



**IMU BOARD OF TRUSTEES OF THE ELECTRIC,
WATER AND COMMUNICATIONS UTILITIES**

May 9, 2022

5:30 PM

City Hall Council Chambers

110 N 1st Street

Agenda

- 1. Call to Order**
- 2. Roll Call**
- 3. Public Comment**
- 4. Consent Agenda:**
 - A. Approval of Claims
 - B. Approval of the March financial report.
 - C. Approval of Minutes of the prior board meeting.
- 5. Electric Utility Action Items**
 - A. Resolution dissolving Fund 625 and returning the remaining amount to Fund 630.
- 6. Electric Utility Informational Items**
 - A. Discussion regarding MEAN's draft 2022 Integrated Resource Plan.
- 7. Water Utility Action Items**
 - A. Authorization for Warren Water District to serve a customer within their territory upon proper notice to IMU since the customer is within 2 miles of the IMU territory, located at 12753 140th Avenue.
- 8. Water Utility Informational Items**
- 9. Communications Utility Informational Items**
- 10. Combined Electric, Water and Communications Action Items**
 - A. Approval of an engagement letter with Dickinson, Mackaman, Tyler and Hagen PC for legal services.
- 11. Combined Electric, Water and Communications Informational Items**
- 12. Other Business**
- 13. Adjourn**

MEMORANDUM

To: IMU Board of Trustees of the Electric, Water and Communications Utilities
From:
Date: May 9, 2022
Subject: Approval of Claims

Recommendation: Simple motion is in order.

Attachments: 1. 051022 Elation Claims List

AP Check Preview

Date Range: All Dates

Indianola Municipal Utilities

Wednesday, May 4, 2022
7:46:58 AM

Vendor	Due Date	Notes	Terms	Bill Total	Discount	Interest	Amount Due	Payment	Invoice Number	Bill Number
Account To Be Paid From 0000-10120-999										
ACCO UNLIMITED CORP. - VEND-2810										
	4/13/2022	ACCO liquid chlorinating	Open Terms	1,608.39	0.00	0.00	1,608.39	1,608.39	0221273-IN	BL-8189
							1,608.39	1,608.39		
Ahlers & Cooney P.C. - VEND-1002										
	5/28/2022	Legal fees	Net 30	3,315.00	0.00	15.00	3,315.00	3,315.00	822364	BL-8221
							3,315.00	3,315.00		
AUTOMATIC SYSTEMS CO. - VEND-51495										
	4/13/2022	Well #9 PLC upgrade	Open Terms	8,439.00	0.00	0.00	8,439.00	8,439.00	20220212	BL-8172
	4/29/2022	Service call	Open Terms	1,470.00	0.00	0.00	1,470.00	1,470.00	37143 S	BL-8214
							9,909.00	9,909.00		
Avesis Third Party Administrators Inc - VEND-1108										
	5/31/2022	0522 Vision	Net 30	382.84	0.00	15.00	382.84	382.84	2860892	BL-8206
							382.84	382.84		
Bally Sports Midwest - VEND-1222										
	5/25/2022	0422 Exp Basic	Net 30	4,566.88	0.00	15.00	4,566.88	4,566.88	T89949	BL-8235
							4,566.88	4,566.88		
Big Ten Network - VEND-1096										
	5/30/2022	0422 BTN	Net 30	1,837.70	0.00	15.00	1,837.70	1,837.70	141478	BL-8234
							1,837.70	1,837.70		
Brick Gentry P.C. - VEND-1004										
	5/25/2022	Legal services	Net 30	120.00	0.00	15.00	120.00	120.00	374555	BL-8158
							120.00	120.00		
Cappel's Ace Hardware - VEND-1204										
	5/15/2022	Pipe thread, smart straw and fasteners	Net 30	12.16	0.00	15.00	12.16	12.16	002579	BL-8187
	5/26/2022	Acid muriatic	Net 30	29.97	0.00	15.00	29.97	29.97	002625	BL-8188
							42.13	42.13		
CCP INDUSTRIES INC. - VEND-8925										
	4/21/2022	Wasp Spray	Open Terms	98.08	0.00	0.00	98.08	98.08	IN03004214	BL-8230
							98.08	98.08		
CDW Government - VEND-1029										

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	5/7/2022	Computer equipment	Net 30	244.96	0.00	15.00	244.96	244.96	V644653	BL-8165
	5/8/2022	Computer equipment	Net 30	1,397.01	0.00	15.00	1,397.01	1,397.01	V686641	BL-8166
							1,641.97	1,641.97		
Cedar Falls Utilities - VEND-1045 - BL-8245										
	6/1/2022	Labor and rack space	Net 30	5,422.90	0.00	15.00	5,422.90	5,422.90	92135	BL-8245
							5,422.90	5,422.90		
Cintas Corporation - VEND-1007										
	5/26/2022	First aid supplies	Net 30	67.88	0.00	15.00	67.88	67.88	5105581985	BL-8254
							67.88	67.88		
City Of Indianola - VEND-1008 - BL-8171										
	5/19/2022	Square streetscape project	Net 30	31,825.00	0.00	15.00	31,825.00	31,825.00	2843	BL-8171
							31,825.00	31,825.00		
City Of Indianola - VEND-1008 - BL-8223										
	6/1/2022	0522 Professional Services	Net 30	86,490.68	0.00	15.00	86,490.68	86,490.68	2848	BL-8223
							86,490.68	86,490.68		
Consortia Consulting - VEND-1009										
	5/20/2022	Consulting	Net 30	1,252.50	0.00	15.00	1,252.50	1,252.50	23548	BL-8253
							1,252.50	1,252.50		
CROSSROADS MOBILE MAINTENANCE - VEND-102507										
	5/3/2022	Unit 6 Repairs	Open Terms	10,749.62	0.00	0.00	10,749.62	10,749.62	204S2422.02	BL-8217
							10,749.62	10,749.62		
Crystal Clear Communications LLC - VEND-1205										
	5/31/2022	Monthly retainer and stock photography	Net 30	2,549.00	0.00	15.00	2,549.00	2,549.00	CCC-0291	BL-8199
							2,549.00	2,549.00		
Des Moines Register Media - VEND-1010										
	4/30/2022	BOT minutes	Net 30	501.97	0.00	15.00	501.97	501.97	4530959	BL-8160
							501.97	501.97		
DES PLANQUES, CHRIS - VEND-101766										
	5/2/2022	0522 Mobile Device	Open Terms	75.00	0.00	0.00	75.00	75.00	0522 Mobile Device	BL-8255

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							75.00	75.00		
Doug Pagel - VEND-1283										
5/31/2022	0522 Mobile Device	Net 30	75.00	0.00	15.00	75.00	75.00	0522 Mobile Device	BL-8256	
							75.00	75.00		
Doug Shull - VEND-1105										
5/31/2022	0522 Treasury Contract	Net 30	83.34	0.00	15.00	83.34	83.34	0522 Treasury Contract	BL-8179	
							83.34	83.34		
Dust Pros Janitorial - VEND-1011										
5/18/2022	0422 Cleaning - EL	Net 30	1,016.50	0.00	15.00	1,016.50	1,016.50	2523	BL-8167	
5/18/2022	Cleaning supplies - EL	Net 30	32.90	0.00	15.00	32.90	32.90	2524	BL-8168	
5/29/2022	Cleaning supplies - WA	Net 30	76.25	0.00	15.00	76.25	76.25	2532	BL-8211	
							1,125.65	1,125.65		
Dylan Michelsen - VEND-1180										
5/31/2022	0522 Mobile Device	Net 30	75.00	0.00	15.00	75.00	75.00	0522 Mobile Device	BL-8183	
							75.00	75.00		
Elisha Brown - VEND-1209										
5/31/2022	0522 Mobile Device	Net 30	25.00	0.00	15.00	25.00	25.00	0522 Mobile Device	BL-8186	
							25.00	25.00		
Emily McAllister - VEND-1141 - BL-8260										
5/4/2022	Credit Refund	Net 30	272.01	0.00	0.00	272.01	272.01	00006424-4	BL-8260	
							272.01	272.01		
Eva Borchert - VEND-1141 - BL-8259										
5/4/2022	Credit Refund	Net 30	118.57	0.00	0.00	118.57	118.57	00026994-5	BL-8259	
							118.57	118.57		
Fuse Technic LLC - VEND-1012										
6/1/2022	Consulting	Net 30	825.00	0.00	15.00	825.00	825.00	FT20220502005	BL-8242	
							825.00	825.00		
HACH COMPANY - VEND-20810										

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Vendor	Due Date	Notes	Terms	Bill Total	Discount	Interest	Amount Due	Payment	Invoice Number	Bill Number
	4/20/2022	Ascorbic acid, ferrover and edta soln	Open Terms	226.91	0.00	0.00	226.91	226.91	12990127	BL-8213
							226.91	226.91		
ImOn Communications LLC - VEND-1072										
	5/30/2022	Regulatory and billing notes	Net 30	7,206.03	0.00	15.00	7,206.03	7,206.03	INV0033558	BL-8243
							7,206.03	7,206.03		
Impact - VEND-1141 - BL-8222										
	5/3/2022	Refund for overpayment on closed account #51	Net 30	167.93	0.00	0.00	167.93	167.93	00056947-1	BL-8222
							167.93	167.93		
IMU - VEND-8629										
	4/2/2022	Utilities - WA	Open Terms	13,243.98	0.00	0.00	13,243.98	13,243.98	10193678	BL-8191
	4/2/2022	Utilities - Util Svcs	Open Terms	195.92	0.00	0.00	195.92	195.92	10189642	BL-8178
	4/2/2022	Utilities - EL	Open Terms	2,089.56	0.00	0.00	2,089.56	2,089.56	10192691	BL-8150
	5/2/2022	Utilities - EL	Open Terms	1,892.16	0.00	0.00	1,892.16	1,892.16	10194864	BL-8149
	5/2/2022	Utilities - Util Svcs	Open Terms	216.15	0.00	0.00	216.15	216.15	10199013	BL-8156
	5/2/2022	Utilities - WA	Open Terms	14,879.94	0.00	0.00	14,879.94	14,879.94	10200063	BL-8216
							32,517.71	32,517.71		
Innovative Systems - VEND-1048										
	6/1/2022	May elation maint fee and additional utilities so	Net 30	22,435.56	0.00	15.00	22,435.56	22,435.56	INV-02944	BL-8205
							22,435.56	22,435.56		
Internal Revenue Service - VEND-1307										
	5/29/2022	941 Income Tax Payable	Net 30	71,452.12	0.00	15.00	71,452.12	71,452.12	941 Income Tax Payable	BL-8200
							71,452.12	71,452.12		
Iowa Department Of Human Services - VEND-1310										
	5/29/2022	Garnishment Payable	Net 30	3,122.97	0.00	15.00	3,122.97	3,122.97	Garnishment Payable	BL-8202
							3,122.97	3,122.97		
Iowa Dept Of Revenue - VEND-1117										
	5/29/2022	IA Income Tax Payable	Net 30	12,552.22	0.00	15.00	12,552.22	12,552.22	IA Income Tax Payable	BL-8203
	6/1/2022	1st Qtr 22 Use Tax	Net 30	66.23	0.00	15.00	66.23	66.23	1st Qtr 22 Use Tax	BL-8204
							12,618.45	12,618.45		
Iowa One Call - VEND-1015										

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	5/27/2022	Locates	Net 30	561.60	0.00	15.00	561.60	561.60	240434	BL-8215
	5/27/2022	Locates	Net 30	532.80	0.00	15.00	532.80	532.80	240054	BL-8233
							1,094.40	1,094.40		
Iowa Radio Plus - VEND-1223										
	5/24/2022	:30 Web ad	Net 30	6.84	0.00	15.00	6.84	6.84	22040395	BL-8248
	5/24/2022	:30 Web ad	Net 30	21.42	0.00	15.00	21.42	21.42	22040396	BL-8249
							28.26	28.26		
Iowa Utilities Board - VEND-1016										
	6/1/2022	2021 IEC/CGRER Assessment	Net 30	15,345.00	0.00	15.00	15,345.00	15,345.00	54515	BL-8157
							15,345.00	15,345.00		
IOWA WORKFORCE DEVELOPMENT - VEND-25050										
	4/16/2022	Employee Benefits	Open Terms	6,280.00	0.00	0.00	6,280.00	6,280.00	Employee Benefits	BL-8196
							6,280.00	6,280.00		
IPERS - VEND-1309										
	5/29/2022	IPERS Payable	Net 30	48,788.22	0.00	15.00	48,788.22	48,788.22	IPERS Payable	BL-8201
							48,788.22	48,788.22		
Irby - VEND-1259										
	5/15/2022	i-Phase Junction Cabinet	Net 30	1,305.40	0.00	15.00	1,305.40	1,305.40	S012950820.002	BL-8218
	5/15/2022	Junction Cabinet Basement	Net 30	353.10	0.00	15.00	353.10	353.10	S012950820.001	BL-8219
							1,658.50	1,658.50		
John Deere Financial - VEND-1106										
	5/13/2022	Hanger hose	Net 30	14.99	0.00	15.00	14.99	14.99	3357775	BL-8173
							14.99	14.99		
Judy Gwinn - VEND-1141 - BL-8258										
	5/4/2022	Credit Refund	Net 30	40.91	0.00	0.00	40.91	40.91	00000314-9	BL-8258
							40.91	40.91		
K.M. KING INC - VEND-101515										
	4/21/2022	Retained percentage	Open Terms	8,588.50	0.00	0.00	8,588.50	8,588.50	Retained percentage	BL-8170
							8,588.50	8,588.50		
KEYSTONE LABORATORIES INC - VEND-29056										

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	4/19/2022	Finished tap on wells	Open Terms	241.00	0.00	0.00	241.00	241.00	NT2203132	BL-8175
							241.00	241.00		
KNIA/KRLS - VEND-1090										
	5/24/2022	:30 Web ad	Net 30	151.56	0.00	15.00	151.56	151.56	22040484	BL-8250
	5/24/2022	:30 Web ad	Net 30	475.74	0.00	15.00	475.74	475.74	22040485	BL-8251
	5/24/2022	Package	Net 30	94.25	0.00	15.00	94.25	94.25	22040486	BL-8252
							721.55	721.55		
Koch Office Group - VEND-1306										
	5/12/2022	Record of minutes municipal utilities board of t	Net 30	479.33	0.00	15.00	479.33	479.33	INV436443	BL-8176
							479.33	479.33		
Kurt Gocken - VEND-1023										
	5/31/2022	0522 Mobile Device	Net 30	75.00	0.00	15.00	75.00	75.00	0522 Mobile Device	BL-8180
							75.00	75.00		
Kurt Ripperger - VEND-1025										
	5/31/2022	0522 Mobile Device	Net 30	75.00	0.00	15.00	75.00	75.00	0522 Mobile Device	BL-8181
							75.00	75.00		
LOGAN CONTRACTORS SUPPLY INC. - VEND-32620										
	4/16/2022	Lineshop concrete rebar and keyway	Open Terms	1,812.37	0.00	0.00	1,812.37	1,812.37	A50014	BL-8224
	4/26/2022	Concrete materials	Open Terms	160.32	0.00	0.00	160.32	160.32	A52513	BL-8209
							1,972.69	1,972.69		
LONGER, CHRIS - VEND-34025										
	5/2/2022	0522 Mobile Device	Open Terms	75.00	0.00	0.00	75.00	75.00	0522 Mobile Device	BL-8184
	5/3/2022	Conference - Mileage	Open Terms	19.89	0.00	0.00	19.89	19.89	Mileage	BL-8193
							94.89	94.89		
Luke Worden - VEND-1141 - BL-8257										
	5/4/2022	Credit Refund	Net 30	37.16	0.00	0.00	37.16	37.16	00028529-6	BL-8257
							37.16	37.16		
Marquee Sports Network - VEND-1165										
	5/30/2022	0422 Expanded Basic	Net 30	2,821.22	0.00	15.00	2,821.22	2,821.22	0422 Expanded Basic	BL-8236

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							2,821.22	2,821.22		
MELLEN & ASSOCIATES INC - VEND-34176										
4/30/2022	SAR07.6, installation and mounting bracket	Open Terms	18,815.93	0.00	0.00	18,815.93	18,815.93	031289	BL-8210	
							18,815.93	18,815.93		
METCALF, MIKE - VEND-34230										
5/2/2022	0522 Mobile Device	Open Terms	75.00	0.00	0.00	75.00	75.00	0522 Mobile Device	BL-8185	
							75.00	75.00		
Mid American Energy Co - VEND-1018										
5/18/2022	Electric - Muni Plant Substation - west side sub	Net 30	10.00	0.00	15.00	10.00	10.00	524845584	BL-8164	
5/20/2022	Gas - Util Svcs	Net 30	74.56	0.00	15.00	74.56	74.56	525007856	BL-8177	
5/20/2022	Gas - 1300 E Iowa Bldg A	Net 30	214.57	0.00	15.00	214.57	214.57	524963146	BL-8153	
5/20/2022	Gas - 1300 E Iowa Bldg B	Net 30	12.46	0.00	15.00	12.46	12.46	524949394	BL-8154	
							311.59	311.59		
Mission Square - VEND-1303										
5/29/2022	042922 Payroll, 040122 Roth, 041522 Roth	Net 30	4,082.96	0.00	15.00	4,082.96	4,082.96		BL-8197	
5/29/2022	030422 Roth, 031822 Roth	Net 30	1,659.75	0.00	15.00	1,659.75	1,659.75		BL-8198	
							5,742.71	5,742.71		
MUNICIPAL ENERGY AGENCY OF NEBRASKA - VEND-35805										
5/21/2022	IMU portion of attachment O filing by Spiegel &	Net 30	250.00	0.00	15.00	250.00	250.00	302976	BL-8169	
							250.00	250.00		
Mutual Of Omaha - VEND-1107										
5/31/2022	0522 Premiums	Net 30	4,825.79	0.00	15.00	4,825.79	4,825.79	1353116949	BL-8194	
							4,825.79	4,825.79		
Nexstar Broadcasting, Inc - VEND-1092										
5/30/2022	0422 WHO	Net 30	6,328.87	0.00	15.00	6,328.87	6,328.87	440235	BL-8237	
5/30/2022	0422 NewsNation	Net 30	328.44	0.00	15.00	328.44	328.44	440236	BL-8238	
							6,657.31	6,657.31		
Power & Tel - VEND-1037										
5/14/2022	Closure and tray	Net 30	1,673.55	0.00	15.00	1,673.55	1,673.55	7467514-00	BL-8239	
							1,673.55	1,673.55		
POWER LINE SUPPLY - VEND-103039										

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	4/20/2022	Connectors	Open Terms	497.68	0.00	0.00	497.68	497.68	56652894	BL-8231
							497.68	497.68		
Rickee Chaplin - VEND-1141 - BL-8261										
	5/4/2022	Credit Refund	Net 30	1,019.06	0.00	0.00	1,019.06	1,019.06	00051538-6	BL-8261
							1,019.06	1,019.06		
Secure Shred - VEND-1063										
	6/1/2022	Shred service	Net 30	52.00	0.00	15.00	52.00	52.00	67737	BL-8241
							52.00	52.00		
Skye McBroom - VEND-1026										
	5/31/2022	0522 Mobile Device	Net 30	75.00	0.00	15.00	75.00	75.00	0522 Mobile Device	BL-8182
							75.00	75.00		
SPEE-DEE DELIVERY SERVICE INC - VEND-102273										
	4/17/2022	Shipping to Skarshaug's testing	Open Terms	41.87	0.00	0.00	41.87	41.87	563106	BL-8155
							41.87	41.87		
STEW HANSEN DODGE - VEND-50362										
	3/31/2022	2022 Ram 3500	Open Terms	37,803.00	0.00	0.00	37,803.00	37,803.00	F22R1760	BL-8163
							37,803.00	37,803.00		
T.R.M. DISPOSAL LLC - VEND-101016										
	4/25/2022	0522 Trash	Open Terms	42.00	0.00	0.00	42.00	42.00	23325	BL-8195
							42.00	42.00		
Teklink - VEND-1262										
	5/24/2022	Conduit bury and bore	Net 30	8,692.00	0.00	15.00	8,692.00	8,692.00	WE 4/23/22	BL-8247
	5/29/2022	Conduit bury and bore	Net 30	11,271.00	0.00	15.00	11,271.00	11,271.00	WE 4/30/22	BL-8246
							19,963.00	19,963.00		
Tifco Industries - VEND-1296										
	5/15/2022	Shop hardware	Net 30	54.53	0.00	15.00	54.53	54.53	71753071	BL-8152
							54.53	54.53		
TRUCK EQUIPMENT INC - VEND-53754										
	4/23/2022	Lights, lift gate, back rack, cab steps for new 2	Open Terms	6,399.22	0.00	0.00	6,399.22	6,399.22	84886	BL-8148
	4/30/2022	New truck - backup alarm install	Open Terms	87.29	0.00	0.00	87.29	87.29	84807	BL-8228

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							6,486.51	6,486.51		
U.S. Cellular - VEND-1104										
5/12/2022	0422 Cel Phone	Net 30	714.48	0.00	15.00	714.48	714.48	502623798	BL-8161	
							714.48	714.48		
Unite Private Networks - VEND-1054										
5/31/2022	Dark fiber	Net 30	3,368.60	0.00	15.00	3,368.60	3,368.60	SI-22-013253	BL-8244	
							3,368.60	3,368.60		
United States Treasury - VEND-1138										
4/30/2022	Q1-2022 Federal Excise Tax	Net 30	1,398.96	0.00	15.00	1,398.96	1,398.96	Q1-2022 Federal Excise Tx	BL-8162	
							1,398.96	1,398.96		
Vanderpool Plumbing & Heating - VEND-1066										
5/25/2022	Valve, straps and labor	Net 30	2,880.09	0.00	15.00	2,880.09	2,880.09	5483	BL-8190	
							2,880.09	2,880.09		
VEENSTRA & KIMM - VEND-57600										
4/23/2022	Engineer X	Open Terms	1,162.00	0.00	0.00	1,162.00	1,162.00	285105-8	BL-8192	
							1,162.00	1,162.00		
VISION METERING LLC - VEND-103244										
4/29/2022	2S Solar Meters	Open Terms	418.20	0.00	0.00	418.20	418.20	207132	BL-8226	
							418.20	418.20		
WESCO - VEND-60220										
4/14/2022	Lineman invoice	Open Terms	29.80	0.00	0.00	29.80	29.80	136637	BL-8151	
4/20/2022	Single Anchors and Anchor Rods	Open Terms	486.80	0.00	0.00	486.80	486.80	144070	BL-8232	
4/23/2022	Wire and Contact Paste	Open Terms	244.46	0.00	0.00	244.46	244.46	149371	BL-8229	
							761.06	761.06		
Check Count: 78				Totals:			\$518,250.33	\$518,250.33		

MEMORANDUM

To: IMU Board of Trustees of the Electric, Water and Communications Utilities

From:

Date: May 9, 2022

Subject: Approval of the March financial report.

Recommendation: Simple motion is in order.

Attachments: 1. 0322 Financials Summary

**Water Utility
Fund Summary
March 31, 2022**

	FY 2022 Beg Cash Balance	YTD *Revenue	YTD **Expenditures	YTD Accrual Adj	FY 2022 YTD Cash Balance	*Rev Compared to Budget	**Exp Compared to Budget	Notes
					\$ 2,826,600	\$ 2,381,557		O&M Budget Revenue & Expenses
					\$ 424,900	\$ 849,800		Capital Budget Revenue & Expenses
						75.00%		Percent of Budget Comparison for July
					3,251,500	3,231,357		Total Budget Revenue & Expenses
WATER	\$ 2,785,176	\$ 2,450,452	\$ 2,253,298	\$ 84,613	\$ 2,897,717	75.36%	69.73%	
Total								
Reserve Targets:								
Days - Cash on Hand	352 Days							

Other Operating Data

		Gallons Pumped				Inventory on Hand	
		FY21-22	FY20-21			FY21-22	FY20-21
July		45,915,600	43,766,000			\$ 70,025	\$ 60,294
August		46,698,000	46,527,000			\$ 86,918	\$ 68,321
September		44,528,000	38,938,000			\$ 86,965	\$ 75,317
October		41,430,000	37,065,000			\$ 81,330	\$ 63,699
November		36,116,000	32,846,000			\$ 114,388	\$ 63,642
December		37,914,000	31,668,000			\$ 114,500	\$ 65,648
January		39,718,000	32,729,000			\$ 109,986	\$ 63,009
February		35,271,000	30,974,000			\$ 106,121	\$ 55,918
March		37,951,000	34,765,000			\$ 101,264	\$ 87,967
April							\$ 89,167
May							\$ 84,617
June							\$ 70,899
YTD TOTAL		365,541,600	329,278,000	YTD AVG		\$ 96,833	\$ 70,708
		11.0%				36.9%	

**Electric Utility
Fund Summary
March 31, 2022**

ELECTRIC
Total

Reserve Targets:
Days - Cash on Hand

FY 2022 Beg Cash Balance	YTD *Revenue	YTD **Expenditures	YTD Accrual Adj	FY 2022 YTD Cash Balance	*Rev Compared to Budget	**Exp Compared to Budget	Notes
					\$ 16,587,878	\$ 15,564,255	O&M Budget Revenue & Expenses
					\$ 1,173,600	\$ 2,348,000	Capital Budget Revenue & Expenses
						75.00%	Percent of Budget Comparison for July
					17,761,478	17,912,255	Total Budget Revenue & Expenses
\$ 12,929,148	\$ 15,281,738	\$ 11,091,958	\$ 2,101,992	\$ 15,016,935	86.04%	61.92%	
371 Days							

Other Operating Data

		Kwh's Billed				Inventory on Hand	
		FY21-22	FY20-21			FY21-22	FY20-21
July		11,445,992	8,914,241			\$ 989,343	\$ 994,613
August		12,112,667	13,234,240			\$ 992,348	\$ 988,447
September		13,038,750	13,646,968			\$ 997,025	\$ 1,011,061
October		13,556,254	13,400,541			\$ 1,020,121	\$ 1,003,522
November		9,944,562	10,297,980			\$ 1,057,167	\$ 1,082,990
December		8,421,475	8,891,505			\$ 1,020,372	\$ 1,089,326
January		8,740,491	9,124,796			\$ 1,019,488	\$ 1,087,587
February		9,557,105	10,298,289			\$ 1,046,682	\$ 1,045,063
March		11,392,890	11,922,604			\$ 1,043,108	\$ 1,018,846
April							\$ 976,098
May							\$ 1,028,556
June							\$ 992,530
YTD TOTAL		98,210,186	99,731,164	YTD AVG		\$ 1,020,628	\$ 1,026,553
		-1.5%				-0.6%	

**Fiber Utility
Fund Summary
March 31, 2022**

	FY 2022 Beg Cash Balance	YTD *Revenue	YTD **Expenditures	YTD Accrual Adj	FY 2022 YTD Cash Balance	*Rev Compared to Budget	**Exp Compared to Budget	Notes
						\$ 4,882,300	\$ 4,960,689	O&M Budget Revenue & Expenses Capital Budget Revenue & Expenses 75.00% Percent of Budget Comparison for July
						4,882,300	4,960,689	Total Budget Revenue & Expenses
FIBER Total	\$ 222,680	\$ 3,497,845	\$ 2,933,158	\$ 401,405	\$ 385,961	71.64%	59.13%	
Reserve Targets: Days - Cash on Hand	36 Days							

Other Operating Data

Subscriptions				Inventory on Hand			
	FY21-22	FY20-21	YOY Increase %	FY21-22	FY20-21		
July	2,995	2,402	25%	\$ 1,379,250	\$ 1,041,499		
August	3,039	2,455	24%	\$ 1,381,182	\$ 1,050,027		
September	3,087	2,519	23%	\$ 1,391,655	\$ 1,130,772		
October	3,136	2,594	21%	\$ 1,403,383	\$ 1,145,629		
November	3,173	2,633	21%	\$ 1,395,733	\$ 1,162,303		
December	3,214	2,685	20%	\$ 1,513,915	\$ 1,168,993		
January	3,249	2,722	19%	\$ 1,566,346	\$ 1,184,037		
February	3,294	2,760	19%	\$ 1,586,673	\$ 1,235,109		
March	3,338	2,807	19%	\$ 1,542,603	\$ 1,257,544		
April					\$ 1,300,743		
May					\$ 1,299,534		
June					\$ 1,383,366		
YTD AVG	3,169 21.0%	2,620	YTD AVG	\$ 1,462,305 22.2%	\$ 1,196,630		

**IMU Admin
Fund Summary
March 31, 2022**

	FY 2022 Beg Cash Balance	YTD *Revenue	YTD **Expenditures	YTD Accrual Adj	FY 2022 YTD Cash Balance	*Rev Compared to Budget	**Exp Compared to Budget	Notes
620 Utility Services						\$ 691,200	\$ 691,200	O&M Budget Revenue & Expenses-Utility Services
						\$ 560,711	\$ 560,711	O&M Budget Revenue & Expenses-IMU Admin
							75.00%	Percent of Budget Comparison for July
						1,251,911	1,251,911	Total Budget Revenue & Expenses
	\$ 382,873	\$ 1,046,745	\$ 934,396	\$ 72,964	\$ 422,257	83.61%	74.64%	
Reserve Targets:								
Days - Cash on Hand	\$ 124	Days						

MEMORANDUM

To: IMU Board of Trustees of the Electric, Water and Communications Utilities

From:

Date: May 9, 2022

Subject: Approval of Minutes of the prior board meeting.

Recommendation: Simple motion is in order.

Attachments: 1. 04252022 BOT Minutes



**IMU BOARD OF TRUSTEES OF THE ELECTRIC,
WATER AND COMMUNICATIONS UTILITIES**

April 25, 2022

5:30 PM

City Hall Council Chambers

110 N 1st Street

Minutes

The Indianola Municipal Utilities Board of Trustees met in regular session at 5:30 p.m. on April 25, 2022, in the City Hall Council Chambers. Chairperson Lori Smith called the meeting to order and on roll call the following members were present: Deb White, Lesley Forbush (via Zoom due to the pandemic), Lori Smith, Mike Rozga, and Adam Voigts. Absent: None.

No public comments were offered.

White moved to approve the consent agenda and Voigts seconded it. Question was called for and on voice vote the Chairperson declared the motion carried unanimously. The consent agenda was as follows:

- Approval of Claims
- Approval of Minutes of the prior board meeting

General Manager Chris Des Planques provided the Trustees with a financial analysis of purchasing bore machines versus contracting out the project. Doing the work in-house, including hiring one staff member, provides significant savings. Electric Superintendent Mike Metcalf reviewed the quotes for the equipment and recommended purchasing from Vermeer.

Rozga moved to approve Resolution 2022-025 authorizing the purchase of two directional bore machines, trailers, and mixing systems for the Electric Department. Voigts seconded it. On roll call, the vote was AYES: White, Forbush, Smith, Rozga, Voigts. NAYS: None.

Whereas the Chairperson declared the motion carried unanimously.

Metcalf stated the capital improvement budget for FY23 includes turbine 8 controls replacement. The project will begin in July and includes the purchase of one piece of equipment.

Voigts moved to approve Resolution 2022-026 approving a proposal from P&E Engineering Company for the Turbine 8 control replacement project and White seconded it. On roll call, the vote was AYES: White, Forbush, Smith, Rozga, Voigts. NAYS: None. Whereas the Chairperson declared the motion carried unanimously.

Metcalf reported that the voltage on the solar panel project had been changed; bids on the project will be posted soon.

White moved to approve the authorization for Warren Water District to serve a customer within their territory upon proper notice to IMU since the customer is within 2 miles of the IMU territory, located at 12244 140th Avenue. Rozga seconded it. Question was called for and on voice vote the Chairperson

declared the motion carried unanimously.

Water Superintendent Lou Elbert explained the City pays for the water used to fill the pool and when the season is over, a reimbursement check is given for up to 1.5 million gallons. Doug Bylund, Parks and Recreation Director for the City of Indianola, stated usage was higher last year due to dry, hot weather, irrigation, and a leak in the gutter in the shallow depth entry. Repairs have been completed to fix that issue. Elbert said the maximum refund amount for this year would be \$9,375.

Voigts moved to approve a water waiver request from the Memorial Building Commission for water consumption and White seconded it. Question was called for and on voice vote the Chairperson declared the motion carried unanimously.

Elbert reported the last water tap had been completed on Phase 2 of the Streetscape Project and the West Boston Project began April 25, after being delayed due to weather.

Kurt Ripperger reported there has been good progress on installing the temporary drops. The Telecommunications staff is also working on other installations.

Des Planques stated job descriptions are being updated to formerly add tasks that the director and superintendent have been taking on.

Board Member Forbush left the meeting at 6:11 PM.

White moved to approve the Finance/HR Director job description and Rozga seconded it. Question was called for and on voice vote the Chairperson declared the motion carried unanimously.

Rozga moved to approve the Telecommunications Superintendent job description and White seconded it. Question was called for and on voice vote the Chairperson declared the motion carried unanimously.

Des Planques explained the salaries are being adjusted due to a change in job descriptions and as a market adjustment. Chris Longer's salary is retroactive to when the payroll conversion began in September 2021. Voigts moved to approve Resolution 2022-027 approving salaries and White seconded it. On roll call, the vote was AYES: White, Smith, Rozga, Voigts. NAYS: None. ABSENT: Forbush. Whereas the Chairperson declared the motion carried unanimously.

Des Planques suggested using a risk-based approach to determine the amount of reserves needed in the health insurance fund. The Trustees suggested that staff should come up with a formula for the policy in order to find the dollar amount. Council Member Ron Dalby stated that the new city manager needs to be included in any policy change discussions. Clerk Jackie Raffety reviewed the direction provided to staff at the joint meeting. The Trustees directed IMU staff to work with the city staff, after the city manager begins, to develop a formula to determine reserve levels.

White moved to approve Resolution 2022-028 approving health insurance benefits for the employees of Indianola Municipal Utilities. Rozga seconded it. In discussion, Voigts stated to make sure that the extra HSA contribution is funded by the reserve amount. On roll call, the vote was AYES: White, Smith, Rozga, Voigts. NAYS: None. ABSENT: Forbush. Whereas the Chairperson declared the motion carried unanimously.

Des Planques and Smith informed the Board they had interviewed Brick Gentry and Dickinson, Mackaman, Tyler and Hagen PC on legal services they could provide to IMU. They recommended the firm of Dickinson, Mackaman, Tyler and Hagen PC. The Trustees directed staff to develop an engagement agreement with the recommended firm for consideration at the next meeting.

Ripperger provided three options on camera systems. The Trustees directed staff to research a 4K option for the Board to review.

White moved to enter into closed session at 6:55 PM in accordance with Iowa Code Section 388.9(1) to discuss marketing and pricing strategies and proprietary information of the telecommunications division whose competitive position will be harmed by public disclosure that is not required of potential or actual competitors and no public purpose is served by such disclosure. Rozga seconded it. On roll call, the vote was White, Smith, Rozga, Voigts: None. NAYS: None. ABSENT: Forbush. Whereas the Chairperson declared the motion carried unanimously.

Voigts moved to exit the closed session at 7:09 PM and Rozga seconded it. On roll call, the vote was White, Smith, Rozga, Voigts: None. NAYS: None. ABSENT: Forbush. Whereas the Chairperson declared the motion carried unanimously.

The meeting was adjourned at 7:09 PM on a motion by Rozga and seconded by Voigts. Question was called for and on voice vote the Chairperson declared the motion carried unanimously.

Lori Smith, Chairperson

ATTEST:

Jackie Raffety, City Clerk

MEMORANDUM

To: IMU Board of Trustees of the Electric, Water and Communications Utilities

From:

Date: May 9, 2022

Subject: Resolution dissolving Fund 625 and returning the remaining amount to Fund 630.

Recommendation: Included in the packet is the June 25, 2001 Board of Trustees memorandum and meeting minutes in order to provide history of Fund 625.
Roll call is in order.

Attachments:

1. June 25 Meeting Memo - RLF
2. June 25 Minutes - RLF
3. Res 2022- Dissolve Fund 625

MEMORANDUM

TO: Board of Trustees
FROM: Mark A. Ramthun, General Manager
SUBJECT: June 25, 2001 Trustee Advisory Meeting
DATE: June 22, 2001

Please note that we will meet at the E. Iowa turbine/substation site. Kim Keller is the chairperson for this meeting. Following the tour, we can continue the meeting in the control house or some other convenient spot.

2. Turbine Tour:

It was suggested by Kim Keller that we meet at the turbine site and visually see the improvements that have been added to the generation facilities and answer any questions from the Board. In your packet is a map of the facility for your review.

Bruce Gomm knows the turbine inside and out and will explain the components that have been discussed at our meetings plus other major issues. Some things we will show you include:

- The Mark V computer controls
- The diesel starting engine
- The water injection skid & tank
- The new control house
- The water cooling skid
- The rebuilt fuel-skid
- The inlet and exhaust stacks
- The black start generator and the first turbine
- The 69KV step-up transformer

The bottom line is that the addition of the second turbine has been, and will continue to be, a very positive addition to the IMU system and Indianola will receive the benefits of our generation capacity for many years, both in reliable service and in lower electric rates. Although we have had our problems with the installation, I still think the purchase was the right thing to do.

It may also be an opportune time to visually see the proximity of the generating turbine units to the proposed church and residential area to the west. When and if more and more houses are built, the possibility becomes greater that IMU will receive complaints of noise or other distractions from a person's property.

We need to remember that IMU was in the area much longer than the residential area, but we may need to provide fencing or vegetation between properties with conflicting zoning.

Feel free to ask Bruce or I any questions about the unit. No action is necessary.

3. IMU Treasurer's Report:

In your packet are copies of the May, 2001 Treasurer's report and the investment financial report for May as prepared by Wells Fargo Investment Bank. The Board is responsible for 46% of the portfolio.

Also in your packet is a copy of the variance report with Todd's explanations attached. Revenues for both the electric and water funds continue to be strong. Todd has also included a projected accrual operations statement that should give you a good idea of what to expect in the FY01 audit report.

Doug or I will be able to answer your questions.

Simple motion approving the May, 2001 Treasurer's report is in order.

4. Painting Contract:

In your packet are the painting plans and specifications prepared by Emil Segebart and submitted to bidders last August. Proposals were received in September and were all rejected due to:

- The extra costs being incurred to complete the turbine project, and
- The time required to complete the painting, and
- The lateness of the year and the concern about cold weather.

It was suggested that we re-address the painting project in the Spring of 2001.

Since the Board will be meeting at the site anyway, it will be a good opportunity to look at the condition of the structures to see what needs there are and determine if we should proceed with the painting improvements.

I support and encourage the Board to authorize the painting project for 2001. I have included \$35,000 in the turbine maintenance budget for the project.

As you will see, there are many areas on the turbines, the cooling skids, the fuel tanks, the water tank and other structures that are in need of attention. I do not think it would be wise to delay this maintenance work any longer. The paint on the tanks and first turbine are still the original application and have lasted over 25 years. However, the time has come that preventive maintenance be taken.

Simple motion authorizing advertising for bids is in order.

5. Revolving Loan Fund:

It was mentioned by Brad Butler in February at an IMU meeting that the Board should consider establishing a new revolving loan fund and roll any outstanding balances from the budgeted economic development contribution fund to the new fund on an annual basis.

The purpose of the revolving loan fund would be to annually accumulate budgeted, unspent monies in a separate account with the hope that we could

provide more incentives to potential business prospects and provide financing options for new opportunities that currently do not exist.

In the electric department budget, we budget \$50,000/year for economic development activities and \$50,000/year for in-kind/community improvement activities. The annual contributions to the IDC and the WCEDC are taken from the economic development account, leaving around \$30,000 - \$35,000 for specific project requests on a first come, first served basis.

In your packet is a copy of the FY2001 economic development contribution fund balance showing that there is \$14,500 remaining.

Todd Kielkopf has indicated that it would not be any problem to establish the revolving account for unspent IMU economic development funds and it would also be an interest bearing account. It would show up separately on the Treasurer's report with the other IMU electric and water funds.

Please be aware that any amount transferred to the revolving fund would no longer be included in the beginning balance of the electric operations fund the following year, thereby making it unavailable for other uses. However, if the new fund were to grow substantially over the next few years, we may be able to eliminate the separate economic development line item in the electric operations budget.

Todd and I will be glad to answer any questions you may have.

Simple motion authorizing staff to create the IMU Economic Development revolving loan fund prior to June 30th and transfer the remaining balance of \$14,500 in FY01 to the new fund is in order.

BOARD OF TRUSTEE MINUTES
REGULAR SESSION – JUNE 25, 2001

The Board of Trustees met in regular session at 5:30 p.m. at the IMU Turbine Site, 1300 E. Iowa. Chairperson Kim Tierney Keller called the meeting to order and on roll call the following members were present: Bradley K. Butler, Kim Tierney Keller, Shelley Lucas, Gary Ruble and David Zwanziger.

The May 2001 City Treasurer's report was approved on a motion by Lucas and seconded by Zwanziger. Question was called for and on voice vote the Chairperson declared the motion carried unanimously.

A motion was made by Zwanziger and seconded by Butler to approve a new revolving loan fund and transfer the FY 2001 outstanding balance of \$14,500 from the budgeted economic contribution fund to the new fund. Question was called for and on voice vote the vote was, AYES: Keller, Butler, Lucas and Zwanziger. NAYS: Ruble. Whereupon the Chairperson declared the motion carried.

Bruce Gomm, Electric Superintendent, gave the Board a tour of the new IMU Turbine Site.

It was moved by Lucas and seconded by Butler to authorize Mark Ramthun, General Manager of Utilities, to advertise for bids to paint the fuel tanks, turbines and other miscellaneous structures. Question was called for and on voice vote the Chairperson declared the motion carried unanimously.

The Board presented Bruce Gomm, Electric Superintendent, a plaque of appreciation for his dedicated work on the new turbine.

Meeting adjourned on a motion by Lucas and seconded by Butler.

Kim Tierney Keller, Chairperson

Todd Kielkopf, Trustee Clerk

Indianola Municipal Utilities
RESOLUTION NO 2022-

RESOLUTION DISSOLVING FUND 625 AND RETURNING REMAINING FUNDS TO FUND 630

WHEREAS, on June 25, 2001, the Indianola Municipal Utilities Board of Trustees created a Revolving Loan Fund as Fund 625; and

WHEREAS, the purpose of Fund 625 was to annually accumulate budgeted, unspent monies in a separate account in order to provide incentives to potential business prospects and provide financing options for new opportunities; and

WHEREAS, \$14,500 in Fiscal Year 21 was transferred to Fund 625 from Electric Department Fund 630; and

WHEREAS, the balance of Fund 625 today is \$114,097.24; and

WHEREAS, Fund 625 is no longer used to provide incentives to potential business prospects nor to provide financing options for new opportunities and should be dissolved.

NOW, THEREFORE, BE IT RESOLVED by the Indianola Municipal Utilities Board of Trustees that Fund 625 is hereby dissolved and the IMU Finance Director is authorized to transfer the balance of \$114,097.24 in Fund 625 to Fund 630.

APPROVED this 9th day of May 2022.

Lori Smith, Chairperson

ATTEST:

Jackie Raffety, City Clerk

MEMORANDUM

To: IMU Board of Trustees of the Electric, Water and Communications Utilities

From:

Date: May 9, 2022

Subject: Discussion regarding MEAN's draft 2022 Integrated Resource Plan.

Recommendation:

Attachments: 1. mean-draft-2022-irp-vol-1_1



*Municipal Energy
Agency of Nebraska*

2022 Integrated Resource Plan

DRAFT



8377 Glynoaks Drive
Lincoln, NE 68516

p. 402.474.4759
f. 402.474.0473

MEAN_IRP@nmppenergy.org
www.nmppenergy.org

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- B. November 2020 Board and Committee Meetings
- C. January 2021 Board and Committee Meetings
- D. May 2021 Board and Committee Meetings
- E. August 2021 Board and Committee Meetings
- F. November 2021 Board and Committee Meetings
- G. January 2022 Board and Committee Meetings
- H. April 2022 Power Supply Committee Workshop

XVIII. **Appendix B – Phase I Supply Side Option Data** **B-1**

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LIST OF ABBREVIATIONS

APPA	American Public Power Association
ARR	Auction Revenue Rights
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BTMG	Behind the Meter Generation
BTU	British Thermal Unit
CCR	Coal Combustion Residuals
CCS	Carbon Capture and Sequestration
CDD	Cooling Degree Days
CF	Capacity Factor
CO	Carbon Monoxide
CO ₂	Carbon Dioxide
CP	Coincident Peak
CPP	Clean Power Plan
CRSP	Colorado River Storage Project
CSAPR	Cross-State Air Pollution Rule
DG	Distributed Generation
DLC	Direct Load Control
DMEA	Delta-Montrose Electric Association
DOE	Department of Energy
DSM	Demand-Side Management
EGS	Enhanced Geothermal Systems
EIA	Energy Information Administration
EIS	Energy Imbalance Service
EPA	Environmental Protection Agency
EPAct	Energy Policy Act of 1992
EPRI	Electric Power Research Institute
ERPA	Electrical Resources Pooling Agreement
FCRC	Fixed Cost Recovery Charge

FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
FY	Fiscal Year
GGS	Gerald Gentleman Station
GHG	Greenhouse Gasses
HDD	Heating Degree Days
HVAC	Heating, Ventilating, and Air Conditioning
IM	Integrated Marketplace
IMU	Indianola Municipal Utilities
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
kW	Kilowatt
kWh	Kilowatt-Hour
LAP	Loveland Area Projects
LED	Light Emitting Diode
LES	Lincoln Electric System
LF	Load Factor
LFG	Landfill Gas
LMP	Locational Marginal Price
LTCR	Long-Term Congestion Rights
MATS	Mercury and Air Toxics Standards
MBA	Member Based Association
MCF	Thousand Cubic Feet
MEAN	Municipal Energy Agency of Nebraska
MEC	MidAmerican Energy Company
MISO	Midcontinent Independent System Operator
MSW	Municipal Solid Waste
MUP	Multi-Unit Participation Agreement
MW	Megawatt
MWh	Megawatt-Hour
NAAQS	National Ambient Air Quality Standards
NCP	Non-Coincident Peak

NESHAP	National Emissions Standards for Hazardous Air Pollutants
NGCC	Natural Gas Combined Cycle
NGCT	Natural Gas Combustion Turbine
NITSA	Network Integration Transmission Service Agreement
NMPP	Nebraska Municipal Power Pool
NOAA	National Oceanic and Atmospheric Administration
NOx	Nitrous Oxide
NPPD	Nebraska Public Power District
NREL	National Renewable Energy Laboratory
PCT	Participant Cost Test
PHES	Pumped Hydropower Energy Storage
PM	Particulate Matter
PPA	Purchased Power Agreement
PPGA	Public Power Generation Agency
PRM	Planning Reserve Margin
PSD	Prevention of Significant Deterioration
PTC	Production Tax Credit
PTP	Point-To-Point Transmission
RCRA	Resource Conservation and Recovery Act
RDF	Refuse-Derived Fuel
RECS	Residential Energy Consumption Survey
RICE	Reciprocating Internal Combustion Engine
RMR	Rocky Mountain Region
RPS	Renewable Portfolio Standard
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SLCA	Salt Lake City Area
SO ₂	Sulfur Dioxide
SPP	Southwest Power Pool
TCR	Transmission Congestion Rights
TDF	Tire-Derived Fuel
TES	Thermal Energy Storage

TO	Transmission Owner
TRC	Total Resource Cost
TRP	Total Requirements Participant
UCT	Utility Cost Test
UGP	Upper Great Plains
WAPA	Western Area Power Administration
WEC	Whelan Energy Center
WECC	Western Electricity Coordinating Council
WSEC	Walter Scott Energy Center
WU	Waverly Utilities

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I. Executive Summary

A. IRP Requirements

Integrated resource planning was mandated by the Energy Policy Act of 1992 (“EPAct”).

EPAct requires all Western Area Power Administration (“WAPA”) customers to submit Integrated Resource Plans (“IRPs”) to WAPA every five years. The requirement is included in WAPA’s power sales contracts with long-term firm electric service customers.

WAPA has identified the following criteria for customer IRPs:

- Identify and compare all practicable energy efficiency and energy supply resource options.
- Include action plan with timing set by customer.
- Describe efforts to minimize adverse environmental effects of new resource acquisitions.
- Provide ample opportunity for full public participation.
- Conduct load forecasting.
- Include brief description of measurement strategies for options identified in IRP to determine whether objectives are being met.

IRPs and alternative reports will be evaluated by WAPA on the basis of:

- Meeting all criteria in 10 CFR 905
- Reasonableness of the plan with regard to: customer size, type, resource needs, geographic area and competitive situation
- Resource choice selection (EPAct 1992 section 114)

B. Introduction

1. Purpose

The purpose of this Integrated Resource Plan is to develop long-range implementation plans to serve MEAN’s Total Requirements Participants’ power supply requirements consistent with prudent utility planning practices utilizing the lowest cost, environmentally responsible energy supply. The IRP serves as MEAN’s guidance for future plans to achieve its 2050 Vision for carbon neutrality.

This plan is also designed to fulfill the requirements of the Western Area Power Administration according to the Energy Policy Act of 1992, as described in section II.A.

2. Scope

This resource plan encompasses a time period of 15 years on the basis of MEAN’s fiscal year. MEAN’s fiscal year begins April 1st and ends March 31st. This IRP is inclusive of the planning period of FY 2022-23 to FY 2037-38.

The IRP conducts resource planning for MEAN’s entire service footprint as a whole, as well as within the individual Regional Transmission Organizations (“RTO”) regions in which MEAN’s designated resources are assigned. MEAN operates in the Southwest Power Pool (“SPP”) RTO, Midcontinent Independent System Operator (“MISO”) RTO, and in the West region. Resources must be designated to meet the load and required reserve margin of

each region separately. However, there are several metrics that MEAN evaluates on an accumulated basis for the entire service area.

This IRP will consider all reasonable options for supply side resources and demand side management. Supply side and demand side options will be given equal consideration for incorporation into the future resource portfolio.

3. Methodology

The IRP analysis will begin with a high-level evaluation of all resource options. Criteria for resource selection are determined and weighted according to input from the MEAN membership. Using static performance and cost characteristics of each option, the complete list of resources will be narrowed to a smaller list of qualified options that receive the highest ranking in accordance with the weighted criteria.

The qualified resource options will be subject to an economic analysis that applies resource availability and cost to MEAN's hourly loads and projected market conditions. The sum of the hourly costs and revenues over the study period will be calculated to arrive at a total revenue requirement for each option for comparison purposes. The economic analysis will be repeated under various load and pricing sensitivity scenarios to calculate the impact of potential changes to key inputs. The variation caused by these scenarios is considered the volatility, or risk, inherent in each portfolio.

In addition to the total cost parameters, the resource options will be compared in terms of their carbon emissions impact. MEAN's future resource acquisitions will be selected not only in terms of financial cost and reliability to serve load, but also in their ability to advance MEAN toward the 2050 Vision of carbon neutrality. This means that each future resource should contribute toward a decrease in the net emission of the portfolio.

The combined results of the base case revenue requirement, the variability due to sensitivity cases, and the carbon emissions impact will ultimately lead to the determination of a preferred portfolio for future resource acquisition planning.

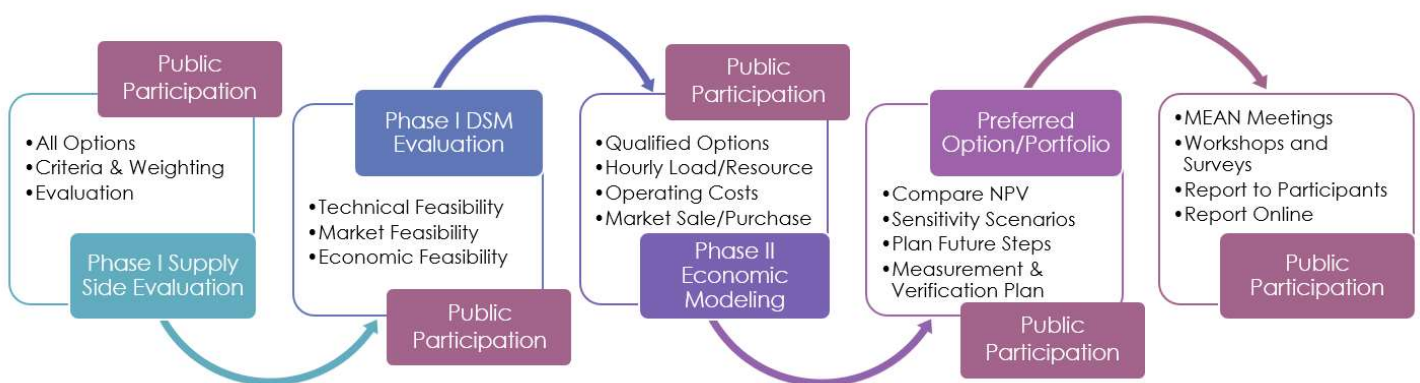


Figure I-1

4. About MEAN

The Municipal Energy Agency of Nebraska (“MEAN”) is a body corporate and politic under the laws of the State of Nebraska. MEAN was created on June 22, 1981 under the Municipal Cooperative Financing Act, Sections 18-2401 through 18-2485, Reissue Revised Statutes of Nebraska (the “Act”). MEAN was created for the purpose of planning, acquiring, financing and operating facilities to generate and transmit electric power and energy.

MEAN’s power supply system consists of ownership and contractual rights and interests in various electric generating and transmission resources and supplies (the “Power Supply System”). MEAN uses the Power Supply System to provide wholesale power supply, transmission and ancillary services to its participating municipal utilities (“Participants”). MEAN’s services include power supply, dispatching, energy load forecasting, wheeling arrangements, load research, limited political action, demand-side management, load factor improvement, training, community development, compliance reporting, and energy cost analysis. Through its professional staff, MEAN also provides planning, engineering, financing, regulatory, and governmental affairs services to its Participants.

MEAN’s 70 Participants currently include 42 municipalities and one public power district in Nebraska, 14 municipalities and one joint action agency in Colorado, two Wyoming municipalities and 10 Iowa municipalities. Each of the Participants owns and operates an electrical utility system that provides electric service to consumers. 62 of the Participants (the “*Total Requirements Participants*”) receive “total-requirements” electric supply services from MEAN, exclusive only of their allocations of firm power and energy from the Western Area Power Administration of the U.S. Department of Energy (“WAPA”), except for certain generating facilities of Waverly Utilities (a municipal utility of the City of Waverly, Iowa) and the City of Aspen, Colorado.

Together, the Total Requirements Participants provide electric utility service at retail to approximately 102,723 residential, commercial, institutional, agricultural and industrial customers, representing a total population of approximately 174,800.

MEAN’s participant communities are mapped in *Figure I-2*.

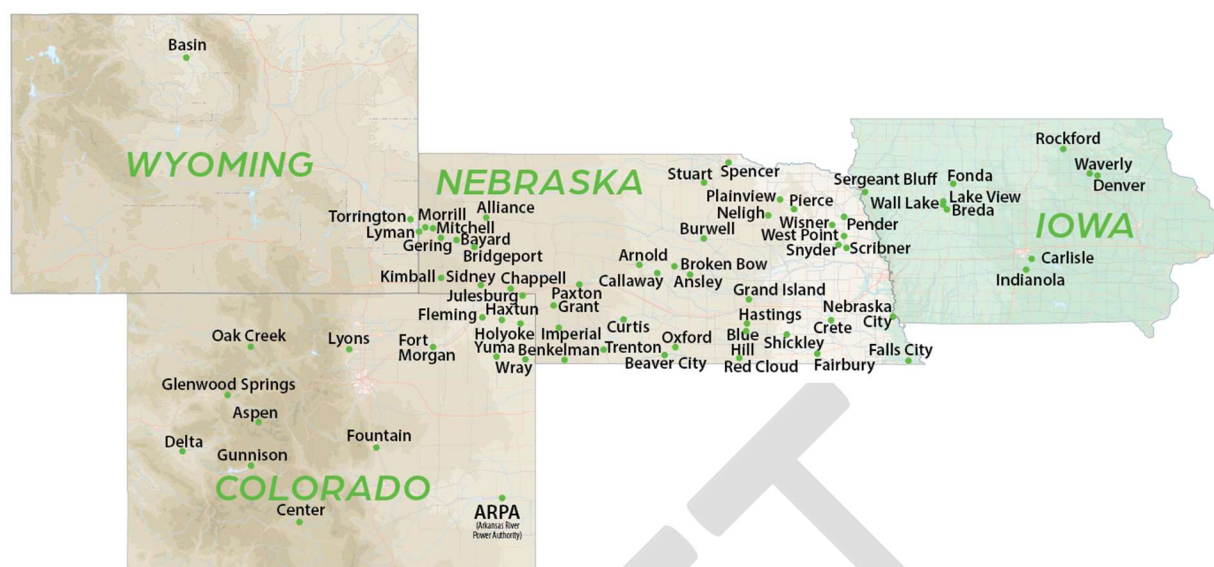


Figure I-2

MEAN's regional footprint stretches from Central Iowa across Nebraska and into Colorado and Wyoming. Due to this footprint, MEAN is required to operate in two regional transmission organizations, MISO and SPP. Both MISO and SPP operate day-ahead and real-time energy markets. Market participants must pay for costs to serve load and receive revenue for their electrical generation. MEAN also operates in the western United States through the Western Electricity Coordinating Council ("WECC") and participates in the Western Energy Imbalance Service ("WEIS"). In July of 2021, the SPP board of directors and Strategic Planning Committee approved the terms and conditions for regional transmission organization (RTO) expansion in the Western Interconnection. MEAN has communicated its intent to join a future SPP West RTO.

C. Uncertainties/Limitations

There are many parameters that impact the inputs to the IRP analysis. Many of these parameters have been calculated or assigned with certain assumptions. Should these assumptions be incorrect or prove to change over time, the outcome of the analysis could potentially change as well. This section explores some of the uncertainties and limitations underlying these variable inputs to the analysis.

1. Environmental Legislation

Electric utilities are subject to evolving environmental regulation. Various environmental permits and approvals from state and federal agencies are necessary in order to operate the Power Supply System. To date, MEAN reports that all environmental permits and approvals necessary for the operation of the Power Supply System have been obtained. However, federal, state, and local standards and procedures that regulate the environmental impact of electric utilities are subject to change. These changes may arise from continuing legislative, regulatory and judicial action regarding such standards and procedures. Consequently, there is no assurance that the Power Supply System and the utility facilities owned or operated by the Participants will remain subject to the regulations currently in effect or indefinitely maintain current compliance status. An inability to comply with environmental standards could result in reduced operating levels,

increased capital or operating costs, or the complete shutdown of individual electric generating units.

There is increased concern by the public, the scientific community, and Congress regarding environmental damage resulting from the use of fossil fuels. There are a number of pending or recently enacted legislative proposals in Congress and state legislatures that may affect the electric utility industry. Increased environmental regulation has created and may create additional barriers to new facility development and modification of existing facilities, both physically and operationally. The additional expenses, including time, human resources, uncertainty and delay, could increase the cost of electricity from affected resources and ultimately reduce their market dispatch. This type of legislation may ultimately have significant influence on nationwide or regional resource mixes and market operations as some types of resources experience increased costs of compliance or compulsory carbon taxes while other types of resources avoid such costs or receive financial incentives for generation, thereby effecting the feasibility of resource retirement and new construction. Further regulation may impose additional costs and long-term investments in retirement and decommissioning activities when a facility ceases operation.

2. Load Forecast

MEAN employs a robust statistical method for forecasting load. A number of input variables are used to formulate a forward-looking equation to calculate the monthly peak demand and monthly energy usage for each participant community for the entirety of the study period. However, the statistical analysis is dependent upon several variables, such as weather data, population, and income. Changes in any of these factors will impart changes in the load forecast.

Extreme weather events have made a notable impact on energy markets in recent years. In 2020, Hurricane Laura hit MISO's Gulf Coast region, resulting in a 500-MW load shed and massive transmission and distribution system destruction. In February 2021, Winter Storm Uri effected fuel supply and resource availability as well as load levels for several days in the SPP and ERCOT regions, leading to massive outages and extraordinarily high energy pricing. This type of weather event is unforeseeable and is not included in the weather projections used for load forecasting.

Throughout the MEAN footprint, demand side management ("*DSM*") measures are being adopted by utilities and end-use customers in participant communities. DSM measures act to reduce either the peak demand for electricity or the total electricity consumption.

Distributed Generation ("*DG*") is customer and/or community ownership of generating assets to serve end use load. Each installation of DG removes energy consumption from the MEAN system and thereby decreases the resource need, either on a capacity or energy basis depending on the timing of DG energy supply. Recent MEAN policy changes allow for an increased installation of DG resources as a percentage of energy consumption. The future rate of DG installation and therefore its impact on load projections is unknown.

Recent years have seen an emphasis on energy efficiency and energy conservation on all levels: residential, commercial, and industrial. The widespread use of these practices has

led to a decrease in the growth rate of electric loads, and is a trend which is likely to continue, but at a pace that is difficult to predict.

3. Electrification

Electrification refers to the process of replacing technologies that use fossil fuels with technologies that use electricity as a source of energy. As more carbon-free resources are integrated into the grid to generate electricity, electrification can potentially reduce carbon emissions from the transportation, building, and industrial sectors. Given the adoption of state and federal regulations to reduce emissions, electrification activities are likely to proliferate. This gives entities more opportunity to reduce overall system carbon emissions with the possibility of serving this load with carbon free resources.

This move toward electrification will alter MEAN's resource portfolio as demand and consumption increase and end users require more carbon-free power. This change will also result in changes in the operations and economics of the energy markets. Evidence of a trend toward electrification would prompt a recalibration of resource planning to resize planned acquisitions or add incremental acquisitions in the appropriate future years.

4. Energy Markets

In the integrated markets, loads are served and resources dispatched according to market dynamics and the balance of bids and offers in an attempt to cost effectively optimize the pool of resources. Since the establishment of the SPP and MISO Integrated Markets, several changes have been introduced that have changed the way resources are designated to load, the way resources are dispatched into the marketplace, and energy prices and cost recovery for generation resources. Given the fast pace of developments in the markets, it is likely that changes will continue in the future.

Within the integrated markets, market prices are determined by variable costs of generating units throughout the entire market. Therefore, the construction of new units and retirement of existing units has the potential to change the order of economic dispatch of resources and, as a result, marginal pricing. The integration of non-dispatchable, renewable generation into the resource mix impacts the operation of other resources, particularly peaking units dispatched in response to supply fluctuations and cycling coal plants.

Effective Load Carrying Capability ("ELCC") study results indicate that with increasing penetrations of wind and solar resources, the capacity value provided by those resources as a percent of nameplate capacity generally tends to decrease. This has impacts on the magnitude of resources needed to serve load, which directly affect the inputs and results of this analysis.

The existing markets and potential creation of future markets present significant opportunity for uncertainty.

5. Fuel Pricing

Fuel pricing is an obvious source of uncertainty.

Recent natural gas pricing has been elevated compared to historical pricing and has seen higher volatility in recent months. As a global resource, natural gas is subject to the influence of global supply and demand. This relationship carries with it the risk of price fluctuations in response to market occurrences elsewhere. Fuel pricing projections assume high pricing and volatility in the near future. However, this contains inherent uncertainty.

Coal prices are similarly subject to external influence and resulting volatility. Despite some years of uncertainty due to the dynamics of domestic and foreign coal consumption, recently coal prices have stabilized and remained relatively low. Coal in most regions has seen flat or declining pricing over the past five years. However, fuel prices respond to a number of factors and the impacts of overseas markets can be difficult to predict.

Sensitivity cases are included in the economic analysis to capture the effects of changes in fuel pricing.

D. System Load Forecast

1. Methodology

MEAN employed multiple regression analysis to forecast the non-coincident peaks for each of its Total Requirement Participants for FY 2022-2023 (annual forecast) through FY 2037-38 (15-year forecast). The model took into consideration three main factors as independent variables: economic factors such as population growth and income growth; temperature factors such as average daily temperature, heating degree days (“HDD”) and cooling degree days (“CDD”); and calendar factors such as weekdays and month.

The coincident peak forecast is calculated as MEAN’s non-coincident peak multiplied by the coincidence factor. The coincidence factor was forecasted based upon regression analysis of the difference between the mean temperature and the max temperature at the time of historical peaks.

With many unknown factors potentially impacting MEAN’s future load obligations, the IRP considers resource needs under a variety of future load scenarios. Five scenarios were investigated:

Load Scenario 1: Reference case load forecast, which is based on normalized weather and represents the 50% confidence interval of the statistical distribution.

Load Scenario 2: Low load scenario, which is based on normalized weather and represents the 10% confidence interval of the statistical distribution.

Load Scenario 3: High load scenario, which is based on normalized weather and represents the 90% confidence interval of the statistical distribution.

Load Scenario 4: Electrification scenario, which is based on normalized weather and assumes a high rate of electrification throughout the footprint resulting in a much higher annual growth rate. The inputs to this scenario were informed by NREL’s Electrification

Futures Study. This load scenario was not modeled however, as it would require a completely different resource acquisition schedule that would not be comparable to the other scenarios.

Load Scenario 5: Recession scenario, which is based on normalized weather and represents a scenario in which an economic recession takes place mid-way through the time period. Recovery follows historical patterns.

2. MEAN System

MEAN's load forecast for peak demand and energy consumption for the entire system for the 15-year study period is shown in the graphs in *Figures I-9* and *I-10* illustrating all five load scenarios:

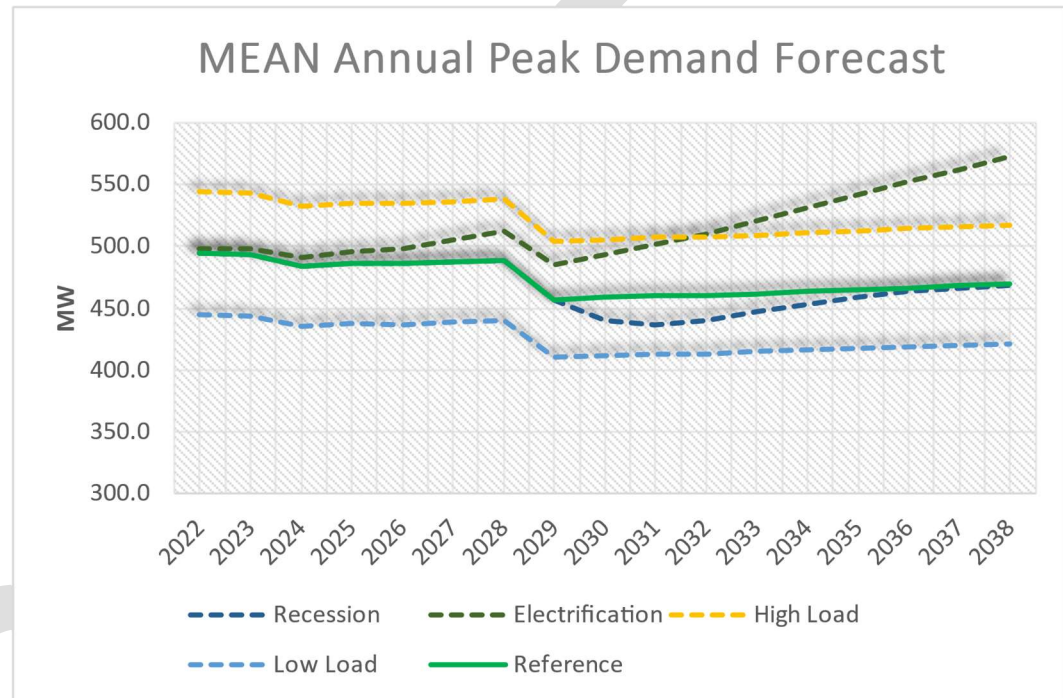


Figure I-3

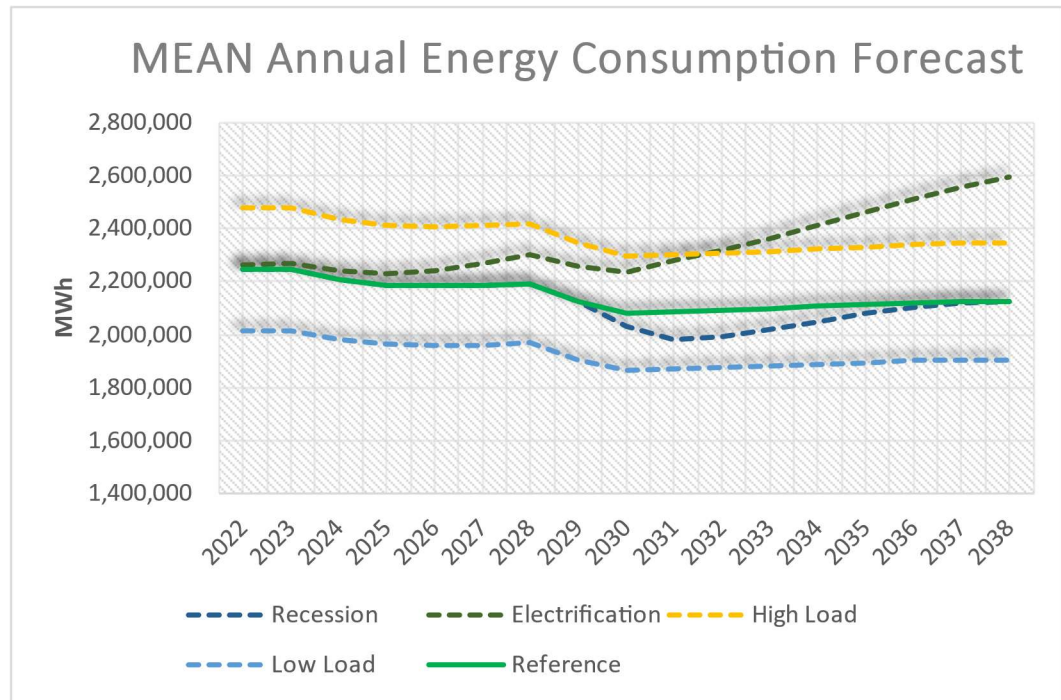


Figure I-4

Load Forecast figures for each region are shown in Section V of the report for each of the load scenarios as well as seasonal breakouts of demand and energy.

3. Reserve Margin and Transmission Losses

MEAN must maintain capacity to serve not only the forecasted load in each region, but the total resource obligation which adds to the peak demand a reserve margin and transmission losses.

The SPP and MISO market constructs require each load serving entity to maintain a designated percentage of reserve capacity in addition to the entity's forecasted peak load. In SPP, the established required Reserve Margin is 12%. For the 2022/23 planning year, the MISO Planning Reserve Margin ("PRM") is 9.4%. As the MISO definition of the PRM is specific to the operation of the upcoming year, the PRM changes annually.

For loads and resources in the west, there is no prescribed reserve margin. MEAN incorporates a 12% reserve margin in addition to forecasted load when determining the load and resource balance in the west.

MEAN's total obligation for service must also include the losses that occur throughout the transmission system. The rate of loss depends on the transmission system and is typically reported to MEAN on an annual basis. However, MEAN does not have to provide for transmission loss on WAPA allocations. Therefore, this amount is deducted from the calculations. In total, MEAN serves network load on six transmission systems.

MEAN adds the required margins to the forecasted peak demand to determine the total obligation for service in each region. This value is reflected in the figures throughout this report.

E. System Resources

1. Summary

The Power Supply System consists of owned, leased and purchased power supply resources as well as transmission system arrangements used to transmit resources to the Total Requirements Participants. MEAN receives transmission services provided by SPP, MISO and multiple transmission providers in the Western Interconnected System (the “*Western Interconnection*”).

MEAN is party to a number of long-term resource commitments. However, MEAN is not a majority owner or operator of any of its resource contracts. As such, many of these resources will remain in MEAN’s resource portfolio for the entire service life of the asset, despite MEAN’s 2050 Vision for carbon neutrality. Although this poses a challenge in terms of carbon emissions and the required offsets to achieve neutrality, MEAN acknowledges the reliability and resource adequacy offered by such resources. In fact, many of these resources supply the capacity necessary to qualify renewable intermittent resources that generate energy with a low accredited capacity. As market conditions change and continue to favor the economics of renewable resources, fossil fuel plants will likely be dispatched at lower levels, which will decrease the energy generation and therefore the emissions without reducing the capacity contribution.

The table in *Figure I-11* summarizes MEAN’s long-term power supply resources as of the date of this report:

Resource	MEAN Nameplate Capacity	Primary Energy Source	Market Region ⁽¹⁾	% of Capacity
<i>Total Requirements Committed Facilities (Participant Owned Generation)</i>	124.2 MW	Oil/Gas	MISO (69.5 MW), SPP (48.3 MW), WEST (6.4 MW)	18.9%
WAPA ⁽²⁾	124.7 MW	Hydroelectric	MISO (7.5 MW), SPP (29.1 MW), WEST (88.1 MW)	19.0%
Whelan Energy Center Unit 2	80 MW	Coal	SPP	12.2%
WAPA Displacement Agreement ⁽³⁾	61.9 MW	Hydroelectric	WECC	9.4%
Walter Scott Energy Center Unit 4	59.2 MW	Coal	MISO	9.2%
<i>NPPD Multi-Unit Participation</i>				
Cooper Nuclear Station	26 MW	Nuclear	SPP	4.0%
Gerald Gentleman Station	24 MW	Coal	SPP	3.7%
Kimball Wind LLC	30 MW	Wind	WECC	4.6%
Laramie River Station Unit 1	9.9 MW	Coal	SPP	1.5%
Laramie River Station Unit 2 & Unit 3	18.6 MW	Coal	WECC	2.8%
Wygen Unit I	20 MW	Coal	WECC	3.0%
Neil Simpson Unit 2 ⁽⁴⁾	8 MW	Coal	WECC	1.2%
Wygen Unit III ⁽⁴⁾	7 MW	Coal	WECC	1.1%
Wessington Springs Wind Project	10 MW	Wind	SPP	1.5%
Louisa Generating Station	8.2 MW	Coal	MISO	1.2%
NPPD Elkhorn Ridge Wind Plant	8 MW	Wind	SPP	1.2%
NPPD Laredo Ridge Wind Project	8 MW	Wind	SPP	1.2%
DMEA Shavano Falls/Drop 4 & Drop 6	7.6 MW	Hydroelectric	WECC	1.2%
NPPD Ainsworth Wind Energy Facility	7 MW	Wind	SPP	1.1%
Whelan Energy Center Unit 1	5.3 MW	Coal	SPP	0.8%
Waste Management Landfill Gas Facility	4.8 MW	Landfill Gas	MISO	0.7%
NPPD Crofton Bluffs Wind Project	4.2 MW	Wind	SPP	0.6%
TOTAL	656.6 MW			
(1) Resources located in MISO and SPP are dispatched by MISO and SPP. (2) All but approximately 7 MW constitutes North American Tribes' and Total Requirements Participants' WAPA allocations. (3) Under the WAPA displacement agreement, MEAN receives hydroelectric energy (excluding renewable energy credits) in WECC from the capacity in the agreement. Operationally, MEAN provides an equal amount of capacity to WAPA's customers in SPP from various MEAN contracted resources. The contracted resources designated for WAPA's customers in SPP may vary throughout the term of the agreement. (4) Per contract, the total capacity available to MEAN from Neil Simpson Unit 2 and Wygen Unit III was 20 MW in 2017-2018, is currently 15 MW and reduces to 10 MW in 2023.				

Figure I-5

2. Regional Markets and Energy Dispatch

The values of energy shown in the resource mix charts are indications of available energy from each resource, primarily based on operating characteristics, outage schedules, and historical performance. However, this may not be an accurate projection of actual energy generated in the future as it does not reflect the effects that increased renewable generation will have on reducing the economic dispatch of fossil fuel units.

In the SPP and MISO integrated markets, each resource is dispatched by the market according to its offer price in comparison to the locational marginal price (LMP) at the unit's specific location, which is a value that changes every five minutes based on the conditions of the entire market and transmission system. In the RTO markets, the offer prices for generating resources are most typically equal to the unit's variable operating costs, consisting primarily of fuel cost. The low or zero cost of fuel for renewable resources lowers the market price at which resources will be dispatched. Therefore, the higher the penetration level of renewables, the lower the market price, and the less often conventional resources will be dispatched.

The proliferation of low-cost renewable resources has driven market prices down in recent years. Future environmental regulations are likely to increase the operating cost of fossil fuel units, which will cause the market to dispatch these units less often.

3. Resource Mix by Fuel Type

It is very important to note in the following section that the values shown simply represent the currently contracted capacity. It is quite obvious that the relative values will (and sometimes do) change if MEAN's total capacity changes. Increase or decrease in relative percentages does not always correlate to the same magnitude of increase or decrease in MWs, given that the totals change. The varying capacity factors and accreditation values of different types of resources, particularly renewable resources, also mean that the "Future" capacity values represent accredited capacity that is required and are not necessarily predictive of the actual nameplate capacity of future assets. MEAN will size future resources to satisfy the energy needs of our total forecasted load as well as resource adequacy requirements.

For each region, a chart is included in Section VI of the report to show the resource mix in 2022 and 2038 as well as an intermediate year that represents change in the region. When presenting resource mix metrics, resource capacity is listed according to unit nameplate.

In terms of energy, future projections are based on a combination of availability as a function of historical operation and economic dispatch in response to changing market prices. As the total resource mix of each market changes, the operation of MEAN's resources may change from the projected profiles.

MEAN Capacity

In 2022, 51% of MEAN's resource mix is provided by fossil fueled resources in terms of capacity, divided between coal and participant owned generation. Hydro from WAPA allocations and the WAPA Displacement agreement supply 31% of the total. Renewable resources, including wind, small hydro, and landfill gas, account for 14% of MEAN's capacity. 4% of MEAN's capacity mix is nuclear powered.

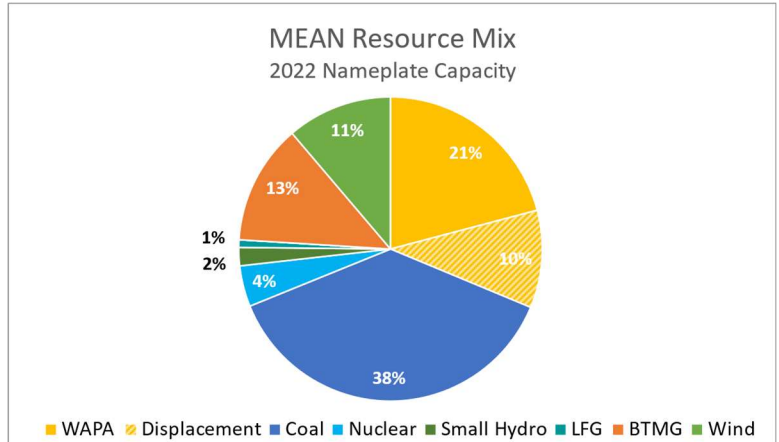


Figure I-6

In 2029, the percentage of fossil fueled capacity remains roughly the same at 53% despite the expiration of the Black Hills PPA and the NPPD Multi-Unit Participation Agreement. WAPA power is now at 19%, since the Displacement agreement has expired, and the renewable total has increased slightly to 19%. 9% of accredited capacity needed for resource adequacy will be supplied by future resources.

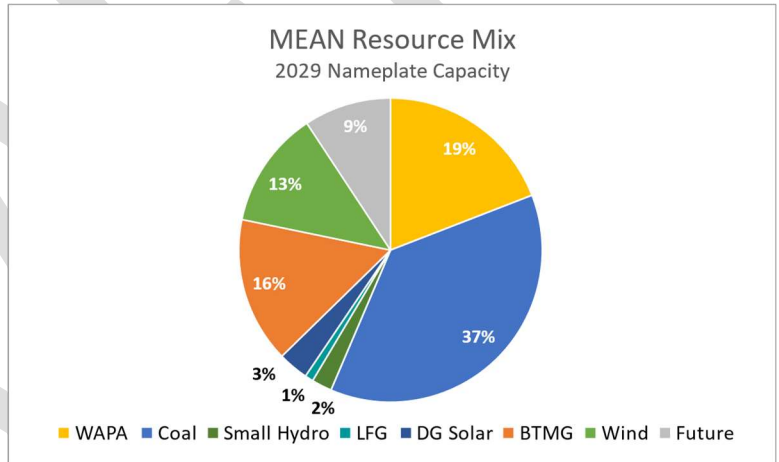


Figure I-7

By 2038, the Landfill Gas PPA will terminate, along with several wind PPAs. The capacity percentages see little change, and 14% of MEAN's total required accredited capacity will be supplied by future resources.

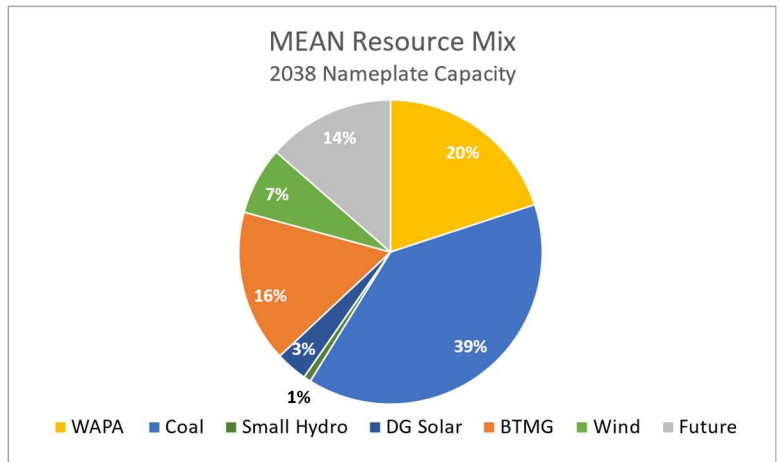


Figure I-8

MEAN Energy

MEAN's resource mix in 2022 in terms of energy generation capability shows that the largest contribution comes from coal resources, at 54% of the total. Non-emitting resources make up the remaining 46%. 24% of the total energy is supplied by WAPA allocations and the WAPA Displacement agreement, 13% of MEAN's energy is renewable, and 8% is generated by a nuclear resource. MEAN entered into a short-term energy purchase to hedge against high market prices in 2022.

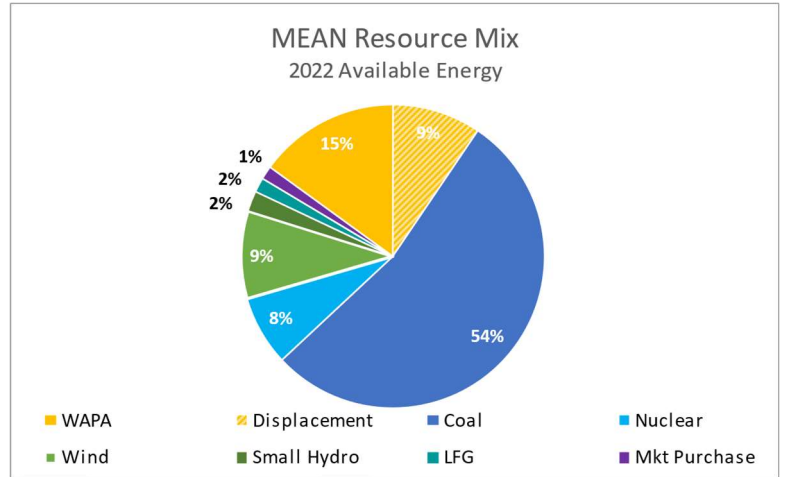


Figure I-9

Into the future, the energy availability of coal resources decreases slightly to 49% of the total, the contribution of WAPA allocations decreases to 19%, and the renewable resource percentage increases to 16% with the installation of DG Solar. Only 16% of MEAN's total energy in 2029 must be generated by future resources.

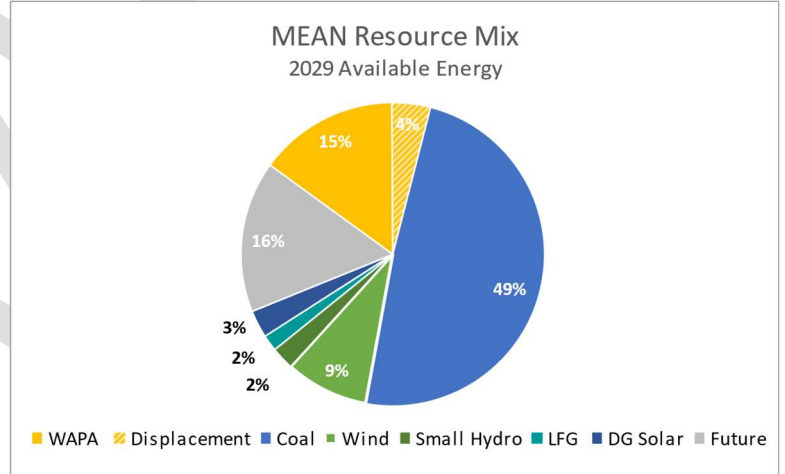


Figure I-10

Out into 2038, MEAN's energy from coal is projected to remain constant at 50%. WAPA drops to 15% with the expiration of the WAPA Displacement Agreement. Renewables decrease to 8% as Wind PPAs, the Landfill Gas PPA, and the Shavano Falls Hydro PPA end. MEAN will require an estimated 27% of energy in 2038 from future resources.

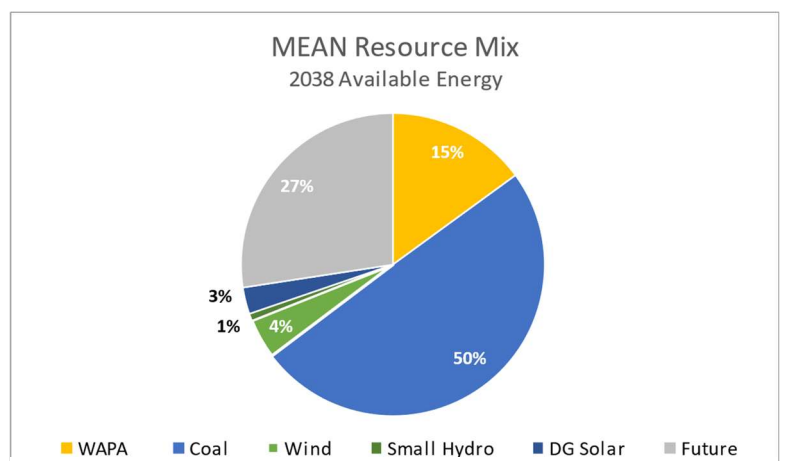


Figure I-11

F. Distributed Generation

1. Renewable Distributed Generation Policy

MEAN adopted a Renewable Distributed Generation Policy (the “*DG Policy*”) in 2016 that, in limited amounts and in certain circumstances, allows the Total Requirements Participants to (a) permit their retail customers to utilize output from renewable generation resources to supply all or a portion their own loads, (b) purchase output from renewable generation resources owned by their retail customers, and (c) subject to a cap set forth in the DG Policy, own and operate renewable generation resources, including community solar projects, to offset a portion of their total requirements purchases from MEAN.

In November of 2019, the Board approved an increase in the policy limits, allowing Participants to install a distributed renewable generating resource capable of generating 5% of the Participant’s average annual energy needs. The type of resource determines the capacity factor, and therefore the allowable capacity of the installed resource.

A 2016 MEAN Participant survey found that throughout the entire MEAN footprint, there is a total installed grandfathered DG capacity of 2,875 kW. Since the establishment of the grandfathered distributed generation, MEAN Participants have installed a total of 4,932 kW of distributed generation.

2. Community Solar Request for Proposals

In 2019, MEAN surveyed member communities regarding interest in installation of community-owned solar assets. On behalf of these interested communities, MEAN released a Request for Proposals for community-owned solar facilities. The aggregated Request for Proposals was pursued as the increased volume of solar installation required of the combined projects provided advantageous pricing compared to a standalone project in one community. The RFP was released in July 2021 and bids received in September 2021. After evaluation of bids and consultation with members, MEAN awarded the bid for a total of 14.2 MW-DC of community-sited and -owned solar facilities. Project installation is scheduled to begin in Summer 2022 with all commercial operation dates by Spring 2023.

G. Existing Demand Side Management

MEAN has conducted several Demand Side Management (“*DSM*”) programs in the past, with varying degrees of adoption and impact. Currently MEAN provides a suite of five energy efficiency programs that offer cash incentives paid directly to customers to help cover the cost of energy efficient upgrades.

1. Commercial Programs

LED Lighting Program: This program provides cash incentives paid directly to commercial customers to help cover the cost of lighting upgrades and replacements to existing facilities. The energy and demand savings achieved through this program in FY21-22 are listed below:

Equipment Info (Conversion)	Fixtures Retrofitted	KW Savings	Hours ran (annual)	Coincidence	Annual KWh Savings	Peak KW Savings
High Bay: 9-65 watts LED	354	14.2	4,160	95%	55,960	13.5
High Bay: 66-130 watts LED	78	5.1	4,160	95%	20,037	4.8
High Bay: 131-240 watts LED	197	19.7	4,160	95%	77,854	18.7
Linear Replace/Retrofit: 9-22 watt LED	5,170	93.1	5,200	95%	459,716	88.4
Linear Replace/Retrofit: 23-45 watt LED	663	13.3	5,200	95%	65,504	12.6
Linear Replace/Retrofit: 46-68 watt LED	436	15.3	5,200	95%	75,384	14.5
Linear Replace/Retrofit: 69-90 watt LED	335	16.8	5,200	95%	82,745	15.9
LED Exit: under 8 watts	371	7.4	8,672	95%	61,129	7.0
LED Refrigerator	26	1.0	8,672	95%	8,568	1.0
Customized Application Fixtures (Linear)	697	19.5	5,200	95%	96,409	18.5
FY21-22 Totals	8,327	205			1,003,307	195

Figure I-12

2. Residential Programs

Smart Thermostat Program: Provides a cash incentive from \$25 to \$100 paid directly to residential customers to help cover the cost of installing a qualifying smart thermostat.

Attic Insulation Program: Provides cash incentives of \$0.15/per square foot with a maximum incentive of \$300 per existing residential dwelling for attic insulation.

Cooling System Tune-Up Program: Provides a \$30 cash incentive to residential homeowners who have their cooling system tuned up by a HVAC contractor, regardless of what type or age of cooling system (air conditioner/air or water source heat pump).

High Efficiency Heat Pump Program: Provides cash incentives ranging from \$400 to \$3,000 to residential homeowners who are installing a new high efficiency heat pump system to their residential single-family dwelling.

As these programs were initiated in 2020, there are no measured results of energy or demand savings to date. In FY21-22, eighteen MEAN communities participated in the residential energy efficiency programs and 48 projects were completed. This was up significantly from FY20-21 which saw 34 projects completed.

3. Community Programs

The 2016 Participant DSM survey revealed a total of 17 communities with 33 DSM programs in place. The non-coincident sum of the demand and energy savings from these DSM programs is 4.03 MW and 2,635 MWh. Of this total, a large portion of the available demand savings is in the form of interruptible load supplied to irrigation wells. The projected annual savings of the community DSM programs are summarized in Figure I-36.

Region	Communities	Programs	Total Demand Under Control (kW)	Total Demand Savings (kW)	Total Energy Savings (kWh)
MISO	5	9	2,500	415	218,116
SPP	8	12	14,468	2,136	2,386,085
West	4	12	0	1,477	31,052

Figure I-13

H. Renewable Energy Resources

1. 2050 Vision

In 2020, the Board approved a resolution laying out a vision to work toward transitioning MEAN's wholesale power resource portfolio to achieve carbon neutrality by 2050 through the elimination of carbon emissions or balancing emissions with carbon removal through carbon offset mechanisms. The resolution authorizes MEAN's staff to work collaboratively with the MEAN Power Supply Committee to develop policies around resource planning, portfolio optimization and emissions reduction to support future actions to achieve the 2050 carbon neutral goal. The formation of the plan will begin with resource analysis and the portfolios recommended as part of this IRP. MEAN's current resource capacity portfolio consists of 49 percent non-carbon resources from projects around the region, including Total Requirements Participant allocations of federal hydropower from WAPA. MEAN's actual energy generation from carbon free resources in FY20-21 was over 50% of the total. The IRP is exploring the opportunities in the coming years to transition toward higher levels of carbon neutrality as power purchase agreement contracts expire and capital debt is paid on its shared ownership of power resources with other utilities

2. Renewable Resource Mix

As contract terms for existing assets expire, MEAN looks to replace the energy and capacity with carbon-free resources. As part of the 2050 Vision, MEAN aims to make resource acquisitions that only decrease the total carbon emissions of our portfolio.

The future resources considered for this resource planning analysis will be evaluated in part on their ability to decrease the carbon emissions in MEAN's current portfolio. Although environmental impact ranked 9th in MEAN's member survey of the importance of resource evaluation criteria, the equivalent carbon emissions factor was an element of scoring in the Phase I supply side resource evaluation. Also factored into this evaluation was the sensitivity of resource options to a future carbon tax and future changes in environmental legislation, which largely correspond with emissions levels. Finally, the performance of each future resource is calculated in terms of the change in carbon intensity of the MEAN resource portfolio.

3. Renewable Resource Pools

To respond to the disparity in local goals for renewable or carbon-free energy, MEAN offers a Wind Pool and a Landfill Gas Pool where participants can elect to purchase specified amounts of those resources in terms of energy from MEAN's portfolio. This allows individual communities to control their own resource mix. MEAN communicates annually to participants to inform them of their actual energy mix for the prior year. The rates for these pools are established by the Board of Directors in accordance with policy.

Currently, the Wind Pool is fully subscribed with all MWh allocated to participants per contract. The Landfill Gas Pool was 34.2% subscribed in 2021. As MEAN expands its portfolio in terms of carbon-free resources, the resource pools and the energy rates for these resources may evolve accordingly. The pools may need to expand to accommodate the acquisition of future carbon free resources and varying demand for carbon free energy from individual MEAN member communities.

I. Load and Resource Balance

Previous sections of this report have quantified the forecasted total load obligation that MEAN expects to serve in future years, in various future scenarios, as well as the capacity and energy available to MEAN for service of this load. To determine the timing and magnitude of MEAN's future resource needs, the annual peak demand must be compared to the resource capacity available during the peak and the total annual energy consumption must be compared against the expected and/or available generation of the portfolio's resources.

For the calculation of load and resource balance, resources will be quantified according to accredited capacity, or the maximum capacity that is expected to be available during the system peak load. The peak demand as shown in the load and resource balance in the total service obligation, which includes not only the forecasted peak load, but also the required reserve margin and the expected transmission losses. Resource capability in terms of capacity and energy is classified by fuel type.

The load and resource balance for the entire MEAN system is shown below. However, since MEAN serves load and procures resources on a regional basis, the regional load and resource balance values are utilized for resource planning to determine the need for future resources. These regional balance figures are shown in Section X of the report.

1. MEAN System

The graph in *Figure I-37* shows the balance of peak demand and resource capacity for MEAN's entire footprint. Available capacity is sufficient to serve load until 2024. At that point, MEAN has a slowly growing capacity need into the future. The total picture of MEAN's total energy balance begins with an energy deficit in 2029 of approximately 16% of load, which grows to a 27% deficit in 2038.

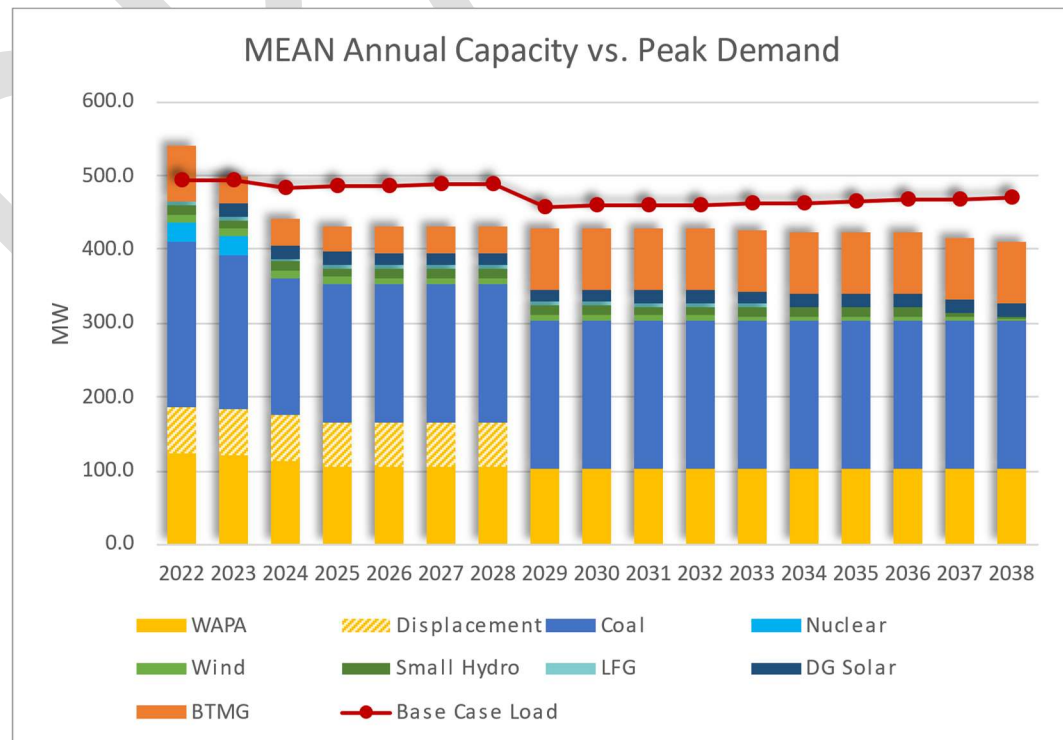


Figure I-14

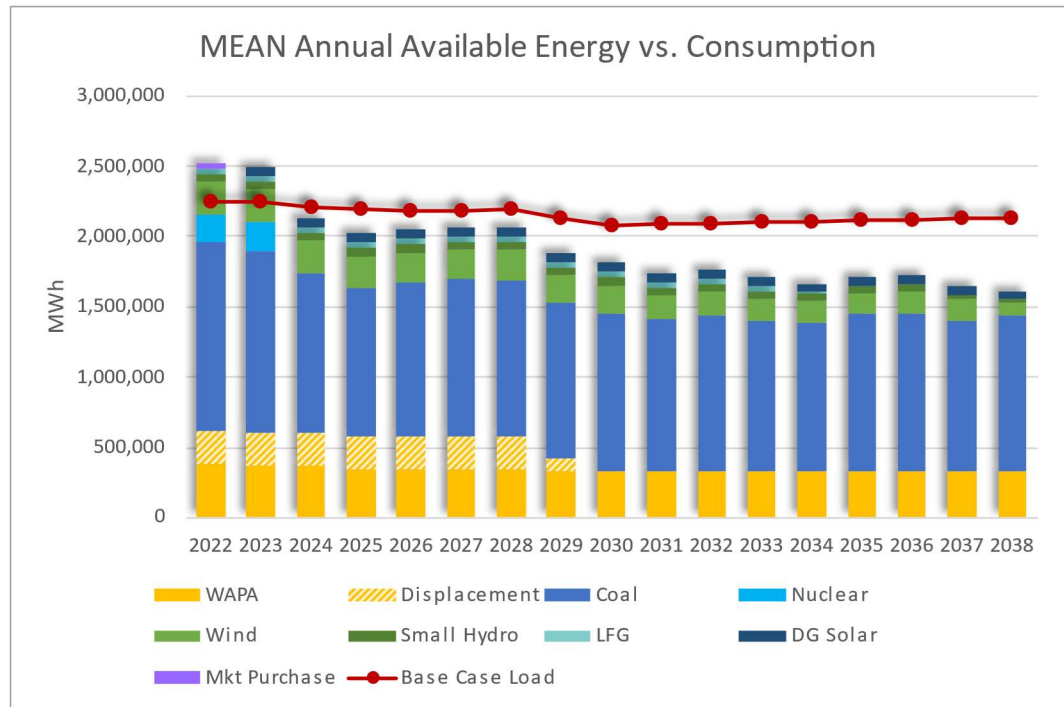


Figure I-15

1. Projected Capacity and Energy Needs

Assigning the capacity needs into regional resource deficits, SPP has a need for approximately 55 MW of capacity from 2024 to 2028. The end of the WAPA Displacement Agreement eliminates the need for capacity in SPP in 2029. The West region first sees a capacity deficit of approximately 10 MW in 24, which increases sharply to 45 MW in 2029 and increases throughout the remainder of the study period to 65 MW in 2038. MISO has a very minor capacity deficit of less than 5 MW from 2034 to 2038.

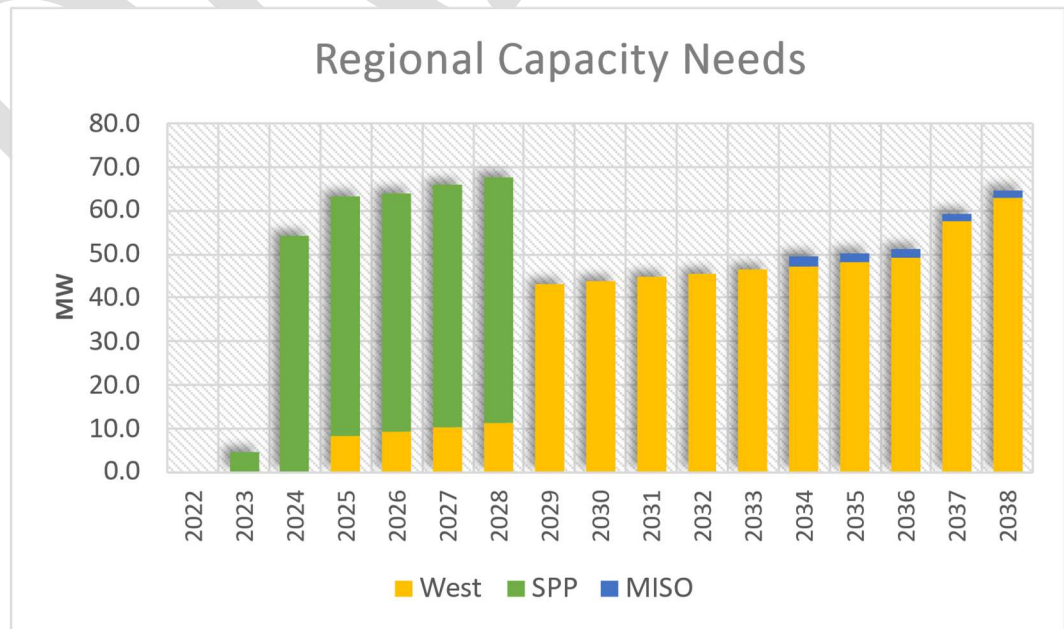


Figure I-16

The regional energy needs look very different. Both SPP and the West have an energy deficit from 2024 until 2038. SPP's energy need starts at 118,000 MWh in 2024 and increases to 250,000 MWh in 2038. In the West, resources are needed to supply 46,000 MWh in 2024 and grow to 358,000 MWh in 2038. MISO has no energy needs in the future.

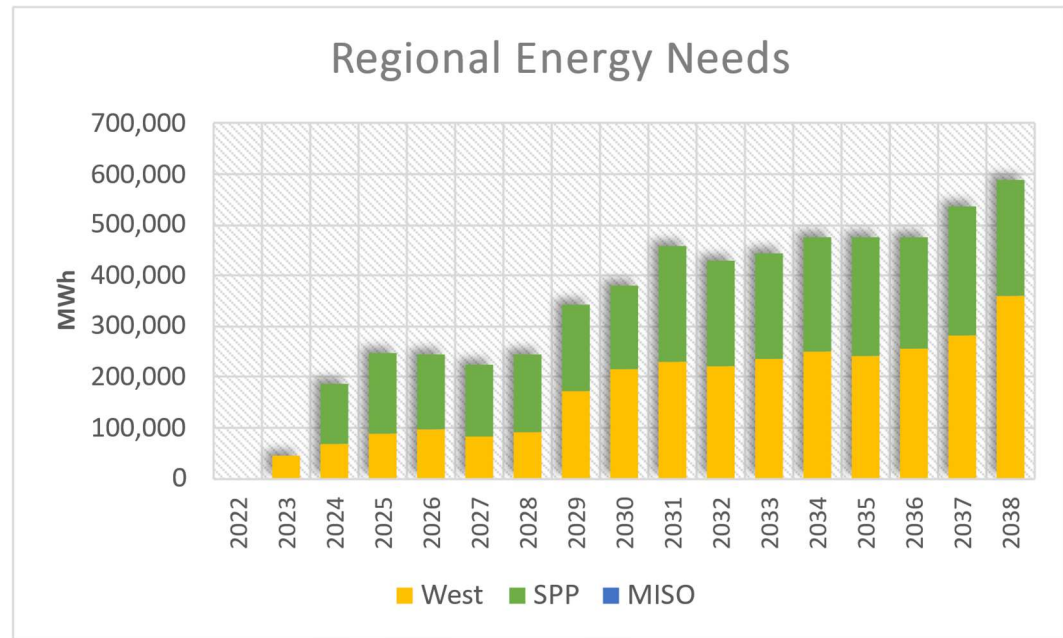


Figure I-17

J. Transmission

MEAN is a transmission-dependent utility and receives transmission services provided by SPP, MISO and multiple transmission providers in the Western Interconnection.

SPP and MISO network and point-to-point transmission service agreements provide MEAN with sufficient access to transmission facilities to deliver energy to the MEAN Participants, to participate in the SPP and MISO energy markets, and to sell excess generation and purchase replacement energy when generation is not available or it is economically beneficial.

MEAN has several agreements with Black Hills Power which provide for firm point-to-point transmission service and non-firm point-to-point transmission service for use in making deliveries to Participant loads, resource deliveries to adjacent transmission networks, as well as energy sales to other regional utilities. WAPA-RMR and WAPA-CRCM provide network integration transmission service to MEAN Participants connected to these two transmission systems. MEAN's point-to-point transmission service agreements with WAPA-RMR permit electricity produced from certain west resources to be moved to the transmission networks of other providers. MEAN contracts for network transmission service, short-term point-to-point transmission service, and non-firm point-to-point transmission service with Tri-State and PSCo.

MEAN has recently requested rights to transfer energy from east to west across the DC Tie at the Sidney Converter Station. MEAN's request under study would grant rights to transfer 34 MW beginning in 2024. A request has been submitted to obtain additional rights when they become available in future years. This allows MEAN to expand the application of resources to load with the

ability to utilize SPP resources in the West. However, transmission across the DC Ties has associated costs, which have yet to be defined or quantified as the SPP West RTO is being developed

K. Phase I Supply Side Resource Evaluation

1. Phase I Supply Side Evaluation Objectives

Phase I is a preliminary evaluation undertaken to investigate a comprehensive list of supply side options and focus this list down to fewer qualified options that prove to be feasible potential additions to the MEAN portfolio. The Phase I evaluation is in large part qualitative and based on simplified, static metrics. A more in-depth economic analysis is reserved for the qualified options in Phase II.

2. Supply Side Options

To follow in *Figure I-47* is the complete list of the supply side options included in the Phase I evaluation for MEAN's future resource needs.

Supply-Side Resource Options	
Fossil Fuel	Natural Gas Combustion Turbine
	Natural Gas Combined Cycle*
	Reciprocating IC Engine
	Co-Fire (retrofit existing)
Carbon Neutral	Small Modular Nuclear
	Nuclear Large Scale
	Geothermal
	Biomass (100%)
	Landfill Gas/ MSW
	Hydropower
	Wind
	Utility Solar
	Community Solar
	Green Hydrogen
	Fuel Cell
Storage	Battery Storage
	Solar + Storage
	Pumped Hydropower

*with and without CCS

Figure I-18

3. Criteria

The goal of Phase I was to narrow the complete list of supply side options to a list of qualified options that represent the most feasible supply side resources for MEAN to input into the portfolio model. To select the qualified options, appropriate criteria had to be assigned. To this end, MEAN conducted an online survey wherein the participants were asked to rank a list of criteria in terms of importance in resource selection.

The results of the survey indicated that the participants' most important criteria in resource selection is Cost. This was followed by Long Term Debt, Transmission Availability and Cost, Local Benefit, Resource Adequacy, and Future Capital and Decommissioning

Costs. The lowest priorities were Fuel Diversity, PPA vs. Ownership, and Environmental Policy Risk. The complete results are shown in the graph in *Figure I-48*.

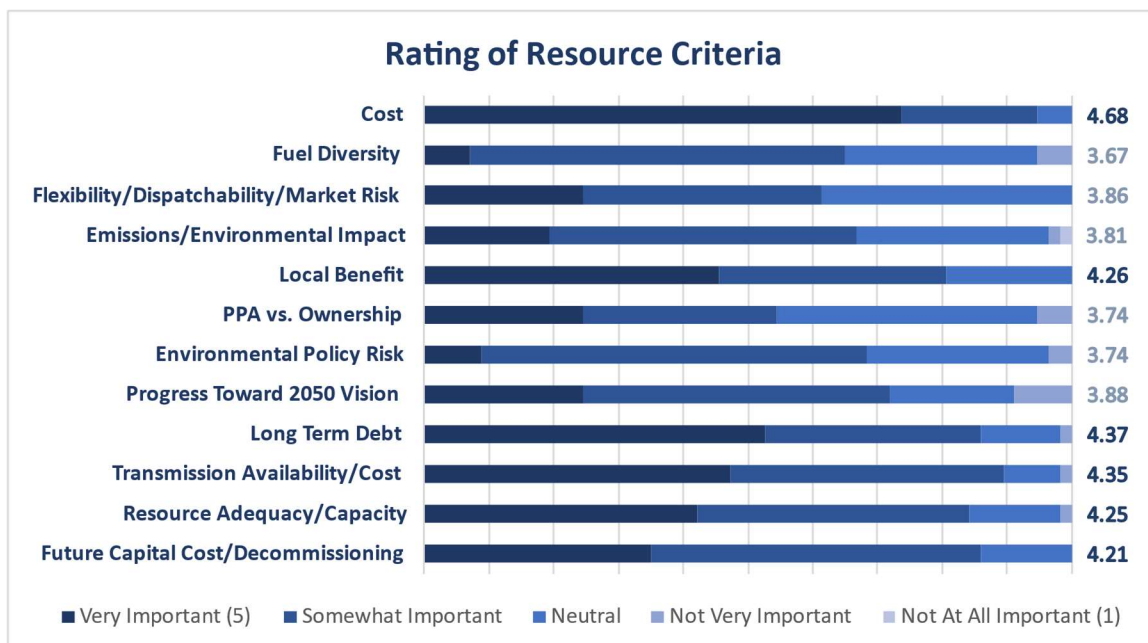


Figure I-19

The chart in *Figure I-49* shows the total combined weighted score for each of the supply side options. The individual components of the score are color coded by criteria as described above. Input data for this evaluation is located in Appendix B.

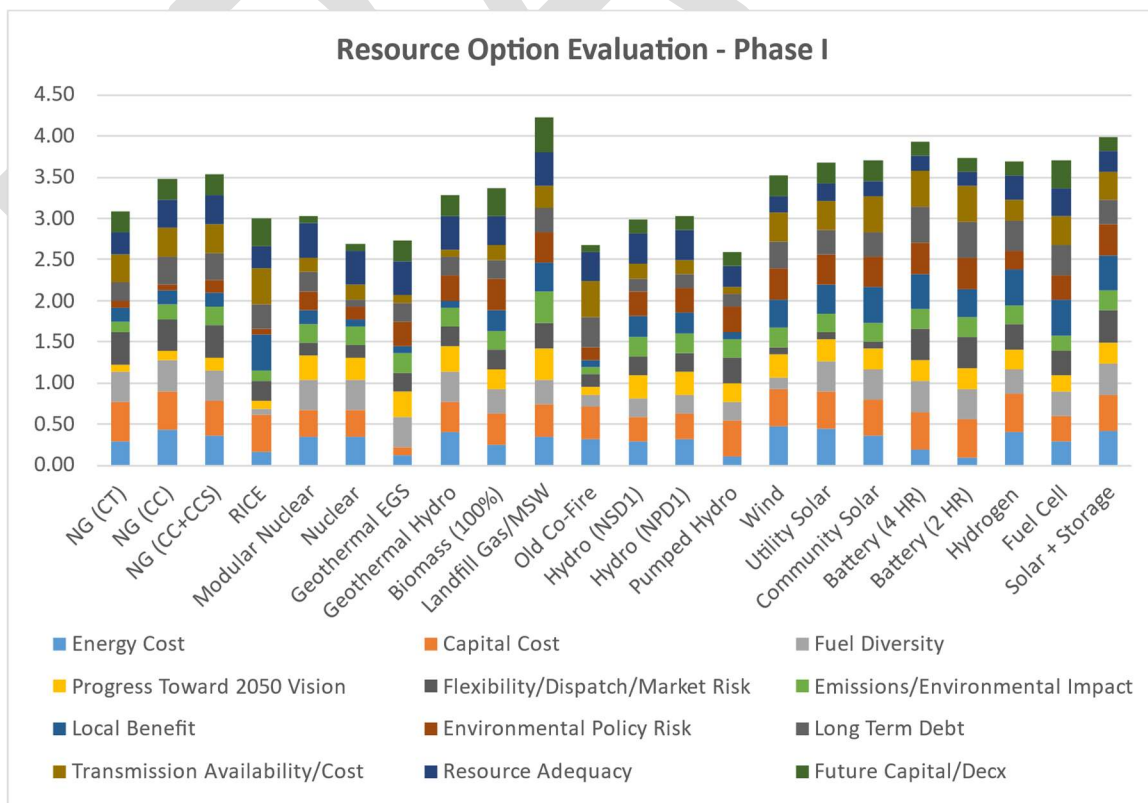


Figure I-20

4. Qualified Options

The Phase I evaluation resulted in final combined weighted scores for each of the supply side options defined at the beginning of the process. Because the criteria were weighted according to the participants' survey, the scores reflect the options most likely to achieve the priorities of the participants. The top scoring options were:

- Landfill Gas/Municipal Solid Waste
- Solar+Storage
- Battery Storage
- Utility/Community Solar
- Fuel Cell
- Wind
- Hydrogen Storage
- Natural Gas Combined Cycle

In discussions at the Power Supply Committee meetings and discussions with individual member representatives, participants suggested adding to the qualified options determined by the Phase I evaluation.

Next Era Solar: MEAN is in discussions with NextEra Energy regarding a proposed solar installation near the town of Sidney, Nebraska.

Local Hydropower: Although hydropower scored too low in the Phase I evaluation to qualify for Phase 2 modeling, MEAN has considered specific potential local hydropower projects for Power Purchase Agreement participation.

Participant Owned Generation: Several workshop attendees favorably discussed the option of allowing participants to install new behind-the-meter generation to their community fleet and add these units to MEAN's portfolio through the same contract by which MEAN leases existing generation. This is an option that would fulfill capacity needs in portfolios that add intermittent generation with low capacity accreditation.

Extension of PPAs: MEAN is party to several Power Purchase Agreements that are scheduled to expire during the study period. An extension of a PPA for power from Cooper Nuclear Station was added as an option. This has not been officially offered or discussed with NPPD and is only added as a studied option to determine its viability compared to other supply side resources.

Extension of Marketing Agent Arrangements: Under the Marketing Agent Agreement, MEAN leases certain capacity amounts termed Short-Term Leased Capacity and Excess Capacity at different payment terms for 2-3 year time periods. This agreement includes a total of approximately 40 MW. The current contract term extends through the MISO Planning year 2022-23. Of the total behind-the-meter generation of IMU and WU, a portion is exported from MISO to SPP. Extension of these contracts would provide SPP with additional capacity needed for resource adequacy to allow future renewable generation resources that carry low accredited capacity.

L. Demand Side Option Evaluation

Demand side management (“DSM”) programs can be utilized to reduce peak demand and thereby eliminate or delay the need for future capacity additions. Alternately, DSM measures can be designed to lower energy consumption to decrease the energy generation required by existing and future resources. Since MEAN’s load and resource balance shows a future deficit in terms of both capacity and energy, both types of DSM are viable solutions.

In an attempt to minimize the required supply side resources to meet MEAN’s total obligation, a demand side resource evaluation was performed to determine the value of proposed DSM programs.

1. Market Feasibility

The first step in the analysis was to determine the market feasibility of the potential programs. In January 2021 MEAN conducted an online survey to ask each community’s MEAN representative to rate the potential implementation in their community of each of the prospective DSM programs. The results of the survey are shown in *Figure I-50*.

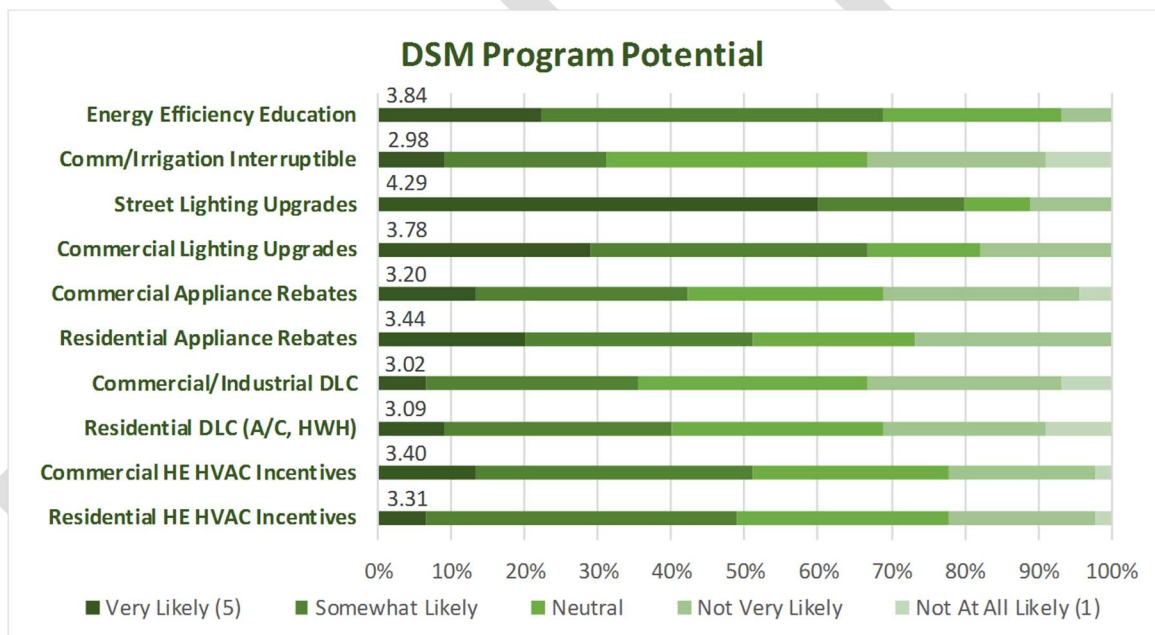


Figure I-21

2. Qualified Options

Based on the results of the Participant survey, the qualified options were Residential and Commercial Appliance Rebates and Residential and Commercial High Efficiency HVAC Incentives. In order to perform a more accurate analysis, these categories were studied and more specific programs defined for the next step in the analysis. The following DSM programs were advanced to the final analysis:

Residential and Commercial Appliance Rebate Programs:

- Refrigerator Rebate
- Freezer Rebate

Residential and Commercial High Efficiency HVAC Incentives:

- Heat Pump Water Heater Incentive
- Room Air Conditioner Upgrade Incentive
- Central Air Conditioner Upgrade Incentive

3. Economic Feasibility

The costs and benefits of the proposed DSM programs were compared using three different calculation methods, all of which are commonly used by utilities for this purpose. These three tests consider the costs and benefits of the DSM programs from different perspectives. A calculated ratio greater than 1 indicates benefits that exceed costs.

- The Utility Cost Test (“UCT”), also called the Program Administrator Cost Test. This test measures cost-effectiveness from the viewpoint of MEAN.
- Participant Cost Test (“PCT”). This test measures benefits and costs to the retail end-use customers participating in DSM programs.
- Total Resource Cost Test (“TRC”). This test examines each program from the viewpoint of the entire system, from MEAN to the retail end-use customer.

The table in *Figure I-51* summarizes the benefits and costs included in the calculations of the ratios.

TEST	BENEFITS	COSTS
Utility Cost Test	Utility Avoided Costs	• Program Administration Costs • Incentives/Rebates Paid
Participant Cost Test	Net Bill Savings	• Incremental Cost of Investment (Net of Incentive/Rebate)
Total Resource Cost Test	Utility Avoided Costs	• Program Administration Costs • Incremental Cost of Investment

Figure I-22

4. Results

The costs and benefits as described above were applied to the number of potential market participants for each of the proposed DSM programs. The costs were escalated and summed for a ten-year period. Finally, a Net Present Value was calculated for the annual costs and benefits and this value used to determine the final benefit/cost ratio. The results of the three Benefit/Cost tests are shown in *Figure I-52*.

DSM PROGRAM	UTILITY COST TEST (Benefit/Cost)	PARTICIPANT COST TEST (Benefit/Cost)	TOTAL RESOURCE COST TEST (Benefit/Cost)
Room Air Conditioner Rebate	0.0310	1.2112	0.0365
Central Air Conditioner Incentive	0.0706	0.0931	0.0396
Refrigerator Rebate	0.0246	0.0468	0.0147
Freezer Rebate	0.1473	0.8461	0.1831
Heat Pump Water Heater Rebate	0.2425	0.5353	0.2179

Figure I-23

As stated initially, only a ratio greater than 1 would indicate that a program is likely to result in benefits that outweigh its costs and therefore provide a net positive impact to MEAN or the end-use customer, depending on the test. In total, only one program had a favorable result, and in only one of the tests. Therefore, none of the potential programs would prove beneficial to MEAN and the end-use customer to a point that would compensate for the required costs.

5. Other Future DSM Projects

- Through work with the Nebraska Municipal Power Pool organization and other statewide utilities, MEAN continues to seek opportunities to assist communities with energy efficiency education efforts. Recent educational sessions have been made available for MEAN member communities on topics including Electric Vehicle Charging Stations and Specifications as well as Community Solar Projects. MEAN's Services Committee regularly evaluates the potential for future programs and continuing education opportunities that align with overall member interest and budget limitations
- MEAN and Pool will be exploring the implementation of an incentive for residential electric vehicle charging stations. MEAN anticipates that several communities will have a high degree of interest to participate. The potential applications and developments of this project could prompt a high level of collaboration between MEAN staff and member community staff and intense study of community interest, use profiles, and retail rate structure.
- MEAN is working on a project to provide advanced metering infrastructure (AMI) services to member communities. In response to member community interest, MEAN conducted an RFP for pricing of an aggregate AMI procurement. Fourteen (14) communities have signed letters of intent to participate in this project, representing a total of approximately 10,500 meters. Participating communities could use this system to perform demand side management at the individual meter level. With the proliferation of residential distributed generation, electric vehicle charging, and residential energy storage, AMI offers significant opportunity for demand control for the enhancement of DSM technologies. The use of DSM allows communities to control their energy peak and by extension, potentially reduce the need for MEAN to procure additional resources in the future.

M. Phase II Analysis and Results

The qualified options from the Phase I supply side evaluation are combined with MEAN's existing contracted resources to create a number of future resource portfolios for study in the Phase II economic analysis. Each resource was sized to provide for the energy deficit of the region, and additional required capacity above the accredited capacity of the resource was modeled as a capacity purchase, prioritizing the lease of member owned generation resources. The date on which a resource is modeled to begin generation is aligned with the timing of the regional resource deficit.

1. Studied Portfolios

SPP

- Portfolio 1: Natural Gas Combined Cycle
- Portfolio 1D: Natural Gas Combined Cycle with Carbon Capture
- Portfolio 2: Landfill Gas
- Portfolio 3: Municipal Solid Waste
- Portfolio 4: Utility Scale Wind
- Portfolio 5: Utility Scale Solar
- Portfolio 6: Natural Gas Fuel Cell
- Portfolio 7: Hydropower
- Portfolio 8: Wind + Battery Energy Storage
- Portfolio 9: Solar + Battery Energy Storage
- Portfolio 10: Extension of Cooper Nuclear Station PPA

West Region

- Portfolio 1: Natural Gas Combined Cycle
- Portfolio 1D: Natural Gas Combined Cycle with Carbon Capture
- Portfolio 2: Landfill Gas
- Portfolio 3: Municipal Solid Waste
- Portfolio 4: Utility Scale Wind
- Portfolio 5: Utility Scale Solar
- Portfolio 6: Natural Gas Fuel Cell
- Portfolio 7: Hydropower
- Portfolio 8: Wind + Battery Energy Storage
- Portfolio 9: Solar + Battery Energy Storage

2. Economic System Model

The Economic System Model used for the portfolio analysis is depicted in the *Figure I-53* graphic:

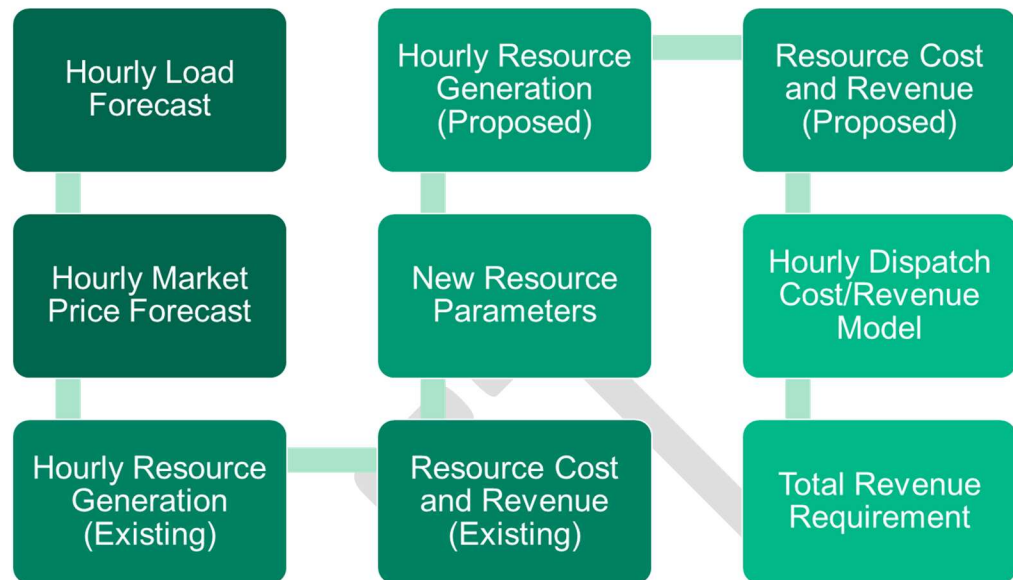


Figure I-24

3. Sensitivity Scenario Analysis

The model was expanded to include the effects of a number of different scenarios. As external conditions change, generation costs and market costs change. This alters the economics of each portfolio in a different way. Three very significant factors that affect generation are system load, natural gas prices, and the potential of a carbon tax.

The sensitivity analysis included three levels of system load and natural gas pricing: low (lower than current projections), base (equal to current projections), and high (higher than current projections). These variables were combined with two different carbon tax structures. In this way, comparisons between different scenarios can isolate the impact of load, natural gas pricing, and carbon cost, as the other variables are held constant.

The table in *Figure I-54* displays the scenarios under which the model was simulated. Each portfolio was entered into the model for each sensitivity.

Scenario	System Load	NG Pricing	CO ₂ Tax
Scenario 1: Reference	Base Case Load	Base Case NG	No CO ₂ Tax
Scenario 2: High Load	High Load	Base Case NG	No CO ₂ Tax
Scenario 3: Low Load	Low Load	Base Case NG	No CO ₂ Tax
Scenario 4: High NG	Base Case Load	High NG	No CO ₂ Tax
Scenario 5: Low NG	Base Case Load	Low NG	No CO ₂ Tax
Scenario 6: Zero Carbon*	Base Case Load	Base Case NG	No CO ₂ Tax
Scenario 7: High NG CO₂	Base Case Load	High NG	CO ₂ Tax
Scenario 8: Low NG CO₂	Base Case Load	Low NG	CO ₂ Tax
Scenario 9: Carbon Tax	Base Case Load	Base Case NG	CO ₂ Tax

*Zero Carbon Scenario assumes regulatory conditions that allow no future addition of carbon emitting resources.

Figure I-25

For the model results, Scenario 1, which included the base case load, base case natural gas pricing and no carbon tax, was considered the base case. Other scenarios indicate a variation from the base case conditions.

4. SPP Model Results

Figure I-55 shows the results of the SPP model for all eleven portfolios listed in Section I.M.1. and all nine scenarios shown in Figure I-54. The dark blue bar represents the base case total revenue requirement for each portfolio. The light blue vertical line shows the range between the maximum revenue requirement of the sensitivity scenarios and the minimum revenue requirement of the sensitivity scenarios. This range is termed the “scenario variance”.

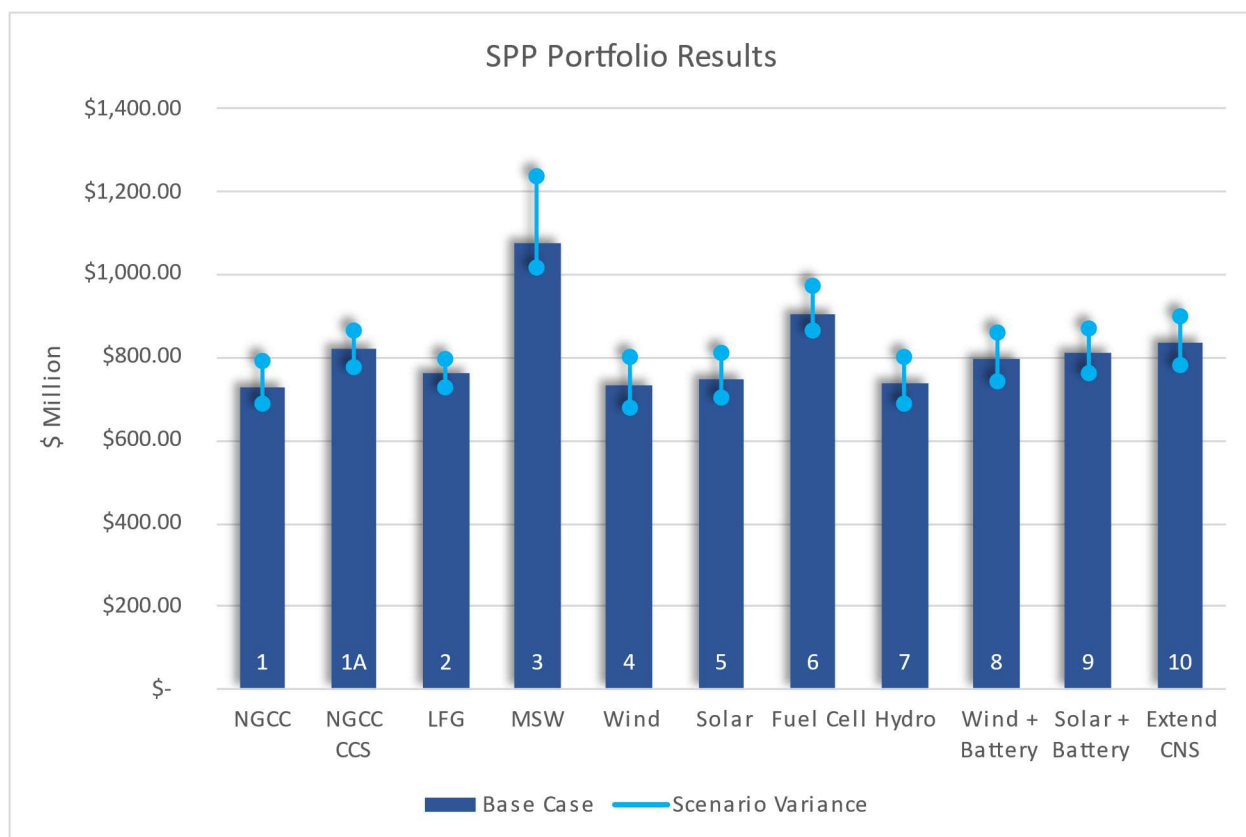


Figure I-26

The positive variance, or the differential between the maximum scenario revenue requirement and the base case revenue requirement, quantifies the volatility or risk inherent in each portfolio relative to possible changes in system load, fuel pricing, and carbon tax levels. Plotting the base case revenue requirement against this variance allows a concurrent view of cost and risk for each of the SPP Portfolios. To get a more distinct picture of the relative positions of the portfolios, Portfolio 3 is omitted from the graph in Figure I-56 to follow as its outlying position distorted the scale of the graph.

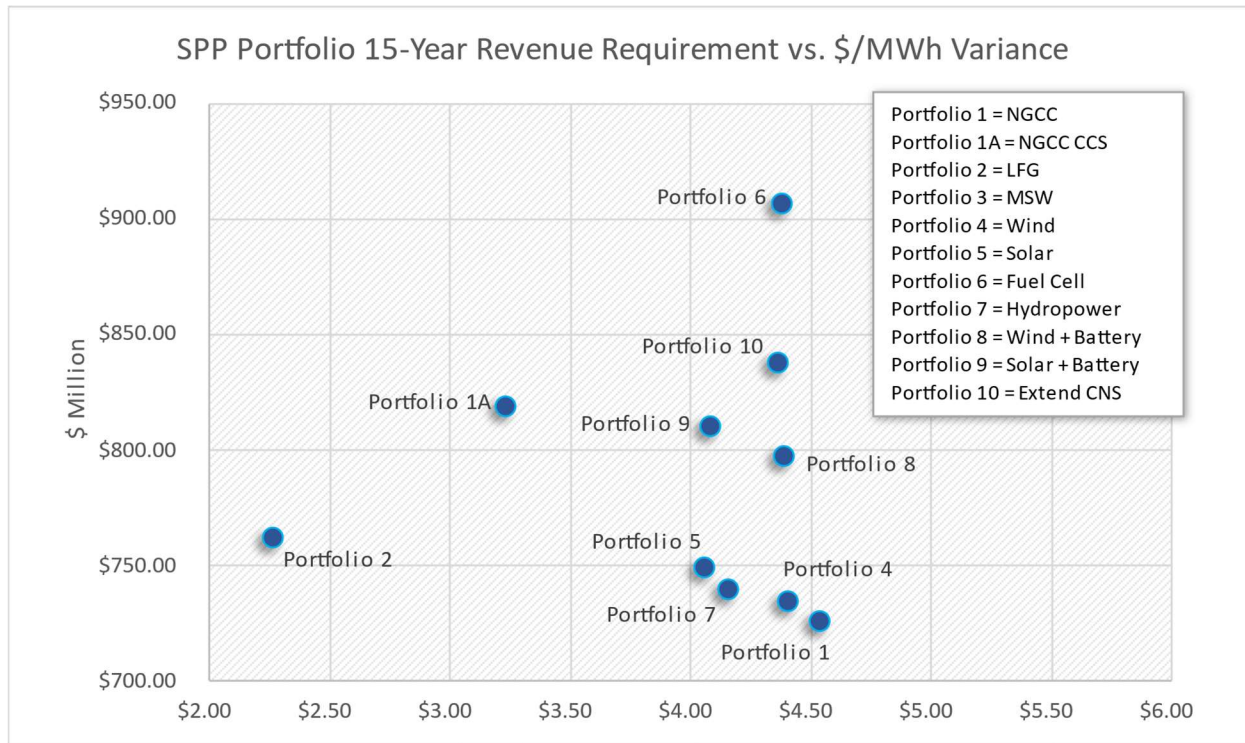


Figure I-27

The values and graphical results show that Portfolio 1, the natural gas combined plant, has the lowest revenue requirement. However, Portfolio 4 (Wind), Portfolio 7 (Hydro), Portfolio 5 (Solar) also have low revenue requirements and have variance levels that are as low or lower than Portfolio 1. Portfolio 2 (LFG) has a slightly higher revenue requirement and a much lower variance level.

5. West Region Model Results

Figure I-57 shows the results of the west model for all nine portfolios and all nine scenarios. The dark green bar represents the base case total revenue requirement for each portfolio. The light green vertical line shows the range between the maximum revenue requirement of the sensitivity scenarios and the minimum revenue requirement of the sensitivity scenarios. This range is termed the “scenario variance”.

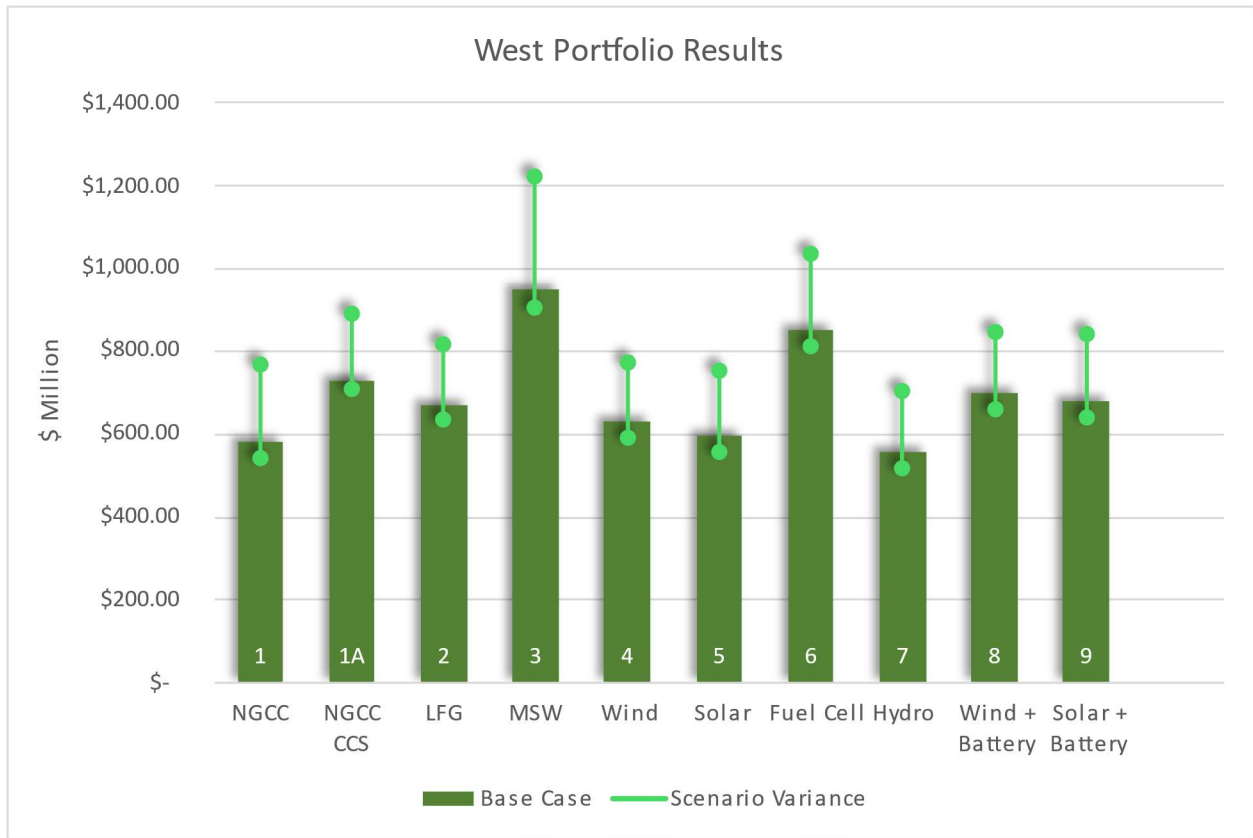


Figure I-28

The positive variance, or the differential between the maximum scenario revenue requirement and the base case revenue requirement, quantifies the volatility or risk inherent in each portfolio relative to possible changes in system load, fuel pricing, and carbon tax levels. Plotting the base case revenue requirement against this variance allows a concurrent view of cost and risk for each of the west Portfolios. To get a more distinct picture of the relative positions of the portfolios, Portfolio 3 is omitted from the graph in *Figure I-58* to follow.

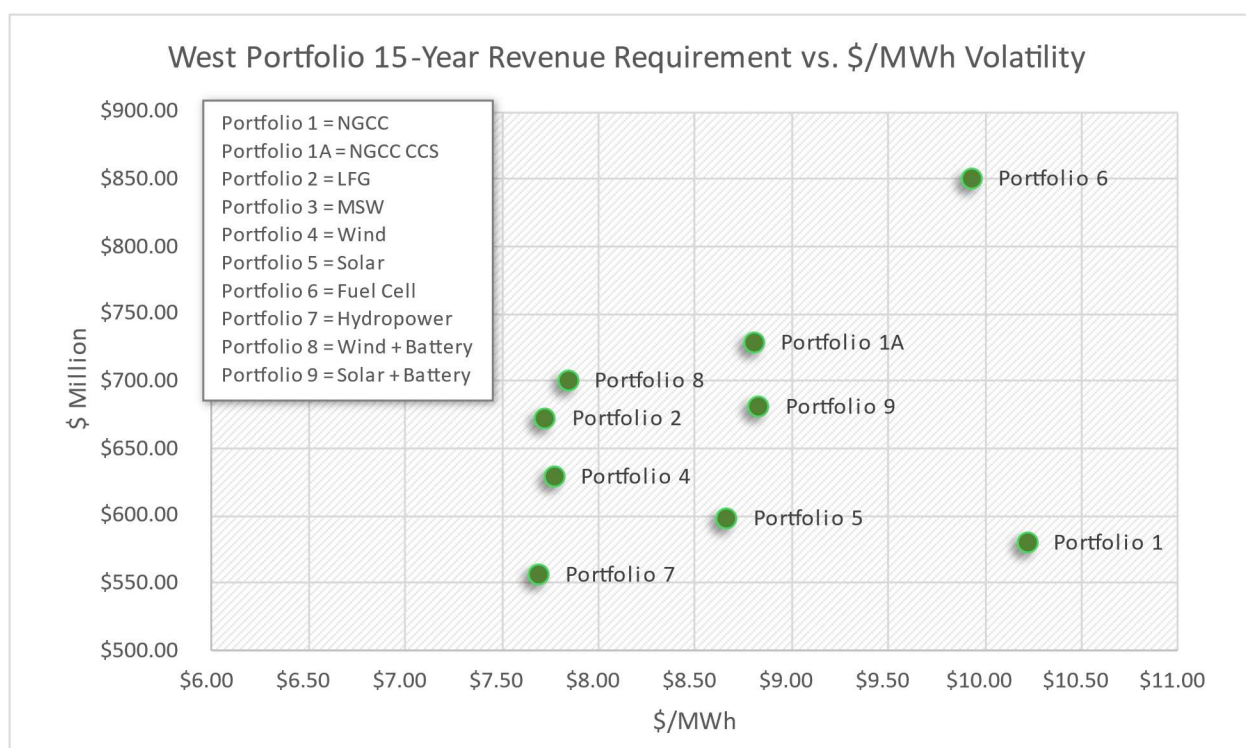


Figure I-29

The values and graphical results show that Portfolio 7, the hydropower plant, has the lowest revenue requirement, and the lowest variance level. However, Portfolio 5 (Solar) and Portfolio 4 (Wind) and revenue requirements and variance levels similar to that of Portfolio 7. Portfolio 1 (NGCC) resulted in a low revenue requirement, but a much higher level of variance. Portfolio 8 (Wind + Battery) and Portfolio 9 (Solar + Battery) align well with the corresponding Portfolios 4 and 5, but have the expected higher cost. Portfolio 2 (LFG) has a low variance level and a moderate revenue requirement.

N. Environmental Impact

1. Existing Environmental Considerations

MEAN is subject to environmental and other regulations, in varying degrees, at federal, state and local levels. As part of a long-term strategy, MEAN has invested in environmental regulation compliant base load generating resources expected to provide highly reliable base load generation for the Participants' present and future energy requirements. In addition to these state-of-the-art coal facilities and WAPA allocations, MEAN has acquired renewable resources and nuclear capacity.

MEAN has adopted the 2050 Vision which aims to create a carbon neutral resource portfolio by the year 2050. Future resource planning will follow the direction of the 2050 Vision, replacing carbon emitting resources with carbon free resources as existing contracts expire or resources reach the end of their operating life.

In the Phase I evaluation of supply side options, environmental impact was considered for all options as part of the scoring process.

2. Portfolio Carbon Intensity

To comply with the internal 2050 Vision direction to reduce the emissions of MEAN's resource portfolio with the goal of reaching carbon neutrality by 2050, resources must be evaluated on their impact to the portfolio's carbon intensity, or the tons of carbon emitted per MWh of energy generated.

Using the resultant energy generation of each resource in the candidate portfolios, both existing resources and future proposed resources, and the known emissions factor and heat rate of each resource, the carbon intensity of the portfolio can be calculated on the basis of tons of carbon emissions per MWh of electricity generated. This calculation is shown for all portfolios in the graphs below. *Figure I-59* shows all SPP Portfolios, while *Figure I-60* excludes Portfolio 3 to better show the comparative scale of the remaining Portfolios.

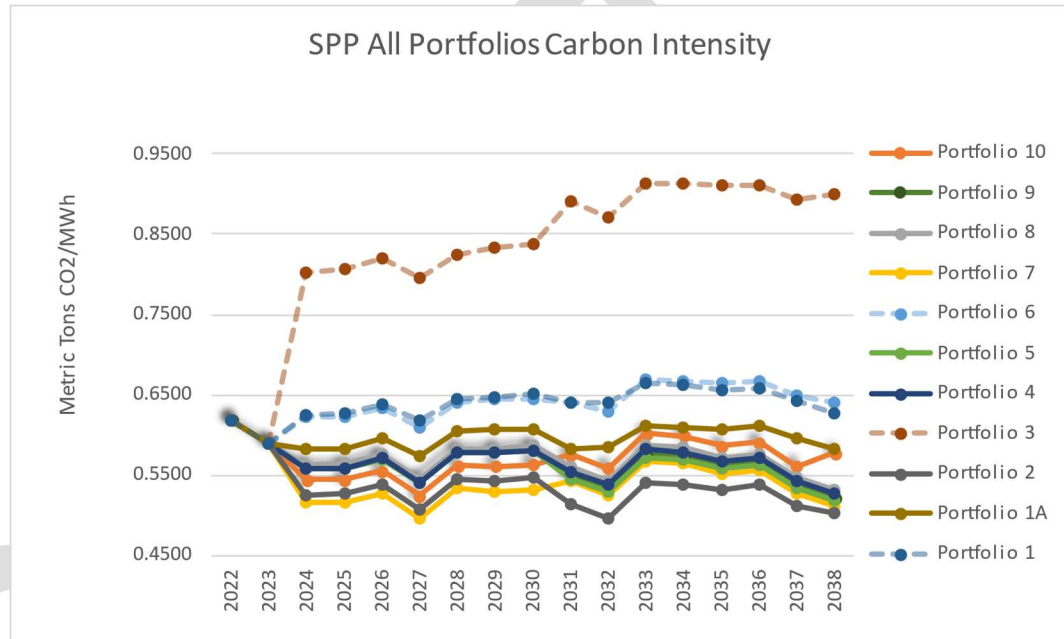


Figure I-30

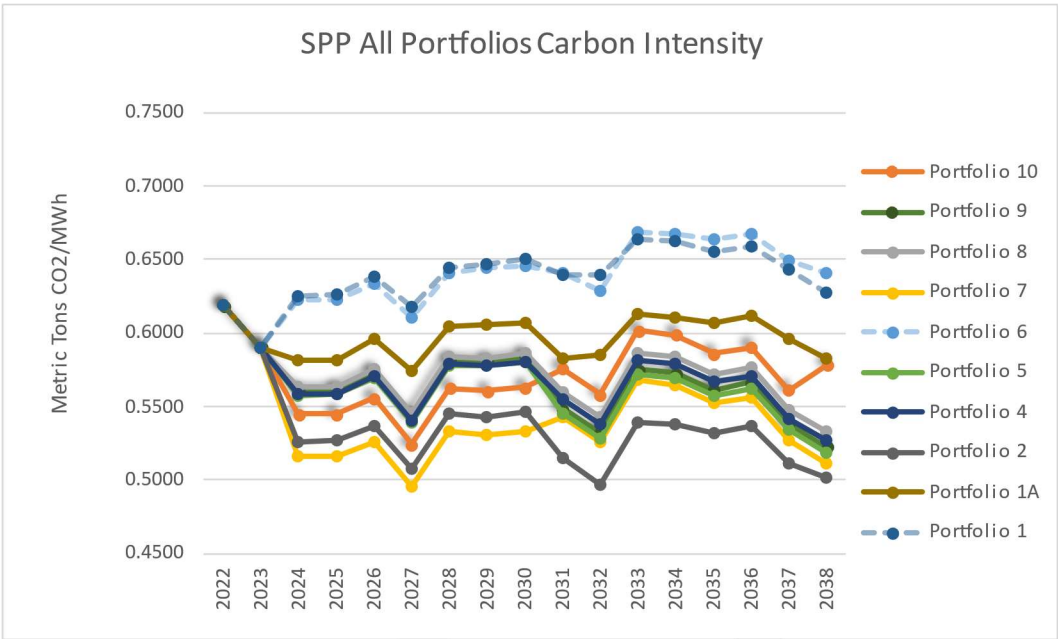


Figure I-31

Figure I-59 shows all West Portfolios, while Figure I-60 excludes Portfolio 3 to better show the comparative scale of the remaining Portfolios.

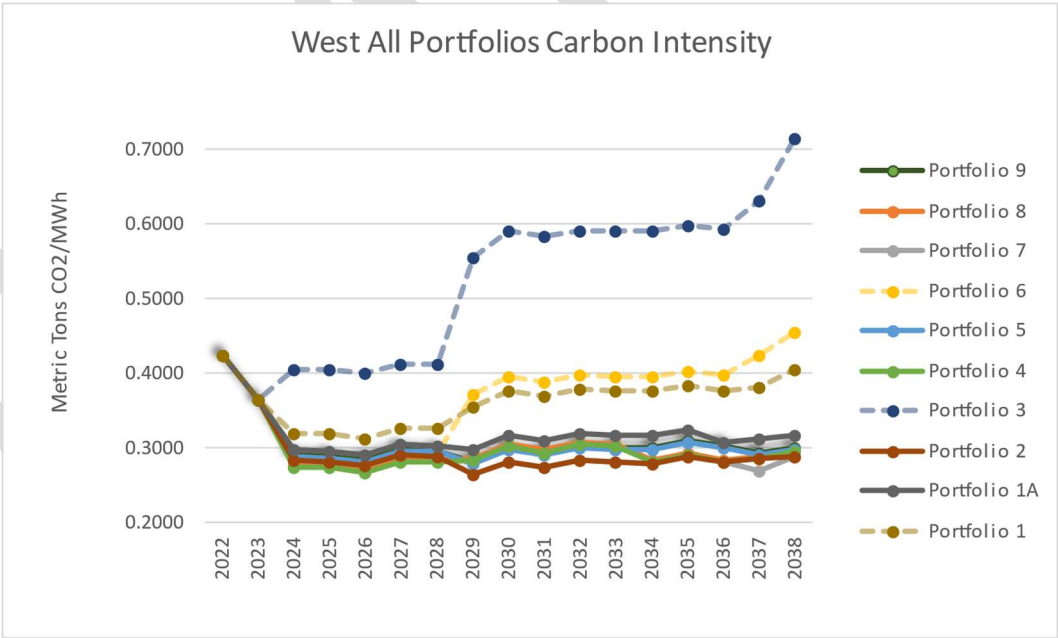


Figure I-32

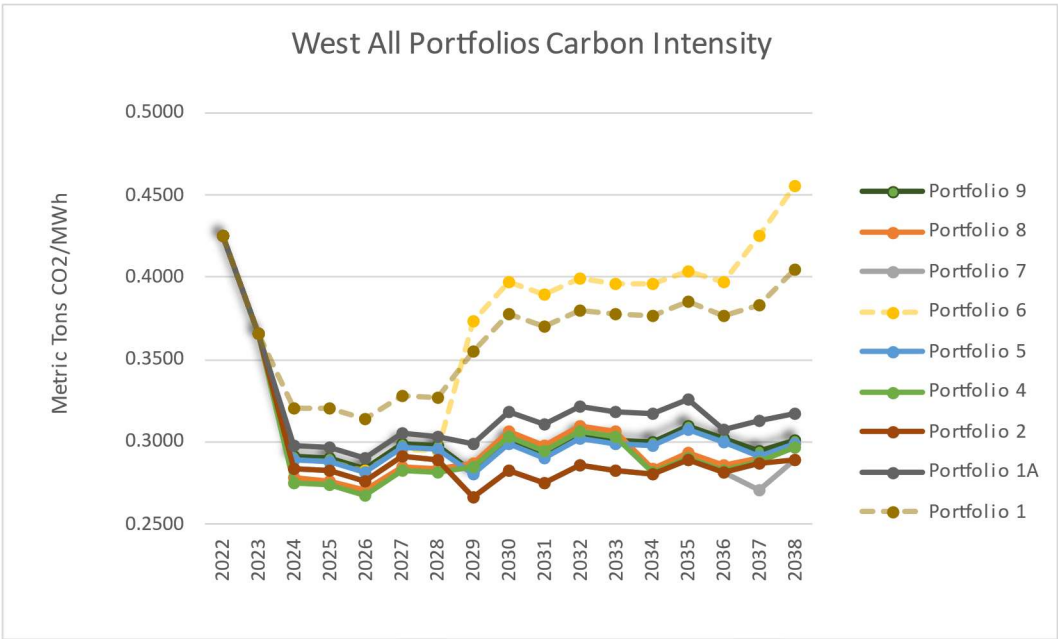


Figure I-33

3. Carbon Cost Scenario Impact

The inclusion of the carbon tax sensitivity scenarios provides a method by which the impact of carbon emissions can be financially quantified for each portfolio as a whole. For each level of natural gas pricing, the results for the scenarios with no carbon tax can be compared against the results for the scenarios with a carbon tax to show the consequence of the carbon emissions level in the portfolio. The average variance resulting from only the carbon tax (holding the natural gas pricing constant) is shown in *Figures I-61 and I-62*.

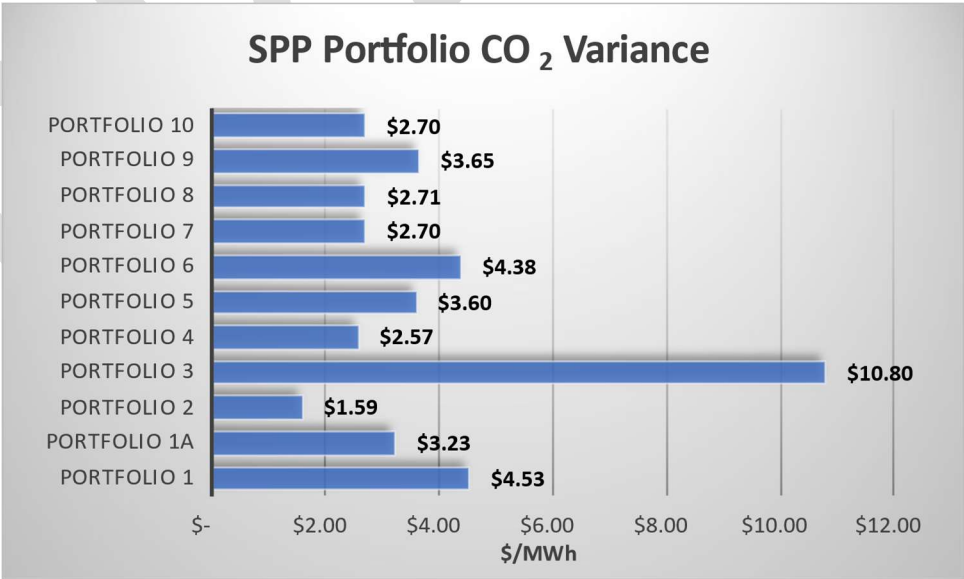


Figure I-34

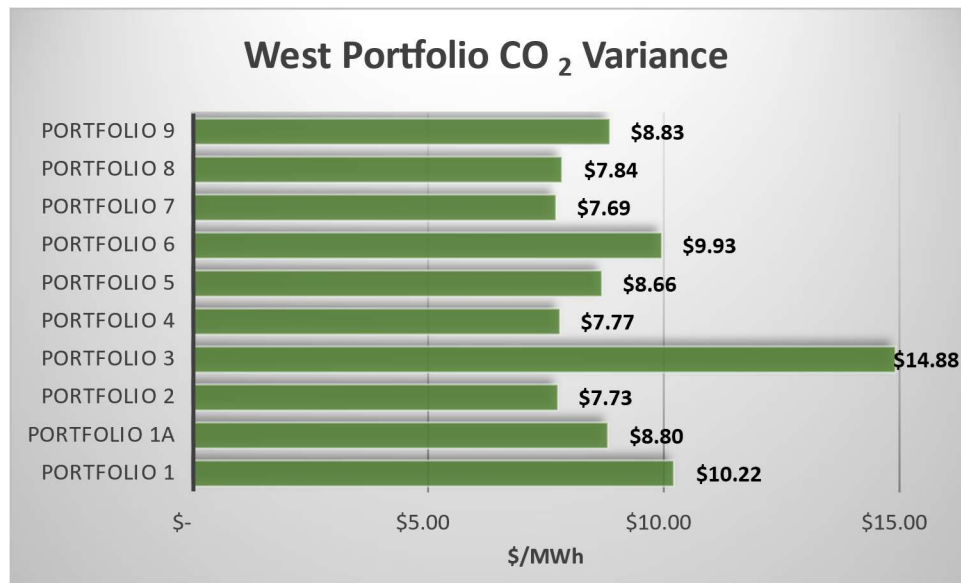


Figure I-35

These results show an expected relation. Portfolios that include more fossil fueled generation see a higher cost impact from a carbon tax. In this way, higher emitting resources are “penalized” in the model with a higher degree of variance. The effects of carbon emissions were included in the variance factor used in the analysis of the final portfolio results.

O. Conclusions and Recommended Action Plan

Based on the data and analysis in this IRP report, MEAN has developed conclusions relative to proposed demand side solutions and supply side solutions.

1. MEAN’s Future Resource Needs - Conclusions

In the SPP service territory, MEAN has a need for capacity in the near term only. A capacity deficit of approximately 55-60 MW occurs from 2024-29 and is resolved when the WAPA Displacement Agreement ends. The energy deficit occurs throughout the study period, increasing with time.

In the West region, MEAN has capacity deficit of approximately 10 MW from 2025-28, which then increases to 45 MW when the WAPA Displacement Agreement ends and grows for the remainder of the study period to about 65 MW in 2038. The West region has a need for energy throughout the entire 15 years, which increases each year.

2. Demand Side Management – Conclusions

New DSM Programs: The costs and benefits of the proposed new DSM programs were compared using three different calculation methods. In total, only one program had a favorable result, but in only one of the three tests. Therefore, none of the potential programs would prove beneficial to MEAN and the end-use customer to a point that would compensate for the required costs. MEAN has plans to investigate future energy efficiency education opportunities and a program to offer incentives for residential EV chargers. Data will be presented to the MEAN Services Committee for approval in the coming months.

Commercial LED Lighting Upgrade Program: The average annual energy savings achieved by the program are approximately 1,247 MWh, and the peak demand savings per year has been approximately 249 kW. These savings are reflected in the current load forecast. The NMPP Services Committee has approved the continuance of the LED Lighting Upgrade program through FY 22-23.

Residential Energy Efficiency Programs: After the successful introduction of these programs in FY21-22, incentives available for Cooling System Tune-Ups, Attic Insulation, High Efficiency Heat Pumps and Smart Thermostat Installations will continue to be offered to MEAN participants.

Advanced Metering Infrastructure: MEAN is working on a project to provide advanced metering infrastructure (AMI) services to member communities. Fourteen (14) communities have signed letters of intent to participate in this project, representing a total of approximately 10,500 meters. If approved, this project is slated to begin implementation in 2022.

Other MEAN DSM programs currently active will be continued.

Participant DSM Programs: The 2021 Participant DSM survey revealed a total of 17 communities with 33 DSM programs in place. The non-coincident sum of the demand and energy savings from these DSM programs is 4.03 MW and 2,635 MWh, respectively. These community programs are expected to be maintained in future years. MEAN repeats the DSM survey on an annual basis to track these programs and the impact on MEAN's demand and load.

3. Supply Side Resources – Conclusions

Based on multiple opportunities for member feedback, this analysis has prioritized future resource portfolios that achieve a low 15-year revenue requirement, offer progress toward the 2050 Vision by reducing the carbon intensity of the regional portfolio over time, maintained the required flexibility to appropriately respond to market changes, and present potential for local benefit. Throughout the analysis, measurement of these priorities has been incorporated into the quantitative results.

SPP:

- The proposed portfolio in SPP that best achieved the primary goal of low cost was Portfolio 1, the addition of capacity and energy from a natural gas combined cycle plant located in the SPP footprint. This option also provides for operational flexibility and fuel diversity, but not local benefit. Portfolio 1 does not result in a decrease in carbon intensity for MEAN's resource portfolio.
- Portfolio 4, a wind resource for energy generation accompanied by a capacity purchase sized as required for resource adequacy, has a 15-year revenue requirement only marginally higher than that of the lowest cost option, and resulted in a lower cost variance across the pricing scenarios. In addition, Portfolio 4 allows for a 14.8% reduction in SPP portfolio carbon intensity.
- Portfolio 7, the hydropower option, also resulted in a low revenue requirement, a low cost variance, and a 17.4% reduction in carbon intensity for SPP. In SPP

there is not likely to be a hydropower resource that provides benefit to a MEAN community.

- The solar resource in Portfolio 5 had the lowest modeled cost variance and a 15-year revenue requirement that was similar to the lowest cost options. This option is also emissions free and therefore leads to a 16.2% reduction in the portfolio's carbon intensity over time. Additional required capacity would be provided by leased member generation as available.
- Portfolio 2, the landfill gas resource, has a lower than average revenue requirement and a much lower variance level. A landfill gas plant also has the potential to provide local benefit and lowers the carbon intensity of MEAN's SPP portfolio.
- Portfolios 8 and 9, the wind and solar with battery storage, may prove to be viable options in the future if the incremental cost of batteries decreases as expected in the future.

West:

- The proposed portfolio in the west that best achieved the primary goal of low cost was Portfolio 7, the hydropower resource. This portfolio also saw a very low level of cost variance, or cost risk. Being a carbon free resource, the addition of hydropower resulted in a 32.2% reduction in the carbon intensity of the West portfolio. MEAN is aware of hydropower options that may allow for a benefit to a MEAN community.
- The next lowest cost option in the West was Portfolios 5, the solar resource, with additional leased capacity from member generation. This portfolio carried increased volatility as compared to the hydro option. Solar also offers a local benefit potential and a reduction in carbon intensity of 29.9% in the West.
- The wind resource, Portfolio 4, has many of the same benefits. This option is lower than average revenue requirement, low cost variance, and reduces the carbon intensity of the west portfolio by 30.3%. Additional capacity is acquired through the lease of member generation.
- Portfolio 1, the Natural Gas Combined Cycle plant, results in a very low 15-year revenue requirement, but unfortunately carries a high variance risk as this option is impacted by natural gas pricing and CO₂ tax. This resource is unlikely to offer a local benefit, and only achieves a modest 4.9% reduction in carbon intensity.
- Portfolios 8 and 9, wind and solar with batteries, once again show the potential to be feasible options should the capital cost of battery storage decrease in the future.

4. Recommended Action Plans

Based on the conclusions of this report and Board recommendations, MEAN will determine short term and long-term action plans in relation to demand side management

resources and supply side resources in response to future projected capacity and energy deficits throughout its service territory.

Short-Term Recommended Action Plan (0-5 Years)

MEAN will continue to administer all current DSM programs. MEAN will revisit the proposed new programs upon any significant change in the analysis inputs to reevaluate the benefit to cost ratio. MEAN will perform analysis to determine the participation and economic feasibility of a residential EV charger incentive program. Participants will be encouraged to continue existing DSM programs and initiate any new measures welcomed by their communities. MEAN will continue to perform the DSM annual survey and include DSM demand and energy savings into the load forecast.

MEAN will continue to pursue the aggregated Advanced Metering Infrastructure project to assist member communities with the installation of hardware and software systems to facilitate smart metering and load control.

In SPP, MEAN will proceed toward the recommended portfolio option(s) to address the impending need for capacity and energy. MEAN has initiated discussions with and has received proposed cost and performance data from a developers and resource owners in SPP for projects that align with MEAN's needs. The IRP recommendations of the Board will direct these efforts and determine the projects MEAN staff will pursue.

In the West, MEAN will pursue the recommended portfolio(s) option to address the impending need for capacity and energy. MEAN has contracted to prepare and release a Request for Information to solicit offers for qualified resources in the West. This will provide cost and performance data on projects in development and available to fulfill MEAN's future resource needs.

In the summer of 2022 installation is scheduled to begin on the community solar projects MEAN is facilitating for member communities. MEAN will guide communities through the construction period and monitor system performance as individual facilities come online in 2023. MEAN will continue efforts to assist members with analysis and procurement of distributed generation systems.

MEAN will continue to monitor actual load for all participant communities and compare against the load forecast and against existing capabilities. Any significant change will trigger a revised resource plan to determine required modifications and future actions. MEAN will continue to survey members annually to gather input and verification of load and load-impacting developments in member communities.

MEAN will also continue to study the operation and performance of existing resources. In conjunction with changes to the SPP and MISO market constructs and the renewable penetration within these markets, MEAN will determine the ongoing impact to capacity accreditation and unit dispatch and the resulting change to the long-term load and capability balance.

In the short-term, MEAN will maintain communication with WAPA and review the hydrological forecasts pertaining to WAPA hydropower assets. If indications of future drought conditions persist, MEAN will prepare future load and capability scenarios to plan

for long-term reductions in available power from these resources and the acquisition of required replacement power.

Throughout MEAN's footprint, continual efforts will be made to acquire additional load. This development would allow further additions of carbon free resources to effect additional change to the portfolio's carbon intensity. Strategic load that can be shaped in the off-peak can also contribute to more efficient use of MEAN's energy generation.

Long -Term Recommended Action Plan (5-15 Years)

MEAN will regularly evaluate the impact and implementation of existing DSM programs. Based on the results of the evaluation, MEAN will continue to administer successful programs. MEAN will revisit the proposed new programs on a regular basis to recalculate the analysis inputs and reevaluate the benefit to cost ratio. Participants will be encouraged to continue existing DSM programs and initiate any new measures welcomed by their communities.

MEAN will explore opportunities to assist additional communities with optimizing AMI systems for load study and possible applications in load control and demand side management.

In SPP, in accordance with the recommendation of the Power Supply Committee, MEAN will secure a long-term solution for an energy resource for future years. MEAN will need to supplement the resource acquired in the short-term plan to generate additional energy in the out years. With cost and performance data available from the new short-term resource contract, future costs of new resources, and future market changes MEAN will perform updated analysis to determine if the resource portfolio recommended in this report is still the optimal selection.

In the West, MEAN will explore options to acquire contracts for the recommended resources for capacity and energy as determined by the Board. The long-term balance in the West requires a resource or multiple resources to provide capacity and energy in addition to new resources in the short-term time frame. Concurrently, MEAN will solicit its participants for opportunities to lease new or existing participant owned generation. Again, resource planning will require updated data and analysis in response to changes in resource costs, fuel costs, regulatory and market conditions, and current generation projections for existing resources.

MEAN will continue to monitor actual load for all participant communities and compare against the load forecast and against existing capabilities. Any significant change will trigger a revised resource plan to determine required modifications and future actions. MEAN will pay particular attention to activities targeted to increase electrification in member communities and study the anticipated changes in load profile and load growth. MEAN will continue to survey members annually to gather input and verification of load and load-impacting developments in member communities.

As discussions and development continues regarding plans to expand SPP to a West RTO, MEAN will remain engaged in the design of market structures and rules and will be prepared to optimize the current and future resource portfolio within the anticipated parameters of this new market. In the absence of an SPP West RTO, MEAN will closely monitor efforts in the Colorado legislature to enforce mandatory participation in an RTO.

MEAN will also continue to study the operation and performance of existing resources. In conjunction with changes to the SPP and MISO market constructs and the renewable penetration within these markets, MEAN will determine the ongoing impact to capacity accreditation and unit dispatch and the resulting change to the long-term load and capability balance.

MEAN will monitor federal, state, and local legislation to ensure that resources remain in compliance with all applicable regulations. Particular attention will be paid to regulations requiring investment in environmental controls and future resource transition plans. MEAN will also follow all portfolio standards and system emissions reduction requirements.

Throughout MEAN's footprint, continual efforts will be made to acquire additional load and extend terminating contracts. Depending on the load profile in comparison to the rest of MEAN's system load and resource additions made in the short term, there may be opportunities to supply energy without additional capacity investment. Opportunities to add off-peak load or control specific loads may change the utilization and economics of some resources.

P. Tracking/Measurement Strategy

MEAN will employ the following Measurement Strategies to gauge the progress and impacts of the Recommended Action Plans described above.

METRIC	MEASUREMENT STRATEGY	MEASUREMENT BASELINE
Load vs. Forecast	MEAN will annually compare the actual peak demand and energy consumption against the forecast values. Data will be tracked by participant, region, and system. MEAN also conducts an annual load survey to aid in this measurement.	• Annual Load Forecast • 15-Year Load Forecast • Hourly/Monthly Participant Load Data • Participant Load Survey
Load vs. Capability	On a semi-annual basis, MEAN is required to calculate and present to the Board the upcoming peak season Load and Capability balance for planning purposes. MEAN typically presents a long-term outlook. In this way, changes in the timing of deficits can be foreseen to prepare via resource planning.	• Annual Load Forecast • 15-Year Load Forecast • Resource Contracts • Hourly Resource Generation Data • Outage Schedules • Current Season Load and Capability Report
DSM Savings/Impact	MEAN conducts an annual DSM survey to all participants to gather data on the programs offered and the expected demand and energy savings. Responses will be compared year-to-year to verify savings. This is valuable in the contemplation of future programs. MEAN also tracks data on its administered Lighting Upgrade Program for estimated power savings.	• Previous Year Hourly Participant Load Data – Peak and Energy Usage • DSM Survey Responses • Energy Star® Energy Efficiency Calculation Tools
Distributed Generation	MEAN will continue to support efforts by member communities to install qualified projects	• Member Meter Data – Load • Member Meter Data – Generation

	under the DG Policy. Discussions initiated to explore other distributed technologies, such as energy storage and fuel cells, will continue as well. MEAN will explore the installation of MEAN-owned systems located in member communities and collaborations available with this approach. Load and meter data will be collected to measure the performance of the DG systems as available. This will be compared to expected generation. MEAN will update load forecasts and anticipated capacity and energy needs.	• DG System Performance • Evolving Costs of DG Installations
Existing Resource Performance	MEAN tracks the operation, performance, and cost of its contracted resources. This is measured against expected, budgeted, and contracted values and can be used to gauge the cost-effectiveness of existing and future resources. In the SPP and MISO markets, MEAN also tracks the locational marginal price to determine the actual total cost of the resource.	• Resource Contracts • Previous Year Hourly Resource Generation Data • Resource Invoices • LMP Data
New Resource Parameters	MEAN regularly tracks research on the costs and parameters of new resources. Understanding the performance of established and emerging technologies and the total generating cost in relation to market conditions will prepare MEAN for future resource acquisition. MEAN regularly discusses with developers their projects in the interconnection queue or under investigation.	• Resource Data Used for IRP (EIA, NREL, DOE) • Market Pricing • Developer Project Data
Market Construct Parameters	MEAN is actively involved with SPP, MISO, and WEIS Stakeholder Groups to engage in discussions regarding market constructs and rules. MEAN is also monitoring potential developments of a resource adequacy program in the West. In resource planning activities, MEAN will prepare a variety of future scenarios responsive to contemplated changes to quantify the impact to the MEAN system and inform future plans.	• Resource Adequacy Models • Resource Accreditation • SPP, MISO, and WEIS Tariffs • Current Market Constructs
Environmental Regulation	MEAN continually monitors environmental regulations, paying particular attention to future legislation affecting the power supply industry. When changes are proposed or adopted, MEAN projects the impacts on existing or potential future resources. Currently, MEAN is alert for changes in the status of the Clean Power Plan and power resource tax credits.	• Status Quo Regulations • MEAN's current compliance status

Figure I-36

II. IRP Requirements and Checklist

A. WAPA Requirements

Integrated resource planning was mandated by the Energy Policy Act of 1992 (“EPAct”).

EPAct requires all Western Area Power Administration (“WAPA”) customers to submit Integrated Resource Plans (“IRPs”) to WAPA every five years. The requirement is included in WAPA’s power sales contracts with long-term firm electric service customers. The current Resource Planning Approval Criteria (10 CFR Part 905) went into effect May 1, 2000, after WAPA reviewed the original regulations and completed a public process.

WAPA has identified the following criteria for customer IRPs:

- Identify and compare all practicable energy efficiency and energy supply resource options.
- Include action plan with timing set by customer.
- Describe efforts to minimize adverse environmental effects of new resource acquisitions.
- Provide ample opportunity for full public participation.
- Conduct load forecasting.
- Include brief description of measurement strategies for options identified in IRP to determine whether objectives are being met.

IRPs and alternative reports will be evaluated by WAPA on the basis of:

- Meeting all criteria in 10 CFR 905
- Reasonableness of the plan with regard to: customer size, type, resource needs, geographic area, and competitive situation
- Resource choice selection (EPAct 1992 section 114)

B. WAPA Utility/Customer Overview

The following customer profile data listed in *Figure II-1* is submitted to the U.S. Energy Information Administration (EIA) as part of the form EIA-861, summarizing MEAN’s service obligations during the most recent annual reporting period.

Reporting Period	
Reporting Period Start Date (mm/dd/yyyy)	01/01/2021
Reporting Period End Date (mm/dd/yyyy)	12/31/2021
Energy Sales & Usage	
Energy sales to Ultimate End Customers (MWh)	0
Energy sales for Resale (MWh)	1,982,845
Energy Furnished Without Charge (MWh)	0
Energy Consumed by Respondent Without Charge (MWh)	0
Total Energy Losses (MWh entered as positive number)	86,206
Total Energy Usage (sum of previous 5 lines in MWh)	2,069,051

Peak Demand (Reporting Period)	
Highest Hourly Summer (Jun. – Sept.) Peak Demand (MW)	477.0
Highest Hourly Winter (Dec. – Mar.) Peak Demand (MW)	399.0
Date of Highest Hourly Peak Demand (mm/dd/yyyy)	07/28/2021
Hour of Highest Hourly Peak Demand (hh AM/PM)	05 PM
Peak Demand (Historical)	
All-Time Highest Hourly System Peak Demand (MW)	536.1
Date of All-Time Hourly System Peak Demand (mm/dd/yyyy)	07/23/2012
Hour of All-Time Hourly Peak System Demand (hh AM/PM)	04 PM
Number of Customers/Meters (Year End of Reporting Period)	
Number of Residential Customers	84,066
Number of Commercial Customers	18,238*
Number of Industrial Customers	419
Other (Specify):	

*This is a calculated number as not all Participants report numbers based on customer type. The total is as reported.

Figure II-1

Historical Energy Use: The peak system demand and total annual energy use for the preceding ten (10) reporting years is listed below in *Figure II-2*. Values listed are by calendar year.

Reporting Year	Peak Demand (MW)	Total Energy (MWh)
2012	536.1	2,557,670
2013	518.5	2,593,620
2014	502.8	2,525,660
2015	467.9	2,352,270
2016	434.0	2,270,592
2017	434.0	2,388,559
2018	477.0	2,497,995
2019	480.0	2,010,413
2020	477.0	1,883,643
2021	477.0	1,982,845

Figure II-2

C. Checklist

The checklist of questions in *Figure II-3* is provided by WAPA as a means for customers to determine the completion of their IRP document and satisfaction of WAPA standards for IRP reporting. MEAN has indicated the section of the report wherein the question is addressed.

1. Does the IRP evaluate the full range of alternatives for new energy resources (905.11(a))?	
• New generating capacity?	Section XII.C.
• Power purchases?	Section XII.C. Section XII.G.
• Energy conservation and efficiency?	Section XIII
• Cogeneration and district heating/cooling applications?	Section XII.C.
• Renewable energy resources?	Section XII.C.
2. Does the IRP provide adequate and reliable service to the customer's electric consumers (905.11(a))?	Section X.
3. Does the IRP take into account the necessary features for system operation (905.11(a))?	
• Diversity?	Section XII.D.
• Reliability?	Section XII.D.
• Dispatchability?	Section XII.D.
• Other risk factors?	Section XIV.F.-G. Section XV.B.
4. Does the IRP take into account the ability to verify energy savings achieved through energy efficiency (905.11(a))?	Section VIII.C.,D.,E. Section XIII.E. Section XVI.D.
5. Does the IRP take into account the projected durability of such savings measured over time (905.11(a))?	Section XIII.E. Section XIV.G. Appendix C
6. Does the IRP treat demand and supply resources on a consistent and integrated basis (905.11(a))?	Section XIII.E. Section XIV.B. Section XIV.G. Section XVI.A.,C.,D.
7. Does the IRP consider electrical energy resource needs? (905.11(b)).	Section X.
8. Does the IRP identify and compare resource options? The customer must conduct an assessment and comparison of available existing and future supply and demand-side resource options based on its size, type, resource needs, geographic location and competitive situation. The options should relate to the customer's unique resource situation as determined by profile data (service area, geographical characteristics, customer mix, historical loads, projected growth, existing system data, rates and financial information) (905.11(b)(1)).	
• Supply-side options include, but are not limited to, purchased power contracts, and conventional and renewable generation options (905.11(b)(1)(i)).	Section XII. Section XIV.
• Demand-side options alter the customer's use pattern to provide for an improved combination of energy services to the customer and ultimate consumer (905.11(b)(1)(ii)).	Section VII. Section VIII. Section XIII. Section XIV.
• Considerations that may be used to develop potential options include cost, market potential, consumer preferences, environmental impacts, demand or energy impacts, implementation issues, revenue impacts, and commercial availability (905.11(b)(1)(iii)).	Section XII. Section XIII. Section XIV.
9. Does the IRP clearly demonstrate that decisions were based on a reasonable analysis of the options (905.11(b)(1)(iv))?	Section XII. Section XIV.
10. Does the IRP include an action plan describing specific actions the customer will take to implement the IRP (905.11(b)(2))?	Section XVI.C.

11. Does the IRP list the time period that the action plan covers (905.11(b)(2)(i))?	Section XVI.C.
12. Does the IRP include an action plan summary consisting of (905.11(b)(2)(ii)(a-c):	
• Actions the customer expects to take in accomplishing the goals identified in the IRP?	Section XVI.B.,C.,D.
• Milestones to evaluate accomplishment of those actions during implementation?	Section XVI.D.
• Estimated energy and capacity benefits for each action planned?	Section XIV. Section XV.
13. Does the IRP, to the extent practicable, minimize adverse environmental effects of new resource acquisitions and document these efforts (905.11(b)(3))?	Section XV.
14. Does the IRP include a qualitative analysis of environmental effects in a summary format (905.11(b)(3))?	Section XII.D.,F. Section XV.
15. Does the IRP provide ample opportunity for full public participation in preparing and developing the IRP (905.11(b)(4))?	Section II.D. Appendix A
16. Does the IRP include a brief description of public involvement activities (905.11(b)(4))?	
• How the customer gathered information from the public?	Section II.D. Appendix E
• How public concerns were identified?	Section II.D. Section XII.G.2. Appendix E
• How information was shared with the public?	Section II.D. Appendix A
• How public comments were responded to?	Section II.D. Section XII.G.2. Appendix E
17. Does the IRP document that each MBA member approved the IRP, confirming that all requirements have been met (905.11(b)(4)(i))? [Effective July 21, 2008, IRPs submitted by member-based associations no longer need unanimous approval of the MBA's members.]	Section XVI.B. Appendix F
18. Does the IRP contain the signature of each MBA member's responsible official, or document passage of an approval resolution by the appropriate governing body (905.11(b)(4)(i))?	Section XVI.B. Appendix F
19. Does the IRP contain a statement that the customer conducted load forecasting, including specific data (905.11(b)(5))?	Section V.
20. Does the IRP contain a brief description of measurement strategies for identified options to determine whether the IRP's objectives are being met (905.11(b)(6))?	Section XVI.D.
21. Does the IRP identify a baseline from which the customer will measure the benefits of IRP implementation (905.11(b)(6))?	Section XVI.D.
22. Does the IRP specify the responsibilities and participation levels of individual members of the MBA and the MBA (905.12(b)(2))?	Section III.E.,F.

Figure II-3

D. Public Participation

The following actions were taken by MEAN to ensure the provision of ample opportunity for public participation throughout the IRP process.

1. Board and Committee Meetings – November 2019

MEAN Quarterly Board and Committee Meetings were held on November 20-21, 2022 in Kearney, NE. This is a public meeting subject to the State of Nebraska Public Meetings Act and the requirements contained therein. On November 20, the Power Supply Committee met to hear presentations and vote on issues under the purview of the committee. The IRP falls under the jurisdiction of this committee. All members of the Power Supply Committee (see description of this committee in Section III.E.) are invited to attend, and a quorum must be present to conduct the meeting. On November 21, the MEAN Board of Directors met to hear presentations and vote on recommendations from the committees that met the previous day. All members of the Board are invited, and a quorum must be present to conduct the meeting and vote on proposed resolutions. A presentation on MEAN's Resource Planning and future parameters surrounding MEAN's resource portfolio was presented at each of these meetings. The presentation material and attendance list are included in Appendix A.

2. Board and Committee Meeting – November 2020

On November 12-13, 2020, MEAN conducted its quarterly Board and Committee Meetings in Kearney, NE. On November 12, the Power Supply Committee convened. A presentation was conducted to preview the process of the upcoming Phase I Resource Evaluation and the online survey to be sent to all members. The presentation included an explanation of the evaluation criteria and the supply side resources under consideration. The next day on November 13, the MEAN Board of Directors met and were presented the same material. The materials presented and a list of attendees are included in Appendix A.

3. Online Survey – January 2021

In January, in anticipation of the IRP process, an online survey was sent to all MEAN participants to gather input for the IRP Phase I evaluation. Questions were asked regarding MEAN's resource mix, renewable energy, local renewable goals, resource procurement criteria, and demand side management. The survey questions and responses are included in Appendix A.

4. Board and Committee Meeting – January 2021

On January 20-21, 2021, MEAN conducted its quarterly Board and Committee Meetings in Kearney, NE. The Power Supply Committee met first on January 20. One of the topics presented was the progress of the IRP and potential supply side resources. The presentation included an explanation of the Phase II supply side modeling and the risk metrics to be utilized for evaluation of the candidate portfolios. The next day on January 21, the MEAN Board of Directors met. The board presentations were an abbreviated version of the material presented to the Power Supply Committee. The materials presented at the January 2021 meetings are included in Appendix A.

5. Board and Committee Meeting – May 2021

On May 19-20, 2021, MEAN conducted its quarterly Board and Committee Meetings in Kearney, NE. On May 19, the Power Supply Committee convened. The presentation to the committee centered around the results of the IRP survey from January, including local carbon-free goals, demand side management participation, resource evaluation criteria, and supply side options. The presentation also reviewed the results of the Phase I resource evaluation. The next day on May 21, the MEAN Board of Directors met. The presentations at the May board meeting included the same topics presented to the Power Supply Committee. The materials presented at the May meetings are included in Appendix A.

6. Board and Committee Meeting – August 2021

On August 18-19, 2021, MEAN conducted its quarterly Board and Committee Meetings in Kearney, NE. The Power Supply Committee met on August 18. One of the topics presented at the meeting was the progress of the IRP. The presentation included load and capability projections, results of the Phase I evaluation, planned scenarios for load forecasts and market pricing to be used in Phase II, and applicable legislative actions. The next day on the 18th, the MEAN Board of Directors met and were presented an abbreviated version of the same materials. The materials presented at the August meetings are included in Appendix A.

7. Online Survey – September 2021

In September, to gather additional input for the IRP, an online survey was sent to all MEAN participants regarding renewable energy. Questions were asked regarding each community's goals for renewable energy in relation to MEAN's 2050 Vision, renewable energy pricing, and electric vehicle adoption. The survey questions and responses are included in Appendix A.

8. Board and Committee Meeting – November 2021

On November 17-18, 2021, MEAN conducted its quarterly Board and Committee Meetings in Kearney, NE. On November 17, the Power Supply Committee was presented with the results of the renewable energy survey, specific supply side resource evaluations, and upcoming opportunities for discussion and participation on the IRP. The next day on the 18th, the MEAN Board of Directors reviewed and discussed the same presentation topics. The materials presented at the November meetings are included in Appendix A.

9. Board and Committee Meeting – January 2022

On January 19-20, 2022, MEAN held its quarterly Board and Committee Meetings in Kearney, NE. On the 19th, the Power Supply Committee convened and discussed the IRP in detail. Topics included upcoming action items and meeting opportunities, the portfolio modeling process, assumptions and sensitivity analysis, review of Phase I, a preview of the Phase II and DSM analyses, and load and capability projections. The material also included information on distributed generation and resource options under investigation. The MEAN Board of Directors met on January 20 to discuss the same topics and review the presentations. The January meeting presentations and attendance records are included in Appendix A.

10. Power Supply Committee Workshop – April 2022

A public workshop of the Power Supply Committee will be held on April 21, 2022. The purpose of this workshop is to guide attendees through the draft IRP report and gather input from committee members as well as members of the public. The committee will utilize this workshop to prepare to make a recommendation to the Board at the May Board Meeting. This workshop was advertised on MEAN's website with a link to access the virtual meeting.

11. Distribution of Draft Report – April 2022

An up-to-date draft version of the IRP document in pdf format was distributed to all MEAN participants via email on April 19, 2022. At this time, an email address dedicated to receipt of comments and questions related to the IRP was established and communicated to participants for direction of responses to the draft. Participants were invited to make the draft report and email address available to their community members in either hard copy or electronic format and to advertise the availability of the document. It was communicated that public comment would be accepted for 25 days following the posting of the draft IRP document.

12. Public Comment

As explained throughout this report, comment and direction received from the MEAN participants was incorporated into each step of the IRP process and is reflected in the conclusions and recommended plans for MEAN's future resource planning. All MEAN Board and Committee meetings are public meetings at which public comment is accepted. MEAN was purposeful in presenting the procedures and results of each step of the IRP to the board and committee members to solicit input and gather feedback. All public comment received will be summarized in Appendix E with MEAN responses and references to how the comments were addressed within the final report.

13. Distribution and Submittal of Final IRP Report

All comments received from internal and external stakeholders were collected for evaluation throughout the IRP process. This narrative points to instances where MEAN participants guided the process in terms of priorities and options and finally the determination of the recommended action plan. The final report will incorporate all conclusions from participant discussions and will ultimately reflect the directives of the Participants. The final report will be completed prior to July 1, 2022, at which time it will be submitted to WAPA, posted to the NMPP Energy website, and distributed to all Participant representatives.

E. MEAN Strategic Plan

1. Overview

The Mission Statement of MEAN is *"To collaborate with municipal utilities to provide economical and dependable power supply and utility related services that support local control and community needs and are consistent with environmental and regulatory stewardship."*

In 2016, MEAN completed a company-wide Strategic Plan. The planning process involved MEAN staff as well as the members of the Executive Committee. In defining the strategic initiatives of the organization, goals were prioritized and assigned action plans for

implementation. Timelines and staff assignments were established for each goal. “Resource Management,” one of the five Strategic Goals, identifies a Tier One Goal to “Develop a Comprehensive Integrated Resource Plan.”

MEAN has budgeted for an updated Strategic Plan to be developed in September 2022. New goals and action items specific to the IRP and resource planning in general will be used to direct long-term and short-term resource acquisitions and planning.

2. Resource Planning

MEAN’s Strategic Plan calls for the IRP to be utilized as a strategic and operational working document. The individual tasks outlined to achieve this goal include the following:

- Evaluate existing owned resource obligations
- Energy efficiency and demand side management (“DSM”)
- Investigate new generation opportunities and maintain existing generation in participant communities in line with Distributed Generation concepts

III. Introduction

A. Purpose

The purpose of this Integrated Resource Plan is to develop long-range implementation plans to serve MEAN's Total Requirements Participants' power supply requirements consistent with prudent utility planning practices utilizing the lowest cost, environmentally responsible energy supply. The IRP serves as MEAN's guidance for future plans to achieve its 2050 Vision for carbon neutrality.

The Strategic Plan put in place by MEAN's leadership has called for a comprehensive Integrated Resource Plan to guide future resource acquisition and portfolio planning. The plan is to be a living document that is consulted prior to resource decisions and revisited when circumstances change.

This plan is also designed to fulfill the requirements of the Western Area Power Administration according to the Energy Policy Act of 1992, as described in section II.A.

B. Scope

This resource plan encompasses a time period of 15 years on the basis of MEAN's fiscal year. MEAN's fiscal year begins April 1st and ends March 31st. This IRP is inclusive of the planning period of FY 2022-23 to FY 2037-38.

The IRP conducts resource planning for MEAN's entire service footprint as a whole, as well as within the individual Regional Transmission Organizations ("RTO") regions in which MEAN's designated resources are assigned. MEAN operates in the Southwest Power Pool ("SPP") RTO, Midcontinent Independent System Operator ("MISO") RTO, and in the West region. Resources must be designated to meet the load and required reserve margin of each region separately. However, there are several metrics that MEAN evaluates on an accumulated basis for the entire service area.

C. Approach/Methodology

This IRP will consider all reasonable options for supply side resources and demand side management. Supply side and demand side options will be given equal consideration for incorporation into the future resource portfolio.

The IRP analysis will begin with a high-level evaluation of all resource options. Criteria for resource selection are determined and weighted according to input from the MEAN membership. Using static performance and cost characteristics of each option, the complete list of resources will be narrowed to a smaller list of qualified options that receive the highest ranking in accordance with the weighted criteria.

The qualified options will be subject to an economic analysis that applies resource availability and cost to MEAN's hourly loads and projected market conditions. The sum of the hourly costs and revenues over the 15-year study period will be calculated to arrive at a revenue requirement for each option for comparison purposes.

Lastly, the economic analysis will be repeated under various sensitivity scenarios to calculate the impact of potential changes to key inputs. This input-sensitive variability will quantify the risk inherent in each portfolio.

In addition to the total cost parameters, the resource options will be compared in terms of their carbon emissions impact. MEAN's future resource acquisitions will be selected not only in terms of financial cost and reliability to serve load, but also in their ability to advance MEAN toward the 2050 Vision of carbon neutrality. This means that each future resource should contribute toward a decrease in the net emission of the portfolio.

The combined results of the base case revenue requirement and the variability due to sensitivity cases will ultimately lead to the determination of a preferred portfolio for future resource acquisition planning.

This methodology is displayed graphically in *Figure III-1*.

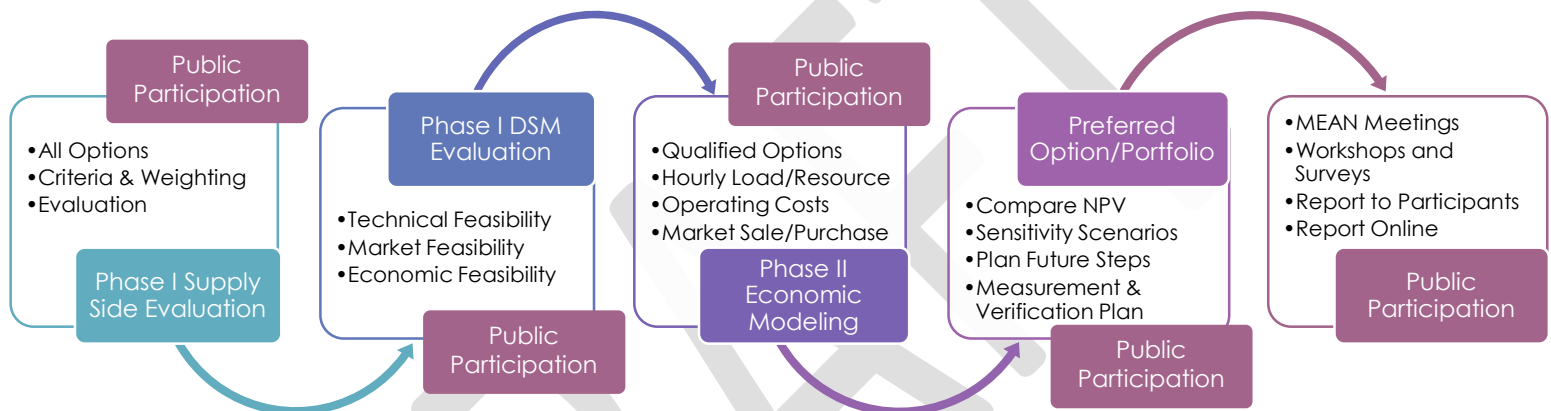


Figure III-1

D. MEAN Overview

The Municipal Energy Agency of Nebraska ("MEAN") is a body corporate and politic under the laws of the State of Nebraska. MEAN was created on June 22, 1981 under the Municipal Cooperative Financing Act, Sections 18-2401 through 18-2485, Reissue Revised Statutes of Nebraska (the "Act"). MEAN was created for the purpose of planning, acquiring, financing and operating facilities to generate and transmit electric power and energy.

MEAN's power supply system consists of ownership and contractual rights and interests in various electric generating and transmission resources and supplies (the "Power Supply System"). MEAN uses the Power Supply System to provide wholesale power supply, transmission and ancillary services to its participating municipal utilities ("Participants"). MEAN's services include power supply, dispatching, energy load forecasting, wheeling arrangements, load research, limited political action, demand-side management, load factor improvement, training, community development, compliance reporting, and energy cost analysis. Through its professional staff, MEAN also provides planning, engineering, financing, regulatory, and governmental affairs services to its Participants.

The Municipal Cooperative Financing Act (“The Act”) authorizes MEAN to plan, construct, operate, participate in or acquire facilities, within or outside the State of Nebraska, for the generation, transmission or distribution of electric power and energy, solely or in common with others. Under the Act, MEAN may sell or exchange excess capacity of any project or electric power or energy owned, purchased, or leased by MEAN not required by its Participants. The Act authorizes MEAN to issue its bonds, notes and other evidences of indebtedness. In the acquisition of property, MEAN may exercise the power of eminent domain.

E. MEAN Membership

MEAN’s 70 Participants currently include 42 municipalities and one public power district in Nebraska, 14 municipalities and one joint action agency in Colorado, two Wyoming municipalities and 10 Iowa municipalities. Each of the Participants owns and operates an electrical utility system that provides electric service to consumers. 62 of the Participants (the “*Total Requirements Participants*”) receive “total-requirements” electric supply services from MEAN, exclusive only of their allocations of firm power and energy from the Western Area Power Administration of the U.S. Department of Energy (“WAPA”), except for certain generating facilities of Waverly Utilities (a municipal utility of the City of Waverly, Iowa) and the City of Aspen, Colorado. Additional municipalities may become Participants of MEAN with the approval of the Board of Directors of MEAN.

Together, the Total Requirements Participants provide electric utility service at retail to approximately 102,723 residential, commercial, institutional, agricultural and industrial customers, representing a total population of approximately 174,800. Participants’ total energy usage for MEAN’s fiscal year ended March 31, 2022 was 2,200,763 MWh (which includes 371,508 MWh of Participant WAPA allocations).

MEAN’s participant communities are mapped in *Figure III-2*.

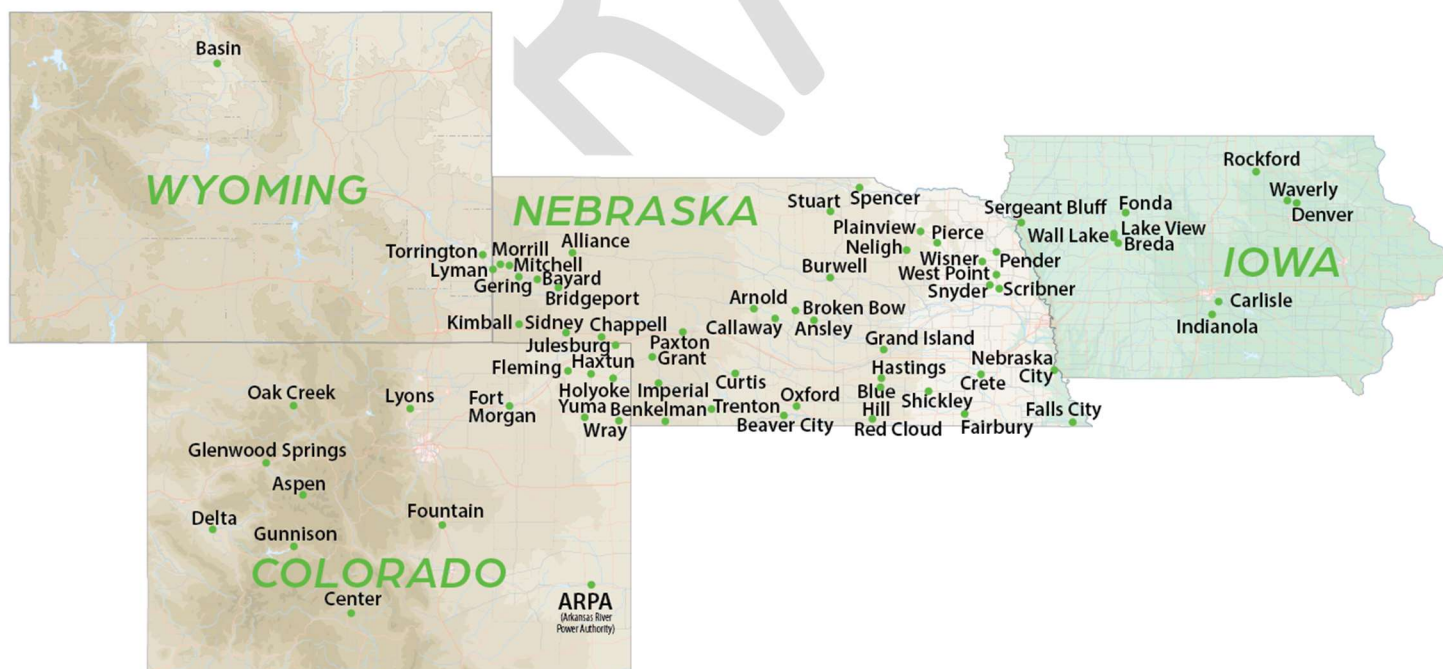


Figure III-2

Participants may take additional steps to become members of MEAN (“Members”) under the Act by making application with the Nebraska Power Review Board. Each Member appoints and is represented by a director on the MEAN Board of Directors, as described below. MEAN currently has 57 Members, which are indicated in *Figure III-3*.

COMMUNITY	MEMBER	ASSOCIATE MEMBER	SUPPORTER CLASS	LONG- TERM TRP	SHORT- TERM TRP
COLORADO					
Arkansas River Power Authority		X			
Aspen	X			X	
Center	X		X		X
Delta	X			X	
Fleming	X			X	
Fort Morgan	X			X	
Glenwood Springs	X				X
Gunnison	X			X	
Haxtun	X			X	
Holyoke		X			X
Julesburg	X			X	
Lyons	X			X	
Oak Creek	X			X	
Wray	X				X
Yuma	X			X	
IOWA					
Breda	X			X	
Carlisle	X			X	
Denver	X			X	
Fonda			X	X	
Indianola Municipal Utilities	X			X	
Lake View		X			X
Rockford		X		X	
Sergeant Bluff	X			X	
Wall Lake	X			X	
Waverly Municipal Electric Utility	X			X	
NEBRASKA					
Alliance	X			X	
Ansley	X			X	
Arnold	X			X	
Bayard	X			X	
Beaver City	X			X	
Benkelman	X			X	
Blue Hill	X			X	
Bridgeport	X			X	
Broken Bow	X			X	
Burwell	X			X	
Callaway	X			X	
Chappell	X			X	
Crete	X			X	
Curtis	X			X	

COMMUNITY	MEMBER	ASSOCIATE MEMBER	SUPPORTER CLASS	LONG-TERM TRP	SHORT-TERM TRP
Fairbury	X			X	
Falls City	X				
Gering	X			X	
Grand Island		X			
Grant	X			X	
Hastings			X		
Imperial Public Power District	X			X	
Kimball	X			X	
Lyman	X			X	
Mitchell	X			X	
Morrill	X			X	
Nebraska City	X				
Neligh	X				
Oxford	X			X	
Paxton			X		X
Pender	X			X	
Pierce	X			X	
Plainview	X			X	
Red Cloud	X			X	
Scribner			X		
Shickley	X			X	
Sidney	X			X	
Snyder			X		X
South Sioux City			X		
Spencer		X		X	
Stuart	X			X	
Trenton			X		X
West Point	X			X	
Wisner	X			X	
WYOMING					
Basin	X			X	
Torrington	X			X	

Figure III-3

A Participant may elect to become a Total Requirements Participant, in which case it receives all power and energy from MEAN (exclusive only of its firm power and energy allocations from WAPA). Alternatively, a Participant may elect to become a Service Schedule Participant, in which case it retains full responsibility for meeting its power and energy requirements and may enter into buy/sell power and energy or other transactions with MEAN.

Fifty-four of the Participants (the “Long-Term Total Requirements Participants”) have entered into Service Schedule M contracts (the “Long-Term Power Supply Contracts”). The Long-Term Total Requirements Participants, with the limited exception of Aspen, Colorado and Waverly Utilities, have agreed to purchase all their firm electric requirements from MEAN, exclusive of any firm power and energy allocated to such Long-Term Total Requirements Participants by WAPA. The term of the

Long-Term Power Supply Contracts is concurrent with the life of MEAN's bond debt and other resource obligations. Waverly and Aspen have certain external contracts for renewable energy.

Eight of the Total Requirements Participants (*"Limited-Term Total Requirements Participants"*) have contracted with MEAN for total-requirements electric supply services by entering into a Supplemental Agreement to Service Schedule J contract (*"Service Schedule J Participants"*) or Service Schedule K or K-1 contract (*"Service Schedule K and K-1 Participants"*). Such Participants have agreed to purchase all their electric requirements from MEAN, exclusive of any firm power and energy allocated to such Limited-Term Total Requirements Participants by WAPA. These agreements vary in length, but generally have terms of five to ten years. Collectively, the Long-Term Total Requirements Participants and the Limited-Term Total Requirements Participants are referred to herein as the *"Total Requirements Participants."*

Eight of the Participants (*"Service Schedule Participants"*) do not receive total-requirements electric supply services from MEAN, and instead may enter into buy/sell power and energy or other transactions with MEAN from time to time. Four of the Service Schedule Participants currently receive only agent and scheduling services from MEAN with respect to transactions in the Southwest Power Pool (*"SPP"*) Integrated Marketplace (*"IM"*). MEAN also enters into other agreements and interchange sales with non-Participant electric utilities and organizations such as SPP and Midcontinent Independent System Operator (*"MISO"*) markets.

MEAN Participant membership is governed by the General Terms and Conditions, which replaced this function of the former Electric Resources Pooling Agreement (*"ERPA"*). In addition, terms of MEAN's lease of member-owned behind-the-meter generation (*"BTMG"*) are detailed in the Asset Management Policies and Procedures (*"AMPP"*) document, formerly documented in the ERPA.

F. MEAN Organization

MEAN is governed by a board of directors (*"Board of Directors"*) consisting of one director for each of the Members, appointed by the mayor or chair of each Member, and approved by the governing body of each Member. Each director serves until his or her successor is appointed and is entitled to one vote unless he or she has been suspended or unless the Member is an Inactive Member as defined by MEAN's by-laws. A director may be removed for any cause at any time by the governing body of the Member that such director represents or may be suspended or removed by the MEAN Board of Directors for any cause by at least a two-thirds vote. Amending the MEAN charter requires an affirmative vote of a majority of the Members. Most other actions require the approval of a majority of the Members present.

The Act authorizes the Board of Directors to create one or more project committees to which the Board of Directors may delegate such powers and duties with respect to a project as the Board of Directors shall specify. The Board of Directors has created the following standing committees: Executive Committee, Power Supply Committee, Services Committee, Finance Committee, Risk Oversight Committee. Oversight of the IRP process falls under the purview of the Power Supply Committee.

The officers of MEAN are elected each January by the Board of Directors of MEAN to serve terms of one year beginning April 1.

G. NMPP Energy

MEAN, Nebraska Municipal Power Pool, Public Alliance for Community Energy and National Public Gas Agency comprise a coalition referred to by the trade name NMPP Energy pursuant to a Joint Operating Committee Agreement. MEAN and the other participating organizations share administrative resources and staff, allowing them to more efficiently run their operations and their systems. The coalition provides substantial benefits to MEAN and the other participating organizations, including: (i) the development and utilization of a highly skilled and professional staff with specialized technical expertise in business management, administration, engineering, finance, accounting, governmental affairs, law, and other disciplines; (ii) achieving economies of scale and the sharing of facilities and overheads; (iii) the development and execution of projects, plans, and services that benefit multiple organizations; and (iv) the sharing of institutional experience through the Joint Operating Committee. MEAN and each of the other organizations included in NMPP Energy is an independent financial entity. None of the organizations are financially liable for the debts or obligations of any other associated organization.

H. Regional Energy Markets and Coordination

MEAN's regional footprint stretches from Central Iowa across Nebraska and into Colorado and Wyoming. Due to this footprint, MEAN is required to operate in two regional transmission organizations, MISO and SPP. Both MISO and SPP operate day-ahead and real-time energy markets. Market participants must pay for costs to serve load and receive revenue for their electrical generation. MEAN also operates in the western United States through the Western Electricity Coordinating Council ("WECC") and participates in the Western Energy Imbalance Service ("WEIS").

SPP was founded in 1941, incorporated as a nonprofit entity in 1994 and became a FERC-approved Regional Transmission Organization in 2004. SPP's members, including investor-owned utilities, municipalities, cooperatives, state power agencies, independent power producers, power marketers, independent transmission companies and federal agencies, serve over 18 million people. SPP provides transmission services on more than 70,000 miles of transmission lines in 14 states: Nebraska, Kansas, Missouri, Oklahoma, Arkansas, New Mexico, Texas, Louisiana, Iowa, Minnesota, Montana, North Dakota, South Dakota and Wyoming.

The SPP Integrated Market ("IM"), which was launched on March 1, 2014, replaced the Energy Imbalance Service ("EIS") market that SPP had operated since 2007. The IM restructured the EIS market by establishing a day-ahead market along with a real-time energy and operating reserve market. Consolidating 16 balancing authorities into a single SPP-operated balancing authority was designed to maximize energy efficiency and reduce transaction costs. The IM also utilizes locational-marginal pricing, transmission congestion rights, and virtual transactions.

MEAN became a member of SPP on October 20, 2015. As a member, MEAN works with other SPP members to identify ways to improve market operations and overall organizational effectiveness.

MISO is an independent organization whose purpose is to ensure the reliability of its integrated, regional electrical transmission system, to facilitate a regional wholesale marketplace, to provide non-discriminatory access to the transmission system and to maintain and improve system reliability. Its members include vertically-integrated utilities, stand-alone transmission owners, load-serving entities, energy marketers, state regulatory authorities and independent power producers.

MEAN became a non-transmission owning member of MISO on October 22, 2015.

MEAN also operates in the western United States through WECC. For operations in WECC, MEAN enters into other agreements and transactions with various electric utilities that are not MEAN Participants pursuant to which such electric utilities may purchase power and energy from MEAN or sell power and energy to MEAN.

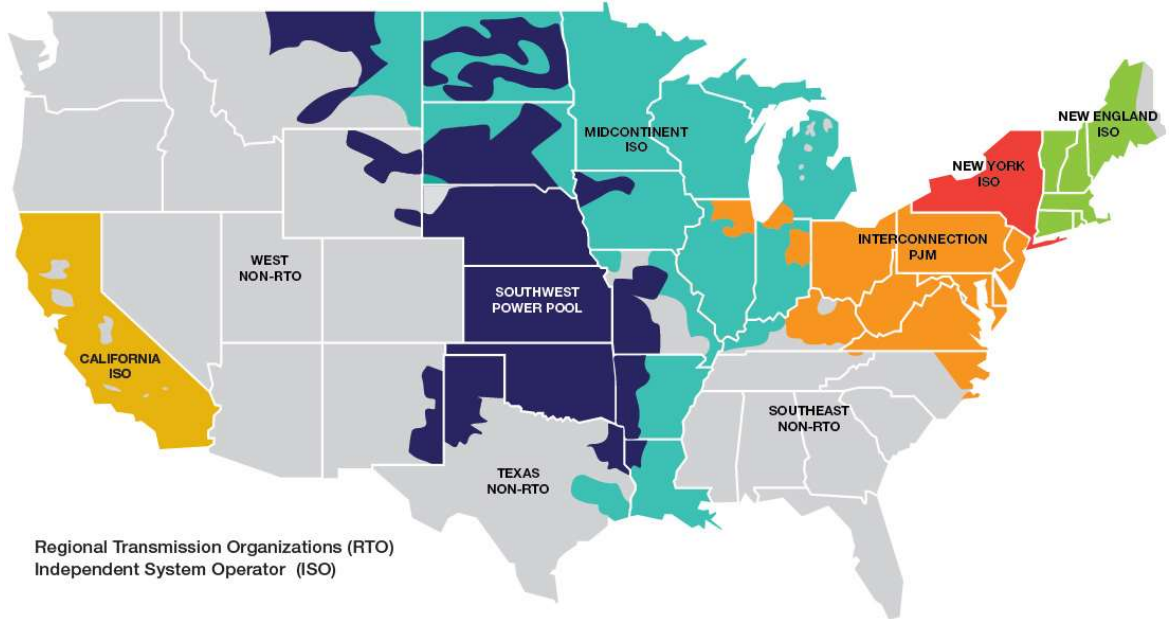


Figure III-4

MEAN and several other regional utilities are participants in SPP's Western Energy Imbalance Service (WEIS) market which went live February 1, 2021. SPP's WEIS market balances generation and load regionally in real time by centrally dispatching energy from participating resources every five minutes for participants in the Western Interconnection. As WEIS administrator, SPP maintains reliability of the region's transmission system and meets demand with the most cost-effective generation available. Market participants submit offers for registered resources for use by the WEIS market, and the WEIS market dispatches the resources based on economic offers submitted while honoring resource parameters and transmission limitations. SPP delivers energy between participating generators and load in WEIS using a form of intra-hour non-firm transmission service. The WEIS market also allows parties to continue to trade bilaterally. SPP posts scheduled settlement statements for a given set of operating dates, and on a weekly basis invoices cumulative market activity for each market participant. For governance and stakeholder involvement, SPP's Western Markets Working Group is the forum for customers of WEIS to engage in matters of WEIS Market related governance and strategy with other stakeholders.

In July of 2021, the SPP board of directors and Strategic Planning Committee approved the terms and conditions for regional transmission organization (RTO) expansion in the Western Interconnection. This formation would extend SPP's market structure into the West, including day-ahead wholesale electricity market administration, transmission planning, reliability coordination, and resource adequacy. MEAN has communicated its intent to join a future SPP West RTO. Current projections state that the SPP West RTO could begin operation in Q2 of 2025.

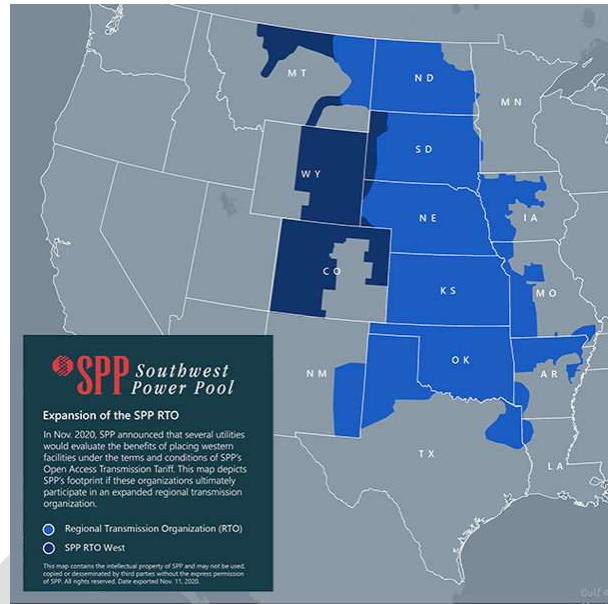


Figure III-5

IV. Uncertainties/Limitations

There are many factors that impact the inputs to the IRP analysis. Many of these parameters are uncertain and have therefore been calculated or assigned with certain assumptions. Should these assumptions be incorrect or prove to change over time, the outcome of the analysis could potentially change as well. This section explores some of the uncertainties and limitations underlying these variable inputs to the analysis.

A. Environmental Legislation

Electric utilities are subject to evolving environmental regulation. Various environmental permits and approvals from state and federal agencies are necessary in order to operate the Power Supply System. To date, MEAN reports that all environmental permits and approvals necessary for the operation of the Power Supply System have been obtained. However, federal, state, and local standards and procedures that regulate the environmental impact of electric utilities are subject to change. These changes may arise from continuing legislative, regulatory and judicial action regarding such standards and procedures. Consequently, there is no assurance that the Power Supply System and the utility facilities owned or operated by the Participants will remain subject to the regulations currently in effect or indefinitely maintain current compliance status. An inability to comply with environmental standards could result in reduced operating levels, increased capital or operating costs, or the complete shutdown of individual electric generating units.

There is increased concern by the public, the scientific community, and Congress regarding environmental damage resulting from the use of fossil fuels. There are a number of pending or recently enacted legislative proposals in Congress and state legislatures that may affect the electric utility industry. Increased environmental regulation has created and may create additional barriers to new facility development and modification of existing facilities, both physically and operationally. The additional expenses, including time, human resources, uncertainty and delay, could increase the cost of electricity from affected resources and ultimately reduce their market dispatch. This type of legislation may ultimately have significant influence on nationwide or regional resource mixes and market operations as some types of resources experience increased costs of compliance or compulsory carbon taxes while other types of resources avoid such costs or receive financial incentives for generation, thereby effecting the feasibility of resource retirement and new construction. Further regulation may impose additional costs and long-term investments in retirement and decommissioning activities when a facility ceases operation.

1. Renewable Portfolio Standards

Several states have implemented renewable portfolio standards (“RPS”) requiring electricity providers to obtain a minimum percentage of their power from renewable energy resources by a certain date.

One of the first states in the country to do so, Iowa adopted a renewable portfolio standard only for investor-owned utilities in 1983. The minimal requirements of this RPS have been long surpassed by Iowa’s IOUs.

In 2004, Colorado adopted a renewable portfolio standard affecting investor-owned utilities, electric cooperatives and municipal utilities, except municipal utilities serving less than 40,000 customers. For affected Colorado utilities, the RPS requires that the utility provide the following percentages of renewable energy from eligible resources: 30% by 2020 for IOUs, 10% or 20% for municipal utilities and electric cooperatives

depending on size, and 100% clean energy by 2050 for utilities serving 500,000 or more customers. Presently, this RPS is not affecting MEAN's Colorado Participants.

Nebraska and Wyoming have not adopted an RPS.

Other state legislation has directed a schedule of reductions in electric utility carbon emissions as compared to a baseline year's emissions. Typically states have set targets specific to the electric utility industry, designated separately from state-wide targets and targets for other industries. In 2019, Colorado enacted such legislation, calling for state-wide emissions reductions of 26% by 2025, 50% by 2030, and 90% by 2050 and delegating authority to the Air Quality Control Commission to adopt rules to make progress towards those goals. Specific to electric utilities, the 2019 legislation states that a utility shall not be subject to additional emissions reduction mandates if the utility files a clean energy plan demonstrating a minimum 80% reduction from 2005 levels by 2030. Currently, MEAN and its member utilities are not under the jurisdiction of this legislation as it applies to utilities serving 500,000 or more customers. Further energy legislation continues to be introduced in the Colorado legislature, and MEAN regularly follows these developments. Nebraska, Iowa, and Wyoming do not have any emissions reduction regulations.

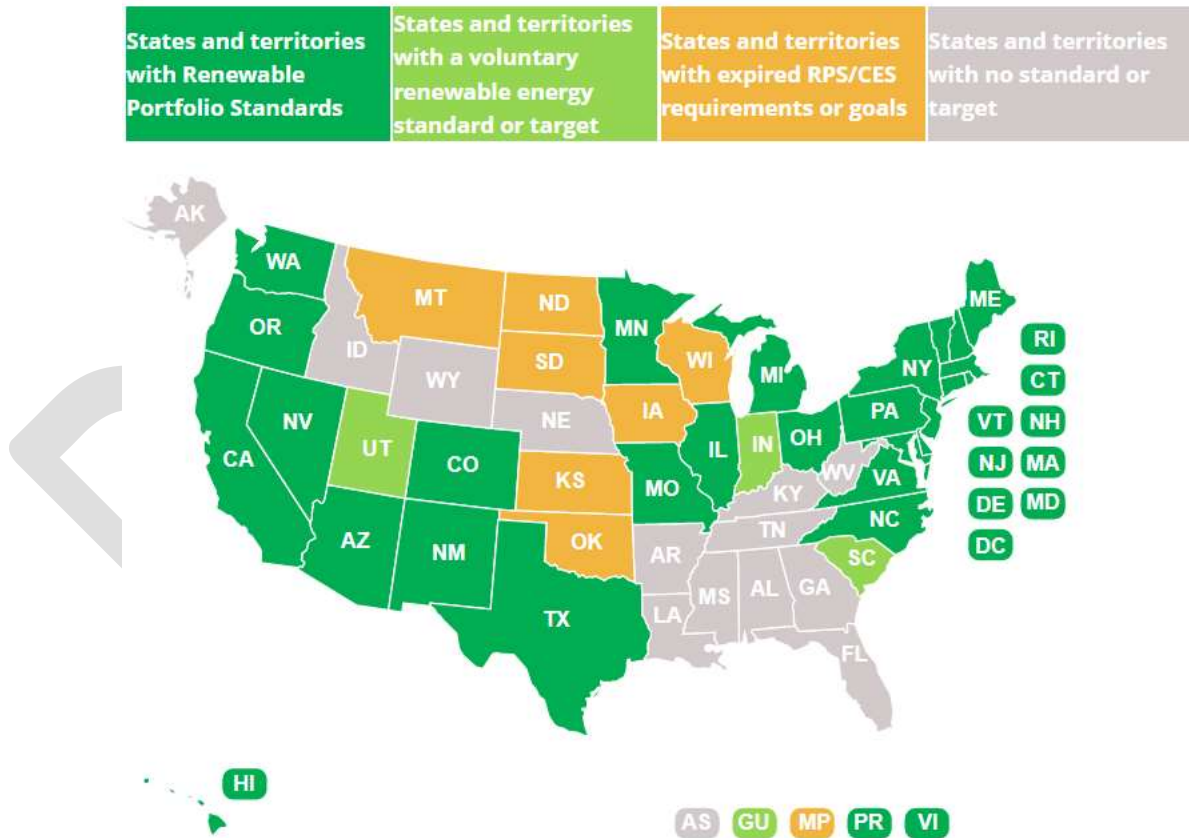


Figure IV-1

For the IRP base case scenario, it is assumed that RPS and emissions reduction requirements will remain as currently mandated.

2. Clean Air Act

The 1990 Amendments to the Clean Air Act seek to improve the ambient air quality throughout the United States by reducing sulfur dioxide (SO₂) and nitrogen oxide (NO_x), emissions caused by electric utility power plants, particularly those fueled by coal. This is administered through a cap and trade system of emission allowances. Currently, all of MEAN's coal-fired generation resources meet the NO_x compliance requirements. Additionally, MEAN purchases allowances for SO₂ emissions to cover annual requirements for the plants impacted by the EPA Acid Rain Program. SO₂ and NO_x emissions are monitored continuously and reported quarterly in compliance with EPA regulations.

In recent years, legislative bills have been introduced in both the House and Senate that if enacted, would require the addition of pollution control equipment to further reduce emissions of SO₂, NO_x, mercury and carbon dioxide ("CO₂") from coal fired electric power plants. Regulations promulgated by the EPA or by state governments could have a similar effect. MEAN's generating resources have installed the required mercury reduction capability and further mandatory CO₂ reductions could substantially increase MEAN's operations and maintenance expenses and possibly require switching fuel from coal to natural gas. MEAN continually monitors emissions reduction legislation.

3. Clean Power Plan and Affordable Clean Energy Rule

The EPA released a statement on February 12, 2021 that it "does not expect states to take any further action to develop and submit plans under Clean Air Act section 111(d) with respect to greenhouse gas emissions from power plants at this time."

On August 3, 2015, EPA released its final Clean Power Plan under Section 111(d) of the Clean Air Act ("Clean Power Plan") which sets performance standards for existing power plants to reduce carbon dioxide (CO₂) emissions. The Clean Power Plan required each state to reduce its CO₂ emissions rate from existing fossil fuel plants relative to 2005 emission levels to meet state-specific standards starting in 2022, with a final rate for 2030 and beyond. The Clean Power Plan was challenged in court and never went into effect.

On July 8, 2019 the EPA concurrently repealed the CPP and published the Affordable Clean Energy ("ACE") Rule. ACE provided states with new emission guidelines and delegated to the states the development of standards of performance to reduce carbon dioxide emissions from existing coal-fired electric generating units ("EGUs"). ACE established heat rate improvement ("HRI"), or efficiency improvement, as the best system of emissions reduction (BSER) for CO₂ from coal-fired EGUs, with the goal of more efficiently generating electricity with less carbon intensity. The ACE rule was also challenged in the courts and on January 19, 2021, the District of Columbia Circuit Court vacated the ACE Rule remanding it back to the EPA. In October 2021, the Supreme Court agreed to review the D.C. Circuit's decision. While there are still legal proceedings relative to the ACE Rule, it is expected that the EPA will undertake new rulemaking to replace the ACE Rule.

Although the Clean Power Plan and the ACE Rule were not fully implemented, the structure of this legislation stands as an indication of future efforts to reduce the environmental impact of power generation facilities.

4. Cross-State Air Pollution Rule

In July 2011, the EPA finalized the Cross-State Air Pollution Rule ("CSAPR"), which would require the reduction of NO_x and SO₂ in 28 targeted states in the eastern and mid-western

United States by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. Under CSAPR, EPA sets a pollution limit (referred to as a “budget”) for each state covered by the rule. CSAPR allows sources in each state to determine how to meet the emission budgets, including unlimited trading of emissions allowances between power plants in the same state and limited interstate trading under certain conditions.

Various legal challenges resulted in the EPA issuing the CSAPR Update rule which became final on September 7, 2016, and went into effect beginning with the May 1, 2017 to September 30, 2017 ozone season. The CSAPR Update rule did not replace CSAPR; however, it did require additional reductions in NO_x emissions from utilities in 22 states in the eastern United States, during the ozone season. In September and October 2019, the U.S. Court of Appeals for the D.C. Circuit remanded the rule to the EPA for further consideration. Following the court remand, the EPA published a final Revised CSAPR Update Rule in the Federal Register, and that rule became effective on June 29, 2021. The Revised CSAPR Update places additional ozone season emission reductions on electric utilities in 12 states. Several eastern states, including Iowa, may see reductions in NO_x ozone season allowances under the Revised CSAPR Update Rule. Litigation regarding this new CSAPR regulation is ongoing.

Nebraska and Iowa are among the 28 states that are subject to CSAPR’s requirements to reduce annual emissions of NO_x and SO₂. MEAN believes its generating resources are well positioned to meet any requirements relating to CSAPR’s implementation. MEAN does not anticipate that CSAPR or the CSAPR Update Rule will have a material impact on the Power Supply System or its generating resources.

5. Mercury and Air Toxics Standards

On December 16, 2011, the EPA issued final rules titled “Mercury and Air Toxics Standards” (“MATS”). The rules establish national emission standards for mercury and other hazardous air pollutants from coal- and oil-fired power plants. They require significant reductions in mercury and acid gas emissions from coal-fired power plants and apply to electric generating units greater than 25 MW.

The Supreme Court initially rejected the final MATS rule in 2015, and in December of that year, the D.C. Circuit remanded the rule to EPA without vacating the rule. On April 14, 2016, EPA issued its final supplemental finding stating that, after consideration of costs, it is appropriate and necessary to set standards for emissions of air toxics from coal-and oil-fired power plants.

MEAN’s impacted facilities are all currently MATS compliant. WSEC 4 was originally constructed with emissions controls which enable the plant to comply with MATS. Included with the purchase of the Air Quality Control System for WEC 2 was the necessary equipment to use activated carbon injection as a control of mercury emission to enable compliance with MATS. Wygen Unit I’s current emission control equipment enables the plant to comply with MATS. Laramie River Station completed installation of equipment in order to meet a June 2015 compliance deadline to comply with MATS. Ongoing compliance with MATS must be demonstrated by each affected facility.

6. Reciprocating Internal Combustion Engine Subpart ZZZZ

Beginning in May of 2013, the National Emissions Standards for Hazardous Air Pollutants (“NESHAP”) for Stationary Reciprocating Internal Combustion Engines (“RICE”) (40 CFR, Part 63, Subpart ZZZZ) were updated by the EPA. The RICE NESHAP update included a required reduction of emissions of hazardous air pollutants from covered engines located at major sources of hazardous air pollutant emissions such as power plant sites. For most of the effected units, this required the installation of an oxidation catalyst on the exhaust stack to reduce the emissions of carbon monoxide (CO). In addition, a monitoring system was required to verify and report the performance of the catalyst. All of MEAN’s applicable Committed Facilities have installed the required catalyst and monitoring equipment. MEAN staff worked extensively with participants to ensure that all necessary policies and procedures were adopted and continues efforts to assist participants in compliance with the RICE NESHAP regulations and annual testing and reporting.

7. Regional Haze Rule

The EPA’s Regional Haze Rule requires emissions controls using best available retrofit technology (“BART”) for industrial facilities emitting air pollutants that impair visibility in Class I areas (national parks and wilderness areas). Such pollutants include fine particulate matter (PM_{2.5}) and compounds that contribute to PM_{2.5} such as NO_x, SO₂, certain volatile organic compounds, and ammonia. Each state is required to submit a State Implementation Plan (“SIP”) to demonstrate compliance.

Nebraska, as a CSAPR-affected state, will be able to substitute CSAPR for any requirements related to the Regional Haze Rule. WEC 2 is well positioned to meet any requirements relating to CSAPR’s implementation. Based on a determination by the state of Iowa, WSEC 4 is not subject to the Regional Haze Rule. Wygen Unit I is not currently subject to CSAPR, though it is well positioned to meet any requirements relating to CSAPR’s implementation.

In 2014 the EPA issued a final ruling on the Wyoming state implementation plan for Laramie River Station that required installation of selective catalytic reduction (“SCR”) technology for all three units at Laramie River Station. The Wyoming Department of Environmental Quality and coal plant operators evaluated various options for Laramie River Station compliance and ultimately negotiated a settlement with the EPA. In 2019, selective noncatalytic reduction controls were installed on two units and SCR control on one unit to meet these compliance standards.

8. National Ambient Air Quality Standards

The EPA promulgated final rules and guidance for fine particulate matter, known as the PM_{2.5} Standard, under the National Ambient Air Quality Standards (“NAAQS”), which regulates particles less than 2.5 microns in diameter. No county in Colorado, Iowa, Nebraska or Wyoming has been included in the EPA’s list of PM_{2.5} “non-attainment” areas, *i.e.*, not in compliance with air quality standards.

In 2008, the EPA promulgated new primary and secondary national ambient air quality standards for ozone, with revised NAAQS for ground-level ozone becoming effective in 2015. The revision set stricter standards and requires modeling and low ambient air testing to confirm compliance. Based on current data and public information, all areas of Colorado, Iowa, Nebraska and Wyoming are either in attainment or are unclassifiable.

The EPA Good Neighbor Plan would establish an allowance-based ozone season trading program with nitrogen oxides (NOX) emissions budgets for fossil fuel-fired power plants in 25 states. Wyoming is the only state in the MEAN footprint that would be impacted by this proposed update to the NAAQS.

9. Greenhouse Gas and Climate Change Issues

In April 2009, the EPA issued final findings that the current and projected concentrations of the mix of six key greenhouse gases (“GHG”s)—carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride—in the atmosphere threaten the public health and welfare of current and future generations.

On May 13, 2010, the EPA issued a final rule that requires Prevention of Significant Deterioration (“PSD”) and Title V operating permits to be obtained by stationary sources, including power plants. PSD permitting requirements for compliance with GHG emission criteria require a “best available control technology” (“BACT”) analysis. WEC 2, WSEC 4 and Wygen Unit I are all operated under BACT standards. WEC 2, WSEC 4, Wygen Unit 1, and Laramie River Station currently have the necessary Title V operating permits and acid rain permits. Title IV of the Clean Air Act created an SO₂ allowance trading program as part of the federal acid rain program. Sufficient allowances are held for Wygen Unit I and WEC 2.

On August 3, 2015, the EPA finalized performance standards for new, modified and reconstructed fossil fuel-fired electric generating units. Under the rule, new coal-fired power plants will be required to employ partial carbon capture and sequestration technology to meet emission standards for carbon dioxide. For new natural gas-fired units, EPA has concluded that compliance should be achievable without additional controls. The performance standards will not apply to existing plants.

There have been numerous other judicial and legislative challenges to the EPA’s efforts to regulate GHGs that may impact the regulatory status outlined above.

10. Coal Combustion Residuals

The Disposal of Coal Combustion Residuals (“CCRs”) from Electric Utilities rule (the “CCR Rule”) which became effective on October 19, 2015, regulates coal combustion byproducts (“CCBs”) under Subtitle D of the Resource Conservation and Recovery Act as non-hazardous solid waste. The CCR Rule establishes guidelines and new minimum standards for the disposal of CCBs in landfills and surface impoundments and mandates closure of unlined surface impoundments upon a specified triggering event. Under the CCR Rule, if after multiple levels of monitoring and an alternate source demonstration, a statistically significant level of contamination cannot be attributed to another source, a company was required to retrofit or close the pond. In August 2018, the D.C. Circuit Court ordered that the CCR Rule be vacated with respect to the provisions that permit unlined surface impoundments to continue receiving coal ash unless they leak. On several instances in 2019 and 2020, the EPA further amended the CCR Rule. Key features of these amendments include: the reconsideration of beneficial use criteria, reclassification of clay-lined impoundments to be considered unlined, limited permission for some unlined surface impoundments to continue to operate, and revision of the alternate closure provisions.

The EPA's August 28, 2020 amendments require all impoundments that do not meet the liner requirements outlined in the Rule to cease receiving CCR and non-CCR waste streams CCR material and initiate closure by April 11, 2021, regardless of compliance status. If not technically feasible, an alternate date to cease receiving CCR material and initiate closure could be secured from the EPA through an extension request process, to be submitted to the EPA no later than November 30, 2020.

Basin Electric Power Cooperative ("BEPC"), as the Operating Agent for Laramie River Station, hired a consultant to conduct detection monitoring in 2016 and 2017. The consultant detected a statistically significant increase ("SSI") in one or more of the indicator constituents from the Laramie River Station ash pond. BEPC worked with the consultant to determine if the SSI could be attributed to an alternative source. The consultant analyzed soil samples and performed further groundwater monitoring. The consultant who ultimately could not determine that the SSI came from an alternate source. BEPC concluded that the CCR Rule required a corrective action for the ash pond and proceeded with design and engineering work to meet the revised deadline of April 11, 2021 for all unlined CCR surface impoundments and surface impoundments that fail the aquifer location restrictions to initiate closure or retrofit.

PPGA is currently in the process of groundwater monitoring at WEC 2, working with a third-party consultant. The results of the comprehensive monitoring and modeling will determine the extent and source of contaminants, which will direct the course of action with regard to the need for an ash pond liner. PPGA is also actively marketing WEC 2's ash in an attempt to decrease the size and mitigate the effects of the coal ash pond. PPGA has not yet determined the cost or the extent of any potential corrective action required. PPGA has requested an extension from the EPA.

11. Effluent Limitation Guidelines

EPA promulgated the Steam Electric Power Generating Effluent Guidelines and Standards in 1974 and amended the regulations several times since. The regulations cover wastewater discharges from power plants operating as utilities. The Steam Electric regulations are incorporated into NPDES permits. The EPA has in recent years adopted more stringent limits for new pollutants and parameters for individual wastewater streams generated by steam electric power plants, with a particular focus on coal fired power plants.

Under a new rule which became effective on January 4, 2016, new requirements for existing power plants will be phased in between 2018 and 2023. The rule established wastewater limits for heavy metals from coal combustion residual products. Following legal challenges and petitions for administrative reconsideration to such rule, on November 22, 2019, the EPA issued a proposed rule revising the 2015 rule. The proposed rule was finalized on October 13, 2020 and updated what constitutes "best available technology" (BAT) guidelines for bottom ash transport water and FGD wastewater. The updated rule extended the deadline for meeting the BAT limitations to no later than December 31, 2025. Consistent with Executive Order 13990 issued by President Biden, the EPA has also filed an August 2, 2021 notice in the Federal Register indicating it intends to initiate a supplemental Effluent Limitation Guidelines rulemaking to strengthen certain discharge limits in the Steam Electric Generating category. According to the EPA, the new rule is expected to be issued in 2022.

12. Water Quality

The Federal Clean Water Act regulates the discharge of process wastewater and certain storm water under the National Pollutant Discharge Elimination System permit program. WSEC 4 is not impacted by the Clean Water Act. WEC 2, Wygen Unit I and Laramie River Station have proper permitting in place under the Clean Water Act.

In 2015, the act was revised with regard to the regulatory definition of the term “waters of the United States.” However, later that year the US Court of Appeals for the Sixth Circuit issued a stay on the revision. In response, federal agencies reverted to the prior definition for enforcement. In February 2017, the President issued an executive order directing the EPA and Army Corps of Engineers to review and revise or rescind the 2015 rule. As recently as November 2021, the EPA again proposed to revert to the pre-2015 definition of WOTUS. The manner in which this term is defined will impact requirements for wastewater discharge from power plants located upstream of community water sources.

13. Future Legislation and Rules

In recent years various Congressional bills have been introduced in both the House of Representatives and the Senate that would require increased generation of carbon-free energy and the further reduction of emissions of sulfur dioxides, nitrogen oxides, mercury and carbon dioxide from coal-fired electric generating units. In addition, recent efforts to expand and extend tax credits for carbon capture technologies have been introduced in Congress. Proposed bills such as the Green New Deal, the CLEAN Future Act, and the Clean Electricity Performance Program indicate support for enacting significant economic incentives for increased clean energy production and corresponding penalties for carbon emissions.

In December 2020, Congress passed an omnibus package which includes the first major energy policy since 2007. The bipartisan bill includes research and development and deployment for clean energy technologies, clean energy tax incentives, and directs EPA to phase down the production and consumption of hydrofluorocarbons.

MEAN cannot predict at this time whether any additional legislation or rules will be enacted in the future that will affect the operations of the Power Supply System, MEAN or the Participants, and if such laws or rules are enacted, what the costs to MEAN and the Participants might be in the future because of such action.

MEAN is continually monitoring, and evaluating the best ways to meet, the requirements of current federal and state air quality and other environmental laws.

B. Load Forecast

MEAN employs a robust statistical method for forecasting load. As fully described in Section V. System Load Forecast, a number of input variables are used to formulate a forward-looking equation to calculate the monthly peak demand and monthly energy usage for each participant community for the entirety of the study period. The individual participant load forecasts are combined to result in a total load forecast for each region. However, the statistical analysis is dependent upon several variables, such as weather data, population, and income. Changes in any of these factors will impart changes in the load forecast.

Extreme weather events have made a notable impact on energy markets in recent years. In 2020, Hurricane Laura hit MISO's Gulf Coast region, resulting in a 500-MW load shed and massive transmission and distribution system destruction. In February 2021, Winter Storm Uri effected fuel supply and resource availability as well as load levels for several days in the SPP and ERCOT regions, leading to massive outages and extraordinarily high energy pricing. This type of weather event is unforeseeable and is not included in the weather projections used for load forecasting.

In addition to the variables identified as inputs to the load forecast calculation, throughout the MEAN footprint, demand side management (“DSM”) measures are being adopted by utilities and end-use customers in participant communities, encouraged and supported by MEAN and NMPP. DSM measures act to reduce either the peak demand for electricity or the total electricity consumption. Consumers are gaining interest and knowledge in the control and reduction of their energy consumption and carbon footprint. As such, we can expect the deployment and adoption of DSM to continue and likely increase in the future, leading to a decrease in load. This effect is fully explored in the Demand Side Management section of this report, although the actual future use of DSM is difficult to accurately forecast. And element of DSM impact is included in the load forecast.

In addition to controlling and reducing their energy consumption, some customers also have interest in providing for their own energy supply. Distributed Generation (“DG”) is customer and/or community ownership of generating assets to serve end use load. DG, particularly in terms of wind, solar, and combined heat and power, are becoming more popular “behind the meter” installations. Also of recent increased interest are residential energy storage systems, particularly in the territories of utilities that have instituted time-of-day rates. Each installation of DG removes energy consumption from the MEAN system and thereby decreases the resource need, either on a capacity or energy basis depending on the timing of DG energy supply. Recent MEAN policy changes allow for an increased installation of DG resources as a percentage of energy consumption. The future rate of DG installation and therefore its impact on load projections is unknown.

Recent years have seen an emphasis on energy efficiency and energy conservation on all levels: residential, commercial, and industrial. From improved performance of household appliances to the use of energy efficient materials in building construction to conscious selection of efficient HVAC systems, customers are making choices to decrease their energy usage and cost. The widespread use of these practices has led to a decrease in the growth rate of electric loads, and is a trend which is likely to continue, but at a pace that is difficult to predict.

C. Electrification

Electrification refers to the process of replacing technologies that use fossil fuels with technologies that use electricity as a source of energy. As more carbon-free resources are integrated into the grid to generate electricity, electrification can potentially reduce carbon emissions from the transportation, building, and industrial sectors. Given the adoption of state and federal regulations to reduce emissions, electrification activities are likely to proliferate. This gives entities more opportunity to reduce overall system carbon emissions with the possibility of serving this load with carbon free resources.

This move toward electrification would alter MEAN’s resource portfolio as demand and consumption increase and end users require more carbon-free power. This change will also result in changes in the operations and economics of the energy markets.

Although the actual adoption rates and impacts are unknown, the report does show a load forecast that assumes a level of electrification corresponding to the NREL Electrification Futures Study. This load scenario was not modeled however, as it would require a completely different resource acquisition schedule that would not be comparable to the other scenarios.

To explore one aspect of future Electrification, MEAN asked member communities about their interest in one of the biggest drivers of increased electric load: electric vehicles. To begin a determination of future load growth due to electric vehicle load, MEAN asked about the installation of charging infrastructure and the interest in the application of funding sources for these installations. The response indicated that this increased load may be developing in several MEAN communities in the coming years. The survey questions and responses are illustrated below:

Is your community interested in the installation of electric vehicle charging infrastructure?

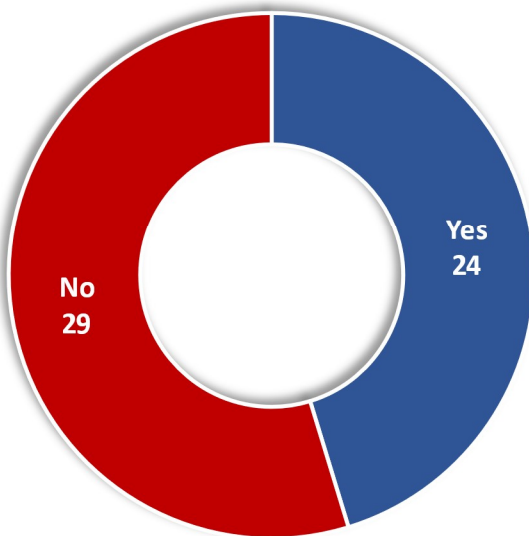


Figure IV-2

Would your community be interested in funding opportunities for electric vehicle infrastructure if state or local funds were available for this purpose?

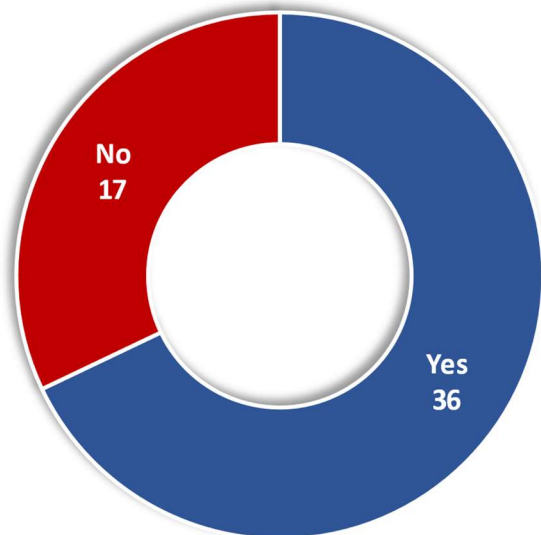


Figure IV-3

D. Future Load Acquisition

MEAN maintains a goal toward strategic growth to benefit the membership and the long-term health of the organization. This means adding new load when it can be economically served. When Requests for Proposals for power supply are released, MEAN conducts a statistical analysis to determine the cost at which the load can be served by the existing Power Supply System or future resources if needed. Adding load, particularly when new resources are not required, benefits the remainder of the total requirements participants as MEAN's fixed costs are allocated among more communities.

Obviously, although load addition is a priority for MEAN, it cannot be accurately forecast. Therefore, this represents an unknown potential change in MEAN's load and resource balance and the timing and magnitude of future resource needs.

E. Energy Markets

In the integrated markets, loads are served and resources dispatched according to market dynamics and the balance of bids and offers in an attempt to cost effectively optimize the pool of resources. In addition, the Transmission Congestion Rights markets give participants a financial hedge against the market price fluctuations that occur due to transmission congestion.

Since the establishment of the SPP and MISO Integrated Markets, several changes have been introduced that have changed the way resources are designated to load, the way resources are dispatched into the marketplace, and energy prices and cost recovery for generation resources. Given the fast pace of developments in the markets, it is likely that changes will continue in the future.

Within the integrated markets, market prices are determined by variable costs of generating units throughout the entire market. Therefore, the construction of new units and retirement of existing units has the potential to change the order of economic dispatch of resources and, as a result, marginal pricing. The integration of non-dispatchable, renewable generation into the resource mix impacts the operation of other resources, particularly peaking units dispatched in response to supply fluctuations and cycling coal plants.

SPP and MISO perform Effective Load Carrying Capability (“ELCC”) studies to calculate the capacity value of renewable capacity and determine the impacts of continued renewable capacity growth. ELCC is defined as the amount of incremental load a resource can reliably serve, while also considering probabilistic parameters of unserved load caused by forced outages, load uncertainty, and other factors. ELCC study results indicate that with increasing penetrations of wind and solar resources, the capacity value provided by those resources as a percent of nameplate capacity generally tends to decrease. This has impacts on the magnitude of resources needed to serve load, which directly affect the inputs and results of this analysis.

Both SPP and MISO are also contemplating changes to resource accreditation, resource adequacy, outage scheduling, and seasonality of the market construct, among other investigations.

Adding to all of these market uncertainties the possibility of the SPP West or CAISO expansions in the west region increases the potential for unforeseen circumstances within MEAN’s power supply system.

F. Fuel Pricing

1. Natural Gas

Recent natural gas pricing has been extraordinarily high and has experienced considerable volatility, as shown in *Figure IV-4*.

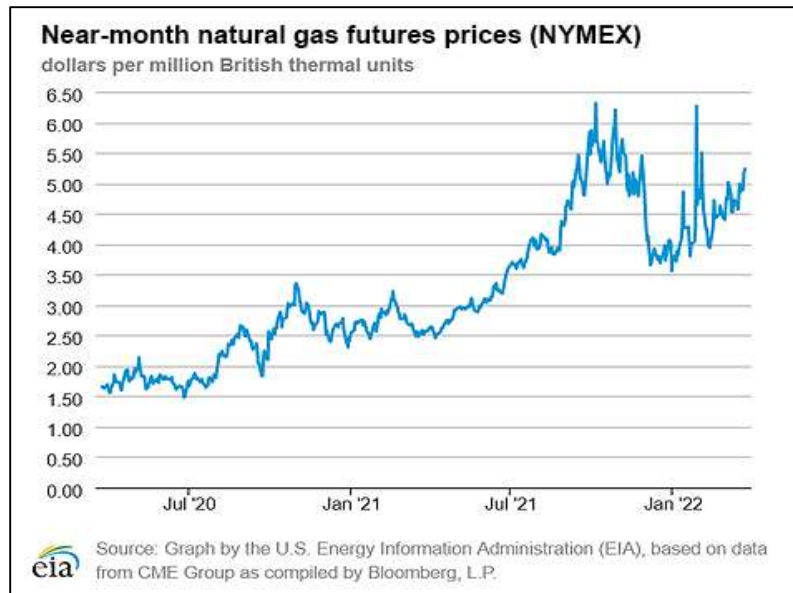


Figure IV-4

There are myriad factors influencing this natural gas price hike. Domestic demand is rebounding after the lull in consumer and manufacturing activity caused by the Covid-19 pandemic. Simultaneously, the supply side has slowed as natural gas producers are still at the reduced levels of the pandemic economy.

The European energy climate also caused upward pressure on prices. Storage levels in Europe were down due to a more intense winter season in 2020. Wind and hydropower output were low on the European continent as well, meaning increased demand for natural gas-fired power. Europe relies heavily on natural gas from Russia, which has slowed exports due to political frictions. Recent upticks in demand from Asia are also tightening the supply market.

The months-long escalation in natural gas pricing has an obvious correlation with energy prices. The following figure from the *SPP MMU State of the Market Report* illustrates these recent trends.

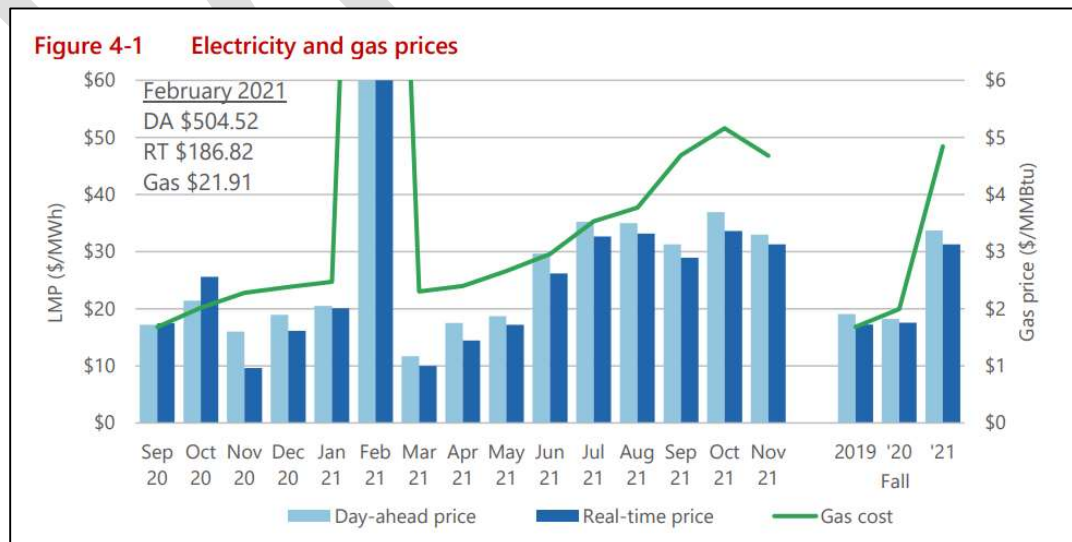


Figure IV-5

Not only are prices high, but pricing has been experiencing considerable volatility, which makes economic projections and modeling less reliable.

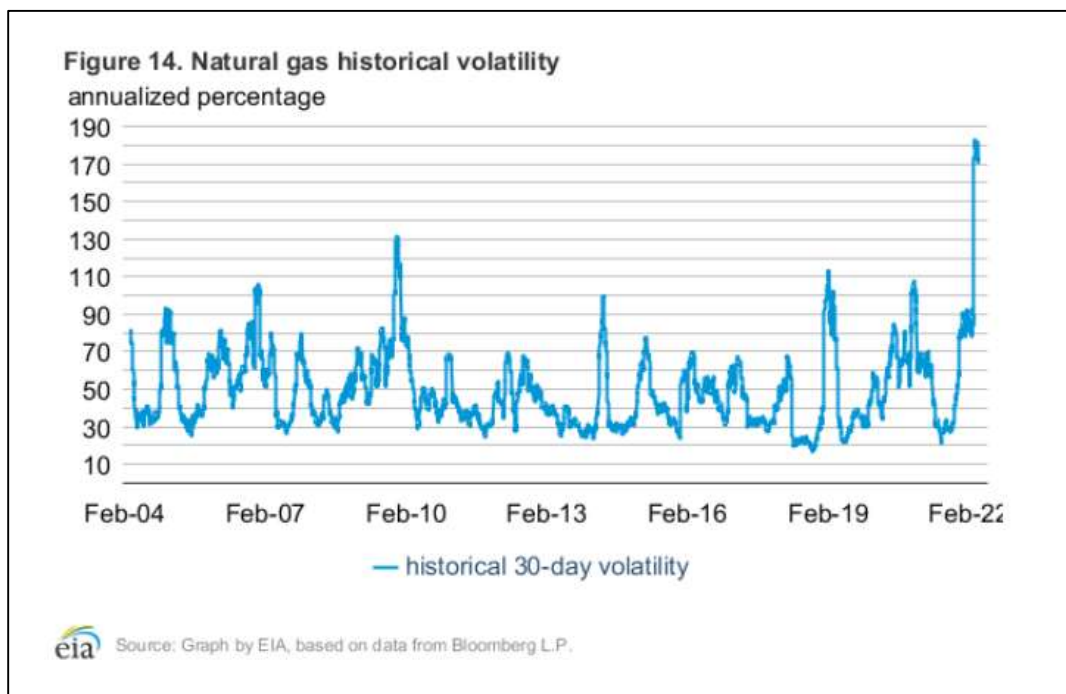


Figure IV-6

Natural gas prices are likely to remain elevated for years to come. The EIA Short-Term Energy Outlook from January 2022 predicts a continuation of prices around the \$4 per MMBtu range.

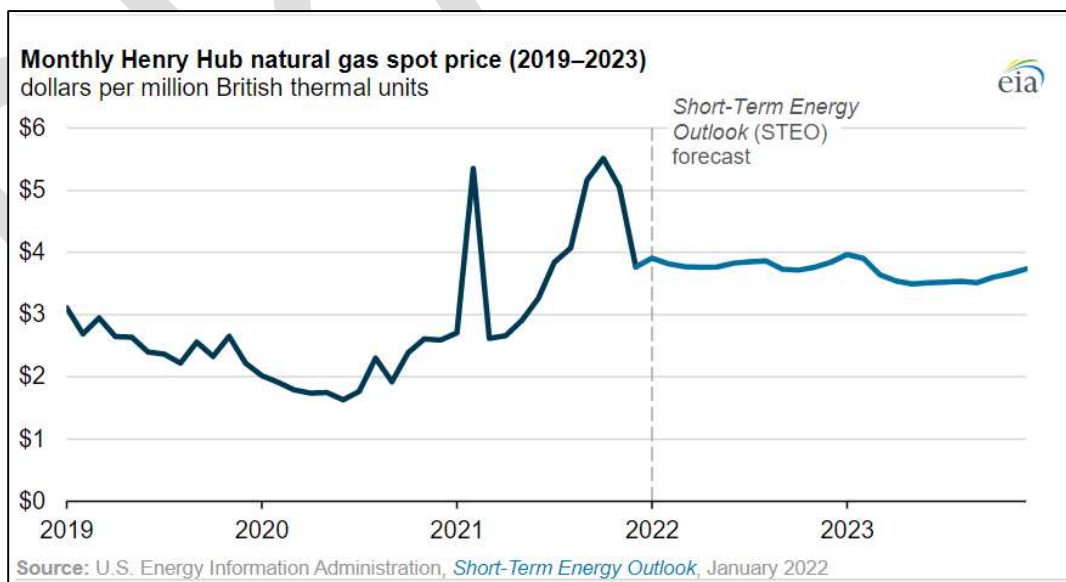


Figure IV-7

Due to the number of factors that influence natural gas pricing and the interconnection of those factors, this input remains an item of inherent uncertainty.

2. Coal

Coal prices in the US have stabilized in recent years and remained relatively low. Coal in most regions has seen flat or declining pricing over the past ten years. Coal for electricity production is typically purchased, at least in part, on long term contracts, thereby dampening the pricing volatility. A ten-year trend is shown in *Figure IV-8*.

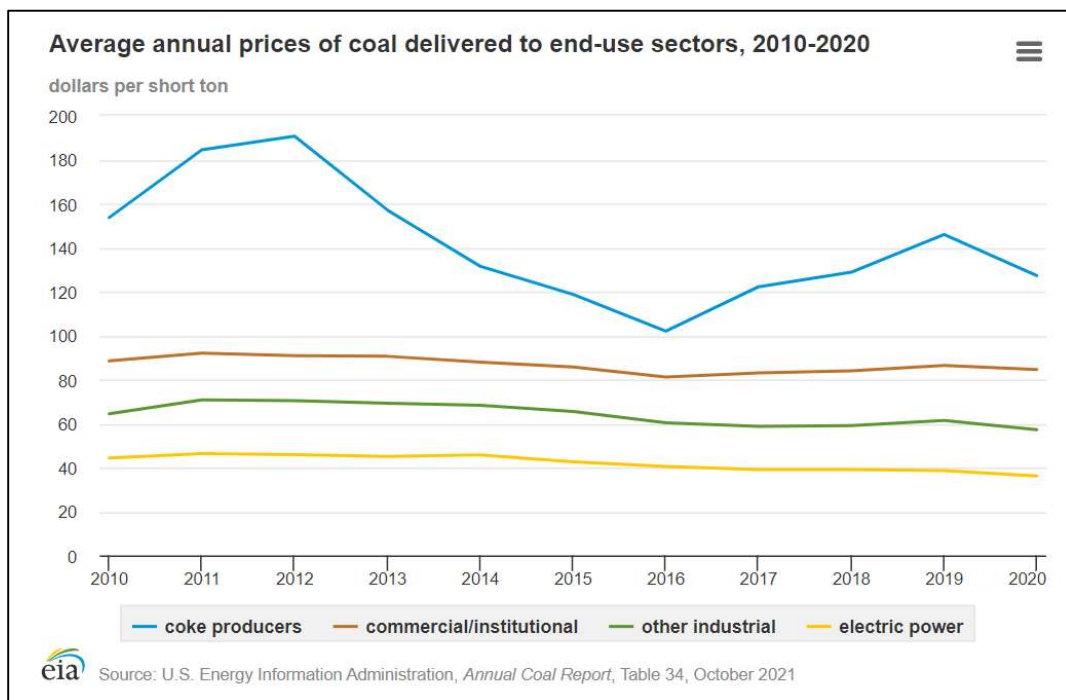


Figure IV-8

Particularly in contrast to the recent upsurge and unpredictability of natural gas prices (depicted as Henry Hub spot price below), coal prices are very constant and look to remain so for at least the short term.

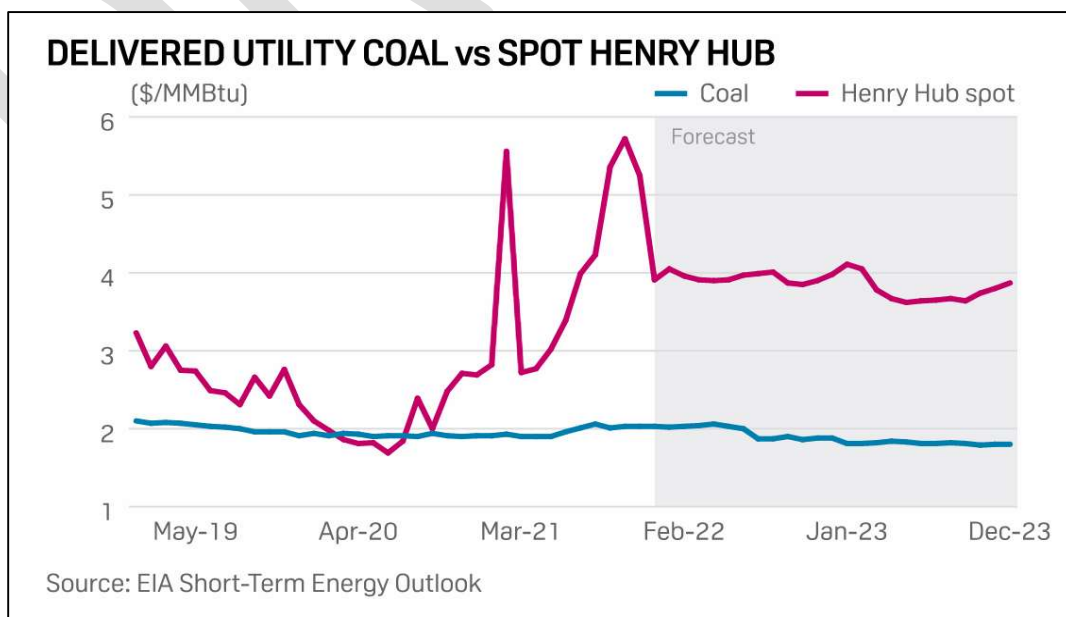


Figure IV-9

Global power markets and economics will certainly play a part in future coal prices, and supply conditions will also factor in as mining and transport companies attempt to weather the impacts of the changing domestic market.

G. Other Factors

In addition to these items described above, a number of other factors are having or may have significant impacts on the electric utility industry generally and on the financial and operating condition of individual utilities. These factors include, among other things:

- corporate or utility clean energy goals
- commercial viability and development of new generating technologies or environmental controls.
- the development and impact of alternate energy sources, and government changes to tax credits and grants for renewable energy projects;
- the lack of a comprehensive national energy policy;
- effects of competition from other electric utilities (including increased competition resulting from mergers, acquisitions and strategic alliances of competing electric and natural gas utilities), independent power producers and marketers, brokers and federal power marketing agencies
- grid expansion allowing the transmission of less expensive electricity from greater distances over an interconnected system;
- changes in state regulations that determine the pricing and incentives for distributed generation, including net metering rate structures;
- volatility in the price of energy purchased on the wholesale market that may occur in times of high peak demand;
- local, regional and national economic conditions.

It is not possible to predict what impact these and other factors will have on the financial and operating position of MEAN or the Participants. The foregoing discussion is a general summary of complex matters. This discussion is not comprehensive or definitive and the matters discussed are subject to change.

V. System Load Forecast

A. Methodology

1. Non-Coincident Peak Demand

MEAN employed multiple regression analysis to forecast the non-coincident peaks for each of its Total Requirement Participants for FY 2022-2023 (annual forecast) thru FY 2037-38 (15-year forecast). The annual forecast model utilized the daily peak demand data from 2006 to 2021 as a dependent variable, while the 15-year forecast model used monthly peak demand data of the same period. Both models took into consideration three main categories of independent variables: economic factors such as population growth and income growth; temperature factors such as average daily temperature, heating degree days (“HDD”) and cooling degree days (“CDD”); and calendar factors such as weekdays and month. Historical average daily temperatures, HDD and CDDs were gathered from NOAA station data, historical population data were gathered from the U.S. Census Bureau, and historical income data was sourced from the Bureau of Labor Statistics. The estimated population and income data used for the forecast were calculated from separate simple linear regressions.

To ensure that monthly peak demand was forecasted under normalized weather conditions for each town, actual weather data from the past ten years was used, and ten sets of monthly peak demand were forecasted. The median was used as the normalized peak demand of the town for the given month. Non-coincident peak demand was then calculated by summing all the normalized peak demands of each town for each month.

2. Energy for load forecast

The same methodology used in the 15-year peak demand forecast was used for energy forecasts for each town. The only modification was the change of the dependent variable from monthly peak demand to monthly energy usage. All data was obtained from the same resources as in the demand forecast, and the same weather normalization process used in the demand forecast was used in the energy forecast.

3. Coincident Peak Forecast

The coincident peak forecast is calculated as MEAN’s non-coincident peak multiplied by the coincidence factor. The coincidence factor was forecasted based upon regression analysis of the difference between the mean temperature and the max temperature at the time of historical peaks. The historical weather data used in the regression was based on NOAA station data. The historical coincidence factor used for regression was derived by using the dates and times of historical peak. In the detailed regression analysis, a stepwise selection procedure was used and two variables, Max Temperature Differential and Mean Temperature Differential, were selected to define the equation for the coincidence factor.

To arrive at the expected weather normal coincidence peak, MEAN looked at historical mean temperature differences and the max temperature differences for all the dates and times of historical peaks. The medians were then calculated and reinserted into the regression equation to find the expected coincidence factor. The final expected coincident factor was 96.24% in SPP, 93.94% in MISO, and 96.43% in the West.

The regression analysis also resulted in the below statistical output:

- Model description and fit
- Residual Analysis
- Variance Inflation Factors (Collinearity Analysis)
- ANOVA (Analysis of Variance)
- Confidence Intervals
- Forecast Evaluation Statistics

4. Annual Participant Load Survey

To validate the load forecast statistical calculations, MEAN conducts an annual load survey to all participants. MEAN presents the results of its 15-year forecast for the participant community and asks the representatives to review it with their knowledge of the community's peak load and energy consumption.

Specifically, the survey asks if there are any recent or planned additions to load or losses of load. Any information collected in response to the survey is then incorporated into the community's load forecast and the regional and system-wide forecasts are corrected accordingly.

B. Factors Affecting Load Growth

MEAN Participants and their end-use customers are implementing demand side management ("DSM") measures to reduce peak demand and/or energy use. MEAN administers DSM programs to control peak demand to minimize the need for future resources. Participant utilities adopt DSM programs to decrease their peak demand in an effort to lower the Fixed Cost Recovery Charge paid to MEAN, which is based on the 3-year historical average peak. End-use customers participate in DSM programs to reduce their utility bill. Although the actual impact of these measures is often difficult to measure or predict, successful DSM programs will ultimately slow the rate of load growth into the future.

Growing awareness of energy issues and pricing has increased customer interest in owning generation to serve their own load. As technologies become more available and affordable, MEAN Participants and their end-use customers will have more incentive to install distributed generation assets. From residential rooftop solar to industrial combined heat and power to community wind and solar, distributed generation is being aggressively marketed and eagerly adopted. These assets ultimately decrease the load obligation that MEAN has to serve by increasing behind-the-meter capacity. MEAN's Renewable Distributed Generation policy was updated in November of 2019 to increase the size of allowable installation of community-owned and locally-sited renewable resources from 2% of annual energy consumption to 5% of annual energy consumption. MEAN does not limit distributed generation installations of retail end-use customers.

Energy efficiency and energy conservation are widely promoted initiatives and are becoming easier to integrate into everyday life. As electricity rates increase, the economic benefit of efficiency and conservation gives consumers, businesses, and institutions ample reason to adopt behaviors and make purchases with the goal of reducing energy consumption. This has a long-term effect on all load profiles.

C. Recent Developments

Since the submittal of the 2017 IRP, MEAN's load has been impacted by a few changes to the organization's membership.

1. Load Loss

Since 2017, no MEAN power supply Participants have discontinued their contracts, and therefore MEAN has not lost wholesale load customers. However, some MEAN participants have recently lost load within their individual communities. MEAN and NMPP continually work with the membership to prevent and mitigate negative impacts of such load loss.

2. Load Additions

Since the 2017 IRP, MEAN has engaged the following additional power supply obligations:

- Center, Colorado signed a 5-year SSJ contract for limited term total requirements power supply in excess of their WAPA allocations. The contract effective date was April 1, 2020.
- Glenwood Springs, Colorado extended their SSK-1 contract for limited term total requirements power supply in excess of their WAPA allocation, which was originally set to expire on December 31, 2022. The new contract effective date was June 1, 2019 with a 10-year term.
- Holyoke, Colorado extended their SSJ contract for limited term total requirements power supply in excess of their WAPA allocations, which expired on September 30, 2018. The new contract effective date was October 1, 2018 with a 5-year term.
- Wray, Colorado extended their SSJ contract for limited term total requirements power supply in excess of their WAPA allocations, which expired on June 30, 2018. The new contract effective date was July 1, 2018 with a 5-year term.
- Lake View, Iowa extended their SSJ limited term total requirements power supply contract for power needs in excess of their WAPA allocation, which was originally set to expire on May 31, 2021. The new contract effective date was June 1, 2021 with a 3-year term.
- Snyder, Nebraska extended their SSJ limited term total requirements power supply contract, which was originally set to expire on May 31, 2021. The new contract effective date was June 1, 2020 with a 6-year term.
- Trenton extended their SSJ limited term total requirements power supply contract, which was originally set to expire on December 31, 2021. The new contract effective date was January 1, 2021 with a 10-year term.

As opportunities are announced via Requests for Proposals, MEAN engages in deliberate analysis to determine the benefits and costs of service additions and responds to all viable requests. MEAN continues to pursue additional load, through the initiation of new contracts and assisting existing communities with economic development to grow loads within their territories.

D. Reserves and Transmission Losses

MEAN must maintain capacity to serve not only the forecasted load in each region, but the total resource obligation which adds to the peak demand a reserve margin and transmission losses.

1. Reserve Margin

The SPP and MISO market constructs require each load serving entity to maintain a designated percentage of reserve capacity in addition to the entity's forecasted peak load.

The SPP Open Access Transmission Tariff requires a Load Responsible Entity (LRE) to maintain adequate capacity to meet its Resource Adequacy Requirement for the upcoming summer season. Maintaining appropriate planning reserves ensures that SPP will have sufficient capacity to serve peak demand obligations. The Planning Criteria defines the Planning Reserve Margin (PRM) as 12% for each LRE, unless the LRE's capacity is comprised of at least 75% hydro-based generation, in which case the PRM for the LRE is 9.89%.

In MISO, the required Planning Reserve Margin ("PRM") is calculated such that the Loss of Load Expectation ("LOLE") for the next planning year is one day in 10 years. The minimum amount of capacity above Coincident Peak Demand in the MISO region required to meet the reliability criteria is used to establish the PRM. The PRM is established as an unforced capacity requirement based upon the weighted average forced outage rate of all Planning Resources in the MISO Region. For the 2021-22 planning year, the PRM is 9.4%. As the MISO definition of the PRM is specific to the operation of the upcoming year, the PRM changes annually. The most recent LOLE study shows the PRM trending slightly lower in future years.

For loads and resources in the west, there is no prescribed reserve margin. MEAN incorporates a 12% reserve margin in addition to forecasted load when determining the load and resource balance in the west. The Western Power Pool is currently collaborating with SPP to design a resource adequacy program, termed the Western Resource Adequacy Program, which would establish a reserve margin in the west region. Enforcement and compliance of this program is undetermined at this time.

MEAN adds the required margins to the forecasted peak demand to determine the total obligation for service in each region. This value is reflected in the figures throughout this section.

2. Transmission Losses

MEAN's total obligation for service must also include the losses that occur throughout the transmission system. The rate of loss depends on the transmission system and is typically reported to MEAN on an annual basis. However, MEAN does not have to provide for transmission loss on WAPA allocations. Therefore, this amount is deducted from the calculations. In total, MEAN serves network load on six transmission systems. Because of variation in WAPA allocations as a percentage of load and locations on different transmission systems, the calculated loss factor for each Participant community is unique.

Calculated transmission loss is included in the charts shown throughout this section.

E. Load Forecast Scenarios

With many unknown factors potentially impacting MEAN's future load obligations, the IRP considers resource needs under a variety of future load scenarios. Five scenarios were investigated:

1. Load Scenario 1: Reference Case

Load Scenario 1: Reference case load forecast, which is based on normalized weather and represents the 50% confidence interval of the statistical distribution. Annual load growth is approximately 0.11% over the 15-year time period.

2. Load Scenario 2: Low Load

Load Scenario 2: Low load scenario, which is based on normalized weather and represents the 10% confidence interval of the statistical distribution. Annual load growth is approximately 0.11% over the 15-year time period.

3. Load Scenario 3: High Load

Load Scenario 3: High load scenario, which is based on normalized weather and represents the 90% confidence interval of the statistical distribution. Annual load growth is approximately 0.11% over the 15-year time period.

4. Load Scenario 4: Electrification

Load Scenario 4: Electrification scenario, which is based on normalized weather and assumes a high rate of electrification throughout the footprint. This may be facilitated by electric home appliances, conversion of building heating and cooling systems, electric vehicle adoption, and other methods of replacing technologies traditionally powered by fossil fuels with those powered by electricity. The inputs to this load forecast scenario were informed by NREL's Electrification Futures Study. Annual load growth is approximately 1.4% over the 15-year time period. This load scenario was not modeled, as it would require a completely different resource acquisition schedule that would not be comparable to the other scenarios.

5. Load Scenario 5: Recession

Load Scenario 5: Recession scenario, which is based on normalized weather and represents a scenario in which an economic recession takes place mid-way through the time period. Recovery follows historical patterns. Annual load growth is varying throughout the time period as conditions change.

The graphs illustrating regional and system load forecasts below show all five scenarios. The first set of graphs per region groups the scenarios together on an annual basis for comparison. The next set of graphs per region breaks out the scenarios and shows seasonal data for each scenario.

F. MISO

MISO experiences a very consistent load curve. A slight decrease in peak demand will occur from 2023 to 2024 due to the contract expiration of Lake View (if not renewed). The average year-over-year load decreases 0.127% after this load reduction for an essentially flat long-term load forecast.

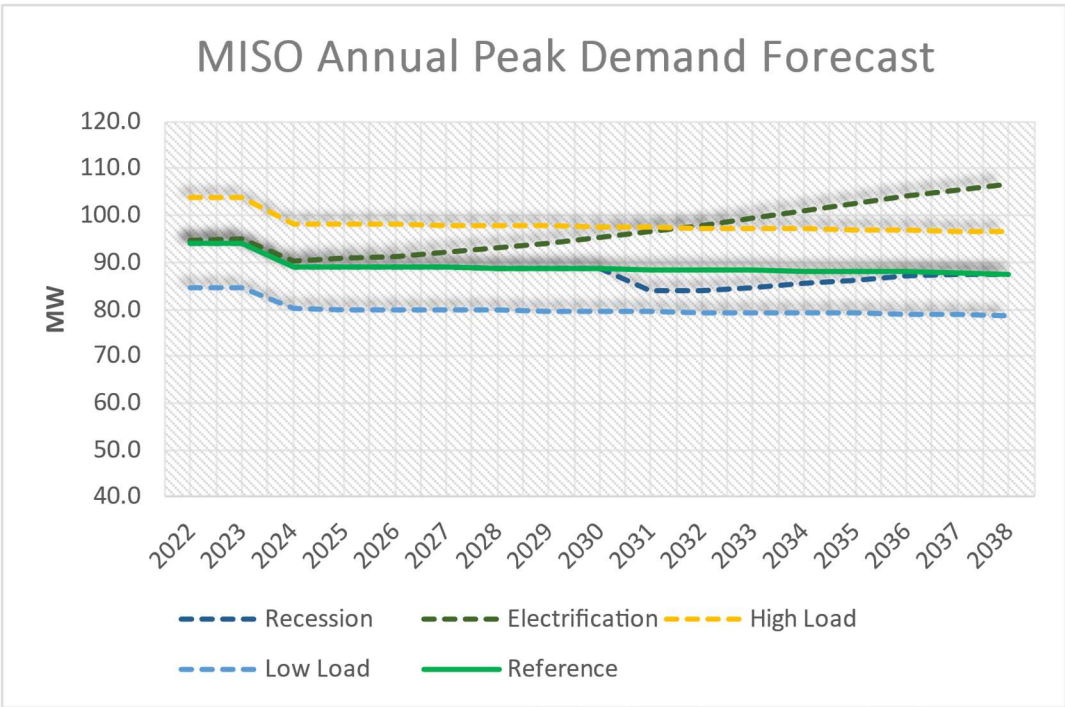


Figure V-1

As with peak demand, the energy consumption in MISO sees little change on an annual basis. A slight energy requirement decrease will occur in 2024 due to the contract expiration of Lake View (if not renewed). For the years following, the energy requirements in MISO decrease by 0.14% each year.

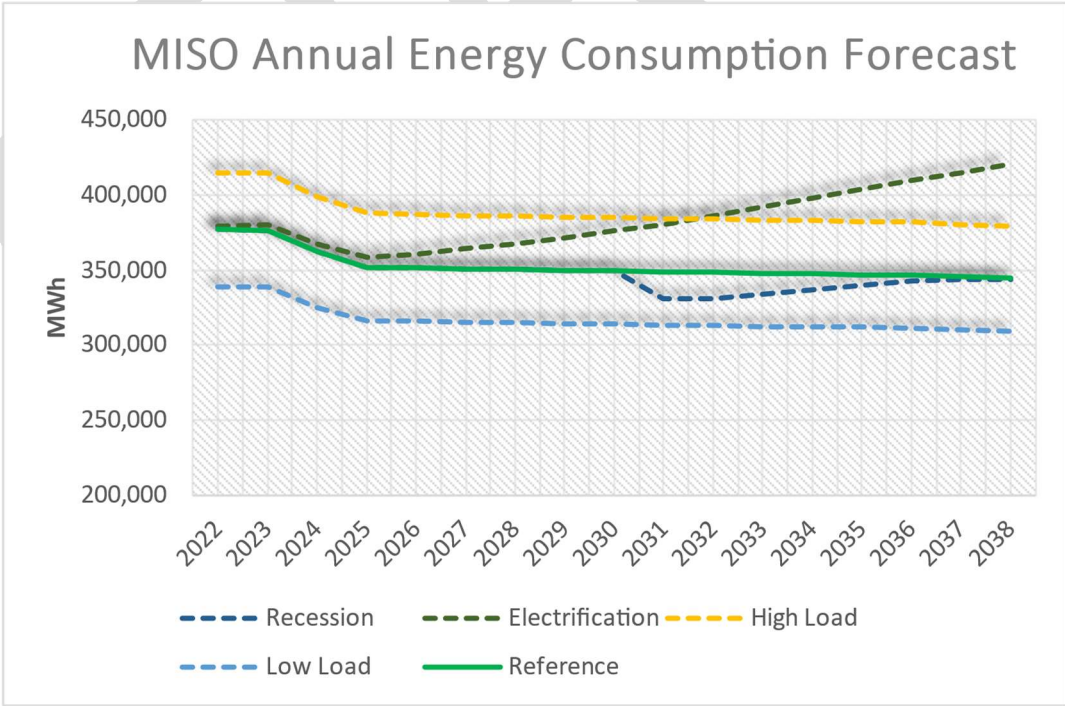


Figure V-2

Seasonal forecasts for MISO for both peak demand and energy consumption are shown below for each load forecast scenario:

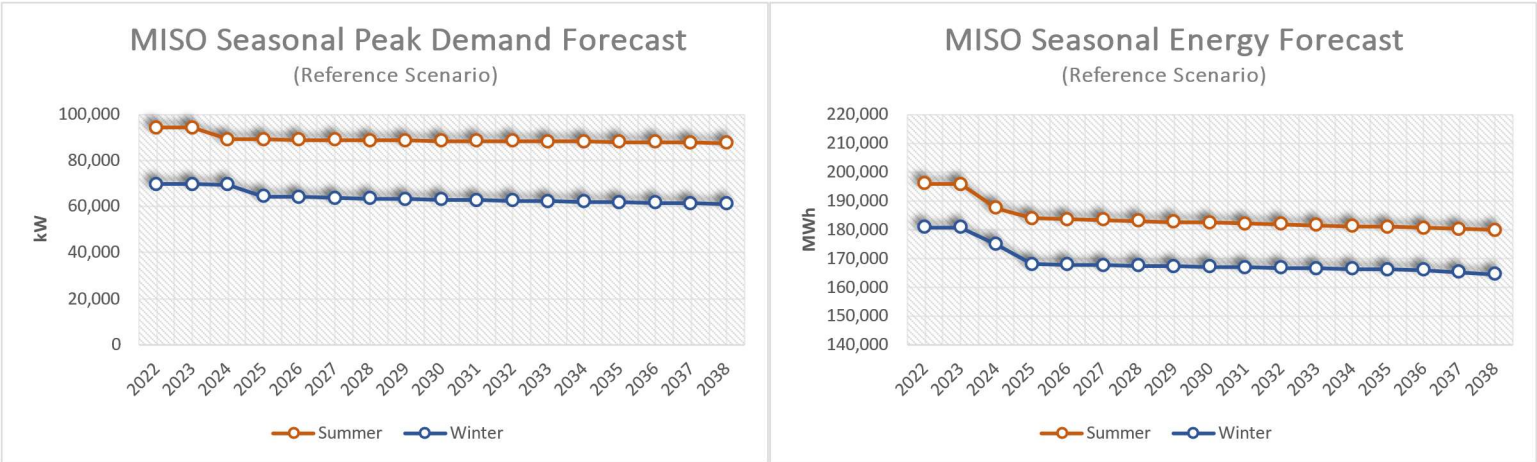


Figure V-3

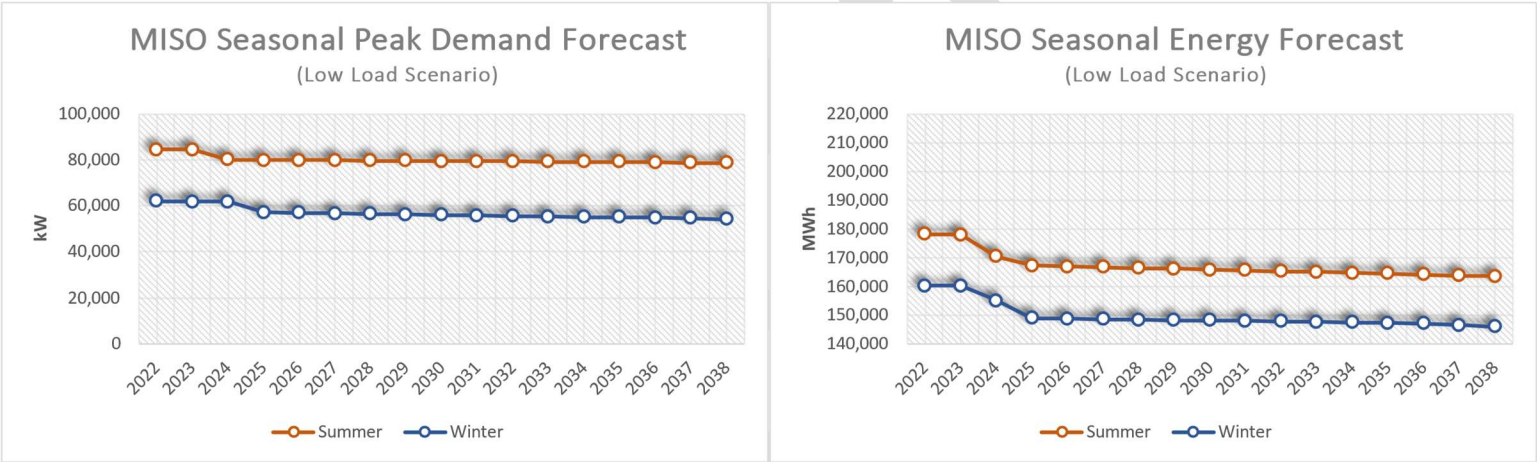


Figure V-4

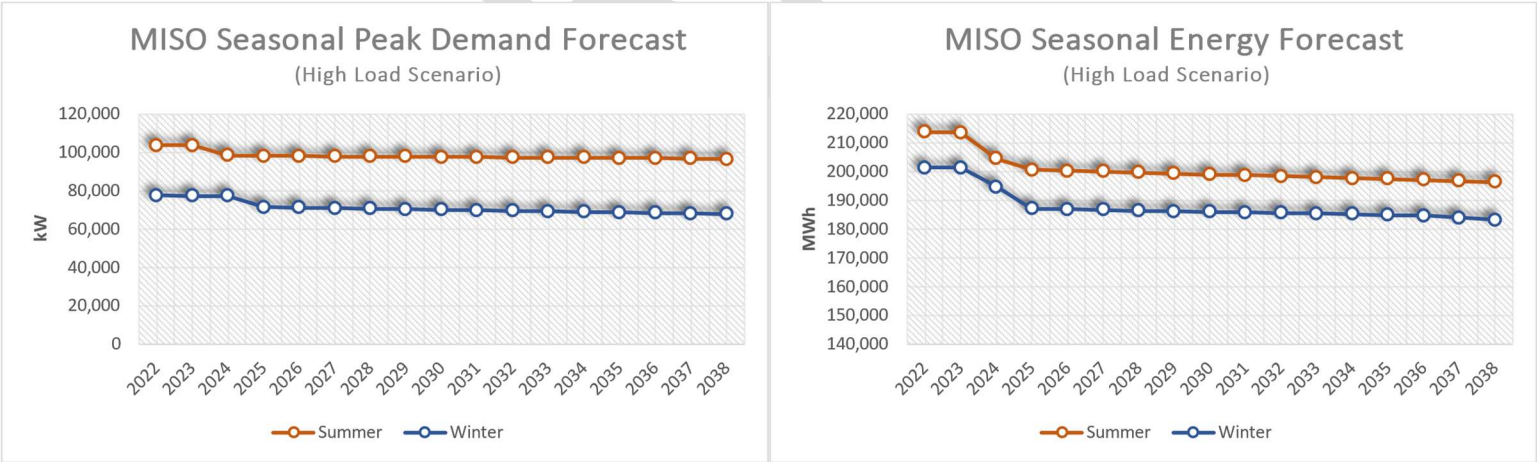


Figure V-5

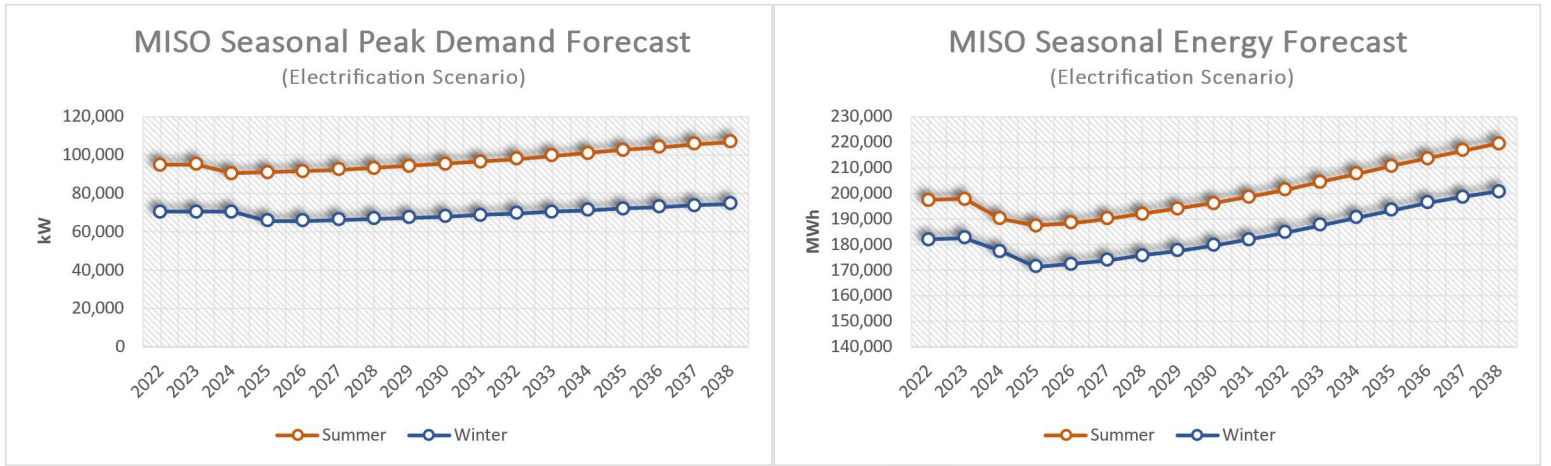


Figure V-6

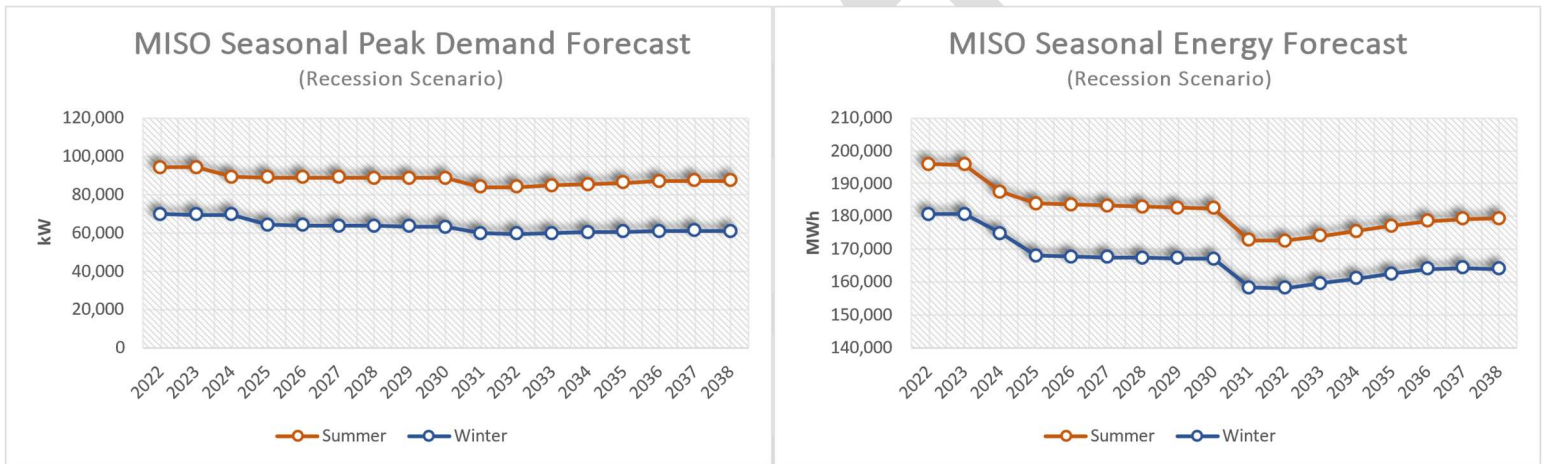


Figure V-7

The table in *Figure V-8* summarizes the MISO participant contracts that were initiated from the date of the previous IRP submittal or are set to expire through the end of the study period.

MISO Region Participants Schedule Start Dates 2017-2022			
Town	Schedule	RTO	Schedule Start Date
Lake View	J	MISO	6/1/2021
MISO Region Participants Schedule End Dates 2017-2037			
Town	Schedule	RTO	Schedule End Date
Lake View	J	MISO	5/31/2024

Figure V-8

G. SPP

As shown in *Figure V-9*, for the period of 2022 to 2037, the summer peak demand for SPP is expected to increase slightly from 184,950 kW to 186,810 kW. If not renewed, the contracts of Paxton, Snyder, and Trenton will expire in 2024, 2026, and 2031 respectively but don't have a major influence on the SPP total demand. The minor reduction in demand from 2028 to 2029 represents the expiration of the WAPA Displacement contract at which time MEAN will no longer have the load obligation for WAPA's customers' reserve margin. The remainder of the years see an average 0.5% increase in peak demand.

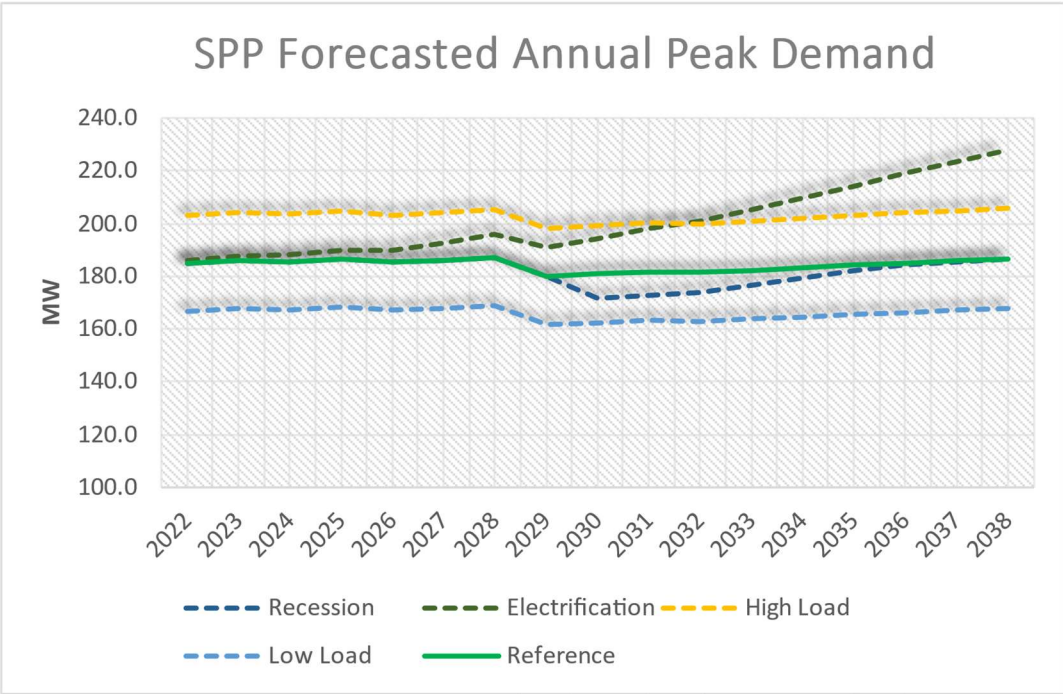


Figure V-9

The energy forecast for SPP looks much the same as peak demand. Over the 15-year study period, energy consumption increases an average of 0.19% year-over-year.

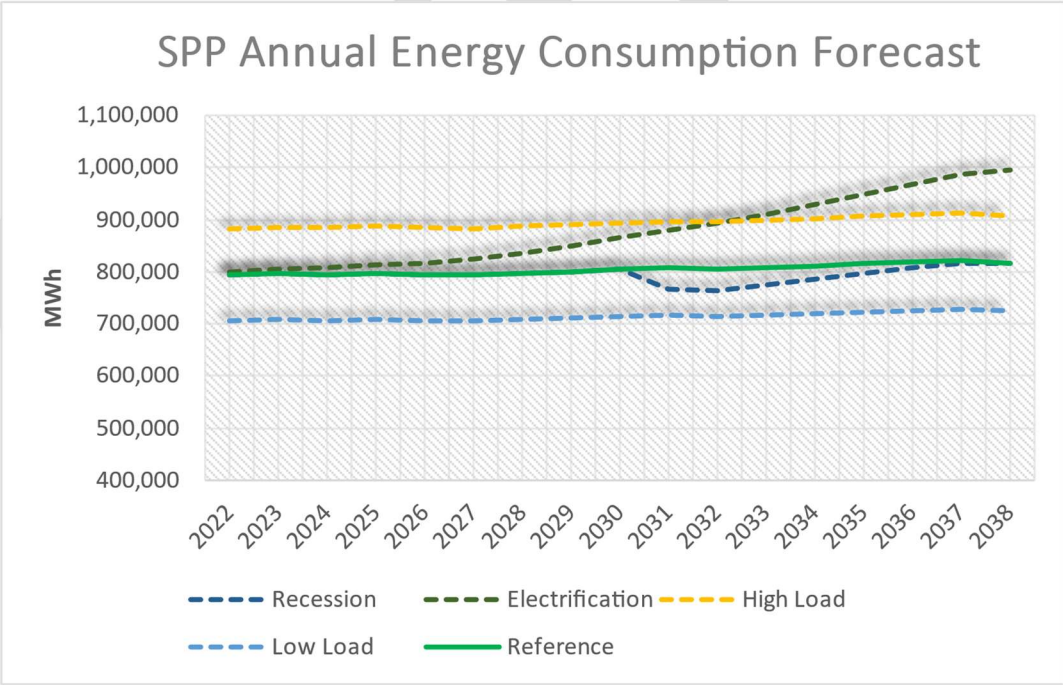


Figure V-10

For a seasonal view, the following charts illustrate the SPP peak demand and energy consumption for each of the load forecast scenarios.

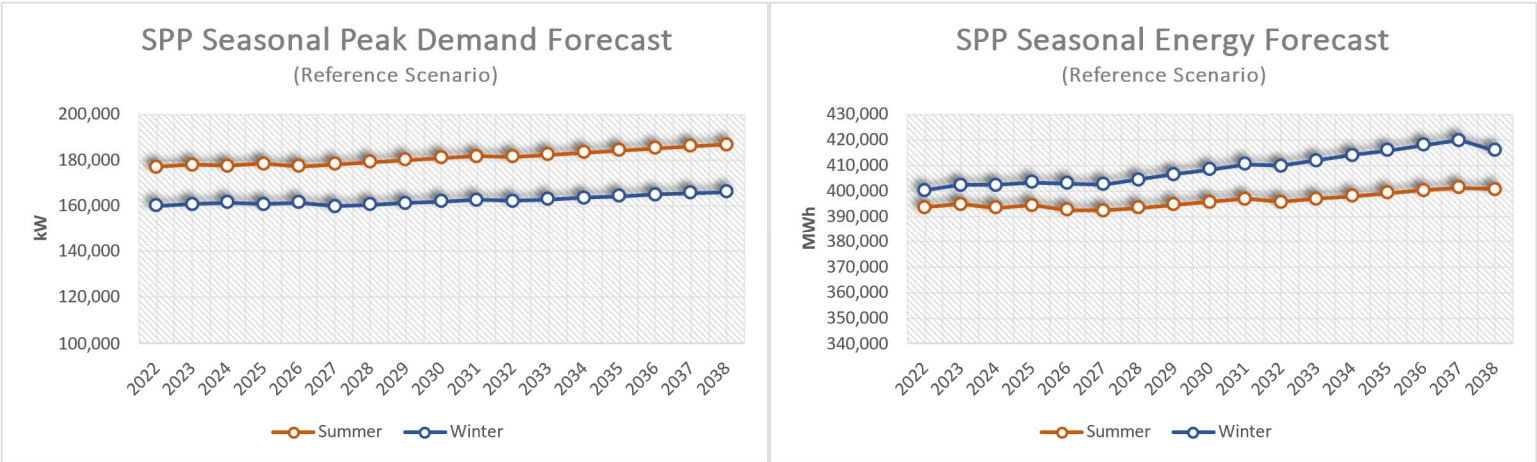


Figure V-11

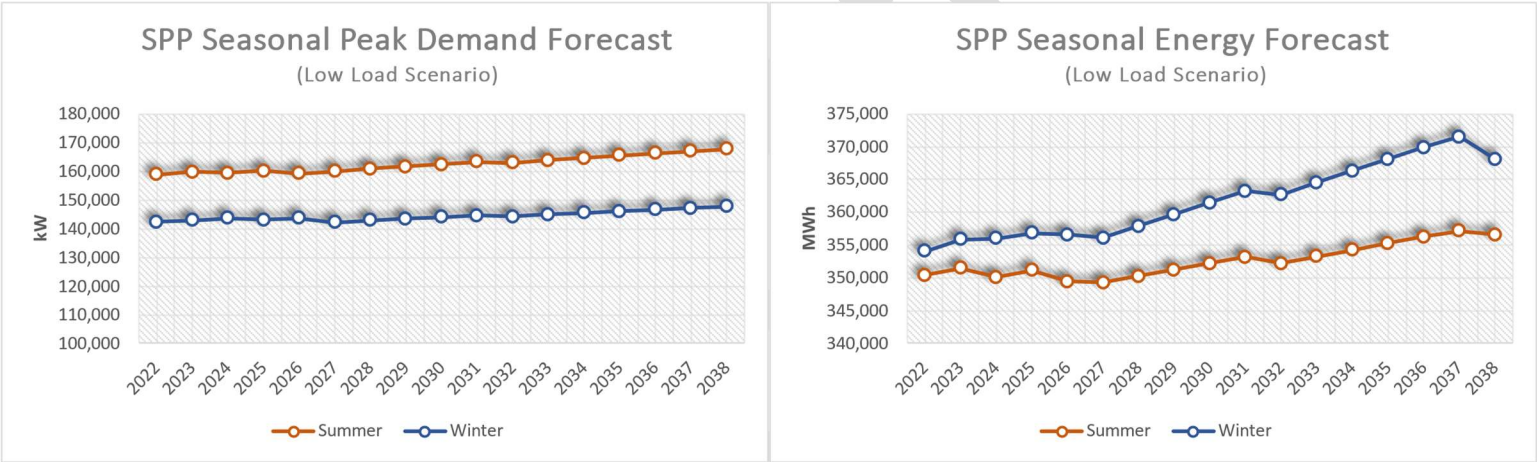


Figure V-12

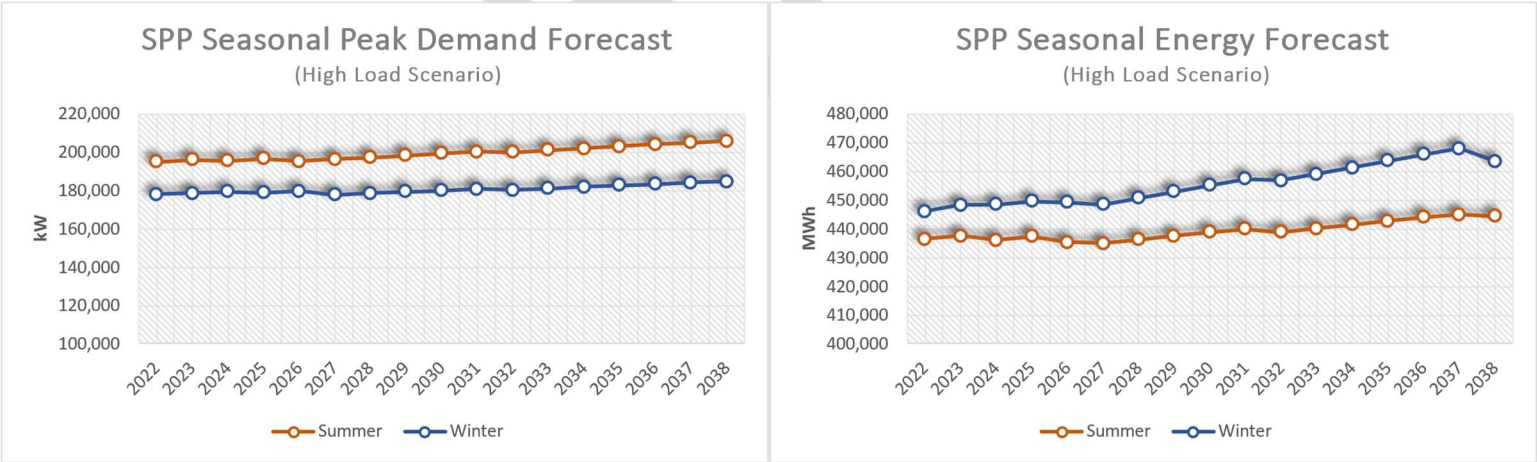


Figure V-13

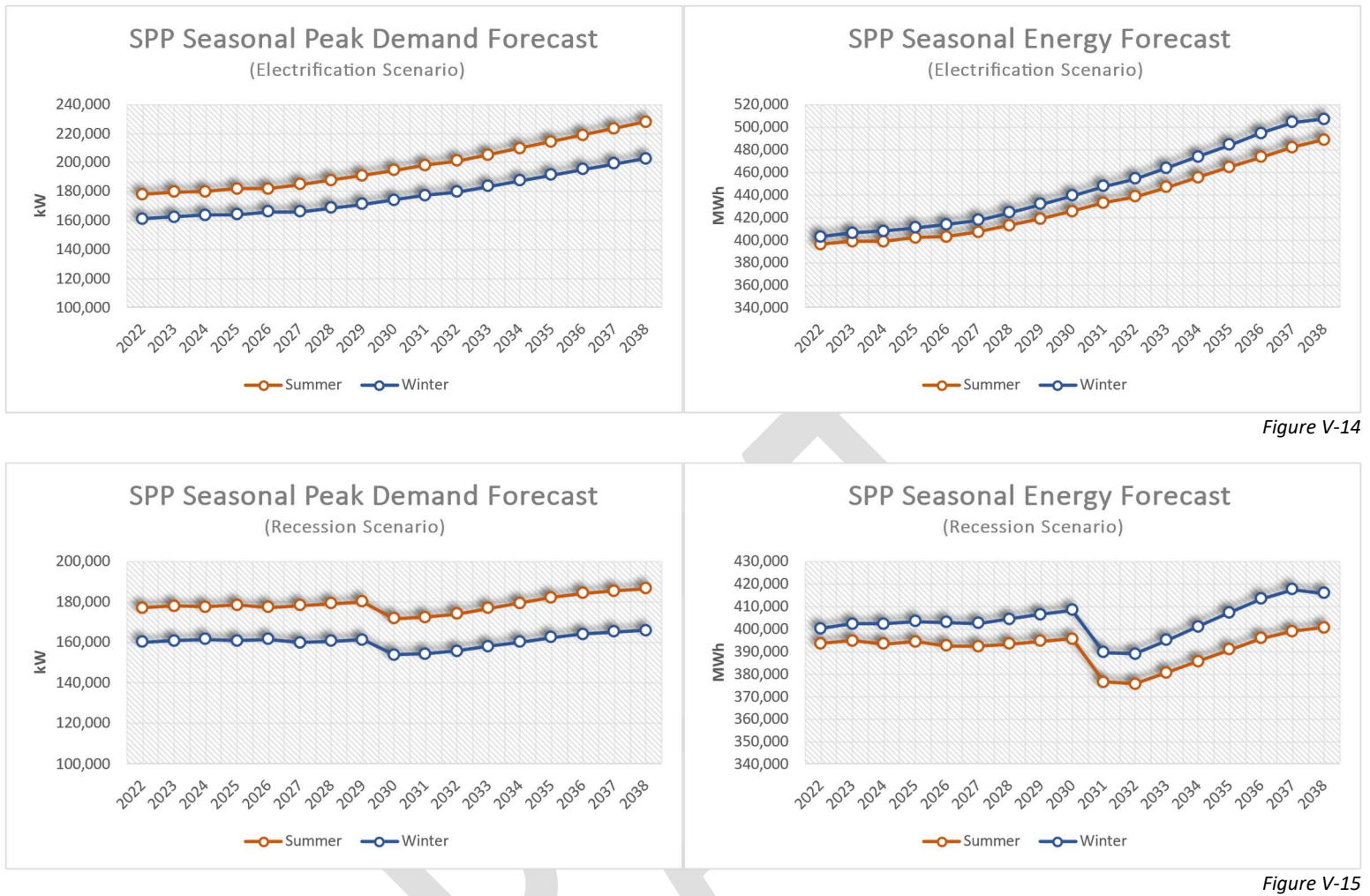


Figure V-16 summarizes the SPP participant contracts that were initiated or are set to expire from the date of the previous IRP submittal through the end of the study period.

SPP Region Participants Schedule Start Dates 2017-2022			
Town	Schedule	RTO	Schedule Start Date
Snyder	J	SPP	6/1/2020
Trenton	J	SPP	1/1/2021
SPP Region Participants Schedule End Dates 2017-2037			
Town	Schedule	RTO	Schedule End Date
Sargent	K	SPP	2/28/2017
Paxton	K	SPP	2/28/2024
Snyder	J	SPP	5/31/2026
Trenton	J	SPP	12/31/2031

Figure V-16

H. West

As shown in Figure V-17, for the period of 2017 to 2032, the peak demand for the west is expected to decrease from 215,480 kW to 194,880 kW. If the contracts are not renewed, decreases will occur due to the contract expiration of Wray and Holyoke in 2023, Center in 2025, and Glenwood Springs in 2029. In years without terminations, the average load increase is 0.4% annually.

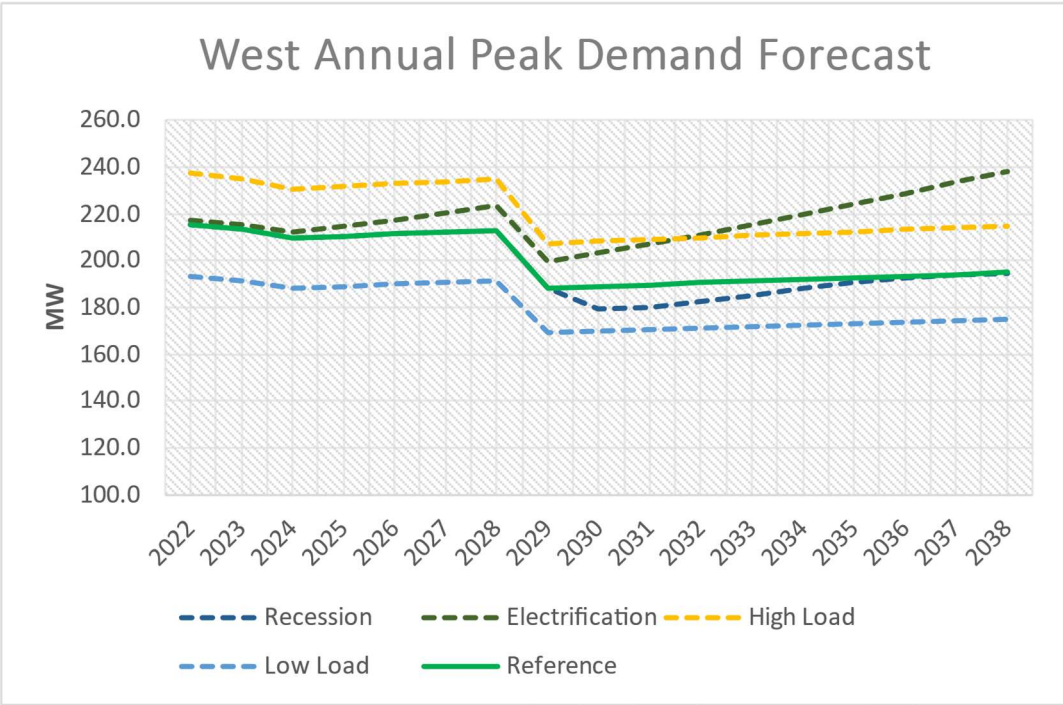


Figure V-17

As shown in *Figure V-18*, for the period of 2017 to 2032, the annual energy requirement is expected to decrease at varying rates until 2029, and then increase at a modest average rate of 0.49%. Once again, the decreases will occur in the energy requirement due to the contract expiration (if not renewed) of Wray and Holyoke in 2023, and of Glenwood Springs in 2029.

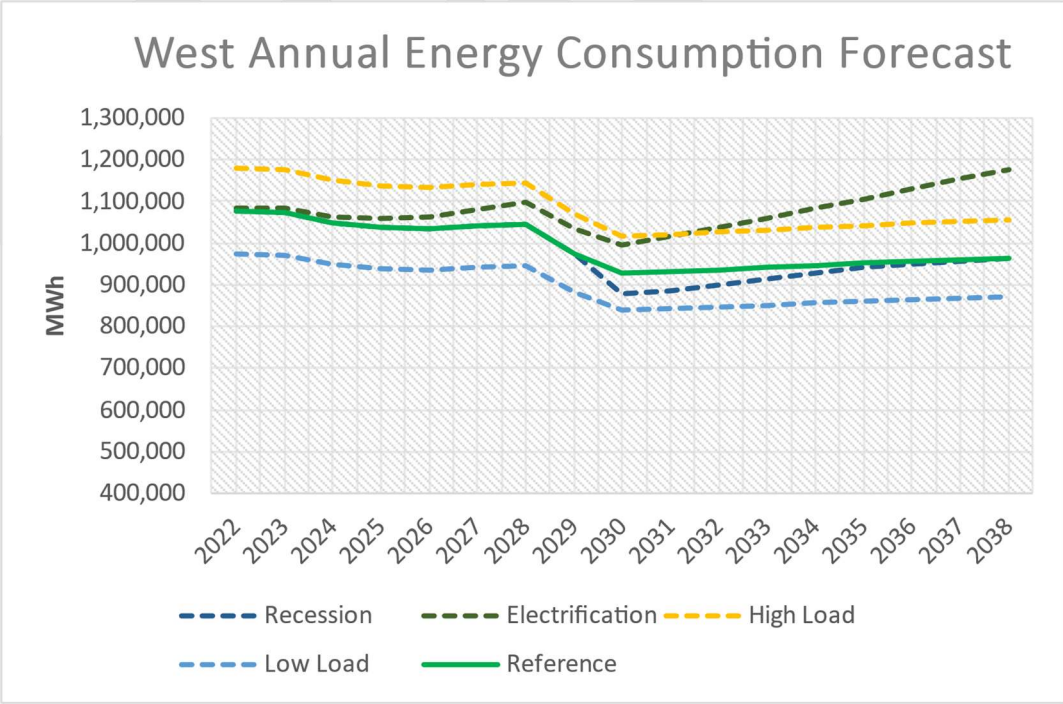


Figure V-18

The unique load profile of the West can be seen clearly in the following graphs, which represent the seasonal peak demand and energy for each of the load scenarios.

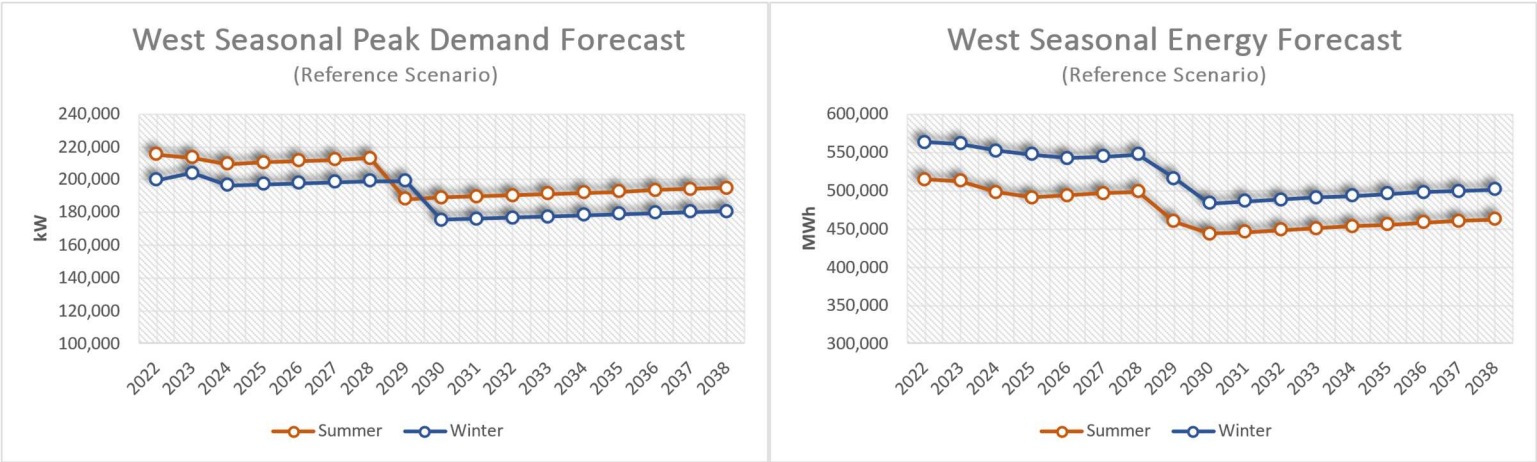


Figure V-19

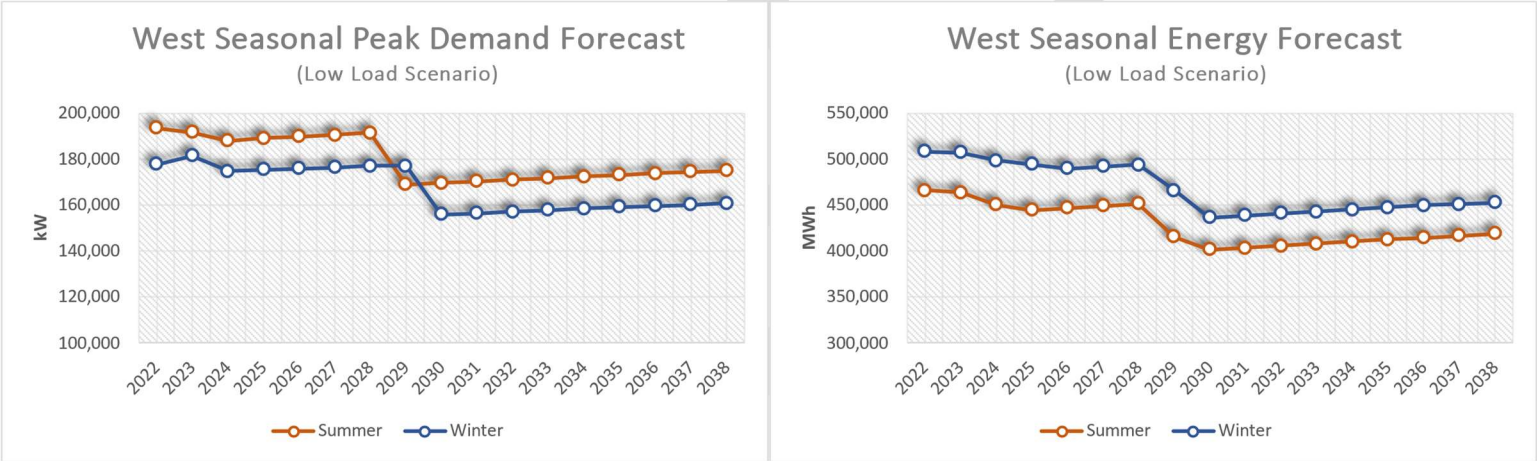


Figure V-20

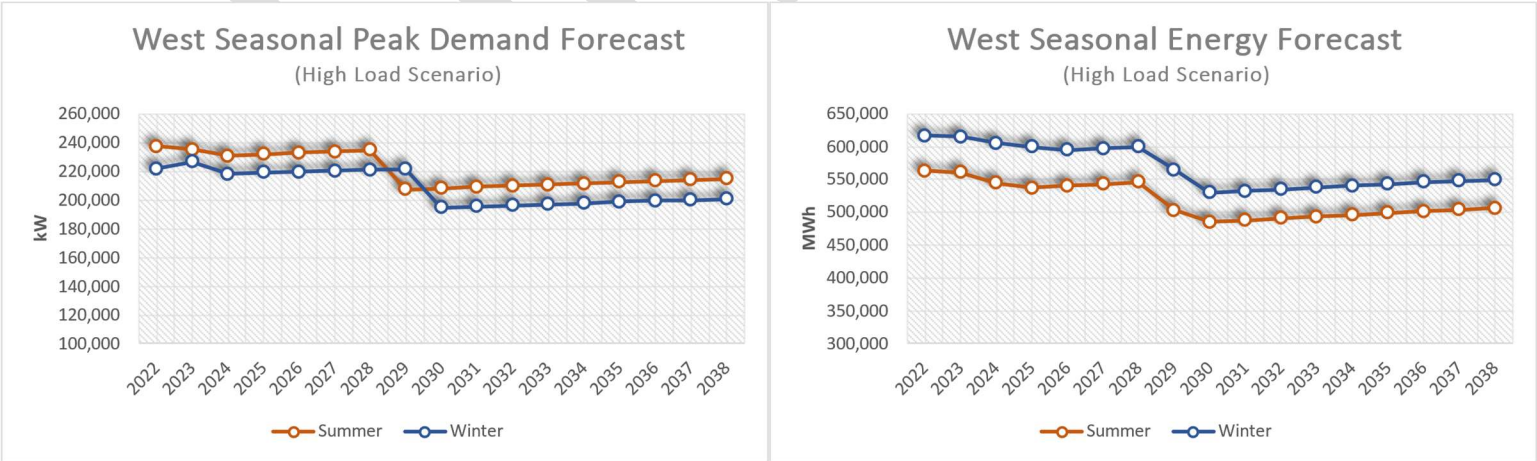


Figure V-21

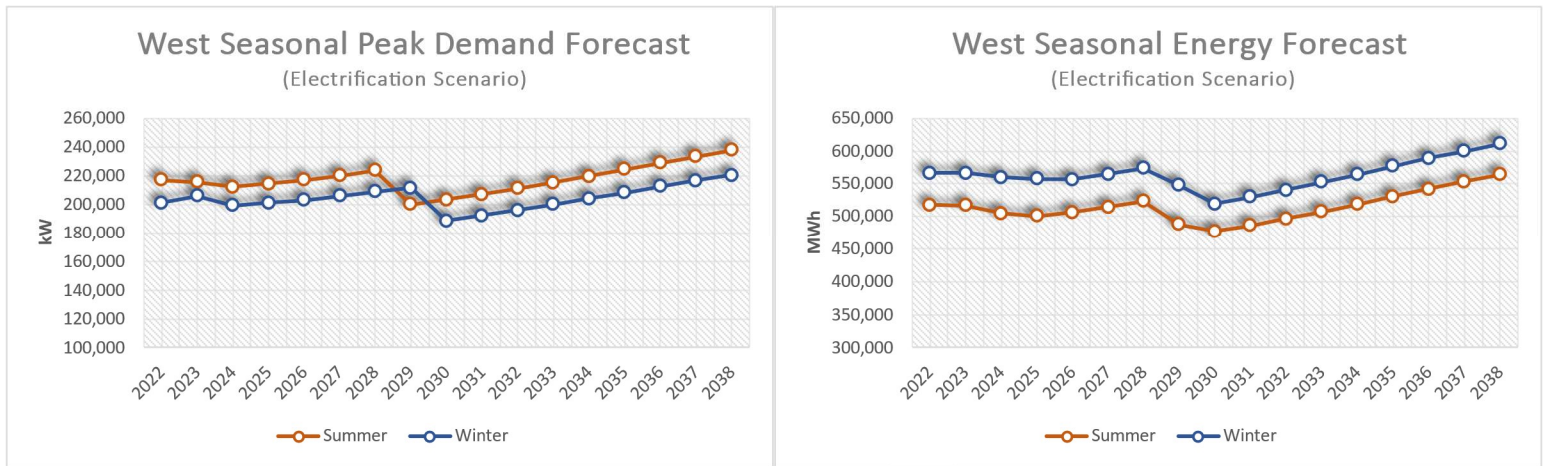


Figure V-22

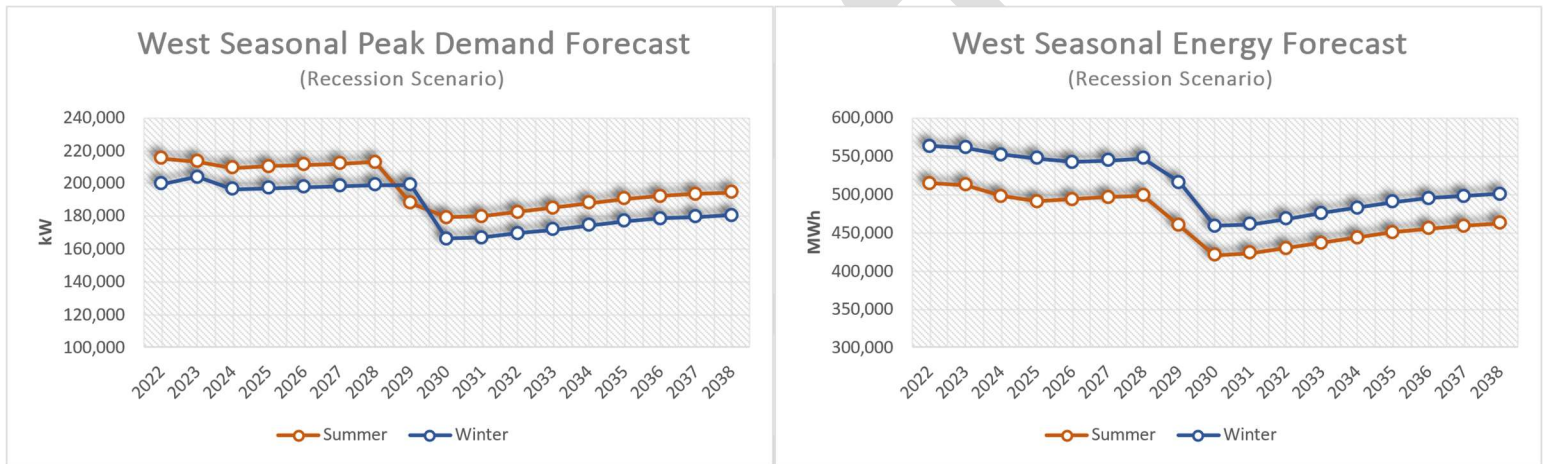


Figure V-23

Figure V-24 summarizes the west region participant contracts that were initiated or are set to expire from the date of the previous IRP submittal through the end of the study period.

West Region Participants Schedule Start Dates 2017-2022			
Town	Schedule	RTO	Schedule Start Date
Wray	J	West	7/1/2018
Holyoke	J	West	10/1/2018
Glenwood Springs	K-1	West	1/1/2013
Center	J	West	4/1/2020
West Region Participants Schedule End Dates 2017-2037			
Town	Schedule	RTO	Schedule End Date
Wray	J	West	6/30/2023
Holyoke	J	West	9/30/2023
Center	J	West	3/31/2025
Glenwood Springs	K-1	West	5/31/2029

Figure V-24

I. MEAN System

As shown in *Figure V-25*, for the period 2022 to 2037, the system peak demand will decrease from 494,570 kW to 469,240 kW. Notable load changes occur at the expiration of Glenwood Springs’ SSK-1 contract and the expiration of the SSJ contracts with Holyoke and Wray. After these dates, the peak demand increases at an annual average of 0.3%.

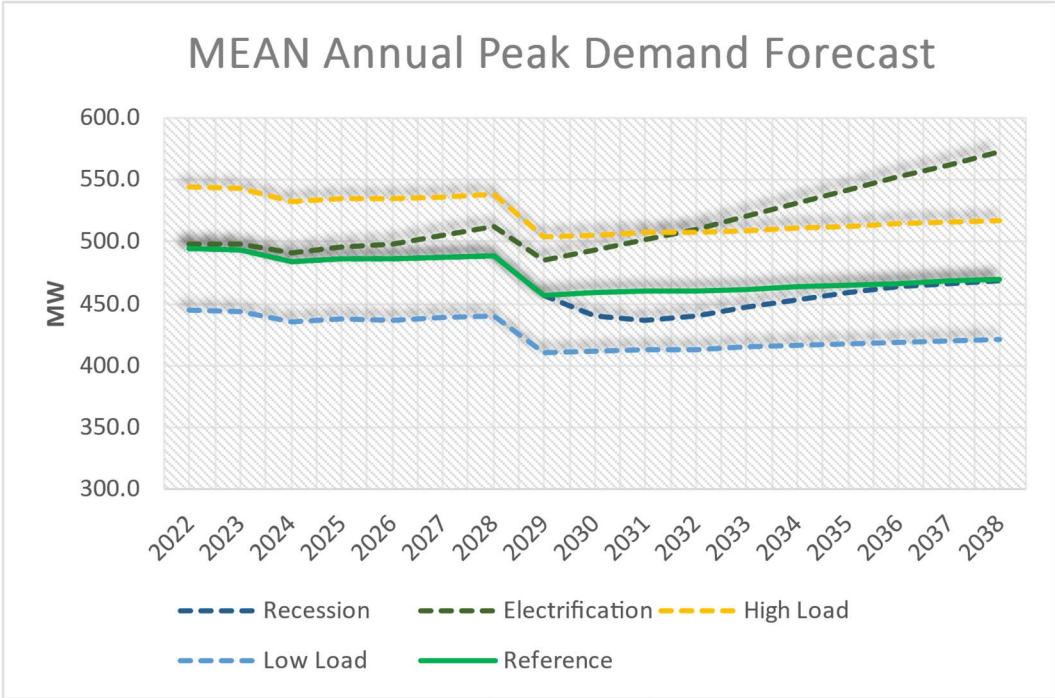


Figure V-25

The energy consumption forecast looks similar with most of the decrease in load occurring due to scheduled contract terminations. Following these events, the energy consumption increases at an average of 0.265% year-over-year.

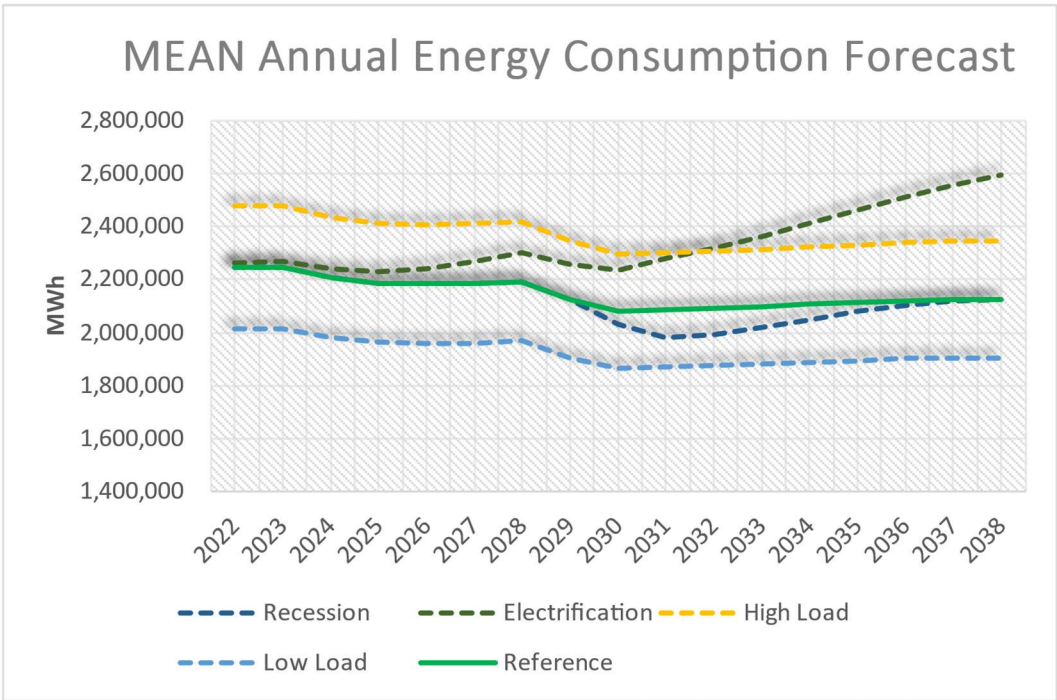


Figure V-26

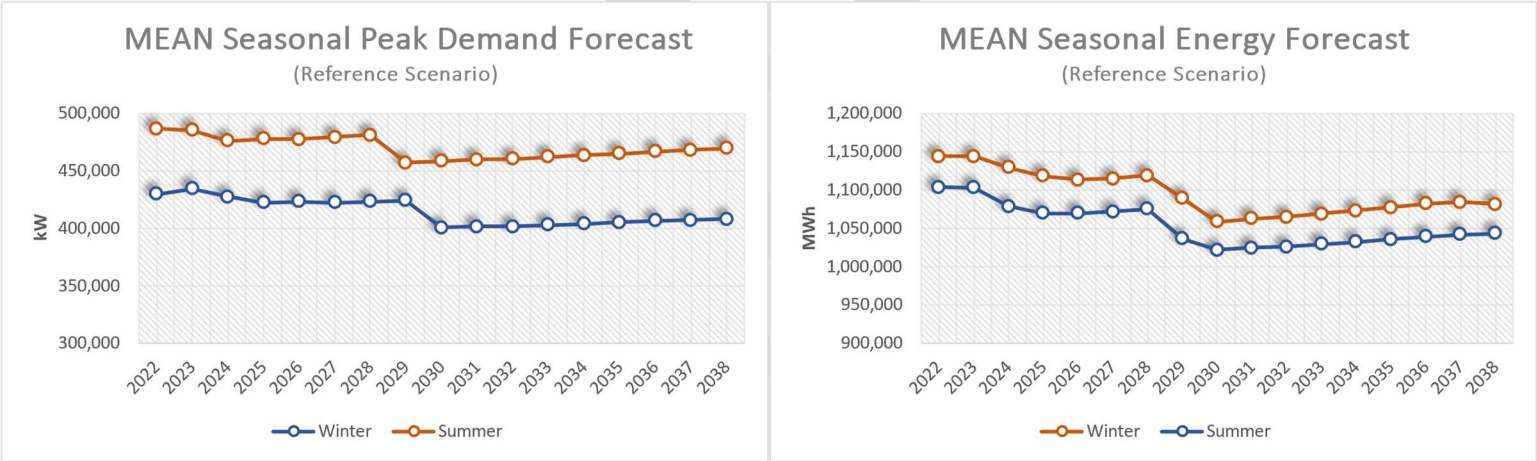


Figure V-27

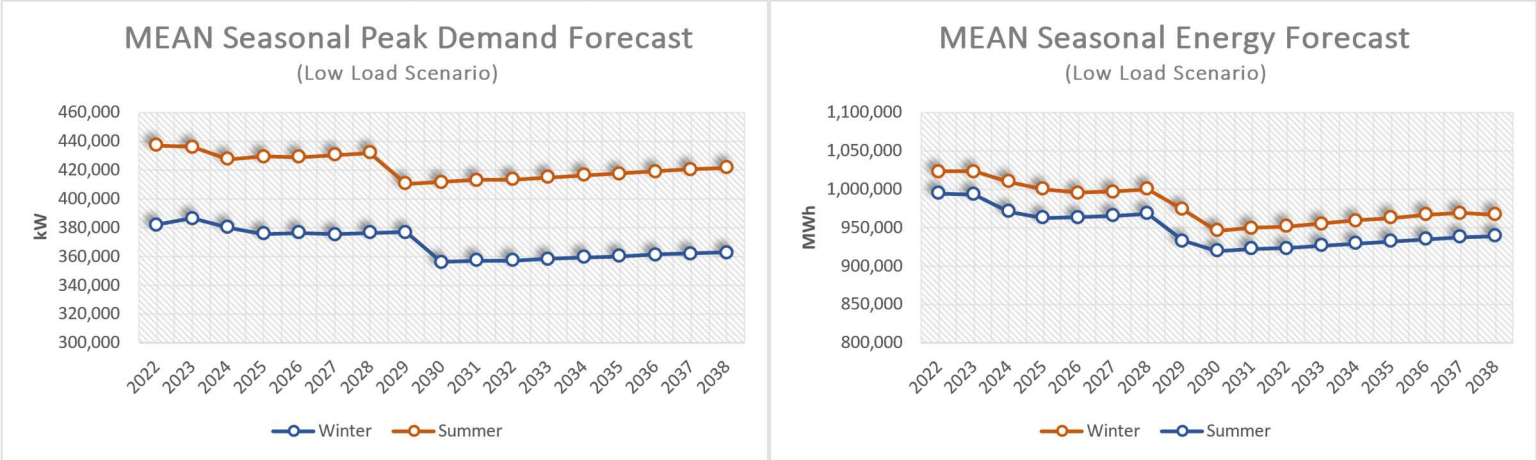
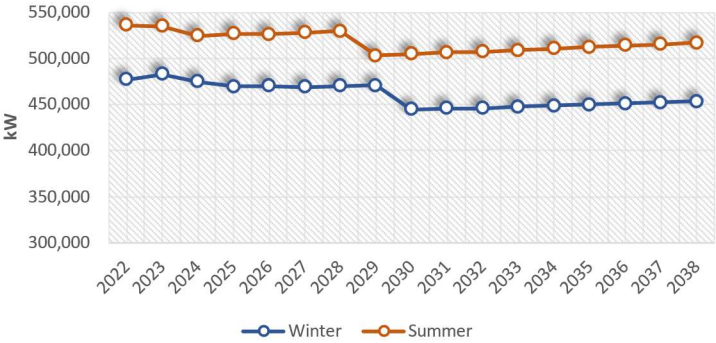


Figure V-28

MEAN Seasonal Peak Demand Forecast
(High Load Scenario)



MEAN Seasonal Energy Forecast
(High Load Scenario)

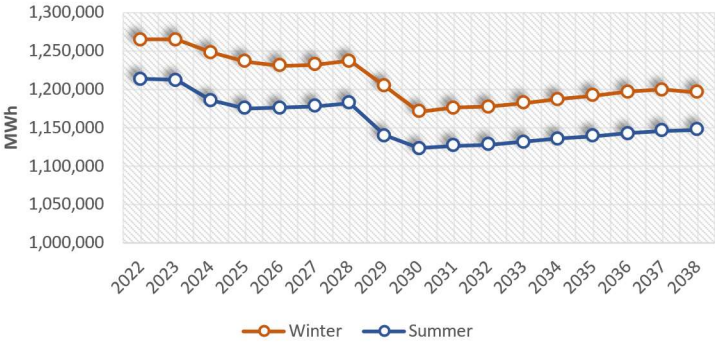
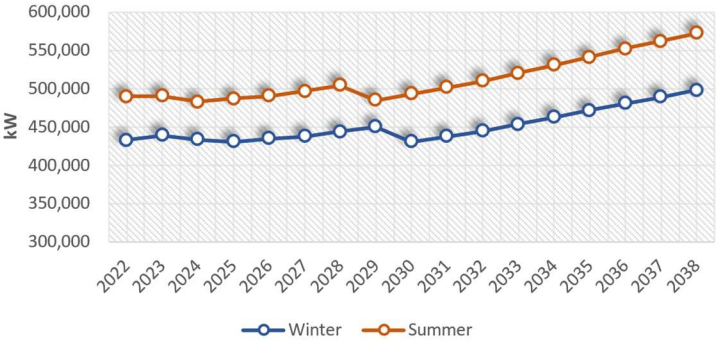


Figure V-29

MEAN Seasonal Peak Demand Forecast
(Electrification Scenario)



MEAN Seasonal Energy Forecast
(Electrification Scenario)

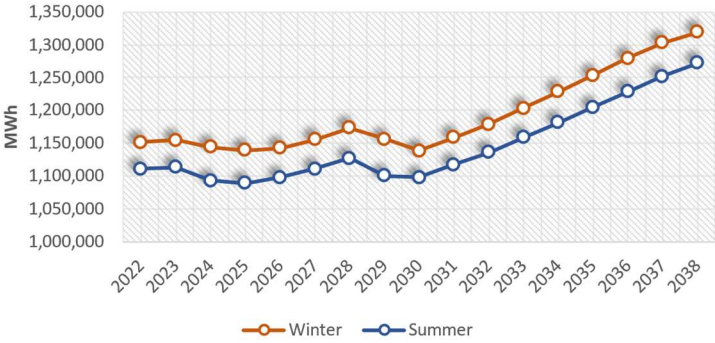
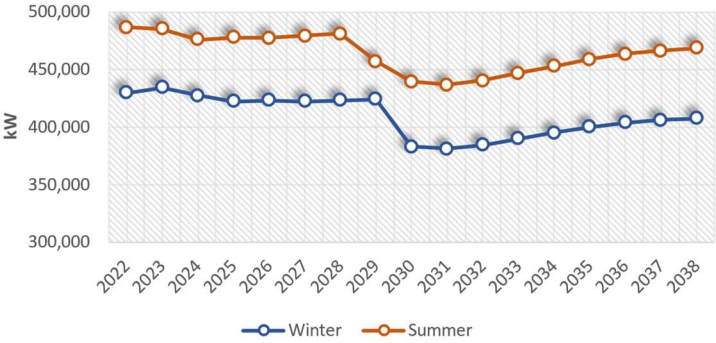


Figure V-30

MEAN Seasonal Peak Demand Forecast
(Recession Scenario)



MEAN Seasonal Energy Forecast
(Recession Scenario)

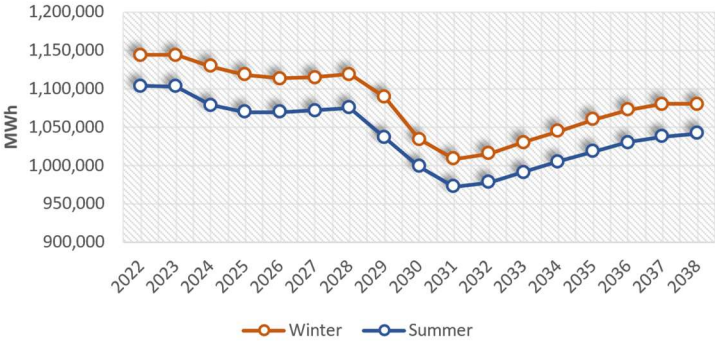


Figure V-31

VI. System Resources

A. Summary

The Power Supply System consists of owned, leased and purchased power supply resources as well as transmission system arrangements used to transmit resources to the Total Requirements Participants. MEAN receives transmission services provided by SPP, MISO and multiple transmission providers in the Western Interconnected System (the “*Western Interconnection*”).

MEAN adheres to a strategic and integrated resource plan that includes a variety of resources providing stable and economical power and energy to the Participants. MEAN has a policy in place establishing a goal to receive no more than 15% of MEAN’s capacity from a single generating unit. In the event that a generation unit does represent more than 15% of MEAN’s capacity, MEAN will investigate potential exchanges or insurance products to reduce the potential cost impacts and disruption of service that could be caused by a major unit outage. The Risk Management Committee and the Power Supply Committee will continue to evaluate this policy as the MEAN portfolio evolves to ensure that it still reflects participant goals and provides adequate protection to MEAN’s financial position.

MEAN is party to a number of long-term resource commitments. However, MEAN is not a majority owner or operator of any of its resource contracts. As such, many of these resources will remain in MEAN’s resource portfolio for the entire service life of the asset, despite MEAN’s 2050 Vision for carbon neutrality. Although this poses a challenge in terms of carbon emissions and the required offsets to achieve neutrality, MEAN acknowledges the reliability and resource adequacy offered by such resources. In fact, many of these resources supply the capacity necessary to qualify MEAN’s resource adequacy when operating renewable intermittent resources that generate energy with a low accredited capacity. As market conditions change and continue to favor the economics of renewable resources, fossil fuel plants will likely be dispatched at lower levels, which will decrease the energy generation and therefore the emissions without reducing the capacity contribution.

Figure VI-1 summarizes MEAN’s long-term power supply resources as of the date of this report:

Resource	MEAN Nameplate Capacity	Primary Energy Source	Market Region ⁽¹⁾	% of Capacity
<i>Total Requirements Committed Facilities (Participant Owned Generation)</i>	124.2 MW	Oil/Gas	MISO (69.5 MW), SPP (48.3 MW), WEST (6.4 MW)	18.9%
WAPA ⁽²⁾	124.7 MW	Hydroelectric	MISO (7.5 MW), SPP (29.1 MW), WEST (88.1 MW)	19.0%
Whelan Energy Center Unit 2	80 MW	Coal	SPP	12.2%
WAPA Displacement Agreement ⁽³⁾	61.9 MW	Hydroelectric	WECC	9.4%
Walter Scott Energy Center Unit 4	59.2 MW	Coal	MISO	9.2%
<i>NPPD Multi-Unit Participation</i>				
Cooper Nuclear Station	26 MW	Nuclear	SPP	4.0%
Gerald Gentleman Station	24 MW	Coal	SPP	3.7%
Kimball Wind LLC	30 MW	Wind	WECC	4.6%
Laramie River Station Unit 1	9.9 MW	Coal	SPP	1.5%
Laramie River Station Unit 2 & Unit 3	18.6 MW	Coal	WECC	2.8%
Wygen Unit I	20 MW	Coal	WECC	3.0%
Neil Simpson Unit 2 ⁽⁴⁾	8 MW	Coal	WECC	1.2%
Wygen Unit III ⁽⁴⁾	7 MW	Coal	WECC	1.1%
Wessington Springs Wind Project	10 MW	Wind	SPP	1.5%
Louisa Generating Station	8.2 MW	Coal	MISO	1.2%
NPPD Elkhorn Ridge Wind Plant	8 MW	Wind	SPP	1.2%
NPPD Laredo Ridge Wind Project	8 MW	Wind	SPP	1.2%
DMEA Shavano Falls/Drop 4 & Drop 6	7.6 MW	Hydroelectric	WECC	1.2%
NPPD Ainsworth Wind Energy Facility	7 MW	Wind	SPP	1.1%
Whelan Energy Center Unit 1	5.3 MW	Coal	SPP	0.8%
Waste Management Landfill Gas Facility	4.8 MW	Landfill Gas	MISO	0.7%
NPPD Crofton Bluffs Wind Project	4.2 MW	Wind	SPP	0.6%
TOTAL	656.6 MW			
(1) Resources located in MISO and SPP are dispatched by MISO and SPP. (2) All but approximately 7 MW constitutes North American Tribes' and Total Requirements Participants' WAPA allocations. (3) Under the WAPA displacement agreement, MEAN receives hydroelectric energy (excluding renewable energy credits) in WECC from the capacity in the agreement. Operationally, MEAN provides an equal amount of capacity to WAPA's customers in SPP from various MEAN contracted resources. The contracted resources designated for WAPA's customers in SPP may vary throughout the term of the agreement. (4) Per contract, the total capacity available to MEAN from Neil Simpson Unit 2 and Wygen Unit III was 20 MW in 2017-2018, is currently 15 MW and reduces to 10 MW in 2023.				

Figure VI-1

The table in Figure VI-2 shows the amounts of energy obtained by MEAN from its principal power supply resources, for MEAN'S last five fiscal years:

**ENERGY SUPPLY FOR FISCAL YEAR ENDED MARCH 31
(GWH AND % OF TOTAL)**

	2021		2020		2019		2018		2017	
Total Requirements Committed Facilities	3.5	0.2%	1.2	0.1%	1.6	0.1%	1.5	0.1%	1.4	0.1%
WAPA ⁽¹⁾	406.9	18.6%	401.3	16.5%	411.4	14.4%	411.0	15.2%	400.3	15.2%
WAPA Displacement Agreement ⁽²⁾	237.1	10.8%	237.1	9.8%	237.1	8.3%	238.4	8.8%	237.1	9.0%
Whelan Energy Center Unit 2 ⁽³⁾	243.5	11.1%	376.6	15.5%	405.1	14.2%	307.5	11.4%	349.8	13.4%
Walter Scott Jr. Energy Center Unit 4 ⁽⁴⁾	189.6	8.6%	261.1	10.7%	434.2	15.2%	342.1	12.6%	259.8	9.9%
NPPD Multi Unit Participation										
Gerald Gentleman Station Units 1 and 2	108.2	4.9%	132.5	5.5%	135.7	4.8%	133.2	4.9%	131.2	5.0%
Cooper Nuclear Station	178.4	8.1%	216.8	8.9%	183.4	6.4%	205.2	7.6%	189.1	7.2%
Laramie River Station	124.3	5.7%	146.4	6.0%	191.7	6.7%	184.1	6.8%	188.7	7.2%
Wygen Unit I	156.5	7.1%	162.8	6.7%	150.2	5.3%	166.8	6.2%	167.9	6.4%
Wygen Unit III and Neil Simpson Unit 2	123.5	5.6%	112.7	4.6%	136.5	4.8%	163.2	6.0%	171.8	6.5%
Wind Project at Kimball ⁽⁵⁾							0.4	0.0%	8.7	0.3%
Kimball Wind Facility ⁽⁶⁾	122.8	5.6%	119.8	4.9%	88.9	3.1%				
Wessington Springs Wind Project	42.2	1.9%	36.6	1.5%	34.4	1.2%	38.3	1.4%	42.4	1.6%
NPPD Elkhorn Ridge Wind Plant	16.0	0.7%	21.0	0.9%	22.2	0.8%	24.4	0.9%	25.7	1.0%
NPPD Laredo Ridge Wind Project	22.8	1.0%	26.4	1.1%	29.1	1.0%	30.3	1.1%	32.6	1.2%
Louisa Generating Station	27.5	1.3%	28.5	1.2%	54.4	1.9%	40.9	1.5%	42.0	1.6%
DMEA Shavano Falls/Drop 4 & 6	33.9	1.5%	31.8	1.3%	31.0	1.1%	33.3	1.2%	30.0	1.1%
NPPD Ainsworth Wind Energy Facility	12.0	0.5%	15.6	0.6%	17.7	0.6%	19.4	0.7%	20.7	0.8%
Whelan Energy Center Unit 1	24.3	1.1%	18.6	0.8%	21.8	0.8%	19.8	0.7%	18.9	0.7%
WM Des Moines Landfill Gas Facility	38.6	1.8%	40.1	1.7%	39.0	1.4%	38.9	1.4%	38.8	1.5%
NPPD Crofton Bluffs Wind Project	16.3	0.7%	16.1	0.7%	15.3	0.5%	16.1	0.6%	17.4	0.7%
All Others ⁽⁷⁾	<u>65.3</u>	<u>3.2%</u>	<u>27.1</u>	<u>1.0%</u>	<u>207.0</u>	<u>7.4%</u>	<u>294.3</u>	<u>10.9%</u>	<u>260.2</u>	<u>9.6%</u>
TOTAL	2,193.2	100.0%	2,430.1	100.0%	2,847.7	100.0%	2,709.1	100.0%	2,634.5	100.0%

- (1) Comprised mostly of Long-Term Total Requirements Participant allocations. MEAN serves as purchasing agent for the majority of MEAN Total Requirements Participants. Amounts shown include all Total Requirements Participant WAPA allocations regardless of whether MEAN serves as purchasing agent.
- (2) Under the WAPA Displacement Agreement, MEAN receives hydroelectric generated energy in WECC from the 61.9 MW of capacity in the agreement. Under a Bilateral Settlement Schedule, MEAN pays SPP for the related energy for WAPA's customers in SPP. MEAN also provides an equal amount of capacity to WAPA's customers in SPP from various MEAN contracted resources. MEAN does not receive Renewable Energy Credits for this resource.
- (3) Includes MEAN's participation in Public Power Generation Agency (PPGA). Also includes power sales agreement between MEAN and Hastings Utilities through April 30, 2018.
- (4) Includes MEAN ownership interest and assignment from Waverly Utilities.
- (5) Wind Project at Kimball was decommissioned during the fiscal year ended March 31, 2018.
- (6) Began commercial operation in June 2018.
- (7) Includes economy and short-term firm purchases.

Figure VI-2

B. Description of Resources

Participant Owned Generation

By execution of the AMPP and a firm power service agreement under the applicable service schedule, 18 Total Requirements Participants commit to MEAN all of the output of all existing compliant generation facilities owned by them for the common benefit of the Total Requirements Participants, except the power and energy generated by three hydroelectric plants owned or contracted by Aspen, Colorado, and by three hydroelectric plants



and three wind turbines owned by Waverly Utilities. The aggregate capacity of the generating facilities that the Total Requirements Participants have committed to MEAN (the “Participant Owned Generation”) under the ERPA as of the date of this report is 124.2 MW. All of Participant Owned Generation units are fueled by natural gas and/or fuel oil.

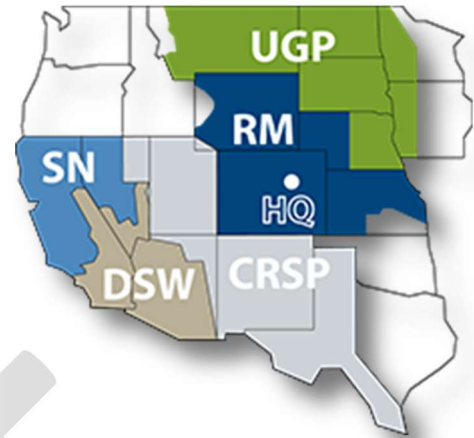
Under the AMPP, each of these Total Requirements Participants is required, upon MEAN’s request, to supply to MEAN the total committed capacity of its Participant Owned Generation. Each such Total Requirements Participant is required to maintain its Participant Owned Generation in good operating condition. The MEAN Board voted at the May 2017 quarterly meeting to approve a new requirement for Participants to exercise the Participant Owned Generation at least quarterly, with MEAN paying for the fuel consumed during these exercises. Scheduled outages must be coordinated with MEAN. Each Total Requirements Participant retains the right to retire its Participant Owned Generation from service with proper notice as defined in the AMPP.

The Participant Owned Generation units are primarily electric generators that are located within the service areas of the Total Requirements Participants. Three facilities totaling 69.5 MW of nameplate capacity are located in MISO. Fifteen facilities totaling 48.3 MW of nameplate capacity are located in SPP. Two facilities totaling 6.4 MW of nameplate capacity are located in the Western Interconnect. The hydroelectric and wind generating facilities owned by Aspen, Colorado and Waverly Utilities as described above are not Participant Owned Generation under the Participant’s AMPP but are part of the respective Participant’s overall resource mix as exceptions to the general rule of leasing all power production back to MEAN as part of the Long-Term Power Supply Contracts.

Western Area Power Administration

WAPA is one of four power marketing administrations within the U.S. Department of Energy. WAPA’s role is to market and transmit wholesale electricity from multi-use water projects. WAPA’s service area encompasses a 15-state region of the central and western U.S. where WAPA’s more than 17,000 circuit mile transmission system carries electricity from 57 hydropower plants operated

by the Bureau of Reclamation, U.S. Army Corps of Engineers and the International Boundary and Water Commission. WAPA also markets power from the Navajo Generating Station coal-fired plant near Page, Arizona. Together, these plants have an installed capacity of 10,504 megawatts. WAPA sells power to preference customers such as federal and state agencies, cities and towns, rural electric cooperatives, public utility districts, irrigation districts and Native American tribes. These entities provide retail electric service to millions of consumers in the West.



MEAN has an allocation from the U.S. Department of Energy, through WAPA, of firm power under contract from Loveland Area Projects hydroelectric plants of approximately 7 MW. MEAN recently executed an extension of this contract through 2054.

MEAN has entered into Benefit Crediting Agreements with WAPA and four Native American Tribes. Under these Agreements MEAN manages the allocations which represent 8 MW from the Loveland Area Projects. MEAN receives the energy from WAPA in exchange for providing a financial credit to the tribes. These contracts are set to terminate in 2024.

MEAN has also signed a Capacity and Energy Displacement Agreement (“WAPA Displacement Agreement”) whereby WAPA provides to MEAN additional allocations of approximately 62 MW of capacity and 237,097 MWh of energy in the LAP footprint, and MEAN provides equivalent capacity and energy to WAPA eastern interconnection customers in Nebraska and Kansas. MEAN commits 47 MW of behind-the-meter participant owned generation and 15 MW of capacity from the WEC 2 coal-fired plant located in SPP to the WAPA Displacement Agreement. MEAN recently extended the Displacement Agreement until May 31, 2029.

The Total Requirements Participants have allocations through WAPA totaling approximately 109.5 MW. Electric capacity and energy generated by WAPA has been and continues to be a low-cost capacity and energy resource for the Total Requirements Participants. WAPA reviews its energy rates annually to ensure that such rates generate sufficient revenues to cover its operating and other expenses.

MEAN acts only as an agent with respect to Participant WAPA allocations. MEAN provides these services on a cost pass-through basis to the Total Requirements Participants and has no beneficial interest in the Total Requirements Participants’ power allocations as the power allocations are retained by the Total Requirements Participants, and the Total Requirements Participants are financially responsible for paying all costs associated with their power allocation(s). MEAN has contracted to collect payments for WAPA capacity and energy purchased by certain Total Requirements Participants and remits these payments to WAPA. Since MEAN is only acting as an agent, these amounts are not reflected as revenue or expense in MEAN’s financial statements.

Participants receiving WAPA allocations are located in the WAPA Rocky Mountain Region (“RMR”) Marketing Area, the WAPA Upper Great Plains (“UGP”) Marketing Area, and the WAPA Colorado River Storage Project (“CRSP”) Management Center. The WAPA UGP Marketing Area contracts were due to expire in December 2020. A 30-year term extension of the UGP contracts was enacted by WAPA through its 2021 Power Marketing Initiative. Existing allocation contracts in the RMR

Marketing Area, which serves customers with power from the Loveland Area Projects (“LAP”), extend until September 2024. The Rocky Mountain 2025 Power Marketing Initiative will extend the LAP Firm Electric Service contracts for 30 years to 2054. Existing allocation contracts in the CRSP Management Center, which serves customers with power from the Salt Lake City Area (“SLCA”) integrated projects, extend until September 2024. Through the CRSP 2025 Power Marketing Plan, WAPA will extend the contracts 40 years from the date of contract execution for SLCA customers.

Due to current and expected continuation of drought conditions in the West, certain WAPA hydropower facilities are anticipating lower generation in upcoming years. As a result, WAPA has reduced the monthly Deliverable Sales Amount guaranteed to Colorado River Storage Project (“CRSP”) customers through December 2022. WAPA will purchase replacement power at market rates to supply the reduced energy as requested by customers. Accordingly, this will increase WAPA’s rates during that time period. MEAN has committed to supply this power to TRPs that receive CRSP allocations, thereby increasing MEAN’s load obligation.

Whelan Energy Center Unit 2

MEAN is a participant in the Public Power Generation Agency (“PPGA”) which was created solely for the purpose of owning, financing, acquiring, constructing and operating the Whelan Energy Center Unit 2 (“WEC2”). WEC2 is a nominally rated 220 MW pulverized coal-fired steam electric generating facility and related electric interconnection, transmission, rail car storage, and other facilities located near Hastings, Nebraska. Its commercial operation began in May, 2011. The unit includes pollution control equipment, a cooling tower, water treatment facilities, material storage facilities, control and administrative buildings, and other ancillary facilities. The unit is connected to the regional transmission grid through a network of 115 kV transmission lines. Hastings Utilities is the operating agent for WEC 2.



MEAN holds a 36.36% Entitlement Share of WEC2 representing approximately 80 MW of output of WEC2. Under its Participation Agreement with PPGA, MEAN has agreed to pay a corresponding percentage of all of PPGA’s costs of owning and operating WEC2, including debt service on PPGA’s bonds, regardless of whether or not WEC2 or any portion thereof is operable, or operating, and notwithstanding suspension, interruption, interference, reduction or curtailment of the WEC2 output or services of the WEC2. Payments to PPGA pursuant to the Participation Agreement are included in MEAN’s operating expenses. The previous power sales agreement dated June 9, 2008, between Hastings Utilities and MEAN, whereby Hastings Utilities agreed to sell annual amounts of capacity and associated energy from its Entitlement Share under its Participation Agreement with PPGA at cost expired on April 2018.

Walter Scott, Jr. Energy Center Unit 4

MEAN entered into a Joint Ownership Agreement with MidAmerican Energy Company (“MEC”) and other entities to develop, design, construct, own and operate Walter Scott, Jr. Energy Center Unit 4 (“WSEC 4”), a 790 net MW super-critical, coal-fired steam electric generating plant fueled with low-sulfur coal located near the city of Council Bluffs, Iowa. The plant began commercial operation in June 2007. MEC is the majority owner, developer and operator of WSEC4. MEAN originally owned an undivided 6.67% interest in WSEC4. In 2012, MEAN acquired an additional 0.25% interest in WSEC4, for a total undivided interest of 6.92%, or 56 MW. In addition, Waverly Utilities granted MEAN a partial assignment of Waverly Utilities’ interest in WSEC4, which includes rights to receive 0.4% (approximately 3 MW) of the output from WSEC4 and continues through the term of Waverly Utilities’ Long-Term Power Supply Contract with MEAN.



MEAN’s ownership interest and partial assignment of interest in WSEC4 provides MEAN with approximately 59 MW of capacity and energy, providing MEAN with a long-term, cost-based source of power and energy.

Nebraska Public Power District Multi-Unit Participation

MEAN and NPPD entered into a Multi-Unit Participation Agreement that became effective January 1, 2011 (the “NPPD MUP Agreement”). Under the NPPD Agreement, NPPD provides MEAN with 50 MW of capacity and related energy. NPPD’s obligation to deliver capacity and related energy to MEAN pursuant to the NPPD Agreement is contingent on availability and operation of NPPD’s Gerald Gentleman Station Units No. 1 (12 MW) and No. 2



(12 MW) located near Sutherland, Nebraska, and NPPD’s Cooper Nuclear Station (26 MW) located near Brownville, Nebraska. The NPPD Agreement is effective through December 31, 2023. In the event NPPD and MEAN participate in the same new baseload generation unit prior to December 31, 2023, MEAN has the right, but not the obligation, to terminate the NPPD Agreement upon the commercial operation of such unit.

Laramie River Station

In 1982, MEAN and Lincoln Electric System (“LES”) entered into two agreements (“Laramie River Agreements”) which collectively provide for the sale to MEAN of a portion of LES’s undivided interest in the Laramie River Electric Generating Station (“Laramie River Station”) and an associated transmission system. Laramie River Station is a coal-fired steam-electric generating station that consists of three units totaling 1,697 MW. It is located in



Platte County, Wyoming on the Laramie River and is owned by LES and five other utilities, as tenants in common. The three units of the Laramie River Station began commercial operation in 1980 and 1982. MEAN began making purchases of electric power and energy under its original agreement with LES on June 1, 1982. MEAN’s total interest in Laramie River Station is 1.67% or 28 MW. Basin Electric Power Cooperative operates and maintains the Laramie River Station.

MEAN pays to LES: (1) MEAN’s proportionate share of operation and maintenance costs, capital improvements, repairs, administrative costs, and all other fixed costs relating to ownership interest in Laramie River Station; (2) the costs related to the production of energy in proportion to the energy scheduled and produced from Laramie River Station for MEAN during each month; and (3) any costs incurred by LES directly related to the scheduling and dispatching of MEAN’s power and energy generated by Laramie River Station. Laramie River Station Unit 1 is dispatched by SPP while Laramie River Station Unit 2 and Unit 3 are in the Western Interconnection.

Under a Displacement Contract dated as of July 1, 1986, between MEAN and Basin Electric Power Cooperative, MEAN receives scheduling and delivery rights in the Western Interconnection for Laramie River Station’s West Side units (known as “West Allotment”) and delivery rights in the associated transmission system. MEAN’s West Allotment entitles MEAN to schedule and deliver up to 8.3% of the LES entitlement of power and energy from Laramie River Station.

Wygen Unit I

In 2009, MEAN acquired an undivided 23.5% interest in the Wygen Unit I which provides MEAN approximately 20 MW of capacity and energy. The Wygen Unit I, located in Campbell County, Wyoming, near the town of Gillette, is an approximately 85 MW coal-fired electric generating plant fueled with low-sulfur Powder River Basin Coal. Wygen I is collocated with the Wyodak coal mine, which supplies fuel to the plant. Black Hills Wyoming, Inc. developed, designed, constructed and operates the Wygen Unit I, which began commercial operation in February 2003, and owns the remaining 76.5% of the Wygen Unit I.

Neil Simpson Unit 2 and Wygen Unit III

MEAN has entered into a Power Purchase Agreement with Black Hills Power, Inc. (“Black Hills Power”) that became effective April 1, 2010. The Power Purchase Agreement is unit contingent on Neil Simpson Unit 2 and Wygen Unit III. Under the original Power Purchase Agreement, Black Hills Power agreed to provide MEAN with the capacity and related energy output in the following amounts:



CONTRACT YEAR	CAPACITY (MW)
4/1/2010 – 5/31/2018	20 MW (10 MW from Wygen Unit III and 10 MW from Neil Simpson Unit 2)
6/1/2018 – 5/31/2020	15 MW (10 MW from Wygen Unit III and 5 MW from Neil Simpson Unit 2)
6/1/2020 – 5/31/2022	12 MW (6 MW from Wygen Unit III and 6 MW from Neil Simpson Unit 2)
6/1/2022 – 5/31/2023	10 MW (5 MW from Wygen Unit III and 5 MW from Neil Simpson Unit 2)

In 2019, MEAN and Black Hills renegotiated the terms of the Power Purchase Agreement. MEAN will now receive a combined 15 MW of capacity and energy from the two units until May 31, 2023. At the end of this term, the purchase will continue at 10 MW until May 31, 2028 unless unilaterally terminated by MEAN.

Louisa Generating Station

MEAN purchases the power and energy associated with Waverly Utilities’ interest in the Louisa Generating Station, a coal-fired generating unit which began commercial operation in October 1983. The power sales agreement includes rights to receive 1.1% or approximately 8 MW of the output from the Louisa Generating Station and continues for the term of Waverly Utilities’ Long-Term Power Supply Contract.



Delta-Montrose Electric Association Shavano Falls/Drop 4 and Drop 6

MEAN entered into a 22-year power purchase agreement with Delta-Montrose Electric Association (“DMEA”) for the purchase of renewable hydro energy from the Shavano Falls hydro project. MEAN’s share of the project includes 2.8 MW from Drop 6 and 4.8 MW from Drop 4. The project began commercial operation in May 2015. Shavano is a run-of-river facility from which MEAN receives capacity and energy during the months of operation, typically March through October.

***Whelan Energy Center Unit 1***

Pursuant to the Participation Power Sales Agreement between MEAN and the City of Hastings, Nebraska, MEAN purchases 6.95%, or approximately 5.3 MW, of the electric power and energy generated by Whelan Energy Center Unit 1, a 77 MW coal-fired steam electric generating station operated by Hastings Utilities and located in Adams County, Nebraska (the “Whelan Energy Center”). The Participation Power Sales Agreement terminates on the later of the date of (i) the final maturity of the indebtedness incurred by Hastings to pay the costs of the Whelan Energy Center or capital additions thereto, which occurred on January 1, 2019, or (ii) the date Hastings removes the Whelan Energy Center and/or its associated transmission system from commercial operation.



Waste Management Des Moines Landfill Gas Facility

MEAN has entered into a long-term Power Purchase Agreement with Waste Management for the total output of the facility, which has 4.8 MW total nameplate capacity, until March 2034. The facility utilizes methane gas extracted at the Metro Park East landfill located in Mitchellville, Iowa, which is converted to renewable energy in four (4) 1.2 MW nameplate units.



Wind Resources

The following is a summary of MEAN's owned or purchased wind resources:

- ***Wind Project at Kimball.***

MEAN previously owned and operated a 10.5 MW wind project located near Kimball, Nebraska, which began commercial operation on October 1, 2002. This project was decommissioned during the summer of 2017. MEAN executed a 20-year Purchase Power Agreement with Kimball Wind LLC to purchase the energy output of a new 30 MW wind farm constructed on the same and adjacent site. The new wind farm began commercial operation in June 2018.



- ***Wessington Springs Wind Project.***

Heartland Consumers Power District purchases all the output of the 51.15 MW Wessington Springs Wind Project and resells 19.55% (10 MW) of the output to MEAN under the agreement. The original agreement was written to expire in February 2029. However, the facility owner repowered the site in December 2020 to increase the efficiency of the generators. As a result, Heartland and MEAN signed contract extensions through the end of 2039.

- ***NPPD Elkhorn Ridge Wind Plant.***

MEAN purchases from NPPD 10.0% of the output of the Elkhorn Ridge Wind Plant, or approximately 8 MW of the 80 MW nameplate capacity, under a contract ending March 2029.

- ***NPPD Laredo Ridge Wind Project.***

MEAN purchases from NPPD 10.0% of the output of the Laredo Ridge Wind Project, or approximately 8 MW of the 80 MW nameplate capacity, under a contract ending February 2031.

- *NPPD Ainsworth Wind Energy Facility.*

MEAN purchases from NPPD 11.78% of the output of the Ainsworth Wind Energy Facility, or approximately 7 MW of 60 MW nameplate capacity, under a contract ending October 2025 which may be extended for terms of 5 years each or until the end of the operational life of the facility.

- *NPPD Crofton Bluffs Wind Project.*

MEAN purchases from NPPD 10.0% of the output of the Crofton Bluffs Wind Project, or approximately 4.2 MW of 42 MW nameplate capacity, under a contract ending November 2032.

Market Purchases

MEAN utilizes short-term purchases of market energy to meet MEAN's load and reserve obligations when circumstances prevent our contracted resources from supplying our full obligations. MEAN enters into purchase and sale transactions in the MISO, SPP, and WECC markets.

Ruedi/Maroon Creek

The City of Aspen, Colorado owns and operates the Ruedi hydroelectric plant under a permit issued by the Federal Energy Regulatory Commission ("FERC") with a rated capacity of 5 MW and a hydroelectric project known as Maroon Creek with a rated capacity of 0.5 MW. These projects are used to supply capacity and energy to Aspen for resale to its customers. MEAN and the City of Aspen have executed an agreement whereby Aspen's energy purchases from MEAN are reduced by the output of Ruedi, and the generation is treated similar to a WAPA allocation. The term of the Ruedi agreement between Aspen and MEAN is concurrent with Aspen's Total Requirements contract with MEAN.



For resource planning purposes therefore, Ruedi and Maroon Creek are counted as resources to credit against Aspen's load.

Ridgway

Aspen has acquired an interest in a portion of the output of the Ridgway Hydropower Project ("Ridgway"). Specifically, Aspen has rights to all of the plant's capacity and energy during the months of October through May. Aspen has assigned to MEAN the exclusive responsibility for scheduling and managing the City's share of the Ridgway output. MEAN uses and schedules 4.5 MW of the Ridgway output as a designated network resource for MEAN's designated network load on the Tri-State transmission system. For resource planning purposes therefore, Ridgway is counted as a resource and included in resource mix allocations. Aspen's contract with Tri-County Water Conservancy District for the Ridgway output extends to 2034.

C. Regional Energy Markets and Coordination

The SPP Integrated Market (“IM”), which was launched on March 1, 2014, replaced the Energy Imbalance Service (“EIS”) market that SPP had operated since 2007. The IM restructured the EIS market by establishing a day-ahead market along with a real-time energy and operating reserve market. Consolidating 16 balancing authorities into a single SPP-operated balancing authority that was designed to maximize cost-effectiveness of generation and reduce transaction costs. The IM also utilizes locational-marginal pricing, transmission congestion rights, and virtual transactions.

The IM allows generators to submit offers to sell energy and operating reserves. Additionally, it allows load serving entities to submit bids to purchase energy. After day-ahead submissions, SPP clears the offers and bids via security-constrained unit commitment and security-constrained economic dispatch algorithms. A financially binding schedule matches sale offers with demand bids to meet operating reserve requirements.

Financial transmission rights (termed Transmission Congestion Rights (“TCRs”) in SPP and Financial Transmission Rights (“FTRs”) in MISO) are used to mitigate variances between Location Marginal Prices (“LMPs”) at load locations and LMPs at generation locations due to transmission congestion. Long-Term Congestion Rights (“LTCRs”) and Auction Revenue Rights (“ARRs”) are awarded to market participants based on firm transmission rights on the SPP network. Transmission congestion rights are automatically converted from awarded LTCRs and can be converted from awarded ARRs.

The SPP IM added market functionality and coordinates next-day generation across the region. The IM maximizes cost-effectiveness, provides participants with greater access to reserve energy, improves regional balancing of electricity supply and demand, and facilitates the integration of renewable resources.

Like SPP, MISO allows generators to submit offers to sell energy and operating reserves and load serving entities to submit bids to purchase energy, after which MISO clears the offers and bids via security-constrained unit commitment and economic dispatch algorithms. The end product is a financially binding schedule that matches sale offers with demand bids and satisfies operating reserve requirements. Similar to SPP, MISO also operates auction revenue rights and a financial transmission rights auction. In addition, MISO administers a capacity market where market participants can purchase or sell excess deliverable capacity facilitated in an annual auction. MISO has filed with FERC to modify their market construct to be conducted on a seasonal basis rather than annual, which would impact unit accreditation, outage scheduling, and the capacity auction, among other functions.

The impacts of the RTOs’ facilitation and integration of renewable resources have been very noticeable in the past five years with the build out of renewables. Noteworthy levels of renewable integration have been achieved in SPP as Wind surpassed Coal and Natural Gas as the most abundant annual fuel source in 2020. In addition, in March 2022, SPP set a new renewable energy penetration record of 90.2%. This means SPP served 90.2% of the demand for electricity across its 14-state service territory with renewable energy sources, which marks the first time a regional transmission organization served more than 90% of its load with renewables; 88.5% of the 90.2% was served by wind. This abundance of low-cost wind and other renewable resources reduces the need to operate traditional fossil fuel resources during high wind periods and in turn reduces carbon emissions.

MEAN also operates in the western United States through WECC within the Western Area Power Administration, Colorado-Missouri (WACM) and Public Service Company of Colorado (PSCo) Balancing Authorities. For operations in WECC, MEAN enters into other agreements and transactions with various electric marketers and power suppliers that are not MEAN Participants pursuant to which such electric utilities may purchase capacity and energy from MEAN or sell capacity and energy to MEAN. Regional markets are emerging and are in initial stages in WECC. In WACM, MEAN is currently participating in the recently formed Western Energy Imbalance Service (WEIS) operated by SPP. The initial WEIS members are pursuing membership in an expanded SPP RTO market to the west. PSCO recently initiated participation in the WEIS market but is also exploring the SPP Markets+ market in the initial stages of development.

D. Available Energy vs. Dispatched Energy

The values of energy shown in the resource mix charts (in Section E. below) are indications of available energy from each resource, primarily based on operating characteristics, outage schedules, and historical performance. However, this may not be an accurate projection of actual energy generated in the future as it does not reflect the effects that increased renewable generation will have on reducing the economic dispatch of fossil fuel units.

In the SPP and MISO integrated markets, each resource is dispatched by the market according to its offer price in comparison to the locational marginal price (LMP) at the unit's specific location, which is a value that changes every five minutes based on the conditions of the entire market and transmission system. In the RTO markets, the offer prices for generating resources are most typically equal to the unit's variable operating costs, consisting primarily of fuel cost. Wind and solar resources generally have no cost associated with the fuel source. With tax credits, the resources can often be offered in with a negative offer price to ensure the resource is dispatched and produces energy (dispatched energy) to receive the tax credits. This creates a situation where fossil fuel units are not economic to operate, and the market will not dispatch them. The chart below, from the EIA, reflects some of this impact showing the reduction of energy produced by coal plants not only from retirements, but reduced energy production from lower utilization of the facilities that remain in service.

The proliferation of low-cost renewable resources has driven market prices down in recent years. Future environmental regulations are likely to increase the operating cost of fossil fuel units, which will cause the market to dispatch them less often. We have seen the effects of this already. From 2008 to 2020, coal generation has diminished 29% due to unit retirements, and another 32% due to lower utilization.

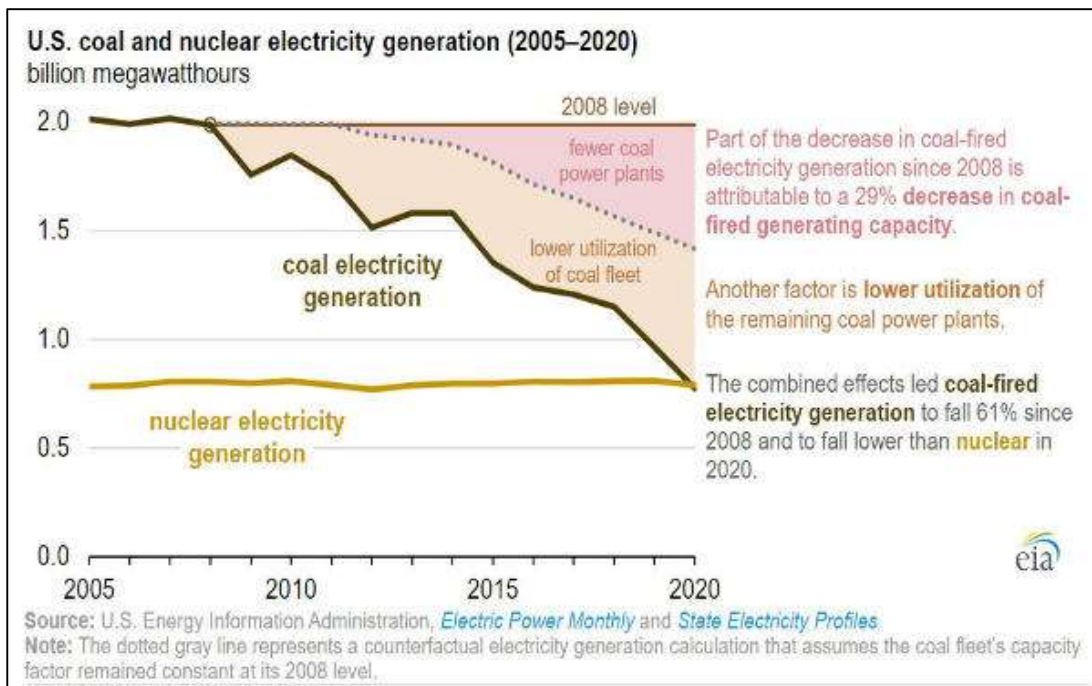


Figure VI-3

Capacity factor is the measure of how often a power plant runs over a specific period of time. It's expressed as a percentage and calculated by dividing the actual unit electricity output by the maximum possible output. This ratio is important because it indicates how fully a unit's capacity is used. Typical capacity factors vary considerably by plant and fuel type as shown in the chart below.

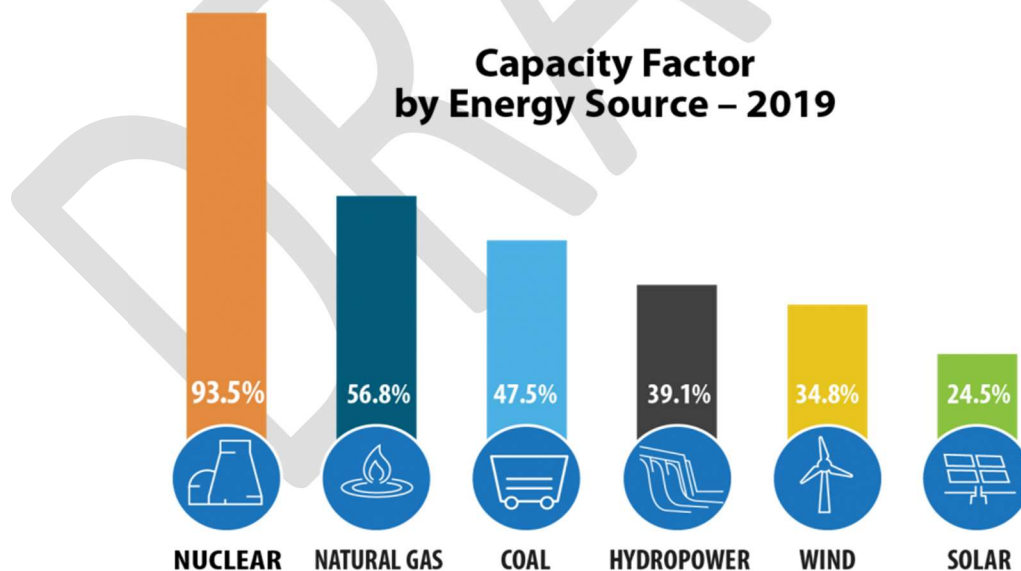


Figure VI-4

Source: U.S. Energy Information Administration

Capacity factors can be impacted by many factors such as plant maintenance outages, fuel availability, economic dispatch, and the resource type. Nuclear plants generally have very high capacity factors because nuclear fuel produces energy at a very steady level, and these units are

generally not designed to be operated below design output levels. Natural gas and coal plants are often operated based on economics, which is becoming more prevalent in the RTO markets. If these units generated whenever physically capable (available energy) their capacity factor would increase. However, dispatched economically (dispatched energy), their capacity factor decreases. In contrast, wind and solar resources generally operate at less than 50% capacity factors because of the variability of wind and sunshine – consider that the wind would need be at maximum design speed every hour of the year for them to achieve a 100% capacity factor.

In fact, the coal units in MEAN's portfolio have experienced this as well, largely as a result of operating based on economic dispatch in the SPP and MISO markets. Since 2011, the weighted capacity factor of MEAN's coal fleet has decreased from 77.4% to 47.8%. Looking specifically at the coal units that operate in the SPP and MISO integrated markets, the weighted capacity factor has fallen from 71.4% to 37.9%. If this trend continues, and the volume of renewables in the SPP and MISO interconnection queues indicates that it will, we can reasonably expect MEAN's coal units to generate at lower levels in the future.

Weighted Average Capacity Factor
of Coal Plants in MEAN's Portfolio

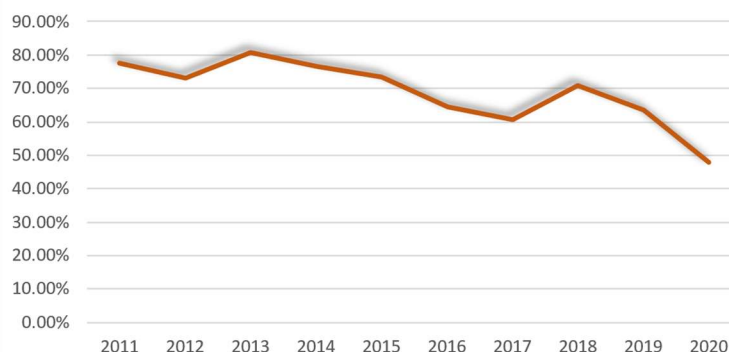


Figure VI-5

Weighted Average Capacity Factor
of SPP and MISO Coal Plants in MEAN's Portfolio

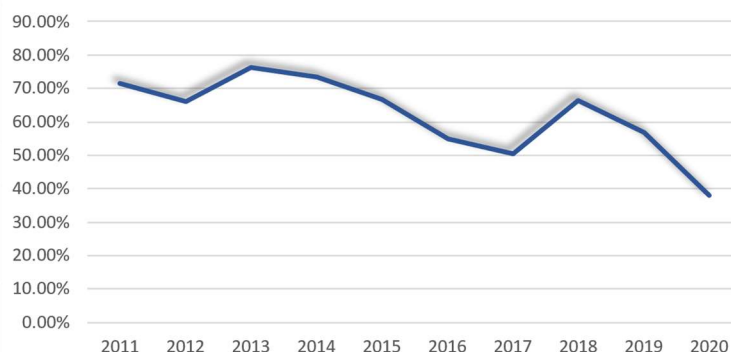


Figure VI-6

E. Resource Mix by Fuel Type

1. Capacity

When presenting resource mix metrics, resource capacity is listed according to unit nameplate. This is notable in relation to intermittent resources, namely existing wind contracts. "BTMG" represents Participant Owned Generation, or "Behind-the-Meter Generation."

It is very important to note in the following section that the values shown simply represent the currently contracted capacity. It is quite obvious that the relative values will (and sometimes do) change if MEAN's total capacity changes. Increase or decrease in relative percentages does not always correlate to the same magnitude of increase or decrease in MWs, given that the totals change. The varying capacity factors and accreditation values of different types of resources, particularly renewable resources, also mean that the "Future" capacity values represent accredited capacity that is required and are not necessarily predictive of the actual nameplate capacity of future assets. MEAN will size future resources to satisfy the energy needs of our total forecasted load as well as resource adequacy requirements.

For each region, a chart is included to show the resource mix in 2022 and 2038 as well as an intermediate year that represents change in the region.

In the west region the majority of the existing capacity, 61%, is provided by WAPA allocations and the WAPA Displacement Agreement. This means only 22% of the west capacity is fossil fueled, from coal resources and participant owned generation, a much lower percentage than in other regions. The remaining 17% of capacity in the west is renewable, comprised of wind and small hydropower.

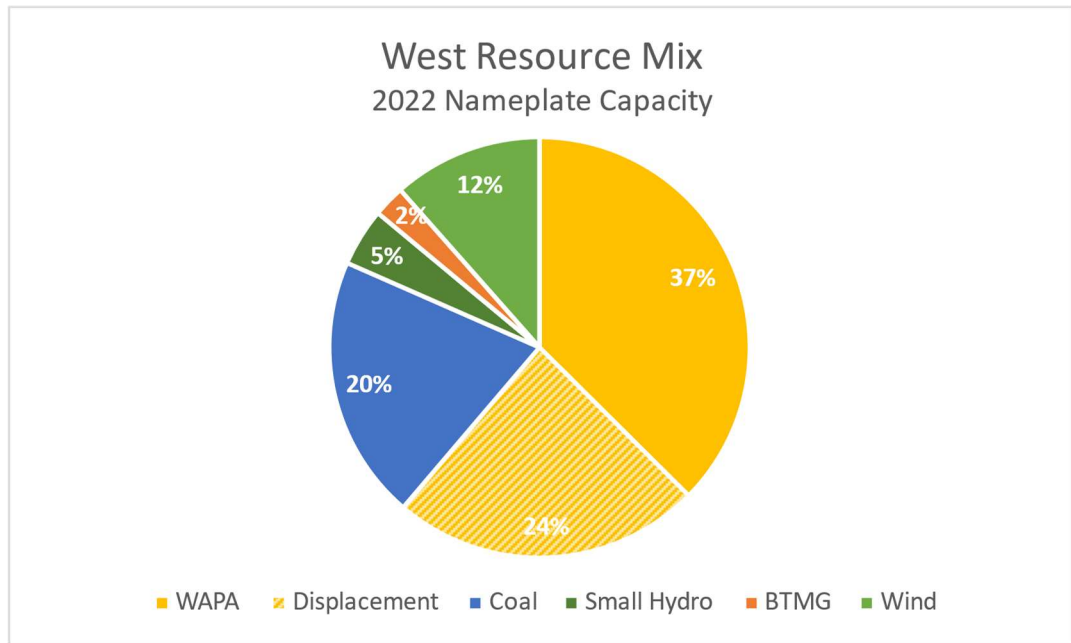


Figure VI-7

In the 2029 snapshot, the total WAPA capacity decreases dramatically due to the expiration of the WAPA Displacement contract in that year. The coal share also decreases with the termination of the Black Hills PPA in 2023. The newly planned Distributed Generation in the form of community-owned solar generation contributes a small portion in 2029. This leaves 21% of the required capacity to be supplied by future resources.

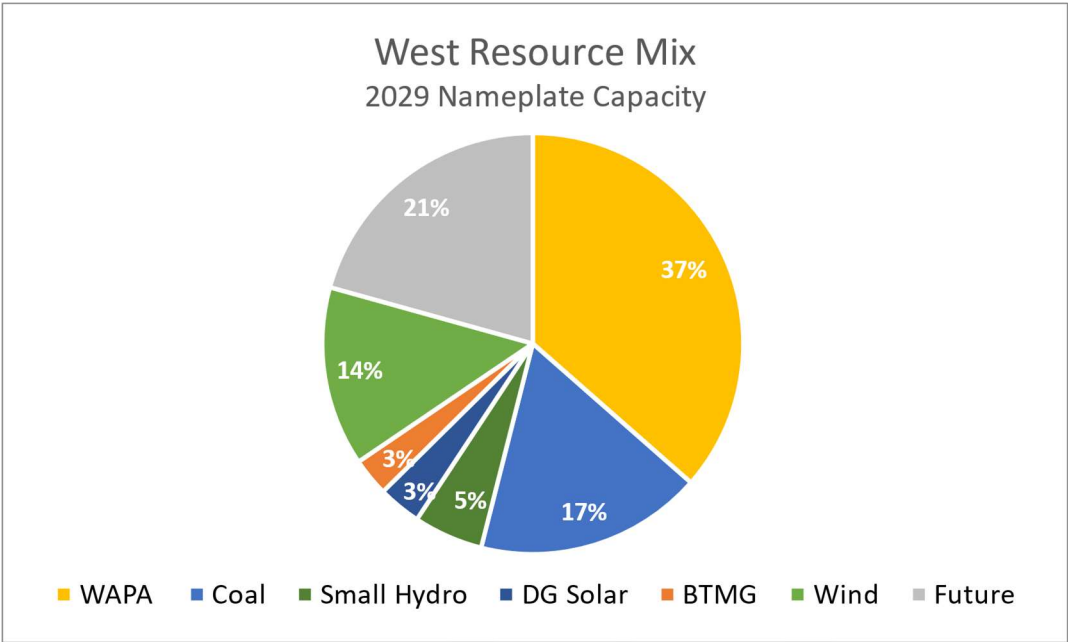


Figure VI-8

By 2038 the Kimball Wind Farm PPA and the Shavano Falls PPA will have expired. Most other resources in the portfolio remain, leaving 32% of required capacity to be provided by future resources. Again, due to the reduced accreditation of most renewable resources, this nameplate capacity percentage is likely to be higher.

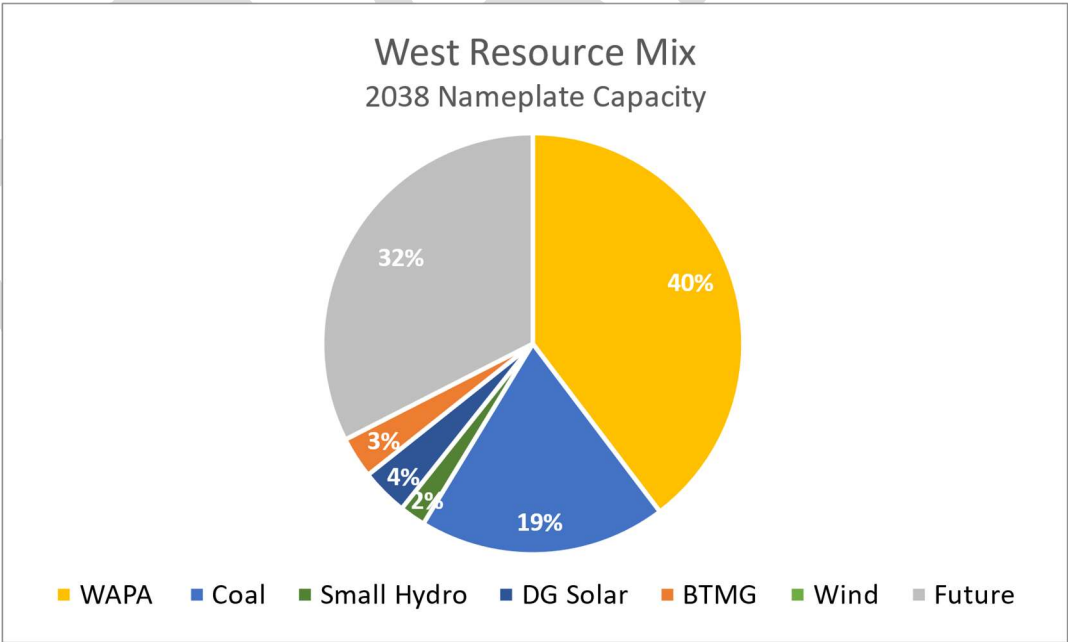


Figure VI-9

SPP capacity is supplied largely by fossil fuel resources. Coal and participant owned generation account for a total of 64% of the capacity in 2022. (This participant owned generation includes 40 MW imported from MISO.) In SPP, WAPA allocations total only 9% of the region's capacity. The wind farms provide renewable capacity of 16%. Lastly,

Cooper Nuclear Station (included in the NPPD Multi-Unit Participation Agreement) totals approximately 11% of SPP capacity.

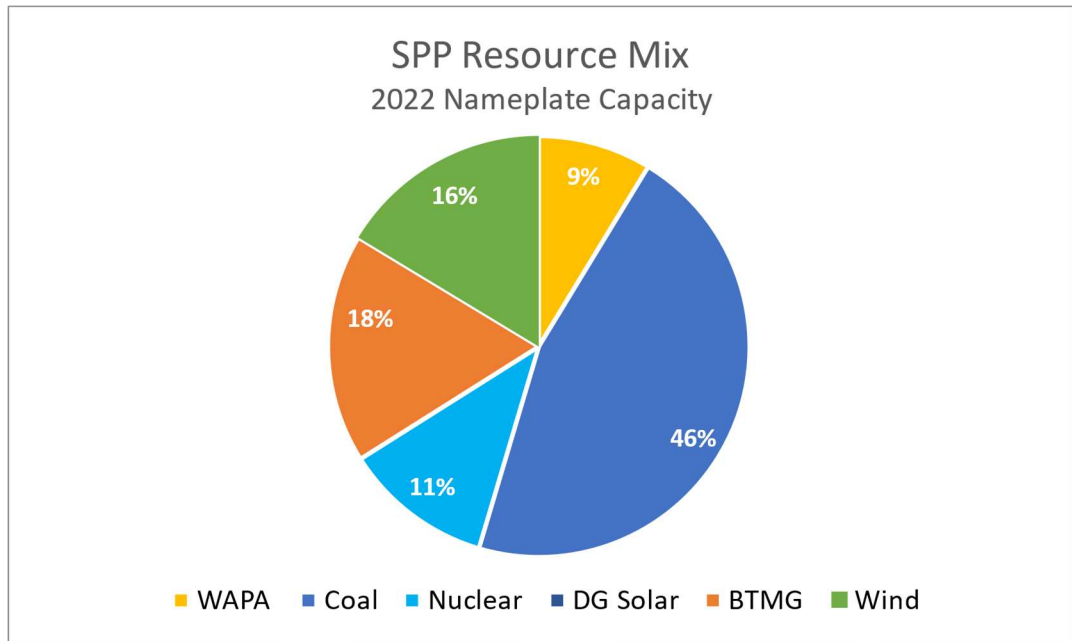


Figure VI-10

For the interim SPP graph, 2028 was selected rather than 2029 because of the need for capacity resources up to this year. In 2029, SPP no longer has a capacity need. In 2028 the coal and nuclear decrease with the expiration of the NPPD Multi-Unit Participation Agreement. The total of participant owned generation imported from MISO reduces as the Marketing Agent Arrangement with IMU and WU expires in 2023. Other WAPA allocations see little change, providing 9% of 2028 capacity. Renewable capacity reduces to 14% of the total as some of the wind PPAs will have expired by this year, but new community-owned solar Distributed Generation facilities will be operational. Therefore 27% of the required 2029 capacity must be furnished by future resources.

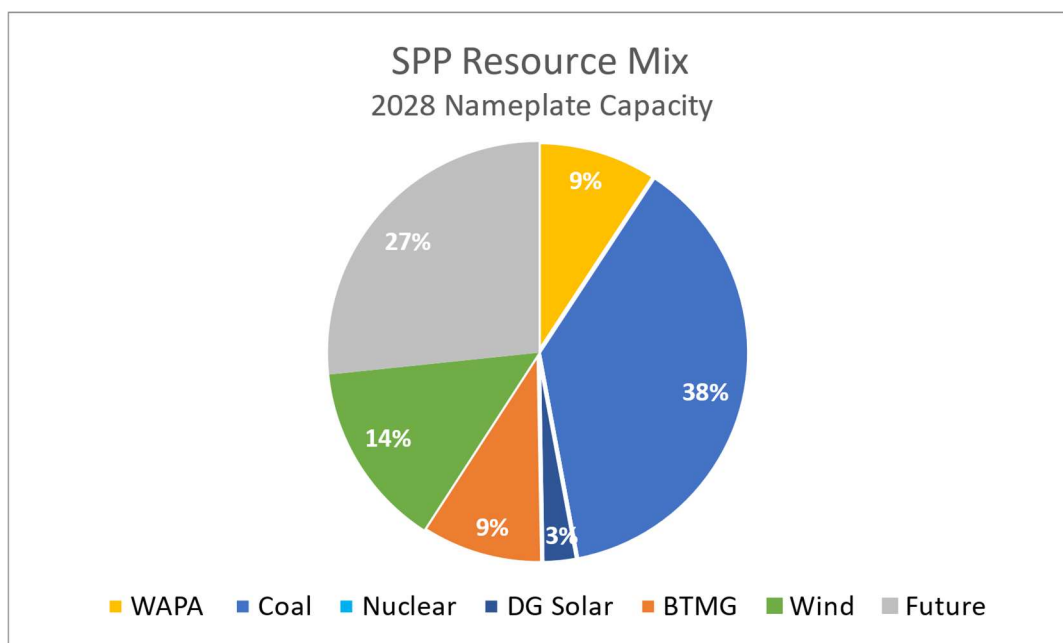


Figure VI-11

2038 sees significant change as the expiration of the WAPA Displacement Agreement means the member generation previously utilized to serve WAPA's Kansas load now returns to MEAN's portfolio. No future capacity is needed in 2038.

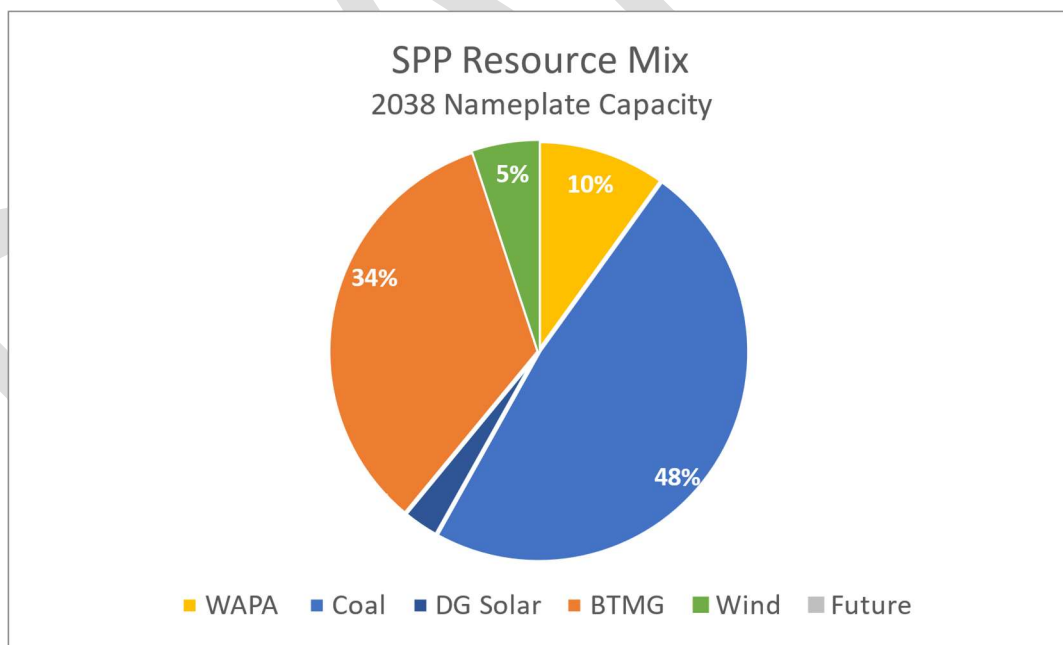


Figure VI-12

With coal at 62% and participant owned generation at 27%, MISO capacity is largely fossil fueled. Only 7% of capacity is provided by WAPA allocations and 4% by renewable resources in the form of landfill gas.

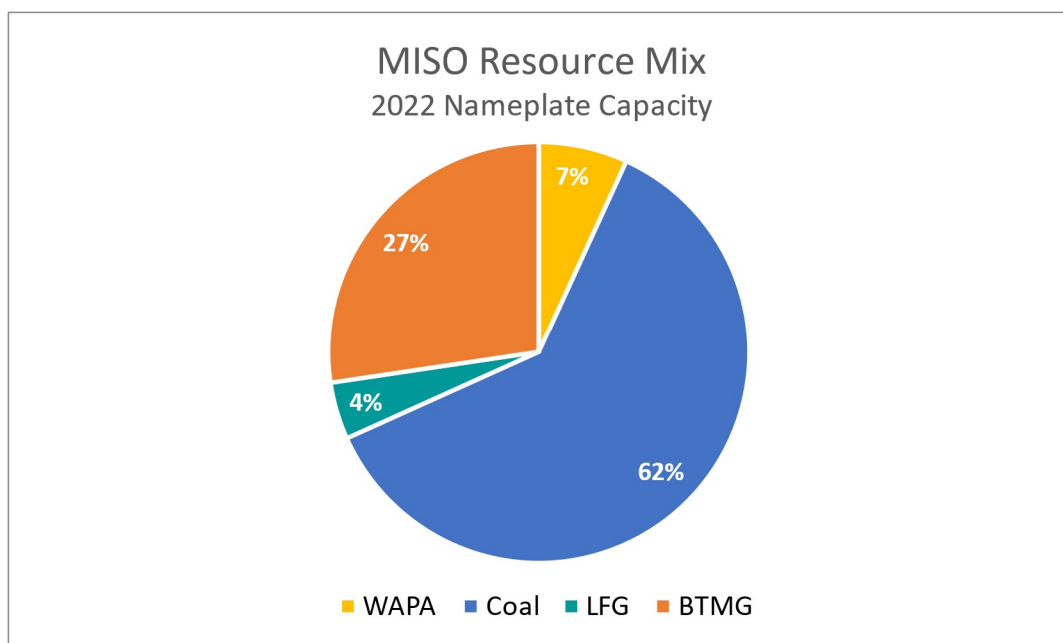


Figure VI-13

The MISO picture changes very little in the future. Behind the Meter Generation accounts for slightly less with contract expiration of the Marketing Agent Agreement, although it is likely that this same generation will provide needed capacity to backup intermittent resources in MEAN's SPP footprint. The total in WAPA allocations decreases with the expiration of one of the participant service contracts. The contribution of community-owned solar adds capacity in the Distributed Generation category. No future resources are required in MISO.

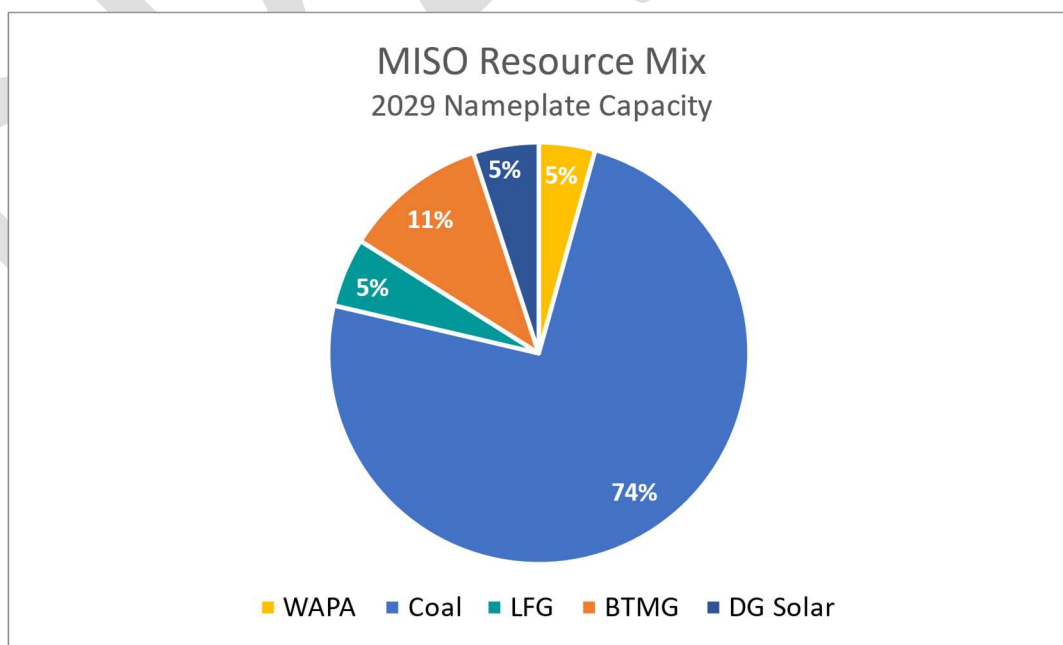


Figure VI-14

In 2038, the LFG contract expires, leaving a small need for future resources to replace this capacity. The MISO region remains essentially resource adequate throughout the study period.

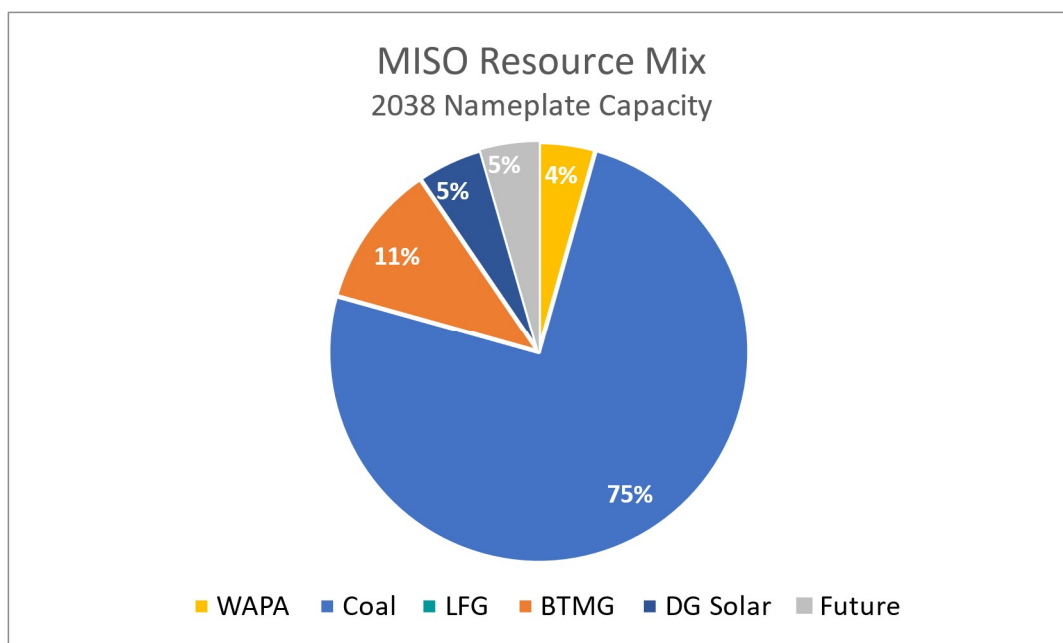


Figure VI-15

In 2022, 51% of MEAN's resource mix is provided by fossil fueled resources in terms of capacity, divided between coal and participant owned generation. Hydro from WAPA allocations and the WAPA Displacement agreement supply 31% of the total. Renewable resources, including wind, small hydro, and landfill gas, account for 14% of MEAN's capacity. 4% of MEAN's capacity mix is nuclear powered.

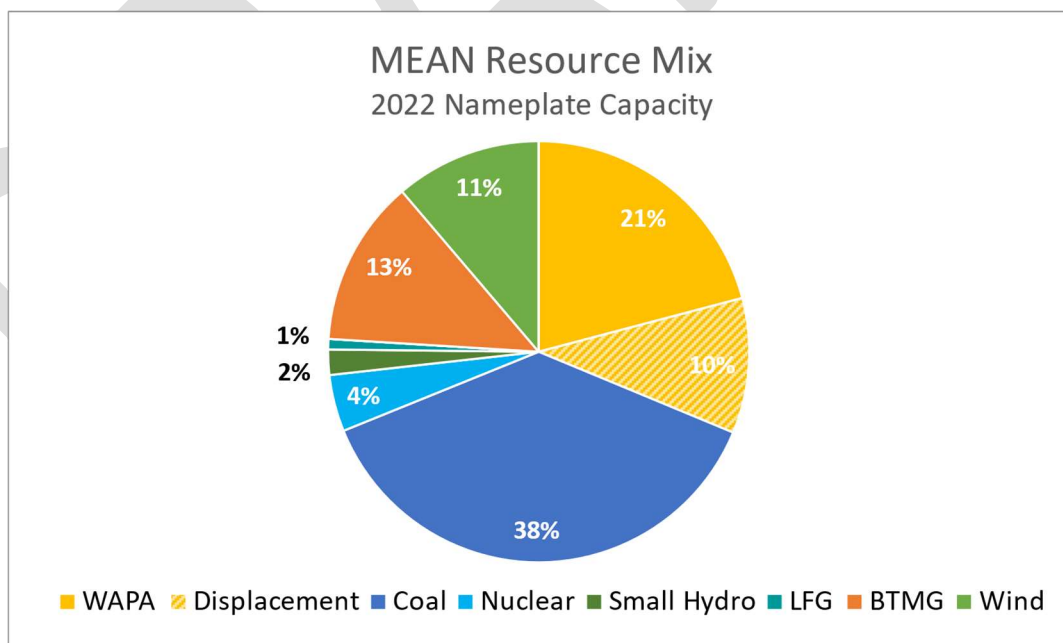


Figure VI-16

In 2029, the percentage of fossil fueled capacity remains roughly the same at 53%. WAPA power is now at 19%, since the Displacement agreement has expired, and the renewable total has increased slightly to 19%. 9% of accredited capacity needed for resource adequacy will be supplied by future resources.

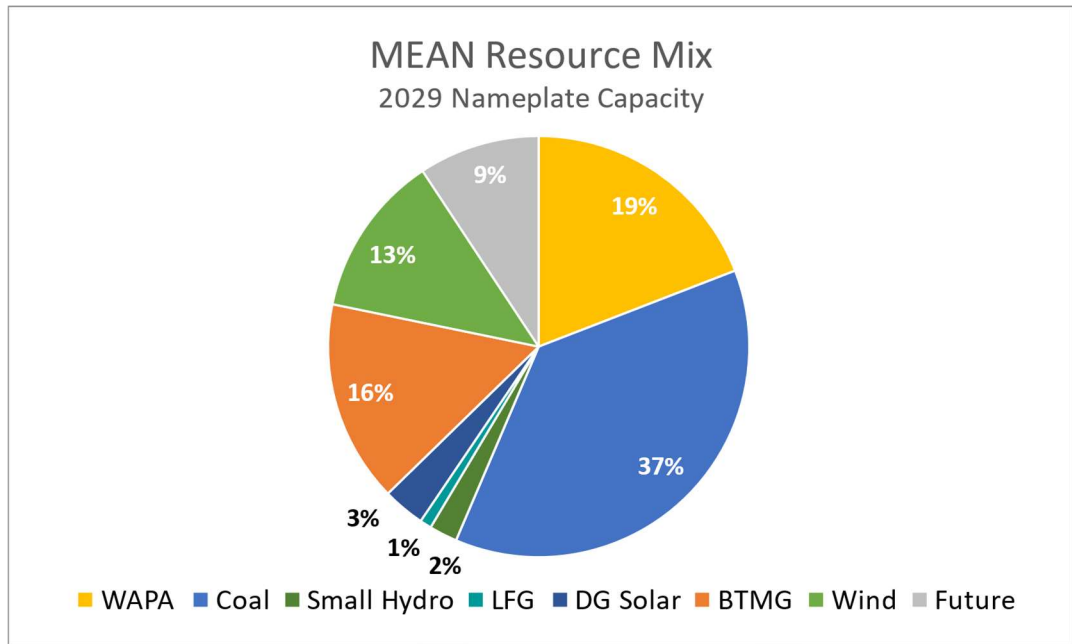


Figure VI-17

By 2038, the Landfill Gas PPA will terminate, along with several wind PPAs. The capacity percentages see little change, and 14% of MEAN's total required accredited capacity will be supplied by future resources.

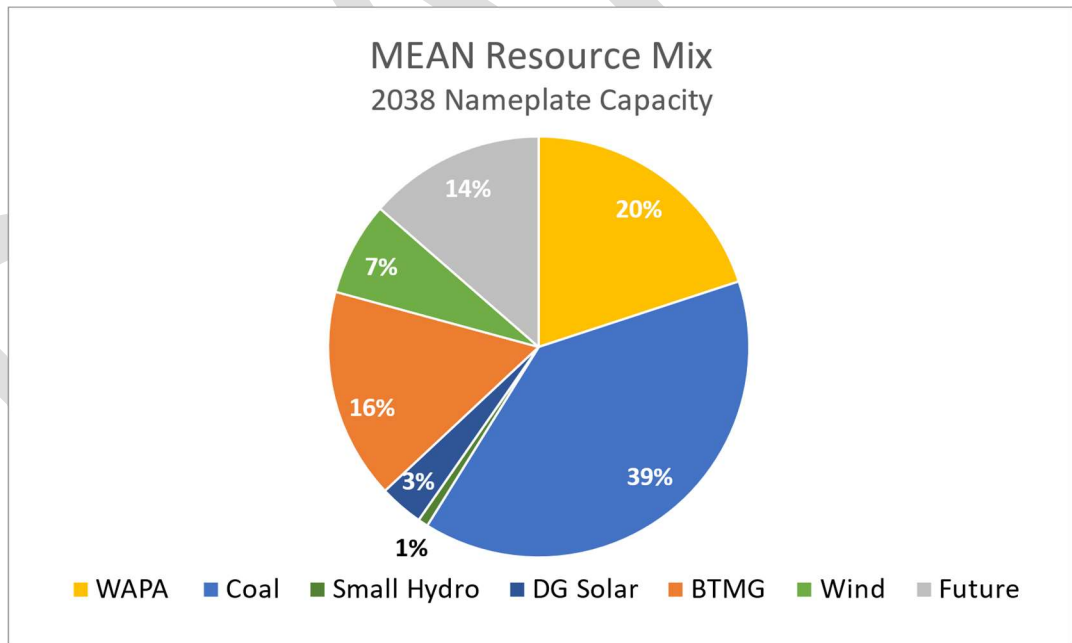


Figure VI-18

2. Energy

In terms of energy, future projections are based on a combination of availability as a function of historical operation and economic dispatch in response to changing market prices. As the total resource mix of each market changes, the operation of MEAN's resources may change from the projected profiles.

The energy proportions in the west show the contribution of baseload coal units. Due to the high capacity factor of these units, the 36% of MEAN energy produced by the coal resources is a larger percentage than MEAN's coal capacity in the west. Conversely, WAPA resources operate at a lower capacity factor, and therefore WAPA provides a smaller percentage of energy than capacity. The intermittent nature of renewable resources is also reflected in the low amount of energy produced relative to the capacity. Participant owned generation is generally not called to operate many hours of the year, and therefore does not produce a notable amount of energy.

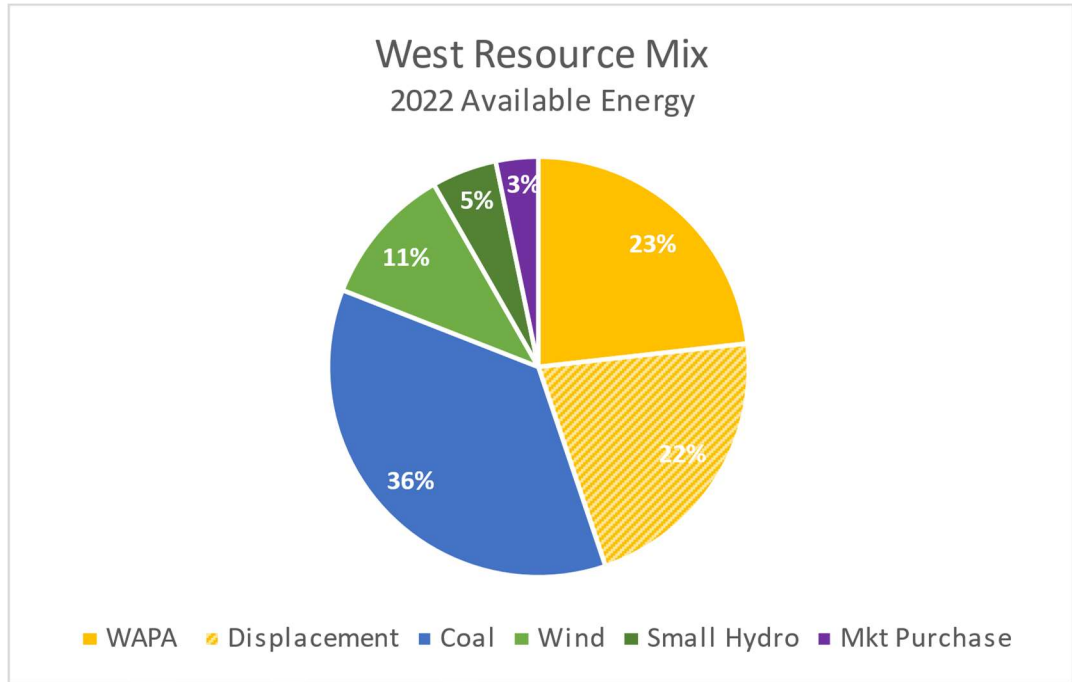


Figure VI-19

In 2029, the coal generation in the West decreases due to the expiration of the Black Hills PPA in 2023. The energy supplied by the WAPA Displacement Agreement is reduced as that contract ends in June of that year. Renewables contribute the same energy percentages. In the west region, 18% of energy in 2029 will come from future resources.

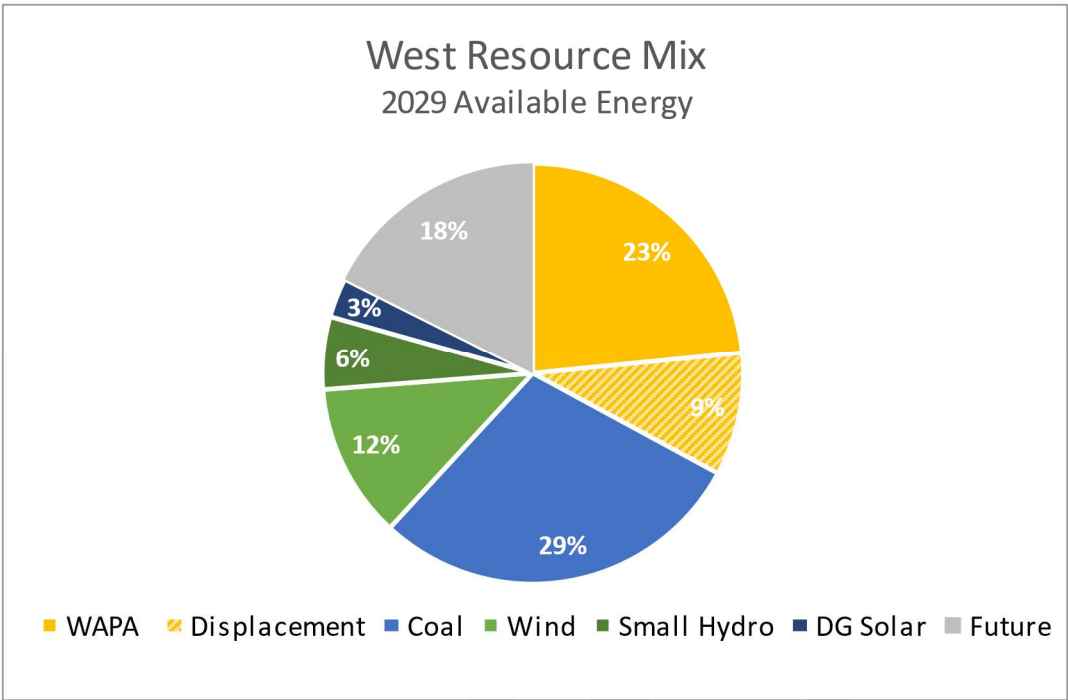


Figure VI-20

By 2038, the Kimball Wind PPA and the Shavano Hydro PPA will have expired, increasing the need for future energy resources to 37% of the west portfolio.

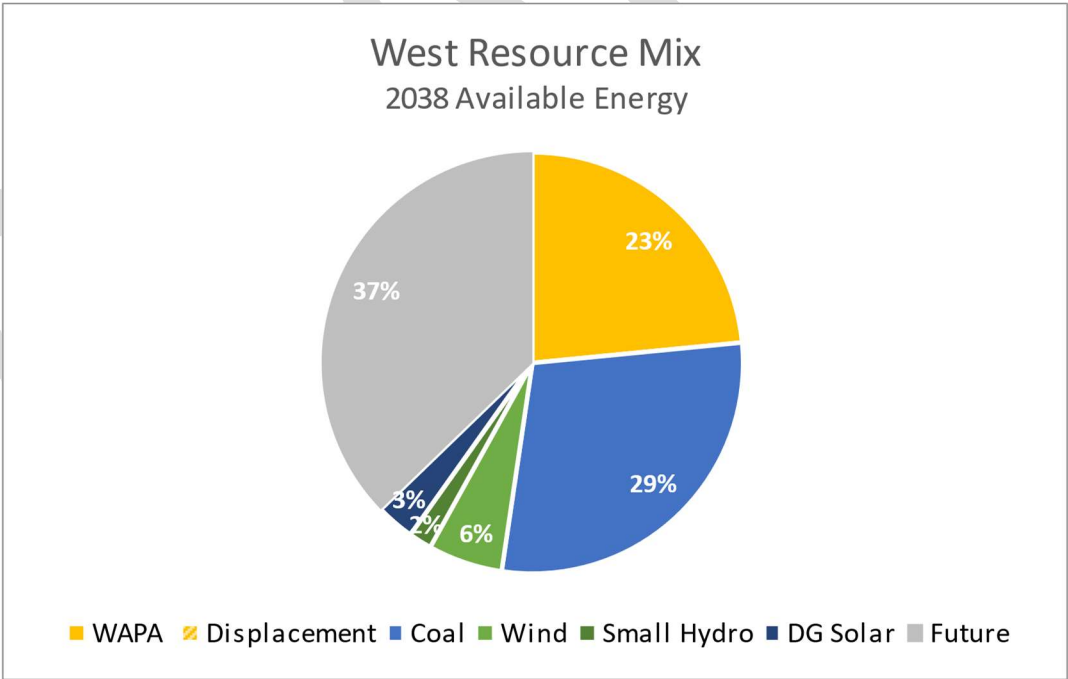


Figure VI-21

The baseload operation of coal and nuclear assets in SPP is evident in the high percentage of energy generated by these units. In total, 79% of MEAN's SPP energy in 2022 is produced by these resources. WAPA hydro operates at a lower capacity factor as shown by the relative contribution to the total energy at only 9%. The renewable resources in SPP consist of wind turbines, which also achieve a lower annual capacity factor and

constitute 12% of MEAN's energy in SPP. Again, the behind the meter participant owned generation contributes virtually no energy on an annual basis.

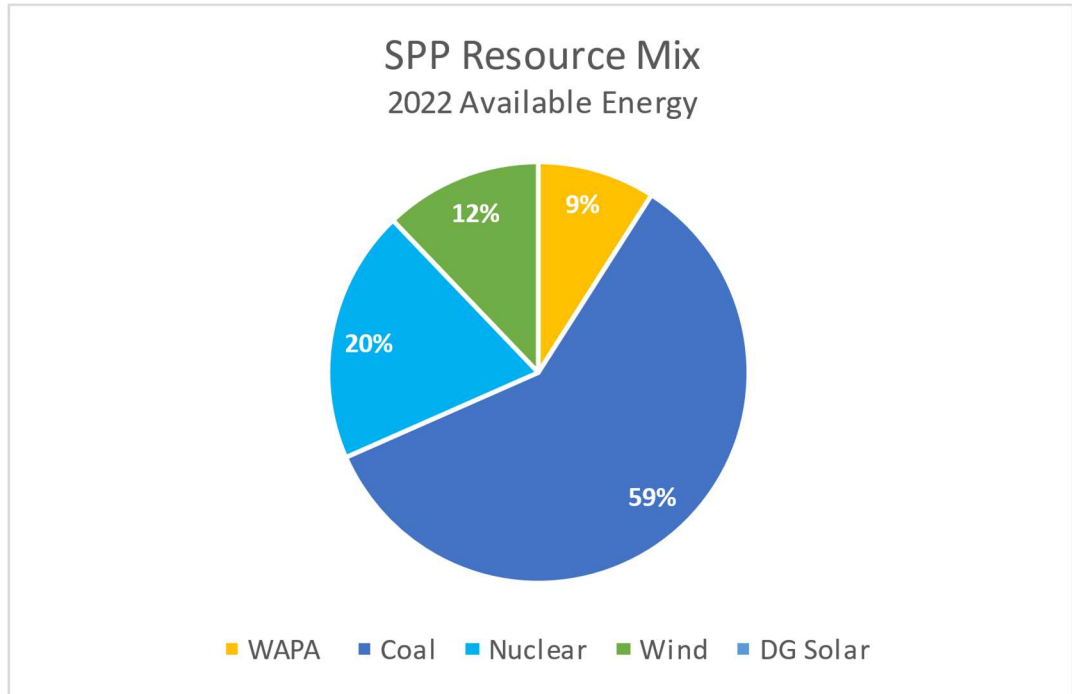


Figure VI-22

In the future, as the MUP contract with NPPD is discontinued and the wind PPAs expire, there is a decrease in energy from coal, nuclear, and wind generation. The WAPA energy changes little, and the DG Solar makes up a small percentage. The amount of energy to be produced by future resources in 2029 is approximately 23%.

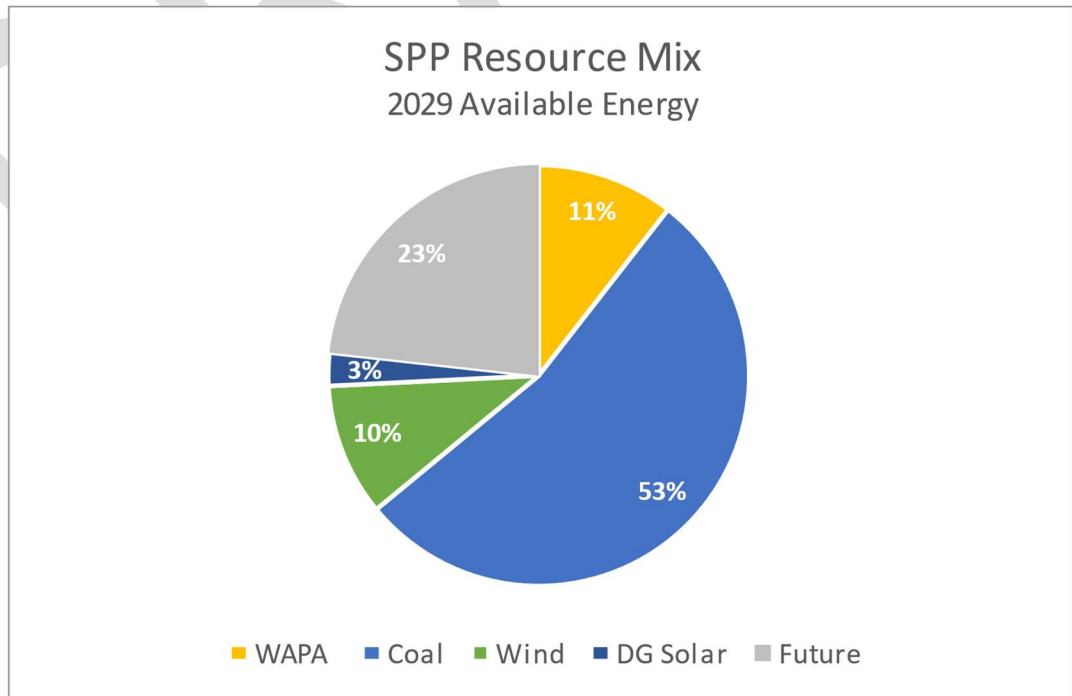


Figure VI-23

In 2038, SPP still has an energy need to be supplied by future resources, which has now grown to 30%. Coal generation and WAPA allocations remain constant. Wind generation decreases with the termination of several wind PPAs.

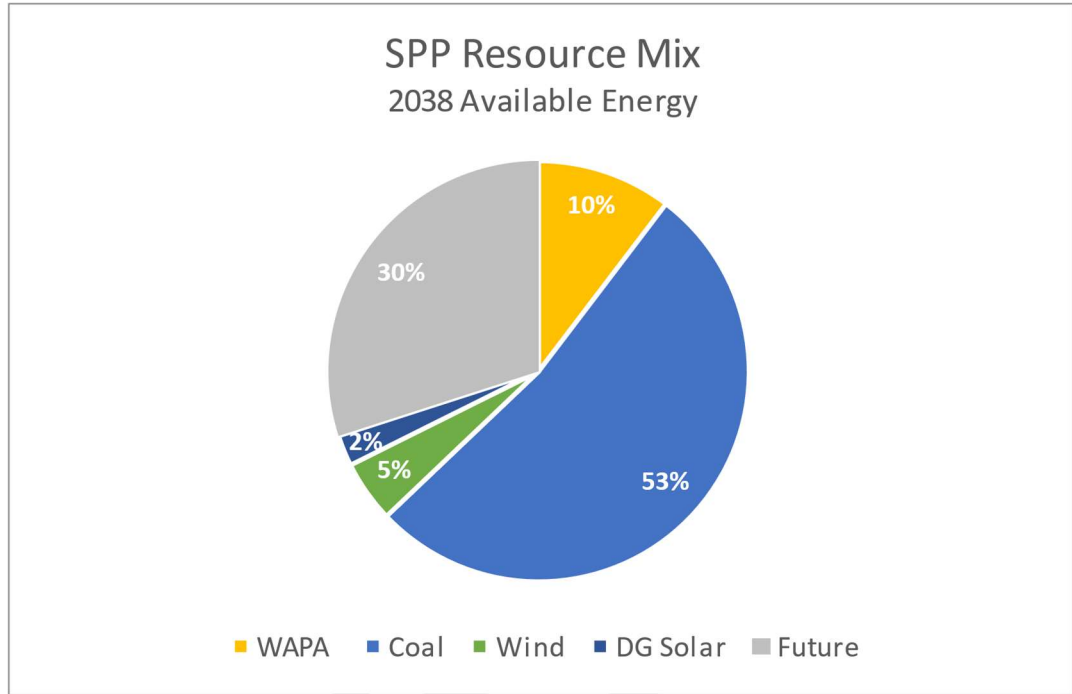


Figure VI-24

In MISO, an overwhelming majority of the MEAN energy generated is sourced from coal units. Only 17% of the total energy comes from non-fossil fueled sources, with 8% from WAPA allocations and 9% from renewables.

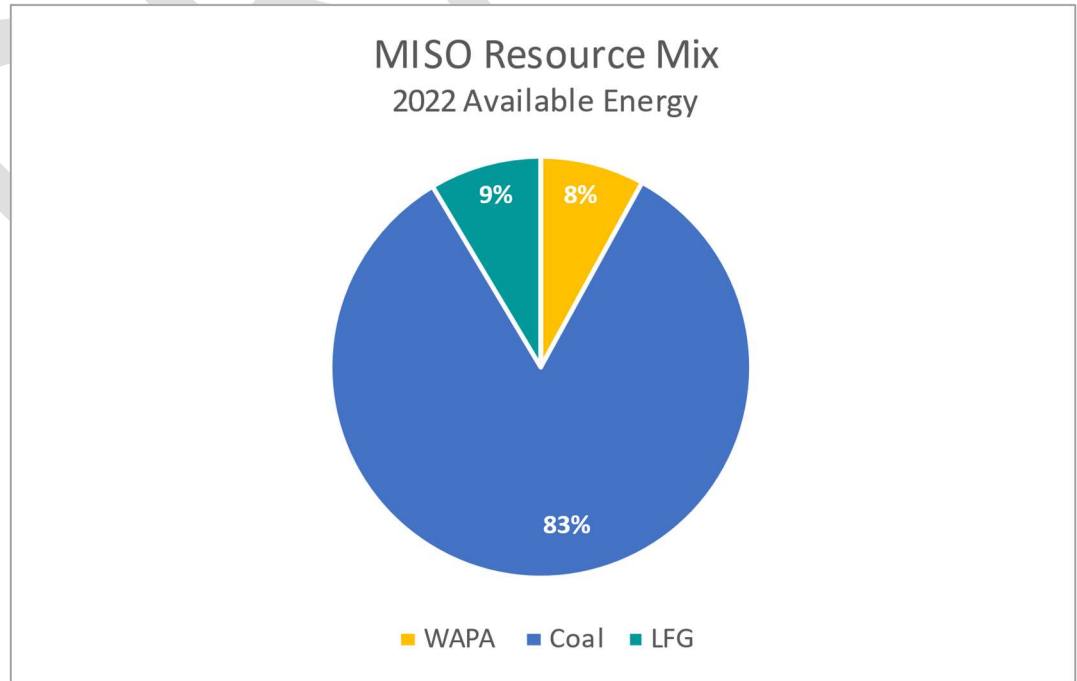


Figure VI-25

The only change in MISO to occur by 2029 is the decrease in WAPA allocations with the expiration of a short-term power supply contract and the introduction of DG Solar.

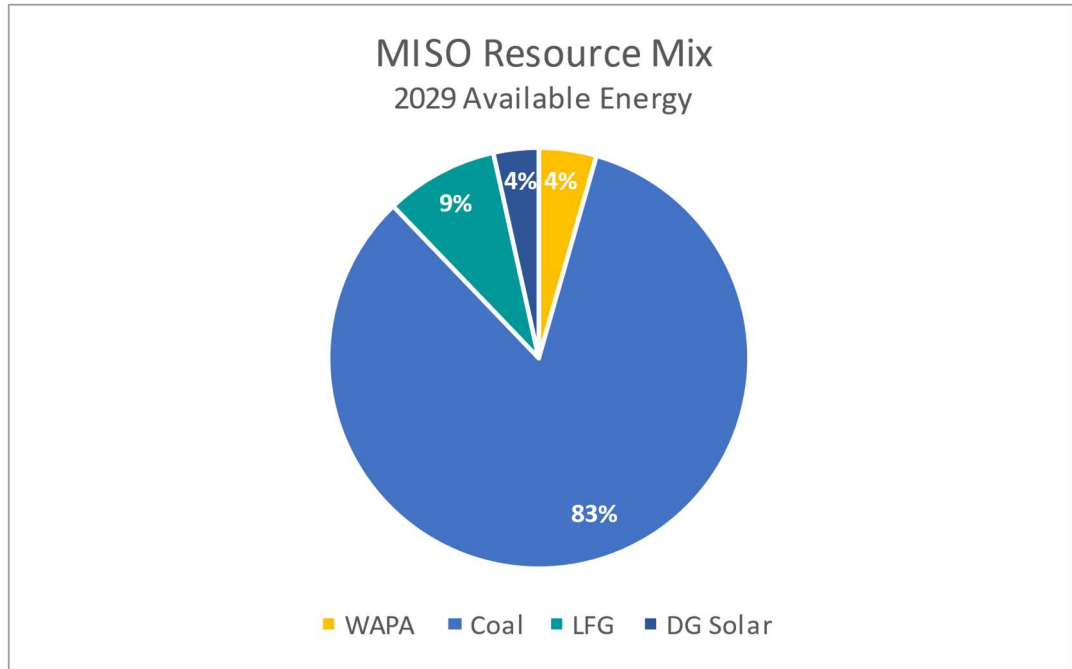


Figure VI-26

Finally, in 2038, MISO sees the expiration of the Landfill Gas PPA. There is no need for additional energy in MISO throughout the 15-year study period.

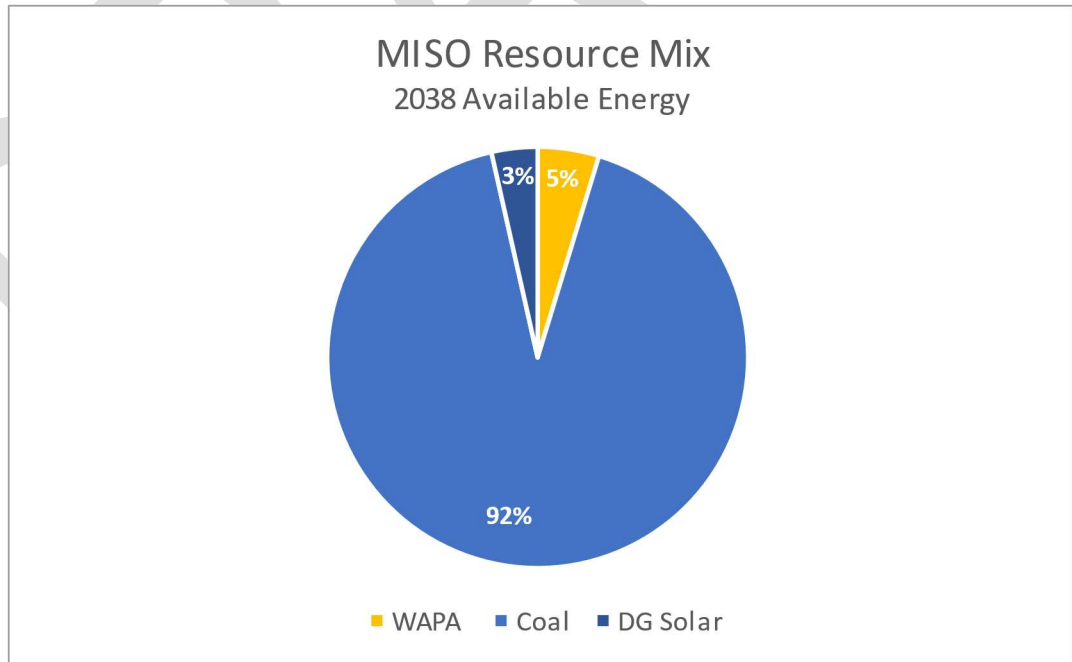


Figure VI-27

MEAN's resource mix in 2022 in terms of energy generation capability shows that the largest contribution comes from coal resources, at 54% of the total. Non-emitting resources make up the remaining 46%. 24% of the total energy is supplied by WAPA

allocations and the WAPA Displacement agreement, 13% of MEAN's energy is renewable, and 8% is generated by a nuclear resource. MEAN entered into a short-term energy purchase to hedge against high market prices in 2022.

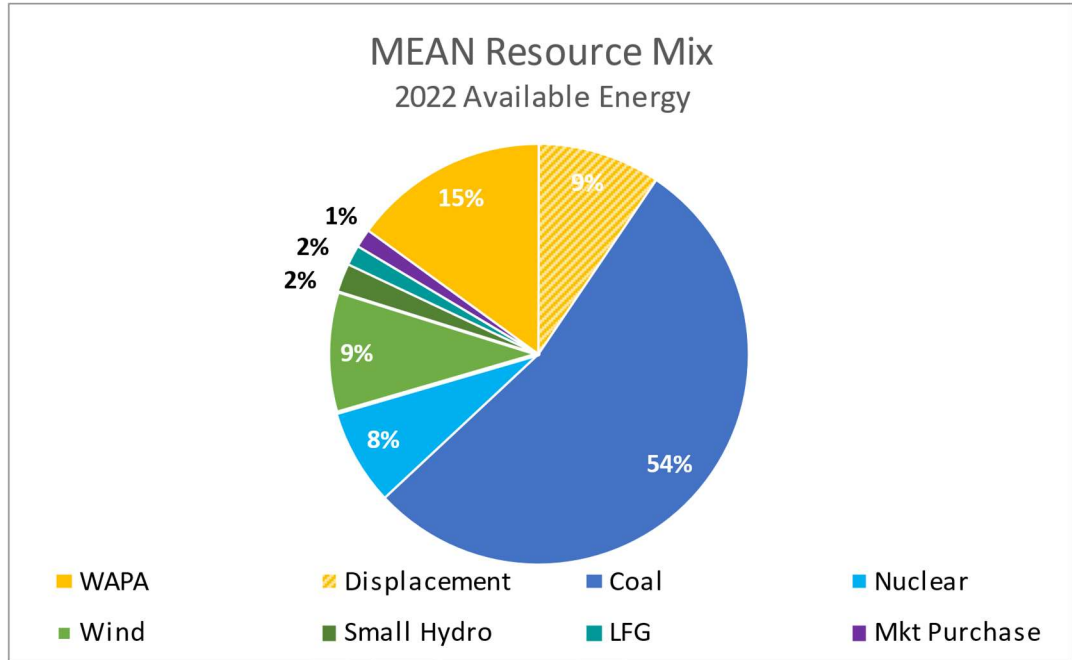


Figure VI-28

Into the future, the energy availability of coal resources decreases slightly to 49% of the total, the contribution of WAPA allocations decreases to 19%, and the renewable resource percentage increases to 16% with the installation of DG Solar. Only 16% of MEAN's total energy in 2029 must be generated by future resources.

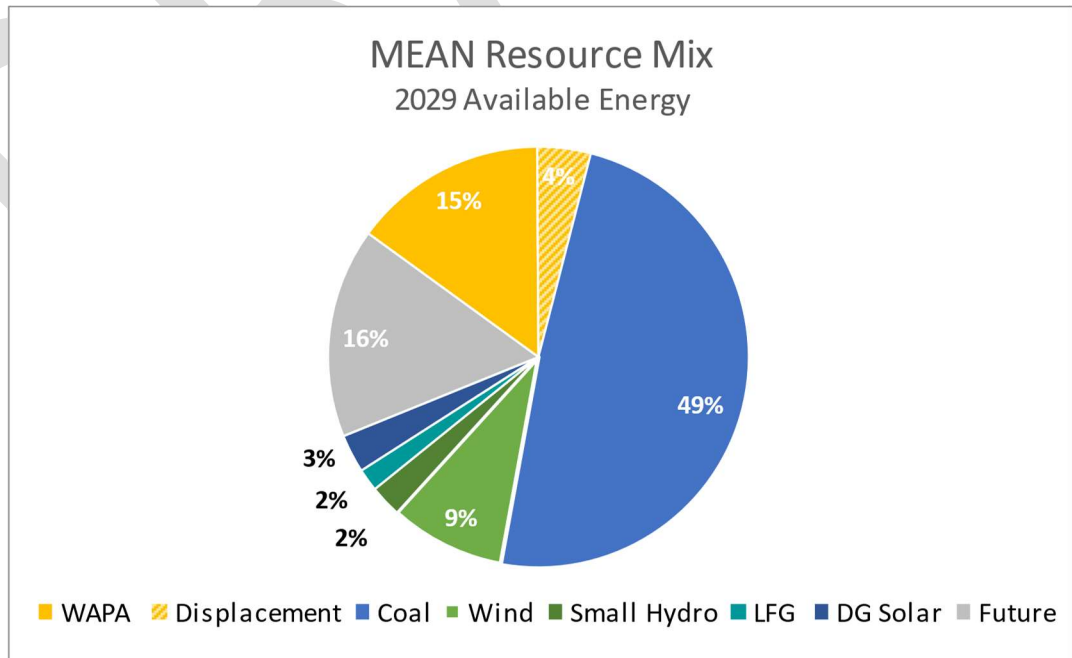


Figure VI-29

Out into 2038, MEAN's energy from coal is projected to remain constant at 50%. WAPA drops to 15% with the expiration of the WAPA Displacement Agreement. Renewables decrease to 8% as Wind PPAs, the Landfill Gas PPA, and the Shavano Falls Hydro PPA end. MEAN will require an estimated 27% of energy in 2038 from future resources.

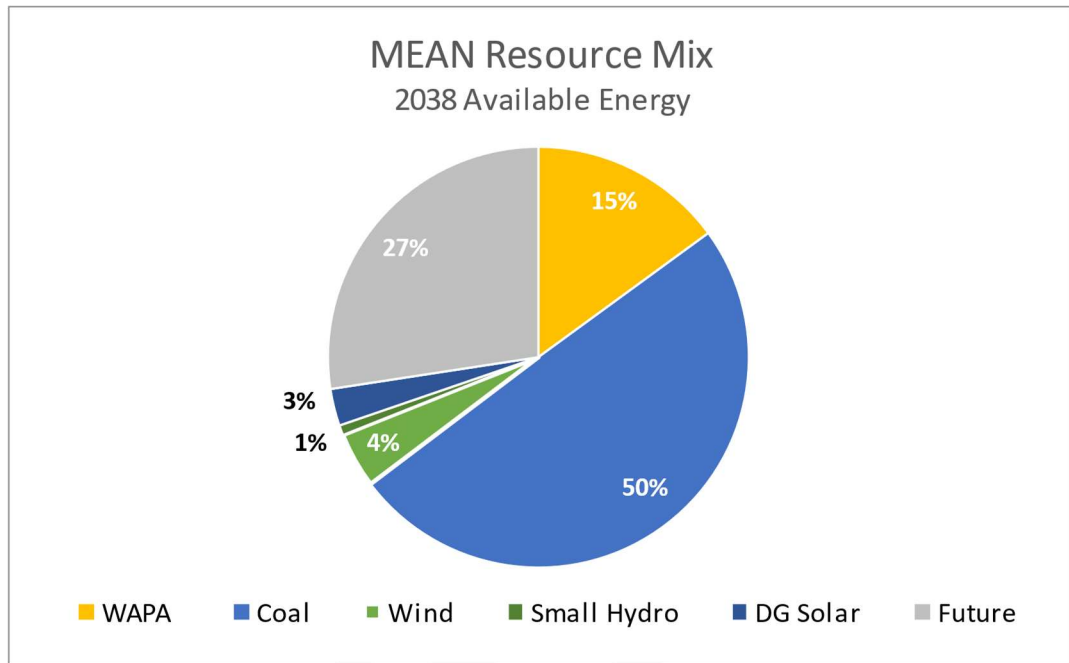


Figure VI-30

Again, the future energy mix is a projection based on not only the availability of resources, but the operation based on historical capacity factors and contract energy requirements. Changes in market dynamics and the introduction of an integrated market in the west could substantially alter the actual energy production and likely reduce energy produced by fossil fuel resources.

F. Resource Mix by Contract Type

MEAN's resource portfolio consists of assets obtained through various contract vehicles. The rights to the capacity and energy of a given unit as well as the way costs are incurred is dependent upon whether the contract is an ownership or a Power Purchase Agreement ("PPA"). In addition, WAPA provides allocations that are applied directly to load, separate from ownership or power purchase.

1. Capacity

In terms of nameplate capacity, 31.4% of MEAN's resource portfolio is controlled through an ownership interest, 20.4% of the total portfolio is assigned to MEAN as an allocation, 35.7% is contracted via a PPA, and 12.5% leased Member Generation. For purposes of this illustration, the WAPA Displacement Agreement is considered a Power Purchase Agreement.

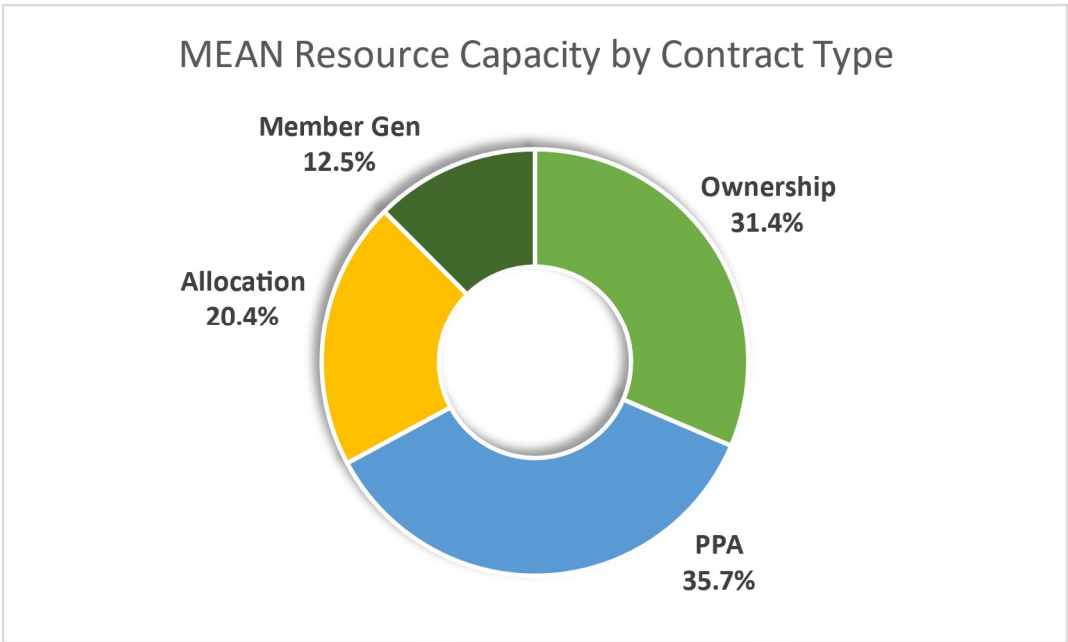


Figure VI-31

2. Energy

In total, 42.2% of the energy generated by MEAN’s resource portfolio is controlled through an ownership interest, 15% of the total portfolio is assigned to MEAN as an allocation, and 42.7% is contracted via a PPA (including the WAPA Displacement Agreement.)

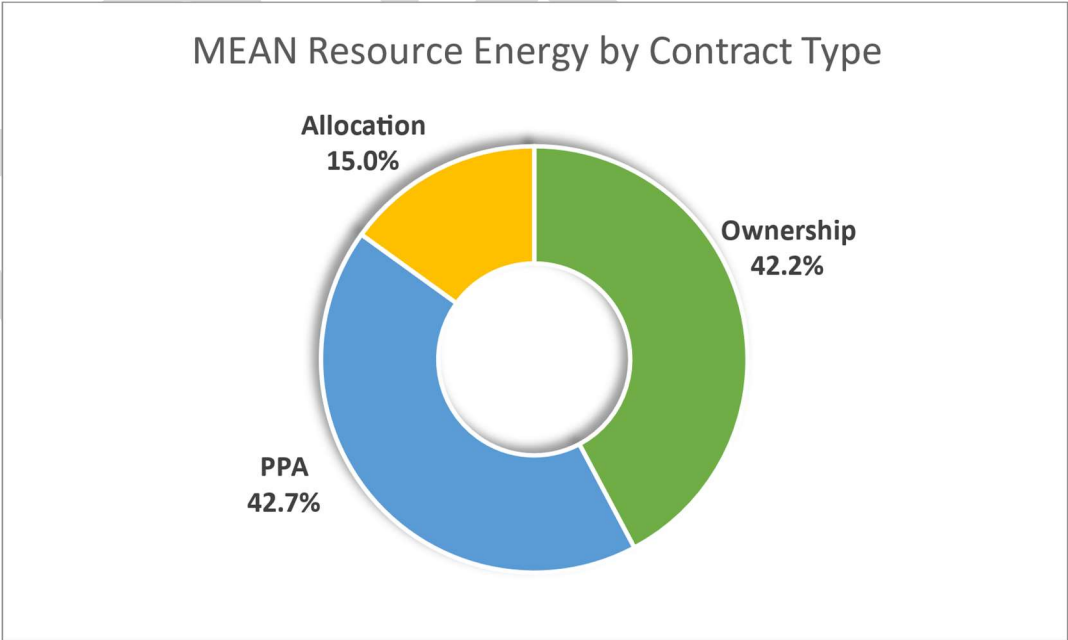


Figure VI-32

VII. Distributed Generation

A. Renewable Distributed Generation Policy

MEAN adopted a Renewable Distributed Generation Policy (the “*DG Policy*”) in 2016 that, in limited amounts and in certain circumstances, allows the Participants that have committed to purchase all of their electricity requirements from MEAN to (a) permit their retail customers to utilize output from renewable generation resources to supply all or a portion their own loads, (b) purchase output from renewable generation resources owned by their retail customers, and (c) subject to a cap set forth in the DG Policy, own and operate renewable generation resources, including community solar projects, to offset a portion of their total requirements purchases from MEAN. The DG Policy includes provisions to mitigate any adverse economic impacts of renewable generation resources purchased or undertaken by an individual Participant on MEAN and its other Participants. MEAN anticipates that the DG Policy will be revised from time to time to reflect developments in distributed and renewable generation, including any applicable regulatory requirements.

In November of 2019, the Board approved an increase in the policy limits, allowing Participants to install a distributed renewable generating resource capable of generating 5% of the Participant’s average annual energy needs. The type of resource determines the capacity factor, and therefore the allowable capacity of the installed resource.

B. Existing Distributed Generation

In 2016, MEAN conducted a Participant survey in preparation for the creation of the DG Policy to determine the installed DG in each community. This serves as a baseline of “grandfathered” distributed generation which will not be counted against the Participant’s 5% cap if the asset is community-owned. This installed capacity is already reflected in the historical load values, and therefore is also included in future load forecasts.

The survey found that throughout the entire MEAN footprint, there was a total installed grandfathered DG capacity of 2,875 kW. Of this total, 71 kW were located in SPP, 739 kW were located in MISO, and 2,065 kW in the West.

Since the establishment of the grandfathered distributed generation, retail end users of MEAN communities have installed a total of 4,932 kW of distributed generation. Of this installed DG, 151 kW are located in SPP, 990 kW in MISO, and 3,791 kW in the West.

C. MEAN Community Solar Request for Proposals

In 2019, MEAN surveyed member communities regarding interest in installation of community-owned solar assets. In response to this survey, eight communities expressed initial interest. Further discussion increased this number to eleven interested communities. On behalf of these interested communities, MEAN released a Request for Proposals for community-owned solar facilities. The interested communities were required to supply a controlled site adequate for the project size and would contract directly with the solar developer. MEAN would administer and negotiate the contract and assist members in sizing and specifications of the installation. The aggregated Request for Proposals was pursued as the increased volume of solar installation required of the combined projects provided advantageous pricing compared to a standalone project in one community.

The RFP was released in July 2021 and bids received in September 2021. After evaluation of bids and consultation with members, MEAN awarded the bid for a total of 14.2 MW-DC of community-sited and -owned solar facilities. Since that time, additional communities have joined the project. Project installation is scheduled to begin in Summer 2022 with all commercial operation dates by Spring 2023. Following is a list of MEAN communities participating in the project to date and the capacity of each planned installation. (This list may not be final and is pending the receipt of executed PPA contracts.)

Community	Nameplate (kW-AC)	Nameplate (kW-DC)	Yr-1 Production (MWh)
Alliance NE	2,350	2,819	5499
Ansley NE	92	110	210.1
Crete NE	2,539	3,047	5735
Shickley NE	78	94	177.9
Stuart NE	124	149	275.8
Waverly IA	3,324	3,988	6903
West Point NE	1,142	1,370	2518
Delta CO	830	996	2102
Pender NE	324	389	709
Sergeant Bluff IA	858	1,030	1827
Aspen CO	919	1,103	2241
Gering NE	976	1,171	2280
Indianola IA	3,083	3,700	6639
Lyons CO	252	303	572.2
Oxford NE	106	127	252.2
Sidney NE	1,550	1,860	3744
Fort Morgan CO	4,156	4,987	10090
Imperial NE	499	598	1196
Denver IA	348	418	712
Wray CO	254	304	620.1
Total	23,803	28,564	54,303

Figure VII-1

MEAN encourages this type of development within communities in accordance with bond advisor recommended limits. We look for additional projects of this type in the future and anticipate participation approaching the full 5% of MEAN energy consumption. The following graph shows the impact if all MEAN communities installed their qualified level of distributed generation.

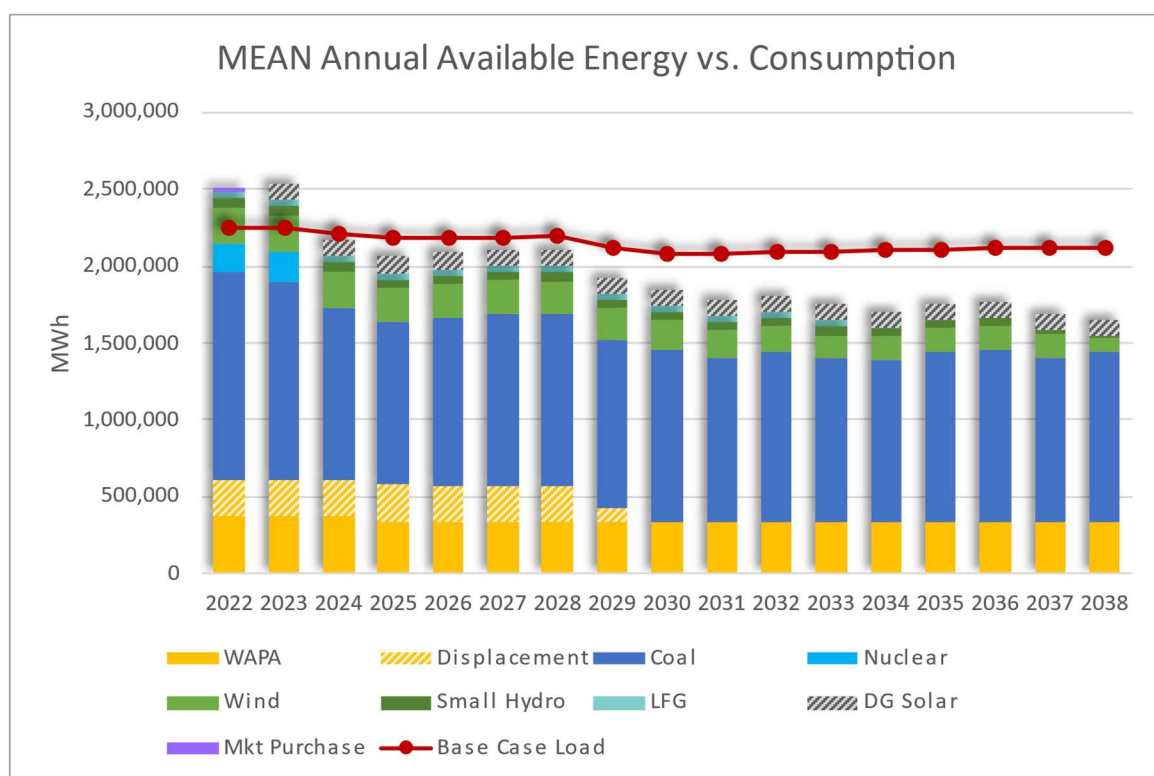


Figure VII-2

MEAN communities have also expressed interest in the installation of alternate distributed generation technologies, such as fuel cells, cogeneration facilities, and energy storage. Under evolving policy, projects may be incorporated into MEAN's load and resource balance into the future and would ultimately decrease the need for other resources.

D. Ultimate Impact of DG

Installed DG located behind the retail meter reduces the energy that Participant utilities supply to end users and consequently, the energy MEAN supplies to Participants. An increase in DG installations has the potential to reduce revenue for both the Participants and MEAN. There are a number of costs, on the other hand, that do not decrease proportionally with lower energy sales. There is a portion of costs that are avoided with a reduced energy supply, but many of MEAN's costs remain.

Fortunately, MEAN has designed the rate structure to directly bill for a portion of fixed costs on a basis that includes the capacity of DG. Because MEAN must maintain the Power Supply System to provide for the Participants' load even when the DG units are not generating, some fixed costs are allocated on this basis. This ensures that MEAN maintains a system capable of supplying firm power to our Participants under full load conditions. MEAN has performed deliberate calculations of its avoided costs throughout the footprint for application in distributed generation installations and continues to evaluate this calculation as conditions change.

As MEAN considers the acquisition of new resources to supply needs into the future, the installation of distributed generation reduces the needs in terms of energy and capacity. This solution also helps to progress MEAN toward the 2050 Vision of carbon neutrality and provides local benefit to MEAN communities. The pricing received for PPAs in the latest RFP also demonstrates that this type of resource can be economically competitive with other resources.

VIII. Existing Demand Side Management

A. Existing Demand Side Management – MEAN Programs

MEAN has conducted several Demand Side Management (“DSM”) programs in the past, with varying degrees of adoption and impact. Currently MEAN provides a suite of five energy efficiency programs that offer cash incentives paid directly to customers to help cover the cost of energy efficient upgrades.

1. Commercial Programs

LED Lighting Program: This program provides cash incentives paid directly to commercial customers to help cover the cost of lighting upgrades and replacements to existing facilities. The program covers:

- Indoor high/low bay lighting
- Linear replacement or retrofit lighting
- LED Exit signs
- Fluorescent freezer/refrigerator case lighting
- Occupancy sensors (new for 2022)
- Customized requests

Converting to more efficient lighting can have a favorable impact on a business’s bottom line. Interior lighting accounts for about 30 percent of a commercial business’s total energy use. Lighting technologies, such as LEDs, can help cut lighting costs while improving output, visibility and reducing environmental impacts.

The MEAN Board of Directors approved the program for all long-term MEAN participants, with a maximum of \$2,500 per customer/owner per year. The program is available to commercial businesses of MEAN long-term power participants. Incentives are allocated in the order that applications are received and approved and will be continued until the annual budget (currently \$80,000) is exhausted.

The program year coincides with MEAN’s fiscal year and runs April 1 through March 31. The program was initiated in FY16-17 and has been renewed thru FY22-23. Funding (updated as of April 1, 2022) is distributed according to the schedule below:

Lighting Efficiency Measure	New LED Wattage	Incentive
High Bay, Low Bay	9-65 watts	\$8
	66-130 watts	\$16
	131-240 watts	\$24
LED Exit Signs	under 8 watts	\$10
Uncensored Control	Occupancy sensor	\$15
Linear Fluorescent	9-22 watt LED	\$2
	23-45 watt LED	\$4
	46-68 watt LED	\$6
	69-90 watt LED	\$8
Fluorescent Freezer/Refrigerator Case Lighting	5’ or 6’ strips	\$20

Figure VIII-1

2. Residential Programs

MEAN offers four residential energy efficiency programs providing cash incentives to homeowners for making energy efficient upgrades. A budget of \$25,000 for FY22-23 has been authorized by the Board to be distributed with staff discretion across the various incentive categories.

- 1) Smart Thermostat Program: Provides a cash incentive from \$25 to \$100 paid directly to residential customers to help cover the cost of installing a qualifying smart thermostat.
- 2) Attic Insulation Program: Provides cash incentives of \$0.15/per square foot with a maximum incentive of \$300 per existing residential dwelling for attic insulation.
- 3) Cooling System Tune-Up Program: Provides a \$30 cash incentive to residential homeowners who have their cooling system tuned up by a HVAC contractor, regardless of what type or age of cooling system (air conditioner/air or water source heat pump).
- 4) High Efficiency Heat Pump Program: Provides cash incentives ranging from \$400 to \$3,000 to residential homeowners who are installing a new high efficiency heat pump system to their residential single-family dwelling.

B. Existing Demand Side Management – MEAN Community Programs

MEAN conducts an annual DSM survey to gather information from all member communities detailing the demand side programs they administer, including the magnitude of load under control for peak shaving and the energy and demand savings attained by participation in the programs. The high amount of load under control in SPP stems from the substantial irrigation load under control in central Nebraska. The responses from the 2021 survey, indicating 2020 data is shown in the table below:

Region	Communities	Programs	Program Type	Total Demand Under Control (kW)
MISO	5	9	- Energy Efficient Appliance Rebate Program (Residential, Commercial) - Recycling/Disposal Program (Residential) - Energy Efficient Light Bulb Program (Commercial) - Direct Control Load Management Program - AC/Thermostat Control - Refrigerator/Freezer Recycling Program (Residential) - Interruptible Load Program – (Commercial/ Industrial)	2,500
SPP	8	12	- AC Direct Control - Energy Efficient Light Bulb Program (Commercial) - Light Sensor Program - Street Lights - Pump/Motor & Fans - Audit and Building Envelope Program	14,468

			• Process Measures - Solar Water Heating • Interruptible Load Program • Recycling/Disposal Program (Residential) • Energy Efficient Appliance Rebate Program (Residential)	
West	4	12	• Audit and Building Envelope Measures - (Residential, Commercial, Industrial) • Energy Efficient Rebate Program (Residential) • Energy Efficient Light Bulb Program (Residential) • Recycling/Disposal Program (Residential) • Light Sensor Program (Commercial/Industrial) • Pump/Motor & Fans - Variable Speed Drives • Energy Savings Program • Energy Efficient Appliance Rebate Program (Residential)	0

Figure VIII-2

C. Historical Results - MEAN

1. Commercial Programs

LED Lighting Program: The current program was reinstated on April 1, 2016, for indoor commercial LED lighting conversions. The cumulative total budget of \$405,000 from April 1, 2016, to March 31, 2021, has been widely utilized with 46 MEAN communities participating in the program to date. Of these participants, 7 were communities in Colorado, 7 in Iowa, 31 in Nebraska and 1 in Wyoming.

In the past 5 program years (FY17-18 thru FY21-22) the Commercial LED Lighting program has approved approximately 650 projects totaling roughly \$420,000 in funding. In total, 54,912 fixtures were approved to be retrofitted during this time frame. The average annual energy savings achieved by the program over this 5-year span is approximately 1,247 MWh. The average annual peak demand savings over the same time period was 249 kW.

The 5-year average total cost of the LED Lighting Program per kW of savings is \$338. This compares very favorably to even the most economical supply side option for additional resources, making DSM the lowest cost alternative to meet MEAN's future resource needs in terms of capacity.

After a slower program year during FY20-21 (due to the Pandemic labor and material shortages), participation numbers steadily increased again during FY21-22 with 70 LED lighting projects approved in 29 communities (approximately \$68,000 in approved applications). Detailed results specific to program year FY21-22 are shown below:

Equipment Info (Conversion)	Fixtures Retrofitted	KW Savings	Hours ran (annual)	Coincidence	Annual KWh Savings	Peak KW Savings
High Bay: 9-65 watts LED	354	14.2	4,160	95%	55,960	13.5
High Bay: 66-130 watts LED	78	5.1	4,160	95%	20,037	4.8
High Bay: 131-240 watts LED	197	19.7	4,160	95%	77,854	18.7
Linear Replace/Retrofit: 9-22 watt LED	5,170	93.1	5,200	95%	459,716	88.4
Linear Replace/Retrofit: 23-45 watt LED	663	13.3	5,200	95%	65,504	12.6
Linear Replace/Retrofit: 46-68 watt LED	436	15.3	5,200	95%	75,384	14.5
Linear Replace/Retrofit: 69-90 watt LED	335	16.8	5,200	95%	82,745	15.9
LED Exit: under 8 watts	371	7.4	8,672	95%	61,129	7.0
LED Refrigerator	26	1.0	8,672	95%	8,568	1.0
Customized Application Fixtures (Linear)	697	19.5	5,200	95%	96,409	18.5
FY21-22 Totals	8,327	205			1,003,307	195

Figure VIII-3

Participation in the LED Lighting Program continues to be utilized by a wide variety of commercially metered customers in MEAN communities including municipal buildings, schools, churches, hospitals, grocery stores, industrial/agriculture as well as retail/service businesses. Below is a breakdown of projects by type for FY21-22 which saw 70 projects authorized:

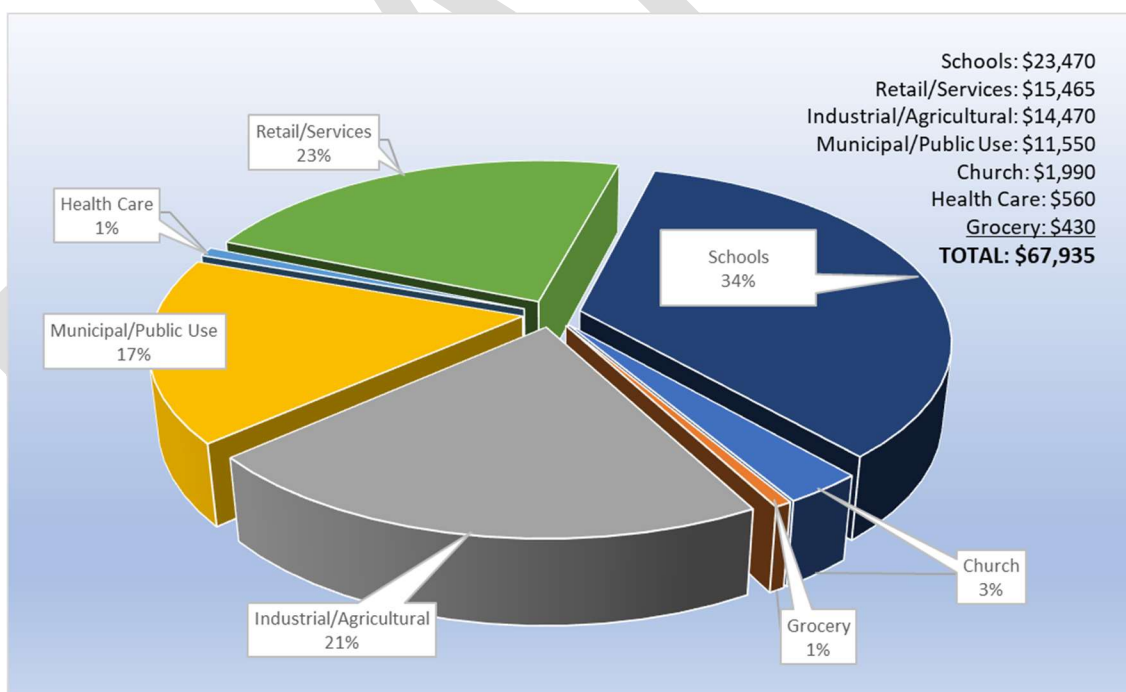


Figure VIII-4

2. Residential Programs

In FY21-22, eighteen MEAN communities participated in the residential energy efficiency programs and 48 projects totaling \$9,270 were completed. This was up significantly from FY20-21 which saw 34 projects completed totaling \$2,361 in incentives paid out. FY21-22 program category totals are illustrated below:

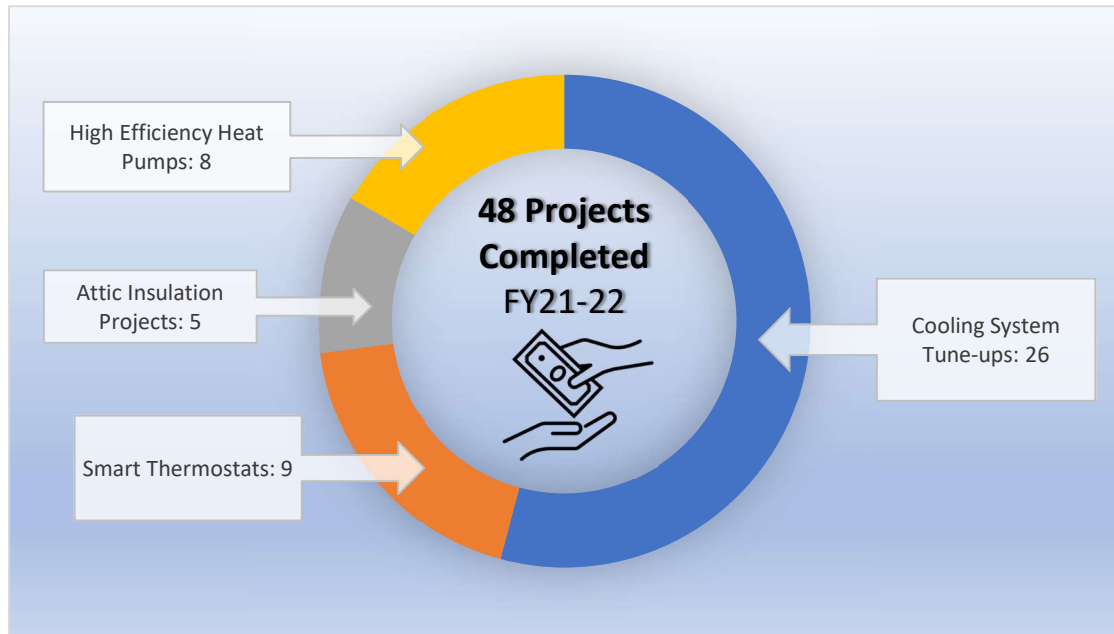


Figure VIII-5

D. Historical Results – MEAN Communities

The 2021 DSM survey asked participants to provide actual or estimated savings resulting from the DSM programs in their communities, both in terms of demand and energy. The results are shown in the table below:

Region	Communities	Programs	Total Demand Savings (kW)	Total Energy Savings (kWh)
MISO	5	9	415	218,116
SPP	8	12	2,136	2,386,085
West	4	12	1,477	31,052

Figure VIII-6

E. Continuing DSM Programs

1. MEAN Programs

The following established MEAN DSM programs will be continued as part of MEAN's overall resource portfolio:

- **Commercial LED Lighting Program:** The MEAN Board has approved the continuance of the LED Lighting program through FY22-23 with a budget of \$80,000. With the decrease in the cost of LED lighting materials, incentive amounts by lighting efficiency measure and new wattage were decreased in accordance with industry standards. With the potential additional funds available in this program category, efforts are being made to develop additional

programs for commercial customers of MEAN participant communities including for Cooling System Tune-Ups as well as Heat Pump Water Heaters.

- Residential Energy Efficiency Programs: Incentives available for Cooling System Tune-Ups, Attic Insulation, High Efficiency Heat Pumps and Smart Thermostat Installations will continue to be offered to MEAN participants. A budget of \$25,000 for FY22-23 has been authorized by the Board to be distributed across the various project categories.
- Infrared Energy Audits: This service identifies abnormal heat in electrical and mechanical systems, helps predict equipment trouble and revenue loss. These valuable audits are beneficial to large account customers to lower their electricity costs and increase system reliability in order to maximize their bottom line.
- Energy Audits: Staff assists MEAN bulk power participants by performing an energy audit, recommending steps to improve energy efficiency for commercial/industrial customers (upon request).
- In addition to paying American Public Power Association (APPA dues), MEAN also pays 100% of the Demonstration of Energy & Efficiency Developments (DEED) dues for all MEAN Service Schedule M and K/K-1 Participants. Payment of dues on behalf of Participants by MEAN ensures each community receives access to the benefits of APPA membership.
- Member Exclusive Education Sessions: Workshops, retreats and forums are held throughout the year covering a variety of topics geared for member communities and their development. Sessions are hosted and planned by NMPP on a rotating basis and can be held in any participant community in accordance with interest and requests.
 - Past workshops topics include generation, load management, smart grid operations, net metering, energy efficiency, economic development, and employee retention and recruitment.
- NMPP Energy News Subscription: All members of NMPP receive the monthly NMPP Energy News newsletter. The newsletter covers news pertinent to the membership of NMPP with topics featured including energy efficiency, utility rates, legislative and regulatory updates and mutual aid. The newsletter also includes news about other members and updates on the NMPP Energy entities.

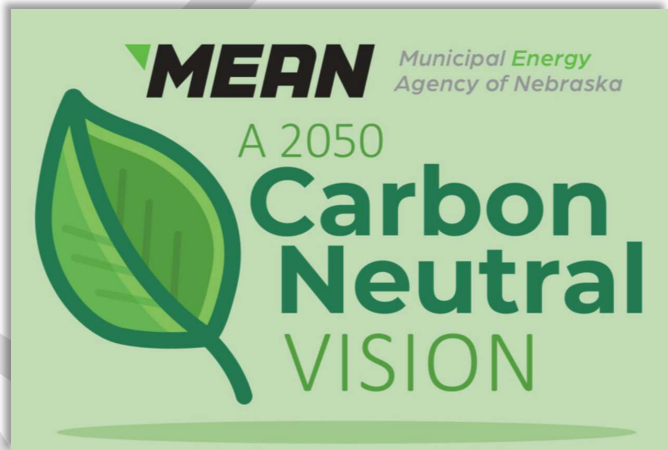
2. Community Programs

The participant DSM survey did not indicate any intentions to discontinue any existing DSM programs administered within MEAN communities. Therefore, it is assumed that all existing programs will continue into the future. The future rate of growth in demand and energy savings is unknown. Some of the programs are newly implemented and therefore do not have estimates of savings. Still others are not separately metered, and therefore do not have exact savings measured. As more data is collected and communities continue to invest in metering systems, it is expected that the actual savings attributable to these programs will be further quantified in future years.

IX. Renewable and Carbon-Free Energy Resources

A. MEAN's 2050 Vision

In 2020, the Board approved a resolution laying out a vision to work toward transitioning MEAN's wholesale power resource portfolio to achieve carbon neutrality by 2050 through the elimination of carbon emissions or balancing emissions with carbon removal through carbon offset mechanisms. The resolution authorizes MEAN's staff to work collaboratively with the MEAN Power Supply Committee to develop policies around resource planning, portfolio optimization and emissions reduction to support future actions to achieve the 2050 carbon neutral goal. The formation of the plan will be initiated in MEAN's 2022 Integrated Resource Plan. MEAN's current resource capacity portfolio consists of 49 percent non-carbon resources from projects around the region, including Total Requirements Participant allocations of federal hydropower from WAPA. MEAN's actual energy generation from carbon free resources in FY20-21 was over 50% of the total. MEAN will have opportunities in the coming years to transition toward higher levels of carbon neutrality as power purchase agreement contracts expire and capital debt is paid on its shared ownership of power resources with other utilities.



Achieving MEAN's 2050 vision will require industry advancements and technological innovations, particularly those that add stability to the grid and offset the intermittent production of renewable energy such as from wind and solar resources. Other needed advancements include the development of dispatchable renewable baseload energy resources, the increased availability of economical energy storage solutions and affordable deployment of carbon capture, utilization and storage technologies. Potential solutions are not yet viable on a utility scale or economically feasible, and emerging technologies must still be developed in order for MEAN to meet its carbon neutral goal.

B. Local Energy Goals

To determine how specific local energy goals correspond with MEAN's 2050 Vision, Participants were asked a number of related questions in the January 2021 online survey. Of the respondents, one third are interested in increasing their community's renewable portfolio. However, of those that indicated an interest in increasing their proportion of renewable energy, less than 25% are willing to pay a higher wholesale rate for lower emissions in their portfolio. When asked if the respondent's community would like to increase the carbon-neutral energy in their resource mix at an accelerated rate or concurrent with MEAN's progress toward the 2050 Vision of carbon neutrality, the overwhelming majority prefer to progress at the same rate as the overall organization.

The disparity in these results supports MEAN's establishment of the Wind Pool and the Landfill Gas Pool, allowing Participants to subscribe for certain amounts of power supply from wind and landfill gas resources to control the level of emissions in their power supply portfolio. On an annual basis,

MEAN sends a document to each Participant detailing the community’s resource mix for the previous year in terms of energy generation to serve their load. This allows each Participant to make informed decisions about MEAN’s total portfolio and their individual resource mix as well.

Survey results are shown in *Figures IX-1 through IX-4*.

Has your community established a local renewable or carbon-free energy target (separate from MEAN’s 2050 Vision)?

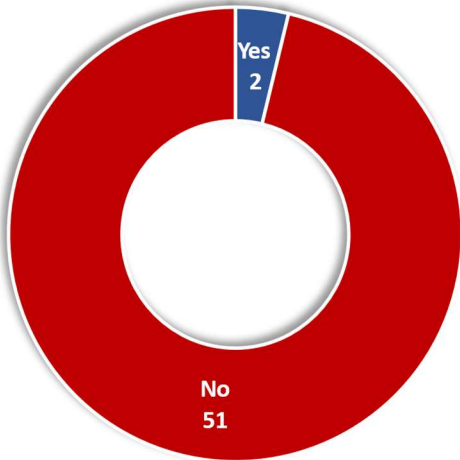


Figure IX-1

Is your community interested in increasing the amount of carbon-free energy in your resource mix?

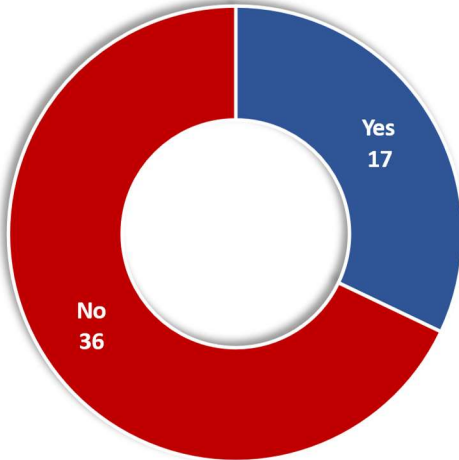


Figure IX-2

If yes, would your community be willing to pay a higher wholesale price for an increase in carbon-free energy?

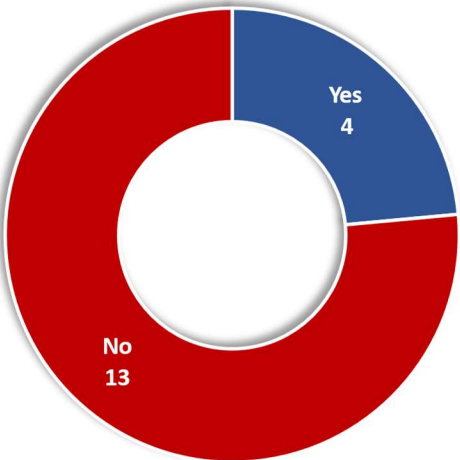


Figure IX-3

Does your community prefer to increase the carbon-neutral portion of your resource mix concurrently with MEAN’s overall percentage, or to increase the carbon-neutral portion of your resource mix on a more accelerated schedule?

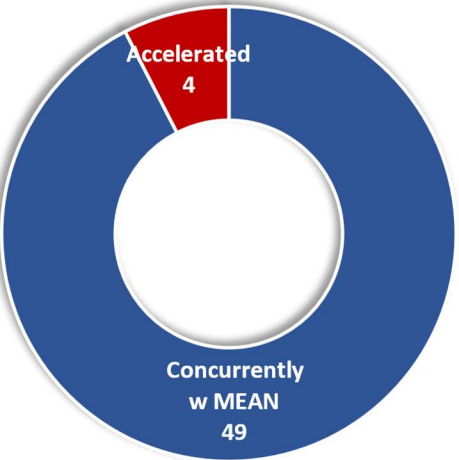


Figure IX-4

C. Interim Carbon Goal

The renewable survey also explored the schedule of progress toward the 2050 Vision of carbon neutrality. Given MEAN's portfolio and the extent of our long-term resource contracts combined with the unpredictable future of environmental compliance requirements and economic and environmental dispatch, the intervening years are to be determined based on resource acquisitions and the performance of new assets. As part of the January 2021 renewable survey, the members were asked whether MEAN should consider establishing an interim goal for a carbon-free percentage in our portfolio. Of the respondents, 65% answered in favor of an interim goal.

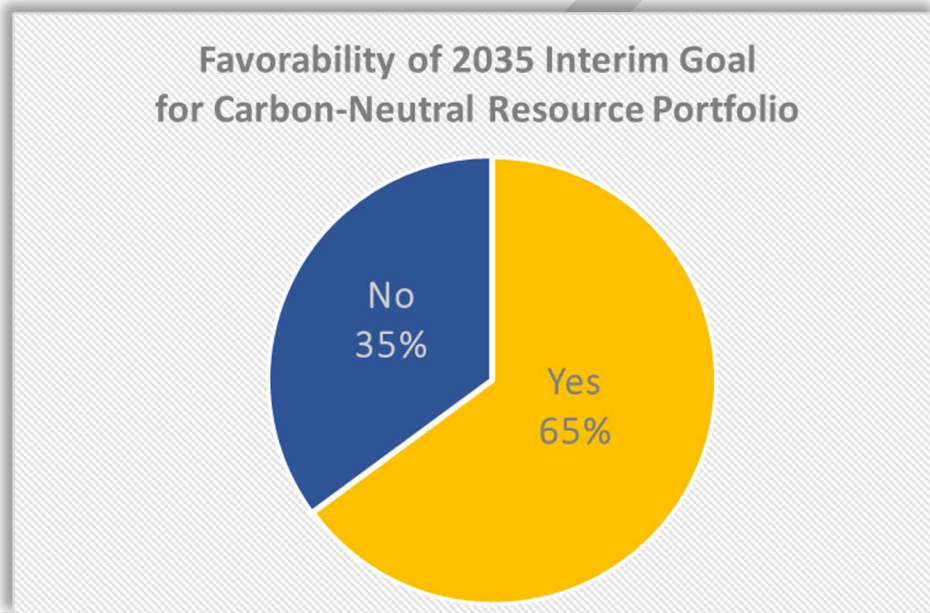


Figure IX-5

Of those in support of the interim goal, a follow up question asked for a suggested percentage to be achieved by 2035. The responses ranged from 25% to 100%, with an average of 61%.

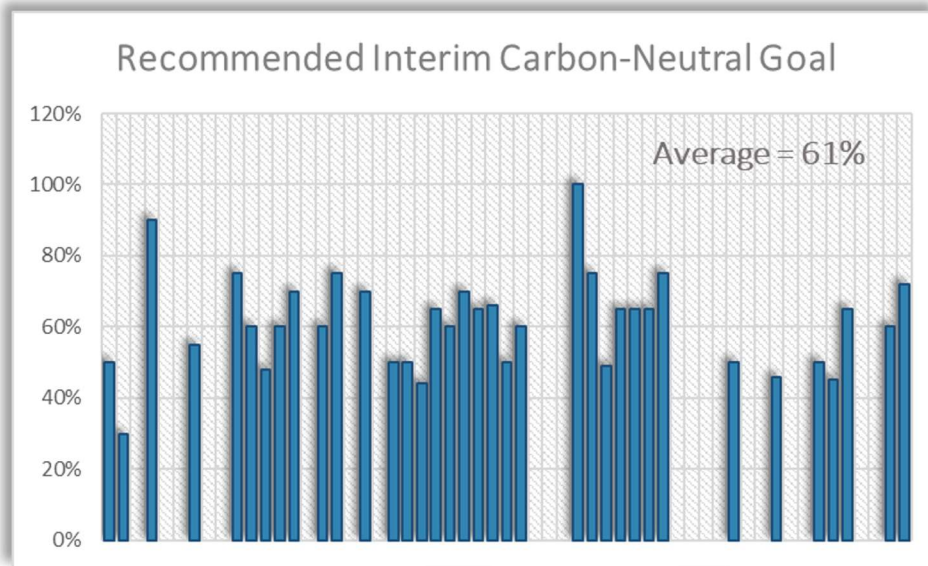


Figure IX-6

D. Existing Carbon-Free Resources

MEAN currently serves its total load obligation with the following carbon-free resources:

Resource	Nameplate Capacity
Kimball Wind Farm	30.0 MW
Shavano Falls Hydro	7.6 MW
Ridgway Hydro	4.0 MW
Reudi Hydro	4.5 MW
Ainsworth Wind	7.0 MW
Crofton Bluffs Wind	4.2 MW
Elkhorn Ridge Wind	8.0 MW
Laredo Ridge Wind	8.0 MW
Wessington Springs Wind	10.0 MW
WM Des Moines Landfill Gas	4.8 MW
Cooper Nuclear Station	26.0 MW
WAPA Allocations	124.7 MW
WAPA Displacement Agreement	61.9 MW

Figure IX-7

E. Carbon Free Resource Mix

As contract terms for these renewable assets expire, MEAN looks to replace the energy and capacity with carbon-free resources. As part of the 2050 Vision, MEAN aims to make resource acquisitions that only decrease the total carbon emissions of our portfolio.

The future resources considered for this resource planning analysis will be evaluated in part on their ability to decrease the carbon emissions in MEAN's current portfolio. Although environmental impact ranked 9th in MEAN's member survey of the importance of resource evaluation criteria, the

equivalent carbon emissions factor was an element of scoring in the Phase I supply side resource evaluation. Also factored into this evaluation was the sensitivity of resource options to a future carbon tax and future changes in environmental legislation, which largely correspond with emissions levels. Finally, the performance of each future resource is calculated in terms of the change in carbon intensity of the MEAN resource portfolio.

While attempting to formulate a future resource portfolio that reduces MEAN's carbon emissions, the goals of reliability and resource adequacy cannot be abandoned.

F. Renewable Resource Costs/Incentives

Certain investment or production incentive exist to subsidize the generation and investment in renewable energy resources. In December of 2015, Congress extended the Investment Tax Credit ("ITC") for solar energy projects. This legislation allowed a federal tax credit of 30% of the capital invested in solar generation installed through 2019. The ITC decreased to 26% in 2020 and was scheduled to step down until 2022. In December 2020, Congress extended the ITC with a 26% credit for systems installed in 2020-2022 and 22% for systems installed in 2023. The ITC expires in 2024 unless extended again.

The Production Tax Credit ("PTC") for wind projects provides a ten year \$23/MWh credit for all wind generated energy for projects initiated in 2016. For projects that began construction in 2017, the PTC decreased to \$19/MWh and continued to decline for each year through the end of 2021 at \$15/MWh.

Recently, bills in Congress have proposed not only an extension for wind and solar tax credits, but also tax credits for carbon capture and energy storage.

As a tax-exempt entity, MEAN cannot claim tax credits for carbon-free energy generation. However, through power purchase agreements with developers, MEAN can obtain pricing that reflects these credits as calculated into the revenue requirements of the project. Credits are also being considered for energy storage, and state and local funding has recently been available for storage projects.

As a conservative approach, the Phase II analysis did not include any tax credits for energy resources. Due to the uncertainty of future policy that would extend or terminate existing credits for renewable resources and policy that may enact credits for other technologies, it would not be accurate to speculate on these values or their duration.

G. Resource Pools

To respond to the disparity in local goals for renewable or carbon-free energy, MEAN offers a Wind Pool and a Landfill Gas Pool where participants can elect to purchase specified amounts of those resources in terms of energy from MEAN's portfolio. This allows individual communities to control their own resource mix. MEAN communicates annually to participants to inform them of their actual energy mix for the prior year. The rates for these pools are established by the Board of Directors in accordance with policy.

Currently, the Wind Pool is fully subscribed with all MWh allocated to participants per contract. The Landfill Gas Pool was 34.2% subscribed in 2021, with approximately 25,760 MWh available for contract. Per current MEAN policy, the rates for energy from the two renewable pools is based on actual costs paid for these resources.

As MEAN expands its portfolio in terms of carbon-free resources, the resource pools and the energy rates for these resources may evolve accordingly. The pools may need to expand to accommodate the acquisition of future carbon free resources and varying demand for carbon free energy from individual MEAN member communities. MEAN will continue to strive to offer increased levels of carbon-free energy to participants while also maintaining reliability and low rates.

H. Social Cost of Carbon vs. Carbon Tax

The concept of the social cost of carbon is an attempt to put a financial value on the current and future impact of systems and facilities that emit carbon. In addition, some formulations also calculate a monetary benefit from emissions reductions.

In lieu of a social cost of carbon, which has yet to be precisely or consistently quantified, the IRP model uses a carbon tax to allocate a cost to resources that emit carbon in a manner that is easily integrated with the chosen revenue requirement metric and takes into account the impacts on the market as a whole in addition to the impacts to individual resources.

In the market pricing projections used in the Phase II modeling of candidate portfolios, pricing scenarios 7, 8, and 9 include various forms of a carbon emissions tax. Scenarios 7 and 8 assume a CO₂ Limit in the future. These Scenarios then compare the calculated emissions of the projected resource mix for the region to the projected allowances under the carbon limit. This determines the carbon tax, which varies by year according to the actual carbon exceeding the projected allowance limit. Scenario 9, however, simply applies a linearly escalating carbon tax rate to all CO₂ emissions in all years of the model.

In these scenario calculations, MEAN applied this carbon tax to all carbon emissions from all resources, existing and future, in the portfolio. The carbon tax ranges from \$3.00 to \$105.00 per ton with a 2029 start in Scenario 7, \$2.00 to \$238.00 per ton with a delayed start in 2034 in Scenario 8, and \$16.00 to \$83.00 per ton for all years in Scenario 9.

X. Load and Resource Balance

A. Capacity/Demand Balance

Previous sections of this report have quantified the forecasted total load obligation that MEAN expects to serve in future years, in various future scenarios, as well as the capacity and energy available to MEAN for service of this load. To determine the timing and magnitude of MEAN's future resource needs, the annual peak demand must be compared to the resource capacity available during the peak and the total annual energy consumption must be compared against the expected and/or available generation of the portfolio's resources.

For the calculation of load and resource balance, resources will be quantified according to accredited capacity, or the maximum capacity that is expected to be available during the system peak load. For baseload and dispatchable resources, the accredited capacity is most typically equal to the nameplate capacity. However, intermittent or non-dispatchable resources cannot be depended on to supply nameplate capacity at any given hour but are subject to the availability of irregular occurrences such as wind and solar irradiance. SPP has provided an equation to determine the accredited capacity of such resources, which MEAN utilizes in this analysis. SPP and MISO continue to study this subject and offer annual updates to the accreditation process.

SPP currently uses the Effective Load Carrying Capability (ELCC) method for calculating accredited capacity of renewable resources. As SPP describes it: "Using ELCC practices, a facility's accreditation is a fractional probabilistic measure of the facility's nameplate rating that can be relied on to serve load. ELCC can express the value that generation contributes to a system as penetration of the specific resource type increases." This is a phenomenon particular to intermittent resources. As more of the resource type is installed, the less value each resource of that type contributes to the resource adequacy of the system, and therefore the lower the ELCC of all resources of that type.

The peak demand as shown in the load and resource balance is the total service obligation, which includes not only the forecasted peak load, but also the required reserve margin and the expected transmission losses. Resource capability in terms of capacity and energy is classified by fuel type. Behind-the-Meter-Generation ("BTMG") designates Participant Owned Generation.

1. MEAN System

The graph in *Figure X-1* shows the balance of peak demand and resource capacity for MEAN's entire footprint. Available capacity is sufficient to serve load until 2024. At that point, MEAN has a slowly growing resource need into the future.

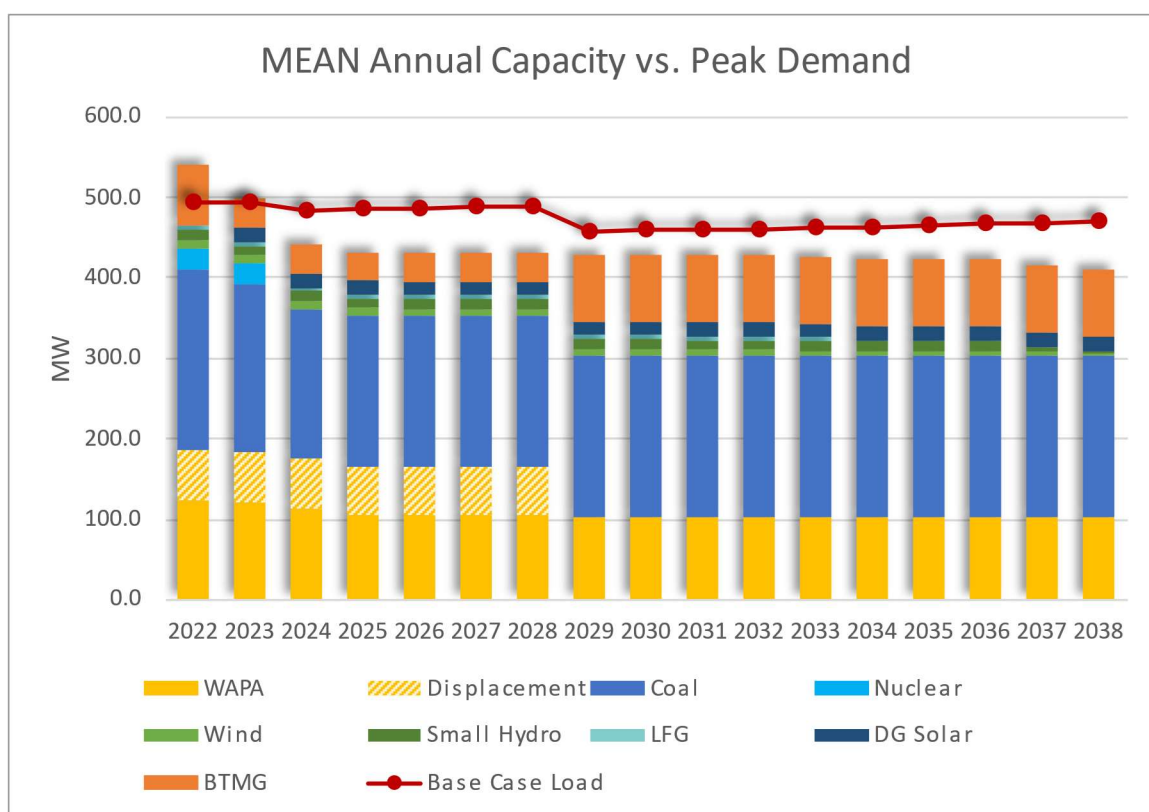


Figure X-1

However, since MEAN serves load and designates resources in each individual region, the load and resource balance must be divided by region to determine the course of future resource acquisition.

2. West Region

The graph in *Figure X-2* shows the peak demand and resource capacity balance for the west region. The major changes on the load side occur in 2023 with the expiration of the limited term contracts with Wray and Holyoke and in 2029 with the expiration of the Glenwood Springs service contract.

On the resource side, the Black Hills PPA terminates in 2023, and the WAPA Displacement contract is set to expire in June of 2029. Then several wind PPAs expire late in the 15-year time period.

The west region is resource adequate until 2029. At that point, the region has a deficit of 21.9% of the load obligation. This continues through the remainder of the study period.

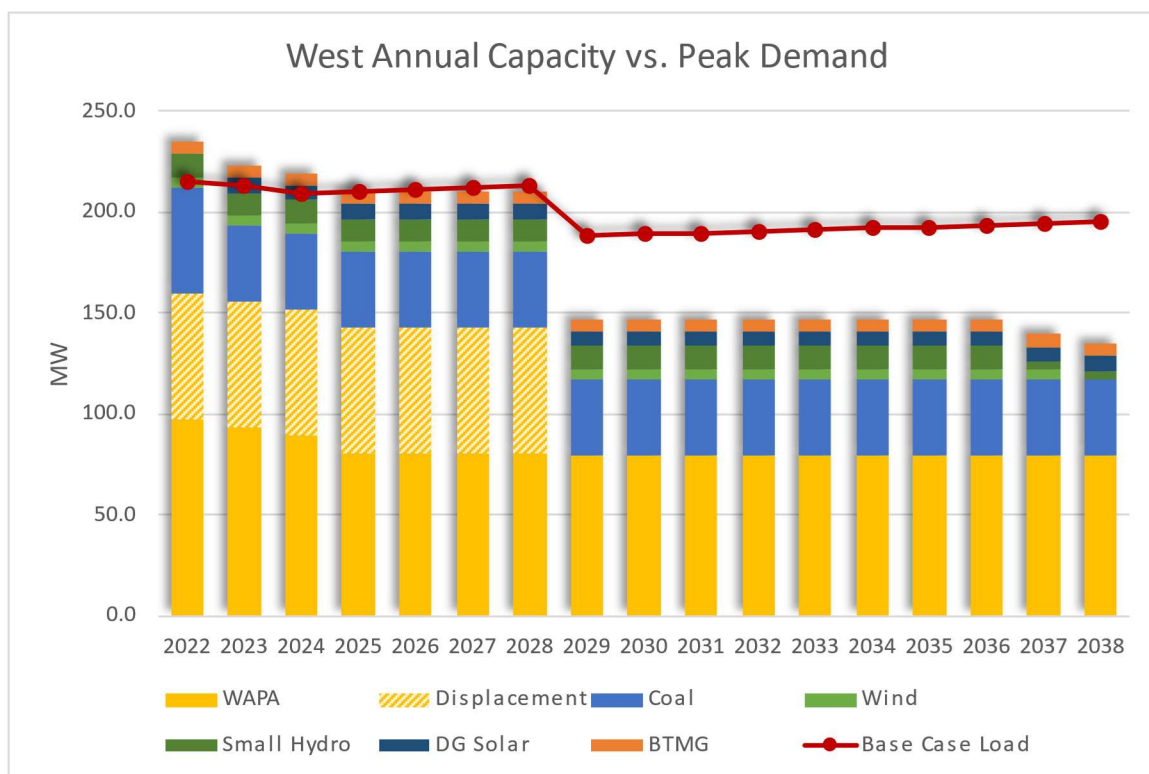


Figure X-2

3. SPP Region

The graph in *Figure X-3* illustrates the peak demand and resource capacity balance for SPP. In 2022, capacity remains adequate to cover the service obligation. However, with the termination in 2023 of the Marketing Agent Arrangement with Indianola Municipal Utilities (“IMU”) and Waverly Utilities (“WU”) contracting excess member owned generation, SPP capacity is no longer sufficient to meet the load. The termination of the NPPD MUP in 2023 is evident in the further reduction of resource levels after that year. In 2029, the WAPA Displacement Agreement ends, allowing the capacity dedicated to that contract to be again applied to MEAN’s load. Therefore, the SPP system has no further capacity needs after 2029.

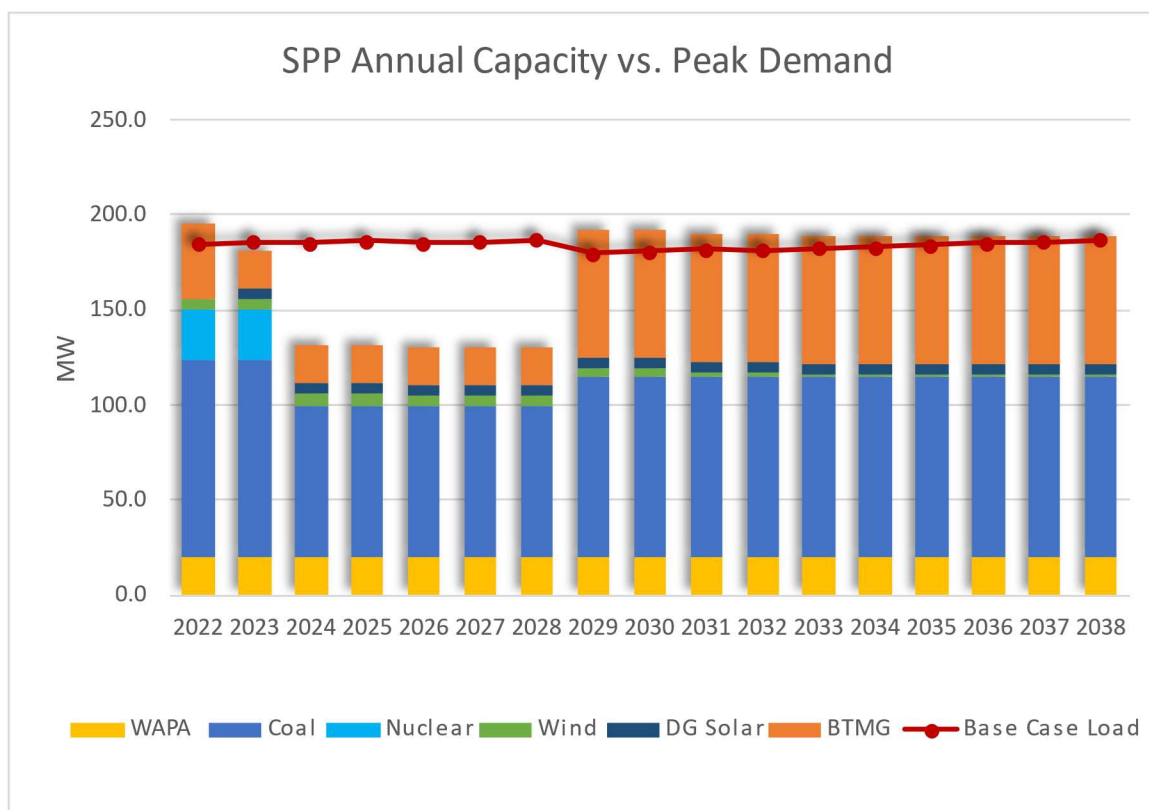


Figure X-3

4. MISO Region

Throughout the study period, MEAN has sufficient capacity in MISO, as shown in *Figure X-4*. There are very few changes in resources or load during this time. There is a slight decrease in load when the limited term contract with Lake View expires. Resource levels are constant, with the exception of the end of the Marketing Agent Arrangement with IMU and WU that ends following the peak season of 2023 and the end of the Landfill Gas PPA in 2034. There is a very minor resource deficiency in MISO beginning in 2034.

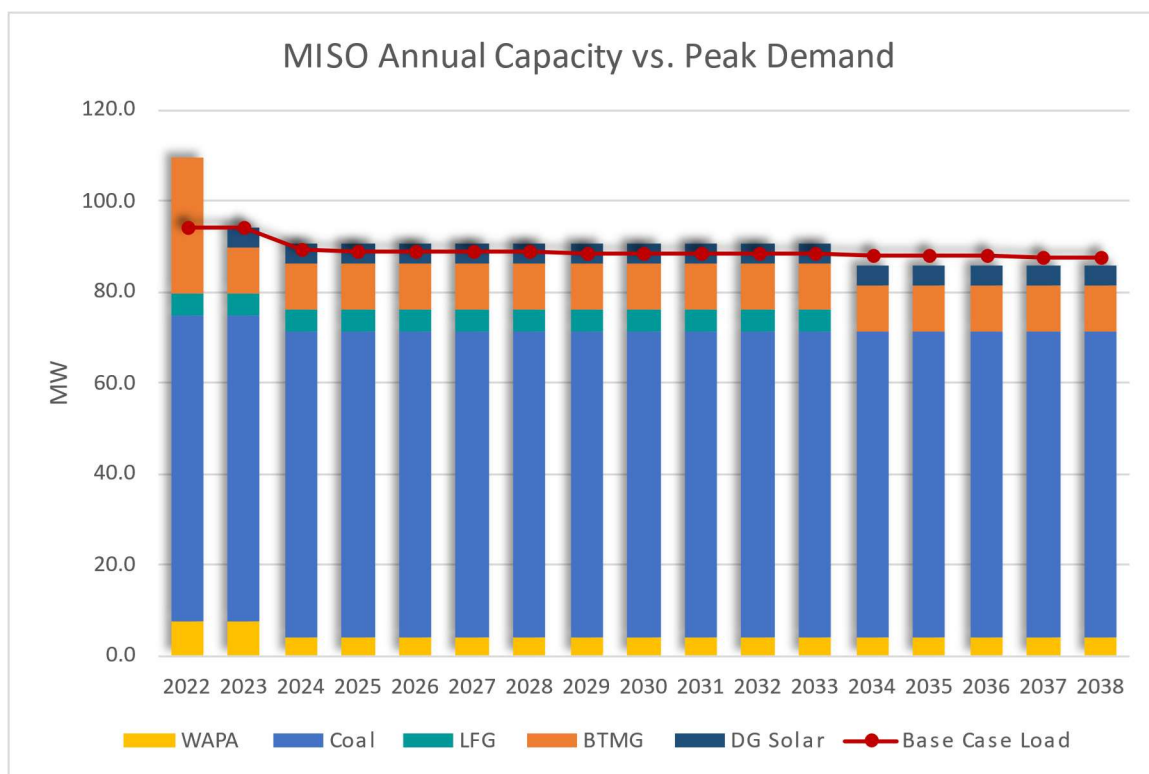


Figure X-4

B. Monthly Balance

The graphs in *Figures X-5 through X-7* show the regional load and resource capability balance on a monthly basis to illustrate the periodic change in the balance. *Figure X-8* shows the monthly balance for the MEAN system as a whole.

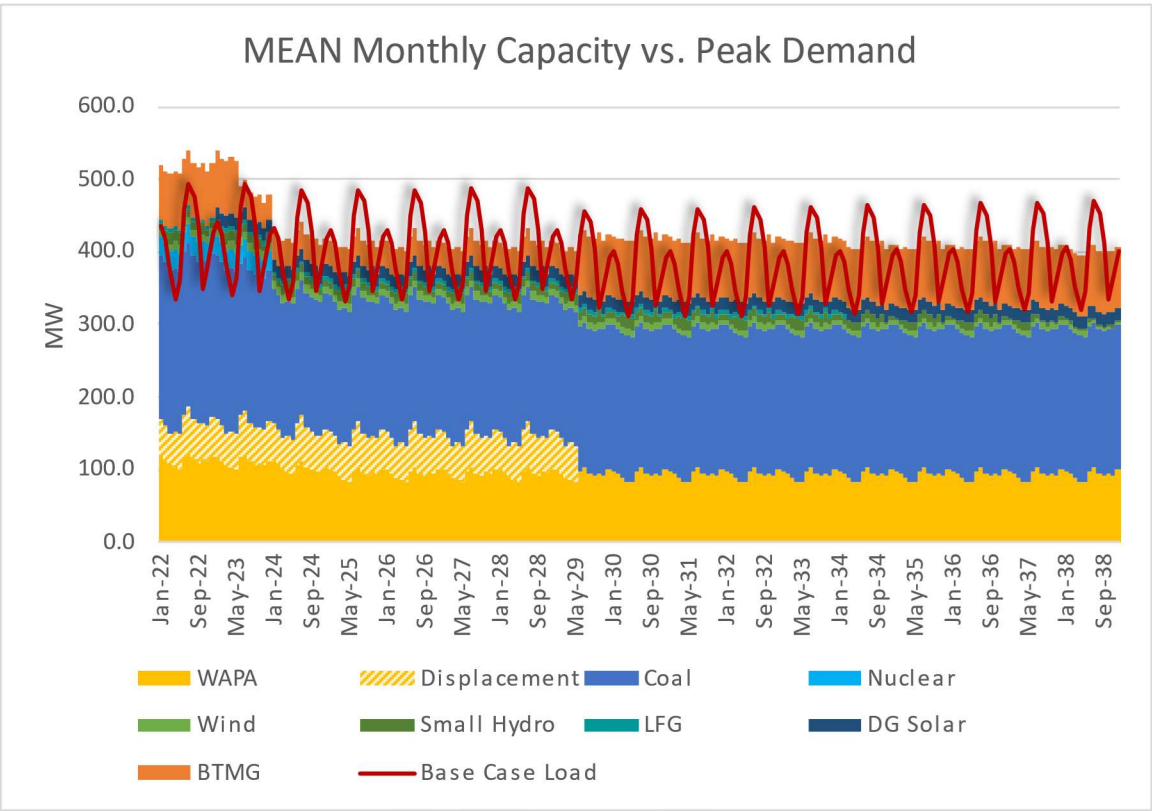


Figure X-5

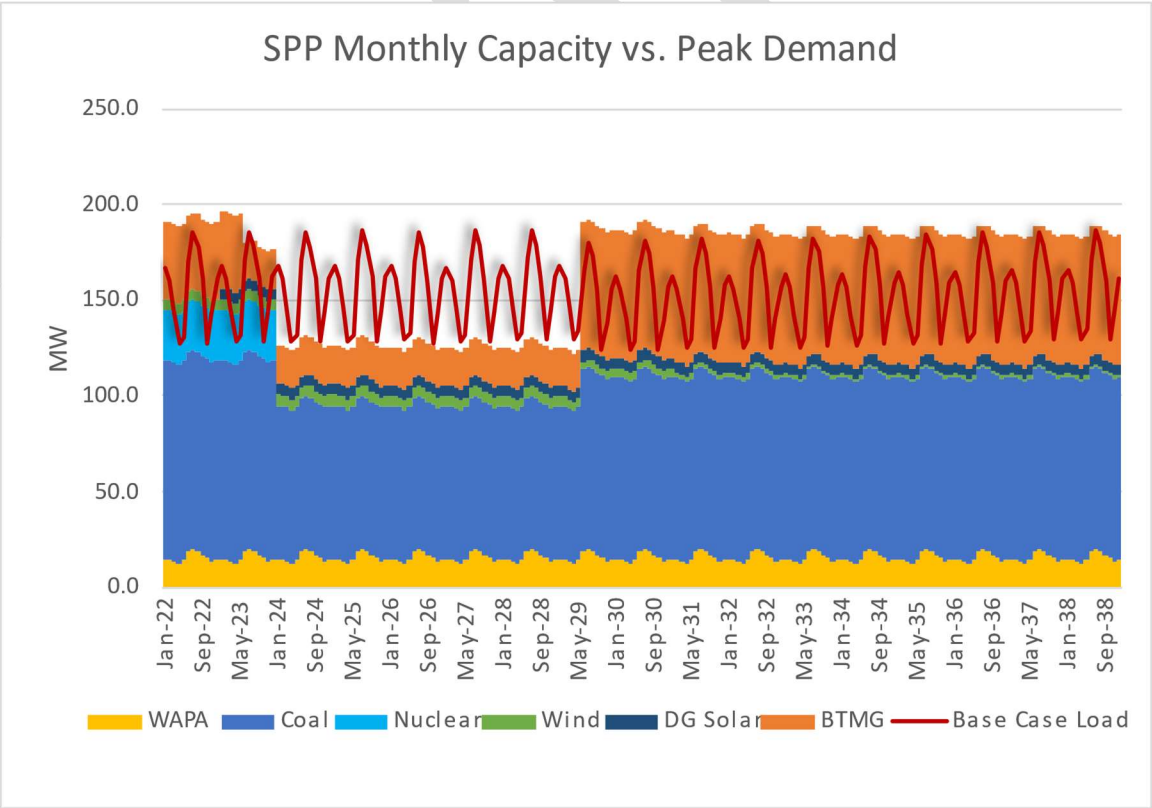


Figure X-6

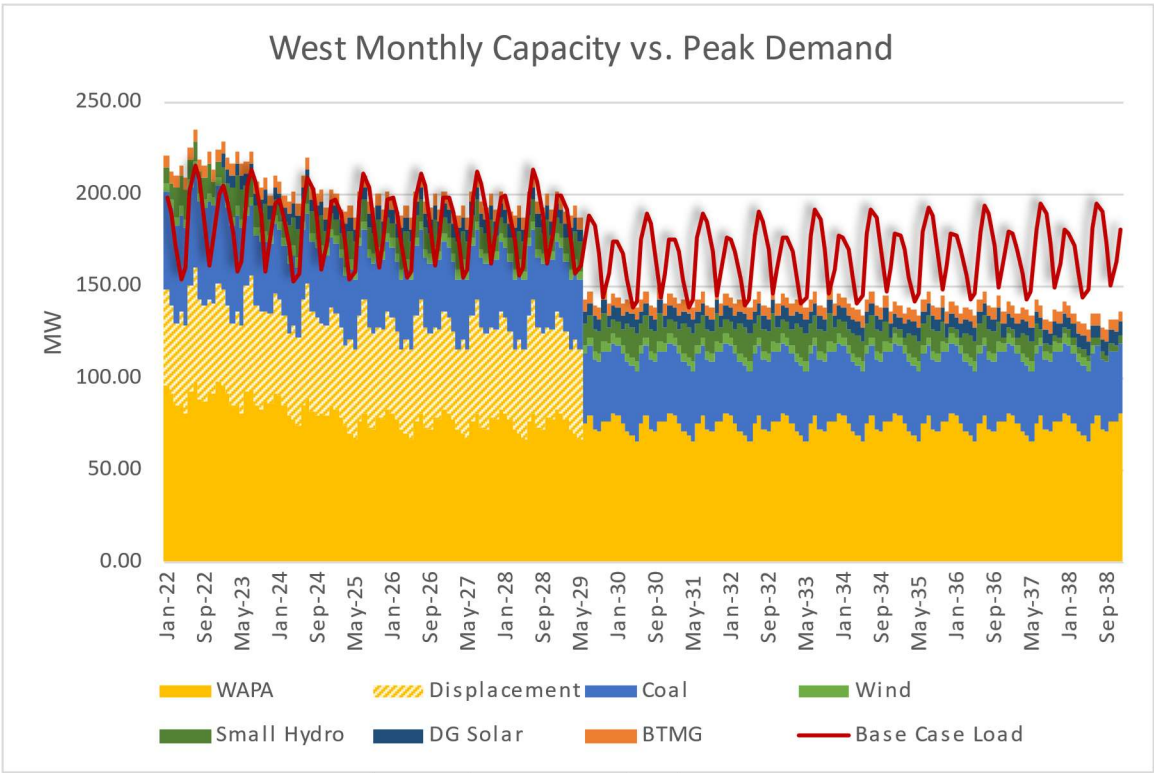


Figure X-7

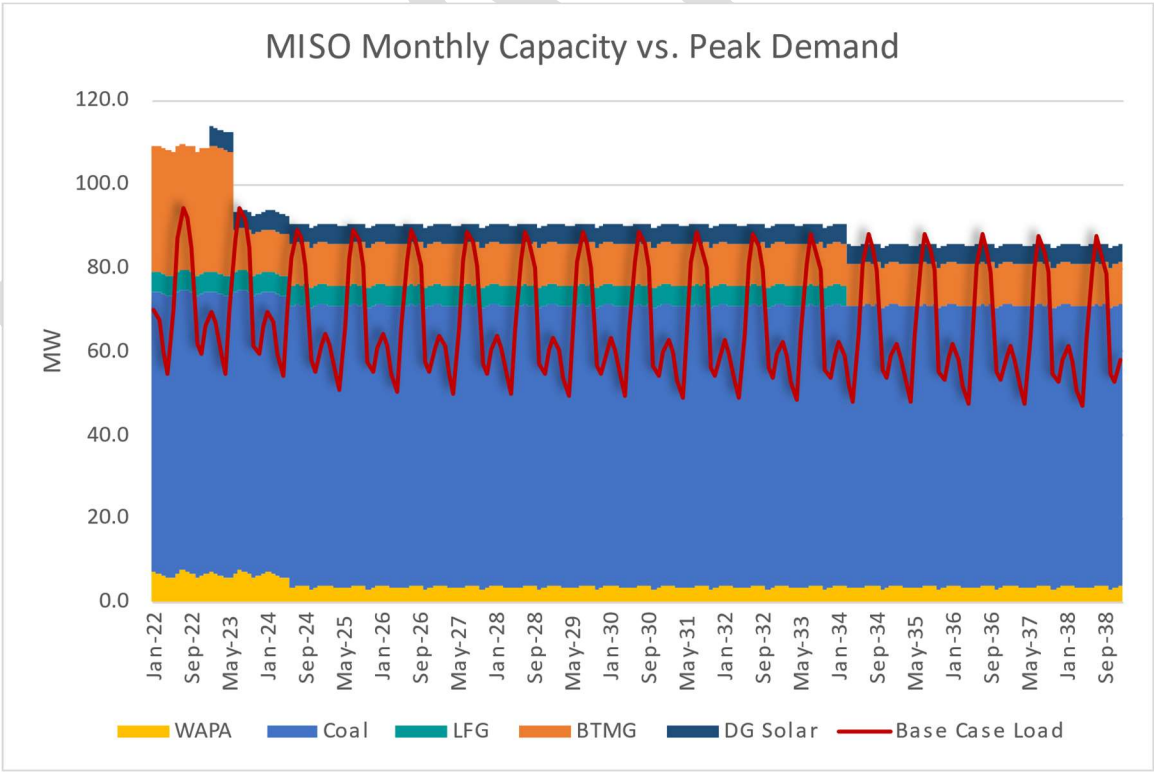


Figure X-8

C. Energy/Load Balance

When showing future energy output of MEAN resources for purposes of quantifying the balance of load and capability, expectations are based on total unit capability as well as historical operation and energy production. Depending on market conditions, real load, unit maintenance, and fuel pricing, actual production can vary from the predicted values.

1. MEAN System

The total picture of MEAN's total energy balance begins with an energy deficit in 2029 of approximately 16% of load, which grows to a 27% deficit in 2038.

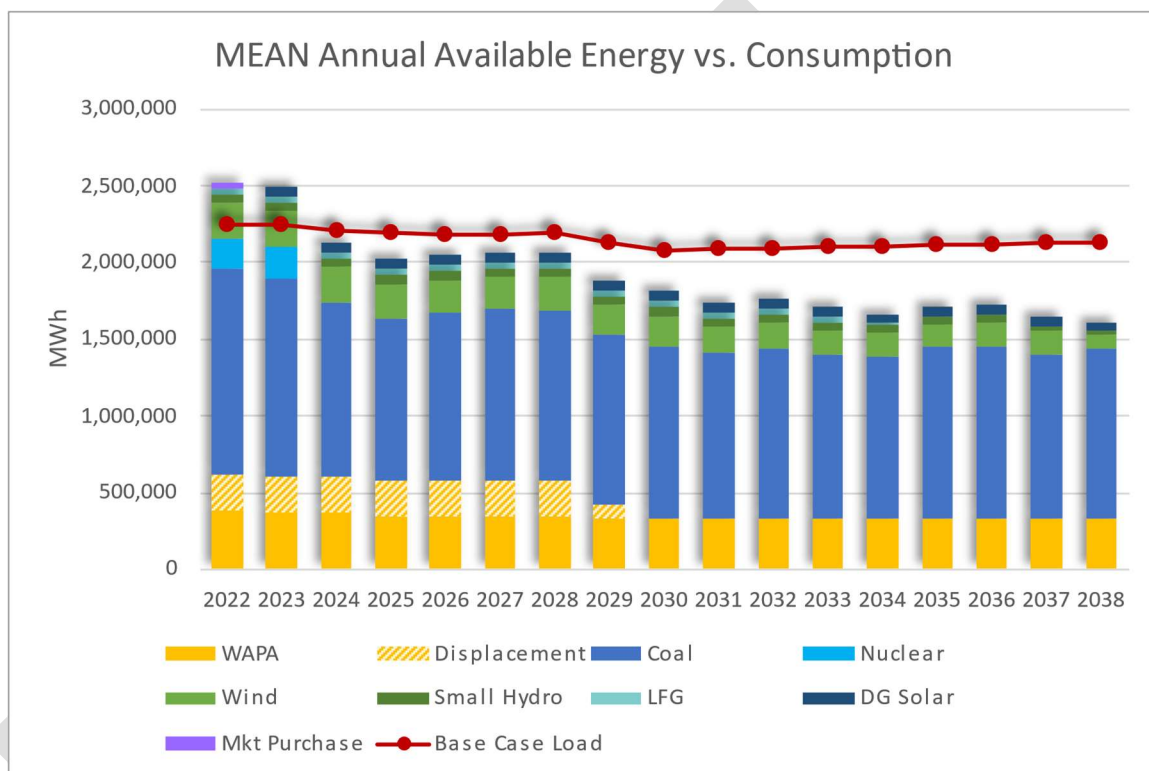


Figure X-9

However, as noted previously, MEAN serves load and designates resources per region, and therefore the level of energy generation in comparison to load must be analyzed for each region.

2. West Region

In the west, an annual energy deficit of 18% begins immediately in 2023 with the expiration of the Black Hills PPA and grows larger to 37% in 2029 when the WAPA Displacement Agreement ends. *Figure X-10* shows the long-term balance.

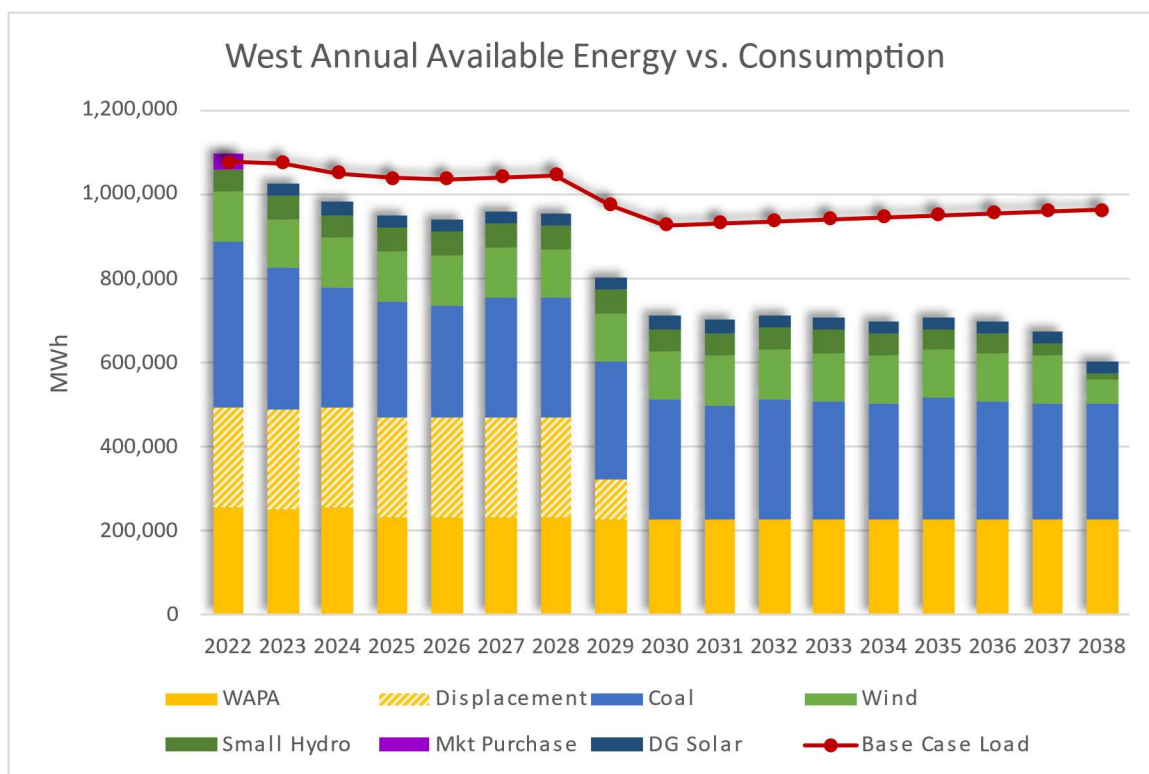


Figure X-10

3. SPP Region

Resource generation in SPP is sufficient to cover load until the expiration of the NPPD MUP at the end of 2023. At that point, the region has a 23% energy deficit that grows to 30% in 2038. The end of the WAPA Displacement that returns the capacity of the behind-the-meter generation to MEAN's portfolio does not result in additional energy, so SPP continues to have an energy deficit even when capacity adequate. The long-term energy balance for SPP is shown in *Figure X-11*.

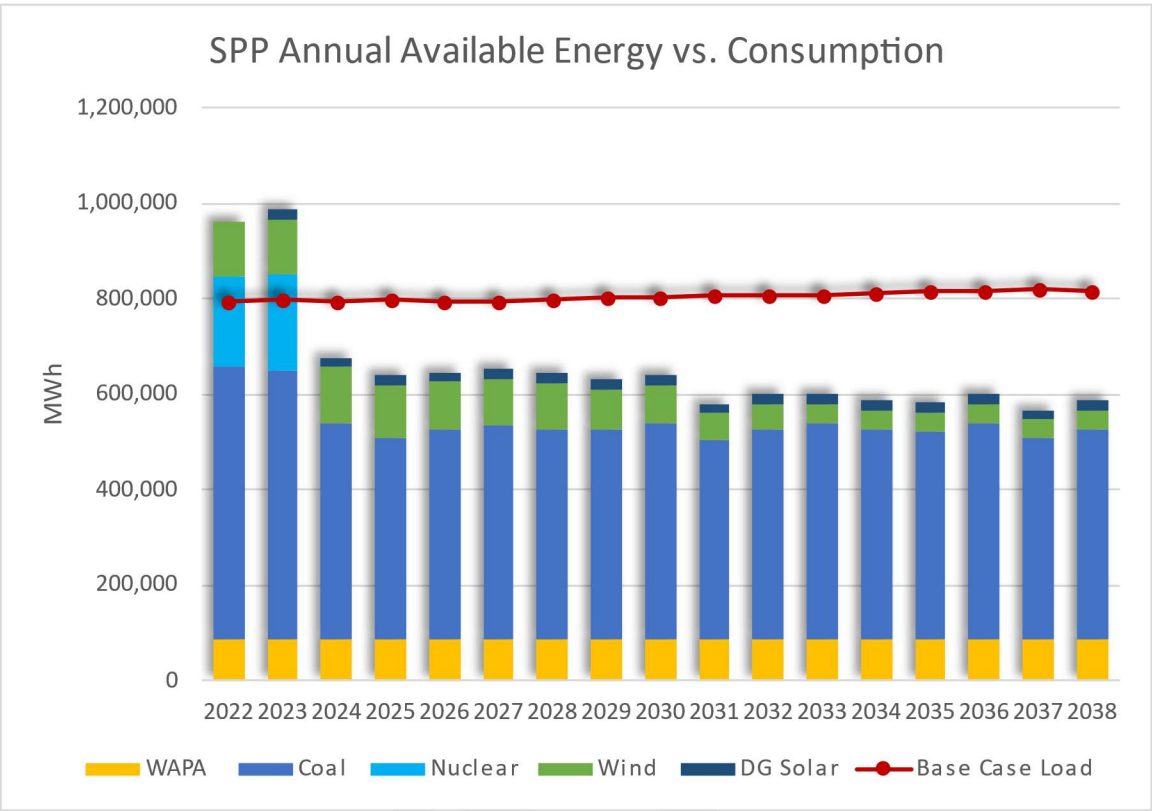


Figure X-11

4. MISO Region

Throughout the entirety of the study period, the MISO region is long on energy with no resource needs in terms of energy. As in the other regions, the coal resources in MISO have been historically operated at high capacity factors, while the average participant load factor in MISO is 48%. This balance is illustrated in *Figure X-12*.

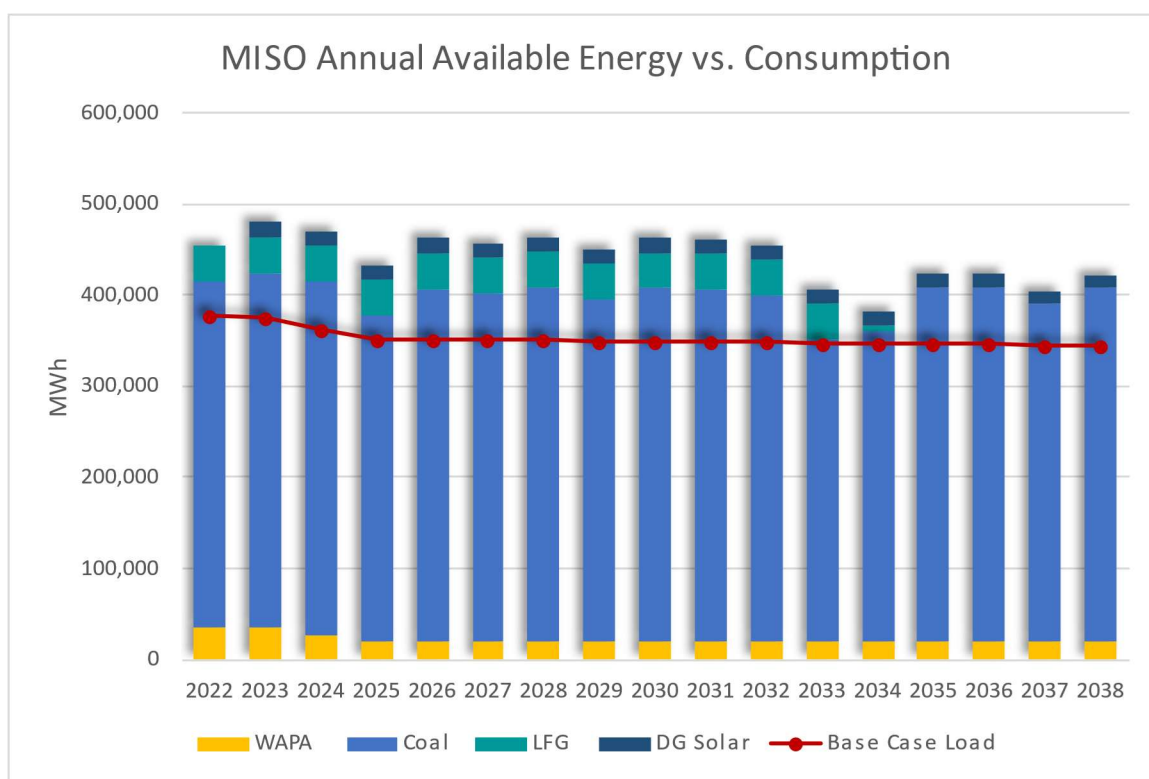


Figure X-12

D. Next Anticipated Resource Addition

It is important to clearly identify MEAN's future resource needs in terms of timing and scale in order to move forward with an evaluation to select the preferred resource portfolio. *Figure X-13* summarizes MEAN's total future capacity needs.

MEAN's need for additional capacity begins in 2024 with a capacity deficit that lasts the duration of the study period and increases throughout. In total, MEAN has a resource need of approximately 55 MW starting in 2024 which increases to a maximum resource need of 78 MW in 2028 before reducing to 43 MW the following year and then growing steadily to 65 MW in 2038.

Assigning the capacity needs into regional resource deficits, SPP has a need for approximately 55 MW of capacity from 2024 to 2028. The end of the WAPA Displacement Agreement eliminates the need for capacity in SPP in 2029. The West region first sees a capacity deficit of approximately 10 MW in 2024, which increases sharply to 45 MW in 2029 and increases throughout the remainder of the study period to 65 MW in 2038. MISO has a very minor capacity deficit of less than 5 MW from 2034 to 2038.

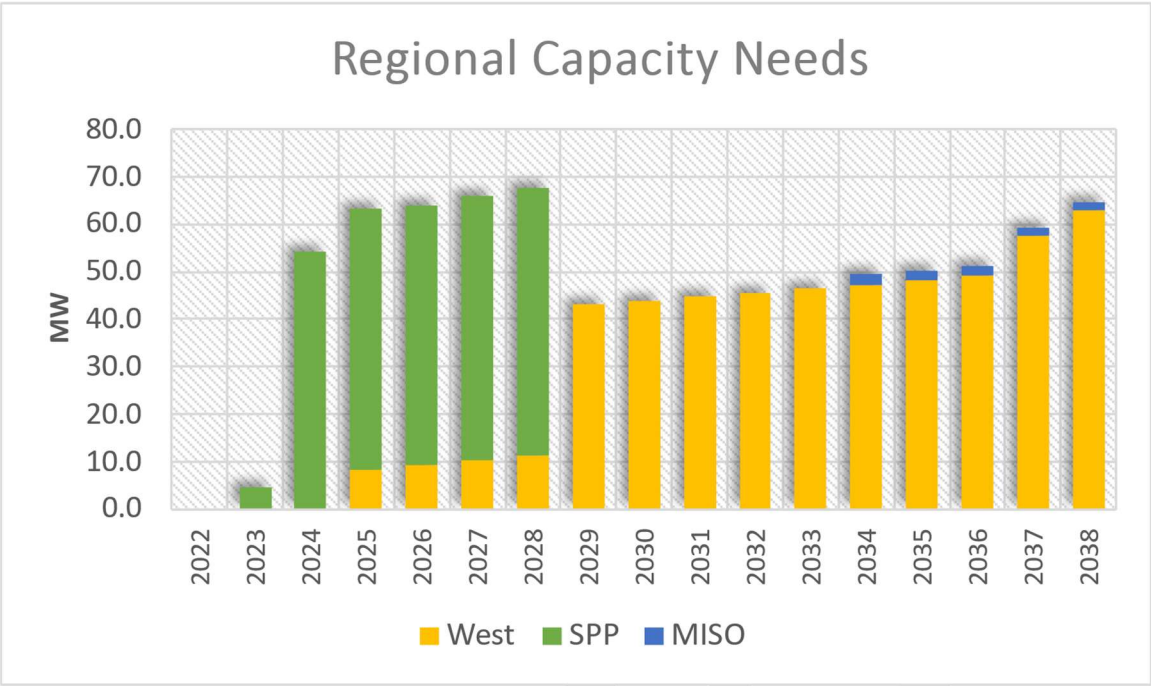


Figure X-13

The regional energy needs look very different. Both SPP and the West have an energy deficit from 2024 until 2038. SPP's energy need starts at 118,000 MWh in 2024 and increases to 250,000 MWh in 2038. In the West, resources are needed to supply 46,000 MWh in 2024 and grow to 358,000 MWh in 2038. MISO has no energy needs in the future.

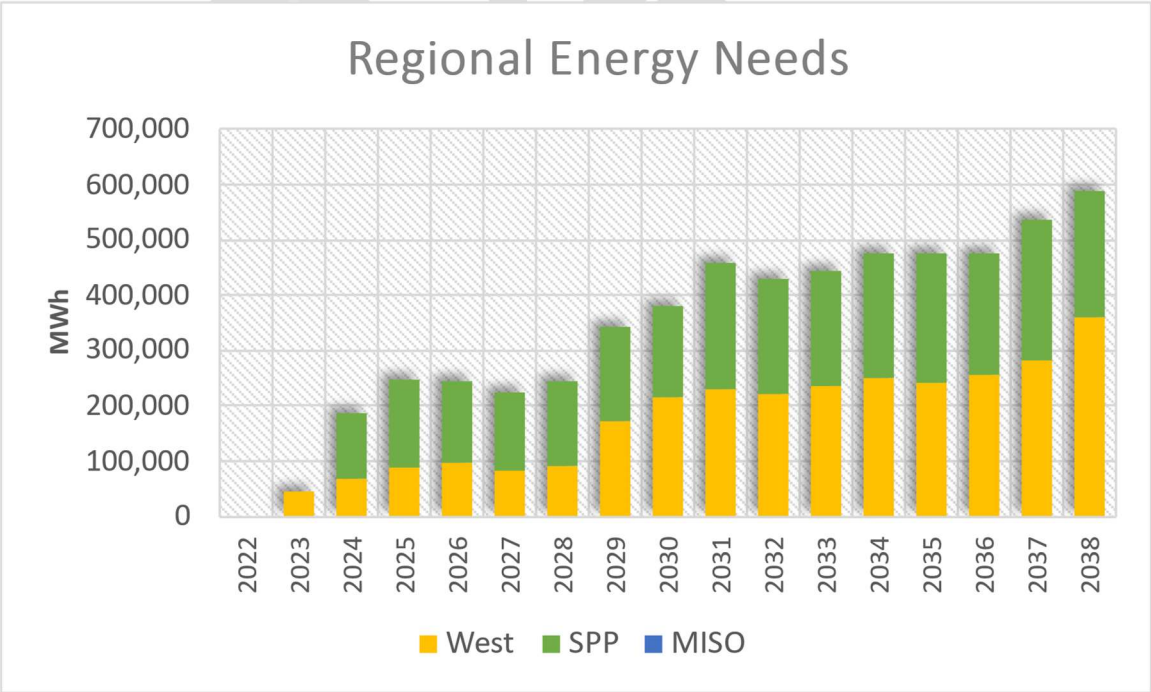


Figure X-14

XI. Transmission

MEAN is a transmission-dependent utility and receives transmission services provided by SPP, MISO and multiple transmission providers in the Western Interconnection. Transmission costs include network integration transmission service and point-to-point transmission service. Transmission costs also include the impact of auction revenue rights (“ARR”) and transmission congestion rights (“TCR”) in SPP and auction revenue rights and financial transmission rights (“FTR”) in MISO. These financial instruments were primarily designed to allow firm transmission customers the opportunity to offset price differences due to transmission congestion costs between resources and loads.

MEAN has also contracted to collect payments for transmission service purchased on behalf of certain Participants and remits these payments to the respective providers. Since MEAN is only acting as an agent, these amounts are not reflected as revenue or expense in MEAN’s financial statements.

A. SPP and MISO

SPP and MISO each have integrated, regional electrical transmission systems and facilitate a regional wholesale marketplace. Network and point-to-point transmission service agreements provide MEAN with sufficient access to transmission facilities to deliver energy to the MEAN Participants, to participate in the SPP and MISO energy markets, and to sell excess generation and purchase replacement energy when generation is not available or it is economically beneficial. These MISO and SPP agreements are valid as long as MEAN continues to be the power supplier for the loads in the MISO or SPP market, as applicable. MEAN also purchased a 50 MW point-to-point transmission path from MISO to SPP, which is used to transfer 40 MW of participant owned generation capacity from Indianola Municipal Utilities and Waverly Utilities contracted under the Marketing Agent Agreement. This transmission agreement expires in 2033.

MEAN has experienced significant increases in transmission costs since it began participating in the SPP EIS market, which transitioned into SPP’s IM in 2014. Such increased transmission costs are the result of transmission congestion caused by the increased dispatch of generation resources in newly integrated balancing areas, which raises the price to serve load, and increased transmission expansion in response to congestion. The increased costs are exacerbated by the fact that MEAN, as a transmission dependent utility, does not receive revenues from transmission expansion projects that transmission owners (“TOs”) receive to offset the higher costs.

B. Black Hills Common Use System

MEAN has several agreements with Black Hills Power which provide for firm point-to-point transmission service and non-firm point-to-point transmission service for use in making deliveries to Participant loads, resource deliveries to adjacent transmission networks, as well as energy sales to other regional utilities. The agreements have varying expiration dates and have rollover provisions to optimize future resource arrangements.

C. WAPA-RMR and WAPA-CRCM

WAPA-RMR and WAPA-CRCM provide network integration transmission service to MEAN Participants connected to these two transmission systems under Contract Numbers 18-RMR-2964 and 12-RMR-2321. WAPA provides this service to MEAN under a transmission tariff that is not subject to FERC jurisdiction. MEAN's point-to-point transmission service agreements with WAPA-RMR permit electricity produced from the resources of Black Hills, Laramie River Station, and Kimball Wind to be moved to the transmission networks of other providers. These agreements continue through November 20, 2024. Due to a non-contiguous transmission system, MEAN also purchases a long-term point-to-point transmission reservation from WAPA-CRCM to move Ridgway generation across to the Tri-State network.

D. Tri-State and PSCo

MEAN contracts for network transmission service with Tri-State and PSCo to deliver WAPA Displacement, Laramie River Station, Shavano Falls, and Ridgway Hydro to its member load within these transmission providers' service territories. MEAN has agreements with Tri-State and PSCo for short-term point-to-point transmission service and non-firm point-to-point transmission service to facilitate deliveries to Participant loads and resource deliveries to adjacent transmission networks.

Recent transmission expansion planning by Tri-State and PSCo have indicated the potential for future transmission rate increases of its wholesale network transmission customers. Much of the planning has been designed to meet recently enacted Colorado legislature as well as anticipated renewable resource development along the Colorado front range.

E. Other

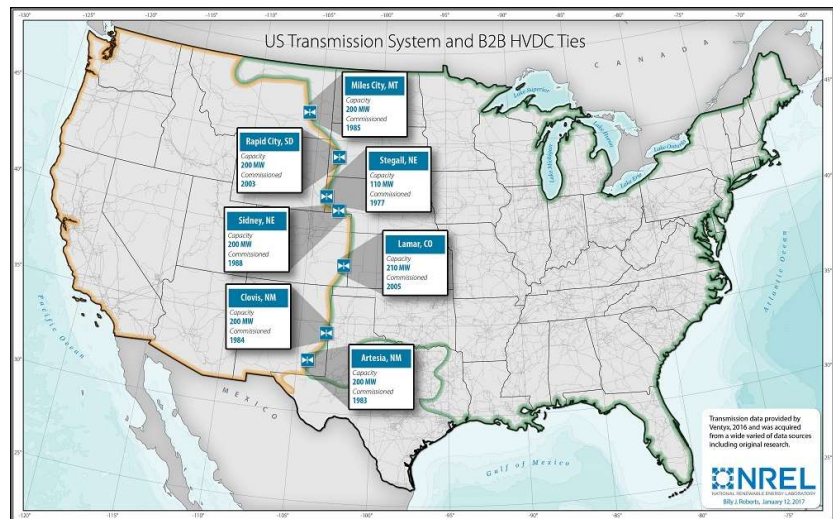
MEAN owns proportionate transmission rights in the transmission facilities associated with the Laramie River Station, WSEC 4, and WEC2 pursuant to the Laramie River Agreements, WSEC 4 Agreements, and the WEC2 Agreement, respectively.

F. DC Tie Rights

MEAN's load and resources in SPP and the West are connected at the Direct Current Ties ("DC Ties") that serve to integrate the eastern and western interconnects of the bulk electric system. Generators within each interconnect operate in the same phase and frequency. However, the frequencies do not match between the two interconnects, as the systems are too large and have too much inertia to be synchronous. The DC Ties allow a limited amount of power to flow back and forth between the systems, acting to absorb the variation in frequency. There are seven DC Ties in the US, three of which lie in MEAN's footprint.

MEAN has recently requested rights to transfer energy from east to west across the DC Tie at the Sidney Converter Station. MEAN's request under study would grant rights to transfer 34 MW beginning in 2024. A request has been submitted to obtain additional rights when they become available in future years. This allows MEAN to expand the application of resources to load with the

ability to utilize SPP resources in the West. However, transmission across the DC Ties has associated costs, which have yet to be defined or quantified as the SPP West RTO is being developed. As such, MEAN cannot accurately model the costs of this optionality. The possibilities inherent in this transfer of power will be considered in the ultimate process of resource acquisition.



XII. Phase I Supply Side Resource Evaluation

A. Phase I Supply Side Evaluation Objectives

Phase I is a preliminary evaluation undertaken with the goal of examining a comprehensive list of supply side options and focusing this list down to fewer qualified options that prove to be feasible potential additions to the MEAN portfolio. The Phase I evaluation is in large part qualitative, directly reflective of Participant priorities, and based on simplified metrics. A more in-depth economic analysis is reserved for the qualified options in Phase II.

B. Phase I Supply Side Evaluation Process

Phase I begins with the identification of the full list of all supply side options to be considered. These include fossil-fueled resources, non-carbon resources, and storage resources.

A list of criteria on which these options will be evaluated is weighted by the MEAN participants as a way to determine the collective priorities. Each of the options is given a score for each criterion, and the score is weighted according to the ranking received from the participants.

The weighted scores are compared to arrive at the qualified options that will be the subject of the detailed economic analysis in Phase II.

C. Supply Side Options

Figure XII-1 displays the complete list followed by a simple description of the supply side options included in the Phase I evaluation for MEAN's future resource needs.

Supply-Side Resource Options	
Fossil Fuel	Natural Gas Combustion Turbine
	Natural Gas Combined Cycle*
	Reciprocating IC Engine
	Co-Fire (retrofit existing)
Carbon Neutral	Small Modular Nuclear
	Nuclear Large Scale
	Geothermal
	Biomass (100%)
	Landfill Gas/ MSW
	Hydropower
	Wind
	Utility Solar
	Community Solar
	Green Hydrogen
Storage	Fuel Cell
	Battery Storage
	Solar + Storage
	Pumped Hydropower

*with and without CCS

Figure XII-1

1. Natural Gas Combustion Turbine

This option describes a simple cycle combustion turbine fueled by natural gas. NGCT plants are available as conventional or advanced technologies. For the purposes of this evaluation, the average value was used. Various configurations and turbine classes are available. The heat rate of CT units is assumed for this analysis at 10,000 Btu/kWh. NGCT plants can be operated as peaking units with capacity factors expected around the 5% range, or as intermediate units with capacity factors around 48-50%. This option could be contracted as an ownership portion or a power purchase. Natural gas resources are highly flexible resources, enabling them to respond to changes in supply from intermittent resources.

2. Natural Gas Combined Cycle

This option includes power generation from a natural gas fueled combined cycle unit where the combination of a gas turbine and a steam turbine can produce up to 50% more electricity than a simple cycle plant. The waste heat from the combustion turbine is used in a heat recovery steam generator to create steam which is fed into a steam turbine to produce a second energy stream. The average heat rate of a combined cycle unit is 6,609 Btu/kWh. As the combined cycle is the most economic natural gas plant configuration, it is typically operated as an intermediate or baseload resource. Capacity factors can run from 48 to 87%. The NGCC option was considered with and without a CCS system. Natural gas resources are highly flexible resources, enabling them to respond to changes in supply from intermittent resources.

3. Reciprocating Internal Combustion Engine

The Reciprocating Internal Combustion Engine (RICE) option would install one or more diesel-fired units, similar to MEAN's existing member-owned behind-the-meter generation. RICE units must be equipped with catalytic emission control devices for compliance with NESHAP regulations. RICE plants can be operated as peaking or emergency resources as they are equipped with very rapid ramping capabilities and can have stable turndown at 20% of full load. The average capacity factor of a RICE unit in 2021 was 16% per EIA. MEAN's RICE units average less than 1% capacity factor. Typical heat rate of a new unit is 8,295 Btu/kWh. This type of unit has become increasingly valuable with continued penetration of renewables to respond to the fluctuations in output from these intermittent resources.

4. Co-Fire (New or Retrofit)

This option contemplates a new or existing plant that co-fires on coal and biomass. Using biomass as a partial substitute for coal has little impact on boiler efficiency but has significant environmental advantages and offers opportunities for financial savings and local benefits, depending on location. Retrofitting an existing coal boiler to burn biomass typically has a lower capital cost than construction of a new dedicated biomass-fired plant. The average heat rate of a new co-fired plant burning 10-15% biomass is 9,880 Btu/kWh, and that of a retrofitted unit is 10,740 Btu/kWh. The average capacity factor is 52%.

5. Nuclear

The nuclear option used in this analysis includes a typical advanced nuclear fission-powered plant equipped with the requisite auxiliary systems. Nuclear plants generate electricity similar to other plants, except that the steam is created by the heat produced in the nuclear reaction. Average heat rate for a nuclear power plant is 10,480 Btu/kWh. Nuclear plants operate as baseload resources, and for this analysis a capacity factor of 92% was used. This option offers certain benefits as a non-emitting resource. Also included as an option in the analysis is a system of small modular reactors. This design uses the same fission technology, but in combinations of smaller units, typically sized from tens of MWs to hundreds of MW. This modular concept has advantages over traditional nuclear plants in that the much smaller physical size allows off-site manufacture of the units, more options for siting, lower capital cost, and the ability to expand the plant in response to future needs.

6. Geothermal

The geothermal option presents two different technologies for generating renewable energy using heat extracted from below the earth's surface. Hydrothermal geothermal plants are a mature technology that injects fluid into naturally occurring reservoirs to create steam to power a turbine. Enhanced Geothermal Systems ("EGS") artificially produce these conditions by fracturing hot rock below the surface for injection and extraction of fluid. For each of these plant types, two energy conversion processes are common: binary (using a heat exchanger to transfer geothermal energy to the steam turbine generator) and flash (creating steam directly from the geothermal fluid through a change in pressure). This analysis includes hydrothermal binary and near field EGS plant configurations. Both of these options operate at an average 80% capacity factor.

7. Biomass (100%)

Biomass plants are similar to coal plants with the exception of the feedstock. This option includes a dedicated plant burning 100% biomass. The cost and operation of a biomass plant are largely location dependent due to variations in fuel supply. The average capacity factor of a dedicated biomass plant is 52%. The typical heat rate is 13,500 Btu/kWh. Biomass plants have a lower emissions rate than coal plants and can also offer a local benefit if nearby feedstock supply is abundant.

8. Landfill Gas

Landfill gas (“LFG”) is a natural byproduct of the decomposition of organic materials in landfills. LFG is approximately 50% methane and 50% carbon dioxide, with a small amount of other organic compounds. LFG plants capture and convert this naturally occurring gas to be burned in internal combustion engines, turbines, microturbines, or fuel cells to generate electricity. Preventing the escape of methane into the atmosphere is a notable environmental benefit as methane is a more potent greenhouse gas than CO₂. Therefore, LFG facilities are considered to have zero or net negative emissions. LFG plants run at a high capacity factor, averaging 70.2%. The expected heat rate is 7,900 Btu/kWh.

9. Municipal Solid Waste

Municipal Solid Waste (“MSW”) contains biomass, non-biomass combustible materials, and noncombustible materials. The fuel can be utilized in two forms. Mass burn technology, the most common MSW-to-electricity technology, involves the combustion of unprocessed or minimally processed refuse. Refuse-derived fuel (“RDF”) typically consists of pelletized or fluff MSW produced by a resource recovery operation, which removes non-combustible materials. As the MSW is incinerated, heat from the combustion process is used to generate steam, which is then routed to a steam turbine-generator for power generation. MSW has relatively high carbon emissions factors but is generally considered a renewable fuel. A typical MSW plant will run at capacity factors around 68-70%.

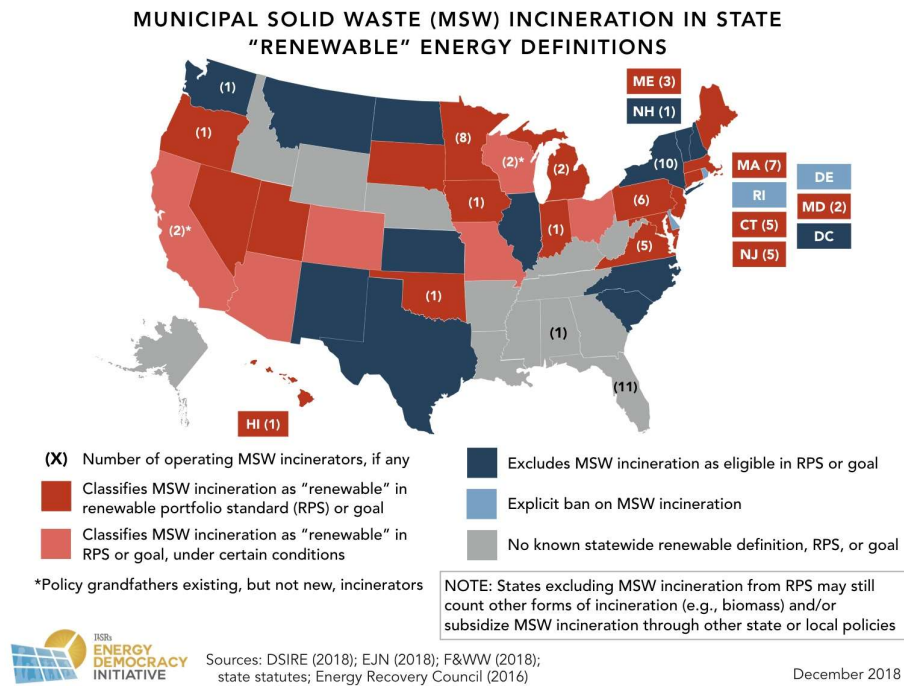


Figure XII-2

10. Hydropower

New hydropower resources can be originated either by powering non-powered dams ("NPD") or by construction of a new dam via new stream-reach development ("NSD"). These plant types are further defined based on the head and capacity at the specific location. This analysis aimed to be conservative and used values for low head, low capacity units. For the NPD units, a capacity factor of 62% was input, and for the NSD units, a capacity factor of 66% was input. In reality, the capacity factor is a function of actual operation required to meet reservoir management needs using the plant's dispatch capability.

11. Wind

MEAN's service territory is a favorable area for wind resources. Recent years have seen an increase in development of large wind farms across Iowa, Nebraska, Colorado, and Wyoming. Wind resources constructed prior to the end of 2021 have a financial benefit in that they qualified for the Production Tax Credit ("PTC"), receiving a tax credit for each MWh produced for the first ten years of operation. For projects initiated in 2016, the credit is \$23/MWh, which decreased by 20% each year and expired at the end of 2021. Legislation continues to be introduced to extend the tax credits. As experience with wind power and wind turbine installation grows, equipment pricing and installation costs continue to decrease. This is a favorable condition, as consideration of the PTC end dates starts to impact PPA pricing. In line with recent wind farm operation in the area, the analysis uses a 45% capacity factor. The ELCC method of accreditation calculation will reduce the accredited capacity with higher levels of penetration.

12. Utility or Community Solar

This option investigates a utility-scale photovoltaic solar installation owned by MEAN or a participant community. In fact, discussions among participants have even introduced

the concept of several communities jointly owning such an asset. In total, 23.6 GW of solar was installed in the US in 2021. SPP added 20 MW of solar in 2020, with plans to add 100 MW in 2021. Similar to wind resources, as the rate of adoption increases, material and installation costs continue to fall to new lows. In addition to a decrease in capital costs, the Investment Tax Credit (“ITC”) offers a further savings benefit for systems constructed or substantially procured by the end of 2022. While not as ideal as the southwest regions, the solar irradiance in the MEAN footprint is at an acceptable level for solar installations. A capacity factor of 29% was used in the calculations for a solar resource. The representative resource is a single axis tracking solar system. The ELCC method of accreditation will reduce the accredited capacity with higher levels of penetration.

13. Green Hydrogen Storage

Electrolysis is a potential option for carbon-free hydrogen production using renewable and nuclear resources. Electrolysis is the process of using electricity to split water into hydrogen, oxygen, and free electrons. This reaction takes place in a unit called an electrolyzer. Electrolyzers can range in size from small, appliance-size equipment for small-scale distributed hydrogen production to large-scale, central production facilities that could be tied directly to renewable or other carbon-free forms of electricity generation. These systems have a target capacity factor of 97%, making them a rare baseload carbon free resource. Electrolyzers can be built in modular systems to facilitate turndown for efficiency, load following, and scalability.

14. Fuel Cell

A fuel cell is a device that runs hydrogen and oxygen through chemical reactions in a process that generates electricity and heat, which can then be used as energy sources. In this analysis, natural gas is used as the fuel from which to derive the hydrogen. Natural gas, primarily composed of methane (CH₄), must be separated into the carbon and hydrogen components to be used in the fuel cell. Separation is typically performed in a steam methane reformer that subjects the natural gas to steam at high temperature and pressure with a metal catalyst to facilitate a chemical reaction which produces hydrogen and small amounts of carbon dioxide and carbon monoxide. The hydrogen produced in this reaction is supplied to the fuel cell, while the other gases are vented. Water output from the fuel cell can be collected and returned to the reformer, recycling it to be heated into steam for the methane reformation process. Fuel cells are energy-efficient since they produce electricity chemically rather than through combustion. Fuel cells also result in lower emissions than other natural gas-fired energy resources, with a heat rate of approximately 6,400 Btu/kWh. Electrical output is available in a wide range to provide scalable options for a variety of applications.

15. Battery Storage

A battery storage system is integrated with a generation source to act as a sink for the electricity when it is not required for load and a source of that same electricity when load levels increase. In this way, battery storage can increase the value of an intermittent resource by dispatching energy to match the timing of the load, or alternately to optimize market pricing. There are various battery technologies available for this application, including but not limited to: lead-acid, lithium-ion, sodium-sulfur, nickel-cadmium, sodium-nickel-chloride, and flow batteries. However, the most mature and commonly installed technology for utility-scale storage is the lithium-ion battery. Lithium-ion

battery systems have high efficiency and are very flexible, with varying discharge times available. Although energy density and performance characteristics can vary widely among the different technologies, this analysis refers to lithium-ion batteries specific to a renewable integration application. Although lithium-ion batteries currently have a high capital cost, costs are expected to trend downward in the future due to an increase in manufacturing volume, design improvements, and chemistry improvements. For this analysis, both 2-hour and 4-hour batteries were considered.

16. Pumped Hydropower

The pumped hydropower energy storage (“PHES”) option represents a mature technology that is widely used throughout the US and the world. In fact, PHES power plants constitute over 90% of installed electrical storage capacity across the globe. Conventional pumped hydro storage systems use two water reservoirs at different elevations. The system is charged during off-peak hours by pumping water from the lower to the upper reservoir. When loads are sufficiently high, the energy is discharged by releasing water from the upper to the lower reservoir, powering a turbine and generator. There are different options for the upper and lower reservoirs, which can take advantage of local geography. Discharge times can be from hours to days. The efficiency of PHES plants is in the range of 70 % to 85%. Once constructed, PHES systems enjoy a very long service life. However, opportunities are dependent on location.

17. Thermal Storage

Thermal Energy Storage (“TES”) systems are yet another method by which energy demand is shifted from peak hours to off-peak hours. TES systems store thermal energy for peak demand dispatch by heating or cooling a storage medium for use in heating or cooling applications or power generation. Available technologies include sensible heat storage, latent heat storage, and thermo-chemical storage. Sensible heat storage stores energy through a temperature change of the storage medium and is applicable to domestic systems, district heating and cooling, and industrial needs. Since these applications are directed to end-use customers, MEAN is unable to administer such options. Latent heat storage stores energy through a phase change of the storage medium. Examples include molten salts in concentrated solar plants. Thermo-chemical storage uses chemical reactions to store and release thermal energy. Examples include adsorption processes and desiccant cooling. Most latent heat and thermo-chemical storage applications are in the development or demonstration phase and are high in cost and are therefore unlikely to be pursued by MEAN.

D. Criteria

The goal of Phase I was to narrow the complete list of supply side options to a list of qualified options that represent the most feasible supply side resources for MEAN. To select the qualified options, appropriate criteria had to be determined. To this end, MEAN conducted an online survey wherein the participants were asked to rank the following criteria in terms of importance in resource selection:

- **Cost:** This includes the total cost of energy. In an ownership scenario, this is inclusive of fuel costs, fixed O&M costs, variable O&M costs, and capital cost recovery. In a PPA scenario, this includes the contracted price of energy. Transmission costs would also be added if applicable.

- **Fuel Diversity:** Fuel diversity of MEAN's resource mix is primarily determined using nameplate capacity, but the percentage of energy provided by each fuel will also be assessed. A higher level of fuel diversity reduces the impact of fuel price spikes, volatility, or supply availability.
- **Flexibility/Dispatchability/Market Risk:** This factor considers whether a resource is dispatchable (i.e., coal, natural gas, some hydropower, batteries) or intermittent (i.e., wind or solar) and whether the resource output can be reduced to a minimum level that allows response to market conditions. A resource's dispatchability is also a measure of its reliability.
- **Emissions/Environmental Impact:** Measures the resource emissions factors for NO_x, SO₂, CO₂, and Mercury. Water consumption will also be considered.
- **Local Benefit:** Locating a resource in or near a participant community to allow for economic development opportunities and/or localized environmental benefits.
- **PPA vs. Ownership:** Evaluates the impact on MEAN's long-term debt position and resource mix dependent upon whether a resource is acquired in an ownership stake as opposed to a power purchase.
- **Environmental Policy Risk:** Evaluates whether a resource is vulnerable to increased regulation (and possibly additional costs) as a result of future environmental policy.
- **Progress Toward 2050 Vision:** This criterion estimates a resource's contribution to the overall decrease of carbon emissions in MEAN's portfolio and the ability to sustain that reduction to 2050.
- **Long Term Debt:** Some resource contracts may require that MEAN contribute to payments on the facility's long-term debt, and in fact some contract lengths are tied to the term of existing debt. Resource contracts that require MEAN's obligation to pay long-term debt have impacts on the organization's financials and the length of Service Schedule M participants.
- **Transmission Availability/Cost:** Since MEAN is not a transmission owner, resources must obtain a transmission path from the source to the market or to the sink. Depending on the operation and location of the resource, this transmission service may come at an additional cost. Also, the availability of existing transmission means the resource will not be responsible for additional upgrade costs.
- **Resource Adequacy/Capacity Accreditation:** Resource capacity is accredited based on its type and its historical and predicted future performance. MEAN must have adequate accredited capacity to meet its projected peak demand. Therefore, the lower a resource's accreditation, the larger the nameplate capacity required. Baseload resources, such as coal and nuclear receive 100% accreditation, whereas wind and solar resources can be accredited as low as 10%. Resources with low accreditation sometimes require an additional capacity purchase to provide resource adequacy, thereby increasing the cost.
- **Future Capital Cost/Decommissioning:** Some types of resources have compliance measures that must be met to retire the resource at the end of its useful life. These measures typically

come at a significant cost. Other types of resources may see high future capital cost to meet new future environmental compliance regulations.

The results of the survey indicated that the participants' most important criteria in resource selection is cost. With a score of 4.68 out of 5, Cost was the most highly rated criteria. This was followed by Long Term Debt with a score of 4.37, Transmission Availability/Cost with a score of 4.35, Local Benefit with a score of 4.26, Resource Adequacy/Capacity Accreditation with a score of 4.25, and Future Capital Cost/Decommissioning with a score of 4.21. The lowest priorities were Fuel Diversity, PPA vs. Ownership, and Environmental Policy Risk. The complete results are shown in *Figure XII-3*.

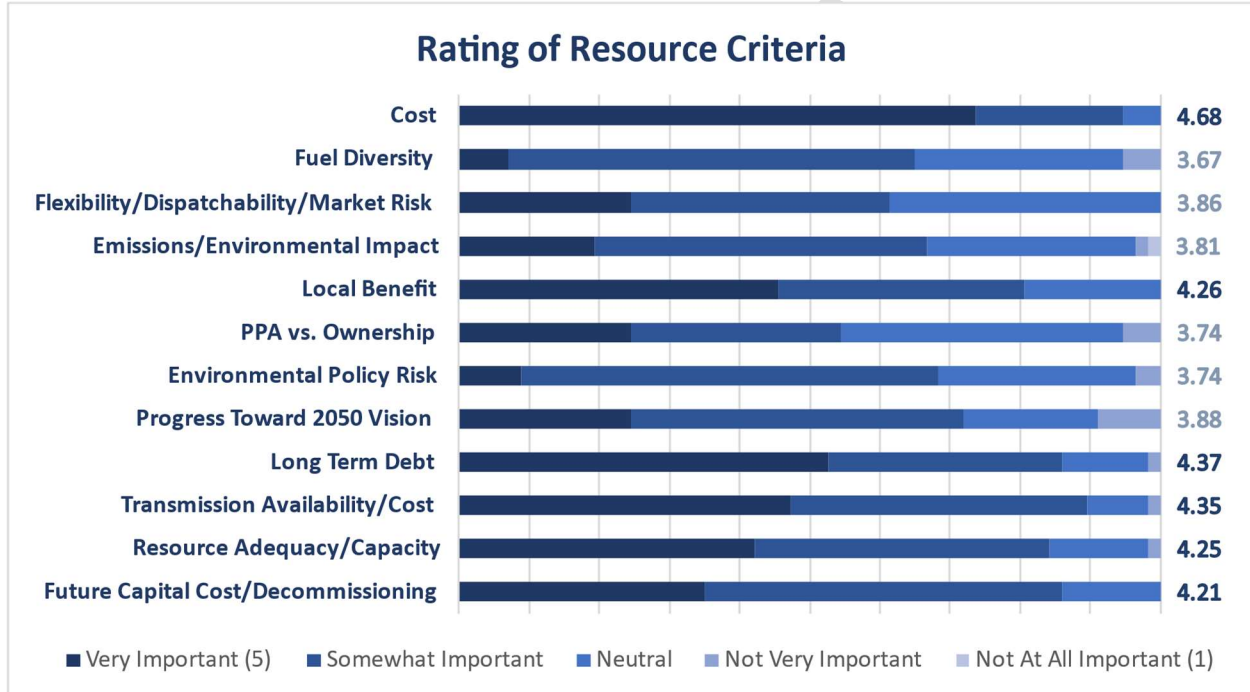


Figure XII-3

E. Input Data

Each of the supply side options was scored on each of the criteria using a variety of metrics obtained from the U.S. Energy Information Administration ("EIA"), the National Renewable Energy Laboratory ("NREL"), the Department of Energy ("DOE"), the Electric Power Research Institute ("EPRI"), and other publicly available studies. Specific data used as the scoring values for the Phase I evaluation is shown graphically in Appendix B.

F. Evaluation

The chart in *Figure XII-4* shows the total combined weighted score for each of the supply side options. The individual components of the score are color coded by criteria as described above.

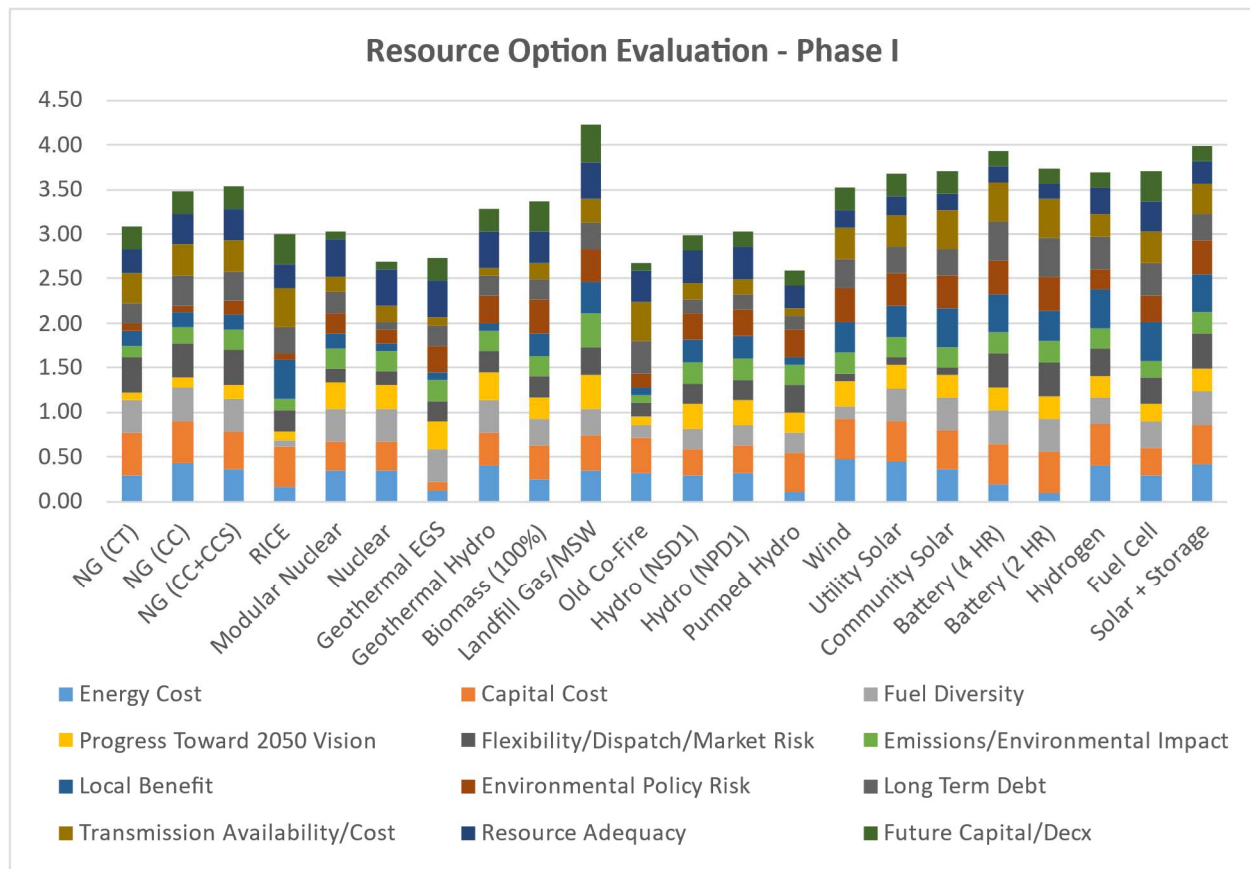


Figure XII-4

G. Qualified Options

1. Evaluation

The Phase I evaluation resulted in final combined weighted scores for each of the supply side options defined at the beginning of the process. Because the criteria were weighted according to the participants' survey, the scores reflect the options most likely to achieve the priorities of the participants. As highlighted in *Figure XII-5*, the top scoring options were:

- Landfill Gas/Municipal Solid Waste
- Solar+Storage
- Battery Storage
- Utility/Community Solar
- Fuel Cell
- Wind
- Hydrogen Storage
- Natural Gas Combined Cycle

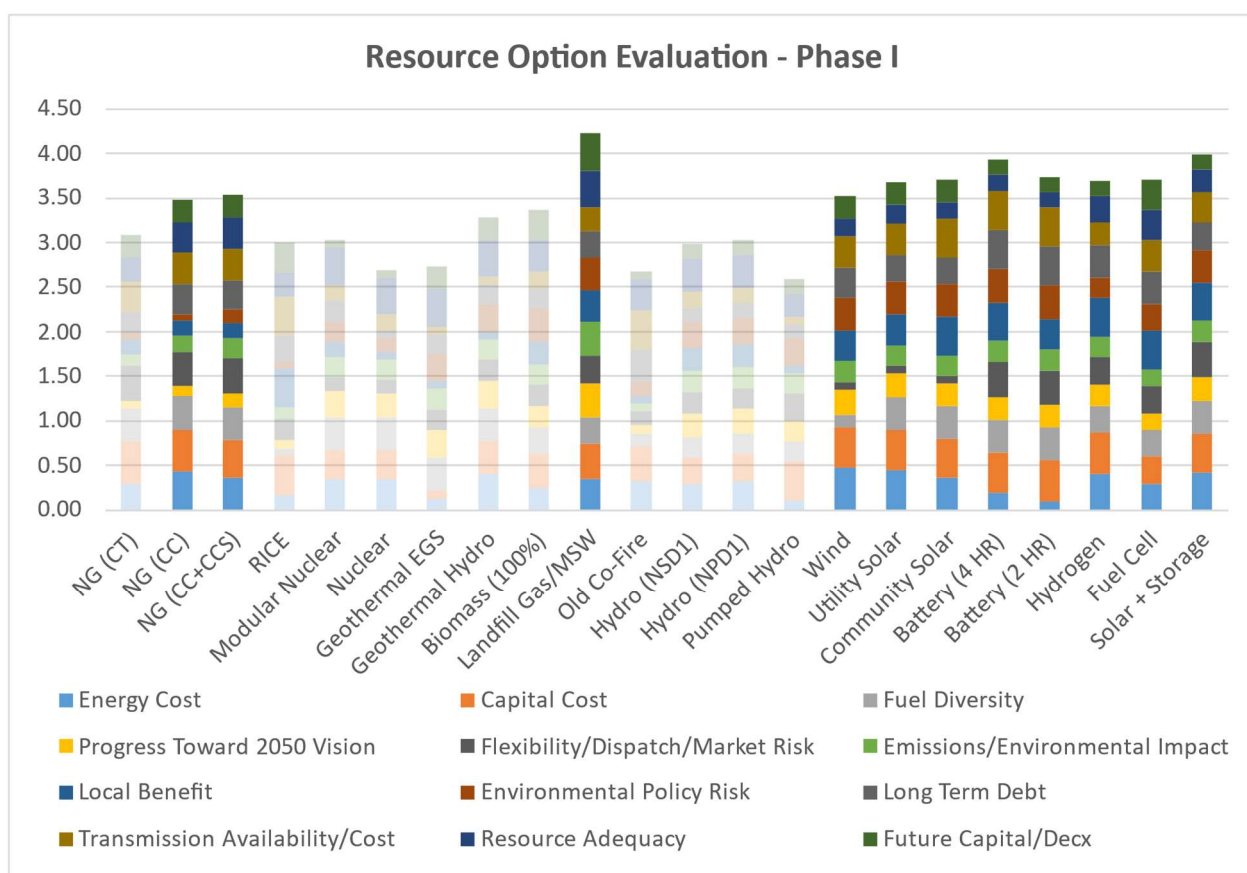


Figure XII-5

2. Public Participation

In discussions at the Power Supply Committee meetings and discussions with individual member representatives, participants suggested adding to the qualified options determined by the Phase I evaluation.

NextEra Solar: MEAN is in discussions with NextEra Energy regarding a proposed solar installation near the town of Sidney, Nebraska. This proposal has not yet been approved by the MEAN Board, and terms are not finalized. However, since solar resources were qualified for future evaluation based on the Phase I results, certain components of the NextEra project will be used to inform the inputs and assumptions for the solar facility model.

Local Hydropower: Although hydropower scored too low in the Phase I evaluation to qualify for Phase 2 modeling, MEAN has considered specific potential local hydropower projects for Power Purchase Agreement participation. The initial details of these opportunities warrant further investigation, and therefore a modeling option will be added with pricing and performance characteristics based on an average of these potential projects.

Participant Owned Generation: Several workshop attendees favorably discussed the option of allowing participants to install new behind-the-meter generation to their community fleet and add these units to MEAN's portfolio through the same contract by which MEAN leases existing generation. This is an option that would supply capacity and energy while at the same time provide a benefit to a participant community. MEAN would

intend to release a Request for Proposals to participants wherein the unit parameters are specified to allow MEAN to control the resource mix and enhance the performance of the participant owned generation fleet. Participant Owned Generation can also serve to fulfill capacity needs in portfolios that add intermittent generation with low capacity accreditation.

Extension of PPAs: MEAN is party to several Power Purchase Agreements that are scheduled to expire during the study period. Market dynamics may present an environment in which MEAN can negotiate an extension of these contracts favorable in terms of pricing and operating strategy. Contracts considered were the NPPD Multi-Unit Participation Agreement (GGS 1 and 2 and Cooper Nuclear Station), the Black Hills PPA (Wygen III and Neil Simpson 2), and the NPPD Wind PPAs. The Black Hills PPA was discounted for the lack of flexibility and dispatchability as well as the carbon emissions factor. The NPPD wind contracts were excluded as the assets are expected to be at or near the end of their useful service life when the contracts expire and would be an inferior option when compared to a new wind facility. An extension of a PPA for power from Cooper Nuclear Station was added as an option. This has not been offered or officially discussed with NPPD, and is only added as a studied option to determine its viability compared to other supply side resources.

Extension of Marketing Agent Arrangements: In January 2005, the MEAN Board placed a moratorium on participant owned generation, disallowing any generating unit additions to the committed facilities fleet. When Indianola Municipal Utilities and Waverly Utilities joined MEAN, they operated in their communities significant generating assets that they wished to lease to MEAN. The Board agreed to lift the moratorium to lease 15 MW from each participant under the existing ERPA contract. Under a separate contract, the Marketing Agent Agreement, MEAN leases certain capacity amounts termed Short-Term Leased Capacity and Excess Capacity at different payment terms for 2-3 year time periods. This agreement includes a total of approximately 49 MW. The current contract term extends through the MISO Planning year 2022-23. Of the total behind-the-meter generation of IMU and WU, a portion is exported from MISO to SPP. Extension of these contracts would provide SPP with additional capacity needed for resource adequacy to allow future renewable generation resources that carry low accredited capacity.

XIII. Demand Side Management Evaluation

A. Demand Side Management Evaluation Process

Just as new a supply side resource can be added to MEAN's portfolio to supply additional energy to meet the demands of the end-user, conversely end-user demand can be decreased to require less energy to be generated by supply side resources. Demand side management ("DSM") programs can be utilized to reduce peak demand and thereby eliminate or delay the need for future capacity additions. Reducing peak demand also has the added benefit of decreasing resource adequacy (capacity) needs, allowing for the use of more resources that offer energy generation with little accredited capacity (i.e., intermittent renewable resources.) Alternately, DSM measures can be designed to lower energy consumption to decrease the energy generation required by existing and future resources. Since MEAN's load and resource balance shows a future deficit in terms of both capacity and energy, both types of DSM are viable solutions.

In an attempt to minimize the required supply side resources to meet MEAN's total obligation, a demand side resource evaluation was performed to determine the value of proposed DSM programs.

B. Demand Side Options

In addition to the established DSM programs that MEAN plans to continue as described in Section VII, a list of potential future programs was compiled for evaluation. The total list for the initial investigation included:

- Energy Efficiency Education
- Street Lighting Upgrades
- Commercial/Irrigation Interruptible Service
- Commercial/Industrial Direct Load Control
- Commercial High Efficiency HVAC Incentives
- Appliance Recycling Incentive
- Residential Direct Load Control (Air Conditioners, Water Heaters)
- Residential High Efficiency HVAC Incentives

C. Market Feasibility

The first step in the analysis was to determine the market feasibility of the potential programs. In other words, an estimation of the probability that each program would be accepted and applied by the end-user market. In January, MEAN conducted an online survey to ask each community's Board representative to rate the potential implementation of each of the prospective DSM programs. The results of the survey are shown in *Figure XIII-1*.

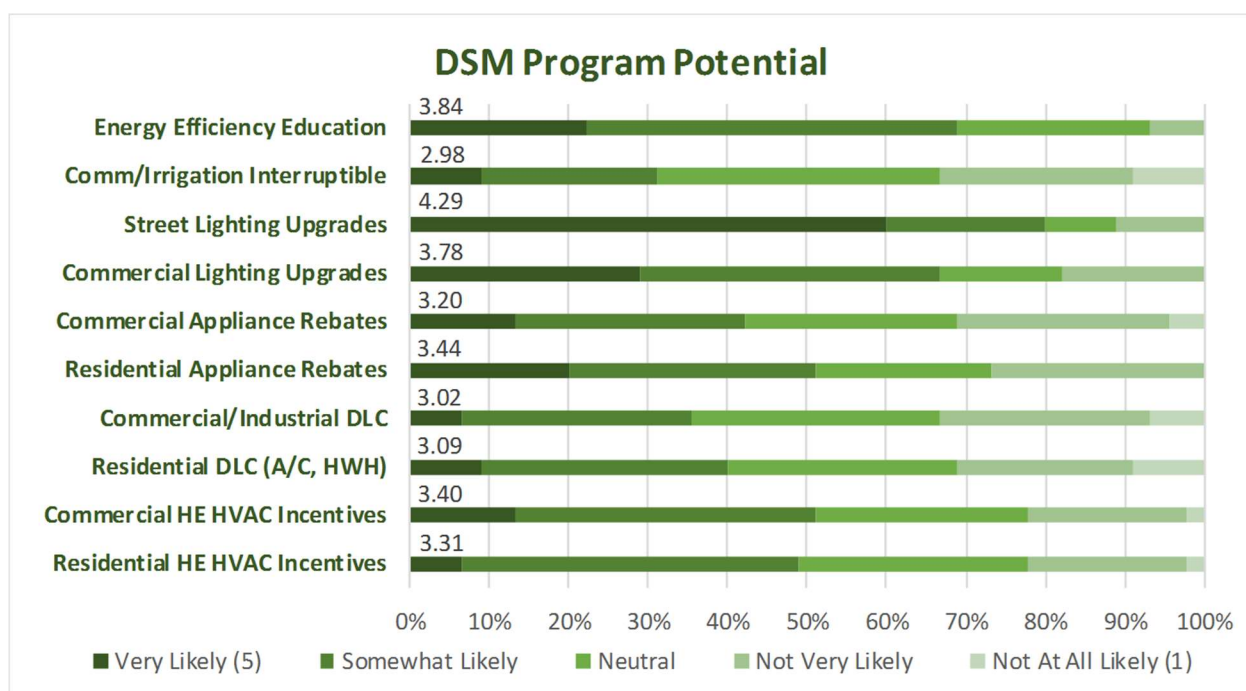


Figure XIII-1

The options with the highest scores for market feasibility were: Street Lighting Upgrades, Energy Efficiency Education, Commercial High Efficiency HVAC Upgrades, Residential High Efficiency HVAC Upgrades, and Appliance Recycling Incentives.

MEAN previously administered a program to incentivize street lighting upgrades. However, as one of the goals of the DSM program is to decrease system demand, the reduction of street lighting load, which occurs noncoincident with peak load, did not contribute to advancement of the program goal. The street lighting program has since been discontinued.

In addition, as part of the four new energy efficiency programs rolled out in 2021, MEAN recently implemented a High Efficiency Heat Pump incentive program for either converting an existing natural gas system or upgrading from a conventional electric system. The results of the survey indicate that MEAN should continue to fund and support these programs.

The lowest scoring options were: Residential Direct Load Control, Commercial/Industrial Direct Load Control, and Commercial/Irrigation Interruptible Rates. These programs were eliminated from further consideration.

D. Qualified Options

Based on the results of the Participant survey, the qualified options were broadly categorized as Residential and Commercial Appliance Rebates, Residential and Commercial High Efficiency HVAC Incentives, and Energy Efficiency Education. In order to perform a more accurate analysis, these categories were studied and more specific programs defined for the next step in the analysis.

To respond to customer interest as indicated by recent programs administered by other regional utilities and to create programs designed to be useful and effective for a minimum 10-year span, the following DSM programs were advanced to the final analysis:

Residential and Commercial Appliance Rebate Programs:

- Refrigerator Rebate
- Freezer Rebate

Residential and Commercial High Efficiency HVAC Incentives:

- Room Air Conditioner Upgrade Incentive
- Central Air Conditioner Upgrade Incentive
- Heat Pump Water Heater Rebate

E. Economic Feasibility

1. Benefit/Cost Ratio Tests

The costs and benefits of the proposed DSM programs will be compared using three different calculation methods, all of which are commonly used by utilities for this purpose. These three tests consider the costs and benefits of the DSM programs from different perspectives. A calculated ratio greater than 1 indicates benefits that exceed costs.

- The Utility Cost Test (“UCT”), also called the Program Administrator Cost Test. This test measures cost-effectiveness from the viewpoint of MEAN. If MEAN’s avoided power supply costs exceed the costs incurred by MEAN in administering the program and paying the incentives or rebates to the end-use customer, the program is a net benefit to MEAN.
- Participant Cost Test (“PCT”). This test measures benefits and costs to the end-use customers participating in DSM programs. The test compares net bill savings, considering electric bills and gas bills, against incremental costs of the efficient HVAC equipment or appliance, which are calculated to include the incentive or rebate received from the utility. If the savings exceed the incremental costs, the program provides a positive financial impact to end-use customers.
- Total Resource Cost Test (“TRC”). This test examines each program from the viewpoint of the entire MEAN system. The TRC test compares the program benefits of avoided power supply costs against the administration costs to the utility and the customer costs of upgrading equipment. The payment of incentives or rebates is a net zero as it is a cost to the utility but a benefit to the end-use customer. Bill savings also net out, both between the retail customer and supplier and the wholesale customer and supplier. A passing score on the TRC indicates a decrease in total resource costs, benefitting MEAN and the customer.

The table in *Figure XIII-2* summarizes the benefits and costs included in the calculations of the ratio.

TEST	BENEFITS	COSTS
Utility Cost Test	Utility Avoided Costs	• Program Administration Costs • Incentives/Rebates Paid
Participant Cost Test	Net Bill Savings	• Incremental Cost of Investment (Net of Incentive/Rebate)
Total Resource Cost Test	Utility Avoided Costs	• Program Administration Costs • Incremental Cost of Investment

Figure XIII-2

2. Market Potential

The first step in quantifying the costs and benefits of the proposed DSM programs is to determine the potential market for each program. MEAN used the 2020 and 2015 Residential Energy Consumption Survey ("RECS") conducted by the U.S. Energy Information Administration, which details the statistics of appliance and HVAC equipment ownership. Data is available on the number of owned systems by type, age, efficiency rating, and capacity.

MEAN first tabulated the total percentage of regional customers who owned the applicable system or appliance and applied this percentage to the total number of residential meters in the MEAN system. Next, the type and age were considered to determine the number of systems likely to be eligible for replacement. Lastly, an estimate of the expected rate of participation was applied to the number of eligible systems/meters.

The table in *Figure XIII-3* shows the results of the market potential calculations for each program. This total number was distributed evenly over the ten-year assumed span of the program.

DSM PROGRAM	TOTAL METERS	OWNED SYSTEMS	ELIGIBLE SYSTEMS	PARTICIPATION	TOTAL POTENTIAL
Room Air Conditioner Rebate	84,066	26.52%	20.00%	25%	1,115
Central Air Conditioner Incentive	84,066	70.45%	34.85%	30%	6,192
Refrigerator Rebate	84,066	99.24%	11.45%	30%	2,866
Freezer Rebate	84,066	38.64%	49.04%	25%	3,982
Heat Pump Water Heater Rebate	84,066	64.39%	36.36%	20%	3,937

Figure XIII-3

3. Energy Efficiency Assumptions

To estimate the impact of each DSM program in terms of energy savings, MEAN used Energy Star Life Cycle Cost Estimate calculation tools (U.S. Department of Energy) and the Federal Energy Management Program Energy Cost Calculator for Electric and Gas Water Heaters.

The Air Source Heat Pump program replaces a traditional natural gas forced-air furnace and electric air conditioner with an electric air source heat pump. A programmable thermostat is not included in the calculations. This replacement results in an overall increase in electric energy consumption, as the annual energy used by the heat pump system exceeds that saved by the elimination of the conventional air conditioner. This is accompanied by a decrease in natural gas consumption with the elimination of the furnace. Therefore, the impact to the retail customer is a net positive savings, and the impact to MEAN's system in terms of energy is a net negative savings.

The Room Air Conditioner program simply replaces a minimum efficiency conventional unit with an Energy Star rated unit with higher efficiency.

The Central Air Conditioner program replaces a minimum efficiency conventional unit with an Energy Star rated unit with higher efficiency.

The Refrigerator program replaces a minimum efficiency standard appliance with an Energy Star rated unit with higher efficiency.

The Freezer program replaces a minimum efficiency standard appliance with an Energy Star rated unit with higher efficiency.

Previously, MEAN looked at a Water Heater program to replace a natural gas-fired water heater with an electric water heater, which has the effect of an increase in electric energy consumption and a decrease in natural gas consumption. Therefore, the impact to MEAN's system in terms of energy is a net negative savings. The current analysis instead includes an upgrade of a standard electric water heater with an Energy Star rated heat pump water heater unit.

The calculations are included in Appendix C, and the results are tabulated in *Figure XIII-4*.

DSM PROGRAM	ENERGY SAVINGS (MWh/year/unit)	POTENTIAL UNITS	PROGRAM SAVINGS (MWh/year)
Room Air Conditioner Rebate	0.124	111	13.82
Central Air Conditioner Incentive	0.482	619	298.46
Refrigerator Rebate	0.061	287	17.48
Freezer Rebate	0.315	398	125.43
Heat Pump Water Heater Rebate	2.242	394	882.68

Figure XIII-4

4. Costs and Savings

MEAN will incur DSM program costs in two ways. First, MEAN will require staff time to administer the program. It was assumed in this analysis that one staff member could be devoted to administration of all six programs. However, a pro-rated percentage of the staff member's time and salary would be allocated to individual programs. MEAN will also pay the cost of the incentives or rebates received by the end-use customers. Incentive and rebate amounts were projected based on the average offers from regional utilities for similar programs.

From the customer's perspective, the cost incurred is the incremental cost paid for the higher efficiency equipment or appliance as compared to the purchase of a standard unit. This data was calculated in the Energy Star Life Cycle Cost calculation tools as shown in Appendix C as well as general market data. This incremental cost must be adjusted to include the incentive or rebate received from MEAN for participation.

The costs for each program are listed in *Figure XIII-5*:

DSM PROGRAM	ADMINISTRATION COST (\$/year)	INCENTIVE/REBATE	INCREMENTAL CUSTOMER COST
Room Air Conditioner Rebate	\$14,846	\$45	\$51
Central Air Conditioner Incentive	\$14,846	\$300	\$856
Refrigerator Rebate	\$14,846	\$60	\$200
Freezer Rebate	\$14,846	\$60	\$100
Heat Pump Water Heater Rebate	\$14,846	\$400	\$850

Figure XIII-5

MEAN's benefit is quantified by its avoided cost. Every MWh that is not consumed at the end-use customer level is a MWh that MEAN does not have to generate or purchase. While all of MEAN's costs are not directly attributable to energy production, and therefore not avoided with a decrease in energy consumption, there is a portion of MEAN's costs that is avoided when energy consumption decreases. This is termed MEAN's "avoided cost." MEAN's current calculated avoided cost rate is \$0.4209, a value that is recalculated annually with changing system parameters. In the benefit/cost analysis, this cost is escalated at a rate of 3% per year.

The end-use customer's benefit is determined by the net energy bill savings. For the Air Source Heat Pump program, this is the total of the increase in electric billing costs and the decrease in natural gas billing costs. For this analysis, a seasonal and regional weighted average of \$0.0944 per kWh with a 1% annual escalation was used for the electric billing rate, and \$0.97 per therm with a 2% escalation was used for the gas billing rate.

5. Results

The costs and benefits as described above were applied to the potential market participants for each of the proposed DSM programs. The costs were escalated and

summed for a ten-year period. Finally, a Net Present Value was calculated for the annual costs and benefits and this value used to determine the final benefit/cost ratio. The results of the three Benefit/Cost tests are shown in *Figure XIII-6*.

DSM PROGRAM	UTILITY COST TEST (Benefit/Cost)	PARTICIPANT COST TEST (Benefit/Cost)	TOTAL RESOURCE COST TEST (Benefit/Cost)
Room Air Conditioner Rebate	0.0310	1.2112	0.0365
Central Air Conditioner Incentive	0.0706	0.0931	0.0396
Refrigerator Rebate	0.0246	0.0468	0.0147
Freezer Rebate	0.1473	0.8461	0.1831
Heat Pump Water Heater Rebate	0.2425	0.5353	0.2179

Figure XIII-6

As stated initially, only a ratio greater than 1 would indicate that a program is likely to result in benefits that outweigh its costs and therefore provide a net positive impact to MEAN or the end-use customer, depending on the test.

In total, only one program had a favorable result, and in only one of the tests. Therefore, none of the potential programs would prove beneficial to MEAN and the end-use customer to a point that would compensate for the required costs.

Fortunately, MEAN has recently expanded DSM offerings to retail customers. See the “Existing Demand Side Management” section for details on the four new energy efficiency programs initiated in 2021. To date, these programs have been successful and have shown energy and demand savings. MEAN will evaluate the future level of funding based on participation and measured savings for all participants.

F. Energy Efficiency Education

The DSM survey indicated that future energy efficiency education would likely see a high degree of participation in MEAN member communities. Through work with the Nebraska Municipal Power Pool organization and other statewide utilities, MEAN continues to seek opportunities to assist communities with education efforts. Recent educational sessions have been made available for MEAN member communities on topics including Electric Vehicle Charging Stations and Specifications as well as Community Solar Projects. MEAN’s Services Committee regularly evaluates the potential for future programs and continuing education opportunities that align with overall member interest and budget limitations. To this end, MEAN regularly provides communications materials for communities to share with retail and residential customers promoting the benefits of the new energy efficiency programs and specific instructions for application.

G. Electric Vehicle Charging Stations

Another prospective Demand Side project that MEAN and Pool will be exploring in the near future is an incentive for residential electric vehicle charging stations. Other regional utilities have recently

introduced similar programs, and MEAN anticipates that several communities will have a high degree of interest to participate. The potential applications and developments of this project could prompt a high level of collaboration between MEAN staff and member community staff and intense study of community interest, use profiles, and retail rate structure. This project will be introduced for discussion and consideration at a future Services Committee meeting.

H. Advanced Metering Infrastructure

MEAN is working on a project to provide advanced metering infrastructure (AMI) services to member communities. In the fall of 2019, MEAN conducted a business case study and survey of member representatives seeking interest in installing and employing Advanced Metering Infrastructure (“AMI”). Initial positive response was received from 20 towns. With this information, MEAN conducted an RFP for pricing of an aggregate AMI procurement.

AMI has the ability to provide two-way communication with community retail electric meters. It allows for remote meter reading, remote disconnections, and remote monitoring of system conditions. Following implementation, participating communities could use this system to perform demand side management at the individual meter level. With the proliferation of residential distributed generation, electric vehicle charging, and residential energy storage, AMI offers significant opportunity for demand control for the enhancement of DSM technologies. The use of DSM allows communities to control their energy peak and by extension, potentially reduce the need for MEAN to procure additional resources in the future. MEAN would have access to the data collected by the participating communities. MEAN could use this data to enhance load monitoring and forecasting activities.

Fourteen (14) communities have signed letters of intent to participate in this project, representing a total of approximately 10,500 meters. These communities vary in size and location across MEAN’s footprint. If approved, this project is slated to begin implementation in 2022.

XIV. Phase II Analysis and Results

A. Phase II Supply Side Analysis

The qualified options from the Phase I supply side evaluation are combined with MEAN's existing contracted resources to create a number of future resource portfolios for study. The date on which a resource is modeled to begin generation is aligned with the timing of the regional resource deficit as defined in Section X "Load and Resource Balance".

The Phase II analysis aims to investigate the simulated operation of each of the hypothetical MEAN portfolios to calculate the 15-year revenue requirement and thereby determine the least cost option. The revenue requirement of the portfolios will be calculated for a number of future scenarios in terms of market pricing and load. The variance between these scenarios will indicate the volatility or risk of each portfolio, which will be presented as an evaluation criterion. In addition, the portfolios will be assessed in terms of environmental impact and progression toward MEAN's 2050 Vision of carbon neutrality.

The preferred option(s) will be integrated with the demand side management measures showing a favorable cost/benefit relationship to arrive at recommended short-term and long-term plans.

B. Impact of DSM Qualified Options

After conducting a survey of Participants to identify the DSM measures most likely to be implemented in the Participant communities and performing a cost/benefit analysis of those qualified options, no new programs are recommended for initiation. The analysis determined that the proposed new programs would result in a net cost to both the end use customer and to MEAN. Should cost parameters change in the future, particularly natural gas prices or retail electric rates, these options should be studied again for consideration.

MEAN's existing programs and the programs administered by individual Participant communities are quite successful and will be maintained into the future. The effects of these programs in decreasing demand and energy consumption have been quantified where possible and have already been incorporated into the regional load forecasts. Particularly in regard to the four new energy efficiency programs initiated in 2021, energy and demand savings will be projected and incorporated into future load forecasts and will be refined as data is collected in the future.

C. Studied Portfolios

The Phase I evaluation and subsequent discussions with members determined the following qualified supply side resource options:

- Natural Gas Combined Cycle
- Natural Gas Combined Cycle with Carbon Capture and Sequestration
- Landfill Gas
- Municipal Solid Waste
- Wind
- Utility/Community Solar
- Natural Gas Fuel Cell
- Hydropower

- Wind + Storage
- Solar + Storage
- Extension of Cooper Nuclear Station PPA

As each of these options offers different operational capabilities in terms of capacity factor (the relation of energy generation and nameplate capacity), some can provide the full capacity and energy needs of a region, while others can provide only capacity and others primarily only energy. To maintain an equal basis for comparison, each supply side resource was sized to meet the energy needs of the region, calculated using the resource's capacity factor, and additional capacity needs for resource adequacy were modeled as a capacity purchase, using accredited capacity calculations. This capacity purchase would initially be facilitated through leases of member-owned locally sited resources. Any needs exceeding member units would be contracted with a third party.

The qualified options were applied to the resource deficits of each region to create portfolios that would offer varying solutions to the needs of each region. The portfolios are as follows:

1. SPP

Portfolio 1: Natural Gas Combined Cycle

MEAN would contract for a partial ownership or a power purchase agreement for capacity and energy from a natural gas combined cycle plant sized to meet the energy needs in SPP. The NGCC plant would be operated in SPP's integrated marketplace, subject to economic dispatch. A capacity purchase is added from 2024-2029 for resource adequacy. This portfolio achieves the goal of diversifying MEAN's resource portfolio in terms of fuel source, reduces emissions as compared to coal facilities, and provides reliability and a high degree of operational flexibility.

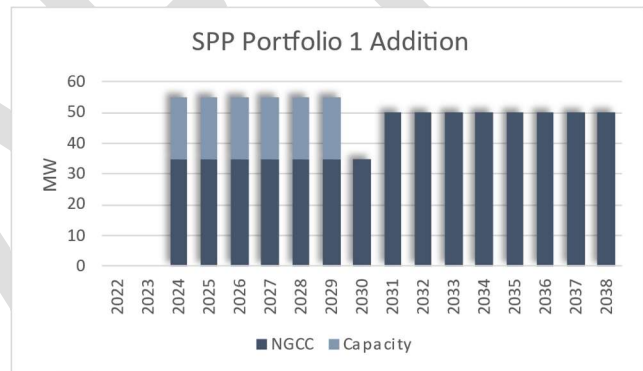


Figure XIV-1

Portfolio 1A: Natural Gas Combined Cycle with Carbon Capture

MEAN would contract for a partial ownership or a power purchase agreement for capacity and energy from a natural gas combined cycle plant fitted with a carbon capture system sized to meet the energy needs in SPP. This plant is operated by economic dispatch in the SPP integrated marketplace and would provide both capacity and energy to MEAN's load. A capacity purchase is added from 2024-2029 for resource adequacy. This portfolio allows

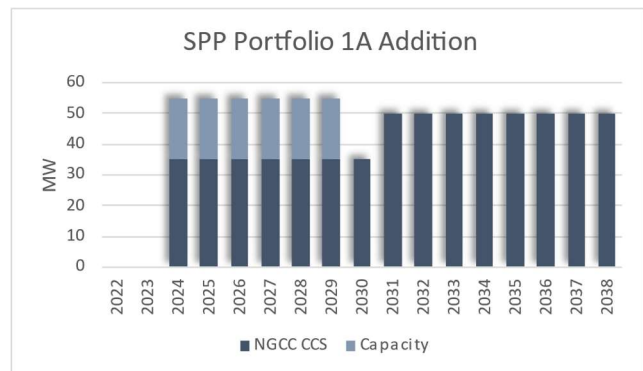


Figure XIV-2

MEAN to diversify the fuel sources of its resource portfolio, allows a reduction of emissions as compared to the coal units in the portfolio, and achieves the goals of resource flexibility and reliability.

Portfolio 2: Landfill Gas

MEAN would contract for a partial ownership or a power purchase agreement for capacity and energy from one or more landfill gas plants sized to meet the energy needs in SPP. Landfill gas plants can be operated as must-run units or can be controlled with limited dispatch flexibility. The Phase II economic model considers the LFG plant dispatched according to marketplace economics to provide capacity and energy. A capacity purchase is added from 2024-2029 for resource adequacy. The LFG portfolio increases MEAN's percentage of renewables in SPP as well as the reliability and fuel diversity of MEAN's portfolio.

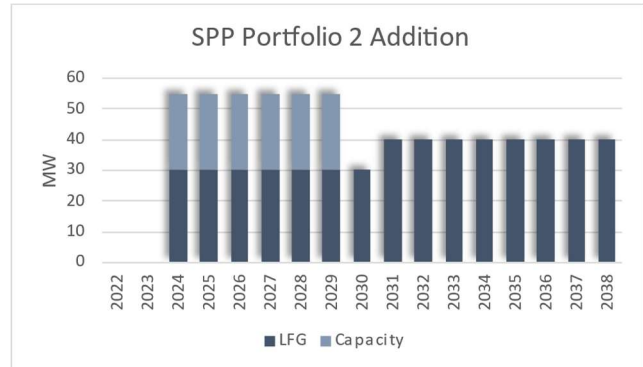


Figure XIV-3

Portfolio 3: Municipal Solid Waste

This portfolio would add capacity and energy from an MSW plant to MEAN's portfolio via a partial ownership contract or a power purchase agreement sized to meet the energy needs in SPP. The MSW plant would be operated via economic dispatch in SPP's integrated marketplace. A capacity purchase is added from 2024-2029 for resource adequacy. Although this option results in an increase in carbon emissions, MSW energy plants are considered renewable resources in many instances. This portfolio contributes to the renewable percentage in MEAN's SPP portfolio and creates a more diversified portfolio with regard to fuel source.



Figure XIV-4

Portfolio 4: Wind

MEAN would enter into a power purchase agreement for wind generation sized to meet the energy needs in SPP. As wind receives a low accreditation value per ELCC calculations, a larger capacity purchase is added from 2024-2029 for resource adequacy. Wind would be an intermittent resource in SPP. The wind portfolio adds a significant amount of renewable energy generation to MEAN's resource mix but does not contribute to reliability or flexibility.



Figure XIV-5

Portfolio 5: Solar

In this portfolio, MEAN would enter into a power purchase agreement for utility owned solar generation to provide for energy needs in SPP. The solar nameplate capacity is quite large due to the low capacity factor of solar generation facilities. And because of the ELCC accreditation, a capacity purchase will be required from 2024-2029. This portfolio increases MEAN's renewable energy in SPP but reduces flexibility to respond to load fluctuations or market pricing changes.

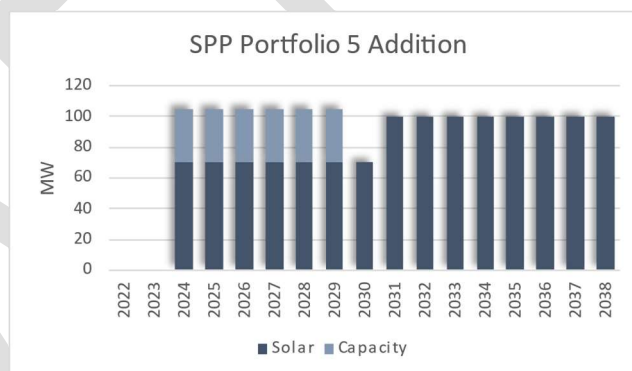


Figure XIV-6

Portfolio 6: Fuel Cell

MEAN would contract for a partial ownership or a power purchase agreement for capacity and energy from one or more natural gas-fired fuel cell plants in an aggregate size to meet the energy needs in SPP. The fuel cell plant would be operated in SPP's integrated marketplace, subject to economic dispatch. A capacity purchase is added from 2024-2029 for resource adequacy. This portfolio achieves the goal of diversifying MEAN's resource portfolio in terms of fuel source, achieves a level of reduced emissions as compared to coal facilities, and provides reliability and operational flexibility.

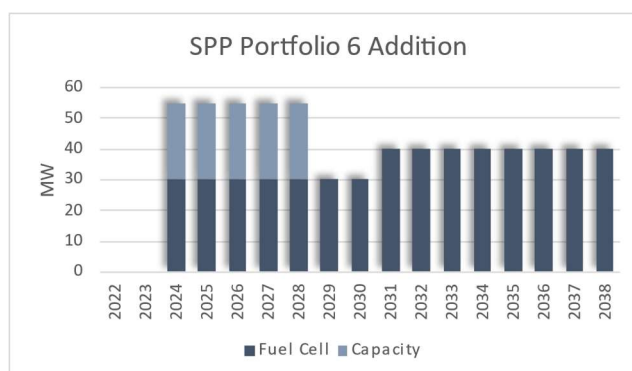


Figure XIV-7

Portfolio 7: Hydropower

Portfolio 7 adds a power purchase agreement for full or partial capacity and energy from a dispatchable hydropower plant. The agreement would be sized to meet energy needs in SPP. The hydropower plant would be operated at limited dispatch as restricted by other water use downstream and in response to market conditions. No additional capacity purchase is required with this resource option. The hydropower portfolio grants MEAN additional renewable energy in SPP while also maintaining a moderate degree of flexibility and reliability.

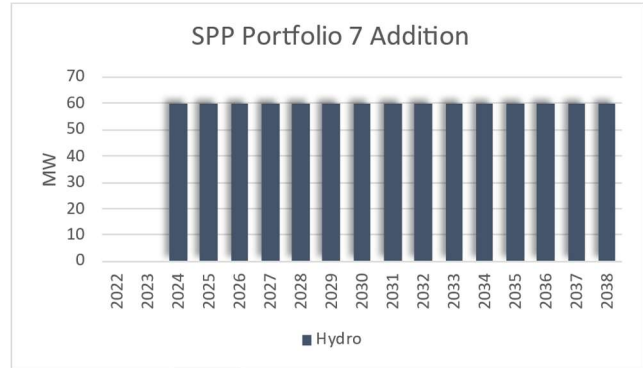


Figure XIV-8

Portfolio 8: Wind + Battery Storage

This portfolio begins with the same wind resource and capacity purchase modeled in Portfolio 4, but also adds a 4-hour battery to the system. The battery would be charged as available and discharged in response to market pricing. This portfolio allows MEAN to increase the renewable energy generation in SPP and realizes additional value in the limited dispatch of the battery storage.

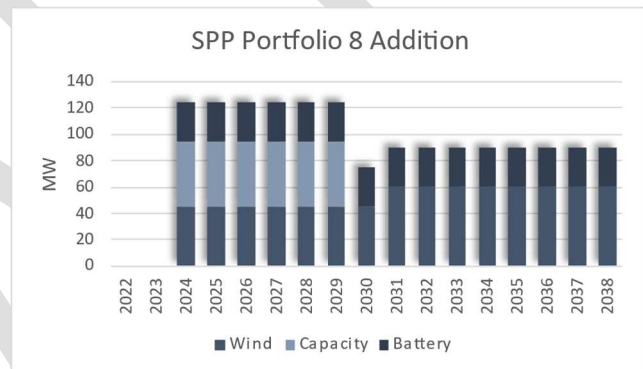


Figure XIV-9

Portfolio 9: Solar + Battery Storage

In the same manner, Portfolio 9 adds a 4-hour battery to the solar resource and capacity purchase modeled in Portfolio 5. The battery would be charged as available and discharged in response to market pricing. This solar plus storage portfolio gives MEAN an increased level of renewable energy generation in SPP, thereby reducing carbon emissions, and realizes additional value in the limited dispatch of the battery storage.

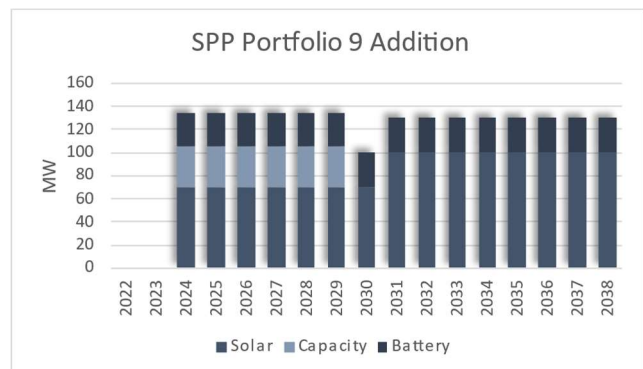


Figure XIV-10

Portfolio 10: Extend Power Purchase of Cooper Nuclear Station

Portfolio 10 retains in MEAN's portfolio a carbon free resource whose contract would otherwise end in 2024. The same capacity and energy from Cooper Nuclear Station would remain in MEAN's resource portfolio with an additional capacity purchase from 2024-2029 for resource adequacy. This resource provides MEAN with a carbon free resource that has a high capacity factor and full accreditation. Although this resource has proven reliable in the past, CNS is a must-run unit that does not allow for flexibility.

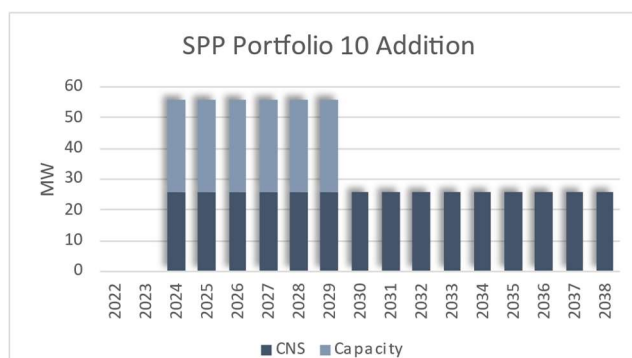


Figure XIV-11

2. West RegionPortfolio 1: Natural Gas Combined Cycle

MEAN would contract for a partial ownership or a power purchase agreement for capacity and energy from a natural gas combined cycle plant sized to meet the energy needs in the West. The NGCC plant would be operated in response to load until such time that an RTO is adopted in the West. No additional capacity purchase is required for resource adequacy. This portfolio achieves the goal of diversifying MEAN's resource portfolio in terms of fuel source, reduces emissions as compared to coal facilities, and provides reliability and a high degree of operational flexibility.



Figure XIV-12

Portfolio 1D: Natural Gas Combined Cycle with Carbon Capture

MEAN would contract for a partial ownership or a power purchase agreement for capacity and energy from a natural gas combined cycle plant fitted with a carbon capture system sized to meet the energy needs in the West. This plant is operated in response to load and unit operating parameters and would provide both capacity and energy to MEAN's load. No capacity



Figure XIV-13

purchase is required for resource adequacy. This portfolio allows MEAN to diversify the fuel sources of its resource portfolio, allows a reduction of emissions as compared to the coal units in the portfolio, and achieves the goals of resource flexibility and reliability.

Portfolio 2: Landfill Gas

MEAN would contract for a partial ownership or a power purchase agreement for capacity and energy from one or more landfill gas plants sized to meet the energy needs in the West. Landfill gas plants can be operated as must-run units or can be controlled with limited dispatch flexibility. The Phase II economic model for the West considers the LFG plant dispatched according to load requirements to provide capacity and energy. No purchase of additional capacity is required for resource adequacy. The LFG portfolio increases MEAN's percentage of renewables in the West as well as the reliability and fuel diversity of MEAN's portfolio.



Figure XIV-14

Portfolio 3: Municipal Solid Waste

This portfolio would add capacity and energy from an MSW plant to MEAN's portfolio via a partial ownership contract or a power purchase agreement sized to meet the energy needs in the West. The MSW plant would be operated according to load levels, unit operating parameters, and feedstock processing rates. The fully accredited capacity of the MSW plant is sufficient for resource adequacy, and no additional purchase is required. Although this option results in an increase in carbon emissions, MSW energy plants are considered renewable resources in many instances. This portfolio contributes to the renewable percentage in MEAN's West portfolio and creates a more diversified portfolio with regard to fuel source.

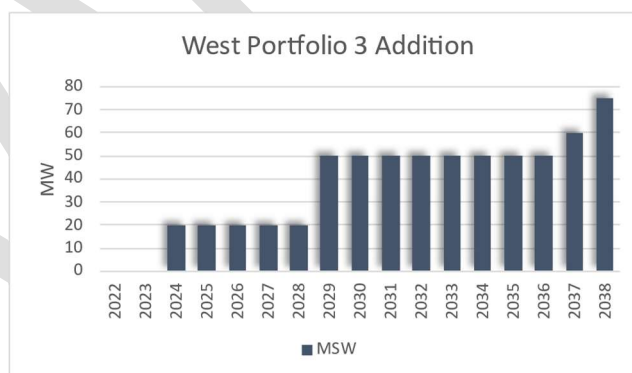


Figure XIV-15

Portfolio 4: Wind

MEAN would enter into a power purchase agreement for wind generation sized to meet the energy needs in the West. As wind receives a low accreditation value per ELCC calculations, an additional capacity purchase is added in 2025, with an increased amount from 2029 to 2038 for resource adequacy. Wind would be an intermittent resource in the West. The wind portfolio adds a significant amount of renewable energy generation to MEAN's resource mix but does not contribute to reliability or flexibility.

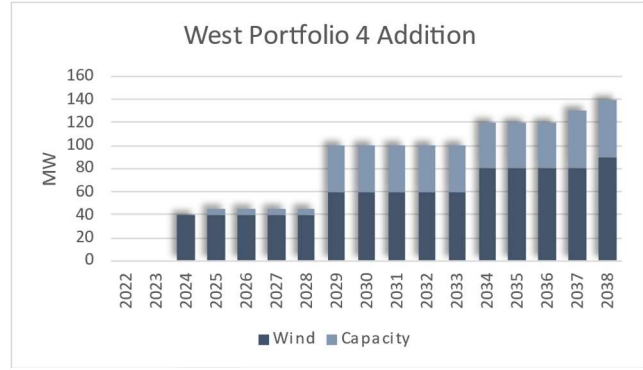


Figure XIV-16

Portfolio 5: Solar

In this portfolio, MEAN would enter into a power purchase agreement for utility owned solar generation to provide for energy needs in the West. The solar nameplate capacity is quite large due to the low capacity factor of solar generation facilities. And because of the ELCC accreditation method, a capacity purchase will be required from 2029 to 2038. This portfolio increases MEAN's renewable energy in the West but reduces flexibility to respond to load fluctuations or market pricing changes.



Figure XIV-17

Portfolio 6: Fuel Cell

MEAN would contract for a partial ownership or a power purchase agreement for capacity and energy from one or more natural gas-fired fuel cell plants in an aggregate size to meet the energy needs in the West. The fuel cell plant would be operated to match load requirements, until an RTO is implemented in the West. No additional capacity is required for resource adequacy. This portfolio achieves the goal of diversifying MEAN's resource portfolio in terms of fuel source, achieves a level of reduced emissions as compared to coal facilities, and provides reliability and operational flexibility.

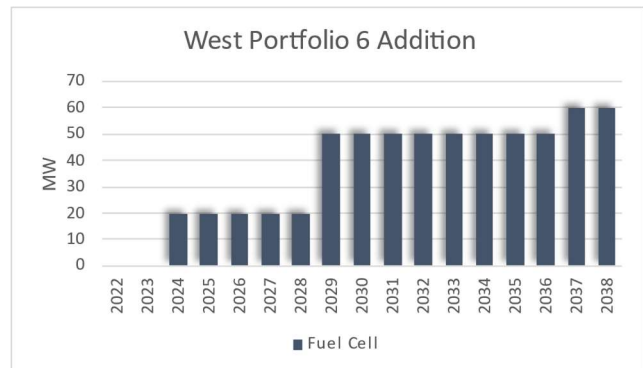


Figure XIV-18

Portfolio 7: Hydropower

Portfolio 7 adds a power purchase agreement for full or partial capacity and energy from a dispatchable hydropower plant. The agreement would be sized to meet energy needs in the West. The hydropower plant would be operated at limited dispatch as restricted by other water use downstream and in response to West load. No additional capacity purchase is required with this resource option. The hydropower portfolio grants MEAN additional renewable energy in the West while also maintaining a moderate degree of flexibility and reliability.



Figure XIV-19

Portfolio 8: Wind + Battery Storage

This portfolio begins with the same wind resource and capacity purchase modeled in Portfolio 4, but also adds a 4-hour battery to the system. The battery would be charged as available and discharged in response to West load. An additional capacity purchase is required throughout the study period, starting small in 2025 and increasing in 2029. This portfolio allows MEAN to increase the renewable energy generation in the West and realizes additional value in the limited dispatch of the battery storage.



Figure XIV-20

Portfolio 9: Solar + Battery Storage

In the same manner, Portfolio 9 adds a 4-hour battery to the solar resource and capacity purchase modeled in Portfolio 5. The battery would be charged as available and discharged in response to MEAN's West load. This solar plus storage portfolio gives MEAN an increased level of renewable energy generation in SPP, thereby reducing carbon emissions, and realizes additional value in the limited dispatch of the battery storage.

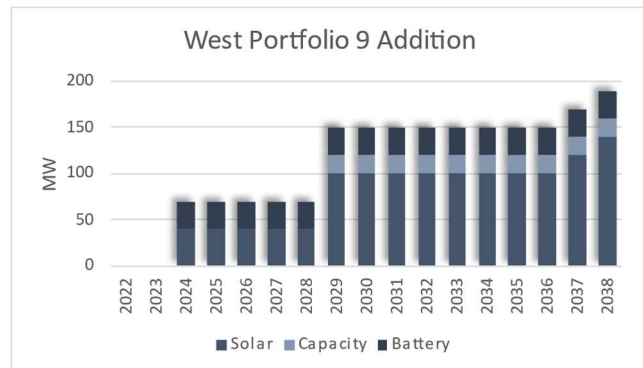


Figure XIV-21

D. Hourly Resource Profile

To study each of the proposed portfolios, the model determines the generation of each resource in the portfolio on an hourly basis. This begins with the hourly resource profile, or hourly available capacity.

Available capacity is determined according to season of year, time of day, planned maintenance, forced outage rates, and variable fuel costs. Availability of existing resources is modeled on historical operating data, unit minimums, and planned outage schedules. For proposed new resources, availability is modeled after similar existing resources, known capacity factors, projected planned and forced outage rates, and for intermittent resources, hourly generation profiles of similar technologies in similar locations. Batteries' availability is dependent on charge level.

However, resource availability does not ensure dispatch. Actual generation of a resource depends on its operation type. Intermittent and must-run resources run solely on availability without control over operation. Some units have operating minimums that limit the turndown level of generation, which influences the hourly generation. For dispatchable resources, the model dispatches resources differently in SPP and the West. In the SPP model, it is assumed that any dispatchable resources will be operated in response to market pricing, within unit operating parameters. In the West, the dispatchable resources are modeled to operate according to load requirements, again within the unit's operating parameters. Battery systems are modeled to optimize the renewable resource output in terms of market price or system load.

E. Economic System Model

The Economic System Model used for the portfolio analysis is depicted in *Figure XIV-22*:

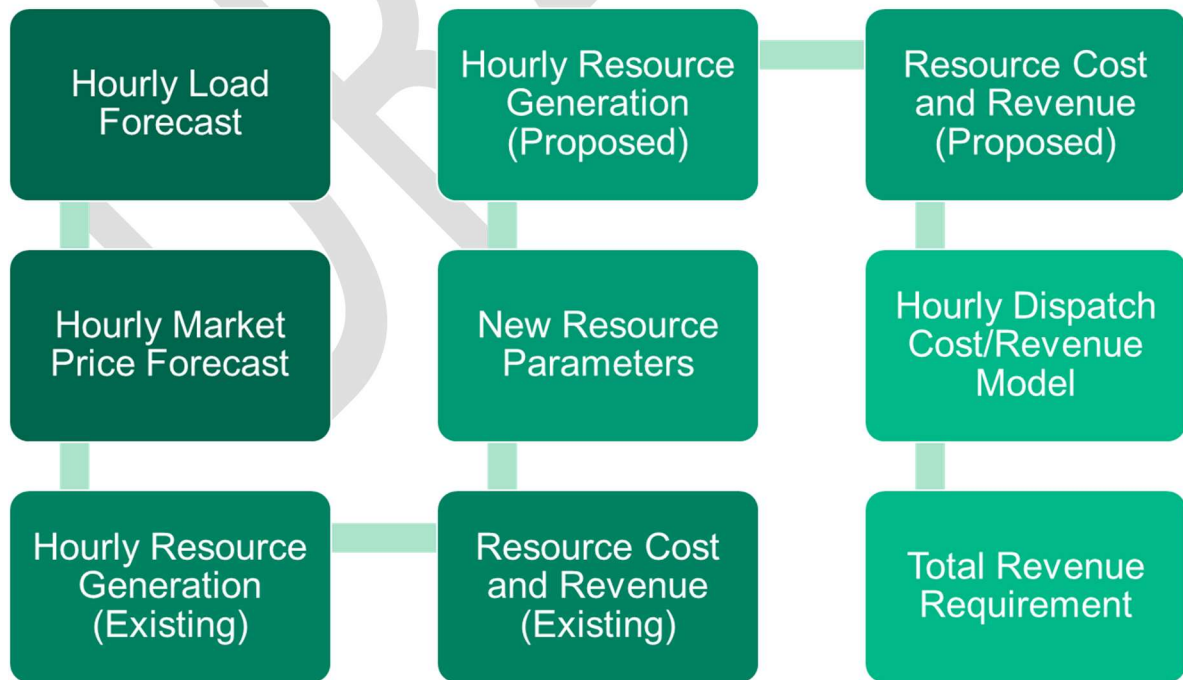


Figure XIV-22

The model calculates the deployment of available capacity, as determined by market and unit economics, to meet anticipated demand on a least-cost basis. Due to regional differences, separate models were created for SPP and the West.

Since market conditions and economics change on an hourly basis, each region's load was calculated hour by hour for the entire 15-year time range. This was accomplished by calculating each town's annual hourly load profile (including reserve margin and transmission loss) averaged over the last 10 years and applying the hourly profile to the forecasted monthly peak demand and energy consumption and finally summing each region's hourly load.

Hourly market pricing was provided by a third-party consultant. The pricing provided was specific to regional areas. Since economic dispatch in market constructs is determined in part by the locational marginal pricing, the model needed the individual nodal prices for each MEAN resource and proposed future resource as well as a load price. Comparing historical nodal pricing to a historical average regional price on an hourly basis created an hourly profile that related the nodal price to the regional price. This profile was then applied to the forward pricing projections for the larger areas. This calculated pricing per hour for the 15-year study period for each resource and the MEAN load node in SPP. In the west, the subregional hourly pricing was used per resource location.

For existing resources, current costs of generation were compiled, including fixed operation and maintenance costs, variable operation and maintenance costs, fuel costs, debt service, A&G costs, and anticipated capital investment. The escalation rates for future pricing were extracted from past billings, contract terms, and budgets supplied by unit owners. In addition, actual operating parameters were recorded, such as heat rates and emissions factors.

Similarly, operating parameters and costs were estimated for new resources. Operating metrics, such as capacity factor, emissions data, outage rates, minimum turndown, etc. were collected primarily from publicly available data from EIA, NREL, and other DOE sources as well as some published studies. From these same sources, the generating costs of the proposed resources were calculated using capital costs, fixed O&M, variable O&M, and fuel costs with a determination of the escalation rate of each cost.

For some of the studied resources, MEAN has obtained proposed contract terms and operating data for actual resources of the same type. In these cases, the actual data was utilized if possible and if in relative agreement with the publicly sourced data for representative resources.

The hourly resource profile as described above only determined when each resource was available to operate, and in the case of existing and intermittent resources, the typical expected generation for each hour. Resource availability, however, does not guarantee resource operation for dispatchable resources. To account for economic dispatch in the SPP market, the variable operating costs of a resource were compared against the nodal locational marginal price on an hourly basis.

Each resource was then categorized according to its operating mode – intermittent resources, must-run resources, WAPA allocations, resources with minimum operating levels, and dispatchable resources. All resources were dispatched into the model against the hourly load according to operating mode. This resulted in a tabulation of the hourly generation, the hourly cost of generation, the hourly revenue from market sales, the hourly cost of market purchases, and the hourly cost of load (in SPP).

Each portfolio was entered into its regional model, and the revenue requirements were calculated for each portfolio. All costs and revenues were summed on an hourly basis, then combined on an annual basis, and finally summed for the entire 15-year study period to arrive at the total revenue requirement.

It should be noted that the revenue requirements calculated by the model include only resource-related costs of the components input into the model. These values are not intended to represent MEAN's total revenue requirements.

F. Sensitivity Scenario Analysis

The model was expanded to include the effects of a number of different scenarios. As external conditions change, generation costs and market costs change. This alters the economics of each portfolio in a different way. Three very significant factors that affect generation are system load, natural gas prices, and the potential of a carbon tax. The total system load will determine the resources called online in the generation stack and will therefore set the marginal price. Changes in natural gas pricing influence the generation level of natural gas resources, which are very often the marginal units, and as a result will affect the generation of other resources to compensate in response to load demand, which in turn affects the pricing of other fuels. In this way, fuel pricing impacts the overall regional resource mix as well as setting the market price. In the same way, the imposition of a carbon tax will increase the generating cost of some resources, which changes generating levels, fuel costs, and market costs.

In addition to changes in market pricing and carbon tax, the scenarios also include fuel adjustments resulting from the scenario conditions. These adjustments were applied to existing and proposed future resources.

The sensitivity analysis looked at nine possible scenarios that involve variations of these factors. The table in *Figure XIV-23* displays the scenarios under which the model was simulated. Each portfolio was entered into the model for each sensitivity.

Scenario	System Load	NG Pricing	CO ₂ Tax
Scenario 1: Reference	Base Case Load	Base Case NG	No CO ₂ Tax
Scenario 2: High Load	High Load	Base Case NG	No CO ₂ Tax
Scenario 3: Low Load	Low Load	Base Case NG	No CO ₂ Tax
Scenario 4: High NG	Base Case Load	High NG	No CO ₂ Tax
Scenario 5: Low NG	Base Case Load	Low NG	No CO ₂ Tax
Scenario 6: Zero Carbon*	Base Case Load	Base Case NG	No CO ₂ Tax
Scenario 7: High NG CO₂	Base Case Load	High NG	CO ₂ Tax
Scenario 8: Low NG CO₂	Base Case Load	Low NG	CO ₂ Tax
Scenario 9: Carbon Tax	Base Case Load	Base Case NG	CO ₂ Tax

*Zero Carbon Scenario assumes regulatory conditions that allow no future addition of carbon emitting resources.

Figure XIV-23

G. Model Results

Each region’s model was run with each portfolio and for each scenario. The results of the models are shown below in terms of energy, capacity, revenue requirement, and volatility.

1. SPP

Below are the graphs illustrating the energy and capacity generated by each type of resource in MEAN’s SPP portfolio over the 15-year study period with the adoption of each studied resource:

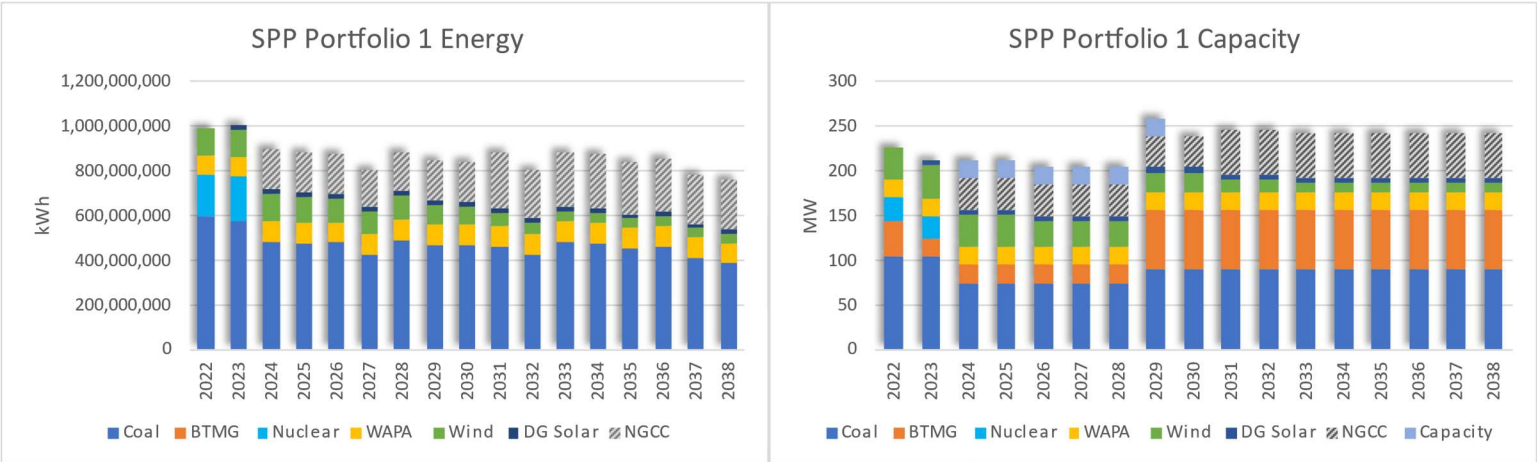


Figure XIV-24

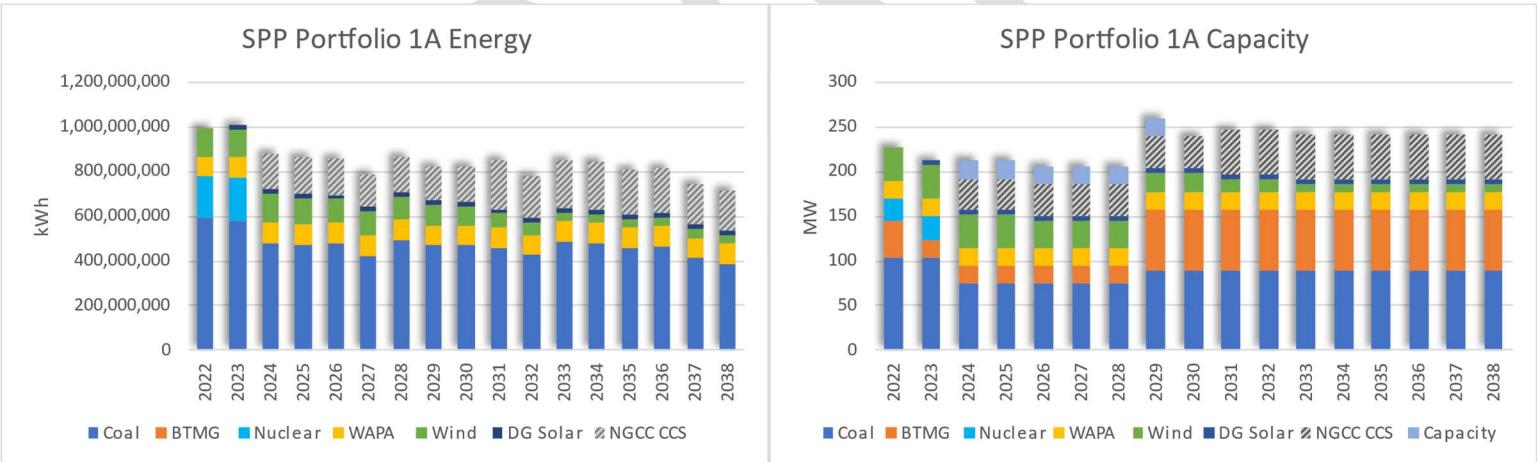
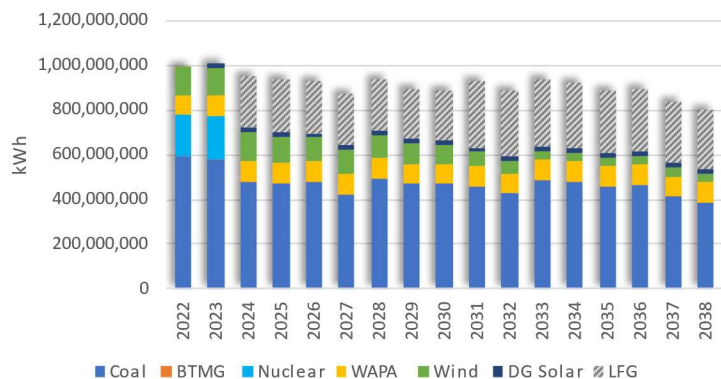


Figure XIV-25

SPP Portfolio 2 Energy



SPP Portfolio 2 Capacity

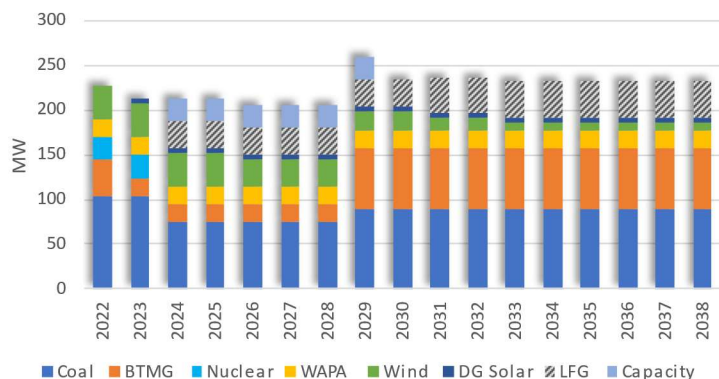
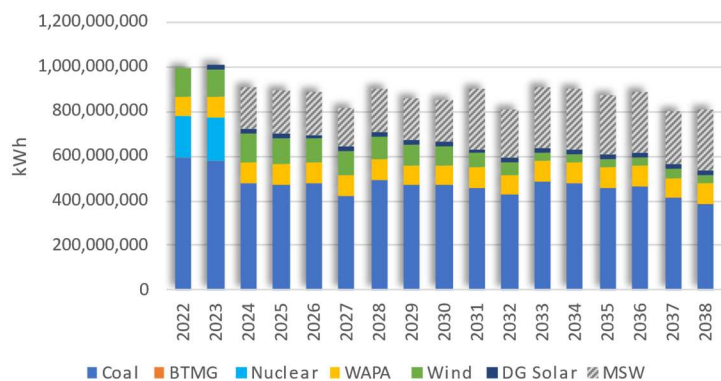


Figure XIV-26

SPP Portfolio 3 Energy



SPP Portfolio 3 Capacity

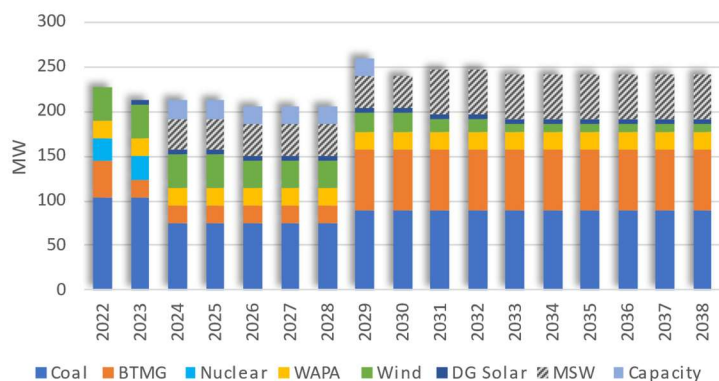
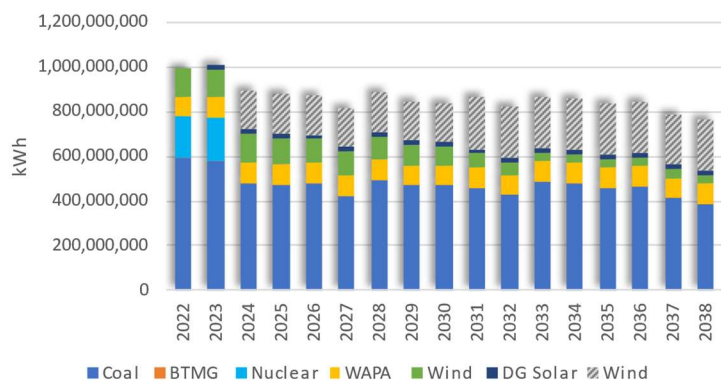


Figure XIV-27

SPP Portfolio 4 Energy



SPP Portfolio 4 Capacity

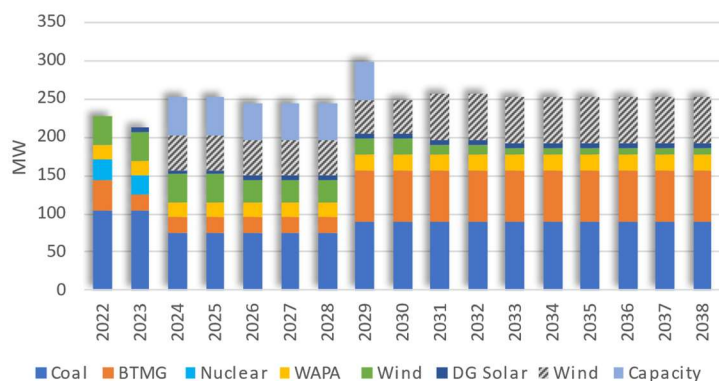


Figure XIV-28

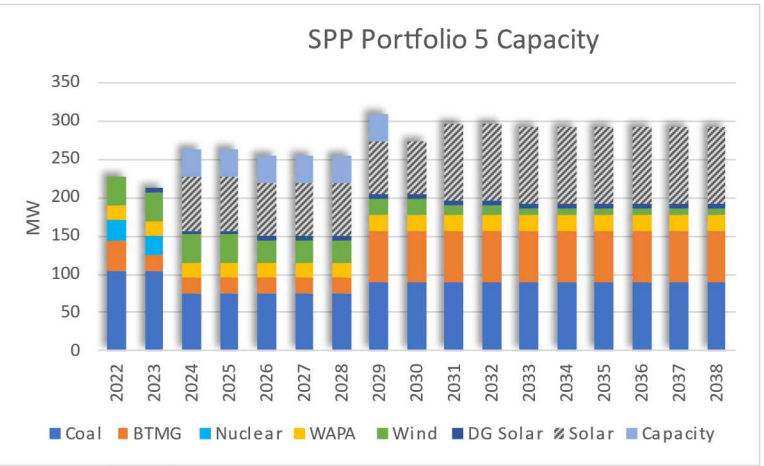
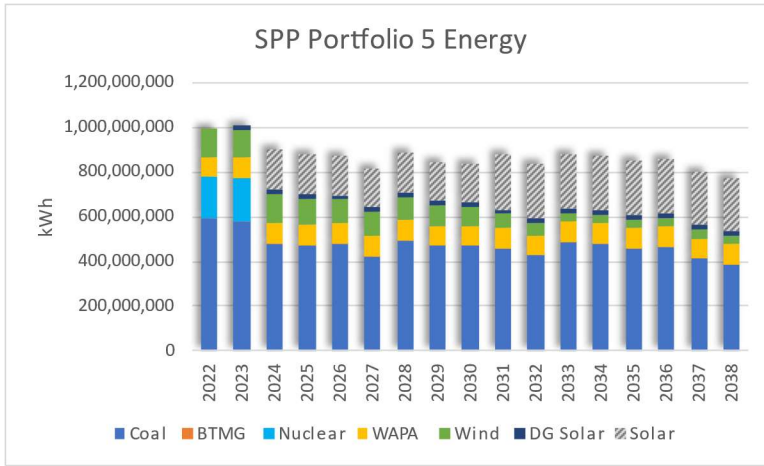


Figure XIV-29

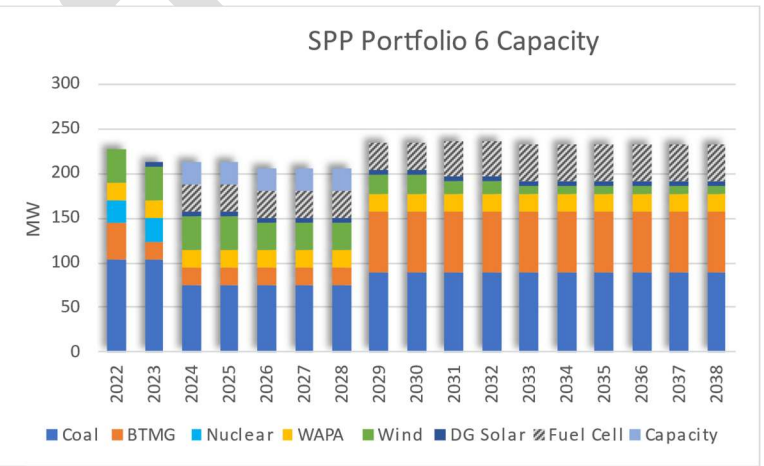
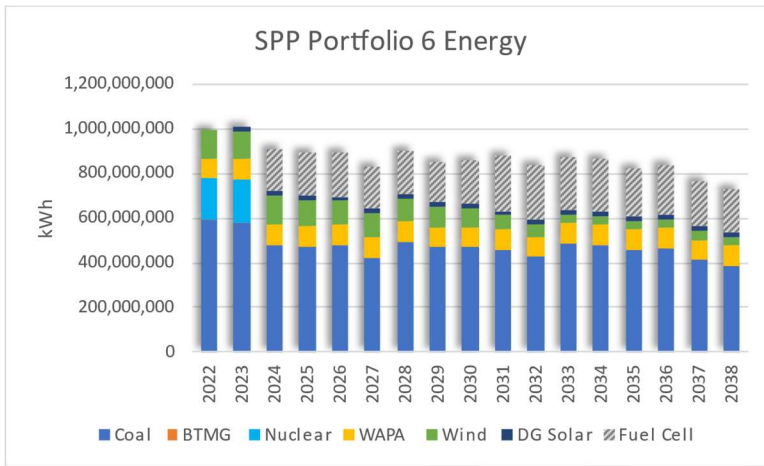


Figure XIV-30

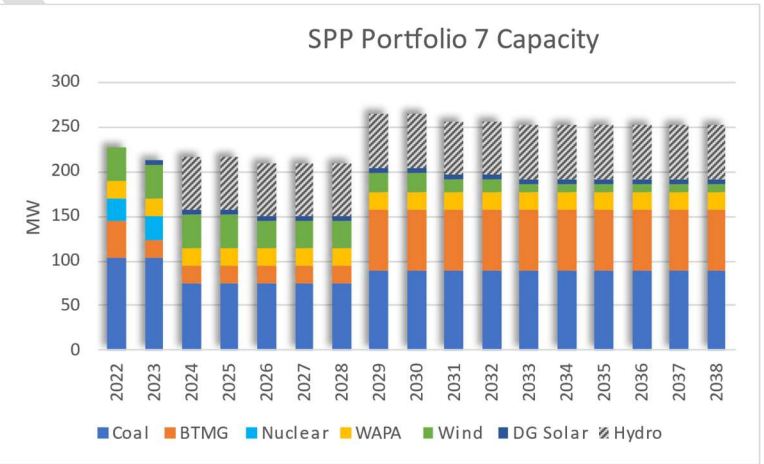
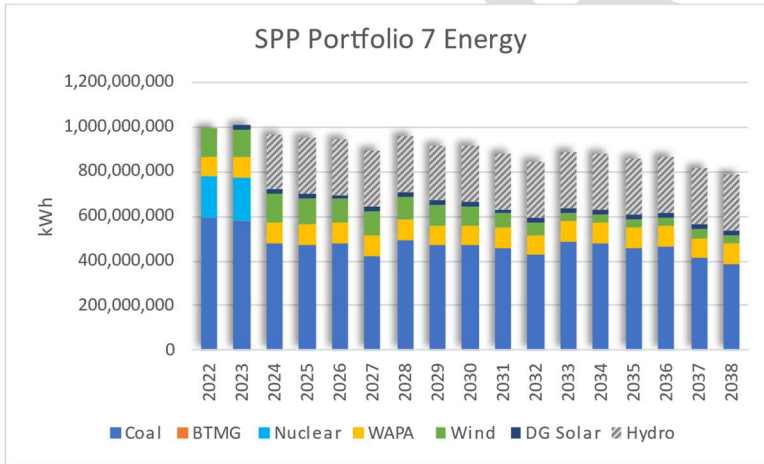


Figure XIV-31

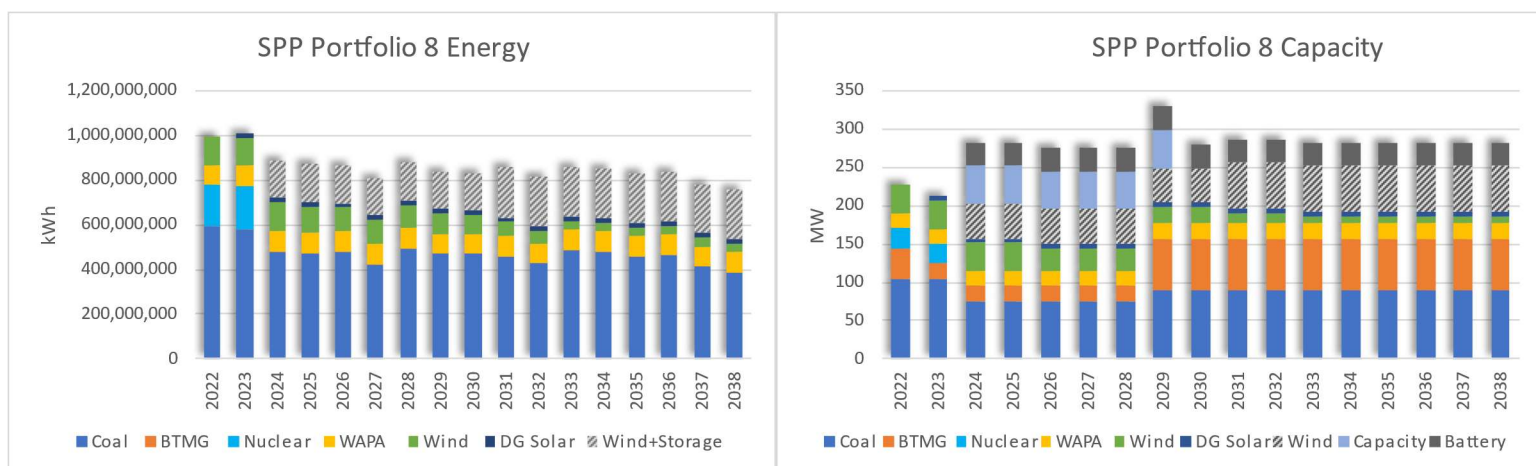


Figure XIV-32

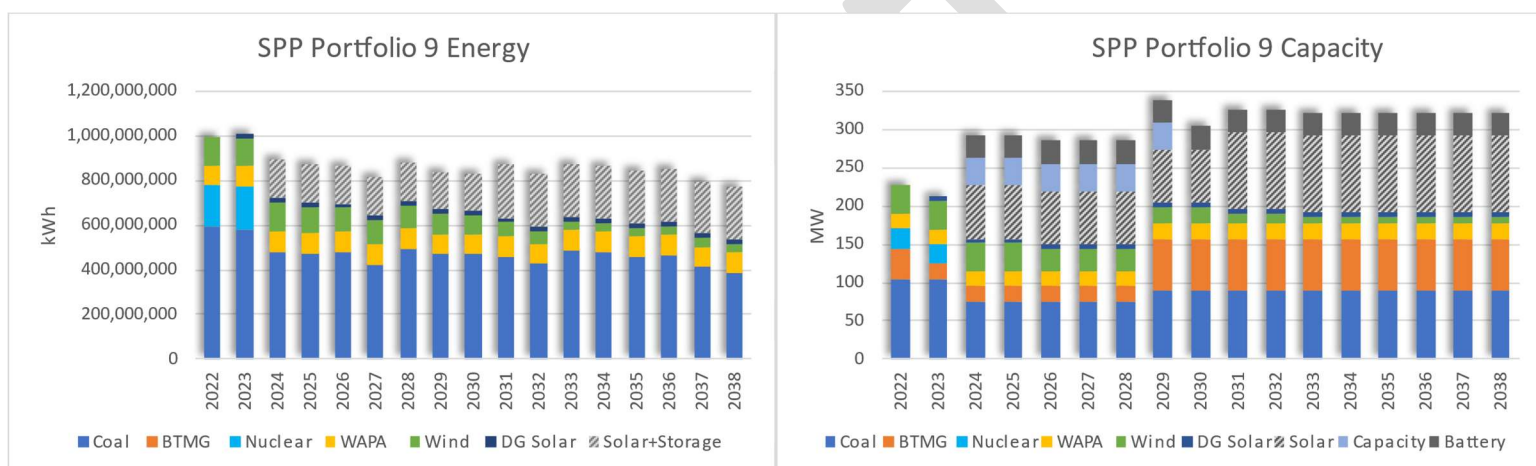


Figure XIV-33

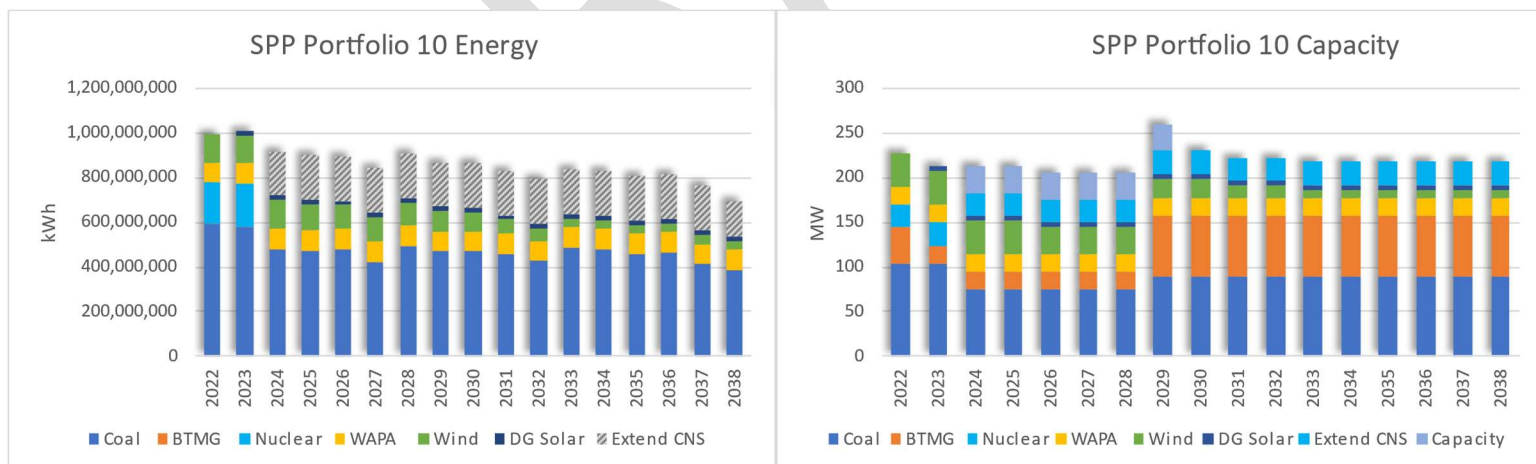


Figure XIV-34

The chart in *Figure XIV-35* shows the revenue requirement results of the SPP model for all ten portfolios described in Section XIV.C.1. and Section XIV.C.2. and all nine scenarios tabulated in *Figure XIV-23*. The dark blue bar represents the base case total 15-year revenue requirement for each portfolio. The light blue vertical line shows the positive and negative deviation from the base case, or the range from the maximum revenue

requirement of the sensitivity scenarios and the minimum revenue requirement of the sensitivity scenarios. This range is termed the “scenario variance”.

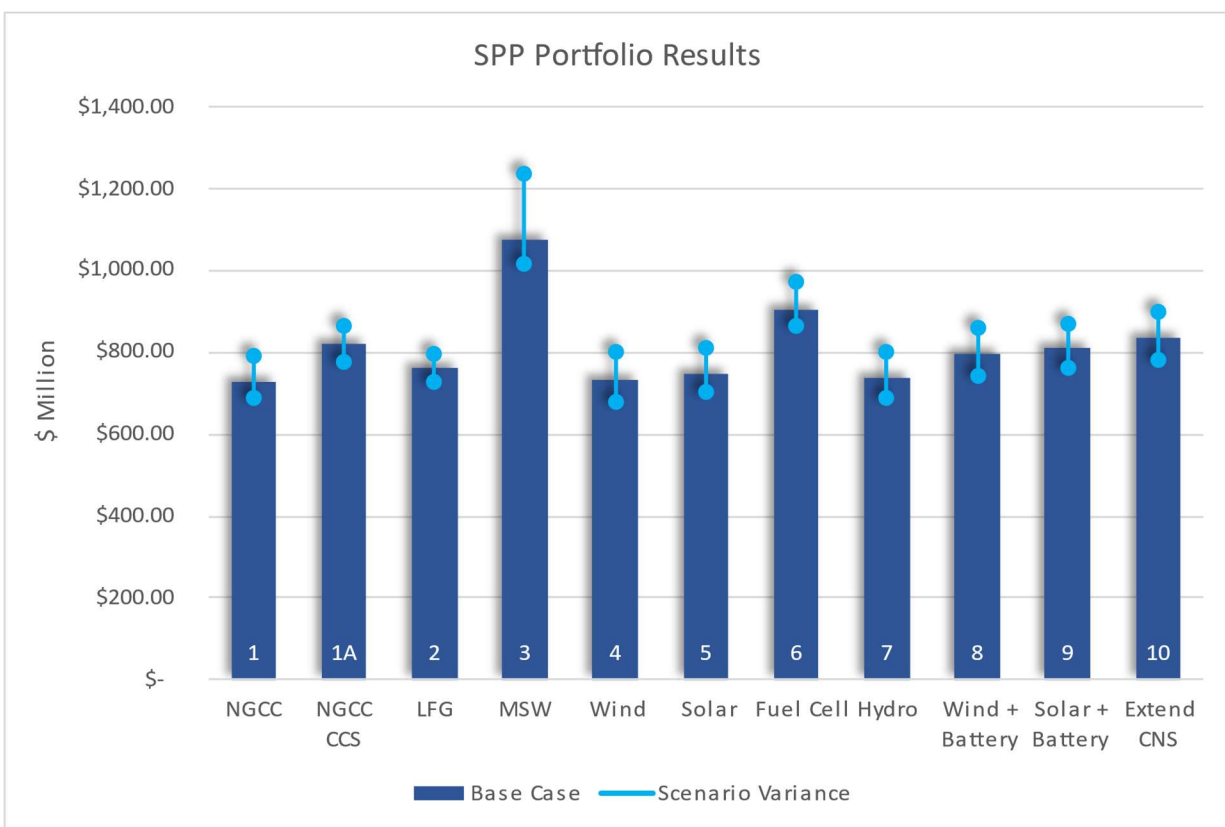


Figure XIV-35

The table in Figure XIV-36 illustrates the same data with the values displayed and the addition of two metrics showing the incremental percentage above the lowest cost portfolio, termed “Cost Premium,” and the positive variance above the reference scenario in terms of \$/MWh.

Portfolio #	Description	Revenue Requirement (Reference Case)	Cost Premium	\$/MWh Variance
Portfolio 1	NGCC	\$ 726,236,996	0.00%	\$ 4.53
Portfolio 1A	NGCC CCS	\$ 819,371,754	12.82%	\$ 3.23
Portfolio 2	LFG	\$ 761,767,195	4.89%	\$ 2.26
Portfolio 3	MSW	\$ 1,073,853,337	47.87%	\$ 10.80
Portfolio 4	Wind	\$ 735,024,122	1.21%	\$ 4.40
Portfolio 5	Solar	\$ 749,466,854	3.20%	\$ 4.05
Portfolio 6	Fuel Cell	\$ 906,794,624	24.86%	\$ 4.38
Portfolio 7	Hydro	\$ 739,806,994	1.87%	\$ 4.15
Portfolio 8	Wind + Battery	\$ 797,677,434	9.84%	\$ 4.39
Portfolio 9	Solar + Battery	\$ 810,162,441	11.56%	\$ 4.08
Portfolio 10	Extend CNS	\$ 838,043,559	15.40%	\$ 4.36

Figure XIV-36

The \$/MWh Variance, or the differential between the maximum scenario and the base case scenario revenue requirement on a per MWh basis, quantifies the volatility or the risk inherent in each portfolio relative to possible changes in realized load, fuel pricing, and carbon tax levels. Plotting the base case revenue requirement against this variance allows a concurrent view of cost and risk for each of the SPP Portfolios. These metrics are displayed in *Figure XIV-37*.

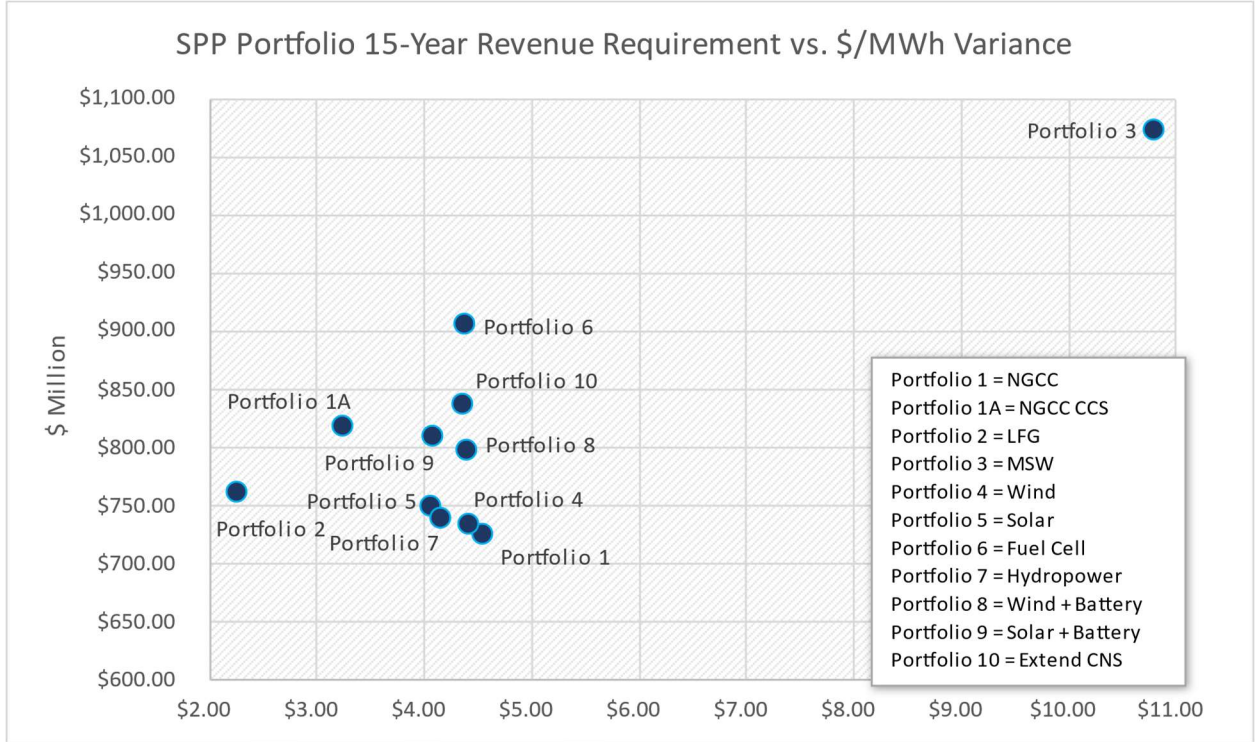


Figure XIV-37

To get a more distinct picture of the relative positions of the portfolios, Portfolio 3 is omitted from the graph in *Figure XIV-38*.

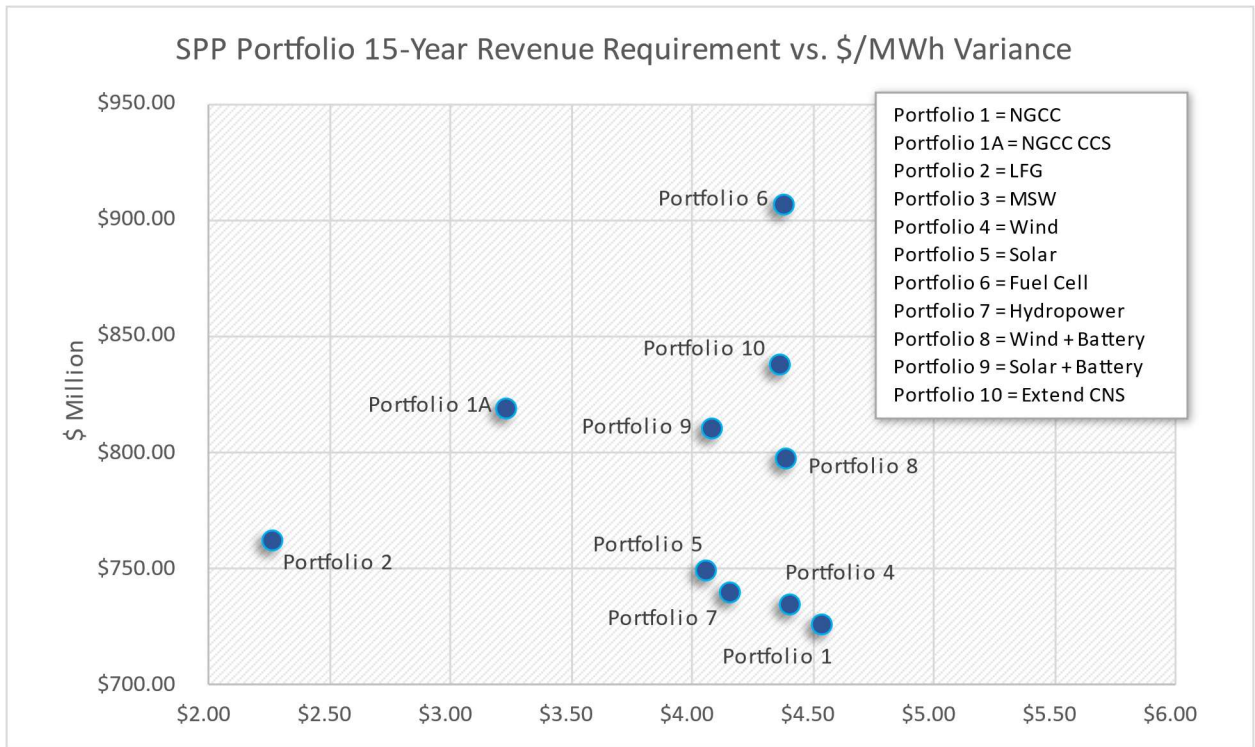


Figure XIV-38

The values and graphical results show that Portfolio 1, the natural gas combined cycle plant, has the lowest revenue requirement. However, Portfolio 4 (Wind), Portfolio 7 (Hydro), and Portfolio 5 (Solar) also have low revenue requirements and have variance levels that are as low or lower than Portfolio 1. Portfolio 2 (LFG) has a slightly higher revenue requirement and a much lower variance level.

2. West Region

Below are the graphs illustrating the energy and capacity generated by each type of resource in MEAN's West portfolio over the 15-year study period with the adoption of each studied resource:

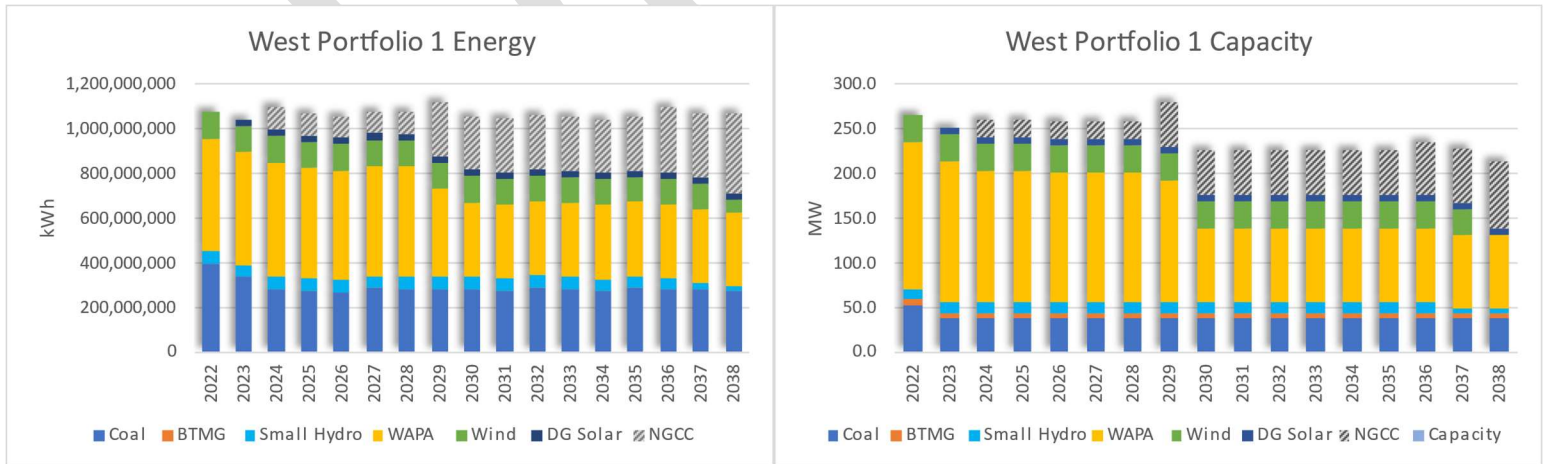


Figure XIV-39

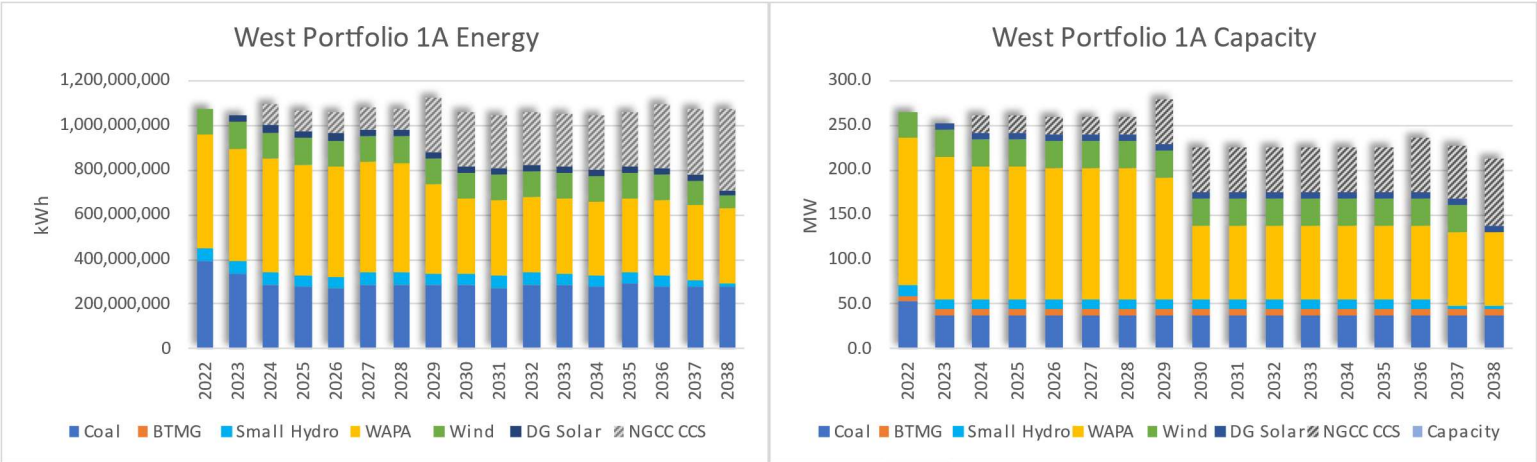


Figure XIV-40

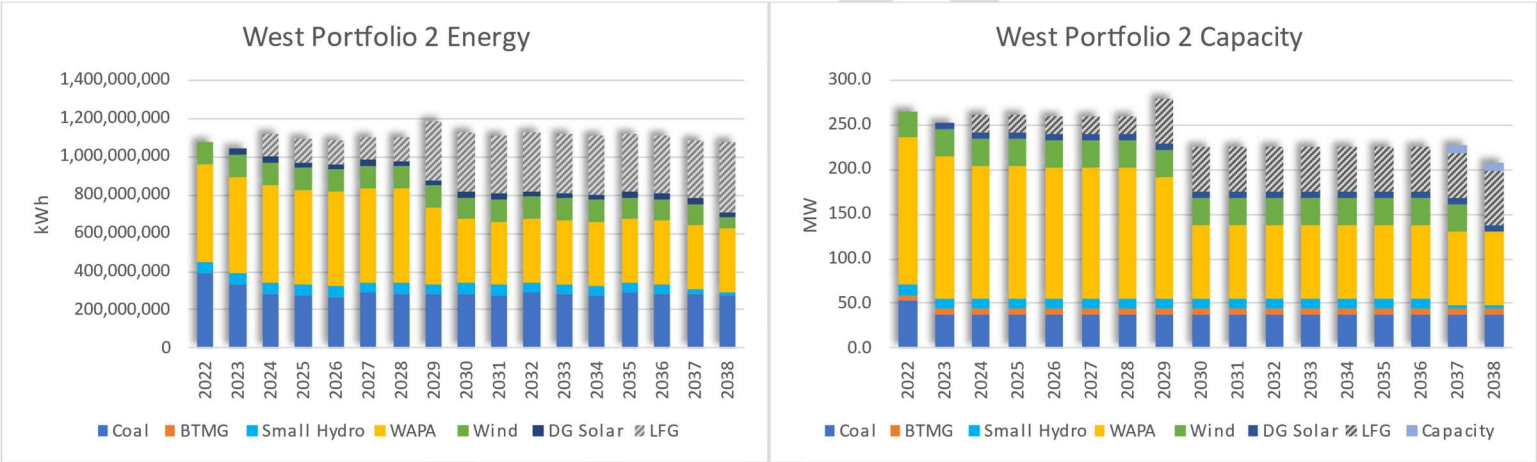


Figure XIV-41

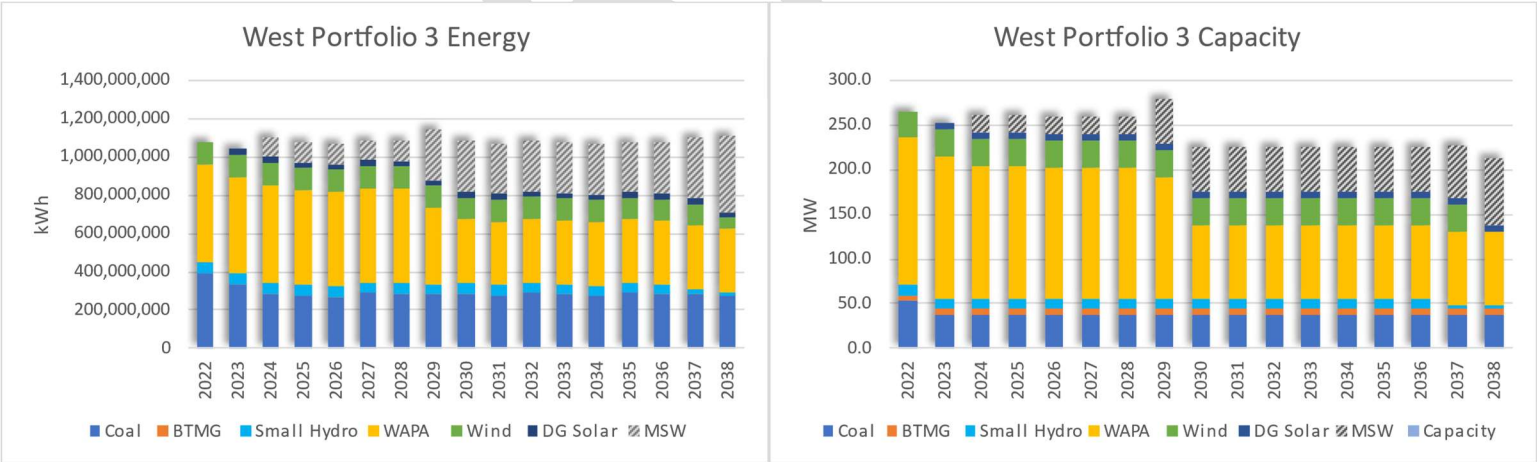


Figure XIV-42

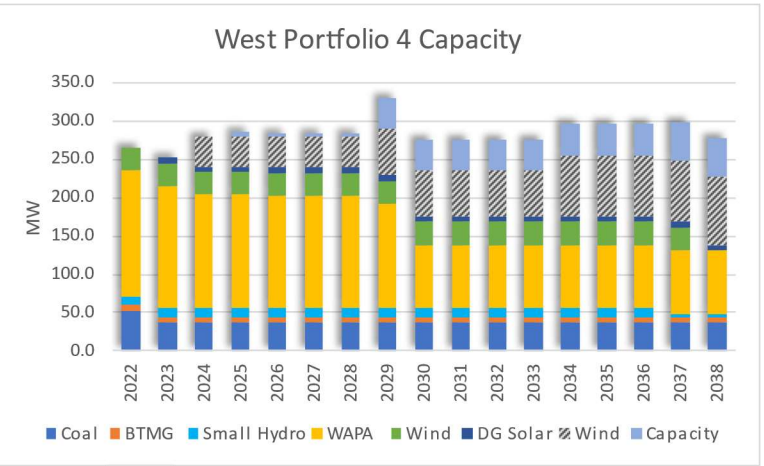
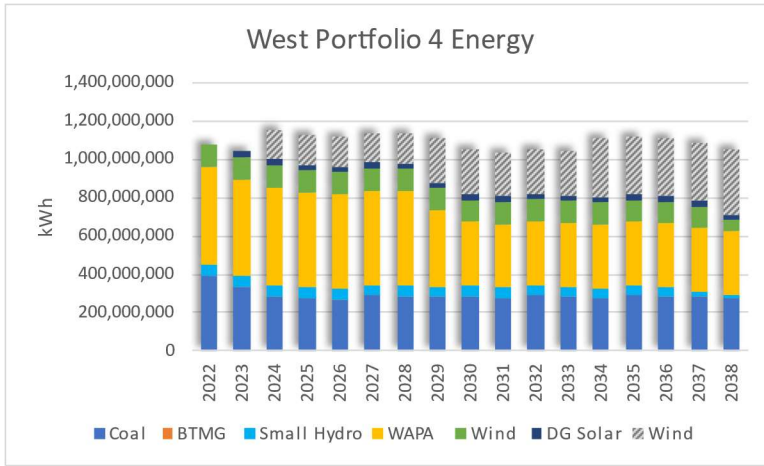


Figure XIV-43

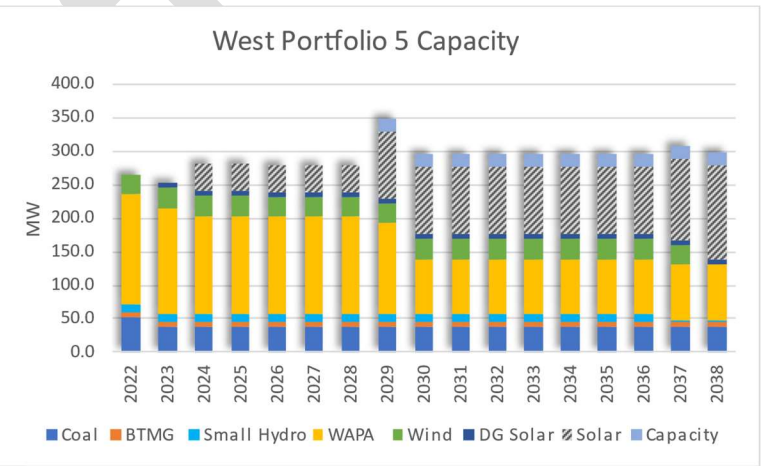
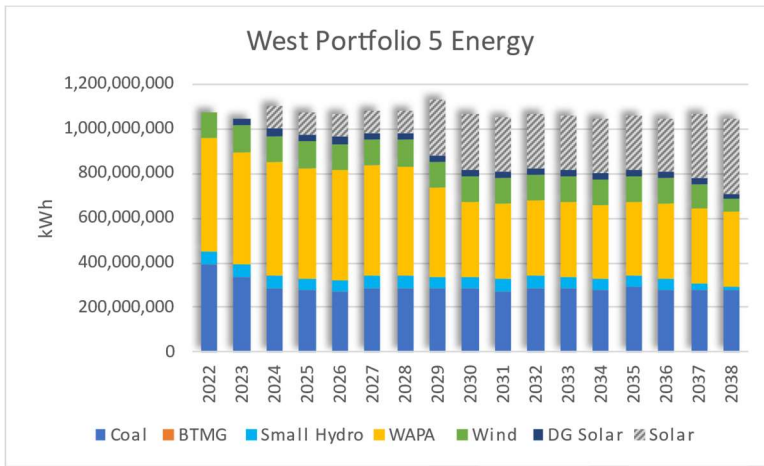


Figure XIV-44

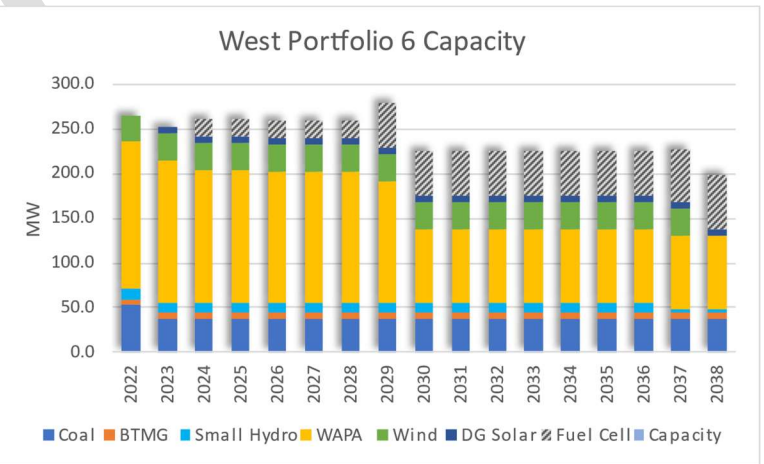
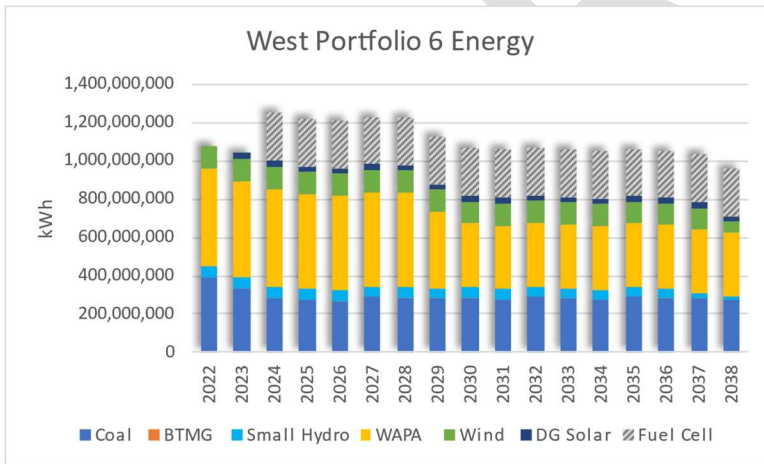


Figure XIV-45

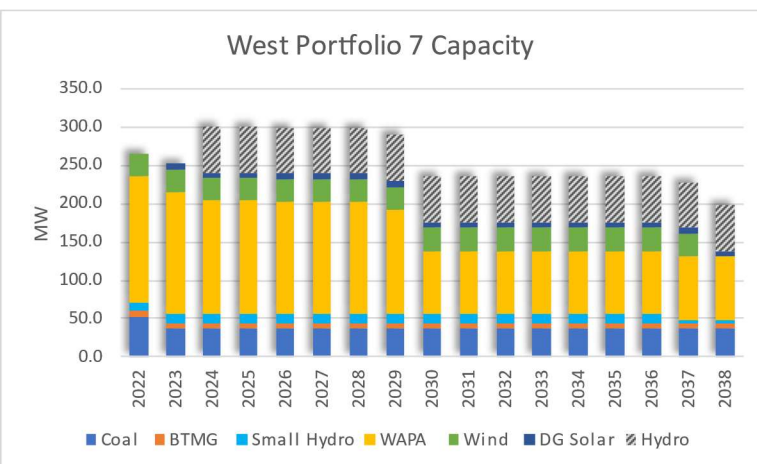
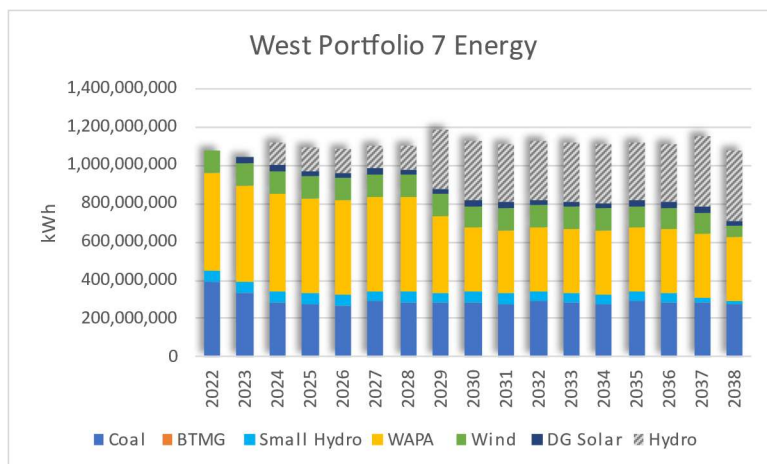


Figure XIV-46

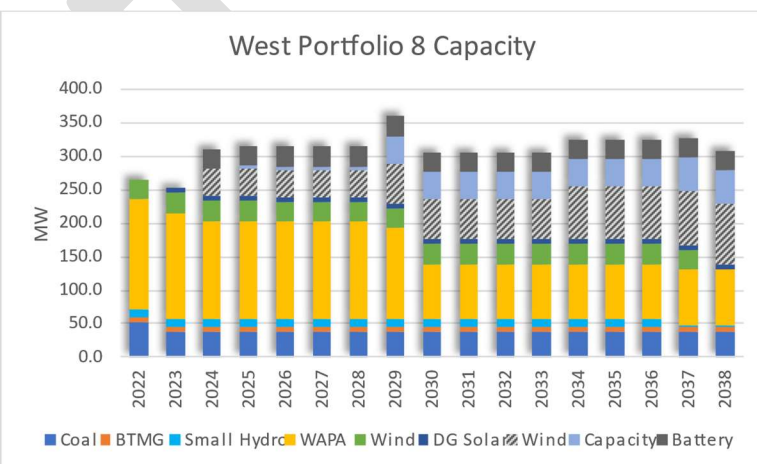
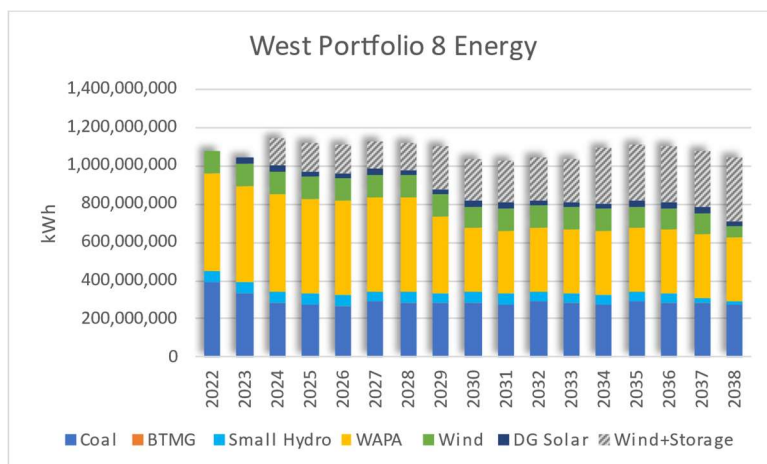


Figure XIV-47

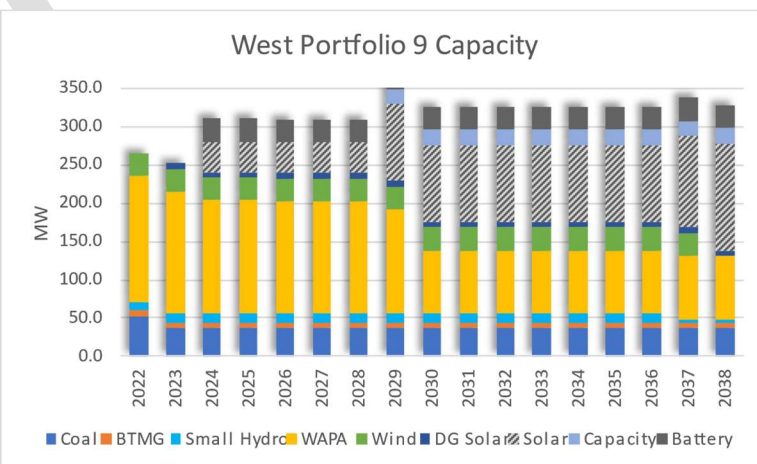
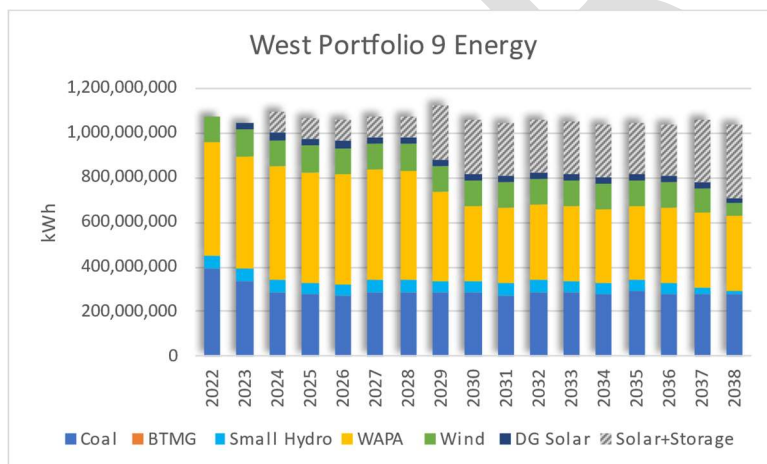


Figure XIV-48

The chart in *Figure XIV-49* shows the results of the west model for all nine portfolios and all nine scenarios. The dark green bar represents the base case total revenue requirement for each portfolio. The light green vertical line shows the positive and negative deviation from the base case, or the range from the maximum revenue requirement of the sensitivity scenarios and the minimum revenue requirement of the sensitivity scenarios. This range is termed the “scenario variance”.

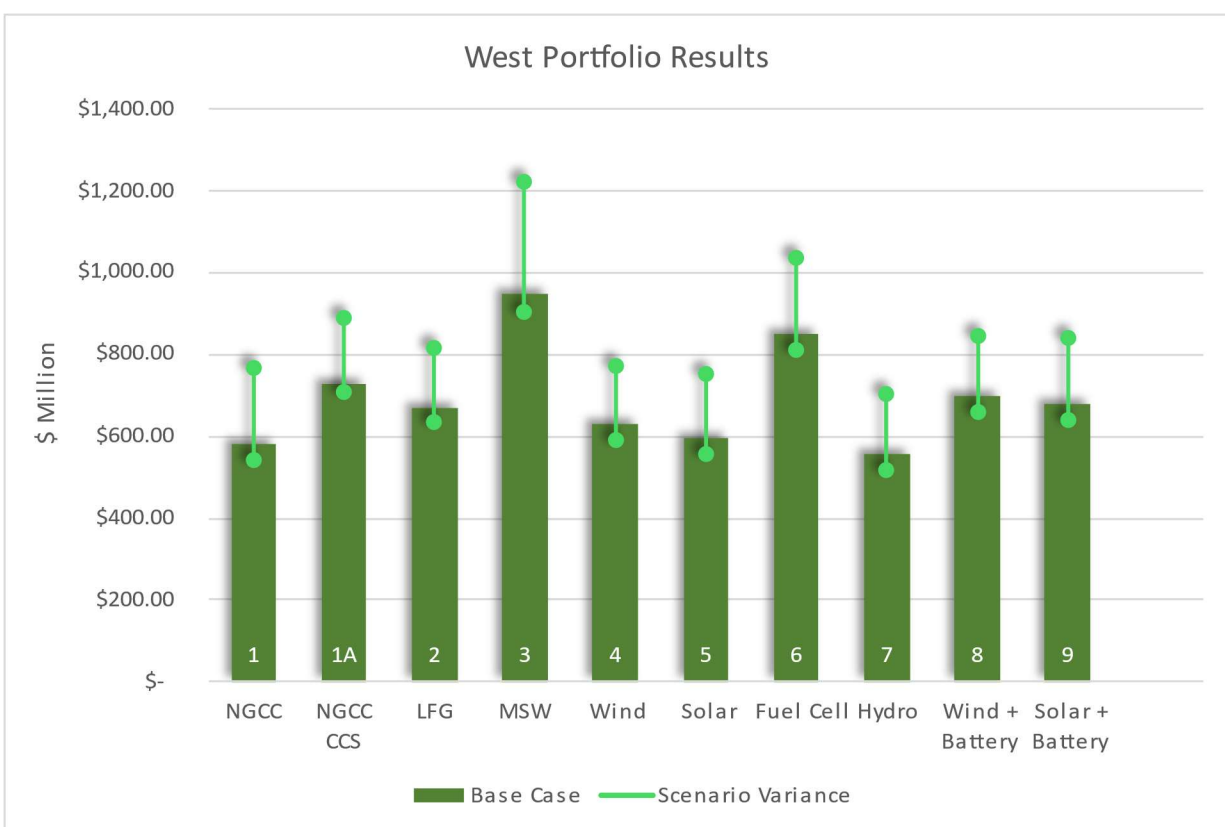


Figure XIV-49

The table in *Figure XIV-50* illustrates the same data with the values displayed and the addition of a metric showing the incremental percentage above the lowest cost portfolio, termed the “Cost Premium,” and the positive variance of the highest cost scenario above the reference scenario in terms of \$/MWh.

Portfolio #	Description	Revenue Requirement (Reference Case)	Cost Premium	\$/MWh Variance
Portfolio 1	NGCC	\$ 580,496,106	4.26%	\$ 10.22
Portfolio 1A	NGCC CCS	\$ 728,669,416	30.87%	\$ 8.80
Portfolio 2	LFG	\$ 672,001,680	20.69%	\$ 7.73
Portfolio 3	MSW	\$ 946,464,782	69.99%	\$ 14.88
Portfolio 4	Wind	\$ 629,945,559	13.14%	\$ 7.77
Portfolio 5	Solar	\$ 597,626,725	7.33%	\$ 8.66
Portfolio 6	Fuel Cell	\$ 850,591,267	52.77%	\$ 9.93
Portfolio 7	Hydro	\$ 556,790,179	0.00%	\$ 7.69
Portfolio 8	Wind + Battery	\$ 700,196,261	25.76%	\$ 7.84
Portfolio 9	Solar + Battery	\$ 681,653,840	22.43%	\$ 8.83

Figure XIV-50

The positive variance, or the differential between the maximum scenario revenue requirement and the base case revenue requirement, quantifies the risk inherent in each portfolio relative to possible changes in fuel pricing and carbon tax levels. Plotting the base case revenue requirement against this variance allows a concurrent view of cost and risk for each of the West Portfolios. These metrics are displayed in *Figure XIV-51*.

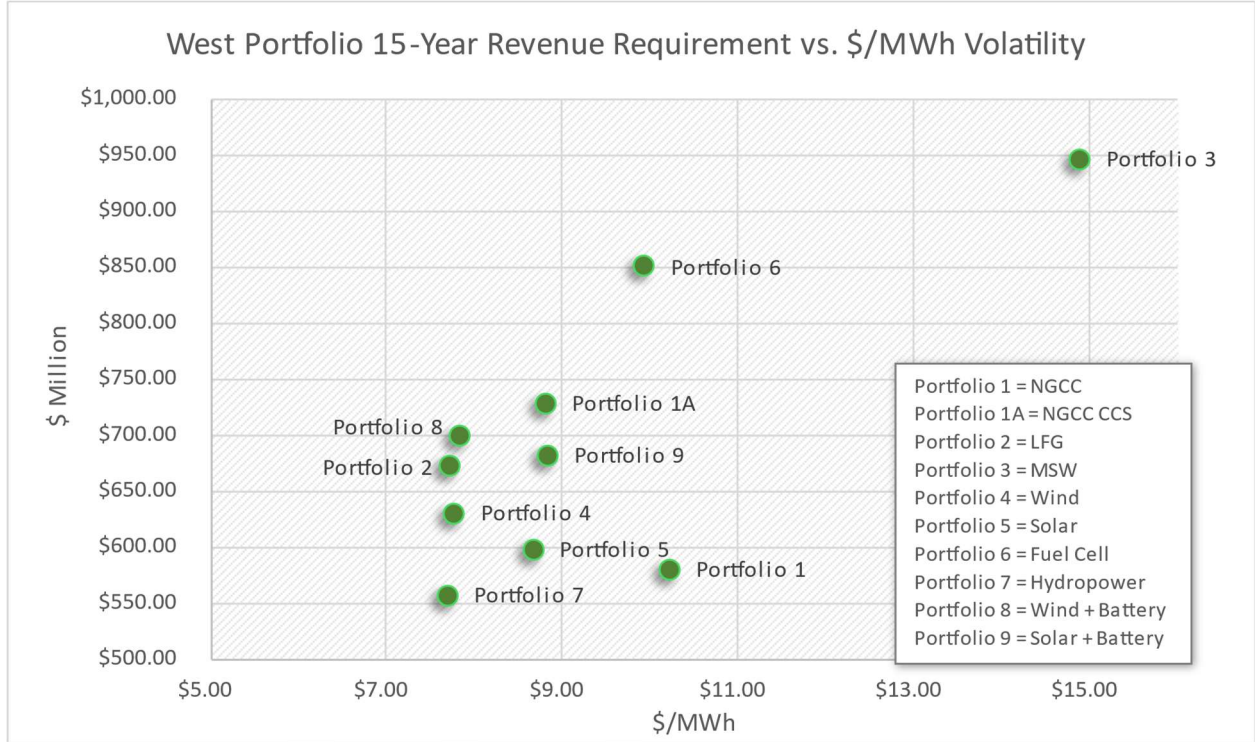


Figure XIV-51

To get a more distinct picture of the relative positions of the portfolios, Portfolio 3 is omitted from the graph in *Figure XIV-52*.

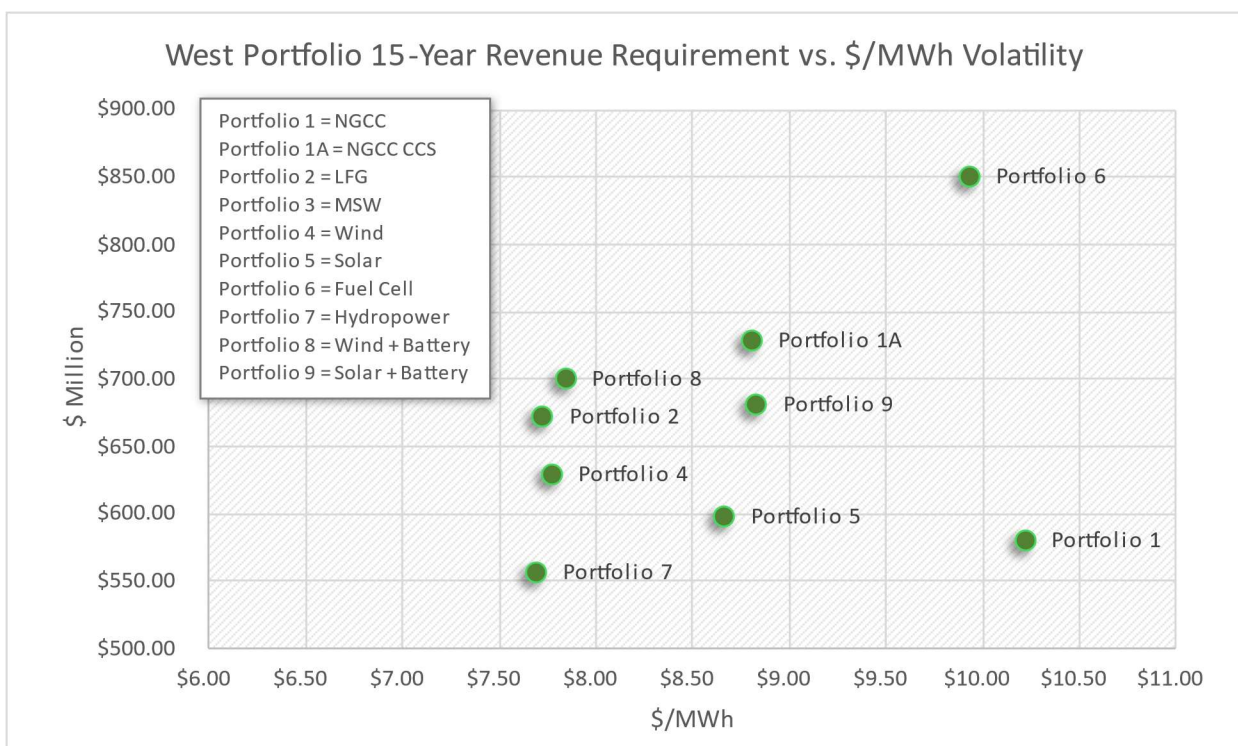


Figure XIV-52

The values and graphical results show that Portfolio 7, the hydropower plant, has the lowest revenue requirement, and the lowest variance level. However, Portfolio 5 (Solar) and Portfolio 4 (Wind) and revenue requirements and variance levels similar to that of Portfolio 7. Portfolio 1 (NGCC) resulted in a low revenue requirement, but a much higher level of variance. Portfolio 8 (Wind + Battery) and Portfolio 9 (Solar + Battery) align well with the corresponding Portfolios 4 and 5 but have the expected higher cost. Portfolio 2 (LFG) has a low variance level and a moderate revenue requirement.

XV. Environmental Impact

A. Existing Environmental Considerations

MEAN is subject to environmental and other regulations, in varying degrees, at federal, state and local levels. These regulations, as well as MEAN's compliance status, are detailed in Section IV.A.

As part of a long-term strategy, MEAN has invested in base load generating resources compliant with environmental regulations and expected to provide highly reliable base load generation for the Participants' present and future energy requirements. In addition to state-of-the-art coal facilities and WAPA allocations, MEAN has acquired renewable resources and carbon-free nuclear capacity and energy. MEAN has adopted the 2050 Vision which aims to create a carbon neutral resource portfolio by the year 2050. Future resource planning will follow the direction of the 2050 Vision, replacing carbon emitting resources with carbon free resources as existing contracts expire or resources reach the end of their operating life.

In the Phase I evaluation of supply side options, environmental impact was considered for all options as part of the scoring process. Three criteria reflected the consideration of a resource's current and future effects on the environment. Scoring categories included:

- Emissions/Environmental Impact, which calculated and compared the emissions levels for carbon, SO₂, NO_x, and mercury.
- Environmental Policy Risk, which estimated the degree to which a resource could be affected by the imposition of future environmental regulations.
- Progress Toward the 2050 Vision, which considered whether a resource will contribute toward a decrease in carbon emissions.

In the participant survey, these categories ranked near the middle, and therefore had an average weighting in relation to other criteria. As a result, the initial round of supply side resource evaluation acted to eliminate resource options that resulted in a high level of environmental impact.

B. Supply Side Resource Options Environmental Impact

Using the resultant energy generation of each resource in the candidate portfolios, both existing resources and future proposed resources, and the known emissions factor and heat rate of each resource, the carbon intensity of the portfolio can be calculated on the basis of tons of carbon emissions per MWh of electricity generated.

1. SPP

The progression of MEAN's SPP regional resource mix carbon intensity achieved with each portfolio is shown in the figures below:

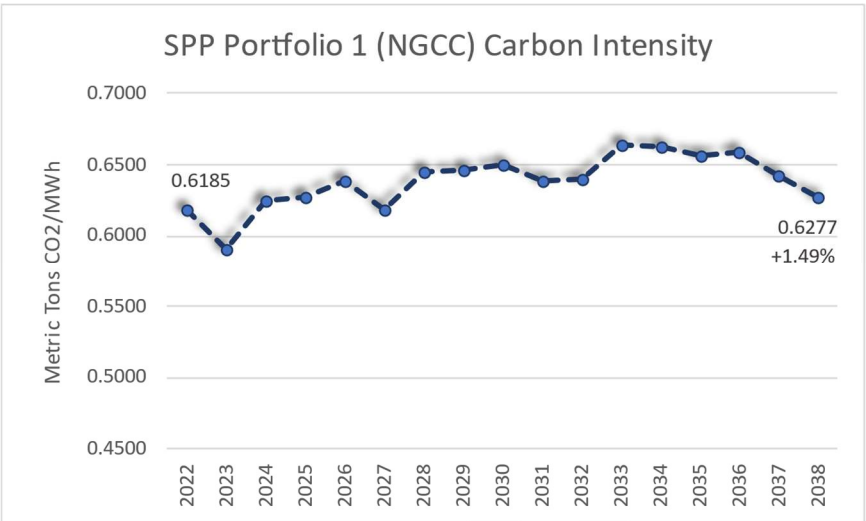


Figure XV-1

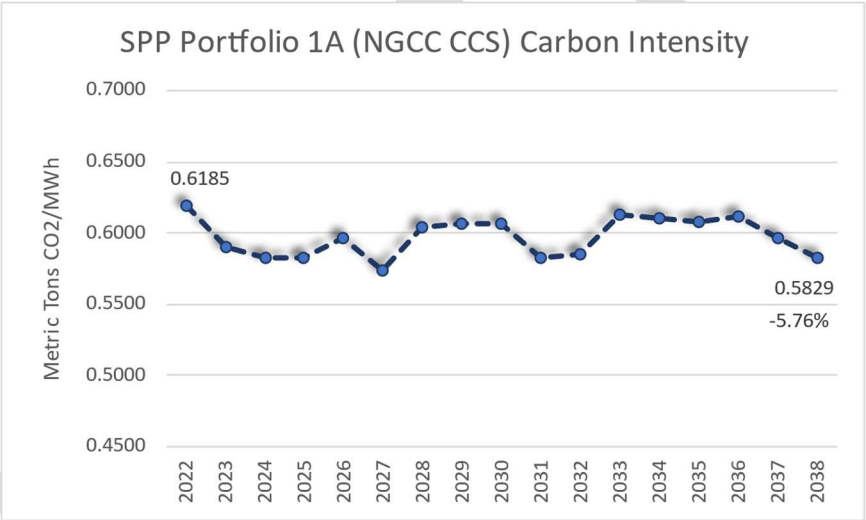


Figure XV-2

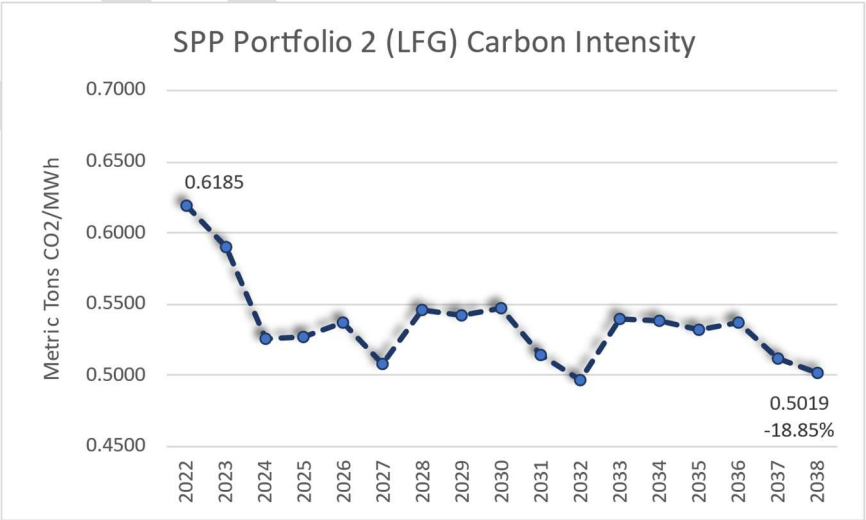


Figure XV-3

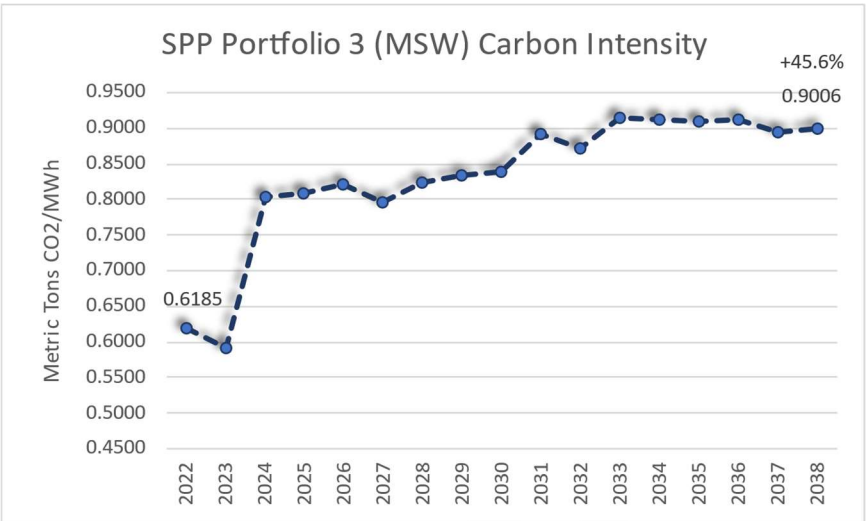


Figure XV-4

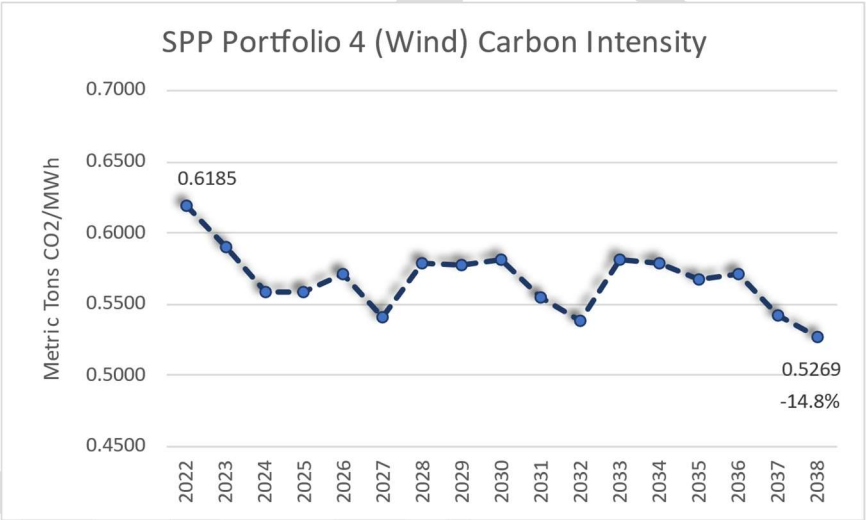


Figure XV-5

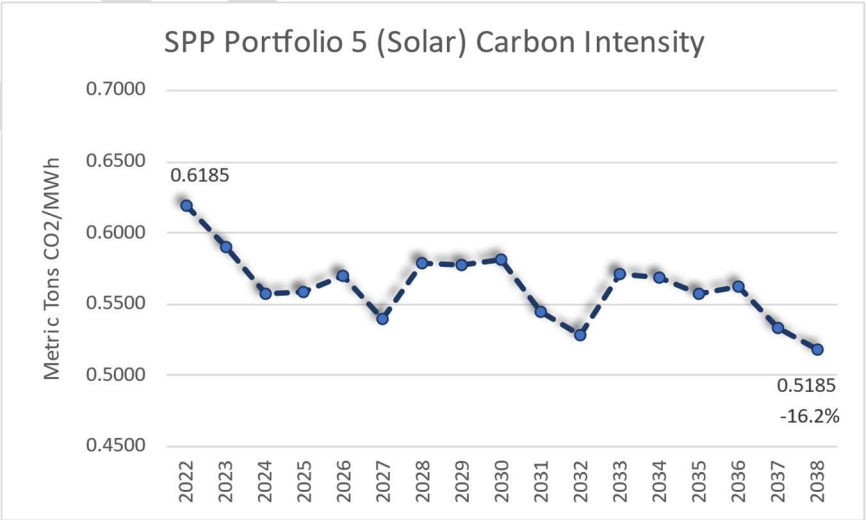


Figure XV-6

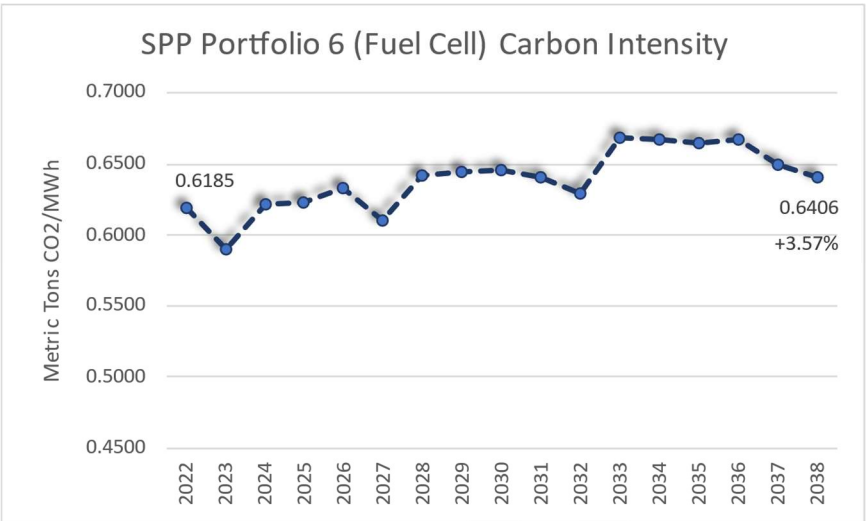


Figure XV-7

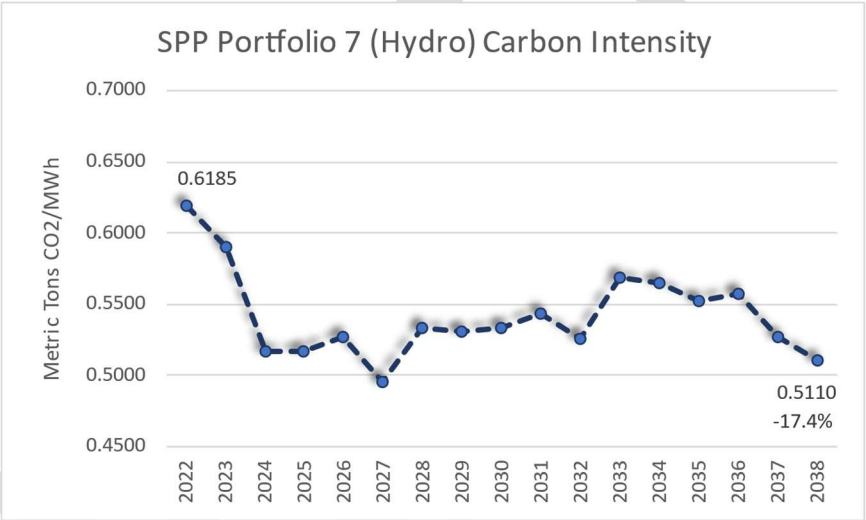


Figure XV-8

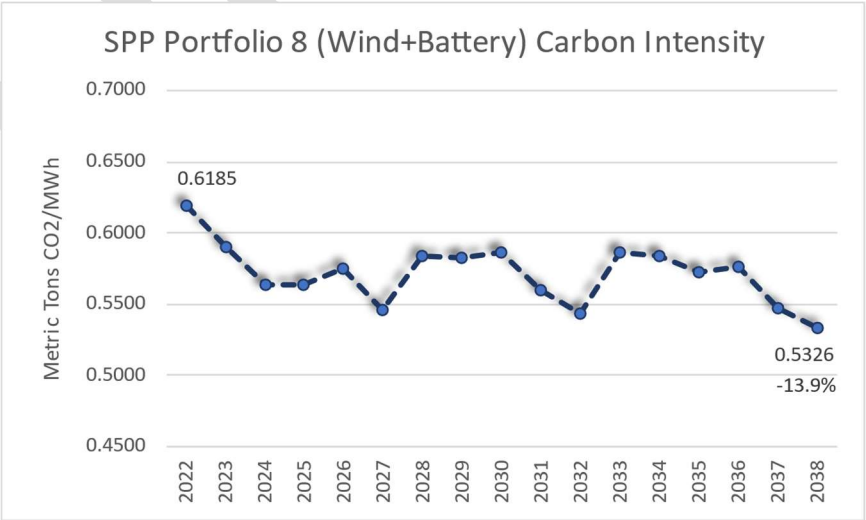


Figure XV-9

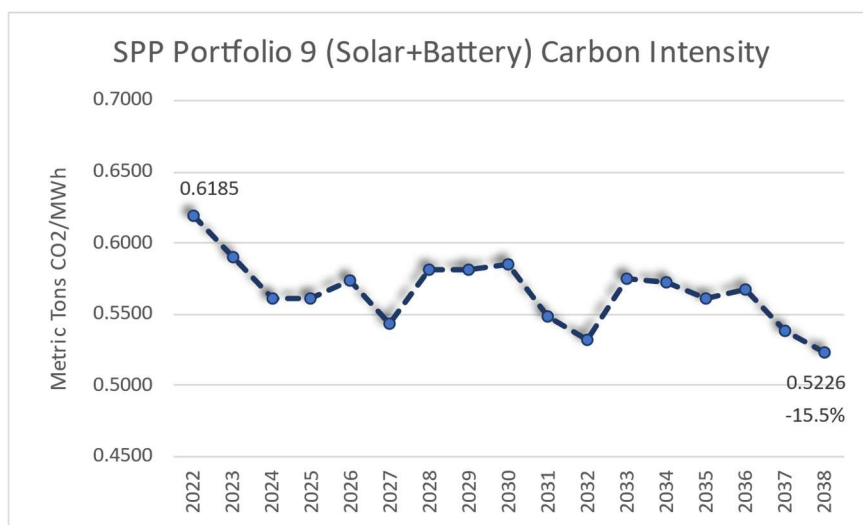


Figure XV-10

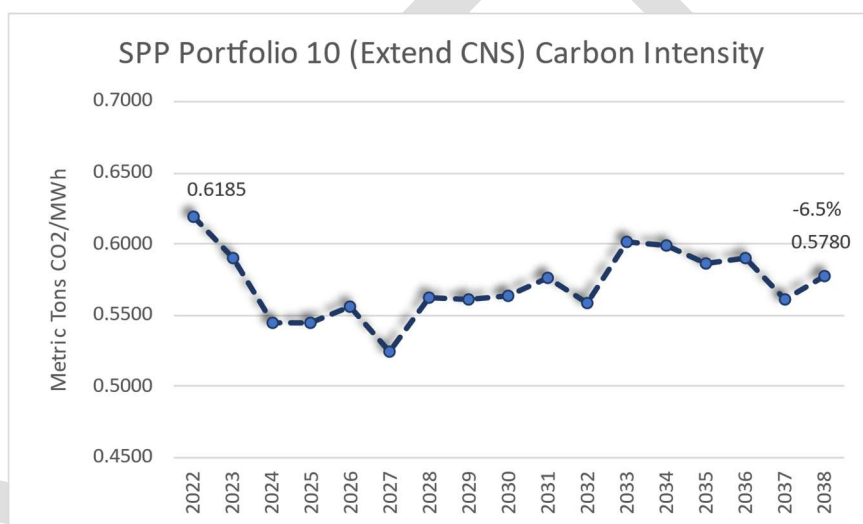


Figure XV-11

2. West Region

The progression of MEAN's West regional resource mix carbon intensity achieved with each portfolio is shown in the figures below:

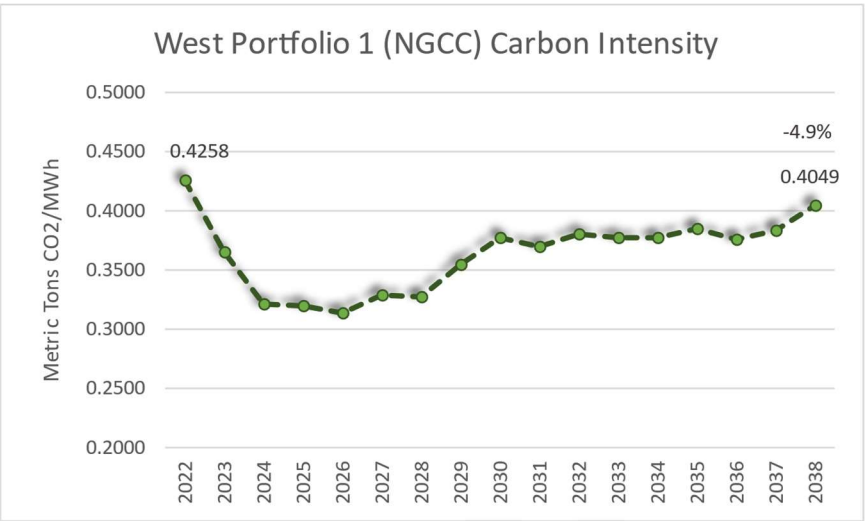


Figure XV-12

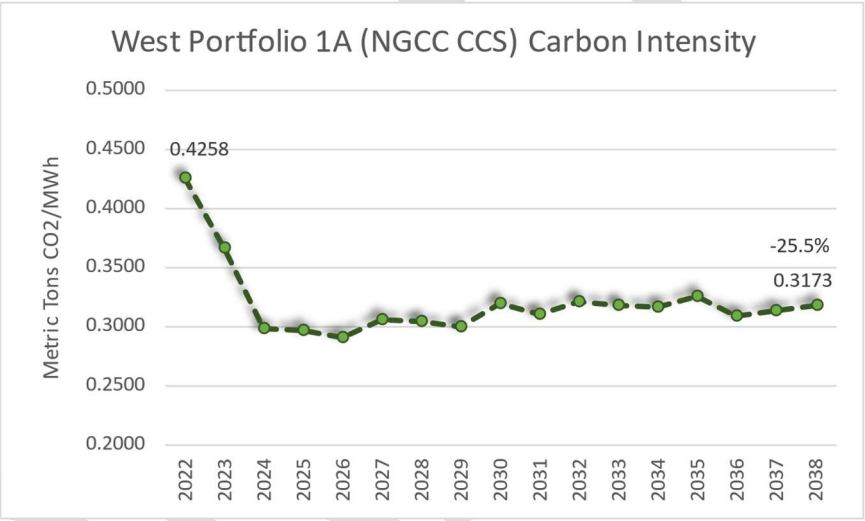


Figure XV-13

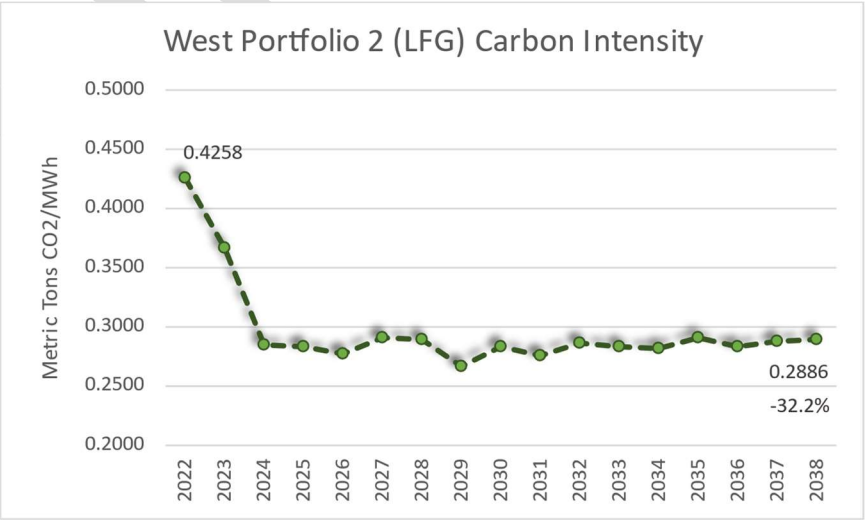


Figure XV-14

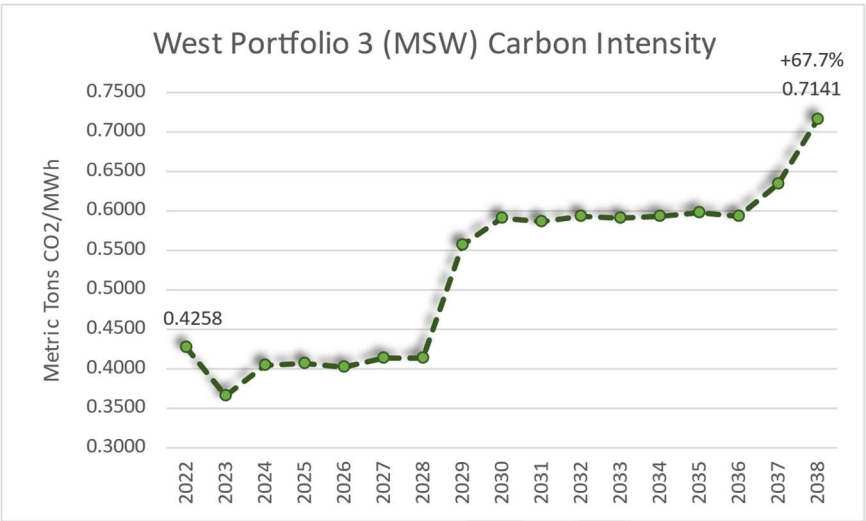


Figure XV-15

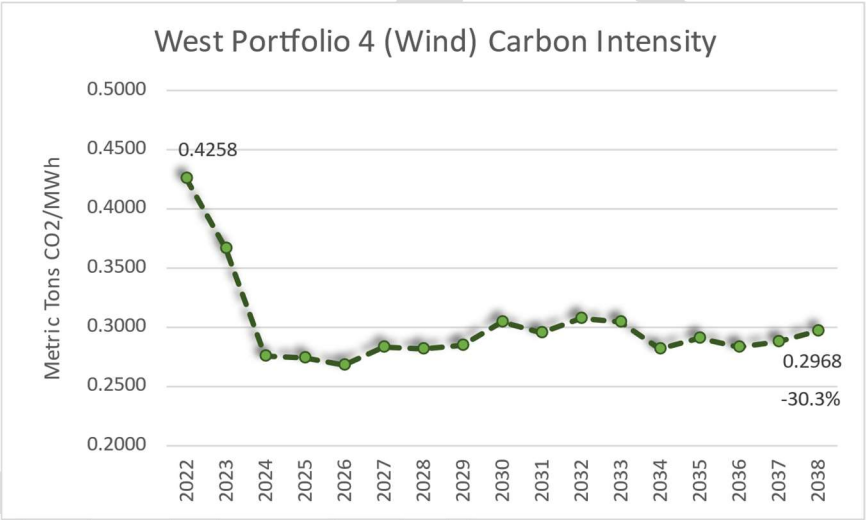


Figure XV-16

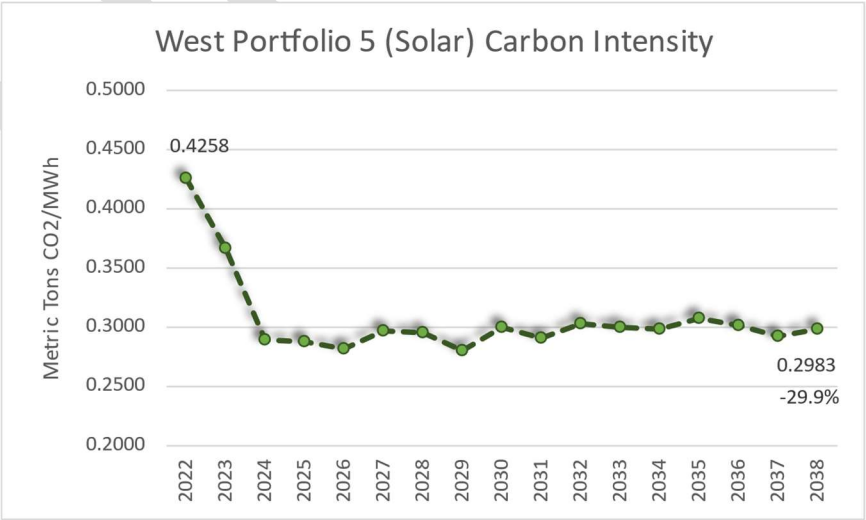


Figure XV-17

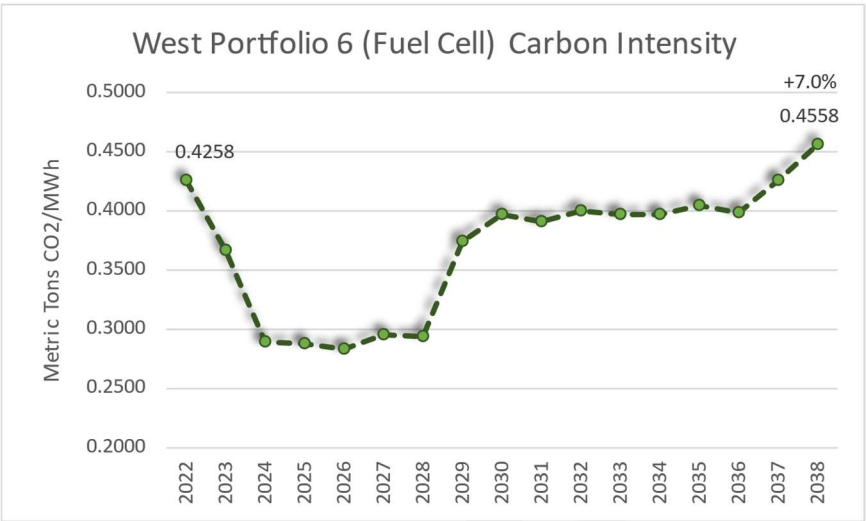


Figure XV-18

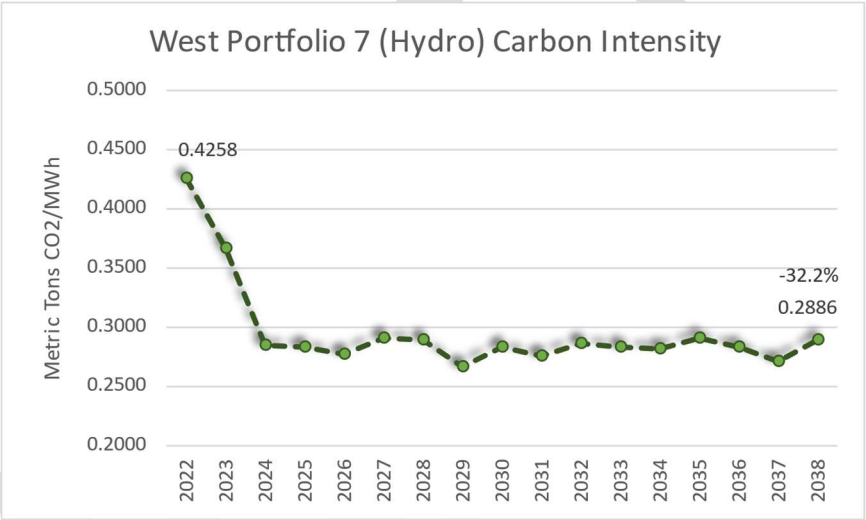


Figure XV-19

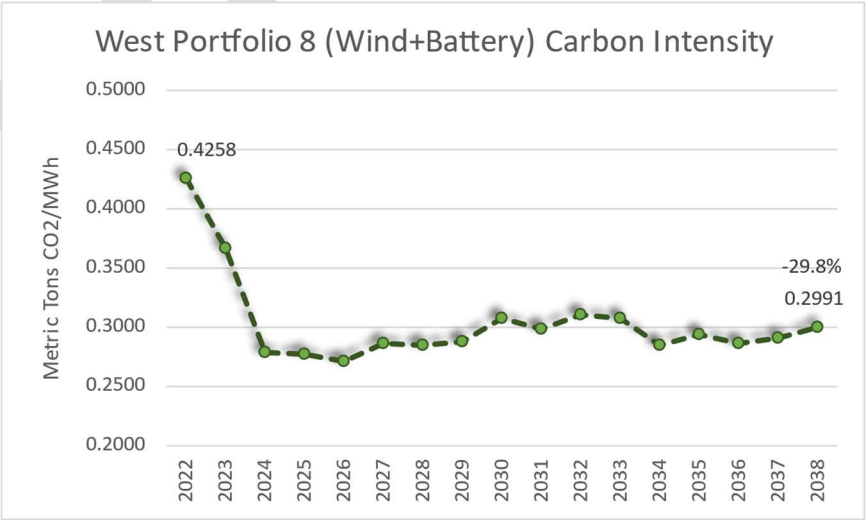


Figure XV-20

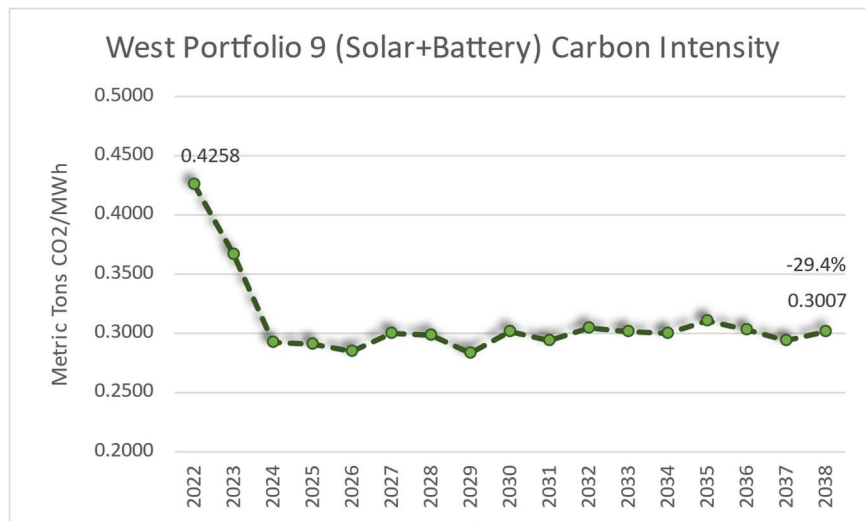


Figure XV-21

C. Carbon Cost Scenario Impact

The inclusion of the carbon tax sensitivity scenarios provides a method by which the impact of carbon emissions can be quantified for each portfolio as a whole. For each level of natural gas pricing, the results for the scenarios with no carbon tax can be compared against the results for the scenarios with a high carbon tax to show the consequence of high carbon emissions.

In the market pricing projections used in the Phase II modeling of candidate portfolios, pricing scenarios 7, 8, and 9 include various forms of a carbon emissions tax. These carbon tax scenarios are explained in Section IX.H. A comparison of Scenario 1 (base case load, base case NG price, and no CO₂ tax) to Scenario 9 (base case load, base case NG price, and CO₂ tax) provides a direct relation where the only variable that changes is the implementation of a carbon tax. Likewise, a comparison of Scenario 4 (base case load, high NG price, and no CO₂ tax) to Scenario 7 (base case load, high NG price, and CO₂ tax) shows the impact of a tax imposed as part of a carbon limit regulation. And a comparison of Scenario 5 (base case load, low NG price, and no CO₂ tax) to Scenario 8 (base case load, low NG price, and CO₂ tax) shows the impact of the same carbon limit tax on a different implementation schedule.

1. SPP

The average variance resulting from only the carbon tax (holding the natural gas pricing constant) in terms of \$/MWh is shown in *Figures XV-22* for only Scenario 1 vs. 9 and *Figure XV-23* adds comparisons for Scenario 4 vs. 7 and Scenario 5 vs. 8.

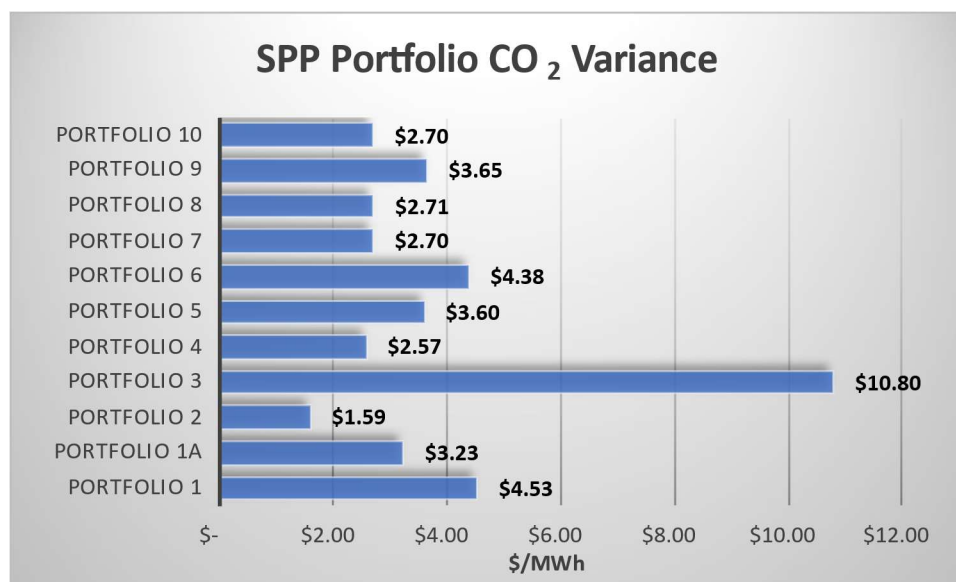


Figure XV-22

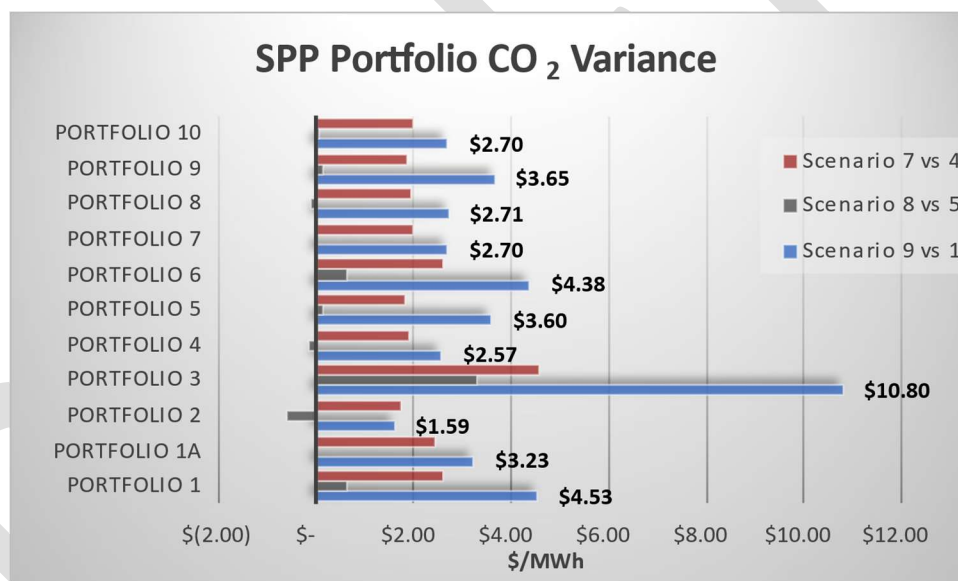


Figure XV-23

2. West Region

The average variance resulting from only the carbon tax (holding the natural gas pricing constant) in terms of \$/MWh is shown in *Figures XV-24* for only Scenario 1 vs. 9 and *Figure XV-25* adds the comparisons of Scenario 4 vs. 7 and Scenario 5 vs. 8.

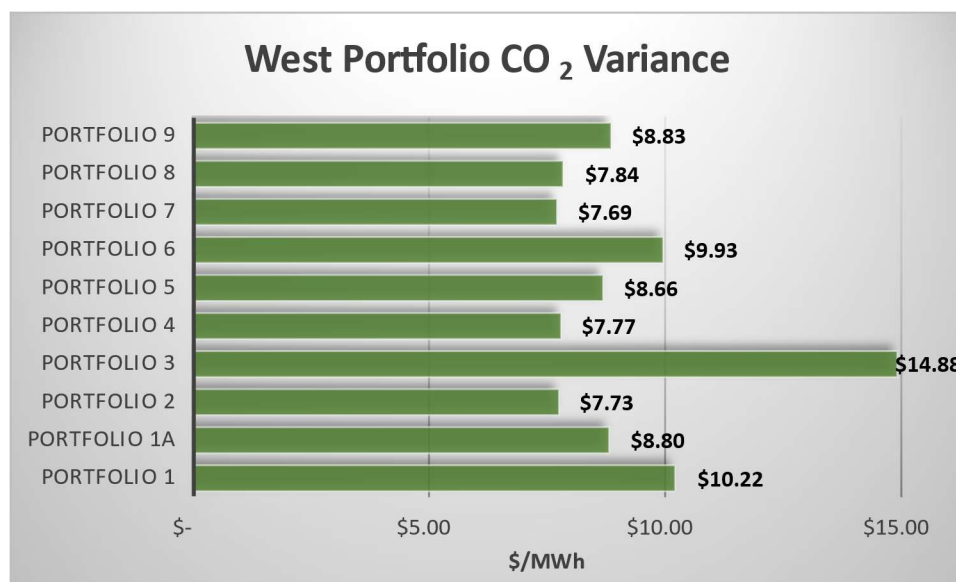


Figure XV-24

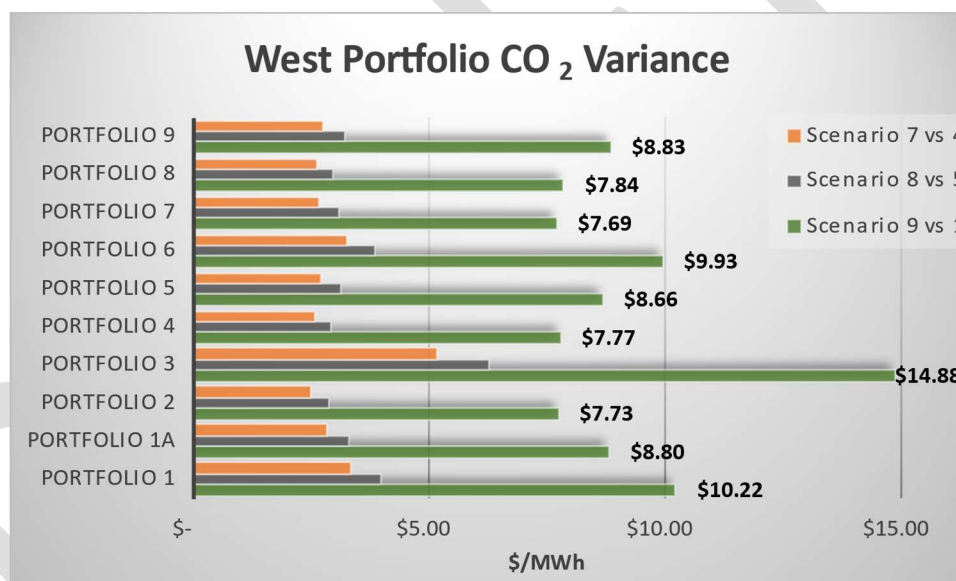


Figure XV-25

These results show an expected relation. Portfolios that include more fossil fueled capacity or more market energy purchases see a higher cost impact from a carbon tax. In this way, higher emitting resources are “penalized” in the model with a higher degree of variance. The effects of carbon emissions were included in the variance factor used in the analysis of the final portfolio results.

XVI. Conclusions and Recommended Action Plan

Based on the data and analysis in this IRP report, MEAN has developed conclusions relative to proposed demand side solutions and supply side solutions.

A. Conclusions

1. MEAN's Future Resource Needs

In the SPP service territory, MEAN has a need for capacity in the near term only. A capacity deficit of approximately 55-60 MW occurs from 2024-29 and is resolved when the WAPA Displacement Agreement ends. The energy deficit occurs throughout the study period, increasing with time.

In the West region, MEAN has capacity deficit of approximately 10 MW from 2025-28, which then increases to 45 MW when the WAPA Displacement Agreement ends and grows for the remainder of the study period to about 65 MW in 2038. The West region has a need for energy throughout the entire 15 years, which increases each year.

2. Demand Side Management – Conclusions

New DSM Programs: The costs and benefits of the proposed new DSM programs were compared using three different calculation methods. These three tests consider the costs and benefits of the DSM programs from different perspectives. A calculated ratio of benefits to costs greater than 1 indicates that a program is likely to result in benefits that outweigh its costs and therefore provide a net positive impact to MEAN or the end-use customer, depending on the test. In total, only one program had a favorable result, but in only one of the three tests. Therefore, none of the potential new programs studied would prove beneficial to MEAN and the end-use customer to a point that would compensate for the required costs.

MEAN has plans to investigate future energy efficiency education opportunities and a program to offer incentives for residential EV chargers as well as maintain its existing programs. Data will be presented to the MEAN Services Committee for approval in the coming months.

Commercial LED Lighting Upgrade Program: This program was initiated in FY 2016-17 and was successfully implemented throughout MEAN's system. The average annual energy savings achieved by the program are approximately 1,247 MWh, and the peak demand savings per year has been approximately 249 kW. These savings are reflected in the current load forecast. The NMPP Services Committee has approved the continuance of the LED Lighting Upgrade program through FY 22-23.

Residential Energy Efficiency Programs: After the successful introduction of these programs in FY21-22, incentives available for Cooling System Tune-Ups, Attic Insulation, High Efficiency Heat Pumps and Smart Thermostat Installations will continue to be offered to MEAN participants.

Advanced Metering Infrastructure: MEAN is working on a project to provide advanced metering infrastructure (AMI) services to member communities. In the fall of 2019, MEAN

conducted a business case study and survey of member representatives seeking interest in installing and employing AMI. With this information, MEAN conducted an RFP for pricing of an aggregate AMI procurement. Fourteen (14) communities have signed letters of intent to participate in this project, representing a total of approximately 10,500 meters. If approved, this project is slated to begin implementation in 2022.

Other MEAN DSM programs to be continued include: Infrared Energy Audits, Energy Audits, American Public Power Association (APPA) dues, Demonstration of Energy & Efficiency Developments (DEED) dues, Member Exclusive Education Sessions, NMPP Energy News Subscription.

Participant DSM Programs: The 2021 Participant DSM survey revealed a total of 17 communities with 33 DSM programs in place. The non-coincident sum of the demand and energy savings from these DSM programs is 4.03 MW and 2,635 MWh, respectively. These community programs are expected to be maintained in future years. MEAN repeats the DSM survey on an annual basis to track these programs and the impact on MEAN's demand and load.

3. Supply Side Resources – Conclusions

Based on the January 2021 Participant survey, the preferred resource portfolio option should consider low cost as a requisite condition. To reflect this preference, the Phase I evaluation highly weighted the capital cost and energy cost of each option. To further investigate the life cycle cost of each proposed resource portfolio, the Phase II economic analysis calculated the total revenue requirement related to each portfolio's resources over the 15-year study period. The final results clearly indicate the portfolio options with the lowest cost.

In January 2020, the MEAN Board of Directors approved the 2050 Vision establishing a goal to achieve a carbon neutral resource portfolio by the year 2050. To progress toward this goal, MEAN will need to fulfill resource needs with future resources that contribute toward a decrease in the carbon intensity of MEAN's overall resource portfolio. The results of the portfolio model were formulated to calculate the carbon intensity of each portfolio over the 15-year study period and determine which portfolios align with the 2050 Vision.

In the course of multiple participant meetings and workshop sessions, MEAN received feedback from participants that signified an inclination toward resource solutions that provide a local benefit or allow for local participation. In fact, this criterion was also scored as the highest non-cost criterion in the participant survey conducted in January 2021. Participants discussed the leasing of additional participant owned generation and renewable distributed generation, such as community solar. In response, MEAN heavily weighted the Local Benefit score for each of the supply side options in the Phase I evaluation. In the Phase II portfolio modeling, resources were sized to provide for the energy needs of the region. To supplement the accredited capacity of the resource and meet the required resource adequacy for peak demand, additional capacity purchases were incorporated into the portfolio model. This additional capacity is to be leased member owned generation as available.

Internal feedback from MEAN Operations communicated an appeal for resources that allow for operational flexibility. Due to constantly changing market conditions, the ability to schedule the output of a resource in response to changes in load and market price is very valuable. The value of this flexibility often translates into financial value as well, which relates to the priority of cost-effectiveness. Also, since the economic model used in the Phase II analysis included both generating costs and market sale and purchase costs, dispatchable resources could operate in response to this differential and either realize financial benefit or avoid disadvantaged pricing, whereas non-dispatchable resources did not operate in this manner.

SPP:

- The proposed portfolio in SPP that best achieved the primary goal of low cost was Portfolio 1, the addition of capacity and energy from a natural gas combined cycle plant located in the SPP footprint. This option also provides for operational flexibility and fuel diversity, but not local benefit. Portfolio 1 does not result in a decrease in carbon intensity for MEAN's resource portfolio.
- Portfolio 4, a wind resource for energy generation accompanied by a capacity purchase sized as required for resource adequacy, has a 15-year revenue requirement only marginally higher than that of the lowest cost option, and resulted in a lower cost variance across the pricing scenarios. In addition, Portfolio 4 allows for a 14.8% reduction in SPP portfolio carbon intensity.
- Portfolio 7, the hydropower option, also resulted in a low revenue requirement, a low cost variance, and a 17.4% reduction in carbon intensity for SPP. In SPP there is not likely to be a hydropower resource that provides benefit to a MEAN community.
- The solar resource in Portfolio 5 had the lowest modeled cost variance and a 15-year revenue requirement that was similar to the lowest cost options. This option is also emissions free and therefore leads to a 16.2% reduction in the portfolio's carbon intensity over time. Additional required capacity would be provided by leased member generation as available.
- Portfolio 2, the landfill gas resource, has a lower than average revenue requirement and a much lower variance level. A landfill gas plant also has the potential to provide local benefit and lowers the carbon intensity of MEAN's SPP portfolio.
- Portfolios 8 and 9, the wind and solar with battery storage, may prove to be viable options in the future if the incremental cost of batteries decreases as expected in the future.

West:

- The proposed portfolio in the west that best achieved the primary goal of low cost was Portfolio 7, the hydropower resource. This portfolio also saw a very low level of cost variance, or cost risk. Being a carbon free resource, the addition of hydropower resulted in a 32.2% reduction in the carbon intensity of the West

portfolio. MEAN is aware of hydropower options that may allow for a benefit to a MEAN community.

- The next lowest cost option in the West was Portfolios 5, the solar resource, with additional leased capacity from member generation. This portfolio carried increased volatility as compared to the hydro option. Solar also offers a local benefit potential and a reduction in carbon intensity of 29.9% in the West.
- The wind resource, Portfolio 4, has many of the same benefits. This option is lower than average revenue requirement, low cost variance, and reduces the carbon intensity of the west portfolio by 30.3%. Additional capacity is acquired through the lease of member generation.
- Portfolio 1, the Natural Gas Combined Cycle plant, results in a very low 15-year revenue requirement, but unfortunately carries a high variance risk as this option is impacted by natural gas pricing and CO₂ tax. This resource is unlikely to offer a local benefit, and only achieves a modest 4.9% reduction in carbon intensity.
- Portfolios 8 and 9, wind and solar with batteries, once again show the potential to be feasible options should the capital cost of battery storage decrease in the future.

B. Proposed Future Resource Portfolios

1. Committee Recommendation to the Board of Directors

Following the presentation of the Phase II Economic Modeling results and the relative revenue requirements, cost variance risk, and impact to carbon intensity resulting from each proposed portfolio, the Power Supply Committee will consider the portfolios in light of the conclusions described above. The Committee will make a recommendation to the Board of Directors as to the preferred portfolio(s) for each region. This does not dictate that the preferred resource must be procured by MEAN as an addition to the portfolio. It provides direction to MEAN staff to pursue the preferred portfolio resources when making resource planning decisions and acquisitions to meet MEAN's demand and energy needs in the future.

The Power Supply Committee's recommendation will be detailed in this section of the final report.

C. Recommended Action Plans

Based on the above conclusions and Board recommendations, MEAN will determine short term and long-term action plans in relation to demand side management resources and supply side resources in response to future projected capacity and energy deficits throughout its service territory.

1. Short-Term Recommended Action Plan (0-5 Years)

MEAN will continue to administer all current DSM programs: LED Lighting Upgrades, Residential Energy Efficiency Programs (Smart Thermostats, Attic Insulation, Cooling System Tune-Up, and High Efficiency Heat Pumps), Infrared Energy Audits, Member Education Sessions, and the *Essent* Newsletter subscriptions. MEAN will revisit the proposed new programs upon any significant change in the analysis inputs to reevaluate

the benefit to cost ratio. MEAN will perform analysis to determine the participation and economic feasibility of a residential EV charger incentive program.

MEAN will continue to pursue the aggregated Advanced Metering Infrastructure project to assist member communities with the installation of hardware and software systems to facilitate smart metering and load control.

Participants will be encouraged to continue existing DSM programs and initiate any new measures welcomed by their communities. MEAN will continue to perform the DSM annual survey and include DSM demand and energy savings into the load forecast.

In SPP, MEAN will proceed toward the recommended portfolio option(s) to address the impending need for capacity and energy. MEAN has initiated discussions with and has received proposed cost and performance data from a developers and resource owners in SPP for projects that align with MEAN's needs. The IRP recommendations of the Board will direct these efforts and determine the projects MEAN staff will pursue.

In the West, MEAN will pursue the recommended portfolio(s) option to address the impending need for capacity and energy. MEAN has contracted to prepare and release a Request for Information to solicit offers for qualified resources in the West. This will provide cost and performance data on projects in development and available to fulfill MEAN's future resource needs.

In the summer of 2022 installation is scheduled to begin on the community solar projects MEAN is facilitating for member communities. MEAN will guide communities through the construction period and monitor system performance as individual facilities come online in 2023. This information will be used by other members to evaluate installation of similar systems in the future. MEAN will continue efforts to assist members with analysis and procurement of distributed generation systems.

MEAN will continue to monitor actual load for all participant communities and compare against the load forecast and against existing capabilities. Any significant change will trigger a revised resource plan to determine required modifications and future actions. MEAN will continue to survey members annually to gather input and verification of load and load-impacting developments in member communities.

MEAN will also continue to study the operation and performance of existing resources. In conjunction with changes to the SPP and MISO market constructs and the renewable penetration within these markets, MEAN will determine the ongoing impact to capacity accreditation and unit dispatch and the resulting change to the long-term load and capability balance.

In the short-term, MEAN will maintain communication with WAPA and review the hydrological forecasts pertaining to WAPA hydropower assets. If indications of future drought conditions persist, MEAN will prepare future load and capability scenarios to plan for long-term reductions in available power from these resources and the acquisition of required replacement power.

Throughout MEAN's footprint, continual efforts will be made to acquire additional load. This development would allow further additions of carbon free resources to effect

additional change to the portfolio's carbon intensity. Strategic load that can be shaped in the off-peak can also contribute to more efficient use of MEAN's energy generation.

2. Long -Term Recommended Action Plan (5-15 Years)

MEAN will regularly evaluate the impact and implementation of existing DSM programs. Based on the results of the evaluation, MEAN will continue to administer successful programs. MEAN will revisit the proposed new programs on a regular basis to recalculate the analysis inputs and reevaluate the benefit to cost ratio. Programs that receive a favorable ratio should be planned for a trial roll-out in interested communities to verify projected savings prior to widespread execution. Participants will be encouraged to continue existing DSM programs and initiate any new measures welcomed by their communities.

MEAN will explore opportunities to assist communities with optimizing AMI systems for load study and possible applications in load control and demand side management.

In SPP, in accordance with the recommendation of the Power Supply Committee, MEAN will secure a long-term solution for an energy resource for future years. MEAN will need to supplement the resource acquired in the short-term plan to generate additional energy in the out years. With cost and performance data available from the new short-term resource contract, future costs of new resources, and future market changes MEAN will perform updated analysis to determine if the resource portfolio recommended in this report is still the optimal selection.

In the West, MEAN will explore options to acquire contracts for the recommended resources for capacity and energy as determined by the Board. The long-term balance in the West requires a resource or multiple resources to provide capacity and energy in addition to new resources in the short-term time frame. Concurrently, MEAN will solicit its participants for opportunities to lease new or existing participant owned generation. Again, resource planning will require updated data and analysis in response to changes in resource costs, fuel costs, regulatory and market conditions, and current generation projections for existing resources.

MEAN will continue to monitor actual load for all participant communities and compare against the load forecast and against existing capabilities. Any significant change will trigger a revised resource plan to determine required modifications and future actions. MEAN will pay particular attention to activities targeted to increase electrification in member communities and study the anticipated changes in load profile and load growth. MEAN will continue to survey members annually to gather input and verification of load and load-impacting developments in member communities.

As discussions and development continues regarding plans to expand SPP to a West RTO, MEAN will remain engaged in the design of market structures and rules and will be prepared to optimize the current and future resource portfolio within the anticipated parameters of this new market. In the absence of an SPP West RTO, MEAN will closely monitor efforts in the Colorado legislature to enforce mandatory participation in an RTO.

MEAN will also continue to study the operation and performance of existing resources. In conjunction with changes to the SPP and MISO market constructs and the renewable penetration within these markets, MEAN will determine the ongoing impact to capacity

accreditation and unit dispatch and the resulting change to the long-term load and capability balance.

MEAN will monitor federal, state, and local legislation to ensure that resources remain in compliance with all applicable regulations. Particular attention will be paid to regulations requiring investment in environmental controls and future resource transition plans. MEAN will also follow all portfolio standards and system emissions reduction requirements.

Throughout MEAN's footprint, continual efforts will be made to acquire additional load and extend terminating contracts. Depending on the load profile in comparison to the rest of MEAN's system load and resource additions made in the short term, there may be opportunities to supply energy without additional capacity investment. Opportunities to add off-peak load or control specific loads may change the utilization and economics of some resources.

D. Tracking/Measurement Strategy

MEAN will employ the following Measurement Strategies to gauge the progress and impacts of the Recommended Action Plans described above.

METRIC	MEASUREMENT STRATEGY	MEASUREMENT BASELINE
Load vs. Forecast	MEAN will annually compare the actual peak demand and energy consumption against the forecast values. Data will be tracked by participant, region, and system. MEAN also conducts an annual load survey to aid in this measurement.	• Annual Load Forecast • 15-Year Load Forecast • Hourly/Monthly Participant Load Data • Participant Load Survey
Load vs. Capability	On a semi-annual basis, MEAN is required to calculate and present to the Board the upcoming peak season Load and Capability balance for planning purposes. MEAN typically presents a long-term outlook. In this way, changes in the timing of deficits can be foreseen to prepare via resource planning.	• Annual Load Forecast • 15-Year Load Forecast • Resource Contracts • Hourly Resource Generation Data • Outage Schedules • Current Season Load and Capability Report
DSM Savings/Impact	MEAN conducts an annual DSM survey to all participants to gather data on the programs offered and the expected demand and energy savings. Responses will be compared year-to-year to verify savings. This is valuable in the contemplation of future programs. MEAN also tracks data on its administered Lighting Upgrade Program for estimated power savings.	• Previous Year Hourly Participant Load Data – Peak and Energy Usage • DSM Survey Responses • Energy Star® Energy Efficiency Calculation Tools
Distributed Generation	MEAN will continue to support efforts by member communities to install qualified projects under the DG Policy. Discussions initiated to explore other distributed technologies, such as	• Member Meter Data – Load • Member Meter Data – Generation • DG System Performance

	energy storage and fuel cells, will continue as well. MEAN will explore the installation of MEAN-owned systems located in member communities and collaborations available with this approach. Load and meter data will be collected to measure the performance of the DG systems as available. This will be compared to expected generation. MEAN will update load forecasts and anticipated capacity and energy needs.	• Evolving Costs of DG Installations
Existing Resource Performance	MEAN tracks the operation, performance, and cost of its contracted resources. This is measured against expected, budgeted, and contracted values and can be used to gauge the cost-effectiveness of existing and future resources. In the SPP and MISO markets, MEAN also tracks the locational marginal price to determine the actual total cost of the resource.	• Resource Contracts • Previous Year Hourly Resource Generation Data • Resource Invoices • LMP Data
New Resource Parameters	MEAN regularly tracks research on the costs and parameters of new resources. Understanding the performance of established and emerging technologies and the total generating cost in relation to market conditions will prepare MEAN for future resource acquisition. MEAN regularly discusses with developers their projects in the interconnection queue or under investigation.	• Resource Data Used for IRP (EIA, NREL, DOE) • Market Pricing • Developer Project Data
Market Construct Parameters	MEAN is actively involved with SPP, MISO, and WEIS Stakeholder Groups to engage in discussions regarding market constructs and rules. MEAN is also monitoring potential developments of a resource adequacy program in the West. In resource planning activities, MEAN will prepare a variety of future scenarios responsive to contemplated changes to quantify the impact to the MEAN system and inform future plans.	• Resource Adequacy Models • Resource Accreditation • SPP, MISO, and WEIS Tariffs • Current Market Constructs
Environmental Regulation	MEAN continually monitors environmental regulations, paying particular attention to future legislation affecting the power supply industry. When changes are proposed or adopted, MEAN projects the impacts on existing or potential future resources. Currently, MEAN is alert for changes in the status of the Clean Power Plan and power resource tax credits.	• Status Quo Regulations • MEAN's current compliance status

Figure XVI-1

MEMORANDUM

To: IMU Board of Trustees of the Electric, Water and Communications Utilities

From:

Date: May 9, 2022

Subject: Authorization for Warren Water District to serve a customer within their territory upon proper notice to IMU since the customer is within 2 miles of the IMU territory, located at 12753 140th Avenue.

Recommendation: Under state regulations for water service territories, Warren Water District (WWD) is required to provide notice to IMU when a customer has requested service from WWD when the location is within 2 miles of the IMU service territory. A resident at 12753 140th Avenue has requested service from WWD and WWD has provided notification to IMU as the property is within 2 miles of the IMU water district. To serve this customer outside of the IMU district, IMU would have to construct a 1.5 mile extension to the property. Superintendent Lou Elbert is recommending the Board of Trustees acknowledge the notification from WWD to serve the property as it is within WWD service territory and WWD already has a water main at this location.

A simple motion approving the notification from WWD to service this property outside of the IMU water service territory is in order.

Attachments: 1. WWD Request



Overview



Legend

Roads

- <all other values>
- Interstate
- Highway
- Ramp
- County Gravel
- County Level B
- County Level C
- City Gravel
- City Street
- Private Street

- Corporate Limits
- Parcels
- Political Township

Major Roads

- County Hwy
- State Hwy
- US Hwy
- Interstate
- Water

Parcel ID	13000320664	Alternate ID	n/a	Owner Address	MAY, MICHAEL L TST/MAY, MARY J TST
Sec/Twp/Rng	32-76-23	Class	R		602 W SALEM AVE
Property Address		Acreage	n/a		INDIANOLA, IA 50125
District	13350				
Brief Tax Description	32-76-23 PCL C SW SW				
	(Note: Not to be used on legal documents)				

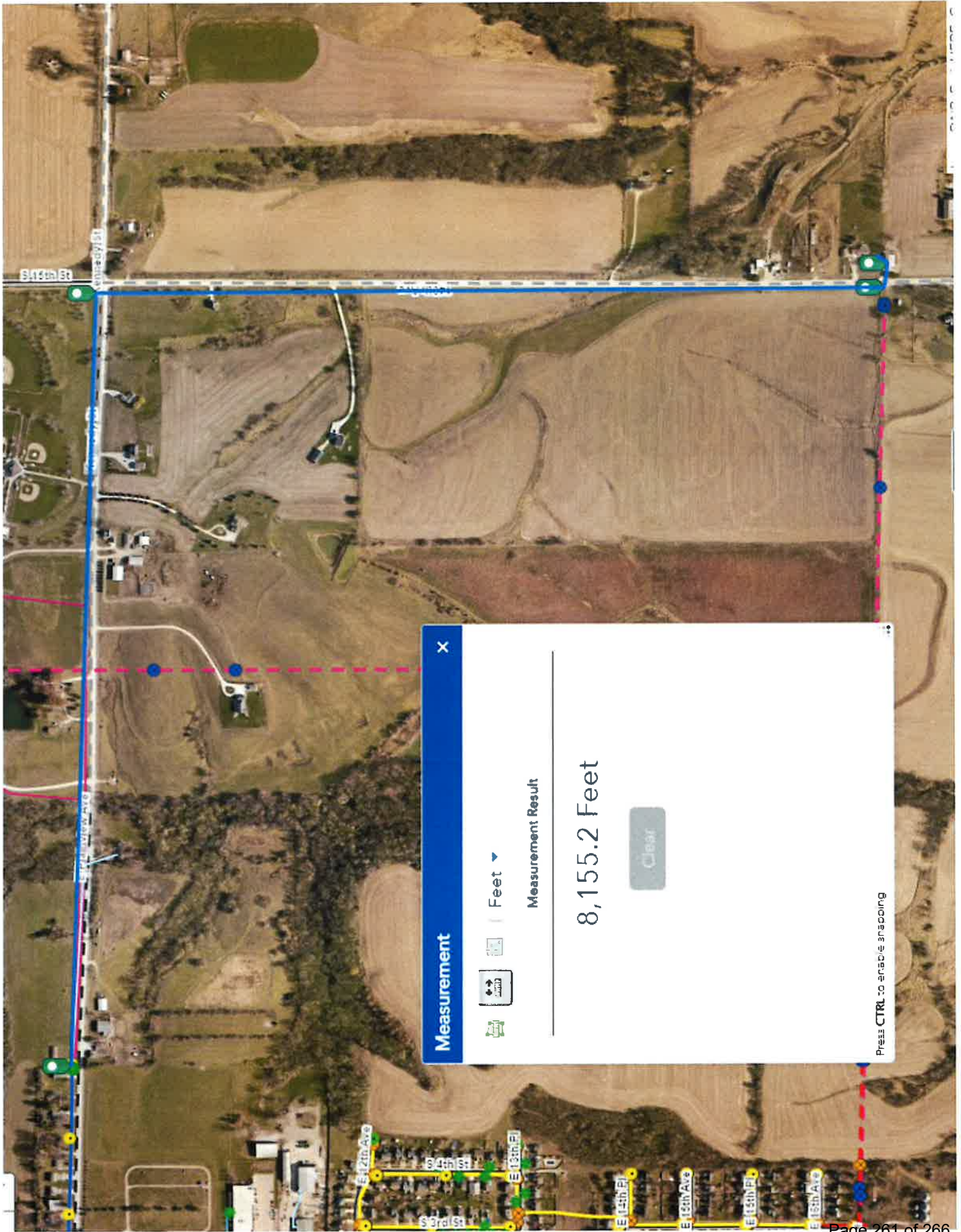
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Date created: 4/27/2022
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GEOSPATIAL



Measurement

X



Feet ▼

Measurement Result

8,155.2 Feet

Clear

Press CTRL to enable snapping

MEMORANDUM

To: IMU Board of Trustees of the Electric, Water and Communications Utilities

From:

Date: May 9, 2022

Subject: Approval of an engagement letter with Dickinson, Mackaman, Tyler and Hagen PC for legal services.

Recommendation: Simple motion is in order.

Attachments: 1. Engagement Letter



May 3, 2022

Indianola Municipal Utilities
Chris DesPlanques
210 2nd Ave.
Indianola, IA 50125

Re: Engagement Letter for Services

Dear Chris:

We are very pleased that you have decided to retain us as counsel to represent Indianola Municipal Utilities (“IMU”). This agreement describes the basis on which our firm will provide legal services to IMU and how we will be compensated for our services within the scope of the present engagement. In the event that IMU retain us for subsequent matters, the terms of our agreement set forth in this agreement will continue to apply unless otherwise communicated.

I will have primary responsibility for IMU’s representation, and will utilize other attorneys and legal assistants in the office in the best exercise of my professional judgment. If, at any time, you have questions, concerns or criticisms, please contact me at once. Either at the beginning or during the course of the representation, we might informally express opinions or beliefs concerning the matters involved in the representation and the results that might be anticipated. Any such statement by us is an expression of opinion only and is not a promise or guarantee of results. We will keep IMU informed of our progress, and we will respond to IMU as promptly as possible. In return, we need IMU to keep us informed of any developments that may affect all matters as to which we represent IMU as soon as IMU becomes aware of them and to be available when we need to consult with you.

Fees and Costs: We will generally bill IMU monthly for the legal services we provide. We take into account many factors in billing for services rendered, and I will review all statements before they are issued to ensure that the amount charged is appropriate. The principal factor is usually our schedule of hourly rates; most statements for services are simply the product of the hours worked multiplied by the hourly rates for the attorneys and legal assistants who did the work. Our schedule of hourly rates for attorneys and other members of the professional staff is based on years of experience, specialization in training and practice, and level of professional attainment. The hourly rates we will charge are: Shareholder/Of-Counsel Level Attorney: \$240; Associate Level Attorney: \$165; Paralegal: \$95; Law Student/Clerk: \$95. Our hourly rates will remain the same for the first three (3) years of our representation, and may be adjusted after that by mutual agreement.

May 3, 2022

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In addition, we charge and expect reimbursement for out-of-pocket expenses that we have incurred on your behalf. Such expenses may include, but may not be limited to, airfare, mileage expenses outside of Polk County, long-distance telephone costs, filing fees, deposition costs, printing costs, and advertising costs. We do not add any overhead costs to such third party charges. We will not bill for mileage expenses within Polk County or basic computer research expenses. If your matter requires it, we may charge you for use of sophisticated software to sort and analyze electronically stored information ("ESI"). Use of the ESI review software will reduce the amount of attorney time otherwise required to review and manage ESI. IMU will be billed at the rate of \$100 per hour for each hour that attorneys or paralegals use the software. IMU will not be charged for time when the system is processing or storing data and no attorney or paralegal is using the system.

Communication and Email: IMU's desire when communicating with me and my office to transmit and receive information from time to time by encrypted or unencrypted email, secure or non-secure internet, cellular telephone or other electronic means of communication. There is a risk that these communications may be intercepted by third parties, and third parties may argue communication by such means is not protected by the attorney-client privilege. We cannot guaranty that third parties will never intercept our communications or that attorney-client privilege will be upheld. With full understanding of these risks, you consent to the transmission of information by encrypted or unencrypted email, secure or non-secure internet, cellular telephone or other electronic means of communication, and accept the risk of diminished confidentiality. We will communicate with you using the email address you provided to us during our initial consultation. This consent will not apply to information or material which you advise us in writing not to transmit by such means. You further understand that we do not regard the transmission of an email as an urgent request for legal services or response. **Any matter that requires our urgent or time sensitive attention must be conveyed to us by a personal telephone call.**

During the course of our representation there may be periods of time when IMU does not hear from us. In any matter there are often periods of time when attorneys are waiting for information or action from the court, or from opposing and/or third parties. Absence of communication, however, does not mean we are not working on your matter. If IMU ever has questions about the status of your matter, please do not hesitate to contact us for an update.

Termination of Representation: IMU will have the right to terminate our representation at any time for any reason. We will have the same right. For example, we may discontinue legal services if invoices are not paid currently. Unless previously terminated, our representation of IMU in connection with any particular matter will end when we send our final statement of fees. IMU is not excused from paying us for our fees when you terminate our representation. After our representation of IMU in connection with any particular matter ends, there might be changes in laws or regulations that might affect your future rights and liabilities, but my firm does not have an obligation to continue to advise IMU about future legal developments unless IMU engage us to do so. After our representation of IMU in connection with any particular matter ends, my firm will store your file in accordance with my firm's file retention policies. The terms and conditions of this agreement will govern any dispute between us after termination of our representation of IMU.

May 3, 2022

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File Retention: We will retain our files pertaining to our representation, including material prepared by or for the internal use of our attorneys. We have internal policies that determine retention periods for closed representation files. We will provide such portions of these file materials to you as required by the applicable rules of professional responsibility or other legal requirements upon reasonable request, and if you pay reasonable expenses associated with producing a copy. If IMU does not request return of file material, this agreement is notice that we have the right to destroy the file material without further notification to IMU at the end of the defined retention period, which is usually six years after termination of our representation. Unless applicable rules of professional responsibility require an earlier return, we may retain such file material pending receipt of payment of any outstanding fees or costs.

Dispute Resolution: To timely resolve any concerns you may have regarding billing, fees, or costs, IMU should notify us within ten (10) days of receipt of our billing statement about your concerns. Otherwise, the billing statement will be assumed to be valid. In the unlikely event of a dispute between IMU and us regarding our representation of IMU that we are unable to resolve through good faith negotiations, we all agree to submit the dispute to confidential mediation before pursuing any other remedies. If either party desires to pursue litigation based on our representation, IMU agree that such litigation must be commenced within five (5) years of the date services are billed.

Please review the foregoing and, if it meets with your approval, sign a copy of the agreement and return it to me in the enclosed envelope. This agreement may be executed in multiple counterparts with original, electronic, or facsimile signatures. The signature pages may be returned via email, fax, or regular mail. All of the signature pages when combined will constitute the entire agreement.

On a personal note, I am very pleased that IMU has selected our firm to represent them. We look forward to serving IMU and shall use our best efforts on your behalf. If you have questions, please contact me.

Very truly yours,



Bryan P. O'Neill

May 3, 2022

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AGREED AND ACCEPTED this ____ day of _____, 2022.

Indianola Municipal Utilities

JEL/cw

Document2