobee:* Nest and Ecobee product data was used to develop equipment cost assumptions.
- *Other DR Potential Studies:* the absence
- *EM&V Analysis of Buckwood Pilot Program:* Energy and demand impacts for the CVR analysis
- *Power System Engineering Report:* Energy and demand impacts for the CVR analysis

A.5 AVOIDED COST/ECONOMIC ANALYSIS

Avoided costs and related economic assumptions were used to assess cost-effectiveness. In addition, historical incentive levels were tied to willingness-to-participate (WTP) research to assess long-term market adoption in the achievable potential scenario.

- *Electric and Natural Gas Avoided Costs:* Avoided cost values for electric energy, electric capacity, and avoided transmission and distribution (T&D) were provided by Vectren as part of an initial data request. Electric energy is based on an annual system marginal cost. For years outside of the avoided cost forecast timeframe, future year avoided costs are escalated by the rate of inflation. Natural gas avoided costs are calculated using EIA Annual Outlook reference tables combined with demand rates and basis differentials provided by Vectren Gas Supply.

- *Other Economic Assumptions:* Includes the discount rate, inflation rate, line loss assumptions and reserve margin requirement. All economic assumptions were provided by Vectren and consistent with economic modeling assumptions used for other utility planning efforts.
- *Historical DSM Filings/Scorecards:* Historical DSM costs and savings data from 2011 to 2017 were used to determine non-incentive program delivery costs as well as cross-cutting portfolio costs.
- *Primary Market Research:* Vectren conducted over 300 surveys in the residential sector (online only) and 38 on-site surveys in the commercial sector regarding customer willingness-to-purchase energy efficient equipment at various incentive levels. This Vectren-specific customer data was used to determine long-term adoption rates by end-use for the MAP and RAP achievable potential scenarios.

APPENDIX B *DSM Market Potential Study Residential Measure Detail*

Vectren Electric	Residential Measure Assumptions													
Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	Historical Incentive Amount	UCT Ratio	Measure Description
1001	Appliances	ENERGY STAR Air Purifier	SF	N/A	MO	733.0	67%	488.0	0.084	9.0	$70.00	$25.00	9.24	Air Purifier meeting ENERGY STAR spec
1002	Appliances	ENERGY STAR Refrigerator	SF	NLI	MO	569.0	9%	53.0	0.008	17.0	$40.00	$20.00	2.05	ES Qualified Refrigator (~9% more efficient)
1003	Appliances	Smart Refrigerator_ET	SF	NLI	MO	569.0	12%	70.0	0.011	17.0	$680.00	$340.00	0.16	ES Qualified Refrigerator w/ Smart Technology
1004	Appliances	ES Refrigerator Replacement	SF	LI	DI	1,193.0	35%	412.2	0.063	17.0	$580.00	$580.00	0.55	Replace Existing Refrigerator with ES Qualified Unit
1005	Appliances	Refrigerator Recycling	SF	N/A	Recycle	1,044.0	100%	1,044.0	0.140	8.0	$130.00	$130.00	3.14	Refrigerator Recycle (No Replacement)
1006	Appliances	ENERGY STAR Clothes Washer (Electrc WH/Dryer)	SF	N/A	MO	522.0	22%	112.4	0.430	14.0	$84.00	$40.00	1.95	ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline)
1007	Appliances	ENERGY STAR Clothes Washer (NG WH/E Dryer)	SF	N/A	MO	383.7	27%	101.8	0.390	14.0	$84.00	$40.00	1.82	ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline)
1008	Appliances	ENERGY STAR Clothes Washer (NG WH/NG Dryer)	SF	N/A	MO	42.3	44%	18.5	0.071	14.0	$84.00	$40.00	0.82	ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline)
1009	Appliances	Smart/CEE Tier3 Clothes Washer (Electrc WH/Dryer)_ET	SF	N/A	MO	522.0	40%	209.2	0.801	14.0	$141.00	$70.00	2.07	CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline)
1010	Appliances	Smart/CEE Tier3 Clothes Washer (NG WH/E Dryer)_ET	SF	N/A	MO	383.7	26%	100.9	0.386	14.0	$141.00	$70.00	1.33	CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline)
1011	Appliances	Smart/CEE Tier3 Clothes Washer (NG WH/NG Dryer)_ET	SF	N/A	MO	42.3	-3%	-1.2	-0.005	14.0	$141.00	$70.00	0.62	CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline)
1012	Appliances	ENERGY STAR Dishwasher (E WH)	SF	N/A	MO	307.0	12%	37.0	0.105	11.0	$76.00	$40.00	0.42	ES Qualified Dishwasher (v3.0)
1013	Appliances	ENERGY STAR Dishwasher (NG WH)	SF	N/A	MO	135.1	12%	16.3	0.046	11.0	$79.00	$40.00	0.27	ES Qualified Dishwasher (v3.0)
1014	Appliances	Smart Dishwasher (E WH)_ET	SF	N/A	MO	307.0	15%	45.5	0.129	11.0	$395.00	$200.00	0.10	Smart ES Qualified Dishwasher (v3.0)
1015	Appliances	Smart Dishwasher (NG WH)_ET	SF	N/A	MO	135.1	15%	20.0	0.057	11.0	$395.00	$200.00	0.07	Smart ES Qualified Dishwasher (v3.0)
1016	Appliances	ENERGY STAR Dehumidifier	SF	N/A	MO	904.6	20%	180.9	0.111	12.0	$9.52	$5.00	24.59	ES Qualified Dehumidifer (L/kWh = 2.0)
1017	Appliances	ENERGY STAR Freezer	SF	N/A	MO	349.5	10%	35.1	0.006	22.0	$35.00	$20.00	1.64	ES Qualified Freezer (10% more Efficient than NAECA)
1018	Appliances	Freezer Recycling	SF	N/A	Recycle	927.0	100%	927.0	0.100	8.0	$130.00	$130.00	2.62	Freezer Recycle (No Replacement)
1019	Appliances	ENERGY STAR Clothes Dryer (Electric)	SF	NLI	MO	768.9	21%	160.4	0.567	16.0	$152.00	$75.00	1.52	ES Qualified Dryer (CEF=3.93)
1020	Appliances	ENERGY STAR Clothes Dryer (NG)	SF	NLI	MO	123.0	21%	25.7	0.091	16.0	$152.00	$75.00	0.57	ES Qualified Dryer (CEF=3.93)
1021	Appliances	Smart Clothes Dryer (Electric)_ET	SF	NLI	MO	768.9	26%	202.7	0.716	16.0	$236.00	$120.00	1.20	Smart ES Qualified Dryer (5.5% additional energy savings)
1022	Appliances	Smart Clothes Dryer (NG)_ET	SF	NLI	MO	123.0	26%	32.4	0.115	16.0	$236.00	$120.00	0.45	Smart ES Qualified Dryer (5.5% additional energy savings)
1023	Appliances	Heat Pump Dryer	SF	NLI	MO	768.9	73%	558.0	1.972	12.0	$412.00	$205.00	1.57	Heat Pump Dryer (CEF=10.4)
1024	Appliances	Dryer Vent Cleaning (Electric)	SF	LI	DI	768.9	6%	42.3	0.149	2.0	$80.00	$80.00	0.06	Dryer Vent Cleaning (5.5% Savings)
1025	Appliances	Dryer Vent Cleaning (NG)	SF	LI	DI	123.0	6%	6.8	0.024	2.0	$80.00	$80.00	0.02	Dryer Vent Cleaning (5.5% Savings)
1026	Appliances	ENERGY STAR Water Cooler	SF	N/A	MO	105.9	46%	48.6	0.006	10.0	$17.00	$10.00	2.22	ES Water Cooler (Cold Water Only)
1027	Appliances	ENERGY STAR Air Purifier	SF	N/A	NC	733.0	67%	488.0	0.084	9.0	$70.00	$25.00	9.24	Air Purifier meeting ENERGY STAR spec
1028	Appliances	ENERGY STAR Refrigerator	SF	N/A	NC	569.0	9%	53.0	0.008	17.0	$40.00	$20.00	2.05	ES Qualified Refrigator (~9% more efficient)
1029	Appliances	Smart Refrigerator_ET	SF	N/A	NC	569.0	12%	70.0	0.011	17.0	$680.00	$340.00	0.16	ES Qualified Refrigerator w/ Smart Technology
1030	Appliances	ENERGY STAR Clothes Washer (Electrc WH/Dryer)	SF	N/A	NC	522.0	22%	112.4	0.430	14.0	$84.00	$40.00	1.95	ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline)

Vectren Electric — Residential Measure Assumptions

Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	Historical Incentive Amount	UCT Ratio	Measure Description
1031	Appliances	ENERGY STAR Clothes Washer (NG WH/E Dryer)	SF	N/A	NC	383.7	27%	101.8	0.390	14.0	$84.00	$40.00	1.82	ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline)
1032	Appliances	ENERGY STAR Clothes Washer (NG WH/NG Dryer)	SF	N/A	NC	42.3	44%	18.5	0.071	14.0	$84.00	$40.00	0.82	ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline)
1033	Appliances	Smart/CEE Tier3 Clothes Washer (Electrc WH/Dryer)_ET	SF	N/A	NC	522.0	40%	209.2	0.801	14.0	$141.00	$70.00	2.07	CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline)
1034	Appliances	Smart/CEE Tier3 Clothes Washer (NG WH/E Dryer)_ET	SF	N/A	NC	383.7	26%	100.9	0.386	14.0	$141.00	$70.00	1.33	CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline)
1035	Appliances	Smart/CEE Tier3 Clothes Washer (NG WH/NG Dryer)_ET	SF	N/A	NC	42.3	-3%	-1.2	-0.005	14.0	$141.00	$70.00	0.62	CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline)
1036	Appliances	ENERGY STAR Dishwasher (E WH)	SF	N/A	NC	307.0	12%	37.0	0.105	11.0	$76.00	$40.00	0.42	ES Qualified Dishwasher (v3.0)
1037	Appliances	ENERGY STAR Dishwasher (NG WH)	SF	N/A	NC	135.1	12%	16.3	0.046	11.0	$79.00	$40.00	0.27	ES Qualified Dishwasher (v3.0)
1038	Appliances	Smart Dishwasher (E WH)_ET	SF	N/A	NC	307.0	15%	45.5	0.129	11.0	$395.00	$200.00	0.10	Smart ES Qualified Dishwasher (v3.0)
1039	Appliances	Smart Dishwasher (NG WH)_ET	SF	N/A	NC	135.1	15%	20.0	0.057	11.0	$395.00	$200.00	0.07	Smart ES Qualified Dishwasher (v3.0)
1040	Appliances	ENERGY STAR Dehumidifier	SF	N/A	NC	904.6	20%	180.9	0.111	12.0	$9.52	$5.00	24.59	ES Qualified Dehumidifer (L/kWh = 2.0)
1041	Appliances	ENERGY STAR Freezer	SF	N/A	NC	349.5	10%	35.1	0.006	22.0	$35.00	$20.00	1.64	ES Qualified Freezer (10% more Efficient than NAECA)
1042	Appliances	ENERGY STAR Clothes Dryer (Electric)	SF	N/A	NC	768.9	21%	160.4	0.567	16.0	$152.00	$75.00	1.52	ES Qualified Dryer (CEF=3.93)
1043	Appliances	ENERGY STAR Clothes Dryer (NG)	SF	N/A	NC	123.0	21%	25.7	0.091	16.0	$152.00	$75.00	0.57	ES Qualified Dryer (CEF=3.93)
1044	Appliances	Smart Clothes Dryer (Electric)_ET	SF	N/A	NC	768.9	26%	202.7	0.716	16.0	$236.00	$120.00	1.20	Smart ES Qualified Dryer (5.5% additional energy savings)
1045	Appliances	Smart Clothes Dryer (NG)_ET	SF	N/A	NC	123.0	26%	32.4	0.115	16.0	$236.00	$120.00	0.45	Smart ES Qualified Dryer (5.5% additional energy savings)
1046	Appliances	Heat Pump Dryer	SF	N/A	NC	768.9	73%	558.0	1.972	12.0	$412.00	$205.00	1.57	Heat Pump Dryer (CEF=10.4)
1047	Appliances	ENERGY STAR Water Cooler	SF	N/A	NC	105.9	46%	48.6	0.006	10.0	$17.00	$10.00	2.22	ES Water Cooler (Cold Water Only)
1048	Appliances	ENERGY STAR Air Purifier	MF	N/A	MO	733.0	67%	488.0	0.084	9.0	$70.00	$25.00	9.24	Air Purifier meeting ENERGY STAR spec
1049	Appliances	ENERGY STAR Refrigerator	MF	NLI	MO	569.0	9%	53.0	0.008	17.0	$40.00	$20.00	2.05	ES Qualified Refrigator (~9% more efficient)
1050	Appliances	Smart Refrigerator_ET	MF	NLI	MO	569.0	12%	70.0	0.011	17.0	$680.00	$340.00	0.16	ES Qualified Refrigerator w/ Smart Technology
1051	Appliances	ES Refrigerator Replacement	MF	LI	DI	1,193.0	35%	412.2	0.063	17.0	$580.00	$580.00	0.55	Replace Existing Refrigerator with ES Qualified Unit
1052	Appliances	Refrigerator Recycling	MF	N/A	Recycle	1,044.0	100%	1,044.0	0.140	8.0	$130.00	$130.00	3.14	Refrigerator Recycle (No Replacement)
1053	Appliances	ENERGY STAR Clothes Washer (Electrc WH/Dryer)	MF	N/A	MO	522.0	22%	112.4	0.430	14.0	$84.00	$40.00	1.95	ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline)
1054	Appliances	ENERGY STAR Clothes Washer (NG WH/E Dryer)	MF	N/A	MO	383.7	27%	101.8	0.390	14.0	$84.00	$40.00	1.82	ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline)
1055	Appliances	ENERGY STAR Clothes Washer (NG WH/NG Dryer)	MF	N/A	MO	42.3	44%	18.5	0.071	14.0	$84.00	$40.00	0.82	ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline)
1056	Appliances	Smart/CEE Tier3 Clothes Washer (Electrc WH/Dryer)_ET	MF	N/A	MO	522.0	40%	209.2	0.801	14.0	$141.00	$70.00	2.07	CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline)
1057	Appliances	Smart/CEE Tier3 Clothes Washer (NG WH/E Dryer)_ET	MF	N/A	MO	383.7	26%	100.9	0.386	14.0	$141.00	$70.00	1.33	CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline)

Vectren Electric — Residential Measure Assumptions

Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	Historical Incentive Amount	UCT Ratio	Measure Description
1058	Appliances	Smart/CEE Tier3 Clothes Washer (NG WH/NG Dryer)_ET	MF	N/A	MO	42.3	-3%	-1.2	-0.005	14.0	$141.00	$70.00	0.62	CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline)
1059	Appliances	ENERGY STAR Dishwasher (E WH)	MF	N/A	MO	307.0	12%	37.0	0.105	11.0	$76.00	$40.00	0.42	ES Qualified Dishwasher (v3.0)
1060	Appliances	ENERGY STAR Dishwasher (NG WH)	MF	N/A	MO	135.1	12%	16.3	0.046	11.0	$79.00	$40.00	0.27	ES Qualified Dishwasher (v3.0)
1061	Appliances	Smart Dishwasher (E WH)_ET	MF	N/A	MO	307.0	15%	45.5	0.129	11.0	$395.00	$200.00	0.10	Smart ES Qualified Dishwasher (v3.0)
1062	Appliances	Smart Dishwasher (NG WH)_ET	MF	N/A	MO	135.1	15%	20.0	0.057	11.0	$395.00	$200.00	0.07	Smart ES Qualified Dishwasher (v3.0)
1063	Appliances	ENERGY STAR Dehumidifier	MF	N/A	MO	904.6	27%	246.7	0.151	12.0	$75.00	$40.00	4.19	ES Qualified Dehumidifer (L/kWh = 2.2)
1064	Appliances	ENERGY STAR Freezer	MF	N/A	MO	349.5	10%	35.1	0.006	22.0	$35.00	$20.00	1.64	ES Qualified Freezer (10% more Efficient than NAECA)
1065	Appliances	Freezer Recycling	MF	N/A	Recycle	927.0	100%	927.0	0.100	8.0	$130.00	$130.00	2.62	Freezer Recycle (No Replacement)
1066	Appliances	ENERGY STAR Clothes Dryer (Electric)	MF	NLI	MO	768.9	21%	160.4	0.567	16.0	$152.00	$75.00	1.52	ES Qualified Dryer (CEF=3.93)
1067	Appliances	ENERGY STAR Clothes Dryer (NG)	MF	NLI	MO	123.0	21%	25.7	0.091	16.0	$152.00	$75.00	0.57	ES Qualified Dryer (CEF=3.93)
1068	Appliances	Smart Clothes Dryer (Electric)_ET	MF	NLI	MO	768.9	26%	202.7	0.716	16.0	$236.00	$120.00	1.20	Smart ES Qualified Dryer (5.5% additional energy savings)
1069	Appliances	Smart Clothes Dryer (NG)_ET	MF	NLI	MO	123.0	26%	32.4	0.115	16.0	$236.00	$120.00	0.45	Smart ES Qualified Dryer (5.5% additional energy savings)
1070	Appliances	Heat Pump Dryer	MF	NLI	MO	768.9	73%	558.0	1.972	12.0	$412.00	$205.00	1.57	Heat Pump Dryer (CEF=10.4)
1071	Appliances	Dryer Vent Cleaning (Electric)	MF	LI	DI	768.9	6%	42.3	0.149	2.0	$80.00	$80.00	0.06	Dryer Vent Cleaning (5.5% Savings)
1072	Appliances	Dryer Vent Cleaning (NG)	MF	LI	DI	123.0	6%	6.8	0.024	2.0	$80.00	$80.00	0.02	Smart ES Qualified Dryer (5.5% additional energy savings)
1073	Appliances	ENERGY STAR Water Cooler	MF	N/A	MO	105.9	46%	48.6	0.006	10.0	$17.00	$10.00	2.22	ES Water Cooler (Cold Water Only)
1074	Appliances	ENERGY STAR Air Purifier	MF	N/A	NC	733.0	67%	488.0	0.084	9.0	$70.00	$25.00	9.24	Air Purifier meeting ENERGY STAR spec
1075	Appliances	ENERGY STAR Refrigerator	MF	N/A	NC	569.0	9%	53.0	0.008	17.0	$40.00	$20.00	2.05	ES Qualified Refrigator (~9% more efficient)
1076	Appliances	Smart Refrigerator_ET	MF	N/A	NC	569.0	12%	70.0	0.011	17.0	$680.00	$340.00	0.16	ES Qualified Refrigerator w/ Smart Technology
1077	Appliances	ENERGY STAR Clothes Washer (Electrc WH/Dryer)	MF	N/A	NC	522.0	22%	112.4	0.430	14.0	$84.00	$40.00	1.95	ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline)
1078	Appliances	ENERGY STAR Clothes Washer (NG WH/E Dryer)	MF	N/A	NC	383.7	27%	101.8	0.390	14.0	$84.00	$40.00	1.82	ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline)
1079	Appliances	ENERGY STAR Clothes Washer (NG WH/NG Dryer)	MF	N/A	NC	42.3	44%	18.5	0.071	14.0	$84.00	$40.00	0.82	ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline)
1080	Appliances	Smart/CEE Tier3 Clothes Washer (Electrc WH/Dryer)_ET	MF	N/A	NC	522.0	40%	209.2	0.801	14.0	$141.00	$70.00	2.07	CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline)
1081	Appliances	Smart/CEE Tier3 Clothes Washer (NG WH/E Dryer)_ET	*MF*	N/A	NC	383.7	26%	100.9	0.386	14.0	$141.00	$70.00	1.33	CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline)
1082	Appliances	Smart/CEE Tier3 Clothes Washer (NG WH/NG Dryer)_ET	*MF*	N/A	NC	42.3	-3%	-1.2	-0.005	14.0	$141.00	$70.00	0.62	CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline)
1083	Appliances	ENERGY STAR Dishwasher (E WH)	MF	N/A	NC	307.0	12%	37.0	0.105	11.0	$76.00	$40.00	0.42	ES Qualified Dishwasher (v3.0)
1084	Appliances	ENERGY STAR Dishwasher (NG WH)	MF	N/A	NC	135.1	12%	16.3	0.046	11.0	$79.00	$40.00	0.27	ES Qualified Dishwasher (v3.0)
1085	Appliances	Smart Dishwasher (E WH)_ET	MF	N/A	NC	307.0	15%	45.5	0.129	11.0	$395.00	$200.00	0.10	Smart ES Qualified Dishwasher (v3.0)

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	Historical Incentive Amount	UCT Ratio	Measure Description
1086	Appliances	Smart Dishwasher (NG WH)_ET	MF	N/A	NC	135.1	15%	20.0	0.057	11.0	$395.00	$200.00	0.07	Smart ES Qualified Dishwasher (v3.0)
1087	Appliances	ENERGY STAR Dehumidifier	MF	N/A	NC	904.6	27%	246.7	0.151	12.0	$75.00	$40.00	4.19	ES Qualified Dehumidifer (L/kWh = 2.2)
1088	Appliances	ENERGY STAR Freezer	MF	N/A	NC	349.5	10%	35.1	0.006	22.0	$35.00	$20.00	1.64	ES Qualified Freezer (10% more Efficient than NAECA)
1089	Appliances	ENERGY STAR Clothes Dryer (Electric)	MF	N/A	NC	768.9	21%	160.4	0.567	16.0	$152.00	$75.00	1.52	ES Qualified Dryer (CEF=3.93)
1090	Appliances	ENERGY STAR Clothes Dryer (NG)	MF	N/A	NC	123.0	21%	25.7	0.091	16.0	$152.00	$75.00	0.57	ES Qualified Dryer (CEF=3.93)
1091	Appliances	Smart Clothes Dryer (Electric)_ET	MF	N/A	NC	768.9	26%	202.7	0.716	16.0	$236.00	$120.00	1.20	Smart ES Qualified Dryer (5.5% additional energy savings)
1092	Appliances	Smart Clothes Dryer (NG)_ET	MF	N/A	NC	123.0	26%	32.4	0.115	16.0	$236.00	$120.00	0.45	Smart ES Qualified Dryer (5.5% additional energy savings)
1093	Appliances	Heat Pump Dryer	MF	N/A	NC	768.9	73%	558.0	1.972	12.0	$412.00	$205.00	1.57	Heat Pump Dryer (CEF=10.4)
1094	Appliances	ENERGY STAR Water Cooler	MF	N/A	NC	105.9	46%	48.6	0.006	10.0	$17.00	$10.00	2.22	ES Water Cooler (Cold Water Only)
2001	Audit	Audit Recommendations (elec) - Single-family	SF	NLI	Retrofit	19,402.4	0%	32.0	0.006	1.0	$80.00	$80.00	0.02	Walk through audit and recommendations for behavioral and installation measures
2002	Audit	Audit Recommendations (elec) - Single-family	SF	LI	DI	19,402.4	0%	32.0	0.006	1.0	$80.00	$80.00	0.02	Walk through audit and recommendations for behavioral and installation measures
2003	Audit	Audit Recommendations (elec) - Multifamily	MF	NLI	Retrofit	12,314.1	0%	32.0	0.005	1.0	$80.00	$80.00	0.02	Walk through audit and recommendations for behavioral and installation measures
2004	Audit	Audit Recommendations (elec) - Multifamily	MF	LI	DI	12,314.1	0%	32.0	0.005	1.0	$80.00	$80.00	0.02	Walk through audit and recommendations for behavioral and installation measures
2005	Audit	Audit Recommendations (elec) - Mobile	*Mobile*	NLI	Retrofit	19,402.4	0%	32.0	0.006	1.0	$80.00	$80.00	0.02	Walk through audit and recommendations for behavioral and installation measures
2006	Audit	Audit Recommendations (elec) - Mobile	*Mobile*	LI	DI	19,402.4	0%	32.0	0.006	1.0	$80.00	$80.00	0.02	Walk through audit and recommendations for behavioral and installation measures
2007	Audit	Audit Recommendations (gas) - Single-family	SF	NLI	Retrofit	9,318.6	0%	32.0	0.007	1.0	$80.00	$80.00	0.07	Walk through audit and recommendations for behavioral and installation measures
2008	Audit	Audit Recommendations (gas) - Single-family	SF	LI	DI	9,318.6	0%	32.0	0.007	1.0	$80.00	$80.00	0.07	Walk through audit and recommendations for behavioral and installation measures
2009	Audit	Audit Recommendations (gas) - Multifamily	MF	NLI	Retrofit	6,821.7	0%	32.0	0.005	1.0	$80.00	$80.00	0.07	Walk through audit and recommendations for behavioral and installation measures
2010	Audit	Audit Recommendations (gas) - Multifamily	MF	LI	DI	6,821.7	0%	32.0	0.005	1.0	$80.00	$80.00	0.07	Walk through audit and recommendations for behavioral and installation measures
2011	Audit	Audit Recommendations (gas) - Mobile	Mobile	NLI	Retrofit	9,318.6	0%	32.0	0.007	1.0	$80.00	$80.00	0.07	Walk through audit and recommendations for behavioral and installation measures
2012	Audit	Audit Recommendations (gas) - Mobile	Mobile	LI	DI	9,318.6	0%	32.0	0.007	1.0	$80.00	$80.00	0.07	Walk through audit and recommendations for behavioral and installation measures
3001	Behavioral	Home Energy Reports (Heat pump)	SF	N/A	Opt-Out	16,590.8	2%	265.5	0.049	1.0	$7.85	$7.90	1.68	Pre-pay billing

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	Historical Incentive Amount	UCT Ratio	Measure Description
3002	Behavioral	Home Energy Reports (Electric furnace/CAC)	SF	N/A	Opt-Out	21,954.3	2%	351.3	0.051	1.0	$7.85	$7.90	2.13	Distribution of home energy reports encouraging adoption of energy-savings improvements
3003	Behavioral	Pre-pay (Heat pump)	SF	N/A	Opt-In	16,590.8	11%	1,825.0	0.334	3.0	$40.00	$0.00	3E+08	Pre-pay billing
3004	Behavioral	Pre-pay (Electric furnace/CAC)	SF	N/A	Opt-In	21,954.3	11%	2,415.0	0.353	3.0	$40.00	$0.00	3.E+08	Pre-pay billing
3005	Behavioral	Home Energy Management System (Heat pump)	SF	N/A	Retrofit	16,590.8	3%	532.6	0.097	5.0	$90.00	$45.00	2.66	HEMS are hardware and software systems that can control and monitor one or more energy uses in the home
3006	Behavioral	Home Energy Management System (Electric furnace/CAC)	SF	N/A	Retrofit	21,954.3	3%	704.7	0.103	5.0	$90.00	$45.00	3.38	HEMS are hardware and software systems that can control and monitor one or more energy uses in the home
3007	Behavioral	Home Energy Reports (Heat pump)	SF	N/A	NC	15,337.8	2%	245.4	0.036	1.0	$7.85	$7.90	1.55	Pre-pay billing
3008	Behavioral	Pre-pay (Heat pump)	SF	N/A	NC	15,337.8	11%	1,687.2	0.245	3.0	$40.00	$0.00	2.E+08	Pre-pay billing
3009	Behavioral	Home Energy Management System (Heat pump)	SF	N/A	NC	15,337.8	3%	365.0	0.044	5.0	$90.00	$45.00	1.75	HEMS are hardware and software systems that can control and monitor one or more energy uses in the home
3010	Behavioral	Home Energy Reports (Heat pump)	MF	N/A	Opt-Out	11,369.4	2%	181.9	0.022	1.0	$7.85	$7.90	1.10	Pre-pay billing
3011	Behavioral	Home Energy Reports (Electric furnace/CAC)	MF	N/A	Opt-Out	13,171.6	2%	210.7	0.025	1.0	$7.85	$7.90	1.27	Distribution of home energy reports encouraging adoption of energy-savings improvements
3012	Behavioral	Pre-pay (Heat pump)	MF	N/A	Opt-In	11,369.4	11%	1,250.6	0.150	3.0	$40.00	$0.00	2.E+08	Pre-pay billing
3013	Behavioral	Pre-pay (Electric furnace/CAC)	MF	N/A	Opt-In	13,171.6	11%	1,448.9	0.169	3.0	$40.00	$0.00	2E+08	Pre-pay billing
3014	Behavioral	Home Energy Management System (Heat pump)	MF	N/A	Retrofit	11,369.4	3%	422.8	0.049	5.0	$90.00	$45.00	1.97	HEMS are hardware and software systems that can control and monitor one or more energy uses in the home
3015	Behavioral	Home Energy Management System (Electric furnace/CAC)	MF	N/A	Retrofit	13,171.6	3%	492.3	0.071	5.0	$90.00	$45.00	2.39	HEMS are hardware and software systems that can control and monitor one or more energy uses in the home
3016	Behavioral	Home Energy Reports (Heat pump)	MF	N/A	NC	10,959.2	2%	175.3	0.021	1.0	$7.85	$7.90	1.05	Pre-pay billing
3017	Behavioral	Pre-pay (Heat pump)	MF	N/A	NC	10,959.2	11%	1,205.5	0.146	3.0	$40.00	$0.00	2E+08	Pre-pay billing
3018	Behavioral	Home Energy Management System (Heat pump)	MF	N/A	NC	10,959.2	3%	351.8	0.043	5.0	$90.00	$45.00	1.67	HEMS are hardware and software systems that can control and monitor one or more energy uses in the home
3019	Behavioral	Home Energy Reports (Gas furnace/CAC)	SF	N/A	Opt-Out	9,318.6	1%	121.1	0.045	1.0	$7.85	$7.90	1.48	Distribution of home energy reports encouraging adoption of energy-savings improvements
3020	Behavioral	Pre-pay (Gas furnace/CAC)	SF	N/A	Opt-In	9,318.6	11%	1,025.0	0.377	3.0	$40.00	$0.00	3.E+08	Pre-pay billing
3021	Behavioral	Home Energy Management System (Gas furnace/CAC)	SF	N/A	Retrofit	9,318.6	3%	299.1	0.110	5.0	$90.00	$45.00	2.98	HEMS are hardware and software systems that can control and monitor one or more energy uses in the home
3022	Behavioral	Home Energy Reports (Gas furnace/CAC)	SF	N/A	NC	8,582.1	1%	111.6	0.032	1.0	$7.85	$7.90	1.09	Distribution of home energy reports encouraging adoption of energy-savings improvements
3023	Behavioral	Pre-pay (Gas furnace/CAC)	SF	N/A	NC	8,582.1	11%	944.0	0.269	3.0	$40.00	$0.00	2E+08	Pre-pay billing
3024	Behavioral	Home Energy Management System (Gas furnace/CAC)	SF	N/A	NC	8,582.1	3%	275.5	0.078	5.0	$90.00	$45.00	2.18	HEMS are hardware and software systems that can control and monitor one or more energy uses in the home

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	Historical Incentive Amount	UCT Ratio	Measure Description
3025	Behavioral	Home Energy Reports (Gas furnace/CAC)	*MF*	N/A	Opt-Out	6,821.7	1%	88.7	0.022	1.0	$7.85	$7.90	0.91	Distribution of home energy reports encouraging adoption of energy-savings improvements
3026	Behavioral	Pre-pay (Gas furnace/CAC)	*MF*	N/A	Opt-In	6,821.7	11%	750.4	0.183	3.0	$40.00	$0.00	2.E+08	Pre-pay billing
3027	Behavioral	Home Energy Management System (Gas furnace/CAC)	*MF*	N/A	Retrofit	6,821.7	3%	219.0	0.053	5.0	$90.00	$45.00	1.82	HEMS are hardware and software systems that can control and monitor one or more energy uses in the home
3028	Behavioral	Home Energy Reports (Gas furnace/CAC)	*MF*	N/A	NC	10,165.2	1%	132.1	0.021	1.0	$7.85	$7.90	0.96	Distribution of home energy reports encouraging adoption of energy-savings improvements
3029	Behavioral	Pre-pay (Gas furnace/CAC)	*MF*	N/A	NC	10,165.2	11%	1,118.2	0.180	5.0	$40.00	$0.00	3E+08	Pre-pay billing
3030	Behavioral	Home Energy Management System (Gas furnace/CAC)	*MF*	N/A	NC	10,165.2	3%	326.3	0.053	5.0	$90.00	$45.00	1.90	HEMS are hardware and software systems that can control and monitor one or more energy uses in the home
4001	HVAC Equipment	ASHP Tune Up	*SF*	NLI	Retrofit	6,321.2	5%	316.1	0.152	5.0	$64.00	$64.00	1.53	Air source heat pump tune up
4002	HVAC Equipment	Air Source Heat Pump 16 SEER - Heat pump baseline	*SF*	NLI	MO	6,321.2	9%	566.2	0.612	18.0	$870.00	$300.00	2.47	16 SEER 9.0 hspf air source heat pump
4003	HVAC Equipment	Air Source Heat Pump 16 SEER - Furnace baseline	*SF*	NLI	MO	11,684.8	51%	5,929.7	0.922	18.0	$2,121.00	$300.00	13.12	16 SEER 9.0 hspf air source heat pump
4004	HVAC Equipment	AC Tune Up	*SF*	NLI	Retrofit	2,713.0	5%	135.6	0.161	5.0	$64.00	$64.00	1.11	Central air conditioner tune-up
4005	HVAC Equipment	Central Air Conditioner 16 SEER	*SF*	NLI	MO	2,713.0	18%	483.4	0.508	18.0	$400.00	$200.00	3.41	16 SEER central air conditioner
4006	HVAC Equipment	Smart Thermostat - Heat pump baseline	*SF*	NLI	Retrofit	6,321.2	10%	658.6	0.000	15.0	$154.00	$60.00	5.26	Smart thermostat
4007	HVAC Equipment	WIFI Thermostat - Heat pump baseline	SF	NLI	Retrofit	6,321.2	6%	377.8	0.000	15.0	$103.20	$50.00	3.62	WifI (non-smart) thermostat
4008	HVAC Equipment	Smart Thermostat - Furnace baseline	SF	NLI	Retrofit	11,684.8	11%	1,239.0	0.000	15.0	$154.00	$60.00	9.89	Smart thermostat
4009	HVAC Equipment	WIFI Thermostat - Furnace baseline	SF	NLI	Retrofit	11,684.8	5%	568.0	0.000	15.0	$103.20	$50.00	5.44	WifI (non-smart) thermostat
4010	HVAC Equipment	Filter Whistle	SF	NLI	Retrofit	9,132.9	4%	319.7	0.109	15.0	$1.64	$1.64	139.02	Whistle to remind owners to change air filter
4011	HVAC Equipment	ASHP Tune Up	SF	LI	DI	6,321.2	5%	316.1	0.152	5.0	$64.00	$64.00	1.53	Air source heat pump tune up
4012	HVAC Equipment	Air Source Heat Pump 16 SEER - Heat pump baseline	SF	LI	DI	6,321.2	9%	566.2	0.612	18.0	$5,400.00	$5,400.00	0.14	16 SEER 9.0 hspf air source heat pump
4013	HVAC Equipment	Air Source Heat Pump 16 SEER - Furnace baseline	SF	LI	DI	11,684.8	51%	5,929.7	0.922	18.0	$5,400.00	$5,400.00	0.73	16 SEER 9.0 hspf air source heat pump
4014	HVAC Equipment	AC Tune Up	SF	LI	DI	2,713.0	5%	135.6	0.161	5.0	$64.00	$64.00	1.11	Central air conditioner tune-up
4015	HVAC Equipment	Central Air Conditioner 16 SEER	SF	LI	DI	2,713.0	18%	483.4	0.508	18.0	$3,500.00	$3,500.00	0.20	16 SEER central air conditioner
4016	HVAC Equipment	Smart Thermostat - Heat pump baseline	SF	LI	DI	6,321.2	10%	658.6	0.000	15.0	$154.00	$154.00	2.05	Smart thermostat
4017	HVAC Equipment	WIFI Thermostat - Heat pump baseline	SF	LI	DI	6,321.2	6%	377.8	0.000	15.0	$103.20	$103.20	1.75	WifI (non-smart) thermostat
4018	HVAC Equipment	Smart Thermostat - Furnace baseline	SF	LI	DI	11,684.8	11%	1,239.0	0.000	15.0	$154.00	$154.00	3.85	Smart thermostat
4019	HVAC Equipment	WIFI Thermostat - Furnace baseline	SF	LI	DI	11,684.8	5%	568.0	0.000	15.0	$103.20	$103.20	2.64	WifI (non-smart) thermostat
4020	HVAC Equipment	Filter Whistle	SF	LI	DI	9,132.9	4%	319.7	0.109	15.0	$1.64	$1.64	139.02	Whistle to remind owners to change air filter

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	Historical Incentive Amount	UCT Ratio	Measure Description
4021	HVAC Equipment	Air Source Heat Pump 18 SEER - Heat pump baseline	SF	NLI	MO	6,321.2	17%	1,058.6	0.770	18.0	$1,156.00	$500.00	2.33	18 SEER air source heat pump
4022	HVAC Equipment	Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline	SF	NLI	MO	6,321.2	6%	349.5	2.740	18.0	$1,666.67	$500.00	4.51	17 SEER / 9.5 hspf ductless heat pump
4023	HVAC Equipment	Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline	SF	NLI	MO	6,321.2	7%	427.5	2.650	18.0	$2,333.33	$500.00	4.46	19 SEER / 9.5 hspf ductless heat pump
4024	HVAC Equipment	Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline	SF	NLI	MO	6,321.2	8%	523.0	2.589	18.0	$2,833.33	$500.00	4.47	21 SEER / 10.0 hspf ductless heat pump
4025	HVAC Equipment	Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline	SF	NLI	MO	6,321.2	9%	575.2	2.542	18.0	$3,333.33	$500.00	4.46	23 SEER / 10.0 hspf ductless heat pump
4026	HVAC Equipment	Dual Fuel Air Source Heat Pump 16 SEER - Heat pump baseline	SF	NLI	MO	6,321.2	45%	2,871.9	0.612	18.0	$1,000.00	$300.00	2.24	16 SEER Dual-fuel heat pump
4027	HVAC Equipment	Dual Fuel Air Source Heat Pump 18 SEER - Heat pump baseline	SF	NLI	MO	6,321.2	50%	3,171.0	0.770	18.0	$1,286.00	$500.00	1.97	18 SEER Dual-fuel heat pump
4028	HVAC Equipment	Ground Source Heat Pump - Heat pump baseline	SF	NLI	MO	6,321.2	8%	491.2	-0.213	18.0	$3,609.00	$1,000.00	0.12	Geothermal heat pump
4029	HVAC Equipment	Air Source Heat Pump 18 SEER - Furnace baseline	SF	NLI	MO	11,684.8	55%	6,422.1	1.059	18.0	$2,407.00	$500.00	8.71	18 SEER air source heat pump
4030	HVAC Equipment	Ductless Heat Pump 17 SEER 9.5 HSPF - Furnace baseline	SF	NLI	MO	11,684.8	26%	2,988.6	2.915	18.0	$1,666.67	$500.00	7.85	17 SEER / 9.5 hspf ductless heat pump
4031	HVAC Equipment	Ductless Heat Pump 19 SEER 9.5 HSPF - Furnace baseline	SF	NLI	MO	11,684.8	26%	3,066.6	2.825	18.0	$2,333.33	$500.00	7.80	19 SEER / 9.5 hspf ductless heat pump
4032	HVAC Equipment	Ductless Heat Pump 21 SEER 10.0 HSPF - Furnace baseline	SF	NLI	MO	11,684.8	27%	3,207.2	2.765	18.0	$2,833.33	$500.00	7.86	21 SEER / 10.0 hspf ductless heat pump
4033	HVAC Equipment	Ductless Heat Pump 23 SEER 10.0 HSPF - Furnace baseline	SF	NLI	MO	11,684.8	28%	3,259.3	2.718	18.0	$3,333.33	$500.00	7.85	23 SEER / 10.0 hspf ductless heat pump
4034	HVAC Equipment	Dual Fuel Air Source Heat Pump 16 SEER - Furnace baseline	SF	NLI	MO	11,684.8	70%	8,235.5	0.922	18.0	$2,848.00	$300.00	12.88	16 SEER Dual-fuel heat pump
4035	HVAC Equipment	Dual Fuel Air Source Heat Pump 18 SEER - Furnace baseline	SF	NLI	MO	11,684.8	73%	8,534.6	1.059	18.0	$3,134.00	$500.00	8.36	18 SEER Dual-fuel heat pump
4036	HVAC Equipment	Ground Source Heat Pump - Furnace baseline	SF	NLI	MO	11,684.8	50%	5,854.7	0.082	18.0	$3,609.00	$1,000.00	3.31	Geothermal heat pump
4037	HVAC Equipment	Central Air Conditioner 18 SEER	SF	NLI	MO	2,713.0	30%	823.3	0.950	18.0	$800.00	$400.00	2.97	18 SEER central air conditioner
4038	HVAC Equipment	ECM HVAC Motor	SF	NLI	Retrofit	9,132.9	5%	412.0	0.000	10.0	$97.00	$50.00	2.73	Electrically commutated motor
4039	HVAC Equipment	ENERGY STAR Room Air Conditioner	SF	N/A	MO	489.9	10%	49.0	0.110	9.0	$40.00	$10.00	4.83	ENERGY STAR Room Air Conditioner in place of standard efficiency alternative
4040	HVAC Equipment	Smart Room AC_ET	SF	N/A	MO	489.9	3%	14.7	0.033	9.0	$205.00	$60.00	0.24	Window-mounted AC unit with smart capability
4041	HVAC Equipment	Smart Room AC - controls retrofit_ET	SF	N/A	Retrofit	489.9	3%	14.7	0.033	9.0	$110.00	$30.00	0.48	Smart control retrofit kit
4042	HVAC Equipment	Room Air Conditioner Recycling	SF	N/A	Recycle	656.3	100%	656.3	1.475	3.0	$129.00	$40.00	6.17	Recycling of tertiary room air conditioner
4043	HVAC Equipment	Programmable Thermostat - Heat pump baseline	SF	N/A	Retrofit	6,321.2	4%	229.0	0.000	15.0	$35.00	$10.00	10.97	Programmable thermostat
4044	HVAC Equipment	Programmable Thermostat - Furnace baseline	SF	N/A	Retrofit	11,684.8	3%	354.6	0.000	15.0	$35.00	$10.00	16.99	Programmable thermostat

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4045	HVAC Equipment	Smart Vents/Sensors_ET	SF	N/A	Retrofit	9,132.9	10%	913.3	0.313	15.0	$800.00	$400.00	1.63	Smart vents relay temperature and occupancy information to a smart thermostat (or other control device) to reduce energy waste in unoccupied areas of the home
4046	HVAC Equipment	Smart Ceiling Fan_ET	SF	N/A	Retrofit	2,643.1	8%	198.2	0.235	20.0	$2,400.00	$1,000.00	0.31	Smart ceiling fans save energy by turning off when rooms are unoccupied and by helping the home's central HVAC maintain indoor comfort
4047	HVAC Equipment	Whole House Attic Fan	SF	N/A	Retrofit	2,643.1	13%	338.0	0.000	20.0	$546.60	$275.00	0.74	Whole house attic fan
4048	HVAC Equipment	Attic Fan	SF	N/A	Retrofit	2,643.1	10%	264.3	0.000	20.0	$120.48	$40.00	3.96	Attic fans can reduce the need for AC by reducing heat transfer from the attic through the ceiling of the house
4049	HVAC Equipment	Air Source Heat Pump 16 SEER - Heat pump baseline	SF	N/A	NC	4,984.5	8%	419.9	0.405	18.0	$870.00	$300.00	1.97	16 SEER 9.0 hspf air source heat pump
4050	HVAC Equipment	Air Source Heat Pump 18 SEER - Heat pump baseline	SF	N/A	NC	4,984.5	17%	825.1	0.576	18.0	$1,156.00	$500.00	1.92	18 SEER air source heat pump
4051	HVAC Equipment	Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline	SF	N/A	NC	4,984.5	6%	319.4	1.931	18.0	$1,666.67	$500.00	3.57	17 SEER / 9.5 hspf ductless heat pump
4052	HVAC Equipment	Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline	SF	N/A	NC	4,984.5	8%	397.4	1.841	18.0	$2,333.33	$500.00	3.51	19 SEER / 9.5 hspf ductless heat pump
4053	HVAC Equipment	Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline	SF	N/A	NC	4,984.5	10%	485.0	1.780	18.0	$2,833.33	$500.00	3.51	21 SEER / 10.0 hspf ductless heat pump
4054	HVAC Equipment	Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline	SF	N/A	NC	4,984.5	11%	537.1	1.733	18.0	$3,333.33	$500.00	3.48	23 SEER / 10.0 hspf ductless heat pump
4055	HVAC Equipment	Dual Fuel Air Source Heat Pump 16 SEER - Heat pump baseline	SF	N/A	NC	4,984.5	36%	1,797.4	0.405	18.0	$1,000.00	$300.00	2.09	16 SEER Dual-fuel heat pump
4056	HVAC Equipment	Dual Fuel Air Source Heat Pump 18 SEER - Heat pump baseline	SF	N/A	NC	4,984.5	42%	2,083.8	0.576	18.0	$1,286.00	$500.00	1.86	18 SEER Dual-fuel heat pump
4057	HVAC Equipment	Ground Source Heat Pump - Heat pump baseline	SF	N/A	NC	4,984.5	7%	368.9	-0.084	18.0	$3,609.00	$1,000.00	0.14	Geothermal heat pump
4058	HVAC Equipment	Central Air Conditioner 16 SEER	SF	N/A	NC	2,364.4	18%	432.6	0.429	18.0	$400.00	$200.00	3.06	16 SEER central air conditioner
4059	HVAC Equipment	Central Air Conditioner 18 SEER	SF	N/A	NC	2,364.4	30%	711.3	0.716	18.0	$800.00	$400.00	2.57	18 SEER central air conditioner
4060	HVAC Equipment	ENERGY STAR Room Air Conditioner	SF	N/A	NC	489.9	10%	49.0	0.110	9.0	$40.00	$10.00	4.83	ENERGY STAR Room Air Conditioner in place of standard efficiency alternative
4061	HVAC Equipment	Smart Room AC_ET	SF	N/A	NC	489.9	3%	14.7	0.033	9.0	$205.00	$60.00	0.24	Window-mounted AC unit with smart capability
4062	HVAC Equipment	Programmable Thermostat - Heat pump baseline	SF	N/A	NC	4,984.5	4%	185.1	0.000	15.0	$35.00	$10.00	8.87	Programmable thermostat
4063	HVAC Equipment	Smart Thermostat - Heat pump baseline	SF	N/A	NC	4,984.5	10%	517.9	0.000	15.0	$154.00	$60.00	4.14	Smart thermostat
4064	HVAC Equipment	WIFI Thermostat - Heat pump baseline	SF	N/A	NC	4,984.5	6%	306.6	0.000	15.0	$103.20	$50.00	2.94	WifI (non-smart) thermostat
4065	HVAC Equipment	Filter Whistle	SF	N/A	NC	4,984.5	4%	174.5	0.078	15.0	$1.64	$1.64	86.34	Whistle to remind owners to change air filter

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4066	HVAC Equipment	Smart Vents/Sensors_ET	SF	N/A	NC	4,984.5	10%	498.4	0.223	15.0	$800.00	$400.00	1.01	Smart vents relay temperature and occupancy information to a smart thermostat (or other control device) to reduce energy waste in unoccupied areas of the home
4067	HVAC Equipment	ASHP Tune Up	MF	NLI	Retrofit	3,171.0	5%	158.5	0.068	5.0	$64.00	$64.00	0.82	Air source heat pump tune up
4068	HVAC Equipment	Air Source Heat Pump 16 SEER - Heat pump baseline	MF	NLI	MO	3,171.0	7%	217.1	0.182	18.0	$870.00	$300.00	0.90	16 SEER 9.0 hspf air source heat pump
4069	HVAC Equipment	Air Source Heat Pump 16 SEER - Furnace baseline	MF	NLI	MO	4,973.1	41%	2,019.3	0.391	18.0	$2,121.00	$300.00	4.80	16 SEER 9.0 hspf air source heat pump
4070	HVAC Equipment	AC Tune Up	MF	NLI	Retrofit	2,017.5	5%	100.9	0.077	5.0	$64.00	$64.00	0.71	Central air conditioner tune-up
4071	HVAC Equipment	Central Air Conditioner 16 SEER	MF	NLI	MO	2,017.5	19%	382.4	0.259	18.0	$400.00	$200.00	2.30	16 SEER central air conditioner
4072	HVAC Equipment	Smart Thermostat - Heat pump baseline	MF	NLI	Retrofit	3,171.0	10%	324.3	0.000	15.0	$154.00	$60.00	2.59	Smart thermostat
4073	HVAC Equipment	WIFI Thermostat - Heat pump baseline	MF	NLI	Retrofit	3,171.0	7%	226.4	0.000	15.0	$103.20	$50.00	2.17	WifI (non-smart) thermostat
4074	HVAC Equipment	Smart Thermostat - Furnace baseline	MF	NLI	Retrofit	4,973.1	10%	518.2	0.000	15.0	$154.00	$60.00	4.14	Smart thermostat
4075	HVAC Equipment	WIFI Thermostat - Furnace baseline	MF	NLI	Retrofit	4,973.1	6%	297.1	0.000	15.0	$103.20	$50.00	2.85	WifI (non-smart) thermostat
4076	HVAC Equipment	Filter Whistle	MF	NLI	Retrofit	4,115.7	4%	144.0	0.051	15.0	$1.64	$1.64	68.64	Whistle to remind owners to change air filter
4077	HVAC Equipment	ASHP Tune Up	MF	LI	DI	3,171.0	5%	158.5	0.068	5.0	$64.00	$64.00	0.82	Air source heat pump tune up
4078	HVAC Equipment	Air Source Heat Pump 16 SEER - Heat pump baseline	MF	LI	DI	3,171.0	7%	217.1	0.182	18.0	$5,400.00	$5,400.00	0.05	16 SEER 9.0 hspf air source heat pump
4079	HVAC Equipment	Air Source Heat Pump 16 SEER - Furnace baseline	MF	LI	DI	4,973.1	41%	2,019.3	0.391	18.0	$5,400.00	$5,400.00	0.27	16 SEER 9.0 hspf air source heat pump
4080	HVAC Equipment	AC Tune Up	MF	LI	DI	2,017.5	5%	100.9	0.077	5.0	$64.00	$64.00	0.71	Central air conditioner tune-up
4081	HVAC Equipment	Central Air Conditioner 16 SEER	MF	LI	DI	2,017.5	19%	382.4	0.259	18.0	$3,500.00	$3,500.00	0.13	16 SEER central air conditioner
4082	HVAC Equipment	Smart Thermostat - Heat pump baseline	MF	LI	DI	3,171.0	10%	324.3	0.000	15.0	$154.00	$154.00	1.01	Smart thermostat
4083	HVAC Equipment	WIFI Thermostat - Heat pump baseline	MF	LI	DI	3,171.0	7%	226.4	0.000	15.0	$103.20	$103.20	1.05	WifI (non-smart) thermostat
4084	HVAC Equipment	Smart Thermostat - Furnace baseline	MF	LI	DI	4,973.1	10%	518.2	0.000	15.0	$154.00	$154.00	1.61	Smart thermostat
4085	HVAC Equipment	WIFI Thermostat - Furnace baseline	MF	LI	DI	4,973.1	6%	297.1	0.000	15.0	$103.20	$103.20	1.38	WifI (non-smart) thermostat
4086	HVAC Equipment	Filter Whistle	MF	LI	DI	4,115.7	4%	144.0	0.051	15.0	$1.64	$1.64	68.64	Whistle to remind owners to change air filter
4087	HVAC Equipment	Air Source Heat Pump 18 SEER - Heat pump baseline	MF	NLI	MO	3,171.0	16%	500.3	0.330	18.0	$1,156.00	$500.00	1.10	18 SEER air source heat pump
4088	HVAC Equipment	Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline	MF	NLI	MO	3,171.0	9%	270.4	1.065	18.0	$1,666.67	$500.00	2.34	17 SEER / 9.5 hspf ductless heat pump
4089	HVAC Equipment	Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline	MF	NLI	MO	3,171.0	11%	348.4	0.975	18.0	$2,333.33	$500.00	2.25	19 SEER / 9.5 hspf ductless heat pump
4090	HVAC Equipment	Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline	MF	NLI	MO	3,171.0	13%	422.8	0.914	18.0	$2,833.33	$500.00	2.22	21 SEER / 10.0 hspf ductless heat pump

Vectren Electric **Residential Measure Assumptions**

Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	Historical Incentive Amount	UCT Ratio	Measure Description
4091	HVAC Equipment	Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline	MF	NLI	MO	3,171.0	15%	475.0	0.867	18.0	$3,333.33	$500.00	2.19	23 SEER / 10.0 hspf ductless heat pump
4092	HVAC Equipment	Dual Fuel Air Source Heat Pump 16 SEER - Heat pump baseline	MF	NLI	MO	3,171.0	29%	918.5	0.182	18.0	$1,000.00	$300.00	0.82	16 SEER Dual-fuel heat pump
4093	HVAC Equipment	Dual Fuel Air Source Heat Pump 18 SEER - Heat pump baseline	MF	NLI	MO	3,171.0	36%	1,141.1	0.330	18.0	$1,286.00	$500.00	0.99	18 SEER Dual-fuel heat pump
4094	HVAC Equipment	Air Source Heat Pump 18 SEER - Furnace baseline	MF	NLI	MO	4,973.1	46%	2,302.4	0.535	18.0	$2,407.00	$500.00	3.45	18 SEER air source heat pump
4095	HVAC Equipment	Ductless Heat Pump 17 SEER 9.5 HSPF - Furnace baseline	MF	NLI	MO	4,973.1	23%	1,137.5	1.242	18.0	$1,666.67	$500.00	3.64	17 SEER / 9.5 hspf ductless heat pump
4096	HVAC Equipment	Ductless Heat Pump 19 SEER 9.5 HSPF - Furnace baseline	MF	NLI	MO	4,973.1	24%	1,215.5	1.152	18.0	$2,333.33	$500.00	3.56	19 SEER / 9.5 hspf ductless heat pump
4097	HVAC Equipment	Ductless Heat Pump 21 SEER 10.0 HSPF - Furnace baseline	MF	NLI	MO	4,973.1	26%	1,304.1	1.091	18.0	$2,833.33	$500.00	3.54	21 SEER / 10.0 hspf ductless heat pump
4098	HVAC Equipment	Ductless Heat Pump 23 SEER 10.0 HSPF - Furnace baseline	MF	NLI	MO	4,973.1	27%	1,356.3	1.044	18.0	$3,333.33	$500.00	3.51	23 SEER / 10.0 hspf ductless heat pump
4099	HVAC Equipment	Dual Fuel Air Source Heat Pump 16 SEER - Furnace baseline	MF	NLI	MO	4,973.1	55%	2,720.7	0.391	18.0	$2,848.00	$300.00	4.72	16 SEER Dual-fuel heat pump
4100	HVAC Equipment	Dual Fuel Air Source Heat Pump 18 SEER - Furnace baseline	MF	NLI	MO	4,973.1	59%	2,943.3	0.535	18.0	$3,134.00	$500.00	3.33	18 SEER Dual-fuel heat pump
4101	HVAC Equipment	Central Air Conditioner 18 SEER	MF	NLI	MO	2,017.5	31%	631.3	0.470	18.0	$800.00	$400.00	1.91	18 SEER central air conditioner
4102	HVAC Equipment	ECM HVAC Motor	MF	NLI	Retrofit	4,115.7	10%	412.0	0.000	10.0	$97.00	$50.00	2.73	Electrically commutated motor
4103	HVAC Equipment	ENERGY STAR Room Air Conditioner	MF	N/A	MO	489.9	10%	49.0	0.110	9.0	$40.00	$10.00	4.83	ENERGY STAR Room Air Conditioner in place of standard efficiency alternative
4104	HVAC Equipment	Smart Room AC_ET	MF	N/A	MO	489.9	3%	14.7	0.033	9.0	$205.00	$60.00	0.24	Window-mounted AC unit with smart capability
4105	HVAC Equipment	Smart Room AC - controls retrofit_ET	MF	N/A	Retrofit	489.9	3%	14.7	0.033	9.0	$110.00	$30.00	0.48	Smart control retrofit kit
4106	HVAC Equipment	Room Air Conditioner Recycling	MF	N/A	Recycle	656.3	100%	656.3	1.475	3.0	$129.00	$40.00	6.17	Recycling of tertiary room air conditioner
4107	HVAC Equipment	Programmable Thermostat - Heat pump baseline	MF	N/A	Retrofit	3,171.0	4%	134.3	0.000	15.0	$35.00	$10.00	6.43	Programmable thermostat
4108	HVAC Equipment	Programmable Thermostat - Furnace baseline	MF	N/A	Retrofit	4,973.1	4%	180.1	0.000	15.0	$35.00	$10.00	8.63	Programmable thermostat
4109	HVAC Equipment	Smart Vents/Sensors_ET	MF	N/A	Retrofit	4,115.7	10%	411.6	0.145	15.0	$800.00	$400.00	0.80	Smart vents relay temperature and occupancy information to a smart thermostat (or other control device) to reduce energy waste in unoccupied areas of the home
4110	HVAC Equipment	Smart Ceiling Fan_ET	MF	N/A	Retrofit	1,943.4	7%	145.8	0.109	20.0	$2,400.00	$1,000.00	0.20	Smart ceiling fans save energy by turning off when rooms are unoccupied and by helping the home’s central HVAC maintain indoor comfort
4111	HVAC Equipment	Whole House Attic Fan	MF	N/A	Retrofit	1,943.4	17%	338.0	0.000	20.0	$546.60	$275.00	0.74	Whole house attic fan
4112	HVAC Equipment	Attic Fan	MF	N/A	Retrofit	1,943.4	10%	194.3	0.000	20.0	$120.48	$40.00	2.91	Attic fans can reduce the need for AC by reducing heat transfer from the attic through the ceiling of the house

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4113	HVAC Equipment	Air Source Heat Pump 16 SEER - Heat pump baseline	MF	N/A	NC	2,870.1	6%	185.4	0.185	18.0	$870.00	$300.00	0.81	16 SEER 9.0 hspf air source heat pump
4114	HVAC Equipment	Air Source Heat Pump 18 SEER - Heat pump baseline	MF	N/A	NC	2,870.1	16%	445.7	0.329	18.0	$1,156.00	$500.00	1.00	18 SEER air source heat pump
4115	HVAC Equipment	Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline	MF	N/A	NC	2,870.1	9%	265.3	1.031	18.0	$1,666.67	$500.00	2.12	17 SEER / 9.5 hspf ductless heat pump
4116	HVAC Equipment	Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline	MF	N/A	NC	2,870.1	12%	343.3	0.941	18.0	$2,333.33	$500.00	2.04	19 SEER / 9.5 hspf ductless heat pump
4117	HVAC Equipment	Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline	MF	N/A	NC	2,870.1	15%	416.4	0.880	18.0	$2,833.33	$500.00	2.02	21 SEER / 10.0 hspf ductless heat pump
4118	HVAC Equipment	Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline	MF	N/A	NC	2,870.1	16%	468.6	0.833	18.0	$3,333.33	$500.00	1.99	23 SEER / 10.0 hspf ductless heat pump
4119	HVAC Equipment	Dual Fuel Air Source Heat Pump 16 SEER - Heat pump baseline	MF	N/A	NC	2,870.1	28%	815.1	0.185	18.0	$1,000.00	$300.00	0.73	16 SEER Dual-fuel heat pump
4120	HVAC Equipment	Dual Fuel Air Source Heat Pump 18 SEER - Heat pump baseline	MF	N/A	NC	2,870.1	36%	1,020.9	0.329	18.0	$1,286.00	$500.00	0.89	18 SEER Dual-fuel heat pump
4121	HVAC Equipment	Central Air Conditioner 16 SEER	MF	N/A	NC	1,897.8	20%	378.3	0.295	18.0	$400.00	$200.00	2.36	16 SEER central air conditioner
4122	HVAC Equipment	Central Air Conditioner 18 SEER	MF	N/A	NC	1,897.8	32%	602.1	0.498	18.0	$800.00	$400.00	1.87	18 SEER central air conditioner
4123	HVAC Equipment	ENERGY STAR Room Air Conditioner	MF	N/A	NC	489.9	10%	49.0	0.110	9.0	$40.00	$10.00	4.83	ENERGY STAR Room Air Conditioner in place of standard efficiency alternative
4124	HVAC Equipment	Smart Room AC_ET	MF	N/A	NC	489.9	3%	14.7	0.033	9.0	$205.00	$60.00	0.24	Window-mounted AC unit with smart capability
4125	HVAC Equipment	Programmable Thermostat - Heat pump baseline	MF	N/A	NC	2,870.1	4%	122.7	0.000	15.0	$35.00	$10.00	5.88	Programmable thermostat
4126	HVAC Equipment	Smart Thermostat - Heat pump baseline	MF	N/A	NC	2,870.1	10%	293.2	0.000	15.0	$154.00	$60.00	2.34	Smart thermostat
4127	HVAC Equipment	WIFI Thermostat - Heat pump baseline	MF	N/A	NC	2,870.1	7%	207.0	0.000	15.0	$103.20	$50.00	1.98	WifI (non-smart) thermostat
4128	HVAC Equipment	Filter Whistle	MF	N/A	NC	2,870.1	4%	100.5	0.046	15.0	$1.64	$1.64	51.70	Whistle to remind owners to change air filter
4129	HVAC Equipment	Smart Vents/Sensors_ET	MF	N/A	NC	2,870.1	10%	287.0	0.133	15.0	$800.00	$400.00	0.61	Smart vents relay temperature and occupancy information to a smart thermostat (or other control device) to reduce energy waste in unoccupied areas of the home
4130	HVAC Equipment	Smart Thermostat - Gas / CAC	SF	NLI	Retrofit	2,939.6	10%	292.7	0.000	15.0	$154.00	$60.00	7.41	Smart thermostat
4131	HVAC Equipment	WIFI Thermostat - Gas / CAC	SF	NLI	Retrofit	2,939.6	9%	258.0	0.000	15.0	$103.20	$50.00	4.36	WifI (non-smart) thermostat
4132	HVAC Equipment	Filter Whistle	SF	NLI	Retrofit	2,939.6	3%	95.2	0.120	15.0	$1.64	$1.64	105.83	Whistle to remind owners to change air filter
4133	HVAC Equipment	Smart Thermostat - Gas / CAC	SF	LI	DI	2,939.6	10%	292.7	0.000	15.0	$154.00	$154.00	2.89	Smart thermostat
4134	HVAC Equipment	WIFI Thermostat - Gas / CAC	SF	LI	DI	2,939.6	9%	258.0	0.000	15.0	$103.20	$103.20	2.11	WifI (non-smart) thermostat
4135	HVAC Equipment	Filter Whistle	SF	LI	DI	2,939.6	3%	95.2	0.120	15.0	$1.64	$1.64	105.83	Whistle to remind owners to change air filter
4136	HVAC Equipment	Programmable Thermostat - Gas / CAC	SF	N/A	Retrofit	2,939.6	5%	149.8	0.000	15.0	$35.00	$10.00	13.49	Programmable thermostat

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4137	HVAC Equipment	Smart Vents/Sensors_ET	SF	N/A	Retrofit	2,939.6	10%	294.0	0.343	15.0	$800.00	$400.00	1.60	Smart vents relay temperature and occupancy information to a smart thermostat (or other control device) to reduce energy waste in unoccupied areas of the home
4138	HVAC Equipment	Programmable Thermostat - Gas / CAC	SF	N/A	NC	2,479.3	5%	129.5	0.000	18.0	$35.00	$10.00	11.87	Programmable thermostat
4139	HVAC Equipment	Smart Thermostat - Gas / CAC	SF	N/A	NC	2,479.3	10%	245.9	0.000	15.0	$154.00	$60.00	5.28	Smart thermostat
4140	HVAC Equipment	WIFI Thermostat - Gas / CAC	SF	N/A	NC	2,479.3	9%	223.6	0.000	15.0	$103.20	$50.00	3.38	WifI (non-smart) thermostat
4141	HVAC Equipment	Filter Whistle	SF	N/A	NC	2,479.3	3%	81.9	0.107	15.0	$1.64	$1.64	83.65	Whistle to remind owners to change air filter
4142	HVAC Equipment	Smart Vents/Sensors_ET	SF	N/A	NC	2,479.3	10%	247.9	0.305	15.0	$800.00	$400.00	1.21	Smart vents relay temperature and occupancy information to a smart thermostat (or other control device) to reduce energy waste in unoccupied areas of the home
4143	HVAC Equipment	Smart Thermostat - Gas / CAC	MF	NLI	Retrofit	2,163.0	10%	213.2	0.000	15.0	$154.00	$60.00	3.27	Smart thermostat
4144	HVAC Equipment	WIFI Thermostat - Gas / CAC	MF	NLI	Retrofit	2,163.0	9%	202.7	0.000	15.0	$103.20	$50.00	2.53	WifI (non-smart) thermostat
4145	HVAC Equipment	Filter Whistle	MF	NLI	Retrofit	2,163.0	3%	73.4	0.058	15.0	$1.64	$1.64	61.32	Whistle to remind owners to change air filter
4146	HVAC Equipment	Smart Thermostat - Gas / CAC	MF	LI	DI	2,163.0	10%	213.2	0.000	15.0	$154.00	$154.00	1.27	Smart thermostat
4147	HVAC Equipment	WIFI Thermostat - Gas / CAC	MF	LI	DI	2,163.0	9%	202.7	0.000	15.0	$103.20	$103.20	1.22	WifI (non-smart) thermostat
4148	HVAC Equipment	Filter Whistle	MF	LI	DI	2,163.0	3%	73.4	0.058	15.0	$1.64	$1.64	61.32	Whistle to remind owners to change air filter
4149	HVAC Equipment	Programmable Thermostat - Gas / CAC	MF	N/A	Retrofit	2,163.0	5%	117.0	0.000	15.0	$35.00	$10.00	7.56	Programmable thermostat
4150	HVAC Equipment	Smart Vents/Sensors_ET	MF	N/A	Retrofit	2,163.0	10%	216.3	0.166	15.0	$800.00	$400.00	0.83	Smart vents relay temperature and occupancy information to a smart thermostat (or other control device) to reduce energy waste in unoccupied areas of the home
4151	HVAC Equipment	Programmable Thermostat - Gas / CAC	MF	N/A	NC	1,964.8	5%	106.0	0.000	15.0	$35.00	$10.00	7.20	Programmable thermostat
4152	HVAC Equipment	Smart Thermostat - Gas / CAC	MF	N/A	NC	1,964.8	10%	193.8	0.000	15.0	$154.00	$60.00	3.25	Smart thermostat
4153	HVAC Equipment	WIFI Thermostat - Gas / CAC	MF	N/A	NC	1,964.8	9%	183.6	0.000	15.0	$103.20	$50.00	2.40	WifI (non-smart) thermostat
4154	HVAC Equipment	Filter Whistle	MF	N/A	NC	1,964.8	3%	66.5	0.057	15.0	$1.64	$1.64	57.41	Whistle to remind owners to change air filter
4155	HVAC Equipment	Smart Vents/Sensors_ET	MF	N/A	NC	1,964.8	10%	196.5	0.164	15.0	$800.00	$400.00	0.79	Smart vents relay temperature and occupancy information to a smart thermostat (or other control device) to reduce energy waste in unoccupied areas of the home
5001	Lighting	LED 9W (Standard)	SF	NLI	MO	37.5	86%	32.2	0.040	15.0	$1.01	$0.76	25.14	Standard LED Replacing Standard Halogen/CFL Bulb
5002	Lighting	LED 5W Globe (Specialty)	SF	NLI	MO	28.7	84%	24.1	0.023	15.0	$4.00	$3.00	4.36	Specialty LED Replacing Specialty Halogen/Incandescent Bulb

Vectren Electric **Residential Measure Assumptions**

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5003	Lighting	LED R30 Dimmable (Reflector)	SF	NLI	MO	40.1	83%	33.1	0.041	15.0	$5.34	$4.01	4.98	Reflector LED Replacing Standard Halogen/Incandescent Bulb
5004	Lighting	LED Fixtures	SF	NLI	MO	82.0	74%	60.8	0.061	15.0	$20.25	$5.06	8.26	Residential Occupancy Sensors (DIRECT INSTALL)
5005	Lighting	Linear LED	SF	NLI	Retrofit	23.5	44%	10.3	0.014	9.0	$7.00	$5.25	0.73	T8 Linear Tube Fluorescent Replacing T12 LTF
5006	Lighting	Residential Occupancy Sensors	SF	NLI	Retrofit	108.9	35%	38.1	0.048	10.0	$30.00	$7.50	2.46	Residential Occupancy Sensors
5007	Lighting	Smart Lighting Switch_ET	SF	NLI	Retrofit	106.5	35%	37.3	0.047	10.0	$25.00	$6.25	2.88	Residential Occupancy Sensors
5008	Lighting	LED Nightlights	SF	NLI	Retrofit	14.6	93%	13.6	0.005	16.0	$2.75	$0.69	10.02	LED Nightlights Replacing Incandescent Nightlights
5009	Lighting	LED 13W (Exterior)	SF	NLI	MO	126.7	83%	105.2	0.048	15.0	$4.76	$4.00	12.59	Exterior LED Replacing Exterior Halogen/CFL Bulb
5010	Lighting	Exterior Lighting Controls	SF	NLI	Retrofit	178.1	35%	62.3	0.028	10.0	$30.00	$7.50	2.75	Residential Occupancy Sensors
5011	Lighting	DI LED 9W (Standard)	SF	NLI	DI	37.5	86%	32.2	0.040	15.0	$3.00	$3.00	6.35	Standard LED Replacing Standard Halogen/CFL Bulb
5012	Lighting	DI LED 5W Globe (Specialty)	SF	NLI	DI	28.7	84%	24.1	0.023	15.0	$5.00	$5.00	2.62	Specialty LED Replacing Specialty Halogen/Incandescent Bulb (DIRECT INSTALL)
5013	Lighting	DI LED R30 Dimmable (Reflector)	SF	NLI	DI	39.0	83%	32.3	0.040	15.0	$8.63	$8.63	2.25	Reflector LED Replacing Standard Halogen/Incandescent Bulb (DIRECT INSTALL)
5014	Lighting	DI LED Nightlights	SF	NLI	DI	14.6	93%	13.6	0.005	16.0	$2.75	$2.75	2.50	LED Nightlights Replacing Incandescent Nightlights (DIRECT INSTALL)
5015	Lighting	DI LED 9W (Standard)	SF	LI	DI	37.5	86%	32.2	0.040	15.0	$3.00	$3.00	6.35	Standard LED Replacing Standard Halogen/CFL Bulb
5016	Lighting	DI LED 5W Globe (Specialty)	SF	LI	DI	28.7	84%	24.1	0.023	15.0	$5.00	$5.00	2.62	Specialty LED Replacing Specialty Halogen/Incandescent Bulb (DIRECT INSTALL)
5017	Lighting	DI LED R30 Dimmable (Reflector)	SF	LI	DI	39.0	83%	32.3	0.040	15.0	$8.63	$8.63	2.25	Reflector LED Replacing Standard Halogen/Incandescent Bulb (DIRECT INSTALL)
5018	Lighting	DI LED Nightlights	SF	LI	DI	14.6	93%	13.6	0.005	16.0	$2.75	$2.75	2.50	LED Nightlights Replacing Incandescent Nightlights (DIRECT INSTALL)
5019	Lighting	DI LED 13W (Exterior)	SF	LI	DI	126.7	83%	105.2	0.048	15.0	$6.76	$6.76	7.45	Exterior LED Replacing Exterior Halogen/CFL Bulb
5020	Lighting	LED 9W (Standard)	SF	N/A	NC	37.5	86%	32.2	0.040	15.0	$1.01	$0.76	25.14	Standard LED Replacing Standard Halogen/CFL Bulb
5021	Lighting	LED 5W Globe (Specialty)	SF	N/A	NC	28.7	84%	24.1	0.023	15.0	$4.00	$3.00	4.36	Specialty LED Replacing Specialty Halogen/Incandescent Bulb
5022	Lighting	LED R30 Dimmable (Reflector)	SF	N/A	NC	40.1	83%	33.1	0.041	15.0	$5.34	$4.01	4.98	Reflector LED Replacing Standard Halogen/Incandescent Bulb
5023	Lighting	LED Fixtures	SF	N/A	NC	82.0	74%	60.8	0.061	15.0	$20.25	$5.06	8.26	Residential Occupancy Sensors (DIRECT INSTALL)
5024	Lighting	Linear LED	SF	N/A	NC	23.5	44%	10.3	0.014	9.0	$2.50	$1.88	2.06	T8 Linear Tube Fluorescent Replacing T12 LTF
5025	Lighting	Residential Occupancy Sensors	SF	N/A	NC	108.9	35%	38.1	0.048	10.0	$30.00	$7.50	2.46	Residential Occupancy Sensors
5026	Lighting	Smart Lighting Switch_ET	SF	N/A	NC	106.5	35%	37.3	0.047	10.0	$25.00	$6.25	2.88	Residential Occupancy Sensors
5027	Lighting	LED Nightlights	SF	N/A	NC	14.6	93%	13.6	0.005	16.0	$2.75	$0.69	10.02	LED Nightlights Replacing Incandescent Nightlights
5028	Lighting	LED 13W (Exterior)	SF	N/A	NC	126.7	83%	105.2	0.048	15.0	$4.76	$4.00	12.59	Exterior LED Replacing Exterior Halogen/CFL Bulb
5029	Lighting	Exterior Lighting Controls	SF	N/A	NC	178.1	35%	62.3	0.028	10.0	$30.00	$7.50	2.75	Residential Occupancy Sensors

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5030	Lighting	LED 9W (Standard)	MF	NLI	MO	37.5	86%	32.2	0.040	15.0	$1.01	$0.76	25.14	Standard LED Replacing Standard Halogen/CFL Bulb
5031	Lighting	LED 5W Globe (Specialty)	MF	NLI	MO	28.7	84%	24.1	0.023	15.0	$4.00	$3.00	4.36	Specialty LED Replacing Specialty Halogen/Incandescent Bulb
5032	Lighting	LED R30 Dimmable (Reflector)	MF	NLI	MO	40.1	83%	33.1	0.041	15.0	$5.34	$4.01	4.98	Reflector LED Replacing Standard Halogen/Incandescent Bulb
5033	Lighting	LED Fixtures	MF	NLI	MO	82.0	74%	60.8	0.061	15.0	$20.25	$5.06	8.26	Residential Occupancy Sensors (DIRECT INSTALL)
5034	Lighting	Linear LED	MF	NLI	Retrofit	23.5	44%	10.3	0.014	9.0	$7.00	$5.25	0.73	T8 Linear Tube Fluorescent Replacing T12 LTF
5035	Lighting	Residential Occupancy Sensors	MF	NLI	Retrofit	108.9	35%	38.1	0.048	10.0	$30.00	$7.50	2.46	Residential Occupancy Sensors
5036	Lighting	Smart Lighting Switch_ET	MF	NLI	Retrofit	106.5	35%	37.3	0.047	10.0	$25.00	$6.25	2.88	Residential Occupancy Sensors
5037	Lighting	LED Nightlights	MF	NLI	Retrofit	14.6	93%	13.6	0.005	16.0	$2.75	$0.69	10.02	LED Nightlights Replacing Incandescent Nightlights
5038	Lighting	LED 13W (Exterior)	MF	NLI	MO	126.7	83%	105.2	0.048	15.0	$4.76	$4.00	12.59	Exterior LED Replacing Exterior Halogen/CFL Bulb
5039	Lighting	Exterior Lighting Controls	MF	NLI	Retrofit	178.1	35%	62.3	0.028	10.0	$30.00	$7.50	2.75	Residential Occupancy Sensors
5040	Lighting	DI LED 9W (Standard)	MF	NLI	DI	37.5	86%	32.2	0.040	15.0	$3.00	$3.00	6.35	Standard LED Replacing Standard Halogen/CFL Bulb
5041	Lighting	DI LED 5W Globe (Specialty)	MF	NLI	DI	28.7	84%	24.1	0.023	15.0	$5.00	$5.00	2.62	Specialty LED Replacing Specialty Halogen/Incandescent Bulb (DIRECT INSTALL)
5042	Lighting	DI LED R30 Dimmable (Reflector)	MF	NLI	DI	39.0	83%	32.3	0.040	15.0	$8.63	$8.63	2.25	Reflector LED Replacing Standard Halogen/Incandescent Bulb (DIRECT INSTALL)
5043	Lighting	DI LED Nightlights	MF	NLI	DI	14.6	93%	13.6	0.005	16.0	$2.75	$2.75	2.50	LED Nightlights Replacing Incandescent Nightlights (DIRECT INSTALL)
5044	Lighting	DI LED 9W (Standard)	MF	LI	DI	37.5	86%	32.2	0.040	15.0	$3.00	$3.00	6.35	Standard LED Replacing Standard Halogen/CFL Bulb
5045	Lighting	DI LED 5W Globe (Specialty)	MF	LI	DI	28.7	84%	24.1	0.023	15.0	$5.00	$5.00	2.62	Specialty LED Replacing Specialty Halogen/Incandescent Bulb (DIRECT INSTALL)
5046	Lighting	DI LED R30 Dimmable (Reflector)	MF	LI	DI	39.0	83%	32.3	0.040	15.0	$8.63	$8.63	2.25	Reflector LED Replacing Standard Halogen/Incandescent Bulb (DIRECT INSTALL)
5047	Lighting	DI LED Nightlights	MF	LI	DI	14.6	93%	13.6	0.005	16.0	$2.75	$2.75	2.50	LED Nightlights Replacing Incandescent Nightlights (DIRECT INSTALL)
5048	Lighting	DI LED 13W (Exterior)	MF	LI	DI	126.7	83%	105.2	0.048	15.0	$6.76	$6.76	7.45	Exterior LED Replacing Exterior Halogen/CFL Bulb
5049	Lighting	LED 9W (Standard)	MF	N/A	NC	37.5	86%	32.2	0.040	15.0	$1.01	$0.76	25.14	Standard LED Replacing Standard Halogen/CFL Bulb
5050	Lighting	LED 5W Globe (Specialty)	MF	N/A	NC	28.7	84%	24.1	0.023	15.0	$4.00	$3.00	4.36	Specialty LED Replacing Specialty Halogen/Incandescent Bulb
5051	Lighting	LED R30 Dimmable (Reflector)	MF	N/A	NC	40.1	83%	33.1	0.041	15.0	$5.34	$4.01	4.98	Reflector LED Replacing Standard Halogen/Incandescent Bulb
5052	Lighting	LED Fixtures	MF	N/A	NC	82.0	74%	60.8	0.061	15.0	$20.25	$5.06	8.26	Residential Occupancy Sensors (DIRECT INSTALL)
5053	Lighting	Linear LED	MF	N/A	NC	23.5	44%	10.3	0.014	9.0	$2.50	$1.88	2.06	T8 Linear Tube Fluorescent Replacing T12 LTF
5054	Lighting	Residential Occupancy Sensors	MF	N/A	NC	108.9	35%	38.1	0.048	10.0	$30.00	$7.50	2.46	Residential Occupancy Sensors
5055	Lighting	Smart Lighting Switch_ET	MF	N/A	NC	106.5	35%	37.3	0.047	10.0	$25.00	$6.25	2.88	Residential Occupancy Sensors

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	Historical Incentive Amount	UCT Ratio	Measure Description
5056	Lighting	LED Nightlights	MF	N/A	NC	14.6	93%	13.6	0.005	16.0	$2.75	$0.69	10.02	LED Nightlights Replacing Incandescent Nightlights
5057	Lighting	LED 13W (Exterior)	MF	N/A	NC	126.7	83%	105.2	0.048	15.0	$4.76	$4.00	12.59	Exterior LED Replacing Exterior Halogen/CFL Bulb
5058	Lighting	Exterior Lighting Controls	MF	N/A	NC	178.1	35%	62.3	0.028	10.0	$30.00	$7.50	2.75	Residential Occupancy Sensors
6001	Miscellaneous	Pool Heater	SF	N/A	MO	9,785.1	12%	1,173.5	0.000	10.0	$3,333.33	$1,000.00	0.39	Installation of high efficiency pool pump heater
6002	Miscellaneous	Pool Heater - Solar System	SF	N/A	MO	9,785.1	38%	3,735.8	0.000	10.0	$3,500.00	$1,000.00	1.24	This measure replaces a conventional pool heater with a solar system
6003	Miscellaneous	Hot Tub/Spa	SF	N/A	MO	0.0	0%	417.3	0.048	15.0	$350.00	$122.50	2.11	Installation of an efficient hot tub / spa
6004	Miscellaneous	Variable Speed Pool Pump	SF	N/A	MO	1,363.5	86%	1,172.6	2.068	10.0	$750.00	$300.00	7.62	Installation of variable speed pool pump
6005	Miscellaneous	Pool Timer	SF	N/A	Retrofit	0.0	0%	129.0	0.063	25.0	$115.00	$30.00	6.38	Installation of pool pump timer
6006	Miscellaneous	Well Pump	SF	N/A	MO	0.0	0%	187.0	0.022	20.0	$110.00	$30.00	4.80	Installation of high efficiency well pump in place of typical efficiency unit
6007	Miscellaneous	Pool Heater	SF	N/A	NC	9,785.1	12%	1,173.5	0.000	10.0	$3,333.33	$1,000.00	0.39	Installation of high efficiency pool pump heater
6008	Miscellaneous	Pool Heater - Solar System	SF	N/A	NC	9,785.1	35%	3,437.0	0.000	10.0	$3,500.00	$1,000.00	1.14	Installation of a solar pool heater instead of a conventional pool heater
6009	Miscellaneous	Hot Tub/Spa	SF	N/A	NC	0.0	0%	417.3	0.048	15.0	$350.00	$110.00	2.35	Installation of an efficient hot tub / spa
6010	Miscellaneous	Variable Speed Pool Pump	SF	N/A	NC	1,363.5	86%	1,172.6	2.068	10.0	$750.00	$300.00	7.62	Installation of variable speed pool pump
6011	Miscellaneous	Pool Timer	SF	N/A	NC	0.0	0%	108.3	0.063	25.0	$50.00	$20.00	8.85	Installation of pool pump timer
6012	Miscellaneous	Well Pump	SF	N/A	NC	0.0	0%	187.0	0.022	20.0	$110.00	$30.00	4.80	Installation of high efficiency well pump in place of typical efficiency unit
7001	New Construction	Gold Star: HERS Index Score ≤ 63 - Electric Heated	SF	N/A	NC	15,337.8	37%	5,675.0	0.824	25.0	$2,504.19	$700.00	6.78	Construction of home meeting Gold Star standard (HERS <=63)
7002	New Construction	Platinum Star: HERS Index Score ≤ 60 - Electric Heated	SF	N/A	NC	15,337.8	40%	6,135.1	0.891	25.0	$3,079.19	$800.00	6.41	Construction of home meeting Platinum Star standard (HERS <=60)
7003	New Construction	Gold Star: HERS Index Score ≤ 63 - Electric Heated	MF	N/A	NC	10,959.2	37%	4,054.9	0.491	25.0	$2,504.19	$1,000.00	3.32	Construction of home meeting Gold Star standard (HERS <=63)
7004	New Construction	Platinum Star: HERS Index Score ≤ 60 - Electric Heated	MF	N/A	NC	10,959.2	40%	4,383.7	0.531	25.0	$3,079.19	$1,000.00	3.59	Construction of home meeting Platinum Star standard (HERS <=60)
7005	New Construction	Gold Star: HERS Index Score ≤ 63 - Gas Heated	SF	N/A	NC	8,582.1	37%	3,175.4	0.904	25.0	$1,573.27	$175.00	23.67	Construction of home meeting Gold Star standard (HERS <=63)
7006	New Construction	Platinum Star: HERS Index Score ≤ 60 - Gas Heated	SF	N/A	NC	8,582.1	40%	3,432.8	0.977	25.0	$1,778.27	$200.00	22.40	Construction of home meeting Platinum Star standard (HERS <=60)
7007	New Construction	Gold Star: HERS Index Score ≤ 63 - Gas Heated	MF	N/A	NC	10,165.2	37%	3,761.1	0.605	25.0	$1,573.27	$775.00	4.72	Construction of home meeting Gold Star standard (HERS <=63)
7008	New Construction	Platinum Star: HERS Index Score ≤ 60 - Gas Heated	MF	N/A	NC	10,165.2	40%	4,066.1	0.655	25.0	$1,778.27	$900.00	4.40	Construction of home meeting Platinum Star standard (HERS <=60)
8001	Plug Loads	Smart Power Strips - Tier 1	SF	NLI	Retrofit	197.0	12%	23.0	0.003	4.0	$35.00	$35.00	0.10	Use of a smart strip instead of a standard power strip
8002	Plug Loads	Smart Power Strips - Tier 1	SF	LI	DI	197.0	12%	23.0	0.003	4.0	$35.00	$35.00	0.10	Use of a smart strip instead of a standard power strip
8003	Plug Loads	Efficient Laptop	SF	N/A	MO	50.3	72%	36.0	0.004	4.0	$8.00	$5.00	1.22	Installation of high-efficiency laptop computers in homes with laptop computers
8004	Plug Loads	Efficient Monitor	SF	N/A	MO	66.2	61%	40.2	0.020	5.0	$10.00	$5.00	3.83	Installation of high-efficiency displays (50% more efficient than ENERGY STAR minimum spec) for desktop computers in homes with desktop computers
8005	Plug Loads	Efficient Personal Computer	SF	N/A	MO	238.5	32%	77.0	0.023	4.0	$8.00	$5.00	3.34	Installation of high-efficiency desktop computers in homes with desktop computers

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	Historical Incentive Amount	UCT Ratio	Measure Description
8006	Plug Loads	Efficient Multifunction	SF	N/A	MO	70.1	66%	46.4	0.011	6.0	$1.00	$5.00	2.71	Installation of high efficiency multifunction device instead of a standard efficiency unit
8007	Plug Loads	Efficient TV	SF	N/A	MO	664.4	27%	179.4	0.098	6.0	$10.00	$5.00	10.48	ENERGY STAR 7.0 television
8008	Plug Loads	Smart Television	SF	N/A	MO	664.4	27%	179.4	0.098	6.0	$10.00	$5.00	10.48	ENERGY STAR 7.0 television
8009	Plug Loads	Smart Power Strips - Tier 2	SF	N/A	Retrofit	678.0	36%	244.1	0.028	4.0	$80.00	$20.00	1.92	Use of a advanced power strip instead of a standard power strip
8010	Plug Loads	Smart Plug or Outlet_ET	SF	N/A	Retrofit	678.0	0%	0.0	0.000	4.0	$20.00	$10.00	0.00	Installation of smart plug to control plug loads
8011	Plug Loads	Efficient Laptop	SF	N/A	NC	50.3	72%	36.0	0.004	4.0	$8.00	$5.00	1.22	Installation of high-efficiency laptop computers in homes with laptop computers
8012	Plug Loads	Efficient Monitor	SF	N/A	NC	66.2	61%	40.2	0.020	5.0	$10.00	$5.00	3.83	Installation of high-efficiency displays (50% more efficient than ENERGY STAR minimum spec) for desktop computers in homes with desktop computers
8013	Plug Loads	Efficient Personal Computer	SF	N/A	NC	238.5	32%	77.0	0.023	4.0	$8.00	$5.00	3.34	Installation of high-efficiency desktop computers in homes with desktop computers
8014	Plug Loads	Efficient Multifunction	SF	N/A	NC	70.1	66%	46.4	0.011	6.0	$1.00	$5.00	2.71	Installation of high efficiency multifunction device instead of a standard efficiency unit
8015	Plug Loads	Efficient TV	SF	N/A	NC	664.4	27%	179.4	0.098	6.0	$10.00	$5.00	10.48	ENERGY STAR 7.0 television
8016	Plug Loads	Smart Television	SF	N/A	NC	664.4	27%	179.4	0.098	6.0	$10.00	$5.00	10.48	ENERGY STAR 7.0 television
8017	Plug Loads	Smart Power Strips - Tier 1	SF	N/A	NC	197.0	12%	23.0	0.003	4.0	$35.00	$35.00	0.10	Use of a smart strip instead of a standard power strip
8018	Plug Loads	Smart Power Strips - Tier 2	SF	N/A	NC	678.0	36%	244.1	0.028	4.0	$80.00	$20.00	1.92	Use of a advanced power strip instead of a standard power strip
8019	Plug Loads	Smart Plug or Outlet_ET	SF	N/A	NC	678.0	0%	0.0	0.000	4.0	$20.00	$10.00	0.00	Installation of smart plug to control plug loads
8020	Plug Loads	Smart Power Strips - Tier 1	MF	NLI	Retrofit	197.0	12%	23.0	0.003	4.0	$35.00	$35.00	0.10	Use of a smart strip instead of a standard power strip
8021	Plug Loads	Smart Power Strips - Tier 1	MF	LI	DI	197.0	12%	23.0	0.003	4.0	$35.00	$35.00	0.10	Use of a smart strip instead of a standard power strip
8022	Plug Loads	Efficient Laptop	MF	N/A	MO	50.3	72%	36.0	0.004	4.0	$8.00	$5.00	1.22	Installation of high-efficiency laptop computers in homes with laptop computers
8023	Plug Loads	Efficient Monitor	MF	N/A	MO	66.2	61%	40.2	0.020	5.0	$10.00	$5.00	3.83	Installation of high-efficiency displays (50% more efficient than ENERGY STAR minimum spec) for desktop computers in homes with desktop computers
8024	Plug Loads	Efficient Personal Computer	MF	N/A	MO	238.5	32%	77.0	0.023	4.0	$8.00	$5.00	3.34	Installation of high-efficiency desktop computers in homes with desktop computers
8025	Plug Loads	Efficient Multifunction	MF	N/A	MO	70.1	66%	46.4	0.011	6.0	$1.00	$5.00	2.71	Installation of high efficiency multifunction device instead of a standard efficiency unit
8026	Plug Loads	Efficient TV	MF	N/A	MO	664.4	27%	179.4	0.098	6.0	$10.00	$5.00	10.48	ENERGY STAR 7.0 television
8027	Plug Loads	Smart Television	MF	N/A	MO	664.4	27%	179.4	0.098	6.0	$10.00	$5.00	10.48	ENERGY STAR 7.0 television
8028	Plug Loads	Smart Power Strips - Tier 2	MF	N/A	Retrofit	678.0	36%	244.1	0.028	4.0	$80.00	$20.00	1.92	Use of a advanced power strip instead of a standard power strip
8029	Plug Loads	Smart Plug or Outlet_ET	MF	N/A	Retrofit	678.0	0%	0.0	0.000	4.0	$20.00	$10.00	0.00	Installation of smart plug to control plug loads

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	Historical Incentive Amount	UCT Ratio	Measure Description
8030	Plug Loads	Efficient Laptop	MF	N/A	NC	50.3	72%	36.0	0.004	4.0	$8.00	$5.00	1.22	Installation of high-efficiency laptop computers in homes with laptop computers
8031	Plug Loads	Efficient Monitor	MF	N/A	NC	66.2	61%	40.2	0.020	5.0	$10.00	$5.00	3.83	Installation of high-efficiency displays (50% more efficient than ENERGY STAR minimum spec) for desktop computers in homes with desktop computers
8032	Plug Loads	Efficient Personal Computer	MF	N/A	NC	238.5	32%	77.0	0.023	4.0	$8.00	$5.00	3.34	Installation of high-efficiency desktop computers in homes with desktop computers
8033	Plug Loads	Efficient Multifunction	MF	N/A	NC	70.1	66%	46.4	0.011	6.0	$1.00	$5.00	2.71	Installation of high efficiency multifunction device instead of a standard efficiency unit
8034	Plug Loads	Efficient TV	MF	N/A	NC	664.4	27%	179.4	0.098	6.0	$10.00	$5.00	10.48	ENERGY STAR 7.0 television
8035	Plug Loads	Smart Television	MF	N/A	NC	664.4	27%	179.4	0.098	6.0	$10.00	$5.00	10.48	ENERGY STAR 7.0 television
8036	Plug Loads	Smart Power Strips - Tier 1	MF	N/A	NC	197.0	12%	23.0	0.003	4.0	$35.00	$35.00	0.10	Use of a smart strip instead of a standard power strip
8037	Plug Loads	Smart Power Strips - Tier 2	MF	N/A	NC	678.0	36%	244.1	0.028	4.0	$80.00	$20.00	1.92	Use of a advanced power strip instead of a standard power strip
8038	Plug Loads	Smart Plug or Outlet_ET	MF	N/A	NC	678.0	0%	0.0	0.000	4.0	$20.00	$10.00	0.00	Installation of smart plug to control plug loads
9001	HVAC Shell	Duct Sealing - Average Sealing - Heat pump	SF	NLI	Retrofit	7,269.4	3%	242.8	0.064	20.0	$200.00	$175.00	1.14	15% to 10% leakage
9002	HVAC Shell	Duct Sealing - Inadequate Sealing - Heat pump	SF	NLI	Retrofit	7,376.9	5%	397.5	0.158	20.0	$350.00	$300.00	1.21	20% to 15% leakage
9003	HVAC Shell	Duct Sealing/Insulation - Poor Sealing - Heat pump	SF	NLI	Retrofit	7,502.4	14%	1,013.0	0.414	20.0	$1,442.50	$1,000.00	0.94	25% to 15% leakage
9004	HVAC Shell	Wall Insulation - Heat pump	SF	NLI	Retrofit	8,887.1	29%	2,565.9	0.867	25.0	$2,746.80	$450.00	5.67	R0 to R11 wall insulation
9005	HVAC Shell	Air Sealing Average Sealing - Heat pump	SF	NLI	Retrofit	6,321.2	11%	709.6	0.179	15.0	$624.65	$200.00	2.32	10 ACH 50 to 7 ACH 50
9006	HVAC Shell	Air Sealing Inadequate Sealing - Heat pump	SF	NLI	Retrofit	7,284.2	13%	963.0	0.251	15.0	$967.20	$200.00	3.15	14 ACH 50 to 10 ACH 50
9007	HVAC Shell	Air Sealing Poor Sealing - Heat pump	SF	NLI	Retrofit	8,949.1	19%	1,664.9	0.389	15.0	$967.20	$200.00	5.46	20 ACH 50 to 14 ACH 50
9008	HVAC Shell	Attic Insulation - Average Insulation - Heat pump	SF	NLI	Retrofit	6,321.2	3%	190.5	0.067	25.0	$1,259.70	$450.00	0.43	R30 to R60
9009	HVAC Shell	Attic Insulation - Inadequate Insulation - Heat pump	SF	NLI	Retrofit	6,568.9	7%	438.2	0.172	25.0	$1,744.20	$450.00	1.04	R19 to R60
9010	HVAC Shell	Attic Insulation - Poor Insulation - Heat pump	SF	NLI	Retrofit	6,932.3	11%	761.0	0.321	25.0	$1,550.40	$450.00	1.84	R11 to R49
9011	HVAC Shell	Duct Sealing - Average Sealing - Electric furnace	SF	NLI	Retrofit	13,437.5	3%	411.6	0.036	20.0	$200.00	$175.00	1.59	15% to 10% leakage
9012	HVAC Shell	Duct Sealing - Inadequate Sealing - Electric furnace	SF	NLI	Retrofit	13,620.9	5%	677.9	0.109	20.0	$350.00	$300.00	1.65	20% to 15% leakage
9013	HVAC Shell	Duct Sealing/Insulation - Poor Sealing - Electric furnace	SF	NLI	Retrofit	13,842.1	13%	1,759.1	0.282	20.0	$1,442.50	$1,000.00	1.29	25% to 15% leakage
9014	HVAC Shell	Wall Insulation - Electric furnace	SF	NLI	Retrofit	17,267.5	32%	5,582.7	0.887	25.0	$2,746.80	$450.00	10.41	R0 to R11 wall insulation
9015	HVAC Shell	Air Sealing Average Sealing - Electric furnace	SF	NLI	Retrofit	11,684.8	14%	1,598.5	0.215	15.0	$624.65	$200.00	4.58	10 ACH 50 to 7 ACH 50
9016	HVAC Shell	Air Sealing Inadequate Sealing - Electric furnace	SF	NLI	Retrofit	13,876.8	16%	2,192.0	0.294	15.0	$967.20	$200.00	6.27	14 ACH 50 to 10 ACH 50
9017	HVAC Shell	Air Sealing Poor Sealing - Electric furnace	SF	NLI	Retrofit	17,296.5	20%	3,419.8	0.378	15.0	$967.20	$200.00	9.63	20 ACH 50 to 14 ACH 50

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9018	HVAC Shell	Attic Insulation - Average Insulation - Electric furnace	SF	NLI	Retrofit	11,684.8	3%	349.3	0.052	25.0	$1,259.70	$450.00	0.65	R30 to R60
9019	HVAC Shell	Attic Insulation - Inadequate Insulation - Electric furnace	SF	NLI	Retrofit	12,144.6	7%	809.2	0.133	25.0	$1,744.20	$450.00	1.53	R19 to R60
9020	HVAC Shell	Attic Insulation - Poor Insulation - Electric furnace	SF	NLI	Retrofit	12,884.7	11%	1,476.9	0.278	25.0	$1,550.40	$450.00	2.87	R11 to R49
9021	HVAC Shell	Duct Sealing - Average Sealing - Heat pump	SF	LI	DI	7,269.4	3%	242.8	0.064	20.0	$200.00	$200.00	1.00	15% to 10% leakage
9022	HVAC Shell	Duct Sealing - Inadequate Sealing - Heat pump	SF	LI	DI	7,376.9	5%	397.5	0.158	20.0	$350.00	$350.00	1.04	20% to 15% leakage
9023	HVAC Shell	Duct Sealing/Insulation - Poor Sealing - Heat pump	SF	LI	DI	7,502.4	14%	1,013.0	0.414	20.0	$1,442.50	$1,442.50	0.65	25% to 15% leakage
9024	HVAC Shell	Wall Insulation - Heat pump	SF	LI	DI	8,887.1	29%	2,565.9	0.867	25.0	$2,746.80	$2,746.80	0.93	R0 to R11 wall insulation
9025	HVAC Shell	Air Sealing Average Sealing - Heat pump	SF	LI	DI	6,321.2	11%	709.6	0.179	15.0	$624.65	$624.65	0.74	10 ACH 50 to 7 ACH 50
9026	HVAC Shell	Air Sealing Inadequate Sealing - Heat pump	SF	LI	DI	7,284.2	13%	963.0	0.251	15.0	$967.20	$967.20	0.65	14 ACH 50 to 10 ACH 50
9027	HVAC Shell	Air Sealing Poor Sealing - Heat pump	SF	LI	DI	8,949.1	19%	1,664.9	0.389	15.0	$967.20	$967.20	1.13	20 ACH 50 to 14 ACH 50
9028	HVAC Shell	Attic Insulation - Average Insulation - Heat pump	SF	LI	DI	6,321.2	3%	190.5	0.067	25.0	$1,259.70	$1,259.70	0.16	R30 to R60
9029	HVAC Shell	Attic Insulation - Inadequate Insulation - Heat pump	SF	LI	DI	6,568.9	7%	438.2	0.172	25.0	$1,744.20	$1,744.20	0.27	R19 to R60
9030	HVAC Shell	Attic Insulation - Poor Insulation - Heat pump	SF	LI	DI	6,932.3	11%	761.0	0.3	25.0	$1,550.40	$1,550.40	0.53	R11 to R49
9031	HVAC Shell	Duct Sealing - Average Sealing - Electric furnace	SF	LI	DI	13,437.5	3%	411.6	0.036	20.0	$200.00	$200.00	1.39	15% to 10% leakage
9032	HVAC Shell	Duct Sealing - Inadequate Sealing - Electric furnace	SF	LI	DI	13,620.9	5%	677.9	0.109	20.0	$350.00	$350.00	1.42	20% to 15% leakage
9033	HVAC Shell	Duct Sealing/Insulation - Poor Sealing - Electric furnace	SF	LI	DI	13,842.1	13%	1,759.1	0.282	20.0	$1,442.50	$1,442.50	0.89	25% to 15% leakage
9034	HVAC Shell	Wall Insulation - Electric furnace	SF	LI	DI	17,267.5	32%	5,582.7	0.887	25.0	$2,746.80	$2,746.80	1.71	R0 to R11 wall insulation
9035	HVAC Shell	Air Sealing Average Sealing - Electric furnace	SF	LI	DI	11,684.8	14%	1,598.5	0.215	15.0	$624.65	$624.65	1.47	10 ACH 50 to 7 ACH 50
9036	HVAC Shell	Air Sealing Inadequate Sealing - Electric furnace	SF	LI	DI	13,876.8	16%	2,192.0	0.294	15.0	$967.20	$967.20	1.30	14 ACH 50 to 10 ACH 50
9037	HVAC Shell	Air Sealing Poor Sealing - Electric furnace	SF	LI	DI	17,296.5	20%	3,419.8	0.378	15.0	$967.20	$967.20	1.99	20 ACH 50 to 14 ACH 50
9038	HVAC Shell	Attic Insulation - Average Insulation - Electric furnace	SF	LI	DI	11,684.8	3%	349.3	0.052	25.0	$1,259.70	$1,259.70	0.23	R30 to R60
9039	HVAC Shell	Attic Insulation - Inadequate Insulation - Electric furnace	SF	LI	DI	12,144.6	7%	809.2	0.133	25.0	$1,744.20	$1,744.20	0.40	R19 to R60
9040	HVAC Shell	Attic Insulation - Poor Insulation - Electric furnace	SF	LI	DI	12,884.7	11%	1,476.9	0.278	25.0	$1,550.40	$1,550.40	0.83	R11 to R49
9041	HVAC Shell	Radiant Barrier - Heat pump	SF	N/A	Retrofit	6,321.2	1%	82.5	0.1	20.0	$416.67	$130.00	0.90	Installation of radiant barrier
9042	HVAC Shell	Cool Roof - Heat pump	SF	N/A	Retrofit	6,321.2	2%	111.1	0.1	20.0	$3,876.00	$1,000.00	0.18	Installation of cool roof
9043	HVAC Shell	Wall Sheathing - Heat pump	SF	N/A	Retrofit	6,321.2	14%	879.9	0.269	20.0	$2,943.00	$1,000.00	0.77	R12 polyiso
9044	HVAC Shell	ENERGY STAR Windows - Heat pump	SF	N/A	Retrofit	6,321.2	9%	548.8	0.372	25.0	$13,601.25	$1,000.00	0.74	U=0.30; SHGC=0.40
9045	HVAC Shell	Basement Sidewall Insulation - Heat pump	SF	N/A	Retrofit	6,678.1	5%	356.9	0.033	25.0	$2,720.00	$1,000.00	0.28	R0 to R13 sidewall insulation

Vectren Electric	Residential Measure Assumptions													
Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	Historical Incentive Amount	UCT Ratio	Measure Description
9046	HVAC Shell	Floor Insulation Above Crawlspace - Heat pump	SF	N/A	Retrofit	6,359.1	1%	37.9	-0.044	25.0	$316.20	$90.00	0.00	R13 floor insulation
9047	HVAC Shell	ENERGY STAR Door - Heat pump	SF	N/A	Retrofit	6,321.2	2%	129.9	0.046	25.0	$388.00	$120.00	1.10	Fiberglasss
9048	HVAC Shell	Smart Window Coverings - Shade/Blind/Controller/Sensor - Heat pump_ET	SF	N/A	Retrofit	6,321.2	16%	979.8	0.471	7.0	$14,875.00	$1,000.00	0.41	Smart shades
9049	HVAC Shell	Smart Window Coverings - Film/Transformer - Heat pump_ET	SF	N/A	Retrofit	6,321.2	16%	979.8	0.471	7.0	$8,160.75	$1,000.00	0.41	Smart films
9050	HVAC Shell	Radiant Barrier - Electric furnace	SF	N/A	Retrofit	11,684.8	1%	102.2	0.065	20.0	$416.67	$130.00	0.91	Installation of radiant barrier
9051	HVAC Shell	Cool Roof - Electric furnace	SF	N/A	Retrofit	11,684.8	0%	-21.1	0.079	20.0	$3,876.00	$1,000.00	0.06	Installation of cool roof
9052	HVAC Shell	Wall Sheathing - Electric furnace	SF	N/A	Retrofit	11,684.8	16%	1,837.2	0.2	20.0	$2,943.00	$1,000.00	1.31	R12 polyiso
9053	HVAC Shell	ENERGY STAR Windows - Electric furnace	SF	N/A	Retrofit	11,684.8	7%	798.3	0.3	25.0	$13,601.25	$1,000.00	0.89	U=0.30; SHGC=0.40
9054	HVAC Shell	Basement Sidewall Insulation - Electric furnace	SF	N/A	Retrofit	12,616.3	7%	931.6	0.031	25.0	$2,720.00	$1,000.00	0.67	R0 to R13 sidewall insulation
9055	HVAC Shell	Floor Insulation Above Crawlspace - Electric furnace	SF	N/A	Retrofit	11,922.5	2%	237.7	-0.028	25.0	$316.20	$90.00	1.54	R13 floor insulation
9056	HVAC Shell	ENERGY STAR Door - Electric furnace	SF	N/A	Retrofit	11,684.8	2%	227.3	0.035	25.0	$388.00	$120.00	1.58	Fiberglasss
9057	HVAC Shell	Smart Window Coverings - Shade/Blind/Controller/Sensor - Electric furnace_ET	SF	N/A	Retrofit	11,684.8	16%	1,811.1	0.498	7.0	$14,875.00	$1,000.00	0.62	Smart shades
9058	HVAC Shell	Smart Window Coverings - Film/Transformer - Electric furnace_ET	SF	N/A	Retrofit	11,684.8	16%	1,811.1	0.498	7.0	$8,160.75	$1,000.00	0.62	Smart films
9059	HVAC Shell	Duct Sealing - Average Sealing - Heat pump	MF	NLI	Retrofit	3,646.6	8%	300.6	0.140	20.0	$200.00	$175.00	1.81	15% to 10% leakage
9060	HVAC Shell	Duct Sealing - Inadequate Sealing - Heat pump	MF	NLI	Retrofit	3,815.6	16%	624.5	0.281	20.0	$350.00	$300.00	2.20	20% to 15% leakage
9061	HVAC Shell	Duct Sealing/Insulation - Poor Sealing - Heat pump	MF	NLI	Retrofit	4,021.6	41%	1,630.6	0.741	20.0	$981.00	$500.00	3.46	25% to 15% leakage
9062	HVAC Shell	Wall Insulation - Heat pump	MF	NLI	Retrofit	4,066.7	22%	895.7	0.261	25.0	$1,159.20	$450.00	2.04	R0 to R11 wall insulation
9063	HVAC Shell	Air Sealing Average Sealing - Heat pump	MF	NLI	Retrofit	3,171.0	7%	207.6	0.0	15.0	$309.69	$200.00	0.57	10 ACH 50 to 7 ACH 50
9064	HVAC Shell	Air Sealing Inadequate Sealing - Heat pump	MF	NLI	Retrofit	3,580.6	11%	409.6	0.1	15.0	$479.52	$200.00	1.35	14 ACH 50 to 10 ACH 50
9065	HVAC Shell	Air Sealing Poor Sealing - Heat pump	MF	NLI	Retrofit	4,306.5	17%	725.9	0.152	15.0	$479.52	$200.00	2.42	20 ACH 50 to 14 ACH 50
9066	HVAC Shell	Attic Insulation - Average Insulation - Heat pump	MF	NLI	Retrofit	3,171.0	3%	102.4	0.045	25.0	$1,298.70	$450.00	0.27	R30 to R60
9067	HVAC Shell	Attic Insulation - Inadequate Insulation - Heat pump	MF	NLI	Retrofit	3,295.1	7%	226.5	0.101	25.0	$1,798.20	$450.00	0.60	R19 to R60
9068	HVAC Shell	Attic Insulation - Poor Insulation - Heat pump	MF	NLI	Retrofit	3,479.2	11%	393.2	0.178	25.0	$1,598.40	$450.00	1.04	R11 to R49
9069	HVAC Shell	Duct Sealing - Average Sealing - Electric furnace	MF	NLI	Retrofit	5,719.1	8%	457.5	0.203	20.0	$200.00	$175.00	2.71	15% to 10% leakage
9070	HVAC Shell	Duct Sealing - Inadequate Sealing - Electric furnace	MF	NLI	Retrofit	5,935.5	13%	799.9	0.319	20.0	$350.00	$300.00	2.68	20% to 15% leakage
9071	HVAC Shell	Duct Sealing/Insulation - Poor Sealing - Electric furnace	MF	NLI	Retrofit	6,195.8	33%	2,072.8	0.861	20.0	$981.00	$500.00	4.24	25% to 15% leakage

Vectren Electric **Residential Measure Assumptions**

Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	Historical Incentive Amount	UCT Ratio	Measure Description
9072	HVAC Shell	Wall Insulation - Electric furnace	MF	NLI	Retrofit	6,808.6	27%	1,835.5	0.274	25.0	$1,159.20	$450.00	3.52	R0 to R11 wall insulation
9073	HVAC Shell	Air Sealing Average Sealing - Electric furnace	MF	NLI	Retrofit	4,973.1	11%	531.4	0.025	15.0	$309.69	$200.00	1.38	10 ACH 50 to 7 ACH 50
9074	HVAC Shell	Air Sealing Inadequate Sealing - Electric furnace	MF	NLI	Retrofit	5,850.0	15%	876.9	0.094	15.0	$479.52	$200.00	2.50	14 ACH 50 to 10 ACH 50
9075	HVAC Shell	Air Sealing Poor Sealing - Electric furnace	MF	NLI	Retrofit	7,325.7	20%	1,475.7	0.162	15.0	$479.52	$200.00	4.26	20 ACH 50 to 14 ACH 50
9076	HVAC Shell	Attic Insulation - Average Insulation - Electric furnace	MF	NLI	Retrofit	4,973.1	4%	200.1	0.063	25.0	$1,298.70	$450.00	0.46	R30 to R60
9077	HVAC Shell	Attic Insulation - Inadequate Insulation - Electric furnace	MF	NLI	Retrofit	5,177.1	8%	404.1	0.123	25.0	$1,798.20	$450.00	0.92	R19 to R60
9078	HVAC Shell	Attic Insulation - Poor Insulation - Electric furnace	MF	NLI	Retrofit	5,506.9	13%	695.7	0.205	25.0	$1,598.40	$450.00	1.58	R11 to R49
9079	HVAC Shell	Duct Sealing - Average Sealing - Heat pump	MF	LI	DI	3,646.6	8%	300.6	0.140	20.0	$200.00	$200.00	1.58	15% to 10% leakage
9080	HVAC Shell	Duct Sealing - Inadequate Sealing - Heat pump	MF	LI	DI	3,815.6	16%	624.5	0.281	20.0	$350.00	$350.00	1.89	20% to 15% leakage
9081	HVAC Shell	Duct Sealing/Insulation - Poor Sealing - Heat pump	MF	LI	DI	4,021.6	41%	1,630.6	0.741	20.0	$981.00	$981.00	1.76	25% to 15% leakage
9082	HVAC Shell	Wall Insulation - Heat pump	MF	LI	DI	4,066.7	22%	895.7	0.261	25.0	$1,159.20	$1,159.20	0.79	R0 to R11 wall insulation
9083	HVAC Shell	Air Sealing Average Sealing - Heat pump	MF	LI	DI	3,171.0	7%	207.6	0.017	15.0	$309.69	$309.69	0.37	10 ACH 50 to 7 ACH 50
9084	HVAC Shell	Air Sealing Inadequate Sealing - Heat pump	MF	LI	DI	3,580.6	11%	409.6	0.087	15.0	$479.52	$479.52	0.56	14 ACH 50 to 10 ACH 50
9085	HVAC Shell	Air Sealing Poor Sealing - Heat pump	MF	LI	DI	4,306.5	17%	725.9	0.152	15.0	$479.52	$479.52	1.01	20 ACH 50 to 14 ACH 50
9086	HVAC Shell	Attic Insulation - Average Insulation - Heat pump	MF	LI	DI	3,171.0	3%	102.4	0.045	25.0	$1,298.70	$1,298.70	0.09	R30 to R60
9087	HVAC Shell	Attic Insulation - Inadequate Insulation - Heat pump	MF	LI	DI	3,295.1	7%	226.5	0.101	25.0	$1,798.20	$1,798.20	0.15	R19 to R60
9088	HVAC Shell	Attic Insulation - Poor Insulation - Heat pump	MF	LI	DI	3,479.2	11%	393.2	0.178	25.0	$1,598.40	$1,598.40	0.29	R11 to R49
9089	HVAC Shell	Duct Sealing - Average Sealing - Electric furnace	MF	LI	DI	5,719.1	8%	457.5	0.203	20.0	$200.00	$200.00	2.37	15% to 10% leakage
9090	HVAC Shell	Duct Sealing - Inadequate Sealing - Electric furnace	MF	LI	DI	5,935.5	13%	799.9	0.319	20.0	$350.00	$350.00	2.30	20% to 15% leakage
9091	HVAC Shell	Duct Sealing/Insulation - Poor Sealing - Electric furnace	MF	LI	DI	6,195.8	33%	2,072.8	0.861	20.0	$981.00	$981.00	2.16	25% to 15% leakage
9092	HVAC Shell	Wall Insulation - Electric furnace	MF	LI	DI	6,808.6	27%	1,835.5	0.274	25.0	$1,159.20	$1,159.20	1.36	R0 to R11 wall insulation
9093	HVAC Shell	Air Sealing Average Sealing - Electric furnace	MF	LI	DI	4,973.1	11%	531.4	0.025	15.0	$309.69	$309.69	0.89	10 ACH 50 to 7 ACH 50
9094	HVAC Shell	Air Sealing Inadequate Sealing - Electric furnace	MF	LI	DI	5,850.0	15%	876.9	0.094	15.0	$479.52	$479.52	1.04	14 ACH 50 to 10 ACH 50
9095	HVAC Shell	Air Sealing Poor Sealing - Electric furnace	MF	LI	DI	7,325.7	20%	1,475.7	0.162	15.0	$479.52	$479.52	1.78	20 ACH 50 to 14 ACH 50
9096	HVAC Shell	Attic Insulation - Average Insulation - Electric furnace	MF	LI	DI	4,973.1	4%	200.1	0.063	25.0	$1,298.70	$1,298.70	0.16	R30 to R60
9097	HVAC Shell	Attic Insulation - Inadequate Insulation - Electric furnace	MF	LI	DI	5,177.1	8%	404.1	0.123	25.0	$1,798.20	$1,798.20	0.23	R19 to R60
9098	HVAC Shell	Attic Insulation - Poor Insulation - Electric furnace	MF	LI	DI	5,506.9	13%	695.7	0.205	25.0	$1,598.40	$1,598.40	0.44	R11 to R49
9099	HVAC Shell	Radiant Barrier - Heat pump	MF	N/A	Retrofit	3,171.0	-6%	-202.0	-0.062	20.0	$429.57	$130.00	0.00	Installation of radiant barrier

Vectren Electric **Residential Measure Assumptions**

Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	Historical Incentive Amount	UCT Ratio	Measure Description
9100	HVAC Shell	Cool Roof - Heat pump	MF	N/A	Retrofit	3,171.0	-22%	-698.2	-0.120	20.0	$3,996.00	$1,000.00	0.00	Installation of cool roof
9101	HVAC Shell	Wall Sheathing - Heat pump	MF	N/A	Retrofit	3,171.0	10%	311.5	0.091	25.0	$1,242.00	$625.00	0.50	R12 polyiso
9102	HVAC Shell	ENERGY STAR Windows - Heat pump	MF	N/A	Retrofit	3,171.0	8%	266.8	0.162	25.0	$6,743.25	$1,000.00	0.35	U=0.30; SHGC=0.40
9103	HVAC Shell	Basement Sidewall Insulation - Heat pump	MF	N/A	Retrofit	3,477.9	9%	306.9	0.064	25.0	$2,815.20	$1,000.00	0.28	R0 to R13 sidewall insulation
9104	HVAC Shell	Floor Insulation Above Crawlspace - Heat pump	MF	N/A	Retrofit	3,277.2	3%	106.2	0.201	25.0	$849.15	$425.00	0.23	R13 floor insulation
9105	HVAC Shell	Smart Window Coverings - Shade/Blind/Controller/Sensor - Heat pump_ET	MF	N/A	Retrofit	3,171.0	16%	491.5	0.211	7.0	$8,500.00	$1,000.00	0.22	Smart shades
9106	HVAC Shell	Smart Window Coverings - Film/Transformer - Heat pump_ET	MF	N/A	Retrofit	3,171.0	16%	491.5	0.211	7.0	$4,045.95	$1,000.00	0.22	Smart films
9107	HVAC Shell	Radiant Barrier - Electric furnace	MF	N/A	Retrofit	4,973.1	-6%	-281.8	-0.073	20.0	$429.57	$130.00	0.00	Installation of radiant barrier
9108	HVAC Shell	Cool Roof - Electric furnace	MF	N/A	Retrofit	4,973.1	-33%	-1,661.4	-0.092	20.0	$3,996.00	$1,000.00	0.00	Installation of cool roof
9109	HVAC Shell	Wall Sheathing - Electric furnace	MF	N/A	Retrofit	4,973.1	13%	662.3	0.414	25.0	$1,242.00	$625.00	1.44	R12 polyiso
9110	HVAC Shell	ENERGY STAR Windows - Electric furnace	MF	N/A	Retrofit	4,973.1	8%	415.9	0.184	25.0	$6,743.25	$1,000.00	0.48	U=0.30; SHGC=0.40
9111	HVAC Shell	Basement Sidewall Insulation - Electric furnace	MF	N/A	Retrofit	5,634.1	12%	661.0	0.069	25.0	$2,815.20	$1,000.00	0.54	R0 to R13 sidewall insulation
9112	HVAC Shell	Floor Insulation Above Crawlspace - Electric furnace	MF	N/A	Retrofit	7,848.5	37%	2,875.4	-0.304	25.0	$849.15	$425.00	3.86	R13 floor insulation
9113	HVAC Shell	Smart Window Coverings - Shade/Blind/Controller/Sensor - Electric furnace_ET	MF	N/A	Retrofit	4,973.1	16%	770.8	0.238	7.0	$8,500.00	$1,000.00	0.30	Smart shades
9114	HVAC Shell	Smart Window Coverings - Film/Transformer - Electric furnace_ET	MF	N/A	Retrofit	4,973.1	16%	770.8	0.238	7.0	$4,045.95	$1,000.00	0.30	Smart films
9115	HVAC Shell	Duct Sealing - Average Sealing - Gas Heating	SF	NLI	Retrofit	3,380.5	5%	161.5	0.131	20.0	$200.00	$175.00	1.61	15% to 10% leakage
9116	HVAC Shell	Duct Sealing - Inadequate Sealing - Gas Heating	SF	NLI	Retrofit	3,442.6	7%	229.5	0.115	20.0	$350.00	$300.00	1.25	20% to 15% leakage
9117	HVAC Shell	Duct Sealing/Insulation - Poor Sealing - Gas Heating	SF	NLI	Retrofit	3,501.7	15%	526.8	0.297	20.0	$1,442.50	$1,000.00	0.91	25% to 15% leakage
9118	HVAC Shell	Wall Insulation - Gas Heating	SF	NLI	Retrofit	3,509.2	16%	569.6	0.541	25.0	$2,746.80	$450.00	6.29	R0 to R11 wall insulation
9119	HVAC Shell	Air Sealing - Average Sealing - Gas Heating	SF	NLI	Retrofit	2,939.6	7%	206.9	0.353	15.0	$624.65	$100.00	7.18	10 ACH 50 to 7 ACH 50
9120	HVAC Shell	Air Sealing - Inadequate Sealing - Gas Heating	SF	NLI	Retrofit	3,363.5	13%	423.9	0.392	15.0	$967.20	$100.00	10.02	14 ACH 50 to 10 ACH 50
9121	HVAC Shell	Air Sealing - Poor Sealing - Gas Heating	SF	NLI	Retrofit	4,030.0	17%	666.6	0.558	15.0	$967.20	$100.00	15.38	20 ACH 50 to 14 ACH 50
9122	HVAC Shell	Attic Insulation - Average Insulation - Gas Heating	SF	NLI	Retrofit	2,939.6	2%	62.9	0.076	25.0	$1,259.70	$450.00	0.48	R30 to R60
9123	HVAC Shell	Attic Insulation - Inadequate Insulation - Gas Heating	SF	NLI	Retrofit	2,997.7	4%	120.9	0.143	25.0	$1,744.20	$450.00	1.00	R19 to R60
9124	HVAC Shell	Attic Insulation - Poor Insulation - Gas Heating	SF	NLI	Retrofit	3,135.8	8%	241.1	0.225	25.0	$1,550.40	$450.00	1.81	R11 to R49
9125	HVAC Shell	Duct Sealing - Average Sealing - Gas Heating	SF	LI	DI	3,380.5	5%	161.5	0.131	20.0	$200.00	$200.00	1.41	15% to 10% leakage
9126	HVAC Shell	Duct Sealing - Inadequate Sealing - Gas Heating	SF	LI	DI	3,442.6	7%	229.5	0.115	20.0	$350.00	$350.00	1.08	20% to 15% leakage

Vectren Electric — Residential Measure Assumptions

Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	Historical Incentive Amount	UCT Ratio	Measure Description
9127	HVAC Shell	Duct Sealing/Insulation - Poor Sealing - Gas Heating	SF	LI	DI	3,501.7	15%	526.8	0.297	20.0	$1,442.50	$1,442.50	0.63	25% to 15% leakage
9128	HVAC Shell	Wall Insulation - Gas Heating	SF	LI	DI	3,509.2	16%	569.6	0.541	25.0	$2,746.80	$2,746.80	1.03	R0 to R11 wall insulation
9129	HVAC Shell	Air Sealing - Average Sealing - Gas Heating	SF	LI	DI	2,939.6	7%	206.9	0.353	15.0	$624.65	$624.65	1.15	10 ACH 50 to 7 ACH 50
9130	HVAC Shell	Air Sealing - Inadequate Sealing - Gas Heating	SF	LI	DI	3,363.5	13%	423.9	0.392	15.0	$967.20	$967.20	1.04	14 ACH 50 to 10 ACH 50
9131	HVAC Shell	Air Sealing - Poor Sealing - Gas Heating	SF	LI	DI	4,030.0	17%	666.6	0.558	15.0	$967.20	$967.20	1.59	20 ACH 50 to 14 ACH 50
9132	HVAC Shell	Attic Insulation - Average Insulation - Gas Heating	SF	LI	DI	2,939.6	2%	62.9	0.076	25.0	$1,259.70	$1,259.70	0.17	R30 to R60
9133	HVAC Shell	Attic Insulation - Inadequate Insulation - Gas Heating	SF	LI	DI	2,997.7	4%	120.9	0.143	25.0	$1,744.20	$1,744.20	0.26	R19 to R60
9134	HVAC Shell	Attic Insulation - Poor Insulation - Gas Heating	SF	LI	DI	3,135.8	8%	241.1	0.225	25.0	$1,550.40	$1,550.40	0.52	R11 to R49
9135	HVAC Shell	Wall Sheathing - Gas Heating	SF	N/A	Retrofit	2,939.6	4%	125.1	0.192	25.0	$2,943.00	$1,000.00	0.92	R12 polyiso
9136	HVAC Shell	ENERGY STAR Windows - Gas Heating	SF	N/A	Retrofit	2,939.6	8%	249.6	0.535	25.0	$13,601.25	$1,000.00	0.76	U=0.30; SHGC=0.40
9137	HVAC Shell	Basement Sidewall Insulation - Gas Heating	SF	N/A	Retrofit	2,976.4	1%	36.8	0.036	25.0	$2,720.00	$1,000.00	0.48	R0 to R13 sidewall insulation
9138	HVAC Shell	Floor Insulation Above Crawlspace - Gas Heating	SF	N/A	Retrofit	2,908.9	-1%	-30.7	-0.036	25.0	$316.20	$90.00	0.73	R13 floor insulation
9139	HVAC Shell	ENERGY STAR Door - Gas Heating	SF	N/A	Retrofit	2,939.6	1%	34.6	0.052	25.0	$388.00	$120.00	1.25	Fiberglasss
9140	HVAC Shell	Smart Window Coverings - Shade/Blind/Controller/Sensor - Gas Heating_ET	SF	N/A	Retrofit	2,939.6	16%	455.6	0.531	7.0	$14,875.00	$1,000.00	0.53	Smart shades
9141	HVAC Shell	Smart Window Coverings - Film/Transformer - Gas Heating_ET	SF	N/A	Retrofit	2,939.6	16%	455.6	0.531	7.0	$8,160.75	$1,000.00	0.53	Smart films
9142	HVAC Shell	Duct Sealing - Average Sealing - Gas Heating	MF	NLI	Retrofit	2,487.5	26%	638.5	0.484	20.0	$200.00	$175.00	6.06	15% to 10% leakage
9143	HVAC Shell	Duct Sealing - Inadequate Sealing - Gas Heating	MF	NLI	Retrofit	2,631.4	20%	532.0	0.309	20.0	$350.00	$300.00	2.41	20% to 15% leakage
9144	HVAC Shell	Duct Sealing/Insulation - Poor Sealing - Gas Heating	MF	NLI	Retrofit	2,796.3	48%	1,342.7	0.788	20.0	$981.00	$500.00	3.67	25% to 15% leakage
9145	HVAC Shell	Wall Insulation - Gas Heating	MF	NLI	Retrofit	2,385.4	9%	222.4	0.221	25.0	$1,159.20	$450.00	2.12	R0 to R11 wall insulation
9146	HVAC Shell	Air Sealing - Average Sealing - Gas Heating	MF	NLI	Retrofit	2,163.0	9%	200.4	0.183	15.0	$309.69	$100.00	4.26	10 ACH 50 to 7 ACH 50
9147	HVAC Shell	Air Sealing - Inadequate Sealing - Gas Heating	MF	NLI	Retrofit	2,390.9	10%	227.9	0.162	15.0	$479.52	$100.00	5.01	14 ACH 50 to 10 ACH 50
9148	HVAC Shell	Air Sealing - Poor Sealing - Gas Heating	MF	NLI	Retrofit	2,758.6	13%	367.7	0.187	15.0	$479.52	$100.00	7.43	20 ACH 50 to 14 ACH 50
9149	HVAC Shell	Attic Insulation - Average Insulation - Gas Heating	MF	NLI	Retrofit	2,163.0	8%	172.1	0.145	25.0	$1,298.70	$450.00	0.86	R30 to R60
9150	HVAC Shell	Attic Insulation - Inadequate Insulation - Gas Heating	MF	NLI	Retrofit	2,203.0	10%	212.1	0.181	25.0	$1,798.20	$450.00	1.10	R19 to R60
9151	HVAC Shell	Attic Insulation - Poor Insulation - Gas Heating	MF	NLI	Retrofit	2,290.4	13%	291.6	0.245	25.0	$1,598.40	$450.00	1.51	R11 to R49
9152	HVAC Shell	Duct Sealing - Average Sealing - Gas Heating	MF	LI	DI	2,487.5	26%	638.5	0.484	20.0	$200.00	$200.00	5.30	15% to 10% leakage
9153	HVAC Shell	Duct Sealing - Inadequate Sealing - Gas Heating	MF	LI	DI	2,631.4	20%	532.0	0.309	20.0	$350.00	$350.00	2.06	20% to 15% leakage

Vectren Electric — Residential Measure Assumptions

Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	Historical Incentive Amount	UCT Ratio	Measure Description
9154	HVAC Shell	Duct Sealing/Insulation - Poor Sealing - Gas Heating	MF	LI	DI	2,796.3	48%	1,342.7	0.788	20.0	$981.00	$981.00	1.87	25% to 15% leakage
9155	HVAC Shell	Wall Insulation - Gas Heating	MF	LI	DI	2,385.4	9%	222.4	0.221	25.0	$1,159.20	$1,159.20	0.82	R0 to R11 wall insulation
9156	HVAC Shell	Air Sealing - Average Sealing - Gas Heating	MF	LI	DI	2,163.0	9%	200.4	0.183	15.0	$309.69	$309.69	1.38	10 ACH 50 to 7 ACH 50
9157	HVAC Shell	Air Sealing - Inadequate Sealing - Gas Heating	MF	LI	DI	2,390.9	10%	227.9	0.162	15.0	$479.52	$479.52	1.04	14 ACH 50 to 10 ACH 50
9158	HVAC Shell	Air Sealing - Poor Sealing - Gas Heating	MF	LI	DI	2,758.6	13%	367.7	0.187	15.0	$479.52	$479.52	1.55	20 ACH 50 to 14 ACH 50
9159	HVAC Shell	Attic Insulation - Average Insulation - Gas Heating	MF	LI	DI	2,163.0	8%	172.1	0.145	25.0	$1,298.70	$1,298.70	0.30	R30 to R60
9160	HVAC Shell	Attic Insulation - Inadequate Insulation - Gas Heating	MF	LI	DI	2,203.0	10%	212.1	0.181	25.0	$1,798.20	$1,798.20	0.28	R19 to R60
9161	HVAC Shell	Attic Insulation - Poor Insulation - Gas Heating	MF	LI	DI	2,290.4	13%	291.6	0.245	25.0	$1,598.40	$1,598.40	0.43	R11 to R49
9162	HVAC Shell	Wall Sheathing - Gas Heating	MF	N/A	Retrofit	2,163.0	9%	203.7	0.190	25.0	$1,242.00	$625.00	0.96	R12 polyiso
9163	HVAC Shell	ENERGY STAR Windows - Gas Heating	MF	N/A	Retrofit	2,163.0	13%	286.7	0.281	25.0	$6,743.25	$1,000.00	0.64	U=0.30; SHGC=0.40
9164	HVAC Shell	Basement Sidewall Insulation - Gas Heating	MF	N/A	Retrofit	2,293.7	2%	43.4	-0.002	25.0	$2,815.20	$1,000.00	0.26	R0 to R13 sidewall insulation
9165	HVAC Shell	Floor Insulation Above Crawlspace - Gas Heating	MF	N/A	Retrofit	2,157.6	-1%	-27.1	-0.019	25.0	$849.15	$425.00	0.02	R13 floor insulation
9166	HVAC Shell	Smart Window Coverings - Shade/Blind/Controller/Sensor - Gas Heating_ET	MF	N/A	Retrofit	2,163.0	16%	335.3	0.258	7.0	$8,500.00	$1,000.00	0.28	Smart shades
9167	HVAC Shell	Smart Window Coverings - Film/Transformer - Gas Heating_ET	MF	N/A	Retrofit	2,163.0	16%	335.3	0.258	7.0	$4,045.95	$1,000.00	0.28	Smart films
10001	Water Heating	Water Heater Wrap	SF	N/A	Retrofit	3,536.2	2%	80.4	0.009	5.0	$20.00	$20.00	0.98	Add WH Wrap to reduce standby losses (Electric Only)
10002	Water Heating	Water Heater Temperature Setback	SF	NLI	Retrofit	733.6	11%	81.5	0.009	15.0	$6.50	$6.50	8.11	WH Temp Setback from 135 to 120
10003	Water Heating	Water Heater Timer	SF	NLI	Retrofit	3,536.2	9%	318.0	0.036	15.0	$60.00	$30.00	6.85	Install Timer to turn off at night or other periods (Electric Only)
10004	Water Heating	Pipe Wrap	SF	NLI	Retrofit	3,536.2	3%	106.1	0.012	15.0	$1.72	$1.72	39.87	Adding Pipe Wrap to Uninsulated Pipes
10005	Water Heating	Heat Pump Water Heater	SF	N/A	MO	3,536.2	67%	2,368.0	0.935	10.0	$1,000.00	$300.00	3.59	Heat Pump Water Heater
10006	Water Heating	Solar Water Heater with Electric Backup	SF	N/A	MO	3,536.2	50%	1,777.0	0.702	10.0	$9,506.00	$2,850.00	0.26	Solar WH (EF=1.8)
10007	Water Heating	Smart Water Heater - Tank Controls and Sensors_ET	SF	N/A	Retrofit	3,536.2	15%	530.0	0.209	10.0	$120.00	$60.00	4.26	Smart WH Controls
10008	Water Heating	Bathroom Aerator 1.0 gpm	SF	NLI	Retrofit	49.8	47%	23.6	2.153	10.0	$0.52	$0.52	20.53	1.0 GPM Bathroom FA
10009	Water Heating	Kitchen Flip Aerator 1.5 gpm	SF	NLI	Retrofit	396.6	39%	152.8	2.114	10.0	$1.34	$1.34	43.53	1.5 GPM Kitchen FA
10010	Water Heating	Low Flow Showerhead 1.5 gpm	SF	NLI	Retrofit	611.2	43%	262.6	6.429	10.0	$3.32	$3.32	31.13	1.5 GPM Low Flow Showerhead
10011	Water Heating	Thermostatic Restrictor Shower Valve	SF	N/A	Retrofit	611.2	11%	69.7	2.302	10.0	$30.00	$15.00	1.93	Thermostatic Restrictor Shower Valve (on base flow device)
10012	Water Heating	Shower Timer	SF	N/A	Retrofit	611.2	9%	53.6	0.321	2.0	$5.00	$5.00	1.28	Shower Timer limit time to 5 mins (per shower)
10013	Water Heating	Drain water Heat Recovery	SF	N/A	Retrofit	3,536.2	25%	884.0	0.101	20.0	$742.00	$225.00	3.14	Drainpipe heat exchanger
10014	Water Heating	Desuperheater	SF	N/A	Retrofit	3,536.2	44%	1,556.0	0.178	25.0	$620.00	$185.00	7.69	Install Desuperheater (Paid with GSHP)
10015	Water Heating	Bathroom Aerator 1.0 gpm	SF	LI	DI	49.8	47%	23.6	2.153	10.0	$0.52	$0.52	20.53	1.0 GPM Bathroom FA
10016	Water Heating	Kitchen Flip Aerator 1.5 gpm	SF	LI	DI	396.6	39%	152.8	2.114	10.0	$1.34	$1.34	43.53	1.5 GPM Kitchen FA

Vectren Electric Residential Measure Assumptions

Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	Historical Incentive Amount	UCT Ratio	Measure Description
10017	Water Heating	Low Flow Showerhead 1.5 gpm	SF	LI	DI	611.2	43%	262.6	6.429	10.0	$3.32	$3.32	31.13	1.5 GPM Low Flow Showerhead
10018	Water Heating	Pipe Wrap	SF	LI	DI	3,536.2	3%	106.1	0.012	15.0	$1.72	$1.72	39.87	Adding Pipe Wrap to Uninsulated Pipes
10019	Water Heating	Water Heater Temperature Setback	SF	LI	DI	733.6	11%	81.5	0.009	15.0	$6.50	$6.50	8.11	WH Temp Setback from 135 to 120
10020	Water Heating	Water Heater Temperature Setback	SF	N/A	NC	733.6	11%	81.5	0.009	15.0	$6.50	$6.50	8.11	WH Temp Setback from 135 to 120
10021	Water Heating	Water Heater Timer	SF	N/A	NC	3,536.2	9%	318.0	0.036	15.0	$60.00	$30.00	6.85	Install Timer to turn off at night or other periods (Electric Only)
10022	Water Heating	Pipe Wrap	SF	N/A	NC	3,536.2	3%	106.1	0.012	15.0	$1.72	$1.72	39.87	Adding Pipe Wrap to Uninsulated Pipes
10023	Water Heating	Heat Pump Water Heater	SF	N/A	NC	3,536.2	67%	2,368.0	0.935	10.0	$1,000.00	$300.00	3.59	Heat Pump Water Heater
10024	Water Heating	Solar Water Heater with Electric Backup	SF	N/A	NC	3,536.2	50%	1,777.0	0.702	10.0	$9,506.00	$2,850.00	0.26	Solar WH (EF=1.8)
10025	Water Heating	Smart Water Heater - Tank Controls and Sensors_ET	SF	N/A	NC	3,536.2	15%	530.0	0.209	10.0	$120.00	$60.00	4.26	Smart WH Controls
10026	Water Heating	Bathroom Aerator 1.0 gpm	SF	N/A	NC	49.8	47%	23.6	2.153	10.0	$0.52	$0.52	20.53	1.0 GPM Bathroom FA
10027	Water Heating	Kitchen Flip Aerator 1.5 gpm	SF	N/A	NC	396.6	39%	152.8	2.114	10.0	$1.34	$1.34	43.53	1.5 GPM Kitchen FA
10028	Water Heating	Low Flow Showerhead 1.5 gpm	SF	N/A	NC	611.2	43%	262.6	6.429	10.0	$3.32	$3.32	31.13	1.5 GPM Low Flow Showerhead
10029	Water Heating	Thermostatic Restrictor Shower Valve	SF	N/A	NC	611.2	11%	69.7	2.302	10.0	$30.00	$15.00	1.93	Thermostatic Restrictor Shower Valve (on base flow device)
10030	Water Heating	Shower Timer	SF	N/A	NC	611.2	9%	53.6	0.321	2.0	$5.00	$5.00	1.28	Shower Timer limit time to 5 mins (per shower)
10031	Water Heating	Drain water Heat Recovery	SF	N/A	NC	3,536.2	25%	884.0	0.101	20.0	$742.00	$225.00	3.14	Drainpipe heat exchanger
10032	Water Heating	Desuperheater	SF	N/A	NC	3,536.2	44%	1,556.0	0.178	25.0	$620.00	$185.00	7.69	Install Desuperheater (Paid with GSHP)
10033	Water Heating	Water Heater Wrap	MF	N/A	Retrofit	2,662.9	2%	60.5	0.007	5.0	$20.00	$20.00	0.74	Add WH Wrap to reduce standby losses (Electric Only)
10034	Water Heating	Water Heater Temperature Setback	MF	NLI	Retrofit	733.6	11%	81.5	0.009	15.0	$6.50	$6.50	8.11	WH Temp Setback from 135 to 120
10035	Water Heating	Water Heater Timer	MF	NLI	Retrofit	2,662.9	9%	240.0	0.027	15.0	$60.00	$30.00	5.17	Install Timer to turn off at night or other periods (Electric Only)
10036	Water Heating	Pipe Wrap	MF	NLI	Retrofit	2,662.9	3%	79.9	0.009	15.0	$1.72	$1.72	30.03	Adding Pipe Wrap to Uninsulated Pipes
10037	Water Heating	Heat Pump Water Heater	MF	N/A	MO	2,662.9	58%	1,544.0	0.610	10.0	$1,000.00	$300.00	2.27	Heat Pump Water Heater
10038	Water Heating	Smart Water Heater - Tank Controls and Sensors_ET	MF	N/A	Retrofit	2,662.9	15%	399.0	0.158	10.0	$120.00	$60.00	3.21	Smart WH Controls
10039	Water Heating	Bathroom Aerator 1.0 gpm	MF	NLI	Retrofit	57.2	47%	27.1	2.153	10.0	$0.52	$0.52	22.77	1.0 GPM Bathroom FA
10040	Water Heating	Kitchen Flip Aerator 1.5 gpm	MF	NLI	Retrofit	274.9	39%	105.9	2.114	10.0	$1.34	$1.34	31.94	1.5 GPM Kitchen FA
10041	Water Heating	Low Flow Showerhead 1.5 gpm	MF	NLI	Retrofit	649.6	43%	279.1	6.429	10.0	$1.34	$1.34	81.22	1.5 GPM Low Flow Showerhead
10042	Water Heating	Thermostatic Restrictor Shower Valve	MF	N/A	Retrofit	649.6	11%	74.1	2.446	10.0	$30.00	$15.00	2.05	Thermostatic Restrictor Shower Valve (on base flow device)
10043	Water Heating	Shower Timer	MF	N/A	Retrofit	649.6	9%	56.9	0.321	2.0	$5.00	$5.00	1.33	Shower Timer limit time to 5 mins (per shower)
10044	Water Heating	Drain water Heat Recovery	MF	N/A	Retrofit	2,662.9	25%	666.0	0.076	20.0	$742.00	$225.00	2.36	Drainpipe heat exchanger
10045	Water Heating	Desuperheater	MF	N/A	Retrofit	2,662.9	44%	1,172.0	0.134	25.0	$620.00	$185.00	5.80	Install Desuperheater (Paid with GSHP)
10046	Water Heating	Bathroom Aerator 1.0 gpm	MF	LI	DI	57.2	47%	27.1	2.153	10.0	$0.52	$0.52	22.77	1.0 GPM Bathroom FA
10047	Water Heating	Kitchen Flip Aerator 1.5 gpm	MF	LI	DI	274.9	39%	105.9	2.114	10.0	$1.34	$1.34	31.94	1.5 GPM Kitchen FA
10048	Water Heating	Low Flow Showerhead 1.5 gpm	MF	LI	DI	649.6	43%	279.1	6.429	10.0	$1.34	$1.34	81.22	1.5 GPM Low Flow Showerhead
10049	Water Heating	Pipe Wrap	MF	LI	DI	2,662.9	3%	79.9	0.009	15.0	$1.72	$1.72	30.03	Adding Pipe Wrap to Uninsulated Pipes
10050	Water Heating	Water Heater Temperature Setback	MF	LI	DI	733.6	11%	81.5	0.009	15.0	$6.50	$6.50	8.11	WH Temp Setback from 135 to 120

Vectren Electric — Residential Measure Assumptions

Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	Historical Incentive Amount	UCT Ratio	Measure Description
10051	Water Heating	Water Heater Temperature Setback	MF	N/A	NC	733.6	11%	81.5	0.009	15.0	$6.50	$6.50	8.11	WH Temp Setback from 135 to 120
10052	Water Heating	Water Heater Timer	MF	N/A	NC	2,662.9	9%	240.0	0.027	15.0	$60.00	$30.00	5.17	Install Timer to turn off at night or other periods (Electric Only)
10053	Water Heating	Pipe Wrap	MF	N/A	NC	2,662.9	3%	79.9	0.009	15.0	$1.72	$1.72	30.03	Adding Pipe Wrap to Uninsulated Pipes
10054	Water Heating	Heat Pump Water Heater	MF	N/A	NC	2,662.9	58%	1,544.0	0.610	10.0	$1,000.00	$300.00	2.27	Heat Pump Water Heater
10055	Water Heating	Smart Water Heater - Tank Controls and Sensors_ET	MF	N/A	NC	2,662.9	15%	399.0	0.158	10.0	$120.00	$60.00	3.21	Smart WH Controls
10056	Water Heating	Bathroom Aerator 1.0 gpm	MF	N/A	NC	57.2	47%	27.1	2.153	10.0	$0.52	$0.52	22.77	1.0 GPM Bathroom FA
10057	Water Heating	Kitchen Flip Aerator 1.5 gpm	MF	N/A	NC	274.9	39%	105.9	2.114	10.0	$1.34	$1.34	31.94	1.5 GPM Kitchen FA
10058	Water Heating	Low Flow Showerhead 1.5 gpm	MF	N/A	NC	649.6	43%	279.1	6.429	10.0	$1.34	$1.34	81.22	1.5 GPM Low Flow Showerhead
10059	Water Heating	Thermostatic Restrictor Shower Valve	MF	N/A	NC	649.6	11%	74.1	2.446	10.0	$30.00	$15.00	2.05	Thermostatic Restrictor Shower Valve (on base flow device)
10060	Water Heating	Shower Timer	MF	N/A	NC	649.6	9%	56.9	0.321	2.0	$5.00	$5.00	1.33	Shower Timer limit time to 5 mins (per shower)
10061	Water Heating	Drain water Heat Recovery	MF	N/A	NC	2,662.9	25%	666.0	0.076	20.0	$742.00	$225.00	2.36	Drainpipe heat exchanger
10062	Water Heating	Desuperheater	MF	N/A	NC	2,662.9	44%	1,172.0	0.134	25.0	$620.00	$185.00	5.80	Install Desuperheater (Paid with GSHP)

Key Acronyms

DI:	Direct-install
LI:	Low-income
MF:	Multifamily
MO:	Market opportunity
NC:	New Construction
NLI:	Non-low-income
SF:	Single-family

APPENDIX C *DSM Market Potential Study Commercial Measure Detail*

Vectren Electric		Commercial Measure Assumptions						
Measure #	End-Use	Measure Name	% Elec Savings	Per Unit Elec Savings	Per Unit NCP kW	Useful Life	Initial Measure Cost	UCT Ratio
1	Interior Lighting	Compact Fluorescent - 2019	67.8%	198.8	0.039	3.0	$1.20	64.96
2	Interior Lighting	LED Exit Sign	91.3%	206.8	0.021	16.0	$30.00	10.52
3	Interior Lighting	High Performance T8 (vs RWT8) 4ft	19%	50	0.011	15	$18.00	4.98
4	Interior Lighting	Wall Mounted Occupancy Sensor	24.0%	335.3	0.000	8.0	$51.00	4.41
5	Interior Lighting	Fixture Mounted Occupancy Sensor	24%	198	0.000	8	$91.83	1.45
6	Interior Lighting	Remote Mounted Occupancy Sensor	24%	568	0.000	8	$101.00	3.78
7	Interior Lighting	High Bay LED vs (Metal Halide 250W)	35%	476	0.104	15	$200.00	5.65
8	Interior Lighting	High Bay LED vs (Metal Halide 400W)	53%	1,492	0.326	15	$250.00	14.15
9	Interior Lighting	High performance T5 (replacing T8)	44%	461	0.101	15	$100.00	8.20
10	Interior Lighting	CFL Hard Wired Fixture - 2019	69%	199	0.044	12	$37.50	7.94
11	Interior Lighting	CFL High Wattage 31-115 - 2019	55%	383	0.084	3	$21.00	7.46
12	Interior Lighting	CFL High Wattage 150-199 -2019	58%	1,088	0.238	3	$57.00	7.80
13	Interior Lighting	Low Bay LED (vs T8HO)	42%	306	0.067	15	$331.00	1.64
14	Interior Lighting	High Bay LED (vs T8HO)	35%	472	0.103	15	$482.00	1.74
15	Interior Lighting	LED Screw-In Bulb	51%	149	0.027	15	$1.20	207.76
16	Interior Lighting	LED Downlight Fixtures	68%	168	0.037	15	$27.00	11.07
17	Interior Lighting	LED Linear Replacement Lamps	37%	99	0.022	15	$25.00	7.04
18	Interior Lighting	LED Troffer	38%	106	0.023	15	$62.00	3.03
19	Interior Lighting	Light Tube	10%	250	0.104	10	$500.00	0.95
20	Interior Lighting	Central Lighting Controls	10%	4,077	1.000	8	$103.00	43.51
21	Interior Lighting	Lighting Power Density Reduction (NC)	10%	4,077	1.000	15	$220.00	45.78
22	Interior Lighting	Switching Controls for Multi-Level Lighting	30%	12,232	3.000	8	$274.00	49.07
23	Interior Lighting	Smart Advanced Lighting Controls	47%	2	0.001	10	$1.51	2.63
24	Interior Lighting	Smart Web-based lighting Mgmt System	35%	3	0.001	10	$1.15	5.41
25	Exterior Lighting	Outdoor LED (< 250W MH)	65%	495	0.101	15	$238.50	3.01
26	Exterior Lighting	Outdoor LED (> 250W MH)	54%	983	0.201	15	$592.00	2.41
27	Space Cooling - Unitary / Split	Split System, <65,000 Btu/hr (CEE Tier 1)	13%	143	0.123	15	$63.00	8.91
28	Space Cooling - Unitary / Split	Split System, <65,000 Btu/hr (CEE Tier 2)	19%	201	0.173	15	$127.00	6.22
29	Space Cooling - Unitary / Split	Single Package System <65,000 Btu/hr (CEE Tier 1)	7%	66	0.057	15	$63.00	4.14
30	Space Cooling - Unitary / Split	Single Package System <65,000 Btu/hr (CEE Tier2)	13%	124	0.107	15	$127.00	3.85
31	Space Cooling - Unitary / Split	<135,000 Btu/hr (CEE Tier 1) (2019- 2022)	8%	86	0.074	15	$63.00	5.37
32	Space Cooling - Unitary / Split	<135,000 Btu/hr (CEE Tier 2) (2019-2022)	13%	140	0.121	15	$127.00	4.35
33	Space Cooling - Unitary / Split	<135,000 Btu/hr (CEE Advanced Tier) (2023+)	18%	169	0.146	15	$127.00	5.24
34	Space Cooling - Unitary / Split	<240,000 Btu/hr (CEE Tier 1) (2019 - 2022)	6%	69	0.060	15	$63.00	4.31
35	Space Cooling - Unitary / Split	<240,000 Btu/hr (CEE Tier 2) (2019 - 2022)	13%	144	0.125	15	$127.00	4.47
36	Space Cooling - Unitary / Split	<240,000 Btu/hr (CEE Advanced Tier) (2023+)	17%	163	0.141	15	$127.00	5.06
37	Space Cooling - Unitary / Split	<760,000 Btu/hr (CEE Tier 1) (2019 -2022)	6%	69	0.060	15	$19.00	14.37
38	Space Cooling - Unitary / Split	<760,000 Btu/hr (CEE Tier 2) (2019 -2022)	12%	148	0.127	15	$38.00	15.30
39	Space Cooling - Unitary / Split	<760,000 Btu/hr (CEE Advanced Tier) (2023+)	9%	96	0.083	15	$38.00	9.93

Vectren Electric — Commercial Measure Assumptions

Measure #	End-Use	Measure Name	% Elec Savings	Per Unit Elec Savings	Per Unit NCP kW	Useful Life	Initial Measure Cost	UCT Ratio
40	Space Cooling - Unitary / Split	Tier 1) (2019 -2022)	3%	44	0.038	15	$19.00	9.03
41	Space Cooling - Unitary / Split	Tier 2) (2019 -2022)	9%	113	0.097	15	$38.00	11.70
42	Space Cooling - Unitary / Split	PTAC, <7,000 Btu/hr	8%	106	0.078	15	$84.00	4.51
43	Space Cooling - Unitary / Split	PTAC ≥7,000 Btu/h and ≤15,000 Btu/hr	11%	162	0.124	15	$84.00	7.05
44	Space Cooling - Unitary / Split	PTHP, ≥7,000 Btu/hr and ≤15,000 Btu/hr	11%	177	0.130	15	$84.00	7.52
45	Space Cooling - Unitary / Split	HVAC Tune-up (2019-2022)	15%	164	0.000	3	$35.00	1.98
46	Space Cooling - Unitary / Split	HVAC Tune-up (2023+)	15%	150	0.000	3	$35.00	1.80
47	Space Cooling - Unitary / Split	Air Source Heat Pump <65,000 BtuH (CEE Tier 1)	7%	66	0.057	15	$50.00	1.14
48	Space Cooling - Unitary / Split	Air Source Heat Pump <65,000 BtuH (CEE Tier 2)	13%	124	0.107	15	$50.00	2.38
49	Space Cooling - Unitary / Split	Btu/hr (CEE Tier 1) (2019-2022)	10%	117	0.101	15	$50.00	1.99
50	Space Cooling - Unitary / Split	Btu/hr (CEE Tier 1) (2023+)	10%	101	0.088	15	$50.00	2.08
51	Space Cooling - Unitary / Split	Btu/hr (CEE Tier 1) (2019 -2022)	9%	112	0.097	15	$50.00	1.94
52	Space Cooling - Unitary / Split	Btu/hr (CEE Tier 1) (2023+)	9%	97	0.083	15	$50.00	1.76
53	Space Cooling - Unitary / Split	(2019 -2022)	10%	133	0.115	15	$50.00	2.22
54	Space Cooling - Unitary / Split	(2023+)	10%	113	0.098	15	$50.00	2.00
55	Space Cooling - Unitary / Split	Ground Source Heat Pump <135,000 Btu/hr	10%	110	0.095	15	$75.00	1.57
56	Space Cooling - Unitary / Split	Water Source Heat Pump <17,000Btu/hr	13%	147	0.126	15	$75.00	1.90
57	Space Cooling - Unitary / Split	<135,000Btu/hr	7%	76	0.066	15	$75.00	1.05
58	Space Cooling - Unitary / Split	Advanced Rooftop Controls	45%	3,034	2.617	9	$187.50	57.49
59	Space Cooling - Unitary / Split	Commercial/Industrial CO2 Heat Pump	70%	351	0.000	10	$87.78	5.52
60	Space Cooling - Unitary / Split	Room A/C	4%	16	0.037	9	$40.00	2.23
61	Space Cooling - Unitary / Split	Cool roof	15%	89	0.045	20	$88.22	0.65
62	Space Cooling - Unitary / Split	Ceiling Insulation	8%	87	0.044	30	$58.59	2.34
63	Space Cooling - Unitary / Split	Wall insulation	2%	507	0.136	30	$8.32	71.55
64	Space Cooling - Unitary / Split	Roof Insulation	8%	24	0.019	30	$11.36	4.35
65	Space Cooling - Unitary / Split	Destratification Fan	50%	8	-0.007	15	$7.27	0.51
66	Space Cooling - Unitary / Split	EMS	10%	310	0.014	15	$0.86	194.09
67	Space Cooling - Unitary / Split	Duct sealing 15% leakage base	5%	19	0.013	18	$10.85	2.47
68	Space Cooling - Unitary / Split	Integrated Building Design	30%	2	0.000	20	$0.11	16.35
69	Space Cooling - Unitary / Split	Retrocommissioning	16%	1	0.000	7	$0.03	12.80
70	Space Cooling - Unitary / Split	Commissioning	13%	1	0.000	7	$0.12	2.69
71	Space Cooling - Unitary / Split	Commercial Window Film	5%	209	0.050	10	$35.50	1.94
72	Space Cooling - Unitary / Split	High Performance Glazing	6%	2	0.070	20	$6.82	8.95
73	Space Cooling - Unitary / Split	Programable Thermostats	10%	945	0.000	4	$22.44	5.36
74	Space Cooling - Unitary / Split	Cooling	25%	119	0.047	8	$18.89	3.19
75	Space Cooling - Unitary / Split	Smart Thermostats	8%	660	0.000	10	$29.75	6.50
76	Space Cooling - Unitary / Split	Smart Cloud-Based Enery Information System (EIS)	8%	89	0.000	10	$0.61	42.60
77	Space Cooling - Chillers	Air Cooled Chiller <150 tons	13%	318	0.116	20	$127.00	8.04
78	Space Cooling - Chillers	Air Cooled Chiller ≥150 tons	13%	305	0.112	20	$127.00	7.28

Vectren Electric		Commercial Measure Assumptions						
Measure #	End-Use	Measure Name	% Elec Savings	Per Unit Elec Savings	Per Unit NCP kW	Useful Life	Initial Measure Cost	UCT Ratio
79	Space Cooling - Chillers	Water Cooled Screw Chiller <150 ton	13%	191	0.070	20	$177.68	3.46
80	Space Cooling - Chillers	Water Cooled Screw Chiller ≥150 tons and < 300 tons	19%	273	0.100	20	$127.00	6.91
81	Space Cooling - Chillers	Water Cooled Screw Chiller ≥300 ton	21%	300	0.110	20	$87.00	11.09
82	Space Cooling - Chillers	Water Cooled Centrifugal Chiller <150 ton	20%	300	0.110	20	$166.10	5.81
83	Space Cooling - Chillers	tons	27%	410	0.150	20	$122.87	10.71
84	Space Cooling - Chillers	Water Cooled Centrifugal Chiller ≥300 ton	25%	355	0.130	20	$92.22	12.37
85	Space Cooling - Chillers	Air Cooled Chiller Tune-up/Diagnostics	8%	187	0.000	5	$5.66	20.10
86	Space Cooling - Chillers	WaterCooled Chiller/Tune-up/Diagnostics	8%	119	0.000	5	$5.66	12.78
87	Space Cooling - Chillers	Chilled Water Reset Controls	25%	173	0.030	10	$681.34	0.39
88	Space Cooling - Chillers	Cool roof	15%	89	0.045	20	$88.22	0.65
89	Space Cooling - Chillers	Ceiling Insulation	8%	87	0.044	30	$58.59	2.34
90	Space Cooling - Chillers	Wall insulation	2%	507	0.136	30	$8.32	71.55
91	Space Cooling - Chillers	Roof Insulation	8%	24	0.019	30	$11.36	4.35
92	Space Cooling - Chillers	Destratification Fan	50%	8	-0.007	15	$7.27	0.51
93	Space Cooling - Chillers	EMS	10%	310	0.014	15	$0.86	194.09
94	Space Cooling - Chillers	Duct sealing 15% leakage base	5%	19	0.013	18	$10.85	2.47
95	Space Cooling - Chillers	Integrated Building Design	30%	2	0.000	20	$0.11	16.35
96	Space Cooling - Chillers	Retrocommissioning	16%	1	0.000	7	$0.03	12.80
97	Space Cooling - Chillers	Commissioning	13%	1	0.000	7	$0.12	2.69
98	Space Cooling - Chillers	Commercial Window Film	5%	209	0.050	10	$35.50	1.94
99	Space Cooling - Chillers	High Performance Glazing	6%	2	0.070	20	$6.82	8.95
100	Space Cooling - Chillers	Programable Thermostats	10%	945	0.000	4	$22.44	5.36
101	Space Cooling - Chillers	Smart Thermostats	8%	660	0.000	10	$29.75	6.50
102	Space Cooling - Chillers	Smart Cloud-Based Enery Information System (EIS)	8%	89	0.000	10	$0.61	42.60
103	Space Heating	PTHP, <7,000 Btu/hr	8%	65	0.100	15	$84.00	1.12
104	Space Heating	PTHP, ≥7,000 Btu/hr and ≤15,000 Btu/hr	11%	94	0.146	15	$84.00	1.63
105	Space Heating	Tier 1)	4%	33	0.052	15	$50.00	1.14
106	Space Heating	Tier 2)	9%	84	0.130	15	$50.00	2.38
107	Space Heating	System (CEE Tier 1)	6%	57	0.088	15	$50.00	4.14
108	Space Heating	System (CEE Tier 2)	6%	57	0.088	15	$50.00	3.85
109	Space Heating	Btu/hr (CEE Tier 1) (2019-2022)	8%	57	0.089	15	$50.00	1.99
110	Space Heating	Btu/hr (CEE Tier 1) (2023+)	6%	37	0.057	15	$50.00	2.08
111	Space Heating	Btu/hr (CEE Tier 1) (2019 -2022)	9%	61	0.094	15	$50.00	1.94
112	Space Heating	Btu/hr (CEE Tier 1) (2023+)	6%	39	0.061	15	$50.00	1.76
113	Space Heating	(2019 -2022)	9%	61	0.094	15	$50.00	2.22
114	Space Heating	(2023+)	9%	61	0.094	15	$50.00	2.00
115	Space Heating	Ground Source Heat Pump <135,000 Btu/hr	10%	61	0.008	15	$75.00	1.57
116	Space Heating	Water Source Heat Pump < 135,000Btu/hr	13%	68	0.009	15	$75.00	1.90
117	Space Heating	<135,000Btu/hr	7%	38	0.005	15	$75.00	1.05

Vectren Electric — Commercial Measure Assumptions

Measure #	End-Use	Measure Name	% Elec Savings	Per Unit Elec Savings	Per Unit NCP kW	Useful Life	Initial Measure Cost	UCT Ratio
118	Space Heating	Commercial/Industrial CO2 Heat Pump	70%	189	0.000	10	$47.22	5.52
119	Space Heating	Cool roof	15%	41	0.021	20	$88.22	0.65
120	Space Heating	Ceiling Insulation	8%	40	0.020	30	$58.59	2.34
121	Space Heating	Wall insulation	2%	236	0.063	30	$8.32	71.55
122	Space Heating	Roof Insulation	8%	11	0.009	30	$11.36	4.35
123	Space Heating	Destratification Fan	50%	4	-0.003	15	$7.27	0.51
124	Space Heating	EMS	10%	144	0.007	15	$0.86	194.09
125	Space Heating	Duct sealing 15% leakage base	5%	9	0.006	18	$10.85	2.47
126	Space Heating	Integrated Building Design	30%	1	0.000	20	$0.11	16.35
127	Space Heating	Retrocommissioning	16%	0	0.000	7	$0.03	12.80
128	Space Heating	Commissioning	13%	0	0.000	7	$0.12	2.69
129	Space Heating	Commercial Window Film	5%	97	0.023	10	$35.50	1.94
130	Space Heating	High Performance Glazing	6%	1	0.032	20	$6.82	8.95
131	Space Heating	Programable Thermostats	10%	945	0.000	4	$22.44	5.36
132	Space Heating	Cooling	25%	119	0.047	8	$18.89	3.19
133	Space Heating	Smart Thermostats	8%	660	0.000	10	$29.75	6.50
134	Space Heating	Smart Cloud-Based Enery Information System (EIS)	8%	89	0.000	10	$0.61	42.60
135	Ventilation	VFD Supply and Return Fans, < 2 HP	30%	2,497	0.369	15	$1,330.00	2.73
136	Ventilation	VFD Supply and Return Fans, <3 to 10 HP	30%	6,242	0.922	15	$1,622.00	5.59
137	Ventilation	VFD Supply and Return Fans, 11 to 50 HP	30%	37,450	5.530	15	$3,059.00	17.79
138	Ventilation	Enthalpy Economizer	20%	117	0.000	10	$400.00	0.30
139	Ventilation	Improved Duct Sealing	23%	70	0.000	18	$107.91	1.43
140	Ventilation	Electronically-Commutated Permanent Magnet Motors	65%	1,635	0.000	15	$3,059.00	0.78
141	Ventilation	High Volume Low Speed Fans	50%	8,379	3.067	10	$4,185.00	4.03
142	Ventilation	VFD Tower Fan	30%	829	0.265	10	$155.96	5.50
143	Motors	VFD on Chilled Water Pump Motor, 5 HP	15%	28,580	0.000	15	$1,330.00	31.22
144	Motors	VFD on Chilled Water Pump Motor, 7.5 HP	15%	42,870	0.000	15	$1,622.00	38.40
145	Motors	VFD on Chilled Water Pump Motor, 20 HP	15%	171,480	0.000	15	$3,059.00	81.44
146	Motors	High Performance Elevators	80%	12,982	1.406	25	$54,690.00	0.64
147	Motors	Escalators Motor Efficiency Controllers	30%	5,414.000	0.620	20	$6,900.00	1.86
148	Other	NEMA Premium Transformer, single-phase	2%	0.163	0.000	30	$0.24	3.16
149	Other	NEMA Premium Transformer, three-phase	2%	0.244	0.000	30	$0.18	4.81
150	Other	High Efficiency Transformer, single-phase	2%	0.393	0.000	30	$0.46	3.56
151	Other	High Efficiency Transformer, three-phase	2%	0	0.000	30	$0.44	5.50
152	Water Heating	High Efficiency Storage (tank)	0%	9	0.000	15	$70.00	0.18
153	Water Heating	retrofit	20%	1,284	0.000	5	$92.90	7.30
154	Water Heating	On Demand (tankless)	7%	7,905	0.000	5	$1,050.00	3.97
155	Water Heating	dryer	38%	86	0.000	7	$19.35	3.32
156	Water Heating	Electric dryer	25%	542	0.000	7	$72.00	5.62

Vectren Electric		Commercial Measure Assumptions							
Measure #	End-Use	Measure Name	% Elec Savings	Per Unit Elec Savings	Per Unit NCP kW	Useful Life	Initial Measure Cost	UCT Ratio
157	Water Heating	Gas Dryer	33%	429	0.000	7	$66.91	4.78
158	Water Heating	Electric Dryer	27%	884	0.000	7	$93.21	7.08
159	Water Heating	ES Dishwasher, High Temp, Elec Heat, Elec Booster	30%	11,358	0.000	15	$419.05	39.44
160	Water Heating	ES Dishwasher, High Temp, Gas Heat, Elec Booster	26%	4,862	0.000	15	$265.03	26.69
161	Water Heating	ES Dishwasher, High Temp, Gas Heat, Gas Booster	15%	1,699	0.000	15	$115.95	21.32
162	Water Heating	ES Dishwasher, Low Temp, Elec Heat	33%	12,783	0.000	16	$95.07	205.29
163	Water Heating	ES Dishwasher, Low Temp, Gas Heat	5%	584	0.000	16	$8.73	102.14
164	Water Heating	Tank Insulation	91%	468	0.000	15	$2.22	409.25
165	Water Heating	Heat Pump Water Heater	59%	2,124	0.000	10	$433.00	6.77
166	Cooking	High Efficiency Combination Oven	35%	6,368	0.000	12	$100.00	77.30
167	Cooking	Induction Cooktop	20%	784	0.000	11	$3,000.00	0.39
168	Cooking	Electric Energy Star Fryers	17%	3,126	0.000	12	$275.67	13.76
169	Cooking	Electric Energy Star Steamers,3-6 pan	57%	9,967	0.000	12	$3,400.00	3.56
170	Cooking	Energy Star Convection Ovens	16%	1,937	0.000	12	$388.00	6.06
171	Cooking	Energy Star Griddles	12%	1,909	0.000	12	$860.00	2.69
172	Cooking	Energy Star Hot Food Holding Cabinet	53%	1,730	0.000	12	$902.00	2.33
173	Refrigeration	Glass Door Freezer, <15-49 cu ft, Energy Star	43%	3,595	0.000	12	$166.00	26.26
174	Refrigeration	Glass Door Freezer, 50+ cu ft, Energy Star	45%	9,804	0.000	12	$407.00	29.21
175	Refrigeration	Solid Door Freezer, <15-49 cu ft, Energy Star	36%	1,489	0.000	12	$166.00	10.88
176	Refrigeration	Solid Door Freezer, 50+ cu ft, Energy Star	46%	5,322	0.000	12	$407.00	15.86
177	Refrigeration	Glass Door Refrigerator, <15 - 49 cu ft, Energy Star	36%	828	0.000	12	$164.00	6.12
178	Refrigeration	Glass Door Refrigerator, 50+ cu ft, Energy Star	35%	1,577	0.000	12	$249.00	7.68
179	Refrigeration	Solid Door Refrigerator, <15-49 cu ft, Energy Star	38%	635	0.000	12	$164.00	4.70
180	Refrigeration	Solid Door Refrigerator, 50+ cu ft, Energy Star	48%	1,675	0.000	12	$249.00	8.16
181	Refrigeration	self contained	7%	537	0.000	1	$75.00	1.04
182	Refrigeration	contained	7%	1,388	0.000	1	$75.00	2.68
183	Refrigeration	Anti-sweat heater controls on freezers	55%	2,557	0.000	12	$200.00	15.50
184	Refrigeration	Anti-sweat heater controls, on refrigerators	55%	1,082	0.000	12	$200.00	6.56
185	Refrigeration	Vending Miser, Cold Beverage	46%	1,612	0.000	5	$215.50	3.95
186	Refrigeration	Brushless DC Motors (ECM) for freezers and coolers	44%	1,064	0.000	15	$177.00	8.73
187	Refrigeration	Humidity Door Heater Controls for freezers and coolers	55%	1,820	0.000	12	$200.00	11.03
188	Refrigeration	Refrigerated Case Covers	9%	945	0.000	5	$252.00	1.98
189	Refrigeration	Zero Energy Doors for freezers and coolers	20%	1,360	0.000	10	$290.00	6.47
190	Refrigeration	Evaporator Coil Defrost Control	30%	197	0.002	10	$500.00	0.56
191	Refrigeration	Evaporator Fan Motor Control for freezers and coolers	36%	1,524	0.000	16	$291.00	10.64
192	Refrigeration	Ice Machine, Energy Star, Self-Contained	7%	263	0.000	9	$56.00	0.51
193	Refrigeration	LED Case Lighting (retrofit)	45%	437	0.000	8	$250.00	0.19
194	Refrigeration	Efficient Refrigeration Condenser	2%	120	0.000	15	$35.00	0.50
195	Refrigeration	Efficient low-temp compressor	1%	875	0.000	13	$552.00	2.74

Vectren Electric — Commercial Measure Assumptions

Measure #	End-Use	Measure Name	% Elec Savings	Per Unit Elec Savings	Per Unit NCP kW	Useful Life	Initial Measure Cost	UCT Ratio
196	Compressed Air	Automatic Drains	0%	2,097	0.000	5	$355.00	4.15
197	Compressed Air	Cycling and High Efficiency Dryers	35%	4	0.000	10	$6.00	0.93
198	Compressed Air	Efficient Air Compressors	18%	914	0.000	15	$250.00	5.30
199	Compressed Air	Low Pressure Drop-Filters	3%	65	0.000	10	$22.00	4.05
200	Compressed Air	Receiver Capacity Addition	10%	9,159	0.000	10	$2,000.00	6.31
201	Compressed Air	Engineered Nozzles for blow-off	71%	22,230	0.000	15	$14.00	2304.40
202	Compressed Air	Compressed Air Leak Survey and Repair	50%	496	0.000	1	$6.00	11.94
203	Office Equipment	Commercial Plug Load - Smart Strip Outlets	15%	23	0.000	8	$15.00	1.32
204	Office Equipment	Plug Load Occupancy Sensor	15%	169	0.000	8	$70.00	2.03
205	Office Equipment	Energy Star Compliant Refrigerator	20%	120	0.000	17	$30.00	6.35
206	Office Equipment	Energy Star Computers	43%	81	0.000	4	$5.00	9.07
207	Office Equipment	Computer Power Management Software	46%	161	0.000	5	$29.00	3.91
208	Office Equipment	Energy Star UPS	11%	105	0.000	10	$1,303.35	0.11
209	Office Equipment	High Efficiency Hand Dryer	69%	965	0.000	10	$450.00	2.96
210	Office Equipment	Electrically Commutated Plug Fans in data centers	33%	1,445	0.000	15	$718.00	3.90
211	Office Equipment	High Efficiency CRAC unit	30%	162	0.000	15	$62.50	5.03
212	Office Equipment	Computer Room Air Conditioner Economizer	47%	358	0.000	15	$82.00	8.46
213	Office Equipment	Computer Room Hot Aisle Cold Aisle Configuration	13%	125	0.000	15	$156.00	1.55
214	Office Equipment	Computer Room Air Side Economizer	47%	440	0.000	10	$25.00	24.30
215	Office Equipment	VFD for Process Fans -CRAC units	43%	2,279	0.000	15	$200.00	22.07
216	Office Equipment	Vending Miser for Non-Refrig Equip	46%	343	0.000	5	$108.00	0.34
217	Pools	Heat Pump Pool Heater	61%	5,732	0.000	10	$4,000.00	1.98
218	Pools	High efficiency spas/hot tubs	15%	375	0.000	10	$300.00	1.72
219	Pools	VFD Retrofit on Pool Circulation Pump	35%	1,425	0.000	12	$200.00	11.52
220	Behavioral	Reports)	3%	7,852	0.896	2	$8.88	271.30
221	Behavioral	Whole-Building Energy Monitoring	10%	2	0.000	2	$1.00	0.52
222	Behavioral	Energy Use Displays	9%	23,555	2.693	1	$250.00	14.60

APPENDIX D *DSM Market Potential Study Industrial Measure Detail*

Vectren Electric — Industrial Measure Assumptions

Measure #	End-Use	Measure Name	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	UCT Ratio
101	Appliances, Computers, Office Equipment	Energy Star Compliant Single Door Refrigerator	20.0%	120.0	0.000	17.0	$30.00	7.38
102	Appliances, Computers, Office Equipment	Energy Star computers	43.0%	80.5	0.000	4.0	$5.00	17.75
103	Appliances, Computers, Office Equipment	Energy Efficient "Smart" Power Strip for PC/Monitor/Printer	15.0%	23.4	0.000	8.0	$15.00	1.58
104	Appliances, Computers, Office Equipment	PC Network Energy Management Controls replacing no central control	46.0%	161.0	0.000	5.0	$29.00	3.24
106	Appliances, Computers, Office Equipment	Energy Star UPS	10.5%	104.8	0.000	10.0	$1,303.35	0.13
107	Appliances, Computers, Office Equipment	High Efficiency CRAC Unit	30.0%	162.3	0.020	15.0	$62.50	4.96
151	Water Heating	Heat Pump Water Heater	58.8%	2,123.7	0.000	10.0	$433.00	5.08
152	Water Heating	Electric Tankless Water Heater	7.4%	7,905.0	0.000	5.0	$1,050.00	3.97
154	Water Heating	High Efficiency Storage (tank)	0.2%	8.6	0.000	15.0	$70.00	0.18
168	Water Heating	Tank Insulation (electric)	91.0%	468.0	0.000	15.0	$2.22	306.25
169	Water Heating	Drain Water Heat Recovery Water Heater	25.0%	546.0	4.490	25.0	$631.00	2.30
171	Water Heating	Process Cooling Condenser Heat Recovery	33.0%	5,720.0	1.205	15.0	$254.00	49.23
301	Envelope	Integrated Building Design	40.0%	2.0	0.000	15.0	$0.27	9.99
302	Envelope	Energy Efficient Windows	13.9%	2.0	0.022	20.0	$17.04	8.95
302	Envelope	Energy Efficient Windows	13.9%	2.0	0.022	20.0	$17.04	8.95
303	Envelope	Cool Roofing	15.0%	51.3	0.028	20.0	$332.44	0.39
304	Envelope	Ceiling Insulation	8.0%	65.5	0.024	20.0	$47.16	1.46
305	Envelope	Window Improvements	0.7%	85.3	0.033	15.3	$286.16	0.24
306	Envelope	Wall Insulation	1.7%	364.8	0.076	20.0	$4.57	85.75
307	Envelope	Roof Insulation	0.8%	22.1	0.014	20.0	$54.88	2.70
308	Envelope	Improved Duct Sealing	1.4%	37.6	0.019	18.0	$107.91	1.51
321	Ventilation	Economizer	12.0%	136.6	0.001	12.5	$123.00	0.98
327	Ventilation	EMS for Manufacturing HVAC Fan	44.0%	2,197.0	0.250	15.0	$800.00	10.16
328	Ventilation	VFD supply and return fans, <3 to 10 hp	30.0%	6,241.7	0.922	15.0	$2,852.00	7.57
329	Ventilation	VFD supply and return fans, 11 to 50 hp	30.0%	37,450.0	5.530	15.0	$12,899.00	24.08
332	Ventilation	High Volume Low Speed Fans	50.0%	8,379.0	3.067	10.0	$4,197.75	3.99
333	Ventilation	Engineered CKV Hood	42.8%	727.2	0.288	15.0	$124.62	187.25
341	Space Cooling - Chillers	Air-Cooled Chiller, <150 ton	13.1%	318.0	0.086	20.0	$2,540.00	8.04
343	Space Cooling - Chillers	Water Side Economizer	10.0%	1,047.5	0.000	15.0	$50.00	7.75
345	Space Cooling - Chillers	Water-Cooled Chiller > 300 ton	25.0%	355.1	0.096	20.0	$92.22	11.09
348	Space Cooling - Chillers	Water-Cooled Chiller < 150 ton	20.0%	300.5	0.081	20.0	$166.10	5.81
350	Space Cooling - Chillers	Chiller Tune Up	8.0%	119.1	0.032	5.0	$5.66	12.78
362	HVAC Controls	Programmable Thermostats	10.0%	945.3	0.000	4.0	$56.09	5.36
363	HVAC Controls	EMS install	10.0%	310.4	0.014	15.0	$4.71	115.04
364	HVAC Controls	EMS Optimization	0.5%	358.9	0.041	20.0	$37.62	0.00
365	HVAC Controls	HVAC Occupancy Sensors	19.0%	99.3	0.076	15.0	$107.58	0.00
367	HVAC Controls	Zoning	0.0%	187.4	0.000	15.0	$500.00	0.00
368	HVAC Controls	Setback with Electric Heat	10.0%	3,451.6	0.000	9.0	$71.00	0.00
369	HVAC Controls	EMS Pump Scheduling	10.0%	1,524.4	0.280	15.0	$1.32	0.00
370	HVAC Controls	Web Enabled EMS	10.0%	670.8	-0.098	15.0	$19.10	0.00
371	HVAC Controls	Retrocommissioning	9.0%	0.9	0.000	7.0	$0.08	7.54
382	Space Cooling - Unitary and Split AC	DX Packaged Sysytem >65000 Btuh CEE Tier 1	18.2%	86.0	0.055	15.0	$63.00	5.37
384	Space Cooling - Unitary and Split AC	Split System, <65,000 Btu/hr (CEE Tier 1)	12.3%	142.6	0.091	15.0	$897.32	8.91
385	Space Cooling - Unitary and Split AC	Ground Source Heat Pump - Cooling	4.9%	110.3	0.012	15.0	$75.00	1.57
387	Space Cooling - Unitary and Split AC	Water Loop Heat Pump (WLHP) - Cooling	11.5%	146.5	0.094	15.0	$75.00	1.90
391	Space Cooling - Unitary and Split AC	HVAC Tune-up	6.8%	58.6	0.079	3.0	$32.40	1.48
401	Cooking	HE Steamer	56.6%	9,966.7	0.000	12.0	$3,400.00	3.56
402	Cooking	HE Combination Oven	34.8%	6,397.9	0.000	12.0	$100.00	77.30
403	Cooking	HE Convection Ovens	16.1%	1,937.1	0.000	12.0	$388.00	6.06
404	Cooking	HE Holding Cabinet	52.7%	1,730.0	0.000	12.0	$902.00	2.33
405	Cooking	HE Fryer	17.2%	3,126.0	0.000	12.0	$275.67	13.76
406	Cooking	HE Griddle	12.1%	1,909.1	0.000	12.0	$860.00	2.69
408	Cooking	Induction Cooktops	20.0%	784.0	0.000	11.0	$3,000.00	0.29
506	Lighting	High performance T5 (replacing T8)	22.4%	461.1	0.094	15.0	$100.00	8.19
507	Lighting	Outdoor LED (>250 W MH)	56.9%	983.3	0.201	15.0	$592.00	3.01
509	Lighting	LED Exit Sign	81.8%	88.6	0.012	16.0	$30.00	10.52
512	Lighting	LED High Bay Lighting	35.0%	471.8	0.096	15.0	$482.00	1.74
513	Lighting	LED Low Bay Lighting	42.5%	305.0	0.062	15.0	$331.00	1.64
514	Lighting	Light Tube	10.0%	250.0	0.104	10.0	$500.00	0.95
515	Lighting	High bay 4 lamp HPT8 vs (Metal halide 250 W)	50.1%	677.0	0.138	15.0	$200.00	4.69
522	Lighting	CFL Hard Wired Fixture	69.0%	199.0	0.041	12.0	$37.50	7.94
523	Lighting	Compact Fluorescent	67.8%	198.8	0.036	2.5	$1.20	64.96
524	Lighting	LED Screw In Bulb	63.9%	253.5	0.043	15.0	$1.20	207.76
528	Lighting	LED Downlight	66.2%	168.1	0.034	15.0	$27.00	11.07
529	Lighting	LED Troffer	25.1%	58.3	0.012	15.0	$62.00	3.03
536	Lighting	LED Linear Replacement Lamps	26.3%	61.2	0.012	15.0	$25.00	7.04
549	Lighting	SEM	2.3%	36.6	0.001	1.0	$1.00	4.67
551	Lighting Controls	Smart Advanced Lighting Controls	40.0%	2.2	0.001	10.0	$3.02	1.98
552	Lighting Controls	Smart Web Based Lighting Controls	28.5%	3.5	0.001	10.0	$2.30	4.05
557	Lighting Controls	Wall Occupancy Sensor	24.0%	335.0	0.068	8.0	$51.00	4.41
559	Lighting Controls	Central Lighting Control	10.0%	4,077.3	0.704	8.0	$103.00	43.51
560	Lighting Controls	Switching Controls for Multilevel Lighting (Non-HID)	20.0%	8,154.6	1.407	8.0	$274.00	49.07
561	Lighting Controls	Lighting Power Density - Interior	10.0%	4,077.3	0.704	15.0	$220.00	34.34
601	Refrigeration	Vending Miser for Soft Drink Vending Machines	46.0%	1,611.8	0.000	5.0	$215.50	3.95
602	Refrigeration	Refrigerated Case Covers	6.0%	2,900.0	0.331	4.0	$150.00	9.53
603	Refrigeration	Refrigeration Economizer	30.0%	166.7	-0.001	15.0	$126.76	1.18
606	Refrigeration	Commercial Ice-makers	6.8%	263.1	0.041	9.0	$55.00	1.22
607	Refrigeration	Evaporator Fan Motor Controls on S-P motors	25.1%	1,155.0	0.119	5.0	$300.00	2.23
608	Refrigeration	Evaporator Fan Motor Controls on PSC motors	25.0%	796.0	0.082	5.0	$300.00	1.54
609	Refrigeration	Evaporator Fan Motor Controls on ECM motors	35.8%	1,524.0	0.174	16.0	$291.00	7.98
610	Refrigeration	H.E. Evaporative Fan Motors	30.0%	773.2	0.088	15.0	$60.00	18.59
611	Refrigeration	Zero-Energy Doors	20.0%	1,800.0	0.151	10.0	$290.00	6.03
612	Refrigeration	Door Heater Controls	55.0%	1,082.6	0.000	12.0	$200.00	11.03

Vectren Electric		Industrial Measure Assumptions						
Measure #	End-Use	Measure Name	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Useful Life	Initial Measure Cost	UCT Ratio
613	Refrigeration	Discus and Scroll Compressors	7.5%	1,500.0	0.220	13.0	$825.00	2.58
614	Refrigeration	Floating Head Pressure Control	9.2%	1,264.0	0.000	15.0	$80.00	15.46
619	Refrigeration	ENERGY STAR Commercial Solid Door Refrigerators	38.3%	635.0	0.000	12.0	$164.00	4.70
620	Refrigeration	ENERGY STAR Commercial Solid Door Freezers	35.8%	1,489.0	0.000	12.0	$166.00	10.88
621	Refrigeration	ENERGY STAR Commercial Glass Door Refrigerators	30.2%	754.0	0.086	12.0	$600.00	1.54
622	Refrigeration	ENERGY STAR Commercial Glass Door Freezers	33.7%	3,671.0	0.419	12.0	$450.00	9.98
623	Refrigeration	Strip Curtains	80.2%	269.5	0.028	4.0	$7.50	17.14
624	Refrigeration	Efficient Refrigeration Condenser	1.8%	120.0	0.000	15.0	$35.00	1.18
625	Refrigeration	Door Gaskets - Cooler and Freezer	99.7%	98.0	0.011	4.0	$2.25	21.36
626	Refrigeration	Reach-in Refrigerated display case door retrofit	43.0%	1,014.0	0.185	12.0	$670.00	2.97
627	Refrigeration	LED Case Lighting	45.5%	437.5	0.000	8.0	$250.00	1.08
628	Refrigeration	ECM case fan motors	8.8%	1,064.0	0.121	15.0	$177.00	8.73
629	Refrigeration	Efficient low-temp compressor	1.1%	283.5	0.048	13.0	$552.00	0.77
630	Refrigeration	Automatic High Speed Doors - between freezer and cooler	15.0%	968.3	0.110	12.0	$150.00	7.89
631	Refrigeration	Refrigerant charging correction	14.0%	77.7	0.080	2.0	$10.36	7.01
801	Space Heating	PTHP, 1 ton	23.2%	94.3	0.108	15.0	$84.00	1.28
803	Space Heating	Ground Source Heat Pump - Heating	4.9%	22.7	0.014	15.0	$375.00	1.00
805	Space Heating	Water Loop Heat Pump (WLHP) - Heating	11.5%	67.9	0.129	15.0	$75.00	1.03
901	Other	High Efficiency Transformer, single-phase	2.5%	0.4	0.000	30.0	$0.46	3.53
902	Other	NEMA Premium Transformer, single-phase	2.5%	0.2	0.000	30.0	$0.24	2.92
903	Other	NEMA Premium Transformer, three-phase	2.5%	0.2	0.000	30.0	$0.18	2.94
909	Other	High Efficiency Transformer, three-phase	2.5%	0.4	0.000	30.0	$0.44	5.57
911	Other	Parking Garage Exhaust Fan CO Control	48.0%	2,413.0	0.275	15.0	$1,800.00	9.43
912	Other	Optimized Snow and Ice Melt Controls	92.0%	0.1	0.000	15.0	$15.15	1.16
913	Other	Engine Block Heater Timer	64.0%	576.0	0.800	5.0	$50.00	29.89
1001	Machine Drive	Sensors & Controls	3.0%	1.0	0.000	15.0	$0.01	14.66
1002	Machine Drive	Compressed Air Outdoor Air Intake	2.2%	109.8	0.015	20.0	$5.00	52.35
1003	Machine Drive	Electric Supply System Improvements	3.0%	1.0	0.000	15.0	$0.01	20.44
1004	Machine Drive	Advanced Efficient Motors	2.3%	1.0	0.000	20.0	$0.04	5.92
1005	Machine Drive	Industrial Motor Management	1.0%	1.0	0.000	5.0	$0.02	10.33
1006	Machine Drive	Compressed Air Low Pressure Drop Filters	1.3%	64.7	0.010	10.0	$22.00	1.85
1007	Machine Drive	Motor System Optimization (Including ASD)	19.0%	1.0	0.000	15.0	$0.01	21.92
1008	Machine Drive	Pump System Efficiency Improvements	16.4%	1.0	0.000	15.0	$0.01	25.62
1009	Machine Drive	Fan System Improvements	6.0%	1.0	0.000	15.0	$0.02	8.54
1010	Machine Drive	Efficient Air Compressors	18.0%	957.6	0.130	14.0	$177.78	7.15
1011	Machine Drive	Compressed Air Pressure Flow Controller	1.5%	73.0	0.010	15.0	$25.00	5.77
1012	Machine Drive	VFD for Process Fans	28.0%	707.0	0.000	15.0	$46.00	32.68
1013	Machine Drive	VFD for Process Pumps	29.0%	1,082.0	0.000	15.0	$94.00	24.47
1014	Machine Drive	High Efficiency Pumps	7.4%	201.0	0.000	15.0	$31.00	22.86
1015	Machine Drive	Compressed Air Audits and Leak Repair	8.0%	496.1	0.069	1.0	$8.00	9.74
1016	Machine Drive	Compressed Air replacement with Air Blowers	8.5%	5,587.7	4.180	15.0	$620.00	38.08
1017	Machine Drive	Compressed Air Automatic Drains	2.2%	2,097.0	0.332	5.0	$100.00	4.41
1018	Machine Drive	Compressed Air Storage Tank	8.5%	423.0	0.059	20.0	$36.00	28.02
1019	Machine Drive	Compressed Air High Efficiency Dryers	1.0%	48.0	0.000	15.0	$10.00	10.21
1020	Machine Drive	Compressed Air Nozzles	7.5%	21,142.0	6.340	20.0	$76.75	14.60
1026	Process Cooling & Refrig	Sensors & Controls	3.0%	1.0	0.000	15.0	$0.01	14.66
1027	Process Cooling & Refrig	Energy Information System	1.0%	1.0	0.000	15.0	$0.06	3.35
1028	Process Cooling & Refrig	Electric Supply System Improvements	3.0%	1.0	0.000	15.0	$0.01	20.44
1029	Process Cooling & Refrig	Improved Refrigeration	10.0%	1.0	0.000	15.0	$0.00	62.53
1031	Process Heating	Sensors & Controls	3.0%	1.0	0.000	15.0	$0.01	14.66
1032	Process Heating	Energy Information System	1.0%	1.0	0.000	15.0	$0.06	3.35
1033	Process Heating	Electric Supply System Improvements	3.0%	1.0	0.000	15.0	$0.01	20.44
1034	Process Heating	Decrease Oven Exhaust Flow	60.0%	399.0	0.087	20.0	$1.00	43.21
1041	Industrial Other	High Efficiency Welders	12.0%	761.0	0.390	20.0	$200.00	15.35
1042	Industrial Other	3 Phase High Eff Battery Charger	8.0%	2,595.0	0.289	20.0	$872.50	6.74
1043	Industrial Other	Barrel Insulation - Inj. Molding (plastics)	18.0%	1,210.0	0.291	10.0	$80.00	25.78
1044	Industrial Other	Pellet Dryer Insulation (plastics)	17.0%	185.0	0.100	10.0	$40.00	7.71
1045	Industrial Other	Injection Molding Machine - efficient (plastics)	51.0%	223.0	0.050	20.0	$125.00	4.93
1047	Industrial Other	Dewpoint Sensor Control for Dessicant Plastic Dryer	8.5%	565.0	0.100	15.0	$150.00	1.95
1051	Agriculture	Other Industrial -Low-Energy Livestock Waterer	47.7%	1,593.0	1.000	10.0	$788.00	3.12
1052	Agriculture	Other Industrial -Dairy Refrigerator Tune-Up	4.0%	0.1	0.000	5.0	$0.05	1.58
1053	Agriculture	Greenhouse Environmental Controls	10.0%	98.0	0.000	15.0	$125.00	1.67
1054	Agriculture	Scroll Compressor with Heat Exchanger for Dairy Refrigeration	10.5%	190.0	0.000	15.0	$1,500.00	0.27
1055	Agriculture	Variable Speed Drive withHeat Exchanger, Milk	15.0%	878.0	0.000	15.0	$2,725.00	0.69
1056	Agriculture	Milk Pre-Cooler Heat Exchanger	50.0%	1.0	0.000	15.0	$0.15	14.17
1057	Agriculture	Variable Speed Drives for Dairy Vacuum Pumps	34.8%	598.0	0.000	10.0	$250.00	3.69
1058	Agriculture	VFD for Process Fans - Agriculture	23.0%	520.0	0.000	15.0	$46.00	24.03
1059	Agriculture	VFD for Process Pumps - Agriculture	43.0%	290.0	0.000	15.0	$46.00	13.40
1060	Agriculture	VFD for Process Pumps - Irrigation	43.0%	195.0	0.000	10.0	$46.00	6.53
1061	Agriculture	Grain Storage Temperature and Moisture Management Controller	49.0%	349.0	0.000	15.0	$233.00	3.18
1062	Agriculture	Low Pressure Sprinkler Nozzles	15.0%	5.0	0.000	15.0	$1.00	10.63
1063	Agriculture	Fan Thermostat Controller	53.4%	1,586.0	0.000	15.0	$50.00	67.44
1064	Agriculture	LED Poultry Lights	57.4%	5.8	0.001	9.0	$1.53	2.67
1065	Agriculture	Long Daylighting Dairy	30.0%	6.2	0.001	16.0	$1.79	2.57
1066	Agriculture	Evaporator Fan Motor Controls Ag	35.4%	537.1	0.270	20.0	$30.13	5.07

APPENDIX E *DSM Market Potential Study Commercial Opt-Out Results*

This section provides the potential results for technical, economic, MAP and RAP for the commercial sector, with opt-out customers included. Results are broken down by end use. The cost-effectiveness results and budgets for the RAP scenario are also provided.

E.1 SCOPE OF MEASURES & END USES ANALYZED

There were 222 total electric measures included in the analysis. Table E-1 provides the number of measures by end-use and fuel type (the full list of commercial measures is provided in Appendix C). The measure list was developed based on a review of current Vectren programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE E-1 COMMERCIAL ENERGY EFFICIENCY MEASURES – BY FUEL TYPE

End-Use	Number of Unique Measures
Space Heating	32
Cooling	76
Ventilation	8
Water Heating	14
Lighting	26
Cooking	7
Refrigeration	23
Office Equipment	14
Behavioral	3
Other	19

E.2 COMMERCIAL ELECTRIC POTENTIAL

Figure E-1 provides the technical, economic, MAP and RAP results for the 6-year, 10-year, and 20-year timeframes. The 6-year technical potential is 22.2% of forecasted sales, and the economic potential is 20.0% of forecasted sales. The 6-year MAP is 14.8% and the RAP is 6.3%.

FIGURE E-1 COMMERCIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF COMMERCIAL SALES)

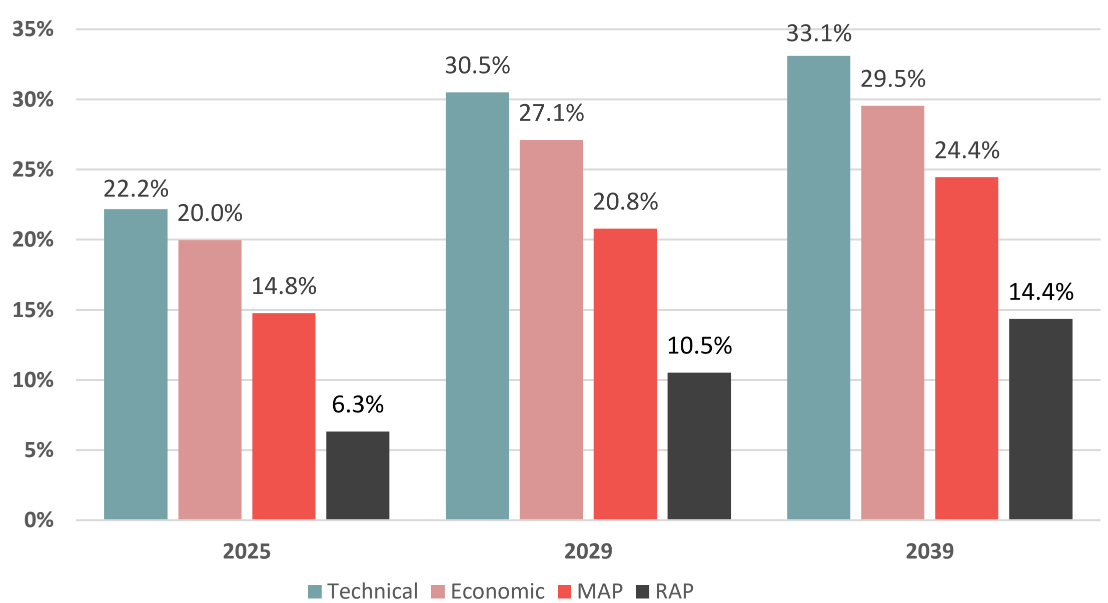


Table E-2 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The RAP reaches 6.3% after six years.

TABLE E-2 COMMERCIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2020	2021	2022	2023	2024	2025
MWh						
Technical	50,170	101,739	156,928	213,761	267,250	316,621
Economic	46,545	93,832	143,992	195,103	242,328	285,256
MAP	29,659	62,928	99,777	138,516	176,072	210,908
RAP	11,578	24,685	39,512	55,740	72,884	90,391
Forecasted Sales	1,390,224	1,392,929	1,400,166	1,408,787	1,421,633	1,428,202
Technical	3.6%	7.3%	11.2%	15.2%	18.8%	22.2%
Economic	3.3%	6.7%	10.3%	13.8%	17.0%	20.0%
MAP	2.1%	4.5%	7.1%	9.8%	12.4%	14.8%
RAP	0.8%	1.8%	2.8%	4.0%	5.1%	6.3%

Table E-3 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 0.8% to 1.4% per year over the next six years.

TABLE E-3 COMMERCIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2020	2021	2022	2023	2024	2025
MWh						
Technical	50,170	54,751	59,038	61,705	61,577	62,517
Economic	46,545	50,469	53,966	55,928	55,202	55,716
MAP	29,659	34,334	38,719	41,744	42,354	43,062
RAP	11,578	13,618	15,630	17,541	18,846	20,006
Forecasted Sales	1,390,224	1,392,929	1,400,166	1,408,787	1,421,633	1,428,202
Technical	3.6%	3.9%	4.2%	4.4%	4.3%	4.4%
Economic	3.3%	3.6%	3.9%	4.0%	3.9%	3.9%
MAP	2.1%	2.5%	2.8%	3.0%	3.0%	3.0%
RAP	0.8%	1.0%	1.1%	1.2%	1.3%	1.4%

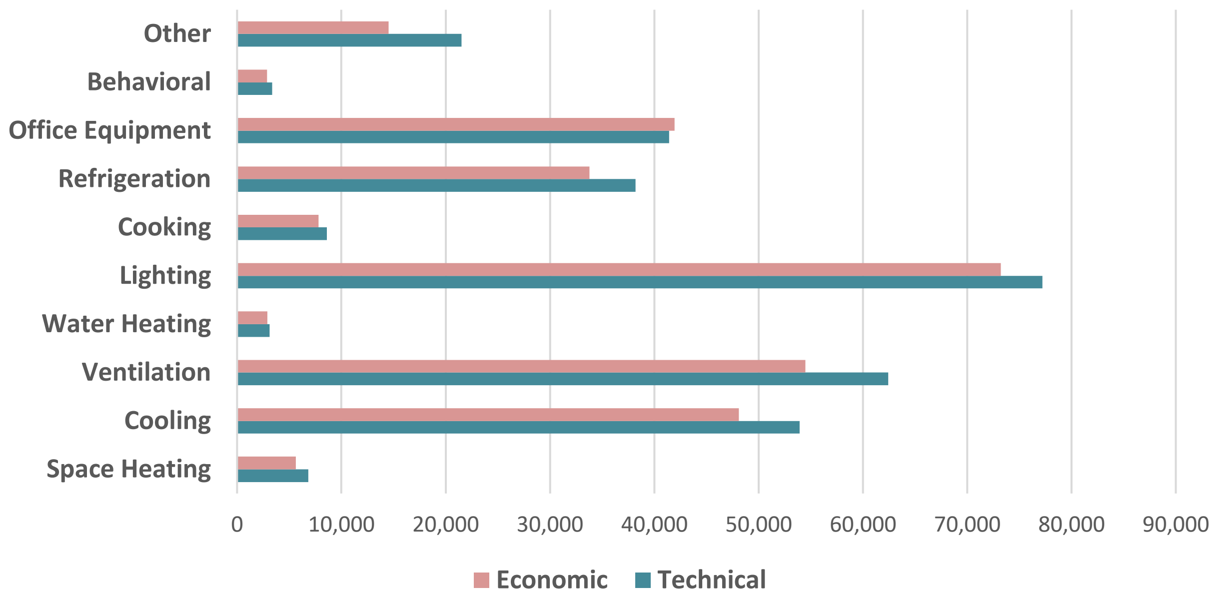
Technical & Economic Potential

Table E-4 provides cumulative annual technical and economic potential results from 2020-2025. Figure E-2 shows a comparison of the technical and economic potential (6-year) by end use. Lighting, Ventilation, and Cooling are the leading stand-alone end uses among technical and economic potential.

TABLE E-4 TECHNICAL & ECONOMIC COMMERCIAL ELECTRIC POTENTIAL

	2020	2021	2022	2023	2024	2025
Energy (MWh)						
Technical	50,170	101,739	156,928	213,761	267,250	316,621
Economic	46,545	93,832	143,992	195,103	242,328	285,256
Peak Demand (MW)						
Technical	7	13	20	28	34	40
Economic	5	10	16	21	27	32

FIGURE E-2 6-YEAR TECHNICAL AND ECONOMIC COMMERCIAL ELECTRIC POTENTIAL – BY END-USE



Maximum Achievable Potential

Figure E-3 illustrates the cumulative annual MAP results by end use across the 2020-2025 timeframe. Like technical and economic potential, Lighting, Ventilation, and Cooling are the leading end uses. Refrigeration and Office Equipment also have significant maximum achievable potential.

FIGURE E-3 COMMERCIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) MAP POTENTIAL BY END-USE

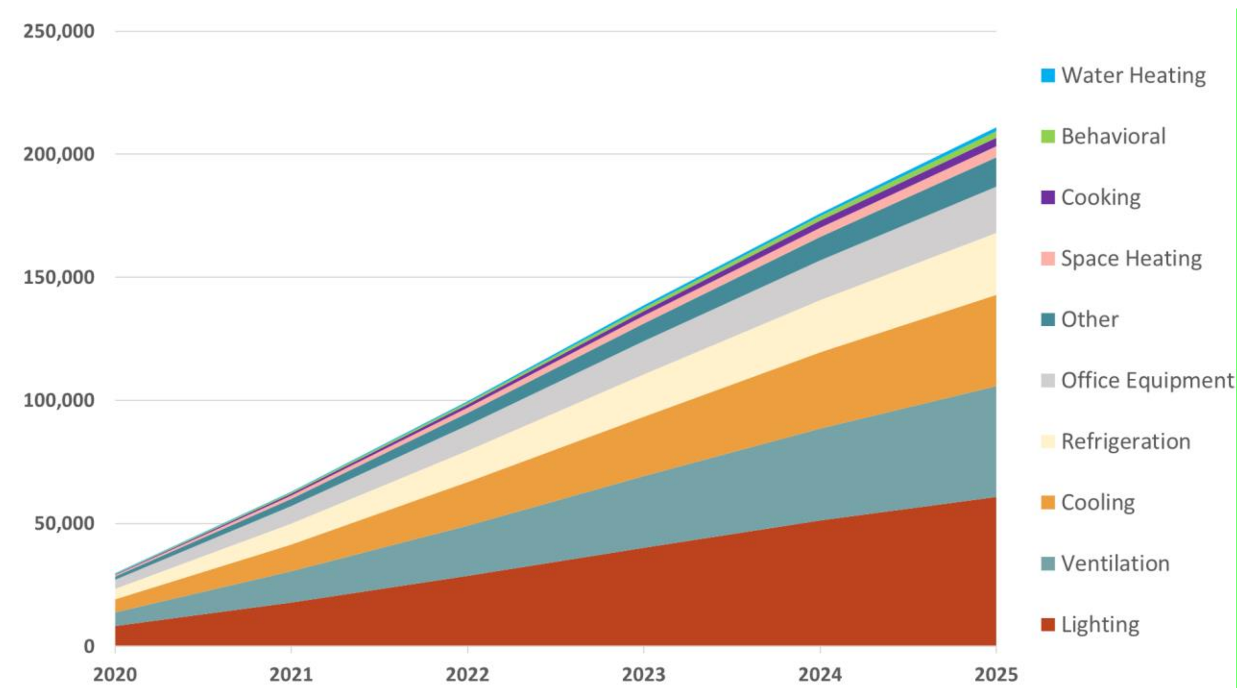


Table E-5 provides the incremental and cumulative annual MAP across the 2020-2025 timeframe. The incremental MAP ranges from 2.1% to 3.0% of forecasted sales across the six-year timeframe. Cumulative annual MAP rises to 14.8% by 2025.

TABLE E-5 COMMERCIAL ELECTRIC MAP BY END-USE

End Use	2020	2021	2022	2023	2024	2025
Incremental Annual MWh						
Space Heating	632	738	812	825	779	690
Cooling	5,164	5,873	6,459	7,175	7,250	6,886
Ventilation	5,703	6,840	7,891	8,528	8,447	7,669
Water Heating	156	204	254	300	336	374
Lighting	8,277	9,662	10,844	11,386	10,957	9,665
Cooking	323	431	548	663	770	863
Refrigeration	4,216	4,939	5,477	5,745	5,754	6,593
Office Equipment	3,624	3,446	3,308	3,275	3,394	5,201
Behavioral	226	297	600	761	1,176	1,437
Other	1,336	1,903	2,525	3,086	3,491	3,684
Total	29,659	34,334	38,719	41,744	42,354	43,062
% of Forecasted Sales	2.1%	2.5%	2.8%	3.0%	3.0%	3.0%
Incremental Annual MW						
Total	2.4	2.9	3.3	3.5	3.5	3.3
% of Forecasted Demand	0.7%	0.9%	1.0%	1.0%	1.0%	1.0%
Cumulative Annual MWh						
Space Heating	632	1,371	2,183	3,008	3,787	4,477
Cooling	5,164	11,037	17,496	24,217	30,902	37,118
Ventilation	5,703	12,543	20,434	28,962	37,409	45,078
Water Heating	156	361	615	914	1,250	1,608
Lighting	8,277	17,939	28,784	40,169	51,127	60,791
Cooking	323	755	1,302	1,965	2,735	3,598
Refrigeration	4,216	8,357	12,760	17,138	21,249	24,958
Office Equipment	3,624	7,070	10,378	13,653	16,245	19,000
Behavioral	226	509	866	1,307	1,855	2,498
Other	1,336	2,986	4,960	7,183	9,513	11,783
Total	29,659	62,928	99,777	138,516	176,072	210,908
% of Forecasted Sales	2.1%	4.5%	7.1%	9.8%	12.4%	14.8%
Cumulative Annual MW						
Total	2.4	5.2	8.4	11.8	15.1	18.2
% of Forecasted Demand	0.7%	1.6%	2.5%	3.5%	4.5%	5.4%

Realistic Achievable Potential

Figure E-4 illustrates the cumulative annual RAP results by end use across the 2020-2025 timeframe. Like maximum achievable potential, Lighting, Ventilation, and Cooling are the leading end uses. Refrigeration and Office Equipment also have significant realistic achievable potential.

FIGURE E-4 COMMERCIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) RAP POTENTIAL BY END-USE

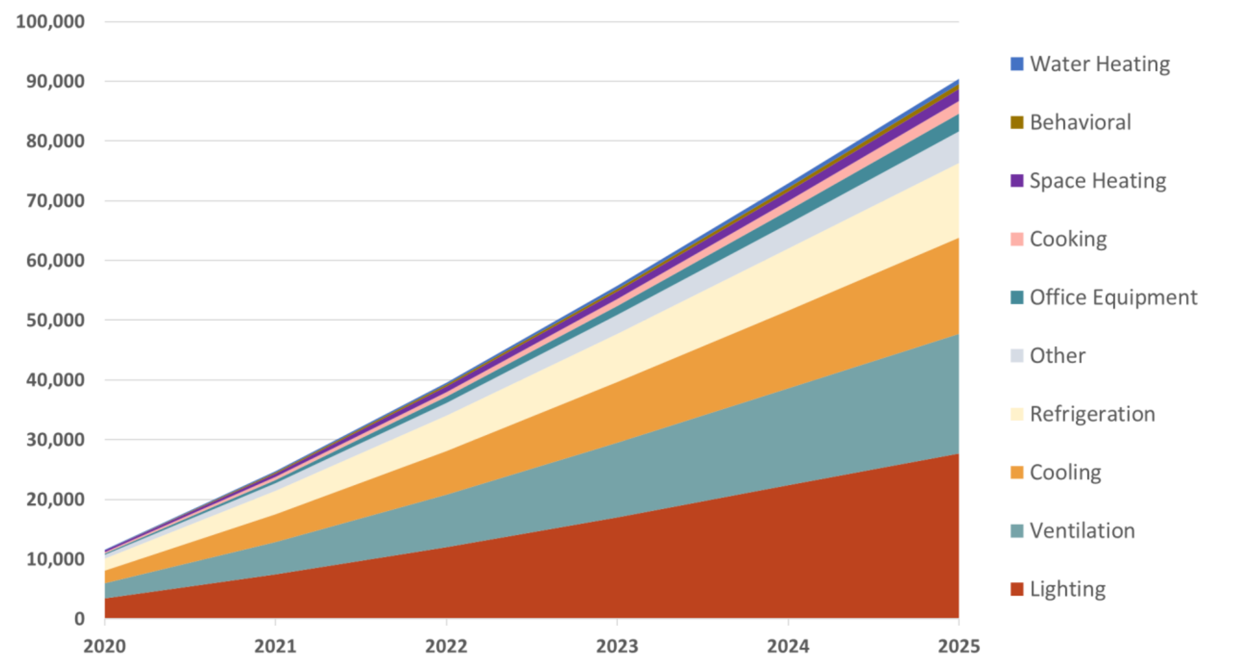


Table E-6 provides the incremental and cumulative annual RAP across the 2020-2025 timeframe. The incremental RAP ranges from 0.8% to 1.4% of forecasted sales across the six-year timeframe. Cumulative annual RAP rises to 6.3% by 2025.

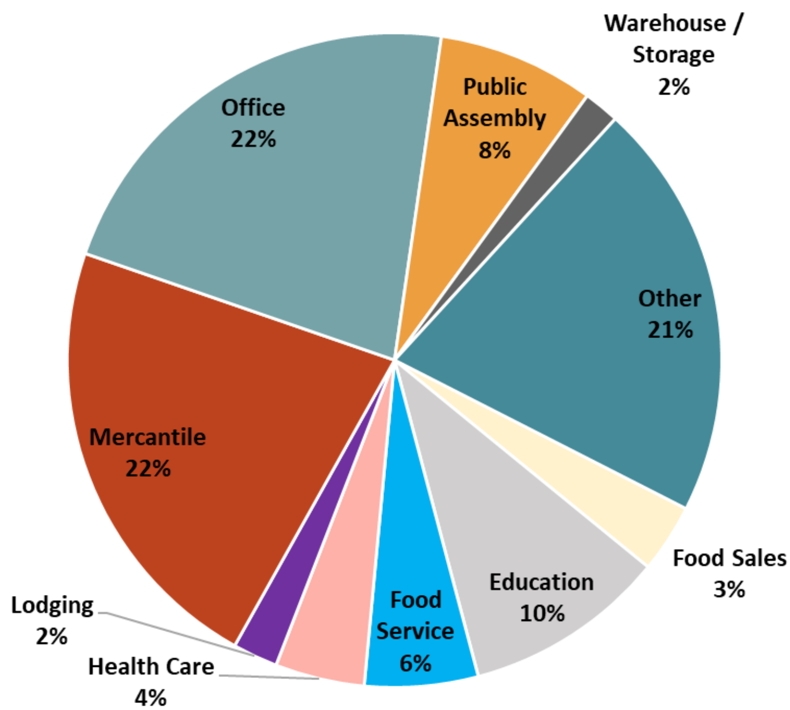
TABLE E-6 COMMERCIAL ELECTRIC RAP BY END-USE

End Use	2020	2021	2022	2023	2024	2025
Incremental Annual MWh						
Space Heating	267	302	331	346	350	344
Cooling	2,200	2,443	2,678	3,082	3,210	3,235
Ventilation	2,515	2,947	3,325	3,641	3,805	3,817
Water Heating	86	108	131	153	174	200
Lighting	3,401	4,020	4,582	5,032	5,306	5,337
Cooking	218	273	330	389	447	503
Refrigeration	1,985	2,301	2,591	2,824	3,010	3,585
Office Equipment	253	322	418	531	655	805
Behavioral	64	90	190	256	397	513
Other	588	813	1,054	1,287	1,491	1,668
Total	11,578	13,618	15,630	17,541	18,846	20,006
% of Forecasted Sales	0.8%	1.0%	1.1%	1.2%	1.3%	1.4%
Incremental Annual MW						
Total	1.0	1.2	1.4	1.5	1.6	1.6
% of Forecasted Demand	0.3%	0.4%	0.4%	0.4%	0.5%	0.5%
Cumulative Annual MWh						
Space Heating	267	570	901	1,247	1,597	1,941
Cooling	2,200	4,643	7,321	10,165	13,103	16,042
Ventilation	2,515	5,463	8,787	12,428	16,234	20,050
Water Heating	86	194	325	478	652	844

End Use	2020	2021	2022	2023	2024	2025
Lighting	3,401	7,421	12,003	17,035	22,341	27,677
Cooking	218	491	822	1,211	1,657	2,160
Refrigeration	1,985	3,873	5,932	8,097	10,316	12,533
Office Equipment	253	574	992	1,524	2,179	2,983
Behavioral	64	150	270	429	626	871
Other	588	1,306	2,158	3,127	4,180	5,290
Total	11,578	24,685	39,512	55,740	72,884	90,391
% of Forecasted Sales	0.8%	1.8%	2.8%	4.0%	5.1%	6.3%
Cumulative Annual MW						
Total	1.0	2.2	3.5	4.9	6.5	8.0
% of Forecasted Demand	0.3%	0.6%	1.0%	1.5%	1.9%	2.4%

Figure E-5 illustrates a market segmentation of the RAP in the commercial sector by 2025. Mercantile, Office, and Education are the leading building types.

FIGURE E-5 2025 COMMERCIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL) RAP POTENTIAL BY MARKET SEGMENT



RAP Benefits & Costs

Table E-7 provides the net present value benefits and cost, as calculated using the UCT, across the 2020-2025 timeframe for the RAP scenario. Cooling and Water Heating are the most cost-effective end-uses, and Lighting also provides significant NPV benefits.

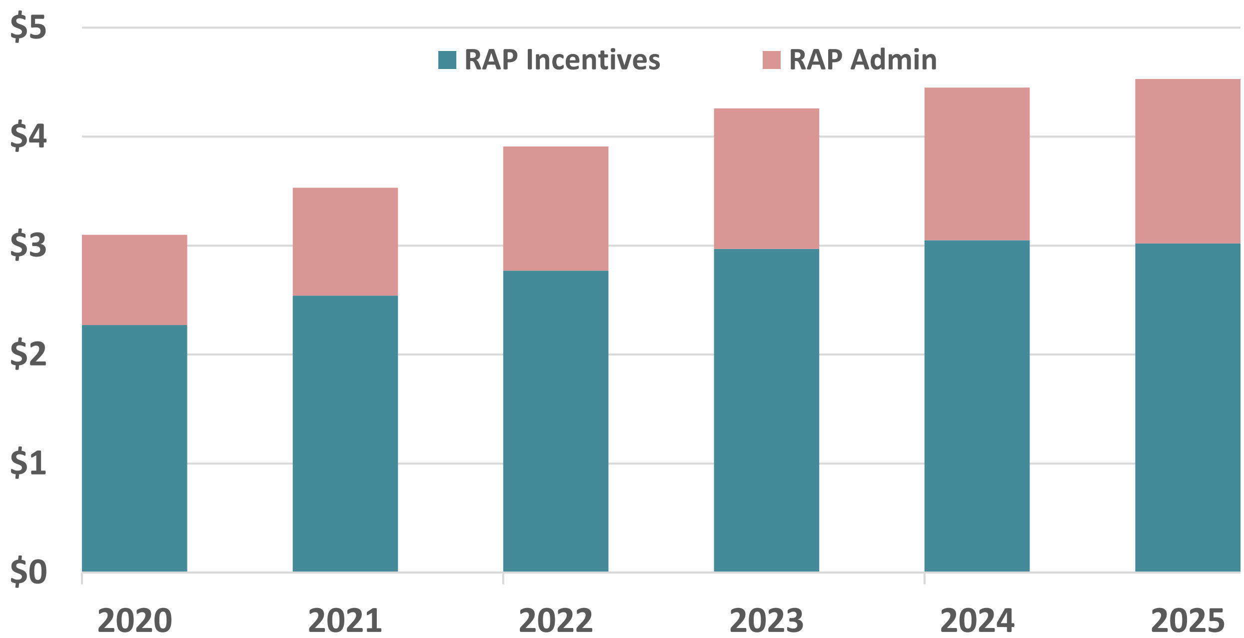
TABLE E-7 COMMERCIAL NPV BENEFITS & COSTS RAP BY END-USE ($ IN MILLIONS)

End Use	NPV Benefits	NPV Costs	UCT Ratio
Space Heating	$0.63	$1.76	0.36
Cooling	$25.49	$7.83	3.25
Ventilation	$7.94	$5.05	1.57
Water Heating	$0.21	$0.08	2.60

End Use	NPV Benefits	NPV Costs	UCT Ratio
Lighting	$10.75	$5.99	1.79
Cooking	$0.69	$0.34	2.06
Refrigeration	$3.45	$2.83	1.22
Office Equipment	$0.72	$0.29	2.47
Behavioral	$0.10	$0.08	1.33
Other	$1.95	$0.62	3.14
Total	$51.9	$24.9	2.09

Figure E-6 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2020-2025 timeframe. The incentives rise from $2.3 million to $2.1 million, and overall budgets rise from $3.1 million to $4.5 million by 2025.

FIGURE E-6 ANNUAL BUDGETS FOR COMMERCIAL RAP ($ IN MILLIONS)



APPENDIX F *DSM Market Potential Study Industrial Opt-Out Results*

This section provides the potential results for technical, economic, MAP and RAP for the industrial sector, with opt-out customers included. Results are broken down by end use. The cost-effectiveness results and budgets for the RAP scenario are also provided.

F.1 SCOPE OF MEASURES & END USES ANALYZED

There were 165 total unique electric measures included in the analysis. Table F-1 provides number of measures by end-use (the full list of industrial measures is provided in Appendix D). The measure list was developed based on a review of current Vectren programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE F-1 INDUSTRIAL ENERGY EFFICIENCY MEASURES – BY FUEL TYPE

End-Use	Number of Unique Measures
Computers & Office Equipment	6
Water Heating	6
Ventilation	7
Space Cooling	22
Space Heating	16
Cooking	7
Refrigeration	25
Lighting	20
Other	7
Machine Drive	21
Process Heating and Cooling	12
Agriculture	16

F.2 INDUSTRIAL ELECTRIC POTENTIAL

Figure F-1 provides the technical, economic, MAP and RAP results for the 6-year, 10-year, and 20-year timeframes. The 6-year technical potential is 18.9% of forecasted sales, and the economic potential is 18.0% of forecasted sales. The 6-year MAP is 13.2% and the RAP is 6.4%.

FIGURE F-1 INDUSTRIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF INDUSTRIAL SALES)

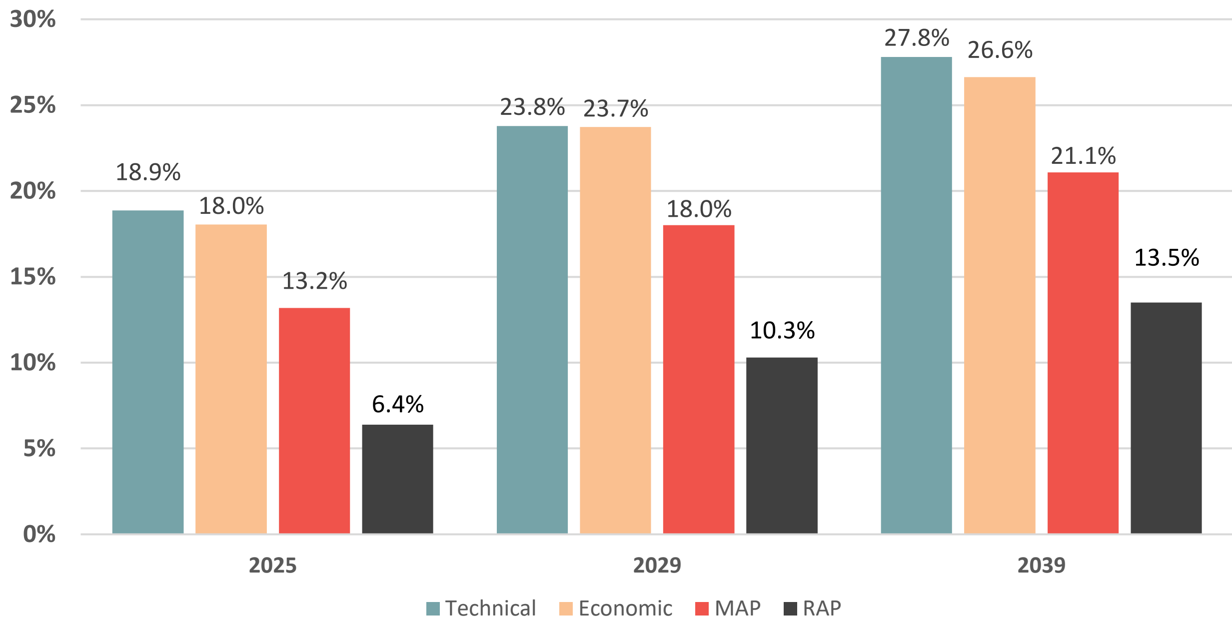


Table F-2 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The RAP reaches 6.4% after six years.

TABLE F-2 INDUSTRIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2020	2021	2022	2023	2024	2025
MWh						
Technical	66,750	142,458	224,968	309,520	383,043	447,367
Economic	63,335	135,371	214,263	295,502	366,107	427,911
MAP	41,085	90,213	146,167	205,384	261,922	312,473
RAP	19,324	41,785	67,208	94,837	123,025	151,326
Forecasted Sales	2,329,890	2,336,776	2,345,264	2,354,201	2,362,591	2,371,200
Energy Savings (as % of Forecast)						
Technical	2.9%	6.1%	9.6%	13.1%	16.2%	18.9%
Economic	2.7%	5.8%	9.1%	12.6%	15.5%	18.0%
MAP	1.8%	3.9%	6.2%	8.7%	11.1%	13.2%
RAP	0.8%	1.8%	2.9%	4.0%	5.2%	6.4%

Table F-3 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 0.8% to 1.6% per year over the next six years.

TABLE F-3 INDUSTRIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2020	2021	2022	2023	2024	2025
MWh						
Technical	66,750	78,664	89,185	95,702	97,760	95,516
Economic	63,335	74,992	85,566	92,390	94,842	92,995
MAP	41,085	51,432	61,105	67,856	71,118	70,784
RAP	19,324	23,576	27,883	31,695	35,218	38,149
Forecasted Sales	2,329,890	2,336,776	2,345,264	2,354,201	2,362,591	2,371,200
Energy Savings (as % of Forecast)						
Technical	2.9%	3.4%	3.8%	4.1%	4.1%	4.0%

	2020	2021	2022	2023	2024	2025
MWh						
Economic	2.7%	3.2%	3.6%	3.9%	4.0%	3.9%
MAP	1.8%	2.2%	2.6%	2.9%	3.0%	3.0%
RAP	0.8%	1.0%	1.2%	1.3%	1.5%	1.6%

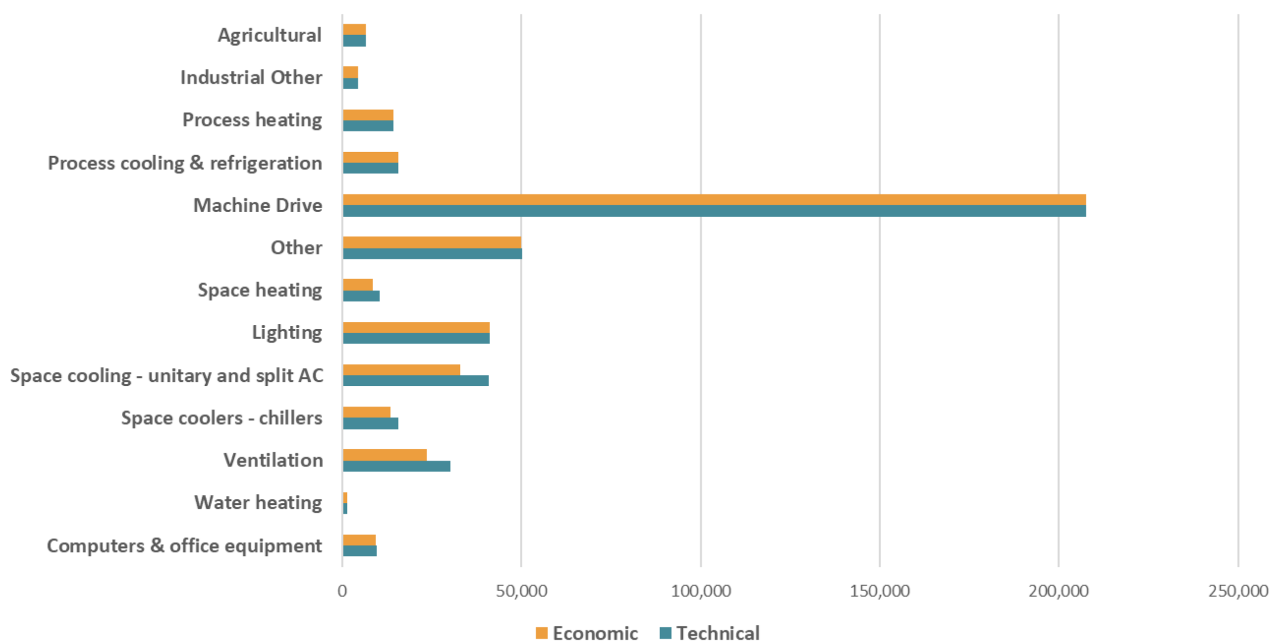
Technical & Economic Potential

Table F-4 provides cumulative annual technical and economic potential results from 2020-2025. Figure F-2 shows a comparison of the technical and economic potential (6-year) by end use. Machine drive, Lighting, and Space Cooling – unitary and split AC are the leading stand-alone end uses among technical and economic potential.

TABLE F-4 TECHNICAL AND ECONOMIC INDUSTRIAL ELECTRIC POTENTIAL

	2020	2021	2022	2023	2024	2025
Energy (MWh)						
Technical	66,750	142,458	224,968	309,520	383,043	447,367
Economic	63,335	135,371	214,263	295,502	366,107	427,911
Peak Demand (MW)						
Technical	12	25	40	54	67	78
Economic	11	24	38	52	64	74

FIGURE F-2 YEAR TECHNICAL AND ECONOMIC INDUSTRIAL ELECTRIC POTENTIAL – BY END-USE



Maximum Achievable Potential

Figure F-3 illustrates the cumulative annual MAP results by end use across the 2020-2025 timeframe. Like technical and economic potential, Machine Drive, Lighting, and Space Cooling – unitary and split AC are the leading end uses. Ventilation and Space coolers – chillers also have significant maximum achievable potential.

FIGURE F-3 INDUSTRIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) MAP POTENTIAL BY END-USE

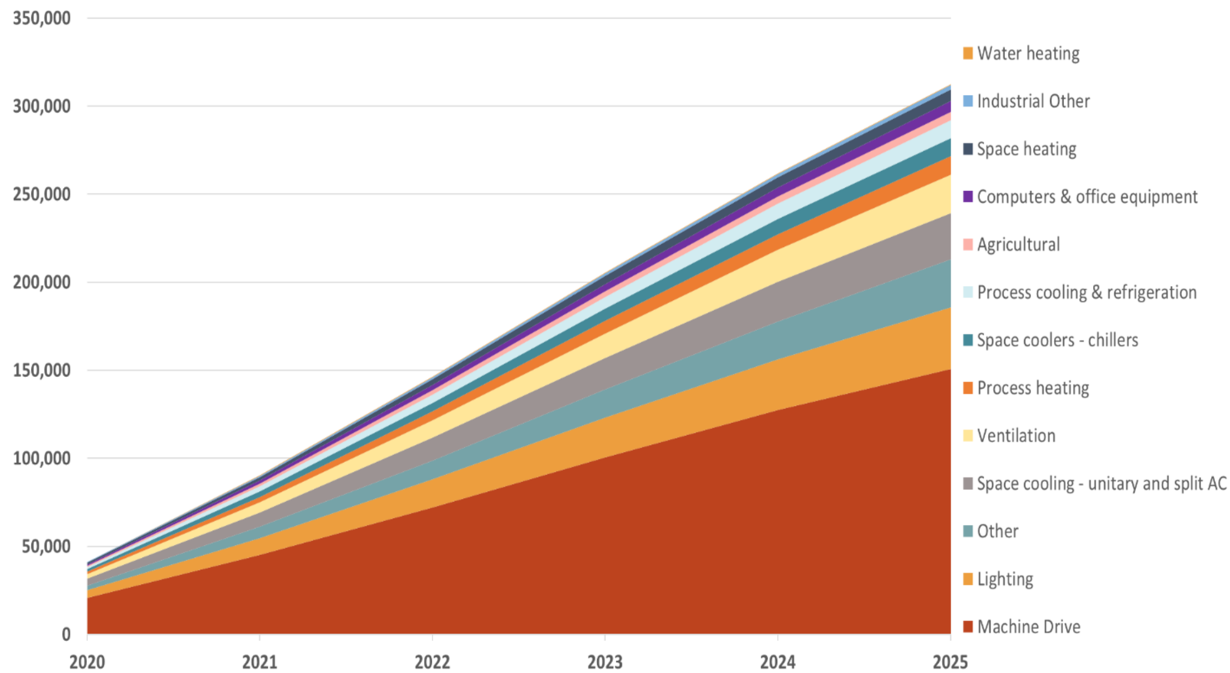


Table F-5 provides the incremental and cumulative annual MAP across the 2020-2025 timeframe. The incremental MAP ranges from 1.8% to 3.0% of forecasted sales across the six-year timeframe. Cumulative annual MAP rises to 13.1% by 2025.

TABLE F-5 INDUSTRIAL ELECTRIC MAP BY END-USE

End Use	2020	2021	2022	2023	2024	2025
Incremental Annual MWh						
Computers & office equipment	747	960	1,161	1,323	1,438	1,690
Water heating	89	92	98	109	123	134
Ventilation	2,728	3,394	3,978	4,236	4,083	3,582
Space coolers - chillers	1,410	1,685	1,908	1,991	2,042	1,872
Space cooling - unitary and split AC	3,688	4,383	4,974	5,221	5,393	4,904
Lighting	4,373	5,445	6,488	7,215	7,379	6,985
Space heating	921	1,103	1,260	1,327	1,381	1,264
Other	2,729	3,547	4,438	5,333	6,285	7,279
Machine Drive	20,695	25,930	30,767	34,161	35,486	35,311
Process cooling & refrigeration	1,307	1,812	2,312	2,747	3,082	3,314
Process heating	1,324	1,836	2,373	2,818	3,105	3,227
Industrial Other	392	433	460	483	509	537
Agricultural	683	810	890	891	812	684
Total	41,085	51,432	61,105	67,856	71,118	70,784
% of Forecasted Sales	1.8%	2.2%	2.6%	2.9%	3.0%	3.0%
Incremental Annual MW						
Total	7	9	11	12	12	12
% of Forecasted Demand	1.8%	2.2%	2.6%	2.9%	3.0%	3.0%

End Use	2020	2021	2022	2023	2024	2025
Cumulative Annual MWh						
Computers & office equipment	747	1,707	2,868	4,191	5,122	5,950
Water heating	89	181	279	389	512	643
Ventilation	2,728	6,101	10,030	14,185	18,147	21,568
Space coolers - chillers	1,410	3,088	4,981	6,947	8,828	10,343
Space cooling - unitary and split AC	3,688	8,010	12,845	17,811	22,452	26,423
Lighting	4,373	9,662	15,802	22,429	28,941	34,762
Space heating	921	2,010	3,237	4,509	5,711	6,752
Other	2,729	6,276	10,711	16,038	21,434	27,268
Machine Drive	20,695	45,027	72,224	100,437	127,306	150,868
Process cooling & refrigeration	1,307	2,901	4,725	6,648	8,513	10,194
Process heating	1,324	2,960	4,887	6,952	8,944	10,679
Industrial Other	392	798	1,196	1,574	1,928	2,258
Agricultural	683	1,493	2,382	3,273	4,084	4,765
Total	41,085	90,213	146,167	205,384	261,922	312,473
% of Forecasted Sales	1.8%	3.9%	6.2%	8.7%	11.1%	13.2%
Cumulative Annual MW						
Total	7	16	26	36	46	54
% of Forecasted Demand	1.8%	3.9%	6.3%	8.8%	11.1%	13.1%

Realistic Achievable Potential

Figure F-4 illustrates the cumulative annual RAP results by end use across the 2020-2025 timeframe. Like maximum achievable potential, Machine Drive, Lighting, and Space Cooling – unitary and split AC are the leading end uses. Ventilation and Space coolers – chillers also have significant maximum achievable potential.

FIGURE F-4 INDUSTRIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) RAP POTENTIAL BY END-USE

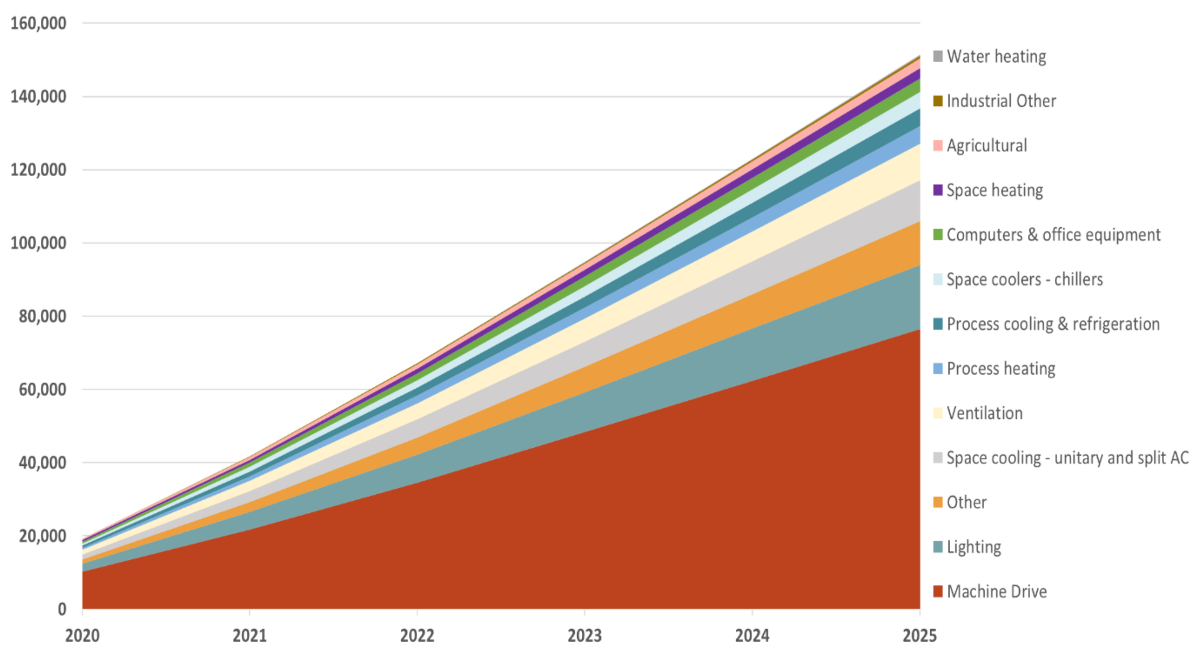


Table F-6 provides the incremental and cumulative annual RAP across the 2020-2025 timeframe. The incremental RAP ranges from 0.8% to 1.6% of forecasted sales across the six-year timeframe. Cumulative annual RAP rises to 6.4% by 2025.

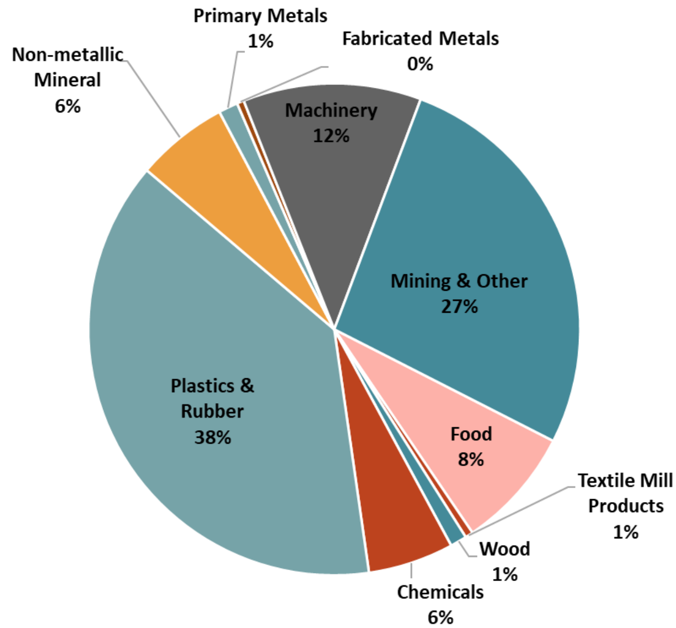
TABLE F-6 INDUSTRIAL ELECTRIC RAP BY END-USE

End Use	2020	2021	2022	2023	2024	2025
Incremental Annual MWh						
Computers & office equipment	512	616	716	810	894	1,062
Water heating	20	27	35	45	55	64
Ventilation	1,246	1,488	1,713	1,858	1,935	1,938
Space coolers - chillers	564	675	777	850	952	980
Space cooling - unitary and split AC	1,385	1,664	1,924	2,100	2,379	2,440
Lighting	2,156	2,621	3,073	3,450	3,738	3,895
Space heating	352	424	492	540	613	630
Other	1,204	1,547	1,939	2,351	2,780	3,281
Machine Drive	10,213	12,370	14,581	16,581	18,298	19,856
Process cooling & refrigeration	625	823	1,031	1,250	1,473	1,689
Process heating	589	796	1,019	1,235	1,446	1,643
Industrial Other	97	121	149	179	212	247
Agricultural	362	404	431	446	444	424
Total	19,324	23,576	27,883	31,695	35,218	38,149
% of Forecasted Sales	0.8%	1.0%	1.2%	1.3%	1.5%	1.6%
Incremental Annual MW						
Total	3	4	5	6	6	7
% of Forecasted Demand	0.9%	1.0%	1.2%	1.4%	1.5%	1.6%
Cumulative Annual MWh						
Computers & office equipment	512	1,127	1,843	2,654	3,164	3,652
Water heating	20	47	83	128	182	245
Ventilation	1,246	2,725	4,418	6,243	8,128	9,996
Space coolers - chillers	564	1,236	2,007	2,847	3,729	4,536
Space cooling - unitary and split AC	1,385	3,023	4,890	6,893	8,957	11,005
Lighting	2,156	4,711	7,639	10,846	14,223	17,623
Space heating	352	769	1,248	1,765	2,302	2,837
Other	1,204	2,751	4,690	7,039	9,365	11,987
Machine Drive	10,213	21,783	34,604	48,291	62,398	76,424
Process cooling & refrigeration	625	1,348	2,156	3,032	3,950	4,876
Process heating	589	1,293	2,108	3,001	3,940	4,886
Industrial Other	97	205	326	458	600	750
Agricultural	362	766	1,197	1,642	2,086	2,509
Total	19,324	41,785	67,208	94,837	123,025	151,326
% of Forecasted Sales	0.8%	1.8%	2.9%	4.0%	5.2%	6.4%
Cumulative Annual MW						

End Use	2020	2021	2022	2023	2024	2025
Total	3	7	12	17	21	26
% of Forecasted Demand	0.9%	1.8%	2.9%	4.1%	5.2%	6.4%

Figure F-5 illustrates a market segmentation of the RAP in the industrial sector by 2025. Plastics & rubber, Mining & Other, and Machinery are the leading market segments.

FIGURE F-5 2025 INDUSTRIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL) RAP POTENTIAL BY MARKET SEGMENT[1]



RAP Benefits & Costs

Table F-6**Error! Reference source not found.** provides the net present value benefits and cost, as calculated using the UCT, across the 2020-2025 timeframe for the RAP scenario. Machine Drive is the most cost-effective end-use. Facility HVAC and Facility Lighting also provide significant NPV benefits.

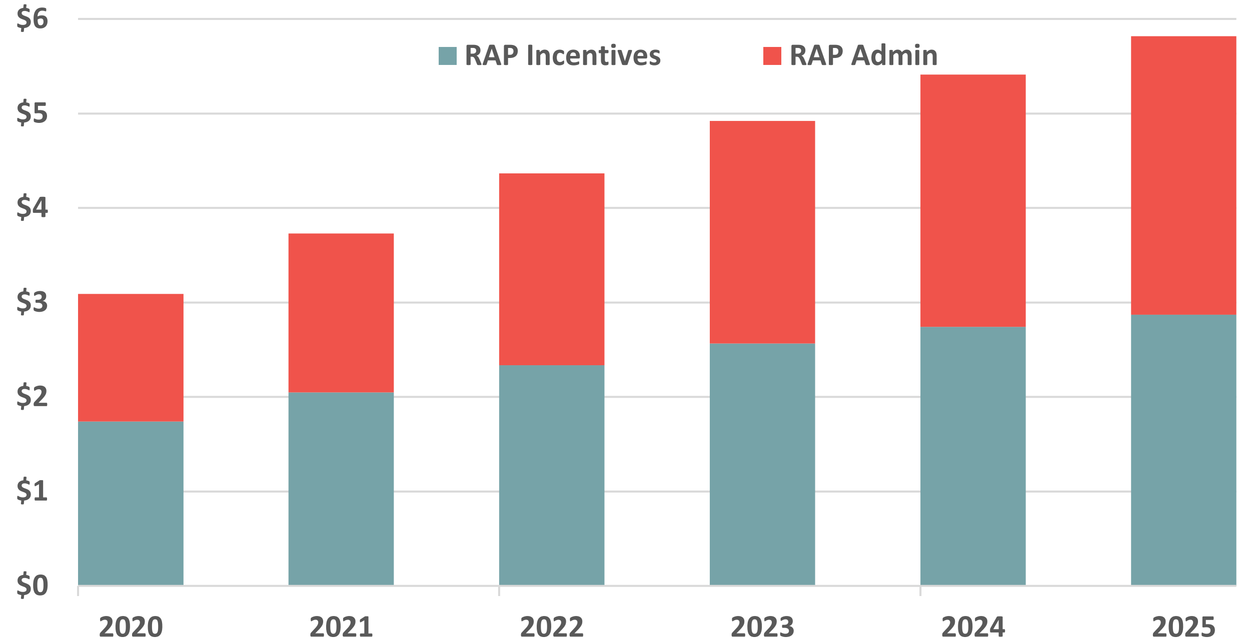
TABLE F-7 INDUSTRIAL NPV BENEFITS AND COSTS RAP BY END-USE ($ IN MILLIONS)

End Use	NPV Benefits	NPV Costs	UCT Ratio
Machine Drive	$49.7	$8.4	5.90
Facility HVAC	$14.4	$3.6	2.81
Facility Lighting	$11.1	$6.0	2.64
Other Facility Support	$5.4	$2.2	1.53
Process Cooling and Refrigeration	$2.7	$0.7	3.64
Process Heating	$2.0	$0.5	4.59
Other	$6.8	$2.2	3.04
Total	92.1	23.5	3.91

Figure F-6 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2020-2025 timeframe. The incentives rise from $1.7 million to $2.9 million, and overall budgets rise from $3.1 million to $5.8 million by 2025.

[1] “Wholesale/Retail” and “Services” industrial types include industrial buildings that devote a minority percentage of floor space to commercial activities like wholesale and retail trade, and construction, healthcare, education and accommodation & food service. Automotive related industries are divided between plastics, rubber, and machinery based on their NAICS codes.

FIGURE F-6 ANNUAL BUDGETS FOR INDUSTRIAL RAP ($ IN MILLIONS)



APPENDIX G *Demand Response Methodology*

G.1 DEMAND RESPONSE PROGRAM OPTIONS

Table G-1 provides a brief description of the demand response program options considered and identifies the eligible customer segment for each demand response program that was considered in this study.

TABLE G-1 DEMAND RESPONSE PROGRAM OPTIONS AND ELIGIBLE MARKETS

DR Program Option	Program Description	Eligible Markets
DLC AC (Switch)	The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle)	Residential and Commercial Customers
DLC AC (Smart Thermostat)	The system operator can remotely raise the AC's thermostat set point during peak load conditions, lowering AC load.	Residential and Commercial Customers
DLC Pool Pumps	The swimming pool pump is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours.	Residential Customers
DLC Water Heaters	The water heater is remotely shut off by the system operator for periods normally ranging from 2 to 8 hours.	Residential and Commercial Customers
Critical Peak Pricing with Enabling Technology	A retail rate in which an extra-high price for electricity is provided during a limited number of critical periods (e.g. 100 hours) of the year. Market-based prices are typically provided on a day-ahead basis, or an hour-ahead basis. Includes enabling technology that connects technologies within building. Only for customers with AC.	Residential and Commercial Customers
Critical Peak Pricing without Enabling Technology	A retail rate in which an extra-high price for electricity is provided during a limited number of critical periods (e.g. 100 hours) of the year. Market-based prices are typically provided on a day-ahead basis, or an hour-ahead basis.	Residential and Commercial Customers
Real Time Pricing	Real Time Pricing reflects the current conditions and is calculated for each hour in the billing period.	Commercial Customers

DR Program Option	Program Description	Eligible Markets
Peak Time Rebate	Instead of charging a higher rate during critical events, participants are paid for load reductions (estimated relative to forecast of what the customer would otherwise have consumed). If customers don't want to participate, they pay the existing rate.	Residential and Commercial Customers
Time of Use Rate	A retail rate with different prices for usage during different blocks of time. Daily pricing blocks could include on-peak, mid-peak, and off-peak periods. Pricing is pre-defined, and once established do not vary with actual cost conditions.	Residential and Commercial Customers

G.2 DEMAND RESPONSE POTENTIAL ASSESSMENT APPROACH

The analysis for this study was conducted using the GDS DR Model. The GDS DR Model is an Excel spreadsheet tool that allows the user to determine the achievable potential for a demand response program based on the following two basic equations that can be chosen to be the model user.

TECHNICAL POTENTIAL ● All technically feasible demand reductions are incorporated to provide a measure of the theoretical maximum demand response potential. This assumes 100% of eligible customers will participate in all programs regardless of cost-effectiveness.

ECONOMIC POTENTIAL ● Economic potential is a subset of technical potential. Only cost-effective demand response program options are included in the economic potential. The cost-effectiveness test applied in this study is the UCT test. Only programs whose net present value of benefits exceed its costs will pass the economic screening.

ACHIEVABLE POTENTIAL ● The cost-effective demand response potential that can practically be attained in a real-world program delivery scenario, if a certain level of market penetration can be attained are included in this scenario. Achievable potential takes into account real-world barriers to convincing customers to participate in cost-effective demand response programs. Achievable savings potential savings is a subset of economic potential.

If the model user chooses to base the estimated potential demand reduction on a per customer CP load reduction value, then:

$$\textit{Achievable DR Potential} = \textit{Potentially Eligible Customers} \times \textit{Eligible Customer Participation Rate} \times \textit{CP kW Load Reduction Per Participant}$$

The framework for assessing the cost-effectiveness of demand response programs is based on *A Framework for Evaluating the Cost-Effectiveness of Demand Response*, prepared for the National Forum on the National Action

Plan (NAPA) on Demand Response.[1] Additionally, GDS reviewed the May 2017 National Standard Practice Manual published by the National Efficiency Screening Project.[2] GDS utilized this guide to define avoided ancillary services and energy and/or capacity price suppression benefits. Appendix A contains a table from the report summarizing the energy efficiency cost and benefits including in all five major benefit cost tests.

The GDS Demand Response Model determines the estimated savings for each demand response program by performing an extensive review of all benefits and cost associated with each program. GDS developed the model such that the value of future programs could be determined and to help facilitate demand response program planning strategies. The model contains approximately 50 required inputs for each program including: expected life, CP kW load reductions, proposed rebate levels, program related expenses such as vendor service fees, marketing and evaluation cost and on-going O&M expenses. This model and future program planning features can be used to standardize the cost-effectiveness screening process between Vectren departments interested in the deployment of demand response resources.

For this study, the Utility Cost Test (UCT) test was used to determine the cost-effectiveness of each demand response program. Benefits are based on avoided demand, energy (including load shifting), wholesale cost reductions and T&D costs. Costs include incremental program equipment costs (such as control switches or smart thermostats), fixed program capital costs (such as the cost of a central controller), program administrative, marketing, and evaluation costs. Incremental equipment program costs are included for both new and replacement units (such as control switches) to account for units that are replaced at the end of their useful life.

Achievable potential is broken into maximum and realistic achievable potential in this study:

MAP represents an estimate of the maximum cost-effective demand response potential that can be achieved over the 20-year study period. For this study, this is defined as customer participation in demand response program options that reflect a "best practices" estimate of what could eventually be achieved. MAP assumes no barriers to effective delivery of programs.

RAP represents an estimate of the amount of demand response potential that can be realistically achieved over the 20-year study period. For this study, this is defined as achieving customer participation in demand response program options that reflect a realistic estimate of what could eventually be achieved assuming typical or "average" industry experience. RAP is a discounted MAP, by considering program barriers that limit participation, therefore reducing savings that could be achieved.

This potential study evaluated DR potential for two achievable potential scenarios:

1 ***Utility Incentivized Scenario:*** The utility incentivized scenario assumes that all cost-effective DR programs will be implemented by Vectren and smart thermostats will be paid for and installed by the utility. Since Vectren already has a smart thermostat energy efficiency program, GDS assumed that the customers participating in this program would already have smart thermostats installed and there would be no additional cost to the utility.
2 ***BYOT Scenario:*** The bring your own thermostat (BYOT) scenario also assumes that all cost-effective DR programs will be implemented, but in this scenario smart thermostats will be used purchased and installed by the customer. GDS assumed there would be a one-time $75 credit[3].

[1] Study was prepared by Synapse Energy Economics and the Regulatory Assistance Project, February 2013.
[2] National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, May 18, 2017, Prepared by The National Efficiency Screening Project
[3] Vectren South 2018 Electric DSM Operating Plan

Demand savings estimates were assumed to be the same for both scenarios, but the costs are different.

G.3 AVOIDED COSTS & OTHER ECONOMIC ASSUMPTIONS

The avoided costs used to determine utility benefits were provided by Vectren. Avoided electric generation capacity refers to the demand response program benefit resulting from a reduction in the need for new peaking generation capacity. Demand response can also produce energy related benefits. If the demand response option is considered “load shifting”, such as direct load control of electric water heating, the consumption of energy is shifted from the control period to the period immediately following the period of control. For this study, GDS assumed that the energy is shifted with no loss of energy. For power suppliers, this shift in the timing of energy use can produce benefits from either the production of energy from lower cost resources or the purchase of energy at a lower rate. If the program is not considered to be “load shifting” the measure is turned off during peak control hours, and the energy is saved altogether. Demand response programs can also potentially delay the construction of new transmission and distribution lines and facilities, which is reflected in avoided T&D costs.

The discount rate used in this study is 7.29%. A peak demand line loss factor of 6.33% and a reserve margin of 8.4 % (for firm load reduction such as direct load control) were also applied to demand reductions at the customer meter. These values were provided by Vectren.

The useful life of a smart thermostat is assumed to be 15 years[4]. Load control switches have a useful life of 15 years[5]. This life was used for all direct load control measures in this study.

The number of control units per participant was assumed to be 1 for all direct load control programs using switches (such as water heaters and air conditioning switches), because load control switches can control up to two units. However, for controllable thermostats, some participants have more than one thermostat. The average number of residential thermostats per single family home was assumed to be 1.72[6].

G.4 CUSTOMER PARTICIPATION

The assumed level of customer participation for each demand response program option is a key driver of achievable demand response potential estimates. Customer participation rates reflect the total number of eligible customers that are likely to participate in a demand response program. An eligible customer is defined as a customer that is eligible to participate in a demand response program. For DLC programs, eligibility is determined by whether a customer has the end use equipment that will be controlled[7]. The eligible customers for each program is shown in Table G-2 and Table G-3.

TABLE G-2 ELIGIBLE RESIDENTIAL CUSTOMERS IN EACH DEMAND RESPONSE PROGRAM OPTION

DR Program Option	Saturation	Source / Description
DLC AC (Switch)	62% of residential customers	Vectren 2016 Electric Baseline Survey - % of residential homes with central AC
DLC AC (Thermostat)	62% of residential customers	Vectren 2016 Electric Baseline Survey - % of residential homes with central AC

[4] Indiana TRM
[5] Provided by Comverge
[6] EIA RECS table HC6.1

DR Program Option	Saturation	Source / Description
DLC Pool Pumps	6% of residential customers	Vectren 2016 Electric Baseline Survey - % of residential homes with swimming pool pumps
DLC Water Heaters	35% of residential customers	Vectren 2016 Electric Baseline Survey - % of residential homes with electric water heaters
Critical Peak Pricing with Enabling Technology	62% of residential customers	Vectren 2016 Electric Baseline Survey - % of residential homes with central AC
Critical Peak Pricing without Enabling Technology	100% of residential customers	GDS Assumption
Peak Time Rebate	100% of residential customers	GDS Assumption
Time of Use	100% of residential customers	GDS Assumption

TABLE G-3 ELIGIBLE NON-RESIDENTIAL CUSTOMERS IN EACH DEMAND RESPONSE PROGRAM OPTION

DR Program Option	Saturation	Source / Description
DLC AC (Switch)	81.5% of commercial customers	GDS Survey of Vectren C&I Customers - % of C&I customers with central AC
DLC AC (Thermostat)	81.5% of commercial customers	GDS Survey of Vectren C&I Customers - % of C&I customers with central AC
DLC Water Heaters	40% of commercial customers	CBECS 2015 - % of commercial customers in East North Central region with electric water heaters
Critical Peak Pricing with Enabling Technology	81.5% of commercial customers	GDS Survey of Vectren C&I Customers - % of C&I customers with central AC
Critical Peak Pricing without Enabling Technology	100% of commercial customers	GDS Assumption
Real Time Pricing	100% of commercial customers	GDS Assumption
Peak Time Rebate	100% of commercial customers	GDS Assumption
Time of Use	100% of commercial customers	GDS Assumption

G.4.1 Existing Demand Response Programs

Vectren and its owner-member cooperatives have offered their Direct Load Control program for many years. This program offers incentives to members who enroll central AC and electric water heaters. However, Vectren plans to transition the DLC AC switch program to be controlled with smart thermostats instead. The DLC water heating and pool pump programs are being phased out. GDS assumed that all DLC programs controlled with switches would be ended by 2023. A cost-effective analysis was still run for these programs, with the assumption that no new switches would be installed and participation would steadily decline until 2023.

G.4.2 Hierarchy

Double-counting savings from demand response programs that affect the same end uses is a common issue that must be addressed when calculating the demand response savings potential. For example, a direct load control program of air conditioning and a rate program both assume load reduction of the customers' air conditioners. For this reason, it is typically assumed that customers cannot participate in programs that affect the same end uses. This hierarchy where direct load control programs come before rate programs was chosen by Vectren. The order of the rest of the programs is based on savings. Programs with higher savings per customer are ranked as higher in the hierarchy.

TABLE G-4 DEMAND RESPONSE HIERARCHY

DR Program Option	Applicable Sector
DLC Programs	Residential, Commercial
Critical Peak Pricing with Enabling Technology	Residential, Commercial
Critical Peak Pricing without Enabling Technology	Residential, Commercial
Real Time Pricing	Commercial
Peak Time Rebates	Residential, Commercial
Time of Use	Residential, Commercial

G.4.3 Participation Rates

The assumed "steady state" participation rates used in this potential study and the sources upon which each assumption is based are shown in Table G-5 for residential and non-residential customers, respectively. The steady state participation rate represents the enrollment rate once the fully achievable participation has been reached. Participation rates are expressed as a percentage of eligible customers. Program participation and impacts (demand reductions) are assumed to begin in 2020. The main sources of participant rates are several studies completed by the Brattle Group. Additional detail about participation rates and sources are shown in Table G-5.

TABLE G-5 STEADY STATE PARTICIPATION RATES FOR DEMAND RESPONSE PROGRAM OPTIONS

DR Program Options	MAP Steady State Participation Rate	RAP Steady State Participation Rate	Source
RESIDENTIAL			
DLC AC (Switch)	0% (existing program declining to 0 participants)	0% (existing program declining to 0 participants)	Vectren
DLC AC (Thermostat)	36%	25%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Participation in BYOD programs is estimated to be 5% higher than in DLC programs.
DLC Pool Pumps	0% (existing program declining to 0 participants)	0% (existing program declining to 0 participants)	Vectren
DLC Water Heaters	0% (existing program declining to 0 participants)	0% (existing program declining to 0 participants)	Vectren

DR Program Options	MAP Steady State Participation Rate	RAP Steady State Participation Rate	Source
Critical Peak Pricing with Enabling Technology	91%	22%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out for MAP, Opt-In for RAP)
Critical Peak Pricing without Enabling Technology	82%	17%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out for MAP, Opt-In for RAP)
Peak Time Rebate	93%	21%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out for MAP, Opt-In for RAP)
Time of Use	85%	28%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out for MAP, Opt-In for RAP)
NON-RESIDENTIAL			
DLC AC (Switch)	0% (existing program declining to 0 participants)	0% (existing program declining to 0 participants)	Vectren
DLC AC (Thermostat)	19%	8%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Participation in BYOD programs is estimated to be 5% higher than in DLC programs.
DLC Water Heaters	0% (existing program declining to 0 participants)	0% (existing program declining to 0 participants)	Vectren
Critical Peak Pricing with Enabling Technology	69%	20%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out for MAP, Opt-In for RAP)
Critical Peak Pricing without Enabling Technology	63%	18%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out for MAP, Opt-In for RAP)
Real Time Pricing	3%	3%	PACIFICORP DEMAND-SIDE RESOURCE POTENTIAL ASSESSMENT FOR 2015-2034

DR Program Options	MAP Steady State Participation Rate	RAP Steady State Participation Rate	Source
Peak Time Rebate	71%	22%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out for MAP, Opt-In for RAP)
Time of Use	74%	13%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out for MAP, Opt-In for RAP)

Customer participation in new demand response programs is assumed to reach the steady state take rate over a five-year period. The path to steady state customer participation follows an “S-shaped” curve, in which participation growth accelerates over the first half of the five-year period, and then slows over the second half of the period (see Figure G-1). Existing programs have already gone through this ramp-up period, so they were escalated linearly to the final participation rate.

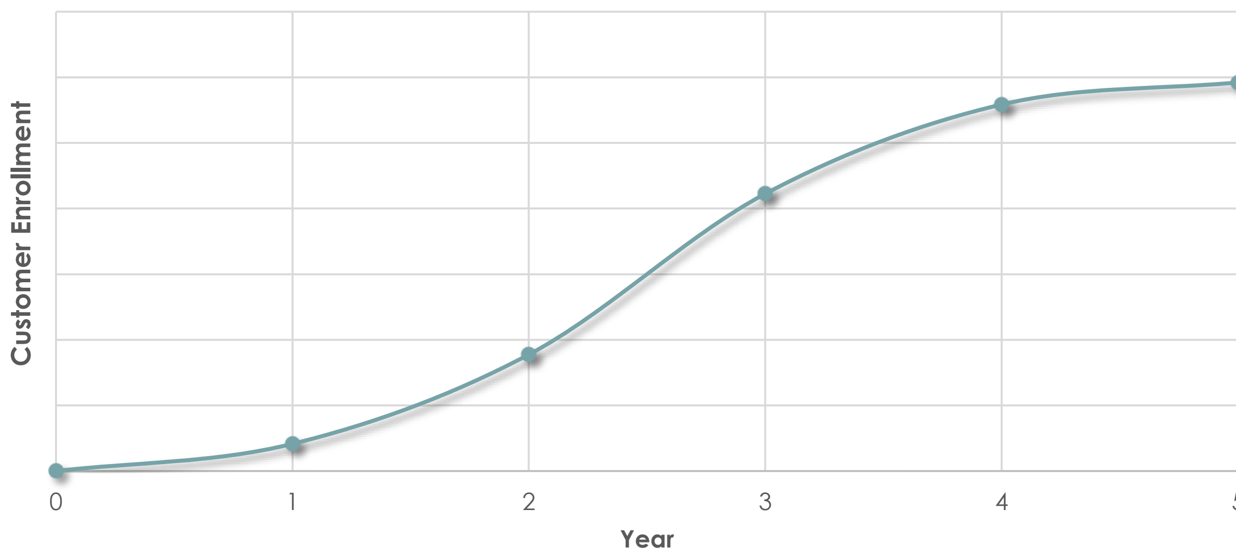


FIGURE G-1 ILLUSTRATION OF S-SHAPED MARKET ADOPTION CURVE

G.5 LOAD REDUCTION ASSUMPTIONS

Table G-6 presents the residential and non-residential per participant CP demand reduction impact assumptions for each demand response program option at the customer meter. Demand reductions were based on load reductions found in Vectren’s existing demand response programs, and various secondary data sources including the FERC and other industry reports, including demand response potential studies.

TABLE G-6 PER PARTICIPANT CP DEMAND REDUCTION ASSUMPTIONS

DR Program Options	Per Participant CP Demand Reduction	Source
RESIDENTIAL		
DLC AC (Switch)	1 kW	2012 FERC Demand Response Survey Data (Reported realized savings data for 20 utility programs, adjusted to account for peak summer temperature differences using NOAA Normal Max Summer Temperature Data, 1981-2010)
DLC AC (Thermostat)	0.87 kW	87% of Load Switch Control. Sources: Smart Thermostats: An Alternative to Load Control Switches? Trends and Strategic Options to Consider for Residential Load Control Programs; 2016 Demand Response Potential Study Conducted by GDS for several Michigan utilities (Confidential pilot program report)
DLC Pool Pumps	1.36 kW	Southern California Edison Pool Pump Demand Response Potential Report, 2008.
DLC Water Heaters	0.4 kW Summer	Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
Critical Peak Pricing with Enabling Technology	31% of coincident peak load	Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
Critical Peak Pricing without Enabling Technology	11.7% of coincident peak load	Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
Peak Time Rebate	12.9% of coincident peak load	Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
Time of Use	5.2% of coincident peak load	Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
NON-RESIDENTIAL		
DLC AC (Switch)	1.6 kW	2012 FERC Demand Response Survey Data (Reported realized savings data for 14 utility programs, adjusted to account for peak summer temperature differences using NOAA Normal Max Summer Temperature Data, 1981-2010)

DR Program Options	Per Participant CP Demand Reduction	Source
DLC AC (Thermostat)	1.39 kW	87% of Load Switch Control. Sources: Smart Thermostats: An Alternative to Load Control Switches? Trends and Strategic Options to Consider for Residential Load Control Programs; 2016 Demand Response Potential Study Conducted by GDS for several Michigan utilities (Confidential pilot program report)
DLC Water Heaters	1.2 kW Summer	Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
Critical Peak Pricing with Enabling Technology	21.5% of coincident peak load	Dynamic Pricing: Transitioning from Experiments to Full Scale Deployments, Michigan Retreat on Peak Shaving to Reduce Wasted Energy, The Brattle Group, August 06, 2014.
Critical Peak Pricing without Enabling Technology	4.2% of coincident peak load	Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (avg of small, med, lrg C&I)
Real Time Pricing	8.4% of coincident peak load	Pacificorp Demand-Side Resource Potential Assessment for 2015-2034
Peak Time Rebate	0.7% of coincident peak load	Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
Time of Use	1.97% of coincident peak load	Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (avg of small, med, lrg C&I)

G.6 PROGRAM COSTS

One-time program development costs of $40,000[8] were included in the first year of the analysis for new programs. No program development costs are assumed for programs that already exist. It was assumed that there would be a cost of $50[9] per new participant for marketing. Marketing costs are assumed to be 33.3% higher for MAP. There was assumed to be an annual administrative cost of $30,000 per program[10]. All program costs were escalated each year by the general rate of inflation assumed for this study.[11] Table G-7 shows the equipment cost assumptions.

[8] TVA Potential Study Volume III: Demand Response Potential, Global Energy Partners, December 2011; $400,000 split between 10 rate programs
[9] TVA Potential Study Volume III: Demand Response Potential, Global Energy Partners, December 2011
[10] Calculated based on the contract labor and Vectren South Expenses in the 2016 DLC Annual Report. GDS divided this cost by the 6 existing programs and assumed a $30,000 cost per program.
[11] The general rate of inflation used for this study was 1.6%. This was provided by Vectren.

TABLE G-7 EQUIPMENT COST ASSUMPTIONS

Device	Cost	Applicable DR Programs	Source
Two-way communicating load control switch using Wi-Fi	$95	DLC programs controlled by switches	Comverge
Load control switch installation	$200	All DLC programs controlled by switches	Comverge
Smart controllable thermostat (such as Nest or Ecobee)	$249	DLC AC Thermostat	Nest / Ecobee

APPENDIX H *Action Plan Combined Gas & Electric Portfolio Summary*

The following tables provide combined electric and gas portfolio targets for all programs for the years 2020-2025, with individual tables for each year.

TABLE H-1 2020 COMBINED PORTFOLIO TARGETS

	Electric							Gas					
	Number of Participants	Total kWh Savings	Total kW (Demand)	Admin.	Implementation	Incentives	Total Budget	Number of Participants	Total Therms Savings	Admin.	Implementation	Incentives	Total Budget
Residential			ELECTRIC							GAS			
Residential Lighting	239,866	8,088,914	905.24	$101,000	$186,419	$463,014	$750,433	[redacted]					
Residential Prescriptive	7,966	2,465,148	691.22	$40,400	$347,608	$632,065	$1,020,073	15,750	1,438,213	$29,600	$1,090,398	$2,456,695	$3,576,693
Residential New Construction	86	188,624	121.46	$5,050	$50,000	$16,775	$71,825	704	305,150	$3,700	$286,083	$379,375	$669,158
Home Energy Assessment	300	519,393	55.48	$5,050	$240,000	-	$245,050	300	20,924	$3,700	$55,000	-	$58,700
Income-Qualified Weatherization	539	778,285	443.32	$20,200	$1,275,176	-	$1,295,376	513	56,971	$14,800	$872,202	-	$887,002
Energy-Efficient Schools	2,600	1,149,200	136.50	$20,200	$113,589	-	$133,789	2,600	38,480	$22,200	$28,397	-	$50,597
Residential Behavioral Savings	49,000	7,049,208	1,574.28	$40,400	$323,803	-	$364,203	34,778	375,933	$37,000	$108,182	-	$145,182
Appliance Recycling	1,251	1,179,811	171.20	$40,400	$143,657	$61,000	$245,057	[redacted]					
CVR Residential	-	1,461,047	430	$30,300	$218,023	-	$248,323						
Smart Cycle (DLC Change Out)	1,000	-	1,015.00	$20,200	$516,000	$96,000	$632,200						
BYOT (Bring Your Own Thermostat)	300	-	240.00	$20,200	$22,280	$52,280	$94,760						
Food Bank	-	-	-	-	-	-	-	-	-	-	-	-	-
Home Energy Management Systems	-	-	-	$10,100	$70,000	-	$80,100	-	-	$11,100	$130,000	-	$141,100
Multi-Family Direct Install	[redacted]							1,700	68,591	$14,800	$397,115	-	$411,915
Targeted Income								46	15,022	$29,600	$74,470	-	$104,070
Home Energy House Call-Integrated								1,122	49,144	$29,600	$179,527	-	$209,127
Neighborhood Program-Integrated								1,000	134,440	$29,600	$185,910	-	$215,510
Residential Subtotal	**302,908**	**22,879,629**	**5,783.70**	**$353,500**	**$3,506,555**	**$1,321,134**	**$5,181,189**	**58,513**	**2,502,868**	**$225,700**	**$3,407,285**	**$2,836,070**	**$6,469,055**
Commercial & Industrial			ELECTRIC							GAS			
Commercial Prescriptive	42,431	14,490,335	3,807.71	$55,550	$622,327	$1,370,010	$2,047,886	1,112	298,228	$66,600	$442,240	$251,057	$759,897
Commercial Custom	196	6,107,234	740.00	$60,600	$344,162	$491,537	$896,299	71	472,810	$74,000	$493,803	$489,600	$1,057,403
Small Business	381	2,940,932	213.00	$5,050	$215,618	$548,167	$768,835	592	16,788	$3,700	$3,096	$5,886	$12,682

	Electric							Gas					
	Number of Participants	Total kWh Savings	Total kW (Demand)	Admin.	Implementation	Incentives	Total Budget	Number of Participants	Total Therms Savings	Admin.	Implementation	Incentives	Total Budget
CVR Commercial	-	1,032,656	214	$30,300	$148,233	-	$178,533	[redacted]					
Commercial & Industrial Subtotal	**43,008**	**24,571,158**	**4,974.71**	**$151,500**	**$1,330,340**	**$2,409,714**	**$3,891,554**	**1,775**	**787,826**	**$144,300**	**$939,139**	**$746,543**	**$1,829,982**
Indirect Costs				ELECTRIC							GAS		
Contact Center							$63,000						$132,080
Online Audit							$42,911						$200,564
Outreach							$410,000						$534,863
Portfolio Costs Subtotal							**$515,911**						**$867,508**
Subtotal (Before Evaluation)							**$9,588,653**						**$9,166,544**
Evaluation							$490,728						$482,414
DSM Portfolio Total							**$10,079,381**						**$9,648,958**
Other Costs				ELECTRIC							GAS		
Emerging Markets							$ 200,000						$ 200,000
Market Potential Study							-						-
Other Costs Subtotal							**$ 200,000**						**$ 200,000**
DSM Portfolio Total including Other Costs							**$10,279,381**						**$9,848,958**

TABLE H -2 2021 COMBINED PORTFOLIO TARGETS

	Electric							Gas					
	Number of Participants	Total kWh Savings	Total kW (Demand)	Admin.	Implementation	Incentives	Total Budget	Number of Participa nts	Total Therms Savings	Admin.	Implementation	Incentives	Total Budget
Residential				ELECTRIC							GAS		
Residential Lighting	262,832	8,704,288	875.28	$102,616	$189,402	$455,001	$747,018	[redacted]					
Residential Prescriptive	8,276	2,618,629	661.70	$41,046	$353,169	$645,510	$1,039,726	16,021	1,456,999	$30,074	$1,107,845	$2,491,995	$3,629,913
Residential New Construction	77	168,932	108.81	$5,131	$57,249	$15,025	$77,405	857	369,380	$3,759	$342,221	$452,875	$798,855
Home Energy Assessment	350	605,959	64.72	$5,131	$258,000	-	$263,131	350	24,412	$3,759	$55,880	-	$59,639
Income-Qualified Weatherization	566	823,215	467.28	$20,523	$1,293,527	-	$1,314,050	538	60,190	$15,037	$885,268	-	$900,304

	Electric							Gas					
	Number of Participants	Total kWh Savings	Total kW (Demand)	Admin.	Implementation	Incentives	Total Budget	Number of Participants	Total Therms Savings	Admin.	Implementation	Incentives	Total Budget
Energy-Efficient Schools	2,600	1,149,200	136.50	$20,523	$117,253	-	$137,776	2,600	38,480	$22,555	$29,313	-	$51,868
Residential Behavioral Savings	49,000	7,049,208	1,574.28	$20,523	$328,984	-	$349,507	34,778	375,933	$22,555	$109,913	-	$132,468
Appliance Recycling	1,344	1,285,473	172.83	$41,046	$159,415	$66,625	$267,086	[redacted]					
CVR Residential	-	-	-	$30,785	$197,378	-	$228,163						
Smart Cycle (DLC Change Out)	1,000	198,000	1,015	$20,523	$536,000	$116,000	$672,523						
BYOT (Bring Your Own Thermostat)	300	-	240.00	$20,523	$30,280	$60,280	$111,083						
Food Bank	6,312	1,564,332	172.21	$20,523	$92,517	-	$113,041	6,312	41,628	$15,037	$4,626	-	$19,663
Home Energy Management Systems	1,000	515,000	80.00	$10,262	$212,900	-	$223,162	1,000	54,400	$11,278	$194,100	-	$205,378
Multi-Family Direct Install	[redacted]							1,700	68,591	$15,037	$403,469	-	$418,506
Targeted Income								46	15,022	$30,074	$75,662	-	$105,735
Home Energy House Call-Integrated								1,122	49,144	$30,074	$182,399	-	$212,473
Neighborhood Program-Integrated								1,000	134,440	$30,074	$188,885	-	$218,959
Residential Subtotal	**333,657**	**24,682,235**	**5,568.60**	**$359,156**	**$3,826,074**	**$1,358,441**	**$5,543,671**	**66,324**	**2,688,619**	**$229,311**	**$3,579,580**	**$2,944,870**	**$6,753,761**
Commercial & Industrial				**ELECTRIC**						**GAS**			
Commercial Prescriptive	48,449	15,981,655	4,131.23	$56,439	$682,432	$1,424,756	$2,163,627	1,193	315,496	$67,666	$487,528	$266,357	$821,550
Commercial Custom	196	6,107,234	740.00	$61,570	$349,669	$491,537	$902,775	71	472,810	$75,184	$501,704	$489,600	$1,066,488
Small Business	382	2,944,615	213.00	$5,131	$219,172	$539,573	$763,876	1,025	18,516	$3,759	$3,209	$6,006	$12,975
CVR Commercial	-	-	-	$30,785	$133,547	-	$164,332	[redacted]					
Commercial & Industrial Subtotal	**49,027**	**25,033,504**	**5,084.23**	**$153,924**	**$1,384,820**	**$2,455,867**	**$3,994,610**	**2,289**	**806,822**	**$146,609**	**$992,441**	**$761,963**	**$1,901,012**
Indirect Costs				**ELECTRIC**						**GAS**			
Contact Center							$64,008						$134,193
Online Audit							$43,598						$203,774
Outreach							$416,560						$543,421

	Electric							Gas					
	Number of Participants	Total kWh Savings	Total kW (Demand)	Admin.	Implementation	Incentives	Total Budget	Number of Participants	Total Therms Savings	Admin.	Implementation	Incentives	Total Budget
Portfolio Costs Subtotal							**$524,166**						**$881,388**
Subtotal (Before Evaluation)							**$10,062,446**						**$9,536,161**
Evaluation							$522,653						$507,425
DSM Portfolio Total							**$10,585,099**						**$10,043,586**
Other Costs	**ELECTRIC**							**GAS**					
Emerging Markets							200,000						200,000
Market Potential Study							300,000						300,000
Other Costs Subtotal							**500,000**						**500,000**
DSM Portfolio Total including Other Costs							**$11,085,099**						**$10,543,586**

TABLE H-3 2022 COMBINED PORTFOLIO TARGETS

	Electric							Gas					
	Number of Participants	Total kWh Savings	Total kW (Demand)	Admin.	Implementation	Incentives	Total Budget	Number of Participants	Total Therms Savings	Admin.	Implementation	Incentives	Total Budget
Residential	**ELECTRIC**							**GAS**					
Residential Lighting	91,708	3,259,915	255.83	$104,258	$144,380	$346,846	$595,484	[redacted]					
Residential Prescriptive	8,303	2,722,283	737.22	$41,703	$358,820	$680,160	$1,080,683	9,522	579,226	$30,555	$535,505	$858,470	$1,424,530
Residential New Construction	75	164,892	106.37	$5,213	$53,186	$14,675	$73,074	1,075	462,060	$3,819	$424,689	$561,725	$990,233
Home Energy Assessment	420	727,151	77.67	$5,213	$263,225	-	$268,438	420	29,294	$3,819	$56,774	-	$60,593
Income-Qualified Weatherization	594	869,076	492.09	$20,852	$1,312,171	-	$1,333,023	564	63,502	$15,277	$980,165	-	$995,443
Energy-Efficient Schools	2,600	670,800	93.60	$20,852	$92,229	-	$113,080	2,600	38,480	$22,916	$30,743	-	$53,659
Residential Behavioral Savings	49,000	7,049,208	1,574.28	$20,852	$334,248	-	$355,099	34,778	375,933	$22,916	$111,671	-	$134,587
Appliance Recycling	1,425	1,360,636	184.89	$41,703	$171,385	$70,500	$283,589	[redacted]					
CVR Residential	-	-	-	$31,277	$190,034	-	$221,311						
Smart Cycle (DLC Change Out)	1,000	198,000	1,015	$20,852	$556,000	$136,000	$712,852						

	Electric							Gas					
	Number of Participants	Total kWh Savings	Total kW (Demand)	Admin.	Implementation	Incentives	Total Budget	Number of Participants	Total Therms Savings	Admin.	Implementation	Incentives	Total Budget
BYOT (Bring Your Own Thermostat)	300	-	240.00	$20,852	$38,280	$68,280	$127,412	[redacted]					
Food Bank	6,312	816,353	69.09	$20,852	$18,800	-	$39,651	6,312	41,628	$15,278	$4,700	-	$19,977
Home Energy Management Systems	1,000	515,000	80.00	$10,426	$219,900	-	$230,326	1,000	54,400	$11,458	$187,100	-	$198,558
Multi-Family Direct Install	[redacted]							1,700	68,591	$15,277	$409,925	-	$425,202
Targeted Income	[redacted]							46	15,022	$30,555	$76,872	-	$107,427
Home Energy House Call-Integrated	[redacted]							1,122	49,144	$30,555	$185,318	-	$215,872
Neighborhood Program-Integrated	[redacted]							1,000	134,440	$30,555	$191,907	-	$222,462
Residential Subtotal	**162,737**	**18,353,314**	**4,926.04**	**$364,902**	**$3,752,658**	**$1,316,461**	**$5,434,021**	**60,139**	**1,911,720**	**$232,980**	**$3,195,369**	**$1,420,195**	**$4,848,544**
Commercial & Industrial				**ELECTRIC**							**GAS**		
Commercial Prescriptive	52,971	17,154,963	4,383.05	$57,342	$733,558	$1,448,274	$2,239,173	1,312	338,606	$68,748	$541,210	$286,137	$896,095
Commercial Custom	196	6,107,234	740.00	$62,555	$355,263	$491,537	$909,355	71	472,810	$76,387	$509,731	$489,600	$1,075,718
Small Business	382	2,949,771	213.00	$5,213	$222,721	$530,824	$758,758	1,135	21,540	$3,819	$3,375	$6,216	$13,410
CVR Commercial	-	-	-	$31,277	$128,261	-	$159,538	[redacted]					
Commercial & Industrial Subtotal	**53,549**	**26,211,968**	**5,336.05**	**$156,387**	**$1,439,803**	**$2,470,635**	**$4,066,825**	**2,518**	**832,956**	**$148,955**	**$1,054,315**	**$781,953**	**$1,985,223**
Indirect Costs				**ELECTRIC**							**GAS**		
Contact Center							$65,032						$136,340
Online Audit							$44,295						$207,034
Outreach							$423,225						$552,116
Portfolio Costs Subtotal							**$532,552**						**$895,490**
Subtotal (Before Evaluation)							**$10,033,398**						**$7,729,257**
Evaluation							$518,856						$415,538
DSM Portfolio Total							**$10,552,254**						**$8,144,795**
Other Costs				**ELECTRIC**							**GAS**		
Emerging Markets							200,000						200,000

	Electric							Gas					
	Number of Participants	Total kWh Savings	Total kW (Demand)	Admin.	Implementation	Incentives	Total Budget	Number of Participants	Total Therms Savings	Admin.	Implementation	Incentives	Total Budget
Market Potential Study							$						$
Other Costs Subtotal							**200,000**						**200,000**
DSM Portfolio Total including Other Costs							**$10,752,254**						**$8,344,795**

TABLE H -4 2023 COMBINED PORTFOLIO TARGETS

	Electric							Gas					
	Number of Participants	Total kWh Savings	Total kW (Demand)	Admin.	Implementation	Incentives	Total Budget	Number of Participants	Total Therms Savings	Admin.	Implementation	Incentives	Total Budget
Residential				**ELECTRIC**						**GAS**			
Residential Lighting	12,231	807,282	19.16	$105,926	$32,756	$78,689	$217,370	[redacted]					
Residential Prescriptive	8,140	2,793,920	812.09	$42,370	$364,561	$707,135	$1,114,066	9,565	580,541	$31,044	$544,073	$863,520	$1,438,637
Residential New Construction	73	160,852	103.94	$5,296	$50,202	$14,325	$69,824	1,253	537,581	$3,880	$491,921	$650,275	$1,146,077
Home Energy Assessment	504	872,581	93.20	$5,296	$267,437	-	$272,733	504	35,153	$3,880	$57,682	-	$61,563
Income-Qualified Weatherization	623	917,290	518.75	$21,185	$1,331,114	-	$1,352,299	591	66,991	$15,522	$1,060,825	-	$1,076,347
Energy-Efficient Schools	2,600	670,800	93.60	$21,185	$98,274	-	$119,460	2,600	38,480	$23,283	$32,758	-	$56,041
Residential Behavioral Savings	49,000	7,049,208	1,574.28	$21,185	$339,596	-	$360,781	34,778	375,933	$23,283	$113,458	-	$136,741
Appliance Recycling	1,435	1,366,149	188.46	$42,370	$174,745	$70,750	$287,865	[redacted]					
CVR Residential	-	1,461,047	430	$31,778	$270,252	-	$302,029						
Smart Cycle (DLC Change Out)	1,000	198,000	1,015	$21,185	$576,000	$156,000	$753,185						
BYOT (Bring Your Own Thermostat)	300	-	240.00	$21,185	$46,280	$76,280	$143,745						
Food Bank	3,156	649,158	46.71	$21,185	$9,550	-	$30,735	3,156	20,814	$15,522	$4,775	-	$20,297
Home Energy Management Systems	1,000	515,000	80.00	$10,593	$234,900	-	$245,493	1,000	54,400	$11,641	$172,100	-	$183,741
Multi-Family Direct Install	[redacted]							1,700	68,591	$15,522	$416,484	-	$432,005
Targeted Income								46	15,022	$31,044	$78,102	-	$109,146
Home Energy House Call-Integrated								1,122	49,144	$31,044	$188,283	-	$219,326

	Electric							Gas					
	Number of Participants	Total kWh Savings	Total kW (Demand)	Admin.	Implementation	Incentives	Total Budget	Number of Participants	Total Therms Savings	Admin.	Implementation	Incentives	Total Budget
Neighborhood Program-Integrated	[redacted]							1,000	134,440	$31,044	$194,978	-	$226,021
Residential Subtotal	**80,062**	**17,461,286**	**5,215.19**	**$370,741**	**$3,795,666**	**$1,103,179**	**$5,269,586**	**57,315**	**1,977,090**	**$236,708**	**$3,355,439**	**$1,513,795**	**$5,105,942**
Commercial & Industrial				**ELECTRIC**							**GAS**		
Commercial Prescriptive	55,283	17,821,076	4,524.43	$58,259	$769,435	$1,434,660	$2,262,354	1,479	365,992	$69,848	$598,626	$307,777	$976,251
Commercial Custom	196	6,107,234	740.00	$63,556	$360,948	$491,537	$916,040	71	472,810	$77,609	$517,886	$489,600	$1,085,096
Small Business	382	2,952,715	213.00	$5,296	$226,003	$521,287	$752,586	1,260	24,996	$3,880	$3,561	$6,456	$13,898
CVR Commercial	-	1,032,656	214	$31,778	$184,861	-	$216,639	[redacted]					
Commercial & Industrial Subtotal	**55,861**	**27,913,681**	**5,691.43**	**$158,889**	**$1,541,248**	**$2,447,483**	**$4,147,620**	**2,810**	**863,798**	**$151,338**	**$1,120,073**	**$803,833**	**$2,075,244**
Indirect Costs				**ELECTRIC**							**GAS**		
Contact Center							$66,073						$138,522
Online Audit							$45,004						$210,346
Outreach							$429,997						$560,949
Portfolio Costs Subtotal							**$541,073**						**$909,818**
Subtotal (Before Evaluation)							**$9,958,279**						**$8,091,004**
Evaluation							$512,192						$431,543
DSM Portfolio Total							**$10,470,471**						**$8,522,547**
Other Costs				**ELECTRIC**							**GAS**		
Emerging Markets							200,000						$200,000
Market Potential Study							$						-
Other Costs Subtotal							**200,000**						**$200,000**
DSM Portfolio Total including Other Costs							**$10,670,471**						**$8,722,547**

TABLE H-5 2024 COMBINED PORTFOLIO TARGETS

	Electric							Gas					
	Number of Participants	Total kWh Savings	Total kW (Demand)	Admin.	Implementation	Incentives	Total Budget	Number of Participants	Total Therms Savings	Admin.	Implementation	Incentives	Total Budget
Residential			ELECTRIC							GAS			
Residential Lighting	14,089	977,297	19.66	$107,621	$38,416	$92,287	$238,324	[redacted]					
Residential Prescriptive	7,892	2,860,501	889.35	$43,048	$370,394	$732,410	$1,145,852	9,584	579,541	$31,540	$552,778	$864,995	$1,449,314
Residential New Construction	71	156,812	101.51	$5,381	$48,144	$13,975	$67,500	1,428	612,092	$3,943	$558,080	$737,775	$1,299,797
Home Energy Assessment	504	840,768	89.03	$5,381	$271,716	-	$277,097	504	35,153	$3,943	$58,605	-	$62,548
Income-Qualified Weatherization	653	967,302	546.35	$21,524	$1,350,360	-	$1,371,884	619	70,571	$15,770	$1,120,207	-	$1,135,977
Energy-Efficient Schools	2,600	670,800	93.60	$21,524	$106,392	-	$127,916	2,600	38,480	$23,655	$35,464	-	$59,119
Residential Behavioral Savings	49,000	7,049,208	1,574.28	$21,524	$345,029	-	$366,554	34,778	375,933	$23,655	$115,273	-	$138,929
Appliance Recycling	1,372	1,300,910	183.54	$43,048	$168,946	$67,325	$279,320	[redacted]					
CVR Residential	-	-	-	$32,286	$315,241	-	$347,528						
Smart Cycle (DLC Change Out)	1,000	198,000	1,015	$21,524	$596,000	$176,000	$793,524						
BYOT (Bring Your Own Thermostat)	300	-	240.00	$21,524	$54,280	$84,280	$160,084						
Food Bank	3,156	649,158	46.71	$21,524	$9,703	-	$31,227	3,156	20,814	$15,770	$4,851	-	$20,622
Home Energy Management Systems	1,000	515,000	80.00	$10,762	$245,940	-	$256,702	1,000	54,400	$11,828	$198,260	-	$210,088
Multi-Family Direct Install	[redacted]							1,700	68,591	$15,770	$423,147	-	$438,918
Targeted Income								46	15,022	$31,540	$79,352	-	$110,892
Home Energy House Call-Integrated								1,122	49,144	$31,540	$191,295	-	$222,835
Neighborhood Program-Integrated								1,000	134,440	$31,540	$198,097	-	$229,638
Residential Subtotal	**81,637**	**16,185,755**	**4,879.02**	**$376,673**	**$3,920,561**	**$1,166,277**	**$5,463,511**	**57,537**	**2,054,181**	**$240,495**	**$3,535,411**	**$1,602,770**	**$5,378,676**
Commercial & Industrial			ELECTRIC							GAS			
Commercial Prescriptive	55,739	18,058,503	4,572.95	$59,191	$791,792	$1,394,674	$2,245,657	1,712	402,215	$70,966	$611,299	$335,962	$1,018,227
Commercial Custom	196	6,107,234	740.00	$64,572	$366,723	$491,537	$922,832	71	472,810	$78,851	$526,173	$489,600	$1,094,624
Small Business	383	2,957,870	213.00	$5,381	$229,663	$512,537	$747,582	1,369	28,020	$3,943	$3,736	$6,666	$14,344

	Electric: Number of Participants	Electric: Total kWh Savings	Electric: Total kW (Demand)	Electric: Admin.	Electric: Implementation	Electric: Incentives	Electric: Total Budget
CVR Commercial	-	-	-	$32,286	$216,561	-	$248,848
Commercial & Industrial Subtotal	**56,318**	**27,123,608**	**5,525.95**	**$161,431**	**$1,604,739**	**$2,398,748**	**$4,164,919**
Indirect Costs							**ELECTRIC**
Contact Center							$67,130
Online Audit							$45,724
Outreach							$436,877
Portfolio Costs Subtotal							**$549,730**
Subtotal (Before Evaluation)							**$10,178,160**
Evaluation							$520,077
DSM Portfolio Total							**$10,698,237**
Other Costs							**ELECTRIC**
Emerging Markets							200,000
Market Potential Study							300,000
Other Costs Subtotal							**500,000**
DSM Portfolio Total including Other Costs							**$11,198,237**

	Gas: Number of Participants	Gas: Total Therms Savings	Gas: Admin.	Gas: Implementation	Gas: Incentives	Gas: Total Budget
CVR Commercial	[redacted]					
Commercial & Industrial Subtotal	**3,152**	**903,045**	**$153,759**	**$1,141,208**	**$832,228**	**$2,127,195**
Indirect Costs						**GAS**
Contact Center						$140,738
Online Audit						$213,712
Outreach						$569,925
Portfolio Costs Subtotal						**$924,375**
Subtotal (Before Evaluation)						**$8,430,246**
Evaluation						$446,225
DSM Portfolio Total						**$8,876,471**
Other Costs						**GAS**
Emerging Markets						200,000
Market Potential Study						300,000
Other Costs Subtotal						**500,000**
DSM Portfolio Total including Other Costs						**$9,376,471**

TABLE H -6 2025 COMBINED PORTFOLIO TARGETS

	Electric: Number of Participants	Electric: Total kWh Savings	Electric: Total kW (Demand)	Electric: Admin.	Electric: Implementation	Electric: Incentives	Electric: Total Budget
Residential							**ELECTRIC**
Residential Lighting	15,913	1,146,410	274.12	$109,343	$44,005	$105,714	$259,061
Residential Prescriptive	8,136	2,974,980	961.29	$43,737	$376,320	$767,435	$1,187,492
Residential New Construction	70	154,792	100.29	$5,467	$46,909	$13,800	$66,176
Home Energy Assessment	504	790,845	83.15	$5,467	$276,063	-	$281,530

	Gas: Number of Participants	Gas: Total Therms Savings	Gas: Admin.	Gas: Implementation	Gas: Incentives	Gas: Total Budget
Residential						**GAS**
Residential Lighting						
Residential Prescriptive	9,591	577,456	$32,045	$561,623	$864,845	$1,458,513
Residential New Construction	1,592	681,668	$4,006	$620,174	$819,500	$1,443,680
Home Energy Assessment	504	35,153	$4,006	$59,543	-	$63,549

	Electric							Gas					
	Number of Participants	Total kWh Savings	Total kW (Demand)	Admin.	Implementation	Incentives	Total Budget	Number of Participants	Total Therms Savings	Admin.	Implementation	Incentives	Total Budget
Income-Qualified Weatherization	685	1,018,544	575.34	$21,869	$1,369,913	-	$1,391,782	649	74,337	$16,022	$1,156,992	-	$1,173,014
Energy-Efficient Schools	2,600	670,800	93.60	$21,869	$117,023	-	$138,891	2,600	38,480	$24,034	$39,008	-	$63,041
Residential Behavioral Savings	49,000	7,049,208	1,574.28	$21,869	$350,550	-	$372,418	34,778	375,933	$24,034	$117,118	-	$141,151
Appliance Recycling	1,253	1,180,913	171.99	$43,737	$155,651	$61,050	$260,438						
CVR Residential	-	-	-	$32,803	$282,073	-	$314,876						
Smart Cycle (DLC Change Out)	1,000	198,000	1,015	$21,869	$616,000	$196,000	$833,869						
BYOT (Bring Your Own Thermostat)	300	-	240.00	$21,869	$62,280	$92,280	$176,429						
Food Bank	3,156	649,158	46.71	$21,869	$9,858	-	$31,727	3,156	20,814	$16,023	$4,929	-	$20,952
Home Energy Management Systems	1,000	515,000	80.00	$10,934	$266,980	-	$277,914	1,000	54,400	$12,017	$214,420	-	$226,437
Multi-Family Direct Install								1,700	68,591	$16,022	$429,918	-	$445,940
Targeted Income								46	15,022	$32,045	$80,621	-	$112,666
Home Energy House Call-Integrated								1,122	49,144	$32,045	$194,356	-	$226,401
Neighborhood Program-Integrated								1,000	134,440	$32,045	$201,267	-	$233,312
Residential Subtotal	**83,617**	**16,348,650**	**5,215.76**	**$382,700**	**$3,973,626**	**$1,236,279**	**$5,592,604**	**57,738**	**2,125,438**	**$244,343**	**$3,679,968**	**$1,684,345**	**$5,608,656**
Commercial & Industrial				**ELECTRIC**							**GAS**		
Commercial Prescriptive	53,882	17,825,085	4,513.77	$60,139	$797,128	$1,331,794	$2,189,060	1,964	439,398	$72,101	$737,459	$363,357	$1,172,917
Commercial Custom	196	6,107,234	740.00	$65,606	$372,590	$491,537	$929,733	71	472,810	$80,112	$534,591	$489,600	$1,104,304
Small Business	383	2,963,026	213.00	$5,467	$233,383	$503,787	$742,637	1,479	31,044	$4,006	$3,915	$6,876	$14,797
CVR Commercial	-	-	-	$32,803	$193,019	-	$225,821	-	-	-	-	-	-
Commercial & Industrial Subtotal	**54,461**	**26,895,345**	**5,466.77**	**$164,014**	**$1,596,120**	**$2,327,118**	**$4,087,252**	**3,514**	**943,252**	**$156,219**	**$1,275,965**	**$859,833**	**$2,292,017**
Indirect Costs				**ELECTRIC**							**GAS**		
Contact Center							$68,204						$142,990
Online Audit							$46,456						$217,131

	Electric							Gas					
	Number of Participants	Total kWh Savings	Total kW (Demand)	Admin.	Implementation	Incentives	Total Budget	Number of Participants	Total Therms Savings	Admin.	Implementation	Incentives	Total Budget
Outreach							$443,867						$579,043
Portfolio Costs Subtotal							**$558,526**						**$939,165**
Subtotal (Before Evaluation)							**$10,238,382**						**$8,839,838**
Evaluation							$520,203						$464,552
DSM Portfolio Total							**$10,758,585**						**$9,304,390**
Other Costs				**ELECTRIC**							**GAS**		
Emerging Markets							200,000						200,000
Market Potential Study													
Other Costs Subtotal							**200,000**						**200,000**
DSM Portfolio Total including Other Costs							**$10,958,585**						**$9,504,390**

APPENDIX I *Action Plan Combined Gas & Electric Costs Summary*

The following tables present combined gas and electric costs for all residential programs for the years 2020-2025, with individual tables for each year. This is immediately followed by a table presenting the combined gas and electric costs for all commercial and industrial programs.

TABLE I-1 2020 COMBINED GAS AND ELECTRIC COSTS – RESIDENTIAL

Residential	Admin. (Electric)	Implementation (Electric)	Incentives (Electric)	Total Budget (Electric)	Admin. (Gas)	Implementation (Gas)	Incentives (Gas)	Total Budget (Gas)
Residential Lighting	$101,000	$186,419	$463,014	$750,433				
Residential Prescriptive	$40,400	$347,608	$632,065	$1,020,073	$29,600	$1,090,398	$2,456,695	$3,576,693
Residential New Construction	$5,050	$50,000	$16,775	$71,825	$3,700	$286,083	$379,375	$669,158
Home Energy Assessment	$5,050	$240,000	-	$245,050	$3,700	$55,000	-	$58,700
Income-Qualified Weatherization	$20,200	$1,275,176	-	$1,295,376	$14,800	$872,202	-	$887,002
Energy-Efficient Schools	$20,200	$113,589	-	$133,789	$22,200	$28,397	-	$50,597
Residential Behavioral Savings	$40,400	$323,803	-	$364,203	$37,000	$108,182	-	$145,182
Appliance Recycling	$40,400	$143,657	$61,000	$245,057				
CVR Residential	$30,300	$218,023	-	$248,323				
Smart Cycle (DLC Change Out)	$20,200	$516,000	$96,000	$632,200				
BYOT (Bring Your Own Thermostat)	$20,200	$22,280	$52,280	$94,760				
Food Bank	-	-	-	-	-	-	-	-
Home Energy Management Systems	$10,100	$70,000	-	$80,100	$11,100	$130,000	-	$141,100
Multi-Family Direct Install					$14,800	$397,115	-	$411,915
Targeted Income					$29,600	$74,470	-	$104,070
Home Energy House Call- Integrated					$29,600	$179,527	-	$209,127
Neighborhood Program- Integrated					$29,600	$185,910	-	$215,510
Residential Subtotal	**$353,500**	**$3,506,555**	**$1,321,134**	**$5,181,189**	**$225,700**	**$3,407,285**	**$2,836,070**	**$6,469,055**

TABLE I -2 2020 COMBINED GAS AND ELECTRIC COSTS – COMMERCIAL & INDUSTRIAL

	Admin.	Implementation	Incentives	Total Budget	Admin.	Implementation	Incentives	Total Budget
Commercial & Industrial	ELECTRIC				GAS			
Commercial Prescriptive	$55,550	$622,327	$1,370,010	$2,047,886	$66,600	$442,240	$251,057	$759,897
Commercial Custom	$60,600	$344,162	$491,537	$896,299	$74,000	$493,803	$489,600	$1,057,403
Small Business	$5,050	$215,618	$548,167	$768,835	$3,700	$3,096	$5,886	$12,682
CVR Commercial	$30,300	$148,233	-	$178,533				
Commercial & Industrial Subtotal	**$151,500**	**$1,330,340**	**$2,409,714**	**$3,891,554**	**$144,300**	**$939,139**	**$746,543**	**$1,829,982**

TABLE I -3 2021 COMBINED GAS AND ELECTRIC COSTS – RESIDENTIAL

	Admin.	Implementation	Incentives	Total Budget	Admin.	Implementation	Incentives	Total Budget
Residential	ELECTRIC				GAS			
Residential Lighting	$102,616	$189,402	$455,001	$747,018				
Residential Prescriptive	$41,046	$353,169	$645,510	$1,039,726	$30,074	$1,107,845	$2,491,995	$3,629,913
Residential New Construction	$5,131	$57,249	$15,025	$77,405	$3,759	$342,221	$452,875	$798,855
Home Energy Assessment	$5,131	$258,000	-	$263,131	$3,759	$55,880	-	$59,639
Income-Qualified Weatherization	$20,523	$1,293,527	-	$1,314,050	$15,037	$885,268	-	$900,304
Energy-Efficient Schools	$20,523	$117,253	-	$137,776	$22,555	$29,313	-	$51,868
Residential Behavioral Savings	$20,523	$328,984	-	$349,507	$22,555	$109,913	-	$132,468
Appliance Recycling	$41,046	$159,415	$66,625	$267,086				
CVR Residential	$30,785	$197,378	-	$228,163				
Smart Cycle (DLC Change Out)	$20,523	$536,000	$116,000	$672,523				
BYOT (Bring Your Own Thermostat)	$20,523	$30,280	$60,280	$111,083				
Food Bank	$20,523	$92,517	-	$113,041	$15,037	$4,626	-	$19,663
Home Energy Management Systems	$10,262	$212,900	-	$223,162	$11,278	$194,100	-	$205,378

	Admin.	Implementation	Incentives	Total Budget	Admin.	Implementation	Incentives	Total Budget
Residential		ELECTRIC				GAS		
Multi-Family Direct Install					$15,037	$403,469	-	$418,506
Targeted Income					$30,074	$75,662	-	$105,735
Home Energy House Call- Integrated					$30,074	$182,399	-	$212,473
Neighborhood Program- Integrated					$30,074	$188,885	-	$218,959
Residential Subtotal	**$359,156**	**$3,826,074**	**$1,358,441**	**$5,543,671**	**$229,311**	**$3,579,580**	**$2,944,870**	**$6,753,761**

TABLE I -4 2021 COMBINED GAS AND ELECTRIC COSTS – COMMERCIAL & INDUSTRIAL

	Admin.	Implementation	Incentives	Total Budget	Admin.	Implementation	Incentives	Total Budget
Commercial & Industrial		ELECTRIC				GAS		
Commercial Prescriptive	$56,439	$682,432	$1,424,756	$2,163,627	$67,666	$487,528	$266,357	$821,550
Commercial Custom	$61,570	$349,669	$491,537	$902,775	$75,184	$501,704	$489,600	$1,066,488
Small Business	$5,131	$219,172	$539,573	$763,876	$3,759	$3,209	$6,006	$12,975
CVR Commercial	$30,785	$133,547	-	$164,332				
Commercial & Industrial Subtotal	**$153,924**	**$1,384,820**	**$2,455,867**	**$3,994,610**	**$146,609**	**$992,441**	**$761,963**	**$1,901,012**

TABLE I -5 2022 COMBINED GAS AND ELECTRIC COSTS – RESIDENTIAL

	Admin.	Implementation	Incentives	Total Budget	Admin.	Implementation	Incentives	Total Budget
Residential		ELECTRIC				GAS		
Residential Lighting	$104,258	$144,380	$346,846	$595,484				
Residential Prescriptive	$41,703	$358,820	$680,160	$1,080,683	$30,555	$535,505	$858,470	$1,424,530
Residential New Construction	$5,213	$53,186	$14,675	$73,074	$3,819	$424,689	$561,725	$990,233
Home Energy Assessment	$5,213	$263,225	-	$268,438	$3,819	$56,774	-	$60,593
Income-Qualified Weatherization	$20,852	$1,312,171	-	$1,333,023	$15,277	$980,165	-	$995,443
Energy-Efficient Schools	$20,852	$92,229	-	$113,080	$22,916	$30,743	-	$53,659

Residential	Admin. (ELECTRIC)	Implementation (ELECTRIC)	Incentives (ELECTRIC)	Total Budget (ELECTRIC)	Admin. (GAS)	Implementation (GAS)	Incentives (GAS)	Total Budget (GAS)
Residential Behavioral Savings	$20,852	$334,248	-	$355,099	$22,916	$111,671	-	$134,587
Appliance Recycling	$41,703	$171,385	$70,500	$283,589				
CVR Residential	$31,277	$190,034	-	$221,311				
Smart Cycle (DLC Change Out)	$20,852	$556,000	$136,000	$712,852				
BYOT (Bring Your Own Thermostat)	$20,852	$38,280	$68,280	$127,412				
Food Bank	$20,852	$18,800	-	$39,651	$15,278	$4,700	-	$19,977
Home Energy Management Systems	$10,426	$219,900	-	$230,326	$11,458	$187,100	-	$198,558
Multi-Family Direct Install					$15,277	$409,925	-	$425,202
Targeted Income					$30,555	$76,872	-	$107,427
Home Energy House Call- Integrated					$30,555	$185,318	-	$215,872
Neighborhood Program- Integrated					$30,555	$191,907	-	$222,462
Residential Subtotal	**$364,902**	**$3,752,658**	**$1,316,461**	**$5,434,021**	**$232,980**	**$3,195,369**	**$1,420,195**	**$4,848,544**

TABLE I -6 2022 COMBINED GAS AND ELECTRIC COSTS – COMMERCIAL & INDUSTRIAL

Commercial & Industrial	Admin. (ELECTRIC)	Implementation (ELECTRIC)	Incentives (ELECTRIC)	Total Budget (ELECTRIC)	Admin. (GAS)	Implementation (GAS)	Incentives (GAS)	Total Budget (GAS)
Commercial Prescriptive	$57,342	$733,558	$1,448,274	$2,239,173	$68,748	$541,210	$286,137	$896,095
Commercial Custom	$62,555	$355,263	$491,537	$909,355	$76,387	$509,731	$489,600	$1,075,718
Small Business	$5,213	$222,721	$530,824	$758,758	$3,819	$3,375	$6,216	$13,410
CVR Commercial	$31,277	$128,261	-	$159,538				
Commercial & Industrial Subtotal	**$156,387**	**$1,439,803**	**$2,470,635**	**$4,066,825**	**$148,955**	**$1,054,315**	**$781,953**	**$1,985,223**

TABLE I -7 2023 COMBINED GAS AND ELECTRIC COSTS – RESIDENTIAL

Residential	Admin. (ELECTRIC)	Implementation (ELECTRIC)	Incentives (ELECTRIC)	Total Budget (ELECTRIC)	Admin. (GAS)	Implementation (GAS)	Incentives (GAS)	Total Budget (GAS)
Residential Lighting	$105,926	$32,756	$78,689	$217,370				
Residential Prescriptive	$42,370	$364,561	$707,135	$1,114,066	$31,044	$544,073	$863,520	$1,438,637
Residential New Construction	$5,296	$50,202	$14,325	$69,824	$3,880	$491,921	$650,275	$1,146,077
Home Energy Assessment	$5,296	$267,437	-	$272,733	$3,880	$57,682	-	$61,563
Income-Qualified Weatherization	$21,185	$1,331,114	-	$1,352,299	$15,522	$1,060,825	-	$1,076,347
Energy-Efficient Schools	$21,185	$98,274	-	$119,460	$23,283	$32,758	-	$56,041
Residential Behavioral Savings	$21,185	$339,596	-	$360,781	$23,283	$113,458	-	$136,741
Appliance Recycling	$42,370	$174,745	$70,750	$287,865				
CVR Residential	$31,778	$270,252	-	$302,029				
Smart Cycle (DLC Change Out)	$21,185	$576,000	$156,000	$753,185				
BYOT (Bring Your Own Thermostat)	$21,185	$46,280	$76,280	$143,745				
Food Bank	$21,185	$9,550	-	$30,735	$15,522	$4,775	-	$20,297
Home Energy Management Systems	$10,593	$234,900	-	$245,493	$11,641	$172,100	-	$183,741
Multi-Family Direct Install					$15,522	$416,484	-	$432,005
Targeted Income					$31,044	$78,102	-	$109,146
Home Energy House Call- Integrated					$31,044	$188,283	-	$219,326
Neighborhood Program- Integrated					$31,044	$194,978	-	$226,021
Residential Subtotal	**$370,741**	**$3,795,666**	**$1,103,179**	**$5,269,586**	**$236,708**	**$3,355,439**	**$1,513,795**	**$5,105,942**

TABLE I -8 2023 COMBINED GAS AND ELECTRIC COSTS – COMMERCIAL & INDUSTRIAL

	Admin.	Implementation	Incentives	Total Budget	Admin.	Implementation	Incentives	Total Budget
Commercial & Industrial	ELECTRIC				GAS			
Commercial Prescriptive	$58,259	$769,435	$1,434,660	$2,262,354	$69,848	$598,626	$307,777	$976,251
Commercial Custom	$63,556	$360,948	$491,537	$916,040	$77,609	$517,886	$489,600	$1,085,096
Small Business	$5,296	$226,003	$521,287	$752,586	$3,880	$3,561	$6,456	$13,898
CVR Commercial	$31,778	$184,861	-	$216,639				
Commercial & Industrial Subtotal	**$158,889**	**$1,541,248**	**$2,447,483**	**$4,147,620**	**$151,338**	**$1,120,073**	**$803,833**	**$2,075,244**

TABLE I -9 2024 COMBINED GAS AND ELECTRIC COSTS – RESIDENTIAL

	Admin.	Implementation	Incentives	Total Budget	Admin.	Implementation	Incentives	Total Budget
Residential	ELECTRIC				GAS			
Residential Lighting	$107,621	$38,416	$92,287	$238,324				
Residential Prescriptive	$43,048	$370,394	$732,410	$1,145,852	$31,540	$552,778	$864,995	$1,449,314
Residential New Construction	$5,381	$48,144	$13,975	$67,500	$3,943	$558,080	$737,775	$1,299,797
Home Energy Assessment	$5,381	$271,716	-	$277,097	$3,943	$58,605	-	$62,548
Income-Qualified Weatherization	$21,524	$1,350,360	-	$1,371,884	$15,770	$1,120,207	-	$1,135,977
Energy-Efficient Schools	$21,524	$106,392	-	$127,916	$23,655	$35,464	-	$59,119
Residential Behavioral Savings	$21,524	$345,029	-	$366,554	$23,655	$115,273	-	$138,929
Appliance Recycling	$43,048	$168,946	$67,325	$279,320				
CVR Residential	$32,286	$315,241	-	$347,528				
Smart Cycle (DLC Change Out)	$21,524	$596,000	$176,000	$793,524				
BYOT (Bring Your Own Thermostat)	$21,524	$54,280	$84,280	$160,084				
Food Bank	$21,524	$9,703	-	$31,227	$15,770	$4,851	-	$20,622
Home Energy Management Systems	$10,762	$245,940	-	$256,702	$11,828	$198,260	-	$210,088
Multi-Family Direct Install					$15,770	$423,147	-	$438,918

	Admin.	Implementation	Incentives	Total Budget	Admin.	Implementation	Incentives	Total Budget
Residential	ELECTRIC				GAS			
Targeted Income					$31,540	$79,352	-	$110,892
Home Energy House Call- Integrated					$31,540	$191,295	-	$222,835
Neighborhood Program- Integrated					$31,540	$198,097	-	$229,638
Residential Subtotal	**$376,673**	**$3,920,561**	**$1,166,277**	**$5,463,511**	**$240,495**	**$3,535,411**	**$1,602,770**	**$5,378,676**

TABLE I -10 2024 COMBINED GAS AND ELECTRIC COSTS – COMMERCIAL & INDUSTRIAL

	Admin.	Implementation	Incentives	Total Budget	Admin.	Implementation	Incentives	Total Budget
Commercial & Industrial	ELECTRIC				GAS			
Commercial Prescriptive	$59,191	$791,792	$1,394,674	$2,245,657	$70,966	$611,299	$335,962	$1,018,227
Commercial Custom	$64,572	$366,723	$491,537	$922,832	$78,851	$526,173	$489,600	$1,094,624
Small Business	$5,381	$229,663	$512,537	$747,582	$3,943	$3,736	$6,666	$14,344
CVR Commercial	$32,286	$216,561	-	$248,848				
Commercial & Industrial Subtotal	**$161,431**	**$1,604,739**	**$2,398,748**	**$4,164,919**	**$153,759**	**$1,141,208**	**$832,228**	**$2,127,195**

TABLE I -11 2025 COMBINED GAS AND ELECTRIC COSTS – RESIDENTIAL

	Admin.	Implementation	Incentives	Total Budget	Admin.	Implementation	Incentives	Total Budget
Residential	ELECTRIC				GAS			
Residential Lighting	$109,343	$44,005	$105,714	$259,061				
Residential Prescriptive	$43,737	$376,320	$767,435	$1,187,492	$32,045	$561,623	$864,845	$1,458,513
Residential New Construction	$5,467	$46,909	$13,800	$66,176	$4,006	$620,174	$819,500	$1,443,680
Home Energy Assessment	$5,467	$276,063	-	$281,530	$4,006	$59,543	-	$63,549
Income-Qualified Weatherization	$21,869	$1,369,913	-	$1,391,782	$16,022	$1,156,992	-	$1,173,014
Energy-Efficient Schools	$21,869	$117,023	-	$138,891	$24,034	$39,008	-	$63,041

	ELECTRIC				GAS			
Residential	Admin.	Implementation	Incentives	Total Budget	Admin.	Implementation	Incentives	Total Budget
Residential Behavioral Savings	$21,869	$350,550	-	$372,418	$24,034	$117,118	-	$141,151
Appliance Recycling	$43,737	$155,651	$61,050	$260,438				
CVR Residential	$32,803	$282,073	-	$314,876				
Smart Cycle (DLC Change Out)	$21,869	$616,000	$196,000	$833,869				
BYOT (Bring Your Own Thermostat)	$21,869	$62,280	$92,280	$176,429				
Food Bank	$21,869	$9,858	-	$31,727	$16,023	$4,929	-	$20,952
Home Energy Management Systems	$10,934	$266,980	-	$277,914	$12,017	$214,420	-	$226,437
Multi-Family Direct Install					$16,022	$429,918	-	$445,940
Targeted Income					$32,045	$80,621	-	$112,666
Home Energy House Call- Integrated					$32,045	$194,356	-	$226,401
Neighborhood Program- Integrated					$32,045	$201,267	-	$233,312
Residential Subtotal	**$382,700**	**$3,973,626**	**$1,236,279**	**$5,592,604**	**$244,343**	**$3,679,968**	**$1,684,345**	**$5,608,656**

TABLE I -12 2025 COMBINED GAS AND ELECTRIC COSTS – COMMERCIAL & INDUSTRIAL

	ELECTRIC				GAS			
Commercial & Industrial	Admin.	Implementation	Incentives	Total Budget	Admin.	Implementation	Incentives	Total Budget
Commercial Prescriptive	$60,139	$797,128	$1,331,794	$2,189,060	$72,101	$737,459	$363,357	$1,172,917
Commercial Custom	$65,606	$372,590	$491,537	$929,733	$80,112	$534,591	$489,600	$1,104,304
Small Business	$5,467	$233,383	$503,787	$742,637	$4,006	$3,915	$6,876	$14,797
CVR Commercial	$32,803	$193,019	-	$225,821				
Commercial & Industrial Subtotal	**$164,014**	**$1,596,120**	**$2,327,118**	**$4,087,252**	**$156,219**	**$1,275,965**	**$859,833**	**$2,292,017**

APPENDIX J *Action Plan Market Research*

RESIDENTIAL SURVEY RESULTS

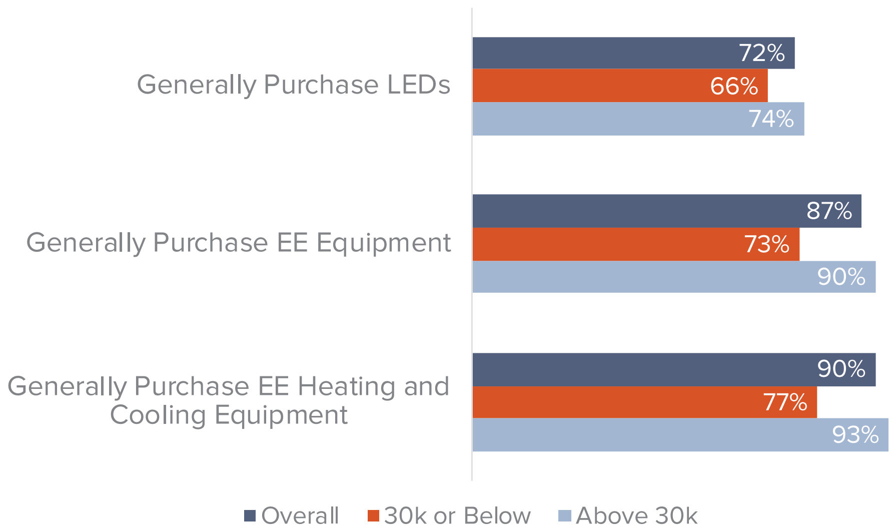
Background

The team completed an online survey of 466 residential customers in Vectren service territory. The survey was completed between June 25 and July 9, 2018. Vectren randomly sampled 4,000 residential customers and sent invitations to complete the survey by email. Customers were offered a$25 incentive upon completion of the survey.

Results

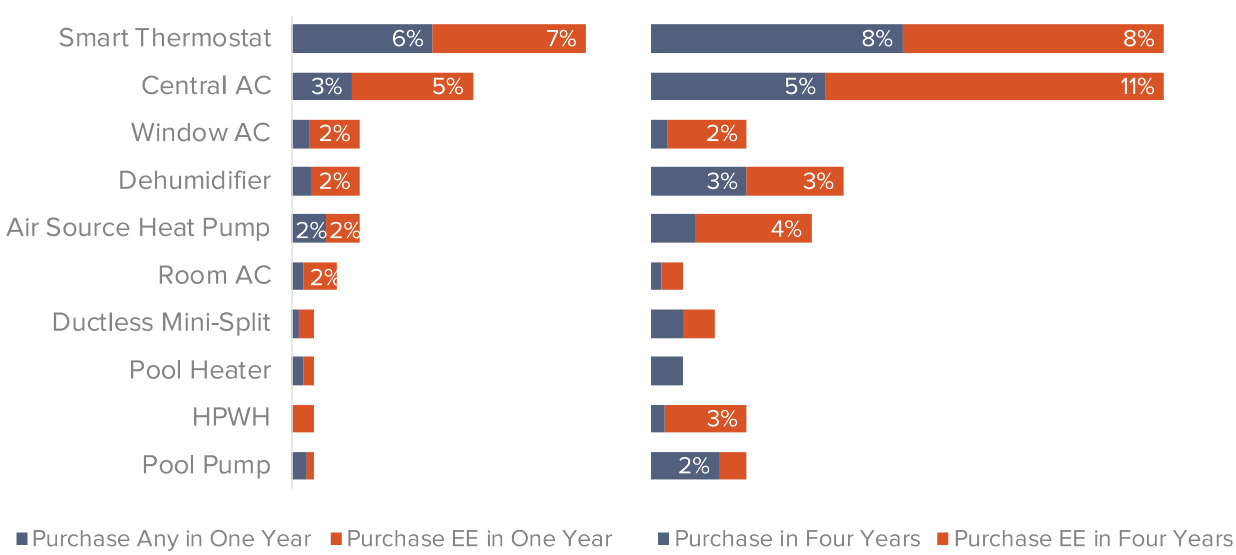
Customers generally reported purchasing energy-efficient equipment (72%, as seen below). As expected, fewer lower income customers (66%) reported purchasing energy-efficient equipment than those making higher incomes (74%).

FIGURE J-1GENERAL PURCHASING BEHAVIOR



Most electric customers did not plan on purchasing any of the equipment discussed in the survey over the next year (76%) or in the next four years (63%). Electric customers most often report planning on purchasing smart thermostats (16%) or central air conditioners (16%) in the next four years.

FIGURE J-2 PLANNED IMPROVEMENTS



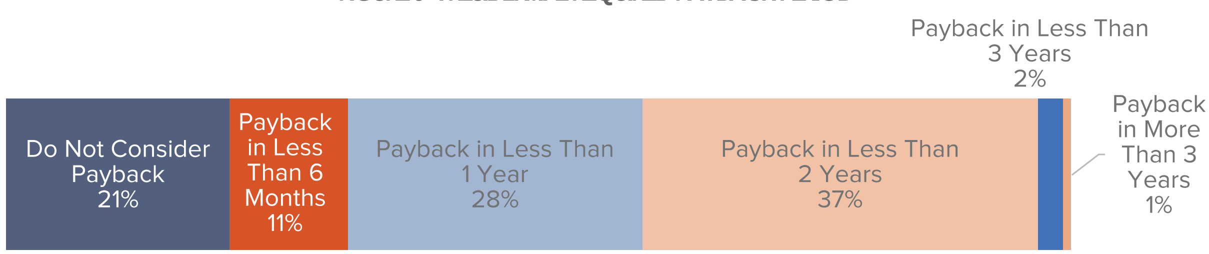
Generally customers reported a lower willingness to pay for weatherization measures and a higher willingness to pay for energy-efficient appliances, as seen in the table below.

FIGURE J-3 WILLINGNESS TO PAY AT VARYING REBATE LEVELS (PERCENT OF INCREMENTAL COST)

Sector	End-Use / Technology	25%	50%	75%	100%
Average Likelihood					
Residential	Appliances	75%	86%	91%	96%
Residential	Space Heating	76%	84%	90%	96%
Residential	Weatherization	61%	72%	82%	93%
Extreme Likelihood (% the responded "10")					
Residential	Appliances	31%	50%	61%	85%
Residential	Space Heating	27%	39%	53%	83%
Residential	Weatherization	16%	20%	29%	76%

Less than one quarter of customers do not consider the payback timeframe of their energy efficiency equipment (21%, as seen below). About three quarters require a payback of two years or less.

FIGURE J-4 RESIDENTIAL REQUIRED PAYBACK PERIOD



COMMERCIAL & INDUSTRIAL ONSITE VISIT RESULTS

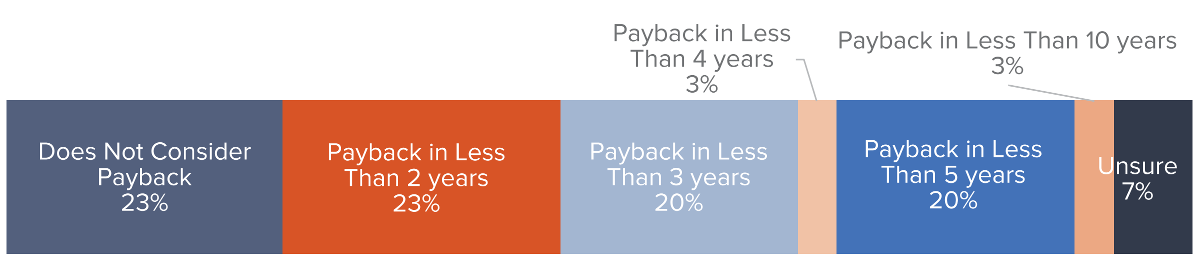
Background

The team completed an audit of 36 commercial and industrial sites in Vectren territory. During these audits, the team asked the company contact questions regarding their energy efficient product purchases and preferences.

Results

Similar to residential customers, about one-quarter of commercial and industrial customers do not consider the payback period of their energy efficiency equipment (23%, as seen below).

FIGURE J-5 COMMERCIAL & INDUSTRIAL REQUIRED PAYBACK PERIOD



Commercial and industrial customers most often reported receiving an incentive as a consideration when purchasing new energy efficient equipment (72%, as seen in the table below). Other regularly reported considerations included lowering monthly electric bills (67%) and increased employee comfort (58%).

TABLE J-6 IMPORTANT CONSIDERATIONS REGARDING ENERGY EFFICIENT EQUIPMENT

Response	Percent (n=36)
Receiving incentive	72%
Lower monthly electric bills	67%
Increased level of employee comfort	58%
Financing options	50%
Improving the image or value of business	36%
Recommendation of sales person, contractor, or consultant	28%
Helping to protect the environment	8%
Other	3%

Commercial and industrial customers most often reported that cost was a barrier to purchasing energy-efficient equipment (67%), followed by the performance of the equipment (44%).

TABLE J-7 BARRIERS TO PURCHASING ENERGY EFFICIENT EQUIPMENT

Response	Percent (n=36)
Cost	67%
Performance of the equipment	44%
Lack of product energy savings information	39%
Payback/ROI	31%
Lack of financing options	17%
Availability of equipment	11%
Other	6%

Commercial and industrial customers reported a higher willingness to purchase more expensive equipment at most levels of rebate incremental cost than residential customers, as seen in the table below.

TABLE J-8 WILLINGNESS TO PAY AT VARYING REBATE LEVELS (PERCENT OF INCREMENTAL COST)

Equipment Price	0%	25%	50%	75%
Equipment Priced Below $200	6%	3%	11%	77%
Equipment Priced Above $1,000	6%	11%	34%	97%

APPENDIX K *Action Plan Measure Library*

The following table provides a list of all the measures included in the Action Plan program concepts, broken up by year of the program.

TABLE K-1 MEASURE LIBRARY

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Residential Lighting	Standard Units	Participation	159,553	180,887	-	-	-	-
Residential Lighting	Standard Units	Total Incentive Budget	$120,861	$128,882	-	-	-	-
Residential Lighting	Standard Units	Total Gross Incremental Savings (kwh)	5,143,874	5,862,548	-	-	-	-
Residential Lighting	Standard Units	NTG	0.84	0.79	-	-	-	-
Residential Lighting	Standard Units	Incremental Cost	$3.00	$3.00				
Residential Lighting	Specialty Units	Participation	64,893	73,570	81,379	-	-	-
Residential Lighting	Specialty Units	Total Incentive Budget	$259,896	$275,336	$281,978	-	-	-
Residential Lighting	Specialty Units	Total Gross Incremental Savings (kwh)	1,945,811	2,209,028	2,446,622	-	-	-
Residential Lighting	Specialty Units	NTG	0.84	0.79	0.74	-	-	-
Residential Lighting	Specialty Units	Incremental Cost	$4.00	$4.00	$4.00			
Residential Lighting	LED Fixtures	Participation	13,700	4,935	5,169	5,351	5,489	5,593
Residential Lighting	LED Fixtures	Total Incentive Budget	$69,356	$24,983	$26,168	$27,089	$27,788	$28,315

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Residential Lighting	LED Fixtures	Total Gross Incremental Savings (kwh)	832,872	299,999	314,224	141,855	145,513	148,270
Residential Lighting	LED Fixtures	NTG	0.84	0.84	0.84	0.84	0.84	0.84
Residential Lighting	LED Fixtures	Incremental Cost	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Residential Lighting	Exterior Lighting Controls	Participation	1,720	3,440	5,160	6,880	8,600	10,320
Residential Lighting	Exterior Lighting Controls	Total Incentive Budget	$12,900	$25,800	$38,700	$51,599	$64,499	$77,399
Residential Lighting	Exterior Lighting Controls	Total Gross Incremental Savings (kwh)	166,357	332,713	499,070	665,427	831,783	998,140
Residential Lighting	Exterior Lighting Controls	NTG	0.84	0.84	0.84	0.84	0.84	0.84
Residential Lighting	Exterior Lighting Controls	Incremental Cost	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00
Residential Prescriptive	Air Source Heat Pump 16 SEER	Participation	40	47	53	59	64	68
Residential Prescriptive	Air Source Heat Pump 16 SEER	Total Incentive Budget	$12,000	$14,100	$15,900	$17,700	$19,200	$20,400
Residential Prescriptive	Air Source Heat Pump 16 SEER	Total Gross Incremental Savings (kwh)	27,760	32,618	36,782	40,946	44,416	47,192
Residential Prescriptive	Air Source Heat Pump 16 SEER	NTG	0.52	0.52	0.52	0.52	0.52	0.52
Residential Prescriptive	Air Source Heat Pump 16 SEER	Incremental Cost	$870.00	$870.00	$870.00	$870.00	$870.00	$870.00

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Residential Prescriptive	Air Source Heat Pump 18 SEER	Participation	13	16	18	20	23	25
Residential Prescriptive	Air Source Heat Pump 18 SEER	Total Incentive Budget	$7,800	$9,600	$10,800	$12,000	$13,800	$15,000
Residential Prescriptive	Air Source Heat Pump 18 SEER	Total Gross Incremental Savings (kwh)	16,822	20,704	23,292	25,880	29,762	32,350
Residential Prescriptive	Air Source Heat Pump 18 SEER	NTG	0.52	0.52	0.52	0.52	0.52	0.52
Residential Prescriptive	Air Source Heat Pump 18 SEER	Incremental Cost	$870.00	$870.00	$870.00	$870.00	$870.00	$870.00
Residential Prescriptive	Attic Insulation - Elec Heated South (Electric Only)	Participation	16	17	13	10	7	5
Residential Prescriptive	Attic Insulation - Elec Heated South (Electric Only)	Total Incentive Budget	$7,200	$7,650	$5,850	$4,500	$3,150	$2,250
Residential Prescriptive	Attic Insulation - Elec Heated South (Electric Only)	Total Gross Incremental Savings (kwh)	12,836	13,638	10,429	8,023	5,616	4,011
Residential Prescriptive	Attic Insulation - Elec Heated South (Electric Only)	NTG	0.76	0.76	0.76	0.76	0.76	0.76
Residential Prescriptive	Attic Insulation - Elec Heated South (Electric Only)	Incremental Cost	$500.00	$500.00	$500.00	$500.00	$500.00	$500.00
Residential Prescriptive	Attic Insulation - Gas Heated South (Dual -- Gas & Electric)	Participation	36	8	6	5	4	3
Residential Prescriptive	Attic Insulation - Gas Heated South (Dual -- Gas & Electric)	Total Incentive Budget	$10,800	$2,400	$1,800	$1,500	$1,200	$900

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Residential Prescriptive	Attic Insulation - Gas Heated South (Dual -- Gas & Electric)	Total Gross Incremental Savings (kwh)	8,602	1,912	1,434	1,195	956	717
Residential Prescriptive	Attic Insulation - Gas Heated South (Dual -- Gas & Electric)	NTG	0.76	0.76	0.76	0.76	0.76	0.76
Residential Prescriptive	Attic Insulation - Gas Heated South (Dual -- Gas & Electric)	Incremental Cost	$500.00	$500.00	$500.00	$500.00	$500.00	$500.00
Residential Prescriptive	Central Air Conditioner 16 SEER	Participation	708	528	632	736	834	923
Residential Prescriptive	Central Air Conditioner 16 SEER	Total Incentive Budget	$141,680	$105,600	$126,400	$147,200	$166,800	$184,600
Residential Prescriptive	Central Air Conditioner 16 SEER	Total Gross Incremental Savings (kwh)	212,326	158,255	189,427	220,598	249,971	276,647
Residential Prescriptive	Central Air Conditioner 16 SEER	NTG	0.52	0.52	0.52	0.52	0.52	0.52
Residential Prescriptive	Central Air Conditioner 16 SEER	Incremental Cost	$400.00	$400.00	$400.00	$400.00	$400.00	$400.00
Residential Prescriptive	Central Air Conditioner 18 SEER	Participation	84	62	74	86	98	108
Residential Prescriptive	Central Air Conditioner 18 SEER	Total Incentive Budget	$41,800	$31,000	$37,000	$43,000	$49,000	$54,000
Residential Prescriptive	Central Air Conditioner 18 SEER	Total Gross Incremental Savings (kwh)	57,819	42,880	51,179	59,479	67,778	74,694
Residential Prescriptive	Central Air Conditioner 18 SEER	NTG	0.52	0.52	0.52	0.52	0.52	0.52

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Residential Prescriptive	Central Air Conditioner 18 SEER	Incremental Cost	$800.00	$800.00	$800.00	$800.00	$800.00	$800.00
Residential Prescriptive	Dual Fuel Air Source Heat Pump 16 SEER	Participation	37	44	51	57	64	70
Residential Prescriptive	Dual Fuel Air Source Heat Pump 16 SEER	Total Incentive Budget	$11,100	$13,200	$15,300	$17,100	$19,200	$21,000
Residential Prescriptive	Dual Fuel Air Source Heat Pump 16 SEER	Total Gross Incremental Savings (kwh)	12,136	14,432	16,728	18,696	20,992	22,960
Residential Prescriptive	Dual Fuel Air Source Heat Pump 16 SEER	NTG	0.52	0.52	0.52	0.52	0.52	0.52
Residential Prescriptive	Dual Fuel Air Source Heat Pump 16 SEER	Incremental Cost	$1,000.00	$1,000.00	$1,000.00	$1,000.00	$1,000.00	$1,000.00
Residential Prescriptive	Duct Sealing Electric Heat Pump - South (Electric Only)	Participation	48	79	71	61	50	40
Residential Prescriptive	Duct Sealing Electric Heat Pump - South (Electric Only)	Total Incentive Budget	$14,400	$23,700	$21,300	$18,300	$15,000	$12,000
Residential Prescriptive	Duct Sealing Electric Heat Pump - South (Electric Only)	Total Gross Incremental Savings (kwh)	39,792	65,491	58,859	50,569	41,450	33,160
Residential Prescriptive	Duct Sealing Electric Heat Pump - South (Electric Only)	NTG	0.76	0.76	0.76	0.76	0.76	0.76
Residential Prescriptive	Duct Sealing Electric Heat Pump - South (Electric Only)	Incremental Cost	$400.00	$400.00	$400.00	$400.00	$400.00	$400.00

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Residential Prescriptive	Duct Sealing Electric Resistive Furnace - South (Electric Only)	Participation	38	64	57	49	40	32
Residential Prescriptive	Duct Sealing Electric Resistive Furnace - South (Electric Only)	Total Incentive Budget	$11,400	$19,200	$17,100	$14,700	$12,000	$9,600
Residential Prescriptive	Duct Sealing Electric Resistive Furnace - South (Electric Only)	Total Gross Incremental Savings (kwh)	51,642	86,976	77,463	66,591	54,360	43,488
Residential Prescriptive	Duct Sealing Electric Resistive Furnace - South (Electric Only)	NTG	0.76	0.76	0.76	0.76	0.76	0.76
Residential Prescriptive	Duct Sealing Electric Resistive Furnace - South (Electric Only)	Incremental Cost	$400.00	$400.00	$400.00	$400.00	$400.00	$400.00
Residential Prescriptive	Duct Sealing Gas Heating with A/C - South (Dual -- Gas & Electric)	Participation	232	384	346	297	245	196
Residential Prescriptive	Duct Sealing Gas Heating with A/C - South (Dual -- Gas & Electric)	Total Incentive Budget	$34,800	$57,600	$51,900	$44,550	$36,750	$29,400
Residential Prescriptive	Duct Sealing Gas Heating with A/C - South (Dual -- Gas & Electric)	Total Gross Incremental Savings (kwh)	38,365	63,500	57,216	49,113	40,514	32,411
Residential Prescriptive	Duct Sealing Gas Heating with A/C - South (Dual -- Gas & Electric)	NTG	0.76	0.76	0.76	0.76	0.76	0.76
Residential Prescriptive	Duct Sealing Gas Heating with A/C - South (Dual -- Gas & Electric)	Incremental Cost	$200.00	$200.00	$200.00	$200.00	$200.00	$200.00

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Residential Prescriptive	Ductless Heat Pump 17 SEER 9.5 HSPF	Participation	8	9	11	12	13	14
Residential Prescriptive	Ductless Heat Pump 17 SEER 9.5 HSPF	Total Incentive Budget	$4,000	$4,500	$5,500	$6,000	$6,500	$7,000
Residential Prescriptive	Ductless Heat Pump 17 SEER 9.5 HSPF	Total Gross Incremental Savings (kwh)	28,998	32,623	39,872	43,497	47,122	50,747
Residential Prescriptive	Ductless Heat Pump 17 SEER 9.5 HSPF	NTG	0.52	0.52	0.52	0.52	0.52	0.52
Residential Prescriptive	Ductless Heat Pump 17 SEER 9.5 HSPF	Incremental Cost	$1,666.67	$1,666.67	$1,666.67	$1,666.67	$1,666.67	$1,666.67
Residential Prescriptive	Ductless Heat Pump 19 SEER 9.5 HSPF	Participation	18	21	24	26	29	31
Residential Prescriptive	Ductless Heat Pump 19 SEER 9.5 HSPF	Total Incentive Budget	$9,000	$10,500	$12,000	$13,000	$14,500	$15,500
Residential Prescriptive	Ductless Heat Pump 19 SEER 9.5 HSPF	Total Gross Incremental Savings (kwh)	66,147	77,172	88,196	95,546	106,571	113,920
Residential Prescriptive	Ductless Heat Pump 19 SEER 9.5 HSPF	NTG	0.52	0.52	0.52	0.52	0.52	0.52
Residential Prescriptive	Ductless Heat Pump 19 SEER 9.5 HSPF	Incremental Cost	$2,333.33	$2,333.33	$2,333.33	$2,333.33	$2,333.33	$2,333.33
Residential Prescriptive	Ductless Heat Pump 21 SEER 10.0 HSPF	Participation	8	9	11	12	13	14
Residential Prescriptive	Ductless Heat Pump 21 SEER 10.0 HSPF	Total Incentive Budget	$6,000	$6,750	$8,250	$9,000	$9,750	$10,500
Residential Prescriptive	Ductless Heat Pump 21 SEER 10.0 HSPF	Total Gross Incremental Savings (kwh)	30,158	33,927	41,467	45,237	49,006	52,776

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Residential Prescriptive	Ductless Heat Pump 21 SEER 10.0 HSPF	NTG	0.52	0.52	0.52	0.52	0.52	0.52
Residential Prescriptive	Ductless Heat Pump 21 SEER 10.0 HSPF	Incremental Cost	$2,833.33	$2,833.33	$2,833.33	$2,833.33	$2,833.33	$2,833.33
Residential Prescriptive	Ductless Heat Pump 23 SEER 10.0 HSPF	Participation	26	30	34	38	42	45
Residential Prescriptive	Ductless Heat Pump 23 SEER 10.0 HSPF	Total Incentive Budget	$19,500	$22,500	$25,500	$28,500	$31,500	$33,750
Residential Prescriptive	Ductless Heat Pump 23 SEER 10.0 HSPF	Total Gross Incremental Savings (kwh)	94,640	109,200	123,760	138,320	152,880	163,800
Residential Prescriptive	Ductless Heat Pump 23 SEER 10.0 HSPF	NTG	0.52	0.52	0.52	0.52	0.52	0.52
Residential Prescriptive	Ductless Heat Pump 23 SEER 10.0 HSPF	Incremental Cost	$3,333.33	$3,333.33	$3,333.33	$3,333.33	$3,333.33	$3,333.33
Residential Prescriptive	Dual Fuel Air Source Heat Pump 18 SEER	Participation	12	16	21	26	32	39
Residential Prescriptive	Dual Fuel Air Source Heat Pump 18 SEER	Total Incentive Budget	$6,000	$8,000	$10,500	$13,000	$16,000	$19,500
Residential Prescriptive	Dual Fuel Air Source Heat Pump 18 SEER	Total Gross Incremental Savings (kwh)	10,680	14,240	18,690	23,140	28,480	34,710
Residential Prescriptive	Dual Fuel Air Source Heat Pump 18 SEER	NTG	0.52	0.52	0.52	0.52	0.52	0.52
Residential Prescriptive	Dual Fuel Air Source Heat Pump 18 SEER	Incremental Cost	$1,666.67	$1,666.67	$1,666.67	$1,666.67	$1,666.67	$1,666.67
Residential Prescriptive	Heat Pump Water Heater	Participation	28	36	45	56	67	78

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Residential Prescriptive	Heat Pump Water Heater	Total Incentive Budget	$11,200	$14,400	$18,000	$22,400	$26,800	$31,200
Residential Prescriptive	Heat Pump Water Heater	Total Gross Incremental Savings (kwh)	66,304	85,248	106,560	132,608	158,656	184,704
Residential Prescriptive	Heat Pump Water Heater	NTG	0.63	0.63	0.63	0.63	0.63	0.63
Residential Prescriptive	Heat Pump Water Heater	Incremental Cost	$1,000.00	$1,000.00	$1,000.00	$1,000.00	$1,000.00	$1,000.00
Residential Prescriptive	Nest On-Line Store South (Electric Only)	Participation	64	64	64	64	64	64
Residential Prescriptive	Nest On-Line Store South (Electric Only)	Total Incentive Budget	$4,800	$4,800	$4,800	$4,800	$4,800	$4,800
Residential Prescriptive	Nest On-Line Store South (Electric Only)	Total Gross Incremental Savings (kwh)	58,455	58,455	58,455	58,455	58,455	58,455
Residential Prescriptive	Nest On-Line Store South (Electric Only)	NTG	0.55	0.55	0.55	0.55	0.55	0.55
Residential Prescriptive	Nest On-Line Store South (Electric Only)	Incremental Cost	$39.16	$39.16	$39.16	$39.16	$39.16	$39.16
Residential Prescriptive	Nest On-Line Store South (Dual -- Electric)	Participation	176	176	176	176	176	176
Residential Prescriptive	Nest On-Line Store South (Dual -- Electric)	Total Incentive Budget	$10,560	$10,560	$10,560	$10,560	$10,560	$10,560
Residential Prescriptive	Nest On-Line Store South (Dual -- Electric)	Total Gross Incremental Savings (kwh)	51,470	51,470	51,470	51,470	51,470	51,470
Residential Prescriptive	Nest On-Line Store South (Dual -- Electric)	NTG	0.55	0.55	0.55	0.55	0.55	0.55

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Residential Prescriptive	Nest On-Line Store South (Dual -- Electric)	Incremental Cost	$175.00	$175.00	$175.00	$175.00	$175.00	$175.00
Residential Prescriptive	Wifi Thermostat - South (Electric)	Participation	720	720	720	720	720	720
Residential Prescriptive	Wifi Thermostat - South (Electric)	Total Incentive Budget	$36,000	$36,000	$36,000	$36,000	$36,000	$36,000
Residential Prescriptive	Wifi Thermostat - South (Electric)	Total Gross Incremental Savings (kwh)	291,665	291,665	291,665	291,665	291,665	291,665
Residential Prescriptive	Wifi Thermostat - South (Electric)	NTG	0.73	0.73	0.73	0.73	0.73	0.73
Residential Prescriptive	Wifi Thermostat - South (Electric)	Incremental Cost	$20.64	$20.64	$20.64	$20.64	$20.64	$20.64
Residential Prescriptive	Smart Programmable Thermostat - South (Electric)	Participation	1,478	1,478	1,478	1,478	1,478	1,478
Residential Prescriptive	Smart Programmable Thermostat - South (Electric)	Total Incentive Budget	$110,850	$110,850	$110,850	$110,850	$110,850	$110,850
Residential Prescriptive	Smart Programmable Thermostat - South (Electric)	Total Gross Incremental Savings (kwh)	729,085	729,085	729,085	729,085	729,085	729,085
Residential Prescriptive	Smart Programmable Thermostat - South (Electric)	NTG	0.55	0.55	0.55	0.55	0.55	0.55
Residential Prescriptive	Smart Programmable Thermostat - South (Electric)	Incremental Cost	$39.16	$39.16	$39.16	$39.16	$39.16	$39.16

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Residential Prescriptive	Variable Speed Pool Pump	Participation	18	28	36	45	56	67
Residential Prescriptive	Variable Speed Pool Pump	Total Incentive Budget	$5,400	$8,400	$10,800	$13,500	$16,800	$20,100
Residential Prescriptive	Variable Speed Pool Pump	Total Gross Incremental Savings (kwh)	21,106	32,832	42,213	52,766	65,664	78,562
Residential Prescriptive	Variable Speed Pool Pump	NTG	0.63	0.63	0.63	0.63	0.63	0.63
Residential Prescriptive	Variable Speed Pool Pump	Incremental Cost	$750.00	$750.00	$750.00	$750.00	$750.00	$750.00
Residential Prescriptive	Wall Insulation - Elec Heated	Participation	5	5	5	5	5	5
Residential Prescriptive	Wall Insulation - Elec Heated	Total Incentive Budget	$2,250	$2,250	$2,250	$2,250	$2,250	$2,250
Residential Prescriptive	Wall Insulation - Elec Heated	Total Gross Incremental Savings (kwh)	4,447	4,447	4,447	4,447	4,447	4,447
Residential Prescriptive	Wall Insulation - Elec Heated	NTG	0.76	0.76	0.76	0.76	0.76	0.76
Residential Prescriptive	Wall Insulation - Elec Heated	Incremental Cost	$500.00	$500.00	$500.00	$500.00	$500.00	$500.00
Residential Prescriptive	Wall Insulation - Gas Heated - South (Electric)	Participation	32	32	32	32	32	32
Residential Prescriptive	Wall Insulation - Gas Heated - South (Electric)	Total Incentive Budget	$7,200	$7,200	$7,200	$7,200	$7,200	$7,200
Residential Prescriptive	Wall Insulation - Gas Heated - South (Electric)	Total Gross Incremental Savings (kwh)	1,876	1,876	1,876	1,876	1,876	1,876

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Residential Prescriptive	Wall Insulation - Gas Heated - South (Electric)	NTG	0.76	0.76	0.76	0.76	0.76	0.76
Residential Prescriptive	Wall Insulation - Gas Heated - South (Electric)	Incremental Cost	$500.00	$500.00	$500.00	$500.00	$500.00	$500.00
Residential Prescriptive	AC Tune Up	Participation	3,344	3,511	3,326	2,994	2,573	2,639
Residential Prescriptive	AC Tune Up	Total Incentive Budget	$83,600	$87,775	$83,150	$74,850	$64,325	$65,975
Residential Prescriptive	AC Tune Up	Total Gross Incremental Savings (kwh)	371,184	389,721	369,186	332,334	285,603	292,929
Residential Prescriptive	AC Tune Up	NTG	-	-	-	-	-	-
Residential Prescriptive	AC Tune Up	Incremental Cost	$64.00	$64.00	$64.00	$64.00	$64.00	$64.00
Residential Prescriptive	ASHP Tune Up	Participation	26	71	67	60	52	53
Residential Prescriptive	ASHP Tune Up	Total Incentive Budget	$1,300	$3,550	$3,350	$3,000	$2,600	$2,650
Residential Prescriptive	ASHP Tune Up	Total Gross Incremental Savings (kwh)	8,195	22,379	21,119	18,912	16,391	16,706
Residential Prescriptive	ASHP Tune Up	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Residential Prescriptive	ASHP Tune Up	Incremental Cost	$64.00	$64.00	$64.00	$64.00	$64.00	$64.00
Residential Prescriptive	Air Purifier	Participation	100	160	181	200	217	231

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Residential Prescriptive	Air Purifier	Total Incentive Budget	$2,500	$4,000	$4,525	$5,000	$5,425	$5,775
Residential Prescriptive	Air Purifier	Total Gross Incremental Savings (kwh)	48,800	78,080	88,328	97,600	105,896	112,728
Residential Prescriptive	Air Purifier	NTG	0.52	0.52	0.52	0.52	0.52	0.52
Residential Prescriptive	Air Purifier	Incremental Cost	$70.00	$70.00	$70.00	$70.00	$70.00	$70.00
Residential Prescriptive	ENERGY STAR Dehumidifier	Participation	368	368	368	368	368	368
Residential Prescriptive	ENERGY STAR Dehumidifier	Total Incentive Budget	$9,200	$9,200	$9,200	$9,200	$9,200	$9,200
Residential Prescriptive	ENERGY STAR Dehumidifier	Total Gross Incremental Savings (kwh)	70,766	70,766	70,766	70,766	70,766	70,766
Residential Prescriptive	ENERGY STAR Dehumidifier	NTG	0.52	0.52	0.52	0.52	0.52	0.52
Residential Prescriptive	ENERGY STAR Dehumidifier	Incremental Cost	$70.00	$70.00	$70.00	$70.00	$70.00	$70.00
Residential Prescriptive	ENERGY STAR Clothes Washer	Participation	56	56	70	76	81	84
Residential Prescriptive	ENERGY STAR Clothes Washer	Total Incentive Budget	$1,400	$1,400	$1,750	$1,900	$2,025	$2,100
Residential Prescriptive	ENERGY STAR Clothes Washer	Total Gross Incremental Savings (kwh)	6,272	6,272	7,840	8,512	9,072	9,408
Residential Prescriptive	ENERGY STAR Clothes Washer	NTG	0.68	0.68	0.68	0.68	0.68	0.68

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Residential Prescriptive	ENERGY STAR Clothes Washer	Incremental Cost	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00
Residential Prescriptive	Smart/CEE Tier3 Clothes Washer	Participation	78	78	141	184	238	299
Residential Prescriptive	Smart/CEE Tier3 Clothes Washer	Total Incentive Budget	$3,900	$3,900	$7,050	$9,200	$11,900	$14,950
Residential Prescriptive	Smart/CEE Tier3 Clothes Washer	Total Gross Incremental Savings (kwh)	16,302	16,302	29,469	38,456	49,742	62,491
Residential Prescriptive	Smart/CEE Tier3 Clothes Washer	NTG	0.68	0.68	0.68	0.68	0.68	0.68
Residential Prescriptive	Smart/CEE Tier3 Clothes Washer	Incremental Cost	$300.00	$300.00	$300.00	$300.00	$300.00	$300.00
Residential Prescriptive	ENERGY STAR Room Air Conditioner	Participation	121	121	121	121	121	121
Residential Prescriptive	ENERGY STAR Room Air Conditioner	Total Incentive Budget	$3,025	$3,025	$3,025	$3,025	$3,025	$3,025
Residential Prescriptive	ENERGY STAR Room Air Conditioner	Total Gross Incremental Savings (kwh)	4,979	4,979	4,979	4,979	4,979	4,979
Residential Prescriptive	ENERGY STAR Room Air Conditioner	NTG	0.80	0.80	0.80	0.80	0.80	0.80
Residential Prescriptive	ENERGY STAR Room Air Conditioner	Incremental Cost	$40.00	$40.00	$40.00	$40.00	$40.00	$40.00
Residential Prescriptive	Clothes Dryer	Participation	28	38	51	67	86	108
Residential Prescriptive	Clothes Dryer	Total Incentive Budget	$1,400	$1,900	$2,550	$3,350	$4,300	$5,400

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Residential Prescriptive	Clothes Dryer	Total Gross Incremental Savings (kwh)	5,519	7,483	10,031	13,159	16,860	21,125
Residential Prescriptive	Clothes Dryer	NTG	0.68	0.68	0.68	0.68	0.68	0.68
Residential Prescriptive	Clothes Dryer	Incremental Cost	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00
Residential New Construction	Gold Star HERS Index Score 63	Participation	17	15	13	11	9	8
Residential New Construction	Gold Star HERS Index Score 63	Total Incentive Budget	$2,975	$2,625	$2,275	$1,925	$1,575	$1,400
Residential New Construction	Gold Star HERS Index Score 63	Total Gross Incremental Savings (kwh)	34,340	30,300	26,260	22,220	18,180	16,160
Residential New Construction	Gold Star HERS Index Score 63	NTG	0.50	0.50	0.50	0.50	0.50	0.50
Residential New Construction	Gold Star HERS Index Score 63	Incremental Cost	$2,038.73	$2,038.73	$2,038.73	$2,038.73	$2,038.73	$2,038.73
Residential New Construction	Platinum Star HERS Index Score 60	Participation	69	62	62	62	62	62
Residential New Construction	Platinum Star HERS Index Score 60	Total Incentive Budget	$13,800	$12,400	$12,400	$12,400	$12,400	$12,400
Residential New Construction	Platinum Star HERS Index Score 60	Total Gross Incremental Savings (kwh)	154,284	138,632	138,632	138,632	138,632	138,632
Residential New Construction	Platinum Star HERS Index Score 60	NTG	0.50	0.50	0.50	0.50	0.50	0.50
Residential New Construction	Platinum Star HERS Index Score 60	Incremental Cost	$2,428.73	$2,428.73	$2,428.73	$2,428.73	$2,428.73	$2,428.73

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Income Qualified Weatherization	Attic Insulation - Electric Resistance Heated	Participation	13	14	15	16	17	18
Income Qualified Weatherization	Attic Insulation - Electric Resistance Heated	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Attic Insulation - Electric Resistance Heated	Total Gross Incremental Savings (kwh)	10,764	11,592	12,420	13,248	14,076	14,904
Income Qualified Weatherization	Attic Insulation - Electric Resistance Heated	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Attic Insulation - Electric Resistance Heated	Incremental Cost	$1,412.60	$1,412.60	$1,412.60	$1,412.60	$1,412.60	$1,412.60
Income Qualified Weatherization	Attic Insulation - Gas Heated (Electric)	Participation	131	138	145	153	161	170
Income Qualified Weatherization	Attic Insulation - Gas Heated (Electric)	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Attic Insulation - Gas Heated (Electric)	Total Gross Incremental Savings (kwh)	18,209	19,182	20,155	21,267	22,379	23,630
Income Qualified Weatherization	Attic Insulation - Gas Heated (Electric)	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Attic Insulation - Gas Heated (Electric)	Incremental Cost	$706.30	$706.30	$706.30	$706.30	$706.30	$706.30
Income Qualified Weatherization	Audit Recommendations - Dual (Electric)	Participation	340	357	374	392	411	431
Income Qualified Weatherization	Audit Recommendations - Dual (Electric)	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Audit Recommendations - Dual (Electric)	Total Gross Incremental Savings (kwh)	23,120	24,276	25,432	26,656	27,948	29,308

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Income Qualified Weatherization	Audit Recommendations - Dual (Electric)	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Audit Recommendations - Dual (Electric)	Incremental Cost	$26.00	$26.00	$26.00	$26.00	$26.00	$26.00
Income Qualified Weatherization	Bathroom Aerator 1.0 gpm - Elec DHW	Participation	112	118	124	131	138	145
Income Qualified Weatherization	Bathroom Aerator 1.0 gpm - Elec DHW	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Bathroom Aerator 1.0 gpm - Elec DHW	Total Gross Incremental Savings (kwh)	1,344	1,416	1,488	1,572	1,656	1,740
Income Qualified Weatherization	Bathroom Aerator 1.0 gpm - Elec DHW	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Bathroom Aerator 1.0 gpm - Elec DHW	Incremental Cost	$0.52	$0.52	$0.52	$0.52	$0.52	$0.52
Income Qualified Weatherization	9W LED	Participation	4,021	4,223	4,435	4,657	4,890	5,135
Income Qualified Weatherization	9W LED	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	9W LED	Total Gross Incremental Savings (kwh)	128,672	135,136	141,920	149,024	156,480	164,320
Income Qualified Weatherization	9W LED	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	9W LED	Incremental Cost	$3.21	$3.21	$3.21	$3.21	$3.21	$3.21
Income Qualified Weatherization	LED 5W Globe	Participation	274	288	303	319	335	352

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Income Qualified Weatherization	LED 5W Globe	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	LED 5W Globe	Total Gross Incremental Savings (kwh)	2,740	2,880	3,030	3,190	3,350	3,520
Income Qualified Weatherization	LED 5W Globe	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	LED 5W Globe	Incremental Cost	$8.75	$8.75	$8.75	$8.75	$8.75	$8.75
Income Qualified Weatherization	LED R30 Dimmable	Participation	803	844	887	932	979	1,028
Income Qualified Weatherization	LED R30 Dimmable	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	LED R30 Dimmable	Total Gross Incremental Savings (kwh)	42,559	44,732	47,011	49,396	51,887	54,484
Income Qualified Weatherization	LED R30 Dimmable	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	LED R30 Dimmable	Incremental Cost	$11.54	$11.54	$11.54	$11.54	$11.54	$11.54
Income Qualified Weatherization	Exterior LED Lamps	Participation	157	165	174	183	193	203
Income Qualified Weatherization	Exterior LED Lamps	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Exterior LED Lamps	Total Gross Incremental Savings (kwh)	14,444	15,180	16,008	16,836	17,756	18,676
Income Qualified Weatherization	Exterior LED Lamps	NTG	1.00	1.00	1.00	1.00	1.00	1.00

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Income Qualified Weatherization	Exterior LED Lamps	Incremental Cost	$7.20	$7.20	$7.20	$7.20	$7.20	$7.20
Income Qualified Weatherization	Filter Whistle	Participation	105	111	117	123	130	137
Income Qualified Weatherization	Filter Whistle	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Filter Whistle	Total Gross Incremental Savings (kwh)	5,775	6,105	6,435	6,765	7,150	7,535
Income Qualified Weatherization	Filter Whistle	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Filter Whistle	Incremental Cost	$1.64	$1.64	$1.64	$1.64	$1.64	$1.64
Income Qualified Weatherization	Kitchen Flip Aerator 1.5 gpm - Elec DHW	Participation	38	40	42	45	48	51
Income Qualified Weatherization	Kitchen Flip Aerator 1.5 gpm - Elec DHW	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Kitchen Flip Aerator 1.5 gpm - Elec DHW	Total Gross Incremental Savings (kwh)	4,560	4,800	5,040	5,400	5,760	6,120
Income Qualified Weatherization	Kitchen Flip Aerator 1.5 gpm - Elec DHW	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Kitchen Flip Aerator 1.5 gpm - Elec DHW	Incremental Cost	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34
Income Qualified Weatherization	LED Nightlight	Participation	490	515	541	569	598	628
Income Qualified Weatherization	LED Nightlight	Total Incentive Budget	-	-	-	-	-	-

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Income Qualified Weatherization	LED Nightlight	Total Gross Incremental Savings (kwh)	6,860	7,210	7,574	7,966	8,372	8,792
Income Qualified Weatherization	LED Nightlight	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	LED Nightlight	Incremental Cost	$2.75	$2.75	$2.75	$2.75	$2.75	$2.75
Income Qualified Weatherization	Low Flow Showerhead 1.5 gpm - Elec DHW	Participation	89	94	99	104	110	116
Income Qualified Weatherization	Low Flow Showerhead 1.5 gpm - Elec DHW	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Low Flow Showerhead 1.5 gpm - Elec DHW	Total Gross Incremental Savings (kwh)	26,700	28,200	29,700	31,200	33,000	34,800
Income Qualified Weatherization	Low Flow Showerhead 1.5 gpm - Elec DHW	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Low Flow Showerhead 1.5 gpm - Elec DHW	Incremental Cost	$3.32	$3.32	$3.32	$3.32	$3.32	$3.32
Income Qualified Weatherization	Pipe Wrap - Elec DHW (per home)	Participation	23	25	27	29	31	33
Income Qualified Weatherization	Pipe Wrap - Elec DHW (per home)	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Pipe Wrap - Elec DHW (per home)	Total Gross Incremental Savings (kwh)	3,404	3,700	3,996	4,292	4,588	4,884
Income Qualified Weatherization	Pipe Wrap - Elec DHW (per home)	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Pipe Wrap - Elec DHW (per home)	Incremental Cost	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Income Qualified Weatherization	Refrigerator Replacement	Participation	35	37	39	41	44	47
Income Qualified Weatherization	Refrigerator Replacement	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Refrigerator Replacement	Total Gross Incremental Savings (kwh)	15,470	16,354	17,238	18,122	19,448	20,774
Income Qualified Weatherization	Refrigerator Replacement	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Refrigerator Replacement	Incremental Cost	$580.00	$580.00	$580.00	$580.00	$580.00	$580.00
Income Qualified Weatherization	Smart Thermostat (Electric)	Participation	26	28	30	32	34	36
Income Qualified Weatherization	Smart Thermostat (Electric)	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Smart Thermostat (Electric)	Total Gross Incremental Savings (kwh)	9,620	10,360	11,100	11,840	12,580	13,320
Income Qualified Weatherization	Smart Thermostat (Electric)	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Smart Thermostat (Electric)	Incremental Cost	$77.00	$77.00	$77.00	$77.00	$77.00	$77.00
Income Qualified Weatherization	Water Heater Temperature Setback - Elec DHW	Participation	75	79	83	88	93	98
Income Qualified Weatherization	Water Heater Temperature Setback - Elec DHW	Total Incentive Budget	-	-	-	-	-	-

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Income Qualified Weatherization	Water Heater Temperature Setback - Elec DHW	Total Gross Incremental Savings (kwh)	6,450	6,794	7,138	7,568	7,998	8,428
Income Qualified Weatherization	Water Heater Temperature Setback - Elec DHW	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Water Heater Temperature Setback - Elec DHW	Incremental Cost	$6.50	$6.50	$6.50	$6.50	$6.50	$6.50
Income Qualified Weatherization	Duct Sealing Gas Heating with A/C	Participation	316	332	349	367	386	406
Income Qualified Weatherization	Duct Sealing Gas Heating with A/C	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Duct Sealing Gas Heating with A/C	Total Gross Incremental Savings (kwh)	72,364	76,028	79,921	84,043	88,394	92,974
Income Qualified Weatherization	Duct Sealing Gas Heating with A/C	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Duct Sealing Gas Heating with A/C	Incremental Cost	$225.00	$225.00	$225.00	$225.00	$225.00	$225.00
Income Qualified Weatherization	Duct Sealing Electric Heat Pump	Participation	37	39	41	44	47	50
Income Qualified Weatherization	Duct Sealing Electric Heat Pump	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Duct Sealing Electric Heat Pump	Total Gross Incremental Savings (kwh)	30,673	32,331	33,989	36,476	38,963	41,450
Income Qualified Weatherization	Duct Sealing Electric Heat Pump	NTG	1.00	1.00	1.00	1.00	1.00	1.00

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Income Qualified Weatherization	Duct Sealing Electric Heat Pump	Incremental Cost	$450.00	$450.00	$450.00	$450.00	$450.00	$450.00
Income Qualified Weatherization	Duct Sealing Electric Resistive Furnace	Participation	45	48	51	54	57	60
Income Qualified Weatherization	Duct Sealing Electric Resistive Furnace	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Duct Sealing Electric Resistive Furnace	Total Gross Incremental Savings (kwh)	60,840	64,896	68,952	73,008	77,064	81,120
Income Qualified Weatherization	Duct Sealing Electric Resistive Furnace	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Duct Sealing Electric Resistive Furnace	Incremental Cost	$450.00	$450.00	$450.00	$450.00	$450.00	$450.00
Income Qualified Weatherization	Air Sealing Gas Furnace w/ CAC	Participation	465	489	514	540	567	596
Income Qualified Weatherization	Air Sealing Gas Furnace w/ CAC	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Air Sealing Gas Furnace w/ CAC	Total Gross Incremental Savings (kwh)	65,100	68,460	71,960	75,600	79,380	83,440
Income Qualified Weatherization	Air Sealing Gas Furnace w/ CAC	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Air Sealing Gas Furnace w/ CAC	Incremental Cost	$100.00	$100.00	$100.00	$100.00	$100.00	$100.00
Income Qualified Weatherization	Air Sealing Heat Pump	Participation	48	51	54	57	60	63
Income Qualified Weatherization	Air Sealing Heat Pump	Total Incentive Budget	-	-	-	-	-	-

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Income Qualified Weatherization	Air Sealing Heat Pump	Total Gross Incremental Savings (kwh)	72,048	76,551	81,054	85,557	90,060	94,563
Income Qualified Weatherization	Air Sealing Heat Pump	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Air Sealing Heat Pump	Incremental Cost	$200.00	$200.00	$200.00	$200.00	$200.00	$200.00
Income Qualified Weatherization	Air Sealing Electric Furnace w/ CAC	Participation	32	34	36	38	40	42
Income Qualified Weatherization	Air Sealing Electric Furnace w/ CAC	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Air Sealing Electric Furnace w/ CAC	Total Gross Incremental Savings (kwh)	150,016	159,392	168,768	178,144	187,520	196,896
Income Qualified Weatherization	Air Sealing Electric Furnace w/ CAC	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Air Sealing Electric Furnace w/ CAC	Incremental Cost	-	-	-	-	-	-
Income Qualified Weatherization	Air Source Heat Pump 16 SEER	Participation	2	3	4	5	6	7
Income Qualified Weatherization	Air Source Heat Pump 16 SEER	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Air Source Heat Pump 16 SEER	Total Gross Incremental Savings (kwh)	1,582	2,373	3,164	3,955	4,746	5,537
Income Qualified Weatherization	Air Source Heat Pump 16 SEER	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Air Source Heat Pump 16 SEER	Incremental Cost	$5,400.00	$5,400.00	$5,400.00	$5,400.00	$5,400.00	$5,400.00

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Income Qualified Weatherization	Central Air Conditioner 16 SEER	Participation	19	20	21	23	25	27
Income Qualified Weatherization	Central Air Conditioner 16 SEER	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Central Air Conditioner 16 SEER	Total Gross Incremental Savings (kwh)	5,700	6,000	6,300	6,900	7,500	8,100
Income Qualified Weatherization	Central Air Conditioner 16 SEER	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Central Air Conditioner 16 SEER	Incremental Cost	$3,500.00	$3,500.00	$3,500.00	$3,500.00	$3,500.00	$3,500.00
Income Qualified Weatherization	Wall Insulation - Dual (gas heated)	Participation	19	21	23	25	27	29
Income Qualified Weatherization	Wall Insulation - Dual (gas heated)	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Wall Insulation - Dual (gas heated)	Total Gross Incremental Savings (kwh)	1,141	1,239	1,357	1,475	1,593	1,711
Income Qualified Weatherization	Wall Insulation - Dual (gas heated)	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Wall Insulation - Dual (gas heated)	Incremental Cost	$877.00	$877.00	$877.00	$877.00	$877.00	$877.00
Income Qualified Weatherization	Water Heater Temperature Setback - Gas DHW	Participation	55	58	61	65	69	73
Income Qualified Weatherization	Water Heater Temperature Setback - Gas DHW	Total Incentive Budget	-	-	-	-	-	-

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Income Qualified Weatherization	Water Heater Temperature Setback - Gas DHW	Total Gross Incremental Savings (kwh)	(1,870)	(1,972)	(2,074)	(2,210)	(2,346)	(2,482)
Income Qualified Weatherization	Water Heater Temperature Setback - Gas DHW	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Water Heater Temperature Setback - Gas DHW	Incremental Cost	-	-	-	-	-	-
Income Qualified Weatherization	Mobile Home Audit (Dual)	Participation	173	181	190	199	208	218
Income Qualified Weatherization	Mobile Home Audit (Dual)	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Mobile Home Audit (Dual)	Total Gross Incremental Savings (kwh)	-	-	-	-	-	-
Income Qualified Weatherization	Mobile Home Audit (Dual)	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Income Qualified Weatherization	Mobile Home Audit (Dual)	Incremental Cost	$26.00	$26.00	$26.00	$26.00	$26.00	$26.00
Income Qualified Weatherization	Mobile Home Audit (Electric)	Participation	26	28	30	32	34	36
Income Qualified Weatherization	Mobile Home Audit (Electric)	Total Incentive Budget	-	-	-	-	-	-
Income Qualified Weatherization	Mobile Home Audit (Electric)	Total Gross Incremental Savings (kwh)	-	-	-	-	-	-
Income Qualified Weatherization	Mobile Home Audit (Electric)	NTG	1.00	1.00	1.00	1.00	1.00	1.00

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Income Qualified Weatherization	Mobile Home Audit (Electric)	Incremental Cost	$106.00	$106.00	$106.00	$106.00	$106.00	$106.00
Energy Efficient Schools	15W LED	Participation	2,600	2,600	-	-	-	-
Energy Efficient Schools	15W LED	Total Incentive Budget	-	-	-	-	-	-
Energy Efficient Schools	15W LED	Total Gross Incremental Savings (kwh)	124,800	124,800	-	-	-	-
Energy Efficient Schools	15W LED	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Energy Efficient Schools	15W LED	Incremental Cost	-	-	-	-	-	-
Energy Efficient Schools	11W LED	Participation	5,200	5,200	-	-	-	-
Energy Efficient Schools	11W LED	Total Incentive Budget	-	-	-	-	-	-
Energy Efficient Schools	11W LED	Total Gross Incremental Savings (kwh)	353,600	353,600	-	-	-	-
Energy Efficient Schools	11W LED	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Energy Efficient Schools	11W LED	Incremental Cost	-	-	-	-	-	-
Energy Efficient Schools	Showerheads	Participation	2,600	2,600	2,600	2,600	2,600	2,600
Energy Efficient Schools	Showerheads	Total Incentive Budget	-	-	-	-	-	-

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Energy Efficient Schools	Showerheads	Total Gross Incremental Savings (kwh)	340,600	340,600	340,600	340,600	340,600	340,600
Energy Efficient Schools	Showerheads	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Energy Efficient Schools	Showerheads	Incremental Cost	-	-	-	-	-	-
Energy Efficient Schools	Kitchen Aerators	Participation	2,600	2,600	2,600	2,600	2,600	2,600
Energy Efficient Schools	Kitchen Aerators	Total Incentive Budget	-	-	-	-	-	-
Energy Efficient Schools	Kitchen Aerators	Total Gross Incremental Savings (kwh)	145,600	145,600	145,600	145,600	145,600	145,600
Energy Efficient Schools	Kitchen Aerators	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Energy Efficient Schools	Kitchen Aerators	Incremental Cost	-	-	-	-	-	-
Energy Efficient Schools	Bathroom Aerators	Participation	5,200	5,200	5,200	5,200	5,200	5,200
Energy Efficient Schools	Bathroom Aerators	Total Incentive Budget	-	-	-	-	-	-
Energy Efficient Schools	Bathroom Aerators	Total Gross Incremental Savings (kwh)	114,400	114,400	114,400	114,400	114,400	114,400
Energy Efficient Schools	Bathroom Aerators	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Energy Efficient Schools	Bathroom Aerators	Incremental Cost	-	-	-	-	-	-

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Energy Efficient Schools	Filter Whistle	Participation	2,600	2,600	2,600	2,600	2,600	2,600
Energy Efficient Schools	Filter Whistle	Total Incentive Budget	-	-	-	-	-	-
Energy Efficient Schools	Filter Whistle	Total Gross Incremental Savings (kwh)	52,000	52,000	52,000	52,000	52,000	52,000
Energy Efficient Schools	Filter Whistle	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Energy Efficient Schools	Filter Whistle	Incremental Cost	-	-	-	-	-	-
Energy Efficient Schools	LED Night Light	Participation	2,600	2,600	2,600	2,600	2,600	2,600
Energy Efficient Schools	LED Night Light	Total Incentive Budget	-	-	-	-	-	-
Energy Efficient Schools	LED Night Light	Total Gross Incremental Savings (kwh)	18,200	18,200	18,200	18,200	18,200	18,200
Energy Efficient Schools	LED Night Light	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Energy Efficient Schools	LED Night Light	Incremental Cost	-	-	-	-	-	-
Residential Behavior Savings	Residential Behavior	Participation	35,298	35,298	35,298	35,298	35,298	35,298
Residential Behavior Savings	Residential Behavior	Total Incentive Budget	-	-	-	-	-	-
Residential Behavior Savings	Residential Behavior	Total Gross Incremental Savings (kwh)	5,600,000	5,600,000	5,600,000	5,600,000	5,600,000	5,600,000

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Residential Behavior Savings	Residential Behavior	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Residential Behavior Savings	Residential Behavior	Incremental Cost	-	-	-	-	-	-
Residential Behavior Savings	Low Income Refill Electric	Participation	13,702	13,702	13,702	13,702	13,702	13,702
Residential Behavior Savings	Low Income Refill Electric	Total Incentive Budget	-	-	-	-	-	-
Residential Behavior Savings	Low Income Refill Electric	Total Gross Incremental Savings (kwh)	1,449,208	1,449,208	1,449,208	1,449,208	1,449,208	1,449,208
Residential Behavior Savings	Low Income Refill Electric	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Residential Behavior Savings	Low Income Refill Electric	Incremental Cost	-	-	-	-	-	-
Appliance Recycling	Refrigerator Recycling	Participation	1,028	1,142	1,206	1,206	1,142	1,028
Appliance Recycling	Refrigerator Recycling	Total Incentive Budget	$51,400	$57,100	$60,300	$60,300	$57,100	$51,400
Appliance Recycling	Refrigerator Recycling	Total Gross Incremental Savings (kwh)	1,013,608	1,126,012	1,189,116	1,189,116	1,126,012	1,013,608
Appliance Recycling	Refrigerator Recycling	NTG	0.71	0.71	0.71	0.71	0.71	0.71
Appliance Recycling	Refrigerator Recycling	Incremental Cost	-	-	-	-	-	-
Appliance Recycling	Freezer Recycling	Participation	161	179	189	189	179	161

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Appliance Recycling	Freezer Recycling	Total Incentive Budget	$8,050	$8,950	$9,450	$9,450	$8,950	$8,050
Appliance Recycling	Freezer Recycling	Total Gross Incremental Savings (kwh)	132,020	146,780	154,980	154,980	146,780	132,020
Appliance Recycling	Freezer Recycling	NTG	0.71	0.71	0.71	0.71	0.71	0.71
Appliance Recycling	Freezer Recycling	Incremental Cost	-	-	-	-	-	-
Appliance Recycling	Room Air Conditioner Recycling	Participation	62	23	30	40	51	64
Appliance Recycling	Room Air Conditioner Recycling	Total Incentive Budget	$1,550	$575	$750	$1,000	$1,275	$1,600
Appliance Recycling	Room Air Conditioner Recycling	Total Gross Incremental Savings (kwh)	34,183	12,681	16,540	22,053	28,118	35,285
Appliance Recycling	Room Air Conditioner Recycling	NTG	0.57	0.57	0.57	0.57	0.57	0.57
Appliance Recycling	Room Air Conditioner Recycling	Incremental Cost	-	-	-	-	-	-
Home Energy Assessment	Audit Education - All sites	Participation	300	350	420	504	504	504
Home Energy Assessment	Audit Education - All sites	Total Incentive Budget	-	-	-	-	-	-
Home Energy Assessment	Audit Education - All sites	Total Gross Incremental Savings (kwh)	18,364	21,424	25,709	30,851	30,851	30,851
Home Energy Assessment	Audit Education - All sites	NTG	1.00	1.00	1.00	1.00	1.00	1.00

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Home Energy Assessment	Audit Education - All sites	Incremental Cost	-	-	-	-	-	-
Home Energy Assessment	LED 5W Globe	Participation	600	700	840	1,008	1,008	806
Home Energy Assessment	LED 5W Globe	Total Incentive Budget	-	-	-	-	-	-
Home Energy Assessment	LED 5W Globe	Total Gross Incremental Savings (kwh)	6,221	7,258	8,710	10,452	10,452	8,361
Home Energy Assessment	LED 5W Globe	NTG	0.96	0.96	0.96	0.96	0.96	0.96
Home Energy Assessment	LED 5W Globe	Incremental Cost	-	-	-	-	-	-
Home Energy Assessment	LED 9W Bulb	Participation	3,000	3,500	4,200	5,040	4,032	3,024
Home Energy Assessment	LED 9W Bulb	Total Incentive Budget	-	-	-	-	-	-
Home Energy Assessment	LED 9W Bulb	Total Gross Incremental Savings (kwh)	94,680	110,460	132,552	159,062	127,250	95,437
Home Energy Assessment	LED 9W Bulb	NTG	0.96	0.96	0.96	0.96	0.96	0.96
Home Energy Assessment	LED 9W Bulb	Incremental Cost	-	-	-	-	-	-
Home Energy Assessment	LED R30 Dimmable	Participation	900	1,050	1,260	1,512	1,512	1,210
Home Energy Assessment	LED R30 Dimmable	Total Incentive Budget	-	-	-	-	-	-

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Home Energy Assessment	LED R30 Dimmable	Total Gross Incremental Savings (kwh)	47,679	55,626	66,751	80,101	80,101	64,081
Home Energy Assessment	LED R30 Dimmable	NTG	0.96	0.96	0.96	0.96	0.96	0.96
Home Energy Assessment	LED R30 Dimmable	Incremental Cost	-	-	-	-	-	-
Home Energy Assessment	LED Night Light	Participation	300	350	420	504	504	504
Home Energy Assessment	LED Night Light	Total Incentive Budget	-	-	-	-	-	-
Home Energy Assessment	LED Night Light	Total Gross Incremental Savings (kwh)	4,091	4,773	5,727	6,873	6,873	6,873
Home Energy Assessment	LED Night Light	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Home Energy Assessment	LED Night Light	Incremental Cost	-	-	-	-	-	-
Home Energy Assessment	Bathroom Aerator	Participation	600	700	840	1,008	1,008	1,008
Home Energy Assessment	Bathroom Aerator	Total Incentive Budget	-	-	-	-	-	-
Home Energy Assessment	Bathroom Aerator	Total Gross Incremental Savings (kwh)	5,400	6,300	7,560	9,072	9,072	9,072
Home Energy Assessment	Bathroom Aerator	NTG	1.06	1.06	1.06	1.06	1.06	1.06
Home Energy Assessment	Bathroom Aerator	Incremental Cost	-	-	-	-	-	-

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Home Energy Assessment	Kitchen Aerator	Participation	300	350	420	504	504	504
Home Energy Assessment	Kitchen Aerator	Total Incentive Budget	-	-	-	-	-	-
Home Energy Assessment	Kitchen Aerator	Total Gross Incremental Savings (kwh)	34,350	40,075	48,090	57,708	57,708	57,708
Home Energy Assessment	Kitchen Aerator	NTG	1.06	1.06	1.06	1.06	1.06	1.06
Home Energy Assessment	Kitchen Aerator	Incremental Cost	-	-	-	-	-	-
Home Energy Assessment	Efficient Showerhead	Participation	300	350	420	504	504	504
Home Energy Assessment	Efficient Showerhead	Total Incentive Budget	-	-	-	-	-	-
Home Energy Assessment	Efficient Showerhead	Total Gross Incremental Savings (kwh)	61,707	71,992	86,390	103,668	103,668	103,668
Home Energy Assessment	Efficient Showerhead	NTG	1.06	1.06	1.06	1.06	1.06	1.06
Home Energy Assessment	Efficient Showerhead	Incremental Cost	-	-	-	-	-	-
Home Energy Assessment	Filter Whistle	Participation	300	350	420	504	504	504
Home Energy Assessment	Filter Whistle	Total Incentive Budget	-	-	-	-	-	-
Home Energy Assessment	Filter Whistle	Total Gross Incremental Savings (kwh)	18,267	21,312	25,574	30,689	30,689	30,689

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Home Energy Assessment	Filter Whistle	NTG	1.15	1.15	1.15	1.15	1.15	1.15
Home Energy Assessment	Filter Whistle	Incremental Cost	-	-	-	-	-	-
Home Energy Assessment	Pipe Wrap (Electric) (per home)	Participation	300	350	420	504	504	504
Home Energy Assessment	Pipe Wrap (Electric) (per home)	Total Incentive Budget	-	-	-	-	-	-
Home Energy Assessment	Pipe Wrap (Electric) (per home)	Total Gross Incremental Savings (kwh)	19,620	22,890	27,468	32,962	32,962	32,962
Home Energy Assessment	Pipe Wrap (Electric) (per home)	NTG	1.09	1.09	1.09	1.09	1.09	1.09
Home Energy Assessment	Pipe Wrap (Electric) (per home)	Incremental Cost	-	-	-	-	-	-
Home Energy Assessment	Water Heater Temperature Setback	Participation	300	350	420	504	504	504
Home Energy Assessment	Water Heater Temperature Setback	Total Incentive Budget	-	-	-	-	-	-
Home Energy Assessment	Water Heater Temperature Setback	Total Gross Incremental Savings (kwh)	25,957	30,283	36,340	43,608	43,608	43,608
Home Energy Assessment	Water Heater Temperature Setback	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Home Energy Assessment	Water Heater Temperature Setback	Incremental Cost	-	-	-	-	-	-
Home Energy Assessment	Wi-Fi Thermostat (Dual Fuel)	Participation	300	350	420	504	504	504

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Home Energy Assessment	Wi-Fi Thermostat (Dual Fuel)	Total Incentive Budget	-	-	-	-	-	-
Home Energy Assessment	Wi-Fi Thermostat (Dual Fuel)	Total Gross Incremental Savings (kwh)	59,400	69,300	83,160	99,792	99,792	99,792
Home Energy Assessment	Wi-Fi Thermostat (Dual Fuel)	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Home Energy Assessment	Wi-Fi Thermostat (Dual Fuel)	Incremental Cost	-	-	-	-	-	-
Home Energy Assessment	Wi-Fi Thermostat (Electric)	Participation	300	350	420	504	504	504
Home Energy Assessment	Wi-Fi Thermostat (Electric)	Total Incentive Budget	-	-	-	-	-	-
Home Energy Assessment	Wi-Fi Thermostat (Electric)	Total Gross Incremental Savings (kwh)	123,657	144,267	173,120	207,744	207,744	207,744
Home Energy Assessment	Wi-Fi Thermostat (Electric)	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Home Energy Assessment	Wi-Fi Thermostat (Electric)	Incremental Cost	-	-	-	-	-	-
Home Energy Assessment	Showerstart Device (TSV Valve)	Participation	-	-	-	-	-	-
Home Energy Assessment	Showerstart Device (TSV Valve)	Total Incentive Budget	-	-	-	-	-	-
Home Energy Assessment	Showerstart Device (TSV Valve)	Total Gross Incremental Savings (kwh)	-	-	-	-	-	-
Home Energy Assessment	Showerstart Device (TSV Valve)	NTG	1.00	1.00	1.00	1.00	1.00	1.00

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Home Energy Assessment	Showerstart Device (TSV Valve)	Incremental Cost	-	-	-	-	-	-
Home Energy Assessment	Tier 1 Advanced Power Strip	Participation	300	350	420	504	504	504
Home Energy Assessment	Tier 1 Advanced Power Strip	Total Incentive Budget	-	-	-	-	-	-
Home Energy Assessment	Tier 1 Advanced Power Strip	Total Gross Incremental Savings (kwh)	-	-	-	-	-	-
Home Energy Assessment	Tier 1 Advanced Power Strip	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Home Energy Assessment	Tier 1 Advanced Power Strip	Incremental Cost	-	-	-	-	-	-
Food Bank	9W LED	Participation	-	25,248	-	-	-	-
Food Bank	9W LED	Total Incentive Budget	-	-	-	-	-	-
Food Bank	9W LED	Total Gross Incremental Savings (kwh)	-	747,979	-	-	-	-
Food Bank	9W LED	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Food Bank	9W LED	Incremental Cost	-	-	-	-	-	-
Food Bank	LED R30 Dimmable	Participation	-	3,156	3,156	-	-	-
Food Bank	LED R30 Dimmable	Total Incentive Budget	-	-	-	-	-	-

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Food Bank	LED R30 Dimmable	Total Gross Incremental Savings (kwh)	-	167,195	167,195	-	-	-
Food Bank	LED R30 Dimmable	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Food Bank	LED R30 Dimmable	Incremental Cost	-	-	-	-	-	-
Food Bank	Low Flow Showerhead 1.5 gpm - Elec DHW	Participation	-	3,156	3,156	3,156	3,156	3,156
Food Bank	Low Flow Showerhead 1.5 gpm - Elec DHW	Total Incentive Budget	-	-	-	-	-	-
Food Bank	Low Flow Showerhead 1.5 gpm - Elec DHW	Total Gross Incremental Savings (kwh)	-	649,158	649,158	649,158	649,158	649,158
Food Bank	Low Flow Showerhead 1.5 gpm - Elec DHW	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Food Bank	Low Flow Showerhead 1.5 gpm - Elec DHW	Incremental Cost	-	-	-	-	-	-
Bring Your Own Thermostat	BYOT (Bring Your Own Device)	Participation	300	300	300	300	300	300
Bring Your Own Thermostat	BYOT (Bring Your Own Device)	Total Incentive Budget	-	-	-	-	-	-
Bring Your Own Thermostat	BYOT (Bring Your Own Device)	Total Gross Incremental Savings (kwh)	-	-	-	-	-	-
Bring Your Own Thermostat	BYOT (Bring Your Own Device)	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Bring Your Own Thermostat	BYOT (Bring Your Own Device)	Incremental Cost	-	-	-	-	-	-

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Smart Cycle	Smart Cycle (DLC Change Out)	Participation	1,000	1,000	1,000	1,000	1,000	1,000
Smart Cycle	Smart Cycle (DLC Change Out)	Total Incentive Budget	$96,000	$116,000	$136,000	$156,000	$176,000	$196,000
Smart Cycle	Smart Cycle (DLC Change Out)	Total Gross Incremental Savings (kwh)	-	198,000	198,000	198,000	198,000	198,000
Smart Cycle	Smart Cycle (DLC Change Out)	NTG	-	1.00	1.00	1.00	1.00	1.00
Smart Cycle	Smart Cycle (DLC Change Out)	Incremental Cost	-	-	-	-	-	-
C&I Prescriptive	Smart Thermostats	Participation	72	91	118	148	177	205
C&I Prescriptive	Smart Thermostats	Total Incentive Budget	$1,080	$1,365	$1,770	$2,220	$2,655	$3,075
C&I Prescriptive	Smart Thermostats	Total Gross Incremental Savings (kwh)	34,137	43,298	56,214	70,552	84,379	97,979
C&I Prescriptive	Smart Thermostats	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Smart Thermostats	Incremental Cost	$39.16	$39.16	$39.16	$39.16	$39.16	$39.16
C&I Prescriptive	Refrigerator Strip Curtains	Participation	18	42	77	122	178	247
C&I Prescriptive	Refrigerator Strip Curtains	Total Incentive Budget	$54	$126	$231	$366	$534	$741
C&I Prescriptive	Refrigerator Strip Curtains	Total Gross Incremental Savings (kwh)	4,198	9,796	17,958	28,454	41,514	57,607

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	Refrigerator Strip Curtains	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Refrigerator Strip Curtains	Incremental Cost	$7.50	$7.50	$7.50	$7.50	$7.50	$7.50
C&I Prescriptive	Agriculture - Livestock Waterer	Participation	1	1	1	1	1	1
C&I Prescriptive	Agriculture - Livestock Waterer	Total Incentive Budget	$33	$33	$33	$33	$33	$33
C&I Prescriptive	Agriculture - Livestock Waterer	Total Gross Incremental Savings (kwh)	266	266	266	266	266	266
C&I Prescriptive	Agriculture - Livestock Waterer	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Agriculture - Livestock Waterer	Incremental Cost	$787.50	$787.50	$787.50	$787.50	$787.50	$787.50
C&I Prescriptive	Agriculture - Poultry Farm Led Lighting	Participation	1	1	1	1	1	1
C&I Prescriptive	Agriculture - Poultry Farm Led Lighting	Total Incentive Budget	$0	$0	$0	$0	$0	$0
C&I Prescriptive	Agriculture - Poultry Farm Led Lighting	Total Gross Incremental Savings (kwh)	292	292	292	292	292	292
C&I Prescriptive	Agriculture - Poultry Farm Led Lighting	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Agriculture - Poultry Farm Led Lighting	Incremental Cost	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00
C&I Prescriptive	Agriculture - VSD Milk Pump	Participation	1	1	1	1	1	1

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	Agriculture - VSD Milk Pump	Total Incentive Budget	$13	$13	$13	$13	$13	$13
C&I Prescriptive	Agriculture - VSD Milk Pump	Total Gross Incremental Savings (kwh)	34	34	34	34	34	34
C&I Prescriptive	Agriculture - VSD Milk Pump	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Agriculture - VSD Milk Pump	Incremental Cost	$4,000.00	$4,000.00	$4,000.00	$4,000.00	$4,000.00	$4,000.00
C&I Prescriptive	Agriculture - High Volume Low Speed Fans	Participation	1	1	1	1	1	1
C&I Prescriptive	Agriculture - High Volume Low Speed Fans	Total Incentive Budget	$250	$250	$250	$250	$250	$250
C&I Prescriptive	Agriculture - High Volume Low Speed Fans	Total Gross Incremental Savings (kwh)	8,543	8,543	8,543	8,543	8,543	8,543
C&I Prescriptive	Agriculture - High Volume Low Speed Fans	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Agriculture - High Volume Low Speed Fans	Incremental Cost	$4,180.00	$4,180.00	$4,180.00	$4,180.00	$4,180.00	$4,180.00
C&I Prescriptive	Agriculture - High Speed Fans	Participation	1	1	1	1	1	1
C&I Prescriptive	Agriculture - High Speed Fans	Total Incentive Budget	$250	$250	$250	$250	$250	$250
C&I Prescriptive	Agriculture - High Speed Fans	Total Gross Incremental Savings (kwh)	625	625	625	625	625	625
C&I Prescriptive	Agriculture - High Speed Fans	NTG	0.80	0.80	0.80	0.80	0.80	0.80

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	Agriculture - High Speed Fans	Incremental Cost	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00
C&I Prescriptive	Agriculture - Dairy Plate Cooler	Participation	1	1	1	1	1	1
C&I Prescriptive	Agriculture - Dairy Plate Cooler	Total Incentive Budget	$17	$17	$17	$17	$17	$17
C&I Prescriptive	Agriculture - Dairy Plate Cooler	Total Gross Incremental Savings (kwh)	76	76	76	76	76	76
C&I Prescriptive	Agriculture - Dairy Plate Cooler	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Agriculture - Dairy Plate Cooler	Incremental Cost	$16.67	$16.67	$16.67	$16.67	$16.67	$16.67
C&I Prescriptive	Agriculture - Heat Mat	Participation	1	1	1	1	1	1
C&I Prescriptive	Agriculture - Heat Mat	Total Incentive Budget	$22	$22	$22	$22	$22	$22
C&I Prescriptive	Agriculture - Heat Mat	Total Gross Incremental Savings (kwh)	657	657	657	657	657	657
C&I Prescriptive	Agriculture - Heat Mat	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Agriculture - Heat Mat	Incremental Cost	$225.00	$225.00	$225.00	$225.00	$225.00	$225.00
C&I Prescriptive	Agriculture - Automatic Milker Take Off	Participation	1	1	1	1	1	1
C&I Prescriptive	Agriculture - Automatic Milker Take Off	Total Incentive Budget	$2	$2	$2	$2	$2	$2

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	Agriculture - Automatic Milker Take Off	Total Gross Incremental Savings (kwh)	556	556	556	556	556	556
C&I Prescriptive	Agriculture - Automatic Milker Take Off	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Agriculture - Automatic Milker Take Off	Incremental Cost	$1.67	$1.67	$1.67	$1.67	$1.67	$1.67
C&I Prescriptive	Agriculture - Heat Reclaimer	Participation	1	1	1	1	1	1
C&I Prescriptive	Agriculture - Heat Reclaimer	Total Incentive Budget	$2	$2	$2	$2	$2	$2
C&I Prescriptive	Agriculture - Heat Reclaimer	Total Gross Incremental Savings (kwh)	153	153	153	153	153	153
C&I Prescriptive	Agriculture - Heat Reclaimer	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Agriculture - Heat Reclaimer	Incremental Cost	$1.67	$1.67	$1.67	$1.67	$1.67	$1.67
C&I Prescriptive	Air Compressor	Participation	1	1	1	1	1	1
C&I Prescriptive	Air Compressor	Total Incentive Budget	$75	$75	$75	$75	$75	$75
C&I Prescriptive	Air Compressor	Total Gross Incremental Savings (kwh)	34,068	34,068	34,068	34,068	34,068	34,068
C&I Prescriptive	Air Compressor	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Air Compressor	Incremental Cost	$250.00	$250.00	$250.00	$250.00	$250.00	$250.00

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	Air Conditioners	Participation	125	125	125	125	125	125
C&I Prescriptive	Air Conditioners	Total Incentive Budget	$34,278	$34,278	$34,278	$34,278	$34,278	$34,278
C&I Prescriptive	Air Conditioners	Total Gross Incremental Savings (kwh)	899,750	899,750	899,750	899,750	899,750	899,750
C&I Prescriptive	Air Conditioners	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Air Conditioners	Incremental Cost	$100.00	$100.00	$100.00	$100.00	$100.00	$100.00
C&I Prescriptive	Anti-Sweat Heater Control	Participation	290	290	290	290	290	290
C&I Prescriptive	Anti-Sweat Heater Control	Total Incentive Budget	$19,366	$19,366	$19,366	$19,366	$19,366	$19,366
C&I Prescriptive	Anti-Sweat Heater Control	Total Gross Incremental Savings (kwh)	263,610	263,610	263,610	263,610	263,610	263,610
C&I Prescriptive	Anti-Sweat Heater Control	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Anti-Sweat Heater Control	Incremental Cost	$200.00	$200.00	$200.00	$200.00	$200.00	$200.00
C&I Prescriptive	Barrel Wrap Insulation	Participation	1	1	1	1	1	1
C&I Prescriptive	Barrel Wrap Insulation	Total Incentive Budget	$30	$30	$30	$30	$30	$30
C&I Prescriptive	Barrel Wrap Insulation	Total Gross Incremental Savings (kwh)	360	360	360	360	360	360

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	Barrel Wrap Insulation	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Barrel Wrap Insulation	Incremental Cost	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00
C&I Prescriptive	Chilled Water Reset Control	Participation	3	3	3	3	3	3
C&I Prescriptive	Chilled Water Reset Control	Total Incentive Budget	$716	$716	$716	$716	$716	$716
C&I Prescriptive	Chilled Water Reset Control	Total Gross Incremental Savings (kwh)	49,608	49,608	49,608	49,608	49,608	49,608
C&I Prescriptive	Chilled Water Reset Control	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Chilled Water Reset Control	Incremental Cost	$681.34	$681.34	$681.34	$681.34	$681.34	$681.34
C&I Prescriptive	Chiller	Participation	72	72	72	72	72	72
C&I Prescriptive	Chiller	Total Incentive Budget	$367,200	$367,200	$367,200	$367,200	$367,200	$367,200
C&I Prescriptive	Chiller	Total Gross Incremental Savings (kwh)	844,776	844,776	844,776	844,776	844,776	844,776
C&I Prescriptive	Chiller	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Chiller	Incremental Cost	$79.46	$79.46	$79.46	$79.46	$79.46	$79.46
C&I Prescriptive	Chiller Tune-Up	Participation	3	3	3	3	3	3

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	Chiller Tune-Up	Total Incentive Budget	$3,816	$3,816	$3,816	$3,816	$3,816	$3,816
C&I Prescriptive	Chiller Tune-Up	Total Gross Incremental Savings (kwh)	29,082	29,082	29,082	29,082	29,082	29,082
C&I Prescriptive	Chiller Tune-Up	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Chiller Tune-Up	Incremental Cost	$1,272.00	$1,272.00	$1,272.00	$1,272.00	$1,272.00	$1,272.00
C&I Prescriptive	Clothes Washer	Participation	3	3	3	3	3	3
C&I Prescriptive	Clothes Washer	Total Incentive Budget	$180	$180	$180	$180	$180	$180
C&I Prescriptive	Clothes Washer	Total Gross Incremental Savings (kwh)	1,626	1,626	1,626	1,626	1,626	1,626
C&I Prescriptive	Clothes Washer	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Clothes Washer	Incremental Cost	$475.33	$475.33	$475.33	$475.33	$475.33	$475.33
C&I Prescriptive	Combination Oven	Participation	3	3	3	3	3	3
C&I Prescriptive	Combination Oven	Total Incentive Budget	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000
C&I Prescriptive	Combination Oven	Total Gross Incremental Savings (kwh)	55,296	55,296	55,296	55,296	55,296	55,296
C&I Prescriptive	Combination Oven	NTG	0.80	0.80	0.80	0.80	0.80	0.80

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	Combination Oven	Incremental Cost	$2,125.00	$2,125.00	$2,125.00	$2,125.00	$2,125.00	$2,125.00
C&I Prescriptive	Compressed Air Nozzles	Participation	2	2	2	2	2	2
C&I Prescriptive	Compressed Air Nozzles	Total Incentive Budget	$13	$13	$13	$13	$13	$13
C&I Prescriptive	Compressed Air Nozzles	Total Gross Incremental Savings (kwh)	1,776	1,776	1,776	1,776	1,776	1,776
C&I Prescriptive	Compressed Air Nozzles	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Compressed Air Nozzles	Incremental Cost	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00
C&I Prescriptive	Convection Oven	Participation	3	3	3	3	3	3
C&I Prescriptive	Convection Oven	Total Incentive Budget	$1,050	$1,050	$1,050	$1,050	$1,050	$1,050
C&I Prescriptive	Convection Oven	Total Gross Incremental Savings (kwh)	9,705	9,705	9,705	9,705	9,705	9,705
C&I Prescriptive	Convection Oven	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Convection Oven	Incremental Cost	$1,113.00	$1,113.00	$1,113.00	$1,113.00	$1,113.00	$1,113.00
C&I Prescriptive	Commercial Dishwasher	Participation	2	2	2	2	2	2
C&I Prescriptive	Commercial Dishwasher	Total Incentive Budget	$2,325	$2,325	$2,325	$2,325	$2,325	$2,325

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	Commercial Dishwasher	Total Gross Incremental Savings (kwh)	25,714	25,714	25,714	25,714	25,714	25,714
C&I Prescriptive	Commercial Dishwasher	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Commercial Dishwasher	Incremental Cost	$616.25	$616.25	$616.25	$616.25	$616.25	$616.25
C&I Prescriptive	Exterior LED	Participation	1,342	1,342	1,342	1,342	1,342	1,342
C&I Prescriptive	Exterior LED	Total Incentive Budget	$144,225	$144,225	$144,225	$144,225	$144,225	$144,225
C&I Prescriptive	Exterior LED	Total Gross Incremental Savings (kwh)	1,356,762	1,356,762	1,356,762	1,356,762	1,356,762	1,356,762
C&I Prescriptive	Exterior LED	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Exterior LED	Incremental Cost	$270.24	$270.24	$270.24	$270.24	$270.24	$270.24
C&I Prescriptive	Freezer	Participation	79	86	93	99	104	109
C&I Prescriptive	Freezer	Total Incentive Budget	$15,800	$17,200	$18,600	$19,800	$20,800	$21,800
C&I Prescriptive	Freezer	Total Gross Incremental Savings (kwh)	240,950	262,300	283,650	301,950	317,200	332,450
C&I Prescriptive	Freezer	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Freezer	Incremental Cost	$220.25	$220.25	$220.25	$220.25	$220.25	$220.25

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	Fryer	Participation	1	1	1	1	1	1
C&I Prescriptive	Fryer	Total Incentive Budget	$80	$80	$80	$80	$80	$80
C&I Prescriptive	Fryer	Total Gross Incremental Savings (kwh)	1,526	1,526	1,526	1,526	1,526	1,526
C&I Prescriptive	Fryer	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Fryer	Incremental Cost	$500.00	$500.00	$500.00	$500.00	$500.00	$500.00
C&I Prescriptive	Griddle	Participation	3	3	3	3	3	3
C&I Prescriptive	Griddle	Total Incentive Budget	$1,650	$1,650	$1,650	$1,650	$1,650	$1,650
C&I Prescriptive	Griddle	Total Gross Incremental Savings (kwh)	30,099	30,099	30,099	30,099	30,099	30,099
C&I Prescriptive	Griddle	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Griddle	Incremental Cost	$2,090.00	$2,090.00	$2,090.00	$2,090.00	$2,090.00	$2,090.00
C&I Prescriptive	Heat Pump Water Heater	Participation	1	1	1	1	1	1
C&I Prescriptive	Heat Pump Water Heater	Total Incentive Budget	$500	$500	$500	$500	$500	$500
C&I Prescriptive	Heat Pump Water Heater	Total Gross Incremental Savings (kwh)	1,534	1,534	1,534	1,534	1,534	1,534

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	Heat Pump Water Heater	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Heat Pump Water Heater	Incremental Cost	$433.00	$433.00	$433.00	$433.00	$433.00	$433.00
C&I Prescriptive	Heat Pump	Participation	135	135	135	135	135	135
C&I Prescriptive	Heat Pump	Total Incentive Budget	$26,758	$26,758	$26,758	$26,758	$26,758	$26,758
C&I Prescriptive	Heat Pump	Total Gross Incremental Savings (kwh)	166,320	166,320	166,320	166,320	166,320	166,320
C&I Prescriptive	Heat Pump	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Heat Pump	Incremental Cost	$143.64	$143.64	$143.64	$143.64	$143.64	$143.64
C&I Prescriptive	Hot Food Holding Cabinet	Participation	2	2	2	2	2	2
C&I Prescriptive	Hot Food Holding Cabinet	Total Incentive Budget	$457	$457	$457	$457	$457	$457
C&I Prescriptive	Hot Food Holding Cabinet	Total Gross Incremental Savings (kwh)	6,584	6,584	6,584	6,584	6,584	6,584
C&I Prescriptive	Hot Food Holding Cabinet	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Hot Food Holding Cabinet	Incremental Cost	$1,110.00	$1,110.00	$1,110.00	$1,110.00	$1,110.00	$1,110.00
C&I Prescriptive	Ice Machine	Participation	3	3	3	3	3	3

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	Ice Machine	Total Incentive Budget	$510	$510	$510	$510	$510	$510
C&I Prescriptive	Ice Machine	Total Gross Incremental Savings (kwh)	2,670	2,670	2,670	2,670	2,670	2,670
C&I Prescriptive	Ice Machine	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Ice Machine	Incremental Cost	$1,333.60	$1,333.60	$1,333.60	$1,333.60	$1,333.60	$1,333.60
C&I Prescriptive	Interior LED - High-Bay (including LED troffer and LED linear tubes)	Participation	1,293	1,475	1,597	1,643	1,627	1,536
C&I Prescriptive	Interior LED - High-Bay (including LED troffer and LED linear tubes)	Total Incentive Budget	$87,717	$93,385	$93,877	$89,141	$80,905	$69,425
C&I Prescriptive	Interior LED - High-Bay (including LED troffer and LED linear tubes)	Total Gross Incremental Savings (kwh)	1,466,262	1,672,650	1,810,998	1,863,162	1,845,018	1,741,824
C&I Prescriptive	Interior LED - High-Bay (including LED troffer and LED linear tubes)	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Interior LED - High-Bay (including LED troffer and LED linear tubes)	Incremental Cost	$113.54	$113.54	$113.54	$113.54	$113.54	$113.54
C&I Prescriptive	Interior LED - Low-Bay (including LED troffer and LED linear tubes)	Participation	37,209	42,854	47,026	49,043	49,258	47,221

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	Interior LED - Low-Bay (including LED troffer and LED linear tubes)	Total Incentive Budget	$530,228	$569,907	$580,659	$558,915	$514,512	$448,319
C&I Prescriptive	Interior LED - Low-Bay (including LED troffer and LED linear tubes)	Total Gross Incremental Savings (kwh)	7,367,382	8,485,092	9,311,148	9,710,514	9,753,084	9,349,758
C&I Prescriptive	Interior LED - Low-Bay (including LED troffer and LED linear tubes)	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Interior LED - Low-Bay (including LED troffer and LED linear tubes)	Incremental Cost	$78.04	$78.04	$78.04	$78.04	$78.04	$78.04
C&I Prescriptive	Lighting Control	Participation	906	906	906	906	906	906
C&I Prescriptive	Lighting Control	Total Incentive Budget	$16,317	$16,317	$16,317	$16,317	$16,317	$16,317
C&I Prescriptive	Lighting Control	Total Gross Incremental Savings (kwh)	557,190	557,190	557,190	557,190	557,190	557,190
C&I Prescriptive	Lighting Control	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Lighting Control	Incremental Cost	$98.75	$98.75	$98.75	$98.75	$98.75	$98.75
C&I Prescriptive	Lighting Power Density Reduction	Participation	10	10	10	10	10	10
C&I Prescriptive	Lighting Power Density Reduction	Total Incentive Budget	$49,958	$49,958	$49,958	$49,958	$49,958	$49,958
C&I Prescriptive	Lighting Power Density Reduction	Total Gross Incremental Savings (kwh)	317,320	317,320	317,320	317,320	317,320	317,320

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	Lighting Power Density Reduction	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Lighting Power Density Reduction	Incremental Cost	$4,995.83	$4,995.83	$4,995.83	$4,995.83	$4,995.83	$4,995.83
C&I Prescriptive	Low Flow Pre-Rinse Sprayer	Participation	1	1	1	1	1	1
C&I Prescriptive	Low Flow Pre-Rinse Sprayer	Total Incentive Budget	$60	$60	$60	$60	$60	$60
C&I Prescriptive	Low Flow Pre-Rinse Sprayer	Total Gross Incremental Savings (kwh)	7,130	7,130	7,130	7,130	7,130	7,130
C&I Prescriptive	Low Flow Pre-Rinse Sprayer	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Low Flow Pre-Rinse Sprayer	Incremental Cost	$92.90	$92.90	$92.90	$92.90	$92.90	$92.90
C&I Prescriptive	Pellet Dryer Duct Insulation	Participation	1	1	1	1	1	1
C&I Prescriptive	Pellet Dryer Duct Insulation	Total Incentive Budget	$30	$30	$30	$30	$30	$30
C&I Prescriptive	Pellet Dryer Duct Insulation	Total Gross Incremental Savings (kwh)	198	198	198	198	198	198
C&I Prescriptive	Pellet Dryer Duct Insulation	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Pellet Dryer Duct Insulation	Incremental Cost	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00
C&I Prescriptive	Programmable Thermostat	Participation	1	1	1	1	1	1

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	Programmable Thermostat	Total Incentive Budget	$50	$50	$50	$50	$50	$50
C&I Prescriptive	Programmable Thermostat	Total Gross Incremental Savings (kwh)	649	649	649	649	649	649
C&I Prescriptive	Programmable Thermostat	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Programmable Thermostat	Incremental Cost	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00
C&I Prescriptive	Refrigerated Case Cover	Participation	1	1	1	1	1	1
C&I Prescriptive	Refrigerated Case Cover	Total Incentive Budget	$10	$10	$10	$10	$10	$10
C&I Prescriptive	Refrigerated Case Cover	Total Gross Incremental Savings (kwh)	158	158	158	158	158	158
C&I Prescriptive	Refrigerated Case Cover	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Refrigerated Case Cover	Incremental Cost	$42.00	$42.00	$42.00	$42.00	$42.00	$42.00
C&I Prescriptive	Refrigerated LED	Participation	84	111	140	172	204	233
C&I Prescriptive	Refrigerated LED	Total Incentive Budget	$2,446	$3,232	$4,077	$5,009	$5,940	$6,785
C&I Prescriptive	Refrigerated LED	Total Gross Incremental Savings (kwh)	25,536	33,744	42,560	52,288	62,016	70,832
C&I Prescriptive	Refrigerated LED	NTG	0.80	0.80	0.80	0.80	0.80	0.80

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	Refrigerated LED	Incremental Cost	$35.89	$35.89	$35.89	$35.89	$35.89	$35.89
C&I Prescriptive	Refrigerator	Participation	7	7	7	7	7	7
C&I Prescriptive	Refrigerator	Total Incentive Budget	$419	$419	$419	$419	$419	$419
C&I Prescriptive	Refrigerator	Total Gross Incremental Savings (kwh)	4,284	4,284	4,284	4,284	4,284	4,284
C&I Prescriptive	Refrigerator	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Refrigerator	Incremental Cost	$180.00	$180.00	$180.00	$180.00	$180.00	$180.00
C&I Prescriptive	Steam Cooker	Participation	1	1	1	1	1	1
C&I Prescriptive	Steam Cooker	Total Incentive Budget	$200	$200	$200	$200	$200	$200
C&I Prescriptive	Steam Cooker	Total Gross Incremental Savings (kwh)	2,210	2,210	2,210	2,210	2,210	2,210
C&I Prescriptive	Steam Cooker	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Steam Cooker	Incremental Cost	$3,500.00	$3,500.00	$3,500.00	$3,500.00	$3,500.00	$3,500.00
C&I Prescriptive	Vending Machine Control	Participation	3	3	3	3	3	3
C&I Prescriptive	Vending Machine Control	Total Incentive Budget	$125	$125	$125	$125	$125	$125

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	Vending Machine Control	Total Gross Incremental Savings (kwh)	3,162	3,162	3,162	3,162	3,162	3,162
C&I Prescriptive	Vending Machine Control	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Vending Machine Control	Incremental Cost	$179.67	$179.67	$179.67	$179.67	$179.67	$179.67
C&I Prescriptive	VFD-Fan	Participation	2	2	3	4	5	6
C&I Prescriptive	VFD-Fan	Total Incentive Budget	$1,725	$1,725	$2,588	$3,450	$4,313	$5,175
C&I Prescriptive	VFD-Fan	Total Gross Incremental Savings (kwh)	48,644	48,644	72,966	97,288	121,610	145,932
C&I Prescriptive	VFD-Fan	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	VFD-Fan	Incremental Cost	$3,638.33	$3,638.33	$3,638.33	$3,638.33	$3,638.33	$3,638.33
C&I Prescriptive	VFD-Pump	Participation	3	4	5	6	7	9
C&I Prescriptive	VFD-Pump	Total Incentive Budget	$2,475	$3,300	$4,125	$4,950	$5,775	$7,425
C&I Prescriptive	VFD-Pump	Total Gross Incremental Savings (kwh)	164,604	219,472	274,340	329,208	384,076	493,812
C&I Prescriptive	VFD-Pump	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	VFD-Pump	Incremental Cost	$3,059.00	$3,059.00	$3,059.00	$3,059.00	$3,059.00	$3,059.00

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	Wifi-Enabled Thermostat	Participation	360	360	360	360	360	360
C&I Prescriptive	Wifi-Enabled Thermostat	Total Incentive Budget	$36,000	$36,000	$36,000	$36,000	$36,000	$36,000
C&I Prescriptive	Wifi-Enabled Thermostat	Total Gross Incremental Savings (kwh)	229,320	229,320	229,320	229,320	229,320	229,320
C&I Prescriptive	Wifi-Enabled Thermostat	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Wifi-Enabled Thermostat	Incremental Cost	$250.00	$250.00	$250.00	$250.00	$250.00	$250.00
C&I Prescriptive	Window Air Conditioner & PTAC	Participation	10	13	16	19	22	26
C&I Prescriptive	Window Air Conditioner & PTAC	Total Incentive Budget	$469	$609	$750	$890	$1,031	$1,218
C&I Prescriptive	Window Air Conditioner & PTAC	Total Gross Incremental Savings (kwh)	2,070	2,691	3,312	3,933	4,554	5,382
C&I Prescriptive	Window Air Conditioner & PTAC	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Window Air Conditioner & PTAC	Incremental Cost	$196.00	$196.00	$196.00	$196.00	$196.00	$196.00
C&I Prescriptive	High Efficiency Hand Dryer	Participation	47	63	88	116	144	179
C&I Prescriptive	High Efficiency Hand Dryer	Total Incentive Budget	$8,460	$11,340	$15,840	$20,880	$25,920	$32,220
C&I Prescriptive	High Efficiency Hand Dryer	Total Gross Incremental Savings (kwh)	36,132	48,432	67,651	89,176	110,701	137,608

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	High Efficiency Hand Dryer	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	High Efficiency Hand Dryer	Incremental Cost	$450.00	$450.00	$450.00	$450.00	$450.00	$450.00
C&I Prescriptive	Efficient low-temp compressor	Participation	-	1	2	3	4	6
C&I Prescriptive	Efficient low-temp compressor	Total Incentive Budget	-	$221	$442	$662	$883	$1,325
C&I Prescriptive	Efficient low-temp compressor	Total Gross Incremental Savings (kwh)	-	678	1,356	2,033	2,711	4,067
C&I Prescriptive	Efficient low-temp compressor	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Efficient low-temp compressor	Incremental Cost	$552.00	$552.00	$552.00	$552.00	$552.00	$552.00
C&I Prescriptive	Commercial Refrigeration Tune-Up	Participation	319	412	511	613	714	810
C&I Prescriptive	Commercial Refrigeration Tune-Up	Total Incentive Budget	$9,570	$12,360	$15,330	$18,390	$21,420	$24,300
C&I Prescriptive	Commercial Refrigeration Tune-Up	Total Gross Incremental Savings (kwh)	186,731	241,170	299,121	358,828	417,950	474,145
C&I Prescriptive	Commercial Refrigeration Tune-Up	NTG	0.80	0.80	0.80	0.80	0.80	0.80
C&I Prescriptive	Commercial Refrigeration Tune-Up	Incremental Cost	$75.00	$75.00	$75.00	$75.00	$75.00	$75.00
C&I Prescriptive	Duct sealing	Participation	-	-	-	-	-	-

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Prescriptive	Duct sealing	Total Incentive Budget	-	-	-	-	-	-
C&I Prescriptive	Duct sealing	Total Gross Incremental Savings (kwh)	-	-	-	-	-	-
C&I Prescriptive	Duct sealing	NTG	-	-	-	-	-	-
C&I Prescriptive	Duct sealing	Incremental Cost	-	-	-	-	-	-
C&I Custom	C&I Custom	Participation	35	35	35	35	35	35
C&I Custom	C&I Custom	Total Incentive Budget	$395,191	$395,191	$395,191	$395,191	$395,191	$395,191
C&I Custom	C&I Custom	Total Gross Incremental Savings (kwh)	4,453,104	4,453,104	4,453,104	4,453,104	4,453,104	4,453,104
C&I Custom	C&I Custom	NTG	1.00	1.00	1.00	1.00	1.00	1.00
C&I Custom	C&I Custom	Incremental Cost	$26,185.00	$26,185.00	$26,185.00	$26,185.00	$26,185.00	$26,185.00
C&I Custom	C&I Custom Pilot	Participation	161	161	161	161	161	161
C&I Custom	C&I Custom Pilot	Total Incentive Budget	$96,347	$96,347	$96,347	$96,347	$96,347	$96,347
C&I Custom	C&I Custom Pilot	Total Gross Incremental Savings (kwh)	1,654,130	1,654,130	1,654,130	1,654,130	1,654,130	1,654,130
C&I Custom	C&I Custom Pilot	NTG	1.00	1.00	1.00	1.00	1.00	1.00

Program	Measure	Description	2020	2021	2022	2023	2024	2025
C&I Custom	C&I Custom Pilot	Incremental Cost	-	-	-	-	-	-
Small Business	Smart Thermostats	Participation	18	22	29	37	44	51
Small Business	Smart Thermostats	Total Incentive Budget	$270	$330	$435	$555	$660	$765
Small Business	Smart Thermostats	Total Gross Incremental Savings (kwh)	13,257	16,203	21,359	27,251	32,406	37,562
Small Business	Smart Thermostats	NTG	0.91	0.91	0.91	0.91	0.91	0.91
Small Business	Smart Thermostats	Incremental Cost	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00
Small Business	Anti-Sweat Heater Control	Participation	6	6	6	6	6	6
Small Business	Anti-Sweat Heater Control	Total Incentive Budget	$1,020	$1,020	$1,020	$1,020	$1,020	$1,020
Small Business	Anti-Sweat Heater Control	Total Gross Incremental Savings (kwh)	5,454	5,454	5,454	5,454	5,454	5,454
Small Business	Anti-Sweat Heater Control	NTG	0.91	0.91	0.91	0.91	0.91	0.91
Small Business	Anti-Sweat Heater Control	Incremental Cost	$170.00	$170.00	$170.00	$170.00	$170.00	$170.00
Small Business	EC Motors	Participation	-	-	-	-	-	-
Small Business	EC Motors	Total Incentive Budget	-	-	-	-	-	-

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Small Business	EC Motors	Total Gross Incremental Savings (kwh)	-	-	-	-	-	-
Small Business	EC Motors	NTG	0.91	0.91	0.91	0.91	0.91	0.91
Small Business	EC Motors	Incremental Cost	$66.76	$66.76	$66.76	$66.76	$66.76	$66.76
Small Business	Exterior LED	Participation	4,263	4,263	4,263	4,263	4,263	4,263
Small Business	Exterior LED	Total Incentive Budget	$380,302	$380,302	$380,302	$380,302	$380,302	$380,302
Small Business	Exterior LED	Total Gross Incremental Savings (kwh)	1,922,613	1,922,613	1,922,613	1,922,613	1,922,613	1,922,613
Small Business	Exterior LED	NTG	0.91	0.91	0.91	0.91	0.91	0.91
Small Business	Exterior LED	Incremental Cost	$89.21	$89.21	$89.21	$89.21	$89.21	$89.21
Small Business	Faucet Aerator	Participation	3	3	3	3	3	3
Small Business	Faucet Aerator	Total Incentive Budget	$14	$14	$14	$14	$14	$14
Small Business	Faucet Aerator	Total Gross Incremental Savings (kwh)	1,512	1,512	1,512	1,512	1,512	1,512
Small Business	Faucet Aerator	NTG	0.91	0.91	0.91	0.91	0.91	0.91
Small Business	Faucet Aerator	Incremental Cost	$4.72	$4.72	$4.72	$4.72	$4.72	$4.72

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Small Business	Interior LED	Participation	3,948	3,948	3,948	3,948	3,948	3,948
Small Business	Interior LED	Total Incentive Budget	$132,653	$123,798	$114,944	$106,089	$97,235	$88,380
Small Business	Interior LED	Total Gross Incremental Savings (kwh)	852,768	852,768	852,768	852,768	852,768	852,768
Small Business	Interior LED	NTG	0.91	0.91	0.91	0.91	0.91	0.91
Small Business	Interior LED	Incremental Cost	$33.60	$33.60	$33.60	$33.60	$33.60	$33.60
Small Business	Lighting Control	Participation	9	9	9	9	9	9
Small Business	Lighting Control	Total Incentive Budget	$400	$400	$400	$400	$400	$400
Small Business	Lighting Control	Total Gross Incremental Savings (kwh)	2,115	2,115	2,115	2,115	2,115	2,115
Small Business	Lighting Control	NTG	0.91	0.91	0.91	0.91	0.91	0.91
Small Business	Lighting Control	Incremental Cost	$44.44	$44.44	$44.44	$44.44	$44.44	$44.44
Small Business	Low Flow Pre-Rinse Sprayer	Participation	3	3	3	3	3	3
Small Business	Low Flow Pre-Rinse Sprayer	Total Incentive Budget	$180	$180	$180	$180	$180	$180
Small Business	Low Flow Pre-Rinse Sprayer	Total Gross Incremental Savings (kwh)	21,390	21,390	21,390	21,390	21,390	21,390

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Small Business	Low Flow Pre-Rinse Sprayer	NTG	0.91	0.91	0.91	0.91	0.91	0.91
Small Business	Low Flow Pre-Rinse Sprayer	Incremental Cost	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00
Small Business	Programmable Thermostat	Participation	70	71	71	67	67	67
Small Business	Programmable Thermostat	Total Incentive Budget	$14,047	$14,248	$14,248	$13,445	$13,445	$13,445
Small Business	Programmable Thermostat	Total Gross Incremental Savings (kwh)	51,590	52,327	52,327	49,379	49,379	49,379
Small Business	Programmable Thermostat	NTG	0.91	0.91	0.91	0.91	0.91	0.91
Small Business	Programmable Thermostat	Incremental Cost	$200.67	$200.67	$200.67	$200.67	$200.67	$200.67
Small Business	Programmable Thermostat (Gas Heat, Electric Cooling)	Participation	27	27	27	27	27	27
Small Business	Programmable Thermostat (Gas Heat, Electric Cooling)	Total Incentive Budget	$4,424	$4,424	$4,424	$4,424	$4,424	$4,424
Small Business	Programmable Thermostat (Gas Heat, Electric Cooling)	Total Gross Incremental Savings (kwh)	19,899	19,899	19,899	19,899	19,899	19,899
Small Business	Programmable Thermostat (Gas Heat, Electric Cooling)	NTG	0.91	0.91	0.91	0.91	0.91	0.91
Small Business	Programmable Thermostat (Gas	Incremental Cost	$163.84	$163.84	$163.84	$163.84	$163.84	$163.84

Program	Measure	Description	2020	2021	2022	2023	2024	2025
	Heat, Electric Cooling)							
Small Business	Refrigerated Case Cover	Participation	30	30	30	30	30	30
Small Business	Refrigerated Case Cover	Total Incentive Budget	$285	$285	$285	$285	$285	$285
Small Business	Refrigerated Case Cover	Total Gross Incremental Savings (kwh)	1,590	1,590	1,590	1,590	1,590	1,590
Small Business	Refrigerated Case Cover	NTG	0.91	0.91	0.91	0.91	0.91	0.91
Small Business	Refrigerated Case Cover	Incremental Cost	$9.50	$9.50	$9.50	$9.50	$9.50	$9.50
Small Business	Refigerated LED	Participation	12	12	12	12	12	12
Small Business	Refigerated LED	Total Incentive Budget	$570	$570	$570	$570	$570	$570
Small Business	Refigerated LED	Total Gross Incremental Savings (kwh)	4,908	4,908	4,908	4,908	4,908	4,908
Small Business	Refigerated LED	NTG	0.91	0.91	0.91	0.91	0.91	0.91
Small Business	Refigerated LED	Incremental Cost	$47.50	$47.50	$47.50	$47.50	$47.50	$47.50
Small Business	Vending Machine Control	Participation	6	6	6	6	6	6
Small Business	Vending Machine Control	Total Incentive Budget	$1,590	$1,590	$1,590	$1,590	$1,590	$1,590

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Small Business	Vending Machine Control	Total Gross Incremental Savings (kwh)	8,460	8,460	8,460	8,460	8,460	8,460
Small Business	Vending Machine Control	NTG	0.91	0.91	0.91	0.91	0.91	0.91
Small Business	Vending Machine Control	Incremental Cost	$265.00	$265.00	$265.00	$265.00	$265.00	$265.00
Small Business	Wifi-Enabled Thermostat	Participation	6	6	6	6	6	6
Small Business	Wifi-Enabled Thermostat	Total Incentive Budget	$2,250	$2,250	$2,250	$2,250	$2,250	$2,250
Small Business	Wifi-Enabled Thermostat	Total Gross Incremental Savings (kwh)	4,422	4,422	4,422	4,422	4,422	4,422
Small Business	Wifi-Enabled Thermostat	NTG	0.91	0.91	0.91	0.91	0.91	0.91
Small Business	Wifi-Enabled Thermostat	Incremental Cost	$375.00	$375.00	$375.00	$375.00	$375.00	$375.00
Small Business	Wifi-Enabled Thermostat (Gas Heat, Electric Cooling)	Participation	36	36	36	36	36	36
Small Business	Wifi-Enabled Thermostat (Gas Heat, Electric Cooling)	Total Incentive Budget	$10,031	$10,031	$10,031	$10,031	$10,031	$10,031
Small Business	Wifi-Enabled Thermostat (Gas Heat, Electric Cooling)	Total Gross Incremental Savings (kwh)	26,532	26,532	26,532	26,532	26,532	26,532
Small Business	Wifi-Enabled Thermostat (Gas Heat, Electric Cooling)	NTG	0.91	0.91	0.91	0.91	0.91	0.91

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Small Business	Wifi-Enabled Thermostat (Gas Heat, Electric Cooling)	Incremental Cost	$278.65	$278.65	$278.65	$278.65	$278.65	$278.65
Small Business	Program the Programmable Thermostat	Participation	3	3	3	3	3	3
Small Business	Program the Programmable Thermostat	Total Incentive Budget	$75	$75	$75	$75	$75	$75
Small Business	Program the Programmable Thermostat	Total Gross Incremental Savings (kwh)	2,211	2,211	2,211	2,211	2,211	2,211
Small Business	Program the Programmable Thermostat	NTG	0.91	0.91	0.91	0.91	0.91	0.91
Small Business	Program the Programmable Thermostat	Incremental Cost	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00
Small Business	Program the Programmable Thermostat (Gas Heat, Electric Cooling)	Participation	3	3	3	3	3	3
Small Business	Program the Programmable Thermostat (Gas Heat, Electric Cooling)	Total Incentive Budget	$56	$56	$56	$56	$56	$56
Small Business	Program the Programmable Thermostat (Gas Heat, Electric Cooling)	Total Gross Incremental Savings (kwh)	2,211	2,211	2,211	2,211	2,211	2,211
Small Business	Program the Programmable Thermostat (Gas Heat, Electric Cooling)	NTG	0.91	0.91	0.91	0.91	0.91	0.91

Program	Measure	Description	2020	2021	2022	2023	2024	2025
Small Business	Program the Programmable Thermostat (Gas Heat, Electric Cooling)	Incremental Cost	$18.75	$18.75	$18.75	$18.75	$18.75	$18.75
Home Energy Management Systems	Home Energy Management System	Participation	-	1,000	1,000	1,000	1,000	1,000
Home Energy Management Systems	Home Energy Management System	Total Incentive Budget	-	-	-	-	-	-
Home Energy Management Systems	Home Energy Management System	Total Gross Incremental Savings (kwh)	-	515,000	515,000	515,000	515,000	515,000
Home Energy Management Systems	Home Energy Management System	NTG	-	1.00	1.00	1.00	1.00	1.00
Home Energy Management Systems	Home Energy Management System	Incremental Cost	-	-	-	-	-	-
Residential CVR	Residential CVR	Participation						
Residential CVR	Residential CVR	Total Incentive Budget	-	-	-	-	-	-
Residential CVR	Residential CVR	Total Gross Incremental Savings (kwh)	1,461,047	-	-	1,461,047	-	-
Residential CVR	Residential CVR	NTG	1.00	1.00	1.00	1.00	1.00	1.00
Residential CVR	Residential CVR	Incremental Cost	-	-	-	-	-	-

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

prepared for

VECTREN ENERGY DELIVERY OF INDIANA

*2020-2025 Integrated **Electric** DSM Market Potential Study & Action Plan*

January
2019

FINAL REPORT

prepared by
GDS ASSOCIATES INC
EMI CONSULTING

Attachment 6.3 All Source RFP

All-Source Request for Proposals

Vectren

6/12/2019

All-Source Request for Proposals

for

Power supply generation facilities, power purchase agreements, and demand resources

Issued
6/12/2019

Proposals due
7/31/2019

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COD	Commercial Operating Date
CSP	Curtailment Service Providers
DA	Definitive Agreement
DIR	Dispatchable Intermittent Resource
DR	Demand Resource
EFORd	Equivalent Forced Outage Rate Demand
EPC	Engineering, Procurement and Construction
ERIS	Energy Resource Interconnection Service
FERC	Federal Energy Regulatory Commission
GDPIPD	Gross Domestic Product Implicit Price Deflator
GI	Generation Interconnection
GIA	Generator Interconnection Agreement
Hg	Mercury
ICAP	Installed Capacity
IRP	Integrated Resource Plan
IURC	Indiana Utility Regulatory Commission

kW	Kilowatt
lb	Pound
LCOE	Levelized Cost of Energy
LCR	Local Clearing Requirement
LMR	Load Modifying Resource
LRZ	Local Resource Zone
LSE	Load Serving Entity
MISO	Midcontinent Independent System Operator
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-Hour
NDA	Non-Disclosure Agreement
NO_X	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRIS	Network Resource Integration Service
OEM	Original Equipment Manufacturer
OVEC	Ohio Valley Electric Corporation
PM	Particulate Matter
PPA	Power Purchase Agreements
PRM	Planning Reserve Margin
RFP	Request for Proposal
SO_2	Sulfur Dioxide

UCAP	Unforced Capacity
Vectren	Vectren Energy Delivery
VOC	Volatile Organize Compounds

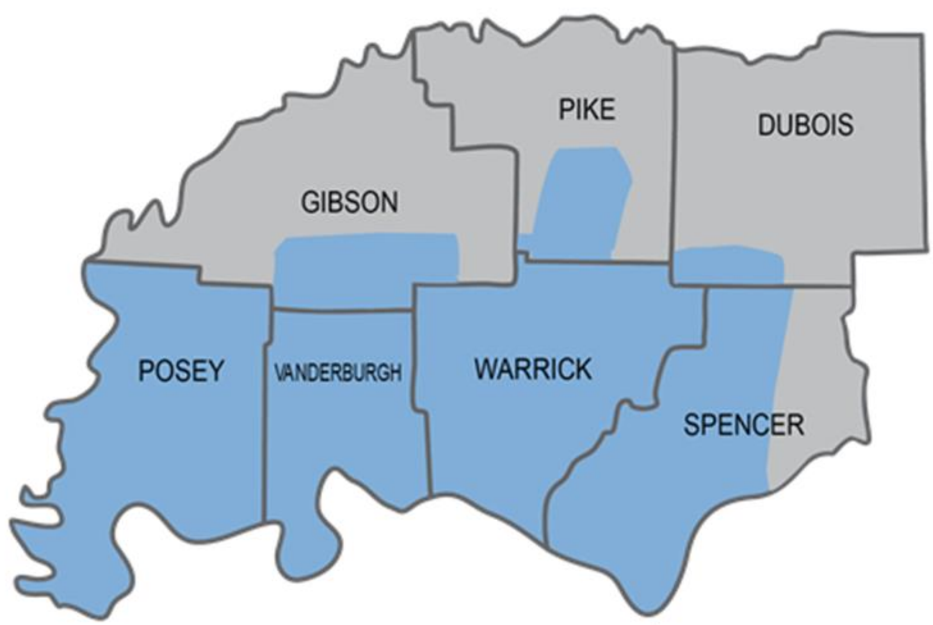
1.0 ALL-SOURCE RFP OVERVIEW

1.1 Introduction

Southern Indiana Gas and Electric (Vectren) is a subsidiary of CenterPoint Energy, headquartered in Houston, Texas. Vectren provides energy delivery services to 144,000 electric customers located in southwestern Indiana. Vectren also owns and operates electric generation to serve its electric customers and optimizes those assets in the wholesale power market.

Vectren's electric customers are currently served by a mixed portfolio of 1,000 megawatts (MW) of coal-fired generation, up to 225 MW of gas-fired generation and 4 MWs of solar coupled with 1 MW of storage. The portfolio also contains 3 MW from a landfill gas to electric project and purchases from the Ohio Valley Electric Corporation (OVEC) of up to 32 MW, wind purchases of up to 80 MW, and purchases from the Midcontinent Independent System Operator (MISO) power pool as needed to meet Vectren's load requirements. Furthermore, interruptible load and demand-side management initiatives can reduce load by approximately 60 MW if needed.

Figure 1-1: Vectren Electric Service Area



1.2 Purpose

Vectren has issued this all-source Request for Proposals (RFP) seeking power supply and demand-side Proposals for capacity and unit-contingent energy to meet the needs of its customers. For asset purchases and power purchase agreements (PPAs) the capacity is preferred to be fully accredited for the 2023/2024

MISO Planning Year (PY). Vectren intends to submit an updated Integrated Resource Plan (2019/2020 IRP) to the Indiana Utility Regulatory Commission (IURC) in 2020 which will evaluate existing resources and identify the preferred resource options to meet capacity and energy requirements. Only resources capable of firm deliverability, further outlined in Section 4.1.1.2, to MISO Local Resource Zone (LRZ) 6 will be considered.

Vectren's resource planning will balance the need for dispatchable capacity with intermittent and demand-side resources to meet customers' needs reliably and cost effectively in an environmentally sustainable manner in both the short and long term. The IRP is designed to provide Vectren customers with a safe, reliable, and affordable power supply.

Vectren prefers Proposals that reflect all of the costs and characteristics of the resource necessary for energy to be financially settled or directly delivered to Vectren's load node (SIGE.SIGW). All potential agreements are subject to IURC approval and are not effective until such approval is final.

All Proposals must be received by the contact designated in Section 2.1 no later than the Proposal Submittal Due Date shown in Section 2.4. Vectren reserves the right in its sole discretion to modify this schedule for any reason.

In connection with this RFP, Vectren has retained the services of an independent third-party consultant, Burns & McDonnell, to manage the entire RFP process and work with Vectren to perform the quantitative and qualitative evaluations of all Proposals. However, Vectren will make final decisions (subject to IURC review, as applicable) in Vectren's sole discretion.

All Respondents will directly interface with Burns & McDonnell for all communications including questions, RFP clarification issues, and RFP bid submittal. All correspondence concerning this RFP should be sent via e-mail to VectrenRFP@burnsmcd.com.

Long term resource planning requires addressing risks and uncertainties created by a number of factors including the costs associated with new resources. As part of ongoing resource planning, Vectren has concluded that it is in the best interest of its customers to seek information regarding the potential to acquire, construct or contract for additional capacity that qualifies as a MISO internal resource (i.e. not pseudo-tied into MISO) with physical deliverability utilizing Network Resource Integration Service (NRIS) to MISO LRZ 6. Hereafter within this document, zonal restrictions will be referred to as being within MISO LRZ 6. Within the context of the 2019 IRP process, Vectren is soliciting all-source RFP for supply-side and demand-side capacity resources. The purpose of the RFP is to identify viable resources available to Vectren in the marketplace to meet the needs of its customers. Dependent upon further evaluation of aging resources, and subject to actual IRP results, Vectren may identify a capacity need of approximately 700 MW beginning in the 2023/2024 planning year. Because Vectren is looking at a number of potential resource portfolio combinations in the IRP, it is likely the 2019/2020 IRP will have scenarios that could result in a need less than or greater than 700 MW. Therefore, Respondents are encouraged to offer less than, or more than, 700 MW depending on the resources they have available. Vectren will also consider alternative timelines related to the capacity acquisition to the extent Respondents are able to provide more competitive pricing and/or terms for delivery beginning prior to or after 2023/2024 planning year. Vectren will aggregate data from the RFP responses, which include a delivered price (pending verification), and input such data into its IRP modeling. The RFP bid evaluation and selection process will be based upon the specific resource needs identified through this IRP modeling as well as the bid evaluation criteria. Through this RFP, Vectren seeks to satisfy the identified capacity need through either a single resource or multiple resources including dispatchable generation, load modifying resources (LMRs)/demand resource (DRs), renewables, stand-alone and paired storage, and contractual arrangements.

Vectren is seeking to provide reliable generation supply and demand resources for its customers. This RFP is issued to:

- Acquire a generation facility or facilities described further in Section 4.0, including the following:
  - Existing or planned dispatchable generation facilities that, at a minimum, meet established industry-wide reliability and performance standards or development requirement
    - Planned resources can be but are not required to be in the MISO generator interconnection queue
  - Existing or planned utility scale renewable resources
  - Existing or planned utility scale storage facilities, either stand-alone or paired with renewables
- Procure power purchase contract options for capacity and energy described further in Section 5.0.
- Procure LMRs/DRs that satisfy the criteria described further in Section 6.0.

Accordingly, you are invited to submit a written, binding Proposal in accordance with the requirements described in this RFP. Entities that submit a Proposal are referred to as Respondents.

The milestone dates for this RFP process are presented below. Additional information about milestone dates for the RFP is provided in Section 2.4.

Table 1-1: RFP Milestone Dates

Milestone	Date
Issue RFP	Wednesday, June 12, 2019
Notice of Intent w/ Pre-Qualification Documents	Thursday, June 27, 2019
Notification of Pre-Qualification	Wednesday, July 3, 2019
Proposals Due	Wednesday, July 31, 2019

2.0 INFORMATION AND SCHEDULE

2.1 Information Provided to Potential Respondents

This RFP and all of its Appendices are available on the RFP website (http://VectrenRFP.rfpmanager.biz/). Interested parties are expected to be able to download this RFP with its required forms and complete the forms in Microsoft Word, Microsoft Excel[1], and/or PDF format. Respondents should submit properly completed forms by the specified due date to the RFP e-mail address (VectrenRFP@burnsmcd.com). Burns & McDonnell will accept only Proposals that are complete. Proposals that are nonconforming, not complete, or that are mailed, or hand delivered may be deemed ineligible and may not be considered for further evaluation. By submitting a Proposal in response to this RFP, the Respondent certifies that it has not divulged, discussed, or compared any commercial terms of its Proposal with any other party (including any other Respondent and/or prospective Respondent), and has not colluded whatsoever with any other party.

2.2 Information on the RFP Website

The information on the RFP website (http://VectrenRFP.rfpmanager.biz/) contains the following:

- This RFP and associated appendices
- Template Information Form Addendum (as described in Section 8.1)
- Form of Notice of Intent
- Form of RFP Non-Disclosure Agreement
- Form of Pre-Qualification Application including Creditworthiness information
- Frequently asked questions and answers about this RFP
- Updates on this RFP process and other relevant information

2.3 Questions

An e-mail address (VectrenRFP@burnsmcd.com) has been set up to collect all communications and questions from potential Respondents as well as a website (http://VectrenRFP.rfpmanager.biz/) to download the RFP and provide uniform communications, relevant questions and answers, including updates and other details as may be provided throughout the bidding process. Phone calls and verbal conversations with Respondents regarding this RFP are not permitted before the Proposal Submittal Due Date. All Respondents will directly interface with Burns & McDonnell through the RFP e-mail address for all communications regarding this resource request. Proposals will be opened in private by Burns &

[1] Microsoft Excel format is required for the submission of Appendix D.

McDonnell on a confidential basis, but written questions will not be considered confidential. Individual questions submitted by e-mail to Burns & McDonnell before the submittal due date will be answered and responses sent back via e-mail to the Respondent as soon as practical. Responses to any questions may be placed on the RFP website for the benefit of all Respondents, with any identifying information redacted from the question.

Proposals will be reviewed by Burns & McDonnell for completeness and offers that do not include the information requirements of this RFP may be notified by Burns & McDonnell and allowed five business days to conform. After Proposals are submitted, Burns & McDonnell will review, and both quantitatively and qualitatively evaluate all conforming Proposals. During the evaluation process Respondents may be contacted for additional data or clarifications by Burns & McDonnell. Any Respondents contacted for further clarifications may or may not be invited to begin further negotiations of terms and details of the offers.

2.4 Schedule

Vectren has retained Burns & McDonnell to act as an independent third-party consultant to assist with this RFP. All Respondents will directly interface with Burns & McDonnell for all communications including questions, RFP clarification issues, and RFP bid submittal. All correspondence concerning this RFP should be sent via e-mail to VectrenRFP@burnsmcd.com.

The schedule below represents Vectren's expected timeline for conducting this resource solicitation. Vectren reserves the right to modify this schedule as circumstances warrant and/or as Vectren deems appropriate.

Table 2-1: RFP Schedule

Step	Date[2]
RFP Issued	Wednesday, June 12, 2019
Notice of Intent, RFP NDA, and Respondent Pre-Qualification Application Due	5:00 p.m. CDT, Thursday, June 27, 2019
Respondents Notified of Results of Pre-Qualification Application Review	5:00 p.m. CDT, Wednesday, July 3, 2019
Proposal Submittal Due Date	5:00 p.m. CDT, Wednesday, July 31, 2019
Initial Proposal Review and Evaluation Period	Wednesday, July 31, 2019 – Wednesday, September 18, 2019
Proposal Evaluation Completion Target and Input to Vectren	2nd Quarter, 2020
Due Diligence and Negotiations Period	Mid 2020
Definitive agreement(s) Executed (subject to regulatory approvals) with Selected Respondent(s)	Late 2020
Petitions (if required) filed with the IURC, the Federal Energy Regulatory Commission (FERC), or any other required agency/commission	TBD

[2] Negotiation schedule for smaller projects can be expedited at Vectren's discretion

3.0 RFP GENERAL REQUIREMENTS

Proposals must meet the general minimum eligibility requirements described below. Burns & McDonnell will screen all Proposals for compliance with these requirements. Proposals that fail to meet one or more of the general minimum eligibility requirements may be disqualified from further consideration as part of this RFP process. Respondents should refer to the Proposal Checklist in Appendix E for high-level guidance on Proposal requirements.

For a Proposal to be eligible under this RFP, it must offer MISO accredited or accreditable capacity (including Zonal Resource Credits) of no less than 10 MW to MISO LRZ 6[3].

Vectren has a preference for Proposals that provide Vectren with operational control of the asset, regardless of ownership position. Where applicable, proposed generation facilities should have no major operational limitations that reduce the ability to run for extended periods.

3.1 Respondent Pre-Qualification

Respondents to this RFP are required to fill out and sign Appendix A: Notice of Intent to Respond, Appendix B: Non-Disclosure Agreement (NDA), and Appendix C: Pre-Qualification Application in its present form.

3.2 Multiple Proposals

In the event that multiple Proposals are submitted by the same Respondent, the Respondent must indicate whether the Proposals are to be evaluated independently of one another or if Proposals are to be considered together.

Respondents may submit up to three Proposals at no cost in response to this RFP. Respondents submitting more than three responses will incur a Proposal Evaluation Fee for each additional Proposal submitted. The non-refundable fee for evaluating each additional Proposal is $5,000. This sum will serve to defray evaluation costs. Respondents can find instructions for paying fees for their Proposal(s) on the RFP website (http://VectrenRFP.rfpmanager.biz/). Vectren and Burns & McDonnell will have sole discretion to determine whether a submission is deemed a single Proposal or multiple Proposals.

[3] Load Modifying Resource suppliers must be located entirely within MISO LRZ 6.

3.3 Non-Disclosure Agreement

This RFP contains an RFP NDA (Appendix B). Respondents shall submit a signed version to the RFP e-mail address (VectrenRFP@burnsmcd.com) by 5:00 p.m. CDT on June 27, 2019. Respondents may download the form from the RFP website (http://VectrenRFP.rfpmanager.biz/).

3.4 Valid Proposal Duration

Proposals must include pricing that is firm and not subject to any revisions during the initial evaluation process. Vectren will receive all associated allowances or credits, if any. Seller agrees to transfer any Financial Transmission Rights or Auction Revenue Rights associated with the asset to the Buyer. Escalation rates shall be fixed or set annually to the Gross Domestic Product Implicit Price Deflator (GDPIPD). The GDPIPD will be reset annually as published by the U.S. Department of Commerce, Bureau of Economic Analysis. Formulaic mechanisms will not be subject to revisions during the evaluation and negotiation process.

All pricing should be provided in Appendix D in terms of US dollars as of the date the term of the contract begins and not subject to a currency exchange rate adjustment. Respondents are strongly encouraged to provide their best pricing with their initial submittal. Vectren is not obligated to provide an opportunity in the evaluation schedule for Respondents to refresh or update their pricing before the final selection(s) are made (if any). Respondents Proposal pricing shall remain valid for 1-year from the Proposal Submittal Due Date.

3.5 Acknowledgement of RFP Terms and Conditions

The submission of a Proposal shall constitute Respondent's acknowledgment and acceptance of all the terms, conditions, and requirements of this RFP.

3.6 RFP Response Summary Information

All Proposals must include a table of contents and provide concise and complete information on the topics described below, organized as follows:

3.6.1 Executive Summary

Please provide a one-page executive summary of the Proposal in the form of a cover letter. Include the facility's location, age or development status and if applicable, MISO generator interconnection project number, size, the primary contact's name, e-mail, and phone number, and an overview of the major features of the Proposal. The Executive Summary must be signed by an officer of the Respondent who is duly authorized to commit the firm to carry out the proposed transaction should Vectren accept the

Proposal (this does not have to be the primary contact). A Table of Contents should be the first page and immediately precede the Executive Summary.

3.6.2 General Information

3.6.2.1 Respondent’s Information and Experience

Please include information on the Respondent’s corporate structure (including identification of any parent companies), the project’s financing plan, the Respondent’s most recent credit rating, quarterly report containing unaudited consolidated financial statements that is signed and verified by an authorized officer of Respondent attesting to its accuracy, a copy of Respondent’s annual report for the prior three years containing audited consolidated financial statements and a summary of Respondent’s relevant experience. Please describe any current litigation or environmental fines involving the Respondent within the last five years, including but not limited to, any litigation, settlements of litigation or fines, that could potentially affect the facility or its operation. Please identify all bankruptcy or insolvency proceedings relating to the Respondent in any way. Please describe any litigation related to PPAs or asset purchases similar to the transactions solicited in this RFP that the Respondent or its parent company have been a party to in the last six years. All financial statements, annual reports and other large documents may be referenced via a website address.

Proposals shall include a list of projects with a brief description of Respondent's experience in the areas of development, financing, permitting, ownership, construction, and operation of all utility-scale power generation facilities or LMRs/DRs.

Please provide a list of projects with a brief description of the Engineering, Procurement and Construction (EPC) contractor’s experience as it relates to utility-scale power generation.

4.0 GENERATION FACILITY PROPOSALS

For generation facility Proposals, Vectren will only consider bids for facilities that have an estimated remaining useful life of five or more years from acquisition date. In all cases, Respondents shall describe the expected useful life of all facilities included in their Proposals.

4.1 Content Requirements for Generation Facility Proposals

This section describes Vectren's requirements for the content of any Proposal that is submitted in response to this RFP as an offer to sell a generation facility to Vectren. Proposals that do not include all of the required information may be deemed ineligible and may not be considered for further evaluation. If it appears that certain information has inadvertently been omitted from a Proposal, Burns & McDonnell may, but is not obligated, to contact the Respondent to obtain the missing information, per Section 2.3. If, during the RFP process, there is a material change to the generation facility or the circumstances of the Respondent that could affect the outcome of the RFP evaluation, the Respondent is obligated to inform Burns & McDonnell within five business days. In addition, any winning Respondent must provide such additional information and data as may be requested by Vectren to support regulatory approvals of the generation facility purchase transaction.

Vectren has a preference for projects located near its load. Non-conforming bids by Respondents to sell a generation facility or facilities not meeting the location requirements may be disqualified from consideration on that basis alone.

Vectren will accept Proposals for new or planned generation facilities that will be complete and operational in advance of the expected acquisition date. A project will be defined as complete and commercially operable if, and only if, it includes all facilities necessary to generate and deliver energy into MISO to at least one single point of interconnection within MISO. More detail on the development milestone requirements for planned facilities are included in Section 4.1.7.

If a facility does not have black start capability installed but could be made black start capable, Proposals should indicate the estimated costs to construct and operate and include the estimated construction timeline.

4.1.1 Capacity Characteristics

Respondents shall state the nameplate capacity, net summer operating capacity, net winter operating capacity and the awarded unforced capacity (UCAP) of the generation facility for the last five MISO planning years (existing facilities).

Respondents also should provide the expected UCAP for the first five MISO planning years beginning June 1, 2023 based on current MISO rules for the applicable generating technology.

4.1.1.1 Acquisition Date

In preparing their Proposals, Respondents shall assume the acquisition of the facility shall be closed and transfer of title shall occur on or before the start of the 2023/24 Planning Resource Auction window, subject to regulatory approvals. If Respondent is able to offer more competitive pricing and terms for title transferring prior to or after June 1, 2023, Respondent should detail the drivers and the optimal date for title transfer.

4.1.1.2 Capacity Availability and Deliverability

For Proposals to sell an existing generation facility to Vectren, the existing generating facility must be commercially operable, including all facilities and requirements necessary to deliver capacity (Zonal Resource Credits) to MISO LRZ 6. Respondents must identify the specific point(s) of interconnection including the type(s) of transmission service (e.g. NRIS or Energy Resource Interconnection Service (ERIS)). Proposals for facilities without existing firm deliverability to MISO LRZ 6 should include cost estimates and transmission studies associated with securing such deliverability.

The Proposal should also include nodal economic analyses (2023, 2028, and 2033) showing expected unit economic metrics (including congestion impacts on: capacity factor, produced energy, and generation revenue) for the project at the proposed delivery point(s).

Vectren reserves the right to reject any Proposal that does not include the full cost of any known or potential interconnection costs or network upgrades that may be required to provide firm deliverability to MISO LRZ 6 and/or that does not include interconnection, reliability, and/or economic analyses supporting interconnection and transmission requirements. Such materials should include a technical description and estimated costs of network upgrades from studies completed or underway.

4.1.2 Technical and Economic Detail

4.1.2.1 Generation Technology

Respondents shall describe the generation technology of the facility, including the make, model, and name of the supplier of all major equipment.

All Proposals to sell a generation facility to Vectren must utilize an existing, proven technology, with demonstrated reliable generation performance that is capable of sustained, predictable operation.

4.1.2.2 Dispatch and Emissions Characteristics

Respondents shall provide the dispatch and emissions characteristics of the generation facility in Appendix D, including, but not limited to:

- Minimum load level
- Maximum load level
- Ramp rates (up and down)
- Number of gas turbines that can be started simultaneously (if applicable)
- Heat rate curve for typical operations, including the minimum load and full load heat rates
  - If applicable, Respondent shall also provide heat rate curves for summer and winter seasons
- Fuel consumption and heat rate during startup, including startup time and the total number of hours annually the facility can be assumed to be in startup mode
- Fuel consumption and heat rate when the facility is being shut down, including how long shutdown takes and the total number of hours annually the facility can be assumed to be in shutdown mode
- An estimation of the total number of hours annually that the facility operates at full load
- Capability decreases as a result of ambient temperature increases
- Supplemental firing capability, including black start capability, and any operating limitations caused by such factors of design
- Pounds/megawatt hour (lb/MWh) emissions rates at relevant dispatch levels (startup, minimum, mid and full loading) and seasons (summer, winter, shoulder) for nitrogen oxides (NO_X), sulfur dioxide (SO_2), carbon dioxide (CO_2), volatile organize compounds (VOC), particulate matter (PM) and carbon monoxide (CO)
- Any other operational limitations that reduce unit availability or reduce a unit’s ability to dispatch or regulate

For renewable resources Respondents shall provide expected capacity factors, including 8760 hourly profiles (actual or based on weather data) and the expected useful life of the asset. If applicable, Respondents shall also provide expected annual degradation rates.

Regarding any major current and/or historical operational limitations, Respondents shall provide a description of the root causes of the limitations (e.g. original equipment manufacturer (OEM) design, material condition of the facility, environmental permits, etc.). To the extent that expected performance deviates from observed performance, the Respondent shall provide the basis for the assumption.

4.1.2.3 Revenues and Operating Costs

For existing generation facilities, Respondents shall provide a detailed breakout of the facility's actual annual revenues for each of the past five years. This will include energy, capacity, and ancillary service market revenues, as well as any other revenues the facility earned, including any congestion revenue (positive or negative), as well as uplift revenues. Associated with these revenues, Respondents shall state the estimated annual output in MWh as well as the operation and maintenance costs of the facility on a fixed ($) and variable ($/MWh) basis and provide the actual annual operation and maintenance costs of the facility for each of the past five years in nominal dollars.

Respondents shall provide a detailed breakout of the generation facility's estimated and actual annual fixed costs for the following categories: labor, benefits, materials, and all others for the past five years. Respondents shall provide a breakdown of the number of people employed at the facility, including permanent and contracted employees, and whether those employees are organized under any labor agreement.

If fixed or variable costs for the generation facility are expected to change in the foreseeable future (e.g., following planned upgrades, etc.), the Respondent should provide both the new expected cost(s) and the year(s) in which the costs are expected to change.

Respondents shall also state and describe any property, state, and local taxes and tax abatements associated with the generation facility, including all state and local taxes including property taxes.

New generation facilities also must provide reasonable expectations for all of the above details associated with plant revenues and costs, including market revenues, fixed and variable operations costs, expected upgrades and service timing, and taxes.

4.1.3 Operating Considerations

4.1.3.1 Operating Data

For an existing generation facility, Respondents shall provide historical operating data consisting of:

- The commercial operation date (COD) of the facility
- The annual run-time hours (per unit, if applicable)
- The annual operating cycles per year (per unit, if applicable)
- The annual facility capacity and availability factors
- The equivalent forced outage rate demand (EFORd)

The above annual data may be limited to the most recent five years. The EFORd should correspond to the UCAP amounts awarded for the last five Planning Years. Respondents shall provide a breakdown of EFORd by failure mode or North American Electric Reliability Corporation/Generating Availability Data System category. Respondents shall provide a description of the major contributors to the generation facility EFORd. If there are particular costs associated with maintaining the EFORd of a generation facility, those must be provided. Generating facilities considered a Dispatchable Intermittent Resource (DIR) in MISO shall provide historical curtailments over the most recent years. New facilities shall put forth a best effort forecast of curtailments by MISO.

Respondents shall provide details on any current generation facility equipment issues and concerns, including the potential drivers and recommended mitigation procedures for the issues and/or concerns. These may include, but are not limited to, any operation of the turbine, generator, or boiler outside recommended parameters established by OEM, compromised turbine or compressor blades, etc. Respondents shall provide a list of any redundant equipment that is currently bypassed or out of service, and the related reason. Respondents shall also provide historical information on such issues and concerns that have arisen, how they were resolved, and the associated costs for the last ten years of operation, or for the commercial life of the generation facility, whichever is lesser.

Respondents shall provide maintenance history for the lesser of the past ten years of operation or the commercial life of the generation facility consisting of: (i) dates of last full unit inspection and findings based on OEM recommendations; and (ii) outstanding OEM recommendations remaining to be implemented, including the cost and outage duration for any major maintenance requirements expected over the coming ten years. Respondents shall provide the outage reports for major planned and forced outages for each of the past five years.

For new or planned generation facilities, Proposals should include the manufacturer or developer quoted expected performance, as well as historical performance of similar facilities in MISO.

As noted in Section 4.1.5.3, below, Proposals shall disclose if the generation facility or any parts thereof are subject to a service agreement.

4.1.3.2 Operating Plan

Proposals should include a summary of the operating plan for the generation facility. Such plan should include software management system(s) and personnel roles and responsibilities for operating, maintaining, and servicing the facility, including any contractual arrangements currently in place.

Respondent shall provide an overview of key scheduled outage and maintenance plans, as well as plans for procuring and maintaining key spare parts.

For new or planned generation facilities, this should include a summary of the intended operating plan for the facility. The plan should include software management system(s) planned or in use (e.g., SAP, etc.), any third-party roles and responsibilities for operating, maintaining, and servicing the facility, including any contractual arrangements to be executed. Respondent shall provide an overview of key scheduled outage and maintenance plans, as well as plans for procuring and maintaining key spare parts.

4.1.3.3 Fuel Supply

Respondents shall provide a description, including detailed cost information, contract duration, and material contract terms (including whether fuel contracts are take or pay, minimum volume requirements, price reopeners, assignability or termination provisions) of all fuel purchase, storage, and transport agreements related to the generation facility Proposal. Cost of fuel commodities shall be provided separately from the cost of fuel transportation. Respondents also must list any provisions or other considerations that would prohibit or impair the assignment and/or affect the performance obligations of either party under the respective contract(s). Respondents shall describe fuel purchase and transport to the generation facility, as well as any existing or known potential operational restrictions or impediments on such fuel purchase and transportation. Respondents also are required to provide a description of the existing fuel supply (and storage) infrastructure serving the generation facility, including the infrastructure for the delivery of secondary fuel for dual-fuel resources. However, Vectren, through this RFP, is exploring the potential purchase of generation facilities, and it is Vectren’s sole discretion whether to assume any contract or contracts associated with the proposed generation facility related to fuel commodities and/or fuel transportation.

Proposals shall describe, to the extent possible, fuel sourcing strategy, including from where their fuel is sourced.

Proposals shall describe the generation facility’s ability to access a reliable fuel supply that would support operation for any hour throughout the year, including the plant’s on-site fuel storage and dual-fuel capabilities, if applicable. Proposals for gas generators shall indicate whether the facility is dual-fuel capable and Proposals should include an indication of the days of on-site fuel storage available. Gas generators without dual fuel capability shall provide information on the costs required to make the facility dual fuel capable to the extent that such cost estimates are available. Natural gas fired facilities shall have firm gas transportation contracts in place for the amount of gas capacity necessary to fulfill the amount of UCAP being bid. Proposals that do not include firm gas supply may be disqualified.

4.1.4 Environmental Considerations

4.1.4.1 Emissions and Waste Disposal Compliance

New and existing resources must be in compliance with all applicable environmental rules and regulations. To the extent applicable, all environmental attributes, including emission reduction credits and/or allowances, related to the power being purchased should be conveyed to Vectren. This includes, but is not limited to, any and all credits in any form (emissions credits, offsets, financial credits, etc.) or baseline emissions associated with both known and unknown pollutants, including but not limited to SO_2, NO_X, Mercury (Hg), and CO_2. Any and all environmental liabilities, including compliance with known and future or unknown regulations or laws will be the sole responsibility of the generation producer or PPA seller.

For Asset Purchase Proposals, the Seller will retain all pre-closing environmental liabilities and obligations as well as all known future environmental liabilities and obligations, in each case associated with the real and personal property transferred with or as part of a Sale of the Plant. This includes both on and off-site liabilities. The Buyer will assume all other post-closing environmental liabilities and obligations. For purposes of facility design, Seller should assume that the unit will be required to meet the proposed New Source Performance Standards for Greenhouse Gases (40 Code of Federal Regulations (CFR) part 60, subpart TTTT).

4.1.4.2 Water Supply

Respondents shall provide a detailed description of the water supply, including but not limited to, contract term, water usage, and cost of water for the generation facility. Respondents shall also provide the status of the facility’s National Pollutant Discharge Elimination System (NPDES) permits, including, but not limited to, permit conditions, permit violations reported over the last five years, the timing of next permit renewal, and any other known concerns.

If applicable, Respondents shall provide a summary of the facility’s water chemistry program, including key systems and suppliers, and its performance in the most recent year.

4.1.4.3 Permits

The generation facility must have all relevant environmental and other permits necessary for operation and maintenance. Facilities without such permits may be disqualified from consideration at Vectren’s sole discretion. Respondents shall provide a description of all permits currently in place for the operation and maintenance of the facility (e.g., Spill Prevention Containment and Control plans, Title IV and Title V permits of the Clean Air Act, Cap and Trade Permits, NPDES permits, Water Withdrawal, and Pollution

Incident Prevention Plan, etc.). Respondents must also state whether there are any provisions that would prohibit the assignment of such permits and/or any consents required for the assignment of such permits.

Respondents shall describe any operating limitations imposed by permitting or environmental compliance that limit plant availability.

Respondents shall provide a description of any identified environmental liabilities (e.g., potential site remediation requirements, etc.) for the facility.

4.1.5 Financial Considerations

4.1.5.1 Capital Expenditures

Respondents shall provide historical actual and budgeted capital expenditures for the generation facility. Historical capital expenditures shall be provided for each of the past five years in nominal dollars. Planned and budgeted capital expenditures shall be provided for each of next five years in nominal dollars along with a description of the projects involved. Respondents also shall disclose any known capital expenditure needs outside of the five-year time horizon that are expected to exceed $1 million dollars.

Respondents shall supply a summary list of all spare parts and components currently owned by the facility and their approximate dollar value. Respondents shall also identify any spare parts or components that are currently needed and/or on order as of the date the Proposal is submitted.

4.1.5.2 Acquisition Price

Respondents shall submit an acquisition price consisting of a single fixed payment that is inclusive of all monetary consideration for the generation facility, working inventory, and, if applicable, ancillary facilities and contractual arrangements (e.g., for fuel supply and transportation, maintenance, pollution control bonds, etc.). Respondents must submit their best and final price with their Proposal. Respondents must provide details regarding any liabilities that Vectren might assume as a buyer of a generation facility.

For new or planned generation facilities, the price offered in the Proposal shall include all costs associated with providing a completed generating asset whose full output will be accredited to the MISO LRZ 6. This includes, in particular, but without limitation, costs associated with transmission interconnection, including engineering studies, siting, permitting, acquisition and construction.[4]

[4] If, during the evaluation, Burns & McDonnell or Vectren determines that the Proposal will be unable to achieve firm delivery to MISO LRZ 6, the Proposal will be rejected.

4.1.5.3 Other Contractual Commitments

Respondents shall provide a description, including detailed cost information, of any other contracts that are currently necessary for generation facility operations, including, but not limited to, long-term service agreements, state union labor contracts and/or technical support contracts, agreements related to capacity and/or energy sales from the facility and any capacity offers submitted to any independent system operator/regional transmission organization related to the generation facility that, if accepted, would be binding on Vectren as a result of an acquisition. Respondents must also state whether there are any provisions that would prohibit the assignment and/or affect the performance obligations of either party under the respective contract, including transfer or cancellation fees.

4.1.6 Legal Considerations

4.1.6.1 Legal Proceedings, Liabilities & Risks

The Proposal shall include a summary of all material actions, suits, claims or proceedings (threatened or pending) against Respondent, its Guarantor (if applicable) or involving the generation facility or the site as of the Proposal due date, including existing liabilities whether or not publicly disclosed, including but not limited to those related to employment and labor laws, environmental laws, or contractual disputes for the development, construction, maintenance, fueling, or operation of the facility.

4.1.6.2 Material Contingencies

Proposals that have material contingencies, such as for financing, may not be considered.

4.1.7 Additional Items Specific to New Facilities

All Proposals for new generation facilities must have a well-defined and credible development plan for Respondent to complete the development, construction, and commissioning of the facility on their proposed development timeline. Respondents submitting Proposals for new or planned facilities should review the Development Risk evaluation metric and be sure to discuss key development milestones in their Proposal.

If available, Respondents shall submit:

1. A copy of an executed MISO Generator Interconnection Agreement
2. A copy of a completed MISO Facilities Study
3. A copy of a completed MISO System Impact Study

4. Nodal economic analyses (2023, 2028, and 2033) showing expected unit economic metrics (including congestion impacts on: capacity factor, produced energy, and generation revenue) for the project at the proposed delivery point(s)

If Respondent cannot provide this information, Respondent must indicate why it cannot be provided and must provide a timeline showing ability to complete key development milestone requirements prior to or after June 1, 2023 including the above referenced items for the MISO generator interconnection queue.

Respondent shall also detail its MISO generator interconnection queue position, if any, and the types and amounts of transmission service requested (e.g. NRIS or ERIS). Respondents submitting Proposals for a new or planned generation facility should also submit a copy of a fully executed EPC contract if available.

Respondents should also provide the following:

- Roles and responsibilities of the companies involved in the design, development, procurement, and construction of the facility. Information about key contributors shall extend to the status of contractual relationship with each key contributor; key contractual assurances, guarantees, warranties or commitments supporting the Proposal, including an executed EPC contract, and any past experience of Respondent working with each key contributor.
- Description of status of major equipment procurement, as well as processes for engineering, procurement, and construction bids and awards.
- Description of the facility site and Respondent's rights (i.e., whether owned, leased, under option) to such site. Please indicate whether additional land rights are necessary for the development, construction, and/or operation of the facility.
- Discussion of the development schedule and associated risks and risk mitigation plans for that schedule, including whether there are contract commitments from contractors supporting the proposed schedule. The Respondent should be prepared to document and commit to a proposed development schedule, which should include a COD.
- Discussion of the financing arrangements secured by the Respondent, including an overview of the sources of funds, and level of commitment from debt, equity, or other investors.
- Discussion on permitting, including a list of all required permits, permitting status of each, and key risks to securing necessary future permit approvals.
- Description of status in MISO queue process and presentation of documents described above.

- Financial information regarding guarantors and sources of equity funding along with either the Respondent's or guarantors' senior unsecured debt and/or corporate issuer ratings documentation from Moody's and Standard & Poor's showing the name of the rating agency, the type of rating, and the rating of the Respondent or guarantor.

Vectren will not assume any responsibility for the successful development, construction, and/or completion of a proposed facility. Accordingly, development schedule, budget, permits and approval risk will be the sole responsibility of the Respondent.

5.0 POWER PURCHASE AGREEMENT PROPOSALS

Vectren will consider meeting some or all of its resource requirements through short, medium and/or long-term PPAs. Vectren will only consider PPAs that have a term of five years or greater.

5.1 Name and Location

Respondents shall state the name of the generating facility, the county where the generating facility is located, the owner of the facility, and the commercial pricing node associated with the facility, if applicable. The facility must qualify as MISO internal generation (i.e. not pseudo-tied into MISO) and be qualified to receive Zonal Resource Credits for Zone 6 consistent with MISO's Module E Planning Resource Auction. Should the facility not be qualified in Zone 6, Respondents shall detail in their Proposals the means by which Zonal Resource Credits will be delivered/fulfilled in Zone 6.

5.2 Net Capability of Generating Facility

Respondents proposing a PPA for existing assets shall state the nameplate capacity, net summer operating capacity, net winter operating capacity and the UCAP of the facility for the 2019/2020 MISO planning year. Respondents shall specifically identify any known derates affecting the facility.

Respondents proposing existing assets shall also list the UCAP awarded to the facility, for the MISO Planning Years, 2015, 2016, 2017, 2018, and 2019. Respondents shall provide the projected UCAP for the facility. In the event that the projected UCAP has sizable deviation from historical UCAP, Respondents shall provide a detailed explanation. Respondents proposing facilities in development shall provide the anticipated UCAP after the asset acquisition date.

5.3 Generation Technology

Respondents shall describe the generation technology of the facility, including the make of the equipment, model, and name of supplier.

5.4 Dispatch and Emissions Characteristics

Respondents shall state/describe the dispatch characteristics of the facility, including, but not limited to, minimum load level, ramp rates (up and down), number of turbines that can be started simultaneously (if applicable), fuel consumption during startup, capability decreases as a result of ambient temperature increases, supplemental firing capability and any operating limitations caused by such factors as design, material condition of the facility, and various permit restrictions. Respondents shall state/describe the emissions profile of the facility, including but not limited to, the lbs/MMBtu at various dispatch profiles as applicable (startup, minimum load, mid, and max output) by season (summer, winter) for applicable emissions: NO_X, SO_2, CO_2, VOC, PM and CO.

Regarding any major operational limitations, Respondents shall provide a description of the root causes of the limitations (e.g., OEM design, material condition of the facility, environmental permits, etc.) Generating facilities considered a DIR in MISO shall provide historical curtailments over the most recent five years. New facilities shall put forth a best effort forecast of curtailments by MISO. Respondents shall also specify how DIR will be addressed (i.e. agreed to MISO offer price, bank of curtailment energy, etc.) within submitted Proposals. Generally, Proposals shall also take into consideration Vectren acting as the MISO Market Participant (responsible for market offers). However, Vectren is willing to consider Proposals where Vectren is not acting as the MISO Market Participant to the extent it is beneficial to Vectren's customers.

5.5 Fuel Supply

Respondents must supply a detailed fuel supply plan that fully details how fuel is purchased and transported to the facility as well as any existing or known potential operational restrictions or impediments on such fuel supply. This applies to all fuel types used to operate a facility, including natural gas, coal, fuel oil, biomass, etc. The Respondent is also required to provide a description, including detailed cost information, of all fuel service and purchase agreements applicable to the facility.

Respondents proposing a PPA shall be solely responsible for maintaining a reliable fuel supply that is delivered to the Respondent's proposed generating unit(s) to ensure reliable delivery of firm capacity and energy to Vectren throughout the Delivery Term. Facilities operating on natural gas must have firm natural gas supply agreement(s) capable of meeting 100% of the facility's maximum daily consumption requirements throughout the Delivery Term. The supply agreement(s) should provide all services required to cause natural gas to be delivered to the facility on a firm basis, which may include both timely and intraday supply, transportation, storage, and/or balancing.

5.6 Financial Considerations

5.6.1 Power Purchase Agreement

Respondents shall submit an annual power purchase price ($ and/or $/MWh as applicable) consisting of a payment that is inclusive of all monetary consideration for the generation facility, working inventory, and, if applicable, ancillary facilities and contractual arrangements (e.g., for fuel supply and transportation, maintenance, pollution control bonds, etc.). Respondents must submit their best and final price with their Proposal. Respondents must provide details regarding any liabilities that Vectren might assume.

For new or planned generation facilities, the price offered in the Proposal shall include all costs associated with providing a completed generating asset whose full output will be accredited to the MISO LRZ 6. This includes, in particular, but without limitation, costs associated with transmission interconnection, including engineering studies, siting, permitting, acquisition and construction.[5]

5.6.2 Asset(s) Specific Financial Information

Respondents shall submit audited or unaudited Financial Statements including Balance Sheets, Income Statements and Cash Flow Statements for the proposed asset(s) for the past three years. Respondents shall clearly indicate book value of the asset(s) in the financial information submitted.

5.6.3 Other Contractual Commitments

Respondents shall state whether there are other contractual commitments limiting or affecting the operation of the facility. Respondents shall state whether there are any other agreements in place for or claims on output from the facility. Such information should include any obligations that may restrict or compromise Vectren's ability to dispatch the facility.

5.6.4 Assets in Development

For PPA supported by proposed assets or assets that have not yet achieved their COD, Respondents must provide the same information requested in Section 4.1.7 for facilities to be developed.

[5] If, during the evaluation, Burns & McDonnell or Vectren determines that the Proposal will be unable to achieve firm delivery to MISO LRZ 6, the Proposal will be rejected.

6.0 LOAD MODIFYING RESOURCES/DEMAND RESOURCES

LMRs/DRs are demand-side resources and behind the meter generation not typically modeled or measured as part of MISO's operations but used during capacity shortages to help meet the energy balance. Vectren will consider LMRs/DRs from one or more MISO customers or curtailment service providers (CSP). LMR suppliers must be located entirely within MISO LRZ 6. Proposals for LMRs/DRs are to be for assets that are eligible to participate in MISO LRZ 6 and can meet the additional performance requirements of Vectren as described in Sections 6.1 and 6.3. In addition, for LMRs/DRs located within Indiana, Respondent must identify how the Proposal conforms with any requirements of the local utility and state law in order to offer resources for capacity accreditation within the MISO market under Module E Capacity Tracking.

Proposals for LMRs/DRs may be combined with another power supply Proposal or may be submitted on a standalone basis. Vectren will consider LMR/DR Proposals that have a term of one year or longer, consistent with MISO planning years.

6.1 Product Definition

To be eligible for participation in this RFP, the LMR/DR offered by a supplier must:

- Meet LMR/DR Requirements for participation in MISO as a demand-side resource, including any future changes to MISO's requirements for LMRs/DRs for the term of the Proposal
- Meet the additional performance requirements described in Section 6.3
- For capacity accreditation, the Proposal must be sourced from locations entirely within the MISO LRZ 6
- For energy accreditation, the Proposal must be sourced from locations entirely within Vectren's electric service territory
- Be at least 10 MW
- Use an existing, proven technology that has demonstrated reliable demand reduction, which may include use of Behind the Meter Generation (as defined by MISO)
- Reduce load by a predetermined amount when notified by Vectren of a Curtailment Event without further direction or communication by or from Vectren.

6.2 Purchase Agreement

If selected, the LMR/DRs supplier and Vectren will negotiate a mutually acceptable agreement to govern any commercial relationship established by the parties. With respect to a Proposal from a CSP, Vectren will not be responsible for making payments to, communicating with, or managing the relationship or performance of any customer within an aggregation, and the CSP shall be solely responsible for the same in all respects. To mitigate risk, Vectren will require the LMR/DR supplier to provide collateral upon execution of a LMR/DR Proposal. Vectren reserves the right to determine the form of that collateral requirement for a winning Proposal.

6.3 Curtailment Events: Notification and Performance Requirements

LMRs/DRs must meet notification and performance requirements applicable to a Curtailment Event, as defined and described herein and comply with MISO current and future testing requirements. For purposes of this RFP, a Curtailment Event shall be one in which either Vectren or MISO determines, in its respective sole discretion. MISO may also initiate a Curtailment Event upon its sole determination that a pre-emergency situation exists.

6.3.1 Notification, Performance, and Test Requirements

Curtailment Events initiated by MISO: For Curtailment Events initiated by MISO, LMR/DR suppliers shall agree to and be capable of meeting, throughout the entire term of the Proposal, all notification and performance requirements applicable to Capacity Performance demand resources. The supplier shall comply with all MISO Module E Capacity Tracking measurement and verification requirements.

Curtailment Events initiated by Vectren: Suppliers shall also agree to and be capable of meeting the following additional notification and performance requirements applicable to Curtailment Events initiated solely by Vectren:

- Suppliers shall curtail Actual Measured Load to Firm Contract Load within the proposed notification time specified in the Proposal
- Notification of a Curtailment Event initiated solely by Vectren will consist of an electronic message issued by Vectren to a device or devices such as telephone, facsimile, or e-mail, selected and provided by the supplier and approved by Vectren. Two-way information capability shall be incorporated by Vectren and the supplier in order to provide confirmation of receipt of notification messages. Vectren will provide the supplier a notification of when Curtailment Events have ended. Operation, maintenance, and functionality of communication devices for receipt of notifications selected by the supplier shall be the sole responsibility of the supplier, and receipt of notifications set out in this paragraph shall be the sole responsibility of the supplier

- During the entire period of a Curtailment Event initiated by Vectren, the supplier's Actual Measured Load must remain at or below its Firm Contract Load. A supplier's Actual Measured Load shall be determined by integrating the megawatts used over every clock hour (hour-ending).

6.3.2 Remedies for Non-Performance

A supplier whose Actual Measured Load exceeds its Firm Contract Load will be subject to performance penalties which may include, but not be limited to, refunding to Vectren monthly payments under the agreement.

A supplier shall be responsible for, and shall indemnify Vectren for, any non-performance penalties, costs, charges, or other amounts assessed by MISO and incurred by Vectren as a result of non-performance attributable to the supplier's LMR/DR, including but not limited to any Capacity Resource Deficiency Charges, Non-Performance Charges, or similar charges or penalties under the MISO agreements. In no event shall the penalties listed above for non-performance during a Curtailment Event be less than the sum of any MISO non-performance penalties, costs, charges, or other amounts incurred by Vectren as a result of non-performance attributable to the supplier's LMR/DR and the Curtailment Event charge.

6.4 Proposal Requirements

6.4.1 Acquisition Price

Suppliers shall submit an acquisition price consisting of a single fixed amount denominated in units of dollars per megawatt-day ($/MW-day), which is to apply for the term of the Proposal. If a Proposal is accepted, the supplier will be compensated in an amount equal to the monthly Curtailable Load times the Acquisition Price. The Proposal shall include all monetary consideration for the LMR/DR offered. Suppliers must submit their best and final price with their Proposal.

Should Vectren execute an agreement with a Respondent, the contract price between Vectren and the Respondent will be the Acquisition Price submitted in its respective Proposal through this RFP process.

6.4.2 Product Description

A Proposal shall include a description of the individual LMR/DR customer(s) and expected load drop values (kW), equipment, and technology that will be deployed and make available any other information required by MISO to meet its registration process, and for CSPs, plans for recruiting, engaging, and maintaining Program Participants.

Proposals should discuss the experience, qualifications, and financial strength of the supplier and other key contributors including the specific number of months the supplier has been providing LMR/DR services in MISO. Responses should indicate whether the supplier has ever been assessed a performance penalty in association with the resource and if so, when any penalties were assessed. For CSPs, Proposals should describe well-defined roles and responsibilities of the supplier and its participants. The supplier should describe successful protocols, if any, they have employed in the MISO LRZ 6 or other MISO zones for dispatching their LMR/DR.

While the product definition requires a load reduction upon notification by Vectren or MISO of a Curtailment Event, there is a preference for resources that can provide a more rapid response and/or ramp up or down in response to specific control signals. Respondents are urged to detail the full, demonstrated capability of the proposed resource in accordance with the evaluation criteria included in Section 7.0.

For planned LMRs/DRs, the supplier must fully describe specific plans detailing what equipment or technology it will deploy and/or utilize to support its operations. For CSPs, Proposals must describe supplier's processes for aggregating participants, how the supplier intends to recruit and engage participants, and/or provide lists of participants. The Proposal also must describe curtailment systems and procedures, budgeting for and structure of dispute resolution, and plans for communicating with participants in connection with a curtailment period.

6.4.3 Technical Requirements

Vectren shall acquire all rights, titles, and interests in the LMR/DR including all the potential capacity and energy revenues. Suppliers must agree to cooperate with Vectren in providing information needed to meet all MISO LMR/DR information requirements.

The supplier will assume all responsibilities and liabilities associated with providing LMRs/DRs. Accordingly, Proposals offering LMRs/DRs must include acknowledgment and agreement that the supplier is responsible for the following non-exhaustive list of activities and obligations:

- Managing load reductions, including all notices, communications, controls, equipment, or other processes required
- If the supplier is a CSP, determining the number of participants, in its aggregation, the number of interruptible hours per customer, and the size of each participant's load reduction
- If the supplier is a CSP, paying any participants according to the CSP's agreement with those participants. Such agreements shall be independent of Vectren's agreement with the CSP and

must hold Vectren harmless for any direct or indirect obligations or liability associated with the program

- Paying penalties assessed due to the non-performance of the LMR/DR

The agreement shall reflect that it will be the supplier's responsibility to reimburse Vectren for any penalties, fees, or charges resulting from non-performance of its LMR/DR, including replacement capacity to maintain Vectren's planning reserve margin requirement, and the supplier's obligation to indemnify and hold Vectren harmless against any claim arising from such non-performance. In the case of a supplier who is a CSP, the agreement will additionally set forth CSP's responsibility to reimburse Vectren for any penalties, fees, or charges resulting from non-performance of any CSP participant, and CSP's obligation to indemnify and hold Vectren harmless against any claim arising from such CSP participants' non-performance.

6.5 Evaluation Methodology

Burns & McDonnell will identify for recommendation to Vectren the LMR/DR Proposal or portfolio of Proposals that contribute to Vectren's capacity needs consistent with the evaluation methodology outlined in Section 7.0. LMRs/DRs will be evaluated independently of supply-side resources and may include other scoring criteria.

6.6 Contract Execution

Vectren does not, by this RFP, obligate itself to purchase any LMR/DR, or to execute an agreement with any Respondent who submits an offer to sell a LMR/DR to Vectren. Vectren may, in its discretion, reject any or all Proposals to sell a LMR/DR to Vectren, as such are described in this RFP.

Selection of a Proposal as a finalist shall not be construed as a commitment by Vectren to execute an agreement. Execution of any agreement is contingent upon Vectren receiving all required regulatory approvals and completion of such due diligence as Vectren in its sole discretion determines is reasonable to confirm the qualifications and performance of a given LMR/DR. During the period between when Burns & McDonnell makes its recommendation(s) to Vectren, and the date of execution of the agreement, Vectren may conduct additional due diligence on the Proposal.

7.0 PROPOSAL EVALUATION AND CONTRACT NEGOTIATIONS

7.1 Initial Proposal Review

An initial review of the bids will be performed by Burns & McDonnell. Proposals will be reviewed for completeness. Proposals that do not meet the requirements of this RFP may be notified. Respondents may also be contacted for additional data or clarifications by Burns & McDonnell, these communications will be initiated via e-mail (VectrenRFP@burnsmcd.com). Each complete bid will be evaluated by quantitative and qualitative factors. The evaluation criteria outlined in this section are intended to relatively compare each Proposal to analogous submissions and will be the starting guidelines for the evaluation. If needed, the scoring may be adjusted to provide distinction between Proposals. This evaluation, in conjunction with the IRP, will be used to determine which resources are most capable of providing Vectren customers with a safe, reliable, and affordable power supply.

7.2 Evaluation Criteria - Generation Facility

Burns & McDonnell will quantitatively and qualitatively evaluate all conforming generation facility Proposals' ability to meet power supply needs. During this evaluation process, Burns & McDonnell may or may not choose to initiate more detailed clarification discussions with one or more Respondents. Discussions with a Respondent shall in no way be construed as commencing contract negotiations. A more detailed quantitative evaluation for select bidders will consider production cost models and nodal analysis.

Table 7-1: Generation Facility Scoring Criteria Summary[6]

	LCOE Evaluation	Energy Settlement Location	Interconnection/ Development Status & LCR	Project Risk Factors
Points	150	100	90	160
%	30%	20%	18%	32%

7.2.1 Levelized Cost of Energy - 150 Points

The initial evaluation will be primarily based on a comparison of each Proposal's Levelized Cost of Energy (LCOE). A LCOE allows for Proposals within asset classes, which have different sizes, pricing, operating characteristics, ownership structures, etc. to be evaluated and compared to each other on an equivalent economic basis. The LCOE analysis will incorporate all costs associated with an asset purchase or PPA over a 20-year/standardized amount of time. These costs will include the applicable

[6] Vectren reserves the right to add up to 100 points to Proposals located in Southern Indiana, as local resources provide multiple benefits: VAR support, economic development, less future congestion risk, etc.

purchase or PPA cost, fixed costs, and variable operating expenses across standard technology respective operating parameters. The levelized value of these costs over this time period are then divided by the energy produced by the respective Proposal.

Vectren specific assumptions used in this analysis will be in accordance with Vectren's 2019/2020 IRP assumptions, including but not limited to

- Discount rate
- Capital recovery factor
- Escalation
- Commodity forecasts

The LCOE evaluation is a screening level economic evaluation which will determine the cost of energy provided by each Proposal relative to similar technology types. Proposals within an evaluation class with the lowest LCOE will receive full scoring for this metric. Based on variance of costs and number of Proposals in each class, points awarded to higher cost Proposals will be scaled accordingly.

The rules for performing the LCOE analysis will be determined by Burns & McDonnell and Vectren in advance of the receipt and review of any Proposals. However, as part of the process of evaluating Proposals, cases may arise where, in order to adequately project asset costs or to facilitate a comparison between qualified Proposals, the rules related to the LCOE analysis may require review and/or adjustment. To the extent that any additions or adjustments are required, such additions or adjustments will be made solely by Burns & McDonnell. In such cases, any and all rules will be applied consistently across all Respondents.

While performing LCOE analyses of Proposals, Burns & McDonnell may request additional or clarifying information from a given Respondent regarding unit performance, operating costs, or other factors that influence the LCOE calculation for a given resource. This evaluation will also include grid congestion analysis. Requests for additional information may be required to ensure that all qualified Proposals are fairly and consistently evaluated. Consistent with Section 2.3, in such cases, Respondents will be required to respond within five business days of receipt of such request. Burns & McDonnell will not consider unsolicited updates from Respondents related to the cost of any power supply resource.

7.2.2 Energy Settlement Location - 100 points

Vectren has a preference for Proposals that include all costs to have energy financially settled or directly delivered to Vectren's load node (SIGE.SIGW). Proposals that meet one of these criteria will receive 100 points, while Proposals failing to meet either criteria will be awarded zero points. Market data from Proposals that include the aforementioned costs will be carried forward into the IRP modeling analysis as described in Section 7.5.

7.2.3 Interconnection and Development Status - 60 Points

Existing resources will receive full credit under this evaluation category. Plants that have not achieved commercial operation but that are in the MISO Generation Interconnection (GI) Queue will be awarded points based on the Definitive Planning Phase they are in. Other projects not in the MISO GI Queue must demonstrate development progress. Facilities failing to meet critical development milestones may be disqualified from consideration at Vectren's sole discretion.

Up to 60 points will be will awarded based on the achievement of certain development milestones towards the facility COD. Five milestones have been selected and 12 points will be awarded for each equally. The selected milestones are as follows:

- Executed a MISO Generator Interconnection Agreement
- Completed a MISO Facilities Study
- Completed a MISO System Impact Study
- Achieved site control and completed zoning requirements
- EPC Contract awarded

7.2.4 Local Clearing Requirement Risk - 30 Points

The MISO footprint is split into ten LRZs. All load serving entities within MISO are required to obtain capacity which meets their respective Planning Reserve Margin (PRM). A Local Reliability Requirement is also established for each LRZ which is the aggregate of all Load Serving Entity's (LSE's) PRMs. Due to Zonal capacity import/export limitations a portion of each LRZ's Local Reliability Requirement must be served locally, this requirement is the zone's Local Clearing Requirement (LCR). The LCR establishes the amount of Unforced Capacity which is required to be located in each respective LRZ.

Proposals located within LRZ 6 provide additional risk avoidance to Vectren's LCR requirements and will receive 30 points; Proposals located outside of LRZ 6 will receive zero points.

7.2.5 Project Risk Factors - 160 Points

Certain risk factors may be unique to a Proposal. Such factors may be significant enough to independently impact the overall ability of the Proposal to meet Vectren's needs.

This category is intended to capture unspecified risk that may be highlighted by a bidder or identified during the Proposal review. The Project Risk Factors Section attempts to identify and score potential risks which may compromise the future performance of the asset[7]. In situations where the level of risk is not accurately represented, scoring may be adjusted. Potential considerations include, but may not be limited to the following:

- Credit and financial plan - Proposals with a long term unsecured credit rating below BBB+ (Baa1 for Moody's) will not be considered in this evaluation. Proposals which have internal financing are preferred and will receive the 20 points for this category[8].
- Development experience - Relevant technology development experience is an important risk factor. Proposals will receive up to 20 points based on the following formula:

$$Points\ awarded = \frac{(nameplate\ MW\ in\ service)}{1{,}500} * 20$$

- Sole ownership vs. partial owner - Due to site and dispatch rights/preferences, a sole ownership Proposal will receive 20 points.
- Proposal ownership structure - Due to a preference for ownership Asset Purchase Proposals will receive 20 points while PPA Proposals will receive zero points.
- Operational control - Proposals which offer Vectren operational control will receive 20 points
- Fuel risk - For applicable Proposals, sites with firm and reliable fuel supply will receive 20 points.
- Delivery date - For each year prior or after 2023, 25% of the 20 possible points will be deducted.
- Site Control - Proposals which have fully achieved site control will receive 20 points

Any such risks shall be disclosed along with a description of the associated measures taken to mitigate the risk. Failure to disclose a reasonably foreseeable risk or risks may be a basis to disqualify a Proposal.

Proposals with no such risks as determined by Burns & McDonnell will receive the full number of points available in this category. Proposals with asset or project-specific risks that are not able to be fully mitigated may receive fewer points depending on Burns & McDonnell's assessment.

7.3 Evaluation Criteria - LMR/DR

Burns & McDonnell will quantitatively and qualitatively evaluate all conforming LMR/DR Proposals. During this evaluation process, Burns & McDonnell may or may not choose to initiate more detailed

[7] Vectren reserves the right to add up to 100 points to Proposals located in Southern Indiana, as local resources provide multiple benefits: VAR support, economic development, less future congestion risk, etc.
[8] Vectren reserves the right to re-evaluate credit rating and exclude bidders at its sole discretion.

clarification discussions with one or more Respondents. Discussions with a Respondent shall in no way be construed as commencing contract negotiations. A more detailed quantitative evaluation for select bidders will consider production cost models and nodal analysis.

Vectren will accept Proposals from LMRs/DRs that meet the requirements as established in this RFP and conforms to MISO requirements. These requirements include but are not limited to, the ability to respond to Curtailment Events initiated either by MISO or by Vectren.

LMR/DR proposals will be evaluated across the following criteria:

Table 7-2: LMR/DR Scoring Criteria Summary[9]

	Cost Evaluation	Historical Performance	Response Time	Proposal Risk Factors
Points	200	100	100	100
%	40%	20%	20%	20%

7.3.1 Cost Evaluation - 200 Points

The cost of each Proposal will be evaluated based on the annual payment per MW for the LMR/DR. The lowest $/MW cost Proposal will receive 200 points for the cost evaluation category. Based on variance of costs and number of Proposals, points awarded to higher cost Proposals will be scaled accordingly.

7.3.2 Historical Performance - 100 Points

An end use customer or CSP with a historical performance record of successfully providing demand response services for three or more years without being assessed a non-performance penalty will receive 100 points for this category.

An end use customer or CSP that has provided such services for between one year and three years without being assessed a non-performance penalty will receive 50 points for this category.

An end use customer or CSP that has not provided such services in the past or that has been assessed a non-performance penalty will receive zero points for this category.

[9] Due to benefits other than capacity accreditation, Vectren reserves the right to add up to 100 points to LMR/DR Proposals located within Vectren's electric service territory.

7.3.3 Response Time - 100 Points

While the product defines a load reduction response time within a Respondent's Proposal, there is a preference for resources that can provide a more rapid response to specific control signals.

Proposals for LMR/DR that have the ability to follow a real-time signal will be awarded 100 points for the response time category. Proposals for LMR/DR that can achieve the load reduction target within 30 minutes of notification will receive 75 points for this category. Proposals for LMR/DR that can achieve the load reduction target within 60 minutes of notification will receive 50 points for this category. Proposals for LMR/DR that can achieve the load reduction target within 120 minutes of notification will receive 25 points for this category.

7.3.4 Proposal Risk Factors - 100 Points

This category is intended to capture unspecified risk that may be highlighted by a LMR/DR Proposal or identified during the Proposal review. The Proposal risk factors category will be used to adjust the overall scoring in cases where there is a material risk identified that may create concerns about the ability of the provider to deliver on their Proposal or that may create a material uncertainty about the cost to Vectren or its customers, significant regulatory uncertainty, or other considerations.

7.4 Discussion of Proposals During Evaluation Period

Based on the quantitative and qualitative evaluations and needs identified during the 2019/2020 IRP, Vectren may or may not select candidates for further discussions. Vectren will contact any selected Respondent in writing to confirm interest in commencing contract negotiations. All negotiations will begin with Vectren's standard contract as a starting point. Vectren's commencement of and participation in negotiations shall not be construed as a commitment to execute a contract. If a contract is negotiated, it will not be effective unless and until it is fully executed with the receipt of all required regulatory approvals.

7.5 Selection of Highest Scoring Proposal(s) based on IRP Analysis

Where possible, aggregated cost and performance information from the RFP bids, which provide a delivered price (pending verification), will be provided to the IRP team to facilitate certain portfolio modeling[10]. The IRP analysis will provide the RFP team with a preferred portfolio based on these costs. RFP bids will be rank ordered consistent with the evaluation criteria and assets will be selected consistent with the RFP evaluation and the IRP determined need. Consistent with that objective, Vectren may need

[10] Proposals that do not provide an energy settlement contract or physical deliverability to Vectren's load node (SIGE.SIGW) will not be included in the IRP analysis, but may be considered for procurement.

to contract with multiple generating assets. Cost certainty and project implementation are key considerations that will be included in qualitative analysis and that will include the ranking of projects with firm price offers and price caps, projects in the MISO GI queue or with signed Generator Interconnection Agreements (GIAs), recent prior development experience, etc. Vectren will seek to secure resources consistent with the preferred portfolio identified in the 2019/2020 IRP. As such, there is no assurance that the individual, highest-scoring qualified Proposal(s) will be selected.

7.6 Contract Execution

Vectren does not, by this RFP, obligate itself to purchase any generation facility or facilities, or to execute the Asset Purchase Agreement or PPA with any Respondent who submits an offer to sell generation capacity and/or energy to Vectren and Vectren may, in its discretion, reject any or all Proposals, as such are described in this RFP.

Selection of a winning Proposal shall not be construed as a commitment by Vectren to execute an agreement. During the period between Burns & McDonnell’s delivery of results to Vectren and the date of execution of any agreement, Vectren will conduct additional due diligence on the Proposal which may include, but not be limited to, onsite visits, management interviews, legal and regulatory due diligence, and detailed engineering assessments and facility dispatch modeling.

8.0 PROPOSAL SUBMISSION

All Proposal documents must be submitted to the RFP Manager via e-mail to VectrenRFP@burnsmcd.com.

8.1 Format and Documentation

All Proposals submitted in response to this RFP must be received by Burns & McDonnell (VectrenRFP@burnsmcd.com) no later than the Proposal Submittal Due Date shown in Section 2.4. Burns & McDonnell and Vectren will not evaluate Proposals as part of this RFP process if submitted after this date and time. Multiple Proposals submitted by the same Respondent must be identified and submitted separately. Financial statements, annual reports, technical specification documents, and other large documents can be sent electronically to the RFP e-mail address. Each Proposal must contain the following:

1. Appendix B: Non-Disclosure Agreement (NDA) in its present form
2. Appendix D: Proposal Data in Excel format

8.2 Certification

A Respondent's Proposal must certify that:

1. There are no pending legal or civil actions that would impair the Respondent's ability to perform its obligations under the proposed PPA or Asset Purchase
2. The Respondent has not directly or indirectly induced or solicited any other Respondent to submit a false Proposal
3. The Respondent has not solicited or induced any other person, firm, or corporation to refrain from submitting a Proposal
4. The Respondent has not sought by collusion to obtain any advantage over any other Respondent.

9.0 RESERVATION OF RIGHTS

Nothing contained in this RFP shall be construed to require or obligate Vectren to select any Proposals or limit the ability of Vectren to reject all Proposals in its sole and exclusive discretion. Vectren further reserves the right to withdraw and terminate this RFP at any time prior to the Proposal Submittal Due Date, selection of bids or execution of a contract. All final contracts will be contingent on IURC approval.

All Proposals submitted to Vectren pursuant to this RFP shall become the exclusive property of Vectren and may be used for any reasonable purpose by Vectren. Vectren and Burns & McDonnell shall consider materials provided by Respondent in response to this RFP to be confidential only if such materials are clearly designated as Confidential. Respondents should be aware that their Proposal, even if marked Confidential, may be subject to discovery and disclosure in regulatory or judicial proceedings that may or may not be initiated by Vectren. Respondents may be required to justify the requested confidential treatment under the provisions of a protective order issued in such proceedings. If required by an order of an agency or court of competent jurisdiction, Vectren may produce the material in response to such order without prior consultation with the Respondent.

10.0 CONFIDENTIALITY OF INFORMATION

All Proposals submitted in response to this RFP become the responsibility of Burns & McDonnell and Vectren upon submittal. Respondents should clearly identify each page of information considered to be confidential or proprietary. Consistent with the RFP NDA (Appendix B), Burns & McDonnell will take reasonable precautions and use reasonable efforts to maintain the confidentiality of all information so identified. Vectren reserves the right to release any Proposals, or portions thereof, to agents, attorneys, or consultants for purposes of Proposal evaluation. Regardless of the confidentiality claimed, however, and regardless of the provisions of this RFP, all such information may be subject to review by, and disclosable by Vectren, to the appropriate state authority, or any other governmental authority or judicial body with jurisdiction relating to these matters, and may also be subject to discovery by other parties subject to fully executed NDAs/confidentiality agreements. Further, because Vectren is conducting this RFP as part of the IRP public advisory process, Vectren will disclose the UCAP MW offered, technology/resource type, average price, general location, proposed ownership structure, and Proposal duration of all Proposals unless a given technology has less than three Respondents in order to inform our stakeholders of the summary results of the RFP. Vectren will also disclose the names of Respondents participating in the RFP.

11.0 REGULATORY APPROVALS

Pursuant to the terms of the definitive agreement(s), the Respondent will agree to use its reasonable best efforts, including, if necessary, providing data and testimony, to obtain any and all State, Federal, or other regulatory approvals required for the consummation of the transaction.

Please note in particular that approval by the IURC, MISO and FERC may be required before the transaction can be consummated between the selected Respondent and Vectren. As part of the regulatory process, responses to the RFP may be provided to parties who have executed an NDA/confidentiality agreement, specifically acknowledging that they are neither affiliated with any party responding to the RFP or serving as a conduit for any party responding to the RFP.

12.0 CREDIT QUALIFICATION AND COLLATERAL

The credit and commitment of any bid will be a critical part of the bid evaluation process. A Respondent must have a credit rating for its senior unsecured debt of BBB+ or higher for Standard & Poor's (or Baa1 or higher for Moody's). If a Respondent is unrated or does not meet this minimum credit rating requirement, the Respondent may provide credit support from a corporate guarantor that meets the requirement.

As part of a final binding contract, and depending on the structure of the transaction, Vectren will further review the credit of the Respondent and the risk associated with the transaction to determine what, if any, additional credit requirements may be necessary to protect its ability to serve its customers in a reliable manner.

For asset purchases, a Respondent shall have the corresponding obligation to post Definitive Agreement (DA) collateral as determined in accordance with its Proposal if selected for the definitive agreement phase of the RFP. DA Collateral must be posted at the execution of the definitive agreement and will be in force until the transfer of title to Vectren for generating asset Proposals.

For PPAs and LMRs/DRs, winning Respondents may be required to post operating collateral over the term of any PPA or LMR/DR agreement consistent with the terms and conditions of final agreements as negotiated between Vectren and the supplier.

In each case, the collateral must be in the form of either: (a) a letter of credit, (b) cash, or (c) a construction bond. Burns & McDonnell and Vectren reserve the right to require a Respondent to post DA Collateral in an amount that exceeds the amounts listed herein as conditions warrant.

Table 12-1: Collateral

Asset	Collateral Amount
Asset Purchase	$50.00/kW (UCAP) at execution of definitive agreement
Asset Purchase	$150.00/kW (UCAP) at regulatory approval
Power Purchase Agreement	12-months expected revenues
LMR/DR	12-months expected revenues

13.0 MISCELLANEOUS

13.1 Non-Exclusive Nature of RFP

Vectren may procure more or less than the amount of assets solicited in this RFP from one or more Respondent(s). Respondents are advised that any definitive agreement executed by Vectren and any selected Respondent may not be an exclusive contract for the provision of assets. In submitting a Proposal(s), Respondent will be deemed to have acknowledged that Vectren may contract with others for the same or similar deliverables or may otherwise obtain the same or similar deliverables by other means and on different terms.

13.2 Information Provided in RFP

The information provided in this RFP, or on the RFP website (http://VectrenRFP.rfpmanager.biz/), has been prepared to assist Respondents in evaluating this RFP. It does not purport to contain all the information that may be relevant to Respondent in satisfying its due diligence efforts. Vectren makes no representation or warranty, express or implied, as to the accuracy, reliability or completeness of the information in this RFP, and shall not be liable for any representation, expressed or implied, in this RFP or any omissions from this RFP, or any information provided to a Respondent by any other source.

13.3 Proposal Costs

Vectren shall not reimburse Respondent and Respondent is responsible for any cost incurred in the preparation or submission of a Proposal(s), in negotiations for an agreement, and/or any other activity contemplated by the Proposal(s) submitted in connection with this RFP. The information provided in this RFP, or on Vectren’s RFP website, has been prepared to assist Respondents in evaluating this RFP. It does not purport to contain all the information that may be relevant to Respondent in satisfying its due diligence efforts.

13.4 Indemnity

Supplementing Respondent’s assumption of liability pursuant to this RFP, Respondent shall indemnify, hold harmless and defend Vectren and its parent company, officers, employees and agents, from any and all damages, liabilities, claims, expenses (including reasonable attorneys’ fees), losses, judgments, proceedings or investigations incurred by, or asserted against, Vectren or its officers, employees or agents, arising from, or are related to, this RFP, or the execution or performance of one or more definitive agreements.

13.5 Hold Harmless

Respondent shall hold Vectren harmless from all damages and costs, including, but not limited, to legal costs in connection with all claims, expenses, losses, proceedings or investigations that arise as a result of this RFP or the award of a Proposal pursuant to the RFP or the execution or performance of a definitive agreement.

13.6 Further Assurances

By submitting a Proposal, Respondent agrees, at its expense, to enter into additional agreements, and to provide additional information and documents, in either case as requested by Burns & McDonnell in order to facilitate: (a) the review of a Proposal, (b) the execution of one or more definitive agreements, or (c) the procurement of regulatory approvals required for the effectiveness of one or more definitive agreements.

13.7 Licenses and Permits

Respondent shall obtain, at its cost and expense, all licenses and permits that may be required by any governmental body or agency necessary to conduct Respondent's business or to perform hereunder. Respondent's subcontractors, employees, agents and representatives of each in performance hereunder shall comply with all applicable governmental laws, ordinances, rules, regulations, orders and all other governmental requirements.

APPENDIX A – NOTICE OF INTENT TO RESPOND

Notice of Intent to Respond

CONTACT INFORMATION			
Company			
Primary Contact:			
Name			
Title			
Telephone			
E-mail			
Mailing Address			
Signature of Respondent		Date	

Due: June 27, 2019

E-mail: VectrenRFP@burnsmcd.com

APPENDIX B – NON-DISCLOSURE AGREEMENT

NON-DISCLOSURE AGREEMENT

THIS NON-DISCLOSURE AGREEMENT (Agreement) is entered into as of the __ day of _________, 2019, between Southern Indiana Gas and Electric Company, Inc., Vectren Energy Delivery of Indiana, Inc. (Vectren) having its headquarters and principal place of business in Evansville, Indiana, and [_________________________________], a [___________] corporation/llc/partnership (the Company), (collectively, the Parties, and individually, Party).

R E C I T A L S:

A. The Parties intend to discuss and evaluate proposals regarding possible energy/capacity transactions that could be entered into between Vectren and the Company, which discussions may include sharing of bid proposal information received from the Company during the competitive bid process administered by Burns & McDonnell on behalf of Vectren (the Transaction).

B. The Parties acknowledge that each Party may make available to the other Party, from time to time, in connection with such discussions, certain Confidential Information, as defined below.

NOW, THEREFORE, in consideration of the premises and the mutual promises and covenants hereinafter set forth, the Parties agree as follows:

1. Non-Disclosure. Subject to Section 4 below, the Party receiving confidential information (the Receiving Party) shall keep strictly confidential and not disclose the following:

(i) all information provided by the disclosing Party (Disclosing Party) or any affiliate, director, officer, employee, agent, advisor, contractor or other representative (individually, Representative, or collectively, Representatives) of the Disclosing Party to the Receiving Party or its Representative(s) in writing, orally or electronically in the course of the Parties' evaluation of the Transaction, whether before or after the date hereof, including, without limitation, any such information

(A) concerning the business, financial condition, operations, products, services, assets and/or liabilities of the Disclosing Party,

(B) relating to technologies, intellectual property or capital, models, concepts, or ideas of the Disclosing Party,

(C) including information from third parties that the Disclosing Party is required under applicable law, contract or other agreement to keep confidential, or

(D) otherwise, clearly identified as confidential or proprietary, including all bid proposal information received by the Receiving Party, during the competitive bid process for intermediate capacity being conducted by Vectren (collectively, the "Confidential Information"); and

(ii) the Disclosing Party's participation in discussions concerning the Transaction, including execution of this Agreement, the Disclosing Party's disclosures of Confidential Information to the Receiving Party or its Representative.

Receiving Party may disclose Confidential Information provided by the Disclosing Party to any Representative of the Receiving Party who needs this Confidential Information to evaluate the Transaction. Receiving Party remains responsible for its Representative(s) compliance with the terms of this Agreement.

2. Use Restriction. The Receiving Party shall not use any Confidential Information of the Disclosing Party for any purpose other than for the Transaction or for regulatory proceedings and RTO/ISO studies and analyses, including for example, an Indiana Utility Regulatory Commission ("IURC") proceeding in which information about the Transaction must be produced by Vectren to satisfy its evidentiary burden. In any such regulatory proceeding, study or analysis, Receiving Party will take care to protect Confidential Information from public disclosure through redacted public filings and other similar measures available to Receiving Party to protect Confidential Information. Receiving Party will advise Disclosing Party as soon as practical, of any such use and the protections in place for the Confidential Information.

3. Exceptions to Confidential Information. Under this Agreement, Confidential Information shall not include information that: (i) is already in Receiving Party's possession at the time of disclosure, as documented by the Receiving Party; (ii) becomes available subsequently to the Receiving Party on a non-confidential basis from a source not known or reasonably suspected by the Receiving Party to be bound by a confidentiality agreement or secrecy obligation owed to the Disclosing Party; (iii) is or becomes generally available to the public other than as a result of a breach of this Agreement by the Receiving Party or its Representative; or (iv) is independently developed by the Receiving Party without use, directly or indirectly, of Confidential Information of the Disclosing Party. If only a portion of the Confidential Information falls under one of the foregoing exceptions, then only that portion shall not be deemed Confidential Information.

4. Required Disclosure. If Receiving Party or its Representative is required, pursuant to any applicable court order, administrative order, statute, regulation or other official order by any government or any agency or department thereof, to disclose Confidential Information, the Receiving Party shall:

(i) provide the Disclosing Party with prompt written notice of any such request or requirement so that the Disclosing Party may seek a protective order or other appropriate remedy or protection and/or waive compliance with the provisions of this Agreement; and

(ii) reasonably cooperate with the Disclosing Party to obtain such protective order or other remedy. If Disclosing Party waives compliance with the relevant provisions of this Agreement or

the Disclosing Party does not receive a protective order or other remedy or protection, the Receiving Party agrees to

(a) provide only that portion of the Confidential Information for which the Disclosing Party has waived compliance with the relevant provisions of this Agreement, or which the Receiving Party is legally required to disclose,

(b) use commercially reasonable efforts to obtain assurances that confidential treatment will be accorded to such information, at Disclosing Party's expense, and

(c) give the Disclosing Party written notice in advance of any disclosure of Confidential Information.

5. Return or Destruction of Confidential Information. Either Party may terminate this Agreement with thirty days written notice. Additionally, at any time for any reason, upon the written request of the Disclosing Party, the Receiving Party and its Representative(s) will promptly:

(i) deliver to the Disclosing Party all original Confidential Information (whether written or electronic) furnished to the Receiving Party by or on behalf of the Disclosing Party, and

(ii) destroy any copies of such Confidential Information (including any extracts there from) if specifically requested by the Disclosing Party, with Receiving Party allowed to retain one archival copy of the Confidential Information in strict confidence for purposes of record retention and compliance or as otherwise required by applicable laws. If the Disclosing Party requests written proof, Receiving Party shall cause a duly authorized officer to certify in writing to the Disclosing Party that the requirements of the preceding sentence have been satisfied in full.

Regardless of the status of discussions regarding the Transaction and any request for return or destruction of Confidential Information, the Receiving Party will continue to be bound by terms of this Agreement.

6. Term. This Agreement is effective as of the date first written, above. It will terminate one (1) year after its effective date unless extended for additional one year terms by agreement of the Parties. If this Agreement is terminated during a term by either Party providing a termination notice pursuant to Section 5 above; the non-disclosure and use restriction obligations for Confidential Information under this Agreement shall survive any termination and remain in effect for the longer of (i) five (5) years, or (ii) such period during which any Confidential Information retains its status as a trade secret or qualifies as confidential under applicable law.

7. Miscellaneous.

(a) The Parties acknowledge and agree that unless and until a definitive agreement with respect to the Transaction has been executed by the Parties, no Party shall be under any legal obligation of any kind whatsoever to the other Party with respect to the Transaction, except as expressly provided in this Agreement.

(b) Receiving Party acknowledges that the Confidential Information is and at all times remains the sole and exclusive property of the Disclosing Party and that the Disclosing Party has the exclusive right, title, and interest to its Confidential Information. No right or license, by implication or otherwise, is granted by the Disclosing Party as a result of disclosure of Confidential Information hereunder. Each Party reserves the right at any time in its sole discretion, for any reason or no reason, to refuse to provide any further access to and to demand the return of the Confidential Information. The Receiving Party agrees that the Disclosing Party and its Representatives (i) makes no warranty as to the accuracy or completeness of the Confidential Information; and (ii) shall have no liability to the Receiving Party or its Representatives resulting from the use of any Confidential Information.

(c) Neither this Agreement nor any right, remedy, obligation or liability arising hereunder shall be assigned by any Party (whether by operation of law or otherwise), and any such assignment shall be null and void, except with the prior written consent of the other Party. Subject to the foregoing, this Agreement shall be binding upon and inure to the benefit of the Parties and their respective successors and permitted assigns. No provision of this Agreement shall create a third-party beneficiary relationship or otherwise confer any benefit, entitlement or right upon any person or entity other than the Parties.

(d) The Parties acknowledge and agree that no failure or delay by a Party in exercising any right or privilege hereunder shall operate as a waiver of that right or privilege. The provisions of this Agreement may be modified or waived only in writing signed by both Parties.

(f) This Agreement shall be governed by and construed in accordance with the laws of the State of Indiana.

(g) This Agreement may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

(h) Each Party acknowledges and agrees that money damages would not be a sufficient remedy for any breach of this Agreement by such Party and that the other Party shall be entitled to seek equitable relief, including seeking an injunction and specific performance, as a remedy for any such breach. Such remedies shall not be deemed to be the exclusive remedies for a breach of this

Agreement, but shall be in addition to all other remedies available at law or equity.

(i) This Agreement constitutes the entire agreement between the Parties with respect to the subject matter herein and supersedes and cancels any prior agreements, representations, warranties, or communications, whether oral or written, between the Parties relating to the subject matter herein.

IN WITNESS WHEREOF, each Party hereto has executed this Agreement, or caused this Agreement to be executed on its behalf, all as of the day and year first above written.

Southern Indiana Gas and Electric Company, Inc.,
d/b/a Vectren Energy Delivery of Indiana, Inc.:

By:____________________________________
Name:
Title:

____________<company name>____________

By:____________________________________
Name:
Title:

APPENDIX C – PRE-QUALIFICATION APPLICATION

PRE-QUALIFICATION APPLICATION

Respondent's Credit-Related Information

Provide the following data to enable Vectren to assess the financial viability of the Respondent as well as the entity providing the credit support on behalf of the Respondent (if applicable). Include any additional sheets and materials with this Appendix as necessary. As necessary, please specify whether the information provided is for the Respondent, its parent, or the entity providing the credit support on behalf of the Respondent.

Full Legal Name of the Respondent: ____

Dun & Bradstreet No. of Respondent: ____

Type of Organization: (Corporation, Partnership, etc.) ____

State of Organization: ____

Respondent's Percent Ownership in Proposal: ____

Full Legal Name(s) of Parent Corporation: ____

Entity Providing Credit Support on Behalf of Respondent (if applicable): ___________________________

Dun & Bradstreet No. of Entity Providing Credit Support: _______________________________________

Address for each entity referenced (provide additional sheets, if necessary): ________________________

____

Type of Relationship: ____

Current Senior Unsecured Debt Rating from each of S&P and Moody's Rating Agencies (specify the entity these ratings are for): ____

OR, if Respondent does not have a current Senior Unsecured Debt Rating, then Tangible Net Worth (total assets minus intangible assets (e.g. goodwill) minus total liabilities):____

Bank References & Name of Institution: ____

Bank Contact: Name, Title, Address and Phone Number: ____

____

Pending Legal Disputes, if any (describe): ____

____

General description of Respondent's ability to construct, operate and maintain project, to the extent applicable:

____

____

Financial Statements of the Respondent or its Credit Support Provider, where applicable, must include Income Statement, Balance Sheet, Statement of Cash Flows, all notes corresponding to those financial statements and applicable schedules for three most recent fiscal years and financial report for the most recent quarter or year-to-date period. Also if available, please provide copies of the Annual Reports and/or 10K for the three most recent fiscal years and quarterly report (10Q) for the most recent quarter ended, if available. If such reports are available electronically, please provide link.

____

____

APPENDIX D – PROPOSAL DATA

SEE ATTACHMENT:
APPENDIX D – PROPOSAL DATA.xlsx

APPENDIX E – PROPOSAL CHECKLIST

PROPOSAL CHECKLIST

Required:

☐Appendix A – Notice of Intent

☐Appendix B – Non-Disclosure Agreement

☐Appendix C – Pre-Qualification Application

☐Appendix D – Proposal Data

☐Executive Summary

☐MISO Generator Interconnection Agreement

☐MISO Facilities Study

☐MISO System Impact Study

☐Proposal Evaluation Fee (if applicable)

☐EPC Contract (if applicable)

Other Data:

☐Nodal economic analyses

☐PSS/E v33 raw or idev file that reflects modeling parameters of the Project at the respective point of interconnection

☐Unit inspection findings and dates and outstanding recommendations yet to be implemented, summary of operating plan, and outage and maintenance plans

☐Water supply description, NPDES permit details, all relevant environmental permits, environmental liabilities, and water chemistry program summary and performance

☐Emissions credits or offsets and baseline emissions of known and unknown pollutants

☐Spare parts list

☐Other contractual commitments

☐Summary of all legal proceedings, claims, actions, or suits against the Respondent, Guarantor, or involving the facility or site

☐Discussion regarding roles and responsibilities of any companies involved, status of major equipment procurement, facility site and Respondent's rights to such site, development schedule and associated risks and risk mitigation plans, and financing arrangements

☐Description of fuel supply, fuel cost information, and fuel contract duration and terms

☐Audited or unaudited financial statements including balance sheets, income statements, and cash flow statements for the proposed asset(s) for the past three years.

LMR/DR Only:

☐Description of how Proposal conforms with requirements of local utility and state law in order to offer resources for capacity accreditation within MISO under Module E Capacity Tracking

☐Description of LMR/DR customer(s), load drop values, equipment and technology, plans detailing deployment or utilization to support its operations, LMR/DR supplier and other key contributors, the supplier's process for aggregating and/or plan for recruiting participants, curtailment systems and procedures, and plans for communicating with participants during curtailment periods

☐Acknowledgement and agreement that LMR/DR supplier is responsible for activities and obligations listed in Section 6.4.3

BURNS McDONNELL

CREATE AMAZING.

Attachment 6.4 1x1 CCGT Study (Redacted)

FINAL

EPC COST - BASIS OF ESTIMATE

A.B. Brown 1x1

B&V PROJECT NO. 400278
B&V FILE NO. 41.0001

PREPARED FORREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

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Executive Summary

The following is a basis of estimate summary for the EPC capital cost AACE Class 2 estimate for the A.B. Brown 1X1 Combined Cycle. The cost estimates contained in this report are based on the preliminary design by Black & Veatch, equipment pricing bids from suppliers of power island, and utilizing prior EPC contractor and vendor bid data. Power island equipment includes the combustion turbine(s), steam turbine, and HRSG(s).

The two plant alternatives that were estimated are as follows:

1X1 CCPP
GE 7FA.05 Fired
GE 7HA.01 Fired

1.0 Estimate Basis

The cost estimate is based on an AACE Class 2 for engineering, equipment and construction costs.

The cost estimate is based upon a lump-sum turnkey EPC approach. Owner will purchase Power Island Equipment and assign to EPC contractor. Under this approach, the EPC contractor would have the responsibility for administration and performance interface of the power island equipment. The EPC structure used for the estimate is based upon the EPC contractor self-performing the work rather than utilizing multiple subcontractors.

The cost estimates are based on competitive bids obtained for power island equipment. Equipment, commodity, and construction services rates were based on EPC contractor and vendor data. Detailed material takeoffs based on the preliminary design of the A.B. Brown combined cycle with reference to similar sized plants that Black & Veatch has designed, constructed, and/or estimated on an EPC basis.

The estimate provided herein is based on preliminary information, and as such is to be considered a non-binding price opinion, and does not represent an offer to sell or a maximum price for the work scope. The estimate assumes moderate level of EPC commercial risk position and does not include specific pricing or schedule impacts for extensive site preparation. Other factors that can impact the price:

- Changes in labor market - A Labor Market Survey may identify craft labor conditions unique to this project that are recommended for further review and evaluation prior to start of construction.
- Final site conditions - Soil boring were secured for the proposed site.
- Noise requirements - Night-time steam blow conditions were assumed.
- Final project schedule.

1.1 QUANTITIES

Quantities that form the basis of the estimate were based on the engineering conceptual design and the engineering Bill of Quantities (BOQ) developed. The conceptual design was based on utilizing some of the existing A.B. Brown common system to support the new combined cycle, detailed information from equipment suppliers for new equipment, and specific site conditions. Where details were not available, assumptions were made based on similar sized plants and arrangements.

1.2 DIRECT COSTS

EPC bid pricing is segregated into two categories: direct and indirect. The direct project costs associated with the BOQs can then be developed by utilizing the unit costs provided by the EPC bidders.

- Unit manhour rates and wage rates are applied against the 1x1 quantities to develop labor cost.

- Unit material cost are applied against the updated quantities for commodities to develop material cost. Cost for major equipment has been scaled off the equipment cost for the major equipment obtained by the EPCs.
- Subcontract pricing was adjusted based upon the rates developed as part of the EPC bid analysis.

To develop the definitive capital cost estimate an RFI was issued to the major OEM Power Island equipment suppliers to obtain budgetary quotes. The OEM proposals included:

- Combustion Turbine and Generator Package
- Steam Turbine and Generator Package
- Heat Recovery Steam Generator

Bid tabulations were developed to evaluate the bids for completeness, scope, and adherence to the specification. The lowest evaluated bid was selected to use as the basis of the estimate.

1.3 CONSTRUCTION MANAGEMENT AND CONSTRUCTION INDIRECTS AND ENGINEERING

Construction Management and Construction Indirects (CMCI) were based on a self-perform (direct-hire) EPC approach instead of a multiple subcontract EPC approach. As a result, the cost for management of the work as well as tools, scaffolding, cranes, warehousing, and laydown to support this work show as a CMCI expense. Under a multiple subcontract approach, these costs would be included in the subcontractor unit rates and appear in the direct cost line items.

Construction management and indirects were estimated based on Black & Veatch's experience with similar plants and scopes of work as well as comparison against the EPC bids. The following costs were developed based upon Black & Veatch's internal metrics and experience then adjusted for schedule and man power loading:

- Project Engineering
- Project Construction Management including Safety, QC, Orientation
- Material Handling
- Mobilization and Demobilization
- Consumables & Small Tools
- Warranty

To obtain competitive bids Black & Veatch, in accordance with IURC code, the estimate includes competitive bids for the following costs:

- Cranes and Construction Equipment
- Scaffolding
- Temporary Facilities

Heavy haul transportation was based on Power Island Equipment delivery to the site and heavy cranes included in the Cranes and Construction Equipment RFQ.

1.4 INDIRECTS

Insurances, warranty, performance bonds, and a letter of credit costs are included, based on the EPC bids.

1.5 CONTINGENCY

[redacted]

[redacted]

FINAL

HRSG BYPASS STACK ANALYSIS

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1201F

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

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Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch examined the benefits and drawbacks of adding a flue gas bypass stack between the combustion turbine and the heat recovery steam generator (HRSG). The bypass stack would allow the HRSG to be taken offline while the combustion turbine operates in simple cycle mode and would also allow the combustion turbines to be put into service up to 6 months before the erection and commissioning of the balance-of-plant equipment.

This analysis considered such factors as cost, plant design, environmental permitting, schedule, and operations, and maintenance. One major consideration is whether a selective catalytic reduction (SCR) system would be required to meet US Environmental Protection Agency (USEPA) emissions permitting requirements. The base cost for the installation of an HRSG bypass stack is estimated as [redacted] the estimated cost with the addition of an SCR system would be [redacted]

The performance of the combined cycle would not be adversely affected by the inclusion of the bypass stack. USEPA standards, however, might limit the number of hours the unit could operate in simple cycle mode. While the addition of a HRSG stack flue gas bypass would provide the benefit of operational flexibility for the power plant, cost and performance impacts typically do not justify including this equipment in the power plant design.

1.0 Introduction

HRSG stack flue gas bypass systems provide the benefit of adding operational flexibility to power plant generation. Flue gas bypasses consist of installing a stack between the combustion turbine and HRSG; a diversion damper allows the combustion turbine exhaust to be diverted either to the bypass stack or the HRSG. Having a bypass stack available allows the HRSG to be taken offline or out of service, while the combustion turbine operates in simple cycle mode. The bypass stack would also allow for the combustion turbines to be put into service up to 6 months prior to erection and commissioning of the balance of plant under a typical consecutive construction schedule or longer for phased or delayed construction. The benefits must outweigh the cost in order for a flue gas bypass system to be feasible.

This evaluation of adding a flue gas bypass on each Combustion Turbine will help determine the cost (+/- 30%) and design impact of a flue gas bypass system to the plant design. Environmental permit considerations due to the flue gas bypass addition will also be reviewed. Schedule impacts, operations, and maintenance activities will also be identified and discussed.

2.0 Arrangement

On a combined cycle power plant, the flue gas bypass stack would be installed between the combustion turbine and the HRSG. Figure 2-1 shows a typical arrangement of a combustion turbine with a HRSG and a bypass stack. The bypass stack contains a damper that diverts the combustion turbine exhaust either up the bypass stack or to the HRSG. During simple cycle operation, the damper would be positioned to shut off flow to the HRSG and direct flow up the bypass stack. Under combined cycle operation, the damper would be positioned to shut off flow to the bypass stack and allow flow through to the HRSG. The diverter damper is actuated through the operating positions by electronically controlled hydraulic system. Figure 2-2 shows the components of the bypass stack.

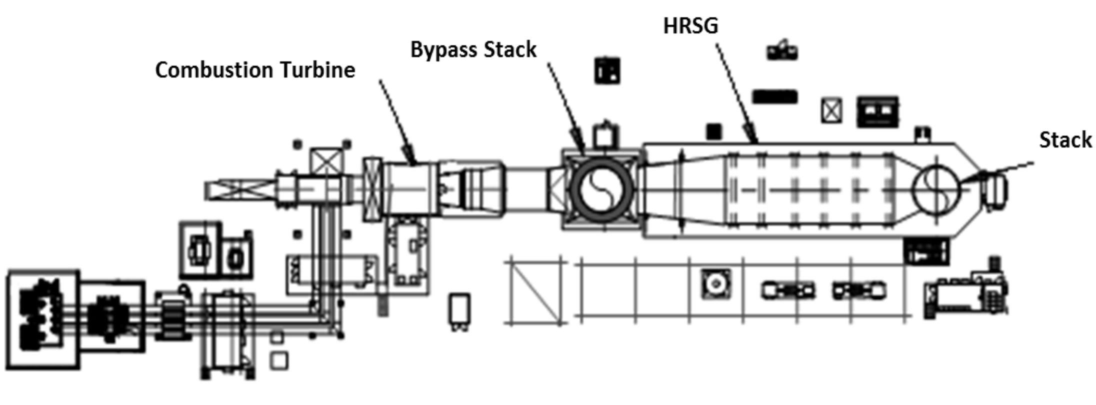

Figure 2-1 Combined Cycle Layout with Bypass Stack

ITEM NO	QTY	DESCRIPTION
1	1	INTEGRATED EXPANSION JOINT
2	2	TRANSITION DUCT HALVES
3	4	SILENCER DUCT QUARTER SECTIONS
4	4	SILENCER DUCT FLAT WALL PANELS
5	2	TRANSITION DUCT HALVES
6	8	VERTICAL STACK SEGMENTS
7	2	VERTICAL STACK SEGMENTS
8		BOTTOM SILENCER PANELS
9		TOP SILENCER PANELS
10		SUPPORT STRUCTURE
11		LADDERS AND PLATFORMS
12		PERSONNEL PROTECTION
13	1	HORIZONTAL TRANSITION
14	1	GUILLOTINE DUCT
15	1	DAMPER

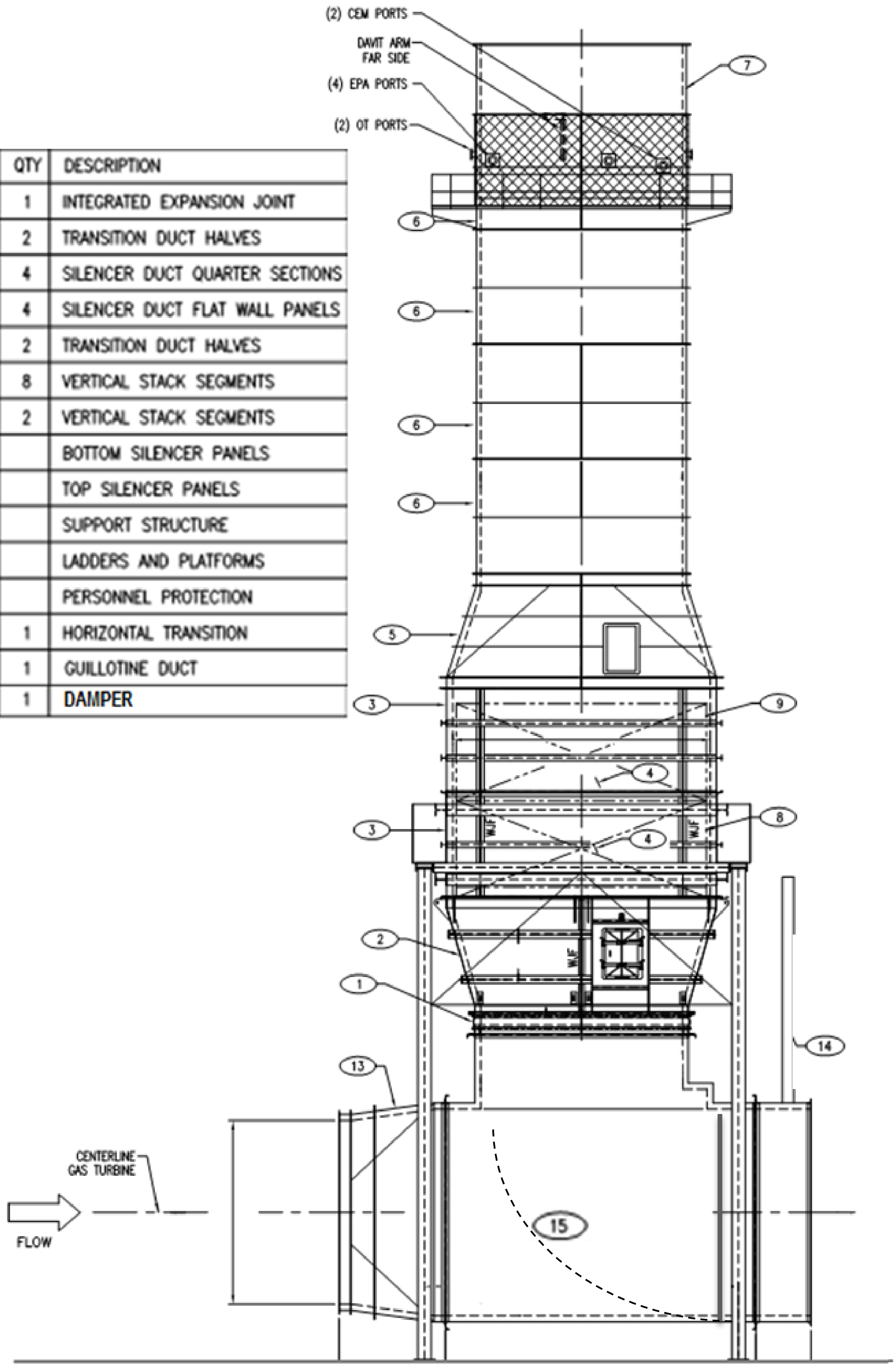

Figure 2-2 Typical Gas Bypass Stack

If an SCR were required, a section could be added to the stack upstream of the silencer to house catalyst, tempering air skid, and ammonia injection equipment. While there is not much industry experience with installing SCRs in the vertical sections of combustion turbine bypass stacks, the technical challenges would be similar to those seen in a coal facility where vertical SCRs are common. The SCR would consist of the following components:

- Catalyst
- Tempering air system to lower combustion turbine exhaust gas to an allowable inlet temperature for the catalyst (<800 °F)
- Mixing vanes and flow distribution
- Ammonia distribution manifold and injection grid
- Ammonia vaporization and flow control unit
- Emission monitoring system

Alternatively, the SCR may be horizontal and then the SCR and bypass stack would be placed in parallel with the HRSG. Air emission requirements are discussed in Section 6.0.

3.0 Capital Costs

Typical suppliers of HRSG bypass stacks include Braden Manufacturing, Peerless-Aarding, and Clyde Bergmann.

Pricing from recent proposals was reviewed to find a budgetary estimate for a bypass stack with a height of 135 ft with stack silencer and continuous emission monitoring (CEMS) system. Also included were all required dampers, motors, controls, insulation, lighting, support steel and platforming as required.

Table 3-1 is a high level breakdown of the costs associated with the bypass stack.

Table 3-1 Capital Costs for HRSG Bypass Stack

DESCRIPTION	INSTALLED COST / UNIT
FOUNDATIONS/CIVIL WORK	[redacted]
STACK (including ductwork, damper, supplementary steel, lighting, electrical)	[redacted]
CEMS (NOx and CO analyzers, includes electrical and controls)	[redacted]
BYPASS STACK (no SCR)	[redacted]
VERTICAL SCR (includes ammonia injection, NO_X and CO catalyst)	[redacted]
BYPASS STACK (with vertical SCR)	[redacted]

4.0 Performance Impacts

Installation of a bypass stack allows for the operation of the combustion turbine in simple cycle mode; however, operating in simple cycle mode may have limited operating hours as discussed in Section 6.0, Permitting and Emissions.

[redacted] It would normally be expected that plant output would decrease due to increased exhaust pressure drop due to a reduction in CTG load, which is only partially offset by an increase in STG load resulting from increased CTG exhaust energy. However, the 7F.05 is shaft-limited at this operating condition and the CTG output is not reduced due to the increased exhaust pressure. Instead, the CTG fires harder to maintain its output, resulting in an increase in exhaust flow, thereby increasing steam production and STG output. Other OEM machines may not have this characteristic and net plant output could be expected to decrease due to increased CTG exhaust pressure.

If an SCR is required, a tempering air skid is required to keep the CTG exhaust below 800 °F to prevent damage to the catalyst. The CTG exhaust reaches 800 °F in less than a minute from ignition as the CTG reaches 5% load. The tempering air fan and the ammonia vaporization and flow control system will have an auxiliary load of 1,000 kW.

5.0 Maintenance

Maintenance consists of correcting deficiencies noted during inspection. For HRSG bypass stacks without an SCR, the primary maintenance concern is the damper seals, diverter damper bearings, and the dampers hydraulic power unit.

Typical diverter maintenance activities include:

- Shaft seal replacement.
- Housing perimeter seal replacement.
- High temperature bearing repair or replacement.
- Shaft seals are typically designed to last five years.

Recommended spare parts include:

- Spare limit switches.
- Position transmitters.
- Seal-air pressure blower.
- Main drive bearing kit.
- Damper seal sets.
- Expansion joints.

If an SCR is required, additional maintenance is required for the hot air tempering skids, ammonia flow control units, and replacement of NO_x and CO catalysts.

6.0 Permitting and Emissions

6.1 FEDERAL REGULATIONS POSING CHALLENGES

Officially titled *Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, 40 CFR Part 60, Subpart TTTT was finalized by the USEPA on August 3, 2015. In this rulemaking, the USEPA established output-based emissions standards for two subcategories of power plants; electric utility steam generating units (e.g., coal-fired power plants) and stationary combustion turbines. The rule makes no distinction between simple cycle and combined cycle combustion turbines. Rather, it requires combustion turbines to meet certain CO_2 emissions standards depending on whether they are classified as baseload or non-baseload units.

The distinction between baseload and non-baseload units is made based upon the number of hours a combustion turbine can operate relative to its design efficiency. If a combustion turbine operates more hours than its net, Lower Heating Value (LHV) design efficiency, then it is considered a baseload unit. Baseload units are required to meet an output-based CO_2 emission standard of 1,000 lb/MWh (gross output, 12-operating month basis).

[redacted]

If the plant is restricted in hours less than the percent of net design efficiency hours, the plant is classified as a non-baseload unit with respect to NSPS Subpart TTTT. Natural gas-fired non-baseload units are subject to a heat-input based CO_2 emission standard 120 lb/MBtu (HHV, 12-operating month basis). This standard is readily achievable because the CO_2 emission rate of natural gas is 117 lb/MBtu.

6.2 AIR PERMITTING CHALLENGES

While an emissions netting analysis (wherein any recent unit shutdowns can be used to demonstrate that net emissions increases from the new installation would not exceed major source permitting thresholds) could allow the project to avoid major source permitting requirements there is still a possibility the project could trigger major source permitting. In such a scenario, the air permitting process would be dictated by the Prevention of Significant Deterioration (PSD) regulations which require, among other things, an evaluation of Best Available Control Technology (BACT). Should BACT be required for NO_X emissions, the project's air construction permit could require the use of an SCR.

7.0 Conclusions

Having a bypass stack available allows the HRSG to be taken offline or out of service, while the combustion turbine operates in simple cycle mode. In addition, the combustion turbines could be put into service up to 6 months prior to erection and commissioning of the balance of plant under a typical consecutive construction schedule or longer for phased or delayed construction.

While the addition of a HRSG stack flue gas bypass would provide the benefit of operational flexibility for the power plant, cost and performance impacts typically do not justify including this equipment in the power plant design. The total installed cost of the bypass stack for a single 1x1 train is approximately [redacted] without an SCR. A vertical SCR would be considered a first of a kind for this application so no cost is easily achievable without a prior design. It is expected that if an SCR is required due to concerns with emissions the cost would be approximately double [redacted] with an SCR. If a horizontal SCR is required due to emission limits, the SCR would not be feasible as it would be approximately the size of the HRSG. The performance of the combined cycle would not be adversely affected by the inclusion of the bypass stack. The amount of hours where the unit can operate in simple cycle mode with the HRSG bypassed may be limited due to NSPS 40 CFR Part 60, Subpart TTTT.

FINAL

HEAT REJECTION / EXISTING COOLING TOWER ANALYSIS

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1202F

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

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Executive Summary

In developing this report, Black & Veatch focused its attention to the specific areas directed by Vectren by analyzing the design impacts and cost comparison of using one existing cooling tower, circulating water pumps, and circulating water pipe for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed multiple existing cooling tower reuse scenarios to evaluate the performance against the design for a new cooling tower. A performance summary for the two most optimal scenarios is provided in Section 2.0.

Black & Veatch evaluated the following three cooling tower alternatives for this study:

- Alternative 1: Reuse Cooling Tower, Circulating Water Pumps, and Existing Piping
- Alternative 2: Reuse Cooling Tower and Circulating Water Pumps with All New Piping
- Alternative 3: All New Cooling Tower, Circulating Water Pumps, and Piping

This report has been summarized in a Cooling Tower Alternatives Comparison Matrix provided in Table ES-1. [redacted] Consequently, it is recommended that Vectren utilize the existing Unit 1 cooling tower, circulating water pumps and piping as the design basis for the new combined cycle power plant.

Table ES-1 Cooling Tower Alternatives Comparison Matrix

ALTERNATIVE	REUSE TOWER, PUMPS, AND PIPING (ALTERNATIVE 1)	REUSE TOWER AND PUMPS WITH ALL NEW PIPING (ALTERNATIVE 2)	NEW TOWER, PUMPS, AND PIPING (ALTERNATIVE 3)
Description	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

ALTERNATIVE	REUSE TOWER, PUMPS, AND PIPING (ALTERNATIVE 1)	REUSE TOWER AND PUMPS WITH ALL NEW PIPING (ALTERNATIVE 2)	NEW TOWER, PUMPS, AND PIPING (ALTERNATIVE 3)
Disadvantages	[redacted]	[redacted]	[redacted]

1.0 Introduction

The purpose of this study is to analyze the A.B. Brown Unit 1 circulating water system to determine whether all or portions of the existing cooling towers, circulating water pumps, and circulating water piping can be reused for use with a new Combined Cycle Power Plant (CCPP). Black & Veatch has evaluated the performance of the existing cooling towers and circulating water pumps to determine the optimal operating scenarios [redacted] when paired with the new CCPP.

This evaluation of reusing the existing circulating water system components will help determine the [redacted] design impact of this system to the new CCPP design. Schedule impacts, operations, and maintenance activities will also be identified and discussed.

2.0 Performance Evaluation

Several operating scenarios were evaluated to determine the best preliminary design basis for reusing the existing cooling towers and circulating water pumps. Upon selection of the final plant design, the preferred number of cooling tower cells in service should be reviewed.

Alternatives 1 and 2 utilize the Unit 1 existing seven cell cooling tower and two circulating water pumps provide a total circulating water flow of 125,000 gallons per minute (gpm).

The existing cooling tower would be larger than the cooling tower for Alternative 3. The design flow rate of the existing cooling tower is larger than the design flow rate would be for the new cooling tower. To accommodate the larger flow rate, the condenser will be larger, and more expensive, but provides better performance. The overall heat rejection system for Alternatives 1 and 2 result in a decrease in steam turbine backpressure and an increase in auxiliary power when compared to the new heat rejection system considered in Alternative 3.

The estimated performance based on nominal 1x1 7F.05 combined cycle performance for the alternatives is shown on Figure 2-1 for unfired heat recovery steam generator (HRSG) operation and Table 2-2 for fired HRSG operation. For reference, Tables 2-1 and 2-2 provide the estimated performance values shown on the graphs.

[redacted]

Table 2-1 Comparative Unfired Plant Performance for Cooling Tower Alternatives

UNFIRED OPERATING CONDITIONS	1X100% CTG LOAD 8.1F/70% AMBIENT EVAP COOLING OFF DUCT FIRING OFF	1X100% CTG LOAD 56.8F/48% AMBIENT EVAP COOLING OFF DUCT FIRING OFF	1X100% CTG LOAD 93.7F/45% AMBIENT EVAP COOLING ON DUCT FIRING OFF
7 Cell Net Plant Output, kW	[redacted]	[redacted]	[redacted]
7 Cell Net Plant Heat Rate (LHV), Btu/kWh	[redacted]	[redacted]	[redacted]
New Tower Net Plant Output, kW	[redacted]	[redacted]	[redacted]
New Tower Net Plant Heat Rate (LHV), Btu/kWh	[redacted]	[redacted]	[redacted]

Table 2-2 Comparative Fired Plant Performance for Cooling Tower Alternatives

FIRED OPERATING CONDITIONS	1X100% CTG LOAD 8.1F/70% AMBIENT EVAP COOLING OFF DUCT FIRING ON	1X100% CTG LOAD 56.8F/48% AMBIENT EVAP COOLING OFF DUCT FIRING ON	1X100% CTG LOAD 93.7F/45% AMBIENT EVAP COOLING ON DUCT FIRING ON
7 Cell Net Plant Output, kW	[redacted]	[redacted]	[redacted]
7 Cell Net Plant Heat Rate (LHV), Btu/kWh	[redacted]	[redacted]	[redacted]
New Tower Net Plant Output, kW	[redacted]	[redacted]	[redacted]
New Tower Net Plant Heat Rate (LHV), Btu/kWh	[redacted]	[redacted]	[redacted]

3.0 Existing Equipment

3.1 EXISTING COOLING TOWER CONDITION

The Unit 1 cooling tower cells were recently rebuilt from wood to fiberglass as such the condition is assumed satisfactory and no major repairs are required. Three of the seven Unit 2 cooling tower cells were recently rebuilt from wood to fiberglass. To extend the life of the Unit 2 cooling tower the remaining four (4) cells would require rebuilding to fiberglass at a cost of approximately [redacted] To eliminate the need for this expenditure, the Unit 1 cooling tower will be used for the new CCPP. The existing cooling tower basins for Unit 1 and Unit 2 are lacking an intake structure for an auxiliary cooling water pump. Modifications will be needed to the basin to add the new intake and pump structure.

3.2 EXISTING CIRCULATING WATER PUMPS

The existing circulating water pumps have been evaluated for both Alternatives 1 and 2 and it has been determined that they have sufficient capacity to meet the required flow and head for the new CCPP circulating water system. To extend the life of the two pumps and motors a shop overhaul would be required.

Black & Veatch evaluated the use of variable frequency drives (VFDs) on the existing circulating water pumps to modify the pump flow rate for different CCPP operating scenarios. Because the static head component is constant for all operating conditions and accounts for the majority of the circulating water pump head requirement, a VFD would provide minimal performance gains [redacted] per pump.

3.3 EXISTING CIRCULATING WATER PIPE

The existing circulating water piping is carbon steel piping with a bitumastic coating. Coatings have been maintained and repaired during normal inspection and repairs throughout the life of the existing A.B. Brown Plant. For this study, it is assumed that the condition of the pipe is satisfactory and no repairs will be required to the piping that is being reused as part of Alternative 1.

4.0 Constructability

For each of the cooling tower reuse alternatives there are several items to consider that could impact both the new CCPP and existing A.B. Brown Unit 1 during the installation and commissioning phase of the project.

4.1 ALTERNATIVE 1

Alternative 1 reuses a significant amount of existing underground steel piping, which will require continued inspection and maintenance to last the 30 year design life of the new CCPP. The existing piping is assumed to be in satisfactory condition given feedback from Vectren that they have performed scheduled inspections and coatings on the piping as required.

4.2 ALTERNATIVE 2

Alternative 2 will require unit outages considerably longer than Alternative 1, up to 2 or 3 months, given that a large section of existing Unit 1 circulating water piping and cooling tower risers are to be replaced in-kind with new steel piping. Once completed, Alternative 2 will result in the existing cooling tower and circulating water pump connected to the new CCPP circulating water system with all new piping, resulting in shutdown of the existing Unit 1 at the time of the tie-in.

4.3 ALTERNATIVE 3

Alternative 3 is an all new circulating water system that includes a 6 cell back-to-back mechanical draft counter flow cooling tower, 2x50 percent circulating water pumps, and steel circulating water piping. Because this system is independent of the existing equipment no unit outage will be required and the existing Units 1 and 2 will be able to operate during and after the installation of the new circulating water system. This alternative also results in the least auxiliary load because of minimizing the size of the circulating water pumps for the new CCPP design conditions.

5.0 Capital Costs

Table 5-1 is a high-level breakdown of the costs for both reusing the existing cooling towers and installing new cooling towers with a new basin.

Table 5-1 Estimated Costs for Cooling Tower Alternatives

DESCRIPTION	REUSE TOWER, PUMPS, AND PIPING (ALTERNATIVE 1)	REUSE TOWER AND PUMPS WITH ALL NEW PIPING (ALTERNATIVE 2)	NEW TOWER, PUMPS, AND PIPING (ALTERNATIVE 3)
New 6 Cell Cooling Tower with Basin (F&E)	[redacted]	[redacted]	[redacted]
Condenser Adder	[redacted]	[redacted]	[redacted]
Circulating Water Pumps	[redacted]	[redacted]	[redacted]
New Piping and Valves (A/G and U/G)	[redacted]	[redacted]	[redacted]
Basin Modifications for Auxiliary Cooling Water Pump	[redacted]	[redacted]	[redacted]
Site Work	[redacted]	[redacted]	[redacted]
Mechanical Installation (Does not include tower erection)	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]
Cost Difference	[redacted]	[redacted]	[redacted]

6.0 Conclusions

Based on the evaluation, the reusing the existing Unit 1 cooling tower, pumps and piping (Alternative 1) is the lowest cost technically acceptable solution and should be used as the design basis for the new combined cycle power plant.

FINAL

FAST START VS. CONVENTIONAL START ANALYSIS

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1203F

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

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1.0 Introduction

This study evaluates designing a 1x1 GE 7F.05 combined cycle power plant with "fast start" capabilities versus a plant design for "conventional" start. The GE 7F.05 is one of several candidate F-Class combustion turbine offerings.

1.1 STARTUP DURATION DEFINITION

Since plant load is affected by ambient conditions, startup durations are typically defined based on achieving a certain operating condition and not a specified operating load. The beginning of the start is typically defined as combustion turbine roll-off or first ignition. Startup is complete when a predefined operating condition is reached.

Startup can be a confusing term as it is used to describe the start from ignition to various ending operating conditions across the industry. These ending operating scenarios can include:

- CTG Full Speed No Load – The point at which the combustion turbine is removed from the static starter and brought to full speed.
- CTG Sync - The point at which the combustion turbine (CTG) is synchronized with the grid.
- Emission Start - Achieving minimum emissions compliance load. This occurs when stack discharge emissions reaching steady state compliance with air quality standards.
- CTG Full Load Start - Combustion turbine at baseload with permitted emissions at the stack.
- Plant Full Load Start - Combustion turbine at baseload and steam turbine bypass valves fully closed. Steam turbine in service.

For the purpose of this study Fast Start is being defined as a rapid start commencing with ignition until the combustion turbine reaches minimum emission load compliance (MECL). When speaking with others in the industry the ending operating condition should be defined.

The type of start is also defined by the amount of time the unit has been shutdown. It is typical to assume the shutdown begins at fuel flow shutoff to the combustion turbines during a normal plant shutdown sequence from a steady state baseload condition. Durations as defined by the project are:

- Hot start = Shutdown 8 hours or less
- Warm start = > 8 hours and < 48 hours
- Cold start = Shutdown 48 hours or more

The lead time activities prior to a warm or cold fast startup typically commence with startup of the auxiliary boiler. Depending on the start condition for the auxiliary boiler and the features incorporated to permit its fast start, this activity may need to commence approximately three hours before the actual combustion turbine start condition.

1.2 CONVENTIONAL VERSUS FAST START

Conventional combined cycle facility startup durations are constrained by steam cycle equipment limitations, specifically the heat recovery steam generator and steam turbine temperature ramp capabilities. Heat recovery steam generators and steam turbines are designed to operate at very high temperatures and pressures and, therefore, are comprised of very thick metal alloy components (e.g. steam drums, steam turbine rotors). These thick components can suffer from high thermal stress and increased life expenditure if they are subjected to large temperature differentials (e.g., 1,000°F steam across an ambient temperature steam turbine rotor) or rapid temperature ramp rates. HRSG and steam turbine suppliers provide strict temperature ramp rates and temperature differential requirements for their equipment that must be used to define and limit the startup sequence and duration in order to protect the equipment.

HRSGs designed through the middle of the last decade were generally not capable of allowing combustion turbines to start at their maximum capability without incurring significant maintenance impacts. These units required pauses (“holds”) at low CTG loads to “heat soak” their heavy-walled components prior to releasing the unit on sustained ramp rates of typically less than 7°F per minute, as measured by the high-pressure (HP) drum steam saturation temperature.

Today’s HRSGs can be more robustly designed for the rapid ramp rates of advanced class combustion turbines, which can exceed 50 megawatts (MW) per minute and yield HRSG temperature ramp rates exceeding 30°F per minute.

Though HRSGs are now designed to allow combustion turbines to start at their maximum capability, steam turbines are not. Cold steam turbines require relatively cool steam, typically in the range of 700°F, on first admission to the equipment. During the startup sequence, steam temperatures downstream of the HRSG are primarily controlled through two means working in tandem, CTG exhaust temperature control and desuperheating of the generated steam. CTG exhaust temperature control tunes the CTG to minimize the exhaust temperature into the HRSG during the startup sequence, as a cooler exhaust temperature produces cooler steam. Desuperheaters spray water into the steam headers to reduce, or “attemperate”, the steam by reducing the level of superheat above the steam saturation temperature.

Most HRSGs include interstage desuperheaters that are installed between superheater and reheater sections to control the final HRSG exit steam temperatures. As the combustion turbine ramps above very low loads towards the MECL, the CTG exhaust temperature control and HRSG interstage desuperheaters are no longer capable of cooling the steam to the temperatures permitted by a relatively cool steam turbine. The steam turbine becomes a critical constraint on the start time unless the HRSG exit steam temperatures can be further reduced to match the steam turbine steam temperature requirements. In effect, the steam turbine must be 'decoupled' from the combustion turbine so that the combustion turbine start is not constrained by the steam cycle.

The steam turbine can be decoupled and its steam temperature requirements met irrespective of combustion turbine load by adding terminal desuperheaters (i.e., desuperheaters downstream of the HRSG in the high-pressure (HP) and hot reheat steam headers) to cool the HRSG exit steam to the steam turbine requirements.

Decoupling the steam turbine from the CTG/HRSG train allows the combustion turbine to ramp to emissions compliance load levels without hold periods in the firing sequence. A no-holds startup sequence is typically referred to as an uninhibited start.

Figure 1-1 provides a high-level comparison of the typical CTG load path for a 1x1 conventional combined cycle to that of a fast-start combined cycle. Additional details on the performance differences between the two startup types are discussed in Section 4.0.

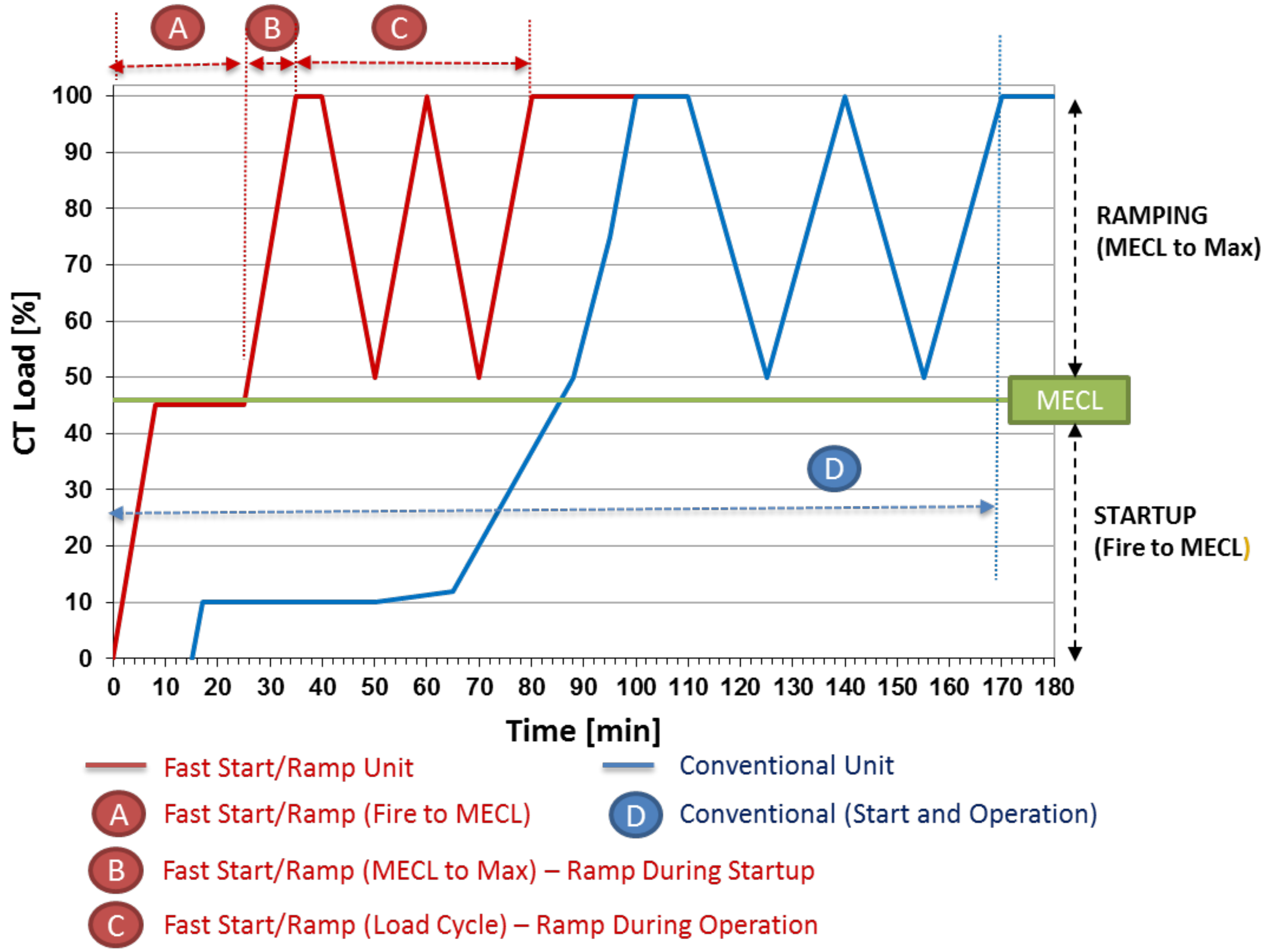

Figure 1-1 Comparison of Combustion Turbine Loading during Hot Start Event (Excludes Purge)

2.0 Design Features

Capital costs are higher for fast start plants than plants designed for conventional starts. Equipment and balance of plant systems affected by the additional design consideration for fast start are as described below and in Table 2-1. Column A of Table 2-1 lists specific design features and equipment required for fast start operation. Column D of Table 2-1 lists design features of conventional start units. Columns B and C will be discussed in the Fast Start vs. Conventional Unit Ramp Rate Analysis (File No. 400278.41.1204F).

Table 2-1 Design Features of Combined Cycles Designed for Various Operating Scenarios

FEATURES REQUIRED TO MEET OPERATING SCENARIO	A FAST START (FIRE TO MECL)	B FAST RAMP (MECL TO MAX)	C FAST RAMP (LOAD CYCLE)	D CONVENTIONAL (START AND OP)
Required Option = ●, Recommended Option = ☐, Standard Option = ◆				
Combustion Turbine				
Fast Start Equipped	●			
Natural Gas Purge Credits	●			☐
Service Life Monitoring System	◆	◆	◆	◆
Advanced Control System	●	●	●	
HRSG				
Advanced Drum Design	●	●		
Enhanced Nozzle Connections	●	●		
Improved HRSG Materials	●	●		
Improved HRSG Geometries	◆	◆	◆	◆
Service Life Monitoring System	☐	☐	☐	
Stack Damper and Insulation	●			☐
Terminal Attemperators	●	●	●	
LP Economizer Recirculation/ Heat Exchanger	●	●		
Steam Turbine				
Optimized Casing Design	●	●		
Advanced Control System	●	●	●	

FEATURES REQUIRED TO MEET OPERATING SCENARIO	A FAST START (FIRE TO MECL)	B FAST RAMP (MECL TO MAX)	C FAST RAMP (LOAD CYCLE)	D CONVENTIONAL (START AND OP)
Service Life Monitoring System	●	●	□	
Advanced Stop Valve Design	●			
Increased Thermal Clearances	●	●		
Advanced Turbine Water Induction Protection	●	●	●	
Emissions Control				
Feed-forward Ammonia Controls	●	●	●	
Auxiliary Steam				
Auxiliary Boiler	●			
Condenser and HRSG Sparging	●			
Feedwater System				
Larger Condensate Pump	●	●	●	
Larger Feedwater Pump	●	●	●	
Higher Stage IP Bleed	●	●	●	
Heat Rejection System				
Surface Condenser – Fast Start Design	●			
Fuel Gas System				
Supplementary Fuel Gas Heating(1)	□			
Water Treatment System				
Condensate Polisher(2)	□			
Auxiliary Electrical System				
Larger Equipment for Higher Loads	●	●	●	

Notes:

1. Supplementary fuel gas heating as required by combustion turbine supplier.
2. Space should be allotted for future condensate polisher installation, if required.

2.1 COMBUSTION TURBINE

Combustion turbines designed for fast-ramping will be equipped with fast start features. These include positive isolation to ensure that purge credits have been maintained per NFPA 85 and that the gas path will not require a purge prior to startup. The control system for fast start of the plant should be fully automated to minimize times between sequential steps and allow for greater consistency during startup.

Both fast start and conventional units are equipped with service life monitoring systems that control unit ramp operations based on predetermined thermal stress limitations. Fast Start units are equipped with advanced control schemes incorporating model based controls (MBC) to optimize startup based on these monitoring systems.

Purge credits established during the shutdown must still be intact. NFPA 85 requires that a fresh air purge of the combustion turbine and HRSG be accomplished prior to start. NFPA 85 requires that at least five volume changes be completed or a minimum purge of 5 minutes prior to ignition. Typical purge durations can range from 5 to 20 minutes. The 2011 edition of NFPA 85 allowed for purge credits to be achieved when the unit is taken off line if the purge is completed and the valving arrangement is shown to positively isolate any fuel from entering the system. The combustion turbine can usually achieve the required purge when coasting down following a loss of ignition.

2.2 HRSG

HRSGs designed for fast-start plants can subject HRSG components such as superheaters and reheaters to rapid heating. Large thermal stresses can be produced by the differential expansion of the tubes within the HRSG. HRSG designs in such plants must be capable of accommodating the rapid change in temperature and flow of flue gas generated by load ramping of advanced class combustion turbines.

To reduce thermal capacity of drums many options are used to decrease the drum size and wall thickness including utilizing Benson style drums, utilizing multiple drums, high strength drum materials, and reduced residence time. Self-reinforced nozzles, full penetration nozzles, full penetration welds, and steam sparger systems further improve the ability to accept rapidly changing exhaust gas conditions and steam conditions. Improved materials throughout the high pressure superheater and reheater can be required. Online, real-time monitoring system should be included to evaluate HRSG life consumption.

In order to reduce the thermal capacity of drums, the residence time may also be reduced for fast start units. Fast start units typically have drum storage time around two minutes. Conventional start plants have drum storage time from 3-5 minutes.

Fast start plants are equipped with a stack damper and with an insulated stack up to the stack damper. The stack damper and insulation are critical as they restrict the flow of flue gas out the HRSG stack minimizing heat loss when the unit is offline. While conventional units do not require stack dampers and insulation, it is a recommended practice to minimize heat loss when the unit is offline.

Both fast start and conventional units have improved HRSG geometries compared to those built a decade ago. Improvements in geometries have been to decrease thermal stresses from unit cycling and are part of the HRSG standard design such as coil flexibility to superheater/reheater interconnecting piping and accommodations for tube-to-tube temperature differentials.

2.3 STEAM TURBINE

The steam turbine must also be designed for the thermal gradients experienced while ramping during start-up. For fast start machines, the casing design must be optimized to reduce the thermal stress during temperature fluctuations and to accept faster start up and load change gradients. The use of higher grade material may be employed in the high pressure and intermediate casings and valves to reduce component thickness. Main steam stop valves must be designed so that these valves can be opened at a relatively higher pressure. Integral rotor stress monitors can be provided; the rotor stress monitor is typically capable of limiting or reducing the steam turbine load or speed increase and is designed to trip the turbine when the calculated rotor stresses exceed allowable limits.

For machines undergoing a fast ramp, attemperators are often required on the high pressure and hot reheat steam lines. Overspray on these attemperators can lead to water in these steam lines; special attention needs to be provided for turbine water induction prevention for units equipped with terminal attemperators.

2.4 EMISSIONS AND AMMONIA FEED

Outlet NO_x from the combustion turbine can vary highly when undergoing fast startup and fast ramp conditions. Conventional units only measure NO_x at the stack; for fast ramping units limiting NO_x measurements to the stack only can lead to over injecting or under injecting ammonia. Higher ammonia slip and potentially greater SO_2 conversion in fast-start and fast-ramp units create additional challenges for control of sulfur-bearing deposits in the colder HRSG areas. Low-pressure evaporators and economizers are particularly at risk. For fast ramping plants, addition of feed forward controls to quicken the saturation of the SCR catalyst (if included) is required. Also the HRSG should be equipped with LP economizer recirculation or heating systems to maintain surfaces above SO_2 dew points.

2.5 AUXILIARY STEAM

Fast start units require an auxiliary boiler to produce steam prior to the startup of the unit. This steam is used for steam line warming, establishing the steam turbine seals, warming up HRSG drums, and condenser sparging to enable uninhibited startup of the unit. The auxiliary boiler may also produce steam when the unit is off line to maintain drum and turbine temperatures.

Conventional units without an auxiliary boiler must use the combustion turbine and HRSG to produce steam to warm the unit and establish seals. During a conventional unit startup, holds are required to complete these warm up periods.

Provisions for fast start of the auxiliary boiler should also be considered which include equipping the auxiliary boiler mud drums with heating coils. Auxiliary boiler heat input, operating hour limits, and emission limits must also be considered.

Note that the auxiliary boiler makes up the majority of the cost to equip a combined cycle with fast start capabilities.

2.6 TERMINAL STEAM ATTEMPERATORS

Conventional start plants hold the combustion turbine load during startup as needed to meet the steam turbine startup steam temperature requirements. Fast-start plants decouple the CTG/HRSG startup from the steam turbine startup by using terminal attemperators at the HRSG outlet for meeting steam turbine startup steam temperature requirements, irrespective of CTG/HRSG load. This allows the steam turbine to come on line independently from the CTG and HRSG. As a result, the plant can increase load more quickly.

While the addition of terminal (final stage) steam attemperators on the main steam and hot reheat lines allow for steam turbine temperature matching, they introduce the risk of two phase flow in the steam lines. An adequate run of straight piping downstream of the attemperators, adequate drainage, and robust instrumentation are a must to minimize the risk of condensate carry-over to the steam turbine. Additional controls should be considered to prevent turbine water induction.

2.7 FEEDWATER SYSTEM

For fast start plants equipped with terminal attemperators, additional condensate and feedwater pump flow is required to meet the attemperation demands. Inter-stage feedwater used for attemperation may be taken off at a later pump stage to meet the pressure demands of the attemperators which could impact feedwater piping wall thickness.

2.8 FUEL GAS SYSTEM

In order to reduce emissions and maintain flame stability, some manufacturers require supplementary fuel gas heating as a part of startup. This heating is in addition to any startup heater used to raise the fuel gas temperature above the dew point.

2.9 WATER TREATMENT SYSTEM

Maintaining water chemistry and meeting the water chemistry requirements of the HRSG and steam turbine are a critical part of startup. Blowdown and makeup systems should be sized accordingly to meet expected startup demands. Provisions for the inclusion of a future condensate polisher should be considered should problems arise. Condensate polishers ensure top quality feedwater.

2.10 AUTOMATED STARTUP SEQUENCE

Additional controls and automation are required for fast-ramp plants to ensure the matching of steam temperatures and to maintain emission compliance. As a result, more plant instrumentation is required in automated plants to allow the plant control system to monitor system status, minimize times between sequential steps and provide consistent startups.

Also fast-ramp plants should consider the use of service life monitoring systems such as thermal stress indicators on the HRSG and steam turbine. These systems allow control of the unit ramp operations based on predetermined thermal stress limitations.

3.0 Capital Costs

Capital costs are higher for fast-start plants than plants designed for conventional starts. Additional costs that must be considered are requirements for a more flexible HRSG (e.g., header returns, tube to header connections, harps per header limits), terminal attemperators and associated systems; more flexible steam piping; improved steam piping drain systems, improved bypass system and controls integration, and requirements for auxiliary steam.

Table 3-1 lists the costs to include the design features listed in Column A of Table 2-1 for a fast start unit. Costs listed in the study are budgetary costs (+/- 30%).

Table 3-1 Fast Start (Fire to MECL) Operating Scenario Costs

FAST START SYSTEM COSTS FOR A 1X1 7F.05 COMBINED CYCLE	
Fast Start Options (Required options in Column A excluding Aux Boiler and Stress Monitoring Systems)	[redacted]
Auxiliary Boiler	[redacted]
Stress Monitoring Systems	[redacted]
Total	[redacted]

4.0 Performance Impacts

Startup durations are dependent on the ambient conditions, time after shutdown, initial steam turbine rotor temperatures, and the particular OEM equipment/features used in the power train in addition to any margins (if the required start-up times are to be guaranteed). There is a relatively wide range variation, however, for rough indicative values, Table 4-1 provides comparative durations [redacted] All fuel consumption and net generation values are based on combustion turbine ignition through the indicated end point.

Table 4-1 Estimated Nominal Startup Times (Minutes)

START TYPE	CONVENTIONAL START TO MECL	FAST START TO MECL	DIFFERENCE (CONVENTIONAL – FAST)
Hot Start = Shutdown 8 hours or less	[redacted]	[redacted]	[redacted]
Warm Start = > 8 hours and < 48 hours	[redacted]	[redacted]	[redacted]
Cold Start = Shutdown 48 hours or more	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

5.0 Startup Emissions

Stack emissions vary widely prior to reaching steady state emissions compliance due to the complexity of starting a combined cycle facility and the plant equipment's ability to operate within threshold limits across a certain operating range. The combustion turbine and the HRSG post-combustion emissions control components (if applicable) are the main equipment governing stack emissions variation.

Combustion turbines are designed with multiple fuel nozzles in each combustor. As combustion turbines start and ramp up to normal operating flow, load, and temperature, the combustion nozzles are sequenced through various combustion operating modes that vary the deflagration type (i.e., diffusion or pre-mixed [i.e., the air and fuel are pre-mixed prior to ignition of the fuel]) and nozzle firing sequences (i.e., which of the multiple nozzles are in service). These startup combustion modes are required so that stable combustion can be maintained in the unit during startup to avoid flame outs. As illustrated in Figure 2-1, in these off-design startup combustion modes, the combustion of the fuel is generally incomplete resulting in higher than normal nitrous oxide (NO_x), carbon monoxide (CO), and volatile organic compound (VOC) emissions concentrations. As the turbine reaches a minimum operating load where its normal combustion mode can be stably maintained, combustion becomes more complete and emissions decrease to a level that can be maintained across a wide operating range. The minimum operating load of the combustion turbine in this emissions compliant operating range is called the Minimum Emissions Compliance Load (MECL).

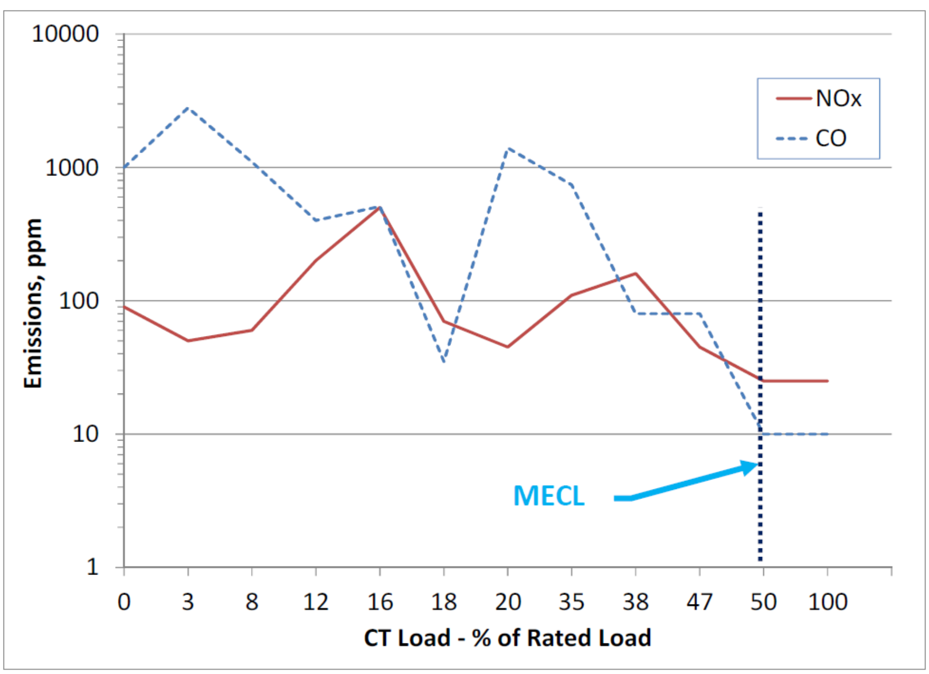

Figure 5-1 Example Combustion Turbine NO_x and CO Emissions versus Rated Load

Below MECL, the mass of air pollutant emissions can accumulate quickly and, therefore, these "startup emissions" are of particular interest to regulators. The steady-stated CTG design exhaust emissions for the turbine technologies considered are approximately 15-25 ppmvd @15% O2 for NO_x and 4-10 ppmvd @15% O2 for CO when operating on natural gas. Steady-state VOC emissions are dependent on the site specific natural gas composition.

An emissions netting analysis will be performed for the new combined cycle plant. If a Prevention of Significant Deterioration (PSD) review is required, the emissions standard that must be met is Best Available Control Technology (BACT), an emissions control mandate by the Environmental Protection Agency (EPA). If applicable, combined cycle BACT requirements dictate NO_x and CO emissions shall be no greater than 2 ppm (parts per million) at the HRSG stack discharge over the entire normal operating range. CTG emissions levels are not sufficient for BACT and post-combustion emissions controls components; oxidation catalyst to reduce CO/VOC emissions and a selective catalytic reduction (SCR) system to reduce NO_x emissions, must be installed in the HRSG to further reduce emissions to BACT levels.

Oxidation catalysts and SCR systems are not effective until they are warmed to a minimum threshold temperature and the SCR ammonia injection (utilized with the catalyst to reduce NO_x emissions) is tuned. In general, these post-combustion emissions controls components are designed such that the minimum threshold temperatures are achieved on a startup at or below the combustion turbine MECL. As noted previously, an "emissions" startup sequence is considered complete after the CTG reaches MECL, and in the event of post-combustion emissions control components, they reach their minimum threshold temperatures, and the SCR ammonia injection is tuned such that stack emissions meet the air quality requirements.

FINAL

FAST START VS. CONVENTIONAL UNIT RAMP RATE ANALYSIS

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1204F

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

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1.0 Introduction

The purpose of this study is to evaluate the differences for conventional and fast ramping options between MECL and full load on unit startup for a 1x1 7F.05 combined cycle. The GE 7F.05 is one of several candidate F-Class combustion turbine offerings.

Since the temperature differential between components is the primary concern of fast ramping between MECL and full load; many of the design features required for fast ramping between MECL and full load are the same as the features required for fast start between combustion turbine ignition to MECL as discussed in the Fast Start vs. Conventional Start Analysis (File No. 400278.41.1203F). Figure 1-1 shows the regions covered under this study noted as Ramping and that covered in the Fast Start vs. Conventional Start Analysis noted as Startup.

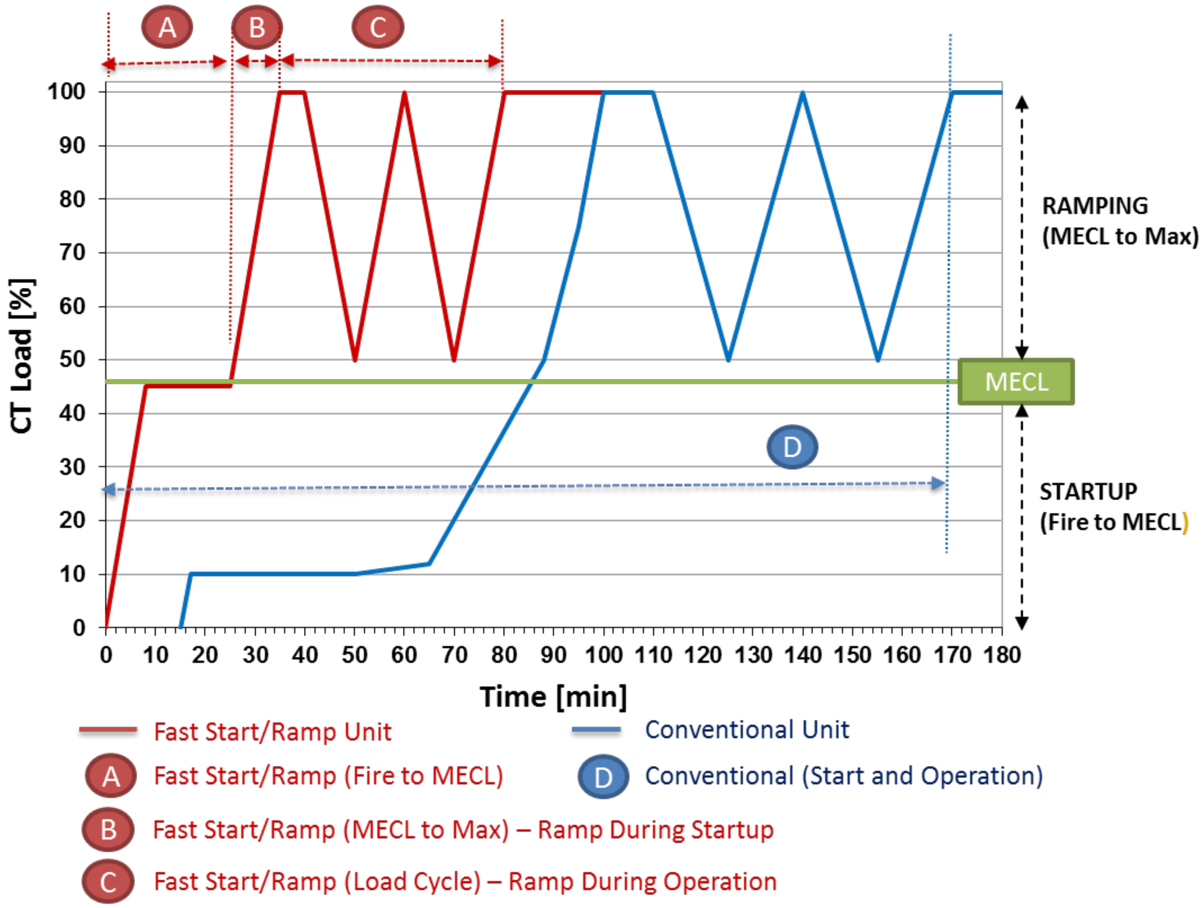

Figure 1-1 Comparison of Combustion Turbine Loading From MECL to Full Load

Table 1-1, Column B indicates the design features that would be required for fast ramping and how they differentiate from a conventional unit, Column D, and a fast start unit, Column A. Descriptions for each of the design features can be found in the Fast Start vs. Conventional Start

Analysis and also included in Appendix A. Items included in Column B also encompass those features in Column C which are required for fast ramping during operation.

Table 1-1 Design Features of Combined Cycles Designed for Various Operating Scenarios

FEATURES REQUIRED TO MEET OPERATING SCENARIO	A FAST START (FIRE TO MECL)	B FAST RAMP (MECL TO MAX)	C FAST RAMP (LOAD CYCLE)	D CONVENTIONAL (START AND OP)
Required Option = ●, Recommended Option = □, Standard Option = ◆				
Combustion Turbine				
Fast Start Equipped	●			
Natural Gas Purge Credits	●			□
Service Life Monitoring System	◆	◆	◆	◆
Advanced Control System	●	●	●	
HRSG				
Advanced Drum Design	●	●		
Enhanced Nozzle Connections	●	●		
Improved HRSG Materials	●	●		
Improved HRSG Geometries	◆	◆	◆	◆
Service Life Monitoring System	□	□	□	
Stack Damper and Insulation	●			□
Terminal Attemperators	●	●	●	
LP Economizer Recirculation/Heat Exchanger	●	●		
Steam Turbine				
Optimized Casing Design	●	●		
Advanced Control System	●	●	●	
Service Life Monitoring System	●	●	□	
Advanced Stop Valve Design	●			
Increased Thermal Clearances	●	●		
Advanced Turbine Water Induction Protection	●	●	●	
Emissions Control				
Feed-forward Ammonia Controls	●	●	●	

FEATURES REQUIRED TO MEET OPERATING SCENARIO	A FAST START (FIRE TO MECL)	B FAST RAMP (MECL TO MAX)	C FAST RAMP (LOAD CYCLE)	D CONVENTIONAL (START AND OP)
Auxiliary Steam				
Auxiliary Boiler	●			
Condenser and HRSG Sparging	●			
Feedwater System				
Larger Condensate Pump	●	●	●	
Larger Feedwater Pump	●	●	●	
Higher Stage IP Bleed	●	●	●	
Heat Rejection System				
Surface Condenser – Fast Start Design	●			
Fuel Gas System				
Supplementary Fuel Gas Heating(1)	□			
Water Treatment System				
Condensate Polisher(2)	□			
Auxiliary Electrical System				
Larger Equipment for Higher Loads	●	●	●	

Notes:
1. Supplementary fuel gas heating as required by combustion turbine supplier.
2. Space should be allotted for future condensate polisher installation, if required.

2.0 Capital Costs

Note that all of the features required for fast ramp are included in Column A of Table 1-1 discussed in the Fast Start vs. Conventional Start Analysis. The costs in Table 2-1 indicate only the costs for Column B of Table 1-1. Costs listed in the study are budgetary costs (+/- 30%).

Table 2-1 Fast Ramp (MECL to Full Load) Operating Scenario Costs

FAST RAMP SYSTEM COSTS FOR A 1X1 7F.05 COMBINED CYCLE	
Fast Ramp Options (Required options in Column B excluding Stress Monitoring Systems)	[redacted]
Stress Monitoring Systems	[redacted]
Total*	[redacted]
NOTE: If a fast start plant is selected, the above costs are not additive to those listed in the Fast Start Study.	

3.0 Performance Impacts

Startup and ramping durations are dependent on the ambient conditions, time after shutdown, initial steam turbine rotor temperatures, and the particular OEM equipment/features used in the power train in addition to any margins (if the required start-up times are to be guaranteed). There is a relatively wide range variation, however, for rough indicative values, Table 3-1 provides comparative durations for a GE 7F.05 1x1 combined cycle. [redacted]

Table 3-1 Estimated Nominal Startup Times (Minutes)

START TYPE	CONVENTIONAL START TO MECL	CONVENTIONAL START TO STG FULL LOAD	FAST START TO MECL	FAST START, TO CTG BASELOAD	FAST START, TO CTG BASELOAD WITH STG LOADED
Hot Start = Shutdown 8 hours or less	Base Conv.	42	Base Fast	7.1	54
Warm Start = > 8 hours and < 48 hours	Base Conv.	37	Base Fast	21	47
Cold Start = Shutdown 48 hours or more	Base Conv.	67	Base Fast	62	98

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

For a conventional start, each combustion turbine is ramping at a nominal rate from MECL to combustion turbine baseload of 17 MW/min or 7.09%/min, while the combustion turbine ramp rate for fast start is 40 MW/min or about 16.66%/min from MECL to combustion turbine baseload.

After startup and after thermal soaking, the unit will able to achieve fast ramping. For a GE 7F.05, each combustion turbine has the ability to ramp 40 MW/minute. For a 1x1 combined cycle, the ramp rate can be stated to be 40 MW/minute. The steam turbine contribution toward fast ramping is typically not quoted since the steam turbine response is much less predictable than the combustion turbine load response. This is due to a lag in HRSG steam production response due to the CTG load changes. Depending on how the combustion turbine is ramped up and down, the output contribution from the steam turbine would take some time to settle out into a steady state performance level. For conventional units, the combustion turbine ramp rates may be limited by the HRSG and steam turbine limitations. For units equipped with fast ramping, the steam conditions can be conditioned to allow the combustion turbine to ramp independently of the steam turbine.

4.0 Emissions

The period for ramping is defined as the period between minimum emissions compliance load and full load. Once the unit has obtained emission compliance, the unit generally stays in compliance for ramping conditions. During a fast ramp the outlet NO_X from the combustion turbine is variable. Conventional units only measure NO_X at the stack; this may lead to short durations of higher NO_X or ammonia slip. For fast ramping units limiting NO_X measurements to the stack only can lead to over injecting or under injecting ammonia. To address this, fast ramping units are equipped with feed-forward NO_X controls which take NO_X measurements at the combustion turbine exhaust as well as the stack to quicken the response to changing combustion turbine exhaust conditions. Both conventional and fast ramping units are designed to operate in compliance with stack emission limits across the averaging period.

Appendix A. Fast Start and Fast Ramp Design Features

Design features for fast start and fast ramping units are as follows:

A.1 COMBUSTION TURBINE

Combustion turbines designed for fast-ramping will be equipped with fast start features. These include positive isolation to ensure that purge credits have been maintained per NFPA 85 and that the gas path will not require a purge prior to startup. The control system for fast start of the plant should be fully automated to minimize times between sequential steps and allow for greater consistency during startup.

Both fast start and conventional units are equipped with service life monitoring systems that control unit ramp operations based on predetermined thermal stress limitations. Fast Start units are equipped with advanced control schemes incorporating model based controls (MBC) to optimize startup based on these monitoring systems.

Purge credits established during the shutdown must still be intact. NFPA 85 requires that a fresh air purge of the combustion turbine and HRSG be accomplished prior to start. NFPA 85 requires that at least five volume changes be completed or a minimum purge of 5 minutes prior to ignition. Typical purge durations can range from 5 to 20 minutes. The 2011 edition of NFPA 85 allowed for purge credits to be achieved when the unit is taken off line if the purge is completed and the valving arrangement is shown to positively isolate any fuel from entering the system. The combustion turbine can usually achieve the required purge when coasting down following a loss of ignition.

A.2 HRSG

HRSGs designed for fast-start plants can subject HRSG components such as superheaters and reheaters to rapid heating. Large thermal stresses can be produced by the differential expansion of the tubes within the HRSG. HRSG designs in such plants must be capable of accommodating the rapid change in temperature and flow of flue gas generated by load ramping of advanced class combustion turbines.

To reduce thermal capacity of drums many options are used to decrease the drum size and wall thickness including utilizing Benson style drums, utilizing multiple drums, high strength drum materials, reduced residence time. Self-reinforced nozzles, full penetration nozzles, full penetration welds, and steam sparger systems further improve the ability to accept rapidly changing exhaust gas conditions and steam conditions. Improved materials throughout the high pressure superheater and reheater can be required. Online, real-time monitoring system should be included to evaluate HRSG life consumption.

In order to reduce the thermal capacity of drums, the residence time may also be reduced for fast start units. Fast start units typically have drum storage time around two minutes. Conventional start plants have drum storage time from 3-5 minutes.

Fast start plants are equipped with a stack damper and with an insulated stack up to the stack damper. The stack damper and insulation are critical as they restrict the flow of flue gas out the HRSG stack minimizing heat loss when the unit is offline. While conventional units do not require stack dampers and insulation, it is a recommended practice to minimize heat loss when the unit is offline.

Both fast start and conventional units have improved HRSG geometries compared to those built a decade ago. Improvements in geometries have been to decrease thermal stresses from unit cycling and are part of the HRSG standard design such as coil flexibility to superheater/reheater interconnecting piping and accommodations for tube-to-tube temperature differentials.

A.3 STEAM TURBINE

The steam turbine must also be designed for the thermal gradients experienced while ramping during start-up. For fast start machines, the casing design must be optimized to reduce the thermal stress during temperature fluctuations and to accept faster start up and load change gradients. The use of higher grade material may be employed in the high pressure and intermediate casings and valves to reduce component thickness. Main steam stop valves must be designed so that these valves can be opened at a relatively higher pressure. Integral rotor stress monitors can be provided; the rotor stress monitor is typically capable of limiting or reducing the steam turbine load or speed increase and is designed to trip the turbine when the calculated rotor stresses exceed allowable limits.

For machines undergoing a fast ramp, attemperators are often required on the high pressure and hot reheat steam lines. Overspray on these attemperators can lead to water in these steam lines; special attention needs to be provided for turbine water induction prevention for units equipped with terminal attemperators.

A.4 EMISSIONS AND AMMONIA FEED

Outlet NO_X from the combustion turbine can vary highly when undergoing fast startup and fast ramp conditions. Conventional units only measure NO_X at the stack; for fast ramping units limiting NO_X measurements to the stack only can lead over injecting or under injecting ammonia. Higher ammonia slip and potentially greater SO2 conversion in fast-start and fast-ramp units create additional challenges for control of sulfur-bearing deposits in the colder HRSG areas. Low-pressure evaporators and economizers are particularly at risk. For fast ramping plants, addition of feed forward controls to quicken the saturation of the SCR catalyst (if included) is required. Also the HRSG should be equipped with LP economizer recirculation or heating systems to maintain surfaces above SO2 dew points.

A.5 AUXILIARY STEAM

Fast start units require an auxiliary boiler to produce steam prior to the startup of the unit. This steam is used for steam line warming, establish the steam turbine seals, warm up HRSG drums, and condenser sparging to enable uninhibited startup of the unit. The auxiliary boiler may also produce steam when the unit is off line to maintain drum and turbine temperatures.

Conventional units without an auxiliary boiler must use the combustion turbine and HRSG to produce steam to warm the unit and establish seals. During a conventional unit startup, holds are required to complete these warm up periods.

Provisions for fast start of the auxiliary boiler should also be considered which include equipping the auxiliary boiler mud drums with heating coils. Auxiliary boiler heat input, operating hour limits, and emission limits must also be considered.

Note that the auxiliary boiler makes up the majority of the cost to equip a combined cycle with fast start capabilities.

A.6 TERMINAL STEAM ATTEMPERATORS

Conventional start plants hold the combustion turbine load during startup as needed to meet the steam turbine startup steam temperature requirements. Fast-start plants decouple the CTG/HRSG startup from the steam turbine startup by using terminal attemperators at the HRSG outlet for meeting steam turbine startup steam temperature requirements, irrespective of CTG/HRSG load. This allows the steam turbine to come on line independently from the CTG and HRSG. As a result, the plant can increase load more quickly.

While the addition of terminal (final stage) steam attemperators on the main steam and hot reheat lines allow for temperature matching, they introduce the risk of two phase flow in the steam lines. An adequate run of straight piping downstream of the attemperators, adequate drainage, and robust instrumentation are a must to minimize the risk of condensate carry-over to the steam turbine. Additional controls should be considered to prevent turbine water induction.

A.7 FEEDWATER SYSTEM

For fast start plants equipped with terminal attemperators, additional condensate and feedwater pump flow is required to meet the attemperation demands. Inter-stage feedwater used for attemperation may be taken off at a later pump stage to meet the pressure demands of the attemperators which could impact feedwater piping wall thickness.

A.8 FUEL GAS SYSTEM

In order to reduce emissions and maintain flame stability, some manufacturers require supplementary fuel gas heating as a part of startup. This heating is in addition to any startup heater used to raise the fuel gas temperature above the dew point.

A.9 WATER TREATMENT SYSTEM

Maintaining water chemistry and meeting the water chemistry requirements of the HRSG and steam turbine are a critical part of startup. Blowdown and makeup systems should be sized accordingly to meet expected startup demands. Provisions for the inclusion of a future condensate polisher should be considered should problems arise. Condensate polishers ensure top quality feedwater.

A.10 AUTOMATED STARTUP SEQUENCE

Additional controls and automation are required for fast-ramp plants to ensure the matching of steam temperatures and to maintain emission compliance. As a result, more plant instrumentation is required in automated plants to allow the plant control system to monitor system status, minimize times between sequential steps and provide consistent startups.

Also fast-ramp plants should consider the use of service life monitoring systems such as thermal stress indicators on the HRSG and steam turbine. These systems allow control of the unit ramp operations based on predetermined thermal stress limitations.

FINAL

NUMBER OF COLD, WARM, AND HOT STARTS ANALYSIS

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1207F

PREPARED FOR

Vectren

31 JANUARY 2020

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1.0 Introduction

Prior to the early 2000s, combined cycles were predominately designed for base load operation with high focus on highest full load efficiency and lowest capital cost. Due to increases in gas pricing, changing power market production cost structure, and renewable energy generation, many of these plants were forced into intermediate or even daily cycling mode. Many problems associated with the fast changing temperatures in the equipment resulted, such as high thermal stresses, high cyclic fatigue, vibration, flow accelerated corrosion, and water induction.

As a result of these industry issues, today's major equipment suppliers design their equipment to withstand the cumulative wear and damage caused by frequent starts and stops. For modern combined cycle equipment operating as high cycling units, major equipment manufacturers take the following into consideration:

- Base equipment designs consider high cycling
- Service life monitoring equipment is recommended for high cycling units
- Time between service intervals decreases with higher cycling

In addition to the number of starts, the time between the unit shutdown and start also has a significant impact on the equipment. When a unit is shutdown, equipment begins to cool. Upon the next start, the equipment would have to be brought back up to operating temperature putting the equipment through a thermal cycle. The duration between shutdown and startup is usually broken down between different start modes whether the equipment is considered hot, warm, or cold. Equipment manufacturers each have their own definition for hot, warm, and cold starts; however, typical start mode durations are listed in Table 1-1.

Table 1-1 Start Mode Definitions

START TYPE	SHUTDOWN DURATION
Hot	< 8 hours
Warm	8-48 hours
Cold	> 48 hours

1.1 BASE EQUIPMENT DESIGN

During startup and shutdown, the unit sees large temperature gradients and thermal stresses. Cycling increases concern for thermally induced creep-fatigue damage as a result of rapid heating of the surface of components such as turbine blades, rotors, casings, drums, and other heavy walled components. Creep-fatigue damage can also result from different thermal expansion between thin and thick components or dissimilar metal welds.

To resolve these issues, manufacturers have incorporated the knowledge of these earlier failures into their standard designs. Manufacturers select geometries, materials, thicknesses, and coatings in such a way as to limit the damage of thermal cycling. Geometries and material selection also alleviate other issues such as flow accelerated corrosion, vibration, and water induction. These designs do not alleviate all the issues with thermal factors but allow the equipment to be monitored in such a way to determine its service life.

1.2 MAINTENANCE INTERVALS

The design life for the facility is 30 years and the operating equipment will need regular maintenance including hot gas path and major inspections. Figure 1-1 shows the equivalent hours-based and starts-based maintenance intervals for GE and Siemens F-class combustion turbines and the potential impact of maintenance factors on maintenance intervals.

The timing of maintenance intervals are impacted by maintenance factors. Hours based maintenance factors consider fuel type, firing temperature, and water or steam injection used for emissions control or power augmentation. Starts based maintenance factors consider the type of start; whether it is a conventional start, fast start, cold start, warm start; load achieved during each start; and shutdown type such as normal cooldown, rapid cooldown or unit trip. The red lines in Figure 1-1 show how starts or hours based factors could affect the timing of maintenance intervals.

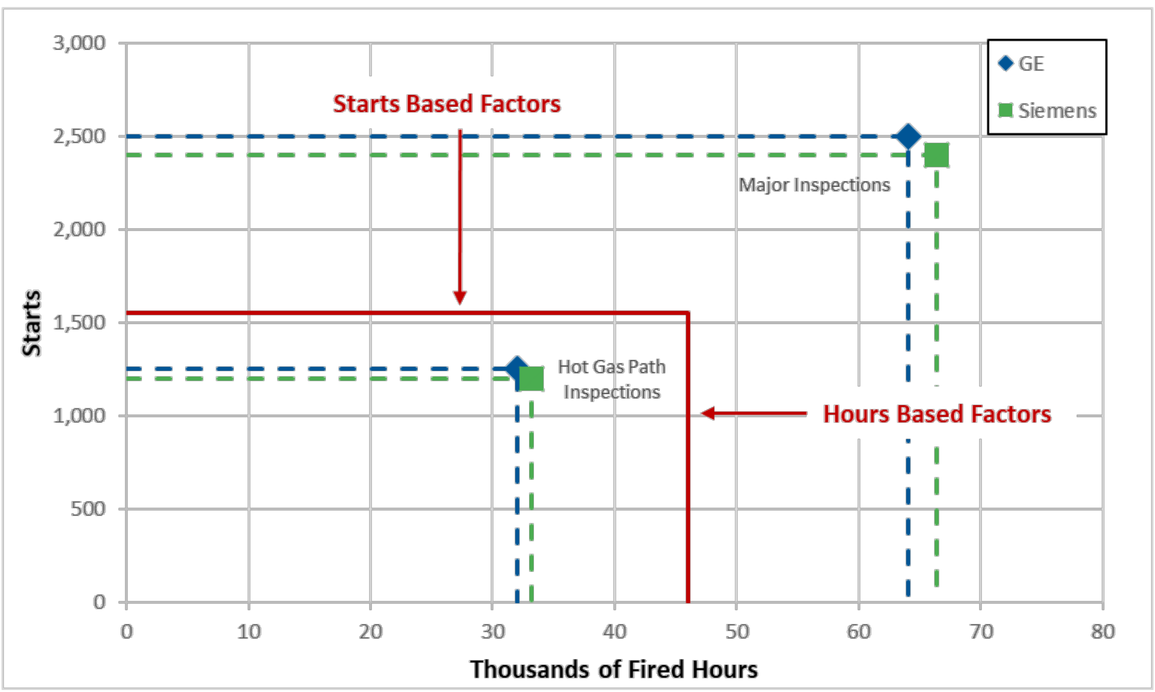

Figure 1-1 Maintenance Factors Reduce Maintenance Intervals

Per GE's Heavy-Duty Gas Turbine Operating and Maintenance Considerations (GER-3620N), a GE unit with a baseline maintenance factor would equate to 4,800 operating hours per year (16 hours/start, 6 starts/week, 50 weeks/year) and 300 starts per year. Those 300 starts would consist of 249 hot starts, 39 warm starts, and 12 cold starts. For the design life of 30 years, GE would base their Long Term Service Agreement (LTSA) on 4 maintenance cycles for a GE 7F.05 with a baseline operating profile. The LTSA relates to the serviceable life of the combustion turbine.

Figure 1-2 shows how operating hours and the number of starts per year affect the duration of the LTSA. A 30 year life is based on roughly 333 equivalent starts per year. An operating regime requiring above 333 equivalent starts per year would have service intervals based on equivalent life and start decreasing the life expectancy of the LTSA. For example, 500 equivalent starts per year would be roughly equivalent to a 20 year LTSA life. When operating below 333 equivalent starts per year the figure shows whether hours based operation or number of starts based operation would determine the maintenance intervals for the plant. Since the facility has a 30 year design life, 333 equivalent starts would be the average yearly allowable for the plant. Based on a design basis of 310 starts per year, the breakdown of recommended number of design basis cold, warm, and hot starts would be as shown in Table 1-2.

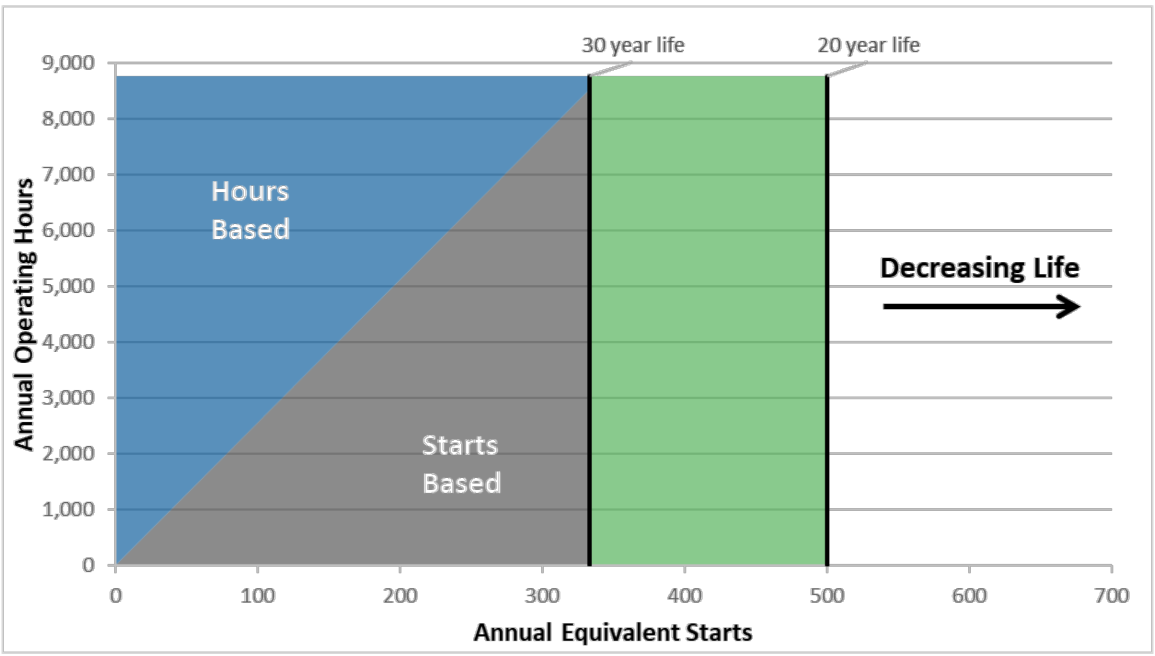

Figure 1-2 Combustion Turbine LTSA Term vs. Starts and Operating Hours Service Intervals

Table 1-2 Operating Conditions Used in Design Basis

OPERATING CONDITIONS	DESIGN BASIS
Operation	Daily Cycling
Yearly Operating Hours	Up to 8,760
Annual Capacity Factor	45% to 100%
Cold Starts Per Year	10
Warm Starts Per Year	100
Hot Starts Per Year	200
Total Starts Per Combustion Turbine	<310

1.3 SERVICE LIFE MONITORING EQUIPMENT

For plants operating in a regime where the starts based maintenance factors are determining the service intervals, it becomes useful to monitor the equipment to avoid costly outages. Service life monitoring systems perform three functions: instrumentation, evaluation, and determination. The instrumentation and sensor systems record the operating parameters such as localized temperature, pressure, and vibration. Based upon the readings, evaluations can be made such as stresses in critical locations in the turbines and the HRSG. The evaluated data is then combined with the operating history of the system to determine the impact on the remaining service life.

Recommended monitoring systems for high cycling plants include:

- Combustion Turbine Stress Controller
- Steam Turbine Stress Controller
- HRSG Stress Controller
- Condition Monitoring System
- Water Quality Monitoring System

Today's F-class combustion turbines come equipped with control systems that monitor speed, acceleration, temperature, and verify that all sensors are active. These sensors measure performance and monitor the machine's health. These systems also count the operating hours and number of equivalent starts or calculate the equivalent life of each start sequence in order to calculate the next service interval.

The steam turbine stress controller consists of a stress evaluation system that calculates and controls stresses in thick walled components including stop and control valves, HP casing and rotor body, and the IP rotor body. The stress controller monitors and controls ramp rates during start up to calculate the cumulative fatigue of cycling the unit. The stress controller also determines the remaining time to the next service interval.

The HRSG stress controller performs a dynamic analysis of the HRSG to determine fatigue. The stress controller determines risk factors based upon the evaluations, such as the probability of crack initiation. These risk factors are used to plan and indicate HRSG maintenance.

Condition monitoring systems measure critical asset parameters such as vibration, temperature, and speed of rotating equipment including boiler feed pumps, condensate pumps, circulating water pumps, cooling tower fans, and fuel gas compressors. The monitoring systems also evaluate trends, such as vibration amplification, and compare it against set points, historical readings, and known failure patterns.

The water quality monitoring system provides additional water and steam sampling to monitor issues with cycling units. Cycling units result in a large demand on the condenser and, in peak demands, on condensate supply and oxygen controls. Additional controls include online monitoring for condenser tube leaks and condenser air in leakage. It also includes monitoring steam blowdown lines for high level of particulates to indicate any safety issues. Water quality monitoring systems are not as important if the unit includes a condensate polisher.

2.0 Service Life Monitoring System Costs

As outlined in Section 1.2, service life monitoring systems are recommended for high cycling plants to help predict and plan maintenance. Table 2-1 provides budgetary cost (+/- 30%) for service life monitoring systems.

Table 2-1 Service Life Monitoring System Costs

SERVICE LIFE MONITORING SYSTEM COSTS	
Combustion Turbine Stress Controller	[redacted]
Steam Turbine Stress Controller	[redacted]
HRSG Stress Controller	[redacted]
BOP Condition Monitoring System	[redacted]
Water Quality Monitoring System	[redacted]
Additional cable and I/O	[redacted]
Total	[redacted]

3.0 Conclusion

Today's combined cycle equipment is designed for high cycling applications and consider problems associated with the fast changing temperatures in the equipment such as high thermal stresses, high cyclic fatigue, vibration, flow accelerated corrosion, and water induction. The design life of the equipment is 30 years with major overhauls of the combustion turbines occurring every 7.5 to 8 years. The time duration between major overhauls is based upon maintenance factors associated with hours of operation and the number of starts.

While the number of operating hours is not expected to shorten the time between maintenance cycles, the number of starts could decrease the operational life. In order to maintain the 7.5 to 8 years between major overhauls, the combustion turbine should have an equivalent number of annual starts less than 333. To avoid decreasing the life of the LTSA, the typical combined cycle design including balance of plant equipment should not exceed 333 starts per year. The breakdown of the recommended number of design cold, warm, and hot starts would be as shown in Table 3-1.

Table 3-1 Design Cold, Warm, and Hot Starts

OPERATING CONDITIONS	
Operation	[redacted]
Yearly Operating Hours	[redacted]
Annual Capacity Factor	[redacted]
Cold Starts Per Year	[redacted]
Warm Starts Per Year	[redacted]
Hot Starts Per Year	[redacted]
Total Starts Per Combustion Turbine	[redacted]

If the plant is expected to be a high cycling unit with a maintenance cycle that would be determined based upon the number of starts rather than the number of hours operated per year, Vectren should consider additional service life monitoring systems to assist in predictive maintenance, as shown in Table 3-2. While these systems do not prevent maintenance, they allow the operator to better understand how the operation of the unit is impacting the service life of the equipment.

Table 3-2 Service Life Monitoring Systems

SERVICE LIFE MONITORING SYSTEM COSTS	
Combustion Turbine Stress Controller	[redacted]
Steam Turbine Stress Controller	[redacted]
HRSG Stress Controller	[redacted]
BOP Condition Monitoring System	[redacted]
Water Quality Monitoring System (not required with a condensate polishing system)	[redacted]
Additional cable and I/O	[redacted]
Total	[redacted]

FINAL

AUXILIARY BOILER ANALYSIS

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1209F

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

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Executive Summary

In developing this report, Black & Veatch reviewed the requirements for the auxiliary steam system for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed multiple pre-start, start-up and shutdown scenarios to determine the required sizing and operation of the auxiliary steam boiler.

The auxiliary steam system users have been summarized in the Auxiliary Steam Demands provided in Table 2-1. The users were estimated based on previous projects using the 7F.05 gas turbines. Based on the maximum co-incident steam demand of the 7F.05 configuration it is recommended that Vectren utilize an auxiliary boiler designed for [redacted] lb/hr and an outlet pressure of [redacted]

1.0 Introduction

The purpose of this study is to determine the specific requirements for the Auxiliary boiler to be installed with the new Combined Cycle Power Plant (CCPP). These Fast start units require an auxiliary boiler to produce steam prior to the startup of the unit. This auxiliary steam is used for steam line warming, establish the steam turbine seals, warm up HRSG drums, and condenser sparging to enable quicker startup of the unit. The auxiliary boiler may also produce steam when the unit is off line to maintain drum and turbine temperatures. Black & Veatch has previously performed the "Fast Start vs Conventional Start Analysis" which demonstrates the need for an auxiliary boiler for a unit with fast start capability.

This evaluation will help determine the design impact of this system to the new CCPP design. Auxiliary system users, auxiliary boiler sizing and operation will also be identified and discussed.

2.0 Auxiliary Boiler Sizing and Outlet Pressure

The auxiliary steam system provides steam to various users during plant startup and shutdown at multiple operating conditions. Several operating scenarios were evaluated to determine the best preliminary design basis for sizing the auxiliary boiler. Upon selection of the final plant design, the selected size of auxiliary boiler should be reviewed.

2.1 COINCIDENT STEAM DEMANDS

The maximum co-incident auxiliary boiler steam demand occurs during startup when supplying maximum steam turbine sealing, fuel heating, maximum condenser sparing steam, and maximum combustion turbine inlet air heating as shown in Table 2-1.

Table 2-1 Coincident Auxiliary Steam Demands

AUXILIARY STEAM USERS	1X1 7F.05
ST Gland Sealing	[redacted]
Startup Steam to Fuel Gas Heater	[redacted]
Condenser Hotwell Sparging	[redacted]
Combustion Turbine Inlet Air Heating	[redacted]
Total Coincident Boiler Steam Flow Required	[redacted]

2.2 NON-COINCIDENT STEAM DEMANDS

During unit pre-start, there are two activities that require auxiliary steam flow, but are not co-incident with the other users. These non-coincident activities occur during HRSG pre-warming and HRSG HP pressure holding. The non-coincident auxiliary steam demands are listed in Table 2-2.

Table 2-2 Non-Coincident Auxiliary Steam Demands During Pre-Start Activities

AUXILIARY STEAM USERS	1X1 7F.05
HRSG Warming	[redacted]
HRSG Pressure Holding	[redacted]

2.3 DESCRIPTION OF USERS

- The turbine seals require steam from the auxiliary system to provide sealing until the steam turbine increases load and becomes self-sealing. When the steam turbine exceeds the point of self-sealing, the flow from the auxiliary system will decrease to near zero.
- A startup steam to fuel gas heater is used to raise the fuel gas to the CT manufacturers specified minimum fuel temperature via a steam to water heat exchanger.
- Condenser hotwell sparging is used to heat the condensate in the condenser to normal operating temperatures prior to starting the units.
- The gas turbine inlet air heating system uses auxiliary steam to provide heat via coils in the CT inlet air structure to minimize the possibility for ice formation in the CT compressor section.
- The HRSG HP warming flow increases the metal temperature of the steam drums and the tubes, allowing for faster startup capability.
- The HRSG HP pressure holding maintains the HP evaporator at a minimum of 275 psig to maintain drum and tube temperatures for faster startup capability.

2.4 BOILER OUTLET CONDITIONS

The delivery steam pressure of the auxiliary boiler is typically 300 psig at saturation temperature to facilitate HP evaporator pressure holding of approximately 275 psig. Electric superheaters will be used to provide superheated steam to the turbine seals. Delivering saturated steam will reduce the heat input to the auxiliary boiler which is limited due to air permits.

3.0 Auxiliary Boiler Operation

3.1 PRE-START CONDITION

The auxiliary steam system should be pressurized, heated and drained up to the steam seal feed valve during pre-start activities. The operating conditions of the auxiliary boiler and system must be verified prior to initiating a unit startup. During cold pre-start activities, the steam for turbine sealing, condenser sparging steam and HP evaporator warming is supplied by the auxiliary boiler. During hot start activities, the steam demand for the HP evaporator warming steam is replaced by the steam demand for HP evaporator pressure holding. Following an HRSG outage or cold restart, the HRSG HP warming flow is set to a maximum flowrate to accelerate warming.

3.2 INITIAL STARTUP AND SHUTDOWN

During initial startup the auxiliary steam for the turbine sealing, CT air inlet heating, fuel gas heating and condenser sparging is provided from an auxiliary boiler. As the plant cycle steam from the HRSG IP drum becomes available it allows the auxiliary boiler to be shut down or unloaded to idle as plant operations allow. During normal operation the HRSG IP drum provides all required auxiliary steam flow for the plant.

During plant shutdown or trip, it is expected that there is enough residual energy in the HRSG to provide auxiliary steam until the steam turbine exhaust vacuum is broken or the auxiliary boiler can be brought online to provide sealing steam. The auxiliary boiler must remain in a ready condition at all times during combined cycle operation. During overnight plant shutdowns the aux boiler can remain in operation to provide sealing steam, condenser sparging steam and allow rapid starting in the morning.

4.0 Conclusions

The purpose of this evaluation was to determine the specific requirements for the auxiliary boiler for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed pre-start, start-up and shut down scenarios to determine the required sizing and operation of the auxiliary boiler.

This report has shown:

- Auxiliary steam users and the estimated demand.
- Non-coincident auxiliary steam users and the estimated demand
- Black & Veatch's recommendation for steam requirements listed in Table 2-1 for various plant configurations.

FINAL

EXISTING FIRE WATER SYSTEM REVIEW

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 42.1212F

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

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Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch reviewed the piping and instrumentation diagrams (P&IDs) for the existing fire protection and service water systems.

The existing system includes existing pumps and a 75,000 gallon raw water storage tank. The raw water storage tank is sized to provide 51,000 gallons of surge capacity devoted to fire water use. To meet the new fire water system design requirements, a third diesel motor fire pump should be added to the system and the pump arrangement modified to a 3x50 percent configuration with two pumps driven by a diesel motor and the other driven by an electric motor. This configuration allows for a fire water demand up to 3,000 gpm. The existing pressure maintenance pump, which is rated for approximately 1 percent for the main pumps flow and same discharge pressure, should remain.

1.0 Existing Equipment

Based on the existing site Fire Protection and Service Water Systems P&ID (F-1024) there are 2x100 percent fire pumps (one electric driven and one diesel driven) that are rated for 1,500 gpm @ 300 FT TDH each. The fire water pumps normally take suction from existing Ranney Well pumps of adequate capacity and the Raw Water Storage Tank (75,000 gallons) via a 12" nominal diameter suction header. The Raw Water Storage Tank is sized to provide 51,000 gallons of surge capacity devoted to fire water use. The fire protection water supply system is also cross tied to the River Water pumps. The existing site has a 10" underground fire water loop. This pipe is assumed to be ductile iron.

Per NFPA 850, the existing water source is large enough to be considered a reliable water source. The multiple pumps installed provide reliability such that a single failure or maintenance event will not impair the ability of the system to responds to a fire event. If a single pump were to be out of service, the remaining pumps will still have sufficient capacity to supply water to the existing water users as well as the maximum fire water demand of 2,500 gpm.

2.0 Design Basis and Clarifications

- A search of the NFPA codes on the Indiana State website did not include NFPA 850. However, for the purposes of this assessment and the design of the new power plant, Black & Veatch has referenced NFPA 850 – 2015.
- There is a discrepancy between some of the code years referenced on the Indiana State website and from the IBC or IFC. Our basis is the most current version when this occurs.
- It is not clear from the P&ID what the material used for the existing underground fire water supply mains. Our basis is currently ductile iron material; please clarify if different.
- Please clarify who the Authority Having Jurisdiction (AHJ) is for the A.B. Brown Site. We have identified the state fire marshal below.

  Indiana State Fire Marshal
  Stephen Cox
  317-232-2222
  http://www.in.gov/dhs/2445.htm

3.0 New Plant Fire Protection Requirements

The new plant's required fire water system supply flow is based on a worst case fire scenario, plus a hose allowance (500 gpm), and any adjacent systems in the immediate area of a potential fire area; as defined in NFPA 850, Section 6.2. The largest system demand is expected to be the Steam Turbine Building/Enclosure at 1,800 gpm in combination with the turbine generator bearings closed head sprinkler system with directional nozzles with a demand of approximately 200 gpm. This total demand will require a main fire pump rated at 2,500 gpm. The velocity limits at this flow require either a 10" DI or 12" HDPE DR 11 pipe.

To meet the new fire water system design requirements a third diesel motor fire pump (1,500 gpm @ 300ft) should be added to the system modifying the pump arrangement to 3x50 percent configuration with two pumps driven by a diesel motor and the other driven by an electric motor. This configuration allows for a fire water demand up to 3,000 gpm. The existing pressure maintenance pump which is rated for approximately 1 percent for the main pumps flow and same discharge pressure should remain. There are no elevated areas for the new or existing plant areas that require booster pumps to obtain adequate pressure for hose stations so a standard pressure rating of 300 ft-H2O at the rated point is expected to be sufficient.

Per NFPA 850 the multiple Ranney Well pumps installed will provide a reliable source of water such that a single failure or maintenance event will not impair the ability of the system to responds to a fire event. In a single pump out of service case the two remaining Ranney Well pumps can provide up to 4,000 gpm. The preliminary water mass balance for other uses states the normal use from non-fire protection demands is approximately 150 gpm. This allows the fire water demand of 2,500 gpm to be met along with the other non-fire protection water users.

The existing 10" fire protection underground system can be reused with new 12" HDPE used for any new underground headers and around the cooling tower. Hydrants will be located as per NFPA 850 and the local code requirements.

4.0 List of Applicable Codes and Standards

675 IAC 13-2.6	Indiana Building Code, 2014 Edition (IBC, 2012 Edition, 1st printing) ANSI A117.1-2009	Effective 12/1/14
675 IAC 22-2.5	Indiana Fire Code, 2014 Edition (IFC 2012 Edition, 1st printing)	Effective 12/1/14

NFPA Standards

NFPA #	Description	Effective Date	IAC Cite
10-2010	Portable Fire Extinguishers	December 15, 2012	675 IAC 28-1-2
11-2005	Low Expansion Foam and Combined Systems	September 22, 2006	675 IAC 28-1-3
12-2005	Carbon Dioxide Extinguishing Systems	September 22, 2006	675 IAC 28-1-4
13-2010	Installation of Sprinkler Systems	September 26, 2012	675 IAC 28-1-5
14-2000	Installation of Standpipe and Hose Systems	December 13, 2001	675 IAC 13-1-9 Repealed 3/21/14
15-2001	Water Spray Fixed Systems	September 22, 2006	675 IAC 28-1-8
20-1999	Installation of Centrifugal Fire Pumps	December 13, 2001 Amended 12/26/02	675 IAC 13-1-10
25-2011	Inspection, Testing and Maintenance of Water Based Fire Protection Systems	May 12, 2013	675 IAC 28-1-12
37-2002	Installation and Use of Stationary Combustion Engines and Gas Turbines	September 22, 2006	675 IAC 28-1-15
70-2008	National Electrical Code	August 26, 2009	675 IAC 17-1.8
72-2010	National Fire Alarm Code	March 23, 2014	675 IAC 28-1-28
2001-2004	Clean Agent Fire Extinguishing Systems	September 22, 2006	675 IAC 28-1-40

5.0 Conclusions

The purpose of this evaluation was to review the existing fire water system. Black & Veatch reviewed P&IDs for both the existing fire protection and service water systems.

This report has shown:

- The raw water storage tank is sized to provide 51,000 gallons of surge capacity devoted to fire water use.
- The existing pressure maintenance pump is sufficient.
- The existing 10 inch fire protection underground system can be reused with new 12 inch HDPE used for any new underground headers and around the cooling tower.
- Black & Veatch's recommendation is to add a third diesel motor fire pump and modify the pump arrangement to a 3x50 percent configuration.

FINAL

NOISE REGULATION REVIEW

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1213F

PREPARED FOR

Vectren

31 JANUARY 2020

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Executive Summary

Black & Veatch reviewed the noise regulations that might apply to the new Combined Cycle Power Plant (CCPP).

Indiana, Posey County, and Marrs Township have no far field noise regulation or ordinances. Far field noise requirements are generally referenced to the site boundary, property line, or other boundary limit. Occupational Safety and Health Administration (OSHA) standards will apply to near field noise emissions. Near field noise requirements are measured along the equipment envelope. During off-normal and intermittent operation such as startup, shutdown, and upset conditions, the equipment sound pressure level shall not exceed a maximum of 115 dBA at all locations along the equipment envelope, including platform areas, that are normally accessible by personnel.

Near field noise mitigation requirements will be required of equipment. Since there were no extant noise regulations specific to this site, no far field noise mitigation is required.

1.0 Results of Noise Regulation Review

Noise requirements fall into two categories: far field or near field. These categories are based upon the distance from the emitter to the receptor. Far field noise requirements are generally referenced to the site boundary, property line, or other boundary limit. Near field noise requirements are measured along the equipment envelope. The envelope is defined as the perimeter line that completely encompasses the equipment package a distance of 3 feet from the face of the equipment.

1.1 FAR FIELD NOISE REQUIREMENTS

There are no extant noise regulations or ordinances for Indiana, Posey County, or Marrs Township. The expectation would be that the general environmental sound levels in the surrounding area would not be substantially different from the sound levels with the two coal units in operation, assuming the coal units will be decommissioned after the new unit is operational.

1.2 NEAR FIELD NOISE REQUIREMENTS

Near field noise requirements are limited by OSHA requirements. The near-field noise emissions for each equipment component furnished under these specifications shall not exceed a spatially-averaged free-field A-weighted sound pressure level of 85 dBA (referenced to 20 micropascals) measured along the equipment envelope at a height of 5 feet above floor/ground level and any personnel platform during normal operation.

During off-normal and intermittent operation such as start-up, shut-down, and upset conditions the equipment sound pressure level shall not exceed a maximum of 115 dBA at all locations along the equipment envelope, including platform areas, that are normally accessible by personnel.

2.0 Conclusions

Near field noise mitigation requirements will be required of equipment. Since there were no extant noise regulations specific to this site, no far field noise mitigation is required.

The attached V100 supplemental, contains the noise abatement requirements to be included with the procurement specifications. Since there were no extant noise regulations specific to this site, the V100 supplemental was developed using the near field requirements which are the typical OSHA limits.

FINAL

CONDENSATE POLISHER EVALUATION SUMMARY

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1214F

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

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Executive Summary

This report provides a summary of Black & Veatch's evaluation of including a condensate polisher system in the conceptual design of the new A.B. Brown Combined Cycle. This summary of the evaluation will show that:

- Five selection criteria for Pre-Coat Condensate Polishers are present in the conceptual design. General industry practice to consider polishing is three or more.

PRE-COAT POLISHER CRITERIA	A.B. BROWN COMBINED CYCLE PLANT
Steam Cation Conductivity $\leq$0.2uS/cm	**Yes – 0.2uS/cm Allowed***
Graywater Cooling	No – River Water
Air Cooled Condenser	No – Wet Surface Condenser
All-Volatile Treatment – Oxidizing Treatment (AVT-O) Cycle Chemistry	**Yes – All-Volatile Treatment-Oxidizing with Phosphate (no oxygen scavenger)**
HP/Main Stream Pressure >2,400 psig	**Yes – HP/Main Steam >2,500 psig**
Cycling with Short Start-up Time	**Yes – Cycling Units with Rapid start**
LP Steam Conductivity Limit?	No
Suspended Solids (TSS) process contamination possible?	**Yes – River water contains levels of TSS**
* GE Steam Purity for Industrial Turbine (Table 4 in document GEK 98965)	

[redacted]

PARAMETERS	1X1 7F.05 (FIRED)
Condensate Design Flow, gpm	[redacted]
Estimated Equipment Costs ($450 per gpm)	[redacted]
Estimated Total Installed Capital Cost (Equipment Costs + $2.28M installation)	[redacted]

Based on the selection criteria identified in the summary report, Black & Veatch's recommendation is to include provisions for a future pre-coat type condensate polisher system in the conceptual design for the project. This includes, but not necessarily limited to, [redacted] allowance in condensate pump sizing, space allocation, spare electrical capacity and connections, and condensate discharge by pass piping connections.

1.0 Introduction

1.1 GENERAL FACILITY OVERVIEW

Vectren (Company) is planning the construction of a combined cycle plant at its existing A.B. Brown Station (ABB) in Evansville, Indiana. This combined cycle configuration will utilize a heat recovery steam generators (HRSG), combustion turbine generator and steam turbine generator to output 440 MW.

Condensate polishing is the process of purifying condensate before returning it to a boiler. Feedwater (condensate and boiler feed) contain various impurities. Corrosion products from the steam cycle, mostly iron, travel through the cycle and can concentrate in the boiler. Impurities in feedwater can affect HRSG performance and can be transported from the HRSG to the steam turbine, causing damage to piping and turbine components from pitting, corrosion, or scaling. They can inhibit heat transfer, cause hot spots and eventual failure of the boiler tubes. Additionally, they can carryover with the steam and degrade the steam purity to the level that it no longer meets the steam turbine suppliers steam purity guarantee requirements.

The water quality required for feedwater is defined by the HRSG manufacturers and is dependent on the unit cycling, chemistry program, and operating pressure of the plant. High pressure (1500 psi or greater) drum boilers have stringent feed water quality requirements in order to meet the steam turbine suppliers steam purity guarantee. Drum boilers meet theses water quality requirements by blowdown to eliminate impurities from the cycle and making up with fresh demineralized water. Condensate polishing provides a means to minimize blowdown and better ensure boiler water quality requirements.

In addition to improving condensate/feed water quality, condensate polishers can decrease unit startup time by minimizing chemistry related delays, minimize impacts of condenser leaks, and reduce frequency of boiler chemical cleaning. Consequently, condensate polishers are a worthy consideration in most high pressure steam cycle units, especially cycling units designed with rapid start.

1.2 EVALUATION OBJECTIVE

The purpose of this study is to:

- Identify the selection criteria for condensate polishing and determine if/which criterion is applicable to the project.
- Evaluate the capital costs associated with condensate polishing.

The following evaluation reports should be viewed in conjunction with this document:

- 41.1207F – Number of Cold, Warm and Hot Starts Analysis
- 41.1203F – Fast Start vs. Conventional Start Analysis
- 41.1217F – Demin Water Analysis Evaluation.

2.0 Condensate Polishing

2.1 SELECTION CRITERIA

Figure 1 below is a flow chart used to confirm whether or not condensate polishing is necessary in the power plant design basis. The primary and secondary factors shown in Figure 1 are used to identify, if necessary, which type of condensate polisher is to be used based on the parameters of the unit; Deep Bed type or Pre-coat type polishers.

Figure 1 –Condensate Polisher Selection Flow Chart

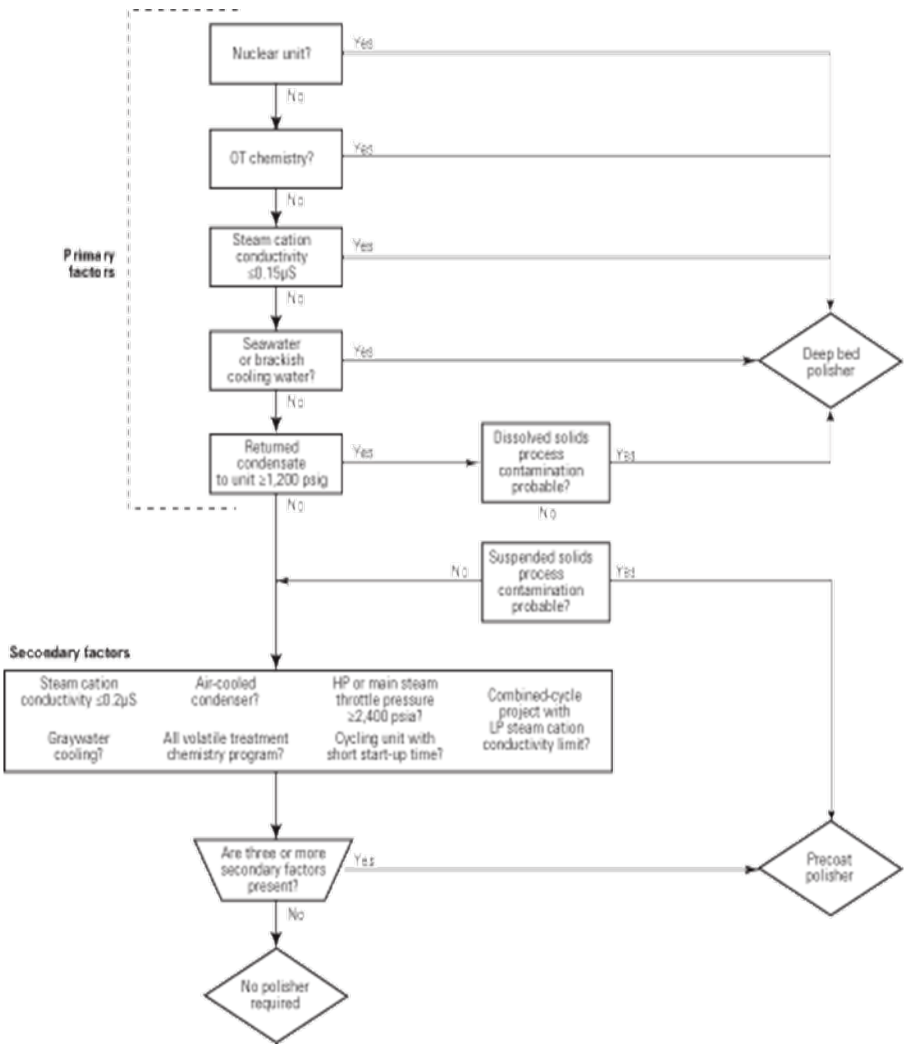


Table 1 reviews the criteria for deep bed type polishers listed and indicates if these factors apply to the project. If one or more of the selection criteria, or factors, apply to ABB, then deep bed condensate polishing should be considered.

Table 1 – Deep Bed Condensate Polisher Selection Criteria

DEEP BED POLISHER CRITERIA	A.B. BROWN COMBINED CYCLE PLANT
Nuclear Plant	No – Fossil Fuel
Oxygenated Treatment (OT) Cycle Chemistry	No – All-Volatile Treatment-Oxidizing with Phosphate
Steam Cation Conductivity <0.15uS/cm	No – 0.2uS/cm Allowed*
Seawater or Brackish Cooling Water	No – Surface Water, Well Water
Returned Condensate to unit >1200 psig	No - 400 psig
* GE Steam Purity for Industrial Turbine (Table 4 in document GEK 98965)	

Based on the design parameters of the plant as shown in Table 1, deep bed condensate polishing would not be considered.

Table 2 reviews the criteria for pre-coat type polishers listed and indicates if these factors apply to the project. General industry practice is if three or more factors apply to ABB, pre-coat polishers should be strongly considered.

Table 2 – Pre-Coat Condensate Polisher Selection Criteria

PRE-COAT POLISHER CRITERIA	A.B. BROWN COMBINED CYCLE PLANT
Steam Cation Conductivity ≤0.2uS/cm	Yes – 0.2uS/cm Allowed*
Graywater Cooling	No – River Water
Air Cooled Condenser	No – Wet Surface Condenser
All-Volatile Treatment – Oxidizing Treatment (AVT-O) Cycle Chemistry	Yes – All-Volatile Treatment-Oxidizing with Phosphate (no oxygen scavenger)
HP/Main Stream Pressure >2,400 psig	Yes – HP/Main Steam >2,500 psig
Cycling with Short Start-up Time	Yes – Cycling Units with Rapid start
LP Steam Conductivity Limit	No
Suspended Solids (TSS) Process Contamination Possible	Yes – River water contains levels of TSS
* GE Steam Purity for Industrial Turbine (Table 4 in document GEK 98965)	

As shown in Table 2, five factors are present in the current design of the project. As a result, pre-coat polishers or design provisions to include future polishers should be considered. The next sections review the benefits of the pre-coat polisher design.

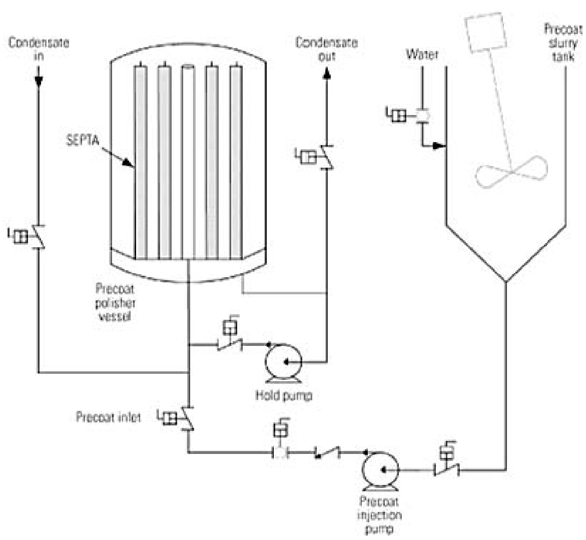
2.2 PRE-COAT TYPE CONDENSATE POLISHING

2.2.1 Overview

Pre-coat polisher is a vessel containing media-retaining filter elements. A powdered media is placed on the elements and the condensate is passed through the media coated filter element and returned to the condensate flow. Figure 2 shows a diagram of a Pre-coat polisher system.

These filter elements, combined with the ion exchanging media (powder coating), has the capability of simultaneous removal of total dissolved solids (TDS) and total suspended solids (TSS). Pre-coat polishers in particular, perform the dual purpose of straining the TSS particulates (iron oxides produced in the condensate system) and removing dissolved solids. Air in-leakage causes corrosion from oxygen pitting and to a lesser degree acidic attack from CO2. Not only does the oxygen damage the carbon steel surfaces but the iron oxides from this corrosion process, both soluble (TDS) and insoluble (TSS), will be transported into the heat recovery steam generator (HRSG) and will deposit on tube surfaces. Over time these deposits reduce unit efficiency, create an environment for under deposit corrosion (boiler tube failures) and necessitate the need for more frequent chemical cleanings.

Figure 2 – Pre-Coat Polisher Diagram



The condensate polisher improves condensate/feed water quality during steady state operations by minimizing the impacts of condenser leaks by the removal of dissolved solids and improves unit startup time by minimizing chemistry related delays by the removal of suspended solids.

2.2.2 Operational Impacts

Dissolved gases can enter the cycle as impurities in the makeup water as well as through air in-leakage to the condenser which is under vacuum. Dissolved gases, particularly uncontrolled oxygen and carbon dioxide, can cause corrosion in the cycle and are generally removed in the condenser and deaerator. However, carbon dioxide can accumulate in the condensate/feed water/boiler train because of its pH equilibrium chemistry and can only be effectively removed with condensate polishing. Particularly during startup and shutdown the condensate/feedwater cycle can and will be exposed to carbon dioxide and oxygen. Their corrosive effects on the carbon steel condensate/feedwater piping can be mitigated with the proper chemistry and blowdown over time, but a polishing unit greatly improves the amount of time necessary to reach optimal cycle chemistry.

If left untreated or detected, these impacts will lead to any number of issues including boiler tube failures, damage to the steam turbine and condenser tube failures.

A condensate polisher is warranted for combined-cycle plants where the steam turbine cation conductivity limit is $\leq$ 0.2 μS/cm, and especially cycling units designed with rapid start. The cation conductivity of the condensate/feedwater stream can typically reach 0.5 to 0.6 μS/cm due to carbon dioxide absorption in the water. The GE steam turbine cation conductivity requirement for A.B. Brown is <0.2 μS/cm.

Without a condensate polisher, and in the event of a major feedwater chemistry excursion, typically a plant will either dump the “out-of-spec” water and re-fill the system with “in-spec” water or operate the feedwater system without generating steam until the boiler feedwater chemical treatment system brings the water back into spec. Worst case scenario for ABB is dumping the approximate +100,000 gallons of water from the cycle (one HRSG and condenser).

Utilizing condensate polishing can reduce the average cycle blowdown during both startup and normal operation to approximately 0.5%-1%. For the ABB project, this blowdown reduction can save up to 1,000,000 gallons of demineralized water each year. This is based on the estimated number of starts per year and capacity factor found in 41.1207F – Number of Cold, Warm and Hot Starts Analysis. Condensate polishing can also potentially reduce the number of boiler chemical cleans over the 30 year expected life of the plant.

3.0 Risk AND Cost Analysis

3.1 RISK ANALYSIS

As stated in Section 3.0, there are several risks associated with operating a combined cycle plant with three or more of the selection factors present in the design. The risk of operating with poor steam/water quality can lead to boiler tube failures, condenser tube failures, and damage to the steam turbine. Table 3 below provides a high level risk analysis of not utilizing a condensate polisher unit.

Table 3 – Risk Analysis Without Condensate Polishing

RISK	SEVERITY	OCCURANCE	DETECTION	LENGTH OF OUTAGE	OVERALL RISK FACTOR
Boiler Tube Failure	High	Medium	High	Medium	High
Steam Turbine Damage	High	Low	Low	High	Medium
Condenser Tube Failure	Medium	Medium	Medium	Medium	Medium
Overall risk factors are indications of estimated number of failure occurrences per year: High = 1 occurrences/yr; Medium = 0.33 occurrences/yr; Low = 0.11 occurrences/yr					

The overall risk factor provides an indication of estimated number of failure occurrences per year. A high overall risk will generally indicate one occurrence per year, while the occurrences per year drop to 33 percent and 11 percent for medium and low factors, respectively.

Utilizing a condensate polisher and a good chemical conditioning program can potentially drop the overall risk factor to the next lower tier for each type of failure.

3.2 COST ANALYSIS

A budgetary cost for a full 2x100% pre-coat condensate polishing system (with pre-coating skid, slurry pumps, air receiver, and resin/precoat recovery tank) is approximately [redacted] An estimated [redacted] for installation, project management, and risk and contingency is used to estimate the total installed cost.

Table 4 – Cost Evaluation - Condensate Polishing

PARAMETERS	1X1 7F.05 (FIRED)
Condensate Design Flow, gpm	[redacted]
Estimated Equipment Costs [redacted]	[redacted]
Estimated Total Installed Capital Cost [redacted]	[redacted]

A temporary/mobile rental condensate polisher could be considered. [redacted]

4.0 Conclusions

4.1 SUMMARY OF CONCLUSIONS

This evaluation report has shown that:

- Five selection factors for Pre-coat condensate polishers are present in the current design of the project. General industry practice to consider polishing is three or more.
- Cycling with rapid startup and <0.2 μS/cm steam cation conductivity, are the two key selection factors that are a part of this project.
- Pre-coat condensate polishers have the capability of simultaneous removal of both TDS and TSS. TSS process contamination is a possibility with any cooling water tube leak utilizing river water makeup.
- The condensate polisher, in combination with a sound cycle chemistry scheme, protects all equipment components in the steam/feedwater cycle.

Based on the selection criteria identified in the summary report, Black & Veatch's recommendation is to include provisions for a future pre-coat type condensate polisher system in the conceptual design for the project. This includes, but not necessarily limited to, [redacted] allowance in condensate pump sizing, space allocation, spare electrical capacity and connections, and condensate discharge by pass piping connections.

FINAL

AUXILIARY COOLING WATER SYSTEM ANALYSIS

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1215F

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

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Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch reviewed different design scenarios for the auxiliary cooling water system. It was determined that the design used for the auxiliary cooling water system on the existing units would not be practical for the CCPP. Three alternative designs were investigated:

- Alternative 1--Auxiliary cooling from makeup and circulating water.
- Alternative 2--Circulating water to cool the closed cycle cooling water equipment.
- Alternative 3--Circulating water to cool closed cycle cooling water equipment and hydrogen and lube oil coolers.

The performance, plant area required, reliability and maintenance, and cost of both shell and tube and plate and frame heat exchangers were considered in conjunction with the three alternatives for the auxiliary cooling water system. [redacted]

1.0 Introduction

Equipment throughout the plant is cooled by water. The source of this cooling water is through a closed loop system Closed Cycle Cooling Water (CCCW) or directly from an auxiliary cooling water source. This report looks at the sources for water for equipment cooling.

The existing plant cooling system is cooled by the raw water system. The raw water system consists of three (3) 3,300 gpm river water pumps which provide cooling water for the coal units closed cooling heat exchangers. The discharge from these existing heat exchangers is then routed to the cooling towers for makeup. The heat duty of the existing closed cycle cooling water system is minimized as the circulating water system directly provides cooling water flow to the generator hydrogen coolers and lube oil coolers.

In developing this report, Black & Veatch reviewed different design scenarios for the auxiliary cooling system for the new Combined Cycle Power Plant (CCPP). It was determined that the design used for the auxiliary cooling water system on the existing units would not be practical for the CCPP. Three alternative designs were investigated.

- The first alternative uses a combination of water from the cooling tower makeup to the cooling towers and circulating water to cool closed cycle cooling water equipment. Turbine hydrogen and lube oil coolers would be cooled directly from the cooling tower makeup.
- The second alternative uses circulating water to cool the closed cycle cooling water equipment. The closed cycle cooling water equipment provides cooling water to all equipment including the turbine hydrogen and lube oil coolers.
- The third alternative uses circulating water to cool the closed cycle cooling water equipment and the turbine hydrogen and lube oil coolers. This scenario differs from the second alternative as circulating water is used to directly cool the hydrogen and lube oil coolers.

This evaluation will evaluate the different alternatives looking at the system performance and cooling capability of the different cooling configurations.

2.0 System Performance – Cooling Capability

Table 2-1 provides a table listing the pros and cons of the different auxiliary cooling water arrangements

Table 2-1 System Performance Capability

ARRANGEMENT	PROS	CONS
Aux Cooling Water from Raw Water Makeup	-	Not Practical for CCPP
Alternative 1 - Circulating water cools CCCW equipment. Aux Cooling Water cools Turbine Lube Oil and Hydrogen Cooling.	Cooler auxiliary cooling water temps. Smaller circulating water pumps. Smaller CCCW system.	Long, large diameter stainless pipe runs to generators. Warmer makeup to cooling tower. Specialized OEM heat exchangers.
Alternative 2 - Circulating water cools CCCW. CCCW cools all equipment.	Standard OEM heat exchangers. Typical CCPP design. Minimizes piping costs.	Warmer circulating water temps. Larger circ water pumps.
Alternative 3 - Circulating water cools CCCW equipment. Circulating water cools Turbine Lube Oil and Hydrogen Cooling.	Cooler auxiliary cooling water temps. Smaller circulating water pumps. Smaller CCCW system.	Long, large diameter stainless pipe runs to generators. Warmer makeup to cooling tower. Specialized OEM heat exchangers.

2.1 ALL AUXILIARY COOLING FROM RAW WATER MAKEUP

The existing raw water makeup pumps consist of three (3) pumps each having a rated a flow capability of 3,300 gpm at 176 ft of head. To maintain a N+1 sparing philosophy, two pumps would be operating and one pump would be in standby providing a cooling water flow of 6,600 gpm since pressure drop to the new cooling tower is expected to be similar to that the existing system.

If the raw water system provides all of the cooling water for the combined cycle, the temperature rise across the heat exchangers would result in an elevated summer make up temperature to the cooling tower not considered acceptable with the cooling tower fill. To limit the temperature rise across the heat exchanger, it is recommended to use the circulating water system instead of the river water for a minimum of the cooling the generator hydrogen coolers and lube oil coolers.

2.2 ALTERNATIVE 1 – AUX COOLING FROM MAKEUP AND CIRC WATER

For Alternative 1, most auxiliary cooling water would be supplied from the river water make up to cool the closed cycle cooling water system while the generator hydrogen coolers and lube oil coolers would be cooled from the circulating water system directly. This scenario would result in a temperature rise for the makeup water system to match the hot water returning from the cooling tower. The temperature rise to the generator hydrogen coolers and lube oil coolers would be designed to match the circulating water temperature rise across the condenser; additional flow to the circulating water system to cool the steam turbine and combustion turbine generator hydrogen coolers and lube oil coolers would be about 3,600 gpm.

Due to the corrosive nature of the circulating water system stainless steel pipe would be required for the piping runs to the generator hydrogen coolers and lube oil coolers. The design for the combustion turbine generator hydrogen coolers and lube oil coolers would need to be coordinated with OEMs. The surface area of these coolers would be approximately twice the size of the standard design to limit the pressure drop across the heat exchanger as needed to match the pressure drop across the condenser as to not adversely impact the circulating water system design. The advantage to supplying cooling water directly from circulating water is that auxiliary cooling water to the generator hydrogen and lube oil coolers is 10°F cooler than if supplied from the closed cycle cooling water system.

2.3 ALTERNATIVE 2 – CIRC WATER COOLS CCCW

A typical design for combined cycle plants is to supply the auxiliary cooling water from the circulating water system. Under this design, circulating water would be supplied to the closed cycle cooling water system. The design of the closed cycle cooling water heat exchangers would limit the temperature rise of the circulating water to match the temperature rise of the circulating water across the condenser; the auxiliary cooling water flow would be sized as required to reject the heat of the closed cycle cooling water system. The cold water temperature of the CCCW would have a design temperature of 105°F; this is standard for equipment provided on combined cycle power plants. Circulating water flow to supply auxiliary cooling water system would be about 5,700gpm.

2.4 ALTERNATIVE 3 – CIRC WATER COOLS CCCW AND HYDROGEN AND LUBE OIL COOLERS

If the 105°F cooling water is a concern for the generator hydrogen and lube oil coolers and hydrogen coolers, they could be cooled directly from the circulating water system. The design for the combustion turbine generator hydrogen coolers and lube oil coolers would need to be coordinated with OEMs. The surface area of these coolers would be approximately twice the size of the standard design to limit the pressure drop across the heat exchanger as needed to match the pressure drop across the condenser as to not adversely impact the circulating water system design. Circulating water flow to supply auxiliary cooling water system would be about 2,000 gpm.

3.0 Conclusions

Since the existing raw water pumps that provide makeup to the cooling tower do not have sufficient flow to meet the requirements of the new combined cycle, a new cooling water arrangement utilizing circulating water is recommended. Since the turbine manufacturers design their heat exchangers including turbine lube oil and hydrogen coolers for cooling water up to 105°F and the CCCW system is designed to meet this condition under the extreme hot summer day, Alternative 2 with all equipment cooling water coming from the CCCW system as it is the lowest cost and allows the use of standard OEM equipment.

FINAL

DEMIN WATER USAGE ANALYSIS

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1217F

PREPARED FOR

Vectren

31 JANUARY 2020

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Executive Summary

In developing this report, Black & Veatch reviewed the requirements for demineralized water for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed multiple pre-start, start-up and steady state scenarios to determine the required sizing and operation of the demineralized water system. Demineralized water storage capacity was evaluated in parallel with system operation. Black & Veatch evaluated water usage based on 1x1 7F.05 gas turbines for this analysis.

The demineralized water system users have been summarized in the steady state demands provided in Table 2-1. Plant pre-start demands have been summarized in Table 2-2 and plant startup demands have been summarized in Table 2-3. For all scenarios, the difference between water demand and existing system capacity is compared. Based on the demineralized water requirements for the multiple scenarios, it is recommended that Vectren utilize an additional water treatment system with a water capacity of [redacted] gpm per Table 3-1. No additional demineralized water storage capacity is required.

1.0 Introduction

The purpose of this study is to determine the specific requirements for demineralized water with the new Combined Cycle Power Plant (CCPP). Based on steady state operation, the existing cycle makeup treatment system can meet water demand. However, during startup and steady state operation with the evaporative cooler in operation, water demand exceeds the existing system capacity. The following tables detail differences in water demand for each configuration and condition.

2.0 Demineralized Water System Operation Demands

The demineralized water system provides water to various users during plant startup and shutdown at multiple operating conditions. Several operating scenarios were evaluated to determine the maximum water usage for the demineralized water system. Plant pre-start activities, plant startup, and plant steady state operation was evaluated for maximum demineralized water demand. The existing demin water treatment system capacity is [redacted] gpm. Demineralized water storage will need to be sufficient to hold three (3) days storage of the CCPP steady state demineralized water demand without evaporative cooling water makeup. Demin water demands excluded in this steady state operation are evaporative cooler makeup for the CCPP, CT#3 water injection and existing Unit 3 and 4 steam cycle demands.

2.1 STEADY STATE AND NON-STEADY STATE DEMANDS

The steady state demineralized water demand occurs during operation when supplying makeup water for CCPP blowdown and sampling losses. Non-steady state demineralized water demands occurs during operation when supplying makeup water for steady state CCPP users plus evaporative cooler operation, existing unit operation and CT#3 water injection operation. Demineralized water demands are shown in Table 2-1. Steady state operation assumes 2% blowdown per the water mass balances. Steady state flows are based on Hot Day Case (93.7F) heat balance. Due to the infrequent operation of existing units and CT#3, storage volume recommendations will account for the excursion in steady state demand for demineralized water.

Table 2-1 Demineralized Water Demands

DEMIN WATER USERS	1X1 7F.05
STEADY STATE DEMANDS	
2% blowdown (gpm)	[redacted]
Sample Analytics (gpm)	[redacted]
Demand w/o Evaporative Cooler Makeup (gpm)	[redacted]
NON-STEADY STATE DEMANDS	
Existing Unit 3 steam cycle demands (gpm)	[redacted]
Evaporative Cooler Makeup on RO Permeate (gpm)	[redacted]
Demand w/ Evaporative Cooler Makeup @ 6 COC (gpm)	[redacted]
CT #3 Water Injection	[redacted]
Instantaneous Demand for Steady State Operation with CT#3 water injection (1)	[redacted]
[redacted]	

2.2 PRE-START DEMANDS

During unit pre-start, the auxiliary boiler is used to warm the HRSG and steam turbine seals. The assumption of 2% blowdown on the auxiliary boiler during this operation is included. During this operation, it is assumed all water is non recoverable. The pre-start usage demands are listed in Table 2-2.

Table 2-2 Demineralized Water Demands during Pre-Start Activities

PRESTART USAGE	1X1 7F.05
Aux Boiler Makeup (gpm) HRSG warming	[redacted]
Difference (gpm) - Existing	[redacted]
Difference (gpm) - Proposed new	[redacted]

2.3 STARTUP DEMANDS

During unit startup, demineralized water usage is at the maximum. HRSG is warm and the condenser sparging and gland steam flows are recovered in the condenser. Steam drains are open until superheat targets are met. 5% blowdown is utilized for startup. The demineralized water demands are listed in Table 2-3.

Table 2-3 Demineralized Water Demands During Startup Activities

STARTUP DEMAND	1X1 7F.05
Aux Boiler Makeup Fast Start (gpm)	[redacted]
Steam Drains to HRSG Blowdown Tank (gpm)	[redacted]
Blowdown (gpm)	[redacted]
Total Instantaneous Startup Demand (gpm)	[redacted]
Difference (gpm)	[redacted]
Difference (gpm) - Proposed new	[redacted]
Hot start lost capacity (gallons) (1)	[redacted]
Warm start lost capacity (gallons) (1)	[redacted]
Cold start lost capacity (gallons) (1)	[redacted]
Time to replace lost capacity during normal op (Hot Start), min	[redacted]
Time to replace lost capacity during normal op (Warm Start), min	[redacted]
Time to replace lost capacity during normal op (Cold Start), min	[redacted]
[redacted]	

3.0 Demineralized System

3.1 WATER REPLENISHMENT

The demineralized water system provides minimal margin for replenishment from startup of the combined cycle. For a typical combined cycle plant, the rule of thumb for storage is 3 days of steady state demand capacity. This relates to a 3 day outage on the demin supply. Table 3-1 details the time to replenish demineralized water capacity.

Table 3-1 Demineralized Water Volumes and Treatment Capacities

DEMINERALIZED WATER SYSTEM	1X1 7F.05
STORAGE CAPACITY	
Existing Demin storage (gallons)	[redacted]
3 day Demin storage capacity required @ steady state demand	[redacted]
Storage Surplus (+) / Storage Deficient (-) during a 3 day outage.	[redacted]
Recommended Additional Demin Storage (gallons) (1)	[redacted]
STEADY STATE TREATMENT DEMAND	
Current Demin Water Treatment Capacity (gpm)	[redacted]
CCPP Steady State Demand (gpm)	[redacted]
Treatment Surplus (+) / Deficient (-) (gpm)	[redacted]
NON-STEADY STATE TREATMENT DEMAND	
Current Demin Water Treatment Capacity (gpm)	[redacted]
CCPP Non- Steady State Demand (gpm)	[redacted]
Treatment Surplus (+) / Deficient (-) (gpm)	[redacted]
PEAK TREATMENT DEMAND	
Current Demin Water Treatment Capacity (gpm)	[redacted]
CCPP Peak (CT#3 + Non- Steady State) Demand (gpm)	[redacted]
Treatment Surplus (+) / Deficient (-) (gpm)	[redacted]
PROPOSED ADDITIONAL DEMINERALIZED WATER TREATMENT CAPACITY (GPM)	[redacted]
Treatment Surplus (+) / Deficient (-) (gpm)	[redacted]
Recover 3 day outage volume, Steady state after (HOURS)	[redacted]
Recover 3 day outage volume, Non-Steady state after (HOURS)	[redacted]
[redacted]	

[redacted]

Based on Black & Veatch's evaluation, the existing demineralized water storage capacity can provide sufficient storage of demineralized water based on the design parameters. Furthermore, a new demineralized water treatment system sized to supplement [redacted] gpm (coupled with the existing [redacted] gpm system) would be sufficient to meet various operating demands of the facility as well as replenish demineralized water volume within the design parameters.

4.0 Conclusions

Based on the evaluation Black & Veatch can conclude:

- The existing demineralized water storage capacity provides adequate storage of demineralized water based on the design parameters.
- A new demineralized water treatment system sized to supplement [redacted] (coupled with the existing [redacted] system) would be sufficient to meet various operating demands of the facility as well as replenish demineralized water volume within the design parameters.

FINAL

BLACK START ANALYSIS

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1221F

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

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Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch examined the capability of using the existing combustion turbine generator (CTG) peaking Unit 3 at A.B. Brown as a means of black starting CTG 5 of the new CCPP

Unit 3 is a GE 7EA turbine capable of operating with either natural gas or distillate fuel oil as the fuel source. Two scenarios were modeled for this evaluation:

- Starting of the largest medium voltage induction motor with all necessary auxiliary electric loads in operation.
- Static starting of CTG 5 with all necessary auxiliary electric loads in operation.

For analysis modeling purposes, the aggregate auxiliary electrical load necessary to start a combustion turbine were based on the preliminary conceptual design of the new CCPP. In addition, the excitation system was assumed to be capable of providing the necessary reactive power required by the simulated scenarios while maintaining 100 percent system voltage at a frequency of 60 Hz at the generator terminals.

Within the boundaries of this evaluation, the Unit 3 generator at A.B. Brown appears to be capable of black starting one combustion turbine of the new CCPP. Further analysis would be required to verify that generator control and system protection would permit synchronization of the Unit 5 generator to the Unit 3 generator to shift auxiliary electrical loads from the Unit 3 generator to the Unit 5 generator.

1.0 Introduction

The purpose of this evaluation is to examine the capability of the existing combustion turbine generator peaking Unit 3 at A.B. Brown to be utilized as a black starting means for the new combined cycle power plant (CCPP). Unit 3 is a GE 7EA turbine capable of operating with either natural gas or distillate fuel oil as the fuel source. The unit has a dedicated diesel generator and starting motor necessary to start. Unit 3 is utilized as a black starting means for existing A.B. Brown coal-fired Units 1 and 2.

Electrical power system analysis software ETAP was utilized to model and evaluate Unit 3 to verify the capability of black starting CTG 5 of the new CCPP. Figure 1-1 provides the one line diagram that was modeled in ETAP. Two scenarios were modeled for this evaluation, starting of the largest medium voltage induction motor with all necessary auxiliary electric loads in operation, and static starting of CTG 5 with all necessary auxiliary electric loads in operation.

[redacted]

2.0 Assumptions

In order to simulate the scenarios included in this evaluation, reasonable assumptions were made in order to model and simulate the black start capability. The assumptions are defined as follows.

2.1 LOAD LIST

It is necessary to determine the aggregate auxiliary electrical load that is necessary to start a combustion turbine of the new CCPP. Table 2-1 provides the load list of all loads considered to be in operation to support the black start. Except ACWP, BFP, CWP, CCWP & CP (major loads), all other loads were modeled as a lump load. For lump load motor power factor of 85% has been considered. A 20 percent margin was added to the lump loads of Table 2-1 for modeling purposes. The loads of Table 2-1 are based on the conceptual design of the new CCPP and are preliminary. All cooling tower fans and CWP have been modeled to show to feed from 6.9kV BUS A & existing 4.16kV BUS 1B respectively.

Table 2-1 Operating Loads during CCPP Starting

BLACK START ANALYSIS LOAD LIST			
LOAD	LOAD TYPE	LOAD RATING	LOAD UNITS
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

BLACK START ANALYSIS LOAD LIST			
LOAD	LOAD TYPE	LOAD RATING	LOAD UNITS
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

BLACK START ANALYSIS LOAD LIST			
LOAD	LOAD TYPE	LOAD RATING	LOAD UNITS
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

2.2 UNIT 3 EXCITATION SYSTEM

This study does not include analysis of the excitation model or transfer function for Unit 3. Therefore, the excitation system is fixed in the ETAP simulation. Additional modeling of the excitation system and transfer function would be necessary in order to more accurately simulate the response to the reactive power demands imposed when black starting one combustion turbine generator of the new CCCP, however, the excitation system is assumed to be capable of providing the necessary reactive power required by the simulated scenarios while maintaining 100 percent system voltage at a frequency of 60 Hz at the generator terminals, as long as the real and reactive demands on the Unit 3 generator do not exceed the limits of the reactive capability curve.

2.3 PROTECTION, CONTROL AND SYNCHRONIZATION

It is recommended during the detailed design phase that the turbine control system of the new CCPP is designed to be capable of allowing the new combustion turbine generator to synchronize with Unit 3 and that existing and new protection schemes are designed to permit synchronization. It also recommended during the detailed design phase that the control system of the existing Unit 3 combustion turbine generator is verified or modified as necessary to permit load sharing of the auxiliary electrical demands of the new CCPP. No investigation into the existing Unit 3 control system or switchyard protection schemes has been performed in support of this black start capability evaluation.

3.0 Static Motor Starting of Largest Motor

The starting of a large motor can have a brief, but significant, impact on the auxiliary electrical system. When voltage is applied to the terminals of an at rest motor, the motor will draw locked-rotor current (LRA), which decays toward full-load amps (FLA) as the motor approaches running speed. This is the result of the motor torque overcoming the combined inertia of the motor and the connected load. For an induction motor, a typical value of LRA is approximately 650 percent of FLA.

In the scenario of the black start, motor starting can result in voltage and frequency sags at the generator output, which will have a corresponding impact on the capability of the motor to start and to the existing loads in operation. The ability of the generator to accommodate starting of large motors is dependent upon the generator capacity, the response of the excitation system, the rotating inertia of the generator and the characteristics of the motor at starting. Should a sag in voltage during motor starting result in the motor's inability to develop the torque necessary to accelerate to full speed, the motor could stall. It is necessary to analyze the worst-case motor starting scenario for the purpose of determining the black start capability of the Unit 3 generator.

As a worst-case scenario, static motor starting of the Boiler Feed Pump, the largest medium voltage motor, was analyzed for 1x1 F class case with all other loads necessary for a black start in operation, with the exception of the Unit 5 generator static starting system. Static motor starting models the motor by locked-rotor impedance during acceleration, simulating the worst impact to loads in operation at the time of motor starting. The properties of the modeled Boiler Feed Pump is 6100 HP, 6.6 kV, 452 FLA, 0.93 power factor, 94 percent efficiency and 6.5 pu LRA.
Figure 3-1 provides the bus voltage, as a percent of nominal, at each bus during starting of the Boiler Feed Pump. The Watt and VAR demand from the Unit 3 generator and the starting motor are also displayed.

The maximum demand from the Unit 3 generator during starting of the Boiler Feed Pump is 8.2 MW and 30.04MVAR. This is well within the capability curve of the Unit 3 generator, considering a 0.85 lagging power factor and 15 degrees Celsius inlet air temperature, as depicted in Figure 3-2. The worst-case motor terminal voltage during starting of the Boiler Feed Pump is 80.54 percent of nominal system voltage. It is typical to specify medium voltage motors rated to start at 80 percent of nameplate voltage. It is also typical to specify motor nameplate voltage below nominal system voltage. In the case of a nominal 6.9 kV system, the corresponding motor nameplate is 6.6 kV, consistent with ANSI C84.1. The result of the static motor starting analysis for the Boiler Feed Pump indicates that the momentary sag in voltage at the motor terminals is not prohibitive to the starting of the motor. The worst-case bus voltage for the BUS & MCC A (6.9kV) is 78.17 percent during starting of the Boiler Feed Pump for F Class. This will not result in drop out of motor contactors since the nominal bus voltage is above 70%. All other medium voltage motors connected to BUS & MCC A (6.9kV) were considered to be running in this scenario. The bus voltage of MCC A1 recovers to 99.96 percent of nominal system voltage once the Boiler Feed Pump has accelerated to rated speed.

UAT impedance have been modeled with 6.5%for this study. The short circuit current level will be well below 40kA for 6.9kV SWGR and MCC A. UAT primary tap position has been set at -2.5% in order to achieve motor terminal voltage of higher than 80%. There is a possibility of further reducing UAT 5 impedance and motor locked rotor amperes to improve starting motor terminal voltage if necessary. A 3-3/C-500kcmil conductor has been considered to feed the BFP during this study.

[redacted]

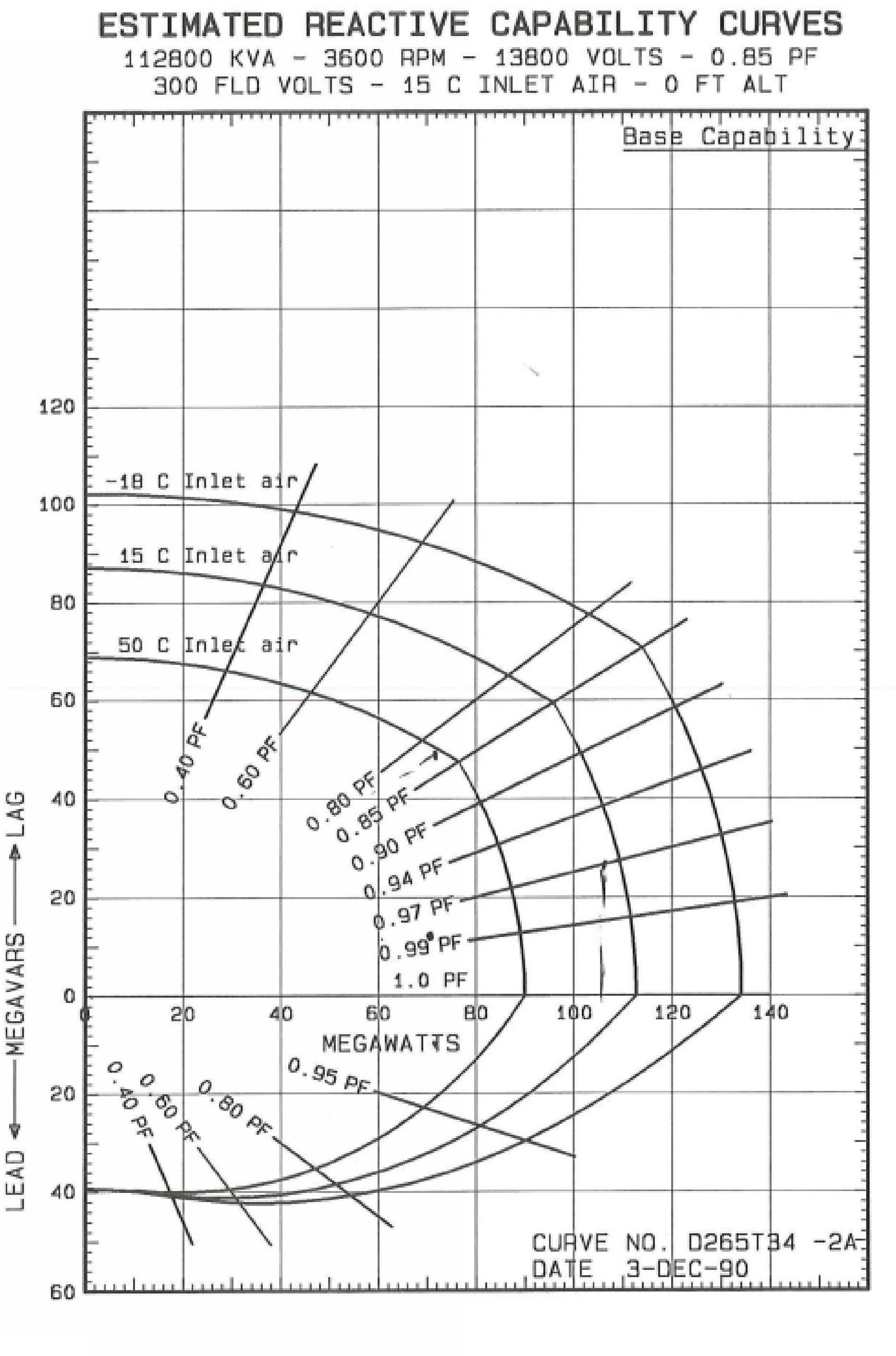

Figure 3-2 Unit 3 Generator Reactive Capability Curve

4.0 CTG 5 Static Starting Load Flow

A load flow model was analyzed during the static starting of the Unit 5 combustion turbine generator. This scenario considered all loads necessary for black starting to be in operation at the time the static starting system was energized. The maximum demand from the Unit 3 generator during static starting of Unit 5 CTG is as 10.55 MW and 5.81 MVAR. This is well within the capability curve of the Unit 3 generator, considering a 0.85 lagging power factor and 15 degrees Celsius inlet air temperature, as depicted in Figure 3-2.

The bus voltage during operation of the static starting system on 6.9 kV BUS A & 4.16kV BUS 1B will be 99.96 and 98.83 percent of nominal system voltage. This is well within the normal operating 'voltage range A' as per ANSI C84.1 and not considered to be a prohibitive impact to operation during black start. Additionally, the static starting system operates for a short duration until the combustion turbine reaches approximately 90 percent of rated speed, at which point it is self-sustaining and the static starting system is removed from operation and the turbine control system receives control of the turbine. This duration is approximately 30 minutes or less, dependent upon starting conditions with respect to the purging of combustible gases from the hot gas path prior to ignition.

[redacted]

[redacted]

5.0 Conclusions

The analyses performed in support of the black starting capabilities of the existing Unit 3 generator at A.B. Brown indicate that the generator has sufficient capacity to provide the required real and reactive power necessary to start the largest medium voltage motor as well as operate the static starting system of the new CCPP. The starting of the Boiler Feed Pump was simulated as a worst-case scenario, with all other loads necessary to support a black start in operation with the exception of the static starting system. Motor terminal voltage and bus voltages were maintained within reasonable limits for the scenario of a black start. Power requirements to support Boiler Feed Pump starting and the static starting system operation were within the capability curve of the Unit 3 generator. Both analyses assume that the Unit 3 generator excitation system is capable of responding appropriately to meet the reactive power needs, and further analysis with the excitation system modeled is necessary to confirm this response. Additionally, further analysis would be required to verify generator control and system protection would permit synchronization of the Unit 5 generator to the Unit 3 generator in order to shift auxiliary electrical loads from the Unit 3 generator to the Unit 5 generator. Within the boundaries of this evaluation, the Unit 3 generator at A.B. Brown appears to be capable of black starting the combustion turbine of the new CCPP.

FINAL

SWITCHYARD EVALUATION AND SEQUENCE

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1222F

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

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Executive Summary

In developing this report, Black & Veatch evaluated the suitability of the existing A.B. Brown 138 kV switchyard for interconnection of a new combustion turbine generator (CTG) and steam turbine generator (STG) operating as a 1x1 Combined Cycle Power Plant (CCPP). This evaluation was performed with existing Unit 2 remaining in operation. Black & Veatch considered preliminary heat balance data for a GE 7FA.05 CCPP as a conservative approach to this evaluation. Switchyard connections and connection sequence were also evaluated.

The continuous current loading of the 3000 Ampere (A) main buses 1 and 2 as well as the 2000 A interpass conductors are not exceeded for the switchyard configurations evaluated. The loading evaluation does not identify any major bus work necessary to independently connect the generators associated with the 1x1 CCPP.

As a result of the available fault current contribution at the existing 138 kV switchyard exceeding 40 kiloampere (kA), with new generation and Unit 2 in service, circuit breakers with a symmetrical interrupting rating 40 kA require replacement. Of the existing 20 circuit breakers in the 138 kV switchyard, 13 are rated 40 kA. [redacted] Therefore, it is recommended to replace all existing circuit breakers in the 138 kV switchyard with 63 kA symmetrical withstand and interrupting rating.

[redacted]

1.0 Introduction

The A.B. Brown 1x1 CCPP is a multi-shaft arrangement, with the combustion turbine (CT) and steam turbine (ST) individually coupled to dedicated generators rated to convert maximum turbine capabilities to electric power. The multi-shaft arrangement differs from a single shaft arrangement, with respect to electrical equipment, in that independent generators coupled to each turbine will transmit electric power via dedicated isolated phase bus duct (IPBD) to dedicated generator step-up transformers (GSU). Each GSU is sized to permit maximum real electric power to be transmitted to the electric power grid, with minimal losses, and to permit reactive electric power to be delivered to and absorbed from the electric power grid. Each turbine generator will also provide source power to 100 percent redundant unit auxiliary transformers (UAT). The high voltage side of each GSU will be independently connected to the existing 138 kV switchyard. Interconnection of the CTG and STG to the existing 138 kV switchyard requires consideration of fault current availability and system load flow relative to existing equipment ratings. Black & Veatch considered preliminary heat balance data for a GE 7FA.05 CCPP as a conservative approach for this evaluation. Configurations of a 1x1 CCPP comprised of turbine classes with lower gross megawatt (MW) output will result in additional margin with respect to switchyard loading and fault current. Each of the new generators were modelled with independent connections to the existing 138 kV switchyard, with Unit 2 remaining in operation.

The method of connection for each generator in a given configuration to the existing 138 kV switchyard is based upon the electrical ratings of the switchyard components, switchyard expansion capability, and operation of existing units. The existing 138 kV switchyard is a breaker and a half configuration with two main buses, rated 3000 A continuous. [redacted] 13 of the 20 existing circuit breakers in the 138 kV switchyard are rated to interrupt 40 kA.

2.0 Switchyard Evaluation

2.1 LOAD FLOW

The interpass connections between Bus 1 and Bus 2 are rated 2,000 A, therefore a single connection to the switchyard is acceptable when the kilowatts (kW) transmitted remain below 430,000 kW at a power factor equal to 0.9. For a single connection above 430,000 kW and less than 645,000 kW, upgrades are required to the entire 138 kV switchyard, such as circuit breaker and disconnect switch replacement with 3000 A continuous rating. Generation exceeding 645,000 kW at a single connection point is not practical at a voltage level of 138 kV as equipment rated above 3000 A continuous is typically not available.

The maximum CTG and STG gross output based on the preliminary fired GE 7FA.05 1x1 considered for this evaluation are 233,750 kW and 243,950 kW and correspond to approximately 974 A and 840 A, respectively. Detailed load flow modelling of the 138 kV switchyard with case permutations of outgoing transmission lines in and out of service is necessary in order to verify the suitability of the 138 kV switchyard to accommodate the connection of two CTGs and identify any overload cases. Initial analysis indicates that the 138 kV switchyard is generally suitable to accommodate independent connection of the new 1x1 CTG and STG while Unit 2 remains in operation.

The maximum current flow in the main and interpass busses for each analyzed case are represented in Table 2-1.

Table 2-1 Max Load in Main and Interpass Buses - 2026 Summer Peak

138 kV Switchyard Loading 1x1 and Unit 2				
Case	Current in 3kA Main Bus (A)	Percent Loading (%)	Current in 2kA Interpass (A)	Percent Loading (%)
All In Service	689.7	22.99	605.1	30.26
Bus 1 Outage	1936.5	64.55	994.3	49.72
Bus 1 and Line Z95 Outage	2219.7	73.99	1166.5	58.33
Bus 1 and Line Z96 Outage	2072.2	69.07	1078.8	53.94
Bus 1 and Line Z94 Outage	2401.8	80.06	1136.8	56.84
Bus 1 and Line Z73 Outage	1996.3	66.54	1031.3	51.57
Bus 1 and Line Z98 Outage	1657.9	55.26	1082	54.10
Bus 1 and Line Z99 Outage	1748.1	58.27	1294	64.70
Bus 1 and Line Z93 Outage	1744.4	58.15	1162.9	58.15
Bus 1 and Line to Culley Outage	1936.5	64.55	994.3	49.72
Bus 1 and Francisco to Gibson Outage	2254.6	75.15	1188.4	59.42
Bus 1 and AB Brown – BREC Reid Outage	2072	69.07	1539	76.95
Bus 2 Outage	1935.6	64.52	1049	52.45

138 kV Switchyard Loading 1x1 and Unit 2				
Case	Current in 3kA Main Bus (A)	Percent Loading (%)	Current in 2kA Interpass (A)	Percent Loading (%)
Bus 2 and Line Z95 Outage	2219	73.97	1167	58.35
Bus 2 and Line Z96 Outage	2071.2	69.04	1079	53.95
Bus 2 and Line Z94 Outage	2401.2	80.04	1137.2	56.86
Bus 2 and Line Z73 Outage	1995.3	66.51	1051.5	52.58
Bus 2 and Line Z98 Outage	1656.8	55.23	1082.3	54.12
Bus 2 and Line Z99 Outage	1747.6	58.25	1293.5	64.68
Bus 2 and Line Z93 Outage	1742.8	58.09	1161.9	58.10
Bus 2 and Line to Culley Outage	1935.6	64.52	1049	52.45
Bus 2 and Francisco to Gibson Outage	2253.7	75.12	1209.7	60.49
Bus 2 and AB Brown – BREC Reid Outage	2071.2	69.04	1539.7	76.99

2.2 FAULT CAPABILITY

13 of the 20 circuit breakers in the existing 138 kV switchyard are rated to withstand and interrupt 40 kA symmetrical fault current. The interrupting capability of the 13 40 kA rated circuit breakers is marginal for three phase faults and exceeded for single phase to ground faults for this evaluated case. Due to the available fault current contribution it is recommended to replace these existing circuit breakers with circuit breakers having sufficient margin beyond maximum fault current contribution. The remaining seven existing circuit breakers are oil filled and are considered to be near the end of service life. It is recommended to replace all of the existing 138 kV switchyard circuit breakers with breakers rated 63 kA symmetrical interrupting duty. This will ensure fault interrupting capability exceeds maximum available fault contribution.

The results of the fault study are included in Table 2-2.

Table 2-2 138 kV Switchyard Fault Currents

Fault Current Availability 1x1 and Unit 2		
Fault type	Fault Component	Value
3-phase fault	Fault Current (A)	39304
	Phase Angle (°)	-87
	Calculated X/R	19.07
1-phase fault	Fault Current (A)	45908.6
	Phase Angle (°)	-87
	Calculated X/R	19.17

3.0 Switchyard Connection Sequence

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

4.0 Conclusions

The withstand and interrupting rating of 40 kA for thirteen of the twenty existing 138 kV switchyard breakers is exceeded for the fault conditions evaluated, therefore circuit breaker replacement is necessary. The remaining seven switchyard circuit breakers are oil-filled breakers and near the end of their service life. It is recommended to replace all existing circuit breakers in the 138 kV switchyard with 63 kA symmetrical withstand and interrupting rating.

The evaluated load flow of the existing 138 kV switchyard permits independent connection of the CTG and STG of the new 1x1 CCPP considering a fired GE 7FA.05 and associated preliminary heat balance gross output. In general, the existing switchyard is capable of a single point of interconnection for 430,000 kW and below. This evaluation did not identify any major bus or interpass modifications for the existing 138 kV switchyard to accommodate the new CCPP and operation of Unit 2.

Connections to the existing switchyard have been planned to permit the construction and commissioning schedule of the new CCPP, while maintaining the existing A.B. Brown Unit 1 connection as late as practical into construction of the new CCPP.

Appendix A. Switchyard Connection Sequence

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Petitioner's Exhibit No. 5 (Public)

[redacted]

[redacted]

Appendix B. Construction Schedule

[redacted]

FINAL

AUXILIARY ELECTRIC SYSTEM MEDIUM VOLTAGE LEVEL COMPARISON

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 195523
B&V FILE NO. 41.1223F

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

19 FEBRUARY 2020

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This evaluation provides a summary comparison of nominal 6.9 kV and 4.16 kV auxiliary electric systems for the conceptual design (CPCN project) of the new A.B. Brown Combined Cycle Power Plant (CCPP). The medium voltage switchgear and motor controllers distribute power to large motor loads, ranging from greater than 250 HP up to several thousand HP, as well as to secondary unit substation (SUS) transformers, which derive 480V to be distributed to the low voltage system components and electrical loads.

Both nominal system voltages of 4.16 kV and 6.9 kV are commonly utilized within power generation and supported by most transformer and motor manufacturers.

Table ES-1 Advantages of 4.16kV and 6.9kV Medium Voltage Systems

MEDIUM VOLTAGE	4.16 KV	6.9 KV
Lower Running Current/Starting Current		X
Smaller Conductor Size		X
Less Heating in Below Grade Cable Ductbank		X
Reduction of Bus Short Circuit Rating		X
Overvoltage Withstand	X	
Conductor Cost Savings		X
UAT Cost Savings		[redacted]
Switchgear Cost Savings		[redacted]
Motor Cost Saving	Equal	Equal

1.0 Auxiliary Electric System Cabling Design Considerations

The cross-sectional area (CSA) of a current-carrying copper conductor is largely dependent upon the continuous current required for rated operation of the electrical load. A larger continuous current necessitates are larger CSA in order to ensure the thermal limitations of the cable insulation and the equipment terminals are not exceeded. An electrical load with a nominal system voltage rating of 6.9 kV will result in an approximate 40% reduction of running current than that of an electrical load with the same power rating, in kVA or HP, and a nominal system voltage rating of 4.16 kV.

For power cables installed in below grade duct bank, a de-rating study must be performed in order to ensure that the implications of the concrete-encased, below grade cable duct on the current-carrying capability of the conductors are properly applied during conductor sizing. The aggregate of thermal impact of the continuous current flowing through the conductors within the duct bank, depth of duct bank, and soil thermal resistivity determine the de-rating of the conductor ampacity. The ampacity of a current-carrying conductor in below grade duct bank is reduced compared to the ampacity of the same conductor in above grade raceway or free air.

It is typical in a CCPP that the electrical loads, particularly medium voltage, are not installed within proximity of the electrical distribution equipment from which the load is sourced. Voltage drop calculations must be performed in order to ensure that the voltage at the load terminals does not fall below the equipment minimum operating voltage. Voltage drop is directly proportional to current, cable length and cable impedance.

2.0 Medium Voltage Motor Starting System Impact

The starting of a large motor can have a significant, albeit brief, impact on the auxiliary electrical system. When voltage is applied to the terminals of an at rest motor, the motor will draw locked-rotor current (LRA), which decays toward full-load amps (FLA) as the motor approaches running speed. This is the result of the motor torque overcoming the combined inertia of the motor and the connected load. For an induction motor, a typical value of LRA is approximately 650% of FLA.

As voltage drop is directly proportional to current, the voltage drop at motor starting due to LRA must be analyzed in order to ensure the motor will start. It is typical to specify medium voltage motors capable of starting at 80% of rated voltage as a means of mitigating this concern.

The starting current of a motor can also have an adverse impact on equipment already in operation at the time of motor starting. Voltage sag resulting from the LRA of the starting motor can result in contactor drop-out in certain circumstances. Methods of avoiding adverse impact of large motor starting to the auxiliary electrical system include on-load tap changers (OLTC) integral to the unit auxiliary transformers for bus voltage regulation, dedicated variable frequency drives (VFD) or soft-starters for the motors of concern. The approximate 40% reduction of FLA and LRA resulting from a 6.9 kV compared to 4.16 kV provides for improved results relative to motor starting.

3.0 Short Circuit Contribution During a System Fault

During a system fault, a motor in operation will contribute current to the fault, in attempt to stabilize the decaying system voltage, as a result of the rotating magnetic field that exists in the rotor at the inception of the fault. Analyses of the auxiliary electric system during a faulted condition must be performed in order to ensure that the bus bracing of the electrical distribution equipment is appropriate relative to fault levels. The reduction of FLA of a higher system voltage correlates to reduced short circuit contribution during in a fault condition. Black & Veatch analyses of system faults utilizing Electrical Transient and Analysis Program (ETAP) indicate that motor short circuit contribution can be reduced by up to 50% by increasing the system voltage from 4.16 kV to 6.9 kV.

The reduction of bus short circuit rating of electrical distribution equipment corresponds to a reduction in capital expenditure for 6.9 kV compared to 4.16 kV.

4.0 Cost Impact of Equipment Voltage Rating

Manufacturers of switching assemblies offer various equipment voltage ratings above typical industry nominal system voltages. Metal-clad switchgear voltage ratings of 5 kV and 7.2 kV are common and correspond to nominal system voltages of 4.16 kV and 6.9 kV, respectively. Confirmation from switching assembly manufacturers indicates that bus and breaker continuous current and interrupting ratings, as well as bus bracing and short circuit rating, are the primary cost drivers. The cost difference of a line-up of metal-clad switchgear with the same continuous current rating, interrupting capability and bus bracing, but different system voltage ratings, is negligible.

Black & Veatch has received similar confirmation from motor suppliers, with respect to the negligible cost difference between 6.6 kV and 4.0 kV rated motors.

5.0 System Loading

The preliminary electrical load list associated with the 2x1 (F and H Class) configuration of the A.B. Brown CCPP conceptual design indicates a total plant running load of approximately 30 MVA. At 6.9 kV, this corresponds to approximately 2500 A of running current in combined cycle operation. The preliminary UAT required to support this auxiliary load is a two-winding transformer with a maximum forced-air cooled rating of 36 MVA. With 100% redundancy, two (2) two-winding UATs correspond to one (1) double-ended (main-tie-main) lineup of 3000A, 6.9 kV switchgear.

With the total plant running MVA, at a system voltage of 4.16 kV, the corresponding running current is approximately 4200 A. Typical switchgear manufacturers offer maximum continuous current ratings of 4000 A, which is achieved using 3000 A rated, fan cooled main circuit breakers. The condition of fan cooling required to achieve this rating is not recommended as it introduces an additional point of failure to the auxiliary electric system.

A system voltage of 4.16 kV would necessitate two (2) three-winding UATs and two (2) double-ended lineups of switchgear in order to adequately source the plant auxiliary load requirements for combined cycle operation. A budgetary cost estimate of [redacted] per UAT and [redacted] of additional metal-clad switchgear would be necessary in order to accommodate auxiliary loads at 4.16 kV system voltage.

6.0 Overvoltage Withstand

Equipment manufacturers specify maximum voltage ratings above the nominal system voltage rating. An industry typical maximum voltage rating for a 4.16 kV nominal system voltage is 5.0 kV, providing approximately 20% headroom in an overvoltage condition. Industry typical maximum voltage rating for a 6.9 kV system voltage is 7.2 kV, though some manufacturers are now offering equipment with maximum system voltage rating of up to 7.65 kV. A maximum voltage rating of 7.2 kV provides approximately 4.3% headroom in an overvoltage condition before exceeding the maximum voltage rating. Dependent upon the generator output voltage and the UAT tap, it is possible to exceed this maximum voltage rating with a 6.9 kV system. However, this is not a normal operating condition and could be mitigated with appropriate protective relaying.

7.0 Conclusions

This evaluation report has shown that:

- The design of insulated conductors is directly impacted by the medium voltage system level.
- Disturbances to the auxiliary electric system as well as motor starting concerns are mitigated by an elevated system voltage.
- Short circuit contribution from medium voltage motors is reduced by an elevated system voltage, which can correspond to a reduction in the short circuit bus rating of electrical distribution equipment.
- The cost associated with an elevated system voltage to plant equipment such as switching assemblies and motor windings is considered negligible.
- The preliminary plant auxiliary loading required for combined cycle operation of the 2x1 configuration is supported by two-winding UATs and one (1) double-ended lineup of medium voltage switchgear at a system voltage of 6.9 kV. A system voltage of 4.16 kV would necessitate three-winding UATs and two (2) double-ended lineups of medium voltage switchgear.
- 4.16 kV system voltage provides more headroom for an overvoltage condition than that of a 6.9 kV system, for industry typical maximum voltage ratings. However, this condition can be mitigated with protective relaying.

Total cost savings for using 6.9 kV medium voltage system in lieu of a 4.16 kV medium voltage system is approximately [redacted]

FINAL

EPC COST - BASIS OF ESTIMATE

A.B. Brown 1x1

B&V PROJECT NO. 400278
B&V FILE NO. 41.0001

PREPARED FORREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

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Executive Summary

The following is a basis of estimate summary for the EPC capital cost AACE Class 2 estimate for the A.B. Brown 1X1 Combined Cycle. The cost estimates contained in this report are based on the preliminary design by Black & Veatch, equipment pricing bids from suppliers of power island, and utilizing prior EPC contractor and vendor bid data. Power island equipment includes the combustion turbine(s), steam turbine, and HRSG(s).

The two plant alternatives that were estimated are as follows:

1X1 CCPP
GE 7FA.05 Fired
GE 7HA.01 Fired

1.0 Estimate Basis

The cost estimate is based on an AACE Class 2 for engineering, equipment and construction costs.

The cost estimate is based upon a lump-sum turnkey EPC approach. Owner will purchase Power Island Equipment and assign to EPC contractor. Under this approach, the EPC contractor would have the responsibility for administration and performance interface of the power island equipment. The EPC structure used for the estimate is based upon the EPC contractor self-performing the work rather than utilizing multiple subcontractors.

The cost estimates are based on competitive bids obtained for power island equipment. Equipment, commodity, and construction services rates were based on EPC contractor and vendor data. Detailed material takeoffs based on the preliminary design of the A.B. Brown combined cycle with reference to similar sized plants that Black & Veatch has designed, constructed, and/or estimated on an EPC basis.

The estimate provided herein is based on preliminary information, and as such is to be considered a non-binding price opinion, and does not represent an offer to sell or a maximum price for the work scope. The estimate assumes moderate level of EPC commercial risk position and does not include specific pricing or schedule impacts for extensive site preparation. Other factors that can impact the price:

- Changes in labor market - A Labor Market Survey may identify craft labor conditions unique to this project that are recommended for further review and evaluation prior to start of construction.
- Final site conditions - Soil boring were secured for the proposed site.
- Noise requirements - Night-time steam blow conditions were assumed.
- Final project schedule.

1.1 QUANTITIES

Quantities that form the basis of the estimate were based on the engineering conceptual design and the engineering Bill of Quantities (BOQ) developed. The conceptual design was based on utilizing some of the existing A.B. Brown common system to support the new combined cycle, detailed information from equipment suppliers for new equipment, and specific site conditions. Where details were not available, assumptions were made based on similar sized plants and arrangements.

1.2 DIRECT COSTS

EPC bid pricing is segregated into two categories: direct and indirect. The direct project costs associated with the BOQs can then be developed by utilizing the unit costs provided by the EPC bidders.

- Unit manhour rates and wage rates are applied against the 1x1 quantities to develop labor cost.

- Unit material cost are applied against the updated quantities for commodities to develop material cost. Cost for major equipment has been scaled off the equipment cost for the major equipment obtained by the EPCs.
- Subcontract pricing was adjusted based upon the rates developed as part of the EPC bid analysis.

To develop the definitive capital cost estimate an RFI was issued to the major OEM Power Island equipment suppliers to obtain budgetary quotes. The OEM proposals included:

- Combustion Turbine and Generator Package
- Steam Turbine and Generator Package
- Heat Recovery Steam Generator

Bid tabulations were developed to evaluate the bids for completeness, scope, and adherence to the specification. The lowest evaluated bid was selected to use as the basis of the estimate.

1.3 CONSTRUCTION MANAGEMENT AND CONSTRUCTION INDIRECTS AND ENGINEERING

Construction Management and Construction Indirects (CMCI) were based on a self-perform (direct-hire) EPC approach instead of a multiple subcontract EPC approach. As a result, the cost for management of the work as well as tools, scaffolding, cranes, warehousing, and laydown to support this work show as a CMCI expense. Under a multiple subcontract approach, these costs would be included in the subcontractor unit rates and appear in the direct cost line items.

Construction management and indirects were estimated based on Black & Veatch's experience with similar plants and scopes of work as well as comparison against the EPC bids. The following costs were developed based upon Black & Veatch's internal metrics and experience then adjusted for schedule and man power loading:

- Project Engineering
- Project Construction Management including Safety, QC, Orientation
- Material Handling
- Mobilization and Demobilization
- Consumables & Small Tools
- Warranty

To obtain competitive bids Black & Veatch, in accordance with IURC code, the estimate includes competitive bids for the following costs:

- Cranes and Construction Equipment
- Scaffolding
- Temporary Facilities

Heavy haul transportation was based on Power Island Equipment delivery to the site and heavy cranes included in the Cranes and Construction Equipment RFQ.

1.4 INDIRECTS

Insurances, warranty, performance bonds, and a letter of credit costs are included, based on the EPC bids.

1.5 CONTINGENCY

[redacted]

[redacted]

FINAL

HRSG BYPASS STACK ANALYSIS

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1201H

PREPARED FOR

VECTREN
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31 JANUARY 2020

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Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch examined the benefits and drawbacks of adding a flue gas bypass stack between the combustion turbine and the heat recovery steam generator (HRSG). The bypass stack would allow the HRSG to be taken offline while the combustion turbine operates in simple cycle mode and would also allow the combustion turbines to be put into service up to 6 months before the erection and commissioning of the balance-of-plant equipment.

This analysis considered such factors as cost, plant design, environmental permitting, schedule, and operations, and maintenance. One major consideration is whether a selective catalytic reduction (SCR) system would be required to meet US Environmental Protection Agency (USEPA) emissions permitting requirements. The base cost for the installation of an HRSG bypass stack is estimated as [redacted] the estimated cost with the addition of an SCR system would be [redacted]

The performance of the combined cycle would not be adversely affected by the inclusion of the bypass stack. USEPA standards, however, might limit the number of hours the unit could operate in simple cycle mode. While the addition of a HRSG stack flue gas bypass would provide the benefit of operational flexibility for the power plant, cost and performance impacts typically do not justify including this equipment in the power plant design.

1.0 Introduction

HRSG stack flue gas bypass systems provide the benefit of adding operational flexibility to power plant generation. Flue gas bypasses consist of installing a stack between the combustion turbine and HRSG; a diversion damper allows the combustion turbine exhaust to be diverted either to the bypass stack or the HRSG. Having a bypass stack available allows the HRSG to be taken offline or out of service, while the combustion turbine operates in simple cycle mode. The bypass stack would also allow for the combustion turbines to be put into service up to 6 months prior to erection and commissioning of the balance of plant under a typical consecutive construction schedule or longer for phased or delayed construction. The benefits must outweigh the cost in order for a flue gas bypass system to be feasible.

This evaluation of adding a flue gas bypass on each Combustion Turbine will help determine the cost (+/- 30%) and design impact of a flue gas bypass system to the plant design. Environmental permit considerations due to the flue gas bypass addition will also be reviewed. Schedule impacts, operations, and maintenance activities will also be identified and discussed.

2.0 Arrangement

On a combined cycle power plant, the flue gas bypass stack would be installed between the combustion turbine and the HRSG. Figure 2-1 shows a typical arrangement of a combustion turbine with a HRSG and a bypass stack. The bypass stack contains a damper that diverts the combustion turbine exhaust either up the bypass stack or to the HRSG. During simple cycle operation, the damper would be positioned to shut off flow to the HRSG and direct flow up the bypass stack. Under combined cycle operation, the damper would be positioned to shut off flow to the bypass stack and allow flow through to the HRSG. The diverter damper is actuated through the operating positions by an electronically controlled hydraulic system. Figure 2-2 shows the components of the bypass stack. Site specific requirements may result in modifications to the arrangement. For example, if air quality controls such as a selective catalytic reduction (SCR) system were required.

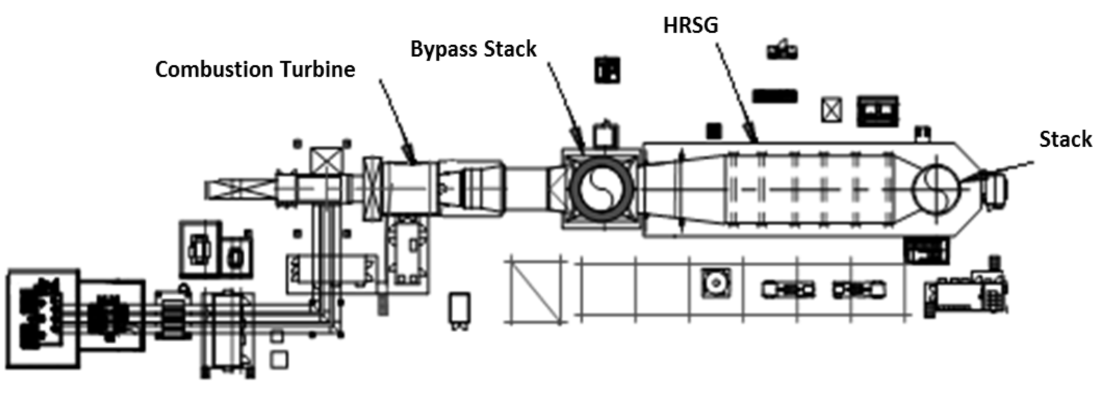

Figure 2-1 Combined Cycle Layout with Bypass Stack

ITEM NO	QTY	DESCRIPTION
1	1	INTEGRATED EXPANSION JOINT
2	2	TRANSITION DUCT HALVES
3	4	SILENCER DUCT QUARTER SECTIONS
4	4	SILENCER DUCT FLAT WALL PANELS
5	2	TRANSITION DUCT HALVES
6	8	VERTICAL STACK SEGMENTS
7	2	VERTICAL STACK SEGMENTS
8		BOTTOM SILENCER PANELS
9		TOP SILENCER PANELS
10		SUPPORT STRUCTURE
11		LADDERS AND PLATFORMS
12		PERSONNEL PROTECTION
13	1	HORIZONTAL TRANSITION
14	1	GUILLOTINE DUCT
15	1	DAMPER

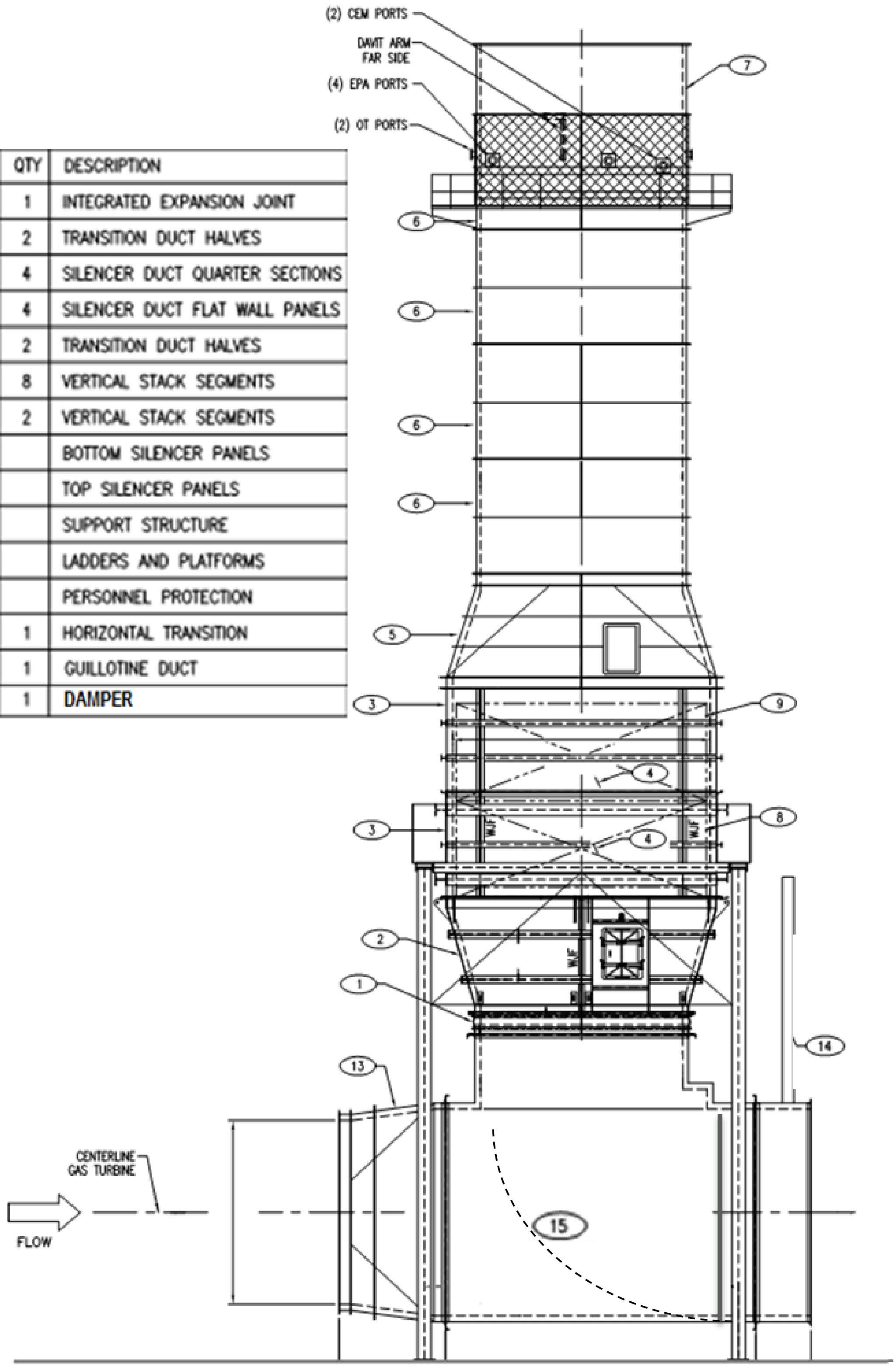

Figure 2-2 Typical Gas Bypass Stack

If an SCR were required, a section could be added to the stack upstream of the silencer to house catalyst, tempering air skid, and ammonia injection equipment. While there is not much industry experience with installing SCRs in the vertical sections of combustion turbine bypass stacks, the technical challenges would be similar to those seen in a coal facility where vertical SCRs are common. The SCR would consist of the following components:

- Catalyst
- Tempering air system to lower combustion turbine exhaust gas to an allowable inlet temperature for the catalyst (<800 °F)
- Mixing vanes and flow distribution
- Ammonia distribution manifold and injection grid
- Ammonia vaporization and flow control unit
- Emission monitoring system

Alternatively, the SCR may be horizontal and then the SCR and bypass stack would be placed in parallel with the HRSG. Air emission requirements are discussed in Section 6.0.

3.0 Capital Costs

Typical suppliers of HRSG bypass stacks include Braden Manufacturing, Peerless-Aarding, and Clyde Bergmann.

Pricing from recent proposals was reviewed to find a budgetary estimate for a bypass stack with a height of 135 ft with stack silencer and continuous emission monitoring (CEMS) system. Also included were all required dampers, motors, controls, insulation, lighting, support steel and platforming as required.

Table 3-1 is a high level breakdown of the installed costs associated with the bypass stack.

Table 3-1 Capital Costs for HRSG Bypass Stack

DESCRIPTION	INSTALLED COST / UNIT
FOUNDATIONS/CIVIL WORK	[redacted]
STACK (including ductwork, damper, supplementary steel, lighting, electrical)	[redacted]
CEMS (NOx and CO analyzers, includes electrical and controls)	[redacted]
BYPASS STACK (no SCR)	[redacted]
VERTICAL SCR (includes ammonia injection, NO_X and CO catalyst)	[redacted]
BYPASS STACK (with vertical SCR)	[redacted]

4.0 Performance Impacts

Installation of a bypass stack allows for the operation of the combustion turbine in simple cycle mode; however, operating in simple cycle mode may have limited operating hours as discussed in Section 6.0, Permitting and Emissions.

[redacted]

If an SCR is required, a tempering air skid is required to keep the CTG exhaust below 800 °F to prevent damage to the catalyst. The CTG exhaust reaches 800 °F in less than a minute from ignition as the CTG reaches 5% load. The tempering air fan and the ammonia vaporization and flow control system will have an approximate auxiliary load of 1,000 kW.

5.0 Maintenance

Maintenance consists of correcting deficiencies noted during inspection. For HRSG bypass stacks without an SCR, the primary maintenance concern is the damper seals, diverter damper bearings, and the dampers hydraulic power unit.

Typical diverter maintenance activities include:

- Shaft seal replacement.
- Housing perimeter seal replacement.
- High temperature bearing repair or replacement.
- Shaft seals are typically designed to last five years.

Recommended spare parts include:

- Spare limit switches.
- Position transmitters.
- Seal-air pressure blower.
- Main drive bearing kit.
- Damper seal sets.
- Expansion joints.

If an SCR is required, additional maintenance is required for the hot air tempering skids, ammonia flow control units, and replacement of NO_x and CO catalysts.

6.0 Permitting and Emissions

6.1 FEDERAL REGULATIONS POSING CHALLENGES

Officially titled *Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, 40 CFR Part 60, Subpart TTTT was finalized by the USEPA on August 3, 2015. In this rulemaking, the USEPA established output-based emissions standards for two subcategories of power plants; electric utility steam generating units (e.g., coal-fired power plants) and stationary combustion turbines. The rule makes no distinction between simple cycle and combined cycle combustion turbines. Rather, it requires combustion turbines to meet certain CO_2 emissions standards depending on whether they are classified as baseload or non-baseload units.

The distinction between baseload and non-baseload units is made based upon the number of hours a combustion turbine can operate relative to its design efficiency. If a combustion turbine operates more hours than its net, Lower Heating Value (LHV) design efficiency, then it is considered a baseload unit. Baseload units are required to meet an output-based CO_2 emission standard of 1,000 lb/MWh (gross output, 12-operating month basis).

[redacted]

If the plant is restricted in hours less than the percent of net design efficiency hours, the plant is classified as a non-baseload unit with respect to NSPS Subpart TTTT. Natural gas-fired non-baseload units are subject to a heat-input based CO_2 emission standard 120 lb/MBtu (HHV, 12-operating month basis). This standard is readily achievable because the CO_2 emission rate of natural gas is 117 lb/MBtu.

6.2 AIR PERMITTING CHALLENGES

While an emissions netting analysis (wherein any recent unit shutdowns can be used to demonstrate that net emissions increases from the new installation would not exceed major source permitting thresholds) could allow the project to avoid major source permitting requirements there is still a possibility the project could trigger major source permitting. In such a scenario, the air permitting process would be dictated by the Prevention of Significant Deterioration (PSD) regulations which require, among other things, an evaluation of Best Available Control Technology (BACT). Should BACT be required for NO_X emissions, the project's air construction permit could require the use of an SCR.

7.0 Conclusions

Having a bypass stack available allows the HRSG to be taken offline or out of service, while the combustion turbine operates in simple cycle mode. In addition, the combustion turbines could be put into service up to 6 months prior to erection and commissioning of the balance of plant under a typical consecutive construction schedule or longer for phased or delayed construction.

While the addition of a HRSG stack flue gas bypass would provide the benefit of operational flexibility for the power plant, cost and performance impacts typically do not justify including this equipment in the power plant design. The total installed cost of the bypass stack fora 1x1 CTG train is approximately [redacted] without an SCR. A vertical SCR would be considered a first of a kind for this application so no cost is easily achievable without a prior design. It is expected that if an SCR is required due to concerns with emissions the cost would be approximately double [redacted] with an SCR. If a horizontal SCR is required due to emission limits, the SCR would not be feasible as it would be approximately the size of the HRSG. The performance of the combined cycle would not be adversely affected by the inclusion of the bypass stack. The amount of hours where the unit can operate in simple cycle mode with the HRSG bypassed may be limited due to NSPS 40 CFR Part 60, Subpart TTTT.

FINAL

HEAT REJECTION / EXISTING COOLING TOWER ANALYSIS

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1202H

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

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Executive Summary

In developing this report, Black & Veatch focused its attention to the specific areas directed by Vectren by analyzing the design impacts and cost comparison of using one existing cooling tower, circulating water pumps, and circulating water pipe for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed multiple existing cooling tower reuse scenarios to evaluate the performance against the design for a new cooling tower. A performance summary for the two most optimal scenarios is provided in Section 2.0.

Black & Veatch evaluated the following three cooling tower alternatives for this study:

- Alternative 1: Reuse Cooling Tower, Circulating Water Pumps, and Existing Piping
- Alternative 2: Reuse Cooling Tower and Circulating Water Pumps with All New Piping
- Alternative 3: All New Cooling Tower, Circulating Water Pumps, and Piping

This report has been summarized in a Cooling Tower Alternatives Comparison Matrix provided in Table ES-1. [redacted] Consequently, it is recommended that Vectren utilize the existing Unit 1 cooling tower, circulating water pumps and piping as the design basis for the new combined cycle power plant.

Table ES-1 Cooling Tower Alternatives Comparison Matrix

ALTERNATIVE	REUSE TOWER, PUMPS, AND PIPING (ALTERNATIVE 1)	REUSE TOWER AND PUMPS WITH ALL NEW PIPING (ALTERNATIVE 2)	NEW TOWER, PUMPS, AND PIPING (ALTERNATIVE 3)
Description	[redacted]	[redacted]	[redacted]
Constructability			
Tower Performance			
Condenser Adder			
Tie-In Outage Length			
Total Installed Cost			
Operating and Maintenance Cost			
Circulating Water Pump Auxiliary Load			
New Major Equipment			
Advantages			

ALTERNATIVE	REUSE TOWER, PUMPS, AND PIPING (ALTERNATIVE 1)	REUSE TOWER AND PUMPS WITH ALL NEW PIPING (ALTERNATIVE 2)	NEW TOWER, PUMPS, AND PIPING (ALTERNATIVE 3)
Disadvantages	[redacted]	[redacted]	[redacted]

1.0 Introduction

The purpose of this study is to analyze the A.B. Brown Unit 1 circulating water system to determine whether all or portions of the existing cooling towers, circulating water pumps, and circulating water piping can be reused for use with a new Combined Cycle Power Plant (CCPP). Black & Veatch has evaluated the performance of the existing cooling towers and circulating water pumps to determine the optimal operating scenarios [redacted] when paired with the new CCPP.

This evaluation of reusing the existing circulating water system components will help determine the [redacted] design impact of this system to the new CCPP design. Schedule impacts, operations, and maintenance activities will also be identified and discussed.

2.0 Performance Evaluation

Several operating scenarios were evaluated to determine the best preliminary design basis for reusing the existing cooling towers and circulating water pumps. Upon selection of the final plant design, the preferred number of cooling tower cells in service should be reviewed.

Alternatives 1 and 2 utilize the Unit 1 existing seven cell cooling tower and two circulating water pumps provide a total circulating water flow of 125,000 gallons per minute (gpm).

The existing cooling tower would be larger than the cooling tower for Alternative 3. The design flow rate of the existing cooling tower is larger than the design flow rate would be for the new cooling tower. To accommodate the larger flow rate, the condenser will be larger, and more expensive, but provides better performance. The overall heat rejection system for Alternatives 1 and 2 result in a decrease in steam turbine backpressure and an increase in auxiliary power when compared to the new heat rejection system considered in Alternative 3.

The estimated performance based on nominal 1x1 7HA.01 combined cycle performance for the alternatives is shown on Figure 2-1 for unfired heat recovery steam generator (HRSG) operation and Table 2-2 for fired HRSG operation. For reference, Tables 2-1 and 2-2 provide the estimated performance values shown on the graphs.

[redacted]

Table 2-1 Comparative Unfired Plant Performance for Cooling Tower Alternatives

UNFIRED OPERATING CONDITIONS	1X100% CTG LOAD 8.1F/70% AMBIENT EVAP COOLING OFF DUCT FIRING OFF	1X100% CTG LOAD 56.8F/48% AMBIENT EVAP COOLING OFF DUCT FIRING OFF	1X100% CTG LOAD 93.7F/45% AMBIENT EVAP COOLING ON DUCT FIRING OFF
7 Cell Net Plant Output, kW	[redacted]	[redacted]	[redacted]
7 Cell Net Plant Heat Rate (LHV), Btu/kWh	[redacted]	[redacted]	[redacted]
New Tower Net Plant Output, kW	[redacted]	[redacted]	[redacted]
New Tower Net Plant Heat Rate (LHV), Btu/kWh	[redacted]	[redacted]	[redacted]

Table 2-2 Comparative Fired Plant Performance for Cooling Tower Alternatives

FIRED OPERATING CONDITIONS	1X100% CTG LOAD 8.1F/70% AMBIENT EVAP COOLING OFF DUCT FIRING ON	1X100% CTG LOAD 56.8F/48% AMBIENT EVAP COOLING OFF DUCT FIRING ON	1X100% CTG LOAD 93.7F/45% AMBIENT EVAP COOLING ON DUCT FIRING ON
7 Cell Net Plant Output, kW	[redacted]	[redacted]	[redacted]
7 Cell Net Plant Heat Rate (LHV), Btu/kWh	[redacted]	[redacted]	[redacted]
New Tower Net Plant Output, kW	[redacted]	[redacted]	[redacted]
New Tower Net Plant Heat Rate (LHV), Btu/kWh	[redacted]	[redacted]	[redacted]

3.0 Existing Equipment

3.1 EXISTING COOLING TOWER CONDITION

The Unit 1 cooling tower cells were recently rebuilt from wood to fiberglass as such the condition is assumed satisfactory and no major repairs are required. Three of the seven Unit 2 cooling tower cells were recently rebuilt from wood to fiberglass. To extend the life of the Unit 2 cooling tower the remaining four (4) cells would require rebuilding to fiberglass at a cost of approximately [redacted] To eliminate the need for this expenditure, the Unit 1 cooling tower will be used for the new CCPP. The existing cooling tower basins for Unit 1 and Unit 2 are lacking an intake structure for an auxiliary cooling water pump. Modifications will be needed to the basin to add the new intake and pump structure.

3.2 EXISTING CIRCULATING WATER PUMPS

The existing circulating water pumps have been evaluated for both Alternatives 1 and 2 and it has been determined that they have sufficient capacity to meet the required flow and head for the new CCPP circulating water system. To extend the life of the two pumps and motors a shop overhaul would be required.

Black & Veatch evaluated the use of variable frequency drives (VFDs) on the existing circulating water pumps to modify the pump flow rate for different CCPP operating scenarios. Because the static head component is constant for all operating conditions and accounts for the majority of the circulating water pump head requirement, a VFD would provide minimal performance gains [redacted] per pump.

3.3 EXISTING CIRCULATING WATER PIPE

The existing circulating water piping is carbon steel piping with a bitumastic coating. Coatings have been maintained and repaired during normal inspection and repairs throughout the life of the existing A.B. Brown Plant. For this study, it is assumed that the condition of the pipe is satisfactory and no repairs will be required to the piping that is being reused as part of Alternative 1.

4.0 Constructability

For each of the cooling tower reuse alternatives there are several items to consider that could impact both the new CCPP and existing A.B. Brown Unit 1 during the installation and commissioning phase of the project.

4.1 ALTERNATIVE 1

Alternative 1 reuses a significant amount of existing underground steel piping, which will require continued inspection and maintenance to last the 30 year design life of the new CCPP. The existing piping is assumed to be in satisfactory condition given feedback from Vectren that they have performed scheduled inspections and coatings on the piping as required.

4.2 ALTERNATIVE 2

Alternative 2 will require unit outages considerably longer than Alternative 1, up to 2 or 3 months, given that a large section of existing Unit 1 circulating water piping and cooling tower risers are to be replaced in-kind with new steel piping. Once completed, Alternative 2 will result in the existing cooling tower and circulating water pump connected to the new CCPP circulating water system with all new piping, resulting in shutdown of the existing Unit 1 at the time of the tie-in.

4.3 ALTERNATIVE 3

Alternative 3 is an all new circulating water system that includes a 6 cell back-to-back mechanical draft counter flow cooling tower, 2x50 percent circulating water pumps, and steel circulating water piping. Because this system is independent of the existing equipment no unit outage will be required and the existing Units 1 and 2 will be able to operate during and after the installation of the new circulating water system. This alternative also results in the least auxiliary load because of minimizing the size of the circulating water pumps for the new CCPP design conditions.

5.0 Capital Costs

Table 5-1 is a high-level breakdown of the costs for both reusing the existing cooling towers and installing new cooling towers with a new basin.

Table 5-1 Estimated Costs for Cooling Tower Alternatives

Description	Reuse tower, Pumps, and Piping (Alternative 1)	Reuse tower and Pumps wIth ALL new piping (Alternative 2)	New tower, pumps, and piping (Alternative 3)
New 6 Cell Cooling Tower with Basin (F&E)	[redacted]	[redacted]	[redacted]
Condenser Adder	[redacted]	[redacted]	[redacted]
Circulating Water Pumps	[redacted]	[redacted]	[redacted]
New Piping and Valves (A/G and U/G)	[redacted]	[redacted]	[redacted]
Basin Modifications for Auxiliary Cooling Water Pump	[redacted]	[redacted]	[redacted]
Site Work	[redacted]	[redacted]	[redacted]
Mechanical Installation (Does not include tower erection)	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]
Cost Difference	[redacted]	[redacted]	[redacted]

6.0 Conclusions

Based on the evaluation, reusing the existing Unit 1 cooling tower, pumps and piping (Alternative 1) is the lowest cost technically acceptable solution and should be used as the design basis for the new combined cycle power plant.

FINAL

FAST START VS. CONVENTIONAL START ANALYSIS

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1203H

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

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1.0 Introduction

This study evaluates designing a 1x1 GE 7HA.01 combined cycle power plant with "fast start" capabilities versus a plant design for "conventional" start. The GE 7HA.01 is one of several candidate H-Class combustion turbine offerings.

1.1 STARTUP DURATION DEFINITION

Since plant load is affected by ambient conditions, startup durations are typically defined based on achieving a certain operating condition and not a specified operating load. The beginning of the start is typically defined as combustion turbine roll-off or first ignition. Startup is complete when a predefined operating condition is reached.

Startup can be a confusing term as it is used to describe the start from ignition to various ending operating conditions across the industry. These ending operating scenarios can include:

- CTG Full Speed No Load – The point at which the combustion turbine is removed from the static starter and brought to full speed.
- CTG Sync - The point at which the combustion turbine (CTG) is synchronized with the grid.
- Emission Start - Achieving minimum emissions compliance load. This occurs when stack discharge emissions reaching steady state compliance with air quality standards.
- CTG Full Load Start - Combustion turbine at baseload with permitted emissions at the stack.
- Plant Full Load Start - Combustion turbine at baseload and steam turbine bypass valves fully closed. Steam turbine in service.

For the purpose of this study Fast Start is being defined as a rapid start commencing with ignition until the combustion turbine reaches minimum emission load compliance (MECL). When speaking with others in the industry the ending operating condition should be defined.

The type of start is also defined by the amount of time the unit has been shutdown. It is typical to assume the shutdown begins at fuel flow shutoff to the combustion turbines during a normal plant shutdown sequence from a steady state baseload condition. Durations as defined by the project are:

- Hot start = Shutdown 8 hours or less
- Warm start = > 8 hours and < 48 hours
- Cold start = Shutdown 48 hours or more

The lead time activities prior to a warm or cold fast startup typically commence with startup of the auxiliary boiler. Depending on the start condition for the auxiliary boiler and the features incorporated to permit its fast start, this activity may need to commence approximately three hours before the actual combustion turbine start condition.

1.2 CONVENTIONAL VERSUS FAST START

Conventional combined cycle facility startup durations are constrained by steam cycle equipment limitations, specifically the heat recovery steam generator and steam turbine temperature ramp capabilities. Heat recovery steam generators and steam turbines are designed to operate at very high temperatures and pressures and, therefore, are comprised of very thick metal alloy components (e.g. steam drums, steam turbine rotors). These thick components can suffer from high thermal stress and increased life expenditure if they are subjected to large temperature differentials (e.g., 1,000°F steam across an ambient temperature steam turbine rotor) or rapid temperature ramp rates. HRSG and steam turbine suppliers provide strict temperature ramp rates and temperature differential requirements for their equipment that must be used to define and limit the startup sequence and duration in order to protect the equipment.

HRSGs designed through the middle of the last decade were generally not capable of allowing combustion turbines to start at their maximum capability without incurring significant maintenance impacts. These units required pauses ("holds") at low CTG loads to "heat soak" their heavy-walled components prior to releasing the unit on sustained ramp rates of typically less than 7°F per minute, as measured by the high-pressure (HP) drum steam saturation temperature.

Today's HRSGs can be more robustly designed for the rapid ramp rates of advanced class combustion turbines, which can exceed 50 megawatts (MW) per minute and yield HRSG temperature ramp rates exceeding 30°F per minute.

Though HRSGs are now designed to allow combustion turbines to start at their maximum capability, steam turbines are not. Cold steam turbines require relatively cool steam, typically in the range of 700°F, on first admission to the equipment. During the startup sequence, steam temperatures downstream of the HRSG are primarily controlled through two means working in tandem, CTG exhaust temperature control and desuperheating of the generated steam. CTG exhaust temperature control tunes the CTG to minimize the exhaust temperature into the HRSG during the startup sequence, as a cooler exhaust temperature produces cooler steam. Desuperheaters spray water into the steam headers to reduce, or "attemperate", the steam by reducing the level of superheat above the steam saturation temperature.

Most HRSGs include interstage desuperheaters that are installed between superheater and reheater sections to control the final HRSG exit steam temperatures. As the combustion turbine ramps above very low loads towards the MECL, the CTG exhaust temperature control and HRSG interstage desuperheaters are no longer capable of cooling the steam to the temperatures permitted by a relatively cool steam turbine. The steam turbine becomes a critical constraint on the start time unless the HRSG exit steam temperatures can be further reduced to match the steam turbine steam temperature requirements. In effect, the steam turbine must be ‘decoupled’ from the combustion turbine so that the combustion turbine start is not constrained by the steam cycle.

The steam turbine can be decoupled and its steam temperature requirements met irrespective of combustion turbine load by adding terminal desuperheaters (i.e., desuperheaters downstream of the HRSG in the high-pressure (HP) and hot reheat steam headers) to cool the HRSG exit steam to the steam turbine requirements.

Decoupling the steam turbine from the CTG/HRSG train allows the combustion turbine to ramp to emissions compliance load levels without hold periods in the firing sequence. A no-holds startup sequence is typically referred to as an uninhibited start.

Figure 1-1 provides a high-level comparison of the typical CTG load path for a 1x1 conventional combined cycle to that of a fast-start combined cycle. Additional details on the performance differences between the two startup types are discussed in Section 4.0.

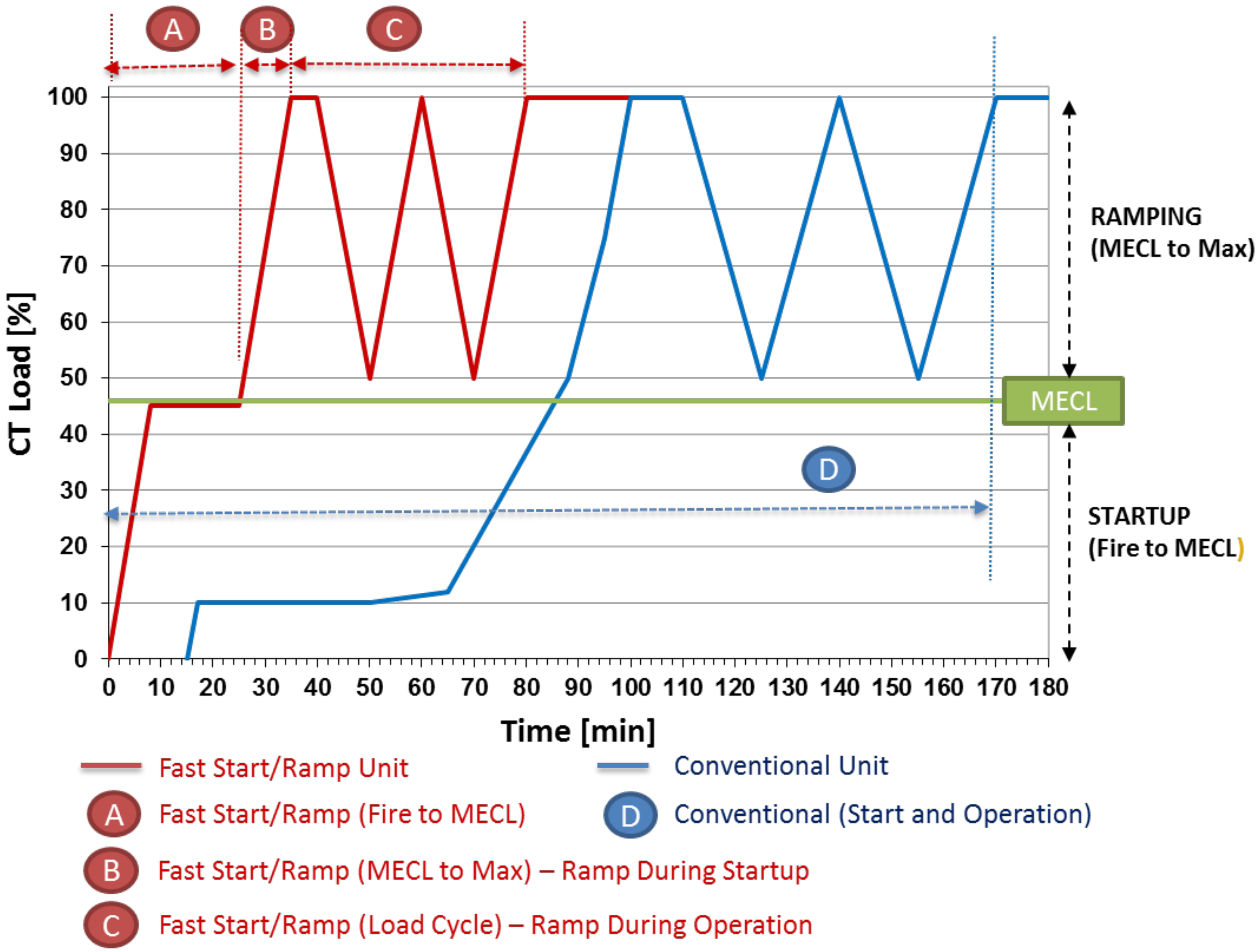

Figure 1-1 Comparison of Combustion Turbine Loading during Hot Start Event (Excludes Purge)

2.0 Design Features

Capital costs are higher for fast start plants than plants designed for conventional starts. Equipment and balance of plant systems affected by the additional design consideration for fast start are as described below and in Table 2-1. Column A of Table 2-1 lists specific design features and equipment required for fast start operation. Column D of Table 2-1 lists design features of conventional start units. Columns B and C will be discussed in the Fast Start vs. Conventional Unit Ramp Rate Analysis (File No. 400278.41.1204H).

Table 2-1 Design Features of Combined Cycles Designed for Various Operating Scenarios

FEATURES REQUIRED TO MEET OPERATING SCENARIO	A FAST START (FIRE TO MECL)	B FAST RAMP (MECL TO MAX)	C FAST RAMP (LOAD CYCLE)	D CONVENTIONAL (START AND OP)
Required Option = ● , Recommended Option = ☐ , Standard Option = ◆				
Combustion Turbine				
Fast Start Equipped	●			
Natural Gas Purge Credits	●			☐
Service Life Monitoring System	◆	◆	◆	◆
Advanced Control System	●	●	●	
HRSG				
Advanced Drum Design	●	●		
Enhanced Nozzle Connections	●	●		
Improved HRSG Materials	●	●		
Improved HRSG Geometries	◆	◆	◆	◆
Service Life Monitoring System	☐	☐	☐	
Stack Damper and Insulation	●			☐
Terminal Attemperators	●	●	●	
LP Economizer Recirculation/ Heat Exchanger	●	●		
Steam Turbine				
Optimized Casing Design	●	●		
Advanced Control System	●	●	●	
Service Life Monitoring System	●	●	☐	

FEATURES REQUIRED TO MEET OPERATING SCENARIO	A FAST START (FIRE TO MECL)	B FAST RAMP (MECL TO MAX)	C FAST RAMP (LOAD CYCLE)	D CONVENTIONAL (START AND OP)
Advanced Stop Valve Design	●			
Increased Thermal Clearances	●	●		
Advanced Turbine Water Induction Protection	●	●	●	
Emissions Control				
Feed-forward Ammonia Controls	●	●	●	
Auxiliary Steam				
Auxiliary Boiler	●			
Condenser and HRSG Sparging	●			
Feedwater System				
Larger Condensate Pump	●	●	●	
Larger Feedwater Pump	●	●	●	
Higher Stage IP Bleed	●	●	●	
Heat Rejection System				
Surface Condenser – Fast Start Design	●			
Fuel Gas System				
Supplementary Fuel Gas Heating(1)	□			
Water Treatment System				
Condensate Polisher(2)	□			
Auxiliary Electrical System				
Larger Equipment for Higher Loads	●	●	●	

Notes:

1. Supplementary fuel gas heating as required by combustion turbine supplier.
2. Space should be allotted for future condensate polisher installation, if required.

2.1 COMBUSTION TURBINE

Combustion turbines designed for fast-ramping will be equipped with fast start features. These include positive isolation to ensure that purge credits have been maintained per NFPA 85 and that the gas path will not require a purge prior to startup. The control system for fast start of the plant should be fully automated to minimize times between sequential steps and allow for greater consistency during startup.

Both fast start and conventional units are equipped with service life monitoring systems that control unit ramp operations based on predetermined thermal stress limitations. Fast Start units are equipped with advanced control schemes incorporating model based controls (MBC) to optimize startup based on these monitoring systems.

Purge credits established during the shutdown must still be intact. NFPA 85 requires that a fresh air purge of the combustion turbine and HRSG be accomplished prior to start. NFPA 85 requires that at least five volume changes be completed or a minimum purge of 5 minutes prior to ignition. Typical purge durations can range from 5 to 20 minutes. The 2011 edition of NFPA 85 allowed for purge credits to be achieved when the unit is taken off line if the purge is completed and the valving arrangement is shown to positively isolate any fuel from entering the system. The combustion turbine can usually achieve the required purge when coasting down following a loss of ignition.

2.2 HRSG

HRSGs designed for fast-start plants can subject HRSG components such as superheaters and reheaters to rapid heating. Large thermal stresses can be produced by the differential expansion of the tubes within the HRSG. HRSG designs in such plants must be capable of accommodating the rapid change in temperature and flow of flue gas generated by load ramping of advanced class combustion turbines.

To reduce thermal capacity of drums many options are used to decrease the drum size and wall thickness including utilizing Benson style drums, utilizing multiple drums, high strength drum materials, and reduced residence time. Self-reinforced nozzles, full penetration nozzles, full penetration welds, and steam sparger systems further improve the ability to accept rapidly changing exhaust gas conditions and steam conditions. Improved materials throughout the high pressure superheater and reheater can be required. Online, real-time monitoring system should be included to evaluate HRSG life consumption.

In order to reduce the thermal capacity of drums, the residence time may also be reduced for fast start units. Fast start units typically have drum storage time around two minutes. Conventional start plants have drum storage time from 3-5 minutes.

Fast start plants are equipped with a stack damper and with an insulated stack up to the stack damper. The stack damper and insulation are critical as they restrict the flow of flue gas out the HRSG stack minimizing heat loss when the unit is offline. While conventional units do not require stack dampers and insulation, it is a recommended practice to minimize heat loss when the unit is offline.

Both fast start and conventional units have improved HRSG geometries compared to those built a decade ago. Improvements in geometries have been to decrease thermal stresses from unit cycling and are part of the HRSG standard design such as coil flexibility to superheater/reheater interconnecting piping and accommodations for tube-to-tube temperature differentials.

2.3 STEAM TURBINE

The steam turbine must also be designed for the thermal gradients experienced while ramping during start-up. For fast start machines, the casing design must be optimized to reduce the thermal stress during temperature fluctuations and to accept faster start up and load change gradients. The use of higher grade material may be employed in the high pressure and intermediate casings and valves to reduce component thickness. Main steam stop valves must be designed so that these valves can be opened at a relatively higher pressure. Integral rotor stress monitors can be provided; the rotor stress monitor is typically capable of limiting or reducing the steam turbine load or speed increase and is designed to trip the turbine when the calculated rotor stresses exceed allowable limits.

For machines undergoing a fast ramp, attemperators are often required on the high pressure and hot reheat steam lines. Overspray on these attemperators can lead to water in these steam lines; special attention needs to be provided for turbine water induction prevention for units equipped with terminal attemperators.

2.4 EMISSIONS AND AMMONIA FEED

Outlet NO_x from the combustion turbine can vary highly when undergoing fast startup and fast ramp conditions. Conventional units only measure NO_x at the stack; for fast ramping units limiting NO_x measurements to the stack only can lead to over injecting or under injecting ammonia. Higher ammonia slip and potentially greater SO_2 conversion in fast-start and fast-ramp units create additional challenges for control of sulfur-bearing deposits in the colder HRSG areas. Low-pressure evaporators and economizers are particularly at risk. For fast ramping plants, addition of feed forward controls to quicken the saturation of the SCR catalyst (if included) is required. Also the HRSG should be equipped with LP economizer recirculation or heating systems to maintain surfaces above SO_2 dew points.

2.5 AUXILIARY STEAM

Fast start units require an auxiliary boiler to produce steam prior to the startup of the unit. This steam is used for steam line warming, establishing the steam turbine seals, warming up HRSG drums, and condenser sparging to enable uninhibited startup of the unit. The auxiliary boiler may also produce steam when the unit is off line to maintain drum and turbine temperatures.

Conventional units without an auxiliary boiler must use the combustion turbine and HRSG to produce steam to warm the unit and establish seals. During a conventional unit startup, holds are required to complete these warm up periods.

Provisions for fast start of the auxiliary boiler should also be considered which include equipping the auxiliary boiler mud drums with heating coils. Auxiliary boiler heat input, operating hour limits, and emission limits must also be considered.

Note that the auxiliary boiler makes up the majority of the cost to equip a combined cycle with fast start capabilities.

2.6 TERMINAL STEAM ATTEMPERATORS

Conventional start plants hold the combustion turbine load during startup as needed to meet the steam turbine startup steam temperature requirements. Fast-start plants decouple the CTG/HRSG startup from the steam turbine startup by using terminal attemperators at the HRSG outlet for meeting steam turbine startup steam temperature requirements, irrespective of CTG/HRSG load. This allows the steam turbine to come on line independently from the CTG and HRSG. As a result, the plant can increase load more quickly.

While the addition of terminal (final stage) steam attemperators on the main steam and hot reheat lines allow for steam turbine temperature matching, they introduce the risk of two phase flow in the steam lines. An adequate run of straight piping downstream of the attemperators, adequate drainage, and robust instrumentation are a must to minimize the risk of condensate carry-over to the steam turbine. Additional controls should be considered to prevent turbine water induction.

2.7 FEEDWATER SYSTEM

For fast start plants equipped with terminal attemperators, additional condensate and feedwater pump flow is required to meet the attemperation demands. Inter-stage feedwater used for attemperation may be taken off at a later pump stage to meet the pressure demands of the attemperators which could impact feedwater piping wall thickness.

2.8 FUEL GAS SYSTEM

In order to reduce emissions and maintain flame stability, some manufacturers require supplementary fuel gas heating as a part of startup. This heating is in addition to any startup heater used to raise the fuel gas temperature above the dew point.

2.9 WATER TREATMENT SYSTEM

Maintaining water chemistry and meeting the water chemistry requirements of the HRSG and steam turbine are a critical part of startup. Blowdown and makeup systems should be sized accordingly to meet expected startup demands. Provisions for the inclusion of a future condensate polisher should be considered should problems arise. Condensate polishers ensure top quality feedwater.

2.10 AUTOMATED STARTUP SEQUENCE

Additional controls and automation are required for fast-ramp plants to ensure the matching of steam temperatures and to maintain emission compliance. As a result, more plant instrumentation is required in automated plants to allow the plant control system to monitor system status, minimize times between sequential steps and provide consistent startups.

Also fast-ramp plants should consider the use of service life monitoring systems such as thermal stress indicators on the HRSG and steam turbine. These systems allow control of the unit ramp operations based on predetermined thermal stress limitations.

3.0 Capital Costs

Capital costs are higher for fast-start plants than plants designed for conventional starts. Additional costs that must be considered are requirements for a more flexible HRSG (e.g., header returns, tube to header connections, harps per header limits), terminal attemperators and associated systems; more flexible steam piping; improved steam piping drain systems, improved bypass system and controls integration, and requirements for auxiliary steam.

Table 3-1 lists the costs to include the design features listed in Column A of Table 2-1 for a fast start unit. Costs listed in the study are budgetary costs (+/- 30%).

Table 3-1 Fast Start (Fire to MECL) Operating Scenario Costs

FAST START SYSTEM COSTS FOR A 1X1 7HA.01 COMBINED CYCLE	
Fast Start Options (Required options in Column A excluding Aux Boiler and Stress Monitoring Systems)	[redacted]
Auxiliary Boiler	[redacted]
Stress Monitoring Systems	[redacted]
Total	[redacted]

4.0 Performance Impacts

Startup durations are dependent on the ambient conditions, time after shutdown, initial steam turbine rotor temperatures, and the particular OEM equipment/features used in the power train in addition to any margins (if the required start-up times are to be guaranteed). There is a relatively wide range variation, however, for rough indicative values, Table 4-1 provides comparative durations, [redacted] All fuel consumption and net generation values are based on combustion turbine ignition through the indicated end point.

Table 4-1 Estimated Nominal Startup Times (Minutes)

START TYPE	CONVENTIONAL START TO MECL	FAST START TO MECL	DIFFERENCE (CONVENTIONAL – FAST)
Hot Start = Shutdown 8 hours or less	[redacted]	[redacted]	[redacted]
Warm Start = > 8 hours and < 48 hours	[redacted]	[redacted]	[redacted]
Cold Start = Shutdown 48 hours or more	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

5.0 Startup Emissions

Stack emissions vary widely prior to reaching steady state emissions compliance due to the complexity of starting a combined cycle facility and the plant equipment's ability to operate within threshold limits across a certain operating range. The combustion turbine and the HRSG post-combustion emissions control components (if applicable) are the main equipment governing stack emissions variation.

Combustion turbines are designed with multiple fuel nozzles in each combustor. As combustion turbines start and ramp up to normal operating flow, load, and temperature, the combustion nozzles are sequenced through various combustion operating modes that vary the deflagration type (i.e., diffusion or pre-mixed [i.e., the air and fuel are pre-mixed prior to ignition of the fuel]) and nozzle firing sequences (i.e., which of the multiple nozzles are in service). These startup combustion modes are required so that stable combustion can be maintained in the unit during startup to avoid flame outs. As illustrated in Figure 2-1, in these off-design startup combustion modes, the combustion of the fuel is generally incomplete resulting in higher than normal nitrous oxide (NO_x), carbon monoxide (CO), and volatile organic compound (VOC) emissions concentrations. As the turbine reaches a minimum operating load where its normal combustion mode can be stably maintained, combustion becomes more complete and emissions decrease to a level that can be maintained across a wide operating range. The minimum operating load of the combustion turbine in this emissions compliant operating range is called the Minimum Emissions Compliance Load (MECL).

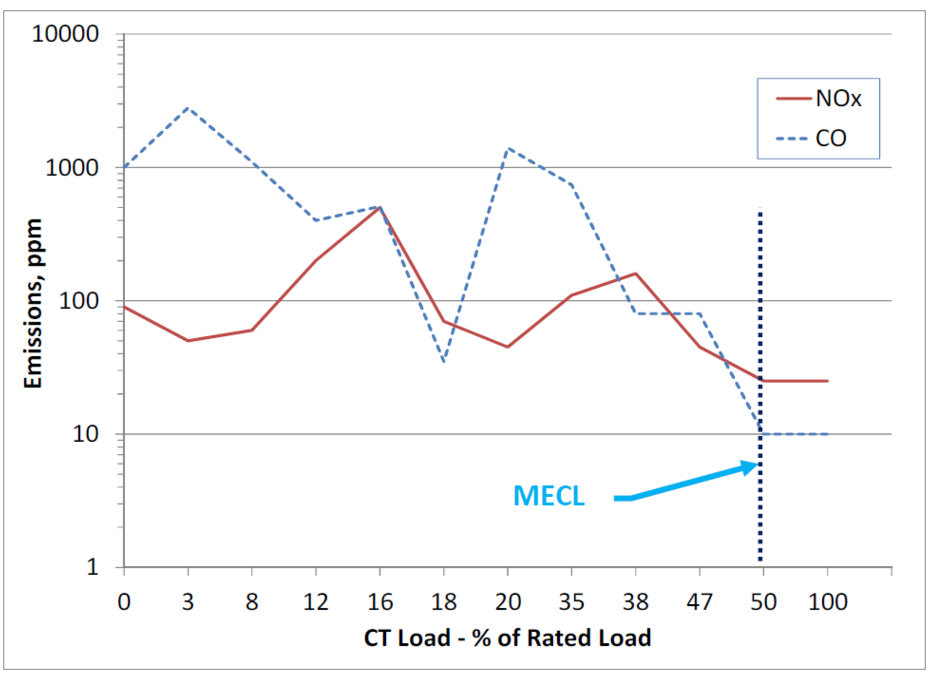

Figure 5-1 Example Combustion Turbine NO_x and CO Emissions versus Rated Load

Below MECL, the mass of air pollutant emissions can accumulate quickly and, therefore, these "startup emissions" are of particular interest to regulators. The steady-stated CTG design exhaust emissions for the turbine technologies considered are approximately 15-25 ppmvd @15% O2 for NO_x and 4-10 ppmvd @15% O2 for CO when operating on natural gas. Steady-state VOC emissions are dependent on the site specific natural gas composition.

An emissions netting analysis will be performed for the new combined cycle plant. If a Prevention of Significant Deterioration (PSD) review is required, the emissions standard that must be met is Best Available Control Technology (BACT), an emissions control mandate by the Environmental Protection Agency (EPA). If applicable, combined cycle BACT requirements dictate NO_x and CO emissions shall be no greater than 2 ppm (parts per million) at the HRSG stack discharge over the entire normal operating range. CTG emissions levels are not sufficient for BACT and post-combustion emissions controls components; oxidation catalyst to reduce CO/VOC emissions and a selective catalytic reduction (SCR) system to reduce NO_x emissions, must be installed in the HRSG to further reduce emissions to BACT levels.

Oxidation catalysts and SCR systems are not effective until they are warmed to a minimum threshold temperature and the SCR ammonia injection (utilized with the catalyst to reduce NO_x emissions) is tuned. In general, these post-combustion emissions controls components are designed such that the minimum threshold temperatures are achieved on a startup at or below the combustion turbine MECL. As noted previously, an "emissions" startup sequence is considered complete after the CTG reaches MECL, and in the event of post-combustion emissions control components, they reach their minimum threshold temperatures, and the SCR ammonia injection is tuned such that stack emissions meet the air quality requirements.

FINAL

FAST START VS. CONVENTIONAL UNIT RAMP RATE ANALYSIS

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1204H

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

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1.0 Introduction

The purpose of this study is to evaluate the differences for conventional and fast ramping options between MECL and full load on unit startup for a 1x1 7HA.01 combined cycle. The GE 7HA.01 is one of several candidate H-Class combustion turbine offerings.

Since the temperature differential between components is the primary concern of fast ramping between MECL and full load; many of the design features required for fast ramping between MECL and full load are the same as the features required for fast start between combustion turbine ignition to MECL as discussed in the Fast Start vs. Conventional Start Analysis (File No. 400278.41.1203H). Figure 1-1 shows the regions covered under this study noted as Ramping and that covered in the Fast Start vs. Conventional Start Analysis noted as Startup.

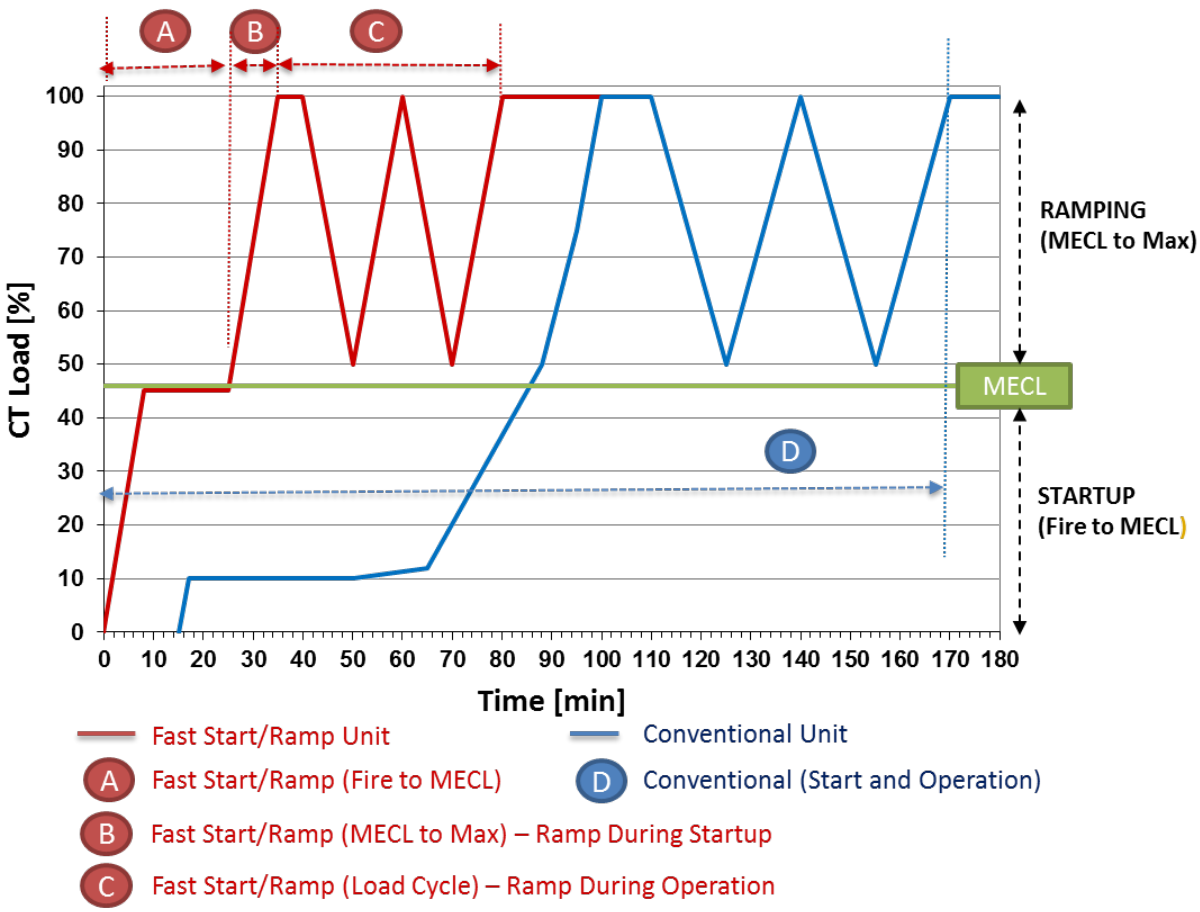

Figure 1-1 Comparison of Combustion Turbine Loading From MECL to Full Load

Table 1-1, Column B indicates the design features that would be required for fast ramping and how they differentiate from a conventional unit, Column D, and a fast start unit, Column A. Descriptions for each of the design features can be found in the Fast Start vs. Conventional Start

Analysis and also included in Appendix A. Items included in Column B also encompass those features in Column C which are required for fast ramping during operation.

Table 1-1 Design Features of Combined Cycles Designed for Various Operating Scenarios

FEATURES REQUIRED TO MEET OPERATING SCENARIO	A FAST START (FIRE TO MECL)	B FAST RAMP (MECL TO MAX)	C FAST RAMP (LOAD CYCLE)	D CONVENTIONAL (START AND OP)
Required Option = ●, Recommended Option = ☐, Standard Option = ◆				
Combustion Turbine				
Fast Start Equipped	●			
Natural Gas Purge Credits	●			☐
Service Life Monitoring System	◆	◆	◆	◆
Advanced Control System	●	●	●	
HRSG				
Advanced Drum Design	●	●		
Enhanced Nozzle Connections	●	●		
Improved HRSG Materials	●	●		
Improved HRSG Geometries	◆	◆	◆	◆
Service Life Monitoring System	☐	☐	☐	
Stack Damper and Insulation	●			☐
Terminal Attemperators	●	●	●	
LP Economizer Recirculation/Heat Exchanger	●	●		
Steam Turbine				
Optimized Casing Design	●	●		
Advanced Control System	●	●	●	
Service Life Monitoring System	●	●	☐	
Advanced Stop Valve Design	●			
Increased Thermal Clearances	●	●		
Advanced Turbine Water Induction Protection	●	●	●	
Emissions Control				
Feed-forward Ammonia Controls	●	●	●	

FEATURES REQUIRED TO MEET OPERATING SCENARIO	A FAST START (FIRE TO MECL)	B FAST RAMP (MECL TO MAX)	C FAST RAMP (LOAD CYCLE)	D CONVENTIONAL (START AND OP)
Auxiliary Steam				
Auxiliary Boiler	●			
Condenser and HRSG Sparging	●			
Feedwater System				
Larger Condensate Pump	●	●	●	
Larger Feedwater Pump	●	●	●	
Higher Stage IP Bleed	●	●	●	
Heat Rejection System				
Surface Condenser – Fast Start Design	●			
Fuel Gas System				
Supplementary Fuel Gas Heating(1)	☐			
Water Treatment System				
Condensate Polisher(2)	☐			
Auxiliary Electrical System				
Larger Equipment for Higher Loads	●	●	●	

Notes:

1. Supplementary fuel gas heating as required by combustion turbine supplier.
2. Space should be allotted for future condensate polisher installation, if required.

2.0 Capital Costs

Note that all of the features required for fast ramp are included in Column A of Table 1-1 discussed in the Fast Start vs. Conventional Start Analysis. The costs in Table 2-1 indicate only the costs for Column B of Table 1-1. Costs listed in the study are budgetary costs (+/- 30%).

Table 2-1 Fast Ramp (MECL to Full Load) Operating Scenario Costs

FAST RAMP SYSTEM COSTS FOR A 1X1 7HA.01 COMBINED CYCLE	
Fast Ramp Options (Required options in Column B excluding Stress Monitoring Systems)	[redacted]
Stress Monitoring Systems	[redacted]
Total*	[redacted]
NOTE: If a fast start plant is selected the above costs are not additive to those listed in the Fast Start Study.	

3.0 Performance Impacts

Startup and ramping durations are dependent on the ambient conditions, time after shutdown, initial steam turbine rotor temperatures, and the particular OEM equipment/features used in the power train in addition to any margins (if the required start-up times are to be guaranteed). There is a relatively wide range variation, however, for rough indicative values, Table 3-1 provides comparative durations for a GE 7HA.01 1x1 combined cycle. [redacted]

Table 3-1 Estimated Nominal Startup Times (Minutes)

START TYPE	CONVENTIONAL START TO MECL	CONVENTIONAL START TO STG FULL LOAD	FAST START TO MECL	FAST START, TO CTG BASELOAD	FAST START, TO CTG BASELOAD WITH STG LOADED
Hot Start = Shutdown 8 hours or less	Base Conv.	42	Base Fast	7.1	54
Warm Start = > 8 hours and < 48 hours	Base Conv.	34	Base Fast	26	52
Cold Start = Shutdown 48 hours or more	Base Conv.	67	Base Fast	67	103

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

For a conventional start, each combustion turbine is ramping at a nominal rate from MECL to combustion turbine baseload of 20.7 MW/min or 7.09%/min, while the combustion turbine ramp rate for fast start is 50 MW/min or about 17.1%/min from MECL to combustion turbine baseload.

After startup and after thermal soaking, the unit will able to achieve fast ramping. For a GE 7HA.01, each combustion turbine has the ability to ramp 50 MW/minute. For a 1x1 combined cycle, the ramp rate can be stated to be 50 MW/minute. The steam turbine contribution toward fast ramping is typically not quoted since the steam turbine response is much less predictable than the combustion turbine load response. This is due to a lag in HRSG steam production response due to the CTG load changes. Depending on how the combustion turbine is ramped up and down, the output contribution from the steam turbine would take some time to settle out into a steady state performance level. For conventional units, the combustion turbine ramp rates may be limited by the HRSG and steam turbine limitations. For units equipped with fast ramping, the steam conditions can be conditioned to allow the combustion turbine to ramp independently of the steam turbine.

4.0 Emissions

The period for ramping is defined as the period between minimum emissions compliance load and full load. Once the unit has obtained emission compliance, the unit generally stays in compliance for ramping conditions. During a fast ramp the outlet NO_X from the combustion turbine is variable. Conventional units only measure NO_X at the stack; this may lead to short durations of higher NO_X or ammonia slip. For fast ramping units limiting NO_X measurements to the stack only can lead to over injecting or under injecting ammonia. To address this, fast ramping units are equipped with feed-forward NO_X controls which take NO_X measurements at the combustion turbine exhaust as well as the stack to quicken the response to changing combustion turbine exhaust conditions. Both conventional and fast ramping units are designed to operate in compliance with stack emission limits across the averaging period.

Appendix A. Fast Start and Fast Ramp Design Features

Design features for fast start and fast ramping units are as follows:

A.1 COMBUSTION TURBINE

Combustion turbines designed for fast-ramping will be equipped with fast start features. These include positive isolation to ensure that purge credits have been maintained per NFPA 85 and that the gas path will not require a purge prior to startup. The control system for fast start of the plant should be fully automated to minimize times between sequential steps and allow for greater consistency during startup.

Both fast start and conventional units are equipped with service life monitoring systems that control unit ramp operations based on predetermined thermal stress limitations. Fast Start units are equipped with advanced control schemes incorporating model based controls (MBC) to optimize startup based on these monitoring systems.

Purge credits established during the shutdown must still be intact. NFPA 85 requires that a fresh air purge of the combustion turbine and HRSG be accomplished prior to start. NFPA 85 requires that at least five volume changes be completed or a minimum purge of 5 minutes prior to ignition. Typical purge durations can range from 5 to 20 minutes. The 2011 edition of NFPA 85 allowed for purge credits to be achieved when the unit is taken off line if the purge is completed and the valving arrangement is shown to positively isolate any fuel from entering the system. The combustion turbine can usually achieve the required purge when coasting down following a loss of ignition.

A.2 HRSG

HRSGs designed for fast-start plants can subject HRSG components such as superheaters and reheaters to rapid heating. Large thermal stresses can be produced by the differential expansion of the tubes within the HRSG. HRSG designs in such plants must be capable of accommodating the rapid change in temperature and flow of flue gas generated by load ramping of advanced class combustion turbines.

To reduce thermal capacity of drums many options are used to decrease the drum size and wall thickness including utilizing Benson style drums, utilizing multiple drums, high strength drum materials, reduced residence time. Self-reinforced nozzles, full penetration nozzles, full penetration welds, and steam sparger systems further improve the ability to accept rapidly changing exhaust gas conditions and steam conditions. Improved materials throughout the high pressure superheater and reheater can be required. Online, real-time monitoring system should be included to evaluate HRSG life consumption.

In order to reduce the thermal capacity of drums, the residence time may also be reduced for fast start units. Fast start units typically have drum storage time around two minutes. Conventional start plants have drum storage time from 3-5 minutes.

Fast start plants are equipped with a stack damper and with an insulated stack up to the stack damper. The stack damper and insulation are critical as they restrict the flow of flue gas out the HRSG stack minimizing heat loss when the unit is offline. While conventional units do not require stack dampers and insulation, it is a recommended practice to minimize heat loss when the unit is offline.

Both fast start and conventional units have improved HRSG geometries compared to those built a decade ago. Improvements in geometries have been to decrease thermal stresses from unit cycling and are part of the HRSG standard design such as coil flexibility to superheater/reheater interconnecting piping and accommodations for tube-to-tube temperature differentials.

A.3 STEAM TURBINE

The steam turbine must also be designed for the thermal gradients experienced while ramping during start-up. For fast start machines, the casing design must be optimized to reduce the thermal stress during temperature fluctuations and to accept faster start up and load change gradients. The use of higher grade material may be employed in the high pressure and intermediate casings and valves to reduce component thickness. Main steam stop valves must be designed so that these valves can be opened at a relatively higher pressure. Integral rotor stress monitors can be provided; the rotor stress monitor is typically capable of limiting or reducing the steam turbine load or speed increase and is designed to trip the turbine when the calculated rotor stresses exceed allowable limits.

For machines undergoing a fast ramp, attemperators are often required on the high pressure and hot reheat steam lines. Overspray on these attemperators can lead to water in these steam lines; special attention needs to be provided for turbine water induction prevention for units equipped with terminal attemperators.

A.4 EMISSIONS AND AMMONIA FEED

Outlet NO_X from the combustion turbine can vary highly when undergoing fast startup and fast ramp conditions. Conventional units only measure NO_X at the stack; for fast ramping units limiting NO_X measurements to the stack only can lead over injecting or under injecting ammonia. Higher ammonia slip and potentially greater SO2 conversion in fast-start and fast-ramp units create additional challenges for control of sulfur-bearing deposits in the colder HRSG areas. Low-pressure evaporators and economizers are particularly at risk. For fast ramping plants, addition of feed forward controls to quicken the saturation of the SCR catalyst (if included) is required. Also the HRSG should be equipped with LP economizer recirculation or heating systems to maintain surfaces above SO2 dew points.

A.5 AUXILIARY STEAM

Fast start units require an auxiliary boiler to produce steam prior to the startup of the unit. This steam is used for steam line warming, establish the steam turbine seals, warm up HRSG drums, and condenser sparging to enable uninhibited startup of the unit. The auxiliary boiler may also produce steam when the unit is off line to maintain drum and turbine temperatures.

Conventional units without an auxiliary boiler must use the combustion turbine and HRSG to produce steam to warm the unit and establish seals. During a conventional unit startup, holds are required to complete these warm up periods.

Provisions for fast start of the auxiliary boiler should also be considered which include equipping the auxiliary boiler mud drums with heating coils. Auxiliary boiler heat input, operating hour limits, and emission limits must also be considered.

Note that the auxiliary boiler makes up the majority of the cost to equip a combined cycle with fast start capabilities.

A.6 TERMINAL STEAM ATTEMPERATORS

Conventional start plants hold the combustion turbine load during startup as needed to meet the steam turbine startup steam temperature requirements. Fast-start plants decouple the CTG/HRSG startup from the steam turbine startup by using terminal attemperators at the HRSG outlet for meeting steam turbine startup steam temperature requirements, irrespective of CTG/HRSG load. This allows the steam turbine to come on line independently from the CTG and HRSG. As a result, the plant can increase load more quickly.

While the addition of terminal (final stage) steam attemperators on the main steam and hot reheat lines allow for temperature matching, they introduce the risk of two phase flow in the steam lines. An adequate run of straight piping downstream of the attemperators, adequate drainage, and robust instrumentation are a must to minimize the risk of condensate carry-over to the steam turbine. Additional controls should be considered to prevent turbine water induction.

A.7 FEEDWATER SYSTEM

For fast start plants equipped with terminal attemperators, additional condensate and feedwater pump flow is required to meet the attemperation demands. Inter-stage feedwater used for attemperation may be taken off at a later pump stage to meet the pressure demands of the attemperators which could impact feedwater piping wall thickness.

A.8 FUEL GAS SYSTEM

In order to reduce emissions and maintain flame stability, some manufacturers require supplementary fuel gas heating as a part of startup. This heating is in addition to any startup heater used to raise the fuel gas temperature above the dew point.

A.9 WATER TREATMENT SYSTEM

Maintaining water chemistry and meeting the water chemistry requirements of the HRSG and steam turbine are a critical part of startup. Blowdown and makeup systems should be sized accordingly to meet expected startup demands. Provisions for the inclusion of a future condensate polisher should be considered should problems arise. Condensate polishers ensure top quality feedwater.

A.10 AUTOMATED STARTUP SEQUENCE

Additional controls and automation are required for fast-ramp plants to ensure the matching of steam temperatures and to maintain emission compliance. As a result, more plant instrumentation is required in automated plants to allow the plant control system to monitor system status, minimize times between sequential steps and provide consistent startups.

Also fast-ramp plants should consider the use of service life monitoring systems such as thermal stress indicators on the HRSG and steam turbine. These systems allow control of the unit ramp operations based on predetermined thermal stress limitations.

FINAL

NUMBER OF COLD, WARM, AND HOT STARTS ANALYSIS

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1207H

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

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1.0 Introduction

Prior to the early 2000s, combined cycles were predominately designed for base load operation with high focus on highest full load efficiency and lowest capital cost. Due to increases in gas pricing, changing power market production cost structure, and renewable energy generation, many of these plants were forced into intermediate or even daily cycling mode. Many problems associated with the fast changing temperatures in the equipment resulted, such as high thermal stresses, high cyclic fatigue, vibration, flow accelerated corrosion, and water induction.

As a result of these industry issues, today's major equipment suppliers design their equipment to withstand the cumulative wear and damage caused by frequent starts and stops. For modern combined cycle equipment operating as high cycling units, major equipment manufacturers take the following into consideration:

- Base equipment designs consider high cycling
- Service life monitoring equipment is recommended for high cycling units
- Time between service intervals decreases with higher cycling

In addition to the number of starts, the time between the unit shutdown and start also has a significant impact on the equipment. When a unit is shutdown, equipment begins to cool. Upon the next start, the equipment would have to be brought back up to operating temperature putting the equipment through a thermal cycle. The duration between shutdown and startup is usually broken down between different start modes whether the equipment is considered hot, warm, or cold. Equipment manufacturers each have their own definition for hot, warm, and cold starts; however, typical start mode durations are listed in Table 1-1.

Table 1-1 Start Mode Definitions

START TYPE	SHUTDOWN DURATION
Hot	< 8 hours
Warm	8-48 hours
Cold	> 48 hours

1.1 BASE EQUIPMENT DESIGN

During startup and shutdown, the unit sees large temperature gradients and thermal stresses. Cycling increases concern for thermally induced creep-fatigue damage as a result of rapid heating of the surface of components such as turbine blades, rotors, casings, drums, and other heavy walled components. Creep-fatigue damage can also result from different thermal expansion between thin and thick components or dissimilar metal welds.

To resolve these issues, manufacturers have incorporated the knowledge of these earlier failures into their standard designs. Manufacturers select geometries, materials, thicknesses, and coatings in such a way as to limit the damage of thermal cycling. Geometries and material selection also alleviate other issues such as flow accelerated corrosion, vibration, and water induction. These designs do not alleviate all the issues with thermal factors but allow the equipment to be monitored in such a way to determine its service life.

1.2 MAINTENANCE INTERVALS

The design life for the facility is 30 years and the operating equipment will need regular maintenance including hot gas path and major inspections.**Error! Reference source not found.Error! Reference source not found.** Figure 1-1 shows the equivalent hours-based and starts-based maintenance intervals for GE and Siemens H-class combustion turbines and the potential impact of maintenance factors on maintenance intervals.

The timing of maintenance intervals are impacted by maintenance factors. Hours based maintenance factors consider fuel type, firing temperature, and water or steam injection used for emissions control or power augmentation. Starts based maintenance factors consider the type of start; whether it is a conventional start, fast start, cold start, warm start; load achieved during each start; and shutdown type such as normal cooldown, rapid cooldown or unit trip. The red lines in Figure 1-1 show how starts or hours based factors could affect the timing of maintenance intervals.

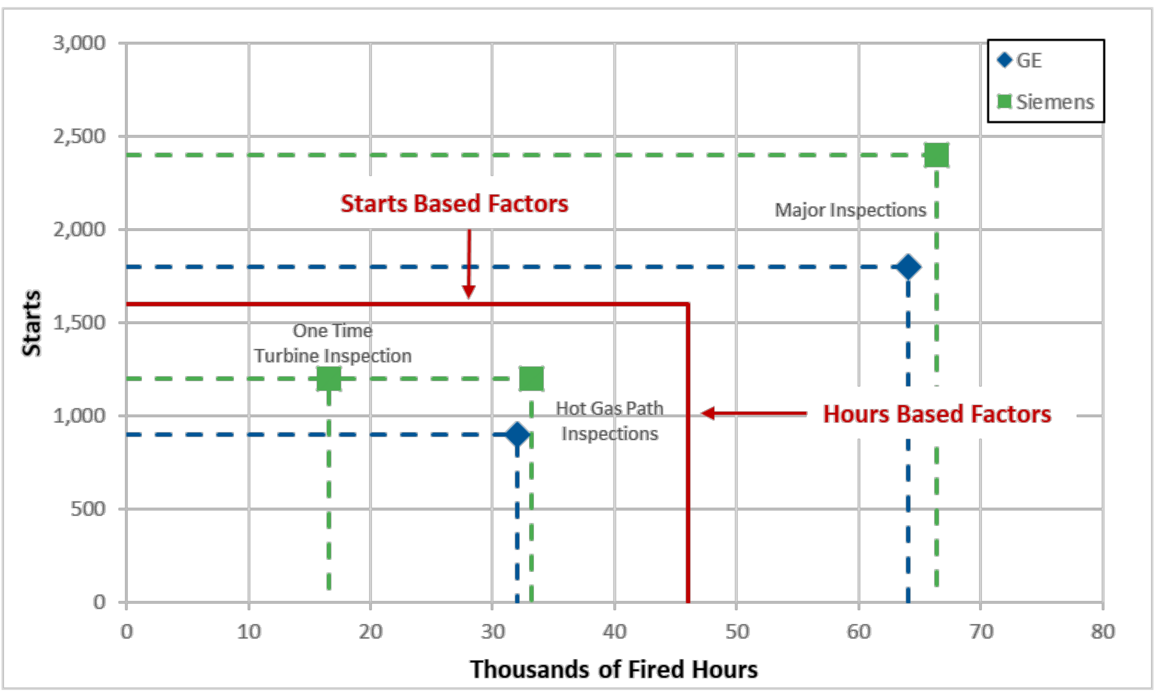

Figure 1-1 Maintenance Factors Reduce Maintenance Intervals

Per GE's Heavy-Duty Gas Turbine Operating and Maintenance Considerations (GER-3620N), a GE unit with a baseline maintenance factor would equate to 4,800 operating hours per year (16 hours/start, 6 starts/week, 50 weeks/year) and 300 starts per year. Those 300 starts would consist of 249 hot starts, 39 warm starts, and 12 cold starts. For the design life of 30 years, GE would base their Long Term Service Agreement (LTSA) on 5 maintenance cycles for a GE 7HA.01 with a baseline operating profile. The LTSA relates to the serviceable life of the combustion turbine.

Error! Reference source not found. Figure 1-2 shows how operating hours and the number of starts per year affect the duration of the LTSA. A 30 year life is based on roughly 300 equivalent starts per year. An operating regime requiring above about 300 equivalent starts per year would have service intervals based on equivalent life and start decreasing the life expectancy of the LTSA. For example, 450 equivalent starts per year would be roughly equivalent to a 20 year LTSA life. When operating below 300 equivalent starts per year the figure shows whether hours based operation or number of starts based operation would determine the maintenance intervals for the plant. Since the facility has a 30 year design life, 300 equivalent starts would be the average yearly allowable for the plant. Based on a design basis of 310 starts per year, the breakdown of calculated and recommended number of design basis cold, warm, and hot starts would be as shown in Table 1-2.

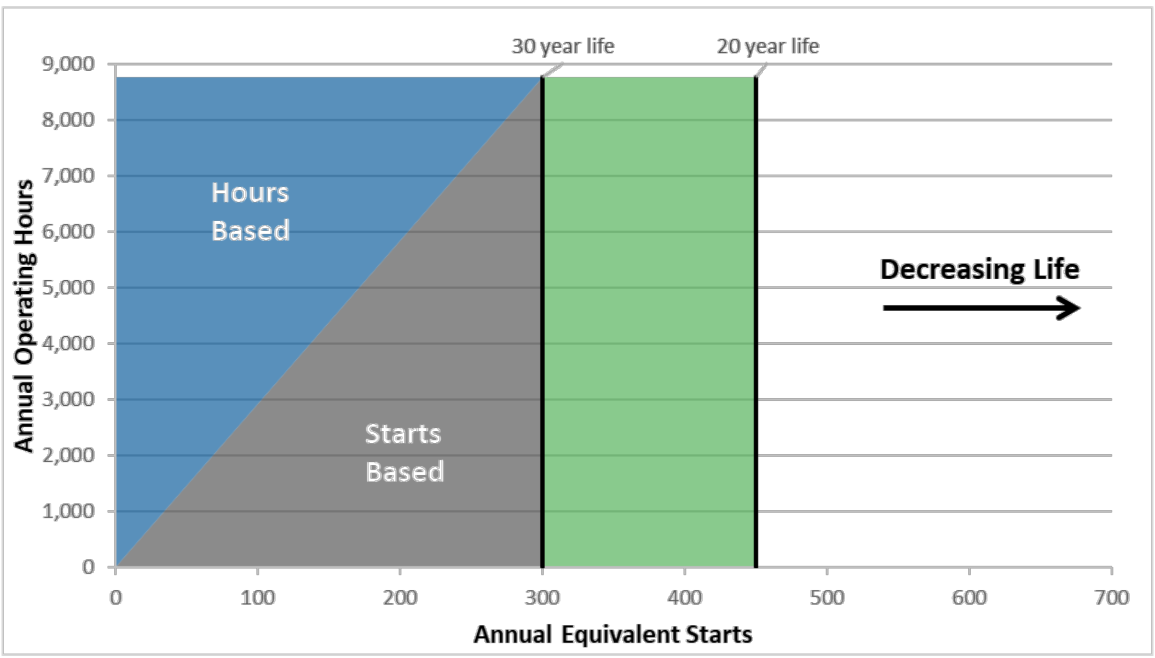

Figure 1-2 Combustion Turbine LTSA Term vs. Starts and Operating Hours Service Intervals

Table 1-2 Operating Conditions Used in Design Basis

OPERATING CONDITIONS	DESIGN BASIS
Operation	Daily Cycling
Yearly Operating Hours	Up to 8,760
Annual Capacity Factor	45% to 100%
Cold Starts Per Year	10
Warm Starts Per Year	100
Hot Starts Per Year	200
Total Starts Per Combustion Turbine	<310

1.3 SERVICE LIFE MONITORING EQUIPMENT

For plants operating in a regime where the starts based maintenance factors are determining the service intervals, it becomes useful to monitor the equipment to avoid costly outages. Service life monitoring systems perform three functions: instrumentation, evaluation, and determination. The instrumentation and sensor systems record the operating parameters such as localized temperature, pressure, and vibration. Based upon the readings, evaluations can be made such as stresses in critical locations in the turbines and the HRSG. The evaluated data is then combined with the operating history of the system to determine the impact on the remaining service life.

Recommended monitoring systems for high cycling plants include:

- Combustion Turbine Stress Controller
- Steam Turbine Stress Controller
- HRSG Stress Controller
- Condition Monitoring System
- Water Quality Monitoring System

Today's H-class combustion turbines come equipped with control systems that monitor speed, acceleration, temperature, and verify that all sensors are active. These sensors measure performance and monitor the machine's health. These systems also count the operating hours and number of equivalent starts or calculate the equivalent life of each start sequence in order to calculate the next service interval.

The steam turbine stress controller consists of a stress evaluation system that calculates and controls stresses in thick walled components including stop and control valves, HP casing and rotor body, and the IP rotor body. The stress controller monitors and controls ramp rates during start up to calculate the cumulative fatigue of cycling the unit. The stress controller also determines the remaining time to the next service interval.

The HRSG stress controller performs a dynamic analysis of the HRSG to determine fatigue. The stress controller determines risk factors based upon the evaluations, such as the probability of crack initiation. These risk factors are used to plan and indicate HRSG maintenance.

Condition monitoring systems measure critical asset parameters such as vibration, temperature, and speed of rotating equipment including boiler feed pumps, condensate pumps, circulating water pumps, cooling tower fans, and fuel gas compressors. The monitoring systems also evaluate trends, such as vibration amplification, and compare it against set points, historical readings, and known failure patterns.

The water quality monitoring system provides additional water and steam sampling to monitor issues with cycling units. Cycling units result in a large demand on the condenser and, in peak demands, on condensate supply and oxygen controls. Additional controls include online monitoring for condenser tube leaks and condenser air in leakage. It also includes monitoring steam blowdown lines for high level of particulates to indicate any safety issues. Water quality monitoring systems are not as important if the unit includes a condensate polisher.

2.0 Service Life Monitoring System Costs

As outlined in Section 1.2, service life monitoring systems are recommended for high cycling plants to help predict and plan maintenance. Table 2-1 provides budgetary cost (+/- 30%) for service life monitoring systems.

Table 2-1 Service Life Monitoring System Costs

SERVICE LIFE MONITORING SYSTEM COSTS	
Combustion Turbine Stress Controller	[redacted]
Steam Turbine Stress Controller	[redacted]
HRSG Stress Controller	[redacted]
BOP Condition Monitoring System	[redacted]
Water Quality Monitoring System	[redacted]
Additional cable and I/O	[redacted]
Total	[redacted]

3.0 Conclusion

Today's combined cycle equipment is designed for high cycling applications and consider problems associated with the fast changing temperatures in the equipment such as high thermal stresses, high cyclic fatigue, vibration, flow accelerated corrosion, and water induction. The design life of the equipment is 30 years with major overhauls of the combustion turbines occurring every 6 years. The time duration between major overhauls is based upon maintenance factors associated with hours of operation and the number of starts.

While the number of operating hours is not expected to shorten the time between maintenance cycles, the number of starts could decrease the operational life. In order to maintain the 6 years between major overhauls, the combustion turbine should have an equivalent number of annual starts less than 310. To avoid decreasing the life of the LTSA, the typical combined cycle design including balance of plant equipment should not exceed 310 starts per year. The breakdown of the recommended number of design cold, warm, and hot starts would be as shown in Table 3-1.

Table 3-1 Design Cold, Warm, and Hot Starts

OPERATING CONDITIONS	
Operation	[redacted]
Yearly Operating Hours	[redacted]
Annual Capacity Factor	[redacted]
Cold Starts Per Year	[redacted]
Warm Starts Per Year	[redacted]
Hot Starts Per Year	[redacted]
Total Starts Per Combustion Turbine	[redacted]

If the plant is expected to be a high cycling unit with a maintenance cycle that would be determined based upon the number of starts rather than the number of hours operated per year, Vectren should consider additional service life monitoring systems to assist in predictive maintenance, as shown in Table 3-2. While these systems do not prevent maintenance, they allow the operator to better understand how the operation of the unit is impacting the service life of the equipment.

Table 3-2 Service Life Monitoring Systems

SERVICE LIFE MONITORING SYSTEM COSTS	
Combustion Turbine Stress Controller	[redacted]
Steam Turbine Stress Controller	[redacted]
HRSG Stress Controller	[redacted]
BOP Condition Monitoring System	[redacted]
Water Quality Monitoring System (not required with a condensate polishing system)	[redacted]
Additional cable and I/O	[redacted]
Total	[redacted]

FINAL

AUXILIARY BOILER ANALYSIS

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1209H

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

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Executive Summary

In developing this report, Black & Veatch reviewed the requirements for the auxiliary steam system for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed multiple pre-start, start-up and shutdown scenarios to determine the required sizing and operation of the auxiliary steam boiler.

The auxiliary steam system users have been summarized in the Auxiliary Steam Demands provided in Table 2-1. The users were estimated based on previous projects using the 7HA.01 gas turbines. Based on the maximum co-incident steam demand of the 7HA.01 configuration it is recommended that Vectren utilize an auxiliary boiler designed for [redacted] lb/hr and an outlet pressure of [redacted].

1.0 Introduction

The purpose of this study is to determine the specific requirements for the Auxiliary boiler to be installed with the new Combined Cycle Power Plant (CCPP). These Fast start units require an auxiliary boiler to produce steam prior to the startup of the unit. This auxiliary steam is used for steam line warming, establish the steam turbine seals, warm up HRSG drums, and condenser sparging to enable quicker startup of the unit. The auxiliary boiler may also produce steam when the unit is off line to maintain drum and turbine temperatures. Black & Veatch has previously performed the “Fast Start vs Conventional Start Analysis” which demonstrates the need for an auxiliary boiler for a unit with fast start capability.

This evaluation will help determine the design impact of this system to the new CCPP design. Auxiliary system users, auxiliary boiler sizing and operation will also be identified and discussed.

2.0 Auxiliary Boiler Sizing and Outlet Pressure

The auxiliary steam system provides steam to various users during plant startup and shutdown at multiple operating conditions. Several operating scenarios were evaluated to determine the best preliminary design basis for sizing the auxiliary boiler. Upon selection of the final plant design, the selected size of auxiliary boiler should be reviewed.

2.1 COINCIDENT STEAM DEMANDS

The maximum co-incident auxiliary boiler steam demand occurs during startup when supplying maximum steam turbine sealing, fuel heating, maximum condenser sparing steam, and maximum combustion turbine inlet air heating as shown in Table 2-1.

Table 2-1 Coincident Auxiliary Steam Demands

AUXILIARY STEAM USERS	1X1 HA.01
ST Gland Sealing	[redacted]
Startup Steam to Fuel Gas Heater	[redacted]
Condenser Hotwell Sparging	[redacted]
Combustion Turbine Inlet Air Heating	[redacted]
Total Coincident Boiler Steam Flow Required	[redacted]

2.2 NON-COINCIDENT STEAM DEMANDS

During unit pre-start, there are two activities that require auxiliary steam flow, but are not co-incident with the other users. These non-coincident activities occur during HRSG pre-warming and HRSG HP pressure holding. The non-coincident auxiliary steam demands are listed in Table 2-2.

Table 2-2 Non-Coincident Auxiliary Steam Demands During Pre-Start Activities

AUXILIARY STEAM USERS	1X1 7HA.01
HRSG Warming	[redacted]
HRSG Pressure Holding	[redacted]

2.3 DESCRIPTION OF USERS

- The turbine seals require steam from the auxiliary system to provide sealing until the steam turbine increases load and becomes self-sealing. When the steam turbine exceeds the point of self-sealing, the flow from the auxiliary system will decrease to near zero.
- A startup steam to fuel gas heater is used to raise the fuel gas to the CT manufacturers specified minimum fuel temperature via a steam to water heat exchanger.
- Condenser hotwell sparging is used to heat the condensate in the condenser to normal operating temperatures prior to starting the units.
- The gas turbine inlet air heating system uses auxiliary steam to provide heat via coils in the CT inlet air structure to minimize the possibility for ice formation in the CT compressor section.
- The HRSG HP warming flow increases the metal temperature of the steam drums and the tubes, allowing for faster startup capability.
- The HRSG HP pressure holding maintains the HP evaporator at a minimum of 275 psig to maintain drum and tube temperatures for faster startup capability.

2.4 BOILER OUTLET CONDITIONS

The delivery steam pressure of the auxiliary boiler is typically 300 psig at saturation temperature to facilitate HP evaporator pressure holding of approximately 275 psig. Electric superheaters will be used to provide superheated steam to the turbine seals. Delivering saturated steam will reduce the heat input to the auxiliary boiler which is limited due to air permits.

3.0 Auxiliary Boiler Operation

3.1 PRE-START CONDITION

The auxiliary steam system should be pressurized, heated and drained up to the steam seal feed valve during pre-start activities. The operating conditions of the auxiliary boiler and system must be verified prior to initiating a unit startup. During cold pre-start activities, the steam for turbine sealing, condenser sparging steam and HP evaporator warming is supplied by the auxiliary boiler. During hot start activities, the steam demand for the HP evaporator warming steam is replaced by the steam demand for HP evaporator pressure holding. Following an HRSG outage or cold restart, the HRSG HP warming flow is set to a maximum flowrate to accelerate warming.

3.2 INITIAL STARTUP AND SHUTDOWN

During initial startup the auxiliary steam for the turbine sealing, CT air inlet heating, fuel gas heating and condenser sparging is provided from an auxiliary boiler. As the plant cycle steam from the HRSG IP drum becomes available it allows the auxiliary boiler to be shut down or unloaded to idle as plant operations allow. During normal operation the HRSG IP drum provides all required auxiliary steam flow for the plant.

During plant shutdown or trip, it is expected that there is enough residual energy in the HRSG to provide auxiliary steam until the steam turbine exhaust vacuum is broken or the auxiliary boiler can be brought online to provide sealing steam. The auxiliary boiler must remain in a ready condition at all times during combined cycle operation. During overnight plant shutdowns the aux boiler can remain in operation to provide sealing steam, condenser sparging steam and allow rapid starting in the morning.

4.0 Conclusions

The purpose of this evaluation was to determine the specific requirements for the auxiliary boiler for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed pre-start, start-up and shut down scenarios to determine the required sizing and operation of the auxiliary boiler.

This report has shown:

- Auxiliary steam users and the estimated demand.
- Non-coincident auxiliary steam users and the estimated demand
- Black & Veatch's recommendation for steam requirements listed in Table 2-1 for various plant configurations.

FINAL

EXISTING FIRE WATER SYSTEM REVIEW

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 42.1212H

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

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Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch reviewed the piping and instrumentation diagrams (P&IDs) for the existing fire protection and service water systems.

The existing system includes existing pumps and a 75,000 gallon raw water storage tank. The raw water storage tank is sized to provide 51,000 gallons of surge capacity devoted to fire water use. To meet the new fire water system design requirements, a third diesel motor fire pump should be added to the system and the pump arrangement modified to a 3x50 percent configuration with two pumps driven by a diesel motor and the other driven by an electric motor. This configuration allows for a fire water demand up to 3,000 gpm. The existing pressure maintenance pump, which is rated for approximately 1 percent for the main pumps flow and same discharge pressure, should remain.

1.0 Existing Equipment

Based on the existing site Fire Protection and Service Water Systems P&ID (F-1024) there are 2x100 percent fire pumps (one electric driven and one diesel driven) that are rated for 1,500 gpm @ 300 FT TDH each. The fire water pumps normally take suction from existing Ranney Well pumps of adequate capacity and the Raw Water Storage Tank (75,000 gallons) via a 12" nominal diameter suction header. The fire protection water supply system is also cross tied to the River Water pumps. The Raw Water Storage Tank is sized to provide 51,000 gallons of surge capacity devoted to fire water use. The existing site has a 10" underground fire water loop. This pipe is assumed to be ductile iron.

Per NFPA 850, the existing water source is large enough to be considered a reliable water source. The multiple pumps installed provide reliability such that a single failure or maintenance event will not impair the ability of the system to responds to a fire event. If a single pump were to be out of service, the remaining pumps will still have sufficient capacity to supply water to the existing water users as well as the maximum fire water demand of 2,500 gpm.

2.0 Design Basis and Clarifications

- A search of the NFPA codes on the Indiana State website did not include NFPA 850. However, for the purposes of this assessment and the design of the new power plant, Black & Veatch has referenced NFPA 850 – 2015.
- There is a discrepancy between some of the code years referenced on the Indiana State website and from the IBC or IFC. Our basis is the most current version when this occurs.
- It is not clear from the P&ID what the material used for the existing underground fire water supply mains. Our basis is currently ductile iron material; please clarify if different.
- Please clarify who the Authority Having Jurisdiction (AHJ) is for the A.B. Brown Site. We have identified the state fire marshal below.

  Indiana State Fire Marshal
  Stephen Cox
  317-232-2222
  http://www.in.gov/dhs/2445.htm

3.0 New Plant Fire Protection Requirements

The new plant's required fire water system supply flow is based on a worst case fire scenario, plus a hose allowance (500 gpm), and any adjacent systems in the immediate area of a potential fire area; as defined in NFPA 850, Section 6.2. The largest system demand is expected to be the Steam Turbine Building/Enclosure at 1,800 gpm in combination with the turbine generator bearings closed head sprinkler system with directional nozzles with a demand of approximately 200 gpm. This total demand will require a main fire pump rated at 2,500 gpm. The velocity limits at this flow require either a 10" DI or 12" HDPE DR 11 pipe.

To meet the new fire water system design requirements a third diesel motor fire pump (1,500 gpm @ 300ft) should be added to the system modifying the pump arrangement to 3x50 percent configuration with two pumps driven by a diesel motor and the other driven by an electric motor. This configuration allows for a fire water demand up to 3,000 gpm. The existing pressure maintenance pump which is rated for approximately 1 percent for the main pumps flow and same discharge pressure should remain. There are no elevated areas for the new or existing plant areas that require booster pumps to obtain adequate pressure for hose stations so a standard pressure rating of 300 ft-H2O at the rated point is expected to be sufficient.

Per NFPA 850 the multiple Ranney Well pumps installed will provide a reliable source of water such that a single failure or maintenance event will not impair the ability of the system to responds to a fire event. In a single pump out of service case the two remaining Ranney Well pumps can provide up to 4,000 gpm. The preliminary water mass balance for other uses states the normal use from non-fire protection demands is approximately 150 gpm. This allows the fire water demand of 2,500 gpm to be met along with the other non-fire protection water users.

The existing 10" fire protection underground system can be reused with new 12" HDPE used for any new underground headers and around the cooling tower. Hydrants will be located as per NFPA 850 and the local code requirements.

4.0 List of Applicable Codes and Standards

675 IAC 13-2.6	Indiana Building Code, 2014 Edition (IBC, 2012 Edition, 1st printing) ANSI A117.1-2009	Effective 12/1/14
675 IAC 22-2.5	Indiana Fire Code, 2014 Edition (IFC 2012 Edition, 1st printing)	Effective 12/1/14

NFPA Standards

NFPA #	Description	Effective Date	IAC Cite
10-2010	Portable Fire Extinguishers	December 15, 2012	675 IAC 28-1-2
11-2005	Low Expansion Foam and Combined Systems	September 22, 2006	675 IAC 28-1-3
12-2005	Carbon Dioxide Extinguishing Systems	September 22, 2006	675 IAC 28-1-4
13-2010	Installation of Sprinkler Systems	September 26, 2012	675 IAC 28-1-5
14-2000	Installation of Standpipe and Hose Systems	December 13, 2001	675 IAC 13-1-9 Repealed 3/21/14
15-2001	Water Spray Fixed Systems	September 22, 2006	675 IAC 28-1-8
20-1999	Installation of Centrifugal Fire Pumps	December 13, 2001 Amended 12/26/02	675 IAC 13-1-10
25-2011	Inspection, Testing and Maintenance of Water Based Fire Protection Systems	May 12, 2013	675 IAC 28-1-12
37-2002	Installation and Use of Stationary Combustion Engines and Gas Turbines	September 22, 2006	675 IAC 28-1-15
70-2008	National Electrical Code	August 26, 2009	675 IAC 17-1.8
72-2010	National Fire Alarm Code	March 23, 2014	675 IAC 28-1-28
2001-2004	Clean Agent Fire Extinguishing Systems	September 22, 2006	675 IAC 28-1-40

5.0 Conclusions

The purpose of this evaluation was to review the existing fire water system. Black & Veatch reviewed P&IDs for both the existing fire protection and service water systems.

This report has shown:

- The raw water storage tank is sized to provide 51,000 gallons of surge capacity devoted to fire water use.
- The existing pressure maintenance pump is sufficient.
- The existing 10 inch fire protection underground system can be reused with new 12 inch HDPE used for any new underground headers and around the cooling tower.
- Black & Veatch's recommendation is to add a third diesel motor fire pump and modify the pump arrangement to a 3x50 percent configuration.

FINAL

NOISE REGULATION REVIEW

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1213H

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

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Executive Summary

Black & Veatch reviewed the noise regulations that might apply to the new Combined Cycle Power Plant (CCPP).

Indiana, Posey County, and Marrs Township have no far field noise regulation or ordinances. Far field noise requirements are generally referenced to the site boundary, property line, or other boundary limit. Occupational Safety and Health Administration (OSHA) standards will apply to near field noise emissions. Near field noise requirements are measured along the equipment envelope. During off-normal and intermittent operation such as startup, shutdown, and upset conditions, the equipment sound pressure level shall not exceed a maximum of 115 dBA at all locations along the equipment envelope, including platform areas, that are normally accessible by personnel.

Near field noise mitigation requirements will be required of equipment. Since there were no extant noise regulations specific to this site, no far field noise mitigation is required.

1.0 Results of Noise Regulation Review

Noise requirements fall into two categories: far field or near field. These categories are based upon the distance from the emitter to the receptor. Far field noise requirements are generally referenced to the site boundary, property line, or other boundary limit. Near field noise requirements are measured along the equipment envelope. The envelope is defined as the perimeter line that completely encompasses the equipment package a distance of 3 feet from the face of the equipment.

1.1 FAR FIELD NOISE REQUIREMENTS

There are no extant noise regulations or ordinances for Indiana, Posey County, or Marrs Township. The expectation would be that the general environmental sound levels in the surrounding area would not be substantially different from the sound levels with the two coal units in operation, assuming the coal units will be decommissioned after the new unit is operational.

1.2 NEAR FIELD NOISE REQUIREMENTS

Near field noise requirements are limited by OSHA requirements. The near-field noise emissions for each equipment component furnished under these specifications shall not exceed a spatially-averaged free-field A-weighted sound pressure level of 85 dBA (referenced to 20 micropascals) measured along the equipment envelope at a height of 5 feet above floor/ground level and any personnel platform during normal operation.

During off-normal and intermittent operation such as start-up, shut-down, and upset conditions the equipment sound pressure level shall not exceed a maximum of 115 dBA at all locations along the equipment envelope, including platform areas, that are normally accessible by personnel.

2.0 Conclusions

Near field noise mitigation requirements will be required of equipment. Since there were no extant noise regulations specific to this site, no far field noise mitigation is required.

The attached V100 supplemental, contains the noise abatement requirements to be included with the procurement specifications. Since there were no extant noise regulations specific to this site, the V100 supplemental was developed using the near field requirements which are the typical OSHA limits.

FINAL

CONDENSATE POLISHER EVALUATION SUMMARY

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1214H

PREPARED FOR

Vectren

31 JANUARY 2020

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Executive Summary

This report provides a summary of Black & Veatch's evaluation of including a condensate polisher system in the conceptual design of the new A.B. Brown Combined Cycle. This summary of the evaluation will show that:

- Five selection criteria for Pre-Coat Condensate Polishers are present in the conceptual design. General industry practice to consider polishing is three or more.

PRE-COAT POLISHER CRITERIA	A.B. BROWN COMBINED CYCLE PLANT
Steam Cation Conductivity ≤0.2uS/cm	**Yes – 0.2uS/cm Allowed***
Graywater Cooling	No – River Water
Air Cooled Condenser	No – Wet Surface Condenser
All-Volatile Treatment – Oxidizing Treatment (AVT-O) Cycle Chemistry	**Yes – All-Volatile Treatment-Oxidizing with Phosphate (no oxygen scavenger)**
HP/Main Stream Pressure >2,400 psig	**Yes – HP/Main Steam >2,500 psig**
Cycling with Short Start-up Time	**Yes – Cycling Units with Rapid start**
LP Steam Conductivity Limit?	No
Suspended Solids (TSS) process contamination possible?	**Yes – River water contains levels of TSS**
* GE Steam Purity for Industrial Turbine (Table 4 in document GEK 98965)	

[redacted]

PARAMETERS	1X1 7HA.01 (FIRED)
Condensate Design Flow, gpm	[redacted]
Estimated Equipment Costs ($450 per gpm)	[redacted]
Total Installed Capital Cost (Equipment Costs + $2.52M installation)	[redacted]

Based on the selection criteria identified in the summary report, Black & Veatch's recommendation is to include provisions for a future pre-coat type condensate polisher system in the conceptual design for the project. This includes, but not necessarily limited to, [redacted] allowance in condensate pump sizing, space allocation, spare electrical capacity and connections, and condensate discharge by pass piping connections.

1.0 Introduction

1.1 GENERAL FACILITY OVERVIEW

Vectren (Company) is planning the construction of a combined cycle plant at its existing A.B. Brown Station (ABB) in Evansville, Indiana. This combined cycle configuration will utilize heat recovery steam generators (HRSG), combustion turbine generators and a single steam turbine generator to output 1,050 MW.

Condensate polishing is the process of purifying condensate before returning it to a boiler. Feedwater (condensate and boiler feed) contain various impurities. Corrosion products from the steam cycle, mostly iron, travel through the cycle and can concentrate in the boiler. Impurities in feedwater can affect HRSG performance and can be transported from the HRSG to the steam turbine, causing damage to piping and turbine components from pitting, corrosion, or scaling. They can inhibit heat transfer, cause hot spots and eventual failure of the boiler tubes. Additionally, they can carryover with the steam and degrade the steam purity to the level that it no longer meets the steam turbine suppliers steam purity guarantee requirements.

The water quality required for feedwater is defined by the HRSG manufacturers and is dependent on the unit cycling, chemistry program, and operating pressure of the plant. High pressure (1500 psi or greater) drum boilers have stringent feed water quality requirements in order to meet the steam turbine suppliers steam purity guarantee. Drum boilers meet theses water quality requirements by blowdown to eliminate impurities from the cycle and making up with fresh demineralized water. Condensate polishing provides a means to minimize blowdown and better ensure boiler water quality requirements.

In addition to improving condensate/feed water quality, condensate polishers can decrease unit startup time by minimizing chemistry related delays, minimize impacts of condenser leaks, and reduce frequency of boiler chemical cleaning. Consequently, condensate polishers are a worthy consideration in most high pressure steam cycle units, especially cycling units designed with rapid start.

1.2 EVALUATION OBJECTIVE

The purpose of this study is to:

- Identify the selection criteria for condensate polishing and determine if/which criterion is applicable to the project.
- Evaluate the capital costs associated with condensate polishing.

The following evaluation reports should be viewed in conjunction with this document:

- 41.1207H – Number of Cold, Warm and Hot Starts Analysis
- 41.1203H – Fast Start vs. Conventional Start Analysis
- 41.1217H – Demin Water Analysis Evaluation.

2.0 Condensate Polishing

2.1 SELECTION CRITERIA

Figure 1 below is a flow chart used to confirm whether or not condensate polishing is necessary in the power plant design basis. The primary and secondary factors shown in Figure 1 are used to identify, if necessary, which type of condensate polisher is to be used based on the parameters of the unit; Deep Bed type or Pre-coat type polishers.

Figure 1 –Condensate Polisher Selection Flow Chart

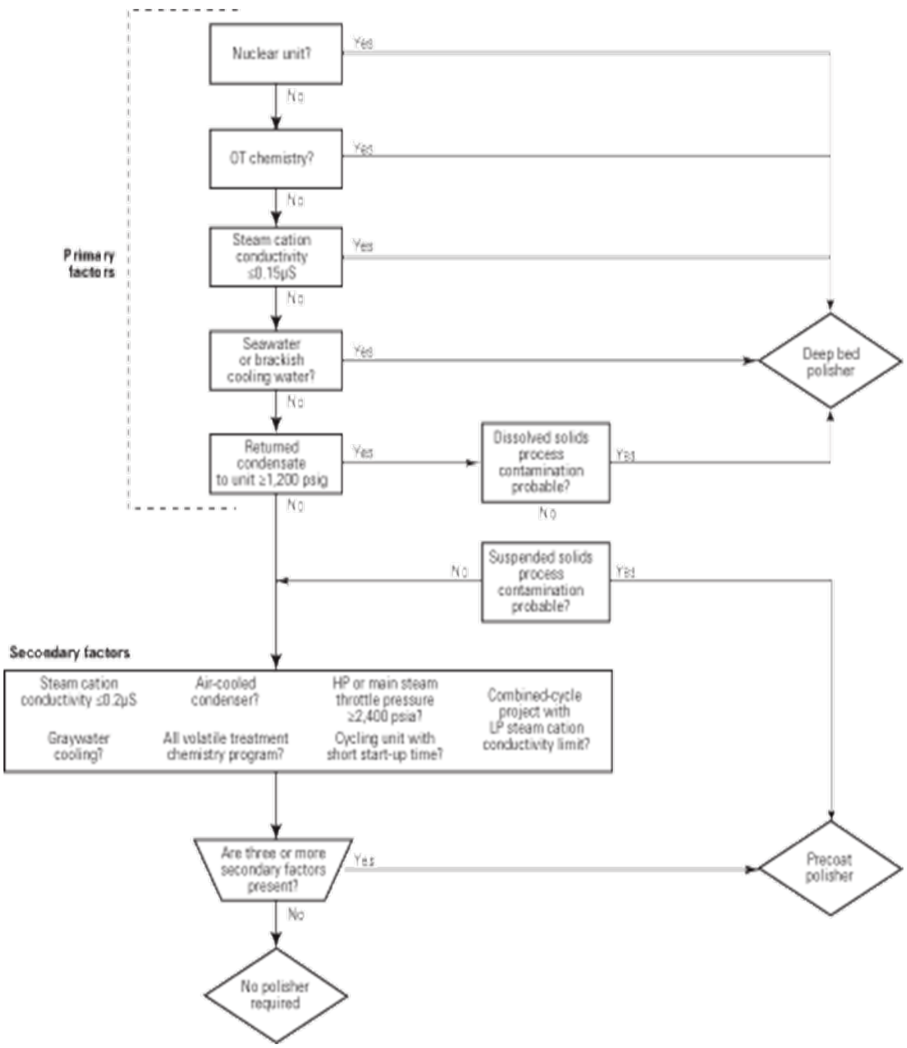


Table 1 reviews the criteria for deep bed type polishers listed and indicates if these factors apply to the project. If one or more of the selection criteria, or factors, apply to ABB, then deep bed condensate polishing should be considered.

Table 1 – Deep Bed Condensate Polisher Selection Criteria

DEEP BED POLISHER CRITERIA	A.B. BROWN COMBINED CYCLE PLANT
Nuclear Plant	No – Fossil Fuel
Oxygenated Treatment (OT) Cycle Chemistry	No – All-Volatile Treatment-Oxidizing with Phosphate
Steam Cation Conductivity <0.15uS/cm	No – 0.2uS/cm Allowed*
Seawater or Brackish Cooling Water	No – Surface Water, Well Water
Returned Condensate to unit >1200 psig	No - 400 psig
* GE Steam Purity for Industrial Turbine (Table 4 in document GEK 98965)	

Based on the design parameters of the plant as shown in Table 1, deep bed condensate polishing would not be considered.

Table 2 reviews the criteria for pre-coat type polishers listed and indicates if these factors apply to the project. General industry practice is if three or more factors apply to ABB, pre-coat polishers should be strongly considered.

Table 2 – Pre-Coat Condensate Polisher Selection Criteria

PRE-COAT POLISHER CRITERIA	A.B. BROWN COMBINED CYCLE PLANT
Steam Cation Conductivity ≤0.2uS/cm	Yes – 0.2uS/cm Allowed*
Graywater Cooling	No – River Water
Air Cooled Condenser	No – Wet Surface Condenser
All-Volatile Treatment – Oxidizing Treatment (AVT-O) Cycle Chemistry	Yes – All-Volatile Treatment-Oxidizing with Phosphate (no oxygen scavenger)
HP/Main Stream Pressure >2,400 psig	Yes – HP/Main Steam >2,500 psig
Cycling with Short Start-up Time	Yes – Cycling Units with Rapid start
LP Steam Conductivity Limit	No
Suspended Solids (TSS) Process Contamination Possible	Yes – River water contains levels of TSS
* GE Steam Purity for Industrial Turbine (Table 4 in document GEK 98965)	

As shown in Table 2, five factors are present in the current design of the project. As a result, pre-coat polishers or design provisions to include future polishers should be considered. The next sections review the benefits of the pre-coat polisher design.

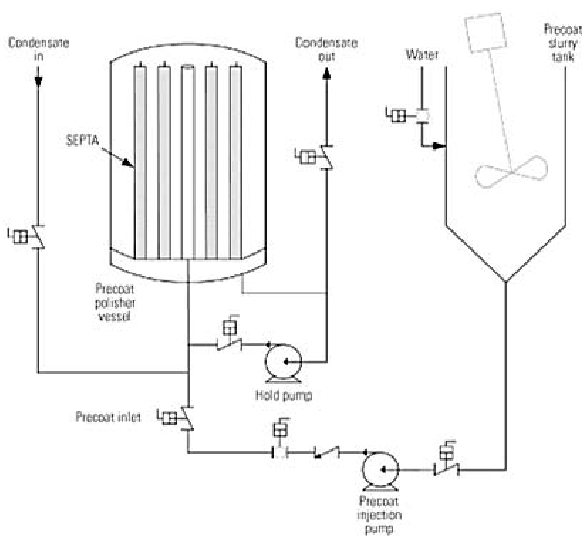
2.2 PRE-COAT TYPE CONDENSATE POLISHING

2.2.1 Overview

Pre-coat polisher is a vessel containing media-retaining filter elements. A powdered media is placed on the elements and the condensate is passed through the media coated filter element and returned to the condensate flow. Figure 2 shows a diagram of a Pre-coat polisher system.

These filter elements, combined with the ion exchanging media (powder coating), has the capability of simultaneous removal of total dissolved solids (TDS) and total suspended solids (TSS). Pre-coat polishers in particular, perform the dual purpose of straining the TSS particulates (iron oxides produced in the condensate system) and removing dissolved solids. Air in-leakage causes corrosion from oxygen pitting and to a lesser degree acidic attack from CO2. Not only does the oxygen damage the carbon steel surfaces but the iron oxides from this corrosion process, both soluble (TDS) and insoluble (TSS), will be transported into the heat recovery steam generator (HRSG) and will deposit on tube surfaces. Over time these deposits reduce unit efficiency, create an environment for under deposit corrosion (boiler tube failures) and necessitate the need for more frequent chemical cleanings.

Figure 2 – Pre-Coat Polisher Diagram



The condensate polisher improves condensate/feed water quality during steady state operations by minimizing the impacts of condenser leaks by the removal of dissolved solids and improves unit startup time by minimizing chemistry related delays by the removal of suspended solids.

2.2.2 Operational Impacts

Dissolved gases can enter the cycle as impurities in the makeup water as well as through air in-leakage to the condenser which is under vacuum. Dissolved gases, particularly uncontrolled oxygen and carbon dioxide, can cause corrosion in the cycle and are generally removed in the condenser and deaerator. However, carbon dioxide can accumulate in the condensate/feed water/boiler train because of its pH equilibrium chemistry and can only be effectively removed with condensate polishing. Particularly during startup and shutdown the condensate/feedwater cycle can and will be exposed to carbon dioxide and oxygen. Their corrosive effects on the carbon steel condensate/feedwater piping can be mitigated with the proper chemistry and blowdown over time, but a polishing unit greatly improves the amount of time necessary to reach optimal cycle chemistry.

If left untreated or detected, these impacts will lead to any number of issues including boiler tube failures, damage to the steam turbine and condenser tube failures.

A condensate polisher is warranted for combined-cycle plants where the steam turbine cation conductivity limit is $\leq$ 0.2 μS/cm, and especially cycling units designed with rapid start. The cation conductivity of the condensate/feedwater stream can typically reach 0.5 to 0.6 μS/cm due to carbon dioxide absorption in the water. The GE steam turbine cation conductivity requirement for A.B. Brown is <0.2 μS/cm.

Without a condensate polisher, and in the event of a major feedwater chemistry excursion, typically a plant will either dump the “out-of-spec” water and re-fill the system with “in-spec” water or operate the feedwater system without generating steam until the boiler feedwater chemical treatment system brings the water back into spec. Worst case scenario for ABB is dumping the approximate +100,000 gallons of water from the cycle (one HRSG’s and condenser).

Utilizing condensate polishing can reduce the average cycle blowdown during both startup and normal operation to approximately 0.5%-1%. For the ABB project, this blowdown reduction can save up to 1,000,000 gallons of demineralized water each year. This is based on the estimated number of starts per year and capacity factor found in 41.1207F – Number of Cold, Warm and Hot Starts Analysis. Condensate polishing can also potentially reduce the number of boiler chemical cleans over the 30 year expected life of the plant.

3.0 Risk AND Cost Analysis

3.1 RISK ANALYSIS

As stated in Section 3.0, there are several risks associated with operating a combined cycle plant with three or more of the selection factors present in the design. The risk of operating with poor steam/water quality can lead to boiler tube failures, condenser tube failures, and damage to the steam turbine. Table 3 below provides a high level risk analysis of not utilizing a condensate polisher unit.

Table 3 – Risk Analysis Without Condensate Polishing

RISK	SEVERITY	OCCURANCE	DETECTION	LENGTH OF OUTAGE	OVERALL RISK FACTOR
Boiler Tube Failure	High	Medium	High	Medium	High
Steam Turbine Damage	High	Low	Low	High	Medium
Condenser Tube Failure	Medium	Medium	Medium	Medium	Medium
Overall risk factors are indications of estimated number of failure occurrences per year: High = 1 occurrences/yr; Medium = 0.33 occurrences/yr; Low = 0.11 occurrences/yr					

The overall risk factor provides an indication of estimated number of failure occurrences per year. A high overall risk will generally indicate one occurrence per year, while the occurrences per year drop to 33 percent and 11 percent for medium and low factors, respectively.

Utilizing a condensate polisher and a good chemical conditioning program can potentially drop the overall risk factor to the next lower tier for each type of failure.

3.2 COST ANALYSIS

A budgetary cost for a full 2x100% pre-coat condensate polishing system (with pre-coating skid, slurry pumps, air receiver, and resin/precoat recovery tank) is approximately [redacted]. An estimated [redacted] for installation, project management, and risk and contingency is used to determine the total installed cost.

Table 4 – Cost Evaluation - Condensate Polishing

PARAMETERS	1X1 7HA.01 (FIRED)
Condensate Design Flow, gpm	[redacted]
Estimated Equipment Costs [redacted]	[redacted]
Total Installed Capital Cost [redacted]	[redacted]

A temporary/mobile rental condensate polisher could be considered. [redacted]

4.0 Conclusions

4.1 SUMMARY OF CONCLUSIONS

This evaluation report has shown that:

- Five selection factors for Pre-coat condensate polishers are present in the current design of the project. General industry practice to consider polishing is three or more.
- Cycling with rapid startup and <0.2 µS/cm steam cation conductivity, are the two key selection factors that are a part of this project.
- Pre-coat condensate polishers have the capability of simultaneous removal of both TDS and TSS. TSS process contamination is a possibility with any cooling water tube leak utilizing river water makeup.
- The condensate polisher, in combination with a sound cycle chemistry scheme, protects all equipment components in the steam/feedwater cycle.

Based on the selection criteria identified in the summary report, Black & Veatch's recommendation is to include provisions for a future pre-coat type condensate polisher system in the conceptual design for the project. This includes, but not necessarily limited to, [redacted] allowance in condensate pump sizing, space allocation, spare electrical capacity and connections, and condensate discharge by pass piping connections.

FINAL

AUXILIARY COOLING WATER SYSTEM ANALYSIS

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1215H

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

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Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch reviewed different design scenarios for the auxiliary cooling water system. It was determined that the design used for the auxiliary cooling water system on the existing units would not be practical for the CCPP. Three alternative designs were investigated:

- Alternative 1--Auxiliary cooling from makeup and circulating water.
- Alternative 2--Circulating water to cool the closed cycle cooling water equipment.
- Alternative 3--Circulating water to cool closed cycle cooling water equipment and hydrogen and lube oil coolers.

The performance, plant area required, reliability and maintenance, and cost of both shell and tube and plate and frame heat exchangers were considered in conjunction with the three alternatives for the auxiliary cooling water system. [redacted]

1.0 Introduction

Equipment throughout the plant is cooled by water. The source of this cooling water is through a closed loop system Closed Cycle Cooling Water (CCCW) or directly from an auxiliary cooling water source. This report looks at the sources for water for equipment cooling.

The existing plant cooling system is cooled by the raw water system. The raw water system consists of three (3) 3,300 gpm river water pumps which provide cooling water for the coal units closed cooling heat exchangers. The discharge from these existing heat exchangers is then routed to the cooling towers for makeup. The heat duty of the existing closed cycle cooling water system is minimized as the circulating water system directly provides cooling water flow to the generator hydrogen coolers and lube oil coolers.

In developing this report, Black & Veatch reviewed different design scenarios for the auxiliary cooling system for the new Combined Cycle Power Plant (CCPP). It was determined that the design used for the auxiliary cooling water system on the existing units would not be practical for the CCPP. Three alternative designs were investigated.

- The first alternative uses a combination of water from the cooling tower makeup to the cooling towers and circulating water to cool closed cycle cooling water equipment. Turbine hydrogen and lube oil coolers would be cooled directly from the cooling tower makeup.
- The second alternative uses circulating water to cool the closed cycle cooling water equipment. The closed cycle cooling water equipment provides cooling water to all equipment including the turbine hydrogen and lube oil coolers.
- The third alternative uses circulating water to cool the closed cycle cooling water equipment and the turbine hydrogen and lube oil coolers. This scenario differs from the second alternative as circulating water is used to directly cool the hydrogen and lube oil coolers.

This evaluation will evaluate the different alternatives looking at the system performance and cooling capability of the different cooling configurations.

2.0 System Performance – Cooling Capability

Table 2-1 provides a table listing the pros and cons of the different auxiliary cooling water arrangements

Table 2-1 System Performance Capability

ARRANGEMENT	PROS	CONS
Aux Cooling Water from Raw Water Makeup	-	Not Practical for CCPP
Alternative 1 - Circulating water cools CCCW equipment. Aux Cooling Water cools Turbine Lube Oil and Hydrogen Cooling.	Cooler auxiliary cooling water temps. Smaller circulating water pumps. Smaller CCCW system.	Long, large diameter stainless pipe runs to generators. Warmer makeup to cooling tower. Specialized OEM heat exchangers.
Alternative 2 - Circulating water cools CCCW. CCCW cools all equipment.	Standard OEM heat exchangers. Typical CCPP design. Minimizes piping costs.	Warmer circulating water temps. Larger circ water pumps.
Alternative 3 - Circulating water cools CCCW equipment. Circulating water cools Turbine Lube Oil and Hydrogen Cooling.	Cooler auxiliary cooling water temps. Smaller circulating water pumps. Smaller CCCW system.	Long, large diameter stainless pipe runs to generators. Warmer makeup to cooling tower. Specialized OEM heat exchangers.

2.1 ALL AUXILIARY COOLING FROM RAW WATER MAKEUP

The existing raw water makeup pumps consist of three (3) pumps each having a rated a flow capability of 3,300 gpm at 176 ft of head. To maintain a N+1 sparing philosophy, two pumps would be operating and one pump would be in standby providing a cooling water flow of 6,600 gpm since pressure drop to the new cooling tower is expected to be similar to that the existing system.

If the raw water system provides all of the cooling water for the combined cycle, the temperature rise across the heat exchangers would result in an elevated summer make up temperature to the cooling tower not considered acceptable with the cooling tower fill. To limit the temperature rise across the heat exchanger, it is recommended to use the circulating water system instead of the river water for a minimum of the cooling the generator hydrogen coolers and lube oil coolers.

2.2 ALTERNATIVE 1 – AUX COOLING FROM MAKEUP AND CIRC WATER

For Alternative 1, most auxiliary cooling water would be supplied from the river water make up to cool the closed cycle cooling water system while the generator hydrogen coolers and lube oil coolers would be cooled from the circulating water system directly. This scenario would result in a temperature rise for the makeup water system to match the hot water returning from the cooling tower. The temperature rise to the generator hydrogen coolers and lube oil coolers would be designed to match the circulating water temperature rise across the condenser; additional flow to the circulating water system to cool the steam turbine and combustion turbine generator hydrogen coolers and lube oil coolers would be about 3,800 gpm.

Due to the corrosive nature of the circulating water system stainless steel pipe would be required for the piping runs to the generator hydrogen coolers and lube oil coolers. The design for the combustion turbine generator hydrogen coolers and lube oil coolers would need to be coordinated with OEMs. The surface area of these coolers would be approximately twice the size of the standard design to limit the pressure drop across the heat exchanger as needed to match the pressure drop across the condenser as to not adversely impact the circulating water system design. The advantage to supplying cooling water directly from circulating water is that auxiliary cooling water to the generator hydrogen and lube oil coolers is 10°F cooler than if supplied from the closed cycle cooling water system.

2.3 ALTERNATIVE 2 – CIRC WATER COOLS CCCW

A typical design for combined cycle plants is to supply the auxiliary cooling water from the circulating water system. Under this design, circulating water would be supplied to the closed cycle cooling water system. The design of the closed cycle cooling water heat exchangers would limit the temperature rise of the circulating water to match the temperature rise of the circulating water across the condenser; the auxiliary cooling water flow would be sized as required to reject the heat of the closed cycle cooling water system. The cold water temperature of the CCCW would have a design temperature of 105°F; this is standard for equipment provided on combined cycle power plants. Circulating water flow to supply auxiliary cooling water system would be about 6,0 00gpm.

2.4 ALTERNATIVE 3 – CIRC WATER COOLS CCCW AND HYDROGEN AND LUBE OIL COOLERS

If the 105°F cooling water is a concern for the generator hydrogen and lube oil coolers and hydrogen coolers, they could be cooled directly from the circulating water system. The design for the combustion turbine generator hydrogen coolers and lube oil coolers would need to be coordinated with OEMs. The surface area of these coolers would be approximately twice the size of the standard design to limit the pressure drop across the heat exchanger as needed to match the pressure drop across the condenser as to not adversely impact the circulating water system design. Circulating water flow to supply auxiliary cooling water system would be about 2,000 gpm.

3.0 Conclusions

Since the existing raw water pumps that provide makeup to the cooling tower do not have sufficient flow to meet the requirements of the new combined cycle, a new cooling water arrangement utilizing circulating water is recommended. Since the turbine manufacturers design their heat exchangers including turbine lube oil and hydrogen coolers for cooling water up to 105°F and the CCCW system is designed to meet this condition under the extreme hot summer day, Alternative 2 with all equipment cooling water coming from the CCCW system as it is the lowest cost and allows the use of standard OEM equipment.

FINAL

DEMIN WATER USAGE ANALYSIS

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1217H

PREPARED FOR

Vectren

31 JANUARY 2020

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Executive Summary

In developing this report, Black & Veatch reviewed the requirements for demineralized water for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed multiple pre-start, start-up and steady state scenarios to determine the required sizing and operation of the demineralized water system. Demineralized water storage capacity was evaluated in parallel with system operation. Black & Veatch evaluated water usage based on 1x1 7HA.01 gas turbines for this analysis:

The demineralized water system users have been summarized in the steady state demands provided in Table 2-1. Plant pre-start demands have been summarized in Table 2-2 and plant startup demands have been summarized in Table 2-3. For all scenarios, the difference between water demand and existing system capacity is compared. Based on the demineralized water requirements for the multiple scenarios, it is recommended that Vectren utilize an additional water treatment system with a water capacity of [redacted] gpm per Table 3-1. No additional demineralized water storage capacity is required.

1.0 Introduction

The purpose of this study is to determine the specific requirements for demineralized water with the new Combined Cycle Power Plant (CCPP). Based on steady state operation, the existing cycle makeup treatment system can meet water demand. However, during startup and steady state operation with the evaporative cooler in operation, water demand exceeds the existing system capacity. The following tables detail differences in water demand for each configuration and condition.

2.0 Demineralized Water System Operation Demands

The demineralized water system provides water to various users during plant startup and shutdown at multiple operating conditions. Several operating scenarios were evaluated to determine the maximum water usage for the demineralized water system. Plant pre-start activities, plant startup, and plant steady state operation was evaluated for maximum demineralized water demand. The existing demin water treatment system capacity is [redacted] gpm. Demineralized water storage will need to be sufficient to hold three (3) days storage of the CCPP steady state demineralized water demand without evaporative cooling water makeup. Demin water demands excluded in this steady state operation are evaporative cooler makeup for the CCPP, CT#3 water injection and existing Unit 3 and 4 steam cycle demands.

2.1 STEADY STATE AND NON-STEADY STATE DEMANDS

The steady state demineralized water demand occurs during operation when supplying makeup water for CCPP blowdown and sampling losses. Non-steady state demineralized water demands occur during operation when supplying makeup water for steady state CCPP users plus evaporative cooler operation, existing unit operation and CT#3 water injection operation. Demineralized water demands are shown in Table 2-1. Steady state operation assumes 2% blowdown per the water mass balances. Steady state flows are based on Hot Day Case (93.7F) heat balance. Due to the infrequent operation of existing units and CT#3, storage volume recommendations will account for the excursion in steady state demand for demineralized water.

Table 2-1 Demineralized Water Demands

DEMIN WATER USERS	1X1 7HA.01
STEADY STATE DEMANDS	
2% blowdown (gpm)	[redacted]
Sample Analytics (gpm)	[redacted]
Demand w/o Evaporative Cooler Makeup (gpm)	[redacted]
NON-STEADY STATE DEMANDS	
Existing Unit 3 steam cycle demands (gpm)	[redacted]
Evaporative Cooler Makeup on RO Permeate (gpm)	[redacted]
Demand w/ Evaporative Cooler Makeup @ 6 COC (gpm)	[redacted]
CT #3 Water Injection	[redacted]
Instantaneous Demand for Steady State Operation with CT#3 water injection (1)	[redacted]

[redacted]

2.2 PRE-START DEMANDS

During unit pre-start, the auxiliary boiler is used to warm the HRSG and steam turbine seals. The assumption of 2% blowdown on the auxiliary boiler during this operation is included. During this operation, it is assumed all water is non recoverable. The pre-start usage demands are listed in Table 2-2.

Table 2-2 Demineralized Water Demands during Pre-Start Activities

PRESTART USAGE	1X1 7HA.01
Aux Boiler Makeup (gpm) HRSG warming	[redacted]
Difference (gpm) - Existing	[redacted]
Difference (gpm) - Proposed new	[redacted]

2.3 STARTUP DEMANDS

During unit startup, demineralized water usage is at the maximum. HRSG is warm and the condenser sparging and gland steam flows are recovered in the condenser. Steam drains are open until superheat targets are met. 5% blowdown is utilized for startup. The demineralized water demands are listed in Table 2-3.

Table 2-3 Demineralized Water Demands During Startup Activities

STARTUP DEMAND	1X1 7HA.01
Aux Boiler Makeup Fast Start (gpm)	[redacted]
Steam Drains to HRSG Blowdown Tank (gpm)	[redacted]
Blowdown (gpm)	[redacted]
Total Instantaneous Startup Demand (gpm)	[redacted]
Difference (gpm)	[redacted]
Difference (gpm) - Proposed new	[redacted]
Hot start lost capacity (gallons) (1)	[redacted]
Warm start lost capacity (gallons) (1)	[redacted]
Cold start lost capacity (gallons) (1)	[redacted]
Time to replace lost capacity during normal op (Hot Start), min	[redacted]
Time to replace lost capacity during normal op (Warm Start), min	[redacted]
Time to replace lost capacity during normal op (Cold Start), min	[redacted]
[redacted]	

3.0 Demineralized System

3.1 WATER REPLENISHMENT

The demineralized water system provides minimal margin for replenishment from startup of the combined cycle. For a typical combined cycle plant, the rule of thumb for storage is 3 days of steady state demand capacity. This relates to a 3 day outage on the demin supply. Table 3-1 details the time to replenish demineralized water capacity.

Table 3-1 Demineralized Water Volumes and Treatment Capacities

DEMINERALIZED WATER SYSTEM	1X1 HA.01
STORAGE CAPACITY	
Existing Demin storage (gallons)	[redacted]
3 day Demin storage capacity required @ steady state demand	[redacted]
Storage Surplus (+) / Storage Deficient (-) during a 3 day outage.	[redacted]
Recommended Additional Demin Storage (gallons) (1)	[redacted]
STEADY STATE TREATMENT DEMAND	
Current Demin Water Treatment Capacity (gpm)	[redacted]
CCPP Steady State Demand (gpm)	[redacted]
Treatment Surplus (+) / Deficient (-) (gpm)	[redacted]
NON-STEADY STATE TREATMENT DEMAND	
Current Demin Water Treatment Capacity (gpm)	[redacted]
CCPP Non- Steady State Demand (gpm)	[redacted]
Treatment Surplus (+) / Deficient (-) (gpm)	[redacted]
PEAK TREATMENT DEMAND	
Current Demin Water Treatment Capacity (gpm)	[redacted]
CCPP Peak (CT#3 + Non- Steady State) Demand (gpm)	[redacted]
Treatment Surplus (+) / Deficient (-) (gpm)	[redacted]
PROPOSED ADDITIONAL DEMINERALIZED WATER TREATMENT CAPACITY (GPM)	[redacted]
Treatment Surplus (+) / Deficient (-) (gpm)	[redacted]
Recover 3 day outage volume, Steady state after (HOURS)	[redacted]
Recover 3 day outage volume, Non-Steady state after (HOURS)	[redacted]
[redacted]	

[redacted]

Based on Black & Veatch's evaluation, the existing demineralized water storage capacity can provide sufficient storage of demineralized water based on the design parameters. Furthermore, a new demineralized water treatment system sized to supplement [redacted] gpm (coupled with the existing [redacted] gpm system) would be sufficient to meet various operating demands of the facility as well as replenish demineralized water volume within the design parameters.

4.0 Conclusions

Based on the evaluation Black & Veatch can conclude:

- The existing demineralized water storage capacity provides adequate storage of demineralized water based on the design parameters.
- A new demineralized water treatment system sized to supplement [redacted] (coupled with the existing [redacted] system) would be sufficient to meet various operating demands of the facility as well as replenish demineralized water volume within the design parameters.

FINAL

BLACK START ANALYSIS

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1221H

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

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Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch examined the capability of using the existing combustion turbine generator (CTG) peaking Unit 3 at A.B. Brown as a means of black starting CTG 5 of the new CCPP

Unit 3 is a GE 7EA turbine capable of operating with either natural gas or distillate fuel oil as the fuel source. Two scenarios were modeled for this evaluation:

- Starting of the largest medium voltage induction motor with all necessary auxiliary electric loads in operation.
- Static starting of CTG 5 with all necessary auxiliary electric loads in operation.

For analysis modeling purposes, the aggregate auxiliary electrical load necessary to start a combustion turbine were based on the preliminary conceptual design of the new CCPP. In addition, the excitation system was assumed to be capable of providing the necessary reactive power required by the simulated scenarios while maintaining 100 percent system voltage at a frequency of 60 Hz at the generator terminals.

Within the boundaries of this evaluation, the Unit 3 generator at A.B. Brown appears to be capable of black starting one combustion turbine of the new CCPP. Further analysis would be required to verify that generator control and system protection would permit synchronization of the Unit 5 generator to the Unit 3 generator to shift auxiliary electrical loads from the Unit 3 generator to the Unit 5 generator.

1.0 Introduction

The purpose of this evaluation is to examine the capability of the existing combustion turbine generator peaking Unit 3 at A.B. Brown to be utilized as a black starting means for the new combined cycle power plant (CCPP). Unit 3 is a GE 7EA turbine capable of operating with either natural gas or distillate fuel oil as the fuel source. The unit has a dedicated diesel generator and starting motor necessary to start. Unit 3 is utilized as a black starting means for existing A.B. Brown coal-fired Units 1 and 2.

Electrical power system analysis software ETAP was utilized to model and evaluate Unit 3 to verify the capability of black starting CTG 5 of the new CCPP. Figure 1-1 provides the one line diagram that was modeled in ETAP. Two scenarios were modeled for this evaluation, starting of the largest medium voltage induction motor with all necessary auxiliary electric loads in operation, and static starting of CTG 5 with all necessary auxiliary electric loads in operation.

[redacted]

[redacted]

2.0 Assumptions

In order to simulate the scenarios included in this evaluation, reasonable assumptions were made in order to model and simulate the black start capability. The assumptions are defined as follows.

2.1 LOAD LIST

It is necessary to determine the aggregate auxiliary electrical load that is necessary to start a combustion turbine of the new CCPP. Table 2-1 provides the load list of all loads considered to be in operation to support the black start. Except ACWP, BFP, CWP, CCWP & CP (major loads), all other loads were modeled as a lump load. For lump load motor power factor of 85% has been considered. A 20 percent margin was added to the lump loads of Table 2-1 for modeling purposes. The loads of Table 2-1 are based on the conceptual design of the new CCPP and are preliminary. All cooling tower fans and CWP have been modeled to show to feed from 6.9kV BUS A & existing 4.16kV BUS 1B respectively.

Table 2-1 Operating Loads during CCPP Starting

BLACK START ANALYSIS LOAD LIST			
LOAD	LOAD TYPE	LOAD RATING	LOAD UNITS
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

BLACK START ANALYSIS LOAD LIST			
LOAD	LOAD TYPE	LOAD RATING	LOAD UNITS
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

BLACK START ANALYSIS LOAD LIST			
LOAD	LOAD TYPE	LOAD RATING	LOAD UNITS
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

2.2 UNIT 3 EXCITATION SYSTEM

This study does not include analysis of the excitation model or transfer function for Unit 3. Therefore, the excitation system is fixed in the ETAP simulation. Additional modeling of the excitation system and transfer function would be necessary in order to more accurately simulate the response to the reactive power demands imposed when black starting one combustion turbine generator of the new CCCP, however, the excitation system is assumed to be capable of providing the necessary reactive power required by the simulated scenarios while maintaining 100 percent system voltage at a frequency of 60 Hz at the generator terminals, as long as the real and reactive demands on the Unit 3 generator do not exceed the limits of the reactive capability curve.

2.3 PROTECTION, CONTROL AND SYNCHRONIZATION

It is recommended during the detailed design phase that the turbine control system of the new CCPP is designed to be capable of allowing the new combustion turbine generator to synchronize with Unit 3 and that existing and new protection schemes are designed to permit synchronization. It also recommended during the detailed design phase that the control system of the existing Unit 3 combustion turbine generator is verified or modified as necessary to permit load sharing of the auxiliary electrical demands of the new CCPP. No investigation into the existing Unit 3 control system or switchyard protection schemes has been performed in support of this black start capability evaluation.

3.0 Static Motor Starting of Largest Motor

The starting of a large motor can have a brief, but significant, impact on the auxiliary electrical system. When voltage is applied to the terminals of an at rest motor, the motor will draw locked-rotor current (LRA), which decays toward full-load amps (FLA) as the motor approaches running speed. This is the result of the motor torque overcoming the combined inertia of the motor and the connected load. For an induction motor, a typical value of LRA is approximately 650 percent of FLA.

In the scenario of the black start, motor starting can result in voltage and frequency sags at the generator output, which will have a corresponding impact on the capability of the motor to start and to the existing loads in operation. The ability of the generator to accommodate starting of large motors is dependent upon the generator capacity, the response of the excitation system, the rotating inertia of the generator and the characteristics of the motor at starting. Should a sag in voltage during motor starting result in the motor's inability to develop the torque necessary to accelerate to full speed, the motor could stall. It is necessary to analyze the worst-case motor starting scenario for the purpose of determining the black start capability of the Unit 3 generator.

As a worst-case scenario, static motor starting of the Boiler Feed Pump, the largest medium voltage motor, was analyzed with all other loads necessary for a black start in operation, with the exception of the Unit 5 generator static starting system. Static motor starting models the motor by locked-rotor impedance during acceleration, simulating the worst impact to loads in operation at the time of motor starting. The properties of the modeled Boiler Feed Pump is 6900 HP, 6.6 kV, 510 FLA, 0.93 power factor, 94 percent efficiency and 6.5 pu LRA.

Figure 3-1 provides the bus voltage, as a percent of nominal, at each bus during starting of the Boiler Feed Pump. The Watt and VAR demand from the Unit 3 generator and the starting motor are also displayed.

The maximum demand from the Unit 3 generator during starting of the Boiler Feed Pump is 8.58 MW and 33.75MVAR. This is well within the capability curve of the Unit 3 generator, considering a 0.85 lagging power factor and 15 degrees Celsius inlet air temperature, as depicted in Figure 3-2. The worst-case motor terminal voltage during starting of the Boiler Feed Pump is 80.11 percent of nominal system voltage. It is typical to specify medium voltage motors rated to start at 80 percent of nameplate voltage. It is also typical to specify motor nameplate voltage below nominal system voltage. In the case of a nominal 6.9 kV system, the corresponding motor nameplate is 6.6 kV, consistent with ANSI C84.1. The result of the static motor starting analysis for the Boiler Feed Pump indicates that the momentary sag in voltage at the motor terminals is not prohibitive to the starting of the motor. The worst-case bus voltage for the BUS & MCC A is 77.43 percent during starting of the Boiler Feed Pump. This will not result in drop out of motor contactors since the nominal bus voltage is above 70%. All other medium voltage motors connected to BUS & MCC A (6.9kV) were considered to be running in this scenario. The bus voltage of BUS & MCC A recovers to 99.92 percent of nominal system voltage once the Boiler Feed Pump has accelerated to rated speed.

UAT impedance have been modeled with 6.5% for this study. The short circuit current level will be well below 40kA for 6.9kV SWGR and MCC A. UAT primary tap position has been set at -2.5% in order to achieve motor terminal voltage of higher than 80%. There is a possibility of further reducing UAT 5 impedance and motor locked rotor amperes to improve starting motor terminal voltage if necessary. A 3-3/C-500kcmil conductor has been considered to feed the BFP during this study.

[redacted]

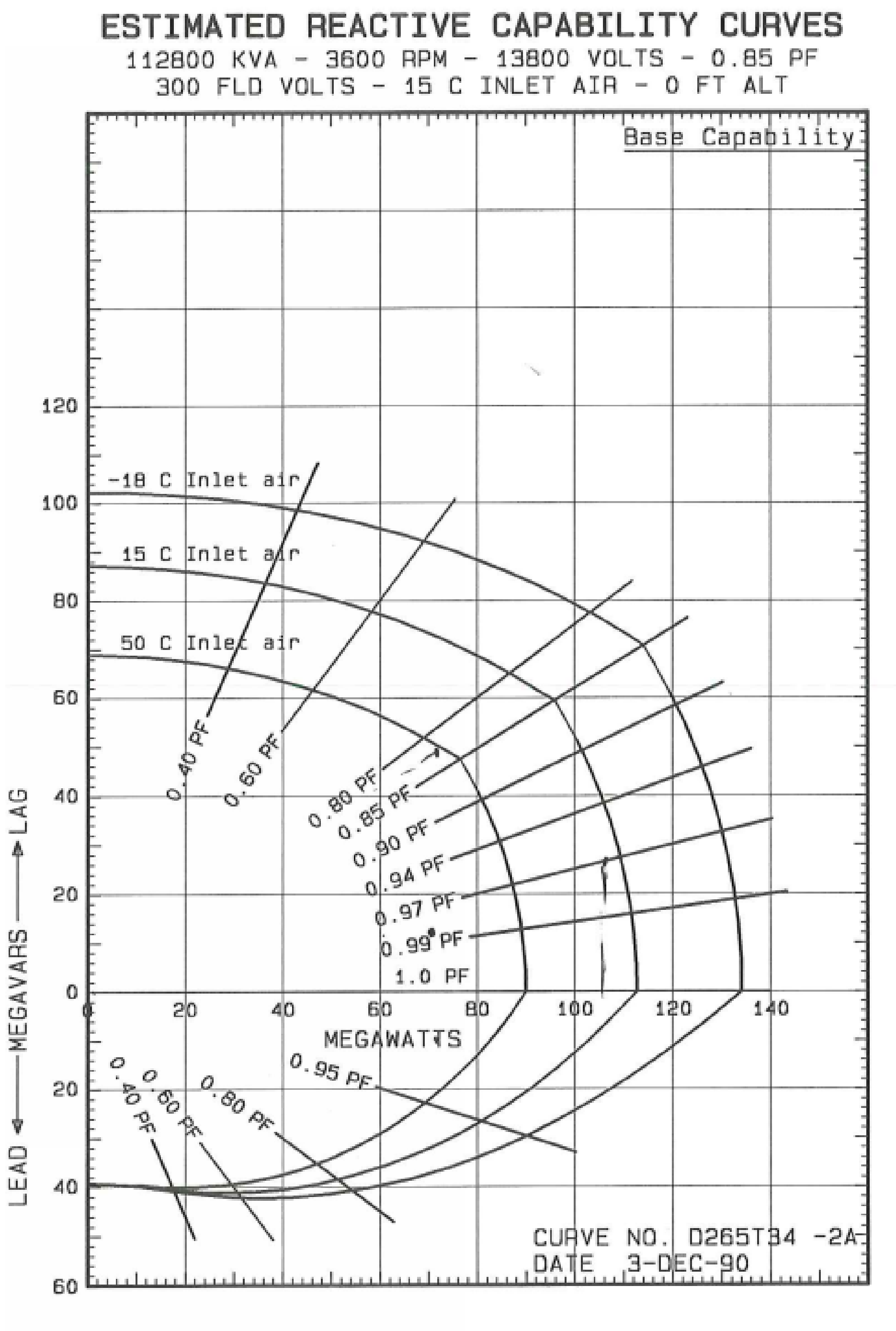

Figure 3-2 Unit 3 Generator Reactive Capability Curve

4.0 CTG 5 Static Starting Load Flow

A load flow model was analyzed during the static starting of the Unit 5 combustion turbine generator. This scenario considered all loads necessary for black starting to be in operation at the time the static starting system was energized. The maximum demand from the Unit 3 generator during static starting of Unit 5 CTG is 11.39 MW and 6.57 MVAR. This is well within the capability curve of the Unit 3 generator, considering a 0.85 lagging power factor and 15 degrees Celsius inlet air temperature, as depicted in Figure 3-2.

The worst-case bus voltage during operation of the static starting system on 6.9 kV BUS and 4.16kV BUS 1B will be 99.92 & 98.72 percent of nominal system voltage. This is well within the normal operating 'voltage range A' as per ANSI C84.1 and not considered to be a prohibitive impact to operation during black start. Additionally, the static starting system operates for a short duration until the combustion turbine reaches approximately 90 percent of rated speed, at which point it is self-sustaining and the static starting system is removed from operation and the turbine control system receives control of the turbine. This duration is approximately 30 minutes or less, dependent upon starting conditions with respect to the purging of combustible gases from the hot gas path prior to ignition.

[redacted]

5.0 Conclusions

The analyses performed in support of the black starting capabilities of the existing Unit 3 generator at A.B. Brown indicate that the generator has sufficient capacity to provide the required real and reactive power necessary to start the largest medium voltage motor as well as operate the static starting system of the new CCPP. The starting of the Boiler Feed Pump was simulated as a worst-case scenario, with all other loads necessary to support a black start in operation with the exception of the static starting system. Motor terminal voltage and bus voltages were maintained within reasonable limits for the scenario of a black start. Power requirements to support Boiler Feed Pump starting and the static starting system operation were within the capability curve of the Unit 3 generator. Both analyses assume that the Unit 3 generator excitation system is capable of responding appropriately to meet the reactive power needs, and further analysis with the excitation system modeled is necessary to confirm this response. Additionally, further analysis would be required to verify generator control and system protection would permit synchronization of the Unit 5 generator to the Unit 3 generator in order to shift auxiliary electrical loads from the Unit 3 generator to the Unit 5 generator. Within the boundaries of this evaluation, the Unit 3 generator at A.B. Brown appears to be capable of black starting the combustion turbine of the new CCPP.

FINAL

SWITCHYARD EVALUATION AND SEQUENCE

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1222H

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

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Executive Summary

In developing this report, Black & Veatch evaluated the suitability of the existing A.B. Brown 138 kV switchyard for interconnection of a new combustion turbine generator (CTG) and steam turbine generator (STG) operating as a 1x1 Combined Cycle Power Plant (CCPP). This evaluation was performed with existing Unit 2 remaining in operation. Black & Veatch considered preliminary heat balance data for a GE 7HA.01 CCPP as a conservative approach to this evaluation. Switchyard connections and connection sequence were also evaluated.

The continuous current loading of the 3000 Ampere (A) main buses 1 and 2 as well as the 2000 A interpass conductors are not exceeded for the switchyard configurations evaluated. The loading evaluation does not identify any major bus work necessary to independently connect the generators associated with the 1x1 CCPP.

As a result of the available fault current contribution at the existing 138 kV switchyard exceeding 40 kiloampere (kA), with new generation and Unit 2 in service, circuit breakers with a symmetrical interrupting rating 40 kA require replacement. Of the existing 20 circuit breakers in the 138 kV switchyard, 13 are rated 40 kA. [redacted] Therefore, it is recommended to replace all existing circuit breakers in the 138 kV switchyard with 63 kA symmetrical withstand and interrupting rating.

[redacted]

1.0 Introduction

The A.B. Brown 1x1 CCPP is a multi-shaft arrangement, with the combustion turbine (CT) and steam turbine (ST) individually coupled to dedicated generators rated to convert maximum turbine capabilities to electric power. The multi-shaft arrangement differs from a single shaft arrangement, with respect to electrical equipment, in that independent generators coupled to each turbine will transmit electric power via dedicated isolated phase bus duct (IPBD) to dedicated generator step-up transformers (GSU). Each GSU is sized to permit maximum real electric power to be transmitted to the electric power grid, with minimal losses, and to permit reactive electric power to be delivered to and absorbed from the electric power grid. Each turbine generator will also provide source power to 100 percent redundant unit auxiliary transformers (UAT). The high voltage side of each GSU will be independently connected to the existing 138 kV switchyard. Interconnection of the CTG and STG to the existing 138 kV switchyard requires consideration of fault current availability and system load flow relative to existing equipment ratings. Black & Veatch considered preliminary heat balance data for a GE 7HA.01 CCPP as a conservative approach for this evaluation. Configurations of a 1x1 CCPP comprised of turbine classes with lower gross megawatt (MW) output will result in additional margin with respect to switchyard loading and fault current. Each of the new generators were modelled with independent connections to the existing 138 kV switchyard, with Unit 2 remaining in operation.

The method of connection for each generator in a given configuration to the existing 138 kV switchyard is based upon the electrical ratings of the switchyard components, switchyard expansion capability, and operation of existing units. The existing 138 kV switchyard is a breaker and a half configuration with two main buses, rated 3000 A continuous [redacted] 13 of the 20 existing circuit breakers in the 138 kV switchyard are rated to interrupt 40 kA.

2.0 Switchyard Evaluation

2.1 LOAD FLOW

The interpass connections between Bus 1 and Bus 2 are rated 2,000 A, therefore a single connection to the switchyard is acceptable when the kilowatts (kW) transmitted remain below 430,000 kW at a power factor equal to 0.9. For a single connection above 430,000 kW and less than 645,000 kW, upgrades are required to the entire 138 kV switchyard, such as circuit breaker and disconnect switch replacement with 3000 A continuous rating. Generation exceeding 645,000 kW at a single connection point is not practical at a voltage level of 138 kV as equipment rated above 3000 A continuous is typically not available.

The maximum CTG and STG gross output based on the preliminary fired GE 7HA.01 1x1 considered for this evaluation are 331,500 kW and 243,950 kW and correspond to approximately 1201 A and 884 A, respectively. Detailed load flow modelling of the 138 kV switchyard with case permutations of outgoing transmission lines in and out of service is necessary in order to verify the suitability of the 138 kV switchyard to accommodate the connection of two CTGs and identify any overload cases. Initial analysis indicates that the 138 kV switchyard is generally suitable to accommodate independent connection of the new 1x1 CTG and STG while Unit 2 remains in operation.

The maximum current flow in the main and interpass busses for each analyzed case are represented in Table 2-1.

Table 2-1 Max Load in Main and Interpass Buses - 2026 Summer Peak

Case	Current in 3kA Main Bus (A)	Percent Loading (%)	Current in 2kA Interpass (A)	Percent Loading (%)
All In Service	1119	37.30	633.2	31.66
Bus 1 Outage	2017.4	67.25	1044.5	52.23
Bus 1 and Line Z95 Outage	2320.1	77.34	1228.5	61.43
Bus 1 and Line Z96 Outage	2169.9	72.33	1139.3	56.97
Bus 1 and Line Z94 Outage	2490.6	83.02	1189.5	59.48
Bus 1 and Line Z73 Outage	2125.4	70.85	1111.4	55.57
Bus 1 and Line Z98 Outage	1735.3	57.84	1133.4	56.67
Bus 1 and Line Z99 Outage	1820	60.67	1358.7	67.94
Bus 1 and Line Z93 Outage	1816.1	60.54	1204.3	60.22
Bus 1 and Line to Culley Outage	2017.4	67.25	1044.5	52.23
Bus 1 and Francisco to Gibson Outage	2333.9	77.80	1327.1	66.36
Bus 1 and AB Brown – BREC Reid Outage	2154.8	71.83	1668.4	83.42
Bus 2 Outage	2016.5	67.22	1200.47	60.02

Case	Current in 3kA Main Bus (A)	Percent Loading (%)	Current in 2kA Interpass (A)	Percent Loading (%)
Bus 2 and Line Z95 Outage	2319.2	77.31	1229	61.45
Bus 2 and Line Z96 Outage	2168.8	72.29	1199.9	60.00
Bus 2 and Line Z94 Outage	2489.9	83.00	1199.5	59.98
Bus 2 and Line Z73 Outage	2124.4	70.81	1196	59.80
Bus 2 and Line Z98 Outage	1734.1	57.80	1199.6	59.98
Bus 2 and Line Z99 Outage	1819.4	60.65	1358.2	67.91
Bus 2 and Line Z93 Outage	1814.4	60.48	1203.3	60.17
Bus 2 and Line to Culley Outage	2016.5	67.22	1200.7	60.04
Bus 2 and Francisco to Gibson Outage	2332.9	77.76	1237.9	61.90
Bus 2 and AB Brown – BREC Reid Outage	2153.90	71.80	1199.5	59.98

2.2 FAULT CAPABILITY

13 of the 20 circuit breakers in the existing 138 kV switchyard are rated to withstand and interrupt 40 kA symmetrical fault current. The interrupting capability of the 13 40 kA rated circuit breakers is marginal for three phase faults and exceeded for single phase to ground faults for this evaluated case. Due to the available fault current contribution it is recommended to replace these existing circuit breakers with circuit breakers having sufficient margin beyond maximum fault current contribution. The remaining seven existing circuit breakers are oil filled and are considered to be near the end of service life. It is recommended to replace all of the existing 138 kV switchyard circuit breakers with breakers rated 63 kA symmetrical interrupting duty. This will ensure fault interrupting capability exceeds maximum available fault contribution.

The results of the fault study are included in Table 2-2.

Table 2-2 138 kV Switchyard Fault Currents

Fault Current Availability 1x1 and Unit 2		
Fault type	**Fault Component**	**Value**
3-phase fault	Fault Current (A)	38881.2
	Phase Angle (°)	-87
	Calculated X/R	18.96
1-phase fault	Fault Current (A)	46287,2
	Phase Angle (°)	-87
	Calculated X/R	19.24

3.0 Switchyard Connection Sequence

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

4.0 Conclusions

The withstand and interrupting rating of 40 kA for thirteen of the twenty existing 138 kV switchyard breakers is exceeded for the fault conditions evaluated, therefore circuit breaker replacement is necessary. The remaining seven switchyard circuit breakers are oil-filled breakers and near the end of their service life. It is recommended to replace all existing circuit breakers in the 138 kV switchyard with 63 kA symmetrical withstand and interrupting rating.

The evaluated load flow of the existing 138 kV switchyard permits independent connection of the CTG and STG of the new 1x1 CCPP considering a fired GE 7HA.01 and associated preliminary heat balance gross output. In general, the existing switchyard is capable of a single point of interconnection for 430,000 kW and below. This evaluation did not identify any major bus or interpass modifications for the existing 138 kV switchyard to accommodate the new CCPP and operation of Unit 2.

Connections to the existing switchyard have been planned to permit the construction and commissioning schedule of the new CCPP, while maintaining the existing A.B. Brown Unit 1 connection as late as practical into construction of the new CCPP.

Appendix A. Switchyard Connection Sequence

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Appendix B. Construction Schedule

[redacted]

FINAL

AUXILIARY ELECTRIC SYSTEM MEDIUM VOLTAGE LEVEL COMPARISON

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 195523
B&V FILE NO. 41.1223H

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

19 FEBRUARY 2020

BLACK & VEATCH

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Executive Summary

This evaluation provides a summary comparison of nominal 6.9 kV and 4.16 kV auxiliary electric systems for the conceptual design (CPCN project) of the new A.B. Brown Combined Cycle Power Plant (CCPP). The medium voltage switchgear and motor controllers distribute power to large motor loads, ranging from greater than 250 HP up to several thousand HP, as well as to secondary unit substation (SUS) transformers, which derive 480V to be distributed to the low voltage system components and electrical loads.

Both nominal system voltages of 4.16 kV and 6.9 kV are commonly utilized within power generation and supported by most transformer and motor manufacturers.

Table ES-1 Advantages of 4.16kV and 6.9kV Medium Voltage Systems

MEDIUM VOLTAGE	4.16 KV	6.9 KV
Lower Running Current/Starting Current		X
Smaller Conductor Size		X
Less Heating in Below Grade Cable Ductbank		X
Reduction of Bus Short Circuit Rating		X
Overvoltage Withstand	X	
Conductor Cost Savings		X
UAT Cost Savings		[redacted]
Switchgear Cost Savings		[redacted]
Motor Cost Saving	Equal	Equal

1.0 Auxiliary Electric System Cabling Design Considerations

The cross-sectional area (CSA) of a current-carrying copper conductor is largely dependent upon the continuous current required for rated operation of the electrical load. A larger continuous current necessitates are larger CSA in order to ensure the thermal limitations of the cable insulation and the equipment terminals are not exceeded. An electrical load with a nominal system voltage rating of 6.9 kV will result in an approximate 40% reduction of running current than that of an electrical load with the same power rating, in kVA or HP, and a nominal system voltage rating of 4.16 kV.

For power cables installed in below grade duct bank, a de-rating study must be performed in order to ensure that the implications of the concrete-encased, below grade cable duct on the current-carrying capability of the conductors are properly applied during conductor sizing. The aggregate of thermal impact of the continuous current flowing through the conductors within the duct bank, depth of duct bank, and soil thermal resistivity determine the de-rating of the conductor ampacity. The ampacity of a current-carrying conductor in below grade duct bank is reduced compared to the ampacity of the same conductor in above grade raceway or free air.

It is typical in a CCPP that the electrical loads, particularly medium voltage, are not installed within proximity of the electrical distribution equipment from which the load is sourced. Voltage drop calculations must be performed in order to ensure that the voltage at the load terminals does not fall below the equipment minimum operating voltage. Voltage drop is directly proportional to current, cable length and cable impedance.

2.0 Medium Voltage Motor Starting System Impact

The starting of a large motor can have a significant, albeit brief, impact on the auxiliary electrical system. When voltage is applied to the terminals of an at rest motor, the motor will draw locked-rotor current (LRA), which decays toward full-load amps (FLA) as the motor approaches running speed. This is the result of the motor torque overcoming the combined inertia of the motor and the connected load. For an induction motor, a typical value of LRA is approximately 650% of FLA.

As voltage drop is directly proportional to current, the voltage drop at motor starting due to LRA must be analyzed in order to ensure the motor will start. It is typical to specify medium voltage motors capable of starting at 80% of rated voltage as a means of mitigating this concern.

The starting current of a motor can also have an adverse impact on equipment already in operation at the time of motor starting. Voltage sag resulting from the LRA of the starting motor can result in contactor drop-out in certain circumstances. Methods of avoiding adverse impact of large motor starting to the auxiliary electrical system include on-load tap changers (OLTC) integral to the unit auxiliary transformers for bus voltage regulation, dedicated variable frequency drives (VFD) or soft-starters for the motors of concern. The approximate 40% reduction of FLA and LRA resulting from a 6.9 kV compared to 4.16 kV provides for improved results relative to motor starting.

3.0 Short Circuit Contribution During a System Fault

During a system fault, a motor in operation will contribute current to the fault, in attempt to stabilize the decaying system voltage, as a result of the rotating magnetic field that exists in the rotor at the inception of the fault. Analyses of the auxiliary electric system during a faulted condition must be performed in order to ensure that the bus bracing of the electrical distribution equipment is appropriate relative to fault levels. The reduction of FLA of a higher system voltage correlates to reduced short circuit contribution during in a fault condition. Black & Veatch analyses of system faults utilizing Electrical Transient and Analysis Program (ETAP) indicate that motor short circuit contribution can be reduced by up to 50% by increasing the system voltage from 4.16 kV to 6.9 kV.

The reduction of bus short circuit rating of electrical distribution equipment corresponds to a reduction in capital expenditure for 6.9 kV compared to 4.16 kV.

4.0 Cost Impact of Equipment Voltage Rating

Manufacturers of switching assemblies offer various equipment voltage ratings above typical industry nominal system voltages. Metal-clad switchgear voltage ratings of 5 kV and 7.2 kV are common and correspond to nominal system voltages of 4.16 kV and 6.9 kV, respectively. Confirmation from switching assembly manufacturers indicates that bus and breaker continuous current and interrupting ratings, as well as bus bracing and short circuit rating, are the primary cost drivers. The cost difference of a line-up of metal-clad switchgear with the same continuous current rating, interrupting capability and bus bracing, but different system voltage ratings, is negligible.

Black & Veatch has received similar confirmation from motor suppliers, with respect to the negligible cost difference between 6.6 kV and 4.0 kV rated motors.

5.0 System Loading

The preliminary electrical load list associated with the 2x1 (F and H Class) configuration of the A.B. Brown CCPP conceptual design indicates a total plant running load of approximately 30 MVA. At 6.9 kV, this corresponds to approximately 2500 A of running current in combined cycle operation. The preliminary UAT required to support this auxiliary load is a two-winding transformer with a maximum forced-air cooled rating of 36 MVA. With 100% redundancy, two (2) two-winding UATs correspond to one (1) double-ended (main-tie-main) lineup of 3000A, 6.9 kV switchgear.

With the total plant running MVA, at a system voltage of 4.16 kV, the corresponding running current is approximately 4200 A. Typical switchgear manufacturers offer maximum continuous current ratings of 4000 A, which is achieved using 3000 A rated, fan cooled main circuit breakers. The condition of fan cooling required to achieve this rating is not recommended as it introduces an additional point of failure to the auxiliary electric system.

A system voltage of 4.16 kV would necessitate two (2) three-winding UATs and two (2) double-ended lineups of switchgear in order to adequately source the plant auxiliary load requirements for combined cycle operation. A budgetary cost estimate of [redacted] per UAT and [redacted] of additional metal-clad switchgear would be necessary in order to accommodate auxiliary loads at 4.16 kV system voltage.

6.0 Overvoltage Withstand

Equipment manufacturers specify maximum voltage ratings above the nominal system voltage rating. An industry typical maximum voltage rating for a 4.16 kV nominal system voltage is 5.0 kV, providing approximately 20% headroom in an overvoltage condition. Industry typical maximum voltage rating for a 6.9 kV system voltage is 7.2 kV, though some manufacturers are now offering equipment with maximum system voltage rating of up to 7.65 kV. A maximum voltage rating of 7.2 kV provides approximately 4.3% headroom in an overvoltage condition before exceeding the maximum voltage rating. Dependent upon the generator output voltage and the UAT tap, it is possible to exceed this maximum voltage rating with a 6.9 kV system. However, this is not a normal operating condition and could be mitigated with appropriate protective relaying.

7.0 Conclusions

This evaluation report has shown that:

- The design of insulated conductors is directly impacted by the medium voltage system level.
- Disturbances to the auxiliary electric system as well as motor starting concerns are mitigated by an elevated system voltage.
- Short circuit contribution from medium voltage motors is reduced by an elevated system voltage, which can correspond to a reduction in the short circuit bus rating of electrical distribution equipment.
- The cost associated with an elevated system voltage to plant equipment such as switching assemblies and motor windings is considered negligible.
- The preliminary plant auxiliary loading required for combined cycle operation of the 2x1 configuration is supported by two-winding UATs and one (1) double-ended lineup of medium voltage switchgear at a system voltage of 6.9 kV. A system voltage of 4.16 kV would necessitate three-winding UATs and two (2) double-ended lineups of medium voltage switchgear.
- 4.16 kV system voltage provides more headroom for an overvoltage condition than that of a 6.9 kV system, for industry typical maximum voltage ratings. However, this condition can be mitigated with protective relaying.

Total cost savings for using 6.9 kV medium voltage system in lieu of a 4.16 kV medium voltage system is approximately [redacted].

Attachment 6.5 Coal to Gas Conversion Study (Redacted)

FINAL

VECTREN NATURAL GAS CONVERSION INDEPENDENT ASSESSMENT REPORT

A.B. Brown Units 1, 2

F.B. Culley Unit 2

BLACK & VEATCH PROJECT NO. 403365
BLACK & VEATCH FILE NO. 40.4100

PREPARED FOR

Vectren

MARCH 17, 2020

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Foreword

For several years, Vectren, a CenterPoint Energy Company, has been updating their integrated resource plan (IRP) to forecast energy demands to ensure reliable service to their customers in the most cost-effective ways. To that end, Vectren has been engaged with several engineering consulting firms to evaluate the use of natural gas, in lieu of coal, for operations at A.B. Brown, Units 1 and 2 and F.B. Culley, Unit 2.

The evaluation covered by this report was undertaken to enable Vectren to assess all concepts and options for natural gas conversion. The following summarizes the steps that have been taken during the course of this Project:

- Burns & McDonnell provide a high level natural gas conversion conceptual design and budgetary cost estimate for A.B. Brown Units 1 & 2 in 2015 and provided an update in 2016.
- Early in 2019 to support the current IRP process, Burns & McDonnell provided an update to this previous study for coal to gas conversion of A.B. Brown Unit 2.
- Black & Veatch further developed the estimate by investigating details surrounding preliminary Prevention of Significant Deterioration (PSD) analysis, potential environmental control technologies, Bill of Quantities (BOQ) level construction estimates, and expected boiler performance.
- Babcock & Wilcox (B&W) provided updates to the Boiler Engineering Study (surface area assessment & expected performance) and budgetary cost estimate for boiler equipment.
- Bowen Engineering performed a site investigation developing BOQ of materials and provided a construction budgetary estimate.
- Black & Veatch reviewed and validated the information provided by B&W and Bowen and developed a Natural Gas Conversion cost estimate consistent with an AACE Class 4 (which has an expected accuracy range of +/- 30%).

Black & Veatch utilized prior assessments from the following firms to validate the project conceptual design and budget level cost estimates for the coal to natural gas conversion:

- Burns & McDonnell – Natural Gas Conversion Conceptual Design and Budgetary Cost Estimate for A.B. Brown, Unit 2.
- Bowen Engineering Corporation – Materials and construction budgetary cost estimate for A.B. Brown, Units 1 and 2; F.B. Culley, Unit 2.
- Babcock & Wilcox – Boiler Engineering Study and Budgetary Cost Estimate for A.B. Brown, Units 1 and 2; F.B. Culley, Unit 2.
- Cormetech, Inc. – Estimated costs for selective catalytic reduction (SCR)/carbon monoxide (CO) catalysts for A.B. Brown, Units 1 and 2; F.B. Culley, Unit 2.
- International Chimney Corporation – Estimated costs for chimney inspection and liner washdowns for A.B. Brown, Units 1 and 2.

1.0 Executive Summary

Vectren requested Black & Veatch to review the concept of converting Vectren's A.B. Brown, Unit 1 and 2 and F.B. Culley, Unit 2 from firing coal to firing 100 percent natural gas. Converting to 100 percent natural gas firing involves the replacement of the existing bituminous coal fired burners with natural gas burners; the existing natural gas igniters will not be replaced. The new natural gas burners would lower emissions during startups and during normal operations by providing up to 100 percent of boiler maximum continuous rated (MCR) heat input. The existing flue gas cleaning equipment (scrubbers, baghouse/precipitator) would be removed from service. The natural gas pipeline supply to the A.B. Brown site boundary was excluded from the scope of this assessment.

When converted to natural gas the heat rate impact will be approximately four percent less for A.B. Brown Units 1 and 2 and three percent less for F.B. Culley Unit 2 due to the decreased boiler efficiency. The typical project schedule is 30 months (including 10 months for permitting activities) with a 10-month construction period that includes a 12 week outage for A.B. Brown Unit 1, a 14 week outage for A.B. Brown Unit 2, and a 14 week outage for F.B. Culley Unit 2. Replacement burner/igniter manufacture and delivery time is 13 months from award of a purchase order. A summary of the A.B. Brown Units 1 and 2 and F.B. Culley Unit 2 boiler impacts when converting to natural gas as assessed by Babcock & Wilcox is included in Table 1-1 and Table 1-2.

Table 1-1 Summary of the A.B. Brown Unit 1 and 2 Boiler Impacts (per Unit Basis)

COMPONENT	RESULTS	COMMENTS
Superheat (SH) and Reheat (RH) Attemperator Flows	SH and RH flow rate less than required for firing coal	Lower amounts of excess air required when firing natural gas as compared to firing coal
Air Heater Performance	The air and flue gas temperature profiles around the air heater were found to be acceptable for firing natural gas; flue gas and air flows and temperatures in/out of air heater were at or below original design values	No field data were available that indicated higher than original air heater leakage; therefore, original air heater leakage of 7.4% was assumed in evaluation
Boiler Performance	• Main steam outlet temperatures, pressures, and flow rates equal to firing bituminous coal • RH steam outlet temperatures and pressure are slightly less when firing natural gas • Boiler efficiency as low as 84.16% compared to 87.92% when firing bituminous coal (because of moisture in losses due to H_2 and H_2O in the natural gas)	Boiler efficiency for coal fired based on original contract performance summary

COMPONENT	RESULTS	COMMENTS
Tube Metal Temperature Evaluation	• Existing tube metal metallurgies in the convection pass tubes do not exhibit any overstress issues; tubes predicted to operate below American Society of Mechanical Engineers (ASME) material code published limits • Header metal temperatures within Babcock & Wilcox standards	No surface modifications or surface removals are required when converting to firing 100% natural gas
Forced Draft (FD) Fans	Test block conditions for both units of the existing FD fans exceed the requirements for firing natural gas in capacity and static pressure rise	Flue gas and air flow requirements for firing natural gas are less than the requirements when firing coal, resulting in less static pressure rise
Induced Draft (ID) Fans	Test block conditions of the existing ID fans far exceed the requirements in capacity and static pressure rise for firing natural gas	Flue gas and air flow requirements for firing natural gas are less than the requirements when firing coal, resulting in less static pressure rise

Table 1-2 Summary of the F.B. Culley Unit 2 Boiler Impacts

COMPONENT	RESULTS	COMMENTS
Pressure Parts	• Reduction in primary superheater surface is required in both cases where FGR is required to avoid exceeding the limits of the existing tube metallurgy • Twelve tube rows would be removed	Increased absorption through the convection pass components is due to FGR, which increases flue gas flow rates
Boiler Performance	• Main steam outlet temperatures, pressures, and flow rates equal to firing bituminous coal • Superheater spray flows as high as 46% above firing bituminous coal • Boiler efficiency firing natural gas as low as 83.93% compared to 87.02% when firing bituminous coal (due to moisture in losses from H_2 and H_2O in the natural gas)	Boiler efficiency of 83.93% is based on primary superheater surface reduction without OFA ports
Attemperator Capacities	Attemperator flows firing natural gas increased compared to firing bituminous coal with/without FGR and/or boiler modifications	Existing spray water attemperator nozzle size would have to be modified by increasing the orifice diameter to meet the required flows; flows would be adequate with this modification at all boiler loads
Air Heater Performance	The air and gas side profiles were found to be acceptable for 100% natural gas firing	No field data were available to indicate amount of air heater leakage; original design value of 10% was used in the evaluation

COMPONENT	RESULTS	COMMENTS
Tube Metal Temperature Evaluation	• Existing tubes in convection pass tube had no overstress issues; tubes predicted to operate at temperatures below ASME material code published limit • Header metal temperatures within Babcock & Wilcox standards	Publishing design tube metal temperatures or unbalanced steam temperatures are not allowed by Babcock & Wilcox policy; available for review in Babcock & Wilcox's offices
Forced Draft (FD) Fans	Test block conditions of the existing fans exceed the requirements for firing natural gas with new burners, with/without OFA ports, with/without primary superheater surface reduction	These results are because the FD fans were originally designed for pressurized firing, which has been converted to balanced draft
Induced Draft (ID) Fans	Test block conditions of the existing ID fans far exceed the requirements for firing natural gas with new burners, with/without OFA ports, with/without primary superheater surface reduction	Flue gas and air flow requirements for firing natural gas are less than the requirements when firing coal, resulting in less static pressure rise

When burning natural gas, flue gas emissions reductions from the boilers for particulate matter (PM), sulfur dioxide (SO_2), and mercury (Hg) would be reduced almost directly proportional to the reduction in coal combustion. Boiler flue gas emissions of nitrogen oxides (NO_X) and CO while firing natural gas would also be reduced compared to firing coal. Options assessed to reduce NO_X and CO emissions include the design and installation of an overfire air (OFA) system, flue gas recirculation (FGR) system, CO catalyst system, and continued operation of the SCRs (A.B. Brown Units 1 and 2 only). For this assessment, all options have been evaluated and costs estimated; final selection will be dependent on final air permitting.

The Natural Gas Conversion Evaluation is consistent with an AACE Class 4 estimate (which has an expected accuracy range of +/- 30%) based on Black & Veatch's review of the third part reports, deliverables, and the level of effort. In addition, Black & Veatch provided the preliminary environmental approach and recommendations, including estimated the cost for SCR and CO2 requirements for the units. These estimates are also consistent with an AACE Class 4 estimate.

2.0 Conceptual Design Basis

2.1 GENERAL

The project concept is to replace existing coal fired equipment with natural gas burners (natural gas igniters are currently in service) to use natural gas for startup and during normal operations at A.B. Brown, Units 1 and 2 and F.B. Culley, Unit 2. The natural gas burners would be sized so that 100 percent of each of the boilers' MCR heat input at full unit load could be supplied by firing 100 percent natural gas.

The implementation of the 100 percent natural gas firing option requires the replacement of the existing coal fired system (burners, pulverizers, coal and ash handling equipment, etc.) with a new low NO_X, natural gas fired burner system (burners, piping, valves, controls, and new burner management system [BMS], as a minimum). A new natural gas supply line from the A.B. Brown and F.B. Culley plant boundary to each of the units is included, along with branches to each of the units.

2.1.1 A.B. Brown Unit 1 and 2

A.B. Brown Units 1 and 2 are similar in design and are balanced draft, subcritical boilers, each with a secondary superheater, primary superheater, reheater, and economizer surfaces. Superheater and reheater temperatures are controlled by interstage spray attemperation and excess air/spray attemperation, respectively. The units are each front and rear wall fired with a total of twenty (24) Babcock & Wilcox 4Z low NO_X burners per unit. Each unit is equipped with six Babcock & Wilcox pulverizers and two Ljungstrom regenerative air heaters (refer to Figure 2-1). The gas conversion included a review of the boiler heating surfaces and adequacy of the existing forced draft (FD) fans and primary air (PA) fans. The differences in Unit 1 and Unit 2 are as follows:

- The furnace height of Unit 1 is 122'-0" compared to the furnace height of Unit 2, which is 124'-0."
- Unit 1 has a full furnace division wall; Unit 2 has six water-cooled furnace wing walls.
- Unit 1 was originally designed with flue gas recirculation (FGR), which has been removed from service; Unit 2 was designed to operate without FGR.

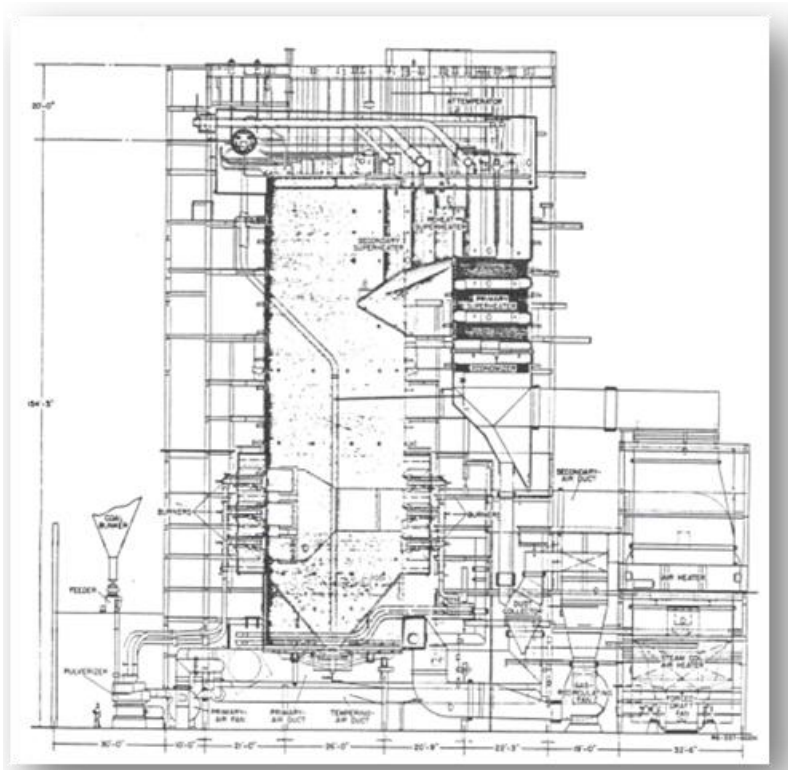

Figure 2-1 A.B. Brown Units 1 and 2 Typical Boiler Diagram

Table 2-1 A.B. Brown Units 1 and 2 Original Design As-Fired Fuel Analyses

CONSTITUENT	PERCENT BY WEIGHT
Carbon (C)	64.00
Hydrogen (H_2)	4.44
Nitrogen (N_2)	1.38
Oxygen (O_2)	6.51
Chlorine (Cl)	0.00
Sulfur (S)	3.52
Moisture (H_2O)	11.35
Ash	8.76
Total	**100.00**
HHV (Btu/lb)	11,533

HHV - higher heating value; Btu/lb - British thermal unit per pound

2.1.2 F.B. Culley Unit 2

F.B. Culley Unit 2 is a subcritical El Paso type radiant boiler and was originally a pressurized fired design; it has been converted to a balanced draft design. The primary and secondary superheater and economizer surfaces are arranged in series (refer to Figure 2-2). Steam temperature is controlled via interstage attemperation. The unit is a front wall fired design and consists of 12 pulverized coal burners. F.B. Culley Unit 2 is different from A.B. Brown Units 1 and 2 in that it is not equipped with an SCR system for NO_X control.

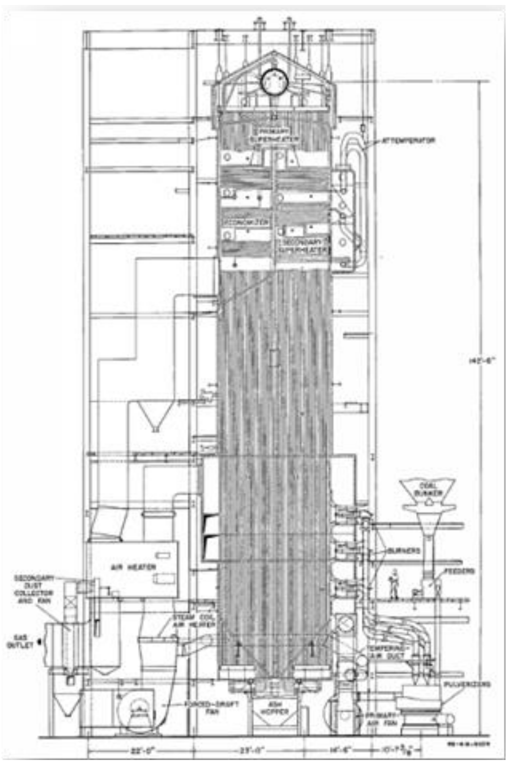

Figure 2-2 F.B. Culley Unit 2 Typical Boiler Diagram

Table 2-2 F.B. Culley Unit 2 Original Design Bituminous Coal Analysis

CONSTITUENT	PERCENT BY WEIGHT
Carbon (C)	55.27
Hydrogen (H_2)	3.70
Nitrogen (N_2)	1.05
Oxygen (O_2)	5.68
Chlorine (Cl)	0.00
Sulfur (S)	3.30
Moisture (H_2O)	19.00
Ash	12.00
Total	**100.00**
HHV (Btu/lb)	10,000

2.2 NATURAL GAS SYSTEM CONCEPTUAL DESIGN

For the conversion both A.B. Brown and F.B. Culley will require a new natural gas pipeline source. The natural gas pipeline supply to the A.B. Brown and F.B. Culley site boundaries were excluded from the scope of this assessment.

A conceptual design was developed for a natural gas supply piping, heating, and regulating system from the gas line tap to the boiler OEM's natural gas fuel controls, metering and pressure regulating skid.

Because of the Joule-Thomson effect, the temperature of natural gas can change during a pressure reduction operation, and its final temperature is related to the amount of pressure drop across the pressure regulating valve. Increasing the temperature of the natural gas may be required prior to pressure reduction to overcome the possibility of moisture condensation and freezing following the cooling effect of the pressure reduction operation. Insulation of the natural gas piping is included as required.

Natural gas heating can be accomplished with natural gas fired heaters, electrical resistance heaters, or using steam. For the purposes of this study, natural gas heating was assumed to be upstream of the site gas line connection by the gas supplier.

2.2.1 Codes and Standards

The conceptual design is based on meeting applicable national codes. The following are the most significant codes and standards applicable to this conceptual design:

- NFPA 85 will be the governing code used in determining the igniter and burner arrangement and operating principles based on a multiple burner boiler.

- ASME B31.1 Power Piping Code and other ASME codes will be used for mechanical design. It is not anticipated that any ASME Section I components will be affected unless boiler heating surfaces are modified.
- NFPA 497 and the National Electric Code (NFPA 70) will also be used in identifying electrical hazardous area classification issues that must be addressed.

2.2.2 A.B. Brown Units 1 and 2 Natural Gas Supply

For the conceptual design, natural gas for the project will be supplied at an assumed pressure at the main gas line connection point on the northwest corner of the site near the existing Unit 2 Cooling Tower at a pressure of approximately 500 psig.

The first stage pressure reduction, metering, and condition station which will reduce the main gas line pressure to around 200 psig will be located at the site gas line connection. From the first stage pressure reduction station a new underground natural gas line will supply the 200 psig natural gas to the southwest corner of Unit 2 where the gas will enter an intermediate regulating station to reduce the pressure to approximately 50 psig required by the boiler OEM. The outlet of the second stage reduction will connect to the Unit 1 and Unit 2 regulating skids provided by boiler OEM, which will further reduce the pressure to a level required for proper operation of the new natural gas burners., Dedicated lines will be routed aboveground to Units 1 and 2 following the second stage regulating stations. At the boilers on Unit 1 and 2, flow control valves and distribution headers will distribute and control the flow of natural gas to the burners located on each level. At each burner, a double block and vent valve arrangement will be furnished. Additional trip, isolation, and header vent valves will be included as part of the boiler OEM's piping internal to the boiler building

The natural gas analysis used in the evaluation was provided by Vectren for A.B. Brown is provided in Table 2-3.

Table 2-3 A.B. Brown Proximate Analysis for Natural Gas

CONSTITUENT	PERCENT BY VOLMUE
Nitrogen (N_2)	0.28
Methane (CH_4)	96.31
Ethane (C_2H_6)	1.46
Carbon Dioxide (CO_2)	1.89
Others	0.06
Total	**100.00**
HHV (Btu/ft^3)	1,037
Btu/ft^3 - British thermal unit per cubic foot	

2.2.3 F.B. Culley Unit 2 Natural Gas Supply

For the conceptual design, natural gas for the project will be supplied at an assumed pressure of approximately 500 psig at the main gas line connection point on the northwest corner of the site near the existing F.B. Culley site gas metering station.

The first stage pressure reduction, metering, and conditioning station which will reduce the main gas line pressure to around 200 psig will be located at the site gas line connection. From the first stage pressure reduction station a new underground natural gas line will supply the 200 psig natural gas to Unit 2 where the gas will enter an intermediate regulating station to reduce the pressure to approximately 50 psig required by the boiler OEM. The outlet of the second stage reduction will connect the regulating skids provided by the boiler OEM, which will further reduce the pressure to a level required for proper operation of the new natural gas burners. Following the second stage regulating stations, flow control valves and distribution headers will distribute and control the flow of natural gas to the burners located on each level. At each burner, a double block and vent valve arrangement will be furnished. Additional trip, isolation, and header vent valves will be included as part of the boiler OEM's piping internal to the boiler building.

The natural gas analysis used in this evaluation was provided by Vectren for F.B. Culley and is shown in Table 2-4.

Table 2-4 F.B. Culley Proximate Analysis for Natural Gas

CONSTITUENT	PERCENT BY VOLUME
Nitrogen (N_2)	1.79
Methane (CH_4)	91.88
Ethane (C_2H_6)	5.12
Others	1.21
Total	**100.00**
HHV (Btu/ft^3)	1,037

2.3 BOILER MODIFICATIONS

There is a shift in heat transfer within the boiler from radiant heat when burning coal to more convective heat transfer when burning natural gas when converting a unit from coal firing to natural gas firing. This is due to the natural gas flame having a lower emissivity that results in less radiant heat output. Additionally, there is more heat transfer in the convective pass of the boiler because there is less ash content produced with firing natural gas. Therefore, an assessment of the heat transfer surfaces, typically by the boiler OEM, is required to determine if any boiler heating surface modifications are required to maintain full load output. For this study, Babcock & Wilcox evaluated performance impacts and/or potential modifications to the boiler heating surfaces of converting the coal fired boilers at A.B. Brown Units 1 and 2 and F.B. Culley Unit 2 to firing 100 percent natural gas.

2.3.1 A.B. Brown Unit 1 and 2 Boiler Modifications

A review of the heating surfaces was performed to assess the boiler pressure part metals at the boiler operating conditions shown in Table 2-5 using the original coal analysis (refer to Table 2-1) and the natural gas analysis provided by Vectren (refer to Table 2-3).

Table 2-5 A.B. Brown Units 1 and 2 Boiler Operating Conditions Used in Metals Evaluation

BOILER LOAD	MCR	60% MCR
Superheater (SH) Steam Flow (lb/h)	1,850,000	1,110,000
Steam Temperature at SH Outlet (°F)	1,005	933
Steam Pressure at SH Outlet (psig)	1,965	1,917
Reheater (RH) Steam Flow (lb/h) w/o attemperator flow	1,666,500	1,000,000
Steam Temperature at RH Outlet (°F)	992	835
Steam Pressure at RH Outlet (psig)	460	261
Feedwater Temperature (°F)	467	417
Excess Air Leaving Economizer (%)	10	18

A detailed boiler analysis for converting A.B. Brown Units 1 and 2 to natural gas was performed by Babcock & Wilcock the boiler OEM to determine possible equipment impacts and estimate performance. Table 2-6 provides a summary of Babcock & Wilcox boiler evaluation.

Table 2-6 Summary of the A.B. Brown Unit 1 and 2 Boiler Evaluation (per Unit Basis)

COMPONENT	RESULTS	COMMENTS
Superheat (SH) and Reheat (RH) Attemperator Flows	SH and RH flow rate less than required for firing coal	Lower amounts of excess air required when firing natural gas as compared to firing coal
Air Heater Performance	The air and flue gas temperature profiles around the air heater were found to be acceptable for firing natural gas; flue gas and air flows and temperatures in/out of air heater were at or below original design values	No field data were available that indicated higher than original air heater leakage; therefore, original air heater leakage of 7.4% was assumed in evaluation
Boiler Performance	• Main steam outlet temperatures, pressures, and flow rates equal to firing bituminous coal • RH steam outlet temperatures and pressure are slightly less when firing natural gas • Boiler efficiency as low as 84.16% compared to 87.92% when firing bituminous coal (because of moisture in losses due to H_2 and H_2O in the natural gas)	Boiler efficiency for coal fired based on original contract performance summary
Tube Metal Temperature Evaluation	• Existing tube metal metallurgies in the convection pass tubes do not exhibit any overstress issues; tubes predicted to operate below American Society of Mechanical Engineers (ASME) material code published limits • Header metal temperatures within Babcock & Wilcox standards	No surface modifications or surface removals are required when converting to firing 100% natural gas

2.3.2 A.B. Brown Units 1 and 2 Combustion Equipment

For A.B. Brown Unit 1 and 2 two modifications were evaluated to convert the existing twenty-four (24) Babcock & Wilcox DRB-4Z® low NO_X coal fired burners to fire natural gas:[1]

The first option was to modify the existing coal burners by adding a "Super-Spud" to each burner configuration. This modification would allow firing natural gas with the ability to continue to fire coal. Refer to Figure 2-3. The Super-Spud is identified in the figure as "Gas Inlet."

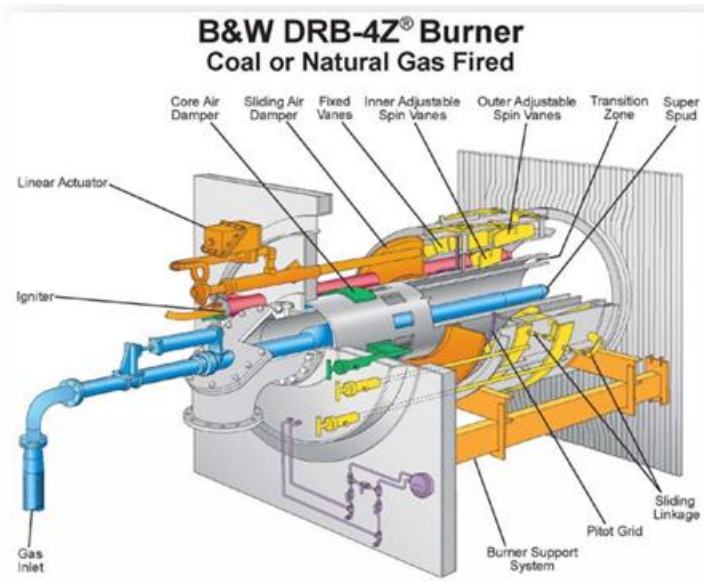

Figure 2-3 Babcock & Wilcox DRB-4Z® Burner (Coal or Gas Fired)

[1] Figures 2-3 and 2-4 were retrieved from Babcock & Wilcox's "Engineering Study for Natural Gas Firing," Contract 591-1048 (317A), June 13, 2019, Rev. 5.

The second option is to remove the existing coal nozzle and replace it with a hemi-spud cartridge. The modification will basically convert the Babcock & Wilcox 4Z low NO_X burners into a Babcock & Wilcox model XCL-S™ burners (refer to Figure 2-4). The XCL-S burner was developed by Babcock & Wilcox to achieve superior NO_X performance utilizing a burner only.

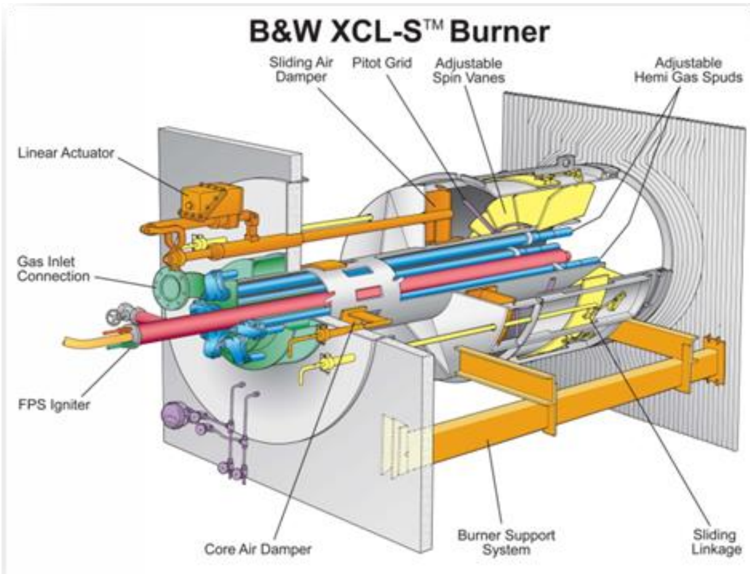

Figure 2-4 Babcock & Wilcox XCL-S™ Burner (Natural Gas Fired)

Additional upgrades to the ignitors and flame scanners are typically required to support the new burner design and control system upgrades.

The existing ignitors will be reused while the flame scanners will be replaced with new UV scanners capable of detecting flames from the new natural gas fuel.

2.3.3 F.B. Culley Unit 2 Boiler Modifications

A review of the heating surfaces was performed to assess the boiler pressure part metals at the boiler operating conditions shown in Table 2-7 using the original coal analysis (refer to Table 2-2) and the natural gas analysis provided by Vectren (refer to Table 2-4).

Table 2-7 F.B. Culley Unit 2 Boiler Operating Conditions Used in Metals Evaluation

BOILER LOAD	MCR	50% MCR
Superheater Steam Flow (lb/h)	840,000	420,000
Steam Temperature at SH Outlet (°F)	955	925
Steam Pressure at SH Outlet (psig)	1,290	1,260
Feedwater Temperature (°F)	425	360
Excess Air Leaving Economizer (%)	10	18

A detailed boiler analysis for converting F.B. Culley Unit 2 to natural gas was performed by Babcock & Wilcock the boiler OEM to determine possible equipment impacts and estimate performance. Table 2-8 provides a summary of Babcock & Wilcox boiler evaluation.

Table 2-8 Summary of the F.B. Culley Unit 2 Boiler Evaluation

COMPONENT	RESULTS	COMMENTS
Pressure Parts	• Reduction in primary superheater surface is required in both cases where FGR is required to avoid exceeding the limits of the existing tube metallurgy • Twelve tube rows would be removed	Increased absorption through the convection pass components is due to FGR, which increases flue gas flow rates
Boiler Performance	• Main steam outlet temperatures, pressures, and flow rates equal to firing bituminous coal • Superheater spray flows as high as 46% above firing bituminous coal • Boiler efficiency firing natural gas as low as 83.93% compared to 87.02% when firing bituminous coal (due to moisture in losses from H_2 and H_2O in the natural gas)	Boiler efficiency of 83.93% is based on primary superheater surface reduction without OFA ports
Attemperator Capacities	Attemperator flows firing natural gas increased compared to firing bituminous coal with/without FGR and/or boiler modifications	Existing spray water attemperator nozzle size would have to be modified by increasing the orifice diameter to meet the required flows; flows would be adequate with this modification at all boiler loads
Air Heater Performance	The air and gas side profiles were found to be acceptable for 100% natural gas firing	No field data were available to indicate amount of air heater leakage; original design value of 10% was used in the evaluation
Tube Metal Temperature Evaluation	• Existing tubes in convection pass tube had no overstress issues; tubes predicted to operate at temperatures below ASME material code published limit • Header metal temperatures within Babcock & Wilcox standards	Publishing design tube metal temperatures or unbalanced steam temperatures are not allowed by Babcock & Wilcox policy; available for review in Babcock & Wilcox's offices

2.3.4 F.B. Culley Unit 2 Combustion Equipment

The existing 12 coal fired burners for F.B. Culley Unit 2 will be replaced with new Babcock & Wilcox XCL-S™ burners which can be retrofitted into the existing burner openings in the furnace walls. Some adjustment to the existing burner throat diameter may be required, which will be dependent on the choice of NO_x reduction technologies: burners only, burners plus OFA, FGR, and any combination of these NO_x reduction technologies. Conical ceramic throat inserts for reducing the burner throat diameter may be installed, or refractory may be removed to increase the burner throat diameter. The chosen design will be based on the results of the engineering phase. It should be noted that all the combustion air will have to be supplied via the secondary air ducting system since PA (for pulverized coal transport) will no longer be available

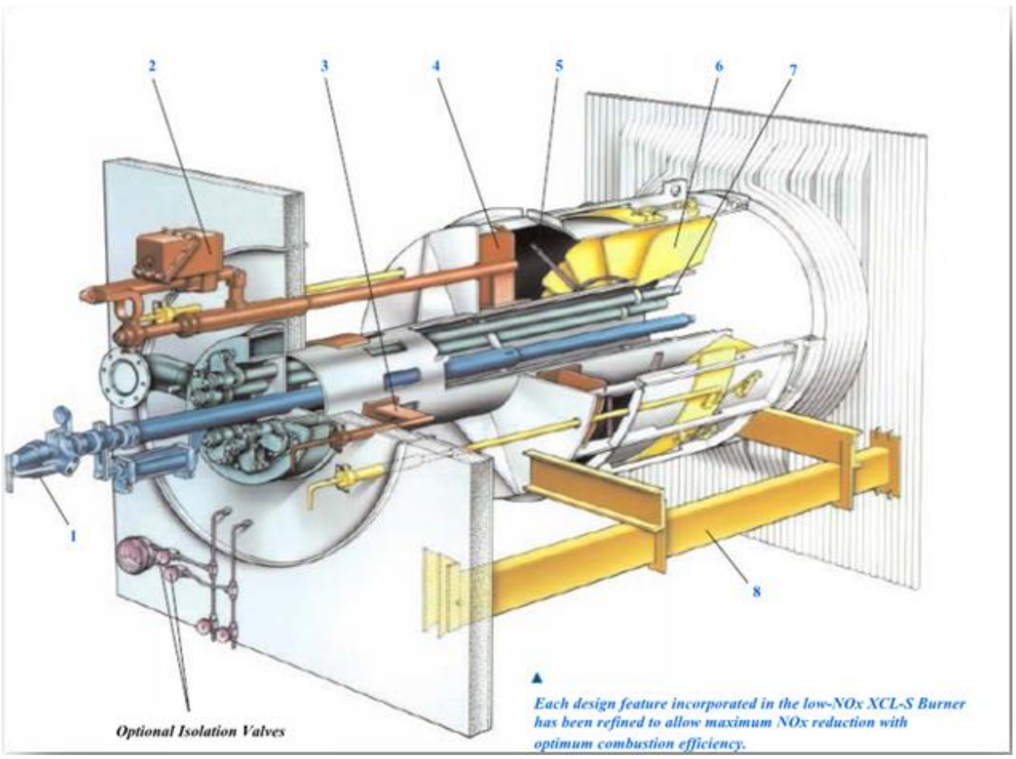

Figure 2-5 Babcock & Wilcox Low-NO_X XCL-S™ Burner[2]

The existing ignitors will be replaced with new high energy spark ignitors and the flame scanners will be replaced with new scanners capable of detecting flames from the new natural gas fuel.

[2] Figure 2-5 was retrieved from Babcock & Wilcox's "Engineering Study for Natural Gas Firing," Contract 591-1022 (293H), June 13, 2019, Rev. 2.

2.4 COMBUSTION AIR SYSTEM

For natural gas firing, the mills and PA fans can be taken out of service (abandoned in place). The portion of the combustion air traveling to the mills is blocked off such that all combustion air travels to the windbox. These changes are easily accomplished in the combustion air ductwork.

Changes to the windbox size to accommodate the additional combustion air may be required to facilitate installation of FGR and/or OFA based on final design. Typically, no changes are required to the air heaters to accommodate the removal of the PA system. If required, these combustion air system modifications for natural gas firing can easily be reversed for a future return to coal firing, if the plant determines to do so.

2.4.1 A.B. Brown Unit 1 and 2 Forced Draft Fan Analysis

The existing forced draft fans on Units 1 and 2 were reviewed for the 100% natural gas firing and determined that no modifications are required to meet the new design conditions as summarized in Table 2-9. The predicated fan performance from the boiler OEM is can be found in Appendix A.

Table 2-9 A.B. Brown Unit 1 and 2 Fan Evaluation

COMPONENT	RESULTS	COMMENTS
Forced Draft (FD) Fans	Test block conditions for both units of the existing FD fans exceed the requirements for firing natural gas in capacity and static pressure rise	Flue gas and air flow requirements for firing natural gas are less than the requirements when firing coal, resulting in less static pressure rise

2.4.2 F.B. Culley Unit 2 Forced Draft Fan Analysis

The existing forced draft fans on Unit 2 were reviewed for the 100% natural gas firing and determined that no modifications are required to meet the new design conditions as summarized in Table 2-10. The predicated fan performance from the boiler OEM is can be found in Appendix B.

Table 2-10 F.B. Culley Unit 2 Fan Evaluation

COMPONENT	RESULTS	COMMENTS
Forced Draft (FD) Fans	Test block conditions of the existing fans exceed the requirements for firing natural gas with new burners, with/without OFA ports, with/without primary superheater surface reduction	These results are because the FD fans were originally designed for pressurized firing, which has been converted to balanced draft

2.5 FLUE GAS SYSTEM

Since natural gas firing has no ash and negligible sulfur compared to firing coal, air quality control systems including fabric filters, electrostatic participators, and flue gas desulfurization (FGD) are generally no longer required post conversion. However, it is typical for fabric filters and electrostatic participators to remain in operation for a short period of time following the natural gas conversion to capture residual coal ash remaining in the equipment and ductwork before eventually being decommissioned in place and the internals removed. FGD systems are abandoned or demolished and new flue gas ductwork installed from the FGD inlet to the stack.

2.5.1 A.B. Brown Unit 1 and 2 Induced Draft Fan Analysis

The existing induced draft fans on Units 1 and 2 were reviewed for the 100% natural gas firing and determined that no modifications are required to meet the new design conditions as summarized in Table 2-11. The predicated fan performance from the boiler OEM is can be found in Appendix A.

Table 2-11 A.B. Brown Unit 1 and 2 Fan Evaluation

COMPONENT	RESULTS	COMMENTS
Induced Draft (ID) Fans	Test block conditions of the existing ID fans far exceed the requirements in capacity and static pressure rise for firing natural gas	Flue gas and air flow requirements for firing natural gas are less than the requirements when firing coal, resulting in less static pressure rise

2.5.2 F.B. Culley Unit 2 Induced Draft Fan Analysis

The existing induced draft fans on Unit 2 were reviewed for the 100% natural gas firing and determined that no modifications are required to meet the new design conditions as summarized in Table 2-12. The predicated fan performance from the boiler OEM is can be found in Appendix B.

Table 2-12 F.B. Culley Unit 2 Fan Evaluation

COMPONENT	RESULTS	COMMENTS
Induced Draft (ID) Fans	Test block conditions of the existing ID fans far exceed the requirements for firing natural gas with new burners, with/without OFA ports, with/without primary superheater surface reduction	Flue gas and air flow requirements for firing natural gas are less than the requirements when firing coal, resulting in less static pressure rise

2.6 CONTROL SYSTEM MODIFICATIONS

The existing BMS and BCS I/O and control processors should be repurposed or replaced along with new control logic and DCS reprogramming to support the new natural gas fired equipment. New instrumentation is required to control the new natural gas supply and burner equipment. Flow transmitters on the natural gas supply to each unit will support boiler fuel input calculations while pressure instrumentation will provide both control and necessary interlocks in accordance with NFPA 85.

2.7 FIRE PROTECTION IMPACTS

In general, converting from coal burners to natural gas burner would not require additional fire protection. However, Black & Veatch recommends getting approval from the local Authority Having Jurisdiction (AHJ) during the project design stages.

2.8 AUXILIARY ELECTRICAL SYSTEM IMPACTS

No major additions to the existing auxiliary electrical system are needed. Burner block and vent valves will be air operated valves and existing ID and FD fans will remain so that no new major power requirements are foreseen.

All systems associated with coal firing (mills, coal and ash handling equipment, etc.) would be removed from service, resulting in a reduction in auxiliary power. Also removed from service will be the precipitator and the dual alkali scrubber which will further reduce the auxiliary load on the plant.

New natural gas pressure reducing stations will require power for control panels. Each reducing station power supply will be fed by existing plant equipment and will have negligible electrical power consumption.

2.9 PLANT WATER SYSTEM IMPACTS

Boiler demineralized water consumption can increase in natural gas conversions if the conversion leads to more cyclical operation. In addition, when the unit is shut down for prolonged periods of time the resulting boiler draining and filling will result in intermittent high demands of demineralized water usage. Wet scrubber technology for the reduction of acid gases from fuel bound nitrogen in the bituminous coal being fired requires a continuous supply of water to make up the continued blowdown system. Water is also utilized for sluicing bottom ash to an ash pond and for the hydroveyor to the barge used for transporting dry fly ash off-site. Water for these systems will no longer be needed with the conversion.

2.10 NFPA IMPACTS

2.10.1 Hazardous Classification Impacts

NFPA 497 defines hazardous area classifications involving flammable or combustible liquids, combustible gases, or combustible dusts. This classification is necessary for the proper selection and installation of electrical equipment. The National Electric Code (NEC), as defined by NFPA 70, defines the requirements for electrical equipment and associated installation methods within the boundaries of hazardous areas defined by NFPA 497. In many cases, this requires vendors to provide equipment in explosion proof enclosures, the installation of purge air systems, or the use of intrinsically safe barrier systems. Electrical installation methods include the use of raceway systems specifically rated for the hazardous area and the use of seal-offs in raceway that cross the hazardous area boundary.

Assuming that the existing powerhouse meets the definition of being well-ventilated, NFPA 497 requires that 15-foot spheres around each potential leakage point be classified as a Class I Division II hazardous area. Long sections of welded natural gas piping without any flanges, valves, or instruments will not require a hazardous area classification. The fuel gas piping to the burners includes flanged connections, stem packing on the control and shutoff valves, and fittings on instrument connections that represent potential leakage points. As a result, all existing electrical components and raceway within the 15-foot sphere of potential leak points not rated for a Class I Division II environment will require replacement with appropriately rated equipment and materials. Examples include lighting, receptacles, communications equipment, power distribution equipment, control panels, drives, and associated raceway. A detailed hazardous area impact study would need to be performed to identify equipment and materials that need to be upgraded or replaced.

2.10.2 NFPA 85 Implosion Control

Although no FD or ID fan modifications are anticipated at this time to enable natural gas firing on any of the units, there may be an increased implosion potential in each boiler due to the firing characteristics of natural gas compared with coal. Natural gas can "flame out" much more quickly than coal, and natural gas does not have residual heat remaining in pulverized fuel pipes like coal. The result is the potential for an immediate drop in boiler temperature, rapidly lowering the internal boiler pressure. To fully evaluate the impacts and required boiler pressure rating due to this operating scenario, a Furnace and Draft System Transient Pressure Analysis study should be completed prior to detailed design. To some extent, the boiler depressurization can be mitigated with controls optimization (damper and fan operation control); this will also need to be evaluated by the study.

2.11 EXISTING EMISSION CONTROL EQUIPMENT IMPACTS

When burning natural gas, flue gas emissions reductions from the boilers for PM, SO2, and Hg are reduced almost directly proportional to the reduction in coal combustion. Therefore, the precipitator and related equipment will not be required for firing 100 percent natural gas. The systems, however, will remain in service for a short time after the conversion to 100 percent natural gas to remove any residual ash remaining in the ducting after the conversion. The dual alkali scrubber has numerous maintenance issues and therefore would also be removed from service, demolished, and replaced with ducting from the precipitator outlet to the stack.

The existing SCRs on A.B. Brown Unit 1 and 2 have been considered as part of the NO_x reduction control technologies and continued operation would be confirmed as part of the final netting analysis and permitting strategy (refer to Section 4.0).

3.0 Performance Impacts Analysis

Compared to firing coal, firing natural gas will reduce the boiler efficiency which will result in an increase in the net plant heat rate. The main impact on boiler efficiency is due to the hydrogen losses from the higher hydrogen content of the natural gas. Water vapor is a byproduct of combusting hydrogen, which requires additional heat to remove the water vapor. This additional heat is a loss in the flue gas rather than being absorbed in the boiler walls to create steam. Babcock & Wilcox has estimated that the excess air requirements for firing natural gas is 10 percent, compared to 20 percent for firing coal. The lower excess air requirement results in less flue gas flow, which equates to smaller losses for heating the flue gas.

A reduction in auxiliary power requirements will be realized since the pulverizers, motors and electrical equipment associated with the scrubbers, coal handling equipment, will no longer be operated after the conversion.

3.1 A.B. BROWN UNITS 1 AND 2 BOILER STEAMING CAPABILITY

Based on an assessment by Babcock & Wilcox, at MCR the main steam temperature leaving the boiler is expected to be the same as with firing coal, however, the hot reheater (HRH) temperature after gas conversion is expected to be less than the HRH temperature from firing coal. A summary of the predicted performance results based on Babcock & Wilcox' evaluation is shown in Table 3-1.

At the 60% MCR flow condition, Table 3-1 shows a more significant reduction in steam temperatures for natural gas operation. Main steam temperature decreases from 1,005 °F to 955 °F and hot reheat temperature decreases from 1,005 °F to 835 °F. Reductions in main steam and reheat steam temperatures will reduce the net turbine heat rate at this operating condition.

In addition, the excess air requirements for firing natural gas are less than the excess requirements for firing coal. This equates to a reduction in the spray water requirements for the main steam and reheater attemperators.

Table 3-1 A.B Brown Units 1 and 2 Predicted Boiler Steam Conditions

LOAD CONDITION	UNITS	MCR	MCR	60%	60%
FUEL	**-**	**100% COAL**	**100% NATURAL GAS**	**100% COAL**	**100% NATURAL GAS**
Superheater Exit Steam Flow	kpph	1,850	1,850	1,110	1,110
CRH Steam Flow	kpph	1,667	1,667	1,000	1,000
Superheater Exit Steam Pressure	psig	1,965	1,965	1,917	1,917
Reheater Exit Steam Pressure	psig	460	460	261	261
Superheater Exit Steam Temperature	F	1,005	1,005	1,005	955
Reheater Exit Steam Temperature	F	1,005	992	1,005	835

One possible way to reduce the impact to the hot reheat steam temperature is to increase air flow through the boiler with the use of FGR and OFA. These systems are typically considered for NOx control but can also be utilized to improve boiler performance by increasing overall combustion air flow through the boiler. The result is more heat transfer in the convective pass of the boiler improving HRH temperatures. A detailed analysis would need to be performed by the OEM or a third-party boiler model developed to evaluate the potential for improved performance.

3.1.1 Steam Turbine Impacts

The increased temperature difference between main steam and hot reheat steam during natural gas firing can have an adverse impact on the steam turbine. Based on the 60% MCR flow conditions for natural gas operation, the temperature difference is estimated to be 120 °F (955 °F – 835 °F). The main steam and hot reheat steam admissions are adjacent to one another in the same turbine shell and thus the initial and reheat temperatures have an important influence on the axial temperature gradient in the turbine shell.

General Electric (GE), the steam turbine OEM, typically provides guidelines on the permissible temperature difference at various operating load points. A review of the A.B. Brown steam turbine operating manual and subsequent discussion with GE indicates that the guideline included by GE for allowable differences between main and reheat steam temperatures is for units with opposed flow HP-IP turbines similar to the A.B. Brown turbines, but with a separate control valve chest. The A.B. Brown turbines however have an integral valve chest (shell mounted). GE has confirmed the provided guideline is also applicable to the A.B. Brown turbines with integral valve chest. The GE provided data indicates the 120°F differential temperature is acceptable at 60% MCR flow. Predicted boiler performance on natural gas operation was not evaluated below 60% MCR flow, therefore this operating condition would need to be assessed to fully understand the possible impacts to the steam turbine at lower loads.

Additional measures to mitigate the reduction in steam temperatures and potentially reducing their temperature difference may include sliding pressure operation at part load (compared to constant main steam pressure at part load), and possible additional measures in the boiler operation. The degree of extension of the constant temperature range for variable pressure operation will vary with a particular steam generator, fuel and other station constraints and would require additional evaluation by Babcock & Wilcox.

Reduced hot reheat steam temperature can result in increased moisture at the low-pressure turbine exhaust. Increased moisture can increase the potential for erosion of the blading of the low-pressure turbine section. The steam turbine OEM should be requested to further evaluate the impact, if any, of this increased exhaust moisture as well as the impact of the changed conditions in the low-pressure turbine section where the onset of condensation will occur (known as the Wilson Line). Initial assessment indicates the exhaust moisture may increase on the order of 3% at the 60% of MCR flow operating conditions.

3.2 F.B. CULLEY UNIT 2 BOILER STEAMING CAPABILITY

It is predicted that the main steam output of the units will not be reduced following the conversion. The excess air requirements for firing natural gas are less than the excess requirements for firing coal. This equates to a reduction in the spray water requirements for the main steam attemperators – the orifice diameter in the spray water attemperator nozzle would have to be increased. The main steam temperature and pressure leaving the boiler is expected to be the same as with firing coal. To meet these conditions, a surface reduction in the primary superheater would be required in the case where flue gas recirculation is utilized. A summary of the predicted performance results based on Babcock & Wilcox' evaluation is shown in Table 3-3.

Table 3-3 F.B. Culley Unit 2 Predicted Boiler Steam Conditions

LOAD CONDITION	UNITS	MCR	MCR	50%	50%
FUEL	**-**	**100% COAL**	**100% NATURAL GAS**	**100% COAL**	**100% NATURAL GAS**
Superheater Exit Steam Flow	kpph	840	840	420	420
Superheater Exit Steam Pressure	psig	1,290	1,290	1,260	1,260
Superheater Exit Steam Temperature	F	955	955	955	955

3.2.1 Steam Turbine Impacts

As shown in Table 3-3 the superheat steam flow and temperature remain consistent between coal and natural gas fired scenarios. Therefore unlike A.B. Brown Units where they drop off at part load, there is not a concern of potential steam turbine impacts to F.B. Culley Unit 2 when firing natural gas.

4.0 NOx and CO Reduction Techniques

Converting the boilers to 100 percent natural gas combustion should significantly decrease the NO_x while increasing CO from the combustion process. Since there is nearly zero fuel-bound nitrogen in natural gas, NO_x production is a direct result of thermal NO_x formation during combustion. In addition, natural gas firing temperatures are typically lower, as less excess air is required to complete combustions compared to coal, reducing the potential for thermal NO_x to form. However, this limited oxygen environment that results in lower NO_x does increase CO from incomplete combustion. It should be noted that even though NOx production is lower for natural gas vs. coal due to less combustion air, the allowable permitting limits for burning natural gas can be much lower than coal. For instance, Unit 1 at A.B. Brown is currently subject to New Source Performance Standard (NSPS) Subpart D, which carries a NO_X limit of 0.70 lb/MBtu for coal-fired units. For natural gas-fired units, the rule prescribes a NO_X limit of 0.20 lb/MBtu. Unit 2 at A.B. Brown is subject to NSPS Subpart Da, which requires that the unit meet a NO_X emission limit of 0.50 lb/MBtu for coal-firing. Following a conversion to natural gas, the unit would be subject to a limit of 0.20 lb/MBtu. F.B. Culley Unit 2 is not subject to any NSPS NO_X limits given its age. Black & Veatch would not anticipate that this would change following a conversion to natural gas assuming that the project is not applicable to major modification permitting requirements.

To control NO_x and CO, additional controls are typically required and for this evaluation included assessment of selective catalytic reduction (SCR), flue gas recirculation (FGR), over-fire air (OFA), and CO Catalyst also referred to as Oxygen catalyst to limit emissions.

Specific reduction techniques considered for A.B. Brown Units 1 and 2 and F.B. Culley Unit 2 are identified in Table 4-1 and Table 4-2. Calculated emission rates for the evaluated emission control technologies are identified in Section 5, Table 5-1.

Table 4-1 A.B. Brown Unit 1 and 2 Optional Methods for NOx Reduction

COMPONENT	RESULTS	COMMENTS
OPTIONAL METHODS FOR NO_X REDUCTION		
Staged Combustion (OFA Ports)	Addition of eight new OFA (aka NO_X ports) in the furnace walls; four in the front wall, four in the rear wall.	Will require windbox and duct work modifications. Since A.B. Brown units are currently equipped with SCR systems OFA may not be required
Flue Gas Recirculation (FGR)	Introduction of recirculated flue gas into the combustion air stream upstream of the burner windbox via new FGR fan pulling flue gas from ducting downstream of the air heater.	Mixing device to be added in the combustion air ductwork to adequately distribute the recirculated flue gas into the incoming combustion air. Since A.B. Brown units are currently equipped with SCR systems, FGR may not be required
Selective Catalytic Reduction (SCR)	Continued operation of existing SCRs including ammonia storage and feed systems.	Existing SCR catalyst would require analysis to determine if any or all layers require replacement to meet targeted NO_x reduction.

OPTIONAL METHODS FOR CO REDUCTION		
CO Catalyst	Addition of a CO (Oxygen) Catalyst to be located in the fourth layer of the existing SCR which is currently unused.	Multiple catalysis technologies are available and include duel SCR and CO catalysis which should be evaluated during detailed design.

Table 4-2 F.B. Culley Unit 2 Optional Methods for NO_x Reduction

COMPONENT	RESULTS	COMMENTS
OPTIONAL METHODS FOR NO_X REDUCTION		
Staged Combustion (OFA Ports)	Addition of eight new OFA (aka NO_X ports) in the furnace walls; four in the front wall, four in the rear wall, located approximately 8 feet above the top burner row	Will require windbox and duct work modifications
FGR	Introduction of recirculated flue gas into the combustion air stream upstream of the burner windbox via new FGR fan pulling flue gas from ducting downstream of the air heater	Mixing device to be added in the combustion air ductwork to adequately distribute the recirculated flue gas into the incoming combustion air
OPTIONAL METHODS FOR CO REDUCTION		
CO Catalyst	Addition of a new CO (Oxygen) Catalyst in the flue gas ductwork between the economizer outlet and air heater inlet.	Would require extensive modifications to the flue gas ductwork to facilitate installation.

4.1 OVER-FIRE AIR (OFA)

Two-staged combustion is a method of achieving a significant reduction in NO_x. Combustion air is directed to the burner zone in quantities (70 percent to 90 percent) that are less than that required to theoretically burn the fuel. The remainder of the combustion air (10 percent to 30 percent) is directed to OFA ports, which are located above the top row of burners. By reducing the excess air in the primary combustion (burner) zone, NO_x formation is stunted due to the limited amount of oxygen in the air. Furthermore, less oxygen means a decrease in the combustion reactions occurring and a decrease in the heat of reaction released, reducing the overall and peak temperatures in the burner zone (first stage). The additional air nozzles also spread the release of heat over a larger area in the furnace. Thermal NO_x formation increases with higher temperatures, so reducing the overall and peak temperatures represses thermal NO_x. Any residual unburned material, such as CO that inevitably escapes the main burner zone, is subsequently oxidized as the OFA is added.

The expected NO_x reduction from a given OFA system depends on a number of factors. The stoichiometry in the burner zone decreases as the amount of OFA is increased, and a point is reached where CO emissions reach high levels and become uncontrollable. The point at which this occurs varies, depending on the balance of flows between individual burners. As the OFA amount approaches 10 to 15 percent, the probability for individual burners to be operating under fuel-rich conditions increases so that pockets of very high CO emissions would be formed.

The total estimated furnish and installed cost for an over-fire air system is shown in Table 4-3.

Table 4-3 Over-Fire Air System Estimated Cost

	A.B. BROWN UNIT 1	A.B. BROWN UNIT 2	CULLEY, UNIT 2
Materials and installation[1]	$1,000,000	$1,000,000	$975,000
Total furnish and installed cost for OFA system	$1,000,000	$1,000,000	$975,000
Note: 1. Includes OFA nozzles, ducting modifications, and dampers			

4.2 FLUE GAS RECIRCULATION

FGR is useful in reducing NO_x when the contribution of fuel nitrogen to the total NO_x formation is a small fraction of the constituents, such as the case with natural gas. Typically, a portion of the flue gas is extracted from the discharge of the economizer (gas side) or discharge of the air heater and introduced into the combustion air flow stream, which lowers the burner peak flame temperatures.

The typical design of an FGR system requires the installation of an FGR fan, ducting, duct supports, and controls. The FGR system utilizes air foils to mix the recirculated flue gas with the combustion air downstream of the FD fan. This ensures that the flue gas and combustion air are thoroughly mixed before reaching the burners.

For retrofit applications, FGR sometimes needs to be provided with OFA ports, because the original burners are not capable of handling the significant increase in mass flow from the recirculated flue gas. The necessary FGR rates can result in throat velocities that exceed the burners' design, which will result in burner instability and potential pulsations while firing.

In general, a significant increase in flue gas recirculation to the burners would produce a large reduction in NO_x emissions. The amount of FGR would be dictated by the emissions levels that are targeted as well as limitations on equipment size and boiler components.

An additional benefit of FGR is that the additional flue gas flow with the combustion air can increase furnace velocities to push heat to the convective heating surfaces, which could increase steam temperatures on coal units that have been converted to gas.

The total estimated furnish and installed cost for a flue gas recirculation system is shown in Table 4-4.

Table 4-4 Flue Gas Recirculation System Estimated Cost

	A.B. BROWN UNIT 1	A.B. BROWN UNIT 2	CULLEY, UNIT 2
Materials and installation[1]	$3,880,000	$3,880,000	$1,560,000
Total furnish and installed cost for FGR system	$3,880,000	$3,880,000	$1,560,000
Notes: 1. Includes FGR fan/motor, ducting, instrumentation, and installation			

4.3 SELECTIVE CATALYTIC REDUCTION

Selective catalytic reduction (SCR) reduces NO_x emissions by introducing ammonia (NH_3) into the flue gas upstream of a reaction chamber. Ammonia readily reduces the NO_x molecules into nitrogen and water at temperatures above 1600°F (870°C). The SCR reaction chamber, which is installed between the economizer and air preheater, is at temperatures much less than is optimal for NH_3-NO_x reactions, so catalysts are needed to promote the reactions. The reaction chamber contains one or multiple layers of catalyst that are made of metals and/or ceramics contained a highly porous structure.

Poisoning of the catalyst from alkali metals and trace elements (especially arsenic) is a steady process that occurs over the life of the catalyst. As the catalyst becomes deactivated, ammonia slip emissions increase, approaching design values. This means that the catalyst in a SCR system is consumable, requiring periodic replacement at a frequency dependent on the level of catalyst poisoning. For natural gas applications, significantly less catalyst poisoning is expected compared to coal burning facilities.

Since the existing SCR catalyst systems at A.B. Brown Unit 1 and Unit 2 have been in use for several years it was assumed for this study and cost estimate that multiple layers of SCR catalyst would need to be replaced to facilitate continued operation and NO_x reduction through the SCRs. The next step would be for Vectren to have a catalyst OEM assess the condition of the existing catalyst and make a recommendation for replacement or reuse for the natural gas conversion operation.

The total estimated furnish and installed cost for a selective catalytic reduction system is shown in Table 4-5.

Table 4-5 Selective Catalytic Reduction System Estimated Cost

	A.B. BROWN UNIT 1	A.B. BROWN UNIT 2	CULLEY, UNIT 2
Total materials	$1,060,000	$1,060,000	N/A
Total installation	$1,000,000	$1,000,000	N/A
Total furnish and installed cost for a SCR system[1] certification	$2,060,000	$2,060,000	NA
Notes: 1. SCR system includes replacement of catalyst, chemical disposal, SCR catalyst replacement, installation.			

4.4 OXGYEN CATALYTIC REDUCTION (CO CATALYST)

Catalytic oxidation is a post-combustion method for reduction of CO and VOC emissions. This control process utilizes a platinum/vanadium catalyst that oxidizes CO to CO2 and VOC to CO2 and water. The process is a straight catalytic oxidation/reduction reaction requiring no reagent. Catalytic CO and VOC emissions reduction methods have been proven for use on natural gas and oil fueled combustion turbine sources, but not coal fired boilers. It should be noted that none of the catalyst components are considered toxic.

The primary technical challenge for including an oxidation catalyst on a coal or natural gas fired boiler is the location of the catalyst in a high temperature regime, which would ideally be prior to the economizer as the optimum exhaust gas temperature range for CO and VOC catalyst operation is between 850°F and 1,110°F (1,560°C and 2,012°C). For the purpose of this study the CO catalyst is assumed to be located between the economizer and air heater.

The total estimated cost for a catalytic oxidation system is shown in Table 4-6.

Table 4-6 Catalytic Oxidation System Estimated Cost

	A.B. BROWN UNIT 1	A.B. BROWN UNIT 2	CULLEY, UNIT 2
Total materials	$3,500,000	$3,500,000	$2,000,000
Total installation	$1,500,000	$1,500,000	$3,000,000
Total furnish and installed cost for CO system[1]	$5,000,000	$5,000,000	$5,000,000
Notes: 1. Includes CO system materials,			

5.0 Emissions Netting

5.1 BACKGROUND

Converting A.B. Brown Units 1 and 2 and F.B. Culley Unit 2 to fire natural gas would constitute a modification of an existing air emissions source and would, therefore, require an air construction permit to authorize construction. The first step in any air construction permit application process is to determine the proposed project's applicability to the federal New Source Review (NSR) pre-construction permitting program.

The Federal Clean Air Act (CAA) NSR provisions are implemented for major modifications at existing major sources under two programs: the Prevention of Significant Deterioration (PSD) program outlined in 40 CFR §52.21 for areas in attainment of the National Ambient Air Quality Standards (NAAQS), and the Non-Attainment NSR (NA-NSR) program outlined in 40 CFR §51 and §52 for areas classified as not in attainment of the NAAQS (i.e., non-attainment areas). Currently, both Posey County and Warrick County, Indiana, are designated as either attainment or unclassifiable for all criteria pollutants. Because of this, a determination of whether the proposed natural gas conversions would qualify as a major modification at an existing major source would need to be made in accordance with the procedures outlined in the PSD program. Projects that are subject to PSD permitting are required to undertake extensive analyses as part of the permit application process, including air dispersion modeling and the identification and application of best available control technology (BACT). Additionally, PSD permitting can take as long as 12-18 months. Non-PSD permitting, or minor source permitting, on the other hand does not typically require modeling or BACT and the associated timeline is typically 3-6 months.

For a project to be deemed a major PSD modification under the definition provided in 40 CFR §52.21, the project must result in both a significant emission increase and a significant net emission increase. The process of determining whether a significant emissions increase will result from the construction of a project is commonly referred to as "Step 1" of the PSD applicability test. Because both A.B. Brown and F.B. Culley are existing major sources under the PSD process, the Step 1 evaluation must be conducted on a pollutant-by-pollutant basis by comparing the emissions increase of each pollutant against the PSD significant emissions rates (SERs). If a project's emissions increase of a given pollutant are larger than the pollutant's respective SER, the project is considered to result in a significant emissions increase. Since the proposed natural gas conversions will involve existing emissions units, this Step 1 emissions increase, or project emissions increase (PEI), can be calculated as the difference between either the project actual emissions (PAE) or the potential to emit (PTE) and the baseline actual emissions (BAE). BAE is defined in the federal PSD regulations as the average rate, in tons per year (tpy), at which the emissions unit actually emitted a regulated NSR pollutant during any consecutive 24 month period selected by the owner or operator within the 5 year period immediately preceding when the owner or operator begins actual construction of the project. However, because air construction permit applications are required to be submitted several months prior to the start of construction, agencies will typically accept BAEs based on the 5-year period immediately preceding the submittal of the air construction permit application.

Because the proposed projects entail the conversion of coal fired boilers to natural gas firing, the PAE cannot easily be determined, as no past operation burning natural gas could be used to base a projection on. Therefore, the PTE would likely be used in conjunction with the BAE to determine the PEI of the proposed natural gas conversions in Step 1 of the PSD applicability determination. According to federal and state definitions, the PTE is "the maximum capacity of a source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type of/amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation is enforceable […]."

Vectren has determined that any air construction permitting strategy for the proposed natural gas conversions at A.B. Brown and F.B. Culley should try to mitigate the need for PSD. As previously noted, obtaining a PSD permit involves several rigorous requirements including the application of Best Available Control Technology (BACT) and the performance of an air dispersion modeling analysis examining the effects of the project's emissions on the ambient air quality. Thus, the PSD review process typically adds significant time in a project schedule to account for application preparation as well as Indiana Department of Environmental Management (IDEM) and Environmental Protection Agency (EPA) review.

5.2 PRELIMINARY PSD APPLICABILITY ANALYSIS

A high-level preliminary emissions analysis was conducted to determine the operational limits (i.e., limits on annual hours of operation) required to keep the Step 1 pollutant-by-pollutant PEI for the natural gas conversion at each facility less than the respective PSD SERs so that PSD permitting would not be required. The analysis examined the added hours of operation that could be achieved utilizing various air quality control technologies.

Assuming all other factors are held equal, because of the cleaner nature of natural gas combustion compared to coal, conversion of the A.B. Brown and F.B. Culley coal fired boilers to natural gas fueled units should result in emissions reductions when comparing the PTE to the BAE for those pollutants that are directly related to fuel makeup (i.e., PM and SO_2). On the other hand, for pollutants where emissions are associated with the combustion process (i.e., NO_X, CO, and VOC), emissions associated with natural gas combustion can yield emissions increases in the Step 1 PEI calculation. Because of this, the preliminary analysis was limited to examine only NO_X, CO, and VOC as the "limiting pollutants."

The NO_X, CO, and VOC BAE for A.B. Brown and F.B. Culley utilized a combination of industry standard emission factors from EPA's AP-42 database, continuous emissions monitoring system (CEMS) data, and fuel usage data. The A.B. Brown baseline includes monthly emissions through February 2019 whereas F.B. Culley's BAE was based on data through the end of 2018. The BAE for both A.B. Brown units and the F.B. Culley unit only considered data dating back to January 2015, which is not consistent with the definition above that specifies a lookback period of 5 years. Black & Veatch notes, however, that this approach is consistent with a decision by IDEM that dictated that operational data prior to January 2015 would not be able to be considered, as it was not representative of the current operating characteristics of the A.B. Brown units.

For the PTE calculations, natural gas fired emissions rates that were developed in previous coal to natural gas conversion study were utilized. These emission rates considered varying configurations of three combustion controls designed to reduce NO_X emissions:

- Low NO_X natural gas burners (XCL-S burners).
- OFA.
- FGR.

In addition to combustion controls, Vectren requested that Black & Veatch examine the impacts of catalyst based post-combustion controls for NO_X, CO, and VOC. Typical post-combustion catalyst-based controls include SCR to control NO_X emissions and oxidation catalyst (i.e., CO catalyst) to control emissions of CO and VOC. A.B. Brown Units 1 and 2 already employ an SCR to control NO_X emissions, and for the expanded analysis, it was assumed that these systems would be left in service following the natural gas conversion. For F.B. Culley, all additional control scenarios would require newly installed equipment. In addition to a separate catalyst system to control NO_X and CO/VOC, Black & Veatch also analyzed a scenario in which a dual catalyst designed to control both NO_X and CO would be used in addition to SCR to achieve the necessary pollutant controls.

The emissions calculation methodology first entailed calculating the threshold magnitude of NO_X, CO, and VOC emissions that could occur without triggering PSD (tpy) by adding the BAE of each unit to the respective SERs (i.e., 40 tpy for NO_X and VOC and 100 tpy for CO). Because the modification at A.B. Brown involves two units, an assumption was made that the threshold emissions increases for the project (the “project” would include the cumulative emissions increases for both unit conversions) would be distributed equally between Unit 1 and Unit 2. The emission rates were then combined with projected heat inputs rates (in million British thermal units per hour [MMBtu/h]) to determine the maximum number of hours that a particular unit could be operated without triggering PSD for at least one of the limiting pollutants. Heat inputs for natural gas-fired operation for all three units were assumed to be identical to heat inputs for coal fired operation.

The analysis examined three different load points: 100 percent load, 60 percent load, and 10 percent load. For each load point, the following air quality control configurations were examined:

- A.B. Brown Units 1 and 2:
  - XCL-S burners only.
  - XCL-S burners and OFA.
  - XCL-S burners, OFA, and FGR.
  - XCL-S burners and FGR.
  - XCL-S burners and CO catalyst.
  - XCL-S burners, existing SCR, and dual catalyst.
  - XCL-S burners, FGR, and CO catalyst.
- F.B. Culley Unit 2:
  - XCL-S burners only.
  - XCL-S burners and OFA.

- XCL-S burners, OFA, and FGR.
- XCL-S burners and FGR.
- XCL-S burners and CO catalyst.
- XCL-S burners, new SCR, and new dual catalyst.
- XCL-S burners, FGR, and CO catalyst.

Preliminary iterations of the analysis examining OFA indicated that the NO_x reduction from OFA is insignificant. As such, the analysis as presented below was refined to only include results from the scenarios that include XCL-S burners, FGR, and post combustion controls. The emission rates that were utilized to calculate the post-conversion PTE's are included in Table 5-1.

Table 5-1 Natural Gas Fired Emission Rates

UNIT	POLLUTANT	XCL-S BURNERS ONLY	XCL-S BURNERS & FGR	XCL-S BURNERS AND CO CATALYST[1]	XCL-S BURNERS, SCR, AND DUAL CATALYST[2]	XCL-S BURNERS, FGR, AND CO CATALYST[1]
A.B. Brown Unit 1	NO_X	0.17	0.07	0.17	0.01	0.07
	CO	0.15	0.15	0.015	0.015	0.015
	VOC	0.003	0.003	0.0017	0.0017	0.0017
A.B. Brown Unit 2	NO_X	0.19	0.07	0.19	0.01	0.07
	CO	0.15	0.15	0.015	0.015	0.015
	VOC	0.003	0.003	0.0017	0.0017	0.0017
F.B. Culley Unit 2	NO_X	0.16	0.07	0.16	0.01	0.07
	CO	0.15	0.15	0.015	0.015	0.015
	VOC	0.003	0.003	0.0017	0.0017	0.0017

Notes:
1. NO_X emissions rates for A.B. Brown Units 1 and 2 and F.B. Culley Unit 2 were obtained from Babcock & Wilcox studies on converting the boilers from coal to natural gas. CO and VOC emissions rates are based on engineering estimate. Assumes 90% and 45% removal efficiency in the CO catalyst, respectively.
2. NO_X and CO emissions are based on Cormetech estimates. VOC emissions rates are based on engineering estimate. Assumes 45% removal efficiency in the dual catalyst.

Figures 5-1 through 5-3 illustrate the hours available to each unit while avoiding PSD permitting at 100 percent, 60 percent, and 10 percent load. Finally, in addition to the hours of operation achievable while not triggering PSD, the figures also include the installed cost estimates for each air quality control scenario.

As can be seen in the figures, the most affordable option available that also allows full operational flexibility for all three units is the addition of XCL-S burners and dual catalyst.

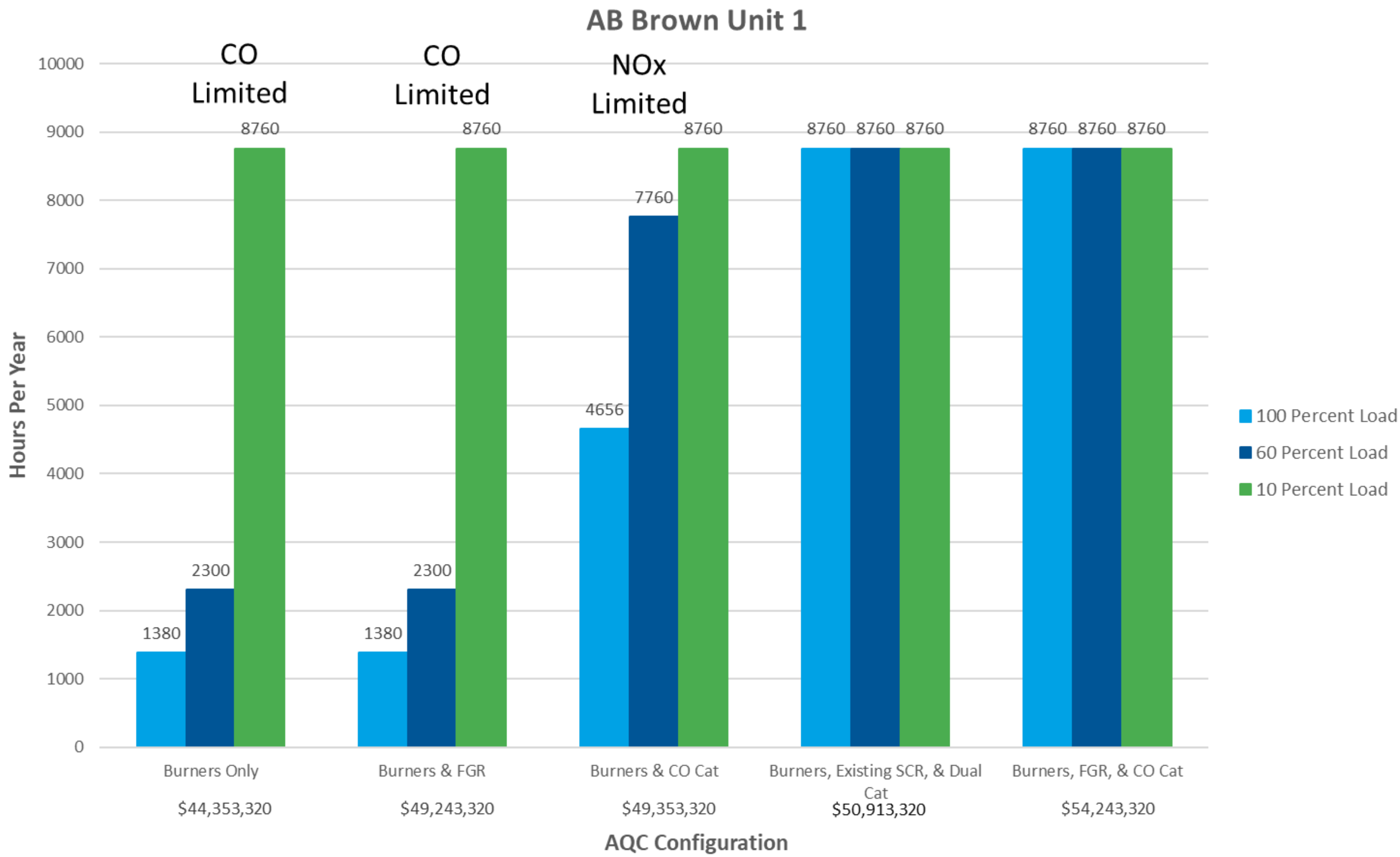

Figure 5-1 **Hours of Operation Achievable without Triggering PSD – A.B. Brown Unit 1**

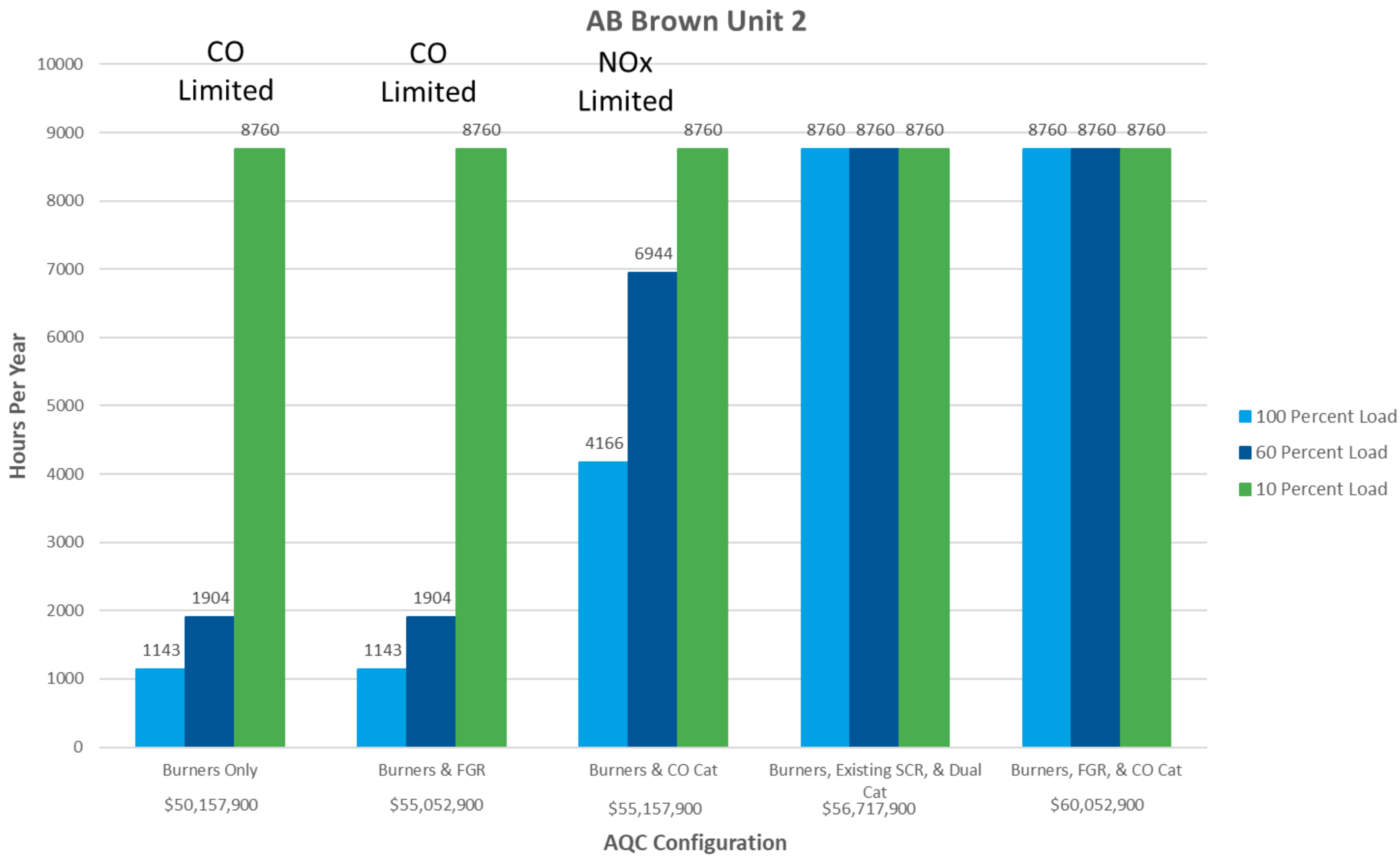

Figure 5-2 Hours of Operation Achievable without Triggering PSD – A.B. Brown Unit 2

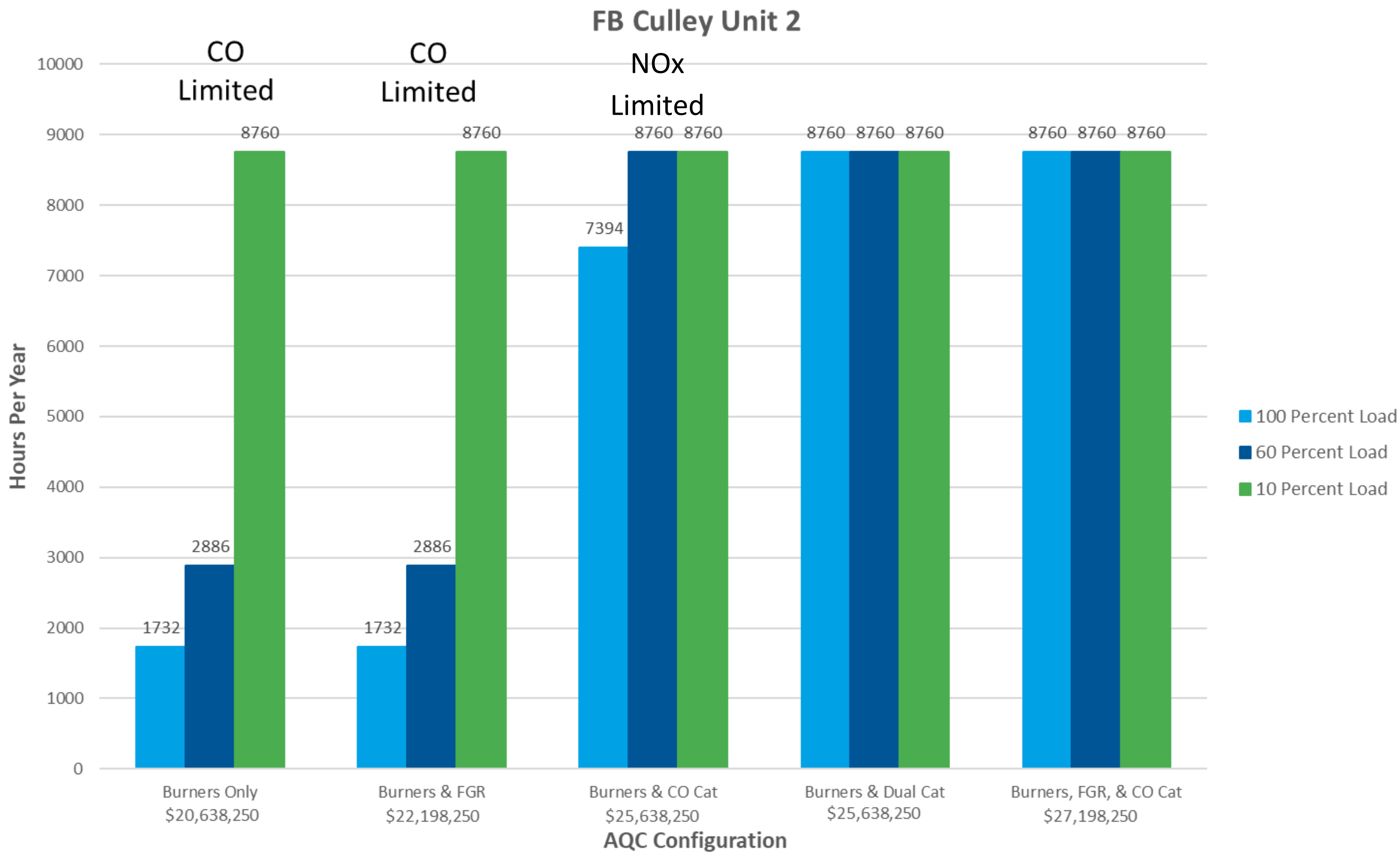

Figure 5-3 Hours of Operation Achievable without Triggering PSD – F.B. Culley Unit 2

6.0 Estimated Costs

The estimated furnish and installation costs for the conversion were provided from multiple sources and are summarized in Table 6-1.

Table 6-1 Estimated Project Costs

	A.B. BROWN UNIT 1	A.B. BROWN UNIT 2	CULLEY , UNIT 2
Materials; burner replacements, ducting metering/regulating station, BOP modifications, etc.	$10,070,000	$11,419,000	$8,880,000
Installation; burner replacements, ducting metering/regulating station, BOP modifications, etc.	$8,639,600	$9,970,000	$3,660,000
Bowen Gas Line from T10 to Tee	$1,618,000	$1,618,000	$685,000
FGD Demo and Bypass Duct	$5,600,000	$7,798,000	N/A
CO Catalyst Layer (materials)	$3,500,000	$3,500,000	$2,000,000
CO Catalyst Layer (installation)	$1,500,000	$1,500,000	$3,000,000
SCR Catalyst (materials) (1)	$1,060,000	$1,060,000	N/A
SCR Catalyst (installation)	$1,000,000	$1,000,000	N/A
Over Fire Air (materials and installation) (1)	$1,000,000	$1,000,000	$975,000
Flue Gas Recirculation System (materials and installation) (1)	$3,880,000	$3,880,000	$1,560,000
General Boiler/Plant Modifications	$9,033,360	$9,185,960	$3,245,273
Owners Consultant (19%)	$8,911,182	$9,866,882	$4,561,002
Total Project Cost	**$55,812,142**	**$61,797,842**	**28,566,275**
Annual Maintenance Costs	**$30,000**	**$30,000**	**$25,000**

Notes:
1. Optional Scope – Pricing included in Total Project Cost

Abbreviations:
BOP – Balance of Plant
DCS - Distributed Control System
CO – Carbon Monoxide
SCR - Selective Catalytic Reduction

7.0 Conclusions

7.1 SUMMARY

A.B. Brown Units 1 and 2 and F.B. Culley Unit 2 were evaluated on the basis of converting the units from firing 100 percent bituminous coal to firing 100 percent natural gas. The study included evaluating design changes that are required to make the conversion: new/modified burners, additional natural gas metering/pressure reducing s, balance-of-plant modifications, BMS controls modifications, etc. Additionally, the evaluations discussed plant performance impacts resulting from the coal-to-natural gas conversion and provided estimated costs for the modifications.

Black & Veatch's review concluded the OEM assessed impacts to performance, reduction in boiler efficiency, gross/net output, auxiliary loads, and an increase in net plant heat rate and steam turbine generator heat rate are consistent and reasonable given our experience and assessments of similar sized units.

Appendix A. Babcock & Wilcox Engineering Study for Natural Gas Firing for A.B. Brown Units 1 and 2

Engineering Study for Natural Gas Firing

for

Vectren Power Supply
AB Brown Station Units 1 & 2
Evansville, Indiana

Contract 591-1048 (317A)
June 13, 2019 - Rev 5

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INTRODUCTION

Vectren Power Supply contracted The Babcock and Wilcox Company (B&W), under B&W contract 591-1048 (317A), to evaluate natural gas firing at the AB Brown Station Units 1 and 2, originally supplied by B&W under contract RB-557 and RB-599. The boiler performance model was reviewed at 100% (Maximum Continuous rating) MCR and 60% load when firing 100% natural gas. An analysis of the allowable tube metal stresses was performed for 100% gas firing at 100% MCR and 60% boiler loads in regards to the primary superheater, secondary superheater and reheat superheater.

BACKGROUND

The AB Brown Units 1 & 2 (RB-557 & RB599) are presently balanced draft (Unit 1 was originally pressure fired and converted to balanced draft operation), subcritical Carolina type radiant boilers, with secondary superheater, primary superheater, reheater and economizer surfaces arranged in series. Superheater steam temperature is controlled by interstage spray attemperation. Reheater steam temperature is controlled by excess air and spray attemperation. The units were originally designed as a front and rear wall, bituminous coal fired units. The original maximum continuous rating for RB-557 and RB-599 is 1,850,000 lbs/hr of main steam at 1005°F and 1965 psig at the superheater outlet with a feedwater temperature of 467°F. The reheat steam flow is 1,666,500 lbs/hr at 1005 F and 485 psig at the reheater outlet. Spray attemperation is used to control superheat and reheat steam temperatures. The units were to be operated at 5% overpressure over the load range.

The units are front and rear wall fired with twenty-four B&W 4Z low NO_x burners, four wide by three high. There are six B&W EL-76 pulverizers for each unit supplying coal to the burners.

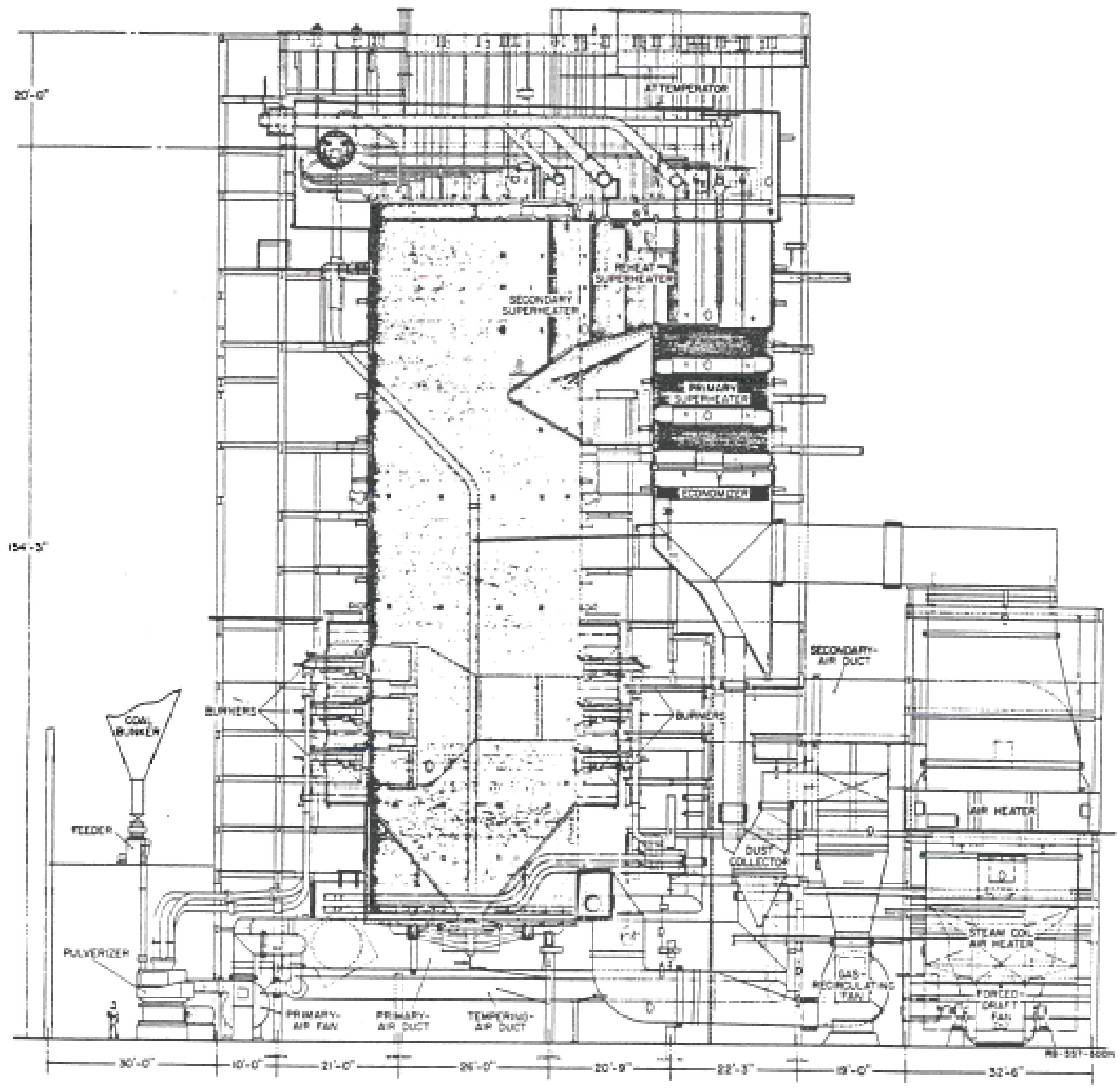
Combustion air is heated through two Ljungstrom regenerative air heaters.

Unit 2 (RB-599) is a semi-duplicate of Unit 1 (RB-557) with the following differences:

- Unit 2 has a furnace height of 124'-0'' compared to 122'-0" for Unit 1. The vertical burner spacing is 10'-0" for Unit 2 compared to 8'-0" for Unit 1.
- Unit 2 has six water-cooled furnace wing walls. Unit 1 has a full furnace division wall.
- Unit 2 was designed without flue gas recirculation. Unit 1 was originally designed with flue gas recirculation. The flue gas recirculation system on Unit 1 has been removed from service.

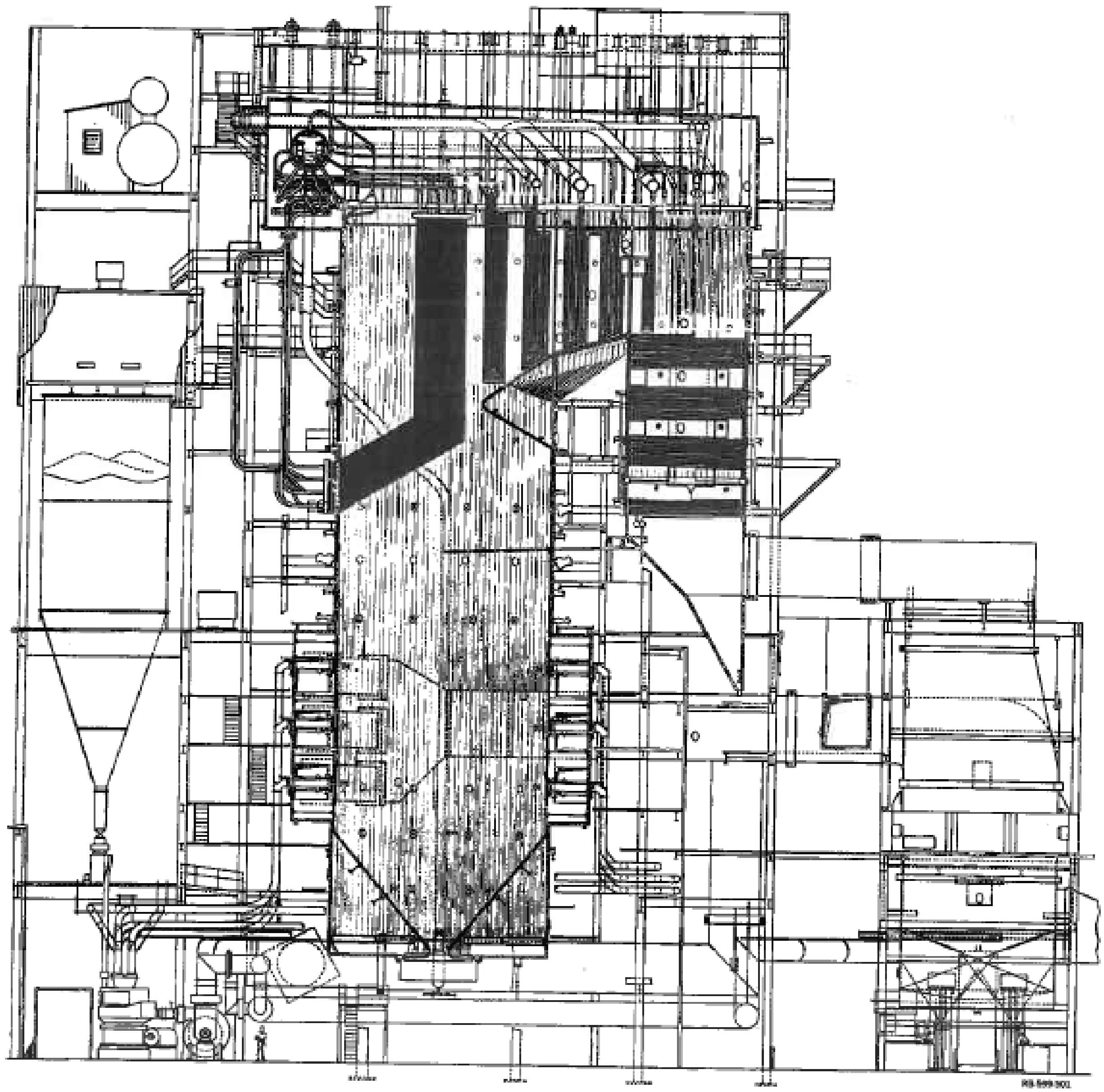
A sectional side view of the boilers is shown in Figures 1a and 1b.

FIGURE 1a



Brown Station Unit 1

B&W Contract Number RB-557



Brown Station Unit 2

B&W Contract Number RB-599

SCOPE FOR PHASE I

B&W evaluated natural gas firing in the radiant boilers originally supplied by B&W under contract numbers RB-557 and RB-599. Boiler component drawings and original performance summary data were used to develop comprehensive thermal models and boiler pressure part assessments. The predicted performance of the proposed natural gas firing was analyzed at MCR load and 60% load. The tube metallurgy requirements for the primary superheater, secondary superheater, reheater and headers were also developed. In addition to superheater metals analysis, predicted performance of the air preheaters and the attemperator capacities were also evaluated relative to overall performance.

SCOPE FOR PHASE II

The Phase II engineering scope of supply includes the entire scope of Phase I. In addition, the need surface modifications for firing 100% natural gas were analyzed. The adequacy of the existing forced draft (FD) fans and the induced draft (ID) fans were also assessed.

BASIS

This boiler pressure part metals assessment requires developing overall unit heat and material balances at the indicated steam flow. The 2015 fuel analyses for coal as supplied by Vectren were found to be very close to original design bituminous coal. Since the 2015 fuel analyses were incomplete, the original design fuel analysis was used. The natural gas analysis was also supplied by Vectren. The original design coal and natural gas fuel analyses are provided in Tables 1 and 2. These were used as a basis for the heat and material balances shown in Table 3.

Table 1: Original Design As-Fired Fuel Analyses for Bituminous Coal, % by weight

Constituent	
C	64.00
H_2	4.44
N_2	1.38
O_2	6.51
Cl	0.00
S	3.52
H_2O	11.35
Ash	8.76
Total	**100.00**
HHV (Btu/lb)	**11533**

Table 2: Proximate Analysis for Natural Gas, % by volume

Constituent	
Nitrogen	0.28
Methane	96.31
Ethane	1.46
CO_2	1.89
Others	0.06
Total	**100.00**
HHV (Btu/ft^3)	**1,037**

Table 3: Boiler Operating Conditions Used in Metals Evaluation

Boiler Load	**MCR**	**60%**
Superheater Steam Flow (lb/hr)	1,850,000	1,110,000
Steam Temperature at SH Outlet (°F)	1005	933
Steam Pressure at SH Outlet (psig)	1965	1917
Reheater Steam Flow (lb/hr) w/o Attemperator Spray	1,666,500	1,000,000
Steam Temperature at RH Outlet (°F)	992	835
Steam Pressure at RH Outlet (psig)	460	261
Feedwater Temperature (°F)	467	417
Excess Air Leaving Econ (%)	10	18

RESULTS

Boiler Performance

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance firing the original bituminous coal at the original design data, recent field data for each of the units and predicted unit performance firing 100% natural gas.

Attemperator Capacity

Along with the metals analysis, attemperation capacities were studied. The attemperator spray flows for gas firing are lower than the spray flows for firing coal due to lower amounts of excess air required when firing natural gas. Current attemperator capacities for both units should be satisfactory at all boiler loads. The results are shown in Table 6.

Table 6: Predicted Attemperator Flows (lbs/hr)

Boiler Load	MCR	60%
Bituminous Coal:		
SH Spray Flow	**77,870**	**88,000**
RH Spray Flow	**19,000**	**0**
Natural Gas		
SH Spray Flow	**53,700**	**0**
RH Spray Flow	**0**	**0**

Air Heater Performance

Air heaters were assessed for natural gas firing. The air and gas side temperature profiles around the air heater were found to be acceptable for the natural gas conversion. Since no field data was provided that would show higher than original air heater leakage or other air heater performance degradation, the predicted air heater performance is based on the original design data with an air heater leakage of 7.4%. Predicted performance is shown on Table 7a and 7b.

Table 7a: Regenerative Air Heater Predicted Performance at

Unit	1 & 2	1	2	1 & 2
Boiler load	MCR	95%	94%	MCR
Data Basis	Original Design	7-14-2015 PI Data	7-10-2015 PI Data	Predicted Performance*
Fuel	Bituminous Coal	Bituminous Coal	Bituminous Coal	Natural Gas
Flue Gas Flow Entering Air Heaters, mlb/hr	2,570	2,584	2,422	2,234
Flue Gas Temp Entering Air Heaters, F	705	650	652	697
Flue Gas Temp Leaving Air Heaters w/o Leakage, F	304	336	346	303
Air Flow Leaving Air Heaters, mlb/hr	2,307	2,323	2,174	2,056
Air Temp Entering Air Heaters, F	85	168	138	85
Air Temp Leaving Air Heaters, F	566	535	554	567

*Based on original design data

Table 7b: Regenerative Air Heater Predicted Performance

Unit	1 & 2	1 & 2
Boiler load	60%	60%
Data Basis	Original Design	Predicted Performance*
Fuel	Bituminous Coal	Natural Gas
Flue Gas Flow Entering Air Heaters, mlb/hr	2,060	1,403
Flue Gas Temp Entering Air Heaters, F	675	617
Flue Gas Temp Leaving Air Heaters w/o Leakage, F	283	259
Air Flow Leaving Air Heaters, mlb/hr	1,867	1,273
Air Temp Entering Air Heaters, F	83	83
Air Temp Leaving Air Heaters, F	547	520

*Based on original design data

Tube Metal Temperature Evaluation

B&W uses an ASME Code accepted method to design its tube metallurgies and thicknesses. The method involves applying upsets and unbalances to determine spot and mean tube metal temperatures. The upsets and unbalances include empirical uncertainty in the calculation of furnace exit gas temperature (FEGT), top to bottom gas temperature deviations, side to side gas temperature deviations, steam flow unbalances (a function of tube side pressure drop and component arrangement) and gas flow unbalances. The method applies these upsets and unbalances simultaneously to a single spot in each row of the superheater. Tube row metallurgy and thickness are then determined from the resultant tube spot and mean temperatures, respectively, according to ASME Code material oxidation limits and allowable stresses. B&W policy does not allow the publishing of design tube metal temperatures or unbalanced steam temperatures. However, these values can be reviewed in B&W's offices, if desired.

The remaining life expectancy of the superheaters is dependent on the prior operating history, especially on actual tube operating temperature compared to design temperature. Thus, the assessment of the adequacy of the existing superheaters is not a simple task.

The SSH outlet bank & RSH outlet bank were replaced on unit 1 in the spring of 2012 and on unit 2 in the fall of 2015. The evaluation is based on the design of the present SSH outlet banks & RSH outlet banks which were supplied by B&W.

B&W has determined the operating hoop stress level (based on the current minimum tube wall thickness) at operating pressure. The predicted tube operating temperatures based on B&W's standard design criteria and the resulting ASME Code allowable stress level for the existing material has also been determined. Comparison of the operating hoop stress with the Code allowable stresses results in the percent over the allowable stress. A modest overstress level indicates a modest shortening of remaining life expectancy and, unless otherwise indicated by past maintenance experience, does not warrant tube modification at this time.

If the tube analysis shows significant overstress or shows that tubes are predicted to operate at temperatures above those for which ASME Code stresses are published, then serious consideration should be given to tube upgrades and replacement. Significant overstresses are considered those tube rows that are 20% or greater overstressed. An overstress of 20% or more does not necessarily mean that immediate replacement of the tube row is required, but it identifies which tube rows should be examined for potential problems. Potential problems could be signs of creep, internal exfoliation or swelling.

This study showed that all tubes were predicted to operate at temperatures less than the existing material use limit. In addition, all existing convection pass tubes and component headers had no overstress issues. Therefore, the existing convection pass tube metallurgy is acceptable for natural gas firing.

Forced Draft Fans

The existing forced draft fans were analyzed to determine if they meet the requirements of 100% natural gas firing. The Unit 1 FD fans were originally designed to supply the combustion air in a pressure fired boiler operating mode. The boiler has since been converted to balanced draft operation, resulting high static pressure rise margins when firing coal. Unit 2 was originally designed as a balanced draft unit. An adjusted test block static pressure rise and test block capacity for the Unit 2 FD fans was developed from the FD fan curve for 100% natural gas firing. The results show the existing FD fan test block conditions for both Units exceed the requirements in capacity and static pressure rise (including higher natural gas burner pressure drop) for all natural gas firing cases. Predicted fan performance is shown in Table 8A:

Table 8a: Forced Draft Fan Performance at MCR Load (balanced draft operation)

Fuel	FD Fan Test Block Unit 1	FD Fan Original Net Design Conditions Bituminous Coal Unit 1	FD Fan Test Block Unit 2	FD Fan Original Net Design Conditions Bituminous Coal Unit 2	FD Fan Test Block Adjusted for 100%Natural Gas Unit 2 From Fan Curve	FD Fan Net Conditions 100% Natural Gas Units 1 & 2
Flow per fan (lb/hr)	1,417,000	1,180,500	1,512,000	1,260,000	1,225,440	1,104,100
Static Pressure Rise (in WC)	37.3	29.8	19.8	15.8	25.1	20.3
Temperature (F)	105	80	105	80	105	80

Induced Draft Fans

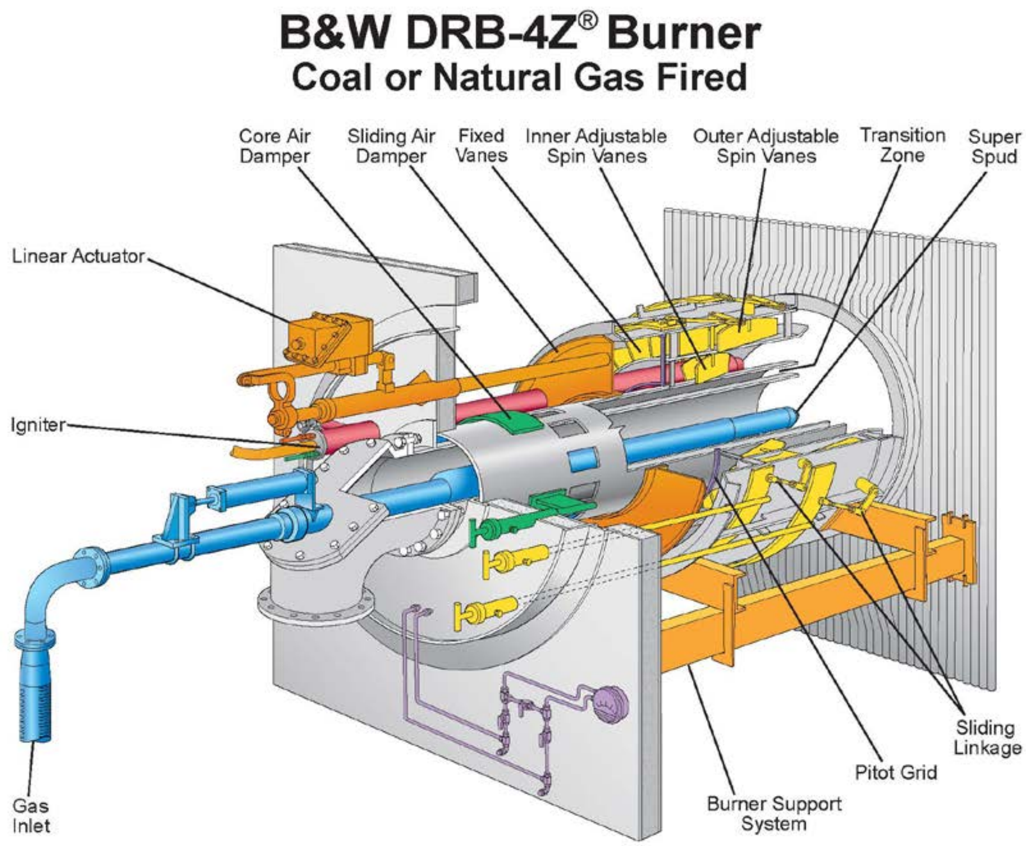
The existing induced draft fans were also analyzed to determine if they meet the requirements of 100% natural gas firing. The results showed the existing ID fans far exceed the requirements in capacity and static pressure rise for all natural gas firing cases. Predicted fan performance is shown in Table 8B:

Table 8b: Induced Draft Fan Performance at MCR Load (balanced draft operation)

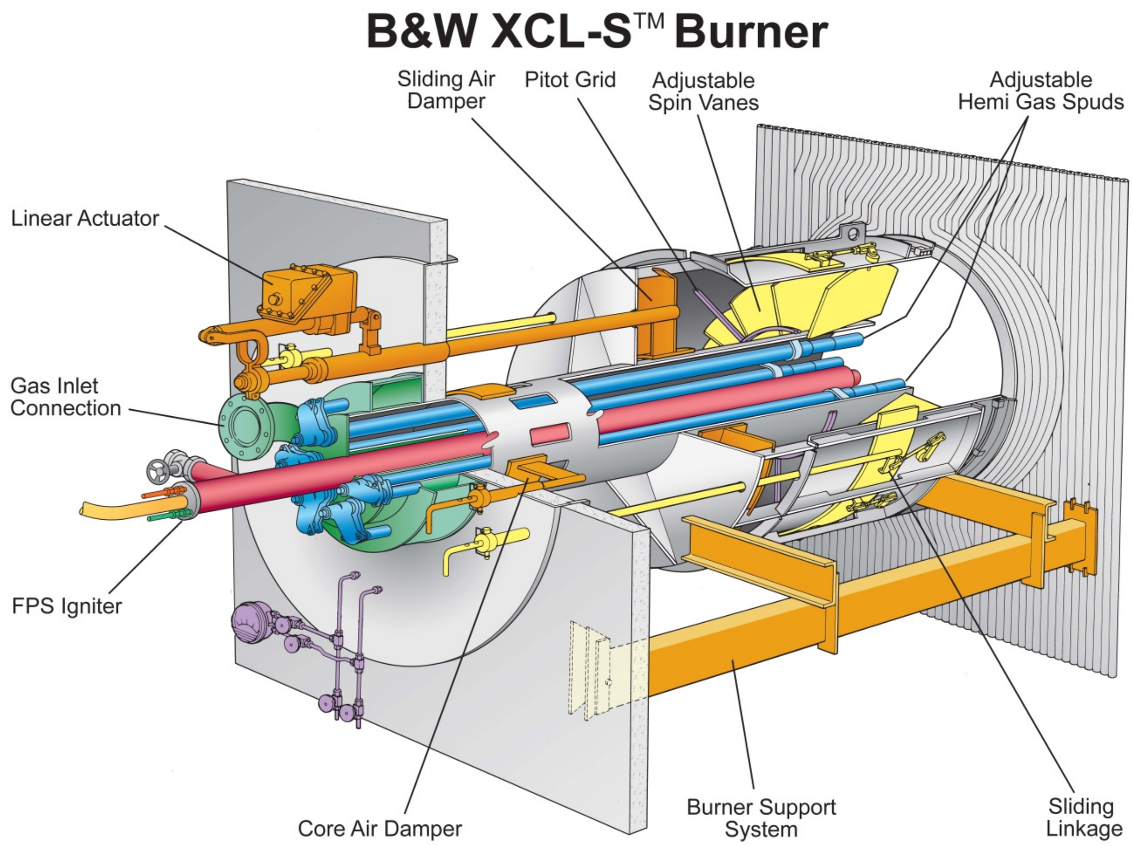
Fuel	ID Fan Test Block Unit 1	Bituminous Coal Unit 1 Original ID Fan Design Net Conditions	100% Natural Gas
Flow per fan (lb/hr)	1,380,100	1,387,610	1,199,390
Static Pressure Rise (in WC)	67.30	47.81	34.22
Temperature (F)	330	305	290

Combustion Equipment

The minimum combustion equipment modifications required to fire natural gas include modifying the twenty-four (24) existing B&W 4Z burners with gas spuds. One option is to add a Super-Spud to each 4Z burner to provide natural gas firing capability to the units. The addition of Super-Spuds will allow the AB Brown units to still fire coal is desired. The figure below shows a 4Z burner with a Super-Spud.



The second option would be to remove the coal nozzle and replace it with a hemi-spud cartridge. This fundamentally converts the 4Z burners to a B&W XCL-S burner as shown in the figure below. B&W XCL-S burner is an advanced low-NOx burner that was developed to achieve superior NOx performance in burner-only applications.



Since the AB Brown units already have SCR's, staged combustion (OFA) or flue gas recirculation (FGR) may not be necessary.

Additional NOx reduction can be achieved with staged combustion and/or flue gas recirculation. For staged combustion, the preferred approach is to locate eight (8) new NOx ports, four on the front wall and four on the rear wall, at an elevation at least eight feet above the top burner row. New NOx ports would require windbox and duct work modifications.

FGR involves the introduction of recirculated flue gas into the combustion air upstream of the burner windbox. A mixing device (such as a slotted air foil in the combustion air duct) is required to adequately distribute the recirculated flue gas in the incoming combustion air.

In addition to the burner modifications, valve racks, gas piping and controls will be needed to supply the natural gas as a main fuel to the modified burners.

Emissions

Emissions predictions are based on converting the unit to fire natural gas as the main fuel. Full load emission predictions for both units are listed in Table 9.

Table 9: Predicted Full Load Emissions on Natural Gas

	XCL-S Burners only		XCL-S Burners and OFA		XCL-S Burners, OFA, and FGR		XCL-S Burners and FGR	
	Brown Unit 1	Brown Unit 2	Brown Unit 1	Brown Unit 2	Brown Unit 1	Brown Unit 2	Brown Unit 1	Brown Unit 2
FGR Rate (&)	N/A	N/A	N/A	N/A	~16%	~18%	~21.5%	~23.5%
NO_x (lb/10^6 Btu)	0.17	0.19	0.15	0.17	0.07	0.07	0.07	0.07
CO (ppmvd corrected to 3% O_2)	200	200	200	200	200	200	200	200
VOC (lb/10^6 Btu)	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003

- CO is predicted to be less than 200ppm. For 200 ppm (dry vol.) CO @ 3% O2 (dry vol.) firing NG with an Fd factor of 8710, B&W calculates 0.148 lb/mmBTU of CO.

CONCLUSIONS

As a result of this study, a review of the existing tube metallurgies on the AB Brown Station Units 1 and 2 revealed that all existing convection pass tubes had no overstress issues. In addition, all tubes were predicted to operate at temperatures below their ASME material code published limit. Header metal temperatures were also checked and showed to meet B&W's standards.

Along with the metallurgical analysis, superheater and reheater spray attemperation capacities were studied. The attemperator spray flows for gas firing are lower than the spray flows for firing coal due to lower amounts of excess air required when firing 100% natural gas. Current attemperator capacities for both units should be satisfactory at all boiler loads.

No surface modifications or surface removal are required when firing 100% natural gas.

Air heaters were assessed for 100% natural gas firing. The air and gas side temperature profiles around the air heater were found to be acceptable for firing natural gas based on the original air heater design parameters.

The existing FD and ID fans were found to exceed the performance requirements when firing 100% natural gas.

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance firing the original bituminous coal and predicted unit performance firing natural gas.

CO-FIRING COAL AND NATURAL GAS

Vectren Power Supply additionally contracted the Babcock and Wilcox Company (B&W), under B&W contract 591-1048 (317A), to evaluate co-firing natural gas and coal in these units.

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance co-firing natural gas and the original bituminous coal at MCR boiler load with the following natural gas inputs:

1. 17% heat input from natural gas through four burners. 83% heat input from coal.
2. 33% heat input from natural gas through eight burners. 67% heat input from coal.
3. 16% heat input (maximum heat input through natural gas ignitors). 84% heat input from coal.

A metallurgical analysis and an analysis of the superheater and reheater spray attemperation capacities were performed for the three conditions above. Current attemperator capacities for both units should be satisfactory at all boiler loads when co-firing natural gas and coal.

This study showed that all tubes were predicted to operate at temperatures less than the existing material use limit. In addition, all existing convection pass tubes and component headers had no overstress issues. Therefore, the existing convection pass tube metallurgy is acceptable for co-firing natural gas and coal.

No surface modifications or surface removal are required when co-firing natural gas and coal.

The air and gas side temperature profiles around the air heater were found to be acceptable for co-firing natural gas and coal based on the original air heater design parameters.

The existing FD and ID fans were found to exceed the performance requirements when co-firing natural gas and coal.

The predicted boiler performance summaries when co-firing natural gas and coal are shown in the Appendix.

Co-firing Operation

When co-firing the two fuels, the preferred arrangement is to fire natural gas through the burners at the higher elevations on a per mill group, or compartment, basis. The compartmented windboxes on the AB Brown units are advantageous for co-firing the multiple fuels. Airflow control by compartment allows each mill group to obtain its own required amount of air, independent of burner load or fuel. The burners firing natural gas will require more secondary air, since primary airflow is zero, than the coal-firing burners. Managing these separate flow rates can be easily accommodated by the compartment controls. Firing coal at the lower elevations takes advantage of the available residence time in the furnace, maximizing coal burnout and optimizing CO and unburned carbon emissions. If a partial conversion were to become the chosen project path, it would be recommended to convert burners on a per mill group basis following the described firing arrangement, adding gas capability to the top mill groups and continuing downward.

It should be noted that while the AB Brown units are already equipped to operate under the third scenario listed above (16% input ignitors, 84% input from coal), it could come at the expense of emissions. With the ignitor being located in an upper quadrant of the burner and operating at 16% of the rated burner input, not all of the air going through the burner is nearby and readily available for the ignitor fuel. This can create scenarios of inadequate fuel and air mixing, resulting in higher CO emissions, especially from the upper burner elevations. NOx emissions may also increase. The annular zone arrangement of the 4Z burner stages the mixing of the fuel and air. With the ignitor being located in the air sleeve, it circumvents this delayed mixing arrangement, potentially increasing NOx. Emissions predictions are not available for this scenario.

APPENDIX A – Preliminary Performance Summaries

Table 10a:

A. B. Brown Units 1 & 2 - Preliminary Performance Summary

Contract No.	317A	GBB	Units 1 & 2	Unit 1	Unit 2	Units 1 & 2
Date	7/31/2015	Load ID	PC Firing	PC Firing	PC Firing	Natural Gas
Revision	0	Boiler Arrangement	Existing	Existing	Existing	Existing
		Data Basis	Original Contract	7-14-2015 PI Data	7-10-2015 PI Data	Predicted Performance
Load Condition			MCR	95% Load	94% Load	MCR
Fuel			Bituminous	Bituminous	Bituminous	Natural Gas
Steam Leaving SH, mlb/hr			1,850	1,814	1,736	1,850
Superheater Spray Water, mlb/hr			77.86	110.32	19.10	53.70
Cold RH Steam Flow, mlb/hr			1,667	1,663	1,590	1,667
Reheater Spray Water, mlb/hr			18.90	60.70	16.30	0.00
% Excess Air Leaving Economizer			20.0	21.9	21.1	10.0
Flue Gas Recirculation, %			None	None	None	None
Heat Input, mmBtu/hr			2,549.3	2,526.4	2,379.8	2,614.9
Quantity mlb/hr	Fuel (mcf/hr if gas)		221.0	219.0	207.0	2604.5
	Flue Gas Entering Air Heaters		2,570	2,584	2,422	2,234
	Total Air To Burners		2,307	2,323	2,174	2,056
Pressure, psig	Steam at SH Outlet		1965	1880	1926	1965
	Steam at RH Outlet		460	431	424	460
Temperature, °F	Steam	Leaving Superheater	1005	1006	999	1005
		Leaving Reheater	1005	997	985	992
	Water	Water Entering Economizer	467	459	452	467
		Superheater Spray Water	380	365	370	380
	Gas	Entering Air Heater	705	650	652	697
		Leaving Air Heater (Excl. Leakage)	304	336	346	303
	Air	Entering Air Heater	85	168	138	85
		Leaving Air Heater	566	535	554	567
Heat Loss Efficiency, %	Dry Gas		4.91	3.86	4.75	3.88
	H_2 & H_2O in Fuel		5.06	4.76	4.92	10.67
	Moisture in Air		0.12	0.10	0.11	0.10
	Unburned Combustible		0.30	0.30	0.30	0.00
	Radiation		0.19	0.19	0.20	0.19
	Unacc. & Mfgs. Margin		1.50	0.50	0.50	1.00
	Total Heat Loss		12.08	9.71	10.78	15.84
	Gross Efficiency of Unit, %		87.92	90.29	89.22	84.16

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Table 10a:

A. B. Brown Units 1 & 2 - Preliminary Performance Summary

Contract No.	317A	GB8	Unit 1 & 2	Unit 1 & 2		
Date	7/31/2015	Load ID	PC Firing	NG Firing		
Revision	0	Boiler Arrangement	Existing	Existing		
		Data Basis	Original Contract	Predicted Performance		
Load Condition			60%	60%		
Fuel			Bituminous	Natural Gas		
Steam Leaving SH, mlb/hr			1,110	1,110		
Superheater Spray Water, mlb/hr			89	0		
Cold RH Steam Flow, mlb/hr			1,000	1,000		
Reheater Spray Water, mlb/hr			0	0		
% Excess Air Leaving Economizer			52.0	18.0		
Flue gas Recirculation, %			None	None		
Heat Input, mmBtu/hr			1,638.3	1,540.9		
Quantity mlb/hr	Fuel (mcf/hr if gas)		142.0	1486.0		
	Flue Gas Entering Air Heaters		2,060	1,403		
	Total Air To Burners		1,867	1,273		
Pressure, psig	Steam at SH Outlet		1917	1917		
	Steam at RH Outlet		261	261		
Temperature, °F	Steam	Leaving Superheater	1005	955		
		Leaving Reheater	1005	835		
	Water	Water Entering Economizer	417	417		
		Superheater Spray Water	350	350		
	Gas	Entering Air Heater	675	617		
		Leaving Air Heater (Excl. Leakage)	283	259		
	Air	Entering Air Heater	83	83		
		Leaving Air Heater	547	520		
Heat Loss Efficiency, %	Dry Gas		5.69	3.35		
	H_2 & H_2O in Fuel		5.03	10.38		
	Moisture in Air		0.14	0.09		
	Unburned Combustible		0.30	0.00		
	Radiation		0.30	0.22		
	Unacc. & Mfgs. Margin		1.50	1.00		
	Total Heat Loss		12.96	15.04		
	Gross Efficiency of Unit, %		87.04	84.96		

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Table 10c:

A. B. Brown Unit 1 - Predicted Performance Summary Co-Firing Coal & Natural Gas

Contract No.	317A	GBB	Unit 1	Unit 1	Unit 1	
Date	8/29/2015	Load ID	PC & NG Firing	PC & NG Firing	PC & NG Firing	
Revision	0	Boiler Arrangement	Existing	Existing	Existing	
		Data Basis	Predicted Performance	Predicted Performance	Predicted Performance	
		Natural Gas Firing Method	Through Burners	Through Burners	Through Ignitors	
		Natural Gas Firing % Heat Input	17	33	16	
		Coal Firing % Heat Input	83	67	84	
Load Condition			MCR	MCR	MCR	
Fuel			Bit. Coal & Natural Gas	Bit. Coal & Natural Gas	Bit. Coal & Natural Gas	
Steam Leaving SH, mlb/hr			1,850	1,850	1,850	
Superheater Spray Water, mlb/hr			99.50	115.17	98.48	
Cold RH Steam Flow, mlb/hr			1,667	1,667	1,667	
Reheater Spray Water, mlb/hr			53.81	57.13	53.80	
% Excess Air Leaving Economizer			21.1	21.1	21.1	
Flue Gas Recirculation, %			None	None	None	
Heat Input Nat. Gas, mmBtu/hr			443.4	869.9	408.0*	
Heat Input Bit. Coal, mmBtu/hr			2164.8	1766.1	2198.6	
Total Heat Input, mmBtu/hr			2608.2	2636.0	2606.6	
Quantity mlb/hr	Coal Flow		187.7	153.2	190.6	
	Natural Gas Flow (mcf/hr)		441.6	866.4	406.3	
	Flue Gas Entering Air Heaters		2,611	2,600	2,612	
	Total Air To Burners		2,358	2,360	2,358	
Pressure, psig	Steam at SH Outlet		1965	1965	1965	
	Steam at RH Outlet		460	460	460	
Temperature, °F	Steam	Leaving Superheater	1005	1005	1005	
		Leaving Reheater	1005	1005	1005	
	Water	Water Entering Economizer	467	467	467	
		Superheater Spray Water	365	365	365	
	Gas	Entering Air Heater	656	658	656	
		Leaving Air Heater (Excl. Leakage)	338	338	338	
	Air	Entering Air Heater	150	150	150	
		Leaving Air Heater	542	544	542	
Heat Loss Efficiency, %	Dry Gas		4.19	4.09	4.19	
	H_2 & H_2O in Fuel		5.76	6.62	5.69	
	Moisture in Air		0.10	0.10	0.10	
	Unburned Combustible		0.25	0.20	0.25	
	Radiation		0.19	0.19	0.19	
	Unacc. & Mfgs. Margin		1.42	1.42	1.42	
	Total Heat Loss		11.91	12.62	11.84	
	Gross Efficiency of Unit, %		88.09	87.38	88.16	

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Predicted performance is based on the original contract boiler performance and PI data as supplied by Vectren

*Maximum heat input from ignitors

Table 10d:

A. B. Brown Unit 2 - Predicted Performance Summary Co-Firing Coal & Natural Gas

Contract No.	317A	GBB	Unit 2	Unit 2	Unit 2	
Date	8/29/2015	Load ID	PC & NG Firing	PC & NG Firing	PC & NG Firing	
Revision	0	Boiler Arrangement	Existing	Existing	Existing	
		Data Basis	Predicted Performance	Predicted Performance	Predicted Performance	
		Natural Gas Firing Method	Through Burners	Through Burners	Through Ignitors	
		Natural Gas Firing % Heat Input	17	33	16	
		Coal Firing % Heat Input	83	67	84	
Load Condition			MCR	MCR	MCR	
Fuel			Bit. Coal & Natural Gas	Bit. Coal & Natural Gas	Bit. Coal & Natural Gas	
Steam Leaving SH, mlb/hr			1,850	1,850	1,850	
Superheater Spray Water, mlb/hr			27.38	42.94	26.70	
Cold RH Steam Flow, mlb/hr			1,667	1,667	1,667	
Reheater Spray Water, mlb/hr			23.02	27.14	23.00	
% Excess Air Leaving Economizer			21.9	21.9	21.9	
Flue Gas Recirculation, %			None	None	None	
Heat Input Nat. Gas, mmBtu/hr			434.6	853.1	408.0*	
Heat Input Bit. Coal, mmBtu/hr			2121.7	1732.0	2147.3	
Total Heat Input, mmBtu/hr			2556.3	2585.1	2555.3	
Quantity mlb/hr	Coal Flow		184.0	150.2	186.0	
	Natural Gas Flow (mcf/hr)		432.8	849.7	406.3	
	Flue Gas Entering Air Heaters		2,568	2,559	2,569	
	Total Air To Burners		2,319	2,322	2,320	
Pressure, psig	Steam at SH Outlet		1965	1965	1965	
	Steam at RH Outlet		460	460	460	
Temperature, °F	Steam	Leaving Superheater	1005	1005	1005	
		Leaving Reheater	1005	1005	1005	
	Water	Water Entering Economizer	467	467	467	
		Superheater Spray Water	380	380	380	
	Gas	Entering Air Heater	668	670	668	
		Leaving Air Heater (Excl. Leakage)	352	353	352	
	Air	Entering Air Heater	150	150	150	
		Leaving Air Heater	552	554	552	
Heat Loss Efficiency, %	Dry Gas		4.51	4.43	4.52	
	H_2 & H_2O in Fuel		5.79	6.66	5.74	
	Moisture in Air		0.11	0.11	0.11	
	Unburned Combustible		0.25	0.20	0.25	
	Radiation		0.19	0.19	0.19	
	Unacc. & Mfgs. Margin		1.42	1.42	1.42	
	Total Heat Loss		12.27	13.01	12.23	
	Gross Efficiency of Unit, %		87.73	86.99	87.77	

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Predicted performance is based on the original contract boiler performance and PI data as supplied by Vectren

*Maximum heat input from ignitors

APPENDIX B – NG Conversion Equipment Scope & Budgetary Costs

SUPER-SPUD OPTION - Burner Modifications, Scanners, Valve Racks, NG Piping System

Item 1: B&W 4Z Burners converted to Nat Gas Firing (Quantity: 24)

- Qty 24, Super-Spud Assemblies to replace existing coal nozzles
- Qty 12, Burner Valve Racks
- Burner Front Flex Hose and Hardware
- Burner Front Piping
- Gas Header Piping
- Burner Front Valves & Gauges

Item 2: Fossil Power Systems (FPS) Flame Scanners

- Qty 24, FPS main UV flame scanners with rigid fiber optic extension
- Qty 1, main flame scanner electronics cabinet
- 1 Lot – Combustion/Cooling air piping from blower skid to burner fronts

Item 3: Natural Gas Regulating Station and Piping

- Main natural gas regulating station – 50 psig supply pressure
- Natural gas piping from regulating station to the burners
- Natural gas burner front gas piping and valve stations excluding vent piping to above the boiler building roof

HEMI-SPUD OPTION - Burner Modifications, Scanners, Valve Racks, NG Piping System

Item 1: B&W 4Z Burners converted to Nat Gas Firing (Quantity: 24)

- Qty 24, Hemispherical Gas Spud Assemblies to replace existing coal nozzles
- Qty 12, Burner Valve Racks
- Burner Front Flex Hose and Hardware
- Burner Front Piping
- Gas Header Piping
- Burner Front Valves & Gauges

Item 2: Fossil Power Systems (FPS) Flame Scanners

- Qty 24, FPS main UV flame scanners with rigid fiber optic extension
- Qty 1, main flame scanner electronics cabinet
- 1 Lot – Combustion/Cooling air piping from blower skid to burner fronts

Item 3: Natural Gas Regulating Station and Piping

- Main natural gas regulating station – 50 psig supply pressure
- Natural gas piping from regulating station to the burners
- Natural gas burner front gas piping and valve stations
- Vent piping from the regulating stations and the burner valve racks to the boiler roof and above the roof is not included

B&W OVERFIRE AIR (OFA) PORTS OPTION

- Qty 8, Furnace Water Wall Openings
- Windbox Extensions or Individual OFA Windboxes
- Qty 8, Automated Air Flow Control Damper with Rotary Drive - per port
- Boiler Closure Casing
- Temperature Monitoring Thermocouple (port style dependent)

FLUE GAS RECIRCULATION (FGR) OPTION

- Flue Gas Recirculation Fan and Motor
- FGR Flues
- AH Outlet to FGR Fan Inlet
- FGR Fan Outlet to Secondary Air Mixing Foils
- FGR Flue expansion joints, hangers, bridging steel
- FGR Mixing Foils
- Windbox O_2 Monitor
- Burner throat assemblies to accommodate the larger B&W XCL-S burners required for FGR firing.

General Services

- Combustion system tuning services using an economizer outlet sampling grid for measurement of NOx per EPA methods.
- Field Service Engineering outage support for construction, start-up, and post-modification testing.
- Burner System Operator Training consisting of two, one day sessions.
- Training includes project specific training manual for up to 20 participants.
- Brickwork Refractory Insulation & Lagging (BRIL) Specifications and Installation design and materials.
- Contract specific System Requirements Specification, I/O Listing, and Functional Logic Diagrams for all supplied equipment.
- Operating and Maintenance Manuals (10 copies).
- New piping, flue, and duct loading to existing steel
- Delivery F.O.B. Brown Plant, Mt Vernon, IN.

Items not Included

- Hazardous material removal or abatement (i.e., lead paint and asbestos).

- Load analysis of existing structural steel or foundations and any required re-enforcement thereof.
- Hardware or reprograming of existing DCS and/or BMS to support natural gas conversion.
- Gas step down equipment. Equipment scope above assumes incoming gas pressure at B&W's terminal to be 30 to 50psi.

Terminal Points

- Inlet of gas regulating station
- Vent out of any valve rack
- Electrical terminals on provided electrical equipment or instruments
- Electrical terminals in shop provided terminal junction boxes as part of skidded equipment

Budgetary Material & Installation Pricing (USD 2019)

Scope Item	Budgetary	
	Material	Installation
Super-Spud Option: Burner Modifications, Scanners, Valve Racks, NG Piping System	$2,602,000	$3,903,000
Hemi-Spud Option: Burner Modifications, Scanners, Valve Racks, NG Piping System	$2,900,000	$4,350,000
Overfire Air (OFA) Option: **Wall Openings, Windbox Modifications, Flow Control Dampers, Temperature Monitoring**	$370,000	$555,000
Flue Gas Recirculation (FGR) Option: **FGR Fan w/ Motor, Flues, Mixing Foils, O_2 Monitoring**	$850,000	$1,275,000

Lead Times

- Material delivery: 52 - 56 weeks
- Installation outage duration: 8 - 10 weeks

B&W has offered these prices in 2019 US dollars and have not attempted to project escalation for time of performance or delivery.

Please note that these prices are budgetary and is not represent an offer to sell, however, we would welcome the opportunity to provide a formal proposal upon request.

Appendix B. Babcock & Wilcox Engineering Study for Natural Gas Firing for F.B. Culley Unit 2

power generation group

Engineering Study for Natural Gas Firing

for

Vectren Power Supply
Culley Station Unit 2
Newburgh, Indiana

Contract 591-1022 (293H)
June 13, 2019
Rev. 2

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INTRODUCTION

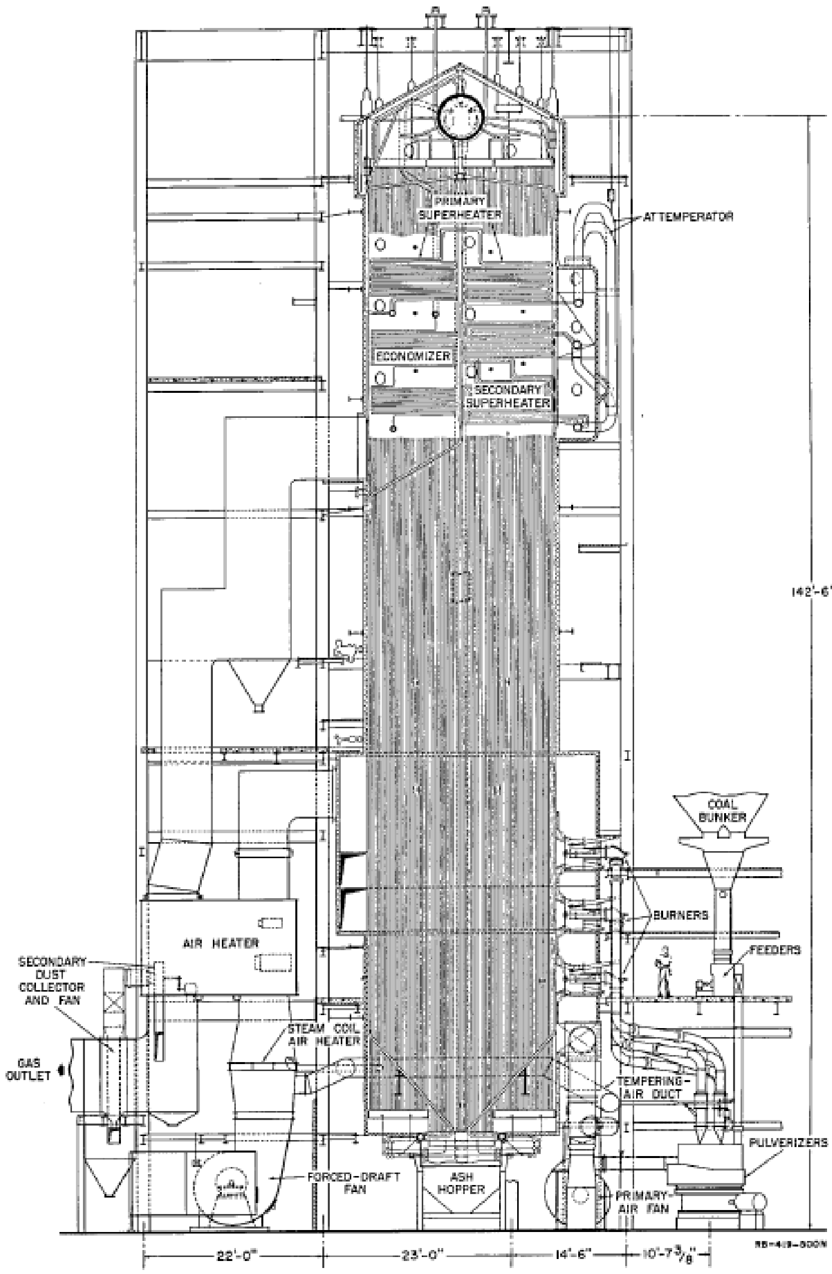
Vectren Power Supply contracted The Babcock and Wilcox Company (B&W), under B&W contract 591-1022 (293H), to evaluate natural gas firing at the Culley Station Unit #2 originally supplied by B&W under contract RB-419. The boiler performance model was reviewed at 100% MCR and 50% load when firing 100% natural gas. An analysis of the allowable tube metal stresses was performed for 100% gas firing at 100% MCR and 50% boiler loads in regards to the primary and secondary superheaters. Modifications to the convection pass components to accommodate natural gas firing were also developed. Also analyzed for adequacy were the forced draft fans, induced draft fans and spray attemperators.

BACKGROUND

Culley Unit #2 (RB-419) is a balanced draft (originally pressure fired), subcritical El Paso type radiant boiler, with secondary superheater, primary superheater, and economizer surfaces arranged in series. Steam temperature is controlled through interstage attemperation. The unit was originally designed as a front wall, bituminous coal fired unit. The original maximum continuous rating for RB-419 is 840,000 lbs/hr of steam at 955°F and 1290 psig at the superheater outlet with a feedwater temperature of 425°F. The unit was designed to accommodate a peak load (low feedwater temperature condition) for a duration of two (2) hours. The peak load rating is 840,000 lbs/hr of steam at 955°F and 1290 psig at the superheater outlet with a feedwater temperature of 383°F.

A sectional side view of the boilers is shown in Figure 1a.

FIGURE 1a



Culley Station Unit 2
B&W Contract Number RB-419

SCOPE FOR PHASE I

B&W evaluated natural gas firing in the radiant boiler originally supplied by B&W under contract RB-419. Boiler component drawings and original performance summary data were used to develop comprehensive thermal models and boiler pressure part assessments. The predicted performance of the proposed natural gas firing was analyzed at MCR load and 50% load. The tube metallurgy requirements for the primary superheater, secondary superheater and headers were also developed. In addition to superheater metals analysis, predicted performance of the air preheaters and the attemperator capacities were also evaluated relative to overall performance.

SCOPE FOR PHASE II

The Phase II engineering scope of supply includes the entire scope of Phase I. In addition, the required surface modifications for firing 100% natural gas were developed. The adequacy of the existing forced draft (FD) fans and the induced draft (ID) fans were also assessed.

BASIS

This boiler pressure part metals assessment requires developing overall unit heat and material balances at the indicated steam flow. The fuel analysis for the original design bituminous coal and natural gas fuel are provided in Tables 1 and 2. These were used as a basis for the heat and material balances shown in Table 3.

Table 1: Original Design As-Fired Fuel Analyses for Bituminous Coal, % by weight

Constituent	
C	55.27
H_2	3.70
N_2	1.05
O_2	5.68
Cl	0.00
S	3.30
H_2O	19.00
Ash	12.00
Total	**100.00**
HHV (Btu/lb)	**10,000**

Table 2: Proximate Analysis for Natural Gas, % by volume

Constituent	
Nitrogen	1.79
Methane	91.88
Ethane	5.12
Others	1.21
Total	**100.00**
HHV (Btu/ft^3)	**1,037**

Table 3: Boiler Operating Conditions Used in Metals Evaluation

Maximum Continuous Rating		
Steam Flow (lb/hr)	840,000	420,000
Steam Temperature at SH Outlet (°F)	955	925
Steam Pressure at SH Outlet (psig)	1290	1260
Feedwater Temperature (°F)	425	360
Excess Air Leaving Econ (%)	10	18

RESULTS

Boiler Pressure Part Modifications

The boiler pressure part modifications consist of a surface reduction to the primary superheater that would be required with both cases where flue gas recirculation (FGR) is required. FGR increases the flue gas flow rate through the convection pass components thus increasing component absorption. A reduction in the PSH surface is required to avoid exceeding the limits of the existing tube metallurgy. Twelve (12) tube rows would be removed from the PSH inlet bank.

Boiler Performance

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance firing the original bituminous coal and predicted unit performance firing natural gas with scenarios including PSH heating surface reduction (if required) and FGR requirements as set by flue gas emissions.

Attemperator Capacity

Along with the metals analysis, attemperation capacities were studied for the boiler operating conditions with and without flue gas recirculation (FGR) and also in regards to surface reductions of the primary superheater (where required). The attemperator spray flows for gas firing are higher than the spray flows for firing 100% coal due to higher flue gas temperatures leaving the furnace and higher component absorption. Required FGR flow rates also raised the total flue gas flow through the convection pass which results in higher convection pass component absorptions. The existing spray water attemperator nozzle size is adequate but would have to be modified by increasing the orifice diameter to meet the required spray flows. With this nozzle modification, capacities should be satisfactory at all boiler loads when firing natural gas. The results are shown in Table 6.

Table 6: Expected Total Attemperator Flows (lbs/hr)

Boiler Load	MCR	50%
Bituminous Coal	54,190	1,800
Natural Gas:		
No FGR or boiler modifications	71,440	27,910
14% FGR with PSH surface reduction	71,750	18,600
19.5% FGR with PSH surface reduction	79,280	18,600

Air Heater Performance

Air heaters were assessed for natural gas firing. The air and gas side temperature profiles around the air heater were found to be acceptable for the natural gas conversion. Since no field data was provided that would show higher than original air heater leakage or other air heater performance degradation, the predicted air heater performance is based on the original design data with an air heater leakage of 10.0%. Predicted performance is shown on Table 7A & 7 B.

Table 7A: Regenerative Air Heater Predicted Performance at MCR Load

Boiler load	MCR	MCR	MCR	MCR
Fuel	**Bituminous Coal**	**Natural Gas**	**Natural Gas**	**Natural Gas**
Boiler Modifications	None	New burners with & without overfire air ports	PSH surface reduction New burners without overfire air ports	PSH Surface Reduction New burners with overfire air ports
Flue Gas Recirculation	None	None	19.5%	14.0%
Flue Gas Flow Entering Air Heaters, mlb/hr	1017	909	918	915
Flue Gas Temp Entering Air Heaters, F	752	726	804	796
Flue Gas Temp Leaving Air Heaters w/o Leakage, F	320	310	334	331
Air Flow Leaving Air Heaters, mlb/hr	902	846	854	851
Air Temp Entering Air Heaters, F	100	100	100	100
Air Temp Leaving Air Heaters, F	604	598	660	653

Table 7B: Regenerative Air Heater Predicted Performance at 50 % Load

Boiler load	**50%**	**50%**	**50%**	**50%**
Fuel	**Bituminous Coal**	**Natural Gas**	**Natural Gas**	**Natural Gas**
Boiler Modifications	None	New burners with & without overfire air ports	PSH surface reduction New burners without overfire air ports	PSH Surface Reduction New burners with overfire air ports
Flue Gas Recirculation	None	None	19.5	14.0
Flue Gas Flow Entering Air Heaters, mlb/hr	541	507	507	507
Flue Gas Temp Entering Air Heaters, F	585	581	606	606
Flue Gas Temp Leaving Air Heaters w/o Leakage, F	264	263	271	270
Air Flow Leaving Air Heaters, mlb/hr	473	466	466	466
Air Temp Entering Air Heaters, F	121	121	121	121
Air Temp Leaving Air Heaters, F	501	504	526	526

Tube Metal Temperature Evaluation

B&W uses an ASME Code accepted method to design its tube metallurgies and thicknesses. The method involves applying upsets and unbalances to determine spot and mean tube metal temperatures. The upsets and unbalances include empirical uncertainty in the calculation of furnace exit gas temperature (FEGT), top to bottom gas temperature deviations, side to side gas temperature deviations, steam flow unbalances (a function of tube side pressure drop and component arrangement) and gas flow unbalances. The method applies these upsets and unbalances simultaneously to a single spot in each row of the superheater. Tube row metallurgy and thickness are then determined from the resultant tube spot and mean temperatures, respectively, according to ASME Code material oxidation limits and allowable stresses. B&W policy does not allow the publishing of design tube metal temperatures or unbalanced steam temperatures. However, these values can be reviewed in B&W's offices, if desired.

The remaining life expectancy of the superheaters is dependent on the prior operating history, especially on actual tube operating temperature compared to design temperature. Thus, the assessment of the adequacy of the existing superheaters is not a simple task.

B&W has determined the operating hoop stress level (based on the current minimum tube wall thickness) at operating pressure. The predicted tube operating temperatures based on B&W's standard design criteria and the resulting ASME Code allowable stress level for the existing material has also been determined. Comparison of the operating hoop stress with the Code allowable stresses results in the percent over the allowable stress. A modest overstress level indicates a modest shortening of remaining life expectancy and, unless otherwise indicated by past maintenance experience, does not warrant tube modification at this time.

If the tube analysis shows significant overstress or shows that tubes are predicted to operate at temperatures above those for which ASME Code stresses are published, then serious consideration should be given to tube upgrades and replacement. Significant overstresses are considered those tube rows that are 20% or greater overstressed. An overstress of 20% or more does not necessarily mean that immediate replacement of the tube row is required, but it identifies which tube rows should be examined for potential problems. Potential problems could be signs of creep, internal exfoliation or swelling.

This study showed that all tubes were predicted to operate at temperatures less than the existing material use limit for all the boiler operating cases shown in Tables 7A and 7B (with PSH surface reduction if required). In addition, all existing convection pass tubes and component headers had no overstress issues.

Therefore, the existing convection pass tube metallurgy is acceptable for natural gas firing for all cases.

Forced Draft Fans

The existing forced draft fans were analyzed to determine if they meet the requirements of natural gas firing. The FD fans were originally designed to supply the combustion air in a pressure fired boiler operating mode. The boiler has since been converted to balanced draft operation, resulting high static pressure rise margins when firing coal. The results showed the existing FD fans far exceed the requirements in capacity and static pressure rise (including higher natural gas burner pressure drop) for all natural gas firing cases. Predicted fan performance is shown in Table 8A:

Table 8A: Forced Draft Fan Performance at MCR Load (balanced draft operation)

Fuel	FD Fan Test Block	Bituminous Coal	Natural Gas	Natural Gas	Natural Gas
Boiler Modifications		None	New burners with & without overfire air ports	PSH surface reduction New burners with overfire air ports	PSH Surface Reduction New burners with overfire air ports
FGR flow (%)	NA	None	None	19.5	14.0
Flow per fan (lb/hr)	620,000	514,500	468,510	472,960	471,790
Static Pressure Rise (in WC)	25.9	7.5	10.82	10.95	10.88
Temperature (F)	125	100	100	100	100

Induced Draft Fans

The existing induced draft fans were also analyzed to determine if they meet the requirements of natural gas firing. The results showed the existing ID fans far exceed the requirements in capacity and static pressure rise for all natural gas firing cases. Predicted fan performance is shown in Table 8B:

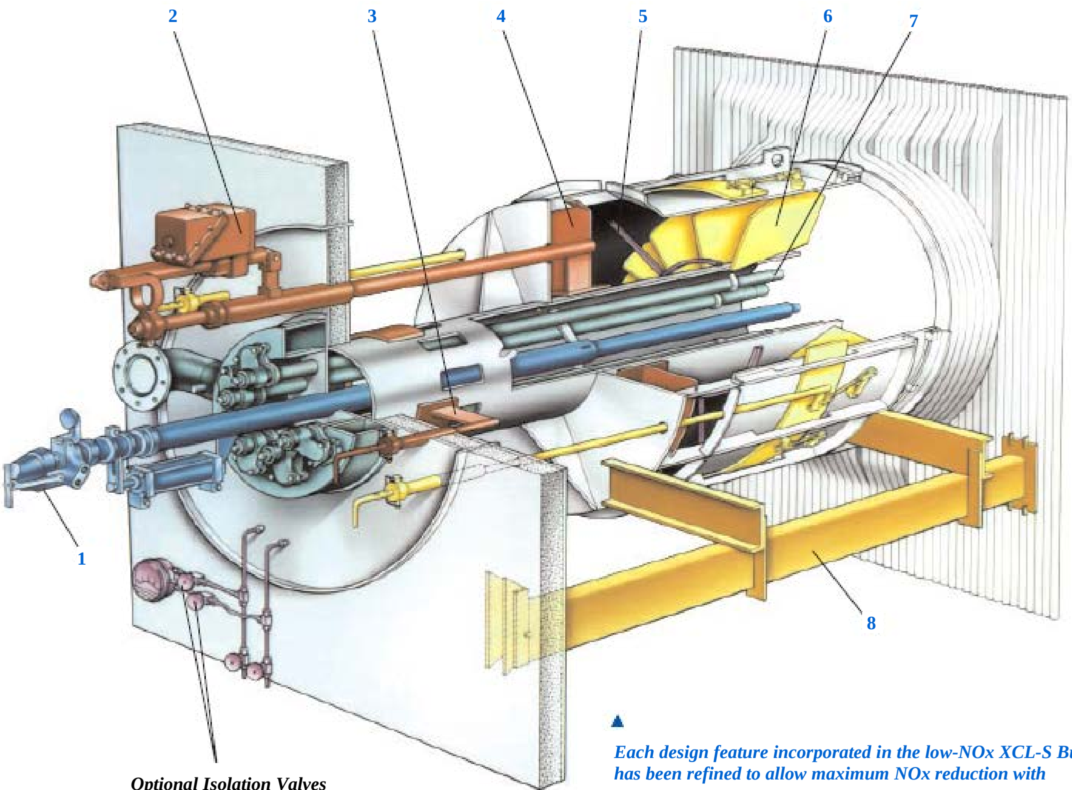
Table 8B: Induced Draft Fan Performance at MCR Load (balanced draft operation)

Fuel	ID Fan Test Block	Bituminous Coal	Natural Gas	Natural Gas	Natural Gas
Boiler Modifications		None	New burners with & without overfire air ports	PSH surface reduction New burners with overfire air ports	PSH Surface Reduction New burners with overfire air ports
FGR flow (%)	NA	None	None	19.5	14.0
Flow per fan (lb/hr)	764,900	559,350	499,450	504,900	503,250
Static Pressure Rise (in WC)	16.0	12.8	9.10	10.13	9.78
Temperature (F)	360	301	293	315	308

Combustion Equipment

The minimum combustion equipment modifications required to fire natural gas include replacing the twelve (12) existing PC burners with twelve (12) XCL-S® natural gas burners with natural gas ignitors. The XCL-S burner, shown below in Figure 2, is an advanced low-NOx burner that was developed to achieve superior NOx performance in burner-only applications and in applications using overfire air (OFA) and/or flue gas recirculation (FGR). It is designed as a simple plug-in, with little or no modifications needed to the rest of the boiler.

Figure 2: Low-NOx XCL-S® Burner



Each design feature incorporated in the low-NOx XCL-S Burner has been refined to allow maximum NOx reduction with optimum combustion efficiency.

Components	Features
1 I-Jet oil gun (optional))	Produces a finer oil spray, reduces particulate and opacity emissions, minimizes atomizer plugging
2 Linear actuator	Easily adjusts the main air sliding damper position for light-off, full-load and out-of-service cooling
3 Core air damper	Adjusts core air flow to the oil gun or gas spuds for optimizing combustion
4 Sliding air damper	Adjusts the majority of secondary air flow to the outer air zone, independent of swirl, to balance air flow among burners during commissioning
5 Air measurement grid	Ensures an accurate indication of relative air flow with a multi-point impact/suction device
6 Externally adjustable spin vanes	Provide proper mixing of the secondary air and fuel (to the end of the flame) – vane position is optimized and fixed during commissioning
7 Adjustable hemispherical gas spuds	Can be rotated to optimize NOx reduction and are removable while the boiler is in service
8 Burner support system	Supports the burner and allows for differential expansion

Additional NOx reduction can be achieved with staged combustion and/or flue gas recirculation. For staged combustion, the preferred approach is to locate eight (8) new NOx ports, four on the front wall and four on the rear wall, at an elevation at least eight feet above the top burner row. New NOx ports would require windbox and duct work modifications.

FGR involves the introduction of recirculated flue gas into the combustion air upstream of the burner windbox. A mixing device (such as a slotted air foil in the combustion air duct) is required to adequately distribute the recirculated flue gas in the incoming combustion air.

The new burners can be retrofitted into the existing burner pressure part openings on the furnace front wall. Depending on the choice of NOx reduction technologies (i.e., burners, burners plus OFA, burners plus OFA and FGR, or burners plus FGR) and the results of the associated detailed engineering in a material contract phase, adjustment to the existing throat diameter may be required. This can be accomplished by conical ceramic throat inserts (for a smaller diameter throat) or removal of pin studs and refractory (for a larger diameter throat) while retaining the existing pressure parts.

Note that all of the combustion air flow must now be supplied via the secondary air ducts and windbox since primary/pulverized coal transport air is no longer required.

Emissions

Emissions predictions are based on converting the unit to fire natural gas as the main fuel. Full load emission predictions for the various options are listed in Table 9. The values are predicted values with margin which B&W expects to be able to guarantee upon material supply.

Table 9: Predicted Full Load Emissions on Natural Gas

	XCL-S Burners only	XCL-S Burners and OFA	XCL-S Burners, OFA, and FGR	XCL-S Burners and FGR
FGR Rate (%)	NA	NA	~14%	~19.5%
NOx (lb/10^6 Btu)	0.16	0.13	0.07	0.07
CO (ppmvd corrected to 3% O_2)	200	200	200	200
VOC (lb/10^6 Btu)	0.003	0.003	0.003	0.003

CONCLUSIONS

As a result of this study, when firing natural gas with FGR, the PSH heating surface needs to be reduced to maintain existing tube metallurgy. A complete review of the existing tube metallurgies on Culley Station Unit #2 considering all natural gas firing cases revealed that all existing convection pass tubes had no overstress issues. In addition, all tubes were predicted to operate at temperatures below their ASME material code published limit. Header metal temperatures were also checked and showed to meet B&W's standards.

Along with the metals analysis, existing attemperator capacities were studied for the boiler operating conditions with and without flue gas recirculation (FGR) and also in regards to surface reductions of the primary superheater (where required). Existing attemperator capacities should be satisfactory (with the modification to the nozzle orifice size) at all boiler loads when firing natural gas.

Air heaters were assessed for natural gas firing. The air and gas side temperature profiles around the air heater were found to be acceptable for firing natural gas.

The existing FD and ID fans were found to exceed the performance requirements when firing natural gas.

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance firing the original bituminous coal and predicted unit performance firing natural gas.

It is recommended that the twelve (12) existing PC burners be replaced XCL-S natural gas burners with natural gas ignitors. The addition of NOx ports and/or flue gas recirculation is recommended in order to provide reduced NOx emissions.

APPENDIX A - Preliminary Performance Summaries

Table 9.a.

Vectren Culley Unit 2 - Preliminary Performance Summary

Contract No.	293H	GBB				
Date	12/16/2013	Load ID	PC Firing	NG Firing	NG Firing	NG Firing
Revision	0	Boiler Arrangement	Existing	New Burners with & without Overfire Air Ports	PSH Surface Reduction New Burners without Overfire Air Ports	PSH Surface Reduction New Burners with Overfire Air Ports
Load Condition			MCR	MCR	MCR	MCR
Fuel			Bituminous	Natural Gas	Natural Gas	Natural Gas
Steam Leaving SH, mlb/hr			840	840	840	840
Superheater Spray Water, mlb/hr			54,190	71,440	79,281	71750
% Excess Air Leaving Economizer			18	10	10	10
Flue Gas Recirculation, %			None	None	19.5	14.0
Heat Input, mmBtu/hr			1028.0	1077.0	1087.2	1083.5
Quantity mlb/hr	Fuel (mcf/hr if gas)		102.8	1038.6	1048.4	1044.9
	Flue Gas Entering Air Heaters		1017	909	918	915
	Total Air To Burners		902	846	854	851
Pressure, psig	Steam at SH Outlet		1290	1290	1290	1290
Temperature, °F	Steam	Leaving Superheater	955	955	955	955
	Water	Water Entering Economizer	425	425	425	425
		Superheater Spray Water	225	225	225	225
	Gas	Entering Air Heater	752	726	804	796
		Leaving Air Heater (Excl. Leakage)	320	310	334	331
	Air	Entering Air Heater	100	100	100	100
		Leaving Air Heater	604	598	660	653
Heat Loss Efficiency, %	Dry Gas		4.89	3.67	4.18	4.06
	H_2 & H_2O in Fuel		5.94	10.42	10.54	10.51
	Moisture in Air		0.12	0.10	0.11	0.11
	Unburned Combustible		0.30	0.00	0.00	0.00
	Radiation		0.23	0.24	0.24	0.24
	Unacc. & Mfgs. Margin		1.50	1.00	1.00	1.00
	Total Heat Loss		12.98	15.38	16.07	15.92
	Gross Efficiency of Unit, %		87.02	84.58	83.93	84.08

B&W Proprietary and Confidential

APPENDIX A - Preliminary Performance Summaries

Table 9.b.

Vectren Culley Unit 2 - Preliminary Performance Summary

Contract No.	293H	GBB				
Date	1/10/2014	Load ID	PC Firing	NG Firing	NG Firing	NG Firing
Revision	1	Boiler Arrangement	Existing	New Burners with & without Overfire Air Ports	PSH Surface Reduction New Burners without Overfire Air Ports	PSH Surface Reduction New Burners with Overfire Air Ports
Load Condition			50%	50%	50%	50%
Fuel			Bituminous	Natural Gas	Natural Gas	Natural Gas
Steam Leaving SH, mlb/hr			420	420	420	420
Superheater Spray Water, mlb/hr			2	28	19	18.5
% Excess Air Leaving Economizer			20	18	18	18
Flue gas Recirculation, %			None	None	19.5	14.0
Heat Input, mmBtu/hr			539.0	561.7	561.5	561.6
Quantity mlb/hr	Fuel (mcf/hr if gas)		53.9	541.7	541.5	541.6
	Flue Gas Entering Air Heaters		541	507	507	507
	Total Air To Burners		473	466	466	466
Pressure, psig	Steam at SH Outlet		1260	1260	1260	1260
Temperature, °F	Steam	Leaving Superheater	955	955	955	955
	Water	Water Entering Economizer	360	360	360	360
		Superheater Spray Water	225	225	225	225
	Gas	Entering Air Heater	585	581	606	606
		Leaving Air Heater (Excl. Leakage)	264	264	271	270
	Air	Entering Air Heater	121	121	121	121
		Leaving Air Heater	501	504	528	525
Heat Loss Efficiency, %	Dry Gas		3.34	2.74	2.90	2.90
	H_2 & H_2O in Fuel		5.76	10.05	10.08	10.08
	Moisture in Air		0.08	0.07	0.08	0.08
	Unburned Combustible		0.30	0.00	0.00	0.00
	Radiation		0.44	0.46	0.46	0.46
	Unacc. & Mfgs. Margin		1.50	1.00	1.00	1.00
	Total Heat Loss		11.42	14.32	14.51	14.51
	Gross Efficiency of Unit, %		88.58	85.68	85.49	85.49

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APPENDIX B – NG Conversion Equipment Scope & Budgetary Costs

BASE SCOPE - Natural Gas Burners, Ignitors, Scanners

Item 1: B&W XCL-S Natural Gas Burners (Quantity: 12)

Each burner to include:

- Externally adjustable secondary air zone spin vanes
- Externally adjustable core zone damper
- Multiple hemispherical gas spuds
- Pitot tube relative air flow measuring device with magnehelic gage
- Provisions to accept ignitor with integral flame detector
- One main flame scanner mount
- Two Type K permanent thermocouples to monitor core zone and burner outer sleeve temperature with two thermocouple heads
- Throat tile ring assembly to reduce the existing burner throat diameter
- Shop insulated cover plate
- Electric Linear Actuator for automated positioning of sliding secondary air damper
- One set of burner support steel with furnace wall and windbox connection hardware

Item 2: Fossil Power Systems (FPS) Gas Ignitors and Flame Scanners

- Qty 12, FPS gas ignitors with high energy spark ignitors and flame rods
- Qty 3 or 6, pre-assembled valve racks
- Qty 1, combustion/cooling air blower skid
- Qty 12, FPS main flame scanners with rigid fiber optic extension
- Qty 1, main flame scanner electronics cabinet
- 1 Lot – Combustion/Cooling air piping from blower skid to burner fronts

Item 3: Natural Gas Regulating Station and Piping

- Main natural gas regulating station – 30 psig supply pressure
- Natural gas piping from regulating station to the burners
- Natural gas burner front gas piping and valve stations including vent piping to above the boiler building roof

OPTION 1 SCOPE - B&W Overfire Air Ports (OFA) – Dual Zone

- Qty 8, Furnace Water wall Openings
- Windbox Extensions or Individual OFA Windboxes
- Qty 8, Automated Air Flow Control Damper with Rotary Drive - per port
- Boiler Closure Casing
- Temperature Monitoring Thermocouple (port style dependent)

OPTION 2 SCOPE - Flue Gas Recirculation (FGR)

- Flue Gas Recirculation Fan and Motor
- FGR Flues
- AH Outlet to FGR Fan Inlet
- FGR Fan Outlet to Secondary Air Mixing Foils
- FGR Flue expansion joints, hangers, bridging steel
- FGR Mixing Foils
- Windbox O_2 Monitor
- Burner throat assemblies to accommodate the larger B&W XCL-S burners required for FGR firing.

General Services

- Combustion system tuning services using an economizer outlet sampling grid for measurement of NOx per EPA methods.
- Performance testing
- Field Service Engineering outage support for construction, start-up, and post-modification testing. Coverage includes one engineer for 30 man-days at 10 hours per day, 6 days per week. In addition, Field Service Engineering to be provided to support system tuning and performance testing for a total of 20 man-days at 10 hours per day, 6 days per week.
- Burner System Operator Training consisting of two, one day sessions.
  - Training includes project specific training manual for up to 20 participants.
- Brickwork Refractory Insulation & Lagging (BRIL) Specifications and Installation design and materials.
- Contract specific System Requirements Specification, I/O Listing, and Functional Logic Diagrams for all supplied equipment.
- Operating and Maintenance Manuals (10 copies).
- New piping, flue, and duct loading to existing steel
- Shop tube butt welds shall be 100% radiographed.
- No weld rings for shop or field welds.
- All tube ends will be prepped, primed, capped and taped.
- All attachments will be shop installed, where possible.
- Shop hydrostatic pressure testing, at 1½ times design pressure, of all fabricated tube assemblies. Loose tubes without tube to tube welds will not be tested. Shop hydrostatic pressure testing will be AI witnessed.
- Pressure part fabrication to be estimated for BWM.
- Delivery F.O.B. Culley Plant, Newburgh, IN.

Items not Included

- Hazardous material removal or abatement (i.e., lead paint and asbestos).
- Load analysis of existing structural steel or foundations and any required re-enforcement thereof.
- Hardware or reprograming of existing DCS and/or BMS to support natural gas conversion.
- Gas step down equipment. Equipment scope above assumes incoming gas pressure at B&W's terminal to be 30 to 50psi.

Terminal Points

- Inlet of gas regulating station
- Interface of new burners to the existing furnace wall
- Field weld at the new wall panel inserts (if any)
- Electrical terminals on provided electrical equipment or instruments
- Electrical terminals in shop provided terminal junction boxes as part of skidded equipment
- FGR duct take off near the existing economizer outlet
- FGR duct tie in at the existing secondary air duct(s)
- OFA duct take off(s) from the existing secondary air duct(s) or windbox

Budgetary Material & Installation Pricing (USD 2019)

Scope Item	Budgetary	
	Material	Installation
BASE SCOPE: Burner, Ignitor, Scanner, NG Piping System	$2,900,000	$4,350,000
OPTION 1 SCOPE: Overfire Air System	$370,000	$555,000
OPTION 2 SCOPE: Flue Gas Recirculation System	$412,000	$618,000

Lead Times

- Material delivery: 52 - 56 weeks
- Installation outage duration: 8 - 10 weeks

B&W has offered these prices in 2019 US dollars and have not attempted to project escalation for time of performance or delivery.

Please note that these prices are budgetary and is not represent an offer to sell, however, we would welcome the opportunity to provide a formal proposal upon request.

Appendix C. Burns & McDonnell A.B. Brown Coal to Gas Conversion, Unit 2

BURNS & McDONNELL

A.B. Brown Coal to Gas Conversion

VECTREN

Vectren Energy Delivery

AB Brown Unit 2 Coal to Gas Boiler Conversion
Project No. 113003

Revision 1
April 2019

A.B. Brown Coal to Gas Conversion

prepared for

Vectren Energy Delivery
AB Brown Unit 2 Coal to Gas Boiler Conversion
Evansville, Indiana

Project No. 113003

Revision 1
April 2019

prepared by

Burns & McDonnell Engineering Co.
Kansas City, MO

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1.0 EXECUTIVE SUMMARY

Vectren Energy Deliveries (Vectren) is studying a coal to gas conversion project (Project) at the A.B. Brown facility. The conversion requires boiler burner modifications and gas infrastructure to fire 100% natural gas and remove coal firing capabilities.

Vectren retained Burns & McDonnell (BMcD) to provide conceptual engineering design to support a feasibility grade cost estimate. This report summarizes the conceptual engineering, performance estimates, and cost estimates for Vectren to evaluate the feasibility of the project.

1.1 Purpose

The purpose of this report is to provide the overall scope, schedule, performance, and capital costs to construct the Project based on the assumptions documented herein, and to provide general information to support project screening and evaluations.

1.2 Project Configuration Summary

A.B. Brown currently has two pulverized coal fired boilers that burn a local bituminous fuel. Each unit has a net output of approximately 240 MW. The boilers are a Babcock and Wilcox (B&W) wall fired design. The boilers are not equipped with over fire air or flue gas recirculation. Unit 1 is the northern unit which includes Selective Catalytic Reduction (SCR), baghouse, and dual alkali scrubber. Unit 2 is the southern unit which includes Selective Catalytic Reduction (SCR), precipitator, and dual alkali scrubber.

The A.B. Brown boilers were evaluated by B&W to estimate boiler performance and retrofit costs. This study compiles the findings from the B&W report attached in Appendix E with balance of plant (BOP) impacts to develop a total plant evaluation.

This report documents the 100% gas conversion of Unit 2 only. Vectren is evaluating new natural gas offsite infrastructure which is not included in this evaluation. This report assumes a new gas line tap in the existing gas yard. New metering and regulating is added in the gas yard along with a new onsite pipeline from the gas yard to the boiler house. The regulating station in the gas yard lowers the incoming pressure to 200 psig and an intermediate regulating station in the boiler house lowers the pressure further to 50 psig. Additional regulating stations provided by B&W are located at each boiler to lower the pressure further from 50 psig to the burner front pressure. New gas supply piping, vents, and valve stations are included up to the burner fronts. The existing burners will be retrofitted with the B&W Hemi-Spud nozzle to fire 100% natural gas.

For 100% natural gas firing, the SCR and dual alkali scrubber are not necessary. Natural gas emissions are low enough that additional controls shouldn't be necessary, an updated netting analysis should be performed to confirm this. The particulate control will remain in service during startup and initial operation to limit any potential particulate emissions from residual ash in the boiler and ductwork. The dual alkali scrubber will be demolished and replaced with ductwork. The scrubber tower has problems with erosion and leaks and Vectren wanted to remove it as a potential maintenance item.

1.3 Performance and Air Emissions Summary

Unit 2 will have an estimated electric generating capacity and heat rate as shown in the table below. The performances are based on adjusting the existing coal performance for the natural gas and co-firing cases.

Table 1-1: Unit 2 Performance Summary

	100% Coal	100% Natural Gas
Net Output, kW	240,000	238,950
Net Heat Rate, Btu/kWhr	10,650	11,175
Gross Output, kW	260,870	255,650
Auxiliary Loads, kW	20,870	16,700
STG Heat Rate, Btu/kWhr	8,615	8,790
Boiler Efficiency, %	87.9%	84.2%

BMcD performed a high-level permitting analysis in 2016 that evaluated the plant while firing 100% natural gas. For two units, this analysis found that while burning 100% natural gas the plant can operate at an approximate 10% capacity factor and not trip PSD. CO was the limiting factor for each case which is based on the 200 ppm estimate from B&W (0.148 lb/MMBtu). The CO emissions while burning natural gas will likely be less than 200 ppm. By only converting a single unit (Unit 2), the capacity factor should increase to almost double. This will be affected by the past operation from 2016 to 2019 though (past actuals vs future potential).

1.4 Contracting Approach

The selected contracting strategy for this report is the Multiple Prime Contracts approach with the Owner contracting B&W for the burner modifications and a balance of plant contractor directly.

1.5 Schedule

The schedule for this project was developed for a generic start date at month zero (0). The critical path for the project runs through receipt of gas burner equipment, construction, and continuing through startup and commissioning. This schedule assumes Vectren will start preliminary engineering and design while the air permit is being developed and reviewed. The project for 100% gas conversion will likely not trip PSD so air permitting should not be a big risk. The project schedule is shown in Appendix C.

1.6 Capital Costs

The capital cost for the gas conversion is presented in Table 1-3 below. The capital cost estimate is an Association for the Advancement of Cost Estimates (AACE) Class IV estimate. Per this classification, the estimate could have a lowest accuracy of -30%/+50% and a highest accuracy of -15%/+20%. Since a site visit was performed and engineering documents were created for estimate takeoffs, this estimate is closer to the highest accuracy range. Due to this, the contingency's below are recommended.

Table 1-2: Unit 2 Capital Costs

	100% Natural Gas
Project Costs w/ B&W Contract, $	$16,340,000
Owners Costs, $	$5,485,000
Total Costs, $	**$21,825,000**

The project cost includes direct material and construction costs for the Project as well as indirect costs including engineering, construction management, and other indirects. A project contingency of 5% is applied to the project costs. Owners costs includes owner specific management, operations, legal costs, startup costs, interest during construction, contingency and other owners costs. An owner's project contingency of 10% is included on the total project costs to cover scope definition and estimate accuracy.

2.0 INTRODUCTION

2.1 Background

Vectren is investigating converting the existing A.B. Brown Unit 2 to burn 100% natural gas. For 100% natural gas conversion, a new natural gas supply will be constructed up to the existing burners which will be retrofitted with gas spuds. The existing emissions controls will be taken out of service except for the particulate control during initial operation.

Vectren retained Burns & McDonnell to provide a feasibility grade cost estimate of the Plant. This report summarizes the conceptual design and presents the project costs to be used by Vectren in evaluating project feasibility.

2.2 Study Scope

The scope of work included preparing the following major conceptual design documents:

1. Site Arrangement Drawing
2. Preliminary Process and Instrumentation Diagrams
3. Project Schedule
4. Capital Costs

2.3 Objectives

The objectives of this study were to establish the conceptual design for the project, to provide an overall project schedule, and to provide a capital cost estimate to support project screening and evaluations. Vectren can use the information from this report to evaluate the natural gas conversion against other generation options.

2.4 Limitations and Qualifications

The costs presented within this report are subject to:

- Design changes for enhanced efficiency/operational flexibility.
- Final negotiation of the Terms and Conditions with the contractors and the major equipment suppliers.
- Final geotechnical report findings.
- Final topographical survey.
- Final determination/negotiation of the project schedule.
- Final selection of the equipment.
- Final permit requirements.
- Changes in federal regulations.

- Full evaluation of existing underground interferences.

3.0 PROJECT DEFINITION

3.1 Plant Overview

3.1.1 Scope of work

The assumptions that formed the basis of the plant conceptual design and cost estimate are summarized in this report. The assumptions were developed through meetings with Vectren and a site visit at A.B. Brown to evaluate how the conversion will impact the existing plant.

3.1.2 Key Design Documents

The following preliminary design documents were developed to form the basis of the project preliminary design and are included in the Appendices.

- Appendix A: Site Arrangement
- Appendix B: Process Flow Diagrams
- Appendix C: Project Schedule
- Appendix D: Capital Cost Estimate Summary

3.2 General Design Criteria

3.2.1 Operating and Control Philosophy

The Plant is expected to be operated as a peaking facility on 100% natural gas. Daily on/off cycling of the plant may be required. Considerations for daily cycling and impacts on existing equipment have not been included in this report.

The plant will be controlled using the existing A.B. Brown control room and distributed control system (DCS). The DCS at A.B. Brown station has recently been upgraded to Emerson Ovation version 3.3.1. Given that this is a modern control system, input/output (I/O) modules can be purchased and added to the system with little impact to the overall control system.

The I/O will change with the conversion from coal to natural gas. In general, a coal-fired station requires more I/O than a gas-fired station, so the gas conversion will be an overall reduction in the DCS I/O. It is assumed that B&W will provide updated instrument lists and I/O lists for the coal to gas conversion that indicate the devices to be removed and new devices that will be added to the control system. This in combination with the balance of plant (BOP) modifications will be used to develop an overall I/O impact. For the purposes of this study, a worse-case scenario was assumed that new DCS cabinets will need to be added to the existing BMS system. During detailed design, the system will be evaluated to determine how the existing system can be best utilized. Most likely, I/O can be relocated and spares can be utilized so that additional hardware is not necessary.

The existing logic will be modified to accommodate the modified gas burners, gas supply equipment, and gas interlocks. The existing master fuel trip (MFT) cabinet will be rewired to accommodate the new configuration. Fuel firing, air flow, and interlock logic will be reviewed and implemented based on the logic diagrams provided by B&W. Additional modifications to the BOP logic will be required to remove systems that are out of service and add logic for gas supply skids. The cost estimate assumes that BMcD will review the proposed logic changes by B&W and develop logic updates for Emerson to program.

The graphics will require evaluation and modification with the coal to gas conversion. During detailed design, BMcD will evaluate the existing graphics compared to the instrument list changes and updated piping configuration provided by B&W to develop graphic update sketches. These sketches will be reviewed with Vectren and then transmitted to Emerson for configuration.

An Emerson Field Service Engineer will be on-site for a portion of the outage to assist BMcD with I/O checkout and resolve any logic or graphic issues. Tuning of the air flow, drum level, furnace draft, throttle pressure control, steam temperature control, and other miscellaneous BOP loops will be required by an Emerson Tuner during startup.

The existing plant operators will be trained for natural gas operation. For the 100% gas firing case, plant operations can be reduced as the gas fired plant will have less equipment operating and require less maintenance.

Plant automation will be designed for secure and safe operation of all equipment. Maintenance support will be supplied by on-site staff as required for routine maintenance activities and may be shared with other Vectren units if such need arises.

3.2.2 Plant Design Summary

Design basis of the Plant can be summarized by the key documents accompanying this report as Appendices. Detailed design basis for each discipline as well as system descriptions are presented in this report.

3.2.2.1 Plant Location and Layout

The A.B. Brown plant is located in Mt. Vernon, IN near Evansville, IN. The conversion will have little impact on the existing plant layout. The existing gas yard has adequate space for the new regulating and metering skids. The regulating stations at the boiler will be housed in the southwest corner of the boiler house. Some existing shelving and storage may need to be relocated to allow room for the new regulating stations and valve stations. For the 100% gas conversion, the existing scrubber vessels will be demolished and replaced with ductwork but existing roads and access will not be impacted. The Site Arrangement Drawing is included in Appendix B.

No modifications to existing roads, switchyard, coal yard, or other plant areas are necessary. Existing building and structure modifications are not required.

3.2.2.2 Plant Utilities and Infrastructures

3.2.2.2.1 Fuel Gas Supply

The A.B. Brown plant site currently has existing gas supply utilized as start-up fuel for Units 1 & 2 and as main fuel supply for the GTG units. Plant personnel indicated that an additional gas line would be required for the additional necessary gas quantities for the conversion of Unit 2. A new gas supply line would also require a new revenue quality regulating and metering station. For the purposes of this study, BMcD located the single additional revenue quality regulating and metering station on the west side of the existing gas yard. The cost estimate scope starts at the inlet to the new regulating station and includes the onsite metering and regulation. The offsite supply line is excluded. This regulating station would be the single point of supply for the primary fuel for the converted unit. The new supply line would be fed by an underground line to the southwest corner of the boiler house to an intermediate regulation station to drop the pressure to B&W's required 50 psig. This line will feed B&W's regulating skid, beginning B&W scope of supply. The boiler regulating station would result in reducing the primary fuel pressure from 50 psig to burner supply pressure. The single regulating station located at the gas yard and the boiler supply regulating stations would be designed based upon NFPA 85 code.

3.2.2.2.2 Water Supply & Discharge

The discontinued use of coal after the 100% gas conversion would have considerable impact to water requirements at the A.B. Brown plant site. Both units currently utilize wet scrubber technology for the reduction of acid gases from fuel bound sulfur. This technology requires a continuous water supply to make up the continued blowdown stream. Both A.B. Brown units sluice bottom ash to an ash pond. Fly ash is transported dry to an onsite silo and then conveyed to barge for offsite utilization. The plant will no longer need water for fly ash sluicing or water for the hydroveyor to the barge. Mercury limitations for wastewater discharge (assuming existing coal pile and ponds are closed) will also be mitigated.

3.2.2.3 Buildings and Enclosure

No changes will be made to the existing boiler house building. The gas yard equipment will not be enclosed. The new gas valve stations and regulators for the conversion will be housed in the existing boiler house with no structural modifications necessary. Since the units already use natural gas for startup fuel, additional ventilation (such as louvers or vent fans) should not be required when converting the coal burners to natural gas.

3.2.3 Unit Modifications

When a boiler is converted to gas firing, there is no longer a need for primary air to convey coal from the coal mill to the burners. Instead, all of the air supply will be sent through the windbox as secondary air. B&W

estimates a boiler efficiency impact of almost 4 percentage points; however, the excess air requirement will drop from ~20% to ~10%. This change in operating conditions results in lower air supply requirements than when firing coal. B&W reviewed the draft system and confirmed that the induced draft and forced draft fans will be adequate for the boiler conversion.

The A.B. Brown Units have the full scope of air quality control system (AQCS) technologies. Natural gas still produces nitrogen oxides (NOx), but the SCR will not be necessary for 100% natural gas firing as it produces much lower NOx. In the case of full gas conversion, both the particulate matter (PM) control and flue gas desulphurization (FGD) technologies could be fully removed from service but Vectren has elected to keep the PM control in service for initial operation to remove any residual particulate in the system. When operating on 100% natural gas, the boiler and gas path will clean up with time and the particulate systems can be removed from service. Due to the low operating hours and uncertain life of the converted plant, owners typically don't demolish the precipitator internals but the bags can be removed from the baghouse. This study assumes that the particulate control devices will be abandoned in place with no demolition.

3.2.3.1 Boiler Modifications

In order to convert the boiler for 100% gas firing, the existing coal burners will be retrofitted by removing the coal nozzle and replacing it with a hemi-spud cartridge as indicated by B&W in Appendix E. The existing natural gas pilot fuel system and ignitors will be reused. The following components will be supplied for each boiler by the boiler vendor for this modification:

<u>Boiler Front Equipment</u>

- Hemispherical Gas Spud Cartridges to replace existing coal nozzles
- Burner Valve Racks ("double block & bleed")
- Burner Front Flex Hose and Hardware
- Burner Front Piping
- Gas Header Piping
- Main UV flame scanners with rigid fiber optic extension
- Main flame scanner electronics cabinet
- Combustion/Cooling air piping from blower skid to burner fronts

<u>Natural Gas Transport Piping and Regulating</u>

- Main natural gas regulating station located within boiler – 50 psig supply pressure to regulator
- Natural gas piping from regulating station to the burners
- Natural gas burner front gas piping and valve stations excluding vent piping

This previous scope of work is typical of the boiler vendor, but Vectren would still be required to install a regulating and metering station at the gas yard for the new gas supply for the primary gas and an intermediate regulation station to lower pressure further to the 50 psig supply pressure to B&W's regulating skid. For the purposes of this study, BMcD placed the new regulating and metering station on the west end of the gas yard and routed a new gas feed along the same path as the existing igniter gas piping. This routing would run east, south of the existing gas turbines and plant road, before turning northeast into the boiler house. The intermediate regulation skid would be located in the boiler house near the existing valve station.

The boiler vendor's scope starts at the southwest corner of the boiler house. Each boiler would require its own low pressure regulating station to allow for primary fuel gas to be isolatable. The boiler regulating stations may be placed adjacent to the existing igniter gas regulating station. The primary fuel gas piping can follow the similar pipe routing to the existing igniter fuel piping for each respective boiler. BMcD pipe sizing criteria for fuel gas is as follows:

- 2-1/2" – 8" Pipe : < 4000 ft/min Line Velocity
- 10" – 20" Pipe : < 5000 ft/min Line Velocity

This design criteria provides lower velocities, resulting in less noise and pipe vibrations as compared to typical velocities when designed by boiler vendors. B&W has not confirmed the line velocity assumed for the burner supply piping they are providing.

In addition to the fuel piping, vent pipe will be required per NFPA 85. This vent piping will be required on both the front and rear elevations of the boiler. B&W did not provide any vent piping in their scope. This vent piping is covered in the BOP scope.

The boiler decks at A.B. Brown Unit 2 appear to have sufficient space; however, the coal piping and elbows should be removed for better access the burner fronts for a full gas conversion. Coal piping can be removed from the burner decks, down to the pulverizer top exits. Pulverizers may be abandoned in place and blanked off.

3.2.4 Switchyard

No switchyard modifications will be required.

3.2.5 Unit 2 Performances

Burning natural gas will be less efficient than burning coal. The main impact on boiler efficiency is from hydrogen losses due to the higher hydrogen content of the natural gas fuel. The byproduct of combusting hydrogen is water vapor, and additional heat is needed to vaporize this water and heat it to the internal boiler temperature. This heat is lost in the flue gas rather than absorbed in the boiler's water walls to create steam.

On the other hand, natural gas is more efficient than coal when it comes to dry gas losses due to less combustion air and excess air. B&W assumed that approximately 10% excess air is needed for proper combustion of natural gas vs. 20% excess air for coal. Less flue gas flow for burning natural gas equates to smaller losses for heating the flue gas.

While the reduced natural gas-fired boiler efficiency reduces net plant output, the reduction in auxiliary power requirements for a gas-fired boiler increases the net plant output accordingly. This study assumes a 20% savings in auxiliary loads for pulverizers, coal handling, soot blowers, etc. that will not be operated on 100% natural gas.

Expected performances for natural gas are shown below along with the existing Unit 2 performances. The boiler efficiency is based on B&W's study. Also based on B&W's boiler evaluation, the STG heat rate will be slightly higher due to lower reheat temperatures.

Table 3-1: Unit 2 Performance Estimates

	100% Coal	100% Natural Gas
Net Output, kW	240,000	238,950
Net Heat Rate, Btu/kWhr	10,650	11,175
Gross Output, kW	260,870	255,650
Auxiliary Loads, kW	20,870	16,700
STG Heat Rate, Btu/kWhr	8,615	8,790
Boiler Efficiency, %	87.9%	84.2%

The 100% natural gas performance will have a lower output and higher heat rate compared to the coal performance based on decreased boiler efficiency, decreased steam turbine gross output and decreased steam turbine heat rate. This is mainly due to the decreased hot reheat temperature while operating on natural gas. The reduction in auxiliary loads could not make up for the reduction in steam turbine performance.

3.3 Environmental & Permitting

A high-level permitting analysis was performed in 2016 for the two A.B. Brown units. This evaluation showed that the plant should be able to net out without tripping PSD. By only converting a single unit, the netting analysis and allowed operating hours should improve. An updated netting analysis was not performed for this study.

3.4 Project Schedule

3.4.1 General

The schedule for this project was developed for a generic start date at month zero (0). This schedule assumes Vectren will start preliminary engineering and design while the air permit is being developed and reviewed. The project for 100% gas conversion should not trip PSD so air permitting should not be a big risk. The project schedule is shown in Appendix C.

3.4.2 Major Equipment

The schedule assumes a 12-month lead time for all boiler and burner equipment. B&W provided a lead time of 52-56 weeks.

3.4.3 Construction

Major construction activities will include the new onsite gas pipeline and fuel yard work, boiler modifications including mechanical and electrical work, and the scrubber vessel demo and replacement with ductwork. Construction of Unit 2 is estimated at approximately 12 months.

3.4.4 Startup

Startup for either the 100% natural gas or co-firing options will be relative short with a duration of approximately 2 months. The unit will be fired and tuned for optimum performance. Since the steam side will not be affected, no steam blows or cleanings will be necessary.

4.0 PROJECT COSTS

4.1 Project Cost Estimate

The detailed capital cost build-up for the 100% natural gas is included in Appendix D. The capital cost summary is shown below. The project costs exclude escalation and are shown as 2019$. The capital cost estimate is an Association for the Advancement of Cost Estimates (AACE) Class IV estimate. Per this classification, the estimate could have a lowest accuracy of -30%/+50% and a highest accuracy of -15%/+20%. Since a site visit was performed and engineering documents were created for estimate takeoffs, this estimate is closer to the highest accuracy range. Due to this, the contingency's below are recommended. A project contingency of 5% is included to cover pricing accuracy and potential labor productivity. An owner contingency of 10% is included to cover the accuracy of the estimate for the scope defined in this report. Owner costs are also included to account for all project costs that may be incurred during the project.

Table 4-1: Unit 2 Capital Costs

	100% Natural Gas
Project Costs w/ B&W Contract, $	$16,340,000
Owners Costs, $	$5,485,000
Total Costs, $	**$21,825,000**

4.2 Cost Estimate Basis

The purpose of the cost estimate basis is to generally describe the scope of the cost estimate and the methodology for estimating the costs.

4.2.1 Contracting Approach

The cost estimate was assembled using multiple prime contract approach. The Owner is responsible for the purchase of all equipment, while each prime contractor is responsible for their subcontracts, and labor. The associated risk for the Owner of using multiple contractors is accounted for in the total project contingency. Costs to administer the contract, participate in OEM's meetings, and review submittals are included under engineering cost.

4.2.2 Engineered Equipment

B&W will provide the majority of the major equipment. The B&W supplied scope is outlined in 3.2.3.1 and in Appendix E. B&W provided a supply and installation cost for the burner equipment. BMcD checked the installation estimate using information from previous gas conversion estimates and found that it was a conservative estimate. Based on this, the B&W installation cost was carried in the estimate even though B&W may or may not perform that work when the project is executed. The BOP contractor will provide the gas yard regulating and metering. All BOP equipment and materials were based on in house pricing from recent projects. The productivity factors for the equipment installation were derived from Burns & McDonnell past project information for union labor in the project area.

4.2.3 Civil

Civil scope for this project is very limited. Scope includes excavation and backfill for the onsite natural gas pipeline and finishing work around the gas yard and scrubber vessel areas. No new roads or grading are required.

4.2.4 Concrete

The gas yard metering and regulation is assumed to be field erected. Some foundation work is included for the scrubber vessel replacement where foundations could not be reused. The valve stations and metering in the boiler house will be mounted to the existing floor slab. This scope also includes estimated quantities for the structural excavation and backfill required for foundation construction. For reinforcing steel, a density of rebar per unit of concrete was provided by engineering for estimating purposes. The production rates and material prices were developed from Burns & McDonnell previous project estimates for construction in the project area.

4.2.5 Structural Steel

Miscellaneous steel such as pipe rack, grating, handrail, etc. are included for structure access that is not otherwise provided as part of the equipment contracts. Structural steel is also estimated to replace the existing scrubber vessels with ductwork. The existing structural steel around the absorbers was assumed to be corroded and was replaced with new steel where necessary. The production rates and material prices were developed from Burns & McDonnell previous project estimates for construction in the project area.

4.2.6 Piping

The BOP piping scope of work includes mostly below grade gas supply piping from the gas yard to the boiler house and vent piping. B&W is providing materials and installation of all the burner supply piping. The piping scope covers purchase of pipe, fittings, flanges, valves, specials, bolt-up kits, supports and pre-fabricated pipe. The piping scope of work does include applicable non-destructive evaluation (NDE) and pressure testing. The piping scope of work includes allowances for underground interferences.

The piping estimate was based on a take-off from the general arrangement with P&IDs. Using these quantities, costs for bulk material, valves, pipe fabrication was based on Burns & McDonnell recent project pricing. The production rates developed from Burns & McDonnell previous project estimates for construction in the project area.

4.2.7 Electrical

The auxiliary power requirements for burning natural gas are generally lower than that required for burning coal. Abandonment of the pulverizers will free up considerable load from the aux power system. Power will be required for the new flame scanners, valves, and blowers, but it is assumed that the existing power distribution can accommodate these additional minor loads. New control wiring has been included from the burner devices to the existing burner junction boxes. New marshalling control wiring has also been included from the burner junction boxes back to the DCS. Wiring has been included to the low pressure and high pressure regulating skids. The existing cable tray around the boiler has adequate space to accommodate the new cable. The production rates and material prices were developed from Burns & McDonnell previous project estimates for construction in the project area.

4.2.8 Instrumentation & Controls

The majority of instrumentation for this project is either skid-mounted or included in the B&W installation estimate. The skid-mounted regulating skids and valve stations are specified such that all instrumentation is installed and wired to a junction box. Some instrumentation will be installed separately for the field erected gas yard metering and regulation. This results in negligible BOP instrumentation installation work. As described in the General Design Criteria section, the worst case scenario was assumed where new DCS cabinets would be necessary to accommodate the BMS. An internal estimate was developed for this DCS cost that includes both hardware and software modifications.

4.3 Indirects

The following methods were used for indirects:

- Cost for construction management and construction indirects were based on a percentage of the project costs based on similar past projects. Costs include construction management staff expenses including travel and living expenses, temporary buildings and utilities, and site maintenance. Additional construction management provided by the contractors is included in the wage rates used in this estimate.

- Cost for engineering was based on a percentage of the project costs based on similar past projects. The engineering estimate includes costs for office and field engineering as well as all per diems, expenses, and general overhead and administrative costs. The engineering estimate also includes costs to review submittals from major equipment OEMs and contract administration tasks such as attending progress meeting, expediting drawing submittals, and reviewing progress report.

- Cost for startup was based on a percentage of the project costs based on similar past projects.

4.3.1 Taxes

All taxes are excluded from the estimate.

4.3.2 Construction Labor Basis

The estimate was developed on the basis that there will be a sufficient labor pool to draw from the Evansville/Mount Vernon area to support the project. The productivity factors were developed based on Burns & McDonnell project history for labor in the area.

4.3.2.1 Labor Wage Rates & Expenses

Wage rates were taken from the 2019 RSMeans Construction Labor Rates for the Mount Vernon, IN area. The wage rates include wages, fringes, general liability and workers compensation insurance, overtime, per diem, incentives and contractor indirects.

4.3.2.2 Work Hours

The estimate assumes a 5-day, 50-hour week to incentivize labor. The shifts are based on a 50 hour work week with 25% of hours of overtime per day at one and a half times base wage rate for overtime pay.

4.3.2.3 Labor Per Diem

Craft per diem included in the craft wage rates.

4.3.3 Escalation

Escalation was excluded from the project costs.

4.3.4 Contingency

A project contingency was included to cover typical final accuracy of pricing, commodity estimates, and accuracy of the defined project scope. Typically the level of contingency is set by the amount of scope definition provided, the amount of engineering and estimating conducted by the OE and Vectren prior to providing cost certainty on the project price, and the amount of risk born by the prime contractors (performance, schedule, scope, payment, etc.). This contingency is NOT intended to cover changes in the general project scope (i.e. addition of buildings, addition of redundant equipment, addition of systems, etc.) NOR major shifts in market conditions that could result in significant increases in contractor margins, major shortages of qualified labor, significant increases in escalation, or major changes in the cost of money (interest rate on loans). A 5% contingency was included as a typical allowance for this indirect cost.

4.3.5 Owner Costs

Vectren's costs were included in the cost estimate. Burns & McDonnell referenced past projects to develop typical owner costs. Costs were included for the following items:

- Project development
- Vectren's project management
- Vectren's legal counsel
- Permitting and license fees
- Permanent plant operating spare parts
- Startup testing fuels and consumables
- Operator training
- Builder's risk insurance
- Interest during construction (10.2% of project costs provide by Vectren)

Owner's contingency takes into account the level of project scoping and engineering completed during the feasibility design phase to support this cost estimate. 10% contingency on the Total Project Cost and Owner Cost was used at this stage. As the scope and estimating accuracy for this project is refined in subsequent phases the amount of contingency carried will shrink.

5.0 CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

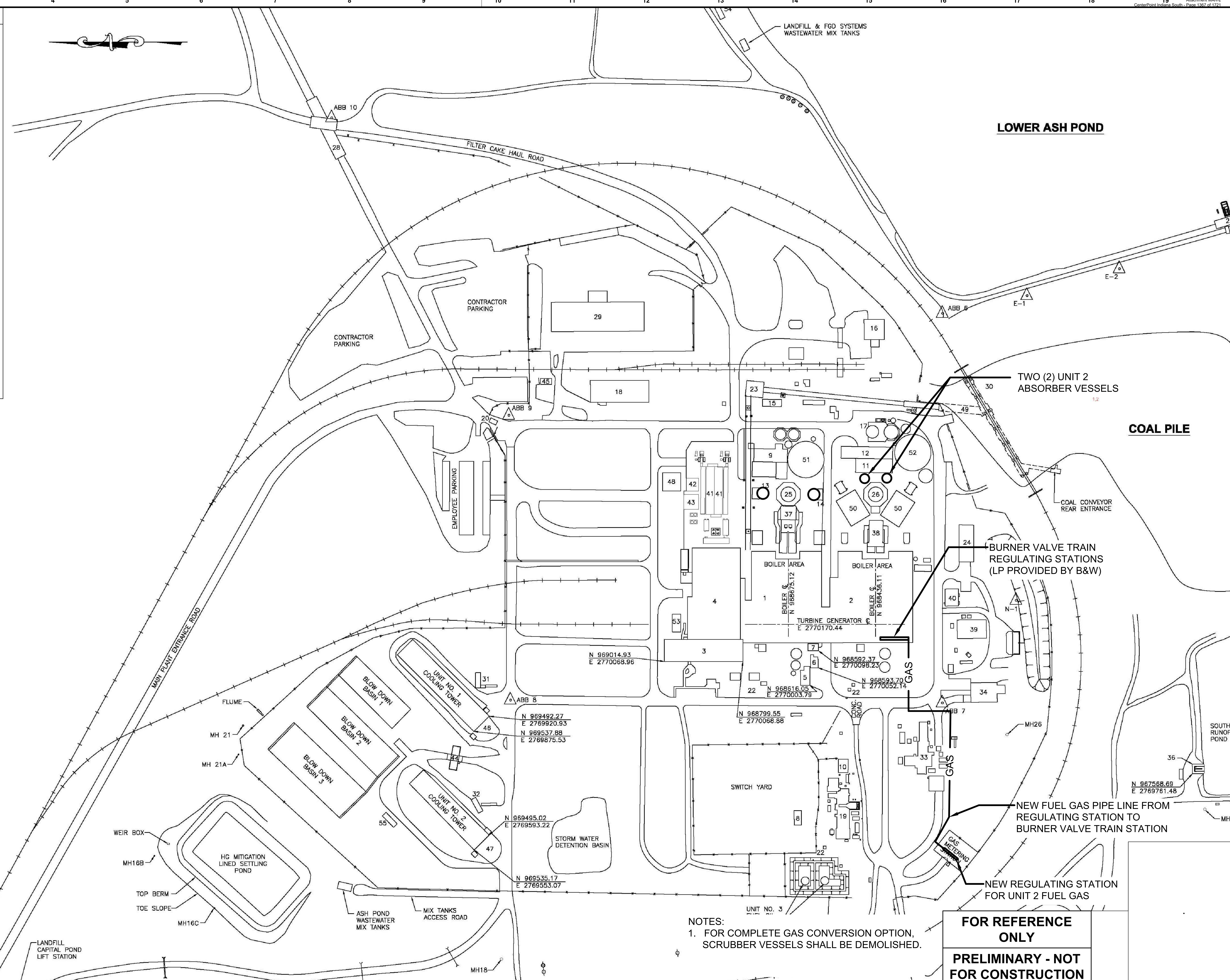
Burns & McDonnell recommends Vectren evaluate the project economics based on the cost and performances presented in this report. If the Plant economics are favorable as a future generation project, then Burns & McDonnell recommends Vectren proceed with a more detailed study to develop budget level pricing and finalize all design and cost considerations.

APPENDIX A – SITE ARRANGEMENT

BUILDING NO. DESCRIPTION

1	UNIT NO. 1 T-G BUILDING & BOILER BUILDING
2	UNIT NO. 2 T-G BUILDING & BOILER BUILDING
3	ADMINISTRATION BUILDING
4	MAINTENANCE SHOP & STOREROOM
5	FIRE PUMP & SERVICE WATER PUMP BUILDING
6	CHLORINE BUILDING
7	HYDROGEN/CARBON DIOXIDE BUILDING
8	SUBSTATION CONTROL BUILDING
9	UNIT NO. 1 FGD SYSTEM FILTER BUILDING
10	BLACK START GENERATOR BUILDING
11	UNIT NO. 2 FGD SYSTEM RECIRC. PUMP HOUSE BUILDING
12	UNIT NO. 2 FGD SYSTEM FILTER BUILDING
13	UNIT NO. 1 FGD SYSTEM NORTH ABSORBER RECIRC. PUMP HOUSE
14	UNIT NO. 1 FGD SYSTEM SOUTH ABSORBER RECIRC. PUMP HOUSE
15	COAL HANDLING SWITCHGEAR BUILDING
16	COAL HANDLING OFFICE & MAINTENANCE SHOP
17	SLAKING SYSTEM PUMP ENCLOSURE
18	LIQUID PRODUCT TANK FARM
19	GAS TURBINE (UNIT NO. 3)
20	GUARD HOUSE
21	ASH POND INTAKE STRUCTURE & RECIRC. PUMPS
22	FIRE PROTECTION VALVE HOUSES (3 TOTAL)
23	COAL CONVEYOR TRANSFER HOUSE (PERSONAL PROPERTY)
24	SHEEP SHED
25	UNIT NO. 1 STACK
26	UNIT NO. 2 STACK
27	TRUCK SCALE BLDG.
28	FGD HAUL ROAD OVERPASS
29	CONSTRUCTION SERVICES (OLD S.I.M.I. BUILDING)
30	COAL TRESTLE
31	UNIT NO. 1 COOLING TOWER LOAD CENTER
32	UNIT NO. 2 COOLING TOWER LOAD CENTER
33	GAS TURBINE (UNIT NO. 4)
34	OIL/WATER SEPARATOR
35	FGD LANDFILL RUNOFF CO2 TANK
36	SOUTH SIDE RUNOFF POND INTAKE STRUCTURE & PUMPS
37	UNIT NO. 1 SCR
38	UNIT NO. 2 SCR
39	AQUEOUS AMMONIA STORAGE TANKS
40	UNIT NO. 2 SOOTBLOWING AIR COMPRESSOR BUILDING
41	UNIT NO. 1 FABRIC FILTER
42	UNIT NO. 1 SERVICE AIR COMPRESSOR BUILDING
43	UNIT NO. 1 SOOTBLOWING AIR COMPRESSOR BUILDING
44	COOLING TOWER SULFURIC ACID SYSTEM BUILDING
45	TRANSFORMER PAD
46	UNIT NO. 1 BLEACH BROMIDE BUILDING
47	UNIT NO. 2 BLEACH BROMIDE BUILDING
48	DRY FLY ASH AIR COMPRESSOR BUILDING
49	COAL TUNNEL
50	UNIT NO. 2 PRECIPITATOR
51	UNIT NO. 1 THICKENER TANK
52	UNIT NO. 2 THICKENER TANK
53	TRAINING TRAILER
54	LANDFILL & FGD SYSTEMS WASTEWATER CHEMICAL BUILDING
55	ASH POND WASTEWATER CHEMICAL BUILDING

NOTE: FOR CONTROL MONUMENT GPS DATA, SEE DRAWING G-1012.



NOTES:
1. FOR COMPLETE GAS CONVERSION OPTION, SCRUBBER VESSELS SHALL BE DEMOLISHED.

FOR REFERENCE ONLY

PRELIMINARY - NOT FOR CONSTRUCTION

no.	date	by	ckd	description
A	09/08/15	ACR	ZDL	FOR OWNER REVIEW

SCALE IN FEET: 0 100' 200'

BURNS & McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: A. ROOT
detailed: M. ATHERTON

VECTREN
POSEY COUNTY, INDIANA

A. B. BROWN POWER STATION
SITE ARRANGEMENT
PLAN

project: 85648
contract:
drawing: SKM-1001
rev.: A
sheet 1 of 1 sheets
file 85648-SKM-1001.dwg

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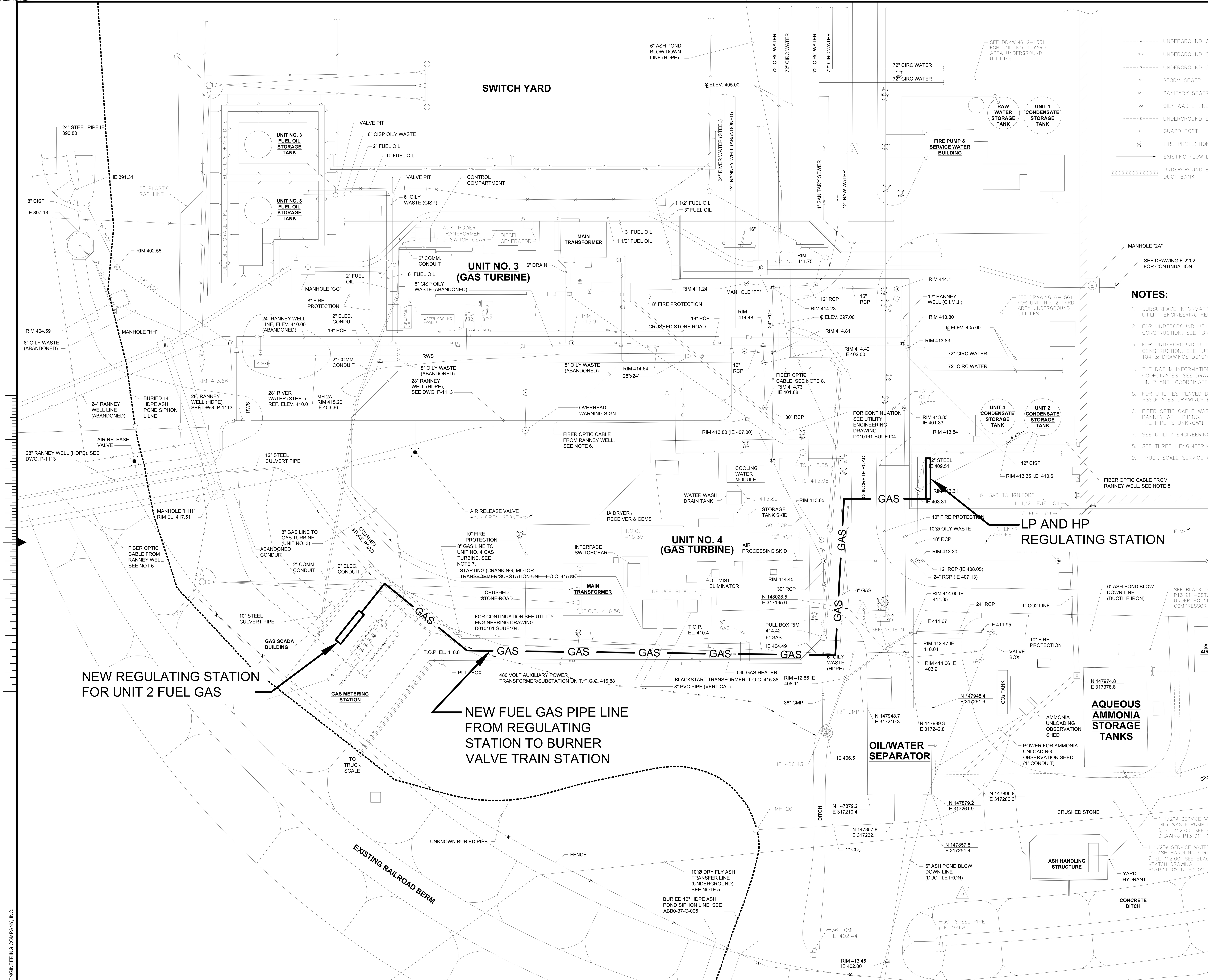

LEGEND

UNDERGROUND WATER	CHAIN LINK FENCE	GROUND ROD
UNDERGROUND COMMUNICATIONS	GUARDRAIL	AREA DRAIN
UNDERGROUND GAS LINE	ACTUATED VALVE	FIRE HYDRANT
STORM SEWER	PRESSURE REGULATING VALVE	PIV
SANITARY SEWER	STRAINER	ELECTRIC JUNCTION BOX
OILY WASTE LINE	STORM SEWER MANHOLE	VALVE OPERATOR
UNDERGROUND ELECTRIC	OILY WASTE MANHOLE	VENT
GUARD POST	ELECTRICAL MANHOLE	LIGHT POLE
FIRE PROTECTION NOZZLE	SILT FENCE	H GUARD POST
EXISTING FLOW LINE	DEMINERALIZED WATER	FUEL OIL LINE
UNDERGROUND ELECTRICAL DUCT BANK	SERVICE AIR	NEW DITCH
		POST INDICATOR VALVE
		FIBER OPTIC VAULT

HORIZONTAL CONTROL

	NORTHING	EASTING
1	148397.12	317198.09
2	148021.59	317223.57
3	147798.81	317286.93

NOTES:

1. SUBSURFACE INFORMATION TAKEN FROM MID-VALLEY, BROWN & ROOT, AND UTILITY ENGINEERING REFERENCE DRAWINGS.
2. FOR UNDERGROUND UTILITIES PLACED DURING UNIT 3 GAS TURBINE CONSTRUCTION. SEE "BROWN & ROOT" DRAWINGS GT-G-1012 THRU GT-G-1023.
3. FOR UNDERGROUND UTILITIES PLACED DURING UNIT 4 GAS TURBINE CONSTRUCTION. SEE "UTILITY ENGINEERING" DRAWINGS D010161-SUUM101 THRU 104 & DRAWINGS D010161-SUUE101 THRU 110.
4. THE DATUM INFORMATION ON THIS DRAWING WAS COMPILED FROM "IN PLANT" COORDINATES. SEE DRAWING G-1012, (HISTORY), FOR AN EXPLANATION OF THE "IN PLANT" COORDINATE SYSTEM.
5. FOR UTILITIES PLACED DURING THE DRY FLY ASH PROJECT, SEE MOORE & ASSOCIATES DRAWINGS E-093007-C01 AND E-093007-C02.
6. FIBER OPTIC CABLE WAS PLACED IN OPEN TRENCH DURING INSTALLATION OF RANNEY WELL PIPING. THE DISTANCE BETWEEN THE FIBER OPTIC CABLE AND THE PIPE IS UNKNOWN.
7. SEE UTILITY ENGINEERING DRAWINGS D010161-SUMM103 AND D101061-SUMM104.
8. SEE THREE I ENGINEERING DRAWING 04015AE30.
9. TRUCK SCALE SERVICE WATER BRANCH VALVE.

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BURNS & McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: A. ROOT
detailed: M. ATHERTON

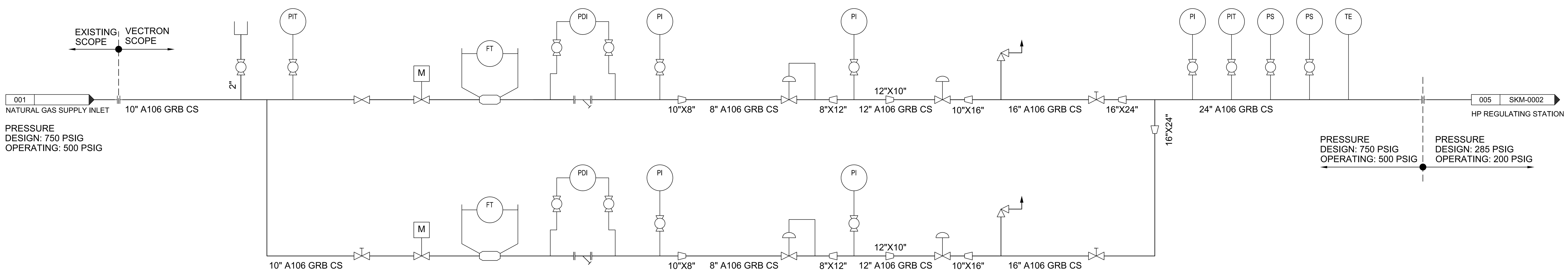
VECTREN

POSEY COUNTY, INDIANA

A. B. BROWN POWER STATION
GENERAL ARRANGEMENT
PLAN

project: 85648
contract:
drawing: SKM-1002
rev.: A
sheet 1 of 1 sheets
file 85648-SKM-1002.dwg

APPENDIX B – PROCESS FLOW DIAGRAMS



FOR REFERENCE ONLY

PRELIMINARY - NOT FOR CONSTRUCTION

no.	date	by	ckd	description
B	02/18/16	ACR	ZDL	REVISED PER B & W REPORT
A	10/29/15	ACR	ZDL	FOR OWNER REVIEW

BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed A. ROOT | detailed S. CHURCHILL

VECTREN

POSEY COUNTY, INDIANA

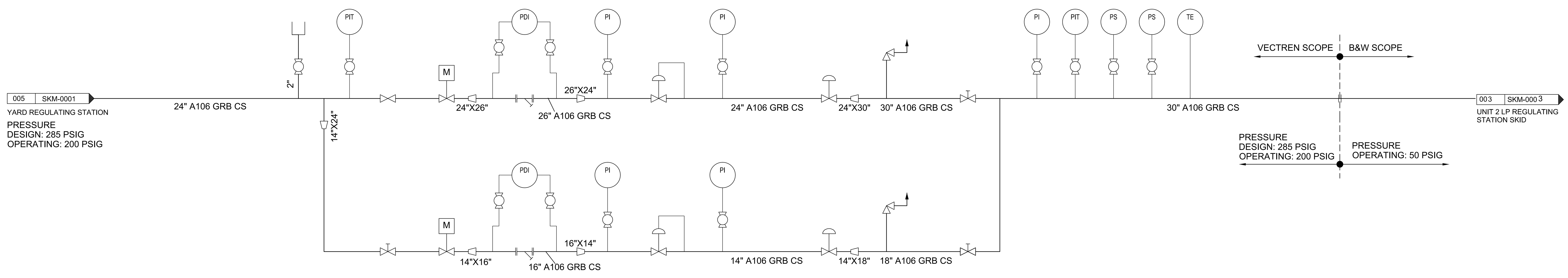
VECTREN COAL TO GAS
YARD REGULATING STATION SKID
A. B. BROWN

project	contract
86548	-

drawing **SKM-0001** rev. **B**

sheet 1 of 1 sheets

file 86548-SKM-0001.dwg



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no.	date	by	ckd	description
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A	10/29/15	ACR	ZDL	FOR OWNER REVIEW

BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

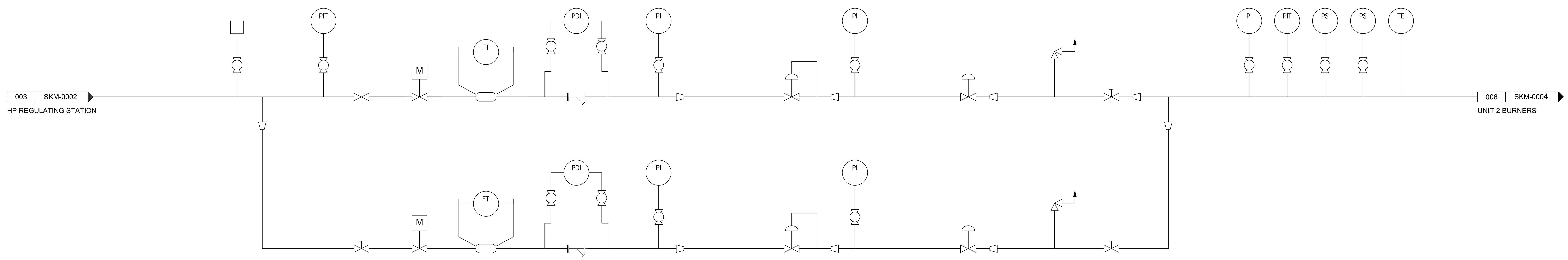
designed: A. ROOT
detailed: S. CHURCHILL

VECTREN

POSEY COUNTY, INDIANA

VECTREN COAL TO GAS
HP REGULATING STATION
A. B. BROWN

project: 86548
contract: -
drawing: **SKM-0002 –** rev. **B**
sheet 1 of 1 sheets
file 86548-SMK-0002



NOTE:

MATERIALS AND DESIGN
PROVIDED BY B&W.

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no.	date	by	ckd	description
B	02/18/16	ACR	ZDL	REVISED PER B & W REPORT
A	10/29/15	ACR	ZDL	FOR OWNER REVIEW

BURNS & McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: A. ROOT
detailed: S. CHURCHILL

VECTREN

POSEY COUNTY, INDIANA

VECTREN COAL TO GAS
UNIT 2 REGULATING STATION SKID
A. B. BROWN

project: 86548
contract: -
drawing: SKM-0003 –
rev.: B
sheet 1 of 1 sheets
file 86548-SKM-0004.dwg

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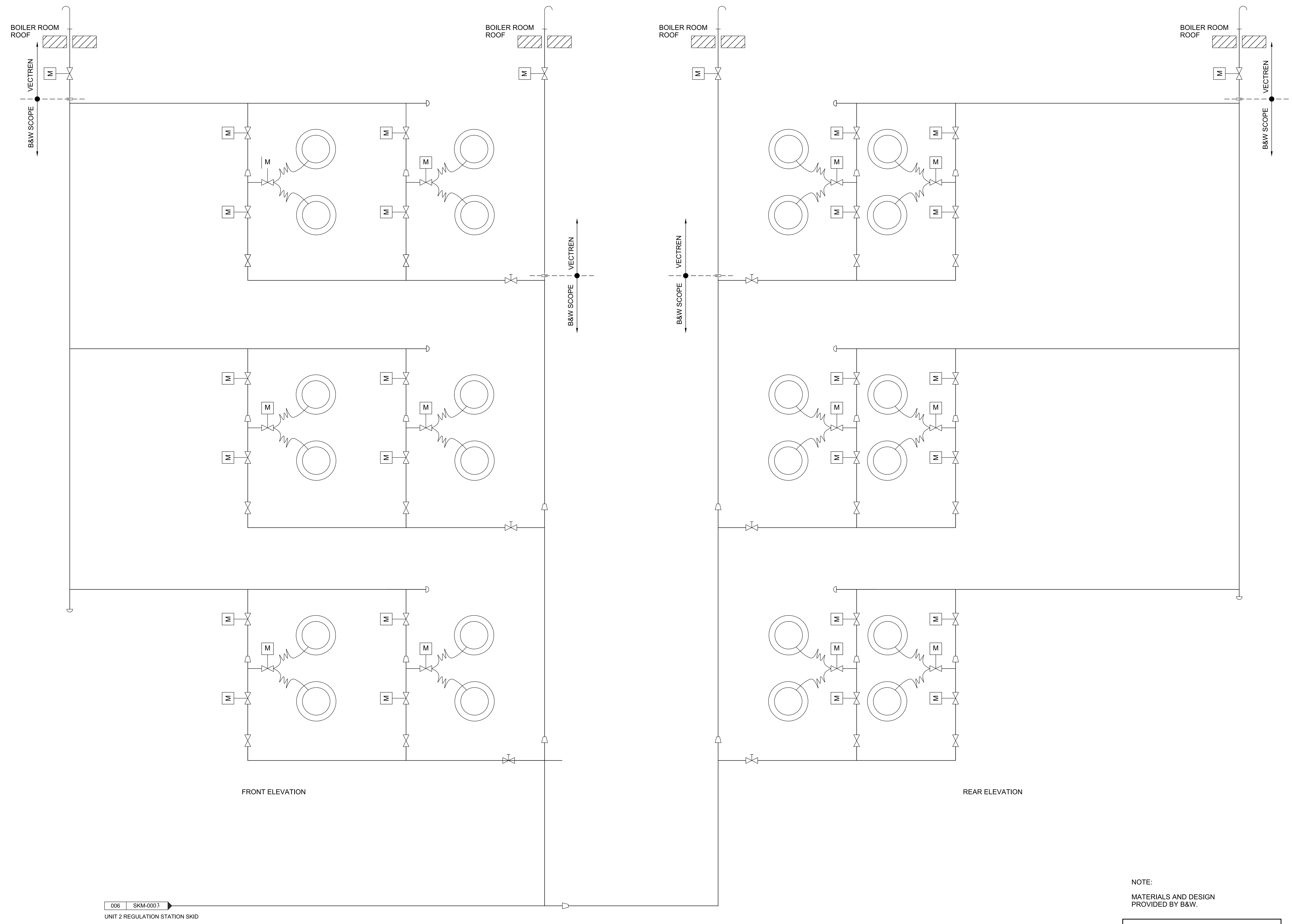

NOTE:

MATERIALS AND DESIGN PROVIDED BY B&W.

FOR REFERENCE ONLY

PRELIMINARY - NOT FOR CONSTRUCTION

no.	date	by	ckd	description
B	02/18/16	ACR	ZDL	REVISED PER B & W REPORT
A	10/29/15	ACR	ZDL	FOR OWNER REVIEW

BURNS & McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: A. ROOT
detailed: S. CHURCHILL

VECTREN
POSEY COUNTY, INDIANA

VECTREN COAL TO GAS
UNIT 2 BOILER
A. B. BROWN

project: 86548
contract: -
drawing: SKM-0004
rev.: B
sheet 1 of 1 sheets
file 86548-SKM-0006.dwg

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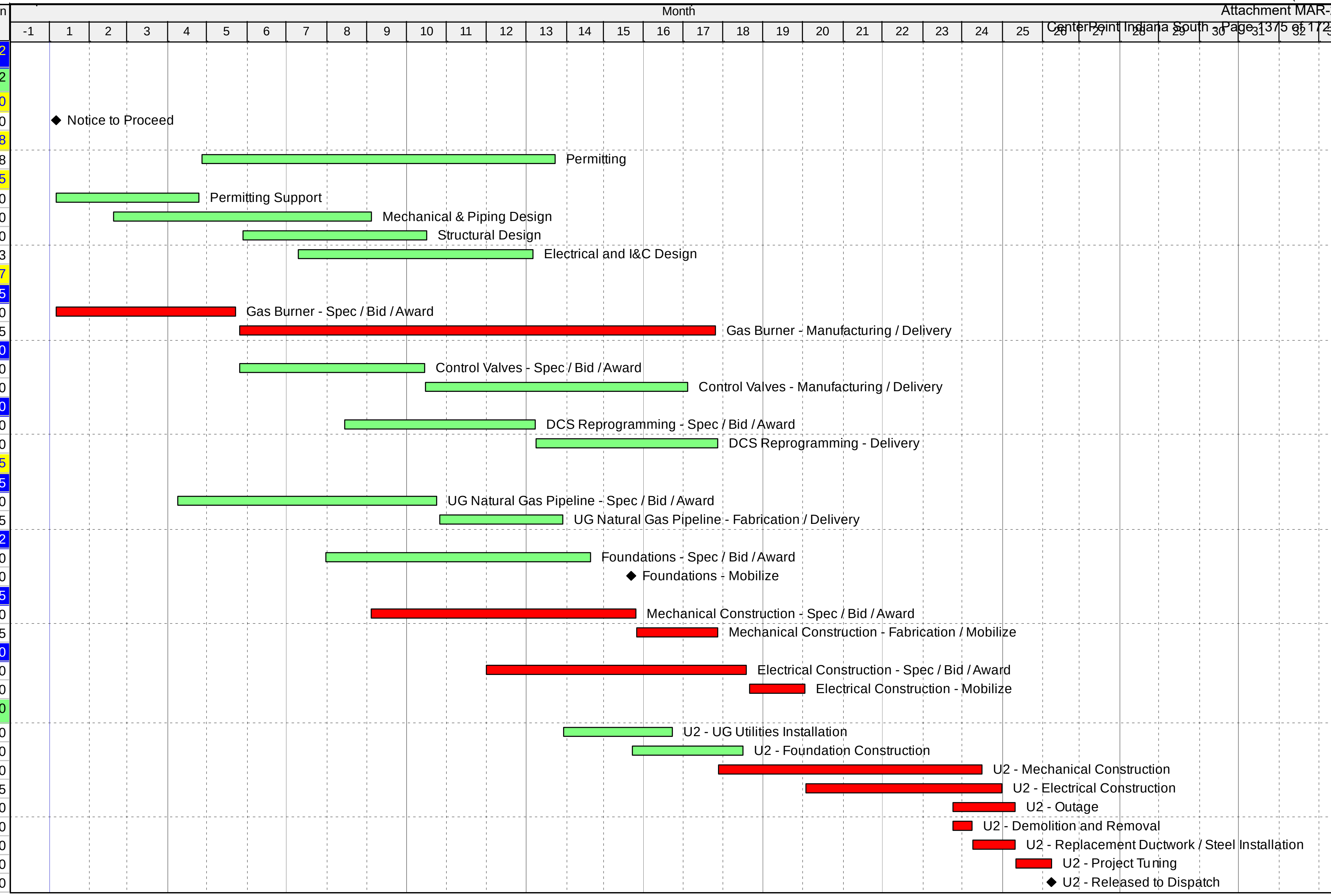
APPENDIX C – PROJECT SCHEDULE

Activity ID	Activity Name	Duration
Vectren A B Brown Coal to Gas Conversion		532
Vectren Gas Conversion Engineering Unit 2		402
Milestones		0
A1000	Notice to Proceed	0
Permitting		188
A1010	Permitting	188
Engineering		255
A1020	Permitting Support	80
A1030	Mechanical & Piping Design	140
A1040	Structural Design	100
A1050	Electrical and I&C Design	123
Procurement		357
Gas Burner		355
A1060	Gas Burner - Spec / Bid / Award	100
A1070	Gas Burner - Manufacturing / Delivery	255
Control Valves		240
A1080	Control Valves - Spec / Bid / Award	100
A1090	Control Valves - Manufacturing / Delivery	140
DCS Reprogramming		200
A1100	DCS Reprogramming - Spec / Bid / Award	100
A1110	DCS Reprogramming - Delivery	100
Construction Contracts		335
UG Natural Gas Pipeline		205
A1120	UG Natural Gas Pipeline - Spec / Bid / Award	140
A1130	UG Natural Gas Pipeline - Fabrication / Delivery	65
Foundations		162
A1140	Foundations - Spec / Bid / Award	140
A1150	Foundations - Mobilize	0
Mechanical Construction		185
A1180	Mechanical Construction - Spec / Bid / Award	140
A1190	Mechanical Construction - Fabrication / Mobilize	45
Electrical Construction		170
A1160	Electrical Construction - Spec / Bid / Award	140
A1170	Electrical Construction - Mobilize	30
Vectren Gas Conversion Construction & Startup Unit 2		260
A1200	U2 - UG Utilities Installation	60
A1210	U2 - Foundation Construction	60
A1220	U2 - Mechanical Construction	140
A1230	U2 - Electrical Construction	105
A1240	U2 - Outage	30
A1250	U2 - Demolition and Removal	10
A1260	U2 - Replacement Ductwork / Steel Installation	20
A1270	U2 - Project Tuning	20
A1280	U2 - Released to Dispatch	0



Remaining Work
Critical Remaining Work
Milestone

BURNS McDONNELL

Vectren - A. B. Brown
Coal to Gas Conversion Project
Page 1 of 1

Date	Revision	Checked	Approved
23-Jan-19	Gas Conversion Proposal	Y Ko	

APPENDIX D – CAPITAL COST ESTIMATE SUMMARY

CAPITAL COST ESTIMATE
VECTREN
AB BROWN
UNIT 2 ONLY NATURAL GAS CONVERSION
MT. VERNON, IN
BMcD #113003

Acct	Area / Discipline	Direct MHRS	Labor Cost	Material Cost	Engr Equip/ Subcontract Cost	Const. Equipment Cost	Total Cost
01	Engineered Equipment	960	$120,000		$7,180,000		$7,300,000
02	Civil	769	$70,000		$50,000	$10,000	$130,000
03	Deep Foundations						
04	Concrete	1,820	$190,000	$40,000	$30,000	$10,000	$270,000
05	Structural Steel	13,028	$1,580,000	$980,000		$280,000	$2,840,000
06	Architectural						
07	Piping	4,191	$550,000	$310,000	$20,000	$30,000	$910,000
08	Electrical	5,407	$680,000	$100,000		$40,000	$820,000
09	Instrument & Control				$270,000		$270,000
10	Insulation				$530,000		$530,000
11	Coatings				$20,000		$20,000
	Total Direct Cost	**26,175**	**$3,190,000**	**$1,430,000**	**$8,100,000**	**$370,000**	**$13,090,000**

Rev.	Revision Date
0	08/27/15
1	02/12/16
2	07/17/18
3	02/01/19

	Cost	Revenue	
Construction Mgmt & Indirects			$780,000
Engineering			$990,000
Start-Up			$290,000
Commercial			$250,000
Escalation (From 2016-Jan2019)			$160,000
Total Indirect Cost			**$2,470,000**
Total Direct and Indirect Costs			**$15,560,000**
	Cost	Revenue	
Project Contingency	5%	5%	$780,000
Total Project Cost			**$16,340,000**
Owner's Project Development			$250,000
Owner's Operational Personnel Prior to COD			Existing
Owner's Engineer			N/A
Owner's Project Management			$300,000
Owner's Legal Costs			$200,000
Owner's Start-up Engineering			$75,000
Temporary Utilities			$110,000
Operator Training			$50,000
Permitting and Licensing Fees			$100,000
Switchyard			Existing
Political Concessions & Area Development Fees			N/A
Startup/Testing (Fuel & Consumables)			
Startup Fuel (@$4/MMBtu)			$1,570,000
Startup Variable O&M (@$1.30/MWhr			$40,000
Startup Power (@$45/MWhr)			$20,000
Test Power Sales (@$-30/MWhr)			-$1,010,000
Initial Fuel Inventory			N/A
Site Security			Existing
Operating Spare Parts			$70,000
Permanent Plant Equipment and Furnishings			Existing
Builders Risk Insurance (0.45% of Construction Costs)			$60,000
Interest During Construction (10.2% Proj Cost)			$1,670,000
Owner Contingency		10%	$1,980,000
Total Owner Costs			**$5,485,000**
Total Project Cost Incl. Owner Costs			**$21,825,000**

BURNS McDONNELL V 3.5

APPENDIX E – B&W BOILER STUDY

Engineering Study for Natural Gas Firing

for

Vectren Power Supply
AB Brown Station Unit 2
Evansville, Indiana

Contract 591-1048 (317A)
April 1, 2019 - Rev. 4

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TABLE OF CONTENTS

INTRODUCTION

Vectren Power Supply contracted the Babcock and Wilcox Company (B&W), under B&W contract 591-1048 (317A), to evaluate natural gas firing at the AB Brown Station Unit 2, originally supplied by B&W under contract RB-599. The boiler performance model was reviewed at 100% (Maximum Continuous rating) MCR and 60% load when firing 100% natural gas. An analysis of the allowable tube metal stresses was performed for 100% gas firing at 100% MCR and 60% boiler loads in regards to the primary superheater, secondary superheater and reheat superheater.

BACKGROUND

The AB Brown Unit 2 (RB599) is presently balanced draft, subcritical Carolina type radiant boiler, with secondary superheater, primary superheater, reheater and economizer surfaces arranged in series. Superheater steam temperature is controlled by interstage spray attemperation. Reheater steam temperature is controlled by excess air and spray attemperation. The unit was originally designed as a front and rear wall, bituminous coal fired units. The original maximum continuous rating for RB-599 is 1,850,000 lbs/hr of main steam at 1005°F and 1965 psig at the superheater outlet with a feedwater temperature of 467°F. The reheat steam flow is 1,666,500 lbs/hr at 1005 F and 485 psig at the reheater outlet. Spray attemperation is used to control superheat and reheat steam temperatures. The unit was to be operated at 5% overpressure over the load range.

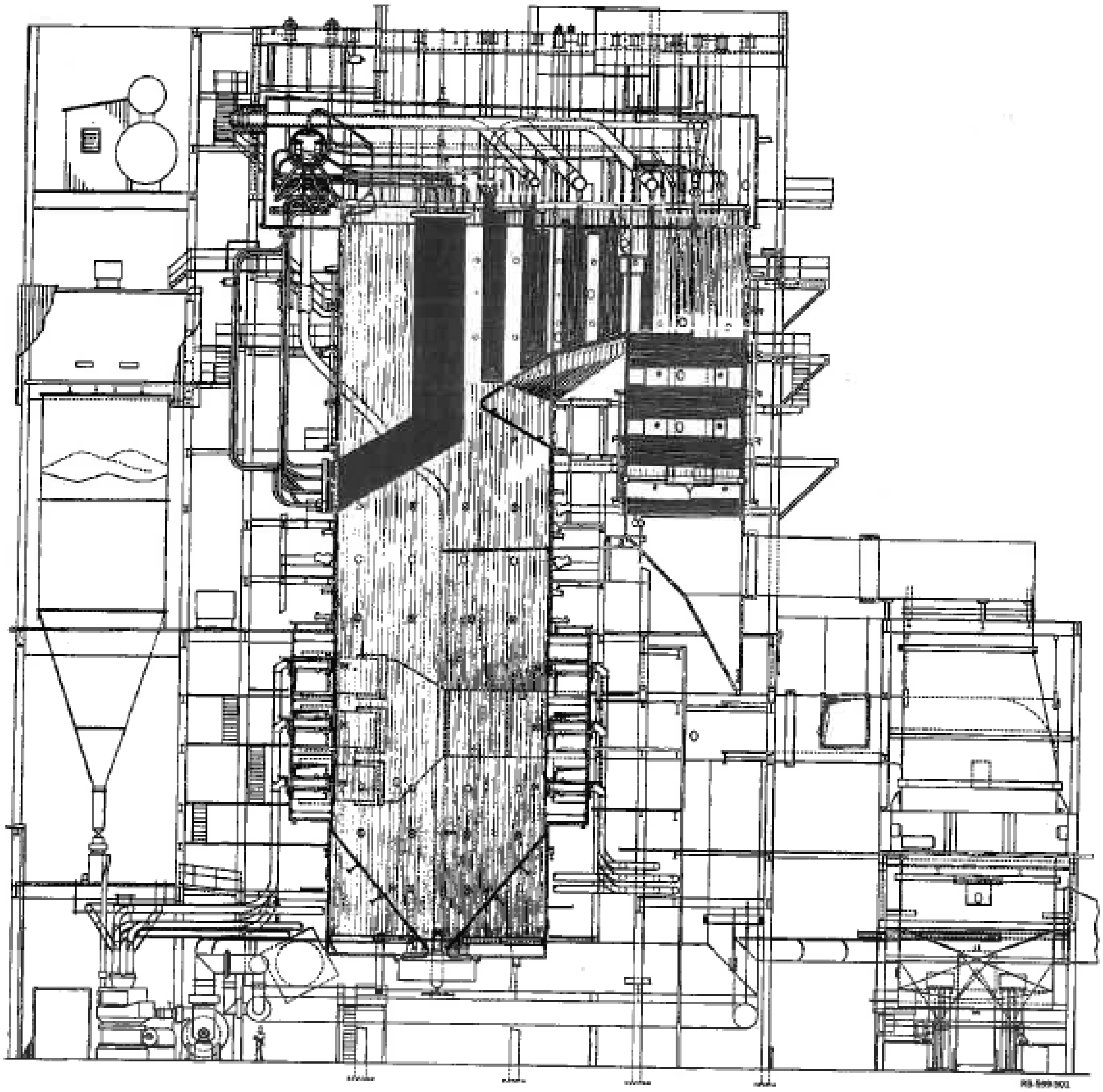
The unit is front and rear wall fired with twenty-four B&W 4Z low NO_x burners, four wide by three high. There are six B&W EL-76 pulverizers supplying coal to the burners.

Combustion air is heated through two Ljungstrom regenerative air heaters.

- Unit 2 has a furnace height of 124’-0’’. The vertical burner spacing is 10’-0” for Unit 2.
- Unit 2 has six water-cooled furnace wing walls.
- Unit 2 was designed without flue gas recirculation.

A sectional side view of the boilers is shown in Figures 1.

FIGURE 1



Brown Station Unit 2

B&W Contract Number RB-599

SCOPE FOR PHASE I

B&W evaluated natural gas firing in the radiant boilers originally supplied by B&W under contract number RB-599. Boiler component drawings and original performance summary data were used to develop comprehensive thermal models and boiler pressure part assessments. The predicted performance of the proposed natural gas firing was analyzed at MCR load and 60% load. The tube metallurgy requirements for the primary superheater, secondary superheater, reheater and headers were also developed. In addition to superheater metals analysis, predicted performance of the air preheaters and the attemperator capacities were also evaluated relative to overall performance.

SCOPE FOR PHASE II

The Phase II engineering scope of supply includes the entire scope of Phase I. In addition, the need surface modifications for firing 100% natural gas were analyzed. The adequacy of the existing forced draft (FD) fans and the induced draft (ID) fans were also assessed.

BASIS

This boiler pressure part metals assessment requires developing overall unit heat and material balances at the indicated steam flow. The 2015 fuel analyses for coal as supplied by Vectren were found to be very close to original design bituminous coal. Since the 2015 fuel analyses were incomplete, the original design fuel analysis was used. The natural gas analysis was also supplied by Vectren. The original design coal and natural gas fuel analyses are provided in Tables 2. These were used as a basis for the heat and material balances shown in Table 3.

Table 1: Original Design As-Fired Fuel Analyses for Bituminous Coal, % by weight

Constituent	
C	64.00
H_2	4.44
N_2	1.38
O_2	6.51
Cl	0.00
S	3.52
H_2O	11.35
Ash	8.76
Total	**100.00**
HHV (Btu/lb)	**11533**

Table 2: Proximate Analysis for Natural Gas, % by volume

Constituent	
Nitrogen	0.28
Methane	96.31
Ethane	1.46
CO_2	1.89
Others	0.06
Total	**100.00**
HHV (Btu/ft^3)	**1,037**

Table 3: Boiler Operating Conditions Used in Metals Evaluation

Boiler Load	**MCR**	**60%**
Superheater Steam Flow (lb/hr)	1,850,000	1,110,000
Steam Temperature at SH Outlet (°F)	1005	933
Steam Pressure at SH Outlet (psig)	1965	1917
Reheater Steam Flow (lb/hr) w/o Attemperator Spray	1,666,500	1,000,000
Steam Temperature at RH Outlet (°F)	992	835
Steam Pressure at RH Outlet (psig)	460	261
Feedwater Temperature (°F)	467	417
Excess Air Leaving Econ (%)	10	18

RESULTS

Boiler Performance

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance firing the original bituminous coal at the original design data, recent field data for each of the unit and predicted unit performance firing 100% natural gas.

Attemperator Capacity

Along with the metals analysis, attemperation capacities were studied. The attemperator spray flows for gas firing are lower than the spray flows for firing coal due to lower amounts of excess air required when firing natural gas. Current attemperator capacities for unit should be satisfactory at all boiler loads. The results are shown in Table 6.

Table 6: Predicted Attemperator Flows (lbs/hr)

Boiler Load	MCR	60%
Bituminous Coal:		
SH Spray Flow	77,870	88,000
RH Spray Flow	19,000	0
Natural Gas		
SH Spray Flow	53,700	0
RH Spray Flow	0	0

Air Heater Performance

Air heaters were assessed for natural gas firing. The air and gas side temperature profiles around the air heater were found to be acceptable for the natural gas conversion. Since no field data was provided that would show higher than original air heater leakage or other air heater performance degradation, the predicted air heater performance is based on the original design data with an air heater leakage of 7.4%. Predicted performance is shown on Table 7a and 7b.

Table 7a: Regenerative Air Heater Predicted Performance at

Unit	2	2	2
Boiler load	MCR	94%	MCR
Data Basis	Original Design	7-10-2015 PI Data	Predicted Performance*
Fuel	Bituminous Coal	Bituminous Coal	Natural Gas
Flue Gas Flow Entering Air Heaters, mlb/hr	2,570	2,422	2,234
Flue Gas Temp Entering Air Heaters, F	705	652	697
Flue Gas Temp Leaving Air Heaters w/o Leakage, F	304	346	303
Air Flow Leaving Air Heaters, mlb/hr	2,307	2,174	2,056
Air Temp Entering Air Heaters, F	85	138	85
Air Temp Leaving Air Heaters, F	566	554	567

*Based on original design data

Table 7b: Regenerative Air Heater Predicted Performance

Unit	2	2
Boiler load	60%	60%
Data Basis	Original Design	Predicted Performance*
Fuel	Bituminous Coal	Natural Gas
Flue Gas Flow Entering Air Heaters, mlb/hr	2,060	1,403
Flue Gas Temp Entering Air Heaters, F	675	617
Flue Gas Temp Leaving Air Heaters w/o Leakage, F	283	259
Air Flow Leaving Air Heaters, mlb/hr	1,867	1,273
Air Temp Entering Air Heaters, F	83	83
Air Temp Leaving Air Heaters, F	547	520

*Based on original design data

Tube Metal Temperature Evaluation

B&W uses an ASME Code accepted method to design its tube metallurgies and thicknesses. The method involves applying upsets and unbalances to determine spot and mean tube metal temperatures. The upsets and unbalances include empirical uncertainty in the calculation of furnace exit gas temperature (FEGT), top to bottom gas temperature deviations, side to side gas temperature deviations, steam flow unbalances (a function of tube side pressure drop and component arrangement) and gas flow unbalances. The method applies these upsets and unbalances simultaneously to a single spot in each row of the superheater. Tube row metallurgy and thickness are then determined from the resultant tube spot and mean temperatures, respectively, according to ASME Code material oxidation limits and allowable stresses. B&W policy does not allow the publishing of design tube metal temperatures or unbalanced steam temperatures. However, these values can be reviewed in B&W's offices, if desired.

The remaining life expectancy of the superheaters is dependent on the prior operating history, especially on actual tube operating temperature compared to design temperature. Thus, the assessment of the adequacy of the existing superheaters is not a simple task.

The SSH outlet bank & RSH outlet bank were replaced on unit 2 in the fall of 2015. The evaluation is based on the design of the present SSH outlet banks & RSH outlet banks which were supplied by B&W.

B&W has determined the operating hoop stress level (based on the current minimum tube wall thickness) at operating pressure. The predicted tube operating temperatures based on B&W's standard design criteria and the resulting ASME Code allowable stress level for the existing material has also been determined. Comparison of the operating hoop stress with the Code allowable stresses results in the percent over the allowable stress. A modest overstress level indicates a modest shortening of remaining life expectancy and, unless otherwise indicated by past maintenance experience, does not warrant tube modification at this time.

If the tube analysis shows significant overstress or shows that tubes are predicted to operate at temperatures above those for which ASME Code stresses are published, then serious consideration should be given to tube upgrades and replacement. Significant overstresses are considered those tube rows that are 20% or greater overstressed. An overstress of 20% or more does not necessarily mean that immediate replacement of the tube row is required, but it identifies which tube rows should be examined for potential problems. Potential problems could be signs of creep, internal exfoliation or swelling.

This study showed that all tubes were predicted to operate at temperatures less than the existing material use limit. In addition, all existing convection pass tubes and component headers had no overstress issues. Therefore, the existing convection pass tube metallurgy is acceptable for natural gas firing.

Forced Draft Fans

The existing forced draft fans were analyzed to determine if they meet the requirements of 100% natural gas firing. Unit 2 was originally designed as a balanced draft unit. An adjusted test block static pressure rise and test block capacity for the Unit 2 FD fans was developed from the FD fan curve for 100% natural gas firing. The results show the existing FD fan test block conditions for Unit exceed the requirements in capacity and static pressure rise (including higher natural gas burner pressure drop) for all natural gas firing cases. Predicted fan performance is shown in Table 8A:

Table 8a: Forced Draft Fan Performance at MCR Load (balanced draft operation)

Fuel	FD Fan Test Block Unit 2	FD Fan Original Net Design Conditions Bituminous Coal Unit 2	FD Fan Test Block Adjusted for 100%Natural Gas Unit 2 From Fan Curve	FD Fan Net Conditions 100% Natural Gas Unit 2
Flow per fan (lb/hr)	1,512,000	1,260,000	1,225,440	1,104,100
Static Pressure Rise (in WC)	19.8	15.8	25.1	20.3
Temperature (F)	105	80	105	80

Induced Draft Fans

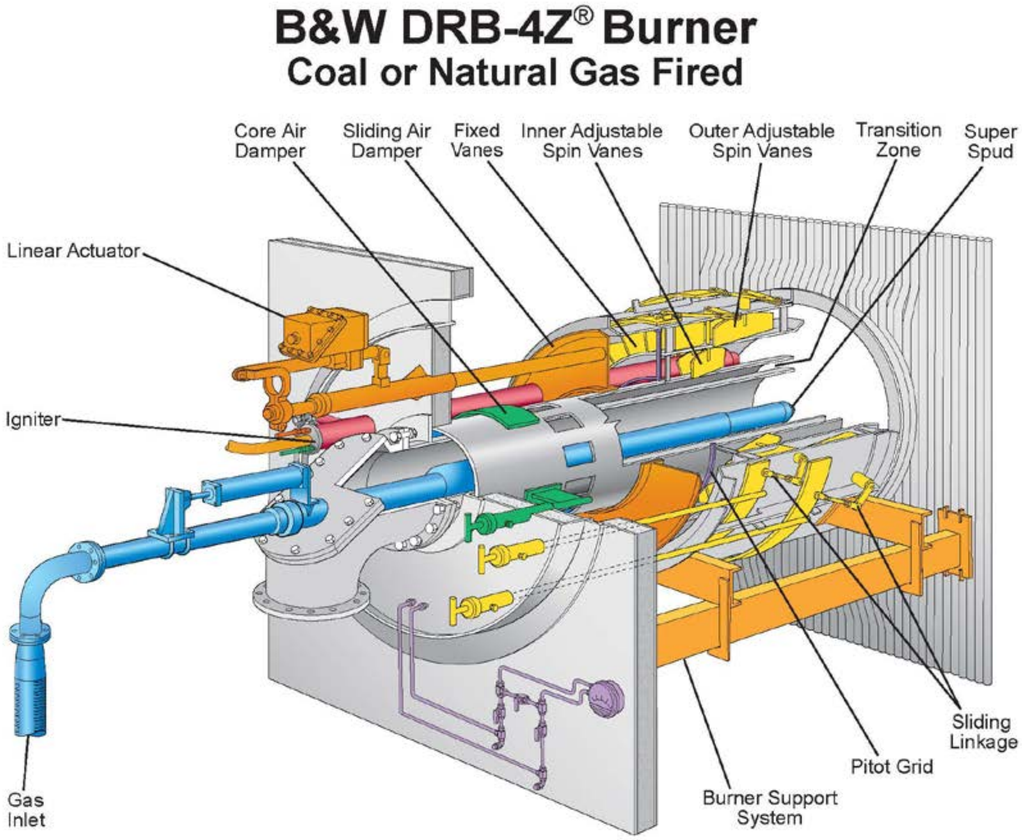
The existing induced draft fans were also analyzed to determine if they meet the requirements of 100% natural gas firing. The results showed the existing ID fans far exceed the requirements in capacity and static pressure rise for all natural gas firing cases. Predicted fan performance is shown in Table 8B:

Table 8b: Induced Draft Fan Performance at MCR Load (balanced draft operation)

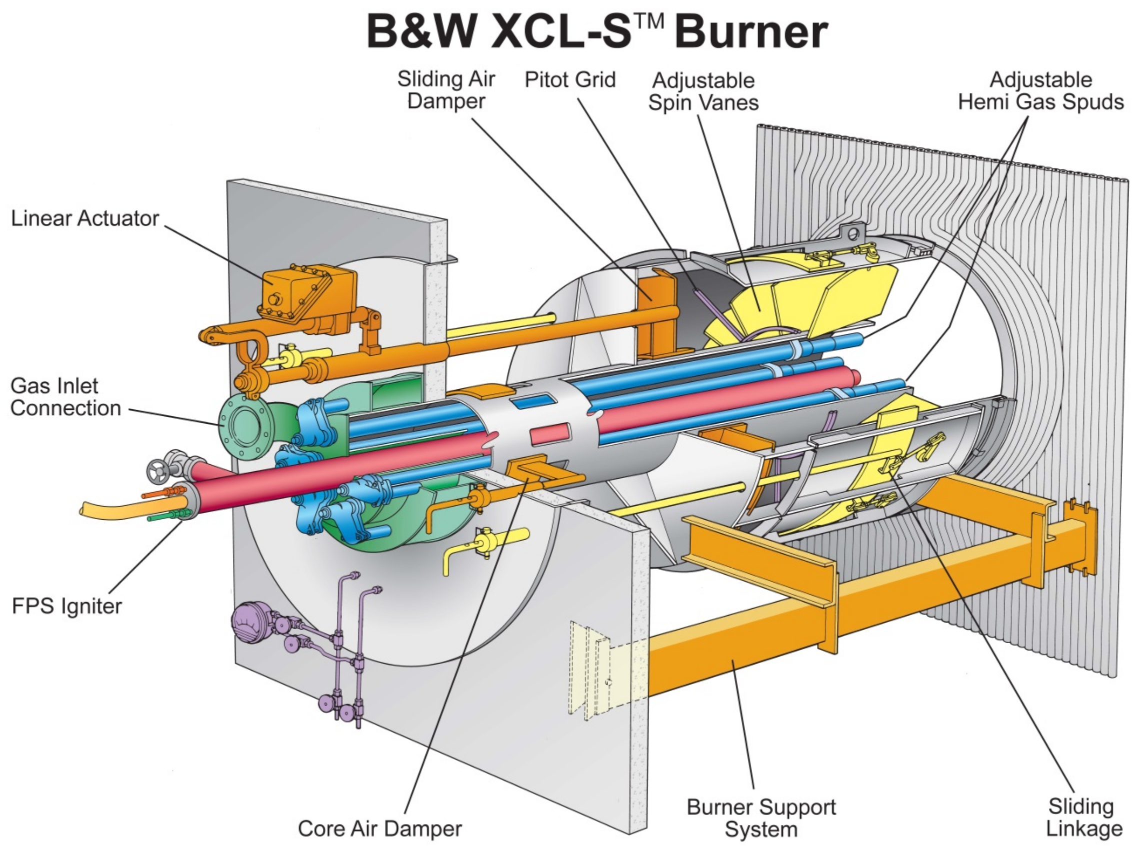
Fuel	ID Fan Test Block Unit 2	Bituminous Coal Unit 2 Original ID Fan Design Net Conditions	100% Natural Gas
Flow per fan (lb/hr)	1,380,100	1,387,610	1,199,390
Static Pressure Rise (in WC)	67.30	47.81	34.22
Temperature (F)	330	305	290

Combustion Equipment

The minimum combustion equipment modifications required to fire natural gas include modifying the twenty-four (24) existing B&W 4Z burners with gas spuds. One option is to add a Super-Spud to each 4Z burner to provide natural gas firing capability to the units. The addition of Super-Spuds will allow the AB Brown unit to still fire coal is desired. The figure below shows a 4Z burner with a Super-Spud.



The second option would be to remove the coal nozzle and replace it with a hemi-spud cartridge. This fundamentally converts the 4Z burners to a B&W XCL-S burner as shown in the figure below. B&W XCL-S burner is an advanced low-NOx burner that was developed to achieve superior NOx performance in burner-only applications.



Since the AB Brown unit already have SCR's, staged combustion (OFA) or flue gas recirculation (FGR) is not recommended.

In addition to the burner modifications, valve racks, gas piping and controls will be needed to supply the natural gas as a main fuel to the modified burners.

Emissions

Emissions predictions are based on converting the unit to fire natural gas as the main fuel. Full load emission predictions for unit are listed in Table 9.

Table 9: Predicted Full Load Emissions on Natural Gas	
	AB Brown Unit 2
NO_x (lb/10^6 Btu)	0.19

- CO is predicted to be less than 200ppm. For 200 ppm (dry vol.) CO @ 3% O2 (dry vol.) firing NG with an Fd factor of 8710, B&W calculates 0.148 lb/mmBTU of CO.

CONCLUSIONS

As a result of this study, a review of the existing tube metallurgies on the AB Brown Station Unit 2 revealed that all existing convection pass tubes had no overstress issues. In addition, all tubes were predicted to operate at temperatures below their ASME material code published limit. Header metal temperatures were also checked and showed to meet B&W's standards.

Along with the metallurgical analysis, superheater and reheater spray attemperation capacities were studied. The attemperator spray flows for gas firing are lower than the spray flows for firing coal due to lower amounts of excess air required when firing 100% natural gas. Current attemperator capacities for unit should be satisfactory at all boiler loads.

No surface modifications or surface removal are required when firing 100% natural gas.

Air heaters were assessed for 100% natural gas firing. The air and gas side temperature profiles around the air heater were found to be acceptable for firing natural gas based on the original air heater design parameters.

The existing FD and ID fans were found to exceed the performance requirements when firing 100% natural gas.

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance firing the original bituminous coal and predicted unit performance firing natural gas.

CO-FIRING COAL AND NATURAL GAS

Vectren Power Supply additionally contracted the Babcock and Wilcox Company (B&W), under B&W contract 591-1048 (317A), to evaluate co-firing natural gas and coal in these units.

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance co-firing natural gas and the original bituminous coal at MCR boiler load with the following natural gas inputs:

1. 17% heat input from natural gas through four burners. 83% heat input from coal.
2. 33% heat input from natural gas through eight burners. 67% heat input from coal.
3. 16% heat input (maximum heat input through natural gas ignitors). 84% heat input from coal.

A metallurgical analysis and an analysis of the superheater and reheater spray attemperation capacities were performed for the three conditions above. Current attemperator capacities for unit should be satisfactory at all boiler loads when co-firing natural gas and coal.

This study showed that all tubes were predicted to operate at temperatures less than the existing material use limit. In addition, all existing convection pass tubes and component headers had no overstress issues. Therefore, the existing convection pass tube metallurgy is acceptable for co-firing natural gas and coal.

No surface modifications or surface removal are required when co-firing natural gas and coal.

The air and gas side temperature profiles around the air heater were found to be acceptable for co-firing natural gas and coal based on the original air heater design parameters.

The existing FD and ID fans were found to exceed the performance requirements when co-firing natural gas and coal.

The predicted boiler performance summaries when co-firing natural gas and coal are shown in the Appendix.

Co-firing Operation

When co-firing the two fuels, the preferred arrangement is to fire natural gas through the burners at the higher elevations on a per mill group, or compartment, basis. The compartmented windboxes on the AB Brown unit are advantageous for co-firing the multiple fuels. Airflow control by compartment allows each mill group to obtain its own required amount of air, independent of burner load or fuel. The burners firing natural gas will require more secondary air, since primary airflow is zero, than the coal-firing burners. Managing these separate flow rates can be easily accommodated by the compartment controls. Firing coal at the lower elevations takes advantage of the available residence time in the furnace, maximizing coal burnout and optimizing CO and unburned carbon emissions. If a partial conversion were to become the chosen project path, it would be recommended to convert burners on a per mill group basis following the described firing arrangement, adding gas capability to the top mill groups and continuing downward.

It should be noted that while the AB Brown unit is already equipped to operate under the third scenario listed above (16% input ignitors, 84% input from coal), it could come at the expense of emissions. With the ignitor being located in an upper quadrant of the burner and operating at 16% of the rated burner input, not all of the air going through the burner is nearby and readily available for the ignitor fuel. This can create scenarios of inadequate fuel and air mixing, resulting in higher CO emissions, especially from the upper burner elevations. NOx emissions may also increase. The annular zone arrangement of the 4Z burner stages the mixing of the fuel and air. With the ignitor being located in the air sleeve, it circumvents this delayed mixing arrangement, potentially increasing NOx. Emissions predictions are not available for this scenario.

APPENDIX A – Preliminary Performance Summaries

Table 10a:

A. B. Brown Unit 2 - Preliminary Performance Summary

Contract No.	317A	GBB	Unit 2	Unit 2	Unit 2
Date	7/31/2015	Load ID	PC Firing	PC Firing	Natural Gas
Revision	0	Boiler Arrangement	Existing	Existing	Existing
		Data Basis	Original Contract	7-10-2015 PI Data	Predicted Performance
Load Condition			MCR	94% Load	MCR
Fuel			Bituminous	Bituminous	Natural Gas
Steam Leaving SH, mlb/hr			1,850	1,736	1,850
Superheater Spray Water, mlb/hr			77.86	19.10	53.70
Cold RH Steam Flow, mlb/hr			1,667	1,590	1,667
Reheater Spray Water, mlb/hr			18.90	16.30	0.00
% Excess Air Leaving Economizer			20.0	21.1	10.0
Flue Gas Recirculation, %			None	None	None
Heat Input, mmBtu/hr			2,549.3	2,379.8	2,614.9
Quantity mlb/hr	Fuel (mcf/hr if gas)		221.0	207.0	2604.5
	Flue Gas Entering Air Heaters		2,570	2,422	2,234
	Total Air To Burners		2,307	2,174	2,056
Pressure, psig	Steam at SH Outlet		1965	1926	1965
	Steam at RH Outlet		460	424	460
Temperature, °F	Steam	Leaving Superheater	1005	999	1005
		Leaving Reheater	1005	985	992
	Water	Water Entering Economizer	467	452	467
		Superheater Spray Water	380	370	380
	Gas	Entering Air Heater	705	652	697
		Leaving Air Heater (Excl. Leakage)	304	346	303
	Air	Entering Air Heater	85	138	85
		Leaving Air Heater	566	554	567
Heat Loss Efficiency, %	Dry Gas		4.91	4.75	3.88
	H_2 & H_2O in Fuel		5.06	4.92	10.67
	Moisture in Air		0.12	0.11	0.10
	Unburned Combustible		0.30	0.30	0.00
	Radiation		0.19	0.20	0.19
	Unacc. & Mfgs. Margin		1.50	0.50	1.00
	Total Heat Loss		12.08	10.78	15.84
	Gross Efficiency of Unit, %		87.92	89.22	84.16

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Table 10b:

A. B. Brown Unit 2 - Preliminary Performance Summary

Contract No.	317A	GBB	Unit 2	Unit 2
Date	7/31/2015	Load ID	PC Firing	NG Firing
Revision	0	Boiler Arrangement	Existing	Existing
		Data Basis	Original Contract	Predicted Performance
Load Condition			60%	60%
Fuel			Bituminous	Natural Gas
Steam Leaving SH, mlb/hr			1,110	1,110
Superheater Spray Water, mlb/hr			89	0
Cold RH Steam Flow, mlb/hr			1,000	1,000
Reheater Spray Water, mlb/hr			0	0
% Excess Air Leaving Economizer			52.0	18.0
Flue gas Recirculation, %			None	None
Heat Input, mmBtu/hr			1,638.3	1,540.9
Quantity mlb/hr	Fuel (mcf/hr if gas)		142.0	1486.0
	Flue Gas Entering Air Heaters		2,060	1,403
	Total Air To Burners		1,867	1,273
Pressure, psig	Steam at SH Outlet		1917	1917
	Steam at RH Outlet		261	261
Temperature, °F	Steam	Leaving Superheater	1005	955
		Leaving Reheater	1005	835
	Water	Water Entering Economizer	417	417
		Superheater Spray Water	350	350
	Gas	Entering Air Heater	675	617
		Leaving Air Heater (Excl. Leakage)	283	259
	Air	Entering Air Heater	83	83
		Leaving Air Heater	547	520
Heat Loss Efficiency, %	Dry Gas		5.69	3.35
	H_2 & H_2O in Fuel		5.03	10.38
	Moisture in Air		0.14	0.09
	Unburned Combustible		0.30	0.00
	Radiation		0.30	0.22
	Unacc. & Mfgs. Margin		1.50	1.00
	Total Heat Loss		12.96	15.04
	Gross Efficiency of Unit, %		87.04	84.96

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Table 10c:

A. B. Brown Unit 2 - Predicted Performance Summary Co-Firing Coal & Natural Gas

Contract No.	317A	GBB	Unit 2	Unit 2	Unit 2
Date	8/29/2015	Load ID	PC & NG Firing	PC & NG Firing	PC & NG Firing
Revision	0	Boiler Arrangement	Existing	Existing	Existing
		Data Basis	Predicted Performance	Predicted Performance	Predicted Performance
		Natural Gas Firing Method	Through Burners	Through Burners	Through Ignitors
		Natural Gas Firing % Heat Input	17	33	16
		Coal Firing % Heat Input	83	67	84
Load Condition			MCR	MCR	MCR
Fuel			Bit. Coal & Natural Gas	Bit. Coal & Natural Gas	Bit. Coal & Natural Gas
Steam Leaving SH, mlb/hr			1,850	1,850	1,850
Superheater Spray Water, mlb/hr			27.38	42.94	26.70
Cold RH Steam Flow, mlb/hr			1,667	1,667	1,667
Reheater Spray Water, mlb/hr			23.02	27.14	23.00
% Excess Air Leaving Economizer			21.9	21.9	21.9
Flue Gas Recirculation, %			None	None	None
Heat Input Nat. Gas, mmBtu/hr			434.6	853.1	408.0*
Heat Input Bit. Coal, mmBtu/hr			2121.7	1732.0	2147.3
Total Heat Input, mmBtu/hr			2556.3	2585.1	2555.3
Quantity mlb/hr	Coal Flow		184.0	150.2	186.0
	Natural Gas Flow (mcf/hr)		432.8	849.7	406.3
	Flue Gas Entering Air Heaters		2,568	2,559	2,569
	Total Air To Burners		2,319	2,322	2,320
Pressure, psig	Steam at SH Outlet		1965	1965	1965
	Steam at RH Outlet		460	460	460
Temperature, °F	Steam	Leaving Superheater	1005	1005	1005
		Leaving Reheater	1005	1005	1005
	Water	Water Entering Economizer	467	467	467
		Superheater Spray Water	380	380	380
	Gas	Entering Air Heater	668	670	668
		Leaving Air Heater (Excl. Leakage)	352	353	352
	Air	Entering Air Heater	150	150	150
		Leaving Air Heater	552	554	552
Heat Loss Efficiency, %	Dry Gas		4.51	4.43	4.52
	H_2 & H_2O in Fuel		5.79	6.66	5.74
	Moisture in Air		0.11	0.11	0.11
	Unburned Combustible		0.25	0.20	0.25
	Radiation		0.19	0.19	0.19
	Unacc. & Mfgs. Margin		1.42	1.42	1.42
	Total Heat Loss		12.27	13.01	12.23
	Gross Efficiency of Unit, %		87.73	86.99	87.77

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Predicted performance is based on the original contract boiler performance and PI data as supplied by Vectren

*Maximum heat input from ignitors

APPENDIX B – NG Conversion Equipment Scope & Budgetary Costs

SUPER-SPUD OPTION - Burner Modifications, Scanners, Valve Racks, NG Piping System

Item 1: B&W 4Z Burners converted to Nat Gas Firing (Quantity: 24)

- Qty 24, Super-Spud Assemblies to replace existing coal nozzles
- Qty 12, Burner Valve Racks
- Burner Front Flex Hose and Hardware
- Burner Front Piping
- Gas Header Piping
- Burner Front Valves & Gauges

Item 2: Fossil Power Systems (FPS) Flame Scanners

- Qty 24, FPS main UV flame scanners with rigid fiber optic extension
- Qty 1, main flame scanner electronics cabinet
- 1 Lot – Combustion/Cooling air piping from blower skid to burner fronts

Item 3: Natural Gas Regulating Station and Piping

- Main natural gas regulating station – 50 psig supply pressure
- Natural gas piping from regulating station to the burners
- Natural gas burner front gas piping and valve stations excluding vent piping to above the boiler building roof

HEMI-SPUD OPTION - Burner Modifications, Scanners, Valve Racks, NG Piping System

Item 1: B&W 4Z Burners converted to Nat Gas Firing (Quantity: 24)

- Qty 24, Hemispherical Gas Spud Assemblies to replace existing coal nozzles
- Qty 12, Burner Valve Racks
- Burner Front Flex Hose and Hardware
- Burner Front Piping
- Gas Header Piping
- Burner Front Valves & Gauges

Item 2: Fossil Power Systems (FPS) Flame Scanners

- Qty 24, FPS main UV flame scanners with rigid fiber optic extension
- Qty 1, main flame scanner electronics cabinet
- 1 Lot – Combustion/Cooling air piping from blower skid to burner fronts

Item 3: Natural Gas Regulating Station and Piping

- Main natural gas regulating station – 50 psig supply pressure
- Natural gas piping from regulating station to the burners
- Natural gas burner front gas piping and valve stations
- Vent piping from the regulating stations and the burner valve racks to the boiler roof and above the roof is not included

General Services

- Combustion system tuning services using an economizer outlet sampling grid for measurement of NOx per EPA methods.
- Field Service Engineering outage support for construction, start-up, and post-modification testing.
- Burner System Operator Training consisting of two, one day sessions.
- Training includes project specific training manual for up to 20 participants.
- Brickwork Refractory Insulation & Lagging (BRIL) Specifications and Installation design and materials.
- Contract specific System Requirements Specification, I/O Listing, and Functional Logic Diagrams for all supplied equipment.
- Operating and Maintenance Manuals (10 copies).
- New piping, flue, and duct loading to existing steel
- Delivery F.O.B. Brown Plant, Mt Vernon, IN.

Items not Included

- Hazardous material removal or abatement (i.e., lead paint and asbestos).
- Load analysis of existing structural steel or foundations and any required re-enforcement thereof.
- Hardware or reprograming of existing DCS and/or BMS to support natural gas conversion.
- Gas step down equipment. Equipment scope above assumes incoming gas pressure at B&W’s terminal to be 30 to 50psi.

Terminal Points

- Inlet of gas regulating station
- Vent out of any valve rack
- Electrical terminals on provided electrical equipment or instruments
- Electrical terminals in shop provided terminal junction boxes as part of skidded equipment

Budgetary Material & Installation Pricing (USD 2015)

Scope Item	Budgetary	
	Material	Installation
Super-Spud Option: Burner Modifications, Scanners, Valve Racks, NG Piping System	$2,244,000	$3,379,000
Hemi-Spud Option: Burner Modifications, Scanners, Valve Racks, NG Piping System	$2,463,000	$3,685,000

Lead Times

- Material delivery: 52 - 56 weeks
- Installation duration: 8 - 10 weeks

B&W has offered these prices in 2018 US dollars and have not attempted to project escalation for time of performance or delivery.

Please note that these prices are budgetary and is not represent an offer to sell, however, we would welcome the opportunity to provide a formal proposal upon request.

Burns & McDonnell World Headquarters
9400 Ward Parkway
Kansas City, MO 64114
Phone: 816-333-9400
Fax: 816-333-3690
www.burnsmcd.com

Burns & McDonnell: Making our clients successful for more than 100 years

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Attachment 6.6 Brown Scrubber Assessment Study

FINAL - REV 1

A.B. BROWN SCRUBBER ASSESSMENT AND ESTIMATE

B&V PROJECT NO. 400278
B&V FILE NO. 40.0001

PREPARED FOR

Vectren Corporation

11 MARCH 2020

BLACK & VEATCH

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1.1 Executive Summary

1.2 INTRODUCTION/BACKGROUND

Units 1 and 2 at Vectren's A. B. Brown Power Station are each nominally 265 megawatt (MW) gross, coal-fired electric generating units (EGUs). The units were built in the late 1970s to the mid-1980s. Each of the existing units is outfitted with an originally supplied, dual alkali (DA) wet flue gas desulfurization (FGD) system for the control of acid gases such as sulfur dioxide (SO_2).

Vectren has contracted with Black & Veatch Corporation (Black & Veatch) to provide order of magnitude conceptual design cost estimating, technology support, and review and consolidation of third-party conceptual design and cost estimates for the inputs into financial modeling of the current and available air quality control (AQC) scrubber technologies that could be employed at Vectren's A.B. Brown Station, for continued operation of both Unit 1 and Unit 2. Black & Veatch, in addition to other architectural engineering consultants hired by Vectren, has performed technology reviews and assessments to develop construction and ongoing operations and maintenance (O&M) costs of these various technologies.

This document presents AQC technologies evaluated for the A. B. Brown coal fired power plant for evaluation in Vectren's 2019 Integrated Resource Plan (IRP) for continued coal operation of A.B. Brown Units 1 and 2. Black & Veatch served as the lead engineer in the FGD evaluation effort. Black & Veatch, AECOM, and Burns & McDonnell all provided technical data and cost information for individual FGD upgrade options, as requested by Vectren. Those reports served to support the technology and costs presented in this report.

- Burns & McDonnell – A.B. Brown Wet Limestone Forced Oxidation FGD Cost Estimate
- AECOM – Wet FGD Limestone Conversion Study for A.B. Brown Station.

1.3 PURPOSE

The purpose in developing this compiled report is to indicate the applicability, reliability, and estimated costs of the AQC technology options that could be utilized at A.B. Brown Station to support continued operation of Unit 1 and Unit 2 on the full range of current coal fuel. The assessment will consider interfaces to the existing equipment and ductwork at the A.B. Brown Units and include evaluation of the reuse and/or removal of the existing auxiliary support equipment (mechanical tanks, pumps, fans, electrical switchgear, etc.).

The technologies evaluated and the responsible lead engineering company performing the work are indicated in Table 1-1.

Table 1-1 Scrubber Technologies

Technology	Lead	Expected Outcome	Water Treatment Impacts	Other Impacts
Wet Limestone Forced Oxidation Scrubber	Burns & McDonnell	Feasible	Yes	Lime Injection FGD Gypsum Market
Limestone Forced Oxidation (Conversion from DA Scrubber)	AECOM	Not Feasible	Yes	Lime Injection
Limestone Inhibited Oxidation (Conversion from DA Scrubber)	AECOM	Not Feasible	Yes	Lime Injection
Inhibited Wet Lime Scrubber	Black & Veatch	Feasible	Yes	Lime Injection Powdered Activated Carbon (PAC) Injection
Spray Dryer Absorber	Black & Veatch	Not Feasible	No	Not Applicable
Circulating Dry Scrubber	Black & Veatch	Feasible	No	PAC Injection
Ammonia Scrubber	Black & Veatch	Feasible	Yes	Lime Injection PAC Injection Fertilizer Market

1.4 SUMMARY TABLE OF RESULTS

1.3.1 Capital Costs Summary

The technologies were reviewed to determine those that merited further analysis on the basis of their ability to meet emissions criteria for the full range of boiler design fuel. The selected technologies were then evaluated to assess the cost to purchase and operate the control technology. Table 1-2 presents the capital cost estimates. The capital cost presented for the LSFO technology includes cost for wastewater treatment but does not include costs for water treatment or landfill. The capital cost presented for Wet Lime Inhibited Oxidation (WLIO) and Circulating Dry Scrubber (CDS) are for the FGD systems only and do not include the need for or costs for water/wastewater treatment (WWT) or landfill. Waste water treatment costs for the Wet Limestone Forced Oxidation (LSFO) and Ammonia (NH_3) FGD system have been included. The LSFO system includes waste water treatment. The NH_3 system includes costs for wastewater treatment of water used for the wet ESP. Refer to Appendix A at the end of the report.

Table 1-2 Capital Cost Estimates

(2019 Dollars x 1000)	Wet Lime Inhibited Oxidation Scrubber (WLIO)	Ammonia Scrubber (NH_3)	Circulating Dry Scrubber (CDS)	Limestone Forced Oxidation Scrubber (LSFO)
Installation Cost (2020 - 2024)	$318,079	$284,835	$269,550	$424,878
Capitalized Cost (2024 - 2039)	$34,313	$30,727	$29,078	$45,834

1.3.2 20 Year Totals 2020 to 2039

The O&M costs start in 2024 assuming the FGD system installation was completed in 2023. The O&M costs are in 2019 dollars and no escalation has been applied; O&M costs for labor are not included in the estimates below. The O&M costs are total cost for 20 years (from 2020 to 2039) and are rounded to the nearest $1,000. Table 1-3 represents the O&M costs for the FGD systems only and does not include the balance-of-plant O&M costs. Refer to Appendix A at the end of the report.

Table 1-3 Operations and Maintenance – 20 Year Totals 2020 to 2039

(2019 Dollars x 1000)	WLIO	NH_3	CDS	LSFO
O&M Schedule Outage	$21,510	$19,262	$18,228	$28,732
O&M – Base Non-Labor	$11,148	$9,983	$9,448	$14,892
Total	$32,659	$29,245	$29,078	$43,624

2.0 List of Abbreviations

acfm	Actual Cubic Foot per Minute
AFUDC	Allowance for Funds Used During Construction
AQC	Air Quality Control
BACT	Best Available Control Technology
BPT	Balance-of-Plant Treatment
$Ca(OH)_2$	Calcium Hydroxide
CaO	Quicklime
$CaSO_3$	Calcium Sulfite
$CaSO_3 \bullet 1/2H_2O$	Calcium Sulfite Hemihydrate
$CaSO_4 \bullet 2H_2O$	Calcium Sulfate Dihydrate
CDS	Circulating Dry Scrubber
CEMS	Continuous Emissions Monitoring System
DA	Dual Alkali
DBA	Dibasic Acid
DCS	Distributed Control System
DESP	Dry Electrostatic Precipitator
ECO	Electrocatalytic Oxidation
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
ESP	Electrostatic Precipitator
FDA	Flash Dryer Absorber
FGD	Flue Gas Desulfurization
H_2SO_4	Sulfuric Acid Mist
Hg	Mercury
ID	Induced Draft
IDEM	Indiana Department of Environmental Management
IRP	Integrated Resource Plan
JET	Jiangnan Environmental Technology, Inc.
L/G	Liquid-To-Gas
lb/Btu	Pound per British Thermal Unit
Lb/h	Pound per Hour
LIFAC	Limestone Injection into the Furnace and Activation of Calcium
LSFO	Limestone Forced Oxidation
LSIO	Limestone Inhibited Oxidation
MBtu	Million British Thermal Unit

MW	Megawatt
NH_3	Ammonia
NIPSCO	Northern Indiana Public Service Company
NO_X	Nitrogen Oxides
NSR	New Source Review
O&M	Operations and Maintenance
PAC	Powdered Activated Carbon
PGLS	Pre-Ground Limestone
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
PM_{10}	Particulate Matter Less than 10 Microns
PSD	Prevention of Significant Deterioration
SCR	Selective Catalytic Reduction
SDA	Spray Dryer Absorber
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SO_X	Sulfur Oxides
TBtu	Trillion British Thermal Units
WESP	Wet Electrostatic Precipitator
WLIO	Wet Lime Inhibited Oxidation
WWT	Wastewater Treatment

3.1 Conceptual Design Basis

3.2 ENVIRONMENTAL REGULATIONS

Black & Veatch anticipates that the installation of a new FGD system or major modification of the existing system will be subject to Federal and Indiana Department of Environmental Management (IDEM) air regulations as a modification to an existing major source. An air construction permit would, therefore, need to be obtained to authorize construction. However, Black & Veatch anticipates that the permit could be obtained as a minor modification and would not be subject to Prevention of Significant Deterioration (PSD) review and Best Available Control Technology (BACT) requirements. Black & Veatch notes that confirmation of air permitting applicability of a given technology cannot be accomplished until a New Source Review (NSR) applicability analysis is conducted. Should PSD BACT ultimately be applicable, the results of a BACT analysis could alter the required technology because emissions targets lower than the current emissions limits may be required. An operating change, such as an expected increase in the unit capacity factor, could cause BACT to be applicable. The conceptual design basis used to screen the scrubber technologies must be able to meet, as a minimum, the minor modification to permit (~98 percent removal).

3.3 BOILER PERFORMANCE

Characteristics for boiler performance parameters used by Black & Veatch were based on a previous study performed in 2013 for A.B. Brown Unit 1. The same information was utilized for A.B. Brown Unit 2 for this high-level assessment.

Table 3-1 Combustion Performance

Parameters	Typical Coal Exhaust Gas Flow (Typical Sulfur)	Maximum Design Exhaust Gas Flow (Maximum Sulfur)	Typical Coal Minimum Exhaust Gas Flow (Typical Sulfur)	Design Maximum Values	Minimum Design Values
Unit Characteristics					
Unit Rating, Gross MW	268	268	~115	268	~115
Unit has an SCR	Yes	Yes	Yes		
Boiler Heat Input, MBtu/h (HHV)	2,690	2,714	1,015	2,714	1,015
Boiler Heat to Steam, MBtu/h	2,351	2,351	893		
Coal Flow Rate, lb/h	241,000	261,000	94,000	241,000	94,000
LOI, % of fly ash	1.79	1.79	1.79	1.79	1.79
Boiler Misc. Heat Losses, %	1.50	1.50	1.50	1.50	1.50
Excess Air at Economizer, %	3.60	3.60	6.80	6.80	3.60
Excess Air, %	22.81	22.82	53.21		
Air Heater Leakage, %	10.84	10.83	28.99		
Fly Ash Portion of Total Ash, %	85	85	85		
Altitude, ft above MSL	415	415	415	415	415
Barometric Pressure, in. Hg Abs	29.496	29.496	29.496		
Ambient Pressure, in. H_2O	401	401	401	401	401
Ambient Temperature, °F	85	85	85	105	-23
Relative Humidity, %	60	60	60		
SO_2 to SO_3 Oxidation Rate by Boiler, percent	0.8	0.8	0.8		
SO_2 to SO_3 Oxidation Rate by SCR, percent	0.5	0.5	0.5		
Total SO_2 to SO_3 Oxidation Rate, percent	1.3	1.3	1.3		
PJFF Inlet Conditions					
Actual flow, acfm	1,040,000	1,080,000	540,000		
Flue Gas Temperature, °F	305	330	285	330	285
Flue Gas Pressure, in. w.g.	-24.0	-24.0	-5.5	-24.0	-5.5
Flue Gas Composition					
O_2, % Vol wet basis	5.29	5.29	9.92		
N_2,% Vol wet basis	73.62	73.61	74.69		
CO_2, % Vol wet basis	11.98	11.84	8.32		
SO_2 , % Vol wet basis	0.27	0.43	0.19		
HCl, % Vol wet basis	0.0013	0.0035	0.0009		

Parameters	Typical Coal Exhaust Gas Flow (Typical Sulfur)	Maximum Design Exhaust Gas Flow (Maximum Sulfur)	Typical Coal Minimum Exhaust Gas Flow (Typical Sulfur)	Design Maximum Values	Minimum Design Values
H_2O, % Vol wet basis	8.83	8.83	6.88		
Sulfur Dioxide Concentration, lb/MBtu	6.72	10.54	6.92		
H_2SO_4 ppmvd	22.1	34.9	15.0		
H_2SO_4, lb/MBtu	0.076	0.120	0.079		
Oxidized Hg, lb/TBtu	4.75	4.75	4.35	4.80	
Elemental Hg, lb/TBtu	0.53	0.53	0.67	1.20	
Total Hg, lb/TBtu	5.28	5.28	5.02	6.00	
Particulate Concentration, lb/MBtu	7.54	12.23	7.76		
Particulate Mass Rate, gr/acf	2.28	3.59	1.70		
PJFF Outlet/ID Fan Inlet Conditions					
Actual flow, acfm	1,340,000	1,350,000	550,000		
Actual flow per duct total of two ducts per boiler, acfm	670,000	675,000	275,000		
Flue Gas Temperature, °F	305	330	285	330	285
Flue Gas Pressure, in. w.g.	-32.0	-32.0	-13.5		
Flue Gas Composition					
O_2, % Vol wet basis	5.29	5.29	9.92		
N_2,% Vol wet basis	73.62	73.61	74.69		
CO_2, % Vol wet basis	11.98	11.84	8.32		
SO_2 , % Vol wet basis	0.27	0.43	0.19		
HCl, % Vol wet basis	0.0013	0.0035	0.0009		
H_2O, % Vol wet basis	8.83	8.83	6.88		
H_2SO_4 ppmvd	19.9	31.4	13.5		
H_2SO_4, lb/MBtu	0.069	0.108	0.071		
Oxidized Hg, lb/TBtu	4.72		4.80	4.80	
Elemental Hg, lb/TBtu	0.13		0.38	1.20	
Total Hg, lb/TBtu	4.85	0.00	5.18	6.00	
PM (Filterable), lb/MBtu	0.010	0.010	0.010		
Ref: Boiler performance from A.B. Brown Unit 1 Environmental Study 2013 Design Basis – Exhaust Flow Information.					

3.4 DESIGN COAL

Table 3-2 Design Coal

Parameters	Design Cases - Bituminous Design Coal	Range - Bituminous Minimum	Maximum
Ultimate Coal Analysis, wet basis			
Carbon, %	62.02	50.80	75.38
Hydrogen, %	4.23	3.50	5.30
Sulfur, %	3.75	0.86	5.48
Nitrogen, %	1.02	0.86	2.20
Oxygen, %	6.91	5.00	11.11
Chlorine, %	0.04	0.01	0.17
Ash, %	9.71	7.00	14.68
Moisture, %	12.32	2.70	16.50
Total, %	100	71	131
Higher Heating Value, Btu/lb	11,143	10,400	12,493
Ref: A.B. Brown Unit 1 Environmental Study 2013 Design Basis – Fuel Information. Installation Scope.			

4.1 Potential Air Quality Control Technologies

The evaluation is being performed to assist Vectren in determining a preliminary selection of the preferred FGD equipment for evaluation in Vectren's 2019 IRP. Black & Veatch has assumed that the installation of a new FGD system will be subject to Federal and IDEM air regulations as a modification to an existing major source, and, therefore, an air construction permit will have to be obtained to authorize construction. However, because of the nature of the project (where the existing air emissions limits are the baseline), it is assumed that the emissions increase as a result of this project, if any, would be less than the PSD significance thresholds. Thus, according to these assumptions, the project would be considered a minor modification and would, therefore, not be subject to PSD BACT requirements. Black & Veatch notes that confirmation of air permitting applicability of a given technology cannot be accomplished until an NSR applicability analysis is conducted. Should PSD BACT ultimately be applicable, the results of a BACT analysis could alter the required technology because emissions targets lower than the current emissions limits may be required. An operating change, such as an expected increase in the unit capacity factor, could result in making BACT applicable.

4.2 REVIEW OF POTENTIAL TECHNOLOGIES

This section identifies, summarizes, and evaluates potential SO_2 control technologies for feasibility of use at the A.B. Brown Station. The current generation of FGD system design represents improvements and advances to previous generations of FGD systems that were first installed in the United States in the 1970s.

Many of the FGD system vendors offer both semi-dry systems (i.e., CDS or spray dryer absorber [SDA] systems) and wet systems (lime- and limestone-based spray/tray towers absorbers) and will offer whichever best meets the utility's particular requirements on a site-by-site basis. Improvements to the wet FGD technologies have also been realized through better process chemistry and the use of chemical additives such as dibasic acid (DBA). The following subsections identify and describe the potential technologies that were evaluated for use at A.B. Brown Station.

4.1.1 Conversion of the Current FGD System to a Limestone-Based Scrubber

Conversion of the existing DA FGD systems to a limestone-based FGD system has been completed on similar type units in industry and was examined in this study. The detailed study of this option was provided in a report completed by AECOM, an engineering firm under separate contract with Vectren. This report is provided as Appendix C at the end of this report. In this report, AECOM presents the option of converting the existing A.B. Brown FGD systems to a limestone-based reagent scrubber using either of two options: limestone inhibited oxidation (LSIO), producing calcium sulfite solids for landfill disposal, or LSFO operations, producing wallboard-quality gypsum that allows for the potential marketing and selling of the byproduct to avoid the landfill costs. AECOM previously converted DA scrubbers at Northern Indiana Public Service Company's (NIPSCO's) Schahfer Station to limestone-based reagent, along with in situ oxidation to produce wallboard-quality gypsum. Both options were assessed with the intention to repurpose and/or reuse as much existing equipment as possible. For this preliminary report, only the use of pre-ground limestone (PGLS) was evaluated. A description of the proposed process configurations, scope of work, capital requirements, and operating cost impacts are presented in the AECOM report. Vectren indicates that additional equipment and construction items that were not included in the AECOM report have been addressed by a local Evansville, Indiana, engineering firm, Three I Design, that has assisted Vectren over the years in the evaluation of the FGD equipment.

4.1.2 Wet Limestone Process

Numerous suppliers offer FGD processes using a limestone slurry as the scrubbing agent. A detailed evaluation of this technology option was provided in a report completed by Burns & McDonnell, an engineering firm under separate contract with Vectren. This report is provided in Appendix B at the end of this report. In this report, Burns & McDonnell presents the option of installing new limestone reagent-based scrubbers using LSFO operations to produce wallboard-quality gypsum that can be landfilled or marketed and sold.

The Wet Limestone process utilizes a ball mill to create a limestone slurry which is fed into the absorber reaction tank to maintain the appropriate pH. Recirculation pumps feed limestone slurry from the reaction tank to the spray lances at the top of the absorber tower. The flue gas flows countercurrent to the sprayed slurry where the SO_2 reacts and is removed from the flue gas stream. The flue gas continues through a set of mist eliminators before leaving the absorber. The SO_2 which reacts with the lime in the system is oxidized to form gypsum. A bleed stream is removed from the absorber reaction tank and sent to the dewatering system where water is removed from the gypsum byproduct.

4.1.3 Wet Lime Process

Wet lime FGD is the generic term for processes using slaked lime as the scrubbing reagent in a spray tower FGD module. Wet lime processes are offered by a number of FGD suppliers. The reagent preparation system equipment is the only significant difference between the equipment used in the wet lime and wet limestone systems. The higher reactivity of the lime allows the equipment to be smaller than with a wet limestone scrubber.

Inhibited oxidation producing a calcium sulfite material is used or forced oxidation is used to promote formation of a fully oxidized gypsum byproduct. For this study, an inhibited oxidation process is assumed that produces a material for landfill disposal.

The primary difference in the wet lime and wet limestone processes is the preparation of scrubbing reagent slurry. In wet lime processes, quicklime (CaO) is slaked to produce a calcium hydroxide [$Ca(OH)_2$] slurry.

4.1.4 Semi-Dry Lime-Based FGD Systems

Semi-dry FGD processes have been extensively used in the United States, where utilities have installed numerous semi-dry FGD systems on boilers using low sulfur fuels. The semi-dry FGD process uses $Ca(OH)_2$ produced from the lime reagent as either a slurry or as a dry powder added to the flue gas in a reactor designed to provide good flue gas-reagent contact. The SO_2 in the flue gas reacts with the calcium in the reagent to produce primarily calcium sulfite hemihydrate ($CaSO_3 \bullet 1/2H_2O$) and a smaller amount of calcium sulfate dihydrate ($CaSO_4 \bullet 2H_2O$) through the following reactions:

$$SO_2 + Ca(OH)_2 \rightarrow CaSO_3 \bullet ½H_2O + ½H_2O$$

$$SO_2 + Ca(OH)_2 + ½O_2 \rightarrow CaSO_4 \bullet 2H_2O$$

Water is also added to the reactor (either as part of the reagent slurry or as a separate stream) to cool and humidify the flue gas, which promotes the reaction and reagent utilization. The amount of water added is typically sufficient to cool the flue gas to within 30° to 40° F of the flue gas adiabatic saturation temperature. Significantly less water is used in these semi-dry FGD processes than in wet FGD processes.

The reaction byproducts and excess reagent are dried by the flue gas and removed from the flue gas by a downstream particulate control device (either fabric filter or dry electrostatic precipitator [DESP]). Fabric filters are preferred for most systems because the additional contact of the flue gas with the particulate on the filter bags provides additional SO_2 removal and higher reagent utilization. A portion of the reaction byproducts collected is recycled to the reagent preparation system to increase the utilization of the lime.

Because of the large amount of excess lime present in the FGD byproducts, the byproducts (and fly ash, if present) will experience pozzolanic (cementitious) reactions when wetted. When wetted and compacted, the byproduct makes a fill material with low permeability (low lengthening characteristics) and high bearing strength. However, other than as structural fill, this byproduct has limited commercial value and typically must be disposed of as a waste material.

The semi-dry FGD processes offer benefits in addition to SO_2 removal, including the lack of a visible vapor plume and sulfur trioxide (SO_3) removal. Because the semi-dry FGD systems do not saturate the flue gas with water, there is no visible plume from the stack under most weather conditions. Environmental concerns with SO_3 emissions are also reduced with the semi-dry scrubber. SO_3 is formed during combustion and will react with the moisture in the flue gas to form sulfuric acid (H_2SO_4) mist in the atmosphere. An increase in H_2SO_4 emissions will increase PM_{10} emissions. The gas temperature leaving the reactor is lowered below the sulfuric acid dew point, and significant SO_3 removal will be attained as the condensed acid reacts with the alkaline reagent. By removing SO_3 in the flue gas, the condensable particulate matter emissions can be reduced. This will reduce the potential for any SO_3 plume that may cause opacity in stacks. Similar type SO_3 removal is not achievable with a wet scrubber.

The following four variants of semi-dry FGD processes are described further in this analysis:

- Spray Dryer Absorber (SDA).
- Circulating Dry Scrubber (CDS).
- Flash Dryer Absorber (FDA).
- Turbosorp.

4.1.4.1 Spray Dryer Absorber

All current SDA designs use a vertical gas flow absorber. These absorbers are designed for co-current or a combination of co-current and countercurrent gas flow. In co-current applications, gas enters the cylindrical vessel near the top of the absorber and flows downward and outward. In combination-flow absorbers, a gas disperser located near the middle of the absorber directs a fraction of the total flue gas flow upward toward the slurry atomizers.

The atomizer produces an umbrella of atomized reagent slurry through which the flue gas passes. The SO_2 in the flue gas is absorbed into the atomized droplets and reacts with the calcium to form calcium sulfite and calcium sulfate. Before the slurry droplet can reach the absorber wall, the water in the droplet evaporates and a dry particulate is formed.

The flue gas, then containing fly ash and FGD byproduct solids, leaves the absorber and is directed to a fabric filter. The fly ash and byproduct solids collected in the fabric filter are pneumatically transferred to a silo for disposal. To improve both reagent utilization and spray solids drying efficiency, a large portion of the collected solids is directed to a recycle system, where it is slurried and re-injected into the spray dryer along with the fresh lime reagent.

SDA installations, primarily located in the western United States, use either lignite or subbituminous coals, such as Powder River Basin, as the boiler fuel and generally have spray dryer systems designed for a maximum fuel sulfur content of less than 2 percent. The semi-dry lime-based FGD system has inherent removal efficiency limitations on higher sulfur fuels with higher SO_2 inlet concentration. This limitation varies with flue gas inlet temperature because the amount of slurry that can be injected into the absorber is limited by how close the flue gas temperature can approach its water saturation temperatures.

4.1.4.2 Circulating Dry Scrubber

The CDS FGD, also known as a circulating fluid bed scrubber, process is a semi-dry, hydrated lime-based FGD process that uses a circulating fluid bed contactor. The CDS absorber module is a vertical solid/gas reactor upstream of a particulate control device. The particulate control device is elevated to allow the recycle of the byproduct back to the fluidized bed in the absorber vessel. Water is sprayed into the reactor to reduce the flue gas temperature to the optimum temperature for reaction of SO_2 with the reagent. Hydrated lime [$Ca(OH)_2$] and recirculated dry solids from the particulate control device are injected concurrently with the flue gas into the base of the absorber module. One or more venturi should be at the bottom of the absorber module to accelerate the flue gas to maintain the fluidized bed in the absorber. The gas velocity in the reactor is reduced, and a suspended bed of reagent and fly ash is developed. The SO_2 in the flue gas reacts with the hydrated lime reagent to form predominantly calcium sulfite ($CaSO_3$).

4.1.4.3 Flash Dryer Absorber

The FDA is a variation of CDS technology. In this system, the fly ash is mixed with lime and water in a mixer/hydrator prior to being injected into the flash dryer. The flue gas is evaporatively cooled and humidified by the water being absorbed onto the dry particulate. Furthermore, SO_2 is removed from the flue gas stream by the reaction with the lime or limestone. The dry particulate is then removed in a fabric filter. A portion of the dry particulate from the fabric filter is collected for disposal, while a significant amount is recirculated to the mixer for conditioning and reuse in the absorber to achieve better reagent use and performance.

4.1.4.4 Limestone Injection into Furnace and Reactivation of Calcium

In the early 1980’s, Tampella Power Inc. of Finland began the development of a humidification process that would enhance the effectiveness of the furnace-injection FGD process by humidifying the flue gas and installing a solid/gas contact reactor upstream of the particulate control device. This process is referred to by the acronym LIFAC (limestone injection into the furnace and activation of calcium). The two major differences between the LIFAC process and the furnace-injection process are the use of a reactor to enhance reagent contact with the flue gas and the recirculation of a portion of the fly ash and byproduct solids collected in the particulate control device to the reactor.

This process is offered only by Tampella Power or one of its affiliated companies and has been applied to full-scale, coal fired utility boilers in Finland, Russia, Canada, and the United States.

4.1.4.5 Turbosorp

The Turbosorp circulating fluidized bed scrubber is a multi-pollutant control technology that removes SO_2, SO_3, hydrochloric acid, and mercury (Hg) from flue gas for coal fired applications. Turbosorp was originally developed by Austrian Energy & Environment and is now offered by Andritz and Babcock Power Environmental Inc.

4.1.5 Ammonia Scrubber

Anhydrous ammonia is used in the ammonia scrubber as the desulfurization absorbent to capture the SO_2, and the byproduct of the process is ammonium sulfate, a known fertilizer material. The only large FGD system of this type in the United States was installed at Dakota Gasification in North Dakota. This site is not a coal burning power plant. At this plant synthetic natural gas is produced by oxidizing lignite coal. The ammonia solution contacts the flue gas in a spray tower type absorber similar to a wet limestone or lime system.

4.1.6 Powerspan Electrocatalytic Oxidation Process

The Powerspan Electrocatalytic Oxidation (ECO) process is a multi-pollutant control technology that oxidizes and removes nitrogen oxides (NO_X), sulfur oxides (SO_X), and Hg from flue gas. The ECO process consists of the following steps:

- Fabric Filter or Electrostatic Precipitator (ESP)--Removes fly ash.
- ECO Reactor--Oxidizes pollutants.
- Absorber Vessel--Removes SO_2 and NO_2.
- Wet Electrostatic Precipitator (WESP)--Removes acid aerosols, fine PM, and oxidized Hg.

4.2 TECHNOLOGY PERFORMANCE EVALUATION CRITERIA (SO_2 AND PM)

An analysis was performed to identify the technical feasibility of the control options identified in Section 4.1, considering source-specific factors. A control option that was determined to be technically infeasible was eliminated. “Technically infeasible” in this case was defined as a control option that has not been proven to meet the emissions limits currently required at the plant for the defined range of potential operating conditions.

The performance requirements are as follows:

- 98 percent SO_2 removal efficiency for all coals.
- Particulate matter (PM) emissions at or below current baseline emissions.

Technologies are also considered infeasible if performance restrictions preclude the technology from achieving the primary emissions target or secondary emissions targets because of physical, chemical, or engineering issues. Secondary emissions targets would include other air or water emissions limits, such as Hg, not necessarily directly controlled by the technology but for which the technology cannot prevent control of the secondary emissions through other means. After completion of this step, technically infeasible options were then eliminated from the review process.

Control options that are not eliminated are considered technically feasible. A "technically feasible" control option is defined as a control technology that has been installed and operated successfully at a similar type of source of comparable size to the proposed facility under review (i.e., "demonstrated"). If the control option cannot be demonstrated, the analysis considers two key concepts: availability and applicability. "Availability" is defined as technology that can be obtained through commercial channels or is otherwise available within the common sense meaning of the term. A technology that is being offered commercially by vendors or is in licensing and commercial demonstration is deemed an available technology. Technologies that are in development (concept stage/research and patenting) and testing stages (bench-scale/laboratory testing/pilot scale testing) are classified as not available. An "available" technology does not mean that it does not have technical or commercial risks that differ from other available technologies. These risks are identified and evaluated during the analysis and considered in later analysis steps.

4.3 ELIMINATED TECHNOLOGIES

In order to eliminate technologies, an evaluation of all the available control technologies identified in Step 1 of the analysis was completed to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar type of source of comparable size, or there is technical agreement that the technology can be applied to the source. Available and applicable are the two terms used to define the technical feasibility of a control technology. Table 4-1 identifies what technologies are considered technically feasible SO_2 options for the A. B. Brown application.

Table 4-1 Summary – Eliminate Technically Infeasible Options

Technology Alternative	Technically Feasible (Yes/No) Available	Applicable
Wet FGD		
Limestone Conversion of Existing DA FGD - Forced Oxidation	Yes	No –would not meet expected emissions requirements when operating over the high sulfur range of the coals used at A.B. Brown.
Limestone Conversion of Existing DA FGD - Inhibited Oxidation	Yes	No –would not meet expected emissions requirements when operating over the high sulfur range of the coals used at A.B. Brown.
Wet Limestone FGD - Forced Oxidation(1)	Yes	Yes
Wet Lime FGD - Inhibited Oxidation(1)	Yes	Yes
Limestone Injection into the Furnace	Yes	No – would not meet expected emissions requirements when operating over the high sulfur range of the coals used at A.B. Brown.
Dry and Semi-Dry Lime FGD		
SDA	Yes	No – SDA has limited SO_2 removal efficiency over the project range of fuels, which are higher sulfur contents.
CDS or Turbosorp	Yes	Yes – Installations comparable in size are in operation. However, no full-scale operational experience is available in the United States over the high sulfur range of the coals used at A.B. Brown.
FDA	Yes	No – FDA has limited SO_2 removal efficiency over the high range of sulfur in the fuels.
Ammonia Scrubber	Yes	Yes – However, only one US application in operation and current interest limited to one Chinese supplier with no US experience.
Powerspan ECO Process	No	No – Only pilot size experience.

(1) Alternate absorber designs in wet lime or limestone FGD (spray tower, double contact spray tower, trays, etc.) are equal for comparison purposes.

On the basis of the initial selection of candidate technologies to address Vectren's objectives, the control technologies identified in Table 4-2 were selected for further evaluation; the firm responsible for the evaluation is also identified.

Table 4-2 Selected Technologies

Option	Acronym	Data Source
Wet Lime Inhibited Oxidation	WLIO	Black & Veatch
Circulating Dry Scrubber	CDS	Black & Veatch
Ammonia	NH_3	Black & Veatch
Limestone Forced Oxidation	LSFO	Burns & McDonnell

4.4 POTENTIAL TO MEET FUTURE REGULATIONS

It should be noted that this analysis is focused on meeting current emissions requirements and meeting Vectren's current objectives. It is possible that future environmental regulations will be promulgated that require A.B. Brown to reduce air emissions beyond the current requirements. If this occurs in the future, additional study will be needed to determine what additional modifications and capital expenditures would be needed for each technology.

5.1 Limestone Forced Oxidation Scrubber (LSFO)

The LSFO study was completed by Burns & McDonnell and is attached in Appendix B.

5.2 DESCRIPTION OF TECHNOLOGY

5.1.1 Basic Process Description

Limestone FGD utilizes crushed limestone ($CaCO_3$) ground and mixed with water to be used as a scrubber reagent that is pumped to a scrubber vessel reaction tank and the slurry in the reaction tank is recirculated by large pumps to the spray headers at the top of the spray tower vessel. The spray headers discharge the slurry into the spray towers with flue gas passing through the spray stream in a countercurrent direction and the removes SO_2 from the gas stream. Oxidation air blowers are provided to push oxygen to the reaction tank to create a gypsum byproduct.

$$CaCO_3 + SO_2 \rightarrow CaSO_3 + CO_2$$

$$CaSO_3 + \frac{1}{2} O_2 + 2H_2O \rightarrow CaSO_4 \bullet 2(H_2O)$$

The gypsum byproduct bleed stream is pumped from the reaction tank through a hydroclone as an initial step to separate solids from liquid. Liquids are returned to the reaction tank and solids are separated and sent to the vacuum filter to further remove liquids before being loaded and shipped to a purchaser or disposed of in a landfill.

For a detailed description of the limestone forced oxidation scrubber technology as provided by Burns & McDonnell, refer to Section 3.2 of the Burns & McDonnell Wet Limestone Forced Oxidation FGD Cost Estimate report included as Appendix B.

5.1.2 Flow Diagram

Figure 5-1 is a typical process flow diagram for an LSFO.

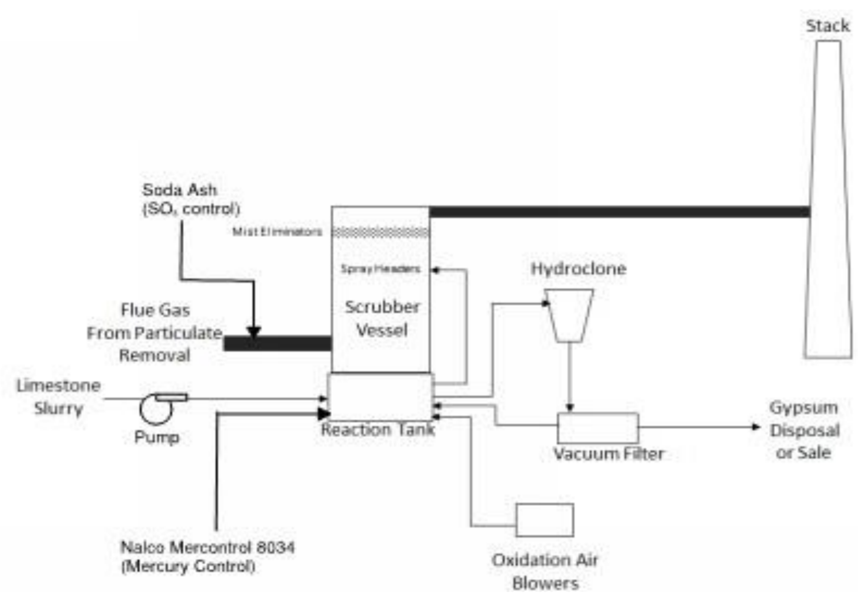

Figure 5-1 Limestone Forced Oxidation Scrubber

5.1.3 Environmental Controls

The existing particulate control systems (fabric filter on Unit 1 and electrostatic precipitator (ESP) on Unit 2) and ash collection systems remain in service with the fly ash continuing to be available for recycle.

Control of SO_3 will be with use of a soda ash injection system (such as AECOM SBS Injection system). The current soda ash injection point is located after the fabric filter on Unit 1 and after the ESP on Unit 2 both locations are upstream of the scrubber vessels.

The LSFO system will use the existing mercury control systems (Nalco Mercontrol 8034) for mercury control. Mercontrol 8034 chemical is injected into the scrubber limestone slurry recirculation piping for mixing and dispersion.

The LSFO scrubber system removes the HCl from the flue gas steam.

Table 5-1 Environmental Controls LSFO

Pollutant	Hg	SO_3	SO_2	PM
Control Technologies	LSFO + Nalco Mercontrol 8034	Existing SBS Injection System	LSFO	Existing PM control: Unit 1 – Fabric Filter Unit 2 - ESP

5.2 ESTIMATING METHODOLOGY

Burns & McDonnell requested budgetary bids from seven FGD system suppliers: Amec Foster Wheeler, Andritz, Babcock & Wilcox, Babcock Power, GE Power, Marsulex and Mitsubishi Hitachi. An average of the budgetary quotes was assumed for the FGD supply cost.

Direct costs were factored based on costs from past FGD projects. Factored costs were used for Indirect costs which include engineering and start-up. Burns & McDonnell developed an estimate of the following balance of plant direct costs:

- Equipment installation.
- Civil and foundation work.
- New chimney for Unit 1.
- Demolition of Unit 1 thickener.
- Concrete.
- Steel.
- Ductwork and insulation.
- Buildings.
- Limestone and gypsum pile canopies.
- Wastewater treatment equipment (falling film evaporator and crystallizer).
- Piping.

- Electrical (new transformers, PCM, switchgear, MCC's and miscellaneous panels).
- Instrumentation and controls.

Refer to Section 3.5 of the Burns & McDonnell report in Appendix B.

5.3 ESTIMATE ASSUMPTION

Burns & McDonnell made the following assumptions in preparation of the cost estimate:

- All estimates aide screening-level in nature, do not reflect guaranteed costs, and are not intended for budgetary purposes.
- Assumes contracting philosophy is Engineer, Procure, Construction (EPC) approach.
- All information is preliminary and should not be used foil construction purposes.
- Assumes project engineering starts January 1, 2020 with both scrubbers in operation by January 2024.
- All capital cost and O&M estimates are stated in 2019 US dollars (USD). Escalation is excluded.
- Fuel and power consumed during construction, startup, and/or testing are included.
- Piling is included under heavily loaded foundations.
- All foundations are new; no re-use of existing foundations.
- Adequate water supply is assumed to be available from existing raw water supplies.
- This estimate assumes that the integrity of the tie-in points is sufficient.
- This estimate assumes that there are no significant underground utilities that would have to be re-routed.
- Removal of hazardous materials is not included.
- Emissions estimates are based on a preliminary review of BACT requirements and provide a basis for the assumed air pollution control equipment included in the capital and O&M costs.
- No new induced draft (ID) fans or booster fans ate included in the capital cost estimate. Burns & McDonnell reviewed the fan curves provided by Vectren and determined there was sufficient capacity to handle the pressure drop through the new FGD system.
- This estimate does not include provisions for either Mercury control or SO_3 control. Vectren can continue using the existing system for each following conversion to the wet LSFO technology.

Refer to Subsection 3.5.1 of the Burns & McDonnell report in Appendix B.

5.4 PROJECT INDIRECT COSTS

Burns & McDonnell included the following indirect costs in the capital cost estimate:

- Performance testing and CEMS/stack emissions testing.
- Pre-operational testing, startup, start-up management and calibration.
- Construction/start-up technical serv ice.
- Engineering.
- Freight.
- Start-up spare parts.

Refer to Section 3.6 of the Burns & McDonnell report in Appendix B.

5.5 OWNER COSTS

Burns & McDonnell did not include the following Owner's costs in the estimates:

- Project development.
- Owner's operational personnel.
- Owner's project management.
- Owner's engineering.
- Owner's startup engineering and training.
- Legal fees.
- Permitting/licensing.
- Construction power, temporary utilities, startup consumables.
- Site security.
- Operating spare parts.
- Political concessions.
- Builder's risk insurance.
- Owner's contingency.
- Allowance for funds used during construction (AFUDC).

Refer to Section 3.7 of the Burns & McDonnell report in Appendix B.

5.6 COST ESTIMATE EXCLUSIONS

The following costs were excluded from Burns & McDonnell's estimate:

- Escalation.
- Sales tax.
- Property tax and property insurance.
- Utility demand costs.
- Salvage values.

Refer to Section 3.8 of the Burns & McDonnell report in Appendix B.

5.7 PRESENTATION OF CAPITAL COSTS

The capital cost of the replacement LSFO system is summarized in Table 5-2. The direct cost includes the cost of the absorber, limestone preparation system, gypsum dewatering system, gypsum canopy for 3 days of gypsum storage, WWT equipment, electrical upgrades, boiler reinforcement, new stack for Unit 1, and installation.

Table 5-2 LSFO Capital Costs

Category	Cost
Total Direct Cost	$265,287,000
Indirect Cost	$66,480,000
Contingency	$65,571,000
Engineering, Procurement, and Construction (EPC) Fee	$27,540,000
Total Project Cost	**$424,878,000**

5.8 OPERATIONS AND MAINTENANCE COSTS – PRESENT 20 YEAR TOTALS

The O&M costs start in 2024 assuming the LSFO system installation was completed in 2023. The O&M costs are in 2019 dollars and no escalation has been applied; labor costs are not included in the O&M estimates in Table 5-3. The O&M costs are total cost for 20 years (from 2020 to 2039) and are rounded to the nearest $1,000. Table 5-3 represents the O&M costs for the LSFO system only and does not include the balance-of-plant O&M costs.

Table 5-3 LSFO Operation and Maintenance Costs

Category	Cost
O&M Schedule Outage	$28,732,000
O&M – Base Non-Labor	$14,892,000
20 Year Total	$43,624,000

5.9 WATER/WASTEWATER TREATMENT/WASTEWATER RECYCLE

The cost estimates developed for this FGD technology includes the assumption that the LSFO process will produce a saleable gypsum product. The chloride content is limited in saleable gypsum, therefore a gypsum cake washing process is required. The estimate includes water treatment and wastewater treatment equipment sized and developed for this process only. The LSFO water and wastewater treatment equipment is not sized to handle or treat flow streams from or to support other parts of the project site.

5.10 RISKS

The normal risks associated with procurement of equipment (domestic or internationally sourced), construction of equipment on a large power project, and operations of the plant once completed are not included in this section. Shut down of the AB Brown coal fired units prior to 20 years of operation will economically impact the selection of scrubber technology.

There are a large number of LSFO systems operating in the United States which have a proven record of achieving the required emissions rates. The limestone reagent required for this system is readily available in the US. The gypsum byproduct will need to be landfilled if a buyer(s) for this material is not found or contracted with to take this material for recycling and re-use.

6.1 Wet Lime Inhibited Oxidation Scrubber (WLIO)

6.2 DESCRIPTION OF TECHNOLOGY

WLIO is one replacement technology with the capability to achieve the SO_2 removal required for A.B. Brown. The technology uses slaked lime in a spray tower scrubber to remove SO_2 from the flue gas producing.

6.1.1 Basic Process Description

Wet lime FGD is the generic term for processes using slaked lime as the scrubbing reagent in a spray tower FGD module. Wet lime processes are offered by a number of FGD suppliers. The reagent preparation system equipment is the only significant difference between the equipment used in the wet lime and wet limestone systems. However, the higher reactivity of the lime allows the equipment to be smaller than with a wet limestone scrubber.

Inhibited oxidation producing a calcium sulfite material is used or forced oxidation is used to promote formation of a fully oxidized gypsum byproduct. For this study, an inhibited oxidation process is assumed that produces a material for landfill disposal.

The primary difference in the wet lime and wet limestone processes is the preparation of scrubbing reagent slurry. In wet lime processes, CaO is slaked to produce a Ca $(OH)_2$ slurry.

$$CaO + H_2O \rightarrow Ca\,(OH)_2$$

For a wet lime FGD process, the chemical reactions are as follows:

$$SO_2 + Ca(OH)_2 \rightarrow CaSO_3 \bullet 1\ 1/2\ H_2O + 1/2\ H_2O$$
$$SO_2 + Ca(OH)_2 + 1/2\ O_2 + H_2O \rightarrow CaSO_4 \bullet 2\ H_2O$$

The reactivity of Ca $(OH)_2$ in the lime slurry is significantly greater than that of limestone. Since lime is typically manufactured by calcination of limestone, the cost of lime is significantly greater than that of limestone.

The lime slurry may be prepared in detention, paste, or ball mill slakers. An inventory of prepared slurry is stored in a slurry feed tank, ready for automatic injection into the FGD module's reaction tank as required to maintain the pH of the reaction tank slurry.

Spray towers for wet lime processes are essentially identical to those used in wet limestone FGD processes, except the absorber can be slightly shorter. Slurry from the FGD module reaction tank is sprayed into the flue gas flow stream; the SO_2 is absorbed from the flue gas by the lime slurry. The height of the tower and the liquid to gas ratio (L/G) may be lower than for limestone systems because of the reactivity of the lime slurry.

The solubility of Ca $(OH)_2$ in the slurry results in a pH in the reaction tank that is higher than in a wet limestone FGD process. The higher pH limits the natural oxidation of sulfites to sulfates to less than that achieved in a wet limestone process, but an oxidation inhibitor additive is required to keep oxidation levels low enough to prevent potential scaling issues.

6.1.2 Flow Diagram

The WLIO system utilizes pebble lime as the reagent, which is slaked producing a 20 percent solids slurry. The slaked lime slurry is fed into a spray tower absorber. The resulting calcium sulfite solids are removed and sent to thickeners and rotary drum filters for dewatering. The byproduct has a high moisture content and must be fixated with fly ash or Portland cement prior to disposal in the landfill. There is no market for the byproduct from a WLIO.

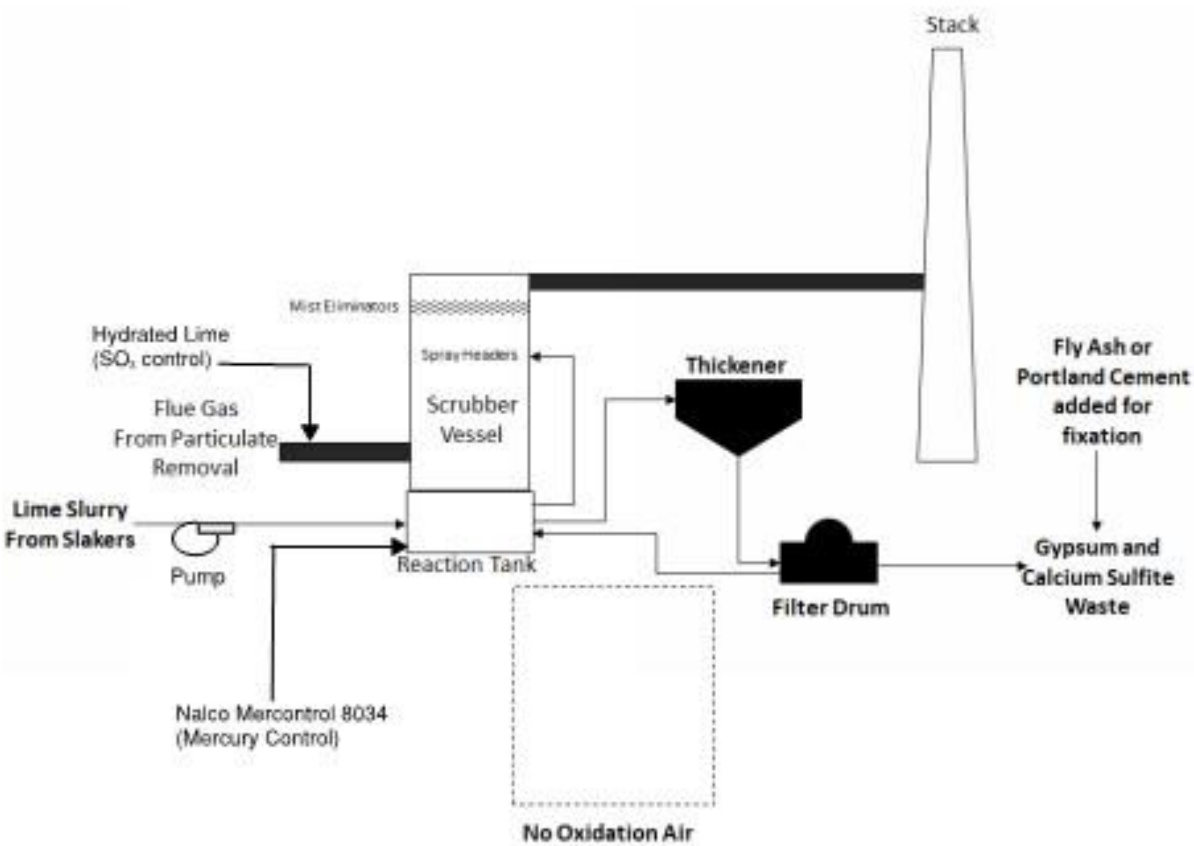

Figure 6-1 Wet Lime Inhibited Oxidation Scrubber

6.1.3 Environmental Controls

The existing particulate control systems (fabric filter on Unit 1 and electrostatic precipitator (ESP) on Unit 2) and ash collection systems remain in service with the fly ash continuing to be available for recycle.

The WLIO system will use the existing mercury control systems (Nalco Mercontrol 8034) for mercury control. Mercontrol 8034 chemical is injected into the scrubber lime slurry recirculation piping for mixing and dispersion. Mercury is captured in the scrubber slurry as it is circulated through the scrubber vessel.

Hydrated lime is pneumatically injected into the duct (DSI) upstream of the scrubber to control SO_3 emissions.

HCl is removed through a combination of hydrated lime injection and the WLIO scrubber system.

Table 6-1 Environmental Controls WLIO

Pollutant	Hg	SO_3	SO_2	PM
Control Technologies	WLIO + Nalco Mercontrol 8034	Hydrated Lime Injection	WLIO	Existing PM control: Unit 1 – Fabric Filter Unit 2 - ESP

6.1.4 Reagent Type, Storage, and Preparation

Pebble lime is utilized as the reagent in a WLIO scrubber. The pebble lime would be shipped to the site by pneumatic truck or railcar and stored in silos. The silos would be designed to store 7 to 14 days of pebble lime on the basis of full load operation. The pebble lime would be fed into a slaker that mixes the pebble lime with water. The exothermic reaction produces a $Ca(OH)_2$ slurry containing about 20 percent solids, which is stored in an agitated slurry tank. Pumps are used to supply the slurry to the absorber based on the demand signal from the control system.

6.1.5 Byproduct Type, Storage, and Handling

The byproduct produced by the WLIO system is a combination of calcium sulfite and calcium sulfate. The high pH in the absorber system naturally inhibits oxidation so the resulting byproduct is mostly calcium sulfite. Dewatering of calcium sulfite is difficult so the resulting byproduct will contain 20 to 30 percent free moisture. The byproduct would be mixed with fly ash or Portland cement in a pug mill before being transported via truck to dispose of in a landfill.

6.1.6 Description of Basic Equipment in Process

The WLIO system includes the following basic equipment:

- Absorber Module, including spray headers, mist eliminators, and recirculation pumps.
- Reagent Preparation System, including fluidized storage system, feeders, lime slakers, slaked lime slurry storage tanks, and reagent feed pumps.
- Dewatering System, including thickeners and rotary drum filters.
- Byproduct Fixation System, including Portland cement silo and pug mill.

6.1.7 Description of Basic Sizing Criteria for Major Equipment

The major equipment was scaled from other projects based on the size of the units (MW), sulfur content of the fuel, and the amount of reagent required to meet the emissions targets.

6.2 ESTIMATING METHODOLOGY

Black & Veatch developed order of magnitude estimates for the feasible SO_2 control technologies. This section details the basis of these estimates, including scope and assumptions used in the estimate development.

6.2.1 Original Equipment Manufacturer Equipment

The capital cost estimate is based on previous EPC bids Black & Veatch received for another project. The costs were adjusted for the size of the units (on a MW basis) and differences in the fuel being burned. The cost was escalated using the Chemical Engineering Plant Cost Index factor to 2019 dollars. To allow for continued operation of the existing units, the location for new FGD equipment installation has been preliminarily selected to be due East of the existing Unit 1 fabric filter. Installation of a new concrete stack for Unit 1 is included in the estimate.

A cost of $18,650,000 was included for the demolition of the existing Unit 1 and Unit 2 scrubbers based on estimated costs for demolition of building and equipment at grade and costs obtained from similar projects for stack demolition. Demolition will occur in two stages to enable continued operation of the units during the construction periods for the new FGD equipment. Demolition includes removal of Unit 1 scrubber equipment, ducts, piping, electrical, and buildings to enable construction of Unit 2 scrubber equipment and reuse of Unit 1 stack for Unit 2 operation. Upon Unit 2 new FGD tie-in and operation, the Unit 2 existing scrubber equipment, ducts, piping, electrical, buildings, sludge handling equipment, and Unit 2 stack will be demolished and removed from the site.

6.2.2 Balance-of-Plant Equipment Needed to Make the Estimate Complete

The balance-of-plant modification costs were also based on the recent projects completed by Black & Veatch for WLIO system additions.

The project costs included the following modifications to the balance-of-plant equipment:

- Induced Draft (ID) Fan Upgrades.
- Auxiliary Electrical Equipment.
- Ductwork.
- Structural Steel.
- Foundations.
- Continuous Emissions Monitoring System (CEMS) System.
- Boiler Reinforcement.
- Service Water System.
- Service and Instrument Air Systems.
- Unit 1 Stack Demolition and New Stack Installation.

6.3 ESTIMATE ASSUMPTIONS

6.3.1 General Assumptions

- No costs associated with existing ash pond were considered.
- Existing soil will have sufficient strength to support the new basins and building.
- No costs were included for existing gravel road repair or new roads.

- A liner was assumed to be needed under the collection basin and settling basins. A liner was not assumed to be needed under new piping.
- No site leveling or raising were included in the estimate.
- The site has sufficient area available to accommodate construction activities including, but not limited to, construction offices (trailers), laydown, and staging.
- No provisions for future expansion of the new WWT equipment were included.
- Equipment sizing was based on two operating units.
- Costs associated with changes to the current FGD wastewater mercury treatment equipment, or any upstream piping or devices from either unit will be made for any options that will reuse the equipment, are included.
- Required instrumentation is included in cost of treatment system.
- Existing excavated dirt is assumed to be suitable for backfill material. No imported fill is included.

6.3.2 Direct Cost Assumptions

The following assumptions are included in the base construction cost estimate for direct costs:

- All costs are expressed in 2019 dollars. No escalation was included.
- Direct costs include the costs associated with the purchase of equipment, erection, and all contractor services.
- Construction costs are based on an EPC construction approach.
- Total capital costs are AACE Class 5 ±50 percent for concept screening, and include the costs associated with the purchase of equipment, erection, and all contractor services.
- Separate FGD absorber systems are provided for each unit with some common equipment for both units, including reagent preparation and byproduct handling.

6.3.3 Indirect Cost Assumptions

The following indirect costs are included in the base construction cost estimate:

- General indirect costs include all necessary services required for checkouts, testing services, and commissioning.
- Insurance, including builder's risk and general liability.
- Field construction management services, including field management staff, supporting staff personnel, field contract administration, field inspection/quality assurance, and project controls.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, performance bond and liability insurance for equipment and tools.
- Startup/commissioning spare parts.

- Construction contractor contingency costs.
- Construction contractor typical profit margin.
- Reagent usage rates provided for variable O&M component.

The following additional items of cost are not included in the construction estimate. These costs shall be determined by Vectren and included in Vectren's cost estimate:

- Owner's contingency costs.
- Federal, state, and local taxes.
- Major equipment spare parts.
- Land.
- Interest during construction.
- Cost and fees for electrical, gas, and other utility interconnections.
- Project development costs, legal, and community outreach.
- All operating plant vehicles.
- No permitting costs have been included.
- Emissions credits.
- Environmental mitigation.

6.4 PROJECT INDIRECT COSTS

The following project indirect costs are included in the capital cost estimate:

- Engineering.
- Construction and field expenses.
- Startup costs.
- Contingencies.
- Freight.
- Performance testing.

6.5 OWNER COSTS

The Owner's costs are not included in the capital cost estimate:

- Project development.
- Owner's operational personnel.
- Owner's project management.
- Owner's engineering.
- Owner's startup engineering and training.

- Legal fees.
- Permitting/licensing.
- Construction power, temporary utilities, startup consumables.
- Site security.
- Operating spare parts.
- O&M base non-labor cost for the plant as provided by Vectren.
- O&M base labor cost for the plant as provided by Vectren.
- Political concessions.
- AFUDC.

6.6 COST ESTIMATE EXCLUSIONS

In addition to the Owner's costs, the following costs were also excluded from the capital cost estimate:

- Escalation.
- Sales tax.
- Property tax.
- Salvage values.
- Utility demand costs.

6.7 PRESENTATION OF CAPITAL COSTS

The capital cost of the replacement WLIO system is summarized in Table 6-2. The direct cost includes the cost of the absorber, reagent preparation system, PAC system, electrical upgrades, ID fan upgrades, boiler reinforcement, silo and pug mill, Unit 1 chimney, and installation. The costs were based on recent projects completed by Black & Veatch.

Table 6-2 WLIO Capital Costs

Category	Cost
Total Direct Cost	$318,079,000
Indirect Cost	Included Above
Contingency	Included Above
EPC Fee	Included Above
Total Project Cost	**$318,079,000**

6.8 OPERATIONS AND MAINTENANCE COSTS – PRESENT 20 YEAR TOTALS

The O&M costs start in 2024 assuming the WLIO system installation was completed in 2023. The O&M costs are in 2019 dollars and no escalation has been applied. Labor costs are not included in the estimates in Table 6-3. The O&M costs are total cost for 20 years from 2020 to 2039 and are rounded to the nearest $1,000. The O&M costs in Table 6-3 only represent the O&M costs for the WLIO system only and do not include the balance-of-plant O&M costs.

Table 6-3 WLIO Operation and Maintenance Costs

Category	Cost
O&M Schedule Outage	$21,510,000
O&M – Base Non-Labor	$11,159,000
20 Year Total	$32,659,000

6.9 WATER/WASTEWATER TREATMENT/WASTEWATER RECYCLE

Water and Wastewater treatment system costs for the WLIO system are negligible. Minor water and wastewater treatment system costs have been included with the balance of plant (BOP) costs for upgrade of those systems. Any water used or wastewater created by the WLIO would effectively be managed by mixing with the byproduct and fixating material (either fly ash or Portland Cement) at a pug mill on the discharge of the filter drum to mix these materials. The discharge waste material is then taken to a designated waste disposal area.

6.10 RISKS

The normal risks associated with procurement of equipment (domestic or internationally sourced), construction of equipment on a large power project, and operations of the plant once completed are not included in this section. Shut down of the AB Brown coal fired units prior to 20 years of operation will economically impact the selection of scrubber technology.

Below is a list of potential risks A.B. Brown may encounter when implementing WLIO technology:

- WLIO scrubbers have the potential to scale which would impact scrubber operation and performance.

7.1 Circulating Dry Scrubber (CDS)

7.2 DESCRIPTION OF TECHNOLOGY

The CDS FGD, also known as a circulating fluid bed scrubber, process is a semi-dry, lime-based FGD process that uses a circulating fluid bed contactor rather than an SDA. The CDS absorber module shown on Figure 7-1 is a vertical solid/gas reactor between the unit's air heater and its particulate control device. The CDS system consists of an absorber module, particulate control device (fabric filter or ESP), air slides, reagent storage silo, water storage tank, water inject lances, and water pumps. The reagent can be either hydrated lime or pebble lime. If pebble lime is utilized, an on-site hydrator is required to hydrate the pebble lime (CaO) to hydrated lime [$Ca(OH)_2$] prior to injection into the absorber module.

7.1.1 Basic Process Description

Water (humidification) is sprayed into the reactor to reduce the flue gas temperature to the optimum temperature for reaction of SO_2 with the reagent. Hydrated lime [$Ca(OH)_2$] and recirculated dry solids from the particulate control device are injected concurrently with the flue gas into the base of the reactor just above the water sprays. The gas velocity in the reactor is reduced, and a suspended bed of reagent and fly ash is developed. The SO_2, SO_3, and HCl in the flue gas reacts with the reagent to form predominantly $CaSO_3$ with some CaCl and $CaSO_4$. Fine particles of byproduct solids, excess reagent, and fly ash are carried out of the reactor and removed by the particulate removal device (either a fabric filter or dry ESP). More than 90 percent of these solids are returned to the reactor to improve reagent utilization and increase the surface area for SO_2/reagent contact.

The CDS FGD system produces an extremely high solids load on the particulate removal device as a result of recycling the byproduct/fly ash mixture. Air slides are used to recycle the large amounts of byproduct to the absorber. Air slides are capable of moving large amounts of solids with less energy consumption. The use of air slides require the particulate control device to be elevated to allow the material to flow down to the absorber vessel.

The byproducts from this process are similar to that produced in the lime SDA discussed previously. No dewatering is required, but the wastes must be wetted for control of fugitive dust emissions during transportation and for compaction at the landfill. When wetted, unreacted lime in the wastes should cause a fixation reaction, decreasing waste permeability and increasing unconfined compressive strength.

The process is controlled through three variables: SO_2 emissions, reactor exit temperature, and reactor differential pressure. SO_2 outlet concentration is monitored, and fresh hydrated lime reagent is introduced at the venturi as required to maintain the desired SO_2 removal efficiency. The reactor outlet temperature is maintained between 160° and 180° F, and an approach temperature of 35° to 40° F is maintained by controlling the quantity of water introduced at the venturi. The pressure drop across the reactor is regulated by the rate of return of recycled material to the reactor. One advantage of the CDS system over the SDA system is the addition of water and reagent is separate, allowing the system to inject more reagent to reach higher emissions removal.

These circulating fluid bed SO_2 absorber systems have been in operation in Europe since 1980. Since 1987, they have recorded an average of 97 percent SO_2 removal rate on a 100 MW lignite fueled plant. The technology has rapidly gained favor with many units as large as 250 to 300 MW on a single absorber. The largest unit operating overseas is 300 MW.

7.1.2 Process Flow Diagram

Figure 7-1 is a flow diagram of the CDS system. The CDS system shown below utilizes hydrated lime as it does not include a hydrator system to convert pebble lime to hydrated lime. The CDS system also includes a dedicated water supply system for the humidification of the flue gas, including a water tank and 2 x 100 percent pumps.

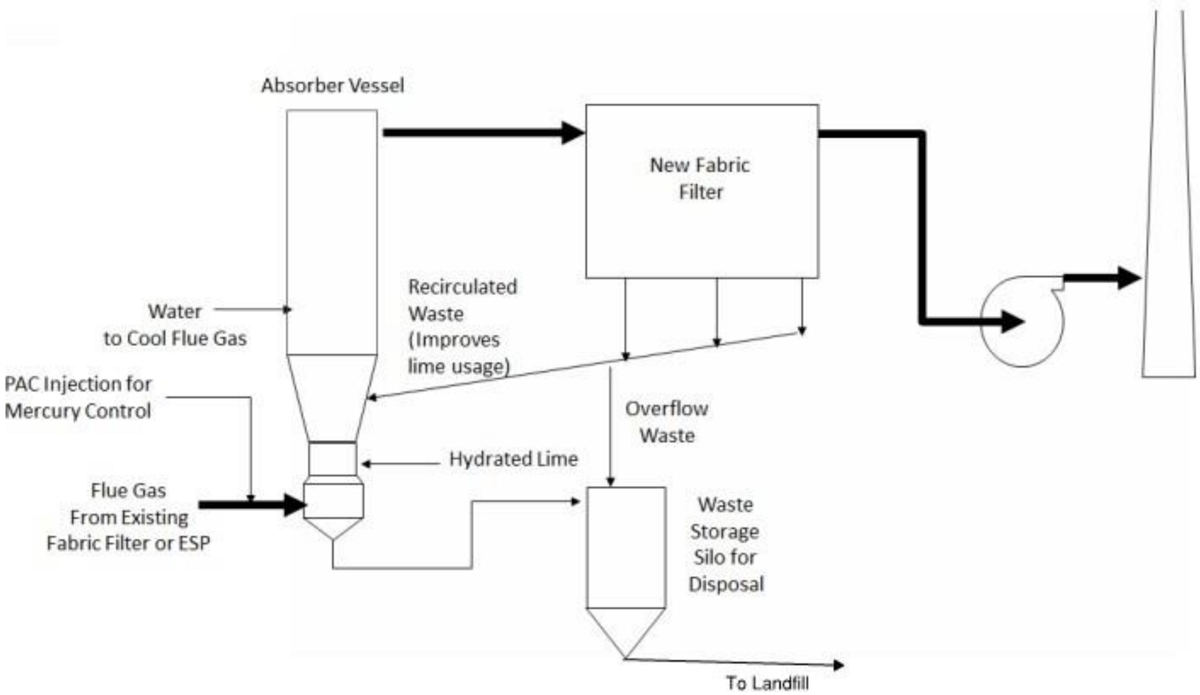

Figure 7-1 Circulating Dry Scrubber

7.1.3 Environmental Controls

The existing particulate control systems (fabric filter on Unit 1 and electrostatic precipitator (ESP) on Unit 2) and ash collection systems remain in service with the fly ash continuing to be available for recycle.

Powdered activated carbon (PAC) is injected upstream of the CDS vessel to control mercury emissions. The PAC material is circulated in the CDS absorber vessel and collects on the fabric filter media bags.

The hydrated lime reagent in the CDS system removes SO_3, HCl, as well as SO_2. The fabric filter located downstream of the CDS absorber vessel collects the hydrated lime and ash (including PAC) particulate and returns the majority of the particulate back to be recirculated in the CDS vessel. A portion of this collected particulate is taken and sent to the waste storage silo for safe disposal.

Table 7-1 Environmental Controls CDS

Pollutant	Hg	SO_3	SO_2	PM
Control Technologies	Powdered Activated Carbon (PAC) Injection	CDS System	CDS System	Existing PM control: Unit 1 – Fabric Filter Unit 2 – ESP Post CDS - Fabric Filter

7.1.4 Reagent Type, Storage, and Preparation

CDS systems utilize either hydrated lime or pebble lime reagent. Hydrated lime is brought in with pneumatic trucks or railcars and pneumatically conveyed into storage silo(s), which typically have 7 to 14 days of storage.

Pebble lime can also be utilized as the reagent for the CDS. The pebble lime is pneumatically conveyed into a storage silo from a pneumatic truck or railcar. Pebble lime (CaO) must be reacted with water in a hydrator to produce hydrated lime [$Ca(OH)_2$]. The hydrator mixes a stoichiometric amount of water with the pebble lime to produce a hydrated lime product with less than 1 percent free moisture. The hydrated lime product is conveyed to the hydrated lime silo where it is stored for use in the CDS absorber.

7.1.5 Byproduct Type, Storage, and Handling

The hydrated lime reagent injected into the CDS module will react with acid gas, including SO_2, SO_3, and HCl. The resulting byproducts are mostly calcium sulfite ($CaSO_3$) with some calcium sulfate ($CaSO_4$) and calcium chloride (CaCl). The byproducts are mixed with fly ash and activated carbon for mercury removal.

The byproduct is pneumatically conveyed to the byproduct silo where it would be conditioned for dust control before being hauled to the landfill. The byproduct has limited reuse potential but can be used for soil stabilization. In most cases the byproduct is sent to a landfill.

7.1.6 Description of Basic Equipment in Process

The CDS system includes the following basic equipment:

- CDS Scrubber Module, including venturi.
- Humidification System, including water tank, pumps, valves, and water injection lances (3 to 4).
- Reagent System, including fluidized storage system, de-aeration bin, weigh belt feeder, rotary valves, and air slide.
- Particulate Collection System, including fabric filter.
- Byproduct Recirculation and Removal System, including air slides and dosing valves.

7.1.7 Description of Basic Sizing Criteria for Major Equipment

The major equipment was scaled from other projects based on the size of the units (MW), sulfur content of the fuel, and the amount of reagent required to meet the emissions targets.

7.2 ESTIMATING METHODOLOGY

Black & Veatch developed order of magnitude estimates for the feasible SO_2 control technologies. This section details the basis of these estimates, including scope and assumptions used in the estimate development.

7.2.1 Original Equipment Manufacturer Equipment Estimate

For the CDS System Black & Veatch used actual pricing from recent projects completed in the last 5 years. The project scope was evaluated and modified as needed to compare to the A.B. Brown requirements. The project costs were scaled based on unit size and sulfur removal. The costs were also escalated to 2019 dollars.

7.2.2 Balance-of-Plant Equipment Needed to Make the Estimate Complete

The balance-of-plant modification costs were also based on the recent projects completed by Black & Veatch for CDS system additions.

The project costs included modifications to the balance-of-plant equipment:

- ID Fan Upgrades.
- Auxiliary Electrical Equipment.
- Ductwork.
- Structural Steel.
- Foundations.
- CEMS System.
- PAC Injection System.
- Boiler Reinforcement.
- Service Water System.
- Service and Instrument Air Systems.

PAC Injection

Activated carbon (PAC) injection was added to the train to control mercury emissions. Hydrated lime is injected in the CDS module, which will control sulfuric acid (SO_3) emissions. Additional hydrated lime injection for SO_3 control would not be necessary. The PAC will be recirculated in the CDS system and coat the fabric filter bags, allowing for a significant residence time in the flue gas.

ID Fan

The existing ID fans do not have the capacity required for the new air quality control train. Due to the added pressure drop of the new fabric filter and CDS module, the ID fans on each unit will need to be replaced. For the purposes of this study, new ID fans have been included in the scope of work.

Balance-of-Plant Modification

The scope of work includes modifications to balance-of-plant equipment like distributed control system (DCS), electrical equipment, CEMS, foundations, service and instrument air systems, boiler reinforcement, ductwork, and structural steel, which would be required to support the addition of the new air quality control system.

7.3 ESTIMATE ASSUMPTIONS

7.3.1 General Assumptions

- No costs associated with existing ash pond were considered.
- Existing soil will have sufficient strength to support the new basins and building.
- No cost was included for existing gravel road repair or new roads.
- A liner was assumed to be needed under the collection basin and settling basins. A liner was not assumed to be needed under new piping.
- No site leveling or raising was included in the estimate.
- The site has sufficient area available to accommodate construction activities including, but not limited to, construction offices (trailers), laydown, and staging.
- No provisions for future expansion of the new WWT equipment were included.
- Equipment sizing was based on two operating units.
- Required instrumentation was included in the cost of the treatment system.
- Existing excavated dirt was assumed to be suitable for backfill material. No imported fill was included.

7.3.2 Direct Cost Assumptions

The following assumptions are included in the base construction cost estimate for direct costs:

- All costs are expressed in 2019 dollars. No escalation was included.
- Direct costs include the costs associated with the purchase of equipment, erection, and all contractor services.
- Construction costs were based on an EPC construction approach.
- Total capital costs are AACE Class 5 ±50 percent for concept screening, and include the costs associated with the purchase of equipment, erection, and all contractor services.
- Separate FGD absorber systems were provided for each unit with some common equipment for both units, including reagent preparation, and byproduct handling.

7.3.3 Indirect Cost Assumptions

The following indirect costs were included in the base construction cost estimate:

- General indirect costs for checkouts, testing services, and commissioning.
- Insurance, including builder's risk and general liability.
- Field construction management services including field management staff, supporting staff personnel, field contract administration, field inspection/quality assurance, and project controls.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, performance bond, and liability insurance for equipment and tools.
- Startup/commissioning spare parts.
- Construction contractor contingency costs.
- Construction contractor typical profit margin.
- Reagent usage rates provided for variable O&M component.

The following additional items of cost were not included in the construction estimate. These costs shall be determined by Vectren and included in Vectren's cost estimate:

- Owner's contingency costs.
- Federal, state, and local taxes.
- Major equipment spare parts.
- Land.
- Interest during construction.
- Cost and fees for electrical, gas, and other utility interconnections.
- Project development costs, legal, and community outreach.
- All operating plant vehicles.
- No permitting costs have been included.
- Emissions credits.
- Environmental mitigation.

7.4 PROJECT INDIRECT COSTS

The following project indirect costs are included in the capital cost estimate:

- Engineering.
- Construction and field expenses.
- Startup costs.

- Contingencies.
- Freight.
- Performance testing.

7.5 OWNER COSTS

The Owner's costs are not included in the capital cost estimate:

- Project development.
- Owner's operational personnel.
- Owner's project management.
- Owner's engineering.
- Owner's startup engineering and training.
- Legal fees.
- Permitting/licensing.
- Construction power, temporary utilities, startup consumables.
- Site security.
- Operating spare parts.
- O&M base non-labor cost for the plant as provided by Vectren.
- O&M base labor cost for the plant as provided by Vectren.
- Political concessions.
- AFUDC.

7.6 COST ESTIMATE EXCLUSIONS

In addition to the Owner's costs, the following costs were also excluded from the capital cost estimate:

- Escalation.
- Sales tax.
- Property tax.
- Salvage values.
- Utility demand costs.

7.7 PRESENTATION OF CAPITAL COSTS

The capital cost of the replacement CDS system is summarized in Table 7-2. The direct cost includes the cost of the absorber, fabric filter, PAC system, electrical upgrades, ID fan upgrades, boiler reinforcement, and installation. The costs were based on recent projects completed by Black & Veatch.

Table 7-2 CDS Capital Costs

Category	Cost
Total Direct Cost	$269,550,000
Indirect Cost	Included Above
Contingency	Included Above
EPC Fee	Included Above
Total Project Cost	**$269,550,000**

7.8 OPERATIONS AND MAINTENANCE COSTS – PRESENT 20 YEAR TOTALS

The O&M costs start in 2024 assuming the CDS system installation was completed in 2023. The O&M costs are in 2019 dollars and no escalation has been applied; labor costs are not included in the estimates in Table 7-3. The O&M costs are total cost for 20 years (from 2020 to 2039) and are rounded to the nearest $1,000. Table 7-3 represents the O&M costs for the CDS system only and does not include the balance-of-plant O&M costs.

Table 7-3 CDS Operations and Maintenance Costs

Category	Cost
O&M Schedule Outage	$18,228,000
O&M – Base Non-Labor	$9,448,000
20 Year Total	$27,676,000

7.9 WATER/WASTEWATER TREATMENT/WASTEWATER RECYCLE

Water and Wastewater treatment system costs for the CDS system are negligible. Minor water and wastewater treatment system costs have been included with the balance of plant (BOP) costs for upgrade of those systems. Any water used or wastewater created by the CDS would effectively be used in the CDS as water to cool the flue gas and control flue gas temperature. Solids in the water/wastewater would be removed from the gas stream using the new fabric filter.

7.10 RISKS

The normal risks associated with procurement of equipment (domestic or internationally sourced), construction of equipment on a large power project, and operations of the plant once completed are not included in this section. Shut down of the AB Brown coal fired units prior to 20 years of operation will economically impact the selection of scrubber technology.

Below is a potential risk A.B. Brown may encounter when implementing CDS scrubber technology.

- Lime Consumption - Large quantities of hydrated lime are required to achieve the removal levels required for these units. The shipping logistics are significant and a delivery interruption could impact unit operation due to material availability to control emissions. The estimated lime consumption would require approximately one pneumatic truck load of pebble lime per hour.

8.1 Ammonia (NH_3) Scrubber

8.2 DESCRIPTION OF TECHNOLOGY

The ammonia (NH_3) scrubber technology uses a spray tower absorber with ammonia reagent to remove SO_2 from the flue gas. Ammonia combines with SO_2 to form ammonium sulfate. The ammonium sulfate is dewatered, crystalized, and dried to form a solid ammonium sulfate byproduct that can be used for fertilizer.

8.1.1 Basic Process Description

In the ammonia scrubber, anhydrous ammonia is used as the desulfurization absorbent to capture SO_2, and the byproduct of the process is a marketable fertilizer material. The only large FGD system of this type in the United States was installed at Dakota Gasification in North Dakota. At this facility, the ammonia solution contacts the flue gas in a spray tower type absorber similar to a wet limestone or lime system. The ammonia solution absorbs the SO_2 to form an ammonium sulfite solution. Air is fed into the absorber to oxidize the ammonium sulfite to an ammonium sulfate solution. The ammonium sulfate solution is concentrated and crystallized into a slurry, which is then transferred to an area where the ammonium sulfate is separated from the solution, and dried. The dried ammonium sulfate can be sold as fertilizer.

Currently one equipment supplier, based in China but with offices in the United States, has expressed interest in the A. B. Brown application. A second potential equipment supplier has indicated that it is currently focusing on industrial applications because of the uncertain operating status of many coal fired power plants. Jiangnan Environmental Technology, Inc. (JET), has completed ammonia scrubbers in China and other overseas countries but has no United States applications to date. The ammonia scrubber technology is similar to the United States application of ammonia scrubbing that currently is in operation in North Dakota; however, JET did not supply the unit in North Dakota.

Dakota Gasification Company’s Great Plains Synfuels Plant is the only large U.S. based industrial plant with an ammonia scrubber installed. Emissions limits and the potential for a visible plume produced by the plant were addressed by the addition of a WESP. The plant also has ammonia discharge emissions limits. For the purpose of this study, a WESP has been included in the scope of work to mitigate emissions.

The quality of the ammonium sulfate byproduct produced or purity for the coal analysis specific to this site was not provided.

8.1.2 Flow Diagram

Figure 8-1 is a flow diagram of the ammonia scrubber. The typical ammonia scrubber uses anhydrous or aqueous ammonia reagent. The scrubber is a spray tower design using recycle pumps to inject the reagent into the flue gas. A bleed stream is removed from the reaction tank to be dewatered prior to drying the final ammonium sulfate byproduct.

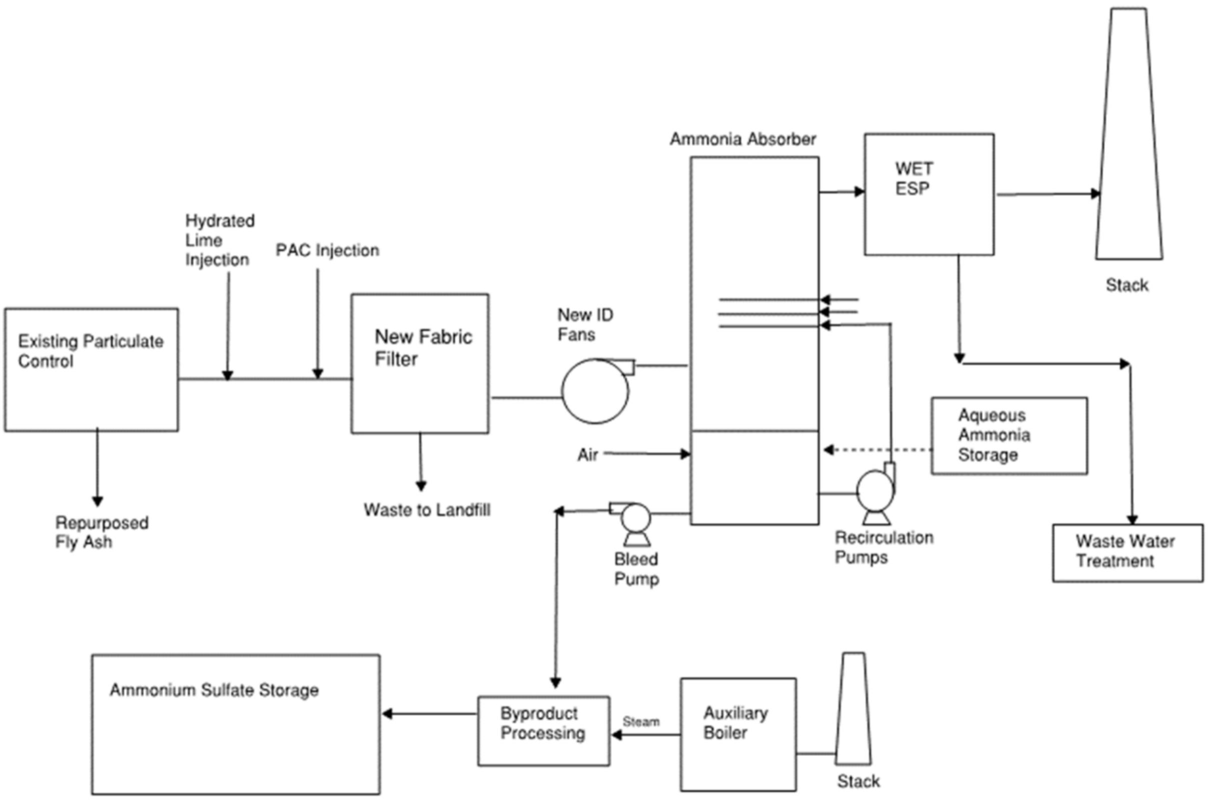

Figure 8-1 Ammonia Scrubber

8.1.3 Environmental Controls

The existing particulate control systems (fabric filter on Unit 1 and electrostatic precipitator (ESP) on Unit 2) and ash collection systems remain in service with the fly ash continuing to be available for recycle.

A dry sorbent injection system (DSI) system utilizing hydrated lime injection downstream of the existing particulate control system is used to control HCl and SO_3 emissions.

Powdered activated carbon (PAC) is injected downstream of the DSI injection to control mercury emissions. A new fabric filter is added to collect the particulate from the PAC and DSI injection. The collected solids from this fabric filter are sent as waste to the landfill.

A wet electrostatic precipitator (ESP) has been included to control ammonia slip and fine particulate emissions.

Table 8-1 Environmental Controls NH_3

Pollutant	Hg	SO_3	SO_2	PM
Control Technologies	Powdered Activated Carbon (PAC) Injection	Hydrated Lime Injection	Ammonia FGD	Existing PM control: Unit 1 – Fabric Filter Unit 2 – ESP Fabric Filters downstream of DSI and PAC injection WESP downstream of NH_3 FGD

8.1.4 Reagent Type, Storage, and Preparation

The reagent is either anhydrous ammonia or aqueous ammonia. Due to concerns regarding the safe storage and handling of anhydrous ammonia Vectren will need to complete a detailed analysis of the risks of storing large quantities of anhydrous ammonia onsite looking at the impact to surrounding communities and public safety.

For the purposes of this study aqueous ammonia was assumed to be utilized at A.B. Brown. The aqueous ammonia would be shipped to the site by a tanker truck or railcar and would be stored in large tanks. Vectren has requested 14 days of storage, which would require about 3,050,000 gallons of storage. The aqueous ammonia would be pumped into the reaction tank based on the demand signal from the process controls.

8.1.5 Byproduct Type, Storage, and Handling

The ammonia reagent combines with the SO_2 to form ammonium sulfate. The ammonium sulfate solution is pumped via a bleed stream from the recirculation tank. The ammonium sulfate must be dewatered and dried. Once the material is dry, the ammonium sulfate can be packaged and stored or bulk stored and shipped to a fertilizer wholesaler for further processing or blending. Ammonium sulfate is water soluble so it must be stored indoors. No information was provided regarding the purity of the ammonium sulfate, contaminants in the ammonium sulfate, particulate size distribution or whether the product was granular or powder. Processed ammonium sulfate can be sold as a fertilizer for agriculture if a market is available.

8.1.6 Description of Basic Equipment in Process

The ammonium scrubber systems can vary from each supplier, however, generally the equipment consists of a spray tower absorber module. Oxidation blowers to help oxidize the byproduct to sulfate. A recirculation tank at or near the bottom of the spray tower stores the recirculation mixture. Recirculation pumps supply the reagent mixture to the spray headers at the top of the absorber so that the reagent is sprayed and falls downward to maximize contact with the up-flow of exhaust gas. A bleed stream from the absorber feeds a small stream of the reagent mixture solution to a liquid and solids separation system. The byproduct is then further concentrated and crystalized to the ammonium sulfate byproduct. A drying system using steam heat is then used to completely dry the ammonium sulfate crystals.

8.1.7 Description of Basic Sizing Criteria for Major Equipment

The auxiliary support equipment required for this technology was scaled from other projects based on the size required, steam heat requirements, and the amount of reagent required to be stored on site to meet the specified days of operation for the emissions targets established.

The ammonia scrubber is to be designed for an inlet SO2 concentration of 6.72 lb/MBtu. The ammonia system is designed to meet an outlet SO2 emission rate of 0.10 lb/MMBtu.

8.2 ESTIMATING METHODOLOGY

8.2.1 Original Equipment Manufacturer Equipment Estimate

Black & Veatch sent a request for quotation to Marsulex and JET. Marsulex declined to provide a bid; JET provided a budgetary quotation for the ammonia scrubber, including the scrubber modules, recirculation tank with pumps, oxidation air fans, ammonia storage, hydrocyclones, dryers, packing machine, and byproduct storage.

8.2.2 Balance-of-Plant Equipment Needed to Make the Estimate Complete

The balance-of-plant modification costs were estimated based on the requirements of the A.B. Brown plant and based on the recent projects completed by Black & Veatch.

The project costs included modifications to the balance-of-plant equipment:

- ID Fan Upgrades.
- Auxiliary Electrical Equipment.
- WESP.
- Auxiliary Boiler.
- Fabric Filters.
- Unit 1 Chimney.
- Ductwork.
- Structural Steel.
- Foundations.
- CEMS System.
- PAC Injection System.
- Boiler Reinforcement.
- Storage Building.
- DCS Upgrade.
- Service and Instrument Air Systems.

Wet ESP

The Dakota Gasification Company's Great Plains Synfuels Plant is the only large industrial plant with an ammonia scrubber installed in the United States. Emissions limits and concerns for a visible plume produced by the plant were mitigated by the addition of a WESP. A.B. Brown has an ammonia discharge emissions limit to comply with. For the purpose of this study, a WESP has been included in the scope of work to ensure emissions compliance and to eliminate the potential for a visible plume.

PAC Injection

Activated carbon (PAC) injection was added to the train to control mercury emissions. Hydrated lime will be injected upstream of the PAC injection to control sulfuric acid (SO_3) emissions. SO_3 impacts the mercury removal performance of the PAC and must be removed from the flue gas prior to the addition of the PAC. New fabric filters have been included to capture the hydrated lime and PAC particulate.

Fabric Filters

To allow A.B. Brown to continue existing operations, a fabric filter has been added to capture the injected activated carbon and hydrated lime reagents. The fabric filter will be located downstream of the existing particulate control device and upstream of the new ammonia scrubber on each unit. For the purpose of this study, a fabric filter has been included in the scope of work to ensure emissions compliance.

ID Fan

The existing ID fans do not have the capacity required for the new air quality control train. Due to the added pressure drop of the new fabric filter, ductwork modifications, and WESP, the ID fans on each unit will need to be replaced. For the purposes of this study, new ID fans have been included in the scope of work.

Auxiliary Boiler

To produce a saleable ammonium sulfate byproduct the bleed stream from the scrubber must be concentrated and dewatered. The resulting dewatered solids must be dried to form a dry granular product suitable for bulk bagging or bulk loading of raw product. Equipment to dewater, dry, and either bag the byproduct or to bulk load equipment into truck or rail containers will be required. A source of steam heat is required to dry the byproduct in preparation for storage and transportation. For the purpose of this study, an auxiliary boiler has been sized and included in the scope of work to provide the required steam to the ammonium sulfate drying system. This will also maintain plant steam supply from the main boiler to the steam turbine to maximize unit output. In addition, Unit 1 and Unit 2 are currently not operated continuously and cannot be depended on to provide a continuous source of steam for heat to the ammonium sulfate drying system.

Unit 1 Chimney

In order to minimize outage time, the conceptual design layout developed would include installing the new air quality control system to the east of the existing air quality control system. A new stack would be built east of the new Unit 1 air quality control system. The existing Unit 1 scrubber system would be demolished, allowing for installation of the Unit 2 system. The new Unit 2 scrubber system would reuse the Unit 1 stack. The existing Unit 2 scrubber and Unit 2 stack would be demolished once the new Unit 2 scrubber system had been placed in service.

Balance-of-Plant Modification

The scope of work includes modifications and additions to balance-of-plant equipment, like DCS, electrical equipment, CEMS, foundations, service and instrument air systems, piping for water and wastewater systems, storage building, ductwork, and structural steel, which would be required to support the addition of the new air quality control system. Boiler, ductwork, and existing particulate collection equipment will require additional reinforcement to comply with National Fire Protection Association (NFPA) 85 recommendations.

8.3 ESTIMATE ASSUMPTIONS

8.3.1 General Assumptions

- No costs associated with existing ash pond were considered.
- Existing soil will have sufficient strength to support the new basins and building.
- No cost was included for existing gravel road repair.
- A liner was assumed to be needed under the collection basin and settling basins. A liner was not assumed to be needed under new piping.
- No site leveling or raising was included in the estimate.
- The site has sufficient area available to accommodate construction activities including, but not limited to, construction offices (trailers), laydown, and staging.
- No provisions for future expansion of the new WWT equipment were included.
- Equipment sizing was based on two operating units.
- Changes to the current FGD wastewater mercury treatment equipment or any upstream piping or devices from either unit will be made for any options that will reuse the equipment.
- WWT for the FGD system was provided for those FGD technologies requiring such.
- Required instrumentation was included in cost of treatment system.
- Existing excavated dirt was assumed to be suitable for backfill material. No imported fill was included.

8.3.2 Direct Cost Assumptions

The following assumptions are included in the base construction cost estimate for direct costs:

- All costs are expressed in 2019 dollars. No escalation is included.
- Direct costs include the costs associated with the purchase of equipment, erection, and all contractor services.
- Construction costs were based on an EPC construction approach utilizing union craft labor.
- Total capital costs are AACE Class 5 ±50 percent for concept screening, and include the costs associated with the purchase of equipment, erection, and all contractor services.
- Separate FGD absorber systems were provided for each unit with some common equipment for both units, including reagent preparation and byproduct handling.

8.3.3 Indirect Cost Assumptions

The following indirect costs are included in the base construction cost estimate:

- General indirect costs include all necessary services required for checkouts, testing services, and commissioning.
- Insurance, including builder's risk and general liability.
- Field construction management services including field management staff, supporting staff personnel, field contract administration, field inspection/quality assurance, and project controls.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, performance bond, and liability insurance for equipment and tools.
- Startup/commissioning spare parts.
- Construction contractor contingency costs.
- Construction contractor typical profit margin.
- Reagent usage rates provided for variable O&M component.

The following additional items of cost are not included in the construction estimate. These costs shall be determined by Vectren and included in Vectren's cost estimate:

- Owner's contingency costs.
- Federal, state, and local taxes except a 25 percent tariff has been placed on the equipment being exported from China.
- Major equipment spare parts.
- Land.
- Interest during construction.

- Cost and fees for electrical, gas, and other utility interconnections.
- Project development costs, legal, and community outreach.
- All operating plant vehicles.
- No permitting costs have been included.
- Emissions credits.
- Environmental mitigation.

8.4 PROJECT INDIRECT COSTS

The following project indirect costs are included in the capital cost estimate:

- Engineering.
- Construction and Field Expenses.
- Startup Costs.
- Contingencies.
- Freight.
- Performance Testing.

8.5 OWNER COSTS

The Owner's costs are not included in the capital cost estimate:

- Project development.
- Owner's operational personnel.
- Owner's project management.
- Owner's engineering.
- Owner's startup engineering and training.
- Legal fees.
- Permitting/licensing.
- Construction power, temporary utilities, startup consumables.
- Site security.
- Operating spare parts.
- O&M base non-labor cost for the plant as provided by Vectren.
- O&M base labor cost for the plant as provided by Vectren.
- Political concessions.
- AFUDC.

8.6 COST ESTIMATE EXCLUSIONS

In addition to the Owner's costs, the following costs were also excluded from the capital cost estimate:

- Escalation.
- Property tax.
- Salvage values.
- Utility demand costs.

8.7 PRESENTATION OF CAPITAL COSTS

The capital cost of the replacement CDS system is summarized in Table 8-2. The direct cost includes the cost of the absorber, ammonia storage, byproduct production, storage and bagging, fabric filters, PAC systems, electrical upgrades, Unit 1 chimney, boiler reinforcement, auxiliary boiler, and installation. The costs were based on recent projects completed by Black & Veatch.

Table 8-2 Ammonia (NH_3) Capital Costs

Category	Cost
Total Direct Cost	$284,835,000
Indirect Cost	Included Above
Contingency	Included Above
EPC Fee	Included Above
Total Project Cost	**$284,835,000**

8.8 OPERATIONS AND MAINTENANCE COSTS – PRESENT 20 YEAR TOTALS

The O&M costs start in 2024 assuming the NH_3 scrubber system installation was completed in 2023. The O&M costs are in 2019 dollars and no escalation has been applied. Labor costs are not included in the estimates in Table 8-3. The O&M costs are total cost for 20 years (from 2020 to 2039) and are rounded to the nearest $1,000. Table 8-3 represents the O&M costs for the NH_3 scrubber system only and does not include the balance-of-plant O&M costs.

Table 8-3 Ammonia (NH_3) Operation and Maintenance Costs

Category	Cost
O&M Schedule Outage	$19,262,000
O&M – Base Non-Labor	$9,983,000
20 Year Total	$29,245,000

8.9 WATER/WASTEWATER TREATMENT/WASTEWATER RECYCLE

Water treatment system costs for the NH3 scrubber system are negligible. Waste water treatment system costs have been included with the NH3 scrubber for treatment of waste water from the wet ESP equipment. Waste water produced from the wet ESP equipment process and intermittent floor drains from equipment washdown is expected. Drains from the cooling water system are considered intermittent and do not result in a continuous flow stream. Use of aqueous ammonia as the reagent will reduce the overall process water requirements, however, the overall water volume decrease has not been confirmed by the manufacturer.

8.10 RISKS

The normal risks associated with procurement of equipment (domestic or internationally sourced), construction of equipment on a large power project, and operations of the plant once completed are not included in this section. Shut down of the AB Brown coal fired units prior to 20 years of operation will economically impact the selection of scrubber technology.

Below is a list of potential risks A.B. Brown may encounter when implementing ammonia scrubber technology.

- Limited experience is found in the United States as there is only one Ammonia Scrubber System installation in the US which is on an industrial gasification plant in North Dakota that is similar to the scale proposed at AB Brown.
- The supplier providing a proposal for this equipment has not installed any equipment in the United States. This would also appear to be the first project that the supplier would perform work as an EPC Contractor on a construction project in the U.S. The supplier has proposed using U.S. craft labor with Chinese supervision on this project.
- Vectren is a power producer that is dispatched on an irregular basis. The amount of ammonium sulfate that would be produced will vary based on the load they are dispatched at. It will be difficult to enter into a contract to sell the ammonium sulfate when there is no guarantee of the amount of material that can be produced. In the event of a long-term outage, Vectren could be responsible and penalized for not providing the ammonium sulfate material as contracted to a manufacturer or distributor.
- The ammonium sulfate byproduct sales are primarily based on seasonal material usage. This will either require the ability to store a large volume on site or pay to store material at a fertilizer manufacturer's or distributor's facility when the demand for ammonium sulfate is low.
- The seasonal sale price of ammonium sulfate significantly impacts the economics of a power plant needing to operate year-round.
- Ammonium sulfate shipping and handling costs can limit the distribution area.
- Transportation required to remove the ammonium sulfate from the site requires loading of approximately 1.5 transport trucks per hour.
- There are limited disposal options if the ammonium sulfate byproduct cannot be sold (no demand) or is found to be out of specification quality required by the purchaser. Ammonium sulfate is water soluble and will necessitate extensive requirements to stabilize the material and enable it to be landfilled.

- Storage of large quantities of liquid anhydrous ammonia is a safety risk to personnel on the site and to the city of Evansville, Indiana. Vectren can mitigate this by the use of a 19% aqueous ammonia as the reagent, however, the trucks required for transportation and storage volume increase by approximately a factor of five. This requires delivery and unloading of more than two transport trucks of 19 percent aqueous ammonia per hour.
- There is a high variability of anhydrous ammonia and aqueous ammonia supply cost.
- No information was provided regarding the purity of the ammonium sulfate, contaminants in the ammonium sulfate, particulate size distribution or whether the product was granular or powder.
- The ammonium sulfate may require additional processing by a fertilizer manufacturer's or distributor's facility to meet the quality needed for a saleable material to the public or farming community. This would impact sale price received for this material.
- An auxiliary boiler is needed to provide steam for heating to be available on a 24/7 basis for the ammonium sulfate drying process. The emissions from the auxiliary boiler combined with emissions from the ammonia scrubber and ammonium sulfate dryer equipment may require Vectren to perform a PSD analysis.

Appendix A. 20 Year Capital and O&M Cost Inputs to the IRP