Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
6/1/2005	9.75%	4.75%	5.00%
7/19/2005	11.50%	4.64%	6.86%
8/5/2005	11.75%	4.62%	7 13%
8/15/2005	10.13%	4.61%	5.52%
9/28/2005	10.00%	4.54%	5.46%
10/4/2005	10.75%	4.53%	6 22%
12/12/2005	11.00%	4.55%	6.45%
12/13/2005	10.75%	4.55%	6 20%
12/21/2005	10.29%	4.54%	5.75%
12/21/2005	10.40%	4.54%	5 86%
12/22/2005	11.00%	4.54%	6.46%
12/22/2005	11.15%	4.54%	6.61%
12/28/2005	10.00%	4.54%	5.46%
12/28/2005	10.00%	4.54%	5.46%
1/5/2006	11.00%	4.53%	6.47%
1/27/2006	9.75%	4.52%	5.23%
3/3/2006	10.39%	4.53%	5 86%
4/17/2006	10.20%	4.62%	5 58%
4/26/2006	10.60%	4.64%	5.96%
5/17/2006	11.60%	4.69%	6.91%
6/6/2006	10.00%	4.75%	5 25%
6/27/2006	10.75%	4.80%	5 95%
7/6/2006	10.20%	4.83%	5.37%
7/24/2006	9.60%	4.86%	4.74%
7/26/2006	10.50%	4 86%	5.64%
7/28/2006	10.05%	4.87%	5 18%
8/23/2006	9.55%	4.89%	4 66%
9/1/2006	10.54%	4.90%	5.64%
9/14/2006	10.00%	4.91%	5.09%
10/6/2006	9.67%	4.92%	4.75%
11/21/2006	10.08%	4.95%	5.13%
11/21/2006	10.08%	4.95%	5 13%
11/21/2006	10.12%	4.95%	5.17%
12/1/2006	10.25%	4.96%	5 29%
12/1/2006	10.50%	4.96%	5.54%
12/7/2006	10.75%	4.96%	5.79%
12/21/2006	10.90%	4.95%	5.95%
12/21/2006	11.25%	4.95%	6.30%
12/22/2006	10.25%	4.95%	5 30%
1/5/2007	10.00%	4.95%	5.05%
1/11/2007	10 10%	4.95%	5.15%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.90%	4.95%	5.95%
1/12/2007	10.10%	4.95%	5.15%
1/13/2007	10.40%	4.95%	5.45%
1/19/2007	10.80%	4.94%	5.86%
3/21/2007	11.35%	4.86%	6.49%
3/22/2007	9.75%	4.86%	4.89%
5/15/2007	10.00%	4 81%	5.19%
5/17/2007	10.25%	4.80%	5 45%
5/17/2007	10.25%	4.80%	5.45%
5/22/2007	10.20%	4.80%	5.40%
5/22/2007	10.50%	4.80%	5.70%
5/23/2007	10.70%	4.80%	5.90%
5/25/2007	9.67%	4.80%	4.87%
6/15/2007	9.90%	4.82%	5.08%
6/21/2007	10.20%	4.83%	5.37%
6/22/2007	10.50%	4.83%	5.67%
6/28/2007	10.75%	4.84%	5.91%
7/12/2007	9.67%	4.86%	4.81%
7/19/2007	10.00%	4.87%	5.13%
7/19/2007	10.00%	4 87%	5.13%
8/15/2007	10.40%	4.88%	5.52%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/9/2007	10.00%	4.91%	5.09%
10/17/2007	9.10%	4.91%	4.19%
10/31/2007	9.96%	4.90%	5.06%
11/29/2007	10.90%	4.87%	6.03%
12/6/2007	10.75%	4.86%	5.89%
12/13/2007	9.96%	4.86%	5.10%
12/14/2007	10.70%	4.86%	5.84%
12/14/2007	10.80%	4.86%	5.94%
12/19/2007	10.20%	4.86%	5.34%
12/20/2007	10.20%	4.86%	5.34%
12/20/2007	11 00%	4.86%	6.14%
12/28/2007	10 25%	4.85%	5.40%
12/31/2007	11 25%	4.85%	6.40%
1/8/2008	10.75%	4.83%	5.92%
1/17/2008	10.75%	4.81%	5.94%
1/28/2008	9.40%	4.80%	4.60%
1/30/2008	10.00%	4.79%	5.21%
1/31/2008	10.71%	4.79%	5.92%
2/29/2008	10.25%	4.75%	5.50%
3/12/2008	10.25%	4.73%	5.52%
3/25/2008	9.10%	4.68%	4.42%
4/22/2008	10.25%	4.60%	5 65%
4/24/2008	10.10%	4.60%	5.50%
5/1/2008	10.70%	4.58%	6.12%
5/19/2008	11.00%	4.56%	6.44%
5/27/2008	10.00%	4.55%	5.45%
6/10/2008	10.70%	4 54%	6 16%
6/27/2008	10.50%	4.54%	5.96%
6/27/2008	11.04%	4.54%	6.50%
7/10/2008	10.43%	4.52%	5.91%
7/16/2008	9.40%	4.51%	4.89%
7/30/2008	10 80%	4.51%	6.29%
7/31/2008	10 70%	4.51%	6.19%
8/11/2008	10.25%	4 50%	5.75%
8/26/2008	10 18%	4.50%	5.68%
9/10/2008	10.30%	4.50%	5.80%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10 65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/30/2008	10 20%	4.47%	5.73%
10/8/2008	10.15%	4.46%	5.69%
11/13/2008	10.55%	4.45%	6.10%
11/17/2008	10 20%	4.44%	5 76%
12/1/2008	10 25%	4.39%	5.86%
12/23/2008	11 00%	4.27%	6.73%
12/29/2008	10.00%	4.24%	5.76%
12/29/2008	10.20%	4.24%	5.96%
12/31/2008	10 75%	4.22%	6.53%
1/14/2009	10 50%	4.15%	6.35%
1/21/2009	10.50%	4.11%	6 39%
1/21/2009	10.50%	4.11%	6.39%
1/21/2009	10.50%	4.11%	6.39%
1/27/2009	10 76%	4.09%	6.67%
1/30/2009	10 50%	4.07%	6.43%
2/4/2009	8.75%	4.06%	4.69%
3/4/2009	10.50%	3.96%	6.54%
3/12/2009	11.50%	3.93%	7.57%
4/2/2009	11 10%	3.85%	7.25%
4/21/2009	10 61%	3.80%	6.81%
4/24/2009	10.00%	3.78%	6.22%
4/30/2009	11 25%	3.77%	7.48%
5/4/2009	10 74%	3.77%	6.97%
5/20/2009	10.25%	3.74%	6.51%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
5/28/2009	10 50%	3.74%	6.76%
6/22/2009	10.00%	3.76%	6.24%
6/24/2009	10.80%	3.76%	7.04%
7/8/2009	10.63%	3.76%	6.87%
7/17/2009	10.50%	3.77%	6 73%
8/21/2009	10 25%	3.80%	6.45%
8/31/2009	10.25%	3.82%	6.43%
10/14/2009	10.70%	4.02%	6.68%
10/23/2009	10.88%	4.06%	6.82%
11/2/2009	10.70%	4.10%	6 60%
11/3/2009	10.70%	4 10%	6.60%
11/24/2009	10.25%	4.16%	6 09%
11/25/2009	10.75%	4.16%	6.59%
11/30/2009	10.35%	4.17%	6.18%
12/3/2009	10.50%	4.18%	6.32%
12/7/2009	10.70%	4.19%	6.51%
12/16/2009	10.90%	4.22%	6.68%
12/16/2009	11.00%	4.22%	6.78%
12/18/2009	10.40%	4.22%	6.18%
12/18/2009	10.40%	4.22%	6.18%
12/22/2009	10.20%	4.23%	5.97%
12/22/2009	10.40%	4.23%	6.17%
12/22/2009	10 40%	4.23%	6.17%
12/30/2009	10 00%	4.26%	5.74%
1/4/2010	10 80%	4.28%	6.52%
1/11/2010	11.00%	4.31%	6.69%
1/26/2010	10.13%	4.35%	5.78%
1/27/2010	10.40%	4.36%	6.04%
1/27/2010	10.40%	4.36%	6 04%
1/27/2010	10.70%	4.36%	6.34%
2/9/2010	9.80%	4.38%	5.42%
2/18/2010	10.60%	4.40%	6.20%
2/24/2010	10.18%	4.41%	5.77%
3/2/2010	9 63%	4.41%	5.22%
3/4/2010	10.50%	4.41%	6 09%
3/5/2010	10 50%	4.41%	6.09%
3/11/2010	11.90%	4.42%	7 48%
3/17/2010	10.00%	4.41%	5.59%
3/25/2010	10.15%	4.42%	5 73%
4/2/2010	10.10%	4.43%	5.67%
4/27/2010	10.00%	4.46%	5.54%
4/29/2010	9.90%	4.46%	5.44%
4/29/2010	10 06%	4.46%	5.60%
4/29/2010	10.26%	4.46%	5.80%
5/12/2010	10.30%	4 45%	5.85%
5/12/2010	10 30%	4.45%	5.85%
5/28/2010	10 10%	4.44%	5.66%
5/28/2010	10.20%	4.44%	5.76%
6/7/2010	10.30%	4.44%	5.86%
6/16/2010	10.00%	4.44%	5.56%
6/28/2010	9.67%	4.43%	5.24%
6/28/2010	10.50%	4.43%	6.07%
6/30/2010	9.40%	4.43%	4.97%
7/1/2010	10.25%	4.43%	5 82%
7/15/2010	10.53%	4 43%	6.10%
7/15/2010	10.70%	4.43%	6.27%
7/30/2010	10.70%	4.41%	6.29%
8/4/2010	10.50%	4.41%	6.09%
8/6/2010	9 83%	4.41%	5.42%
8/25/2010	9 90%	4.37%	5 53%
9/3/2010	10.60%	4.35%	6 25%
9/14/2010	10.70%	4.33%	6.37%
9/16/2010	10.00%	4.32%	5.68%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
9/16/2010	10.00%	4 32%	5.68%
9/30/2010	9 75%	4.28%	5.47%
10/14/2010	10.35%	4.24%	6.11%
10/28/2010	10.70%	4.21%	6.49%
11/2/2010	10.38%	4.20%	6.18%
11/4/2010	10.70%	4 19%	6.51%
11/19/2010	10.20%	4.17%	6.03%
11/22/2010	10.00%	4.17%	5.83%
12/1/2010	10.13%	4.16%	5.97%
12/6/2010	9.86%	4 15%	5.71%
12/9/2010	10.25%	4.15%	6.10%
12/13/2010	10.70%	4.15%	6.55%
12/14/2010	10.13%	4.15%	5.98%
12/15/2010	10.44%	4.15%	6.29%
12/17/2010	10.00%	4.14%	5.86%
12/20/2010	10.60%	4.14%	6.46%
12/21/2010	10.30%	4.14%	6.16%
12/27/2010	9.90%	4.14%	5.76%
12/29/2010	11.15%	4.14%	7.01%
1/5/2011	10.15%	4.13%	6.02%
1/12/2011	10.30%	4.12%	6.18%
1/13/2011	10.30%	4.12%	6.18%
1/18/2011	10.00%	4.12%	5.88%
1/20/2011	9.30%	4.12%	5.18%
1/20/2011	10.13%	4.12%	6.01%
1/31/2011	9.60%	4.11%	5.49%
2/3/2011	10.00%	4.11%	5.89%
2/25/2011	10.00%	4.14%	5.86%
3/25/2011	9.80%	4.18%	5 62%
3/30/2011	10.00%	4.18%	5.82%
4/12/2011	10.00%	4.21%	5 79%
4/25/2011	10.74%	4.23%	6.51%
4/26/2011	9 67%	4.24%	5 43%
4/27/2011	10.40%	4.24%	6.16%
5/4/2011	10.00%	4.25%	5.75%
5/4/2011	10.00%	4.25%	5.75%
5/24/2011	10.50%	4.27%	6.23%
6/8/2011	10 75%	4.30%	6 45%
6/16/2011	9.20%	4.32%	4.88%
6/17/2011	9.95%	4.32%	5.63%
7/13/2011	10.20%	4.37%	5.83%
8/1/2011	9.20%	4.39%	4.81%
8/8/2011	10 00%	4.38%	5.62%
8/11/2011	10 00%	4.38%	5.62%
8/12/2011	10.35%	4.38%	5.97%
8/19/2011	10.25%	4.36%	5.89%
9/2/2011	12.88%	4.32%	8.56%
9/22/2011	10.00%	4 24%	5.76%
10/12/2011	10.30%	4.14%	6.16%
10/20/2011	10.50%	4.10%	6.40%
11/30/2011	10.90%	3.87%	7.03%
11/30/2011	10.90%	3.87%	7.03%
12/14/2011	10 00%	3.79%	6.21%
12/14/2011	10.30%	3 79%	6.51%
12/20/2011	10.20%	3.76%	6.44%
12/21/2011	10 20%	3 75%	6.45%
12/22/2011	9.90%	3.75%	6.15%
12/22/2011	10.40%	3.75%	6.65%
12/23/2011	10 19%	3.74%	6.45%
1/25/2012	10.50%	3.57%	6 93%
1/27/2012	10.50%	3.55%	6.95%
2/15/2012	10.20%	3.47%	6.73%
2/23/2012	9.90%	3.43%	6.47%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
2/27/2012	10.25%	3 42%	6.83%
2/29/2012	10.40%	3.41%	6.99%
3/29/2012	10 37%	3.31%	7.06%
4/4/2012	10.00%	3.29%	6.71%
4/26/2012	10.00%	3.20%	6.80%
5/2/2012	10.00%	3 18%	6.82%
5/7/2012	9.80%	3.16%	6.64%
5/15/2012	10.00%	3 14%	6.86%
5/29/2012	10.05%	3.11%	6 94%
6/7/2012	10.30%	3.07%	7.23%
6/14/2012	9.40%	3.06%	6.34%
6/15/2012	10.40%	3.06%	7.34%
6/18/2012	9.60%	3.05%	6.55%
6/19/2012	9.25%	3.05%	6.20%
6/26/2012	10.10%	3.04%	7.06%
6/29/2012	10.00%	3.04%	6.96%
7/9/2012	10.20%	3 03%	7.17%
7/16/2012	9.80%	3 02%	6.78%
7/20/2012	9.31%	3.01%	6.30%
7/20/2012	9.81%	3.01%	6.80%
9/13/2012	9.80%	2.94%	6 86%
9/19/2012	9.80%	2.94%	6 86%
9/19/2012	10.05%	2 94%	7.11%
9/26/2012	9.50%	2.94%	6.56%
10/12/2012	9.60%	2.93%	6.67%
10/23/2012	9 75%	2.93%	6.82%
10/24/2012	10.30%	2.93%	7.37%
11/9/2012	10.30%	2.92%	7 38%
11/28/2012	10.40%	2 90%	7 50%
11/29/2012	9.75%	2 89%	6.86%
11/29/2012	9.88%	2.89%	6 99%
12/5/2012	9.71%	2.89%	6.82%
12/5/2012	10.40%	2.89%	7.51%
12/12/2012	9 80%	2.88%	6 92%
12/13/2012	9.50%	2.88%	6.62%
12/13/2012	10.50%	2 88%	7.62%
12/14/2012	10.40%	2.88%	7.52%
12/19/2012	9.71%	2 87%	6.84%
12/19/2012	10.25%	2.87%	7.38%
12/20/2012	9.50%	2 87%	6.63%
12/20/2012	9.80%	2.87%	6.93%
12/20/2012	10.25%	2.87%	7.38%
12/20/2012	10.25%	2.87%	7.38%
12/20/2012	10.30%	2.87%	7.43%
12/20/2012	10.40%	2.87%	7.53%
12/20/2012	10.45%	2.87%	7.58%
12/21/2012	10.20%	2.87%	7.33%
12/26/2012	9.80%	2 86%	6.94%
1/9/2013	9.70%	2.84%	6.86%
1/9/2013	9.70%	2.84%	6.86%
1/9/2013	9.70%	2 84%	6.86%
1/16/2013	9.60%	2.84%	6.76%
1/16/2013	9.60%	2.84%	6.76%
2/13/2013	10.20%	2.84%	7.36%
2/22/2013	9.75%	2.85%	6.90%
2/27/2013	10.00%	2 86%	7 14%
3/14/2013	9.30%	2 88%	6.42%
3/27/2013	9.80%	2.90%	6.90%
5/1/2013	9.84%	2.94%	6.90%
5/15/2013	10.30%	2.96%	7.34%
5/30/2013	10.20%	2 98%	7.22%
5/31/2013	9.00%	2.98%	6.02%
6/11/2013	10.00%	3.00%	7.00%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
6/21/2013	9.75%	3.02%	6.73%
6/25/2013	9 80%	3.03%	6 77%
7/12/2013	9.36%	3.08%	6.28%
8/8/2013	9.83%	3.14%	6.69%
8/14/2013	9.15%	3.16%	5.99%
9/11/2013	10.20%	3.27%	6.93%
9/11/2013	10.25%	3.27%	6.98%
9/24/2013	10.20%	3.31%	6.89%
10/3/2013	9.65%	3.33%	6.32%
11/6/2013	10 20%	3.41%	6.79%
11/21/2013	10.00%	3.44%	6 56%
11/26/2013	10.00%	3.45%	6 55%
12/3/2013	10.25%	3.47%	6 78%
12/4/2013	9.50%	3.47%	6.03%
12/5/2013	10.20%	3.48%	6 72%
12/9/2013	8.72%	3.49%	5.23%
12/9/2013	9.75%	3.49%	6.26%
12/13/2013	9 75%	3.50%	6.25%
12/16/2013	9.95%	3 50%	6.45%
12/16/2013	9.95%	3.50%	6.45%
12/16/2013	10.12%	3.50%	6.62%
12/17/2013	9.50%	3.51%	5 99%
12/17/2013	10.95%	3.51%	7 44%
12/18/2013	8.72%	3.51%	5.21%
12/18/2013	9.80%	3.51%	6.29%
12/19/2013	10 15%	3.51%	6.64%
12/30/2013	9.50%	3.54%	5 96%
2/20/2014	9.20%	3.69%	5.51%
2/26/2014	9.75%	3.70%	6 05%
3/17/2014	9.55%	3.72%	5.83%
3/26/2014	9.40%	3.73%	5.67%
3/26/2014	9.96%	3.73%	6 23%
4/2/2014	9.70%	3.73%	5.97%
5/16/2014	9.80%	3.70%	6 10%
5/30/2014	9 70%	3.68%	6 02%
6/6/2014	10.40%	3.67%	6.73%
6/30/2014	9.55%	3.64%	5.91%
7/2/2014	9.62%	3.64%	5 98%
7/10/2014	9.95%	3.63%	6.32%
7/23/2014	9.75%	3.61%	6 14%
7/29/2014	9.45%	3.60%	5 85%
7/31/2014	9.90%	3.60%	6.30%
8/20/2014	9.75%	3.56%	6.19%
8/25/2014	9.60%	3.56%	6.04%
8/29/2014	9 80%	3.54%	6 26%
9/11/2014	9 60%	3.51%	6 09%
9/15/2014	10.25%	3.51%	6.74%
10/9/2014	9.80%	3.44%	6.36%
11/6/2014	9.56%	3.37%	6 19%
11/6/2014	10.20%	3.37%	6.83%
11/14/2014	10.20%	3 35%	6 85%
11/26/2014	9.70%	3.32%	6.38%
11/26/2014	10.20%	3.32%	6.88%
12/4/2014	9.68%	3.30%	6.38%
12/10/2014	9.25%	3.29%	5.96%
12/10/2014	9.25%	3.29%	5 96%
12/11/2014	10 07%	3.28%	6.79%
12/12/2014	10.20%	3.28%	6.92%
12/17/2014	9.17%	3.27%	5 90%
12/18/2014	9.83%	3.26%	6.57%
1/23/2015	9.50%	3.14%	6.36%
2/24/2015	9.83%	3.04%	6.79%
3/18/2015	9.75%	2.98%	6 77%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
3/25/2015	9.50%	2 95%	6.55%
3/26/2015	9.72%	2.95%	6.77%
4/23/2015	10.20%	2.87%	7.33%
4/29/2015	9 53%	2.86%	6.67%
5/1/2015	9.60%	2.85%	6.75%
5/26/2015	9.75%	2.83%	6.92%
6/17/2015	9.00%	2 82%	6.18%
6/17/2015	9.00%	2.82%	6.18%
9/2/2015	9.50%	2.79%	6.71%
9/10/2015	9.30%	2.79%	6.51%
9/25/2015	9.60%	2.80%	6.80%
10/15/2015	9.00%	2 81%	6.19%
11/19/2015	10.00%	2.88%	7.12%
11/19/2015	10.30%	2.88%	7.42%
12/3/2015	10.00%	2.90%	7.10%
12/9/2015	9.14%	2.90%	6.24%
12/9/2015	9.14%	2.90%	6 24%
12/11/2015	10.30%	2.90%	7.40%
12/15/2015	9.60%	2.91%	6 69%
12/17/2015	9.70%	2 91%	6.79%
12/18/2015	9.50%	2.91%	6.59%
12/30/2015	9 50%	2 93%	6.57%
1/6/2016	9.50%	2.94%	6 56%
2/23/2016	9.75%	2.94%	6.81%
3/16/2016	9.85%	2.91%	6 94%
4/29/2016	9.80%	2 83%	6.97%
6/3/2016	9.75%	2.80%	6.95%
6/8/2016	9.48%	2 80%	6 68%
6/15/2016	9.00%	2.78%	6.22%
6/15/2016	9.00%	2.78%	6 22%
7/18/2016	9.98%	2.71%	7.27%
8/9/2016	9.85%	2.66%	7.19%
8/18/2016	9.50%	2.63%	6.87%
8/24/2016	9.75%	2.61%	7 14%
9/1/2016	9.50%	2.59%	6.91%
9/8/2016	10.00%	2.57%	7.43%
9/28/2016	9.58%	2.53%	7.05%
9/30/2016	9.90%	2.53%	7.37%
11/9/2016	9 80%	2 48%	7.32%
11/10/2016	9.50%	2.48%	7.02%
11/15/2016	9.55%	2.49%	7.06%
11/18/2016	10.00%	2.50%	7.50%
11/29/2016	10 55%	2.51%	8.04%
12/1/2016	10 00%	2 51%	7.49%
12/6/2016	8.64%	2 52%	6.12%
12/6/2016	8.64%	2.52%	6.12%
12/7/2016	10.10%	2.52%	7.58%
12/12/2016	9.60%	2.53%	7.07%
12/14/2016	9.10%	2 53%	6.57%
12/19/2016	9.00%	2.54%	6.46%
12/19/2016	9.37%	2.54%	6.83%
12/22/2016	9.60%	2.55%	7.05%
12/22/2016	9.90%	2.55%	7.35%
12/28/2016	9.50%	2 55%	6.95%
1/18/2017	9.45%	2.58%	6.87%
1/24/2017	9.00%	2.59%	6.41%
1/31/2017	10.10%	2.60%	7.50%
2/15/2017	9.60%	2.62%	6.98%
2/22/2017	9.60%	2.64%	6.96%
2/24/2017	9.75%	2.64%	7.11%
2/28/2017	10.10%	2.64%	7.46%
3/2/2017	9.41%	2.65%	6.76%
3/20/2017	9.50%	2.68%	6.82%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
4/4/2017	10.25%	2.72%	7.53%
4/12/2017	9.40%	2.74%	6.66%
4/20/2017	9.50%	2.76%	6 74%
5/3/2017	9.50%	2.79%	6.71%
5/11/2017	9.20%	2.81%	6.39%
5/18/2017	9.50%	2.83%	6.67%
5/23/2017	9.70%	2 84%	6.86%
6/16/2017	9.65%	2.89%	6.76%
6/22/2017	9.70%	2 90%	6.80%
6/22/2017	9.70%	2.90%	6.80%
7/24/2017	9.50%	2.95%	6.55%
8/15/2017	10.00%	2.97%	7.03%
9/22/2017	9.60%	2 93%	6.67%
9/28/2017	9.80%	2 92%	6.88%
10/20/2017	9.50%	2.91%	6.59%
10/26/2017	10.20%	2.91%	7.29%
10/26/2017	10.25%	2 91%	7.34%
10/26/2017	10 30%	2 91%	7.39%
11/6/2017	10.25%	2 90%	7.35%
11/15/2017	11.95%	2.89%	9.06%
11/30/2017	10.00%	2.88%	7.12%
11/30/2017	10.00%	2.88%	7.12%
12/5/2017	9.50%	2.88%	6.62%
12/6/2017	8.40%	2.87%	5.53%
12/6/2017	8.40%	2.87%	5.53%
12/7/2017	9.80%	2.87%	6.93%
12/14/2017	9.60%	2.86%	6.74%
12/14/2017	9.65%	2.86%	6.79%
12/18/2017	9.50%	2.86%	6.64%
12/20/2017	9.58%	2.85%	6.73%
12/21/2017	9.10%	2.85%	6.25%
12/28/2017	9.50%	2.85%	6.65%
12/29/2017	9.51%	2.85%	6.66%
1/18/2018	9.70%	2.84%	6.86%
1/31/2018	9.30%	2.84%	6.46%
2/2/2018	9.98%	2.84%	7.14%
2/23/2018	9.90%	2.85%	7.05%
3/12/2018	9.25%	2.86%	6.39%
3/15/2018	9.00%	2.87%	6.13%
3/29/2018	10 00%	2.88%	7.12%
4/12/2018	9.90%	2.89%	7.01%
4/13/2018	9.73%	2.89%	6.84%
4/18/2018	9.25%	2.89%	6.36%
4/18/2018	10.00%	2.89%	7.11%
4/26/2018	9.50%	2 90%	6.60%
5/30/2018	9.95%	2.94%	7.01%
5/31/2018	9.50%	2.94%	6.56%
6/14/2018	8.80%	2 96%	5.84%
6/22/2018	9.50%	2.97%	6.53%
6/22/2018	9.90%	2 97%	6.93%
6/28/2018	9.35%	2 97%	6.38%
6/29/2018	9.50%	2.97%	6.53%
8/8/2018	9.53%	2.99%	6.54%
8/21/2018	9.70%	3.00%	6.70%
8/24/2018	9.28%	3.01%	6.27%
9/5/2018	9.56%	3.02%	6.54%
9/14/2018	10.00%	3.03%	6.97%
9/20/2018	9.80%	3.04%	6.76%
9/26/2018	9 77%	3.05%	6.72%
9/26/2018	10.00%	3.05%	6.95%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
9/27/2018	9 30%	3.05%	6.25%
10/4/2018	9 85%	3.06%	6.79%
10/29/2018	9.60%	3.10%	6.50%
10/31/2018	9.99%	3.11%	6.88%
11/1/2018	8.69%	3.11%	5.58%
12/4/2018	8.69%	3.14%	5 55%
12/13/2018	9.30%	3.14%	6.16%
12/14/2018	9.50%	3.14%	6.36%
12/19/2018	9 84%	3.14%	6.70%
12/20/2018	9.65%	3.14%	6.51%
12/21/2018	9.30%	3.14%	6.16%
1/9/2019	10 00%	3 14%	6.86%
2/27/2019	9 75%	3 12%	6.63%
3/13/2019	9.60%	3.12%	6.48%
3/14/2019	9.00%	3 12%	5.88%
3/14/2019	9.40%	3.12%	6.28%
3/22/2019	9.65%	3.12%	6.53%
4/30/2019	9 73%	3.11%	6.62%
4/30/2019	9.73%	3.11%	6.62%
5/1/2019	9.50%	3.11%	6.39%
5/2/2019	10.00%	3 11%	6.89%
5/8/2019	9.50%	3 10%	6.40%
5/14/2019	8 75%	3.10%	5.65%
5/16/2019	9.50%	3 09%	6.41%
5/23/2019	9.90%	3.09%	6.81%
8/12/2019	9 60%	2.89%	6.71%
8/29/2019	9.06%	2.81%	6.25%
9/4/2019	10 00%	2 78%	7 22%
9/30/2019	9.60%	2.70%	6.90%
10/31/2019	10.00%	2.60%	7.40%
10/31/2019	10.00%	2.60%	7.40%
11/7/2019	9.35%	2 58%	6 77%
11/29/2019	9 50%	2.52%	6.98%
12/4/2019	8.91%	2.51%	6 40%
12/4/2019	9.75%	2.51%	7 24%
12/16/2019	8 91%	2.48%	6.43%
12/17/2019	9.70%	2.47%	7.23%
12/17/2019	10.50%	2.47%	8.03%
12/19/2019	10 20%	2.47%	7 73%
12/19/2019	10.25%	2.47%	7 78%
12/19/2019	10.30%	2.47%	7.83%
12/20/2019	9.45%	2.46%	6.99%
12/20/2019	9.65%	2.46%	7.19%
12/24/2019	9 70%	2.46%	7.24%
1/8/2020	10 02%	2.43%	7 59%
1/16/2020	8.80%	2.41%	6.39%
1/22/2020	9 50%	2.39%	7.11%
1/23/2020	9 86%	2.39%	7.47%
2/6/2020	10.00%	2.34%	7 66%
2/11/2020	9 30%	2.33%	6 97%
2/14/2020	9 40%	2.32%	7.08%
2/19/2020	8.25%	2.31%	5.94%
2/24/2020	9.75%	2.29%	7.46%
2/27/2020	9.40%	2.28%	7.12%
3/11/2020	9 70%	2.23%	7.47%
3/25/2020	9.40%	2.17%	7.23%
4/17/2020	9 70%	2.07%	7.63%
4/27/2020	9.25%	2.02%	7.23%
5/8/2020	9.90%	1.97%	7.93%
5/20/2020	9.45%	1.94%	7.51%
6/29/2020	9.70%	1.85%	7.85%
6/30/2020	9.10%	1.85%	7.25%
7/1/2020	9.25%	1.84%	7.41%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
7/8/2020	9.40%	1.82%	7.58%
7/14/2020	9.60%	1.81%	7.79%
7/28/2020	9.50%	1.76%	7.74%
8/27/2020	8.20%	1.66%	6.54%
8/27/2020	9.45%	1.66%	7.79%
8/27/2020	10.00%	1.66%	8.34%
10/22/2020	9.50%	1.49%	8.01%
10/28/2020	9.60%	1.48%	8.12%
11/19/2020	8.80%	1.45%	7.35%
11/19/2020	8.80%	1.45%	7.35%
11/24/2020	9.20%	1.44%	7 76%
11/24/2020	9.80%	1.44%	8.36%
12/9/2020	8.38%	1.43%	6 95%
12/9/2020	8 38%	1.43%	6.95%
12/10/2020	9.40%	1.43%	7.97%
12/14/2020	9.50%	1.44%	8.06%
12/15/2020	9.30%	1.44%	7.86%
12/16/2020	9.50%	1.44%	8.06%
12/17/2020	9.90%	1.44%	8.46%
12/18/2020	9.50%	1.44%	8 06%
12/22/2020	9.15%	1.44%	7 71%
12/23/2020	10.00%	1.44%	8.56%
12/30/2020	9.65%	1.45%	8.20%
1/13/2021	9.30%	1.47%	7.83%
3/31/2021	9.60%	1.68%	7 92%
		# of Cases:	1,658

Small Size Premium

	[1] ($Mil)
EPE Texas Equity	$1,042 39
Median Market to Book for Proxy Group	1.86
EPE Texas Implied Market Cap	$1,934.41

Company Name	Ticker	[2] Market Cap ($Mil)	[3] Market to Book Ratio
ALLETE, Inc.	ALE	$ 3,441.61	1.50
Alliant Energy Corporation	LNT	$ 12,582.29	2.21
Ameren Corporation	AEE	$ 19,342.94	2.15
American Electric Power Company, Inc.	AEP	$ 40,130.64	1.96
Avista Corporation	AVA	$ 3,010.10	1.48
CMS Energy Corporation	CMS	$ 16,590.91	3.02
DTE Energy Company	DTE	$ 24,425.10	1.97
Duke Energy Corporation	DUK	$ 70,022.50	1 52
Entergy Corporation	ETR	$ 18,857.71	1.72
Evergy, Inc	EVRG	$ 12,889.12	1.47
Hawaiian Electric Industries, Inc	HE	$ 4,284.06	1.83
IDACORP, Inc.	IDA	$ 4,751.36	1.86
NextEra Energy, Inc.	NEE	$ 145,206.84	3.98
NorthWestern Corporation	NWE	$ 3,131.35	1.50
OGE Energy Corp	OGE	$ 6,327.27	1.74
Otter Tail Corporation	OTTR	$ 1,822.81	2.09
Pinnacle West Capital Corporation	PNW	$ 8,720.36	1.54
Portland General Electric Company	POR	$ 4,040.55	1.55
The Southern Company	SO	$ 63,051.77	2.25
WEC Energy Group, Inc.	WEC	$ 27,451.11	2.62
Xcel Energy Inc.	XEL	$ 33,570.52	2.30
MEDIAN		$ 12,889.12	1.86
MEAN		$ 24,935.76	2.01

	Market Capitalization ($Mil) [4]		
Decile	Low	High	Size Premium
2	$ 13,178.743	$ 28,808.073	0.49%
3	$ 6,743.361	$ 13,177 828	0.71%
4	$ 3,861.858	$ 6,710.676	0.75%
5	$ 2,445.693	$ 3,836.536	1.09%
6	$ 1,591.865	$ 2,444.745	1.37%
7	$ 911.586	$ 1,591.765	1.54%
8	$ 451.955	$ 911 103	1.46%
9	$ 190.019	$ 451.800	2.29%
10	$ 2.194	$ 189.831	5.01%
Proxy Group Median		$ 12,889 120	0 71%
6th Decile Size Premium		$ 1,934.408	1.37%
Difference from Proxy Group Median			0.66%

Notes:
[1] EPE Texas jurisdictional rate base of $2,044 million mutiplied by the proposed common equity ratio of 51%
[2] Source: S&P Global Market Intelligence, 30-day average
[3] Source: S&P Global Market Intelligence, 30-day average
[4] Source: Duff & Phelps Cost of Capital Navigator, CRSP Deciles Size Premia as of December 31, 2020

Small Size Premium

	[1] ($Mil)
EPE Total Company Equity	$1,331.62
Median Market to Book for Proxy Group	1.86
EPE Total Company Implied Market Cap	$2,471.15

Company Name	Ticker	[2] Market Cap ($Mil)	[3] Market to Book Ratio
ALLETE, Inc.	ALE	$ 3,441 61	1.50
Alliant Energy Corporation	LNT	$ 12,582.29	2.21
Ameren Corporation	AEE	$ 19,342.94	2.15
American Electric Power Company, Inc.	AEP	$ 40,130.64	1 96
Avista Corporation	AVA	$ 3,010.10	1.48
CMS Energy Corporation	CMS	$ 16,590.91	3.02
DTE Energy Company	DTE	$ 24,425.10	1.97
Duke Energy Corporation	DUK	$ 70,022 50	1.52
Entergy Corporation	ETR	$ 18,857.71	1.72
Evergy, Inc	EVRG	$ 12,889 12	1.47
Hawaiian Electric Industries, Inc	HE	$ 4,284 06	1.83
IDACORP, Inc	IDA	$ 4,751.36	1.86
NextEra Energy, Inc	NEE	$ 145,206 84	3.98
NorthWestern Corporation	NWE	$ 3,131.35	1.50
OGE Energy Corp.	OGE	$ 6,327.27	1.74
Otter Tail Corporation	OTTR	$ 1,822.81	2.09
Pinnacle West Capital Corporation	PNW	$ 8,720.36	1 54
Portland General Electric Company	POR	$ 4,040.55	1.55
The Southern Company	SO	$ 63,051.77	2.25
WEC Energy Group, Inc.	WEC	$ 27,451.11	2.62
Xcel Energy Inc.	XEL	$ 33,570 52	2.30
MEDIAN		$ 12,889.12	1.86
MEAN		$ 24,935.76	2.01

Market Capitalization ($Mil) [4]			
Decile	Low	High	Size Premium
2	$ 13,178.743	$ 28,808.073	0.49%
3	$ 6,743 361	$ 13,177.828	0 71%
4	$ 3,861 858	$ 6,710.676	0 75%
5	$ 2,445.693	$ 3,836 536	1.09%
6	$ 1,591.865	$ 2,444.745	1 37%
7	$ 911.586	$ 1,591 765	1 54%
8	$ 451.955	$ 911.103	1.46%
9	$ 190.019	$ 451 800	2 29%
10	$ 2.194	$ 189.831	5.01%

Proxy Group Median	$ 12,889.120	0.71%
5th Decile Size Premium	$ 2,471.150	1.09%
Difference from Proxy Group Median		0.38%

Notes:
[1] EPE Total Company rate base of $2,611 million mutiplied by the proposed common equity ratio of 51%
[2] Source: S&P Global Market Intelligence, 30-day average
[3] Source: S&P Global Market Intelligence, 30-day average
[4] Source: Duff & Phelps Cost of Capital Navigator, CRSP Deciles Size Premia as of December 31, 2020

Proxy Group Capital Structure

Company	Ticker	% Common Equity 2020Q3	2020Q2	2020Q1	2019Q4	2019Q3	2019Q2	2019Q1	2018Q4	8Q Average
ALLETE, Inc	ALE	56.62%	57.24%	58.73%	58.84%	58.68%	59.66%	59.53%	59.12%	58.55%
Alliant Energy Corporation	LNT	52.44%	51.39%	52.95%	52.01%	51.73%	50.38%	53.18%	53.11%	52.15%
Ameren Corporation	AEE	54.31%	53.29%	51.93%	52.45%	53.67%	53.03%	52.81%	52.69%	53.02%
American Electric Power Company, Inc	AEP	49.59%	49.41%	49.33%	49.75%	49.91%	48.80%	49.62%	49.40%	49.48%
Avista Corporation	AVA	55.00%	55.98%	55.74%	55.22%	55.80%	56.32%	56.10%	55.09%	55.66%
CMS Energy Corporation	CMS	51.56%	50.12%	49.81%	51.46%	51.70%	53.64%	52.52%	50.27%	51.38%
DTE Energy Company	DTE	48.83%	45.65%	47.27%	50.04%	49.40%	48.76%	48.69%	50.96%	48.70%
Duke Energy Corporation	DUK	53.27%	53.02%	53.21%	53.46%	52.89%	54.48%	53.14%	54.35%	53.48%
Entergy Corporation	ETR	47.71%	47.52%	47.50%	48.73%	49.10%	48.19%	48.81%	50.11%	48.46%
Evergy, Inc	EVRG	60.30%	59.21%	60.11%	60.14%	60.28%	60.51%	58.16%	59.56%	59.78%
Hawaiian Electric Industries, Inc	HE	57.02%	56.41%	56.48%	57.49%	58.15%	57.89%	57.78%	57.70%	57.37%
IDACORP, Inc	IDA	54.04%	51.25%	55.18%	55.14%	55.20%	54.58%	54.36%	54.25%	54.25%
NextEra Energy, Inc	NEE	61.82%	62.33%	58.06%	55.27%	56.15%	61.22%	64.03%	64.37%	60.41%
NorthWestern Corporation	NWE	48.26%	48.61%	47.78%	47.59%	47.80%	48.07%	48.74%	47.88%	48.09%
OGE Energy Corp	OGE	52.78%	53.09%	55.28%	55.15%	54.96%	53.47%	55.38%	53.20%	54.16%
Otter Tail Corporation	OTTR	52.72%	52.84%	50.85%	51.12%	55.43%	53.75%	53.90%	53.58%	53.03%
Pinnacle West Capital Corporation	PNW	51.58%	51.89%	53.66%	52.80%	54.25%	54.41%	54.48%	54.36%	53.43%
Portland General Electric Company	POR	47.85%	48.33%	50.09%	49.85%	51.78%	51.56%	50.60%	50.19%	50.03%
The Southern Company	SO	54.69%	54.19%	54.53%	52.68%	52.36%	52.93%	54.11%	54.21%	53.71%
WEC Energy Group, Inc	WEC	56.45%	55.83%	55.26%	55.44%	55.79%	56.71%	55.73%	53.46%	55.59%
Xcel Energy Inc	XEL	54.01%	52.89%	54.54%	54.22%	53.98%	54.70%	54.51%	54.22%	54.14%
Mean		53.37%	52.88%	53.25%	53.28%	53.76%	53.96%	54.11%	53.91%	53.56%
Median		53.27%	52.89%	53.66%	52.80%	53.98%	53.75%	54.11%	53.58%	53.48%

Operating Company Capital Structure

Operating Company	Parent	2020Q3	2020Q2	2020Q1	2019Q4	2019Q3	2019Q2	2019Q1	2018Q4	8Q Average
		% Common Equity								
Ameren Illinois Company	AEE	56.56%	56.16%	54.31%	53.00%	54.46%	54.05%	53.65%	52.86%	54.38%
Union Electric Company	AEE	52.05%	50.42%	49.55%	51.90%	52.88%	52.00%	51.96%	52.52%	51.66%
AEP Texas Inc	AEP	42.06%	45.04%	44.16%	43.77%	46.97%	46.32%	47.54%	45.38%	45.15%
Appalachian Power Company	AEP	47.10%	46.65%	49.16%	48.74%	48.74%	48.19%	47.77%	49.51%	48.23%
Indiana Michigan Power Company	AEP	48.35%	47.83%	47.42%	46.74%	46.51%	45.83%	45.43%	44.62%	46.59%
Kentucky Power Company	AEP	44.88%	44.57%	44.60%	47.34%	46.94%	46.50%	46.42%	45.72%	45.87%
Kingsport Power Company	AEP	55.42%	54.98%	55.04%	54.62%	54.24%	50.18%	51.54%	50.79%	53.35%
Ohio Power Company	AEP	52.10%	51.75%	51.18%	54.50%	53.63%	52.92%	58.86%	57.80%	54.09%
Public Service Company of Oklahoma	AEP	51.95%	50.57%	49.51%	49.69%	49.89%	48.02%	47.19%	49.16%	49.50%
Southwestern Electric Power Company	AEP	50.57%	49.71%	48.97%	48.80%	48.63%	47.45%	47.59%	46.97%	48.59%
Wheeling Power Company	AEP	53.86%	53.55%	53.89%	53.51%	53.66%	53.83%	54.27%	54.62%	53.90%
ALLETE (Minnesota Power)	ALE	54.30%	55.80%	58.32%	59.59%	59.33%	60.94%	60.87%	61.39%	58.82%
Superior Water, Light and Power Company	ALE	58.94%	58.68%	59.14%	58.08%	58.03%	58.38%	58.19%	56.86%	58.29%
Alaska Electric Light and Power Company	AVA	60.67%	60.62%	60.34%	59.62%	61.28%	61.24%	61.02%	60.29%	60.63%
Avista Corporation	AVA	49.33%	51.35%	51.15%	50.83%	50.33%	51.40%	51.18%	49.89%	50.68%
Consumers Energy Company	CMS	51.56%	50.12%	49.81%	51.46%	51.70%	53.64%	52.52%	50.27%	51.38%
DTE Electric Company	DTE	48.83%	45.65%	47.27%	50.04%	49.40%	48.76%	48.69%	50.96%	48.70%
Duke Energy Carolinas, LLC	DUK	51.93%	51.56%	50.26%	52.11%	51.80%	52.94%	52.32%	51.78%	51.84%
Duke Energy Florida, LLC	DUK	52.10%	51.12%	51.30%	49.91%	52.82%	51.55%	50.56%	50.04%	51.17%
Duke Energy Indiana, LLC	DUK	53.08%	50.12%	50.22%	52.84%	51.52%	54.83%	54.29%	53.26%	52.52%
Duke Energy Kentucky, Inc	DUK	49.28%	51.35%	50.07%	49.37%	45.44%	53.04%	52.81%	51.95%	50.41%
Duke Energy Ohio, Inc	DUK	62.16%	61.73%	65.61%	65.22%	64.90%	64.45%	59.29%	68.09%	63.93%
Duke Energy Progress, LLC	DUK	51.10%	52.23%	51.82%	51.29%	50.86%	50.09%	49.60%	51.00%	51.00%
Entergy Arkansas, LLC	ETR	44.42%	47.93%	47.46%	47.90%	47.72%	46.49%	47.04%	49.42%	47.30%
Entergy Louisiana, LLC	ETR	48.23%	46.62%	46.00%	47.47%	47.13%	46.32%	45.79%	47.37%	46.87%
Entergy Mississippi, LLC	ETR	47.91%	47.09%	48.92%	48.60%	48.35%	44.93%	49.41%	49.11%	48.04%
Entergy New Orleans, LLC	ETR	45.74%	44.82%	44.58%	49.26%	53.69%	52.40%	51.69%	51.19%	49.17%
Entergy Texas, Inc	ETR	52.27%	51.16%	50.53%	50.43%	48.63%	50.79%	50.13%	53.46%	50.92%
Evergy Kansas South, Inc	EVRG	82.55%	82.18%	82.03%	81.96%	81.84%	81.49%	75.13%	74.97%	80.27%
Evergy Metro, Inc	EVRG	48.77%	47.12%	49.97%	50.31%	50.43%	49.62%	46.04%	49.49%	48.97%
Evergy Missouri West, Inc.	EVRG	52.91%	51.74%	50.52%	50.34%	51.18%	51.74%	52.68%	54.71%	51.98%
Westar Energy (KPL)	EVRG	56.97%	55.81%	57.92%	57.97%	57.66%	59.18%	58.80%	59.08%	57.93%
Hawaii Electric Light Company, Inc	HE	NA	NA	NA	NA	NA	NA	NA	NA	NA
Hawaiian Electric Company, Inc	HE	57.02%	56.41%	56.48%	57.49%	58.15%	57.89%	57.78%	57.70%	57.37%
Maui Electric Company, Limited	HE	NA	NA	NA	NA	NA	NA	NA	NA	NA
Idaho Power Company	IDA	54.04%	51.25%	55.18%	55.14%	55.20%	54.58%	54.36%	54.25%	54.25%
Interstate Power and Light Company	LNT	52.10%	50.30%	51.26%	50.23%	50.06%	51.76%	53.33%	53.52%	51.57%
Wisconsin Power and Light Company	LNT	52.78%	52.47%	54.64%	53.78%	53.40%	49.01%	53.03%	52.69%	52.72%
Florida Power & Light Company	NEE	59.99%	63.16%	60.14%	60.24%	59.78%	61.30%	64.03%	64.37%	61.63%
Gulf Power Company	NEE	63.66%	61.51%	55.97%	50.30%	52.52%	61.15%	NA	NA	57.52%
NorthWestern Corporation	NWE	48.26%	48.61%	47.78%	47.59%	47.80%	48.07%	48.74%	47.88%	48.09%
Oklahoma Gas and Electric Company	OGE	52.78%	53.09%	55.28%	55.15%	54.96%	53.47%	55.38%	53.20%	54.16%
Otter Tail Power Company	OTTR	52.72%	52.84%	50.85%	51.12%	55.43%	53.75%	53.90%	53.58%	53.03%
Arizona Public Service Company	PNW	51.58%	51.89%	53.66%	52.80%	54.25%	54.41%	54.48%	54.36%	53.43%
Portland General Electric Company	POR	47.85%	48.33%	50.09%	49.85%	51.78%	51.56%	50.60%	50.19%	50.03%
Alabama Power Company	SO	51.95%	53.00%	53.10%	51.09%	51.45%	52.54%	52.23%	47.77%	51.64%
Georgia Power Company	SO	56.59%	54.59%	55.70%	56.12%	55.38%	56.39%	56.43%	59.02%	56.28%
Gulf Power Company	SO	NA	NA	NA	NA	NA	NA	58.06%	59.73%	58.89%
Mississippi Power Company	SO	55.53%	54.99%	54.80%	50.84%	50.23%	49.87%	49.73%	50.35%	52.04%
Upper Michigan Energy Resources Corporatior	WEC	54.10%	53.52%	52.81%	55.45%	56.09%	54.45%	52.54%	47.01%	53.25%
Wisconsin Electric Power Company	WEC	57.97%	57.19%	56.68%	56.27%	56.92%	56.64%	55.78%	56.03%	56.68%
Wisconsin Public Service Corporation	WEC	57.29%	56.78%	56.29%	54.61%	54.37%	59.04%	58.88%	57.33%	56.82%
Northern States Power Company - MN	XEL	52.20%	50.13%	52.55%	52.20%	51.79%	53.66%	53.64%	52.81%	52.37%
Northern States Power Company - WI	XEL	53.13%	52.61%	54.90%	54.23%	53.56%	53.49%	53.59%	53.60%	53.64%
Public Service Company of Colorado	XEL	56.56%	54.60%	56.58%	56.32%	56.35%	57.53%	56.68%	56.31%	56.37%
Southwestern Public Service Company	XEL	54.15%	54.22%	54.13%	54.14%	54.21%	54.14%	54.13%	54.17%	54.16%
Mean		53.21%	52.78%	53.02%	53.06%	53.29%	53.48%	53.35%	53.40%	53.30%
Median		52.27%	51.75%	51.82%	51.90%	52.82%	52.94%	52.81%	52.81%	52.45%

Source S&P Global Market Intelligence

Proxy Group Capital Structure

		% Long-Term Debt								
Company	Ticker	2020Q3	2020Q2	2020Q1	2019Q4	2019Q3	2019Q2	2019Q1	2018Q4	8Q Average
ALLETE, Inc	ALE	43.38%	42.76%	41.27%	41.16%	41.32%	40.34%	40.47%	40.88%	41.45%
Alliant Energy Corporation	LNT	47.56%	48.61%	47.05%	47.99%	48.27%	49.62%	46.82%	46.89%	47.85%
Ameren Corporation	AEE	45.69%	46.71%	48.07%	47.55%	46.33%	46.97%	47.19%	47.31%	46.98%
American Electric Power Company, Inc.	AEP	50.41%	50.59%	50.67%	50.25%	50.09%	51.20%	50.38%	50.60%	50.52%
Avista Corporation	AVA	45.00%	44.02%	44.26%	44.78%	44.20%	43.68%	43.90%	44.91%	44.34%
CMS Energy Corporation	CMS	48.44%	49.88%	50.19%	48.54%	48.30%	46.36%	47.48%	49.73%	48.62%
DTE Energy Company	DTE	51.17%	54.35%	52.73%	49.96%	50.60%	51.24%	51.31%	49.04%	51.30%
Duke Energy Corporation	DUK	46.73%	46.98%	46.79%	46.54%	47.11%	45.52%	46.86%	45.65%	46.52%
Entergy Corporation	ETR	52.29%	52.48%	52.50%	51.27%	50.90%	51.81%	51.19%	49.89%	51.54%
Evergy, Inc	EVRG	39.70%	40.79%	39.89%	39.86%	39.72%	39.49%	41.84%	40.44%	40.22%
Hawaiian Electric Industries, Inc	HE	42.98%	43.59%	43.52%	42.51%	41.85%	42.11%	42.22%	42.30%	42.63%
IDACORP, Inc	IDA	45.96%	48.75%	44.82%	44.86%	44.80%	45.42%	45.64%	45.75%	45.75%
NextEra Energy, Inc	NEE	38.18%	37.67%	41.94%	44.73%	43.85%	38.78%	35.97%	35.63%	39.59%
NorthWestern Corporation	NWE	51.74%	51.39%	52.22%	52.41%	52.20%	51.93%	51.26%	52.12%	51.91%
OGE Energy Corp	OGE	47.22%	46.91%	44.72%	44.85%	45.04%	46.53%	44.62%	46.80%	45.84%
Otter Tail Corporation	OTTR	47.28%	47.16%	49.15%	48.88%	44.57%	46.25%	46.10%	46.42%	46.97%
Pinnacle West Capital Corporation	PNW	48.42%	48.11%	46.34%	47.20%	45.75%	45.59%	45.52%	45.64%	46.57%
Portland General Electric Company	POR	52.15%	51.67%	49.91%	50.15%	48.22%	48.44%	49.40%	49.81%	49.97%
The Southern Company	SO	45.31%	45.81%	45.47%	47.32%	47.64%	47.07%	45.89%	45.79%	46.29%
WEC Energy Group, Inc	WEC	43.55%	44.17%	44.74%	44.56%	44.21%	43.29%	44.27%	46.54%	44.41%
Xcel Energy Inc	XEL	45.99%	47.11%	45.46%	45.78%	46.02%	45.30%	45.49%	45.78%	45.86%
Mean		46.63%	47.12%	46.75%	46.72%	46.24%	46.04%	45.89%	46.09%	46.44%
Median		46.73%	47.11%	46.34%	47.20%	46.02%	46.25%	45.89%	46.42%	46.52%

Operating Company Capital Structure

% Long-Term Debt

Operating Company	Parent	2020Q3	2020Q2	2020Q1	2019Q4	2019Q3	2019Q2	2019Q1	2018Q4	8Q Average
Ameren Illinois Company	AEE	43.44%	43.84%	45.69%	47.00%	45.54%	45.95%	46.35%	47.14%	45.62%
Union Electric Company	AEE	47.95%	49.58%	50.45%	48.10%	47.12%	48.00%	48.04%	47.48%	48.34%
AEP Texas Inc	AEP	57.94%	54.96%	55.84%	56.23%	53.03%	53.68%	52.46%	54.62%	54.85%
Appalachian Power Company	AEP	52.90%	53.35%	50.84%	51.26%	51.26%	51.81%	52.23%	50.49%	51.77%
Indiana Michigan Power Company	AEP	51.65%	52.17%	52.58%	53.26%	53.49%	54.17%	54.57%	55.38%	53.41%
Kentucky Power Company	AEP	55.12%	55.43%	55.40%	52.66%	53.06%	53.50%	53.58%	54.28%	54.13%
Kingsport Power Company	AEP	44.58%	45.02%	44.96%	45.38%	45.76%	49.82%	48.46%	49.21%	46.65%
Ohio Power Company	AEP	47.90%	48.25%	48.82%	45.50%	46.37%	47.08%	41.14%	42.20%	45.91%
Public Service Company of Oklahoma	AEP	48.05%	49.43%	50.49%	50.31%	50.11%	51.98%	52.81%	50.84%	50.50%
Southwestern Electric Power Company	AEP	49.43%	50.29%	51.03%	51.20%	51.37%	52.55%	52.41%	53.03%	51.41%
Wheeling Power Company	AEP	46.14%	46.45%	46.11%	46.49%	46.34%	46.17%	45.73%	45.38%	46.10%
ALLETE (Minnesota Power)	ALE	45.70%	44.20%	41.68%	40.41%	40.67%	39.06%	39.13%	38.61%	41.18%
Superior Water, Light and Power Company	ALE	41.06%	41.32%	40.86%	41.92%	41.97%	41.62%	41.81%	43.14%	41.71%
Alaska Electric Light and Power Company	AVA	39.33%	39.38%	39.66%	40.38%	38.72%	38.76%	38.98%	39.71%	39.37%
Avista Corporation	AVA	50.67%	48.65%	48.85%	49.17%	49.67%	48.60%	48.82%	50.11%	49.32%
Consumers Energy Company	CMS	48.44%	49.88%	50.19%	48.54%	48.30%	46.36%	47.48%	49.73%	48.62%
DTE Electric Company	DTE	51.17%	54.35%	52.73%	49.96%	50.60%	51.24%	51.31%	49.04%	51.30%
Duke Energy Carolinas, LLC	DUK	48.07%	48.44%	49.74%	47.89%	48.20%	47.06%	47.68%	48.22%	48.16%
Duke Energy Florida, LLC	DUK	47.90%	48.88%	48.70%	50.09%	47.18%	48.45%	49.44%	49.96%	48.83%
Duke Energy Indiana, LLC	DUK	46.92%	49.88%	49.78%	47.16%	48.48%	45.17%	45.71%	46.74%	47.48%
Duke Energy Kentucky, Inc	DUK	50.72%	48.65%	49.93%	50.63%	54.56%	46.96%	47.19%	48.05%	49.59%
Duke Energy Ohio, Inc	DUK	37.84%	38.27%	34.39%	34.78%	35.10%	35.55%	40.71%	31.91%	36.07%
Duke Energy Progress, LLC	DUK	48.90%	47.77%	48.18%	48.71%	49.14%	49.91%	50.40%	49.00%	49.00%
Entergy Arkansas, LLC	ETR	55.58%	52.07%	52.54%	52.10%	52.28%	53.51%	52.96%	50.58%	52.70%
Entergy Louisiana, LLC	ETR	51.77%	53.38%	54.00%	52.53%	52.87%	53.68%	54.21%	52.63%	53.13%
Entergy Mississippi, LLC	ETR	52.09%	52.91%	51.08%	51.40%	51.65%	55.07%	50.59%	50.89%	51.96%
Entergy New Orleans, LLC	ETR	54.26%	55.18%	55.42%	50.74%	46.31%	47.60%	48.31%	48.81%	50.83%
Entergy Texas, Inc	ETR	47.73%	48.84%	49.47%	49.57%	51.37%	49.21%	49.87%	46.54%	49.08%
Evergy Kansas South, Inc	EVRG	17.45%	17.82%	17.97%	18.04%	18.16%	18.51%	24.87%	25.03%	19.73%
Evergy Metro, Inc	EVRG	51.23%	52.88%	50.03%	49.69%	49.57%	50.38%	53.96%	50.51%	51.03%
Evergy Missouri West, Inc	EVRG	47.09%	48.26%	49.48%	49.66%	48.82%	48.26%	47.32%	45.29%	48.02%
Westar Energy (KPL)	EVRG	43.03%	44.19%	42.08%	42.03%	42.34%	40.82%	41.20%	40.92%	42.07%
Hawaii Electric Light Company, Inc	HE	NA	NA	NA	NA	NA	NA	NA	NA	NA
Hawaiian Electric Company, Inc	HE	42.98%	43.59%	43.52%	42.51%	41.85%	42.11%	42.22%	42.30%	42.63%
Maui Electric Company, Limited	HE	NA	NA	NA	NA	NA	NA	NA	NA	NA
Idaho Power Company	IDA	45.96%	46.75%	44.82%	44.86%	44.80%	45.42%	45.64%	45.75%	45.75%
Interstate Power and Light Company	LNT	47.90%	49.70%	48.74%	49.77%	49.94%	48.24%	46.67%	46.48%	48.43%
Wisconsin Power and Light Company	LNT	47.22%	47.53%	45.36%	46.22%	46.60%	50.99%	46.97%	47.31%	47.28%
Florida Power & Light Company	NEE	40.01%	36.84%	39.86%	39.76%	40.22%	38.70%	35.97%	35.63%	38.37%
Gulf Power Company	NEE	36.34%	38.49%	44.03%	49.70%	47.48%	38.85%	NA	NA	42.48%
NorthWestern Corporation	NWE	51.74%	51.39%	52.22%	52.41%	52.20%	51.93%	51.26%	52.12%	51.91%
Oklahoma Gas and Electric Company	OGE	47.22%	46.91%	44.72%	44.85%	45.04%	46.53%	44.62%	46.80%	45.84%
Otter Tail Power Company	OTTR	47.28%	47.16%	49.15%	48.88%	44.57%	46.25%	46.10%	46.42%	46.97%
Arizona Public Service Company	PNW	48.42%	48.11%	46.34%	47.20%	45.75%	45.59%	45.52%	45.64%	46.57%
Portland General Electric Company	POR	52.15%	51.67%	49.91%	50.15%	48.22%	48.44%	49.40%	49.81%	49.97%
Alabama Power Company	SO	48.05%	47.00%	46.90%	48.91%	48.55%	47.46%	47.77%	52.23%	48.36%
Georgia Power Company	SO	43.41%	45.41%	44.30%	43.88%	44.62%	43.61%	43.57%	40.98%	43.72%
Gulf Power Company	SO	NA	NA	NA	NA	NA	NA	41.94%	40.27%	41.11%
Mississippi Power Company	SO	44.47%	45.01%	45.20%	49.16%	49.77%	50.13%	50.27%	49.65%	47.96%
Upper Michigan Energy Resources Corporation	WEC	45.90%	46.48%	47.19%	44.55%	43.91%	45.55%	47.46%	52.99%	46.75%
Wisconsin Electric Power Company	WEC	42.03%	42.81%	43.32%	43.73%	43.08%	43.36%	44.22%	43.97%	43.32%
Wisconsin Public Service Corporation	WEC	42.71%	43.22%	43.71%	45.39%	45.63%	40.96%	41.12%	42.67%	43.18%
Northern States Power Company - MN	XEL	47.80%	49.87%	47.45%	47.80%	48.21%	46.34%	46.36%	47.19%	47.63%
Northern States Power Company - WI	XEL	46.87%	47.39%	45.10%	45.77%	46.44%	46.51%	46.41%	46.40%	46.36%
Public Service Company of Colorado	XEL	43.44%	45.40%	43.42%	43.68%	43.65%	42.47%	43.32%	43.69%	43.63%
Southwestern Public Service Company	XEL	45.85%	45.78%	45.87%	45.86%	45.79%	45.86%	45.87%	45.83%	45.84%
Mean		46.79%	47.22%	46.98%	46.94%	46.71%	46.52%	46.65%	46.60%	46.70%
Median		47.73%	48.25%	48.18%	48.10%	47.18%	47.06%	47.19%	47.19%	47.55%

DOCKET NO. _____

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

DANIEL S. DANE

OF

CONCENTRIC ENERGY ADVISORS, INC.

FOR

EL PASO ELECTRIC COMPANY

JUNE 2021

EXECUTIVE SUMMARY

Daniel S. Dane is a Senior Vice President at Concentric Energy Advisors, Inc. ("Concentric"). Concentric was engaged by El Paso Electric Company ("EPE" or the "Company") to prepare a lead-lag study to determine the Company's cash working capital ("CWC") requirements.

A lead-lag study measures the funds needed due to net timing differences between when a utility expends cash for the costs required to provide utility service and when it receives payment from customers for that service. Specifically, a lead-lag study measures "revenue lags," which are the number of days between when a utility provides service and when its customers pay for that service, and "expense leads," which are the number of days between when a utility incurs expenses and when it must pay for those expenses. The net of the revenue lags and expense leads, when multiplied by the Company's average daily Test Year expenses, results in the cash working capital requirement. The cash working capital requirement should be included as part of EPE's rate base for ratemaking purposes. Mr. Dane applied the leads and lags developed in Concentric's study to pro forma daily average expenses in determining EPE's CWC requirement of negative $3,903,773 to be included as a reduction to rate base.

TABLE OF CONTENTS

EXHIBITS

I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Daniel S. Dane. My business address is 293 Boston Post Road West, 500 Marlborough, Massachusetts 01752.

Q. BY WHOM ARE YOU EMPLOYED, AND IN WHAT POSITION?

A. I am a Senior Vice President with Concentric Energy Advisors, Inc. ("Concentric"), and the Financial and Operations Principal of CE Capital, Inc. ("CE Capital"), a FINRA-member[1] subsidiary of Concentric.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am testifying in this proceeding before the Public Utility Commission of Texas ("PUCT" or the "Commission") on behalf of El Paso Electric Company ("EPE" or the "Company").

Q. PLEASE DESCRIBE CONCENTRIC AND CE CAPITAL.

A. Concentric provides financial and economic advisory services to many and various energy and utility clients across North America. Concentric's financial advisory activities include buy and sell-side merger, acquisition, and divestiture assignments; due diligence and valuation assignments; project and corporate finance services; and transaction support services. Concentric's regulatory, economic, and market analysis services include utility ratemaking and regulatory advisory services; energy market assessments; market entry and exit analysis; corporate and business unit strategy development; demand forecasting; resource planning; and energy contract negotiations. In addition, Concentric provides litigation support services on a wide range of financial and economic issues on behalf of clients throughout North America. CE Capital is a broker-dealer FINRA-member firm that specializes in utility mergers and acquisitions.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL LICENSES.

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[1] FINRA, or the Financial Industry Regulatory Authority, Inc., is a government-authorized not-for-profit organization that oversees U.S. broker-dealers.

A. I have a Master of Business Administration from Boston College in Chestnut Hill, Massachusetts, and a Bachelor of Arts in Economics from Colgate University in Hamilton, New York. I am a Certified Public Accountant and a licensed securities professional (FINRA series 7, 28, 63, 79, and 99 licenses). I have included my résumé as Exhibit DSD-1.

Q. HAVE YOU PREVIOUSLY PRESENTED EXPERT TESTIMONY BEFORE REGULATORY AGENCIES?

A. Yes. I have testified or presented evidence in proceedings before the PUCT and other provincial and state regulators including the Connecticut Public Utilities Regulatory Authority, the Illinois Commerce Commission, the Maine Public Utilities Commission, the Massachusetts Department of Public Utilities, the New Hampshire Public Utilities Commission, the New Mexico Public Regulation Commission, the South Dakota Public Utilities Commission, the Vermont Public Utility Commission, and the Ontario Energy Board.

II. Purpose and Scope

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by the Company to present the results of a lead-lag study prepared by Concentric that was used to develop cash working capital ("CWC") factors and ultimately to calculate the CWC requirement of the Company.

Q. WHAT IS A "CASH WORKING CAPITAL" REQUIREMENT?

A. A cash working capital requirement is the amount of funds the Company needs to keep on hand to finance its day-to-day operations.

Q. WHAT IS A LEAD-LAG STUDY?

A. A lead-lag study measures the funds needed due to net timing differences between when a utility expends cash for the costs required to provide utility service and when it receives payment from customers for that service. Specifically, a lead-lag study measures "revenue lags," which are the number of days between when a utility provides service and when its customers pay for that service, and "expense leads," which are the number of days between when a utility incurs expenses and when it must pay for those expenses. The net of the revenue lags and expense leads, when multiplied by the Company's average daily Test Year Period expenses, results in the cash working capital requirement.

Q. HOW SHOULD THE RESULTS OF THE CASH WORKING CAPITAL ANALYSIS BE TREATED FOR RATEMAKING PURPOSES?

A. The cash working capital requirement should be included as part of EPE's rate base for ratemaking purposes.

Q. WAS THE LEAD-LAG STUDY DEVELOPED BY CONCENTRIC CONSISTENT WITH THE PUCT'S SUBSTANTIVE RULES FOR SUCH STUDIES?

A. Yes, it was. The Commission's rule in 16 Texas Administrative Code ("TAC") § 25.231(c)(2)(B)(iii)(IV), which is provided on page 17 of my direct testimony, addresses the development of a reasonable allowance for cash working capital by the use of a lead-lag study. The lead-lag study was developed by Concentric consistently with those rules.

Q. DID YOU MAKE ANY ADJUSTMENTS TO THE LEAD-LAG STUDY TO REFLECT NON-RECURRING EFFECTS OF THE COVID-19 PANDEMIC AND ITS ASSOCIATED ECONOMIC IMPACTS?

A. Yes. Due to the COVID-19 pandemic and its associated economic impacts, the statutory due dates for certain tax payments were delayed in 2020. Those due dates, however, are expected to be non-recurring and are not reflective of going-forward expectations. As such, I have adjusted the payment dates for certain taxes to the pre-pandemic statutory dates, as discussed further herein.

Q. ARE YOU SPONSORING ANY EXHIBITS OR SCHEDULES IN THIS PROCEEDING?

A. Yes. I sponsor Exhibits DSD-1 through DSD-9 and Schedule E-4. Exhibit DSD-1 contains my résumé and qualifications. Exhibits DSD-2 through DSD-9 show the revenue lags and expense leads that resulted from Concentric's lead-lag study, as well as EPE's requested level of cash working capital for the Test Year. The expense amounts to which the revenue lags and expense leads are applied have been provided by EPE witness Jennifer I. Borden. Schedule E-4 contains the Working Cash Allowance for EPE.

Q. WERE THE SCHEDULES AND EXHIBITS YOU ARE SPONSORING OR CO-SPONSORING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were prepared under my direction and supervision and are accurate and complete to the best of my knowledge and belief.

III. Summary of Findings

Q. FOR WHAT PERIOD WAS THE LEAD-LAG STUDY PERFORMED?

A. The lead-lag study analyzed the Company's cash transactions and invoices for the twelve months ended December 31, 2020 (i.e., the "Test Year" in this proceeding). The calculated revenue lag and expense leads were then applied to adjusted Test Year expenses.

Q. PLEASE SUMMARIZE YOUR FINDINGS REGARDING AN APPROPRIATE CWC ALLOWANCE FOR THE COMPANY.

A. Concentric's lead-lag study resulted in a total Company CWC allowance of negative $3,903,773, which results in a reduction to rate base. That result is provided in Exhibit DSD-2.

IV. Approach

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR APPROACH TO DETERMINING THE COMPANY'S CASH WORKING CAPITAL REQUIREMENT.

A. Concentric analyzed the significant cash inflows and outflows of the Company to develop lead-lag factors for EPE's revenues and expenses to derive a CWC allowance.

Q. WHAT ARE THE VARIOUS LAGS AND LEADS THAT SHOULD BE CONSIDERED IN A CASH WORKING CAPITAL ANALYSIS?

A. Two broad categories of lags and leads should be considered: (1) lag times associated with the collection of revenues owed to a company (i.e., revenue lags); and (2) lead times associated with the payments for goods and services received by a company (i.e., expense leads).

Q. WHAT IS A REVENUE LAG?

A. A revenue lag refers to the elapsed time between the delivery of a company's products and services (i.e., electricity generation, transmission, and distribution) and its ability to use the funds received as payment for the delivery of those products and services. In other words, the revenue lag measures the number of days from the date service was rendered by the Company until the date payment was received from customers and such funds were deposited and available to the Company.

Q. WHAT IS AN EXPENSE LEAD?

A. The expense lead refers to the elapsed time from when a good or service is provided to a company to the point in time when the company pays for the good or service and the funds are no longer available to the company.

Q. WHAT WAS THE SOURCE OF INFORMATION YOU USED TO DETERMINE THE LEADS AND LAGS IN YOUR CASH WORKING CAPITAL ANALYSIS?

A. EPE provided the accounting and financial data necessary for Concentric to complete the study. The information provided by the Company, together with analytical procedures performed by Concentric, led to the determination of the appropriate number of lead-lag days for EPE.

V. Summary of the Cash Working Capital Analysis

A. Revenue Lag

Q. FROM WHAT SOURCES DOES EPE RECEIVE REVENUES?

A. EPE's revenues include: (1) revenue from sales of electricity to retail customers and (2) wholesale and other revenues, which were comprised of (a) sales of electricity to wholesale customers, (b) wholesale transmission service revenues, and (c) other revenues.

Q. DESCRIBE YOUR CALCULATION OF THE REVENUE LAG FOR RETAIL CUSTOMERS.

A. In Concentric's analysis, the revenue lag for retail customers was divided into four distinct components: (1) a service lag, (2) a billing lag, (3) a collections lag, and (4) a payment processing lag. Considered together, these components of the retail revenue lag totaled 45.1 lag days. An explanation of each component of the revenue lag follows, and the calculation of the revenue lag is provided in Exhibit DSD-3, page 1 of 3.

Q. WHAT IS MEANT BY SERVICE LAG?

A. The service lag refers to the number of days from the mid-point of the service period to the meter reading date for that service period. Using the mid-point methodology, which assumes that service is provided evenly throughout the service period, the average lag associated with the provisioning of service was 15.2 days (365 days in the year divided by 12 months divided by 2).

Q. WHAT IS MEANT BY BILLING LAG?

A. Billing lag refers to the average number of days from the date on which the meter was read until the customer was billed. This lag reflects the time needed to send and process meter reading data in the Company's Customer Information System, prepare bills, and deliver bills. Specifically, the meter reading file containing the meter reads obtained during the day is transferred at the end of the business day. That night, the meter reading file is uploaded into the Company's customer billing system, which creates a bill print file. The bill print file is sent to the bill print vendor the following morning. The vendor prints and stuffs the bills and mails them that day. Based on that process, Concentric estimated the billing lag to be 1.0 day.

Q. WHAT IS MEANT BY COLLECTIONS LAG?

A. The collections lag refers to the average amount of time from the date when bills are issued to the date that the Company receives payment from its customers.

Q. HOW DID CONCENTRIC CALCULATE EPE'S COLLECTION LAG FOR PURPOSES

OF THIS PROCEEDING?

A. Concentric calculated the collection lag by analyzing an aging analysis of EPE's accounts receivable. Such an analysis provides data regarding the average amount of time that customer receivables are outstanding before they are collected. That analysis resulted in a collections lag of 27.6 days, as provided in Exhibit DSD-3, page 2 of 3.

Q. WHAT IS MEANT BY THE PAYMENT PROCESSING LAG?

A. The payment processing lag reflects the amount time taken to process customer payments. Specifically, different forms of customer payment take different times, on average, to be processed such that the funds become available to the Company. Concentric inquired of the Company regarding the payment processing time for the various forms of customer payment provided in Exhibit DSD-3, page 3 of 3. The resulting payment processing lag was 1.2 days as shown in Exhibit DSD-3, page 3 of 3.

Q. PLEASE SUMMARIZE THE CALCULATION OF REVENUE LAG DAYS FOR RETAIL CUSTOMERS.

A. The calculation of the overall revenue lag, by lag component, is summarized in the following figure.

Figure DSD-1: Revenue Lag by Component

Component	**Lag Days**
Service Lag	15.2
Billing Lag	1.0
Collections Lag	27.6
Payment Processing Lag	1.2
Total Lag	45.1

Q. WHAT ADDITIONAL TYPES OF REVENUES ARE CONSIDERED IN THE REVENUE LAG?

A. In addition to retail revenues, Concentric also considered wholesale and other revenues, including wholesale generation sales, wholesale transmission sales, and other revenues.

Q. DESCRIBE YOUR CALCULATION OF THE REVENUE LAG FOR WHOLESALE GENERATION AND TRANSMISSION CUSTOMERS.

A. EPE provided Concentric with data regarding the amount and timing of revenue receipts from wholesale generation and wholesale transmission customers. Based on that data, Concentric estimated a revenue lag for wholesale generation revenues of 35 days, and a revenue lag for wholesale transmission revenues of 39.3 days, both of which are shown in Exhibit DSD-4.

Q. WHAT IS INCLUDED IN OTHER REVENUES?

A. Other revenues for the Company include pole rental income, other electric property rental income, and other miscellaneous charges. Based on data provided by the Company for each type of other revenue, Concentric determined a revenue lag of 48.7 days as shown in Exhibit DSD-4. When weighted with wholesale generation sales and wholesale transmission sales, the revenue lag for wholesale and other revenues was 37.9 days, as also shown on Exhibit DSD-4.

Q. WHAT WAS THE RESULTING REVENUE LAG, INCLUSIVE OF BOTH RETAIL REVENUES AND WHOLESALE AND OTHER REVENUES?

A. On a weighted basis, the revenue lag, inclusive of both the retail revenue lag of 45.1 days and the wholesale and other revenue lag of 37.9 days, was 44.4 days as shown on Exhibit DSD-2.

B. Expense Leads

Q. WHAT EXPENSE-RELATED LEADS WERE CONSIDERED IN THE LEAD-LAG ANALYSIS?

A. Lead times associated with the following broad expense categories were considered in the lead-lag study: (a) fuel expenses, (b) payroll and benefits, (c) expenses related to EPE's ownership in the Palo Verde Generating Station ("PVGS"), (d) other operations and maintenance ("O&M") expenses, (e) taxes other than income taxes, (f) income taxes, and (g) interest on customer deposits.

Q. PROVIDE AN EXPLANATION OF THE EXPENSE LEADS ASSOCIATED WITH THE COMPANY'S FUEL EXPENSES.

A. Concentric analyzed data related to EPE's purchase of nuclear fuel and natural gas for its generating units. Payments for nuclear fuel were made on a quarterly basis, with payments made in the month following each quarter. Natural gas purchases were made from multiple vendors, usually on a monthly basis, with payments made following the month of service. The following table provides the expense leads by fuel type, which are also provided in Exhibit DSD-5.

Figure DSD-2: Fuel Expense Leads

Component	Lead Days
Nuclear Fuel	71.5
Natural Gas	40.1

Q. PROVIDE AN EXPLANATION OF THE EXPENSE LEADS ASSOCIATED WITH THE COMPANY'S POWER PURCHASES.

A. Concentric analyzed accounting records related to EPE's purchase of power, including from net-metered customers. Based on that data, Concentric estimated an expense lead of 38.4 as shown in Exhibit DSD-6, page 1 of 2.

Q. PROVIDE AN EXPLANATION OF THE EXPENSE LEADS ASSOCIATED WITH THE COMPANY'S PAYROLL EXPENSES.

A. EPE's regular payroll disbursements are made every two weeks with the 14-day payroll period running from Monday to Sunday two weeks later. Employees are paid for each payroll period on Friday following the end of the pay period, resulting in 26 to 27 regular payroll disbursements during any given 12-month period (depending on when the first Friday falls in the 12-month period). The midpoint of each 14-day payroll period is seven days. There is an additional expense lead of four days from Sunday to midnight Thursday (12:00 a.m. Friday) when payroll is disbursed. In addition, payroll is moved up by one day whenever a holiday falls on a Friday. EPE also provides monthly payments on the first day of each month for the upcoming month under supplemental employee retirement plans

("SERP").[2] Considering both regular payroll and SERP payments, the resulting payroll expense lead was 9.8 days as shown in Exhibit DSD-7, page 1 of 3. Finally, the funds for EPE's payroll taxes are withdrawn approximately one day ahead of its regular payroll funds. Therefore, the payroll expense lead was adjusted downward by one day to arrive at the expense lead for payroll taxes, from 9.8 days to 8.8 days, as discussed further below.

Q. YOUR LEAD-LAG STUDY INCLUDES AN EXPENSE LEAD FOR PAYROLL DEDUCTIONS. WHAT DO THOSE REPRESENT AND HOW DID YOU ESTIMATE AN EXPENSE LEAD?

A. Payroll deductions represent employee contributions towards benefits programs that are deducted directly from employees' payroll. In circumstances in which EPE does not pay associated vendors until some period after payroll is distributed to employees, the expense lead for that portion of employees' payroll is extended, creating a cash working capital benefit for the Company relative to if EPE had relinquished access to that cash on the payroll date. In other words, the expense lead associated with payroll that is deducted for certain payroll deductions is extended by the amount of time between the payroll date and the eventual payment to benefits providers. Examples of these payroll deductions are employee 401(k) contributions, employee contributions to insurance programs (medical, dental, vision, and life insurance), union dues, charity contributions, and other benefits such as flex-spending accounts, parking, and gym memberships.

Concentric received data from EPE for each type of payroll deduction in order to analyze the additional expense lead associated with the portion of gross payroll that is used for payroll deductions. Payroll deductions added an unweighted 2.9 days to the expense lead for that portion of payroll for a total expense lead of 12.7 days (i.e., 9.8 days for payroll plus 2.9 days for payroll deductions) as shown in Exhibit DSD-7, page 2 of 3.

Q. WHAT TYPES OF LEADS ASSOCIATED WITH THE COMPANY'S EMPLOYEE BENEFIT PROGRAMS WERE CONSIDERED IN THE ANALYSIS?

[2] SERP payments included payments under non-qualified pension plans including Supplemental Employee Retirement Plans and Excess Benefit Plans.

A. As shown in Exhibit DSD-7, page 3 of 3, the analysis of lead times associated with employee benefits included consideration of the following types of benefit plans and expenses:

- 401(k) administration and matching;
- The EPE portion of medical, dental, and other health benefits;
- The EPE portion of life insurance premiums;
- The EPE portion of parking benefits; and
- Post-retirement benefit-related costs.

Concentric received data from EPE related to payments made by the Company for each of these programs. The dollar-weighted expense lead for benefits was 30.0 days as shown in Exhibit DSD-7, page 3 of 3.

Q. WHAT CALCULATIONS DID YOU PERFORM RELATED TO THE COMPANY'S INCENTIVE COMPENSATION PAYMENTS?

A. During the Test Year, EPE made incentive compensation payments to its employees. Incentive compensation payments are made in the following year, resulting in an expense lead of 182 days (i.e., the midpoint of the prior year) plus the period between the end of the incentive compensation year and when payments are made, which was approximately 62.7 days in the Test Year. The overall expense lead for non-financially based incentive compensation was thus determined to be 244.7 days as shown in Exhibit DSD-7.

Q. WHAT WAS THE RESULTING WEIGHTED EXPENSE LEAD FOR WAGES, SALARIES, AND BENEFITS?

A. On a weighted basis, the expense lead for wages, salaries, and benefits—inclusive of regular payroll (9.8 days), payroll deductions (12.7 days), benefits (30.0 days), and incentive compensation (244.7 days)—was 25.9 days as shown on Exhibit DSD-7.

Q. DESCRIBE CONCENTRIC'S ANALYSIS OF O&M EXPENSES RELATED TO EPE'S OWNERSHIP IN PVGS.

A. EPE is invoiced weekly for PVGS expenses, with invoices representing estimated charges for the concurrent month. Towards the end of each month, a true-up is performed to charge or credit EPE for any difference between estimated and actual PVGS expenses in the previous month. Concentric analyzed the weekly payments and monthly true-ups related to EPE's PVGS O&M, which had an average expense lead of (1.0) day. The working capital requirement related to PVGS incorporates an adjustment to remove PVGS-related materials and supplies amounts that are charged to O&M and that represent non-cash charges.

Q. WHAT DO "OTHER O&M" EXPENSES INCLUDE, AND WHAT APPROACH DID CONCENTRIC USE TO CALCULATE THE ASSOCIATED EXPENSE LEAD?

A. O&M expense includes all payments made by EPE for O&M expenses that otherwise were not analyzed as part of Concentric's review of fuel, payroll, benefits, and PVGS O&M expenses. For the period January 1, 2020, to December 31, 2020, payments to 58 vendors made up approximately 75% of the total Other O&M expense amount, and the remainder represented payments to smaller vendors. Concentric requested and analyzed representative invoices from those 58 vendors to determine the relevant payment terms. Application of those representative payment terms to the remaining invoices for those 58 vendors resulted in a dollar-weighted expense lead of 46.2 days for approximately 75% of total Other O&M expense.

For the remaining approximately 25% of total Other O&M expense, which was comprised of numerous payments to smaller vendors, Concentric applied the dollar-weighted expense lead from the 58 larger vendors with one adjustment. Specifically, Concentric adjusted the analysis to exclude vendors whose invoices were paid earlier than 30 days after the provision of a product or service. Based on inquiries of EPE, it was determined that such payment terms would not typically be extended to smaller vendors. The result of that adjustment was to increase the expense lead for the smaller vendors to 56.1 days. The overall dollar-weighted expense lead taking into account the 46.2-day expense lead for the 58 larger vendors and the 56.1-day expense lead applied to smaller vendors was 48.6 days.

Finally, Concentric adjusted the working capital requirement related to Other O&M to account for prepaid expenses that were charged to Other O&M and that reflect non-cash charges.

Q. WHAT TAXES OTHER THAN INCOME TAXES AND FEES WERE CONSIDERED IN CONCENTRIC'S ANALYSIS?

A. Concentric's analysis also considered taxes other than income taxes and fees that EPE pays related to utility service. The table below provides those taxes and fees, along with their respective expense leads.

Figure DSD-3: Taxes Other Than Income Taxes and Fees	
Component	**Lead Days**
Payroll Taxes	8.8
PVGS Payroll Taxes	(1.0)
New Mexico Compensating Taxes	44.7
New Mexico Public Regulation Commission Fees	270.0
New Mexico Property Taxes	230.2
Texas Gross Receipts Taxes	77.5
Texas Franchise Fees	96.8
Texas Public Utility Commission Fees	239.5
Texas Property Taxes	212.9
Arizona Property Taxes	214.7

The expense lead for payroll taxes was assumed to be the same as that for regular payroll (i.e., 9.8 days) less one day because the Company's payroll processing provider withdraws payroll taxes the day before payroll is paid. The expense lead for PVGS-related payroll taxes was assumed to be the same as that for PVGS O&M expenses (i.e., (1.0) day). EPE provided accounting and payment data related to each of the other categories of taxes and fees, upon which Concentric estimated expense leads for each as shown above and in Exhibit DSD-8.

Q. HOW DID YOUR STUDY ADDRESS FEDERAL INCOME TAXES?

A. The expense lead attributable to EPE's federal income tax liability was calculated based on quarterly payment dates on or about April 15, June 15, September 15, and December 15 for calendar year taxes. Due to the COVID-19 pandemic, first and second quarter federal taxes for 2020 were not due until July 15, 2020. Those delayed payment dates, however, are not expected to continue into the future, and so Concentric used the more-typical payment dates of April 15 and June 15 for first and second quarter federal income taxes. EPE estimates its quarterly taxable income based on the net income from the prior quarter, which follows a cyclical pattern whereby taxable income tends to be greater in the summer and fall (i.e., in the second and third quarters of the year), following customer usage patterns. Based on the quarterly payment dates and an estimate of the shape of the payments provided by the Company assuming greater taxable income in the second and third quarters of each year relative to the first and fourth quarters, Concentric calculated an expense lead of 16.7 days as shown in Exhibit DSD-9.

Q. HOW DID THE STUDY ADDRESS STATE INCOME TAXES?

A. In the Test Year, state income taxes were paid approximately quarterly. Like federal income taxes, state income tax payments follow a cyclical pattern. Concentric estimated the Company to have an expense lead associated with state income taxes of 16.7 days as shown in Exhibit DSD-9, reflecting a similar adjustment as was made for the federal tax payment dates. The lead-lag study also reflects Texas's state margin taxes, which are paid annually for the current year in May and then trued up in November.[3] The resulting lead reflecting both the annual payment and the true-up was (47.5) days.

Q. WHAT CONSIDERATION DID YOUR STUDY MAKE FOR INTEREST PAID ON CUSTOMER DEPOSITS?

A. Interest is paid by the Company at approximately the end of each calendar year for deposits made during the year. The expense lead was thus determined to be 182.5 days, reflecting the time between the midpoint of the year and payment of interest.

C. Other Components of Cash Working Capital

Q. WHAT OTHER COMPONENTS OF CASH WORKING CAPITAL DID YOU

[3] Like income taxes, Texas state margin payment dates were delayed in 2020 due to the pandemic. Concentric's study, however, reflects expected payment dates in May going forward.

CONSIDER IN YOUR ANALYSIS?

A. EPE has three pass-through taxes and fees that are incurred as part of the provision of utility service but that are remitted to the appropriate taxing authority without being recognized as expenses on the Company's books. Those taxes and fees are (1) New Mexico gross receipts taxes, (2) New Mexico franchise fees, and (3) Texas sales and use taxes. Because collection of those taxes and the associated remittance to taxing authorities occur at different times, there are cash working capital effects on the Company. However, these pass-through taxes and fees are not part of the revenue requirement to which net lags or leads are applied in the lead-lag study, and thus, would not be reflected in the cash working capital requirement without separate consideration. As such, the total cash working capital requirement calculated by Concentric separately includes the net (lead)/lag associated with those taxes and fees as shown on Exhibit DSD-2.

Q. DID CONCENTRIC'S LEAD-LAG STUDY ACCOUNT FOR PETTY CASH?

A. Yes. Consistent with Commission Rule 16 TAC § 25.231(c)(2)(B)(iii)(IV)(-e-), Concentric included petty cash funds in the determination of the overall CWC allowance. Specifically, that part of the Commission rule states that, "the balance of cash and working funds included in the working cash allowance calculation shall consist of the average daily bank balance of all noninterest bearing demand deposits and working cash funds." Petty cash funds are amounts the Company must keep on hand to serve customers (for example, to make change for customers who pay with cash). The Company kept an average petty cash fund balance of $43,898 during the Test Year. That amount, which represents shareholder-supplied funds, was added to the CWC allowance.

Q. BASED UPON THE RESULTS OF THE LEAD-LAG STUDY AND THE LEVEL OF EXPENSES DESCRIBED IN THE TESTIMONY OF EPE WITNESS BORDEN, WHAT IS THE TOTAL COMPANY LEVEL OF CASH WORKING CAPITAL REQUIREMENTS?

A. As shown on Exhibit DSD-2, applying the revenue lag and expense leads that I have calculated to the expense levels provided by EPE witness Borden results in a total Company cash working capital requirement of negative $3,903,773, which results in a reduction to rate base.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?
A. Yes.

16 Texas Administrative Code § 25.231(c)(2)(B)(iii)(IV)

16 TAC § 25.231(c)(2)(B)(iii)(IV) addresses the development of a reasonable allowance for cash working capital by the use of a lead-lag study. Specifically, that rule states:

> For all investor-owned electric utilities a reasonable allowance for cash working capital, including a request of zero, will be determined by the use of a lead-lag study. A lead-lag study will be performed in accordance with the following criteria:
>
> (-a-) The lead-lag study will use the cash method; all non-cash items, including but not limited to depreciation, amortization, deferred taxes, prepaid items, and return (including interest on long-term debt and dividends on preferred stock), will not be considered.
>
> (-b-) Any reasonable sampling method that is shown to be unbiased may be used in performing the lead-lag study.
>
> (-c-) The check clear date, or the invoice due date, whichever is later, will be used in calculating the lead-lag days used in the study. In those cases where multiple due dates and payment terms are offered by vendors, the invoice due date is the date corresponding to the terms accepted by the electric utility.
>
> (-d-) All funds received by the electric utility except electronic transfers shall be considered available for use no later than the business day following the receipt of the funds in any repository of the electric utility (e.g. lockbox, post office box, branch office). All funds received by electronic transfer will be considered available the day of receipt.
>
> (-e-) For electric utilities the balance of cash and working funds included in the working cash allowance calculation shall consist of the average daily bank balance of all noninterest bearing demand deposits and working cash funds.
>
> (-f-) The lead on federal income tax expense shall be calculated by measurement of the interval between the mid-point of the annual service period and the actual payment date of the electric utility.
>
> (-g-) If the cash working capital calculation results in a negative amount, the negative amount shall be included in rate base.

DANIEL S. DANE, CPA

Senior Vice President

Daniel S. Dane has 20 years of experience in the energy, utility, and financial services industries providing advisory services to power companies, natural gas pipelines, and local gas distribution companies in the areas of regulation and ratemaking, litigation support, mergers and acquisitions, valuation, financial statement audits and analysis, and the examination of financial reporting systems and controls. Mr. Dane has also provided expert testimony on regulated ratemaking matters and merger approval applications for investor- and provincially-owned utilities, including on merger impacts, revenue requirements, the cost of capital, capital structure, lead-lag studies/cash working capital, regulatory lag and rate base development. Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts, and a BA in Economics from Colgate University in Hamilton, New York. Mr. Dane is a certified public accountant, and is a licensed securities professional (Series 7, 28, 63, 79, and 99). Mr. Dane also serves as the Financial and Operations Principal of CE Capital Advisors, a FINRA-Member firm and a subsidiary of Concentric.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2004 – Present)

CE Capital Advisors, Inc.

Senior Vice President (Concentric/CE Capital)

Financial and Operations Principal (CE Capital)

Ernst & Young (2000 – 2001, 2003 – 2004)

Staff Auditor and Database Management Associate

ZIA Information Analysis Group (1997 – 2000)

EDUCATION

Boston College

M.B.A., 2003

Colgate University

B.A., Economics, 1996

REPRESENTATIVE PROJECT EXPERIENCE

Ratemaking and Utility Regulation Assignments

Expert Testimony

- Submitted expert testimony on behalf of utilities and other stakeholders in state administrative rate setting and merger approval proceedings regarding merger impacts, revenue requirements, the cost of capital, capital structure, lead-lag studies/cash working capital, regulatory lag and rate base development.

Regulatory Support

- Provided financial modeling, development of expert reports, and preparation of multiple rounds of testimony on behalf of U.S. and Canadian investor-owned electric, natural gas, and water utilities related to multiple aspects of the ratemaking process, including: cost of capital; ring fencing; revenue requirements and lead-lag studies/cash working capital; decoupling; prudence and cost recovery; capital tracker tariff mechanisms; cost allocation and shared services; merger approval; regulatory lag; and ratemaking policy.
- Consulting assignments have included utility clients across the U.S. and Canada.

Financial Advisory Assignments

Competitive Solicitations & Asset Divestitures

- Sell-side support for approximately $2 billion in generating asset transactions, including nuclear, natural gas, and coal generating facilities.
- Buy-side due diligence support for U.S., Canadian, and international investors in electric and natural gas LDC utility operations, wind generation and natural gas pipeline facilities.
- Regulatory policy, ring-fencing, and merger impacts advisory services provided to U.S. and Canadian investor-owned utilities.

Valuation Services

- Developed Fairness Opinions issued by CE Capital Advisors, Inc. to Boards of Directors of companies entering into asset purchases and sales. Led valuation modeling on multiple energy-related valuation assignments using the Income Approach, Cost Approach, and Sales Comparison Approach.

Litigation Advisory Assignments

Prepared economic and valuation analyses and expert reports in proceedings related to contract disputes, takings claims, and bankruptcy proceedings. Clients include international diversified energy companies, regulated utilities, and bondholders.

Management and Operations Consulting Assignments

Performed prudence reviews, including contracting strategy reviews and assessments of project controls and oversight for developers of nuclear-generating capacity uprates and new nuclear facilities.

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Public Accountant, 2004

Massachusetts Society of Certified Public Accountants, 2004

American Institute of Certified Public Accountants, 2011

CERTIFICATIONS

Licensed Securities Professional: NASD Series 7, 28, 63, 79 and 99 Licenses

PRESENTATIONS

"Regulatory Treatment of Timing Differences Related to Pension and OPEB Costs." Presented to the Ontario Energy Board, July 2016 (Docket No. EB-2015-0040).

"Financial Management and Capital Markets." University of Idaho Utility Executive Course, 2018.

"Increasing Shareholder Value through the Capital Markets." University of Idaho Utility Executive Course, 2015, 2016 and 2017.

"A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Jim Coyne and Julie Lieberman), presented to the Ontario Energy Association, June 2007.

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO./ CASE NO.	SUBJECT
Connecticut Public Utilities Regulatory Authority				
SJW Group and Connecticut Water Service, Inc.	4/19	Application of SJW Group and Connecticut Water Service, Inc. for Approval of Change of Control	Docket No. 19-04-02	Merger Impacts
SJW Group and Connecticut Water Service, Inc.	12/18	Application of SJW Group and Connecticut Water Service, Inc. for Approval of Change of Control	Docket No. 18-07-10	Merger Impacts
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Lead-Lag Study Cash Working Capital
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Lead-Lag Study Cash Working Capital
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Lead-lag Study Cash Working Capital
Illinois Commerce Commission				
The Ameren Illinois Utilities	07/10	Central Illinois Light Company; Central Illinois Public Service Company; Illinois Power Company	Docket Nos. 09-0306 thru 09-0311 (cons.)	Rate Base Adjustments Earnings Attrition
Maine Public Utilities Commission				
The Maine Water Company	07/19	Application for Approval of Reorganization Pursuant to 35-A M.R.S. § 708	Docket No. 2019-00096	Merger Impacts, Customer Benefits, Public Interest
Massachusetts Department of Public Utilities				
The Berkshire Gas Company	05/18	The Berkshire Gas Company	D.P.U. 18-40	Revenue Requirement

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO./ CASE NO.	SUBJECT
National Grid	04/18	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 17-170	Impact of the Tax Cuts and Jobs Act of 2017; Administrative and General Expense Allocations
National Grid	11/17	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 17-170	Revenue Requirement Lead-lag Study Cash Working Capital
National Grid	11/20	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 20-120	Revenue Requirement Lead-lag Study Cash Working Capital
New Hampshire Public Utilities Commission				
Liberty Utilities (EnergyNorth Natural Gas) Corp.	04/17	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Docket No. DG 17-048	Temporary Rates
Liberty Utilities (EnergyNorth Natural Gas) Corp.	04/17	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Docket No. DG 17-048	Revenue Requirement
New Mexico Public Regulation Commission				
El Paso Electric Company	05/20	El Paso Electric Company	Case No. 20-00104-UT	Lead-lag Study Cash Working Capital
Public Utility Commission of Texas				
El Paso Electric Company	02/17	El Paso Electric Company	Docket No. 46831	Lead-lag Study Cash Working Capital
South Dakota Public Service Commission				
Northern States Power Company-MN	06/11	Northern States Power Company-MN	EL 11-019	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO./ CASE NO.	SUBJECT
Vermont Public Utility Commission				
Vermont Department of Public Service	08/17	Joint Petition of NorthStar Decommissioning Holdings, LLC, NorthStar Nuclear Decommissioning Company, LLC, NorthStar Group Services, Inc., LVI Parent Corp., NorthStar Group Holdings, LLC, Entergy Nuclear Vermont Investment Company, LLC, and Entergy Nuclear Operations, Inc., and any other necessary affiliates entities to transfer ownership of Entergy Nuclear Vermont Yankee, LLC, and for certain ancillary approvals, pursuant to 30 V.S.A. §§ 107, 231, and 232	Docket No. 8880	Nuclear Facility Transfer
Ontario Energy Board				
Ontario Power Generation	05/16	Ontario Power Generation	EB 2016-0152	Capital Structure
Ontario Power Generation	12/20	Ontario Power Generation	EB 2020-0290	Capital Structure

EL PASO ELECTRIC COMPANY
CASH WORKING CAPITAL REQUIREMENT - LEAD-LAG STUDY
FOR THE TEST YEAR ENDED DECEMBER 31, 2020

Line No.	Description (A)	Total Company Revenue Requirement (B)	Average Daily Amount (C)=(B)/365	Revenue Lag Days (D)	Expense Lead Days (E)	Net (Lead)/Lag (F)=(D)-(E)	Working Capital Requirement (G)=(C)x(F)	Work Paper Reference (H)
1	**Energy Costs:**							
2	Nuclear	$ 41,258,546	$ 113,037	44.4	71.5	(27.1)	$ (3,063,306)	B-1
3	Gas	76,241,203	208,880	44.4	40.1	4.3	898,184	B-2
4	Purchased Power	82,407,848	225,775	44.4	38.4	6.0	1,354,650	B-3, B-4, B-5
5								
6	**Operation & Maintenance Expenses:**							
7	Wages, Salaries and Benefits	84,667,645	231,966	44.4	25.9	18.5	4,291,374	C
8	Palo Verde O&M*	80,387,373	220,239	44.4	(1.0)	45.4	10,001,216	C-3
9	Other O&M*	115,510,304	316,467	44.4	48.6	(4.2)	(1,344,110)	C-4
10								
11	**Taxes Other Than Income Taxes:**							
12	Payroll Taxes	5,121,885	14,033	44.4	8.8	35.6	499,559	C
13	Payroll Taxes - Palo Verde	3,034,559	8,314	44.4	(1.0)	45.4	377,538	C-3
14	New Mexico							
15	Compensating Tax	31,195	85	44.4	44.7	(0.3)	(26)	G-1
16	Public Regulation Commission	909,583	2,492	44.4	270.0	(225.6)	(562,197)	D-1
17	Property	4,022,276	11,020	44.4	230.2	(185.8)	(2,047,504)	D-2
18	Texas							
19	Gross Receipts	10,705,684	29,331	44.4	77.5	(33.1)	(970,844)	D-3
20	Franchise Fees	26,739,003	73,258	44.4	96.8	(52.4)	(3,838,695)	D-4
21	Public Utility Commission Fee	1,057,293	2,897	44.4	239.5	(195.1)	(565,145)	D-5
22	Property	18,239,406	49,971	44.4	212.9	(168.5)	(8,420,816)	D-6
23	Arizona							
24	Property	6,843,321	18,749	44.4	214.7	(170.3)	(3,192,925)	D-7
25								
26	**Income Taxes:**							
27	Federal Current	25,284,127	69,272	44.4	16.7	27.7	1,918,823	E-1
28	State Current (Arizona)	(430,383)	(1,179)	44.4	16.7	27.7	(32,662)	E-2
29	State Current (New Mexico)	1,533,025	4,200	44.4	16.7	27.7	116,342	E-3
30	State Gross Margin Tax	2,145,439	5,878	44.4	(47.5)	91.9	540,180	E-4
31								
32	**Interest on Customer Deposits**	82,820	227	44.4	182.5	(138.1)	(31,335)	F
33								
34	**Cash Working Capital Requirement From Revenue Requirements**						(4,071,699)	
35								
36	**Other**							
37	New Mexico Gross Receipts	10,947,161	29,992	44.4	44.7	(0.3)	(8,998)	G-1
38	New Mexico Franchise Fees	93,194	255	44.4	(26.9)	71.3	18,205	G-2
39	Texas Sales and Use Tax	106,666	292	44.4	40.4	4.0	1,169	G-3
40	Petty Cash Funds						43,898	H
41	Reconciling adjustment**						113,652	
42								
43	**Total Company Working Capital**						$ (3,903,773)	
44								

45 *Includes adjustment for pre-payments and materials and supplies charged to O&M of $9,072,712 (Palo Verde) and $23,819,811 (Other O&M) (source: Schedule E-5)
46 ** Adjustment to reconcile the lead-lag study to Company's revenue requirement calculation, including revenue gross-up factors

Exhibit DSD-2
Page 1 of 1

EL PASO ELECTRIC COMPANY
CASH WORKING CAPITAL REQUIREMENT - LEAD-LAG STUDY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2020
SUMMARY OF REVENUE LAG

Line No.	Revenue Lag Component	Lag Days
	(A)	(B)
1	Service Lag	15.2
2	Billing Lag	1.0
3	Collection Lag	27.6
4	Payment Processing Lag	1.2
5	Total	45.1

Source: Work Paper A

Exhibit DSD-3
Page 1 of 3

EL PASO ELECTRIC COMPANY
CASH WORKING CAPITAL REQUIREMENT - LEAD-LAG STUDY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2020
CALCULATION OF COLLECTIONS LAG

Line No.	Time Period	Midpoint		Revenues	Revenues (%)	Weighted Service Lag
	(A)	(B)		(C)	(D)	(E)
1	0-30 Days	15.0	$	40,344,417	76.0%	11.4
2	31-60 Days	44.5		6,523,306	12.3%	5.5
3	61-90 Days	74.5		2,602,425	4.9%	3.7
4	90+ Days	105.0		3,586,708	6.8%	7.1
5	Total		$	53,056,856	100.0%	27.6

Source: Work Paper A-1

Exhibit DSD-3
Page 2 of 3

EL PASO ELECTRIC COMPANY
CASH WORKING CAPITAL REQUIREMENT - LEAD-LAG STUDY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2020
CALCULATION OF PAYMENT PROCESSING LAG

Line No.	Payment Method (A)	Receipt of Funds Lag (B)	Revenues (%) (C)	Weighted Receipt of Funds Lag (D)
1	ACH Electronic Check	2.00	11.9%	0.2
2	ACH ForRealTime Payment	3.00	3.9%	0.1
3	Bill2Pay ACH	2.00	0.6%	0.0
4	Bill2Pay Credit Card	2.00	3.5%	0.1
5	Bill2Pay Debit Card	2.00	0.0%	0.0
6	Cash	1.00	2.2%	0.0
7	Check	1.00	77.8%	0.8
8	Money Order	2.00	0.0%	0.0
9	Truncated Check (ECA)	2.00	0.0%	0.0
	Total		99.8%	1.2

Exhibit DSD-3
Page 3 of 3

Source: Work Paper A-2

EL PASO ELECTRIC COMPANY
CASH WORKING CAPITAL REQUIREMENT - LEAD-LAG STUDY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2020
SUMMARY OF OTHER REVENUES

Line No.	Description	Lag Days		Revenues	Weighting	Weighted Lag
	(A)	(B)		(C)	(D)	(E)
1	Wholesale Transactions	35.0	$	45,187,312	57.3%	20.0
2	Wholesale Transmission Sales	39.3		24,579,633	31.2%	12.3
3	Other Revenues	48.7		9,036,948	11.5%	5.6
4	Total		$	78,803,894	100.0%	37.9

Source: Work Paper A

Exhibit DSD-4
Page 1 of 1

EL PASO ELECTRIC COMPANY
CASH WORKING CAPITAL REQUIREMENT - LEAD-LAG STUDY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2020
SUMMARY OF FUEL EXPENSE LEADS - NUCLEAR

Line No.	Month	Lead Days	Total Expenses	Weighting	Weighted Lag
	(A)	(B)	(C)	(D)	(E)
1	Rio Grande Resource Trust II	71.5	$ 42,275,052	100.0%	71.5
2	Total		$ 42,275,052	100.0%	71.5

Source: Work Paper B-1

Exhibit DSD-5
Page 1 of 2

EL PASO ELECTRIC COMPANY
CASH WORKING CAPITAL REQUIREMENT - LEAD-LAG STUDY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2020
SUMMARY OF FUEL EXPENSE LEADS - NATURAL GAS

Line No.	Vendor	Lead Days	Total Expenses	Weighting	Weighted Lag
	(A)	(B)	(C)	(D)	(E)
1	Vendor 1	39.7	$ 2,061,888	2.7%	1.1
2	Vendor 2	43.5	2,849,285	3.8%	1.6
3	Vendor 3	39.5	(54,850)	-0.1%	(0.0)
4	Vendor 4	44.0	3,824,145	5.1%	2.2
5	Vendor 5	40.0	30,725	0.0%	0.0
6	Vendor 6	39.4	7,308,954	9.7%	3.8
7	Vendor 7	40.0	4,000	0.0%	0.0
8	Vendor 8	37.1	24,497,947	32.5%	12.1
9	Vendor 9	29.5	898,034	1.2%	0.4
10	Vendor 10	39.4	5,923,665	7.9%	3.1
11	Vendor 11	39.8	3,284,262	4.4%	1.7
12	Vendor 12	38.5	734,025	1.0%	0.4
13	Vendor 13	43.8	11,309,398	15.0%	6.6
14	Vendor 14	44.5	721,011	1.0%	0.4
15	Vendor 15	44.6	4,250,167	5.6%	2.5
16	Vendor 16	39.9	1,621,976	2.2%	0.9
17	Vendor 17	39.7	2,131,357	2.8%	1.1
18	Vendor 18	40.9	1,156	0.0%	0.0
19	Vendor 19	42.8	4,035,240	5.3%	2.3
20			$ 75,432,385	100.0%	40.1

Source: Work Paper B-2

Exhibit DSD-5
Page 2 of 2

EL PASO ELECTRIC COMPANY
CASH WORKING CAPITAL REQUIREMENT - LEAD-LAG STUDY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2020
SUMMARY OF PURCHASED POWER EXPENSE LEADS

Line No.	Description	Lead Days		Total Expenses	Weighting	Weighted Lag
	(A)	(B)		(C)	(D)	(E)
1	Purchased Power	39.1	$	42,344,118	96.7%	37.8
2	RECs - Buy Backs	23.6		732,817	1.7%	0.4
3	RECs - Four Peaks	15.2		688,118	1.6%	0.2
4	Other (WREGIS)	65.6		1,827	0.0%	0.0
5	Total		$	43,766,880	100.0%	38.4

Source: Work Paper B

Exhibit DSD-6
Page 1 of 2

EL PASO ELECTRIC COMPANY
CASH WORKING CAPITAL REQUIREMENT - LEAD-LAG STUDY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2020
SUMMARY OF PURCHASED POWER EXPENSE LEADS

Line No.	Vendor (A)	Lead Days (B)	Total Expenses (C)	Weighting (D)	Weighted Lag (E)
1	Vendor 1	47.3	$ 1,563,816	3.7%	1.7
2	Vendor 2	42.6	8,575,059	20.3%	8.6
3	Vendor 3	36.9	1,543,620	3.6%	1.3
4	Vendor 4	38.4	182,561	0.4%	0.2
5	Vendor 5	37.6	2,031,591	4.8%	1.8
6	Vendor 6	34 4	6,156,257	14.5%	5.0
7	Vendor 7	46.4	2,609,375	6.2%	2.9
8	Vendor 8	45.2	3,214,118	7.6%	3.4
9	Vendor 9	38.7	30,779	0.1%	0.0
10	Vendor 10	35.7	594,266	1.4%	0.5
11	Vendor 11	35.0	5,800	0.0%	0.0
12	Vendor 12	36.9	4,932,143	11.6%	4.3
13	Vendor 13	35.0	150	0.0%	0.0
14	Vendor 14	28.5	820,202	1.9%	0.6
15	Vendor 15	43.2	986,185	2.3%	1.0
16	Vendor 16	38.2	52,793	0.1%	0.0
17	Vendor 17	33.0	204,061	0.5%	0.2
18	Vendor 18	43.6	141,107	0.3%	0.1
19	Vendor 19	33.0	90	0.0%	0.0
20	Vendor 20	37.7	3,075,663	7 3%	2.7
21	Vendor 21	42.0	2,877	0 0%	0.0
22	Vendor 22	40.8	367,776	0.9%	0.4
23	Vendor 23	41.9	52,095	0.1%	0.1
24	Vendor 24	28.6	1,549,785	3.7%	1 0
25	Vendor 25	40.0	28,500	0.1%	0.0
26	Vendor 26	39.0	1,500	0.0%	0.0
27	Vendor 27	34.0	39,850	0.1%	0.0
28	Vendor 28	34.0	1,189,904	2.8%	1 0
29	Vendor 29	37.0	1,263,458	3.0%	1.1
30	Vendor 30	37.0	6,700	0.0%	0.0
31	Vendor 31	39.0	1,027,975	2.4%	0.9
32	Vendor 32	40.0	85,000	0.2%	0.1
33	Vendor 33	35.0	8,800	0.0%	0.0
34	Vendor 34	24.8	262	0.0%	0.0
			$ 42,344,118	100.0%	39.1

Exhibit DSD-6
Page 2 of 2

EL PASO ELECTRIC COMPANY
CASH WORKING CAPITAL REQUIREMENT - LEAD-LAG STUDY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2020
PAYROLL AND BENEFITS EXPENSE LEADS

Line No.	Description (A)	Lead Days (B)	Total Expenses (C)	Weighting (D)	Weighted Lag (E)
1	Gross Regular Payroll Net of Taxes		$ 94,598,945		
2	Less: Payroll Deductions with Incremental Expense Lead		19,856,983		
3	Gross Regular Payroll Net of Payroll Deductions with Incremental Expense Lead	9.8	$ 74,741,961	55.2%	5.4
4	Payroll Deductions with Incremental Expense Lead	12.7	19,856,983	14.7%	1.9
5	Benefits	30.0	34,742,342	25.7%	7.7
6	Incentive Comp	244.7	6,085,232	4.5%	11.0
7	Payroll, Payroll Deductions, Benefits	297.1	$ 135,426,519	100.0%	25.9

Source: Work Paper C

Exhibit DSD-7
Page 1 of 3

EL PASO ELECTRIC COMPANY
CASH WORKING CAPITAL REQUIREMENT - LEAD-LAG STUDY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2020
PAYROLL EXPENSE DEDUCTIONS LEADS

Line No.	Category	Lead Days		Total Expenses	Weighting	Weighted Lag
	(A)	(B)		(C)	(D)	(E)
1	401(k) Employee Contribution	4.1	$	12,785,806	64.4%	2.6
2	Wage Attachments	-		803,785	4.0%	-
3	CARE	7.0		1,040	0.0%	0.0
4	EPIC	1.0		32,883	0.2%	0.0
5	Gym Membership	1.0		5,664	0.0%	0.0
6	Parking	1.0		248,058	1.2%	0.0
7	Union Dues	0.9		276,873	1.4%	0.0
8	United Way	1.0		276,905	1.4%	0.0
9	Medical	1.0		3,607,615	18.2%	0.2
10	Dental	1.0		343,239	1.7%	0.0
11	Vision	1.0		122,083	0.6%	0.0
12	Accident	1.0		81,404	0.4%	0.0
13	Optional Life Insurance	1.0		611,848	3.1%	0.0
14	Flex Dep	1.0		58,880	0.3%	0.0
15	Flex Med	1.0		600,901	3.0%	0.0
16	Total		$	19,856,983	100.0%	2.9
17	Regular Payroll Expense Lead					9.8
18	Total					12.7

Source: C-1B C-1C Summary

EL PASO ELECTRIC COMPANY
CASH WORKING CAPITAL REQUIREMENT - LEAD-LAG STUDY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2020
BENEFITS EXPENSE LEADS

Line No.	Category			Total Expenses	Weighting	Lead Days
	(A)			(B)	(C)	(D)
1	401K Administration	90.0	$	70,949	0.2%	0.2
2	401K Matching	5.3	$	5,233,175	15.1%	0.8
3	Dental - Administration	65.7	$	51,199	0.1%	0.1
4	Dental - Benefits	29.7	$	570,448	1.6%	0.5
5	Insurance (Life/ADD/Disability)	68.0	$	609,097	1.8%	1.2
6	Medical - Administration	74.0	$	1,036,440	3.0%	2.2
7	Medical - Claims	32.4	$	12,641,213	36.4%	11.8
8	Medical - Rx	28.7	$	4,227,505	12.2%	3.5
9	Medical/Rx - Stop Loss	70.9	$	1,683,053	4.8%	3.4
10	OPEB Administration	53.6	$	591,096	1.7%	0.9
11	Parking Benefit	49.4	$	335,223	1.0%	0.5
12	Pension Administration	71.5	$	336,946	1.0%	0.7
13	Pension Funding	19.8	$	7,356,000	21.2%	4.2
14	Total		$	34,742,342	100.0%	30.0

Source: C-1B C-1C Summary

Exhibit DSD-7
Page 3 of 3

EL PASO ELECTRIC COMPANY
CASH WORKING CAPITAL REQUIREMENT - LEAD-LAG STUDY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2020
TAXES OTHER THAN INCOME TAXES

Line No.	Description	Lead Days	Total Expenses
	(A)	(B)	(C)
1	NM Compensating Tax	44.7	$ 11,036,638
2	NM Public Regulation Commission	270.0	874,142
3	New Mexico Property Taxes	230.2	3,463,986
4	Texas Gross Receipts Tax	77.5	9,972,801
5	Texas Franchise Fees	96.8	24,904,055
6	Texas Public Utility Commission Fee	239.5	966,221
7	Texas Property Tax	212.9	16,649,274
8	Arizona Property Taxes	214.7	6,806,622

Source: Work Paper D

Exhibit DSD-8
Page 1 of 1

EL PASO ELECTRIC COMPANY
CASH WORKING CAPITAL REQUIREMENT - LEAD-LAG STUDY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2020
INCOME TAX EXPENSE LEADS

FEDERAL

Line No.	Description	Lead Days	Weighting [1]	Weighted Lag
	(A)	(B)	(C)	(D)
1	1Q 2020	60.0	-44.6%	(26.8)
2	2Q 2020	30.0	74.9%	22.5
3	3Q 2020	30.5	46.6%	14.2
4	4Q 2020	29.5	23.1%	6.8
5	Total		100.0%	16.7

Source: Work Paper E-1

STATE - ARIZONA AND NEW MEXICO

Line No.	Description	Lead Days	Weighting [1]	Weighted Lag
	(A)	(B)	(C)	(D)
6	1Q 2020	60.0	-44.6%	(26.8)
7	2Q 2020	30.0	74.9%	22.5
8	3Q 2020	30.5	46.6%	14.2
9	4Q 2020	29.5	23.1%	6.8
10	Total		100.0%	16.7

Source: Work Paper E-2 and E-3

STATE - TEXAS

Line No.	Description	Lead Days	Weighting [1]	Weighted Lag
	(A)	(B)	(C)	(D)
11	Annual Payment	(47.5)	100.0%	(47.5)
12	Tru-Up Payment	-	0.0%	-
13	Total		100.0%	(47.5)

Source: Work Paper E-4

[1] Weightings are based on the relative weightings of quarterly book income/(losses).

Exhibit DSD-9
Page 1 of 1

DOCKET NO. _____

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

JENNIFER I. BORDEN

FOR

EL PASO ELECTRIC COMPANY

JUNE 2021

EXECUTIVE SUMMARY

Jennifer I. Borden is Director-Regulatory Accounting for El Paso Electric Company ("EPE" or "the Company"). Her responsibilities include the oversight of the scheduling, preparation, and review of jurisdictional regulatory accounting and reporting, including fuel-related filings with the Public Utility Commission of Texas ("PUCT" or "the Commission").

Ms. Borden sponsors the Company's overall cost of service, and describes the pro-forma adjustments that EPE has made to its January 1, 2020 through December 31, 2020 Test Year costs. These adjustments arc to both cost of service (expenses and revenues) and rate base items. Exhibit JIB-2 to her testimony is a list of the pro-forma adjustments that she discusses. She also sponsors and discusses certain of the A (cost of service), B (rate base and return), C (nuclear fuel), G (accounting information), and I (fuel and purchased power) schedules. Ms. Borden also affirms that EPE's rate filing package schedules have been prepared from EPE's books and records, which are maintained as the Commission requires. She also states that the Company is not proposing any post-Test Year adjustments to reflect new plant in service in this filing.

TABLE OF CONTENTS

EXHIBITS

I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jennifer I. Borden. My business address is 100 N. Stanton Street, El Paso, Texas 79901.

Q. HOW ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE" or the "Company") as Director-Regulatory Accounting.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND AND EXPERIENCE.

A. I graduated from The University of Texas at El Paso with a Bachelor of Business Administration in Accounting, with honors. I am a Certified Public Accountant in the State of Texas and a member of the Texas Society of Certified Public Accountants and the American Institute of Certified Public Accountants. I have attended several professional development seminars sponsored by the American Gas Association, Edison Electric Institute, and Nuclear Decommissioning Trust Fund Study Group. In addition, I attended the Advanced Regulatory Studies Program sponsored by the Institute of Public Utilities.

Upon graduation, I was employed by Coopers & Lybrand (currently PricewaterhouseCoopers) in the audit section from 1997 to 1998. From 1998 to 2002, I held various accounting positions at Petro Stopping Centers where my responsibilities included preparation and analysis of internal and external financial statements, preparation of annual 401(k) financial statements, and interpretation and implementation of Generally Accepted Accounting Principles ("GAAP") pronouncements and regulations.

I joined the Company in 2002 and have held various financial, plant and regulatory accounting positions. In March 2021, I accepted my current position of Director-Regulatory Accounting.

Q. WHAT ARE YOUR RESPONSIBILITIES WITH EPE?

A. My responsibilities include the oversight of the scheduling, preparation, and review of jurisdictional regulatory accounting and reporting such as the Company's monthly fuel accounting and reporting and other regulatory filings before the Public Utility Commission of Texas ("PUCT" or "the Commission"), the New Mexico Public Regulation Commission ("NMPRC"), and the Federal Energy Regulatory Commission ("FERC").

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE ANY UTILITY REGULATORY BODIES?

A. Yes, I have previously filed testimony with the PUCT and the NMPRC.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to co-sponsor the Company's overall cost of service. I also sponsor and describe the pro-forma adjustments that EPE has made to its Test Year costs, and I sponsor certain schedules filed as part of this case. The Test Year in this case is the twelve-month period from January 1, 2020, through December 31, 2020.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In Section III, I discuss the Company's overall cost of service. In Section IV, I discuss the schedules required by the PUCT's Electric Utility Rate-Filing Package for Generating Utilities ("RFP") that I sponsor in this case. In Section V, I discuss the pro-forma adjustments made to Test Year expenses, revenues, and rate base that EPE proposes in this case.

III. Overall Cost of Service

Q. WHAT IS THE PROPOSED INCREASE IN REVENUE REQUIREMENTS AND TEXAS BASE RATES?

A. EPE is proposing to increase revenue requirements by $41,097,144 based on a Test Year ended December 31, 2020. EPE is proposing an increase in base rates of $69,688,576 after resetting to zero the existing Transmission Cost Recovery Factor ("TCRF") and Distribution Cost Recovery Factor ("DCRF") riders that are charging customers $27,870,798 annually and reflecting a proposed reduction in miscellaneous service revenues of $720,634. As a result, the net increase in base rate revenues in this application is $41,817,778 or 7.79% over the combined current non-fuel base rate, DCRF, and TCRF revenues. In addition, EPE is proposing to reset its existing Federal tax refund factor ("FTRF") to zero as the reduction in federal income tax rates reflected in the FTRF will now be reflected in base rates. However, as discussed by EPE witness Cynthia S. Prieto, EPE intends to repurpose the FTRF as the tariff to refund to customers over a four-year period amortization of excess accumulated deferred income taxes from the TCJA for the period 2018-2021 that has not been credited to customers.

Q. PLEASE SUMMARIZE THE TOTAL COMPANY BASE RATE REVENUES, COST OF SERVICE, RATE BASE, AND RETURN AMOUNTS THAT EPE IS REQUESTING IN THIS PROCEEDING.

A. The following table, JIB-1, summarizes EPE's revenue requirements and the increase in base rates on a total Company basis and on a Texas jurisdictional basis:

TABLE JIB-1

	Description	Total Company Revenue Requirement	Texas Jurisdictional Revenue Requirement
1	Total Rate Base	$2,611,024,794	$2,043,901,676
2	Cost of Capital	7.985%	7.985%
3	Return on Rate Base	208,496,597	162,210,454
4	Fuel and Purchased Power[1]	199,907,597	147,435,922
5	Operation & Maintenance (O&M)	315,770,140	243,174,207
6	Depreciation & Amortization	131,802,210	102,187,305
7	Taxes other Than Income	76,885,126	68,511,555
8	Federal Income Taxes	30,572,123	23,584,204
9	State Income Taxes	4,505,604	3,528,578
10	Total Revenue Requirement	967,939,397	751,632,225
11	Less: Current Other Operating Revenues[2]	49,828,059	31,816,969
12	Less: Fuel and Purchased Power[1]	203,334,035	146,004,473
13	Adjusted Base Rate Revenue Requirement	714,777,304	573,810,783
14	Annualized Non-Fuel Retail Revenues[3]	660,915,638	532,713,639
15	Revenue Deficiency	53,861,666	41,097,144
16	Plus: Proposed reduction in Misc. Service Revenues	720,634	720,634
17	Plus: TCRF Revenues	7,626,688	7,626,688
18	Plus: DCRF Revenues	20,244,110	20,244,110
19	Total Base Rate Revenue Deficiency	$82,453,098	$69,688,576

[1] Includes amounts from off-system sales of $88,831,799 on a total Company basis, and $65,919,767 on a Texas jurisdictional basis.
[2] Includes revenues from interruptible rates of $4,313,918 on a total Company basis, and $4,147,343 on a Texas jurisdictional basis.
[3] Includes current FTRF revenues and the TCRF and DCRF revenues shown on lines 16 and 17 which will all be moved out of the separate riders and into base rates in this case.

EPE witness Adrian Hernandez discusses the allocation of total Company revenue requirements to the Texas jurisdiction in his testimony.

Q. CAN YOU DESCRIBE THE BASE RATE REVENUE REQUIREMENT IN EPE'S MOST RECENT RATE CASE?

A. Yes. EPE's current base rates were established by the PUCT in Docket No. 46831 (the "2017 Rate Case"), which was a settled case that increased overall base rates by $14.5 million. The settlement agreement in the 2017 Rate Case also provides that EPE's additions to plant from April 1, 2015, through September 30, 2016, were deemed used and useful and prudent and were included in rate base. The Commission adopted the settlement agreement in its Final Order in Docket No. 46831 dated December 18, 2017.

Q. WHAT CIRCUMSTANCES HAVE CREATED THE NEED FOR THIS RATE FILING?

A. EPE witness James Schichtl describes the reasons for this case in his direct testimony. The primary reason is growth in rate base–i.e., the need for EPE to recover a return on and a return of its investment in new plant. As discussed in the testimony of Mr. Schichtl and EPE witness Manuel Carrasco, EPE has reflected rate base additions to transmission and distribution plant in service in its TCRF and DCRF. However, these rate riders have not reflected plant additions to production and general plant or increases in operation and maintenance expenses ("O&M").

IV. Schedules Sponsored

Q. HAS THE COMPANY PREPARED AND INCLUDED IN THIS FILING ALL THE INFORMATION, INCLUDING SCHEDULES, REQUIRED BY THE COMMISSION'S RFP?

A. Yes, it has.

Q. WHAT SCHEDULES FROM THE COMMISSION'S RFP ARE YOU SPONSORING?

A. The schedules I sponsor or co-sponsor are listed in Exhibit JIB-1.

Q. WERE THE SCHEDULES AND EXHIBITS YOU ARE SPONSORING OR CO-SPONSORING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

Q. ARE THE CONTENTS OF THESE SCHEDULES AND EXHIBITS TRUE AND ACCURATE?

A. Yes, they are.

Q. ON WHAT BASIS WERE THE RFP SCHEDULES PREPARED?

A. They were prepared from the books and records of EPE, and they are based on a January 1, 2020, through December 31, 2020, Test Year. They include capital additions from October 1, 2016 through the end of the Test Year.

A. A Schedules (Cost of Service Summary)

Q. WHAT DOES SCHEDULE A ADDRESS?

A. Schedule A, which is co-sponsored by EPE witness Prieto, presents EPE's overall, system-wide cost of service, including such items as O&M expense, depreciation expense, taxes other than income taxes, income taxes, pro-forma adjustments, and return. It also includes fuel and purchased power information for the Test Year. This information is presented on a system-wide (total utility) basis, as EPE serves three jurisdictions (retail in Texas and New Mexico and wholesale under FERC's jurisdiction). This schedule shows that EPE's overall cost of service (including fuel and purchased power) is $967,939,397.

Q WHAT DOES SCHEDULE A-2 ADDRESS?

A. The schedule provides the Company's Test Year cost of service detail by account. I co-sponsor Schedule A-2 with EPE witness Prieto.

Q. WHAT DOES SCHEDULE A-3 (ADJUSTMENTS TO TEST YEAR) ADDRESS?

A. Schedule A-3 provides an explanation of each of the adjustments to EPE's Test Year amounts. Each of these adjustments is discussed in more detail later in my testimony. EPE identified differences between Workpaper ("WP") A-3 and the following individual adjustment workpapers:

1. WP A-3, Adjustment No. 1 in the amount of $54,958;
2. WP A-3, Adjustment No. 13 in the amount of negative $43,648;
3. WP A-3, Adjustment No. 17 in the amount of $5,858; and
4. WP A-3, Adjustment No. 23 in the amount of $28,412.

The effect of these differences resulted in an overstatement of $45,580 in the requested cost of service. Due to timing constraints, EPE will address these adjustments in rebuttal testimony and cost of service.

B. B Schedules (Rate Base and Return)

Q. WHAT DOES SCHEDULE B-1 (TOTAL COMPANY RATE BASE AND RETURN) ADDRESS?

A. Schedule B-1, which EPE witness Prieto co-sponsors, summarizes EPE's total Company rate base and requested rate of return. This schedule also provides the Test Year actual per book amounts (Column b), the adjustments (Column c), and the adjusted rate-base amount (Column d). The adjustments are discussed in more detail later in my testimony.

Q. THE RFP INSTRUCTIONS TO THIS SCHEDULE REQUIRE THE USE OF ORIGINAL COST. ARE THE ITEMS IN SCHEDULE B-1 BASED ON THEIR ORIGINAL COST?

A. Yes, they are, with the exception of Palo Verde Generating Station ("PVGS"), the book value of which is based on the post-bankruptcy fresh start values, which is the method approved in Docket No. 37690 and continued since then, as discussed by EPE witness Larry J. Hancock.

C. Schedules C-6 through C-6.7 (Nuclear Fuel)

Q. WHAT INFORMATION IS IN THE C-6 (NUCLEAR FUEL) SCHEDULES?

A. The C-6 Schedules (extending through Schedule C-6.7), present information about nuclear fuel balances. EPE witnesses David C. Hawkins and Lisa D. Budtke co-sponsor Schedule C-6.8 (Allocation of Unassigned Balance), EPE witness Hawkins sponsors Schedule C-6.9 (Nuclear Fuel Inventory Policy), and EPE witness Budtke sponsors

Schedule C-6.10 (Nuclear Fuel Trust/Lease). As EPE witness Budtke explains, EPE owns an undivided interest in nuclear fuel purchased in connection with PVGS. Arizona Public Service Company ("APS"), as operator of PVGS, manages the nuclear fuel, the nuclear fuel cycle, and various nuclear fuel contracts. The Company finances its interest in nuclear fuel through the Rio Grande Resources Trust ("RGRT"), the financing of which comes from the Company's revolving credit facility and the issuance of senior notes. RGRT owns the nuclear fuel and charges the Company for nuclear fuel as it is consumed. Since RGRT owns the nuclear fuel, the Company records all nuclear fuel in FERC Account 120.6, Nuclear Fuel under Capital Lease. RGRT charges the Company for nuclear fuel as it is consumed, and EPE recovers the cost of nuclear fuel through its fixed fuel factor. As a result, the balance of nuclear fuel in inventory is excluded from rate base in this filing. In addition, as discussed by Ms. Budtke in her testimony, RGRT debt is not reflected in the cost of capital or capital structure of the Company.

Q. WHAT DOES SCHEDULE C-6 (NUCLEAR FUEL) PRESENT?

A. This schedule lists all account balances for FERC Account 120 (120.1 through 120.6) at the end of the Test Year. As previously discussed, since EPE records nuclear fuel under a capital lease, EPE uses only FERC Account 120.6, Nuclear Fuel under Capital Lease, and FERC Account 120.5, Accumulated Provision for Amortization of Nuclear Fuel.

Q. WHAT DO THE OTHER C-6 SCHEDULES YOU SPONSOR PRESENT?

A. A list of the other C-6 schedules that I sponsor are listed below, which are all not applicable due to EPE's financing of nuclear fuel through RGRT as described above:

- C-6.1: Nuclear Fuel in Process,
- C-6.2: Distribution of Costs and Quantities for Account 120.1,
- C-6.3: Distribution of Costs and Quantities for Account 120.2,
- C-6.4: Distribution of Costs for Account 120.3,
- C-6.5: Distribution of Costs for Account 120.4,
- C-6.6: Distribution of Costs for Account 120.5,
- C-6.7: Distribution of Costs for Account 120.6.

D. G Schedules (Accounting Information)

Q. WHAT G SCHEDULES DO YOU SPONSOR?

A. The G Schedules address accounting information. I sponsor or co-sponsor the following G Schedules:

Schedule	Description
Schedule G-4	Summary of Advertising, Contributions & Dues
Schedule G-5.3	Other Exclusions
Schedule G-5.4	Analysis of Prior Rate Case Exclusions
Schedule G-5.5	Comparison of Prior Rate Case Exclusions to Current
Schedule G-11	Deferred Expenses From Prior Docket
Schedule G-12	Below the Line Expenses
Schedule G-13	Nonrecurring or Extraordinary Expenses
Schedule G-14	Regulatory Commission Expenses
Schedule G-14.2	Rate Case Expenses – Prior Rate Applications
Schedule G-15	Monthly O&M Expense

1. Summary of Advertising, Contributions & Dues (G-4 Schedules)

Q. WHAT DOES SCHEDULE G-4 ADDRESS?

A. This schedule summarizes advertising, contributions, and donations expense subject to the 0.3% of revenue limitation required by 16 TAC § 25.231(b)(1)(E). The schedule includes the charged category and the schedule number that details the Test Year expense.

Q. IS EPE SEEKING RECOVERY OF ANY AMOUNTS FOR ADVERTISING EXPENSES AND CONTRIBUTIONS AND DONATIONS IN ITS TEST YEAR COST OF SERVICE?

A. Yes, subject to and consistent with the limitation prescribed by 16 TAC § 25.231(b)(1)(E), EPE is seeking to recover $1,637,980 in advertising costs and $1,260,720 in contributions and donations.

2. Other Exclusions (Schedule G-5.3)

Q. WHAT DOES SCHEDULE G-5.3 CONTAIN?

A. Schedule G-5.3 presents a summary of all Test Year expenditures referred to in 16 TAC § 25.231(b)(2) that are not shown in Schedules G-4.3d, G-4.3e, G-5.1, and G-5.2.

3. Analysis of Prior Rate Case Exclusions (Schedule G-5.4)

Q. WHAT DOES SCHEDULE G-5.4 CONTAIN?

A. Schedule G-5.4 is not applicable since the Company's only rate case within the past five years, Docket No. 46831 was resolved by settlement.

4. Deferred Expenses from Prior Dockets (Schedule G-5.5)

Q. WHAT INFORMATION IS IN SCHEDULE G-5.5?

A. Schedule G-5.5 is not applicable to the Company since its two most recent rate cases were resolved by settlement.

5. Deferred Expenses from Prior Dockets (Schedule G-11)

Q. WHAT INFORMATION IS IN SCHEDULE G-11 (DEFERRED EXPENSES FROM PRIOR DOCKETS)?

A. Schedule G-11 reflects expenses deferred from prior dockets and amortization expense either included in the Test Year or requested in this application. I discuss the amortization of these deferrals later in my testimony.

6. Below-the-Line Expenses (Schedule G-12)

Q. WHAT INFORMATION IS IN SCHEDULE G-12 (BELOW THE LINE EXPENSES)?

A. Schedule G-12 summarizes all expenses charged "below the line" during the Test Year.

7. Nonrecurring or Extraordinary Expenses (Schedule G-13)

Q. WHAT INFORMATION IS IN SCHEDULE G-13 (NONRECURRING OR EXTRAORDINARY EXPENSES)?

A. This schedule requests a complete detailed analysis of all nonrecurring or extraordinary expenses occurring during the test year and included in cost of service. EPE did not have any nonrecurring or extraordinary expenses occurring during the test year and included in cost of service.

8. Regulatory Commission Expense (Schedule G-14)

Q. WHAT INFORMATION IS CONTAINED IN SCHEDULE G-14 (REGULATORY COMMISSION EXPENSE)?

A. Schedule G-14 provides a summary by docket of expenses charged to FERC Account 928 during the Test Year. EPE has removed rate case expenses for Docket Nos. 44941 and 46831, which were being recovered through a separate surcharge. The Test Year costs for this base rate case have been adjusted to represent one fourth of the estimated costs to prepare, file and litigate this case reflecting a proposed four-year amortization period. Please see EPE witness Schichtl's testimony for the Company's proposed recovery of these rate case expenses. These and other adjustments to FERC Account 928 are discussed in more detail later in my testimony.

9. Regulatory Commission Expense (Schedule G-14.2)

Q. WHAT INFORMATION IS IN SCHEDULE G-14.2?

A. Schedule G-14.2 addresses prior rate case expenses related to a previous rate application which was not previously considered by the Commission. As discussed by EPE witness Schichtl, the Company is requesting recovery of the 2017 Rate Case costs incurred after August 31, 2017, per the final order in that case.

10. Monthly O&M Expense (Schedule G-15)

Q. WHAT INFORMATION IS IN SCHEDULE G-15 (MONTHLY O&M EXPENSE)?

A. Schedule G-15 includes EPE's O&M expense for each account in the FERC Uniform System of Accounts, with:

1. expense by month, as booked for the Test Year, and the total;
2. adjustments to the booked amount; and
3. total adjusted O&M expense.

E. The H Schedules (Engineering Information)

Q. WHAT DOES SCHEDULE H-2, SUMMARY OF ADJUSTED TEST YEAR PRODUCTION O&M EXPENSES, ADDRESS?

A. Schedule H-2 provides the information required in Schedule H-1 (Nuclear and Fossil) in the same format for the adjusted Test Year. I co-sponsor this schedule with EPE witnesses Hawkins and J Kyle Olson.

F. The I Schedules (Fuel and Purchased Power Information)

Q. WHAT DO THE I SCHEDULES ADDRESS?

A. The I Schedules contain fuel and purchased power information.

Q. IS EPE SEEKING TO RECONCILE ITS FUEL AND PURCHASED POWER COSTS IN THIS CASE?

A. No, it is not. On September 27, 2019, EPE filed an application in Docket No. 50058 to reconcile its fuel and purchased power costs for the period April 2016 through March 2019. The Commission issued a final order in that reconciliation case on April 7, 2021.

Q. WHAT DOES SCHEDULE I-1.1 ADDRESS?

A. Schedule I-1.1 (Fuel by Account Number) provides fuel expense by account number for each month in the Test Year. All costs in Schedule I-1.1 are considered variable except for Dry Cask Storage costs at PVGS, which are considered semi-variable.

Q. WHAT DOES SCHEDULE I-1.2 ADDRESS?

A. Schedule I-1.2 (Fuel Burned) provides fuel expense by generating station, and by generating unit for PVGS, for each month in the Test Year. For purposes of Schedule I-1.2, gas burned at Newman Power Plant ("Newman"), Rio Grande Power Plant ("Rio Grande"), Montana Power Station ("MPS"), and Copper Power Plant ("Copper") is estimated monthly, and a true-up of the prior month estimate to actual expense is recorded. In any given month, burns may not equal purchases. However, EPE balances current month differences between burns and purchases in succeeding months.

Q. WHAT DOES SCHEDULE I-16 ADDRESS?

A. EPE is not seeking to reconcile its fuel and purchased power costs in this case; therefore, Schedule I-16 is not applicable.

Q. WHAT DOES SCHEDULE I-16.1 ADDRESS?

A. EPE is not seeking to reconcile its fuel and purchased power costs in this case; therefore, Schedule I-16.1 is not applicable.

Q. WHAT DOES SCHEDULE I-16.2 ADDRESS?

A. EPE is not seeking to reconcile its fuel and purchased power costs in this case; therefore, Schedule I-16.2 is not applicable.

Q. WHAT DOES SCHEDULE I-16.3 ADDRESS?

A. EPE is not seeking to reconcile its fuel and purchased power costs in this case; therefore, Schedule I-16.3 is not applicable.

Q. WHAT DOES SCHEDULE I-20 ADDRESS?

A. Schedule I-20 addresses expenses for fuel management travel. The Company did not have any expenses for overnight travel to non-Company facilities during the Test Year.

Q. WHAT DOES SCHEDULE I-22 ADDRESS?

A. EPE is not seeking to reconcile its fuel and purchased power costs in this case; therefore, Schedule I-22 is not applicable.

V. Summary of Pro-Forma Adjustments

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this section of my testimony is to describe the pro-forma adjustments to the cost of service and rate base. The Company is not proposing any post-Test Year adjustments to reflect new plant in service in this filing.

Q. HAVE YOU PREPARED AN EXHIBIT SUMMARIZING THE PRO-FORMA ADJUSTMENTS THAT YOU DISCUSS?

A. Yes, I have. Exhibit JIB-2 is a list of the pro-forma adjustments that I discuss. The adjustments to the cost of service are also shown on Schedule A-3 and associated work papers of EPE's RFP required by Commission rules. Adjustments to rate base are shown on Schedule B-1 and associated workpapers.

A. Adjustments to the Cost of Service

Q. HAVE YOU MADE ADJUSTMENTS TO THE COMPANY'S TEST YEAR COST OF SERVICE?

A. Yes, I have. Several adjustments have been made to the Test Year per book amounts to adjust those values to reflect known and measurable changes.

Q. CAN YOU GENERALLY DESCRIBE THE ADJUSTMENTS INCLUDED IN SCHEDULE A-3?

A. Yes. Generally, the adjustments are revisions to the Test Year revenues, expenses, or rate base items for known and measurable changes at the time of filing. These changes are expected to occur either before or during the time that any final rates will be ordered into effect.

The resulting adjusted revenues, expenses, and rate base are those that, if used as the basis for setting rates for the prospective period following the ordering of final rates in effect, will give the Company a reasonable opportunity to recover its reasonable and necessary expenses and earn a reasonable return on its investment, as is required by the Public Utility Regulatory Act ("PURA") § 36.051.

Q. YOU STATED THAT ADJUSTMENTS WERE MADE FOR KNOWN AND MEASURABLE CHANGES. ON WHAT AUTHORITY DO YOU RELY ON TO MAKE KNOWN AND MEASURABLE CHANGES?

A. I rely on 16 TAC § 25.231(a) and (b), which state:

> (a) Components of the cost of service. Except as provided for in subsection (c)(2) of this section, relating to invested capital; rate base, and §23.23(b) [sic] of this title, (relating to Rate Design), rates are to be based upon an electric utility's cost of rendering service to the public during a historical test year, adjusted for known and measurable changes. The two components of the cost of service are allowable expenses and return on invested capital.
>
> (b) Allowable expenses. Only those expenses which are reasonable and necessary to provide service to the public shall be included

> in allowable expenses. In computing an electric utility's allowable expenses, only the electric utility's historical test year expenses as adjusted for known and measurable changes will be considered, except as provided for in any section of these rules dealing with fuel expenses.

I followed the above criteria to prepare the adjustments included in Schedules A-3 and B-1 for known and measurable changes to historical Test Year data.

Q. HOW DID YOU DETERMINE THE KNOWN AND MEASURABLE CHANGES THAT SHOULD BE TAKEN INTO ACCOUNT IN THIS PROCEEDING?

A. First, EPE made adjustments to per-book data to comply with prior Commission orders or settlements. Then, I reviewed the Company's financial records and determined other adjustments based on my general knowledge of Company operations. Additionally, employees from other departments who have subject matter knowledge about their respective areas provided support for known and measurable changes to Test Year data. These adjustments include insurance premium adjustments and benefit expense adjustments.

Q. IS EPE PROPOSING TO MOVE THE RECOVERY OF THE COSTS OF ANY ITEM FROM BASE RATES TO FUEL?

A. No.

Q. DID THE COMPANY MAKE ANY ADJUSTMENTS FOR KNOWN AND MEASURABLE EXPENSES RELATED TO THE COVID-19 PANDEMIC?

A. Yes. Adjustments No. 7 and Rate Base Adjustment ("RBA") No. 3 removed both costs and reductions to costs related to the COVID-19 pandemic from O&M to set up a regulatory asset in accordance with the Commission's order issued on March 26, 2020, in Project No. 50664, Issues Related to the State of Disaster for the Coronavirus. EPE witness Prieto discusses these adjustments in her testimony. The annual costs proposed to be recovered through a separate rider are included in Workpaper A-3, Adjustment No. 11, and the recovery mechanism is discussed by EPE witness Carrasco.

Q. WHO IS SPONSORING THE ADJUSTMENTS INCLUDED IN SCHEDULE A-3?

A. I am sponsoring the adjustments discussed below, except where otherwise noted.

1. Revenues and Uncollectibles (Adjustment No. 1)

Q. WHAT ADJUSTMENTS WERE MADE TO TEST YEAR REVENUES?

A. Test Year actual revenues are adjusted for known and measurable changes in customers and sales to reflect conditions at the end of the Test Year. EPE witness Carrasco supports the calculation of annualized revenues at current rates presented in the adjustment. EPE witness George Novela supports the weather adjustment to kilowatt-hour ("kWh") sales, and Mr. Carrasco supports the calculation of the revenue adjustment for weather in his testimony. Proposed Revenues are the requested revenue requirement as shown in Schedule A.

Q. HOW IS UNCOLLECTIBLE ACCOUNTS EXPENSE CALCULATED IN ADJUSTMENT NO. 1?

A. During the Test Year, uncollectible accounts expense was adversely impacted by the COVID pandemic. Ms. Prieto discusses the deferral of COVID-related uncollectible accounts expense in her testimony.

The Test Year uncollectible accounts expense rate was determined by dividing uncollectible expense, adjusted for the COVID-related uncollectible expense discussed above, by actual billed Test Year retail revenues. This rate was then applied to the Company's adjusted retail operating revenues to arrive at adjusted uncollectible expense at present rates. Finally, the expense rate is applied to the requested cost of service, including associated revenue-related taxes, to arrive at the adjusted uncollectible expense at requested rates. This results in a decrease of $10,943 to uncollectible expense for adjustments at current rates and an increase of $194,390 at the proposed cost of service.

Q. WERE THE TCRF AND DCRF RIDER REVENUES ADJUSTED OUT OF BASE RATE REVENUES IN CALCULATING THE REVENUE REQUIREMENT IN SCHEDULE A-1?

A. No. As explained in EPE witness Carrasco's testimony, the adjusted base revenues on Schedule A-1 include both TCRF and DCRF adjusted rider revenue. EPE is proposing to reset the DCRF and TCRF riders to zero, in effect moving these revenues from the Commission-approved riders to base rates.

Q. HOW DID YOU DETERMINE WHETHER EPE PREVIOUSLY OVER-RECOVERED ON ITS TCRF?

A. Under Subsection (f) of the TCRF rule, 16 TAC § 25.239, "an over-recovery shall be considered to have occurred if the revenues from the TCRF were greater than the costs that the TCRF was intended to recover." The Commission has interpreted this to mean that an over-recovery is determined by comparing actual revenues collected with the approved revenue requirement on which the TCRF rates were set. Therefore, I took the revenue requirement approved by the Commission in Docket No. 49148, the Company's TCRF filing, and compared that to the actual revenues collected by EPE under the TCRF rider through December 31, 2020, the end of the Test Year.

Q. WHAT WAS THE RESULT OF YOUR ANALYSIS?

As detailed in Exhibit JIB-3, EPE has under-recovered $104,802 through December 31, 2020.

Q. DID YOU MAKE AN ADJUSTMENT TO COST OF SERVICE TO ACCOUNT FOR ANY OVER-RECOVERY UNDER THE COMPANY'S TCRF?

A. No. Since the under-recovery balance is immaterial at the end of the Test Year, EPE proposes to defer any over- or under-recovery adjustment until the Company's next TCRF rider update filing.

Q. DID YOU MAKE AN ADJUSTMENT TO RECONCILE INVESTMENTS RECOVERED THROUGH THE COMPANY'S DCRF?

A. No. Under 16 TAC § 25.243(f), reconciliation of the investments that EPE recovered through its DCRF is unnecessary given the testimony of EPE witness Clay Doyle that the investments complied with PURA, including §§ 36.053 and 36.058, and were prudent, reasonable and necessary.

2. Adjustments to Operation and Maintenance Expenses

Q. WHAT WERE THE ADJUSTMENTS MADE TO TEST YEAR O&M EXPENSES?

A. Several adjustments were made to Test Year O&M expenses in order to provide information on the expected expenses to be incurred when rates are in effect as a result of this proceeding. The purpose of these adjustments is to reflect Test Year actual expenses adjusted for known and measurable changes as described below.

3. Fuel and Purchased Power Expense (Adjustment No. 2)

Q. WHAT WERE THE ADJUSTMENTS TO FUEL EXPENSE?

A. The following adjustments were made to Test Year fuel expense:

1. The Test Year fuel expenses were adjusted to reflect Test Year adjusted kWh sales. The decrease in kWh sales resulting from adjusting the Test Year kWh sales was multiplied by the Test Year average natural gas generation costs. The various adjustments to kWh sales are detailed in EPE witnesses Carrasco's and Novela's testimonies, including adjustments for year-end customer annualization, energy efficiency, normal weather conditions and other known and measurable changes. This resulted in a decrease of $2,653,569 to fuel expense.
2. The Test Year fuel expenses were increased by $105,863 for out-of-period adjustments.

The net adjustment to the Test Year fuel expenses was a decrease of $2,547,706.

Q. WHAT ADJUSTMENT WAS MADE TO PURCHASED POWER EXPENSES?

A. Test Year purchased power expenses were increased by $169,989 to remove an out-of-period adjustment related to New Mexico Voluntary Renewable Energy credits.

4. Salaries and Wages (Adjustment No. 3)

Q. WHAT ADJUSTMENT WAS MADE TO SALARIES AND WAGES FOR EPE EMPLOYEES?

A. This adjustment is to reflect the level of salaries and wages for the Test Year adjusted to reflect known and measurable changes. EPE witness Prieto sponsors this adjustment.

5. Pensions and Benefits (Adjustment No. 4)

Q. WHAT ADJUSTMENT WAS MADE TO PENSIONS AND BENEFITS?

A. EPE witness Prieto sponsors Adjustment No. 4. This adjustment decreases pension and benefits expense by the net amount of $6,782,701 to reflect known and measurable changes.

6. Decommissioning Expense (Adjustment No. 5)

Q. WHAT ADJUSTMENTS WERE MADE TO DECOMMISSIONING EXPENSE?

A. The following adjustments were made to Test Year expenses:

1. Test Year per book PVGS Asset Retirement Obligation ("ARO") accretion expense was removed; and
2. EPE is requesting the ARO accretion expense for local fossil fuel plants.

These adjustments are addressed by EPE witness Hancock.

7. PVGS O&M (Adjustment No. 6)

Q. WHAT IS THE PURPOSE OF THE PVGS O&M ADJUSTMENT?

A. The purpose of this adjustment is the following:

1. To remove the 2019 true-up adjustment for EPE's share of the O&M costs that was recorded in the Test Year. Each year, the owners of PVGS are billed by the operating agent, APS, based, in part, on estimates of certain costs. When actual costs are known, they are compared to the costs billed and the difference is either charged or refunded to the owners as a true-up. The decrease of $1,457,664 is necessary to reflect the actual cost of O&M services billed to EPE by APS to operate the plant during the Test Year.
2. To reflect an increase in Property Insurance and Injuries and Damages costs of $1,234,665 to reflect current premium costs incurred by APS as operating agent.

The net adjustment to PVGS O&M was a decrease of $222,999. EPE witnesses Hawkins and Todd Horton discuss the cost of PVGS operation in their testimonies.

8. COVID-Related O&M Adjustment (Adjustment No. 7)

Q. WHAT ADJUSTMENT WAS MADE TO TEST YEAR O&M FOR COVID-RELATED COSTS?

A. Adjustment No. 7 eliminates Test Year COVID-related O&M costs, net of savings, totaling $3,987,723. EPE witness Prieto discusses this adjustment in her testimony.

9. Outside Services (Adjustment No. 8)

Q. WHAT ADJUSTMENT WAS MADE FOR OUTSIDE SERVICES?

A. The net increase of $30,640 is made to adjust Test Year outside services costs to remove New York Stock Exchange fees and to reflect a net increase for internal and external audit costs based on the Company's 2021 budget. EPE witness Prieto discusses the reasonableness of outside service expenses in her testimony.

10. Property Insurance (Adjustment No. 9)

Q. WHAT ADJUSTMENT WAS MADE TO PROPERTY INSURANCE EXPENSE?

A. The purpose of this adjustment is to increase property insurance costs by $477,475 based on the most recent premiums for each policy.

11. Injuries and Damages (Adjustment No. 10)

Q. WHAT ADJUSTMENT WAS MADE TO INJURIES AND DAMAGES COVERAGE?

A. The purpose of this adjustment is to reflect the cost of various liability insurance and workers' compensation insurance policies based on the most recent premiums for each policy. Because the major component of workers' compensation is allocated to expense and capital based on labor, the Company applied the O&M payroll expense ratio to the gross adjusted workers' compensation costs to arrive at the expense requested. Different policies have different terms, but overall, the costs used in this adjustment reflect annualized premiums at the end of the Test Year. Test Year actual expenses for recurring administrative costs were added to these amounts. The result of this adjustment was a reduction in expenses of $324,935.

This reduction is primarily due to the new Directors and Officers ("D&O") insurance policy EPE obtained after the merger, with reduced coverage because the

Company no longer has public shareholders. This modification to EPE's coverage reduced the cost of the D&O policy to $324,416. The Company has also purchased a "tail" policy to maintain the same terms and conditions and limits of the prior D&O policy for six years, with a total premium of $1,471,565, or a $245,261 annual cost. The Company is not including the cost of the tail policy in the requested cost of service.

12. Regulatory Asset Amortization (Adjustment No. 11)

Q. WHAT ADJUSTMENT WAS MADE FOR REGULATORY ASSET AMORTIZATION?

This adjustment represents the inclusion of $2,781,774 for the amortization of COVID-rclated costs requested for recovery through a rider, as EPE witness Prieto discusses in her testimony.

13. Regulatory Commission Expense (Adjustment No. 12)

Q. WHAT ADJUSTMENT WAS MADE FOR REGULATORY COMMISSION EXPENSES?

A. The decrease of $603,441 in regulatory commission expenses is to adjust the following Test Year costs:

1. Removal of Docket Nos. 44941 and 46831 rate case costs recovered through a separate surcharge;
2. Annualization of costs related to the filing of the 2019 Texas Fuel Reconciliation, Docket No. 50058; and
3. Inclusion of the estimated current rate case expenses and the 2017 Rate Case costs incurred after August 2017 per the final order in that case. EPE witness Schichtl discusses EPE's proposal for the recovery of costs to prepare, file, and litigate this case in his direct testimony.

14. Miscellaneous Generation O&M (Adjustment No. 13)

Q. WHAT IS THE PURPOSE OF THE ADJUSTMENT TO MISCELLANEOUS GENERATION O&M EXPENSE?

A. Adjustment No. 13 removes $48,136 in O&M costs related to Rio Grande Unit 6.

15. Depreciation Expense (Adjustment No. 14)

Q. WHAT ADJUSTMENT WAS MADE TO DEPRECIATION EXPENSE?

A. Adjustment No. 14 presents the adjustment to increase depreciation and amortization expense by an amount of $20,170,465 and is composed of the following items:

- Palo Verde Revaluation,
- Copper Turbine
- New Depreciation Rates,
- Capitalized Incentive Compensation ("CIC"), and
- Other adjustments to depreciable plant.

These adjustments are addressed by EPE witness Hancock.

16. Property Taxes (Adjustment No. 15)

Q. WHAT ADJUSTMENT WAS MADE TO PROPERTY TAXES?

A. This adjustment presents property taxes adjusted to reflect the requested plant balances. EPE witness Sean Ihorn addresses this adjustment in his testimony.

17. Payroll Taxes (Adjustment No. 16)

Q. WHAT ADJUSTMENT WAS MADE TO PAYROLL TAXES FOR THE TEST YEAR?

A. Payroll taxes have been adjusted as described in the testimony of EPE witness Ihorn, who sponsors this adjustment.

18. Revenue-Related Taxes (Adjustment No. 17)

Q. WHAT ADJUSTMENT WAS MADE TO REVENUE RELATED TAXES?

A. This adjustment reflects the change in revenue resulting from the annualization of revenues in Adjustment No. 1 and the change in revenue to reflect the requested revenue requirements. EPE witness Ihorn discusses these taxes in his testimony.

19. State Income Taxes (Adjustment No. 18)

Q. WHAT ADJUSTMENT WAS MADE TO NEW MEXICO AND ARIZONA STATE INCOME TAXES?

A. These adjustments show the change in New Mexico and Arizona state income taxes, respectively. EPE witness Ihorn discusses these taxes in his testimony.

20. Texas State Margin Tax (Adjustment No. 19)

Q. WHAT ADJUSTMENT WAS MADE TO TEXAS STATE MARGIN TAXES?

A. This adjustment reflects the change in Texas state margin taxes. EPE witness Ihorn sponsors this adjustment.

21. Federal Income Taxes (Adjustment No. 20)

Q. WHAT ADJUSTMENT WAS MADE TO FEDERAL INCOME TAXES?

A. This adjustment reflects the change in federal income taxes as a result of the various adjustments made to the requested cost of service and the requested return on rate base. EPE witness Ihorn sponsors this adjustment.

22. Miscellaneous General Expenses (Adjustment No. 21)

Q. WHAT ADJUSTMENT WAS MADE TO MISCELLANEOUS GENERAL EXPENSES?

A. Miscellaneous General Expenses have been reduced by $102,218. This adjustment is addressed by EPE witness Budtke in her testimony and consists of the following:

1. Reduction in the Board of Directors fees to adjust the Test Year costs by $673,429 to reflect annualized costs for the new board; and
2. Inclusion of $571,211 in commitment fees for EPE's revolving credit facility.

23. Interest on Customer Deposits (Adjustment No. 22)

Q. WHAT ADJUSTMENT WAS MADE FOR INTEREST ON CUSTOMER DEPOSITS?

A. In this adjustment of an $82,820 increase, the amount of active deposits as of the end of the Test Year was multiplied by the Commission-approved interest rate in each jurisdiction to determine the amount of interest expense on customer deposits to be included in the cost of service.

24. Advertising Expense (Adjustment No. 23)

Q. WHAT ADJUSTMENT WAS MADE TO ADVERTISING EXPENSE FOR THE TEST YEAR?

A. This adjustment of $184,368 represents a reduction in Test Year costs to only include advertising costs that are allowed per 16 TAC § 25.231(b)(1)(E).

25. Membership Dues (Adjustment No. 24)

Q. WHAT ADJUSTMENT WAS MADE FOR MEMBERSHIP DUES?

A. This adjustment is a net increase of $94,836, which is composed of two parts. One part is a decrease to remove social, political, fraternal, or religious membership dues from the revenue requirement because they are not allowed expenses. The second part is an increase to a remove a refund received during the Test Year for non-recoverable membership dues.

26. Lobbying Expense (Adjustment No. 25)

Q. WHAT ADJUSTMENT WAS MADE TO LOBBYING EXPENSE FOR THE TEST YEAR?

A. This adjustment of $11,680 removes the salary, benefits, payroll taxes, and miscellaneous expenses associated with employees' lobbying activities from the requested cost of service.

27. Recoverable Advertising and Contributions (Adjustment No. 26)

Q. WHAT ADJUSTMENT WAS MADE FOR RECOVERABLE ADVERTISING AND CONTRIBUTIONS EXPENSE?

A. 16 TAC § 25.231(b)(1)(E) provides for the recovery of advertising, contributions, and donations up to an amount that is equal to 0.3% of requested revenues as calculated on Schedule G-4. Test Year advertising, contribution, and donation costs of $2,950,417 are slightly above the allowed amount. Adjusted Test Year advertising expenses of $1,667,980 are already included in the cost of service since they are booked to O&M accounts. Test Year contribution and donation costs of $1,312,437 are recorded in FERC accounts below the line in accordance with FERC's Uniform System of Accounts. The purpose of this adjustment is to move the allowed level of contribution and donation costs of $1,260,720 above the line and include them in the revenue requirement. EPE identified a $5,118 difference in calculating the allowed level of contributions and donations as detailed in Schedule G-4, but did not include the $5,118 additional donations and contributions due to time constraints and the immaterial amount. EPE witness Prieto discusses the reasonableness of advertising, contributions, and donations in her testimony.

B. Adjustments to Rate Base

Q. WHAT ADJUSTMENTS WERE MADE TO RATE BASE INCLUDED IN SCHEDULE B-1?

A. A few adjustments were made to rate base to correctly reflect the investment the Company has made to serve customers in its service territory. I will describe each of the adjustments below.

1. Plant in Service (Rate Base Adjustment No. 1)

Q. WHAT ADJUSTMENTS WERE MADE TO PLANT IN SERVICE IN THIS CASE?

A. Rate Base Adjustment No. 1 is explained by EPE witness Hancock and adjusts plant in service for the following items:

- PVGS Revaluation;
- Copper Gas Turbine;
- Capitalized Incentive Compensation; and
- Other adjustments to plant in service.

2. Accumulated Provision for Depreciation and Amortization (Rate Base Adjustment No. 2)

Q. WHAT ADJUSTMENTS WERE MADE TO ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION?

A. Rate Base Adjustment No. 2 is addressed by EPE witness Hancock and adjusts accumulated provision for depreciation and amortization for the following items:

- PVGS Revaluation;
- Copper Gas Turbine;
- Capitalized Incentive Compensation; and
- FERC Audit Adjustment.

3. Regulatory Assets and Liabilities and Other Additions/Deductions (Rate Base Adjustment No. 3)

Q. WHAT REGULATORY ASSETS AND LIABILITIES ARE INCLUDED IN RATE BASE?

A. Regulatory assets and liabilities included in rate base are limited to:

1. Several regulatory assets and liabilities established pursuant to orders issued by the NMPRC and recovered through rates charged to New Mexico customers;
2. The COVID regulatory asset as discussed in EPE witness Prieto's testimony; and
3. Three-fourths of the estimated current rate case expenses, (EPE witness Schichtl's testimony discusses the proposed recovery of the current rate case costs).

Q. WHAT ADDITIONS AND DEDUCTIONS ARE INCLUDED IN RATE BASE?

A. Miscellaneous deferred debits related to the following items are included in rate base:

1. The unamortized amount of $3,736,073 for the Effluent Agreement that secures a reliable source of cooling water through 2050 for PVGS; and
2. The unamortized amount of $1,017,064 for the ground lease agreement with El Paso Water Utilities for the buffer zone surrounding Newman.

Miscellaneous deferred credits related to the following items are included in rate base:

1. Customer deposits of ($8,321,655); and
2. Customer advances for construction of ($31,754,536).

4. Accumulated Deferred Income Taxes (Rate Base Adjustment No. 4)

Q. WHAT ADJUSTMENTS WERE MADE TO ACCUMULATED DEFERRED INCOME TAXES?

A. Accumulated deferred income taxes have been adjusted as described in the testimony of EPE witnesses Prieto and Ihorn.

5. Tax Regulatory Assets and Liabilities (Rate Base Adjustment No. 5)

Q. WHAT ADJUSTMENTS WERE MADE TO TAX REGULATORY ASSETS AND LIABILITIES?

A. Tax Regulatory Assets and Liabilities have been adjusted as described in the testimony of EPE witnesses Prieto and Ihorn.

6. Non-cash Working Capital (Rate Base Adjustment No. 6)

Q. WHAT ARE THE NON-CASH COMPONENTS OF WORKING CAPITAL?

A. Working capital, excluding the working cash allowance, is made up of 13-month average balances for fuel inventory, materials and supplies, and prepayments.

7. Construction Work In Progress (Rate Base Adjustment No. 7)

Q. WHAT ADJUSTMENT WAS MADE TO CONSTRUCTION WORK IN PROGRESS?

A. Construction Work In Progress has been removed from rate base in this filing. This adjustment is addressed by EPE witness Hancock.

8. Working Cash Allowance (Rate Base Adjustment No. 8)

Q. WHAT WORKING CASH ALLOWANCE IS INCLUDED IN WORKING CAPITAL?

A. The working cash allowance is calculated based on the lead-lag study sponsored by EPE witness Daniel S. Dane.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

SCHEDULES SPONSORED BY J. BORDEN

Schedule	Description	Sponsorship
A	OVERALL COST OF SERVICE	Co-Sponsor
A-2	COST OF SERVICE DETAIL BY ACCOUNT	Co-Sponsor
A-3	ADJUSTMENTS TO TEST YEAR	Sponsor
B-1	RATE BASE AND RETURN – TOTAL COMPANY	Co-Sponsor
C-6	NUCLEAR FUEL	Sponsor
C-6.1	NUCLEAR FUEL IN PROCESS	Sponsor
C-6.2	DISTRIBUTION OF COSTS AND QUANTITIES FOR ACCOUNT 120.1	Sponsor
C-6.3	DISTRIBUTION OF COSTS AND QUANTITIES FOR ACCOUNT 120.2	Sponsor
C-6.4	DISTRIBUTION OF COSTS FOR ACCOUNT 120.3	Sponsor
C-6.5	DISTRIBUTION OF COSTS FOR ACCOUNT 120.4	Sponsor
C-6.6	DISTRIBUTION OF COSTS FOR ACCOUNT 120.5	Sponsor
C-6.7	DISTRIBUTION OF COSTS FOR ACCOUNT 120.6	Sponsor
G-4	SUMMARY OF ADVERTISING, CONTRIBUTIONS & DUES	Co-Sponsor
G-5.3	OTHER EXCLUSIONS	Sponsor
G-5.4	ANALYSIS OF PRIOR RATE CASE EXCLUSIONS	Sponsor
G-5.5	COMPARISON OF PRIOR RATE CASE EXCLUSIONS TO CURRENT	Sponsor
G-11	DEFERRED EXPENSES FROM PRIOR DOCKETS	Sponsor
G-12	BELOW THE LINE EXPENSES	Co-Sponsor
G-13	NONRECURRING OR EXTRAORDINARY EXPENSES	Sponsor
G-14	REGULATORY COMMISSION EXPENSE	Sponsor
G-14.2	RATE CASE EXPENSES - PRIOR RATE APPLICATIONS	Sponsor
G-15	MONTHLY O&M EXPENSE	Co-Sponsor
H-2	SUMMARY OF ADJUSTED TEST YEAR PRODUCTION O&M EXPENSES	Co-Sponsor
I-1.1	FUEL BY ACCOUNT NUMBER	Sponsor

SCHEDULES SPONSORED BY J. BORDEN

I-1.2	FUEL BURNED	Sponsor
I-16	RECONCILABLE FUEL COSTS (NA-fuel rec)	Co-Sponsor
I-16.1	FOSSIL FUEL MIX (BURNED) (NA-fuel rec)	Co-Sponsor
I-16.2	FOSSIL FUEL MIX (PURCHASED) (NA-fuel rec)	Co-Sponsor
I-16.3	COMPETITIVE SPOT FOSSIL FUEL PURCHASES	Co-Sponsor
I-20	FUEL MANAGEMENT TRAVEL	Sponsor
I-22	FUEL COST OVER/UNDER RECOVERY (NA-fuel rec)	Sponsor

LIST OF PRO-FORMA ADJUSTMENTS

Adjustment	Description	Sponsor
	Cost of Service Adjustments	
1	Revenues & Uncollectibles	M. Carrasco / J.Borden
2	Fuel and Purchased Power Expense	J. Borden
3	Salaries & Wages	C. Prieto
4	Pensions & Benefits Expense	C. Prieto
5	Decommissioning Expense	L. Hancock
6	Palo Verde O&M Expense	J. Borden
7	COVID-related O&M	C. Prieto
8	Outside Services	J. Borden
9	Property Insurance Expense	J. Borden
10	Injuries & Damages Expense	J. Borden
11	Regulatory Asset Amortization	J. Borden
12	Regulatory Commission Expense	J. Borden
13	Miscellaneous Generation O&M Expense	J. Borden
14	Depreciation Expense	L. Hancock
15	Property Taxes	S. Ihorn
16	Payroll Taxes	C. Prieto
17	Revenue Related Taxes	S. Ihorn
18	State Income Taxes	S. Ihorn
19	Texas State Margin Tax	S. Ihorn
20	Federal Income Taxes	S. Ihorn
21	Miscellaneous General Expense	J. Borden
22	Interest on Customer Deposits	J. Borden
23	Advertising Expenses	J. Borden
24	Memberships Dues Expense	J. Borden
25	Lobbying Expense	J. Borden
26	Recoverable Adv., Contr., & Donation Expenses	J. Borden
	Rate Base Adjustments	
1	Plant In Service	L. Hancock
2	Accumulated Depreciation	L. Hancock
3	Regulatory Assets and Liabilities and Other Additions/Deductions to Rate Base (Excluding Tax)	J. Borden
4	Accumulated Deferred Income Taxes	S. Ihorn
5	Tax Regulatory Assets and Liabilities	S. Ihorn
6	Non-Cash Working Capital	J. Borden
7	CWIP	L. Hancock
8	Working Cash Allowance	D. Dane

El Paso Electric Company
2021 Texas Rate Case
Reconciliation of TCRF Costs and Revenues (July 30, 2019 - December 2020)

	Total TCRF Costs	Total Compliance Relate Back	TCRF Cost Rider (Revenues)	(Over)/Under Recovery
July Beginning Balance*	$ -		$ -	$ -
August			-	-
September			-	-
October			-	-
November			-	-
December			-	-
January	$ 7,510,407		$ (572,284)	$ 6,938,124
February			$ (529,416)	$ 6,408,708
March**	$ 2,964,943	$ (197,730)	$ (502,842)	$ 8,673,079
April		$ (193,510)	$ (491,224)	$ 7,988,345
May		$ (232,190)	$ (587,302)	$ 7,168,854
June		$ (289,171)	$ (730,027)	$ 6,149,656
July		$ (346,141)	$ (872,085)	$ 4,931,430
August		$ (348,509)	$ (878,237)	$ 3,704,684
September		$ (331,593)	$ (836,356)	$ 2,536,736
October		$ (304,096)	$ (818,680)	$ 1,413,959
November		$ (174,154)	$ (400,685)	$ 839,121
December		$ (207,759)	$ (526,559)	$ 104,802
Total	$ 10,475,350	$ (2,624,853)	$ (7,745,695)	$ 104,802
				-1.00%

*(Initial Order)
**(Start of compliance collection)

DOCKET NO. _____

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

RODERICK W. KNIGHT

OF

TLG SERVICES, LLC.

ON BEHALF OF

EL PASO ELECTRIC COMPANY

JUNE 2021

EXECUTIVE SUMMARY

Mr. Knight's testimony presents the most recent decommissioning cost analysis prepared by TLG Services, LLC. for El Paso Electric Company which provides the estimated costs associated with the shutdown of the three Palo Verde Generating Station Units 1, 2, and 3 in the years 2045, 2046, and 2047, respectively for the DECON (dismantling) scenario. Mr. Knight also provides decommissioning costs associated with several of the supporting facilities on the Palo Verde site, as well as on-site storage of the spent nuclear fuel.

In support of his testimony, Mr. Knight sponsors Exhibit RWK-1 - Resume of Roderick W. Knight and Exhibit RWK-2 - 2019 Decommissioning Cost Study for the Palo Verde Nuclear Generating Station - TLG Document A04-1761-001 Revision 1. Exhibit RWK-2 is also provided in Schedule H-10, sponsored by Mr. Knight.

TABLE OF CONTENTS

EXHIBITS

I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Roderick W. Knight. My business address is TLG Services, LLC., 148 New Milford Road East, Bridgewater, Connecticut 06752.

Q. HOW ARE YOU EMPLOYED?

A. I am employed by TLG Services, LLC. ("TLG"), as Decommissioning Manager. TLG is a wholly owned subsidiary of Entergy Nuclear, Inc. ("ENI").

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of El Paso Electric Company ("EPE" or the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I earned a Bachelor of Science degree in Civil Engineering from the University of New Haven in 1992, graduating Magna Cum Laude. I also earned a Bachelor of Science degree in Natural Resource Management from the University of Maine in 1981. I am a member of Chi Epsilon, an honorary Civil Engineering Society.

Prior to joining TLG Services in August 2016, I started Knight Cost Engineering Services, LLC ("KCES") where I was employed from 2004 until 2016. Prior to KCES I was employed by SCIENTECH, Inc. and by its predecessor NES, Inc. from 1992 until 2004. Prior to NES, Inc., I was an employee of TLG Engineering from 1985 to 1992.

Q. WHAT IS YOUR EXPERIENCE IN NUCLEAR DECOMMISSIONING?

A. I have over 35 years of experience performing cost estimates for the nuclear industry for commercial, government, and research facilities. My expertise includes the analysis of post-shutdown cost reduction methods including the analysis of spent fuel storage options, volume reduction techniques, staffing levels, and schedule optimization. I have also performed numerous prudency reviews of cost estimates developed by others. I have taught classes on how to develop decommissioning cost estimates for the International Atomic Energy Agency ("IAEA") to members from various countries. The IAEA work also includes the development of lesson plans for future workshops. I have also taught a similar class in South Korea.

As the sole proprietor of KCES I was responsible for all aspects of cost engineering including estimating, planning, scheduling, material takeoff, cash flow analysis and litigation support. As an employee of SCIENTECH/NES I served as Project Manager in the preparation of well over 100 decommissioning cost estimates. I also served as one of eleven members on the EM-6 Expert Review Team for the U.S. Department of Energy ("DOE") at Brookhaven National Laboratory. I presented a paper entitled "How Utilities Can Achieve More Accurate Decommissioning Cost Estimates," at the 1999 American Nuclear Society Winter Meeting in Long Beach California. I also developed lesson plans and was an instructor at the SCIENTECH-sponsored Decommissioning Workshop. Prior to this, I was employed by TLG Engineering for seven years, where I was responsible for the management of decommissioning cost estimates from preliminary client contact to preparation of the final report.

I also have extensive international experience including numerous missions with the IAEA. These missions include providing decommissioning cost estimating support in Kazakhstan for the BN-350 Nuclear Power Plant and in Croatia and Slovenia in support of the Krsko Nuclear Power Plant decommissioning plan. I have also worked as part of a SCIENTECH team contracted by PA Government Services ("PA") to assist in developing and promoting a series of reforms for the Armenian energy sector.

In addition to developing decommissioning cost estimates for commercial nuclear power plants, I have developed estimates for a variety of facilities. These estimates were developed for a number of reasons, including proposal support, owner estimates, and project funding. This work includes the development of estimates at several national laboratories, including Los Alamos, Argonne, and Brookhaven. In addition, I have developed estimates for manufacturing facilities and research facilities. Most of these estimates included the remediation of both radiological and hazardous wastes.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY WITH A REGULATORY AGENCY?

A. Yes. I most recently provided direct written testimony in support of the 2016 Decommissioning Cost Study for the Palo Verde Generating Station on behalf of El Paso

Electric for the New Mexico 2020 rate case, New Mexico Public Regulation Commission Case No. 20-00104-UT. I have also provided direct written testimony in support of D. C. Cook Decommissioning Cost Studies on behalf of Indiana Michigan Power Company in 2019, 2016, 2013 and 2007. I have testified in front of the Indiana Utility Regulatory Commission in May 2008 in support of the D. C. Cook Decommissioning Cost Study on behalf of Indiana Michigan Power Company. I provided cost estimates to a confidential client for litigation support in 2005 and 2006. This work included providing my deposition in the winter of 2005 and the fall of 2006. I also provided direct testimony as a material witness in the United States Court of Federal Claims in March of 2004 and was deposed as a witness on behalf of the client in support of the client's claim against the DOE for damages due to failure of the DOE to take receipt of spent nuclear fuel beginning in 1998.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am presenting the results of the 2019 decommissioning cost study prepared by TLG for the Palo Verde Generating Station ("Palo Verde") located in Tonopah, Arizona. My testimony summarizes the results of the update, identifies major changes from the previous estimate, and provides an overview of the decommissioning process.

Q. ARE YOU SPONSORING ANY SCHEDULES OR EXHIBITS IN THIS PROCEEDING?

A. I sponsor Exhibit RWK-2: 2019 Decommissioning Cost Study for the Palo Verde Nuclear Generating Station – TLG Document A04-1761-001 Revision 1. I am also sponsoring my resume, which is attached to my direct testimony as Exhibit RWK-1.

Q. WERE THE SCHEDULE AND EXHIBIT YOU ARE SPONSORING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, I was the project manager for the 2019 study conducted for Palo Verde.

III. Decommissioning Study

Q. PLEASE DESCRIBE THE DECOMMISSIONING STUDY THAT HAS BEEN PERFORMED FOR PALO VERDE GENERATING STATION.

A. TLG prepared a decommissioning cost analysis for Palo Verde under contract to Arizona Public Service Company ("APS"), the operating agent for the Palo Verde owners, in 2019.

The TLG analysis represents a site-specific cost estimate, at a specific point in time (2019), of the removal, packaging, transportation, and disposal of all radioactive material above the U.S. Nuclear Regulatory Commission ("NRC") release limits from the Palo Verde site, using the NRC-approved DECON scenario that is based upon prompt dismantling of the facility. In support of this primary objective, the estimate also includes various additional costs for engineering, project management, site security, and operations during the decommissioning program. In parallel with the decommissioning of the power station, the remaining spent fuel is removed from the three units and placed into dry storage on site. Costs for the final transfer of spent fuel have been included in this estimate.

Following termination of the operating licenses by the NRC, demolition of the physical structures of the site will be performed. Costs for these site restoration activities are included in this estimate. Site restoration activities do not include the electrical switchyard, which is assumed to remain operational in support of the regional grid.

Q. BRIEFLY DESCRIBE PALO VERDE AND EXPLAIN THE COMPANY'S INTEREST IN THE FACILITIES.

A. Palo Verde consists of three identical pressurized water reactors that each generates approximately 1,335 MW electrical power output. The plant is located approximately 50 miles west of Phoenix, in Tonopah, Arizona. The operating licenses were issued in 1984, 1985, and 1987 for Units 1, 2, and 3, respectively. In April 2011, the NRC issued license renewals for all three Palo Verde units, extending their license expiration dates to the years 2045, 2046, and 2047 for Units 1, 2, and 3, respectively. The site has numerous support features, such as a water processing facility, settling ponds, and a dry storage facility for spent nuclear fuel. EPE has a 15.8 percent ownership interest in the Palo Verde station.

Q. ARE THERE ANY FEDERAL REGULATIONS SPECIFICALLY APPLICABLE TO DECOMMISSIONING?

A. Yes. The NRC published the Final Rule entitled "General Requirements for Decommissioning Nuclear Facilities" in the Federal Register of June 27, 1988, (53 Fed. Reg. 24018) to establish technical and financial criteria for decommissioning licensed facilities. The regulations addressed decommissioning planning needs, timing, funding methods, and environmental review requirements with the intent of assuring that decommissioning of all licensed facilities would be accomplished in a safe and timely manner, and that adequate licensee funds would be available for this purpose. In 1996, the NRC published revisions to the Final Rule. The amended regulations clarified ambiguities and codified procedures and terminology as a means of enhancing efficiency and uniformity in the decommissioning process. The amendments allow for greater public participation and better define the transition process from operations to decommissioning. The decommissioning cost analysis prepared for Palo Verde fully satisfies the requirements set forth in the NRC regulations.

In 2011, the NRC published amended regulations to improve decommissioning planning and thereby reduce the likelihood that any current operating facility will become a legacy site. The amended regulations require licensees to conduct their operations to minimize the introduction of residual radioactivity into the site, which includes the site's subsurface soil and groundwater. Licensees also may be required to perform site surveys to determine whether residual radioactivity is present in subsurface areas and to keep records of these surveys with records important for decommissioning. The amended regulations require licensees to report additional details in their decommissioning cost estimate as well as requiring additional financial reporting and assurances. These additional details, including the decommissioning estimate for Independent Spent Fuel Storage Installation ("ISFSI"), are included in this analysis.

Q. WHAT IS THE DECON DECOMMISSIONING ALTERNATIVE AND WHY HAS IT BEEN APPLIED FOR PALO VERDE?

A. The DECON decommissioning alternative is the process under which radioactive material that exceeds the NRC release criteria is removed from the site promptly after shutdown.

This will release the vast majority of the Palo Verde site for other uses in less time than the other NRC-approved decommissioning alternatives. The use of the DECON alternative for Palo Verde enables the use of the existing plant personnel who are already trained and familiar with the plant conditions. Many of the plant systems are all fully functional and able to support the decommissioning process with minimal modifications or repairs. Generally, DECON has been the preferred option for the decommissioning of shutdown units in the United States. APS has selected the DECON alternative for the 2019 study.

IV. Summary of Estimated Costs

Q. PLEASE SUMMARIZE THE DECOMMISSIONING COSTS IDENTIFIED IN YOUR STUDY.

A. Dismantling and demolition of the three power units and all support facilities at Palo Verde is estimated to cost $2,957.6 million in 2019 dollars. A summary of the costs is presented in the following table.

Table RWK-1

Summary of Palo Verde Decommissioning Costs

(Thousands of 2019 Dollars)*

	Total Cost
Unit 1	853,384
Unit 2	835,323
Unit 3	924,279
Independent Spent Fuel Storage Facility	145,994
Stored Steam Generators and Storage Facility	57,074
Water Reclamation Facility	11,027
Water Reclamation Supply System Pipeline & Structures	54,024
Evaporation Ponds	66,009
Make-up Water Reservoir	5,069
Stored Reactor Closure Heads & Storage Facility	5,405
Station Total	2,957,587

*Note: May not add due to rounding; taken from Exhibit RWK-2, Decommissioning Cost Summary, page 10 of 183.