SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO	§	BEFORE THE STATE OFFICE
ELECTRIC COMPANY TO CHANGE	§	OF
RATES	§	ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
CITY OF EL PASO'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. CEP 1-1 THROUGH CEP 1-28

CEP 1-25:

Please identify any generating unit outages during the test year for which EPE has received or expect to receive insurance or vendor settlements and explain how these settlements have been treated for ratemaking purposes.

RESPONSE:

El Paso Electric Company did not receive nor expects to receive insurance or vendor settlements for any generating unit outages during the test year.

Preparer:	Nydia Torres	Title:	Manager – Claims and Risk Management
Sponsor:	J Kyle Olson	Title:	Manager – Power Generation Engineering

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO CITY OF EL PASO'S FIRST REQUEST FOR INFORMATION QUESTION NOS. CEP 1-1 THROUGH CEP 1-28

CEP 1-26:

Please identify and provide the capital investments placed in rate base for the first time in this case whose primary purpose is to increase the operating efficiency, availability or capacity rating of EPE generating facilities.

RESPONSE:

For local generation, please refer to Schedules H-5.2b, projects classified under (4), (6), and (7). For the Palo Verde Generation Station, please refer to Schedule H-5.2a, projects classified under "D".

Preparer:	Pedro Vega Victor Martinez	Title:	Senior Accountant – Power Generation Manager – Resource Planning, Resource Management Regulatory & Quality
Sponsor:	J Kyle Olson Larry J. Hancock David C. Hawkins Todd Horton	Title:	Manager – Power Generation Engineering Manager – Plant Accounting Vice President –Strategy & Sustainability Senior Vice President – Site Operations at the Palo Verde Generating Station

SOAH DOCKET NO. 473-21-2606
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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
CITY OF EL PASO'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. CEP 1-1 THROUGH CEP 1-28

CEP 1-27:

Please provide the most recent economic analyses supporting the planned retirement dates for each EPE generating unit along with the dates of such analyses.

RESPONSE:

The retirement dates for Newman Unit 3, Newman Unit 4, Rio Grande Unit 8, and Copper were established via a retirement planning analysis performed in 2016 by El Paso Electric Company's ("EPE") Resource Planning Department ("RP"). RP developed three alternative retirement loads and resources ("L&R") scenarios. These L&Rs, as well as the Base Case L&R (2015 New Mexico Integrated Resource Plan ("IRP") L&R) can be found in CEP 1-27, Attachment 1. The results of PROMOD and capital expenditures are provided in CEP 1-27, Attachment 2.

The retirements of Rio Grande Unit 7 and Newman Units 1 and 2 are being reevaluated as part of EPE's 2021 IRP that is in currently in progress. As it now stands, the planned retirement dates for these three units in 2022 were affirmed as part of EPE's 2018 IRP in which these units were not selected as being cost effective by the Strategist capacity expansion modeling. The information from the Burns and McDonnell ("BMcD") reports provided as CEP 1-27, Attachments 3 through 5 were utilized as initial starting points to develop cost inputs for the capacity expansion modeling. Additionally, Newman Units 3 and 4 are also being evaluated as part of the 2021 IRP. EPE contracted BMcD to assess the units and provide cost estimates for potential retirement extensions. The BMcD report for Newman Units 3 and 4 is attached as CEP 1-27, Attachment 6 Voluminous.

Preparer:	Omar Gallegos	Title:	Senior Director – Resource Planning Management
Sponsor:	David C. Hawkins	Title:	Vice President – Strategy & Sustainability

El Paso Electric Company
Loads & Resources 2016-2034
2015 IRP 20-Year Base Scenario

April 8, 2015

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	LMS100 3	LMS100 4					1x1 CC		10 MW PV 1x1 CC	20 MW PV LMS100	10 MW PV LMS100	20 MW PV WIND	1x1 CC			10 MW PV	LMS100		LMS100
1 0 GENERATION RESOURCES																			
1 1 RIO GRANDE	275	275	275	275	275	229	229	229	229	229	229	229	87	87	87	87	87	87	87
1 2 NEWMAN	782	782	782	782	782	782	699	553	405	308	308	308	308	308	308	308	308	308	308
1 3 FOUR CORNERS	108	-	-	-	-		-	-	-	-	-		-	-	-	-	-		-
1 4 COPPER	64	64	64	64	64	64	64	64	64	64	-	-	-	-	-	-	-	-	-
1 5 MONTANA	264	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352
1 6 PALO VERDE	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633
1 7 RENEWABLES	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
1 8 NEW BUILD (local)	-	-	-	-	-	-	281	281	572	680	778	820	1,101	1,101	1,101	1,111	1,199	1,199	1,287
1 0 TOTAL GENERATION RESOURCES [1]	**2,127**	**2,107**	**2,107**	**2,107**	**2,107**	**2,061**	**2,259**	**2,113**	**2,256**	**2,267**	**2,301**	**2,343**	**2,482**	**2,482**	**2,482**	**2,492**	**2,580**	**2,580**	**2,668**
2 0 RESOURCE PURCHASES																			
2 1 RENEWABLE PURCHASE (SunEdison & NRG)	29	29	29	29	28	28	28	28	27	27	27	27	27	26	26	26	26	26	25
2 2 RENEWABLE PURCHASE (Hatch)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
2 3 RENEWABLE PURCHASE (Macho Springs)	35	35	34	34	34	34	34	34	33	33	33	33	33	33	32	32	32	32	32
2 4 RENEWABLE PURCHASE (Juwi)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	6	6	6	6	6
2 5 RESOURCE PURCHASE	-	-	-	-		70	-	85	-	-	-	-	-	-	-	-	-	-	-
2 0 TOTAL RESOURCE PURCHASES [2]	**74**	**73**	**73**	**72**	**72**	**142**	**71**	**156**	**70**	**70**	**69**	**69**	**69**	**68**	**68**	**67**	**67**	**67**	**66**
3 0 TOTAL NET RESOURCES (1 0 + 2 0)	**2,201**	**2,180**	**2,180**	**2,179**	**2,179**	**2,203**	**2,330**	**2,269**	**2,326**	**2,337**	**2,370**	**2,412**	**2,551**	**2,550**	**2,550**	**2,559**	**2,647**	**2,647**	**2,734**
4 0 SYSTEM DEMAND																			
4 1 NATIVE SYSTEM DEMAND	**1,852**	**1,896**	**1,933**	**1,969**	**1,998**	**2,039**	**2,076**	**2,113**	**2,144**	**2,187**	**2,225**	**2,263**	**2,297**	**2,343**	**2,384**	**2,422**	**2,456**	**2,504**	**2,547**
4 2 DISTRIBUTED GENERATION	(19)	(22)	(25)	(27)	(29)	(31)	(34)	(37)	(39)	(42)	(44)	(46)	(49)	(52)	(55)	(57)	(59)	(63)	(64)
4 3 ENERGY EFFICIENCY	(11)	(17)	(22)	(28)	(34)	(39)	(45)	(50)	(56)	(61)	(67)	(73)	(78)	(84)	(89)	(95)	(101)	(106)	(112)
4 4 LINE LOSSES	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
4 5 INTERRUPTIBLE SALES	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)
5.0 TOTAL SYSTEM DEMAND (4 1-(4 2+4.3+4.4+4.5)) [3]	**1,768**	**1,803**	**1,832**	**1,860**	**1,881**	**1,914**	**1,942**	**1,971**	**1,994**	**2,029**	**2,059**	**2,089**	**2,115**	**2,152**	**2,185**	**2,215**	**2,241**	**2,280**	**2,316**
6 0 MARGIN OVER TOTAL DEMAND (3 0 - 5 0)	**433**	**377**	**348**	**319**	**298**	**289**	**388**	**298**	**332**	**308**	**311**	**323**	**436**	**398**	**365**	**344**	**406**	**366**	**418**
7.0 PLANNING RESERVE 15% OF TOTAL SYSTEM DEMAND	**265**	**270**	**275**	**279**	**282**	**287**	**291**	**296**	**299**	**304**	**309**	**313**	**317**	**323**	**328**	**332**	**336**	**342**	**347**
8 0 MARGIN OVER RESERVE (6 0 - 7 0)	**168**	**107**	**73**	**40**	**16**	**2**	**97**	**2**	**33**	**4**	**3**	**9**	**119**	**76**	**37**	**12**	**70**	**24**	**71**

Generation Additions

LMS100 (88MW) in 2016
LMS100 (88 MW) in 2017
Drop-In 1x1 CC (281 MW total) in 2022
Drop-In 1x1 CC (281 MW total) in 2024
PV (10 MW) in 2024
LMS100 (88 MW) in 2025
PV (20 MW) in 2025
PV (10 MW) in 2026
LMS100 (88 MW) in 2026
PV (20 MW) in 2027
Wind (100MW) in 2027
Drop-In 1x1 CC (281 MW total) in 2028
PV (10 MW) in 2031
LMS100 (88 MW) in 2032
LMS100 (88 MW) in 2034

Unit Retirements

Four Corners 4 & 5 (108MW total) - July 2016
Rio Grande 7 (46MW) December 2020
Newman 4 CC phased-out (ST 83MW) - December 2021
Newman 4 CC phased-out (CT1 - 72MW) December 2022
Newman 4 CC phased-out (CT2 - 72MW) December 2023
Newman 1 (74MW) - December 2022
Newman 2 (76MW) - December 2023
Newman 3 (97MW) - December 2024
Copper (64MW) December 2025
Rio Grande 8 (142MW) - December 2027

Purchases

SunEdison, NRG, Macho, Juwi and Hatch solar purchases reflect 70% availability at peak hour

Resource Purchase reflects firm transmission available as a result of exchange agreement with McMoRan (Phelps Dodge), from SPS and from PNM from Four Corners after Four Corners retires

1 Generation unit retirements are per Burns & McDonnell study results
2 Purchases based on existing and estimated future purchases including renewable purchases to meet RPS requirements
Resource Purchase reflects additional transmission capacity available through contract with McMoRan (Phelps Dodge), from SPS and from PNM from Four Corners after Four Corners retires
3 System Demand based on Long-term and Budget Year Forecast issued April 1, 2015
Includes state-required energy efficiency targets for conservation, energy efficiency and load management
Interruptible load reflects current and contracts and includes new contract with Western Refinery Excludes Ft Bliss Net Zero initiatives
4 Long-term resource needs will be evaluated based on system needs and are subject to change

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CEP's 1st, Q. No. CEP 1-27
Attachment 1
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El Paso Electric Company
Loads & Resources 2016-2025
Scenario A - Life Extension on NM 1, 2, 3, Copper & RG8 with Purchases

November 2, 2015

Extended Reirement
Additional Purchases

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	LMS100_3	LMS100_4					1x1 CC		50 MW PV		50 MW PV	1x' CC WIND			LMS100	10 MW PV	1x1 CC		50 MW PV
1.0 GENERATION RESOURCES																			
1 1 RIO GRANDE	275	275	275	275	275	229	229	229	229	229	229	229	229	229	229	229	229	87	87
1 2 NEWMAN	782	782	782	782	782	782	699	627	555	555	555	481	481	481	481	481	308	308	308
1 3 FOUR CORNERS	108	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1 4 COPPER	64	64	64	64	64	64	64	64	64	64	64	64	-	-	-	-	-		-
1 5 MONTANA	264	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352
1 6 PALO VERDE	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633
1 7 RENEWABLES	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
1 8 NEW BUILD (local)	-		-	-	-	-	281	281	331	331	381	684	684	684	772	782	1,063	1,063	1,113
1.0 TOTAL GENERATION RESOURCES [1]	2,127	2,107	2,107	2,107	2,107	2,061	2,259	2,187	2,165	2,165	2,215	2,444	2,380	2,380	2,468	2,478	2,586	2,444	2,494
2.0 RESOURCE PURCHASES																			
2 1 RENEWABLE PURCHASE (SunEdison & NRG)	29	29	29	29	28	28	28	28	27	27	27	27	27	26	26	26	26	26	25
2 2 RENEWABLE PURCHASE (Hatch)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
2 3 RENEWABLE PURCHASE (Macho Spnngs)	35	35	34	34	34	34	34	34	33	33	33	33	33	33	32	32	32	32	32
2 4 RENEWABLE PURCHASE (Juwi)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	6	6	6	6	6
2 5 RESOURCE PURCHASE	-	-	-	-		70	-	85	60	100	85	-	30	70	20	45	-	115	105
2.0 TOTAL RESOURCE PURCHASES [2]	74	73	73	72	72	142	71	156	130	170	154	69	99	138	88	112	67	182	171
3 0 TOTAL NET RESOURCES (1 0 + 2 0)	2,201	2,180	2,180	2,179	2,179	2,203	2,330	2,343	2,295	2,335	2,369	2,513	2,479	2,518	2,556	2,590	2,653	2,626	2,665
4 0 SYSTEM DEMAND																			
4 1 NATIVE SYSTEM DEMAND	1,852	1,896	1,933	1,969	1,998	2,039	2,076	2,113	2,144	2,187	2,225	2,263	2,297	2,343	2,384	2,422	2,456	2,504	2,547
4 2 DISTRIBUTED GENERATION	(19)	(22)	(25)	(27)	(29)	(31)	(34)	(37)	(39)	(42)	(44)	(46)	(49)	(52)	(55)	(57)	(59)	(63)	(64)
4 3 ENERGY EFFICIENCY	(11)	(17)	(22)	(28)	(34)	(39)	(45)	(50)	(56)	(61)	(67)	(73)	(78)	(84)	(89)	(95)	(101)	(106)	(112)
4 4 LINE LOSSES	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
4 5 INTERRUPTIBLE SALES	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)
5.0 TOTAL SYSTEM DEMAND (4.1-(4.2+4 3+4 4+4 5)) [3]	1,768	1,803	1,832	1,860	1,881	1,914	1,942	1,971	1,994	2,029	2,059	2,089	2,115	2,152	2,185	2,215	2,241	2,280	2,316
6.0 MARGIN OVER TOTAL DEMAND (3 0 - 5.0)	433	377	348	319	298	289	388	372	301	306	310	424	364	366	371	375	412	345	349
7.0 PLANNING RESERVE 15% OF TOTAL SYSTEM DEMAND	265	270	275	279	282	287	291	296	299	304	309	313	317	323	328	332	336	342	347
8.0 MARGIN OVER RESERVE (6.0 - 7 0)	168	107	73	40	16	2	97	76	2	2	2	111	47	44	43	43	76	3	2

Generation Additions
LMS100 (88MW) in 2016
LMS100 (88 MW) in 2017
Drop-In 1x1 CC (281 MW total) in 2022
Drop-In 1x1 CC (281 MW total) in 2024
PV (10 MW) in 2024
LMS100 (88 MW) in 2025
PV (20 MW) in 2025
PV (10 MW) in 2026
LMS100 (88 MW) in 2026
PV (20 MW) in 2027
Wind (100MW) in 2027
Drop-In 1x1 CC (281 MW total) in 2028
PV (10 MW) in 2031
LMS100 (88 MW) in 2032
LMS100 (88 MW) in 2034

Unit Retirements
Four Corners 4 & 5 (108MW total) - July 2016
Rio Grande 7 (46MW) - December 2020
Newman 4 CC phased-out (ST - 83MW) - December 2021
Newman 4 CC phased-out (CT1 - 72MW) December 2022
Newman 4 CC phased-out (CT2 - 72MW) December 2023
Newman 1 (74MW) - December 2026
Newman 2 (76MW) December 2031
Newman 3 (97MW) - December 2031
Copper (64MW) - December 2027
Rio Grande 8 (142MW) - December 2032

Purchases
SunEdison, NRG, Macho, Juwi and Hatch solar purchases reflect 70% availability at peak hour

Resource Purchase reflects firm transmission available as a result of exchange agreement with McMoRan (Phelps Dodge), from SPS and from PNM from Four Corners after Four Corners retires

1 Generation unit retirements are per Burns & McDonnell study results
2 Purchases based on existing and estimated future purchases including renewable purchases to meet RPS requirements
Resource Purchase reflects additional transmission capacity available through contract with McMoRan (Phelps Dodge), from SPS and from PNM from Four Corners after Four Corners retires
3 System Demand based on Long-term and Budget Year Forecast issued April 1, 2015
Includes state-required energy efficiency targets for conservation, energy efficiency and load management
Interruptible load reflects current and contracts and includes new contract with Western Refinery Excludes Ft Bliss Net Zero initiatives
4 Long-term resource needs will be evaluated based on system needs and are subject to change

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El Paso Electric Company
Loads & Resources 2016-2025
Scenario B Version 2 - Life Extension on NM 3, 4, Copper & RG8 with Purchases

November 2, 2015

Legend
Extended Reirement
Additional Purchases

	LMS100 3	LMS100 4						1x1 CC				100MW PV 1x1 CC		75MW PV		1x1 CC			1x1 CC
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
1.0 GENERATION RESOURCES																			
1 1 RIO GRANDE	275	275	275	275	275	275	275	229	229	229	229	229	229	229	229	229	229	229	87
1 2 NEWMAN	782	782	782	782	782	782	782	632	632	632	632	308	308	308	308	308	308	308	308
1 3 FOUR CORNERS	108	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-		-
1 4 COPPER	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	-	-		-
1 5 MONTANA	264	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352
1 6 PALO VERDE	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633
1 7 RENEWABLES	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
1 8 NEW BUILD (local)	-	-	-		-	-		281	281	281	281	662	662	737	737	1,018	1,018	1,018	1,299
1.0 TOTAL GENERATION RESOURCES (1)	2,127	2,107	2,107	2,107	2,107	2,107	2,107	2,192	2,192	2,192	2,192	2,249	2,249	2,324	2,324	2,541	2,541	2,541	2,680
2.0 RESOURCE PURCHASES																			
2 1 RENEWABLE PURCHASE (SunEdison & NRG)	29	29	29	29	28	28	28	28	27	27	27	27	27	26	26	26	26	26	25
2 2 RENEWABLE PURCHASE (Hatch)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
2 3 RENEWABLE PURCHASE (Macho Springs)	35	35	34	34	34	34	34	34	33	33	33	33	33	33	32	32	32	32	32
2 4 RENEWABLE PURCHASE (Juw)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	6	6	6	6	6
2 5 RESOURCE PURCHASE	-	-	-	-		25	55	5	35	75	110	125	115	120	126	-	-	15	[illegible]
2 0 TOTAL RESOURCE PURCHASES (2)	74	73	73	72	72	97	126	76	105	145	179	194	184	188	193	67	67	82	66
3.0 TOTAL NET RESOURCES (1 0 + 2 0)	2,201	2,180	2,180	2,179	2,179	2,204	2,233	2,268	2,297	2,337	2,371	2,443	2,433	2,512	2,517	2,608	2,608	2,623	2,746
4 0 SYSTEM DEMAND																			
4 1 NATIVE SYSTEM DEMAND	1,852	1,896	1,933	1,969	1,998	2,039	2,076	2,113	2,144	2,187	2,225	2,263	2,297	2,343	2,384	2,422	2,456	2,504	2,547
4 2 DISTRIBUTED GENERATION	(19)	(22)	(25)	(27)	(29)	(31)	(34)	(37)	(39)	(42)	(44)	(46)	(49)	(52)	(55)	(57)	(59)	(63)	(64)
4 3 ENERGY EFFICIENCY	(11)	(17)	(22)	(28)	(34)	(39)	(45)	(50)	(56)	(61)	(67)	(73)	(78)	(84)	(89)	(95)	(101)	(106)	(112)
4 4 LINE LOSSES	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
4 5 INTERRUPTIBLE SALES	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)
5 0 TOTAL SYSTEM DEMAND (4.1-(4.2+4 3+4 4+4 5)) (3)	1,768	1,803	1,832	1,860	1,881	1,914	1,942	1,971	1,994	2,029	2,059	2,089	2,115	2,152	2,185	2,215	2,241	2,280	2,316
6 0 MARGIN OVER TOTAL DEMAND (3 0 5 0)	433	377	348	319	298	290	291	297	303	308	312	354	318	360	332	393	367	342	430
7 0 PLANNING RESERVE 15% OF TOTAL SYSTEM DEMAND	265	270	275	279	282	287	291	296	299	304	309	313	317	323	328	332	336	342	347
8 0 MARGIN OVER RESERVE (6.0 - 7 0)	168	107	73	40	16	3	0	1	4	4	4	41	1	38	4	61	31	0	83

Generation Additions

LMS100 (88MW) in 2016
LMS100 (88 MW) in 2017
Drop-In 1x1 CC (281 MW total) in 2023
PV (100 MW) in 2027
Drop-In 1x1 CC (281 MW total) in 2027
PV (75 MW) in 2029
Drop-In 1x1 CC (281 MW total) in 2031
Drop-In 1x1 CC (281 MW total) in 2034

Unit Retirements

Four Corners 4 & 5 (108MW total) - July 2016
Rio Grande 7 (46MW) - December 2022
Newman 4 CC phased-out (ST 83MW) - December 2026
Newman 4 CC phased-out (CT1 - 72MW) - December 2026
Newman 4 CC phased-out (CT2 - 72MW) - December 2026
Newman 1 (74MW) - December 2022
Newman 2 (76MW) - December 2022
Newman 3 (97MW) - December 2026
Copper (64MW) - December 2030
Rio Grande 8 (142MW) December 2033

Purchases

SunEdison, NRG, Macho, Juw and Hatch solar purchases reflect 70% availability at peak hour

Resource Purchase reflects firm transmission available as a result of exchange agreement with McMoRan (Phelps Dodge), from SPS and from PNM from Four Corners after Four Corners retires

1 Generation unit retirements are per Burns & McDonnell study results
2 Purchases based on existing and estimated future purchases including renewable purchases to meet RPS requirements
Resource Purchase reflects additional transmission capacity available through contract with McMoRan (Phelps Dodge), from SPS and from PNM from Four Corners after Four Corners retires
3 System Demand based on Long-term and Budget Year Forecast issued April 1, 2015
Includes state required energy efficiency targets for conservation, energy efficiency and load management.
Interruptible load reflects current and contracts and includes new contract with Western Refinery Excludes Ft. Bliss Net Zero initiatives
4 Long-term resource needs will be evaluated based on system needs and are subject to change

El Paso Electric Company
Loads & Resources 2016-2025
Scenario C - Life Extension on NM 1, 2, 3, 4 (1-yr), Copper & RG8 with Purchases

November 2, 2015

Legend
Extended Reirement
Additional Purchases

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	LMS100_3	LMS100_4						1x1 CC	50 MW PV		50 MW PV	WIND	1x1 CC		LMS100	10 MW PV		1x1 CC	50 MW PV
1.0 GENERATION RESOURCES																			
1.1 RIO GRANDE	275	275	275	275	275	229	229	229	229	229	229	229	229	229	229	229	229	87	87
1.2 NEWMAN	782	782	782	782	782	782	782	699	627	555	555	555	481	481	481	481	481	308	308
1.3 FOUR CORNERS	108	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1.4 COPPER	64	64	64	64	64	64	64	64	64	64	64	64	-	-	-	-	-	-	-
1.5 MONTANA	264	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352
1.6 PALO VERDE	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633
1.7 RENEWABLES	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
1.8 NEW BUILD (local)	-	-	-	-	-	-	-	281	331	331	381	403	684	684	772	782	782	1,063	1,113
1.0 TOTAL GENERATION RESOURCES (1)	**2,127**	**2,107**	**2,107**	**2,107**	**2,107**	**2,061**	**2,061**	**2,259**	**2,237**	**2,165**	**2,215**	**2,237**	**2,380**	**2,380**	**2,468**	**2,478**	**2,478**	**2,444**	**2,494**
2.0 RESOURCE PURCHASES																			
2.1 RENEWABLE PURCHASE (SunEdison & NRG)	29	29	29	29	28	28	28	28	27	27	27	27	27	26	26	26	26	26	25
2.2 RENEWABLE PURCHASE (Hatch)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
2.3 RENEWABLE PURCHASE (Macho Springs)	35	35	34	34	34	34	34	34	33	33	33	33	33	33	32	32	32	32	32
2.4 RENEWABLE PURCHASE (Juwi)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	6	6	6	6	6
2.5 RESOURCE PURCHASE	-	-	-	-		70	100	85	-	100	85	100	30	70	20	45	40	115	105
2.0 TOTAL RESOURCE PURCHASES (2)	**74**	**73**	**73**	**72**	**72**	**142**	**171**	**156**	**70**	**170**	**154**	**169**	**99**	**138**	**88**	**112**	**107**	**182**	**171**
3.0 TOTAL NET RESOURCES (1.0 + 2.0)	**2,201**	**2,180**	**2,180**	**2,179**	**2,179**	**2,203**	**2,232**	**2,415**	**2,307**	**2,335**	**2,369**	**2,406**	**2,479**	**2,518**	**2,556**	**2,590**	**2,585**	**2,626**	**2,665**
4.0 SYSTEM DEMAND																			
4.1 NATIVE SYSTEM DEMAND	1,852	1,896	1,933	1,969	1,998	2,039	2,076	2,113	2,144	2,187	2,225	2,263	2,297	2,343	2,384	2,422	2,456	2,504	2,547
4.2 DISTRIBUTED GENERATION	(19)	(22)	(25)	(27)	(29)	(31)	(34)	(37)	(39)	(42)	(44)	(46)	(49)	(52)	(55)	(57)	(59)	(63)	(64)
4.3 ENERGY EFFICIENCY	(11)	(17)	(22)	(28)	(34)	(39)	(45)	(50)	(56)	(61)	(67)	(73)	(78)	(84)	(89)	(95)	(101)	(106)	(112)
4.4 LINE LOSSES	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
4.5 INTERRUPTIBLE SALES	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)
5.0 TOTAL SYSTEM DEMAND (4.1-(4.2+4.3+4.4+4.5)) (3)	**1,768**	**1,803**	**1,832**	**1,860**	**1,881**	**1,914**	**1,942**	**1,971**	**1,994**	**2,029**	**2,059**	**2,089**	**2,115**	**2,152**	**2,185**	**2,215**	**2,241**	**2,280**	**2,316**
6.0 MARGIN OVER TOTAL DEMAND (3.0 - 5.0)	**433**	**377**	**348**	**319**	**298**	**289**	**290**	**444**	**313**	**306**	**310**	**317**	**364**	**366**	**371**	**375**	**344**	**345**	**349**
7.0 PLANNING RESERVE 15% OF TOTAL SYSTEM DEMAND	**265**	**270**	**275**	**279**	**282**	**287**	**291**	**296**	**299**	**304**	**309**	**313**	**317**	**323**	**328**	**332**	**336**	**342**	**347**
8.0 MARGIN OVER RESERVE (6.0 - 7.0)	**168**	**107**	**73**	**40**	**16**	**2**	**(1)**	**148**	**14**	**2**	**2**	**4**	**47**	**44**	**43**	**43**	**8**	**3**	**2**

Generation Additions

LMS100 (88MW) in 2016
LMS100 (88 MW) in 2017
Drop-In 1x1 CC (281 MW total) in 2022
Drop-In 1x1 CC (281 MW total) in 2024
PV (10 MW) in 2024
LMS100 (88 MW) in 2025
PV (20 MW) in 2025
PV (10 MW) in 2026
LMS100 (88 MW) in 2026
PV (20 MW) in 2027
Wind (100MW) in 2027
Drop-In 1x1 CC (281 MW total) in 2028
PV (10 MW) in 2031
LMS100 (88 MW) in 2032
LMS100 (88 MW) in 2034

Unit Retirements

Four Corners 4 & 5 (108MW total) - July 2016
Rio Grande 7 (46MW) - December 2020
Newman 4 CC phased-out (ST - 83MW) - December 2022
Newman 4 CC phased-out (CT1 - 72MW) - December 2023
Newman 4 CC phased-out (CT2 - 72MW) - December 2024
Newman 1 (74MW) - December 2027
Newman 2 (76MW) - December 2032
Newman 3 (97MW) - December 2032
Copper (64MW) - December 2027
Rio Grande 8 (142MW) - December 2032

Purchases

SunEdison, NRG, Macho, Juwi and Hatch solar purchases reflect 70% availability at peak hour.

Resource Purchase reflects firm transmission available as a result of exchange agreement with McMoRan (Phelps Dodge), from SPS and from PNM from Four Corners after Four Corners retires.

1. Generation unit retirements are per Burns & McDonnell study results.
2. Purchases based on existing and estimated future purchases including renewable purchases to meet RPS requirements.
   Resource Purchase reflects additional transmission capacity available through contract with McMoRan (Phelps Dodge), from SPS and from PNM from Four Corners after Four Corners retires.
3. System Demand based on Long-term and Budget Year Forecast issued April 1, 2015.
   Includes state-required energy efficiency targets for conservation, energy efficiency and load management.
   Interruptible load reflects current and contracts and includes new contract with Western Refinery. Excludes Ft. Bliss Net Zero initiatives.
4. Long-term resource needs will be evaluated based on system needs and are subject to change.

Unit Life Extension PROMOD Results --- Base Case L&R

Year	UOM	Fuel Costs	FC Handling Costs	VOM Costs	FOM Costs	Overhaul Costs	PPA Costs	Market Purchase Costs	Market Sale Costs	Emergency Costs	Total (K$)	Cap Ex (New Const)	PV @ 6.84% Total Costs (k$)
2016	(K$)	150371.23	326.68	5438.27	120531.75	21257	22029.52	1651.27	-38963.33	223.45	282,866	0	282,865.84
2017	(K$)	174633.35		5977.98	113598.63	21675.15	21980.29	2999.58	-46798.91	363.8	294,430	0	275,580.19
2018	(K$)	187041.18		5801.78	121052.02	16858.33	21980.29	3813.31	-46747.1	221.87	310,022	33,400	300,857.19
2019	(K$)	196235.65		5769.88	117988.1	13727.31	21980.29	4448.32	-48797.16	220.79	311,573	97,172	335,158.77
2020	(K$)	207439.2		6102.81	118374.22	13797.34	22029.52	4743.88	-52513.77	224.88	320,198	145,558	357,456.54
2021	(K$)	209478.02		6175.33	124728.32	28143.75	25701.56	5899.86	-49824.92	246.78	350,549	123,059	340,211.59
2022	(K$)	225990.29		9316.99	121721	18070.08	21980.29	3967.42	-59722.39	223.55	341,547	114,411	306,564.28
2023	(K$)	243367.78		10789.39	120242.16	12702.45	26669.2	3075.34	-76103.46	235.96	340,979	76,130	262,489.82
2024	(K$)	252883.95		13371.57	122466.95	21584.21	22275.27	3763.17	-93191.08	234.82	343,389	173,468	304,438.38
2025	(K$)	262979.24		15961.71	115428.41	18680.53	22730.94	3801.24	-106508.32	238	333,312	202,370	295,326.41
2026	(K$)	275007.66		16736.92	115128.08	13800.6	23001.4	4625.86	-111443.85	234.96	337,092	239,444	297,500.24
2027	(K$)	274604.56		16482.73	120970.42	11737.26	31335.71	5282.61	-109872.82	232.81	350,773	145,435	239,657.54
2028	(K$)	275117.87		16852.58	112853.95	14096.46	31589.2	8073.81	-106054.79	220.39	352,749	11,933	164,857.26
2029	(K$)	285718.2		17454.37	114748.86	27533.87	31731.1	10017.4	-106294.93	218.29	381,127	0	161,261.04
2030	(K$)	292162.62		17691.43	127542.43	31845.59	31897.51	11499.48	-96672.32	222.27	416,189	48,827	184,159.18
2031	(K$)	298054.92		17069.53	116189.69	20229.9	32603.84	12825.92	-81622.3	216.46	415,568	87,693	186,545.58
2032	(K$)	308024.3		17383.55	116884.36	17892.27	33022.58	12986.04	-79516.59	211.61	426,888	51,547	165,989.72
2033	(K$)	322999.93		18355.45	123238.24	20636.34	33214.29	13991.19	-80881.83	213.14	451,767	78,782	172,285.82
2034	(K$)	337320.84		18726.27	118824.85	17049.6	26263.45	15480.11	-73127.93	208.7	460,746	13,379	144,106.15
										Total:	6,821,763	1,642,608	4,777,312

Unit Life Extension PROMOD Results --- L&R Scenario B

Year	UOM	Fuel Costs	FC Handling Costs	VOM Costs	FOM Costs	Overhaul Costs	PPA Costs	Market Purchase Costs	Market Sale Costs	Emergency Costs	Total (K$)	Cap Ex (New Const)	PV @ 6.84% Total Costs (k$)
2016	(K$)	150371.23	326.68	5438.27	120531.75	21257	22029.52	1651.27	-38963.33	223.45	282,866	0	282,865.84
2017	(K$)	174633.35		5977.98	113598.63	21675.15	21980.29	2999.58	-46798.91	363.8	294,430	0	275,580.19
2018	(K$)	187041.18		5801.78	121052.02	16858.33	21980.29	3813.31	-46747.1	221.87	310,022	0	271,596.59
2019	(K$)	196235.65		5769.88	117988.1	13727.31	21980.29	4448.32	-48797.16	220.79	311,573	34,032	283,385.82
2020	(K$)	207439.2		6102.81	118374.22	13797.34	22029.52	4743.88	-52513.77	224.88	320,198	99,008	321,730.49
2021	(K$)	213045.78		6234.03	126245.89	28143.75	22942.99	5601.39	-50682.19	234.48	351,766	118,548	337,845.55
2022	(K$)	233184.33		7234.52	121763.54	18070.08	24253.88	5059.04	-58966.6	233.28	350,832	38,799	261,969.04
2023	(K$)	250818.35		9709	117954.06	12702.45	22201.36	4340.04	-77965.46	231.19	339,991	43,797	241,520.51
2024	(K$)	261442.19		10946.9	125449.69	26398.7	23595.97	3561.73	-87258.9	252.38	364,389	89,890	267,578.38
2025	(K$)	264274.33		11168.35	121033.03	18680.53	25364.7	3713.42	-84908.58	235.64	359,561	107,630	257,566.60
2026	(K$)	269840.54		11312.27	119890.75	14455.28	26811.9	4365.59	-83503.9	231.39	363,404	142,737	261,175.58
2027	(K$)	260122.42		14275.02	120520.56	14734.79	29266.07	6842.06	-84372.82	264.38	361,652	154,555	249,316.97
2028	(K$)	266113.5		13919.34	117198.84	11875.01	29830.36	8205.75	-75403.07	242.49	371,982	180,591	249,794.70
2029	(K$)	269641.39		13661.25	118320.56	27533.87	31460.76	10150.22	-67848.66	240.96	403,160	201,293	255,753.76
2030	(K$)	275701.68		14061.49	131186.29	33885.15	32495.78	11886.52	-62344.89	348.66	437,221	73,189	202,136.52
2031	(K$)	296316.01		14968.03	120522.24	26743	26917.44	13609.24	-64271.2	229.02	435,034	115,100	203,920.25
2032	(K$)	313288.79		16767.17	121903.15	16844.37	27080.2	13195.21	-78817.8	228.86	430,490	122,702	191,926.08
2033	(K$)	326319.71		17254.95	128189.25	12206.03	27817.41	14099.21	-77694.75	240.9	448,433	40,158	158,660.81
2034	(K$)	340991.79		19169.11	118976.75	5476.76	19946.51	14488.02	-84141.25	230.08	435,138	13,352	136,314.56
										Total:	6,972,142	1,575,380	4,710,638

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Unit Life Extension PROMOD Results --- Base Case L&R

Year	UOM	Base Fuel Costs	Base FC Handling Costs	Base VOM Costs	Base FOM Costs	Base Overhaul Costs	Base PPA Costs	Base Market Purchase Costs	Base Market Sale Costs	Base Emergency Costs	Base Total (K$)	Base Cap Ex	PV @ 6.84% Total Costs Base PV (k$)
2016	(K$)	150,371.23	326.68	5,438.27	120,531.75	21,257.00	22,029.52	1,651.27	(38,963.33)	223.45	282,865.84	0.00	282,865.84
2017	(K$)	174,633.35		5,977.98	113,598.63	21,675.15	21,980.29	2,999.58	(46,798.91)	363.80	294,429.87	0.00	275,580.19
2018	(K$)	187,041.18		5,801.78	121,052.02	16,858.33	21,980.29	3,813.31	(46,747.10)	221.87	310,021.68	33,400.35	300,857.19
2019	(K$)	196,235.65		5,769.88	117,988.10	13,727.31	21,980.29	4,448.32	(48,797.16)	220.79	311,573.18	97,171.61	335,158.77
2020	(K$)	207,439.20		6,102.81	118,374.22	13,797.34	22,029.52	4,743.88	(52,513.77)	224.88	320,198.08	145,558.25	357,456.54
2021	(K$)	209,478.02		6,175.33	124,728.32	28,143.75	25,701.56	5,899.86	(49,824.92)	246.78	350,548.70	123,058.73	340,211.59
2022	(K$)	225,990.29		9,316.99	121,721.00	18,070.08	21,980.29	3,967.42	(59,722.39)	223.55	341,547.23	114,410.76	306,564.28
2023	(K$)	243,367.78		10,789.39	120,242.16	12,702.45	26,669.20	3,075.34	(76,103.46)	235.96	340,978.82	76,130.24	262,489.82
2024	(K$)	252,883.95		13,371.57	122,466.95	21,584.21	22,275.27	3,763.17	(93,191.08)	234.82	343,388.86	173,468.18	304,438.38
2025	(K$)	262,979.24		15,961.71	115,428.41	18,680.53	22,730.94	3,801.24	(106,508.32)	238.00	333,311.75	202,370.44	295,326.41
2026	(K$)	275,007.66		16,736.92	115,128.08	13,800.60	23,001.40	4,625.86	(111,443.85)	234.96	337,091.63	239,443.95	297,500.24
2027	(K$)	274,604.56		16,482.73	120,970.42	11,737.26	31,335.71	5,282.61	(109,872.82)	232.81	350,773.28	145,434.73	239,657.54
2028	(K$)	275,117.87		16,852.58	112,853.95	14,096.46	31,589.20	8,073.81	(106,054.79)	220.39	352,749.47	11,932.78	164,857.26
2029	(K$)	285,718.20		17,454.37	114,748.86	27,533.87	31,731.10	10,017.40	(106,294.93)	218.29	381,127.16	0.00	161,261.04
2030	(K$)	292,162.62		17,691.43	127,542.43	31,845.59	31,897.51	11,499.48	(96,672.32)	222.27	416,189.01	48,826.76	184,159.18
2031	(K$)	298,054.92		17,069.53	116,189.69	20,229.90	32,603.84	12,825.92	(81,622.30)	216.46	415,567.96	87,692.89	186,545.58
2032	(K$)	308,024.30		17,383.55	116,884.36	17,892.27	33,022.58	12,986.04	(79,516.59)	211.61	426,888.12	51,547.25	165,989.72
2033	(K$)	322,999.93		18,355.45	123,238.24	20,636.34	33,214.29	13,991.19	(80,881.83)	213.14	451,766.75	78,782.23	172,285.82
2034	(K$)	337,320.84		18,726.27	118,824.85	17,049.60	26,263.45	15,480.11	(73,127.93)	208.70	460,745.89	13,378.54	144,106.15
										Total:	6,821,763	1,642,608	4,777,312
												8,464,371	

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Unit Life Extension PROMOD Results --- L&R Scenario B

Highligted if Scenario B value is greater than Base Case value.

Year	UOM	ScenB Fuel Costs	ScenB FC Handling Costs	ScenB VOM Costs	ScenB FOM Costs	ScenB Overhaul Costs	ScenB PPA Costs	ScenB Market Purchase Costs	ScenB Market Sale Costs	ScenB Emergency Costs	ScenB Total (K$)	ScenB Cap Ex	PV @ 6.84% Total Costs ScenB PV (k$)
2016	(K$)	150,371	327	5,438	120,532	21,257	22,030	1,651	(38,963)	223	282,866	-	282,866
2017	(K$)	174,633		5,978	113,599	21,675	21,980	3,000	(46,799)	364	294,430	-	275,580
2018	(K$)	187,041		5,802	121,052	16,858	21,980	3,813	(46,747)	222	310,022	-	271,597
2019	(K$)	196,236		5,770	117,988	13,727	21,980	4,448	(48,797)	221	311,573	34,032	283,386
2020	(K$)	207,439		6,103	118,374	13,797	22,030	4,744	(52,514)	225	320,198	99,008	321,730
2021	(K$)	213,046		6,234	126,246	28,144	22,943	5,601	(50,682)	234	351,766	118,548	337,846
2022	(K$)	233,184		7,235	121,764	18,070	24,254	5,059	(58,967)	233	350,832	38,799	261,969
2023	(K$)	250,818		9,709	117,954	12,702	22,201	4,340	(77,965)	231	339,991	43,797	241,521
2024	(K$)	261,442		10,947	125,450	26,399	23,596	3,562	(87,259)	252	364,389	89,890	267,578
2025	(K$)	264,274		11,168	121,033	18,681	25,365	3,713	(84,909)	236	359,561	107,630	257,567
2026	(K$)	269,841		11,312	119,891	14,455	26,812	4,366	(83,504)	231	363,404	142,737	261,176
2027	(K$)	260,122		14,275	120,521	14,735	29,266	6,842	(84,373)	264	361,652	154,555	249,317
2028	(K$)	266,114		13,919	117,199	11,875	29,830	8,206	(75,403)	242	371,982	180,591	249,795
2029	(K$)	269,641		13,661	118,321	27,534	31,461	10,150	(67,849)	241	403,160	201,293	255,754
2030	(K$)	275,702		14,061	131,186	33,885	32,496	11,887	(62,345)	349	437,221	73,189	202,137
2031	(K$)	296,316		14,968	120,522	26,743	26,917	13,609	(64,271)	229	435,034	115,100	203,920
2032	(K$)	313,289		16,767	121,903	16,844	27,080	13,195	(78,818)	229	430,490	122,702	191,926
2033	(K$)	326,320		17,255	128,189	12,206	27,817	14,099	(77,695)	241	448,433	40,158	158,661
2034	(K$)	340,992		19,169	118,977	5,477	19,947	14,488	(84,141)	230	435,138	13,352	136,315
										Total:	**6,972,142**	**1,575,380**	**4,710,638**
												8,547,521	

Delta PROMOD Results --- L&R Scenario B minus Base Case

Year	UOM	ScenB Fuel Costs	ScenB FC Handling Costs	ScenB VOM Costs	ScenB FOM Costs	ScenB Overhaul Costs	ScenB PPA Costs	ScenB Market Purchase Costs	ScenB Market Sale Costs	ScenB Emergency Costs	ScenB Total (K$)	ScenB Cap Ex	PV @ 6.84% Total Costs ScenB PV (k$)
2016	(K$)	0	0	0	0	0	0	0	0	0	0	0	0
2017	(K$)	0	0	0	0	0	0	0	0	0	0	0	0
2018	(K$)	0	0	0	0	0	0	0	0	0	0	(33,400)	(29,261)
2019	(K$)	0	0	0	0	0	0	0	0	0	0	(63,140)	(51,773)
2020	(K$)	0	0	0	0	0	0	0	0	0	0	(46,550)	(35,726)
2021	(K$)	3,568	0	59	1,518	0	(2,759)	(298)	(857)	(12)	1,217	(4,511)	(2,366)
2022	(K$)	7,194	0	(2,082)	43	0	2,274	1,092	756	10	9,285	(75,612)	(44,595)
2023	(K$)	7,451	0	(1,080)	(2,288)	0	(4,468)	1,265	(1,862)	(5)	(988)	(32,333)	(20,969)
2024	(K$)	8,558	0	(2,425)	2,983	4,814	1,321	(201)	5,932	18	21,000	(83,578)	(36,860)
2025	(K$)	1,295	0	(4,793)	5,605	0	2,634	(88)	21,600	(2)	26,250	(94,741)	(37,760)
2026	(K$)	(5,167)	0	(5,425)	4,763	655	3,811	(260)	27,940	(4)	26,312	(96,707)	(36,325)
2027	(K$)	(14,482)	0	(2,208)	(450)	2,998	(2,070)	1,559	25,500	32	10,879	9,121	9,659
2028	(K$)	(9,004)	0	(2,933)	4,345	(2,221)	(1,759)	132	30,652	22	19,233	168,658	84,937
2029	(K$)	(16,077)	0	(3,793)	3,572	0	(270)	133	38,446	23	22,033	201,293	94,493
2030	(K$)	(16,461)	0	(3,630)	3,644	2,040	598	387	34,327	126	21,032	24,362	17,977
2031	(K$)	(1,739)	0	(2,102)	4,333	6,513	(5,686)	783	17,351	13	19,466	27,407	17,375
2032	(K$)	5,264	0	(616)	5,019	(1,048)	(5,942)	209	699	17	3,602	71,155	25,936
2033	(K$)	3,320	0	(1,101)	4,951	(8,430)	(5,397)	108	3,187	28	(3,334)	(38,624)	(13,625)
2034	(K$)	3,671	0	443	152	(11,573)	(6,317)	(992)	(11,013)	21	(25,608)	(27)	(7,792)
										Total:	150,378	(67,228)	(66,673)

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PUC Docket No. 52195
CEP's 1st, Q. No. CEP 1-27
Attachment 2
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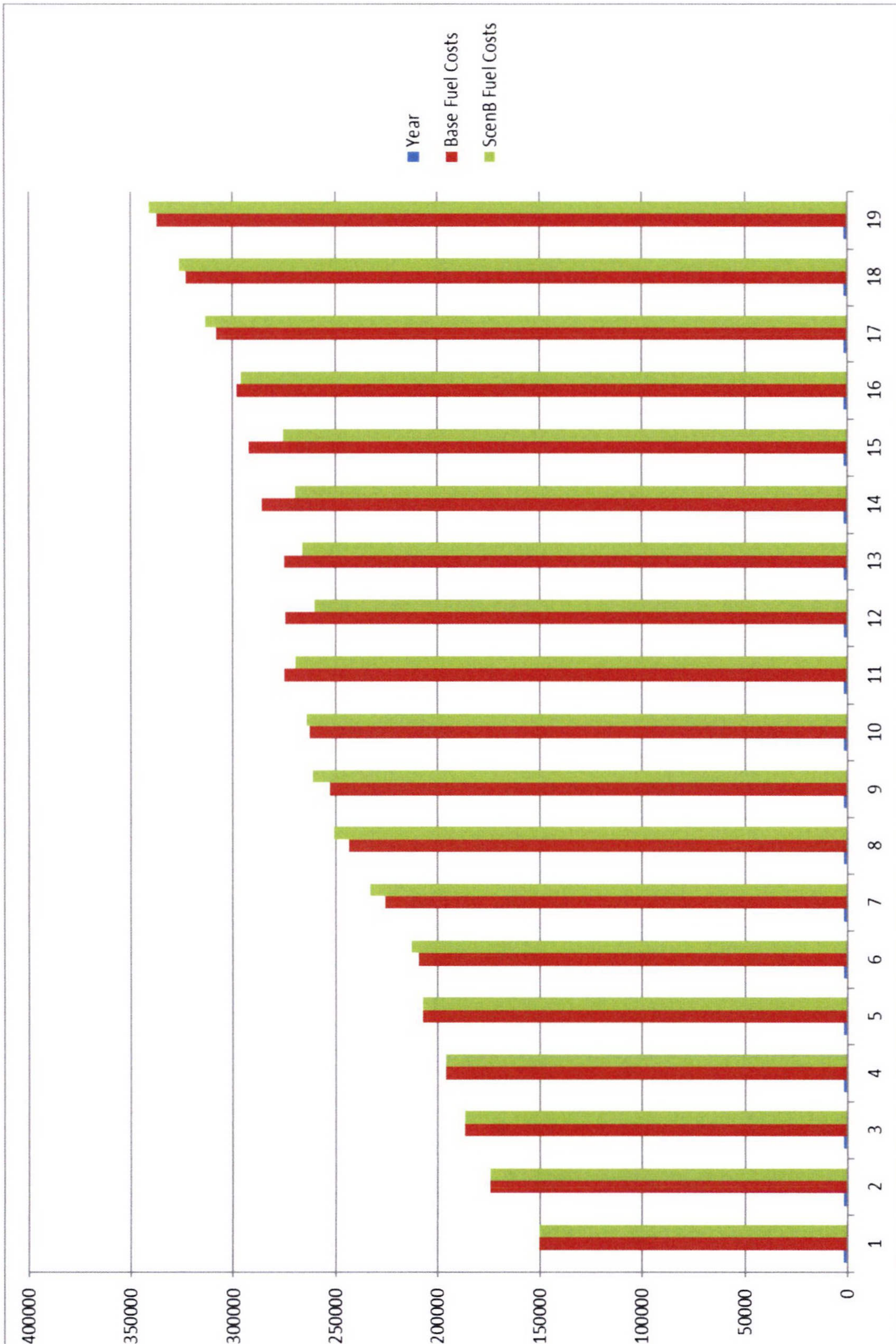
Year
Base Fuel Costs
ScenB Fuel Costs
400000
350000
300000
250000
200000
150000
100000
50000
0
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BURNS & McDONNELL

Rio Grande Unit 6 Condition Assessment

The Electric Company
El Paso Electric

El Paso Electric, Inc.

Life Extension & Condition Assessment
Project No. 101995

Revision 2
7/17/2018

Rio Grande Unit 6
Condition Assessment

prepared for

El Paso Electric, Inc.
Life Extension & Condition Assessment
El Paso, Texas

Project No. 101995

Revision 2
7/17/2018

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
A	Amperes
ASME	American Society of Mechanical Engineers
AVR	Automatic Voltage Regulator
BFP	Boiler Feedwater Pump
BPI	Babcock Power, Inc.
BTU/kWh	British Thermal Unit per Kilowatt Hour
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
°C	Degrees Celsius
DC	Direct Current
DCS	Distributed Control System
EAF	Equivalent Availability Factor
EDG	Emergency Diesel Generator
EFOR	Equivalent Forced Outage Rate
EPE	El Paso Electric, Inc.
EPRI	Electric Power Research Institute
°F	Degrees Fahrenheit
Facility	Rio Grande Power Station
FD	Forced Draft
FSSS	Flame Safety Shutdown and Startup Furnace Purge System
FWH	Feedwater Heater
GADS	Generator Availability Database System

Abbreviation	**Term/Phrase/Name**
gpm	Gallons per Minute
GSU	Generator Step-Up
HP	High Pressure
hp	Horsepower
in	Inch
kA	kiloamperes
kV	Kilovolt
kW	Kilowatt
lb/hr	pounds per hour
LP	Low Pressure
MCR	Maximum Continuous Rating
MVA	Megavolt Amperes
MW	Megawatts
NAAQS	National Ambient Air Quality Standards
NDE	Nondestructive Examination
NERC	North American Electric Reliability Corporation
NFPA	National Fire Protection Association
NOx	Nitrogen Oxide
O&M	Operation and Maintenance
OEM	Original Equipment Manufacturer
PdM	Predictive Maintenance
Plant	Rio Grande Power Station

Abbreviation	**Term/Phrase/Name**
PLC	Programmable Logic Controller
PSS	Power System Stabilizer
psig	Pound Per Square Inch Gauge
PVC	Polyvinyl Chloride
Rio Grande	Rio Grande Power Station
RO	Reverse Osmosis
SJAE	Steam Jet Air Ejector
SPE	Solid Particle Erosion
STG	Steam Turbine Generator
Study	Rio Grande Unit 6 Condition Assessment
Unit	Rio Grande Unit 6
Unit 6	Rio Grande Unit 6
VDC	Volt Direct Current

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1.0 EXECUTIVE SUMMARY

1.1 Objective & Background

El Paso Electric, Inc. (EPE) retained the services of Burns & McDonnell Engineering Company, Inc. (Burns & McDonnell) to perform a study to assess the condition of Unit 6 (Unit or Unit 6) at the Rio Grande Power Station (Plant, Rio Grande, or Facility) The Unit was retired in 2014 but operates in inactive reserve (serves as a contingency reserve Unit). The objective of this assessment is to analyze the current condition of the Unit and estimate the cost of repairing, replacing, maintaining, and operating the Unit through 2027 and 2037 (Study). Burns & McDonnell has included estimated capital and incremental operation and maintenance (O&M) costs associated with operating the Unit safely and reliably for the two life extensions scenarios of 2018 to 2027, and from 2018 to 2037.

The analysis conducted herein is based on historical operations data, maintenance and operating practices of units similar to Rio Grande, and Burns & McDonnell's professional opinion. For this Study, Burns & McDonnell reviewed data gathered as part of past condition assessments, updated information provided by EPE, information obtained during a site interview with plant personnel, and observations from a walkdown of the Unit. Inspections have been performed based on the Unit's inactive reserve designation and much of the previous inspection information was not available for review. Therefore, this assessment is based on the information obtained during the site interviews, a 2006 steam turbine and generator inspection report and the previous condition assessments.

1.2 Results

1.2.1 Capital Expenditures and O&M Costs

Due to the age and condition of the Unit, much of the major equipment and components will need to be replaced or refurbished to continue to operate the Unit safely until 2027 or 2037. Overall, the total capital and maintenance costs for each extended life scenario will be significant. Table 1-1 presents the cumulative capital expenditures and maintenance costs for the time periods from 2018 to 2027 and 2018 to 2037in 2018 dollars. As seen in the table Unit 6 will cost approximately $1,002/kilowatt (kW) for the 2018 to 2027 time period and $2,134/kW for the 2018 to 2037 time period.

Table 1-1: Cumulative Capital and Maintenance Costs (2018$)

Time Period	Total ($000)	Capital ($/kW)	Maintenance ($/kW)	Total ($/kW)
2018 to 2027	$48,081	$666	$336	$1,002
2018 to 2037	$102,445	$1,418	$716	$2,134

1.3 Conclusions

The following provides conclusions based on the observations and analysis from this Study.

1. Rio Grande Unit 6 was placed into commercial service in June 1957. The Unit has reached 60 years of service and appears to be in fair condition considering its age. The typical power plant design assumes a service life of approximately 30 to 40 years. The Unit has served beyond the typical service life of a power generation facility.
2. Despite its age, the Unit has generally not exhibited a significant loss of reliability, which would be indicative of degradation of the major components. This is likely due to several factors including:
    a. Minimal cycling operation
    b. Proper attention to water chemistry
    c. Early adoption of a predictive maintenance program
    d. An arid climate
3. The Unit has performed reliable considering the Unit's retirement designation and age, however, many of the major components and equipment will need to be repaired or replaced to extend the service life of the Unit to nearly 70 or 80 years. Rio Grande Unit 6 could be capable of reliable operations until 2027 or further until 2037 if a significant amount of capital expenditures and increased maintenance costs are incurred to replace and refurbish the major equipment and components.
4. Unit operations appeared to be well planned and carried out in a manner consistent with utility industry standards before the Unit was retired. Since retirement, only critical maintenance items have been performed. Burns & McDonnell believes that the maintenance budget will have to be increased from current levels to actively address issues which could affect operation and reliability of the unit.
5. With the increased penetration of renewable resources, traditional fossil-fueled generation need to provide greater flexibility to system operators to better optimize the power supply resources and costs to account for the variability and uncertainty associated with renewable resource generation.

Rio Grande Unit 6 is a base load unit and does not provide much flexibility regarding ramp rates, start times, or part load operation compared to newer generating resources.

2.0 INTRODUCTION

2.1 General Plant Description

EPE is an investor-owned electrical utility responsible for supplying power through an interconnected system to a service territory encompassing over 400,000 customers in the Rio Grande Valley in West Texas and Southern New Mexico. EPE has interests in the Palo Verde Nuclear Plant, Copper Power Station, Montana Power Station, Rio Grande Power Station, and Newman Power Station. Located in Sunland Park, New Mexico (a suburb of El Paso, Texas), Unit 6 began commercial operation in 1957.

Unit 6 utilizes a natural circulation steam generator boiler designed by Babcock and Wilcox for 450,000 pounds per hour (lb/hr) of steam flow at an outlet pressure of 875 pounds per square inch gauge (psig) and outlet temperature of 910 degrees Fahrenheit (°F). Unit 6 does not have a reheater. The boiler has a pressurized furnace, and a single regenerative Ljungstrom air preheater. Unit 6 also includes a Westinghouse steam turbine, which is a standard two-cylinder machine with a double flow low pressure (LP) condensing unit. The generator is currently rated at 58.8 megavolt amperes (MVA). Cooling water for Unit 6 is circulated through a counter-flow cooling tower with makeup water provided from off-site wells. Boiler makeup water for Unit 6 is also provided from the off-site well water system.

Since retiring in 2014, Unit 6 has operated in inactive reserve (serves as a contingency reserve Unit). Since this retirement, EPE has performed only critical maintenance activities, therefore, the Unit will require a significant amount of investments to operate reliably until 2027 or 2037.

2.2 Study Objectives & Overview

EPE retained the services of Burns & McDonnell to perform a study to assess the condition of Rio Grande Unit 6, and to assess the costs of operating and maintaining this Unit until 2027 or 2037.This Study takes into consideration both the current condition of the Unit as well as operation and maintenance factors that would impact the Plants operating and capital costs. This Study is based on historical operations data and other condition assessment reports provided by EPE, maintenance and operating practices of units similar to Rio Grande Unit 6 and Burns & McDonnell's professional opinion. Burns & McDonnell has also estimated capital expenditures and incremental O&M costs associated with operating the Unit until 2027 or 2037.

To complete this assessment, Burns & McDonnell engineers reviewed plant documentation, interviewed EPE management and plant personnel, and conducted a walkdown of the Plant.

2.3 Study Contents

The following assessment details the current condition of the Unit and presents the capital expenditures and ongoing operations and maintenance costs that would be incurred with continued operation of this Unit until 2027 or 2037. Since virtually any single component within a power plant can be replaced, the remaining useful life of a plant is typically driven by the economics of replacing the various components as necessary to keep the plant operating at industry standards versus shutting it down and either purchasing power or building a replacement facility. The critical physical components that will likely determine the Facility's remaining useful life include the following:

1. Steam generator drum, headers, and tubing
2. High energy piping systems
3. Steam turbine shell, rotor shaft, valves, and steam chest
4. Main generator rotor shaft, stator and rotor windings, stator and rotor insulation, and retaining rings
5. Cooling tower structure and underground circulating water piping
6. Control and electrical system obsolescence

The following items, although not as critical as the above, are also influential components that will also play a role in determining the remaining life of the plant:

1. Steam generator ductwork, air preheater and FD fan
2. Steam turbine blades, diaphragms, nozzle blocks, and casing
3. Generator stator-winding bracing, direct current (DC) exciter, and voltage regulator
4. Condenser, feedwater heaters, balance of plant pumps and motors, controls, and auxiliary switchgear

External influences that will likely be the major determinant of the future life of the Unit include environmental compliance requirements, fuel costs, comparative plant efficiency, system needs associated with flexibility, and the inability to obtain replacement parts and supplies from obsolescence.

3.0 SITE VISIT

Representatives from Burns & McDonnell, along with EPE staff, visited the Plant on May 14th and 15th of 2018. The purpose of the site visit was to gather information to conduct the life extension condition assessment by interviewing plant management, operations staff, and conducting an on-site review of the Unit.

The following representatives from EPE provided information during the site visit:

1. Manuel Gomez, Senior Engineer
2. David Aranda, Plant Manager
3. Ronal Heckman, Principle Electrical Engineer
4. Ron Lamontine, Principle Maintenance Planner
5. Jesus Jimenez, Mechanical Engineer
6. Jorge Garcia, Operations Superintendent
7. T.B. Milikien, Maintenance Planner
8. Micah Manns, Maintenance Support
9. Orly Lujan, Maintenance Support
10. Jim Moyer, Maintenance Support
11. Paul Jordan, Preventative Maintenance Technician

The following Burns & McDonnell representatives comprised the condition assessment team:

1. Kyle Haas, Lead Project Analyst and Mechanical Engineer
2. Sandro Tombesi, Mechanical Engineer
3. Thomas Ruddy, Project Analyst

Through visual observation of the Plant and its operations during the site visit, the Facility appeared to be maintained adequately and in working condition. All buildings seemed to be kept clean with no significant corrosion or structural damage to the sidings or roof. The Plant grounds were clean, organized, and free of clutter and debris.

During the site visit, some items were identified to likely require replacement due to age including the controls and electric systems, boiler/high energy piping components, steam turbine components, cooling tower, motors, fans, and pumps.

4.0 BOILER

Rio Grande Unit 6 utilizes a natural circulation, radiant heat, pressurized boiler designed to burn natural gas in nine wall-mounted burners. This boiler includes a horizontal drainable superheater, one steam drum, and an elevated mud drum. The boiler was originally designed for a maximum continuous rating (MCR) of 450,000 lb/hr of steam at a superheater outlet condition of 875 psig and 910°F. The boiler does not have a reheater. The superheater outlet temperature is controlled by desuperheater sprays. The boiler design also includes a Ljungstrom type tri-sector air heater for flue gas heat recovery.

Unit 6 has utilized natural gas as the primary fuel source with the exception being in the 1970's when fuel oil was used for operation. Unit 6 is normally dispatched at 20 MW and is rarely ramped to meet demand. Boiler chemical cleaning was performed on a five-year cycle before the Unit was retired and last occurred in January 2011. EPE also takes tube samples periodically in high heat flux areas of the boiler to evaluate the extent of boiler tube scaling and determine the need for chemical cleaning of the boiler. Burns & McDonnell recommends chemical cleaning the boiler every five years if it is to operate until 2027 or 2037.

EPE hired Babcock Power, Inc. (BPI) to perform a condition assessment of the boiler and high energy piping in February of 2011.

4.1 Waterwalls

The inner walls of the boiler are made up of vertical boiler waterwall tubes that are not connected with a membrane. Subcritical fluid is supplied from the steam drum to the waterwalls and is heated by the furnace flames before recirculating back to the steam drum.

BPI reported that the boiler waterwall tubes appear to be in good condition. Original tube thickness, per the Plant Data Book, was 0.150-inch (in). Tube thickness measurements were taken with the lowest reading of 0.146-in or 97 percent of the original tube thickness

Plant personnel reported that there have been several external tube ruptures at the bottom of the boiler near the mud drum. Furthermore, the waterwall tubes were reported to be blistering in several location which indicates potential overheating. Typically, the most common damage mechanisms that force replacement of the waterwall tubes are thermal fatigue and fire side corrosion. As plant personnel reported blistered tubes, Burns & McDonnell believes that the tubes are nearing end of life and should be replaced if the Unit is to operate until 2037.

4.2 Superheater

The superheater sections of the boiler are used to raise the temperature of the steam above the saturation temperature (i.e. superheat the steam). Saturated steam exiting the top of the steam drum passes through the various sections of the superheater and the temperature is continually increased until the steam finally exits the superheater outlet header and continues through the main steam line towards the high pressure (HP) steam turbine. The superheater is divided into two stages, primary and secondary, with attemperators positioned between the sections. The Rio Grande Unit 6 boiler design allows for draining of both stages of the superheaters during outages and/or startup.

In 2011, BPI found several burned out tubes in the secondary superheater and severe bowing in both the primary and secondary superheater. Original tube thickness, per the Plant Data Book, was 0.180-in. The tube thickness measurements were taken with the lowest reading of 0.179-in or 99 percent of the original tube thickness. Furthermore, based on the 2009 condition assessment report, EPE replaced four superheater pendants in the past and one superheater pendant has been capped off. EPE has experienced very few superheater tube leaks.

Plant personnel reported that the attemperators have not been serviced and need an overhaul. Plant personnel also believe that the superheater is at the end of its useful life and should be replaced.

Burns & McDonnell recommends replacing the primary and secondary superheaters as well as overhauling the attemperator valves.

The high temperature headers include the primary and secondary superheater outlet headers. These headers operate under severe conditions and are particularly susceptible to localized overheating. These conditions can lead to creep damage and other stress related cracks caused by temperature imbalances side-to-side across the headers. BPI performed a visual inspection (using fiber optics), metallographic replication, and hardness testing on the secondary superheater outlet header. The visual inspection found no evidence of erosion, cracking, or corrosion. They did find some moderate to heavy scale buildup in areas. Two locations adjacent to the girth weld on the secondary superheater outlet header were examined using metallographic replication. Neither location showed evidence of micro-cracking or creep damage. Based on the examinations, BPI considered the header to be in good condition. Plant personnel reported ligament cracks in the secondary superheater outlet header.

Burns & McDonnell recommends replacing the secondary superheater outlet header when the secondary superheater is replaced.

4.3 Drums

The boiler mud drum receives feedwater from the boiler feed system and distributes it to the waterwall tubes. The steam/water mixture from the waterwalls then travels through the steam drum, which separates the steam from the saturated mixture, before being sent to the superheater. There is one 60-in diameter steam drum, one 42-in mud drum, and a lower waterwall header on the unit.

In 2011, BPI's inspection of the steam and mud drums showed them to be in good condition overall with some minor issues being noted. There are no records indicating that the drums have been inspected with all internals removed.

Since the steam and mud drum are most susceptible to fatigue and corrosion damage, Burns & McDonnell recommends regular steam drum inspections including a detailed visual inspection with internals removed; magnetic particle examination of all girth, socket, and nozzle welds; and ultrasonic inspection of the welds and thickness readings at the normal water level.

4.4 Safety Valves

The safety valves are tested and recertified every five years by a third party as required by the facility's insurance company. Also, preventative maintenance is performed on the safety valve drainage system to check for obstruction or leakage.

Burns & McDonnell recommends the valves be tested in accordance with the American Society of Mechanical Engineers (ASME) code requirements. Annual inspections by the safety valves' Original Equipment Manufacturer (OEM) are recommended to determine if refurbishment or replacement is required.

4.5 Burner Control System

Unit 6 has no Flame Safety Shutdown and Startup Furnace Purge System (FSSS). This boiler was constructed before the National Fire Protection Association (NFPA) Codes required all boilers to have FSSS systems to prevent furnace explosions. It has continued to operate as a "grandfathered" unit, dependent on operators implementing appropriate burner ignition practices, which have been successful to date.

During the site visit, plant personnel also mentioned several issues associated with the gas interrupting valve.

Burns & McDonnell recommends installing new burners that comply with current NFPA standards and replacing the gas interrupting valve if the Unit is to operate until 2027 or 2037.

5.0 BOILER AUXILIARY SYSTEMS

5.1 Fans

There is one Westinghouse double inlet centrifugal forced draft (FD) fan that provides combustion air to the furnace. The air is heated in the air heater and is then delivered to the furnace through the boiler wind boxes.

This fan was visually inspected every year during the summer preparation outages with no significant problems being recorded. The inlet guide vanes were cleaned and inspected annually. The Bailey inlet guide vane positioners were replaced once during the life of the plant. In addition, vibration readings are taken monthly and trended as part of the predictive maintenance (PdM) program for rotating equipment. Oil samples are also taken monthly.

Plant personnel reported that the fan appears to be in good condition based on past inspections and on-going maintenance. A rub was reported to occur when the fan starts. Plant personnel also reported that the motor has never been pulled and would need to be cleaned, dipped, and baked or rewound.

Burns & McDonnell recommends inspecting and overhauling the FD fan for both life extension scenarios. Furthermore, Burns & McDonnell recommends pulling the motor and sending it to a shop to be rewound or clean, dipped, and baked if the Unit is to operate until 2027 or 2037.

5.2 Air Heater

Air heating is accomplished by one Ljungstrom type regenerative air heater. This heater was inspected by plant personnel during each annual outage with minor repairs done immediately. Based on the 2012 condition assessment report, the air heater baskets have not been replaced since 2002. BPI performed a limited visual inspection of the air heater from the cold gas discharge during the 2011 inspection. They found the baskets free of debris and the seals in good condition.

Plant personnel reported that the cold end baskets deteriorated when the Unit was tuned to operate with lower nitrogen oxide (NOx). By decreasing the firing temperature, the back-end temperatures were also lowered. Plant personnel also indicated that the hot and cold side lube oil pumps should be replaced, and the entire air heater should be thoroughly inspected.

Burns & McDonnell recommends inspecting the air heater. Furthermore, to operate reliably until 2027 and 2037, Burns & McDonnell recommends that the lube oil pumps and the cold end baskets be replaced.

If the Unit is to operate until 2037, it is also recommended that EPE replace the hot end and intermediate end baskets.

5.3 Flues, Ducts, Casing, & Structure

The ductwork transports combustion air to the boiler and transports hot flue gas away from the boiler, through the air heater, and onto the stack. Since the boiler has operated on natural gas for most of its life, the ducts and flues are in good shape. As part of the predictive maintenance program, station personnel routinely perform thermography to detect hot spots and leaks in the ductwork and flues.

Plant personnel reported a significant amount of casing leaks throughout the boiler and specifically in the roof/penthouse. There have been a higher number near the bottom of the boiler where the waterwall tube failure occurred. During the site visit, Burns & McDonnell also noticed several locations where the casing insulation was discolored indicating a hot spot.

Burns & McDonnell recommends taking a wholistic approach and replacing entire sections of boiler casing in problematic locations as well as continuing to inspect the ducts and flues for continued degradation if the Unit is to operate until 2027 or 2037.

During the site visit, it was also noted that EPE has never inspected the penthouse boiler supports. Burns & McDonnell recommends inspecting these supports for integrity when the casing is repaired in the penthouse.

5.4 Stack

The stack has not been inspected in recent years. Burns & McDonnell recommends inspecting the stack, particularly for structural integrity, as lower exhaust gas temperatures from tuning the boiler to operate with lower NOx increases the likelihood of corrosion in the backend.

5.5 Blowdown System

Unit 6 utilizes an intermediate pressure blowdown tank and a continuous blowdown flash tank to control water silica levels and remove sludge formations from the steam drum. The continuous blowdown from the steam drum is flashed into the intermediate pressure blowdown tank where the flash steam is exhausted to the deaerating heater and the remaining water continues to the continuous blowdown flash tank.

In the 2012 condition assessment, it was reported that the blowdown tanks were visually inspected. There were no reports of significant problems with either tank or the ancillary equipment. During the site visit, a significant amount of corrosion was noted on the continuous blowdown tank. Burns & McDonnell recommends replacing the blowdown tanks if the Unit is to operate until 2027 or 2037.

6.0 STEAM TURBINE

Based on the 2012 condition assessment and site visit, the turbine has exhibited good operation and vibration levels. The last major turbine-generator overhaul took place during the 2006 outage. Water chemistry is well maintained at the Station and the Unit has not been cycled excessively.

The turbine is a major focus of the EPE predictive maintenance program. Advanced vibration analysis, as well as monthly oil analysis, is performed to establish trends. These trends influence the preventive maintenance routines and frequencies. This program was established in 1995 and has been well recognized within the PdM community.

6.1 Turbine

The HP and LP turbines were last overhauled by Siemens Power Generation during the spring 2006 outage. The HP and LP turbine sections were disassembled, inspected, and reassembled. A nondestructive examination (NDE) was performed on the HP, LP, and generator rotors and HP and LP rotor blades by Siemens NDE Group. Siemens Turbine Services machined the journals of the HP rotor and LP rotor. They also performed weld repairs on the nozzle block, No. 1 water gland sealing diaphragm, blended indications on the HP and LP rotor blades, and re-tapped cracked thrust bearing foundation studs. Siemens recommended replacing the HP and LP rotor and blade radial seals, replacing the No. 1 water gland sealing bellow diaphragm, and installing a new LP blade ring during the next outage.

Information provided by EPE for review shows the Unit heat rate has increased from ~11,700 British Thermal Unit (BTU)/kWh in 2014 to ~12,800 BTU/kWh in 2017. This increase could be attributed to several factors associated with the balance of plant equipment, mainly the condenser, but may also be associated with degradation of steam turbine performance. The 2012 condition assessment mentioned issues with solid particle erosion (SPE). SPE could be affecting the HP turbine which would increase the flow area in the turbine and decrease HP turbine efficiency. Furthermore, the machine may also be experiencing a significant amount of seal wear which would also impact performance. Since the turbine has not been overhauled since 2006, it is likely that there are several seal wear issues and potential SPE issues.

Plant personnel also indicated that the LP shell had a large crack that was repaired using a metal stitch process during the last outage. It is unclear what the condition of the stitch repair is or if the shell continues to expand which would require the LP turbine case to be replaced. Siemens did not mention this as an issue in the 2006 inspection report. Plant personnel also indicated that the water gland seals are leaking and would need to be overhauled. Finally, the seal oil gearbox is at the end of its life and requires replacement.

Burns & McDonnell recommends performing two major overhauls for the Unit if it is to operate until 2027 and three major overhauls if it is to operate until 2037. There may be a significant amount of discovery work during the initial overhaul as the Unit was last inspected in 2006. Burns & McDonnell recommends performing a steam path audit and borescope inspecting before the next outage to understand what issues may be present. Furthermore, Burns & McDonnell recommends inspecting the LP turbine shell to understand if it has reached end of life and whether the turbine can be disassembled and assembled without any issues. Burns & McDonnell believes there will be discovery costs associated with repairing the casing and has included costs to stitch weld the casing during the next turbine overhaul if the Unit is to operate until 2037. Finally, Burns & McDonnell recommends replacing the rotor and blade ring seals per Siemens recommendation in 2006 during the next outage.

6.2 Turbine Valves

The turbine valves, consisting of the main steam stop and control valves, were maintained on a four-year cycle, which proved to be adequate. In general, they have exhibited minor SPE when inspected. Information provided by EPE shows that there are no work order numbers associated with inspecting and overhauling the turbine valves since 2007.

Burns & McDonnell recommends overhauling the steam turbine valves per the OEM's recommendations if the Unit is to operate until 2027 or 2037.

7.0 HIGH ENERGY PIPING SYSTEMS

7.1 Main Steam Piping

The main steam piping consists of 12-in schedule 100 pipe manufactured of seamless ASTM A335 P-22 material. The steam line transfers steam from the boiler superheater outlet header to the HP steam turbine. The system operates at approximately 875 psig and 910 °F.

Since this operating temperature is within the creep range (greater than 800°F), this piping system is of concern. Creep is a high temperature, time dependent phenomenon that can progressively occur at the highest stress locations within the piping system.

Due to the catastrophic damage potentially caused by a seam-weld failure on high energy steam lines, the Electric Power Research Institute (EPRI) has issued guidelines and recommendations for utilities to examine longitudinal seams in steam piping systems. EPE has reported there is no P11, P12, or P22 seamed piping in Unit 6.

In 2011, BPI performed metallographic replications, magnetic particle testing, ultrasonic testing, and diametric measurements on several welds of the main steam line. Metallographic replication was performed on seven weld locations along the main steam line. There was no evidence of creep voids or cracking in the base metal, heat-affected zone, or weld metal at any of the locations. The base metal hardness and estimated tensile strength meets the original ASME requirements. Magnetic particle testing was performed at ten locations along the main steam line without any relevant indications found. Ultrasonic shear phased array testing was performed on the same ten locations without any relevant indications found. Diametric measurements were taken at six weld locations on the main steam line. All were within the allowable creep swell tolerance. Based on their findings, BPI considered the main steam line to be in good condition. Based on the age of the Unit, however, EPE should consider replacing the main steam line if the Unit is operated until 2037.

Burns & McDonnell recommends that the pipe support system continue to be visually inspected annually. The hangers should be inspected to verify they are operating within the indicated travel range, that their position has not significantly changed since previous inspections, that the pipe is growing (contracting) in the right directions between cold and hot positions, that the actual load being carried is close to its design point and has not changed, and that the pipe support hardware is intact and operating as designed. In addition, Burns & McDonnell recommends that another high energy piping condition assessment be performed in 2021 and every five years thereafter for both retirement scenarios.

7.2 Extraction Piping

The extraction piping transfers steam from the various steam turbine extraction locations to the feedwater heaters. This piping system is not typically a major concern for most utilities and is not examined to the extent of the main steam system.

During the site walkdown, it was noted that there did not appear to be any modifications to the extraction system regarding the ASME guidelines to prevent water induction into the steam turbine. The current standard is ASME TDP-1-2013, "Prevention of Water Damage to Steam Turbines Used for Electric Power Generation: Fossil-Fuel Plants." (These practices are requirements for newly built plants, but guidelines only for existing plants).

However, the Unit does employ traditional level gauging and optical methods with alarms and sensors along with extraction steam non-return valve maintenance for protection.

Industry-wide, a significant factor in turbine internal damage is turbine water induction from the extraction system, feedwater heater, and associated drains. As such, it is recommended that EPE evaluate whether the Facility follows the ASME recommendations at Rio Grande Unit 6.

7.3 Feedwater Piping

The feedwater piping system transfers water from the deaerator storage tank to the boiler feedwater pumps, through the HP feedwater heaters, and eventually to the boiler drum. Although this piping operates at a relatively low temperature, the discharge of the boiler feedwater pumps is the highest-pressure location in the plant and thus, should be monitored and regularly inspected.

BPI took ultrasonic thickness readings on the first two elbows downstream of the two boiler feed water pumps during the February 2011 inspection. All four test points were found to have uniform thickness readings throughout the elbows. No indications of flow accelerated corrosion were found.

Burns & McDonnel recommends performing testing on the extrados of the sweeping elbows, where turbulence can occur, causing excessive erosion/corrosion every five years for both retirement scenarios.

8.0 BALANCE OF PLANT

8.1 Condensate System

The condensate system transfers condensed steam and boiler water in the condenser hotwell through the LP heaters to the deaerator.

8.1.1 Condenser

Unit 6 is provided with a two-pass tube and shell condenser with divided water boxes. It consists of 25,000 square feet of 90-10 copper nickel alloy tubes. The condenser has never been retubed and experiences very few tube failures. Plant personnel reported no other issues. Burns & McDonnell recommends inspecting the condenser and hydrostatically testing both the hotwell and circulating water sides during the next outage. Based on the age of the Unit, Burns & McDonnell also recommends retubing the condenser if the Unit is to operate until 2037.

8.1.2 Condenser Vacuum System

The condenser vacuum system is used to maintain a negative pressure, or vacuum, in the condenser by removing all air that collects in the condenser. This is accomplished by means of an Allis Chalmers hogging vacuum pump, a Westinghouse Steam Jet Air Ejector (SJAE), and by one 100 percent liquid ring Nash vacuum pump. Plant personnel reported that the hogging and vacuum pumps are in poor condition and should be replaced. Burns & McDonnell recommends replacing these pumps if the Unit is to operate until 2027 or 2037.

8.1.3 Low Pressure Feedwater Heaters

There are two LP vertical closed feedwater heaters and one vertical evaporative condenser installed downstream of the condensate pumps. The heaters were manufactured by Yuba Heat Transfer Corporation. The LP heaters warm the condensate water by transferring heat from the turbine extraction steam to the condensate water in the closed shell and tube, two-pass vertical U-tube design heat exchangers.

The evaporative condenser is permanently out of service, but the condensate is still routed through the tubes. No NDE data or tube map data was available for the LP heaters. Plant personnel reported no issues with the feedwater heaters (FWHs). Since the feedwater heaters are the original equipment and are approaching 55 years of age there is some concern about their condition.

Burns & McDonnell recommends performing an eddy current test of the FWHs to understand if the tube bundles are at the end of life for both retirement scenarios. Burns & McDonnell also recommends performing NDE around the extraction inlet to each LP FWH to understand if there is any erosion caused by two phase flow for both retirement scenarios.

8.2 Feedwater System

The feedwater system is a closed-loop system that transfers water from the deaerator storage tank to the boiler feedwater pumps, through the HP feedwater heaters, through the boiler economizer, and eventually to the boiler drum.

8.2.1 High Pressure Feedwater Heaters

There are two HP closed FWHs installed downstream of the feedwater pumps. These heaters were manufactured by Yuba Heat Transfer Corporation. The HP heaters increase the efficiency of the plant by transferring heat from the turbine extraction steam to the feedwater in the closed shell and tube, horizontal, two-pass U-tube design heat exchangers.

The first point FWH (highest pressure) was replaced by Senior Engineering in 1993. The second point FWH is the original 1956 vintage Griscom-Russel unit which is in average condition.

Burns & McDonnell recommends performing an eddy current test of the FWHs to understand if the tube bundles are at the end of life for both retirement scenarios. Furthermore, as the first point heater operated 36 years before being replaced, indicates that EPE will have to replace a FWH tube bundle if the Unit is to operate until 2027 or 2037.

8.2.2 Deaerator Heater & Storage Tank

The open, tray type deaerator consists of a single vertical vessel containing both the deaerating heater section and storage tank. The deaerator system was manufactured by Cochrane. In the deaerator, extraction steam is used to de-oxygenate and release non-combustible gasses from the water cycle to the atmosphere.

BPI performed magnetic particle testing on the long seam welds, circumferential welds, and accessible penetrating welds during their 2011 inspection. No service-related indications were found. Plant personnel did report that the last time the internals were inspected, over 15 years ago, that there were several tray issues.

Burns & McDonnell recommends that the plant continue to perform visual inspections of the deaerator vessel at each unit planned outage.

8.3 Condensate and Boiler Feed Pumps

The two electric driven vertical condensate pumps manufactured by Byron Jackson are each rated at 920 gallons per minute (gpm) and supply 100 percent of the full load condensate system demand. Plant personnel reported that the condensate pumps are in good condition but that the motors would have to be rebuilt if the Unit is to operate until 2027 or 2037. Burns & McDonnell recommends that EPE send the motors out to be refurbished.

The two main 100 percent capacity boiler feed pumps (BFPs) are motor-driven barrel type Ingersoll Rand pumps rated at 1120 gpm. Both pumps were overhauled in 2004. Spare motors exist for both pumps. Plant personnel reported that the "A" BFP was replaced with a salvaged pump that is larger than originally designed. This pump has issues with cavitation due to its larger size versus system requirements. Plant personnel also indicated that the "B" BFP needs to be refurbished and that the recirculation valves are obsolete and replacement parts cannot be easily sourced. Burns & McDonnell recommends that both BFPs and BFP motors be refurbished and the recirculation valves be replaced if the Unit is to operate until 2027 or 2037.

8.4 Circulating Water System

The circulating water system is used to reject heat from the condenser to the atmosphere. The system utilizes two 50 percent circulating water pumps, to pump cooling water from the cooling tower basin through the circulating water pipe to the condenser water box and then return the water to the cooling tower.

The two electric motor driven horizontal centrifugal circulating water pumps were manufactured by Westinghouse. Each 50 percent capacity pump is direct driven by a Westinghouse electric motor. The circulating water piping is carbon steel. The lines under the powerhouse are encased in concrete.

Plant personnel reported that the circulating water pumps were refurbished in approximately 2011 and were installed with the wrong specification of oil. EPE decided to remove the oil skids and run the pumps with grease rather than correct the oil issue. This caused the pump bearings to run at higher than designed temperature. EPE believes that if the Unit is to operate until 2027 and 2037 then the pumps/motors should be refurbished, and the oil systems should be put back into service. Plant personnel also reported that the circulating water lines need to be relined. Additionally, if the Unit is to operate until 2027, some of the circulating water line would have to be replaced in sections and to operate until 2037, a significant portion of the circulating water line, especially the soil to air interface, would have to be replaced.

Burns & McDonnell recommends sending the circulating water pumps and motors out to be refurbished as well as commissioning the lube oil system. Burns & McDonnell also recommends inspecting the circulating water line to understand the overall integrity of the system. A large portion of the circulating water system may have to be replaced if the Unit continues to operate to 2027 or 2037.

The cooling tower is erected over a concrete basin having a clearwell at one end from which a 48-in effluent cooling water line gravity feeds over the Montoya canal to the horizontal circulating water pumps. The cooling tower is a Marley, 4-cell, cross-flow induced draft tower handling 33,610 gpm. It is designed for a range of 20°F with a 12°F approach at a 67.5°F wet bulb. The original cooling tower casings, gearboxes, and fans were replaced in outages in the late 1990s. The cooling tower is operated at 4.5 cycles of concentration. It is inspected annually, and the plant has expressed concern regarding the structural integrity. The fill in two cells was destroyed during winter due to icing.

Based on the site visit and information provided by plant personnel, Burns & McDonnell recommends replacing the cooling tower if the Unit is to operate until 2027 or 2037.

8.5 Water Treatment, Chemical Feed, & Sample Systems

The water supply for cooling tower makeup, cycle makeup, service water, and potable water demands of the Plant are supplied from off-site deep-wells. The cycle makeup water is filtered and sent through two stages of reverse osmosis (RO) and further demineralized as it passes through a single mixed bed polisher before being directed to the demineralized water storage tank. Demineralizer regeneration wastewater is directed to a polyvinyl chloride (PVC) neutralization tank where its pH is adjusted and discharged to the lower canal. Service water is supplied from the off-site wells and can also be provided from the upper canal. Service water is directed to the plant services after filtration. Potable water is supplied by the off-site wells, chlorinated, and supplied to the plant potable water facilities.

The plant has a 6-in connection to the city water system as a backup source of water.

Plant process wastewater is discharged to two canals located between the cooling towers and the generating units. The upper canal overflows to the lower canal from which the plant wastewater is treated and discharged to the Rio Grande River. The Plant was connected to the City of El Paso sewer system in 2004, which receives the plant sanitary wastewater.

Cooling tower blowdown water is directed to the lower canal and boiler blowdown water is directed to the upper canal. Floor drains and roof drains go to the lower canal; however, many of the boiler plant drains are plugged.

EPE indicated that the plant makeup water supply line from the off-site wells has been inspected. This line is a coated and wrapped carbon steel line and was reported to be in good condition. Service water piping was originally installed as carbon steel material which has experienced major scaling throughout the plant life. About 90 percent of this carbon steel piping has, over an extended period of sequential replacements, been replaced with PVC piping.

Two 2-stage RO units supplied by Fluid Process Systems rated at 80 gpm were installed in 1996. The deep bed demineralizer was replaced with a new 100 gpm unit in 2002. The addition of the RO units has significantly extended the demineralizer run time from 1 million to 2 million gallons between regenerations. Cleaning of the RO membranes is conducted annually, which is a manual process utilizing temporary hoses.

Rio Grande Unit 6 uses a combination of phosphate, oxygen scavenger, and dispersant for cycle water treatment. Condensate water is treated with Eliminox and amines (morpholine & cyclohexane). Phosphate and Nalco 7221 (dispersant) are injected into the boiler steam drums for boiler water treatment. The cycle water treatment equipment is in adequate condition.

Circulating water treatment consists of the injection of sodium bisulfite and ammonia which is occasionally supplemented with bromine powder.

The Plant contracts with Nalco for advising on plant water chemistry. A Nalco consultant is available to the Plant on a weekly basis. The plant chemist reported that the plant water treatment meets or exceeds the industry accepted standards and have only experienced infrequent excursions of copper and ammonia. The general condition of the plant makeup water supply and treatment systems appear to be in adequate condition and with continued attention and proper maintenance, are expected to continue to operate satisfactorily.

8.6 Fire Protection Systems

The Plant is equipped with two electric fire pumps and one diesel fire pump. Fire sensors are located below the control room.

The Plant reported several improvements to the fire protection system. The diesel fire pump suction has been moved to cleaner water. The switchgear for the electric fire pump has been replaced.

The Plant has also added fire stops to the cable penetrations in the control room.

Rio Grande Unit 6 does not incorporate a deluge system for the generator step-up transformer.

8.7 Bridge Crane

During the site visit, plant personnel reported several issues with the bridge crane. Based on its age and the recent failures, Burns & McDonnell recommends overhauling the crane, replacing the motors, and replacing the controls if the Unit is to operate until 2027 or 2037.

8.8 Plant Structures

The Plant structures generally appear to be in good condition even though the boiler steel is outdoors. The Plant has continued the plant structure painting program which includes annual reviews of locations requiring protective coating attention.

9.0 ELECTRICAL AND CONTROLS

9.1 Unit 6 Electrical Systems

9.1.1 Generator

The generator is a 1955 Westinghouse unit rated 58.822 MVA at 13.8 kilovolt (kV). The stator output is 2,460 amperes (A) at a 0.85 power factor. The rotor and stator windings are hydrogen cooled. The exciter is a 1955 vintage direct current generator exciter rated 700 A at 250-volt direct current (VDC). The voltage regulator is a Westinghouse 1955 vintage electromechanical type located on the ground level under the generator.

Generator protection consists of an ABB GPU2000R microprocessor relay with the following functions:

1. Distance backup (21)
2. Volts/hertz (24)
3. Voltage Supervised Overcurrent backup (51V)
4. Generator Differential (87G)
5. Synchronizing (25/25A)
6. Undervoltage Alarm (27)
7. Reverse Power (32)
8. Loss of Excitation (40)
9. Unbalance (46)
10. Overvoltage (59)
11. Loss of Potential (60)
12. Stator Ground (59GN)
13. 100 percent Stator Ground (27TN)
14. Frequency (81)
15. Inadvertent Energizing (50/27)

The generator was last inspected in 2006. Siemens Generator Services cleaned, electrically tested, and checked the core through bolt torque on the generator stator. Siemens Turbine Services machined the generator rotor journals and collector rings. The following tests were performed:

1. Insulation resistance (megger)
2. Dielectric absorption
3. El CID (stator iron)
4. Retaining ring ultrasonic inspection

The testing indicates that the generator is in good condition. Plant personnel indicated that the generator has never been rewound. Plant personnel also reported that the hydrogen cooling pumps need to be replaced with in kind spares that are at site. Plant personnel also believe that the original exciter should be upgraded to a static exciter. Finally, plant personnel indicated that the automatic voltage regulator should be upgraded to a system that includes a power system stabilizer.

Burns & McDonnell recommends replacing the hydrogen cooling pumps and the original exciter with a static exciter if the Unit is to operate until 2027 or 2037. In Burns & McDonnell's experience, EPE should also expect to rewind the generator if the Unit is to operate until 2037. Finally, Burns & McDonnell recommends that the EPE should replace the automatic voltage regulator with one that includes a power system stabilizer if the Unit is to operate until 2037.

9.1.2 Transformers

During the site visit, Facility representatives reported that all the transformers are maintained by the substation group.

9.1.2.1 Main Transformer (Generator Step-up Transformer)

The main generator step-up (GSU) transformer is a 2007, three-phase unit located outdoors near the turbine building. The GSU is rated at 45/60 MVA with a temperature rise of 55/65 degrees Celsius (°C) and an impedance of 9.9 percent at 45 MVA. The oil preservation system is a nitrogen blanket type. A spare main transformer is located on site.

The GSU protection consists of an ABB TPU2000R microprocessor relay with the following functions:

1. Transformer differential (87)

2. Transformer neutral overcurrent (51N)

There are many factors that reduce a transformers theoretical insulation life such as exposure to through-faults, lightning strikes, ambient temperatures, etc. However, it is not unusual to find transformers with more than 50 years of service. Therefore, with the present testing and maintenance practices, the transformer should have enough remaining life to operate until 2027 or 2037 before significant maintenance or replacement is required. Burns & McDonnell recommends continuing the current inspection, maintenance and testing plan, including a dissolved gas analysis performed on a quarterly basis.

9.1.2.2 Auxiliary Transformer

The auxiliary transformer is a 2001, ABB, three-phase unit located outdoors near the turbine building. The unit auxiliary transformer is rated at 3,750/4,200 kVA at 14.4-2.4 kV with a temperature rise of 55/65 °C and an impedance of 5.78 percent at 3,750 kVA. The oil preservation system is a nitrogen blanket type. A cable bus connects the auxiliary transformer secondary to the medium voltage switchgear terminals. The cable bus is rated at 3 kV and 1,340 A and is naturally cooled.

The auxiliary transformer protection consists of an ABB TPU2000R microprocessor relay and an electromechanical circuit opening relay with these functions:

1. Transformer differential (87)
2. Transformer overcurrent (51)

There are many factors that reduce a transformers theoretical insulation life such as exposure to through-faults, lightning strikes, ambient temperatures, etc. However, it is not unusual to find transformers with more than 50 years of service. Therefore, with the present testing and maintenance practices, the transformer should have enough remaining life to operate until 2027 or 2037 before significant maintenance or replacement is required. Burns & McDonnell recommends continuing the current inspection, maintenance and testing plan, including a dissolved gas analysis performed on a quarterly basis.

9.1.2.3 Startup Transformer

The startup source consists of one transformer, T3, located in the substation which is rated at 7.5 MVA and 66-2.4 kV. A naturally cooled cable bus rated at 3.3 kV and 382 A connects the secondary of the startup transformer to a lineup of 5 kV load break switches. These load break switches allow sharing of the startup transformer between units 4, 6, and 7. A set of cables runs from a load break switch to its associated unit medium voltage switchgear terminals.

The startup transformer is rarely heavily loaded and should have a long life. Burns & McDonnell recommends continuing the current inspection, maintenance and testing plan, including a dissolved gas analysis performed on a quarterly basis.

9.1.3 Cable Bus

Cable bus connects the GSU transformer to the generator terminals. The cable bus is rated 15 kV and 5,000 A. The bus is naturally cooled and is considered in average condition.

9.1.4 Medium Voltage Switchgear

The original 1955 Westinghouse 2.4 kV switchgear is installed on the ground floor of the turbine building in an open area. The main breaker is an air magnetic Westinghouse model 50-DH-150 rated 1,200 A, 24 kiloamperes ("kA") interrupting and 39 kA close and latch. The feeder breakers are air magnetic Westinghouse model 50-DH-150 rated 1,200 A, 24 kA interrupting and 39 kA close and latch. The control power for the breakers is 125 VDC.

Based on wide industry experience, the Westinghouse 50-DH-150 breakers have good reliability if kept free from moisture and normal preventative maintenance is performed. The breakers have been regularly inspected, refurbished, and tested (hipot, megger, contact resistance, etc.) and spare breakers are available. The 2.4 kV system is an unground delta system and the indicating voltmeters showed a balanced voltage to ground which indicates that there were no ground faults present at the time.

Plant personnel indicated that the switchgear was last cleaned and tested in 2016. Due to its age, Burns & McDonnell believes that the medium voltage switchgear is at the end of its life and should be replaced if the Unit is to operate until 2027 or 2037.

9.1.5 480 V Load Centers, Switchgear, and Motor Control Centers

The 1955 vintage 480 V switchgear is equipped with Westinghouse 25 kA air magnetic circuit breakers. The main breakers are Westinghouse DB-25 breakers rated 800 A and 25 kA interrupting with 125 VDC control power. The switchgear is located indoors.

The unit has two three-phase, 2.4-0.48 kV, vacuum pressure impregnated dry-type load center transformers in free-standing enclosures. The main load center transformer is rated 750 kVA, while the cooling tower load center is rated 300 kVA.

The load center transformers that feed the 480 V switchgear lineups typically have a useful life of 30 to 40 years. A redundant transformer is not available which means that the failure of a load center transformer immediately impacts plant operation. However, there is a tie to the Unit 7 480V main switchgear which allows operation of the plant until the failed transformer is replaced. The two cooling tower switchgear lineups do not have this tie feature. As the switchgear and load center transformer have already operated beyond the designed useful life, it is recommended that they are replaced if the Unit is to operate until 2027 or 2037.

There are no 480 V motor control centers installed at the plant. The motor starters are located near the loads in individual enclosures.

9.1.6 2400 V Motors

The 2.4 kV motors consist of the following:

1. Circulating Water Pump Motors – two 450 horsepower (hp)
2. Forced draft fan – one 800 hp
3. Boiler feed water pumps – two 900 hp
4. Condensate pumps – two 150 hp

The plant has a very competent PdM group that performs comprehensive testing on 2.4 kV motors. The motors should be reconditioned or replaced as determined by the PdM testing. Plant personnel indicated that these motors should be sent out for refurbishment if the Unit is to operate until 2027 or 2037.

9.2 Station Emergency Power Systems

The Unit 6 station battery, located in a dedicated room, is provided to supply critical plant systems. The battery is an Exide model FTA-21P flooded-cell lead-acid type with a rating of 1,520 amp-hours. A crosstie is provided between the Units 6 and 7 station battery and the Unit 8 station battery to allow one battery to feed two DC systems.

A new battery serving Units 6 was installed in 2005. Station batteries are designed for a 20-year life given ideal conditions meaning the batteries will have to be replaced if the Unit is to operate until 2027 or 2037.

The protective devices in the DC panels are operated infrequently and along with the DC panel itself. They typically have a lifespan in excess of 50 years.

A new battery charger was installed in 2005. The typical life for battery charger power electronics is 20 to 25 years meaning the battery chargers will also need to be replaced if the Unit operates until 2027 or 2037.

The emergency diesel generator (EDG) is a 480 V Cummins unit rated for 175 kW. The diesel generator starting power is supplied by a dedicated set of batteries rated 48 VDC. The EDG is located on the ground floor of the Unit 4 turbine building. With regular exercising and fluid changes, the EDG should last 40-50 years. However, controls may become an issue with age and obsolescence. The starting batteries will probably have to be changed out occasionally as well.

9.3 Electrical Protection

The Unit 6 generator and transformer protection was upgraded in 2004 to microprocessor-based relaying. The 2.4 kV switchgear is protected with electromechanical relays that are nearing the end of their useful life. These electromechanical relays will need to be replaced if the Unit is to operate until 2027 or 2037.

Furthermore, based on information supplied by plant personnel, the substation breaker is obsolete and should be replaced. Burns & McDonnell recommends replacing this breaker if the Unit is to operate until 2027 or 2037.

9.4 2.4 kV Cable

Unit 6 plant medium voltage cables are primarily Kerite unshielded type. The Plant has a very competent PdM group that performs comprehensive testing on 2.4 kV cables. The cables should be replaced as determined by the PdM testing. Burns & McDonnell recommends replacing the underground cabling if the Unit is to operate until 2037.

9.5 Grounding & Cathodic Protection

The plant ground grid consists of copper conductors buried in the soil under and around the Plant. Equipment and structures appeared to be adequately grounded. Steel columns are grounded in numerous places. Cable trays are grounded by connection to the plant structure at regular intervals.

The Plant is located in an average isokeraunic area with an average of 40 thunderstorm days per year. The Plant is protected from lightning by air terminals on the plant stack. Shield wires are installed on the transmission lines and lines to the GSU and startup transformers.

Cathodic protection is an impressed current rectifier type system and is installed to protect the underground gas lines. It is recommended that continuity testing of the rectifier system and integrity of the anodes be checked and repaired as a minimum.

9.6 Control Systems

Unit 6 is controlled via an Allen Bradley programmable logic controller (PLC). Unit 6 was constructed prior to the formation of NFPA 85 burner management requirements. Unit 6 has a manually supervised burner system with some fuel supply interlocks and trips. The Plant has a Panalarm annunciator system, but no sequence of events recorder function is provided. Bently Nevada vibration monitoring systems is installed on the turbine generator.

The continuous emissions monitoring system has not been upgraded or replaced since commissioned. As such, the system is becoming obsolete and should be replaced if the Unit is to operate until 2027 or 2037.

Burns & McDonnell recommends upgrading the burner management system to comply with NFPA 85 as well as upgrade the PLC system to a distributed control system (DCS) if the Unit is to operate until 2037.

The Unit 6 Panalarm system is obsolete and parts may be difficult to obtain. Upgrading the plant controls to a DCS will make the Panalarm system obsolete, as alarming and sequence of events recording capabilities will be included in the DCS.

9.7 Miscellaneous Electrical Systems

Plant lighting typically consists of the following fixture types:

1. General plant lighting-incandescent
2. Turbine bay lighting-incandescent

3. Maintenance shop lighting-fluorescent
4. Office lighting-incandescent
5. Emergency lighting-station battery

No issues have been identified with the plant lighting.

Lighting is not a part of the power production process but should be maintained regularly for safety concerns and plant maintenance. With regular lamp and fixture replacement the lighting systems should function until retirement.

10.0 OPERATION AND MAINTENANCE

Based on the information reviewed, Plant staff interviews, and visual observations of the Unit, Burns & McDonnell estimated capital expenditures and O&M costs associated with operating the Unit safely and reliably to extend the retirement date to 2027 or 2037.

10.1 Reliability and Performance

Burns & McDonnell evaluated the Unit's overall reliability and performance against a fleet average of similar types of generating stations. Figure 10-1 presents the equivalent availability factor (EAF) for the Unit against fleet benchmark data as provided from the North American Electric Reliability Corporation (NERC) Generator Availability Database System (GADS) for similar natural gas-fired steam turbine generator (STG) units. Similarly, Figure 10-2 presents the equivalent forced outage rate (EFOR) for the Unit against the fleet benchmark. As presented in the figures, Unit 6 has operated reliably given its age and the recent decline in maintenance expenditures. The Unit was designated to be in inactive reserve status (serves as a contingency reserve) in 2014. The 5-year average for EAF for the Unit is higher (or better) than the fleet benchmark and the 5-year average for EFOR is considerably lower (or better) compared to the fleet benchmark.

Figure 10-1: Equivalent Availability Factor (%)

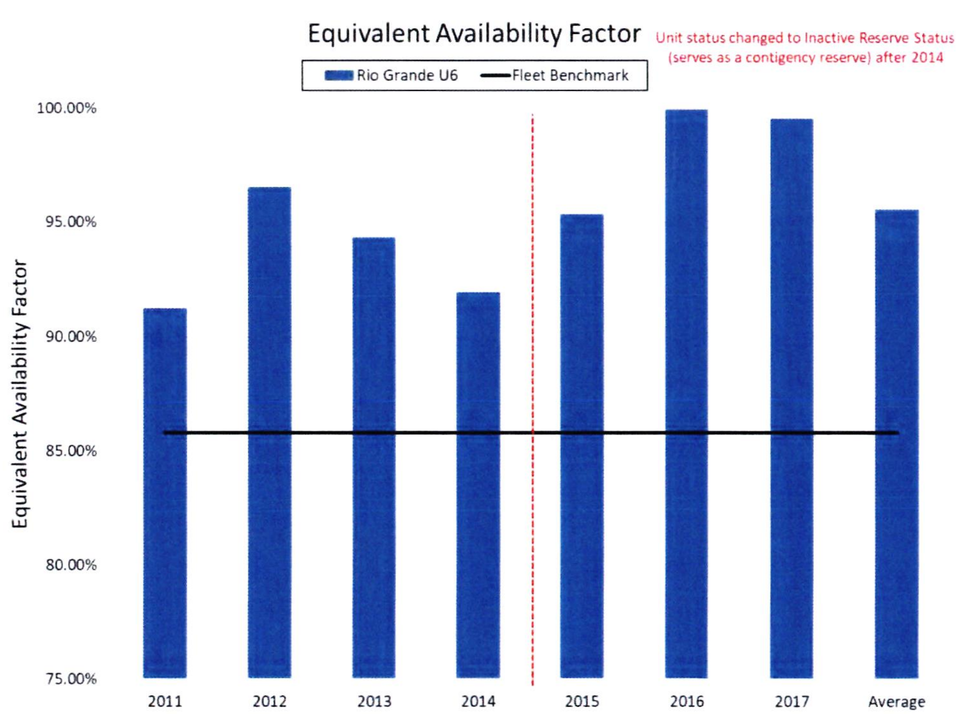
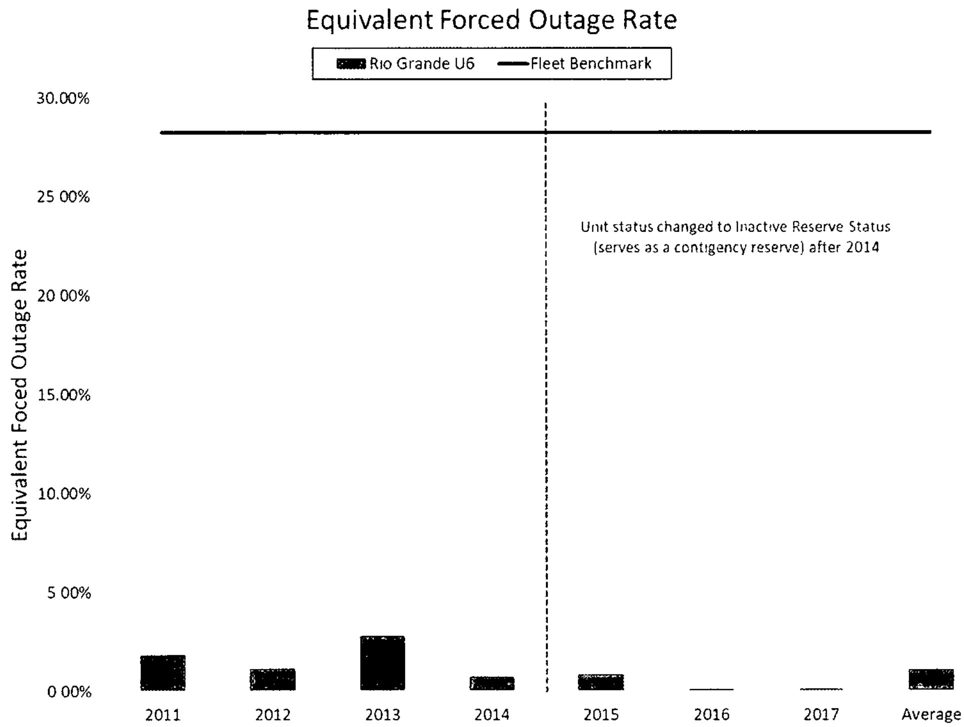


Figure 10-2: Equivalent Forced Outage Rate (%)



10.2 Capital Expenditures Estimate

The Unit was retired in 2014 but continues to operate in inactive reserve (serves as a contingency reserve Unit). Typical power plant design assumes a 30 to 40-year service life. The service life of a unit can be extended if equipment is refurbished or replaced. Based on the current age of the Unit, it has already served past the typical power plant design life. Burns & McDonnell developed a forecast of capital expenditures that would likely be required to extend the service life beyond the scheduled retirement date.

10.2.1 Life Extension through 2027

To extend the useful service life for the Unit until 2027, many major non-recurring repairs and replacements are highly likely to be required due to age and/or obsolescence as soon as possible, as listed below.

1. Perform NDE of selected areas of the boiler and high energy piping
2. Perform STG major inspection and overhaul
3. Install new burners with FSSS standards

4. Comply with TDP-1

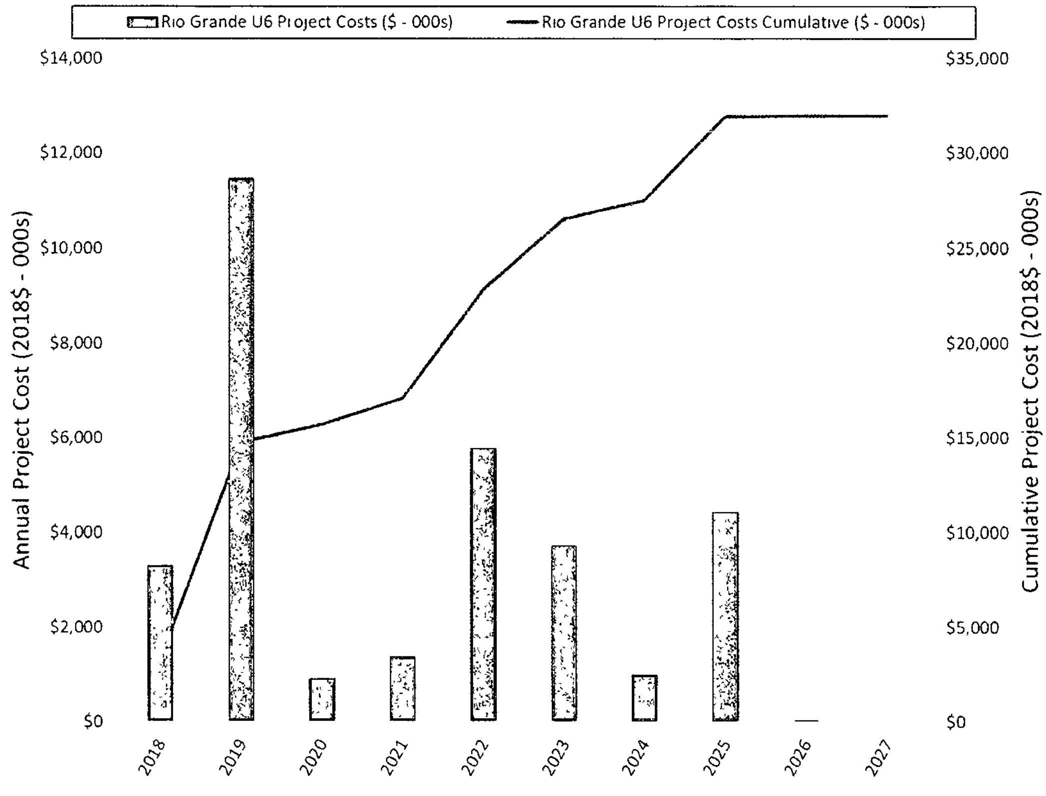
Likewise, the following non-recurring repairs and replacements are highly likely to be required within the next five years.

1. Overhaul of the superheater steam attemperators
2. Replace the air heater lube oil pumps
3. Replace the continuous blowdown tank
4. Inspect and overhaul of the FD fan
5. Replace sections of the boiler casing that are leaking
6. Replace the steam turbine rotor seals and blade ring seals
7. Replace the BFP recirc valves
8. Refurbish the circulating water pumps
9. Install a new liner in the circulating water pipes
10. Replace the cooling tower
11. Replace one FWH
12. Overhaul the crane and replace all motors and controls
13. Replace the switchgear and switchgear protection relays
14. Replace the original exciter with a static exciter
15. Refurbish the BFP, circulating water pump, condensate pump, and FD fan motors

Additionally, recurring maintenance events will need to occur, such as boiler cleanings, NDE inspections, STG major inspections, turbine valve inspections, and replacement of station batteries. Appendix A provides a detailed schedule of the forecasted capital expenditures and maintenance costs required to extend the life of the Unit to 2027.

Figure 10-3 presents a summary of the capital expenditure estimates derived by Burns & McDonnell for Unit 6 in 2018 dollars with no inflation included. Assuming the Unit is in service through 2027, infrastructure replacements and equipment upgrades would be required. For Unit 6, at a nominal capacity of 48 MW, a cost of nearly $32 million will be required to cover capital and maintenance expenditures through 2027, or $666/ kW.

Figure 10-3: Capital Expenditures Forecast through 2027



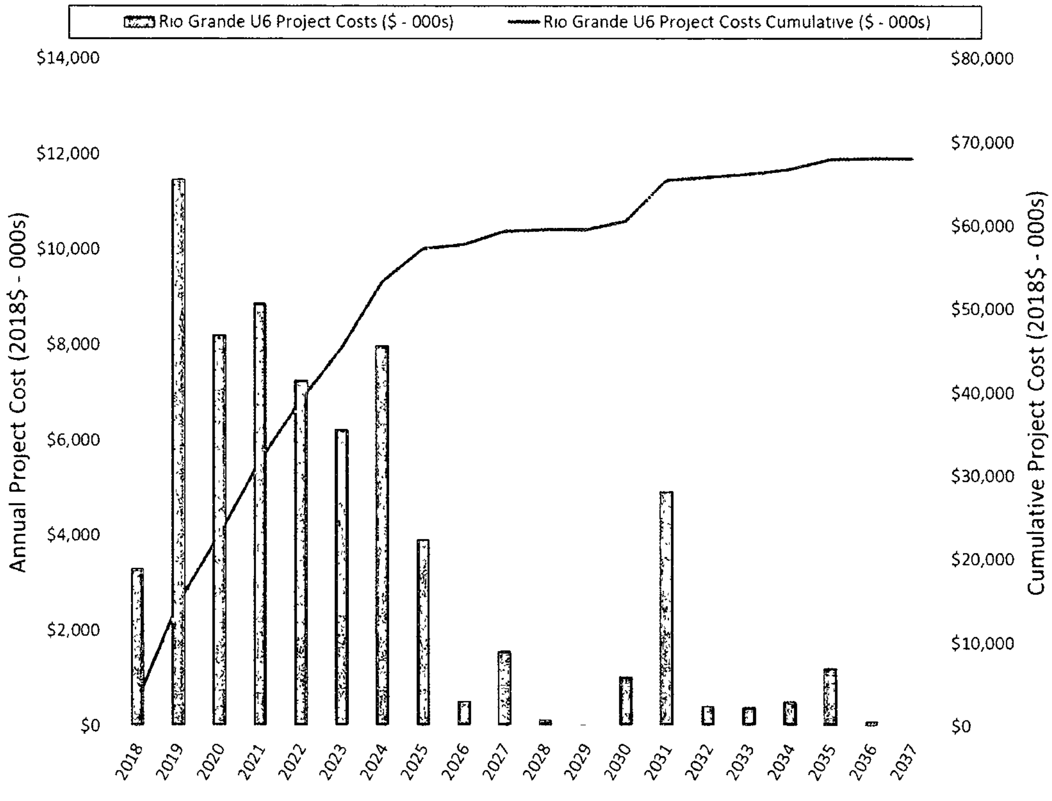
10.2.2 Life Extension through 2037

To extend the useful service life for the Unit until 2037, the projects listed in 2027 should be performed in addition to the projects listed below.

1. Replace the primary and secondary superheaters
2. Replace the waterwall tubes
3. Replace the circulating water bearings and re-commission the lube oil system
4. Replace the underground circulating water pipes
5. Inspection of the condenser and test it hydrostatically
6. Replace the hogger and vacuum pumps
7. Investigate feedwater heater tube life and the possibility of extraction inlet erosion
8. Replace the automatic voltage regulator (AVR) with a new system that includes power system stabilizer (PSS)
9. Upgrade the plant controls to a DCS

Additionally, recurring maintenance events will need to continue, such as boiler cleanings, NDE inspections, air heater cold basket replacements, STG major inspections, turbine valve inspections, and replacement of station batteries. Appendix B provides a detailed schedule of the forecasted capital expenditures and maintenance costs required to extend the life of the Unit to 2037. Figure 10-4 presents a summary of the capital expenditure estimates derived by Burns & McDonnell for Unit 6 in 2018 dollars with no inflation included. Assuming the Unit is in service through 2037, infrastructure replacements and equipment upgrades would be required. For Unit 6, at a nominal capacity of 48 MW, a cost of approximately $68 million will be required to cover capital and maintenance expenditures through 2037, or $1,418/kW.

Figure 10-4: Capital Expenditures Forecast through 2037



10.3 Operations & Maintenance Forecast

In addition to replacing key equipment and components through capital upgrades, much of the remaining equipment would require increased maintenance as the Plant continues to age beyond 60 years of service.

A comprehensive benchmark analysis of similar natural gas-fired steam turbine generators nationwide, demonstrates an increasing trend of maintenance costs associated with the ages of the units. Burns & McDonnell evaluated the trend in fixed operation and maintenance costs associated with similar units (in the 25 MW to 150 MW range). Units with capacity factors lower than 5 percent were excluded from the comparison since those units are used during large peaking loads only. The analysis indicates an upward trend of maintenance costs of approximately 1.25 percent per year. Figure 10-5 and Figure 10-6 present the fixed O&M costs for similar natural gas-fired steam generating power plants with Unit 6 highlighted.

Figure 10-5: Maintenance Cost Trend Evaluation

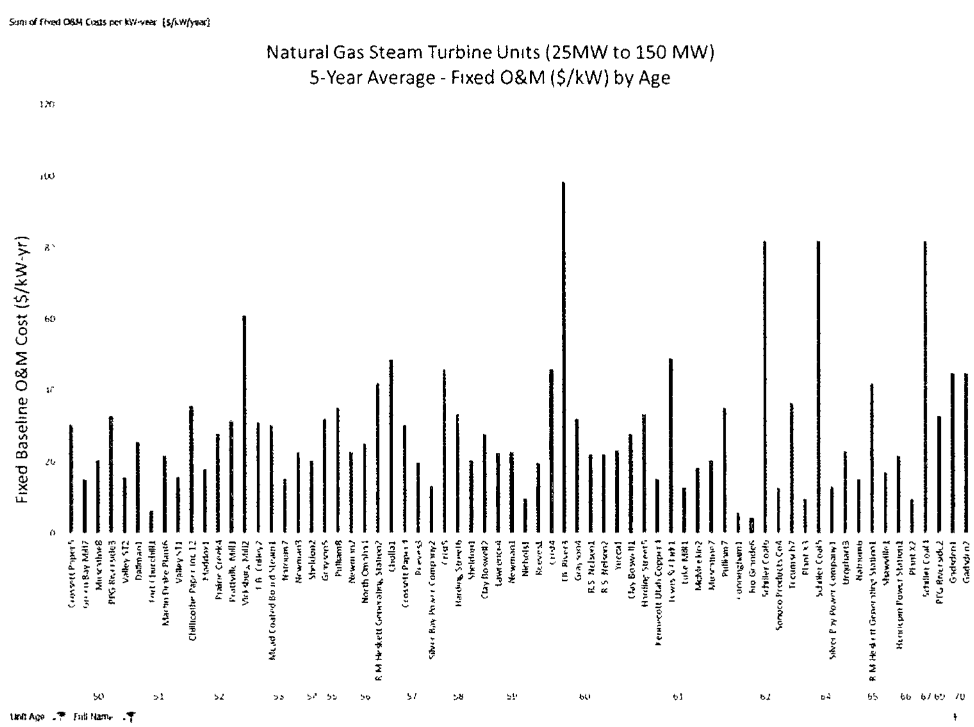
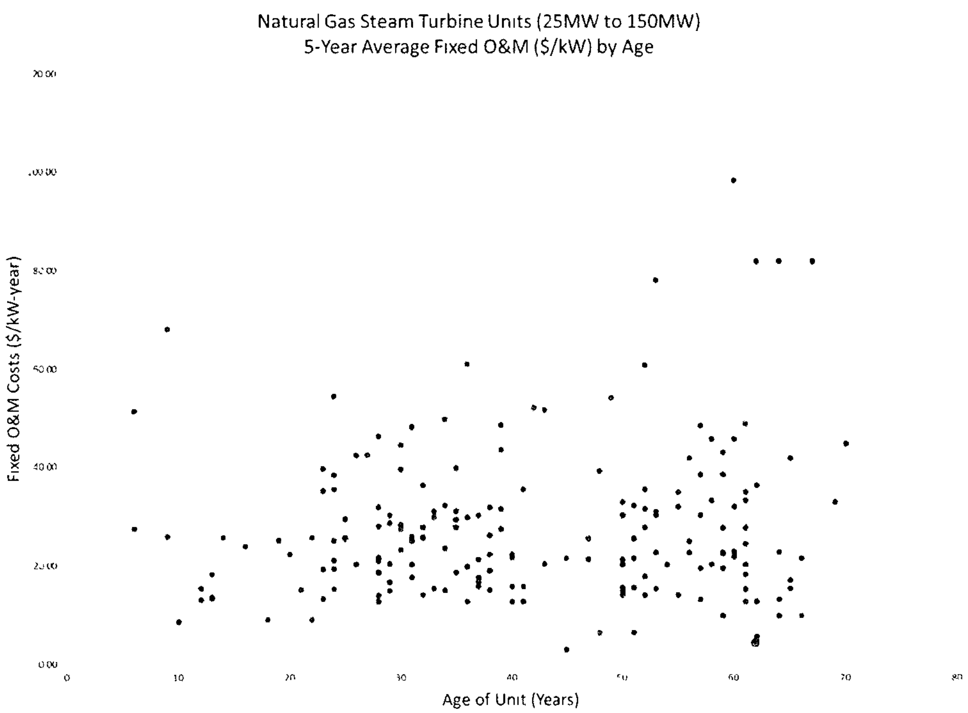


Figure 10-6: Maintenance Cost Trend Evaluation (X-Y Scatter)



In Figure 10-6 the two styles of operating older natural gas units can be distinguished. Units that fall near or below the trend line are being run until failure with limited capital investment and fixed maintenance spend. Units that are significantly above the trendline have taken proactive steps to extend the unit's life by heavily investing in capital upgrades and maintenance activities.

As discussed above, as power plants age the overall cost of maintenance increases at a rate of approximately 1.25 percent but Burns & McDonnell does not anticipate the Unit to maintain low fixed O&M costs of approximately $4.53/kW-year. Burns & McDonnell narrowed the benchmark to determine a more accurate estimate future fixed O&M maintenance cost. A narrowed benchmark analysis was performed on the units having similar natural gas-fired steam turbine generators in the 25 MW to 75 MW range. As of 2018, these units had reached a service life of 60 years or older and had an average capacity factor of at least five percent. A total of 14 power plants, consisting of 15 units, formed the basis of this focused benchmark. Characteristics of these units are provided in Table 10-1.

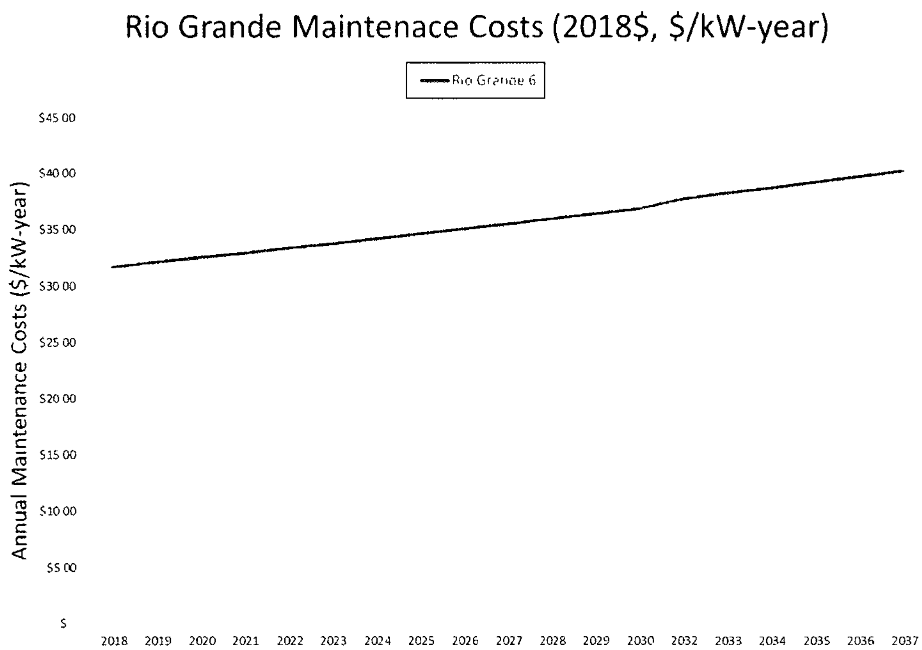
Table 10-1: Benchmark Units

Natural Gas-Fired STG Power Plants between 25 MW to 75 MW and at least 60 Years Old

Power Plant	Age of Unit 2018 (Years)	Operating Capacity (MW)	Fixed O&M ($/kW)	5-Yr Capacity Factor
Clay Boswell 1	61	75	27.81	78%
Cunningham 1	62	75	5.83	26%
Elk River 3	60	25	98.48	51%
Gadsden 1	70	69	45.06	24%
Gadsden 2	70	69	45.06	11%
Grayson 4	60	50	32.22	12%
Hennepin Power Station 1	66	75	21.85	64%
Lewis & Clark 1	61	50	49.06	56%
Luke Mill 1	61	35	13.01	47%
Muscatine 7	61	25	20.56	16%
Natrium 6	65	26	15.57	71%
PPG Riverside 2	69	45	33.09	28%
R.M.Heskett Generating Station 1	65	40	42.05	33%
Silver Bay Power Company 1	64	50	13.38	56%
Sonoco Products Co 4	62	28	13.01	32%
Average	64	49	31.74	39%

Using the average of the benchmarked units in Table 10-1, Burns & McDonnell assumes the Unit will require fixed O&M maintenance costs of $31.74/kW-year. At a rate of 1.25 percent, the maintenance costs would continue to increase for Unit 6 over time from approximately $31.74/kW-year in 2018 to nearly $40.19kW-year in 2037, excluding inflation increases. Figure 10-7 presents the maintenance cost projections for Unit 6. The costs presented in Figure 10-7 are presented in real, constant dollars (2018 dollars) without including inflation.

Figure 10-7: Maintenance Cost Forecast for Unit 6



10.4 Summary

Overall, the total capital and maintenance costs will be significant to extend the useful service life of the Unit. Table 10-2 presents the cumulative capital expenditures and maintenance costs over the periods from 2018 to 2027 and 2018 to 2037The costs do not include inflation. As presented in Table 10-2, Unit 6 will incur costs of approximately $1,002/kW for the 2018 to 2027 life extension scenario and $2,134/kW (2018 dollars) for the 2018 to 2037 life extension scenario.

Table 10-2: Cumulative Capital and Maintenance Costs (2018$)

Time Period	Total ($000)	Capital ($/kW)	Maintenance ($/kW)	Total ($/kW)
2018 to 2027	$48,081	$666	$336	$1,002
2018 to 2037	$102,445	$1,418	$716	$2,134

11.0 CONCLUSIONS & RECOMMENDATIONS

11.1 Conclusions

The following provides conclusions based on the observations and analysis from this Study.

1. Rio Grande Unit 6 was placed into commercial service in June 1957. The Unit has reached 60 years of service and appears to be in fair condition considering its age. The typical power plant design assumes a service life of approximately 30 to 40 years. The Unit has served beyond the typical service life of a power generation facility.
2. Despite its age, the Unit has generally not exhibited a significant loss of reliability, which would be indicative of degradation of the major components. This is likely due to several factors including:
    a. Minimal cycling operation
    b. Proper attention to water chemistry
    c. Early adoption of a predictive maintenance program
    d. An arid climate
3. The Unit has performed reliable considering the Unit's retirement designation and age, however, many of the major components and equipment will need to be repaired or replaced to extend the service life of the Unit to nearly 70 or 80 years. Rio Grande Unit 6 could be capable of reliable operations until 2027 or further until 2037 if a significant amount of capital expenditures and increased maintenance costs are incurred to replace and refurbish the major equipment and components.
4. Unit operations appeared to be well planned and carried out in a manner consistent with utility industry standards before the Unit was retired. Since retirement, only critical maintenance items have been performed. Burns & McDonnell believes that the maintenance budget will have to be increased from current levels to actively address issues which could affect operation and reliability of the unit.
5. With the increased penetration of renewable resources, traditional fossil-fueled generation need to provide greater flexibility to system operators to better optimize the power supply resources and costs to account for the variability and uncertainty associated with renewable resource generation.

The overall condition of Rio Grande Unit 6 appears to be in fair condition considering its age. After review of the design, condition, operations and maintenance procedures, long-range planning, availability of consumables, and programs for dealing with environmental considerations, it is Burns & McDonnell's opinion that Rio Grande Unit 6 should be capable of technical operations until 2027 or further until 2037 if a significant amount of capital expenditures and increased maintenance costs are incurred to replace and refurbish the major equipment and components. In evaluating the economics of extending the life of the Unit, EPE should utilize the capital and O&M costs presented within this report.

11.2 Recommendations

The following is a summary of the recommended actions suggested to maintain the safe and reliable operation of Rio Grande Unit 6 should the Unit's life be extended to 2027. To extend the useful service life for the Unit until 2027, the actions recommended to be performed as soon as possible, as listed below.

1. Inspect the boiler safety valves and team valves
2. Inspect the penthouse boiler supports
3. Install new burners that comply with FSSS standards
4. Perform a boiler chemical clean and drum inspection
5. Clean, dip and bake the FD fan motor
6. Replace sections of the boiler casing in problematic locations
7. Perform a steam path audit and borescope inspection, including the LP shell, before a major overhaul
8. Inspect the main steam pipe support system
9. Perform NDE condition assessment of the high energy piping
10. Replace the cooling tower
11. Replace the gas interrupting valve
12. Investigate feedwater heater tube life and the possibility of extraction inlet erosion
13. Investigate if voids around drains may cause safety concerns

Likewise, the following non-recurring repairs and replacements are highly likely to be required within the next five years.

1. Overhaul superheater attemperators
2. Replace boiler piping
3. Replace the air heater lube oil pumps
4. Replace the continuous blowdown tank
5. Inspect and overhaul the FD fan
6. Replace the steam turbine rotor seals and blade ring seals
7. Make modifications to comply with highest value ASME TDP-1 guidelines

8. Replace the BFP recirculation valves
9. Refurbish circulating water pumps
10. Replace the circulating water pump bearings and re-commission the lube oil system
11. Inspect the condenser and test it hydraulically
12. Replace the hogger and vacuum pumps
13. Overhaul the crane and replace all motors and controls
14. Replace the medium voltage switchgear protection relays
15. Replace the switchgear
16. Replace the original exciter with static exciter
17. Refurbish the BFP, circulating water pump, condensate, and FD fan motors

The following is a summary of the recommended actions suggested to maintain the safe and reliable operation of Rio Grande Unit 6 should the Unit's life be extended to 2037. These recommendations would help maintain the safety, reliability, and reduce the potential for extended unit forced outages. Burns & McDonnell's major recommendations for the unit are:

1. Replace the primary and secondary superheaters
2. Replace the secondary superheater header
3. Replace the waterwall tubes
4. Replace the hot and intermediate end baskets within the air heater
5. Replace the circulating water pipes
6. Replace the underground circulating water pipes
7. Consider adding Bentley Nevada vibration monitoring system
8. Replace the AVR with new system that includes PSS
9. Upgrade the plant controls to DCS
10. Replace the battery charger
11. Rewind the generator

Other recommended practices are described in the subsequent sections.

11.3 External & Environmental Factors

1. Continue to monitor changing air emissions regulations (NAAQS)
2. Continue to monitor well water capacity and quality.

11.3.2 Boiler

1. Conduct regular NDE of selective areas of water wall tubing, steam drum and connections to the steam drum, superheater outlet header and branch connections to the superheater outlet header, reheater outlet header and branch connections to the reheater outlet header, superheater and reheater inlet headers and branch connections to the headers, and superheater and reheater attemperator(s) and downstream piping
2. Perform annual testing of the safety relief valves
3. Conduct boiler chemical cleanings on a 5-year schedule

11.3.3 Steam Turbine-Generator

1. Conduct steam turbine-generator inspections per OEM recommendations
2. Perform regular borescope examinations of the turbine

11.3.4 High Energy Piping Systems

1. Conduct regular non-destructive examination of selective areas of main steam, hot reheat, boiler feedwater piping, and cold reheat piping
2. Perform testing on the extrados of the sweeping elbows, where turbulence can occur, causing excessive erosion/ corrosion
3. Visually inspect the main steam, hot reheat, cold reheat, extraction, and feedwater piping supports on an annual basis

11.3.5 Balance of Plant

1. Conduct eddy current testing of low pressure and high-pressure feedwater heater tubing.
2. Conduct regular non-destructive examination of the feedwater heaters, deaerator and deaerator storage tank, including ultrasonic thickness testing of the storage tank shell at the normal water level
3. Conduct visual inspections of the circulating water piping on a regular basis
4. Inspect the structural integrity of the stack

11.3.6 Electrical

1. Perform quarterly dissolved gas analysis on the main, auxiliary, and start-up transformers
2. Continue testing of the rectifier system and integrity of the anodes

APPENDIX A - COST FORECASTS THROUGH 2027

El Paso Electric, Inc
Rio Grande Unit 6
Burns & McDonnell Project No 101955
Condition Assessment & Life Extension Assessment - 2027

Capital Expenditures and Maintenance Forecasts
All costs are presented in 2018$, no inflation is included

CONFIDENTIAL

CAPITAL EXPENDITURES (Presented in $000)

DESCRIPTION	CATEGORY	LAST	FREQUENCY	NEXT	TOTAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
4 BOILER															
Inspect boiler safety valves regularly	Safety	Unknown	3	ASAP	$300	$100			$100			$100			
Inspect penthouse boiler supports	Industry Practice	Never	Once	ASAP	$200	$200									
Install new burners with FSSS standards	Safety	Never	Once	ASAP	$480	$480									
Overhaul superheater attemperators	Required	Never	Once	Within 5 years*	$600		$600								
Perform boiler chemical cleaning	Industry Practice	2011	6	ASAP	$1,200	$600						$600			
Perform regular drum inspections	Industry Practice	Unknown	3	ASAP	$300	$100			$100			$100			
Replace boiler tubing on an as needed basis	Required	N/A	3	Within 5 years*	$3,000		$1,000			$1,000			$1,000		
5. BOILER AUXILIARY SYSTEMS															
Replace air heater cold end baskets	Industry Practice	2007	10	2022	$400					$400					
Replace air heater lube oil pumps	Required	Never	Once	Within 5 years*	$80			$80							
Replace continuous blowdown tank	Required	Never	Once	Within 5 years*	$500				$500						
Inspect and overhaul FD fan	Industry Practice	Unknown	Once	Within 5 years*	$150		$150								
Replace entire sections of boiler casing in problematic locations	Safety	Never	Once	ASAP	$800	$800									
Inspect stack	Industry Practice	Unknown	10	ASAP	$100	$100									
6 STEAM TURBINE															
Overhaul steam turbine	Industry Practice	2006	6	ASAP	$6,400		$3,200						$3 200		
Perform steam path audit & borescope inspection including LP shell	Required	Unknown	Once	ASAP	$300	$300									
Replace rotor and blade ring seals at next overhaul	Required	Unknown	Once	Within 5 years*	$1,000		$1,000								
Overhaul steam valves	Industry Practice	2007	4	ASAP	$2,400		$1,200				$1 200				
7 HIGH ENERGY PIPING SYSTEMS															
Inspect main steam pipe support system	Industry Practice	Unknown	1	ASAP	$180	$20	$20	$20	$20	$20	$20	$20	$20	$20	
Make modifications to comply with highest value ASME TDP-1 guidelines	Industry Practice	Unknown	Once	Within 5 years*	$300			$300							
Perform NDE condition assessment of energy piping	Industry Practice	2011	3	ASAP	$330	$110			$110			$110			
Test extrados of feedwater piping sweeping elbows	Industry Practice	2011	3	ASAP	$150	$50			$50			$50			
8 BALANCE OF PLANT															
Refurbish BFP A	Required	2004	15	2019	$250		$250								
Refurbish BFP B	Required	2004	15	2019	$250		$250								
Replace BFP recirculation valves	Required	Never	Once	Within 5 years*	$60			$60							
Refurbish circulating water pumps	Required	2011	Once	Within 5 years*	$300				$300						
Re-line circulating water pipes	Required	Never	Once	Within 5 years	$1,000					$1,000					
Replace bearing and re commission lube oil system	Required	Never	Once	Within 5 years*	$250					$250					
Replace the cooling tower	Safety	Never	Once	ASAP	$3,000		$3,000								
Inspect the condenser and test it hydrostatically	Industry Practice	Unknown	Once	Within 5 years*	$200		$200								
Replace hogger and vacuum pump	Required	Never	Once	Within 5 years*	$250			$250							
Replace gas interrupting valves and regulators	Safety	Never	Once	ASAP	$250	$250									
Investigate tube life and possibility of extraction inlet erosion	Industry Practice	Unknown	Once	ASAP	$150	$150									
Replace one FWH tube bundles	Required	Never	Once	Within 10 years*	$1,500						$1,500				
Investigate if voids around drain may cause problems	Required	Never	Once	ASAP	$30	$30									
Overhaul crane and replace all motors and controls	Required	Never	Once	Within 5 years*	$500					$500					
9 ELECTRICAL AND CONTROLS															
Replace medium voltage switchgear protection relays	Industry Practice	Never	Once	Within 5 years*	$400		$400								
Replace station batteries	Industry Practice	2005	20	2025	$200								$200		
Replace switchgear	Industry Practice	Never	Once	Within 5 years*	$2,000					$2,000					
Replace original exciter with static exciter	Industry Practice	Never	Once	Within 5 years*	$500					$500					
Refurbish BFP motors	Industry Practice	Unknown	Once	Within 5 years*	$200		$200								
Refurbish circulating water pump motors	Industry Practice	Unknown	Once	Within 5 years*	$200			$200							
Refurbish condensate pump motors	Industry Practice	Unknown	Once	Within 5 years*	$200				$200						
Refurnish FD fan motor	Industry Practice	Unknown	Once	Within 5 years*	$100					$100					
Upgrade CEMS	Industry Practice	Unknown	Once	Within 10 years*	$500						$500				
Upgrade substation breaker	Required	Unknown	Once	Within 5 years*	$500						$500				
TOTAL															
TOTAL					$31,960	$3,290	$11,470	$910	$1,380	$5,770	$3,770	$980	$4,420	$20	$0

*Distributed over years to spread out expense

SOAH Docket No 473-21-2606
PUC Docket No 52195
CEP's 1st, Q No CEP 1-27
Attachment 3
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APPENDIX B - COST FORECASTS THROUGH 2037

El Paso Electric Inc
Rio Grande Unit 6
Burns & McDonnell Project No 101955
Condition Assessment & Life Extension Assessment - 2037

Capital Expenditures and Maintenance Forecasts
All costs are presented in 2018$ no inflation is included

CONFIDENTIAL

CAPITAL EXPENDITURES (Presented in $000)

DESCRIPTION	CATEGORY	LAST	FREQUENCY	NEXT	TOTAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
4 BOILER																									
Inspect boiler safety valves regularly	Safety	Unknown	3	ASAP	$700	$100			$100			$100			$100			$100			$100			$100	
Inspect penthouse boiler supports	Industry Practice	Never	Once	ASAP	$200	$200																			
Install new burners with FSSS standards	Safety	Never	Once	ASAP	$480	$480																			
Overhaul superheater attemperators	Required	Never	Once	Within 5 years*	$600		$600																		
Perform boiler chemical cleaning	Industry Practice	2011	6	ASAP	$1 800	$600						$600						$600							
Perform regular drum inspections	Industry Practice	Unknown	3	ASAP	$600	$100			$100			$100			$100			$100			$100				
Replace boiler tubing on an as needed basis	Required	N/A	5	Within 10 years*	$1 000									$500					$500						
Replace main steam piping	Required	Never	Once	Within 10 years*	$2 000							$2 000													
Replace primary and secondary superheaters	Required	Never	Once	Within 5 years*	$5 000			$5 000																	
Replace secondary superheater header when replacing secondary superheater	Required	Never	Once	Within 5 years*	$2 000			$2 000																	
Replace waterwall tubes	Required	Never	Once	Within 5 years*	$4 000				$4 000																
5 BOILER AUXILIARY SYSTEMS																									
Replace air heater cold end baskets	Industry Practice	2002	10	2022	$800					$400										$400					
Replace air heater hot and intermediate end baskets	Industry Practice	Never	Once	Within 5 years*	$1 000		$1 000																		
Replace air heater lube oil pumps	Required	Never	Once	Within 5 years*	$80			$80																	
Replace continuous blowdown tank	Required	Never	Once	Within 5 years*	$500				$500																
Inspect and overhaul FD fan	Industry Practice	Unknown	Once	Within 5 years*	$150		$150																		
Replace entire sections of boiler casing in problematic locations	Safety	Never	Once	ASAP	$800	$800																			
Inspect stack	Industry Practice	Unknown	10	ASAP	$200	$100										$100									
6 STEAM TURBINE																									
Overhaul steam turbine	Industry Practice	2006	6	ASAP	$9 600		$3,200						$3 200						$3 200						
Perform steam path audit & borescope inspection including LP shell	Required	Unknown	Once	ASAP	$300	$300																			
Repair turbine casing	Required	2006	Once	Within 10 years*	$500								$500												
Replace rotor and blade ring seals at next overhaul	Required	Unknown	Once	Within 5 years*	$1,000		$1 000																		
Overhaul steam valves	Industry Practice	2007	4	ASAP	$6,000		$1,200				$1 200				$1 200				$1 200				$1,200		
7 HIGH ENERGY PIPING SYSTEMS																									
Inspect main steam pipe support system	Industry Practice	Unknown	1	ASAP	$360	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20		
Make modifications to comply with highest value ASME TDP-1 guidelines	Industry Practice	Unknown	Once	Within 5 years*	$300			$300																	
Perform NDE condition assessment of energy piping	Industry Practice	2011	3	ASAP	$660	$110			$110			$110			$110			$110			$110				
Test extrados of feedwater piping sweeping elbows	Industry Practice	2011	3	ASAP	$300	$50			$50			$50			$50			$50			$50				
8. BALANCE OF PLANT																									
Refurbish BFP A	Required	2004	15	2019	$500		$250															$250			
Refurbish BFP B	Required	2004	15	2019	$500		$250															$250			
Replace BFP recirculation valves	Required	Never	Once	Within 5 years*	$60			$60																	
Refurbish circulating water pumps	Required	2011	Once	Within 5 years*	$300				$300																
Replace bearing and re commission lube oil system	Required	Never	Once	Within 5 years*	$250					$250															
Replace the cooling tower	Safety	Never	Once	ASAP	$3 000		$3 000																		
Replace underground circulating water pipes	Required	Never	Once	Within 5 years*	$3,000					$3 000															
Inspect the condenser and test it hydrostatically	Industry Practice	Unknown	Once	Within 5 years*	$200		$200																		
Retube condenser	Required	Never	Once	Within 10 years*	$1,500							$1,500													
Replace hogger and vacuum pump	Required	Never	Once	Within 5 years*	$250			$250																	
Replace gas interrupting valves and regulators	Safety	Never	Once	ASAP	$250	$250																			
Investigate tube life and possibility of extraction inlet erosion	Industry Practice	Unknown	Once	ASAP	$150	$150																			
Replace one FWH tube bundles	Required	Never	Once	Within 10 years*	$1 500						$1 500														
Investigate if voids around drain may cause problems	Required	Never	Once	ASAP	$30	$30																			
Overhaul crane and replace all motors and controls	Required	Never	Once	Within 5 years*	$500					$500															
9 ELECTRICAL AND CONTROLS																									
Replace AVR with new system that includes PSS	Industry Practice	Never	Once	Within 5 years*	$300			$300																	
Upgrade plant control to DCS	Industry Practice	Never	Once	Within 5 years*	$3 500				$3,500																
Replace battery charger	Industry Practice	2005	25	2030	$50													$50							
Replace medium voltage switchgear protection relays	Industry Practice	Never	Once	Within 5 years*	$400		$400																		
Replace station batteries	Industry Practice	2005	20	2025	$200								$200												
Replace switchgear	Industry Practice	Never	Once	Within 5 years*	$2 000					$2 000															
Replace original exciter with static exciter	Industry Practice	Never	Once	Within 5 years*	$500					$500															
Replace UG cabling	Required	Never	Once	Within 10 years*	$3,000						$3,000														
Rewind generator	Industry Practice	Unknown	Once	Within 10 years*	$3,500							$3 500													
Refurbish BFP motors	Industry Practice	Unknown	Once	Within 5 years*	$200		$200																		
Refurbish circulating water pump motors	Industry Practice	Unknown	Once	Within 5 years*	$200			$200																	
Refurbish condensate pump motors	Industry Practice	Unknown	Once	Within 5 years*	$200				$200																
Refurnish FD fan motor	Industry Practice	Unknown	Once	Within 5 years*	$100					$100															
Upgrade CEMS	Industry Practice	Unknown	Once	Within 10 years*	$500						$500														
Upgrade substation breaker	Required	Unknown	Once	Within 5 years*	$500					$500															
TOTAL																									
TOTAL					$68 070	$3 290	$11 470	$8 210	$8 880	$7 270	$6 220	$7 980	$3 920	$520	$1,580	$120	$20	$1 030	$4 920	$420	$380	$520	$1 220	$100	$0

*Distributed over years to spread out expense

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BURNS & McDONNELL

Life Extension & Condition Assessment for Rio Grande Unit 7

The Electric Company
El Paso Electric

El Paso Electric, Inc.

**Life Extension & Condition Assessment
Project No. 101995**

**Revision 1
7/16/2018**

Life Extension & Condition Assessment for Rio Grande Unit 7

prepared for

El Paso Electric, Inc.
Life Extension & Condition Assessment
El Paso, Texas

Project No. 101995

Revision 1
7/16/2018

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
A	Amperes
ASME	American Society of Mechanical Engineers
BPI	Babcock Power, Inc.
BMS	Burner management system
Btu	British thermal units
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
CCR	Coal combustion residuals
CO	Carbon monoxide
CPP	Clean Power Plan
CWA	Clean Water Act
DA	Deaerator
DCS	Distributed control system
EAF	Equivalent availability factor
EDG	Emergency diesel generator
EFOR	Equivalent forced outage rate
El CID	Electromagnetic Core Imperfection Detection
ELG	Effluent Limitations Guidelines
EPA	Environmental Protection Agency
EPE	El Paso Electric, Inc.
FAC	Flow-accelerated corrosion
Facility	Rio Grande Power Station

Abbreviation	Term/Phrase/Name
FD	Forced draft
FSSS	Flame Safety Scanner System
GADS	Generator Availability Database System
GE	General Electric
gpm	Gallons per minute
GSU	Generator step-up
hp	Horse power
HP	High pressure
KA	Kiloamperes
KVA	Kilovolt amperes
KW	Kilowatt
lb/hr	Pounds per hour
LP	Low pressure
MACT	Maximum Achievable Control Technology
MCR	Maximum continuous rating
MVA	Megavolt amperes
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NDE	Nondestructive examination
NERC	North American Electric Reliability Corporation
NO_2	Nitrogen dioxide
NPDES	National Pollution Discharge Elimination System

Abbreviation	**Term/Phrase/Name**
NSR	New Source Review
O&M	Operation and maintenance
O_3	Ozone
OEM	Original equipment manufacturer
PdM	Predictive maintenance
Plant	Rio Grande Power Station
PLC	Programmable logic controller
PM	Particulate matter
ppb	Parts per billion
PSD	Prevention of Significant Deterioration
psig	Pounds per square inch gauge
RACT	Reasonably available control technology
Rio Grande	Rio Grande Power Station
RO	Reverse osmosis
SJAE	Steam Jet Air Ejector
SO_2	Sulfur dioxide
SPE	Solid particle erosion
STG	Steam turbine generator
Study	Life Extension and Condition Assessment
Unit	Unit 7 of the Rio Grande Power Station
Unit 7	Unit 7 of the Rio Grande Power Station
VDC	Volts DC

Abbreviation	**Term/Phrase/Name**
WQBEL	Water quality-based effluent limits
WQS	Water Quality Standards

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1.0 EXECUTIVE SUMMARY

1.1 Objective & Background

El Paso Electric, Inc. ("EPE") retained the services of Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") to perform a study to assess the condition of Unit 7 ("Unit") of the Rio Grande Power Station ("Plant", "Rio Grande", or "Facility") and determine the overall costs associated with extending the useful service life of the Unit ("Study"). The Unit is currently scheduled for retirement in 2022. The objective of the condition assessment was to estimate the cost of repairing, replacing, maintaining, and operating this Unit to extend the useful service life for the periods through 2027 and 2037. This Study includes an analysis of the current condition of the Plant given the expected service life of the Unit, as well as any matters of concern with current and expected operations, maintenance, external, and environmental factors. Burns & McDonnell has included estimated capital and incremental operation and maintenance ("O&M") costs associated with operating the Unit safely and reliably for the periods from 2018 to 2027 and from 2018 to 2037.

The analysis conducted herein is based on historical operations data, maintenance and operating practices of units similar to Rio Grande, and Burns & McDonnell's professional opinion. For this Study, Burns & McDonnell reviewed data gathered previously combined with updated information provided by EPE, interviewed plant personnel, and conducted a walk-down of the Plant to obtain information on Rio Grande Unit 7. Burns & McDonnell also analyzed any necessary updates for the Unit and need for capital replacements to extend the life through 2027 or 2037.

1.2 Results

1.2.1 Capital Expenditures and O&M Costs

Due to the condition of the Unit, much of the major equipment and components will need to be replaced and refurbished to continue to operate the Unit safely and to extend the life beyond the current retirement date of 2022. Burns & McDonnell developed a capital expenditure and maintenance forecast assuming the retirement date of the Unit was extended to 2027 or 2037.

Overall, the total capital and maintenance costs will be significant to extend the useful service life of the Unit beyond the scheduled retirement date of 2022. Table 1-1 presents the cumulative capital expenditures and maintenance costs over the periods from 2018 to 2027 and 2018 to 2037, presented in 2018$. The costs do not include inflation. As presented in Table 1-1, Unit 7 will incur costs of approximately $881/kW (2018$) for the 2018 to 2027 time period and $1,937/kW (2018$) for the 2018 to 2037 time period.

Table 1-1: Cumulative Capital and Maintenance Costs (2018$)

Time Period	Unit	Total ($000)	Capital ($/kW)	Maintenance ($/kW)	Total ($/kW)
2018 to 2027	Rio Grande Unit 7	$43,041	$615	$281	$897
2018 to 2037	Rio Grande Unit 7	$92,978	$1,337	$600	$1,937

1.3 Conclusions & Recommendations

The following provides conclusions and recommendations based on the observations and analysis from this Study.

1. The Rio Grande Unit 7 was placed into commercial service June of 1958. The Unit is approaching nearly 60 years of service. The typical power plant design assumes a service life of approximately 30 to 40 years. The Unit has served beyond the typical service life of a power generation facility.
2. The overall condition of Rio Grande Unit 7 appears to be reasonably fair to good considering its age, and the Unit could achieve the planned unit life to 2022 if the interventions recommended in this Study are implemented, and if operational and maintenance problems which could affect operation continue to be actively addressed.
3. Despite its age, the Unit has generally not exhibited a significant loss of reliability, which would be indicative of significant general degradation of the major components. This is likely due to several factors including:
   a. Avoidance of cycling operation during much of its life
   b. Proper attention to water chemistry
   c. An aggressive predictive maintenance ("PdM") program
4. While the Unit has experienced relatively good reliability, much of the major components and equipment for the Unit need repair or replacement to extend the service life of the Unit to nearly 70 or 80 years. Rio Grande Unit 7 could be capable of technical operations until 2027 or further until 2037 if a significant amount of capital expenditures and increased maintenance costs are incurred to replace and refurbish much of the major equipment and components.
5. Unit operations and maintenance are generally well planned and carried out in a manner consistent with utility industry standards. Plant personnel should continue to actively address any operational and maintenance issues which could affect operation of the units.

6. The predictive maintenance program used throughout the EPE system has been highly successful in minimizing forced outages in the rotating equipment area. According to EPE, this program has received industry recognition, and should be extended as feasible.
7. With the increased penetration of renewable resources, traditional fossil-fueled generation needs to provide greater flexibility to system operators to better optimize the power supply resources and costs to account for fluctuations within renewable resource generation. The Unit does not provide as much flexibility regarding ramp rates, start times, or part load operation compared to newer generating resources.
8. Recommendations
   a. EPE should perform a boiler and high energy piping condition assessment on a regular basis. The implementation of a regular nondestructive examination ("NDE") program would be prudent to provide early warning of major component deterioration.
   b. In evaluating the economics of extending the life of the Unit, EPE should utilize the capital and O&M costs presented within this report.

2.0 INTRODUCTION

2.1 General Plant Description

El Paso Electric, Inc. ("EPE") is an investor-owned electrical utility responsible for supplying power through an interconnected system to a service territory encompassing over 400,000 customers in the Rio Grande Valley in West Texas and Southern New Mexico. EPE has interests in Palo Verde Nuclear Plant, Copper Power Station, Montana Power Station, Rio Grande Power Station, and Newman Power Station. Located in Sunland Park, New Mexico (a suburb of El Paso, Texas), Rio Grande Unit 7 ("Unit", "Unit 7", "Facility", or "Plant") began commercial operation in 1958. The previous condition assessment that Burns & McDonnell provided for EPE also considered Unit 6, which was retired in 2015 and later brought out of retirement due to issues with Newman Unit 5. Unit 7 is scheduled for retirement in 2022. Unit 7 alone is the focus of this assessment.

EPE typically develops budgets for the upcoming year, and occasionally plans a "long-term" budget that extends a few years.

The typical dispatch of Unit 7 has been to baseload the Unit from May through September, during which the Plant is not cycled, but rather is ramped up and down. The Facility runs about seven months out of the year and has not experienced as much cycling in the past compared to the Newman generating station.

During a freeze event in 2011 Unit 7 was offline. However, later in the week when the Unit was starting, plant staff discovered numerous frozen pipes and leaks. There is a major transmission line outage scheduled in October of 2017 for Palo Verde, for which the natural gas-fired units will be dispatched to provide sufficient energy to meet load.

The Plant undergoes a two-week maintenance outage each year, typically in the spring. The focus of the outage is balance of plant equipment unless any principal equipment is scheduled for major maintenance. Typical spring outage activities involve conditioning oil coolers, cleaning the condenser, conducting all planned inspection and maintenance activities, inspecting the deaerator ("DA"), inspecting the boiler and determining if the boiler needs a chemical cleaning, inspecting valves, and stroking valves.

The Unit 7 major plant equipment includes a natural circulation steam generator boiler designed by Babcock and Wilcox for 350,000 pounds per hour ("lb/hr") steam flow at 1,510 pounds per square inch gauge ("psig") outlet pressure and 1,005°F superheater and reheater outlet temperatures. The boiler has a pressurized furnace, and a single regenerative Ljungstrom air preheater. The boiler previously had the ability to fire fuel oil, but this capability has been disabled. Unit 7 also includes a General Electric

("GE") steam turbine, which is a tandem compound, double-flow condensing unit. The generator is currently rated at 56.8 megavolt amperes ("MVA"). Cooling water for Unit 7 is circulated through a counter-flow cooling tower with makeup water provided from off-site wells. Boiler makeup water for Unit 7 is also provided from the off-site well water system.

The steam turbine generator ("STG") was previously on a maintenance cycle of about 8 years and the valves were on a cycle of 3 years, both regardless of dispatch. These maintenance cycles have since become based on hours instead. The steam turbine generator maintenance is now done according to a cycle of 80,000 hours and the maintenance for the valves is done every 30,000 hours.

The Rio Grande facility also employs a predictive maintenance ("PdM") program, which entails continuous monitoring on the STG by means of a Bently Nevada System 1, visual walk-around observations of other equipment, and monthly testing. Every 30 days the Plant staff perform a vibration analysis, oil analysis, and motor analysis on the major pumps. The Facility utilizes XY probes and thermocouples for the vibration monitoring. Lubricating oil is tested by EPE personnel each month and samples are sent for outside testing each quarter. The motor analysis considers the condensate, boiler feed pumps, air compressors, preheaters, circulating water system, cooling tower, and forced draft ("FD") fan. The Plant has dedicated staff for PdM, that performs a trending analysis using RBM Ware software.

2.2 Study Objectives & Overview

EPE retained the services of Burns & McDonnell to perform a study to assess the condition of Rio Grande Unit 7, and to assess the costs of restoring, operating, and maintaining this Unit to extend its useful service life until 2027 or 2037. This Study includes an analysis of the current condition of the Plant and of the issues with current and expected operations, maintenance, and environmental factors, to assess how such issues would impact the Plant's capital expenditure budget and its operations and maintenance budgets if EPE wanted to extend its life until 2027 or 2037. This Study is based on historical operations data and other condition assessment reports provided by EPE, maintenance and operating practices of units similar to Rio Grande, and Burns & McDonnell's professional opinion. Burns & McDonnell has also estimated capital expenditures and incremental Operation and Maintenance ("O&M") costs associated with operating the unit through 2027 or 2037.

To complete this assessment, Burns & McDonnell engineers reviewed plant documentation, interviewed EPE management and plant personnel, and conducted a walkdown of the Plant to obtain information on the condition of the unit.

2.3 Study Contents

The following report details the current condition of the Unit, and presents the capital expenditures and the ongoing operations and maintenance that would be associated with continued operation of this unit past its current retirement date until 2027 or 2037. Since virtually any single component within a power plant can be replaced, the remaining useful life of a plant is typically driven by the economics of replacing the various components as necessary to keep the plant operating economically at industry standards versus shutting it down and either purchasing power or building a replacement facility. Specifically, the critical physical components that will likely determine the Facility's remaining useful life include the following:

1. Steam generator drum, headers, and downcomers
2. High energy piping systems
3. Steam turbine rotor shaft, valves, and steam chest
4. Main generator rotor shaft, stator and rotor windings, stator and rotor insulation, and retaining rings

The following items, although not as critical as the above, are also influential components that will also play a role in determining the remaining life of the plant:

1. Steam generator tubing, ductwork, air preheater and FD fan
2. Steam turbine blades, diaphragms, nozzle blocks, and casing and shells
3. Generator stator-winding bracing, DC exciter, and voltage regulator
4. Balance of plant condenser, feedwater heaters, feedwater pumps and motors, controls, and auxiliary switchgear
5. Cooling tower structure, structural steel, stack, concrete structures, and station main generator step-up ("GSU") and auxiliary transformers

External influences that will likely be the major determinant of the future life of the Unit include environmental influences such as future environmental compliance requirements, economics including fuel costs, comparative plant efficiency, and system needs associated with flexibility, and obsolescence such as the inability to obtain replacement parts and supplies.

3.0 SITE VISIT

Representatives from Burns & McDonnell, along with EPE staff, visited the Plant on September 14, 2017. The purpose of the site visit was to gather information to conduct the life extension condition assessment, interview the plant management and operations staff, and to conduct an on-site review of the Plant site.

The following representatives from EPE provided information during the site visit:

1. David Aranda, Plant Manager and former Operator
2. David Barraza, Operations Superintendent

The following Burns & McDonnell representatives comprised the condition assessment team:

1. Mike Borgstadt, Associate Project Manager and Mechanical Engineer
2. Victor Aguirre, Lead Project Analyst and Electrical Engineer
3. Sandro Tombesi, Mechanical Engineer

Through visual observation of the Plant and its operations during the site visit, the Facility is maintained adequately and appeared to be in working condition. All buildings seemed to be kept in a clean and proactive manner with no significant corrosion or structural damage to the sidings or roof. The Plant grounds were clean, organized, and free of clutter and debris.

The moving equipment that was visually assessed appeared to be in proper order, free from leakage, and free from any abnormal noise production. Piping appeared to be insulated, sealed, and free from apparent significant leaks. The visual assessment did not reveal any obvious signs of significant deterioration.

During the site visit, some items were identified to likely require replacement due to age and/or obsolescence were the high-pressure piping, boiler, circulating water lines, cooling towers, condenser tubing, fans, and pumps.

4.0 BOILER

The Boiler of Unit 7 at the Rio Grande Station is a natural circulation, radiant heat, pressurized unit designed to burn natural gas in eight wall-mounted burners. This unit includes a horizontal, drainable superheater and reheater, one 60-inch diameter steam drum and a 42-inch elevated mud drum. This boiler design is more commonly known in the industry as the "Babcock & Wilcox El Paso" design. The unit was originally designed for a maximum continuous rating ("MCR") of 350,000 lb/hr main steam at a superheater outlet condition of 1,510 psig and 1005°F. The reheater is designed for an operating temperature of 1005°F. The superheater and reheater outlet temperature is controlled by desuperheater sprays. The boiler design also includes a bare-tube economizer and Ljungstrom type tri-sector air heater for flue gas heat recovery.

Unit 7 frequently sits at minimum load and is ramped up as needed. Boiler chemical cleaning is scheduled on a 4 to 6-year cycle, the last of which occurred this year. In addition, EPE takes tube samples periodically in high heat flux areas of the boiler to evaluate the extent of boiler tube scaling to determine the need for chemical cleaning of the boiler.

EPE hired Babcock Power, Inc. ("BPI") to perform a condition assessment of the boiler and high energy piping in February 2011.

4.1 Waterwalls

BPI reported that the boiler waterwall tubes appeared to be in good condition during the 2011 inspection. At the time, a visual inspection of the furnace found all four waterwalls straight and aligned. Tube thicknesses were also measured, but there was no original tube thickness to compare them to. A regular tube wall thickness nondestructive examination ("NDE") inspection program is recommended to monitor boiler waterwall condition and prevent tube rupture related outages.

4.2 Superheater

The superheater sections of the boiler are used to raise the temperature of the steam above the saturation temperature (i.e. superheat the steam). Saturated steam exiting the top of the steam drum passes through the various sections of the superheater and the temperature is continually increased until the steam finally exits the superheater outlet header and continues through the main steam line towards the high pressure ("HP") steam turbine. The six sections or stages of the superheater are as follows, starting at the steam drum and progressing towards the superheater outlet header:

1. The backpass wall and roof section, which form the sides and roof of the vertical gas path and part of the horizontal gas path.
2. The low temperature horizontal sections, located above the economizer in the rear backpass of the boiler.
3. The low temperature pendant section, located in the furnace rear backpass above the low temperature horizontal sections.
4. The division panel section, located directly above the furnace, between the front wall and the pendant platen section.
5. The pendant platen section, located directly above the furnace in front of the furnace arch.
6. The finishing section, located in the horizontal gas path in the back of the screen wall tubes.

During the 2011 inspection, BPI found secondary superheater tubes in tube rows 4, 9, and 31 completely burned out and extensive bowing of the remaining tubes. The primary superheater appeared to be in good condition, although they found tube row 12 missing. Ultrasonic tube thickness measurements were taken, but BPI had no original tube thickness to compare them to.

Inspection of the attemperators and piping systems downstream of the attemperators is recommended, since the attemperator operation, at the loads where it first initiates flow, creates thermal shocking, and potentially a shortened life expectancy for those components.

4.3 Reheater

The reheater section of the boiler increases the superheat of the steam discharged from the HP turbine. Steam exiting the HP turbine is transported by the cold reheat steam lines to the reheater inlet header, where it then passes through the reheater and the temperature is continually increased until the steam finally exits the reheater outlet header and continues through the hot reheat steam line towards the intermediate pressure steam turbine. At Rio Grande Unit 7, the design of the reheater allows for draining the reheater during outages and/or startup.

BPI's 2011 inspection of the reheater revealed moderate to severe bowing of the tube bundles with several tubes overheated/missing. Ultrasonic tube thickness measurements were taken, but BPI had no original tube thickness to compare them to.

4.4 Economizer

The economizer section of the boiler is used to improve the efficiency of the thermal cycle by using the exhaust gases to raise the temperature of the feedwater entering the boiler. The boiler feedwater system receives feedwater from the condensate system through the deaerator storage tank and utilizes the boiler feed pumps to convey feedwater through the high pressure feedwater heaters before arriving at the economizer inlet header. From the economizer inlet header, the feedwater temperature is then increased throughout the economizer tube sections in the back-pass of the boiler before exiting through the economizer outlet header and traveling to the steam drum.

BPI performed a visual inspection of the economizer tube bundle in 2011. They found the tubes relatively well aligned with only minor bowing in a few tubes. They did note several plugged tubes.

4.5 Drums and Headers

There is one steam drum, and one lower waterwall drum on the unit. The steam drum is visually inspected by plant personnel during each annual outage.

BPI was unable to perform a visual inspection of the steam drum during the 2011 inspection due to an inoperable manway.

Since the drum is susceptible to fatigue and corrosion damage, Burns & McDonnell recommends the steam drum be regularly inspected. The inspections should include a detailed visual inspection, with the internals removed, magnetic particle examination and ultrasonic inspection of girth, socket, and nozzle welds, and thickness readings at the drum water level.

The high temperature headers include the primary and secondary superheater outlet headers and the reheater outlet header. These headers operate under severe conditions and are particularly susceptible to localized overheating, leading to creep damage, and other stress related cracks caused by temperature imbalances side-to-side across the headers.

In 2011, BPI performed visual inspection (using fiberoptics), metallographic replication, and hardness testing on the secondary superheater outlet header and the reheater outlet header. BPI also performed diametric measurement on the reheat outlet header.

The visual inspection on the secondary superheater outlet header found no evidence of erosion, cracking, or corrosion; yet, it did identify moderate scale buildup in areas. One location on the secondary superheater outlet header was examined using metallographic replication. No evidence of micro-cracking or creep damage was found. Magnetic particle testing was performed on a single nozzle saddle weld. Several small indications were found and repaired. Based on the 2011 examinations, BPI considered the secondary superheater outlet header to be in good condition.

The visual inspection on the reheat outlet header also found no evidence of erosion, cracking, or corrosion; yet, it did identify moderate scale buildup in areas. Two locations on the reheater outlet header were examined using metallographic replication. No evidence of micro-cracking or creep damage was found. Magnetic particle testing was performed on a single nozzle saddle weld and no indications were found. Diametric measurements were taken at one location on the header. Based on an assumed original outside diameter of the header, it was determined to be above its allowable creep swell. However, this finding is moderated due to the assumed outside diameter. Based on the 2011 examinations, BPI considered the reheat outlet header to be in good condition.

The primary and secondary superheater headers and the reheater outlet header should be re-inspected in the future using the following non-destructive testing methods, in addition to those performed by BPI:

1. Acid etching of the headers to determine whether longitudinal seam welds exist in the headers.
2. All girth welds, socket welds, and longitudinal welds (if applicable) should be inspected using ultrasonic thickness examination to determine the integrity of the weld and thickness of the material.
3. All girth welds, socket welds, and longitudinal welds (if applicable) should be inspected using magnetic particle examination to detect surface discontinuities in the metal.
4. Pi Measurement tests should be performed along all the headers, to be used as a gauge to detect long term creep by identifying pipe swelling.
5. A header straightness examination should also be performed to identify any signs of sagging associated with long term creep damage.

The lower temperature headers include the economizer inlet and outlet headers. Despite being at a relatively low temperature, these headers, in particular the economizer inlet header, tend to be susceptible to ligament cracking caused by thermal stresses incurred during startups and shutdowns. These headers should be inspected soon and then periodically (based on the findings of the initial examination) to monitor for signs of this type of damage. The low temperature headers should be inspected using the following non-destructive methods:

1. Ultrasonic thickness inspections to monitor for signs of flow-accelerated corrosion ("FAC").
2. Full borescope examination of the headers.
3. Dimensional analysis of the headers.
4. Magnetic particle examination at all girth and select socket / butt weld locations to detect surface discontinuities in the metal.

4.6 Safety Valves

The safety valves are tested and recertified every five years by a third party as required by the facility's insurance company. Preventative maintenance is performed on the safety valve drainage system to check for obstruction or leakage.

Burns & McDonnell recommends the valves be tested in accordance with the American Society of Mechanical Engineers ("ASME") code requirements. Annual inspections by the safety valves' Original Equipment Manufacturer ("OEM") are recommended to determine if refurbishment or replacement is required.

4.7 Burner Control System

The Unit 7 Boiler has a Flame Safety Scanner System ("FSSS"), installed after the 2003 furnace explosion.

5.0 BOILER AUXILIARY SYSTEMS

5.1 Fans

There is one Westinghouse double inlet centrifugal forced draft ("FD") fan that provides combustion air to the furnace. The air is heated in the air heater and is then delivered to the furnace through the boiler wind boxes.

This fan has typically been visually inspected every year during the summer preparation outages, and no significant problems have been noted. In addition, vibration readings are performed monthly and trended as part of the PdM program for rotating equipment. Oil samples are also taken monthly.

The fan appears to be in good condition based on inspections and on-going maintenance.

5.2 Air Heater

Air heating is accomplished by one Ljungstrom type regenerative air heater. This heater is inspected by plant personnel during each annual outage with minor repairs done immediately.

BPI performed a limited visual inspection of the air heater from the cold gas discharge during the 2011 inspection. They found minimal debris and the seals in good condition.

The air heater appears to be in good condition based on inspections and on-going maintenance. It is nevertheless prudent to expect that the cold end baskets will need to be replaced within the next five years.

5.3 Flues & Ducts

The ductwork transports combustion air to the boiler and transports hot flue gas away from the boiler, through the air heater, and on to the stack. Since the boiler has operated on natural gas for most of its life, the ducts and flues are considered to be in good shape. As part of the predictive maintenance program, station personnel routinely perform thermography to detect hot spots and leaks in the ductwork and flues.

5.4 Stack

The stack has not been inspected in recent years. An inspection, particularly for structural integrity, is recommended.

5.5 Blowdown System

Unit 7 design includes an intermediate pressure blowdown tank and another continuous blowdown flash tank. The blowdown system is used to control the water silica levels and remove sludge formations from the steam drum. The continuous blowdown from the steam drum is flashed into the intermediate pressure blowdown tank where the flash steam is exhausted to the deaerating heater and the remaining water continues to the continuous blowdown flash tank.

The blowdown tanks have been visually inspected. There were no reports of significant problems with either the tanks or the ancillary equipment. The blowdown system appears to be in good condition based on inspections and on-going maintenance.

6.0 STEAM TURBINE

In general, EPE has reported that the Unit 7 turbine has exhibited good operation and vibration levels.

The Unit 7 water chemistry is well maintained; therefore, the turbine can be expected to have only minor solid particle erosion ("SPE") and insignificant deposits, as it has in past overhauls.

The turbine is a major focus of the EPE predictive maintenance program. Advanced vibration analysis, as well as monthly oil analysis, is performed to establish trends. These trends then influence the preventive maintenance routines and frequencies. This program was established in 1995 and has been well recognized within the PdM community.

6.1 Turbine

The steam turbine generator was previously on a maintenance cycle of about 8 years, regardless of dispatch; however, maintenance is now done according to a cycle of 80,000 hours. A major inspection is scheduled for the turbine in 2022.

During the fall 2005 outage, the HP and low pressure ("LP") turbines were overhauled by General Electric ("GE") Energy Service. The HP and LP turbine sections were disassembled, inspected and reassembled. The sixth stage turbine buckets were replaced and the sixth stage diaphragms were repaired. The nozzle plates were also repaired. The turbine shell had two major indications that were repaired.

At that time, GE's report noted that the turbine shell was nearing the end of its useful life. Plant personnel noted that the turbine shell had cracks repaired by metal lacing in the late 1980's. These repairs are good for approximately 100,000 hours of operation.

Further NDE of the turbine shell and specifically the crack repairs should be performed to determine remaining life of the shell. During the 2016 generator and turbine valve inspection, it was recommended that plans be made to inspect all the turbine sections.

6.2 Turbine Valves

Per OEM recommendation, the turbine valves were previously on a maintenance cycle of 3 years, regardless of dispatch. Currently the turbine valves are maintained on a cycle of 30,000 hours. The turbine valves consist of the main steam stop and control valves. In general, the valves usually exhibit minor SPE when inspected. The most recent inspection on the valves was performed in the beginning of 2016 by the company Turbine Pros. Prior to the 2016 inspection the main stop valve was reopened during the startup outage following the 2005 inspection, otherwise the valves had not been opened since the fall outage of 2004.

From the 2016 inspection, the valves were found to be heavily contaminated with blue blush, and many of the components, particularly on the control valves, had seized, which greatly interfered with disassembly. Turbine Pros recommended that the valves be greased regularly and that valve outages, routine valve stroking, and trip and over-speed testing be performed at more regular intervals as recommended by the OEM. Many components were recommended for repair and replacement at the next outage. Likewise, NDEs were recommended for the control valves for the next outage as cracks were found on a few control valves. Turbine Pros also recommended replacing the studs and nuts on the lower equalizer valve flange of the intercept valve, as several of the nuts are frozen on the studs keeping the studs from being centered in the flange.