Docket No. 20-035-04

OCS Exhibit No. 5.1S

Compilation of Discovery (Data Request) Responses Referenced in the

Surrebuttal Testimony of Ron Nelson (OCS 5S) on Behalf of

The Office of Consumer Services

November 6, 2020

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OCS Data Request 5.16

Plant Additions – AMI Project. Refer to Exhibit RMP__(SRM-3), page 8.5.35 which includes a description of the "AMI – Utah Meters 2019 – 2020 / AMI-Utah IT Com Network" projects. The description indicates, in part, that the project will deliver considerable operational savings. Please provide the Company's current best estimates of the annual cost savings that will result from this project and indicate when such savings are anticipated to begin. Include all assumptions, work papers and calculations used to derive the projected savings. Additionally, please explain why the anticipated annual level of cost savings were not included as an adjustment in this case.

Response to OCS Data Request 5.16

The Utah AMI project is expected to be completed by the end of 2022. The Company projects annual net operations and maintenance (O&M) savings of approximately $3.8 million, additional revenue of approximately $1.0 million, and capital savings of approximately $0.2 million starting in the year 2023. Please refer to the Attachment OCS 5.16 for cost and savings details.

The Company will begin realizing a portion of the expected benefits in 2022 which is beyond the approved test period for this case and therefore not included.

OCS Data Request 8.21

Reference cost of service Utah GRC 2020 work paper, Inputs tab. Provide a detailed explanation of the data and method used to determine the split between secondary and primary distribution for FERC accounts 364-368. Provide all associated work papers.

Response to OCS Data Request 8.21

Please refer to Attachment OCS 8.21 which shows the calculation of the primary and secondary voltage percentages that are applied to FERC Accounts 364, FERC Account 365, FERC Account 366, and FERC Account 367. These percentages are based upon a 10-year average of material issues from stores.

PacifiCorp 2019 Primary-Secondary Splits for Accounts 364-367
Based Upon Material Issues from Store for 2010 - 2019

%'s	FERC Description	Poles, Towers, Fixtures		Overhead Conductor		Underground Conduit		Underground Conductor	
	FERC Account	364		365		366		367	
State	Voltage Level	Primary	Secondary	Primary	Secondary	Primary	Secondary	Primary	Secondary
CA		98.72%	1.28%	29.61%	70.39%	47.81%	52.19%	58.29%	41.71%
ID		99.99%	0.01%	68.45%	31.55%	56.13%	43.87%	66.48%	33.52%
OR		98.91%	1.09%	54.05%	45.95%	52.80%	47.20%	54.38%	45.62%
UT		99.86%	0.14%	62.96%	37.04%	57.09%	42.91%	71.15%	28.85%
WA		99.74%	0.26%	68.91%	31.09%	50.18%	49.82%	50.03%	49.97%
WY		98.39%	1.61%	79.17%	20.83%	59.06%	40.94%	64.64%	35.36%
Total		99.37%	0.63%	63.98%	36.02%	56.23%	43.77%	66.36%	33.64%

$'s	FERC Description	Poles, Towers, Fixtures		Overhead Conductor		Underground Conduit		Underground Conductor	
	FERC Account	364		365		366		367	
State	Voltage Level	Primary	Secondary	Primary	Secondary	Primary	Secondary	Primary	Secondary
CA		$ 1,013,462.57	$ 13,128.40	$ 98,587.49	$ 234,411.66	$ 32,207.78	$ 35,157.63	$ 610,940.95	$ 437,164.48
ID		$ 3,725,967.13	$ 190.81	$ 678,355.71	$ 312,658.01	$ 126,701.35	$ 99,017.13	$ 4,296,257.59	$ 2,166,458.84
OR		$ 7,259,619.03	$ 79,771.33	$ 2,851,477.14	$ 2,424,245.10	$ 453,125.82	$ 405,021.45	$ 11,687,474.08	$ 9,806,135.71
UT		$ 13,118,063.83	$ 18,846.92	$ 5,543,486.25	$ 3,261,488.09	$ 778,199.17	$ 584,971.15	$ 53,834,752.15	$ 21,826,251.63
WA		$ 2,399,018.18	$ 6,227.36	$ 1,383,179.85	$ 623,907.78	$ 115,692.54	$ 114,885.43	$ 2,482,035.79	$ 2,479,290.23
WY		$ 5,517,696.96	$ 90,251.61	$ 3,049,174.71	$ 802,076.60	$ 781,871.82	$ 541,908.11	$ 6,167,860.28	$ 3,374,018.05
Total		$ 33,033,827.70	$ 208,416.43	$ 13,604,261.15	$ 7,658,787.24	$ 2,287,798.46	$ 1,780,960.88	$ 79,079,320.84	$ 40,089,318.94

DataYear	State	Total$	Pri$	Sec$	Pri%	Sec%	New Code $
2010	CA	$124,890.45	124,323.07	567.38	99.55%	0.45%	$0.00
2011	CA	$131,787.38	130,142.72	1,644.66	98.75%	1.25%	$0.00
2012	CA	$97,158.84	95,557.79	1,601.05	98.35%	1.65%	$0.00
2013	CA	$208,434.20	207,024.86	1,409.34	99.32%	0.68%	$0.00
2014	CA	$110,640.37	108,775.46	1,864.91	98.31%	1.69%	$0.00
2015	CA	$95,118.75	93,719.19	1,399.56	98.53%	1.47%	$0.00
2016	CA	$97,418.94	96,285.26	1,133.68	98.84%	1.16%	$0.00
2017	CA	$86,061.76	84,880.88	1,180.88	98.63%	1.37%	$0.00
2018	CA	$75,080.28	72,753.34	2,326.94	96.90%	3.10%	$0.00
2010	ID	$539,279.36	539,088.55	190.81	99.96%	0.04%	$0.00
2011	ID	$525,405.03	525,405.03	0.00	100.00%	0.00%	$0.00
2012	ID	$397,781.31	397,781.31	0.00	100.00%	0.00%	$0.00
2013	ID	$399,383.99	399,383.99	0.00	100.00%	0.00%	$0.00
2014	ID	$513,776.29	513,776.29	0.00	100.00%	0.00%	$0.00
2015	ID	$430,564.86	430,564.86	0.00	100.00%	0.00%	$0.00
2016	ID	$347,496.32	347,496.32	0.00	100.00%	0.00%	$0.00
2017	ID	$300,534.18	300,534.18	0.00	100.00%	0.00%	$0.00
2018	ID	$271,936.60	271,936.60	0.00	100.00%	0.00%	$0.00
2010	OR	$694,057.53	686,788.37	7,269.16	98.95%	1.05%	$0.00
2011	OR	$767,547.26	756,842.47	10,704.79	98.61%	1.39%	$0.00
2012	OR	$685,964.67	679,494.43	6,470.24	99.06%	0.94%	$0.00
2013	OR	$824,753.18	809,671.31	15,081.87	98.17%	1.83%	$0.00
2014	OR	$827,757.26	819,784.61	7,972.65	99.04%	0.96%	$0.00
2015	OR	$821,423.68	813,868.04	7,555.64	99.08%	0.92%	$0.00
2016	OR	$847,844.42	839,833.78	8,010.64	99.06%	0.94%	$0.00
2017	OR	$893,337.19	886,199.42	7,137.77	99.20%	0.80%	$0.00
2018	OR	$976,705.17	967,136.60	9,568.57	99.02%	0.98%	$0.00
2010	UT	$1,458,078.68	1,454,828.59	3,250.09	99.78%	0.22%	$0.00
2011	UT	$1,974,548.16	1,969,005.45	5,542.71	99.72%	0.28%	$0.00
2012	UT	$1,271,564.12	1,268,634.09	2,930.03	99.77%	0.23%	$0.00
2013	UT	$1,552,419.12	1,551,362.42	1,056.70	99.93%	0.07%	$0.00
2014	UT	$1,385,076.92	1,383,369.16	1,707.76	99.88%	0.12%	$0.00
2015	UT	$1,596,300.64	1,595,285.31	1,015.33	99.94%	0.06%	$0.00
2016	UT	$1,288,710.90	1,287,141.63	1,569.27	99.88%	0.12%	$0.00
2017	UT	$1,256,870.24	1,255,324.01	1,546.23	99.88%	0.12%	$0.00
2018	UT	$1,353,341.97	1,353,113.17	228.80	99.98%	0.02%	$0.00
2010	WA	$247,980.98	242,211.99	5,768.99	97.67%	2.33%	$0.00
2011	WA	$316,485.67	316,027.30	458.37	99.86%	0.14%	$0.00
2012	WA	$236,077.47	236,077.47	0.00	100.00%	0.00%	$0.00
2013	WA	$214,436.02	214,436.02	0.00	100.00%	0.00%	$0.00
2014	WA	$203,828.54	203,828.54	0.00	100.00%	0.00%	$0.00
2015	WA	$361,537.34	361,537.34	0.00	100.00%	0.00%	$0.00
2016	WA	$300,756.43	300,756.43	0.00	100.00%	0.00%	$0.00
2017	WA	$262,718.34	262,718.34	0.00	100.00%	0.00%	$0.00
2018	WA	$261,424.75	261,424.75	0.00	100.00%	0.00%	$0.00
2010	WY	$665,779.14	654,143.09	11,636.05	98.25%	1.75%	$0.00
2011	WY	$728,978.78	714,867.07	14,111.71	98.06%	1.94%	$0.00
2012	WY	$644,024.55	630,163.85	13,860.70	97.85%	2.15%	$0.00
2013	WY	$699,065.29	684,042.38	15,022.91	97.85%	2.15%	$0.00
2014	WY	$703,079.76	692,039.85	11,039.91	98.43%	1.57%	$0.00
2015	WY	$586,881.24	576,863.58	10,017.66	98.29%	1.71%	$0.00
2016	WY	$449,695.27	442,465.43	7,229.84	98.39%	1.61%	$0.00
2017	WY	$505,068.42	501,173.90	3,894.52	99.23%	0.77%	$0.00
2018	WY	$625,376.12	621,937.81	3,438.31	99.45%	0.55%	$0.00
		$37,602,345.20	37,336,599.05	265,746.15			

DataYear	State	Total$	Pri$	Sec$	Pri%	Sec%	New Code $
2010	CA	$43,072.67	9,485.27	33,587.40	22.02%	77.98%	$0.00
2011	CA	$42,365.27	14,652.84	27,712.43	34.59%	65.41%	$0.00
2012	CA	$33,939.05	17,677.16	16,261.89	52.09%	47.91%	$0.00
2013	CA	$54,350.07	28,079.08	26,270.99	51.66%	48.34%	$0.00
2014	CA	$23,870.08	13,585.31	10,284.77	56.91%	43.09%	$0.00
2015	CA	$27,895.83	10,098.23	17,797.60	36.20%	63.80%	$0.00
2016	CA	$28,341.73	5,302.24	23,039.49	18.71%	81.29%	$0.00
2017	CA	$26,050.80	5,966.11	20,084.69	22.90%	77.10%	$0.00
2018	CA	$28,564.87	8,889.36	19,675.51	31.12%	68.88%	$0.00
2019	CA	$24,548.78	-15,148.11	39,696.89	-61.71%	161.71%	$0.00
2010	ID	$110,728.25	68,775.46	41,952.79	62.11%	37.89%	$0.00
2011	ID	$85,238.06	45,938.08	39,299.98	53.89%	46.11%	$0.00
2012	ID	$91,070.97	63,695.33	27,375.64	69.94%	30.06%	$0.00
2013	ID	$52,477.88	19,522.73	32,955.15	37.20%	62.80%	$0.00
2014	ID	$69,776.74	50,407.42	19,369.32	72.24%	27.76%	$0.00
2015	ID	$86,839.37	56,241.54	30,597.83	64.77%	35.23%	$0.00
2016	ID	$121,569.02	94,681.94	26,887.08	77.88%	22.12%	$0.00
2017	ID	$96,849.22	78,254.18	18,595.04	80.80%	19.20%	$0.00
2018	ID	$155,524.52	111,702.23	43,822.29	71.82%	28.18%	$0.00
2019	ID	$120,939.69	89,136.80	31,802.89	73.70%	26.30%	$0.00
2010	OR	$464,099.29	250,113.97	213,985.32	53.89%	46.11%	$0.00
2011	OR	$501,462.30	262,699.05	238,763.25	52.39%	47.61%	$0.00
2012	OR	$405,555.42	175,171.83	230,383.59	43.19%	56.81%	$0.00
2013	OR	$444,798.15	211,320.32	233,477.83	47.51%	52.49%	$0.00
2014	OR	$473,716.63	248,807.48	224,909.15	52.52%	47.48%	$0.00
2015	OR	$560,620.72	283,596.57	277,024.15	50.59%	49.41%	$0.00
2016	OR	$708,425.19	436,311.90	272,113.29	61.59%	38.41%	$0.00
2017	OR	$539,104.23	309,546.21	229,558.02	57.42%	42.58%	$0.00
2018	OR	$537,126.30	297,285.21	239,841.09	55.35%	44.65%	$0.00
2019	OR	$640,814.01	376,624.60	264,189.41	58.77%	41.23%	$0.00
2010	UT	$886,701.20	423,661.50	463,039.70	47.78%	52.22%	$0.00
2011	UT	$1,284,838.41	749,901.29	534,937.12	58.37%	41.63%	$0.00
2012	UT	$542,443.61	286,615.46	255,828.15	52.84%	47.16%	$0.00
2013	UT	$569,275.64	298,176.17	271,099.47	52.38%	47.62%	$0.00
2014	UT	$607,074.31	352,361.60	254,712.71	58.04%	41.96%	$0.00
2015	UT	$1,114,940.34	805,254.85	309,685.49	72.22%	27.78%	$0.00
2016	UT	$915,262.14	651,882.05	263,380.09	71.22%	28.78%	$0.00
2017	UT	$1,063,334.14	759,520.15	303,813.99	71.43%	28.57%	$0.00
2018	UT	$1,014,508.52	710,192.21	304,316.31	70.00%	30.00%	$0.00
2019	UT	$806,596.03	505,920.97	300,675.06	62.72%	37.28%	$0.00
2010	WA	$83,594.24	32,694.59	50,899.65	39.11%	60.89%	$0.00
2011	WA	$152,521.92	87,678.97	64,842.95	57.49%	42.51%	$0.00
2012	WA	$67,018.91	22,394.62	44,624.29	33.42%	66.58%	$0.00
2013	WA	$181,457.41	114,181.44	67,275.97	62.92%	37.08%	$0.00
2014	WA	$275,345.88	222,888.19	52,457.69	80.95%	19.05%	$0.00
2015	WA	$391,274.11	324,125.60	67,148.51	82.84%	17.16%	$0.00
2016	WA	$223,390.33	166,548.53	56,841.80	74.55%	25.45%	$0.00
2017	WA	$182,293.28	133,520.53	48,772.75	73.24%	26.76%	$0.00
2018	WA	$279,232.69	169,228.14	110,004.55	60.60%	39.40%	$0.00
2019	WA	$170,958.86	109,919.24	61,039.62	64.30%	35.70%	$0.00
2010	WY	$391,967.46	300,196.48	91,770.98	76.59%	23.41%	$0.00
2011	WY	$278,149.74	182,032.59	96,117.15	65.44%	34.56%	$0.00
2012	WY	$305,246.11	224,148.62	81,097.49	73.43%	26.57%	$0.00
2013	WY	$366,510.14	270,153.27	96,356.87	73.71%	26.29%	$0.00
2014	WY	$401,400.17	314,770.38	86,629.79	78.42%	21.58%	$0.00
2015	WY	$409,484.86	324,983.68	84,501.18	79.36%	20.64%	$0.00
2016	WY	$204,031.77	147,409.23	56,622.54	72.25%	27.75%	$0.00
2017	WY	$280,089.68	215,186.19	64,903.49	76.83%	23.17%	$0.00
2018	WY	$424,350.42	361,605.43	62,744.99	85.21%	14.79%	$0.00
2019	WY	$790,020.96	708,688.84	81,332.12	89.71%	10.29%	$0.00
		$21,174,798.52	13,356,618.32	7,818,094.72			

DataYear	State	Total$	Pri$	Sec$	Pri%	Sec%	New Code $
2010	CA	$6,364.19	4,015.26	2,348.94	63.09%	36.91%	$0.00
2011	CA	$5,751.71	451.22	5,300.50	7.84%	92.16%	$0.00
2012	CA	$8,310.86	4,436.19	3,874.68	53.38%	46.62%	$0.00
2013	CA	$12,705.56	6,306.42	6,399.15	49.64%	50.36%	$0.00
2014	CA	$8,168.99	4,006.38	4,162.62	49.04%	50.96%	$0.00
2015	CA	$4,611.72	2,304.76	2,306.97	49.98%	50.02%	$0.00
2016	CA	$7,193.58	3,558.18	3,635.40	49.46%	50.54%	$0.00
2017	CA	$930.74	465.37	465.37	50.00%	50.00%	$0.00
2018	CA	$9,995.59	4,997.80	4,997.80	50.00%	50.00%	$0.00
2019	CA	$3,332.46	1,666.23	1,666.23	50.00%	50.00%	$0.00
2010	ID	$41,192.94	34,255.58	6,937.36	83.16%	16.84%	$0.00
2011	ID	$19,700.19	11,004.39	8,695.80	55.86%	44.14%	$0.00
2012	ID	$21,380.25	10,602.94	10,777.32	49.59%	50.41%	$0.00
2013	ID	$26,303.11	13,162.05	13,141.07	50.04%	49.96%	$0.00
2014	ID	$19,522.92	9,660.20	9,862.72	49.48%	50.52%	$0.00
2015	ID	$19,941.48	9,794.53	10,146.96	49.12%	50.88%	$0.00
2016	ID	$17,351.34	8,460.89	8,890.44	48.76%	51.24%	$0.00
2017	ID	$25,486.47	12,593.52	12,892.96	49.41%	50.59%	$0.00
2018	ID	$21,486.80	10,652.56	10,834.24	49.58%	50.42%	$0.00
2019	ID	$13,352.98	6,514.71	6,838.27	48.79%	51.21%	$0.00
2010	OR	$49,262.07	25,174.93	24,087.15	51.10%	48.90%	$0.00
2011	OR	$70,916.67	39,415.52	31,501.15	55.58%	44.42%	$0.00
2012	OR	$74,439.37	37,782.72	36,656.66	50.76%	49.24%	$0.00
2013	OR	$138,267.24	92,863.61	45,403.63	67.16%	32.84%	$0.00
2014	OR	$95,193.56	47,318.51	47,875.05	49.71%	50.29%	$0.00
2015	OR	$71,583.45	34,277.85	37,305.59	47.89%	52.11%	$0.00
2016	OR	$75,004.21	36,770.72	38,233.49	49.02%	50.98%	$0.00
2017	OR	$97,731.47	48,297.49	49,433.98	49.42%	50.58%	$0.00
2018	OR	$104,299.58	51,501.67	52,797.92	49.38%	50.62%	$0.00
2019	OR	$81,449.64	39,722.81	41,726.84	48.77%	51.23%	$0.00
2010	UT	$197,920.73	144,336.84	53,583.89	72.93%	27.07%	$0.00
2011	UT	$227,425.55	178,024.54	49,401.01	78.28%	21.72%	$0.00
2012	UT	$80,639.04	26,990.58	53,648.46	33.47%	66.53%	$0.00
2013	UT	$154,832.44	78,089.73	76,742.71	50.43%	49.57%	$0.00
2014	UT	$108,040.26	54,084.61	53,955.66	50.06%	49.94%	$0.00
2015	UT	$127,770.29	63,733.58	64,036.71	49.88%	50.12%	$0.00
2016	UT	$128,330.09	64,059.10	64,270.99	49.92%	50.08%	$0.00
2017	UT	$117,954.70	58,981.24	58,973.45	50.00%	50.00%	$0.00
2018	UT	$121,541.40	60,692.85	60,848.56	49.94%	50.06%	$0.00
2019	UT	$98,715.81	49,206.10	49,509.71	49.85%	50.15%	$0.00
2010	WA	$19,445.38	10,555.55	8,889.83	54.28%	45.72%	$0.00
2011	WA	$21,945.04	11,560.52	10,384.53	52.68%	47.32%	$0.00
2012	WA	$16,366.82	8,026.79	8,340.03	49.04%	50.96%	$0.00
2013	WA	$32,951.55	16,455.92	16,495.64	49.94%	50.06%	$0.00
2014	WA	$22,134.75	10,728.58	11,406.17	48.47%	51.53%	$0.00
2015	WA	$25,687.14	12,706.23	12,980.91	49.47%	50.53%	$0.00
2016	WA	$24,605.42	12,210.34	12,395.09	49.62%	50.38%	$0.00
2017	WA	$14,548.04	7,143.69	7,404.36	49.10%	50.90%	$0.00
2018	WA	$21,810.09	10,850.30	10,959.80	49.75%	50.25%	$0.00
2019	WA	$31,083.73	15,454.64	15,629.09	49.72%	50.28%	$0.00
2010	WY	$68,882.97	36,255.02	32,627.96	52.63%	47.37%	$0.00
2011	WY	$159,944.30	97,891.55	62,052.76	61.20%	38.80%	$0.00
2012	WY	$112,393.49	54,186.47	58,207.02	48.21%	51.79%	$0.00
2013	WY	$173,642.48	100,343.87	73,298.61	57.79%	42.21%	$0.00
2014	WY	$152,224.94	94,636.67	57,588.27	62.17%	37.83%	$0.00
2015	WY	$99,859.95	55,147.33	44,712.62	55.22%	44.78%	$0.00
2016	WY	$150,793.67	86,702.75	64,090.92	57.50%	42.50%	$0.00
2017	WY	$133,525.39	74,823.97	58,701.42	56.04%	43.96%	$0.00
2018	WY	$153,022.39	109,997.60	43,024.79	71.88%	28.12%	$0.00
2019	WY	$119,490.35	71,886.60	47,603.75	60.16%	39.84%	$0.00
		$4,116,856.64	2,358,125.71	1,758,652.69			

DataYear	State	Total$	Pri$	Sec$	Pri%	Sec%	New Code $
2010	CA	$61,096.95	31,560.11	29,536.84	51.66%	48.34%	$0.00
2011	CA	$183,587.82	136,814.66	46,773.16	74.52%	25.48%	$0.00
2012	CA	$61,612.42	13,540.85	48,071.57	21.98%	78.02%	$0.00
2013	CA	$82,253.54	43,528.29	38,725.25	52.92%	47.08%	$0.00
2014	CA	$69,564.22	53,890.32	15,673.90	77.47%	22.53%	$0.00
2015	CA	$132,615.62	79,454.07	53,161.55	59.91%	40.09%	$0.00
2016	CA	$92,877.68	55,461.92	37,415.76	59.72%	40.28%	$0.00
2017	CA	$102,976.39	58,912.90	44,063.49	57.21%	42.79%	$0.00
2018	CA	$135,055.13	82,468.02	52,587.11	61.06%	38.94%	$0.00
2019	CA	$126,465.66	55,309.81	71,155.85	43.74%	56.26%	$0.00
2010	ID	$407,937.60	267,400.99	140,536.61	65.55%	34.45%	$0.00
2011	ID	$381,493.84	253,320.05	128,173.79	66.40%	33.60%	$0.00
2012	ID	$467,039.30	304,956.04	162,083.26	65.30%	34.70%	$0.00
2013	ID	$554,549.81	376,905.21	177,644.60	67.97%	32.03%	$0.00
2014	ID	$564,253.63	353,005.17	211,248.46	62.56%	37.44%	$0.00
2015	ID	$598,779.65	351,326.75	247,452.90	58.67%	41.33%	$0.00
2016	ID	$597,993.81	360,389.65	237,604.16	60.27%	39.73%	$0.00
2017	ID	$704,575.86	464,752.55	239,823.31	65.96%	34.04%	$0.00
2018	ID	$987,135.10	657,266.24	329,868.86	66.58%	33.42%	$0.00
2019	ID	$1,198,957.83	906,934.94	292,022.89	75.64%	24.36%	$0.00
2010	OR	$1,357,936.01	763,359.60	594,576.41	56.21%	43.79%	$0.00
2011	OR	$1,463,897.97	799,325.71	664,572.26	54.60%	45.40%	$0.00
2012	OR	$1,779,711.30	1,015,314.90	764,396.40	57.05%	42.95%	$0.00
2013	OR	$1,859,923.32	1,117,315.43	742,607.89	60.07%	39.93%	$0.00
2014	OR	$1,636,849.80	730,136.95	906,712.85	44.61%	55.39%	$0.00
2015	OR	$1,978,581.83	1,033,860.00	944,721.83	52.25%	47.75%	$0.00
2016	OR	$2,270,029.36	1,232,366.83	1,037,662.53	54.29%	45.71%	$0.00
2017	OR	$2,880,881.37	1,539,219.93	1,341,661.44	53.43%	46.57%	$0.00
2018	OR	$3,048,168.90	1,618,744.64	1,429,424.26	53.11%	46.89%	$0.00
2019	OR	$3,217,629.93	1,837,830.09	1,379,799.84	57.12%	42.88%	$0.00
2010	UT	$5,391,359.31	4,000,199.56	1,391,159.75	74.20%	25.80%	$0.00
2011	UT	$5,562,927.27	4,086,009.13	1,476,918.14	73.45%	26.55%	$0.00
2012	UT	$5,022,387.93	3,378,597.58	1,643,790.35	67.27%	32.73%	$0.00
2013	UT	$5,231,755.09	3,342,183.82	1,889,571.27	63.88%	36.12%	$0.00
2014	UT	$6,859,010.19	4,629,922.69	2,229,087.50	67.50%	32.50%	$0.00
2015	UT	$6,137,294.05	3,730,039.94	2,407,254.11	60.78%	39.22%	$0.00
2016	UT	$6,923,238.84	4,668,608.10	2,254,630.74	67.43%	32.57%	$0.00
2017	UT	$9,209,149.01	6,650,269.73	2,558,879.28	72.21%	27.79%	$0.00
2018	UT	$13,356,237.51	10,373,481.61	2,982,755.90	77.67%	22.33%	$0.00
2019	UT	$11,967,644.58	8,975,439.99	2,992,204.59	75.00%	25.00%	$0.00
2010	WA	$433,563.35	188,462.76	245,100.59	43.47%	56.53%	$0.00
2011	WA	$367,199.11	148,053.61	219,145.50	40.32%	59.68%	$0.00
2012	WA	$275,284.07	146,926.35	128,357.72	53.37%	46.63%	$0.00
2013	WA	$416,405.51	196,457.20	219,948.31	47.18%	52.82%	$0.00
2014	WA	$490,259.16	266,410.56	223,848.60	54.34%	45.66%	$0.00
2015	WA	$617,996.46	351,616.73	266,379.73	56.90%	43.10%	$0.00
2016	WA	$507,032.43	264,392.17	242,640.26	52.15%	47.85%	$0.00
2017	WA	$406,071.39	171,192.56	234,878.83	42.16%	57.84%	$0.00
2018	WA	$703,677.30	347,405.70	356,271.60	49.37%	50.63%	$0.00
2019	WA	$743,837.24	401,118.15	342,719.09	53.93%	46.07%	$0.00
2010	WY	$883,222.39	543,136.66	340,085.73	61.49%	38.51%	$0.00
2011	WY	$1,160,098.72	787,305.63	372,793.09	67.87%	32.13%	$0.00
2012	WY	$1,059,013.82	622,272.19	436,741.63	58.76%	41.24%	$0.00
2013	WY	$1,060,674.02	667,615.59	393,058.43	62.94%	37.06%	$0.00
2014	WY	$1,261,944.68	828,393.27	433,551.41	65.64%	34.36%	$0.00
2015	WY	$879,475.81	492,133.21	387,342.60	55.96%	44.04%	$0.00
2016	WY	$794,254.44	512,056.99	282,197.45	64.47%	35.53%	$0.00
2017	WY	$717,636.98	511,000.38	206,636.60	71.21%	28.79%	$0.00
2018	WY	$918,180.30	659,110.85	259,069.45	71.78%	28.22%	$0.00
2019	WY	$807,377.17	544,835.51	262,541.66	67.48%	32.52%	$0.00
		$112,098,236.56	73,754,552.73	38,336,404.70			

OCS Data Request 11.1

Plant Additions – AMI Project. Refer to Exhibit RMP__(SRM-3) at pages 223 (Page 8.5.26) and 225 (Page 8.5.28). Also refer to the response to OCS DR 5.16. The attachment provided in response to OCS DR 5.16 shows a total of $77.9M of capital costs for the Utah AMI project, with $27.4M of that amount spent in 2022. Exhibit RMP__(SRM-3) at Pages 8.5.26 and 8.5.28 shows a total of $77M being placed in service for the project during 2020 and 2021 ($31.4M on Page 8.5.26 and $45.6M on Page 8.5.28).

(a) The data response shows capital costs of $17,800,000 in 2017 to 2019. What amount was actually placed into service for the AMI project as of the end of the base year (i.e., December 31, 2019). Please provide the amount by FERC account.

(b) Please explain the discrepancy of the in-service dates between the response to the data request, which shows $27.4M of capital in 2022, and what is reflected Exhibit RMP__(SRM-3), which shows $77M placed into service during 2020 and 2021.

(c) Please provide the amounts actually placed in service, to date, for the Utah AMI project, by month placed into service.

(d) Please provide the current best estimate of the remaining amounts to be placed in service for the project through project completion, by month.

Response to OCS Data Request 11.1

(a) The $17,800,000 from 2017 to 2019 reflects a cash flow basis not plant in service. The in-service amounts are listed in Attachment OCS 11.1.

(b) The Utah Advanced Metering Infrastructure (AMI) project was delayed till the end on 2022 due to cybersecurity concerns, vendor recommended technology changes and COVID-19 pandemic related issues. Current forecasts project $27.4 million in capital expenditures and plant placed in service for 2022. For the Company’s current forecast, please refer to the Company’s response to subpart (d) below.

(c) Please refer to Attachment OCS 11.1

(d) Please refer to Attachment OCS 11.1

OCS Data Request 27.4

Reference Witness Meredith Rebuttal at lines 244-257. Did the Wyoming Public Service Commission explicitly approve or address the sub-functionalization of production and transmission within a rate case order? If yes, please provide the order with line citations to the subject.

Response to OCS Data Request 27.4

Please refer to Attachment OCS 27.4 which provides a copy of the Wyoming Public Service Commission's order in Docket 20000-230-ER-05, which approved a stipulation that specified the unbundling of net power costs. Paragraph 12 on page 33 of the attachment contains the relevant provision of the approved stipulation.

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR APPROVAL OF A GENERAL RATE INCREASE OF APPROXIMATELY $40.2 MILLION PER YEAR FOR RETAIL ELECTRIC UTILITY SERVICE IN WYOMING, AND FOR APPROVAL OF EITHER AN ALTERNATIVE FORM OF REGULATION OR AN UNCONTROLLABLE COST ADJUSTMENT MECHANISM	)))))))))	Docket No. 20000-230-ER-05 (Record No. 10196)

Appearances

For the Applicant, PacifiCorp:
PAUL J. HICKEY and ROGER C. FRANSEN of Hickey & Evans, LLP, Cheyenne, Wyoming.

For the Intervenor, Office of Consumer Advocate (OCA):
CHRISTOPHER B. PETRIE and IVAN H. WILLIAMS, Senior Counsel, Office of Consumer Advocate, Cheyenne, Wyoming.

For the Intervenor, Wyoming Industrial Energy Consumers (WIEC) (an unincorporated association with B.P. America, BreitBurn Energy Company, Chevron U.S.A., Church & Dwight Co., Inc., ConocoPhillips Company, Exxon Mobil Corporation, FMC Corporation, General Chemical Industrial Products, Howell Petroleum Corporation, Marathon Oil Company, Monsanto Company, OCI Wyoming LP, Simplot Phosphates LLC, Sinclair Oil Corporation, and Solvay Chemicals, Inc., as members):
WALTER F. EGGERS, III, of Holland & Hart, Cheyenne, Wyoming; and ROBERT M. POMEROY, JR., and THORVALD A. NELSON of Holland & Hart, Greenwood Village, Colorado.

For the Intervenor, AARP:
THOMAS A. NICHOLAS, III, AND DALE COTTAM of Hirst & Applegate, Cheyenne, Wyoming

For the Intervenors, Kinder Morgan, Inc., Kinder Morgan Interstate Gas Transportation LLC and Canyon Creek Compression Company (collectively, Kinder Morgan):
T. J. CARROLL, III, Vice President and General Counsel, Kinder Morgan, Inc., Lakewood, Colorado.

For the Intervenor, Big Horn Basin Irrigators, an unincorporated group of PacifiCorp irrigation customers (the Irrigators):
RICHARD McKAMEY of Powell, Wyoming, *pro se* for the group.

Pro se Appearance

RICHARD INNES, of Casper, Wyoming.

Heard Before

Chairman STEVE FURTNEY
Deputy Chair KATHLEEN A. "CINDY" LEWIS
Commissioner MARY BYRNES
Chief Counsel STEPHEN G. OXLEY, presiding
pursuant to the order of the Commission

ORDER APPROVING STIPULATION
(Issued March 24, 2006)

This matter is now before the Wyoming Public Service Commission (Commission) on the Application of PacifiCorp (or the Company) for authority to increase its retail electric utility service rates in Wyoming by approximately $40.2 million per year and for approval of an Alternative Form of Regulation (AFOR) or, alternatively, an uncontrollable cost adjustment mechanism (UCAM) (the Application), on the interventions of OCA, WIEC, AARP, the Big Horn Basin Irrigators and Kinder Morgan; on the testimony and exhibits presented at the public hearing in this matter, on the Stipulation and Agreement (Stipulation) filed in this case, and on the testimony of Richard Innes appearing *pro se* herein. The Commission, having heard the testimony and viewed the exhibits in this case, having reviewed the record thereof, the Stipulation and its files concerning PacifiCorp, applicable Wyoming utility law, and being otherwise fully advised in the premises, HEREBY FINDS AND CONCLUDES:

Parties and Procedure

1. On October 14, 2005, PacifiCorp filed the Application; and at the same time filed [i] a Petition for Confidential Treatment seeking confidential treatment of certain of the exhibits sponsored by PacifiCorp witness Mark R. Tallman; and [ii] a Motion for Approval of Confidentiality Agreement, seeking Commission approval of a form of confidentiality agreement to govern generally and efficiently the use of confidential information in this proceeding.

2. On October 14, 2005, the OCA filed its Notice of Intervention in this proceeding under W.S. § 37-2-402(a)(i). It thereupon became a party for all purposes in this proceeding.

3. On October 24, 2005, PacifiCorp filed a Motion for Approval of Procedural Schedule in which it proposed two procedural schedules. The first would provide for an accelerated procedural schedule and early hearing on any stipulation that might be entered into by November 30, 2005, by PacifiCorp and some or all of the other parties. If no such agreement could be reached, an alternative schedule proposed in the motion would provide for a more conventional hearing schedule, culminating in a public hearing in June 2006.

4. By Petition dated October 21, 2005, WIEC moved for leave to intervene in this proceeding as an unincorporated association.

5. On October 26, 2005, WIEC and AARP filed their Joint Objection of Wyoming Industrial Energy Consumers and AARP to PacifiCorp's Motion for Approval of Procedural

Schedule. The movants argued, *inter alia*, that a less than unanimous settlement of the case would not of necessity lessen the number of contested issues or lessen the need for the full development of issues in the generally complicated rate cases filed by PacifiCorp. They argued that PacifiCorp's greatly accelerated schedule denied the due process rights of non-settling parties, especially in light of the MidAmerican Energy Holdings Company purchase of PacifiCorp scheduled to be heard at the same time.

6. On October 26, 2005, the OCA filed its Response in Support of PacifiCorp's Motion for Approval of Procedural Schedule.

7. On October 28, 2005, the Commission issued its Notice of Application. In its Notice, the Commission described generally the Application filed by PacifiCorp in this case and further established November 23, 2005 as the last day for filing motions to intervene and to become a party in this proceeding. Notice of the Application was published once a week for two consecutive weeks in the *Buffalo Bulletin*, the *Casper Star Tribune*, the *Cody Enterprise*, the *Douglas Budget*, the *Uinta County Herald* (Evanston), the *Northern Wyoming Daily News* (Worland), the *Thermopolis Independent Record*, the *Rock Springs Daily Rocket-Miner*, the *Riverton Ranger*, the *Rawlins Daily Times*, the *Pinedale Roundup*, the *Lovell Chronicle*, the *Laramie Daily Boomerang*, the *Kemmerer Gazette*, the *Lander Journal*, the *Green River Star*, and the *Glenrock Independent*. Notice of the Application was also broadcast over a two week period on KBBS (Buffalo), KTWO (Casper), KKTY (Douglas), KODI (Cody), KEVA (Evanston), KOVE (Lander), KMER (Kemmerer), KUWR (Laramie), KRAL (Rawlins), KRKK (Rock Springs), KTHE (Thermopolis), and KWOR (Worland).

8. On October 28, 2005, AARP filed a petition for leave to intervene.

9. On November 1, 2005, Walter F. Eggers, III, counsel for WIEC in this case, filed a Motion for Admission *pro hac vice*, asking that Robert M. Pomeroy, Jr., and Thorvald A. Nelson be admitted to practice before the Commission for all purposes herein.

10. On November 2, 2005, the Commission issued orders granting the intervention petitions of WIEC and AARP. They thereupon became parties for all purposes in this proceeding.

11. On November 2, 2005, the Commission issued its Suspension Order suspending PacifiCorp's filing pursuant to W.S. § 37-3-106(c).

12. On November 3, 2005, the Commission issued its Notice of Motion Argument, setting for November 8, 2005, the argument on PacifiCorp's Motion for Approval of Procedural Schedule, the Office of Consumer Advocate's Response and the Joint Objection of WIEC and AARP. On November 8, 2005, oral arguments on these pleadings were heard by the Commission, with PacifiCorp, WIEC, the Office of Consumer Advocate and AARP appearing through counsel and presenting their arguments.

13. By its November 3, 2005, Order Granting Motion for Admission *Pro hac vice,* the Commission admitted Robert M. Pomeroy, Jr., and Thorvald A. Nelson to practice before the Commission for all purposes in this proceeding.

14. On November 4, 2005, the Commission issued its Order Granting Motion for Approval of Confidentiality Agreement, in which the Commission approved a form of Confidentiality Agreement to facilitate the exchange of confidential information among the parties and the use of that information at hearing and otherwise in this matter.

15. On November 16, 2005, the Irrigators filed their petition to intervene.

16. On November 18, 2005, the Commission issued it Order on Motion for Approval of Procedural Schedule, allowing only in part PacifiCorp's request for a bifurcated schedule under which a stipulation entered into by fewer than all parties and filed by November 30, 2005, would be heard under a greatly accelerated procedural schedule with the public hearing taking place early in 2006. The Commission held that, if a Stipulation among *all* parties to the case were to be filed by the November 30, 2005, deadline, the truncated schedule could be used. If no such Stipulation were filed, the longer and more traditional schedule, including a hearing beginning early in June 2006, would apply. Further, we allowed the parties to bring a Stipulation to the Commission at any time with suggestions for further procedural scheduling of this case. In the order, the Commission made special mention of the procedural due process test of *Laughter v. Board of County Commissioners*, 2005 WY 54, 110 P.3d 892 (Wyo. 2005). In *Laughter*, 2005 WY 54 ¶19, the Court said:

> ". . . this Court held that 'procedural due process is satisfied if a person is afforded adequate notice and an opportunity to be heard at a *meaningful time* and in a *meaningful manner*.'" [Emphasis added.]

At footnote 8 to this statement, the Court drew no distinction between judicial proceedings and contested case proceedings in an administrative context, saying:

> "The parties have not directed this Court's attention to any distinction between the notice and due process requirements of a judicial proceeding or contested case hearing, on the one hand, which were the situations in [cases cited earlier] respectively, and administrative rule-making, on the other hand, which is the situation presently before this Court." [Editorial matter added.]

17. On November 23, 2005, Kinder Morgan moved to intervene in this proceeding.

18. On November 30, 2005, the Commission issued Orders authorizing the intervention of [i] the Irrigators, and [ii] Kinder Morgan. At that time each became a party for all purposes in this case.

19. By its pleading dated December 5, 2005, the Utility Workers Union of America, AFL-CIO (UWUA), filed with the Commission a petition to intervene in this proceeding. This pleading was not served on any party to this case.

20. On December 12, 2005, the UWUA filed the original of its petition to intervene but without evidence of service on any party.

21. On December 19, 2005, PacifiCorp filed in a separate docket, Docket No. 20000-233-EP-05, an application for authority to pass on $16,094,510 in wholesale purchased power costs pursuant to Section 249 of the Commission's Rules (the "Pass-On Case").

22. On December 21, 2006, the UWUA filed another copy of its intervention petition indicating that service had been made on other parties to the case.

23. On January 5, 2006, the UWUA petition to intervene was first considered by the Commission at its regular open meeting of that date. At the request of counsel for the union, the matter was tabled to allow further consultation with the Union.

24. On January 24, 2006, the Commission issued its Notice and Order Setting Consolidated Procedural Conference in this proceeding and the Pass-On Case. The Notice and Order set a procedural conference for January 26, 2006, to address a number of issues regarding the relationship between the cases, including the relationship between power costs in the cases and how a decision in the Pass-On Case might affect the presentation or outcome of the general rate case. The procedural conference was held as noticed and the remaining procedural schedule for the case was settled upon. PacifiCorp told the Commission that the power costs sought to be recovered in this case and in the Pass-On Case were identical. Counsel also represented to the Commission that the parties were working on a Stipulation to settle this case.

25. By a letter of January 25, 2006, the UWUA informed the Commission that it was not represented by counsel (as it had been in previous cases) and that the national union only (and not the Wyoming local union, as in previous cases) sought to intervene here.

26. On January 27, 2006, the Commission issued its Notice and Order Setting Consolidated Hearing to the parties, setting the public hearing for February 9, 2006, and February 2, 2006, as the date by which any stipulation, if reached, should be submitted to the Commission if the February 9, 2006, hearing date were to be preserved.

27. On January 27, 2006, the Commission issued its Notice of Consolidated Public Hearing in this case and the Pass-On Case by which the Commission gave public notice of the February 9, 2006, public hearing and further public notice of the application. The public notice was published once a week for two consecutive weeks in the *Buffalo Bulletin*, the *Casper Star Tribune*, the *Cody Enterprise*, the *Douglas Budget*, the *Uinta County Herald* (Evanston), the *Northern Wyoming Daily News* (Worland), the *Thermopolis Independent Record*, the *Rock Springs Daily Rocket-Miner*, the *Riverton Ranger*, the *Rawlins Daily Times*, the *Pinedale Roundup*, the *Lovell Chronicle*, the *Laramie Daily Boomerang*, the *Kemmerer Gazette*, the *Lander Journal*, the *Green River Star*, and the *Glenrock Independent*. Notice was also broadcast over a two week period on KBBS (Buffalo), KTWO (Casper), KKTY (Douglas), KODI (Cody), KEVA (Evanston), KOVE (Lander), KMER (Kemmerer), KUWR (Laramie), KRAL (Rawlins), KRKK (Rock Springs), KTHE (Thermopolis), and KWOR (Worland).

28. On February 2, 2006, the OCA, AARP, WIEC, the Big Horn Basin Irrigators and PacifiCorp filed the Stipulation resolving, as among themselves, all outstanding issues in this

proceeding. On that day, the Commission posted the entire text of the Stipulation on its web site for the public to review.

29. At its regular open meeting on February 7, 2006, the Commission denied the UWUA petition to intervene. On that day, the Commission mailed and sent by fax transmission a letter to UWUA informing it of that fact and reminding it that it could still attend the hearing and participate "as any other member of the general public." In Commission hearings, members of the public may bring issues before the Commission on the record as sworn testimony. They may bring exhibits and be examined by parties, the Commission and its staff. This decision was formally confirmed in an order on March 9, 2006.

30. Beginning on February 9, 2006, and pursuant to due notice, the Commission held the public hearing in the instant case and the Pass-On Case. PacifiCorp, the Irrigators and the Office of Consumer Advocate presented the testimony of witnesses supporting the Stipulation and describing the Application and analyses supporting this case (and the Pass-On Case) which led them to support the Stipulation. WIEC and AARP presented statements and arguments of counsel describing their analyses of the cases and their reasons for supporting the Stipulation. Neither Kinder Morgan nor the UWUA appeared or participated in the public hearing, and neither filed any document supporting or opposing the Stipulation. Richard Innes testified to his review of this and other PacifiCorp-related cases and how, on balance, he was satisfied with the outcome. At the close of the hearing on February 10, 2006, the Commission conducted deliberations and approved the Stipulation as submitted by the parties, authorized the rate increases and other relief provided for in the Stipulation, and authorized the preparation of orders consistent therewith.

31. On February 22, 2006, the Commission issued its Interim Order Approving Stipulation and Agreement, noting, at ¶5 thereof:

> "At the end of the hearing, the Commission deliberated the case, decided to approve the Stipulation, and directed the preparation of orders consistent therewith. Because of the relatively compressed time schedule on which this case has proceeded, and given the tightly crafted timing relationships of the various parts of the Stipulation, the Commission decided that an interim order should issue, allowing the rates and other provisions of the Stipulation to begin going into effect on March 1, 2006, and thereafter, all as agreed to in the Stipulation. When transcripts are available, the interim order will be followed by a complete final Commission order on the captioned cases."

This interim order allowed the part of the Stipulation providing for a March 1, 2006, general rate increase of $15 million and approving certain other provisions to go into effect.

32. On February 23, 2006, PacifiCorp filed a Motion to Withdraw Application and Dismiss Proceeding in the Pass-On Case; and, on March 9, 2006, the Commission entered its Order Granting Motion to Withdraw Application and Dismiss Proceeding, dismissing the Pass-On Case with prejudice.

33. On February 27, 2006, the Commission accepted and filed the tariff sheets concerning the March 1, 2006, general rate case and other tariff provisions.

The Application

34. On October 14, 2005, PacifiCorp filed the Application and the direct testimony and exhibits of the following witnesses: Judi Johansen, Chief Executive Officer and President of PacifiCorp; Jeffrey K. Larsen, Managing Director of Regulatory Affairs; J. Ted Weston, Regulation Manager; Samuel C. Hadaway, of FINANCO, Inc.; Bruce N. Williams, Treasurer; Barry G. Cunningham, Senior Vice President, Generation; Darrell T. Gerrard, Vice President, Transmission and Distribution Asset and Engineering; Mark T. Widmer, Director, Net Power Costs; Reed C. Davis, Director of Planning; Mark R. Tallman, Managing Director of Commercial and Trading; Erich D. Wilson, Director of Compensation; Daniel J. Rosborough, Director of Employee Benefits; David L. Taylor, Regulatory Manager; David M. Mosier, Wyoming State Regulatory Manager; William R. Griffith, Director of Pricing and Cost of Service; and Carole H. Rockney, Director, Customer and Regulatory Liaison in the Customer Services Department. The filing constituted an entire general rate case with supporting documentation and additional proposals for regulatory innovation.

35. PacifiCorp sought a $40.2 million rate increase in the Application. In addition to this, it also sought to implement a future test year, and, in order of preference, an AFOR, a UCAM or a traditional general rate case using a future test year for the first time in Wyoming. The proposed AFOR would take the place of several future annual litigated rate cases by establishing PacifiCorp's Wyoming revenue requirement on a predetermined formula which includes cost and risk sharing provisions. Failing in this, PacifiCorp sought a UCAM, a simplified commodity balancing account mechanism that includes only wholesale power purchases and sales, wholesale coal purchases from non-affiliated producers and wholesale natural gas purchases and sales. If neither an AFOR nor a UCAM were approved, PacifiCorp sought the rate increase based on a traditional general rate case with bundled rates but using a forecasted test year.

36. PacifiCorp serves in two areas in Wyoming. The first is the "Wyoming East Service Territory" consisting of portions of Albany, Big Horn, Carbon, Converse, Fremont, Hot Springs, Johnson, Natrona, Park, Platte, Sublette, Sweetwater, and Washakie Counties, including, among others, the cities of Buffalo, Casper, Cody, Douglas, Glenrock, Green River, Lander, Laramie, Lovell, Rawlins, Riverton, Rock Springs, Thermopolis, and Worland (Wyoming East, the former Pacific Power & Light Co, service area). The second is the "Wyoming West Service Territory" consisting of portions of Lincoln, Sublette and Uinta Counties, including, among others, the cities of Big Piney, Evanston, Kemmerer, and Pinedale (Wyoming West, the former Utah Power & Light Co. service area). When the two companies merged in 1989, PacifiCorp maintained rate differentials between Wyoming East and Wyoming West. In its Application in this case, PacifiCorp proposed rate changes to achieve final east-west rate parity for residential, general service and large general service schedule customers, constituting a substantial majority of its Wyoming customers. This would substantially finalize the rate parity process directed to be completed by December 31, 2005, in our Order of October 4, 2001, in Docket No. 20000-ER-00-162.

37. The Application also sought a number of housekeeping and other tariff changes discussed more fully below.

Party Positions: PacifiCorp

38. Andrew M. MacRitchie, PacifiCorp's Executive Vice President, testified for PacifiCorp and sponsored the prefiled direct testimony and exhibits of Judi Johansen, Barry Cunningham, Darrell Gerrard, Samuel Hadaway and Bruce Williams. Given the time elapsed since the filing of the Stipulation on February 2, 2006, he presented the Stipulation in detail and testified in support of it, commenting on its need and observing that he expected PacifiCorp to earn a return on equity of less than 6% with current rates -- less than the currently authorized return on equity of 10.75% as well as the 11% percent return asked for in the Application. (Transcript of February 9-10, 2006, public hearing proceedings, hereinafter, Tr., pp. 31-33, 35 and 86-89.)

39. MacRitchie discussed the requested AFOR and UCAM concepts, explaining that they are intended to establish mechanisms for simplified rate adjustments, keeping rates more in line with the cost of service, including increases in net power costs. He noted that the Application included a forecasted test year to support the requested annual increase of approximately $40.2 million. He explained that, after filing the Application, PacifiCorp applied separately for approval of net wholesale purchased power costs amounting to approximately $16.1 million per year in the Pass-On Case. The power costs in the Pass-On Case duplicated the power costs in this case and were not intended to justify an increase in addition to that requested here. He stated that PacifiCorp agreed in ¶6 of the Stipulation to request dismissal of the Pass-On Case upon approval of the Stipulation. (Tr., pp. 37-38 and 42.)

40. MacRitchie testified that the Stipulation was signed by PacifiCorp, the Office of Consumer Advocate, AARP, WIEC and the Irrigators. Kinder Morgan had not signed the Stipulation but had been involved in some settlement discussions and did not oppose the Stipulation. (Tr., pp. 39-40, and 42.)

41. MacRitchie stated that, rather than the $40.2 million per year PacifiCorp sought in the Application, the Stipulation, at ¶7, provides for a rate increase of $25 million to be implemented in stages, $15 million per year effective March 1, 2006, and an additional $10 million effective July 1, 2006. Stipulation ¶8 provides that the $15 million increase will be allocated to all service schedules on the basis of cost of service relationships with certain exceptions explained in ¶23. As is true of the $15 million increase effective March 1, 2006, the $10 million increase is entirely associated with the Application in this docket. Stipulation ¶¶10 and 11 provide that the March 1 and July 1, 2006, revenue increases are cumulative and result in a total increase of $25 million per year. ¶11 clarifies that the whole $25 million increase will be allocated to service schedules using cost of service relationships, subject to the "rate impact mitigation provisions" dealing chiefly with partial requirements Schedules 33 (Partial Requirements Service) and 218 (Partial Requirements Service), as described at ¶23. (Tr., pp. 42-44.; and Stipulation Exhibit 1.)

42. MacRitchie testified that allocating the $25 million revenue increases on a strict cost of service basis would have a disproportionate impact on Schedules 33 and 218 customers on a percentage basis; and the parties agreed the impact should be mitigated. Mitigation is accomplished under ¶23 of the Stipulation by allocating one-half of the Schedule 46 (Large General Service - Time of Use - 1,000 KW and Over) load size charge to the Schedule 33/218 customers and by allocating the remaining one-half of the load size charge to Schedules 25 (General Service) and 206 (General Service) because these Schedule 25/206 customers were receiving a rate increase below the average under a straight cost of service allocation. The parties further agreed that, in PacifiCorp's next general rate case, they would support implementation of the full load size charge for Schedule 33/218 provided, however, that the Load Size Charge shall be supported by cost of service principles. The parties also agreed to initiate a collaborative process among the partial requirements customers and other interested parties to attempt to reach an agreement on an appropriate cost of service methodology for backup facilities and backup demand charges unique to partial requirements customers. As an additional measure to mitigate the effect of the new rates on Schedule 33/218 customers, they have a one-time opportunity to change their contract level of supplemental demand with three months' notice. See ¶24 of the Stipulation. (Tr., pp. 69-72 and 164-165.)

43. ¶12 of the Stipulation provides that, effective July 1, 2006, total net power costs will be unbundled from base rates and would thereafter be recovered through a Power Cost Adjustment Mechanism (PCAM) -- an alternative rate making method allowed by W.S. § 37-2-121. MacRitchie described the PCAM concept as a response to the concerning volatility of power costs that represent 25% to 30% of PacifiCorp's entire cost of service. He testified that PacifiCorp's ability -- or inability -- to recover those power costs in rates significantly impacts earnings and investors' views of PacifiCorp's business risk. MacRitchie explained that the existence of PCAM-type mechanisms are considered favorably by credit rating agencies. In MacRitchie's opinion, a good credit rating is important. He stated:

> "Credit also allows the company to borrow freely, and in a situation of significant investments and volatile costs, our borrowing capability is of great importance to be able to continue to provide energy and services to our customers.
>
> "And also, the company is very active on a daily basis and hourly basis in terms of buying and selling energy to balance its system. We deal with a number of counterparties and these counterparties will only deal with creditworthy counterparties. Therefore, maintaining a good credit rating allows us access to the markets for buying and selling power, which allows us to balance the system and minimize the costs of energy. So credit for all these purposes is hugely important." (Tr., pp. 47-48.)

He concluded that a PCAM would have a positive effect on PacifiCorp's credit ratings and benefit both the Company and its customers. On cross examination, MacRitchie explained that the PCAM addresses the problem of PacifiCorp bearing a disproportionate share of risk because of volatility in power costs which could affect its credit rating and could result in an increased cost of capital. He noted that having a PCAM only in Wyoming would be "helpful" but would not have an immediate effect on PacifiCorp's credit rating. To have the desired effect, PCAMs or something similar needed to be in place in the majority of PacifiCorp states, not just in Wyoming. (Tr., pp. 44-48 and 91-94.) The OCA later confirmed that PacifiCorp is engaged in trying to obtain PCAMs or similar mechanisms in the five other state jurisdictions in which it serves. (Tr., p. 277.)

44. MacRitchie explained the workings of the proposed PCAM. It tracks power costs over a 12-month period and compares them against a baseline net power cost established in a general rate case. The PCAM would make a single annual adjustment to refund or recover costs which differ from the established baseline net power cost with under or over recovery being amortized over the subsequent 12 months. The effective date of the annual adjustments will be April 1 of each year. Annual costs are determined on a 12-month period from December 1 through November 30 and form the basis for an annual PCAM filing on February 1 of each year. (Tr., pp. 50-52.) The Stipulation establishes the initial baseline net power cost at $660 million, which is the baseline amount included in this case as the normalized total net power costs for the 12-month period ending March 2006. MacRitchie observed that the net power costs set out in the Application, but calculated using the proposed future test period ending September 2006, were $745 million. (Tr., p. 53.) Under the Stipulation, the PCAM would start tracking total net power costs as of July 1, 2006, with PacifiCorp's first PCAM Application to be filed on February 1, 2007. Using the $660 million baseline, the Stipulation establishes a prorated baseline cost of $336 million for this first PCAM filing because it uses only a partial base year (July 1, 2006, to November 30, 2006). (Tr., pp. 54-55.)

45. MacRitchie also explained that, as a negotiated incentive for PacifiCorp to delay its next general rate case filing, the parties agreed that, if it files another general rate case on or before February 1, 2007, the baseline would increase to $700 million rather than $660 million. This would reduce the amount PacifiCorp could recover in its PCAM filings. The baseline amount established in the above-captioned case will remain in effect until reset in a future general rate proceeding -- the only time the baseline should be reset. (Tr., pp. 55-57.)

46. MacRitchie testified that all parties will have the opportunity to challenge future PCAM filings and that PacifiCorp will continue to bear the burden of proving that its PCAM application will result in just and reasonable rates and should be approved by the Commission. It undertakes to do so whether or not a challenge is made. (This is the statutory requirement of W.S. § 37-3-106(a).) However, the parties agreed to support the proposed PCAM rates to be effective on April 1, 2007, following the February 1, 2007, filings, regardless of whether the PCAM is challenged. If it is challenged, rates would become effective April 1, 2007, on an interim basis subject to refund with interest at the customer deposit rate established by Section 241 of the Commission's Rules. (Tr., pp. 57-58 and 158-159). The workings of the proposed PCAM, the requested general rate increase and other provisions of the Stipulation are illustrated in the timeline presented in PacifiCorp Ex. 1.

47. Under ¶15 of the Stipulation, the parties agreed that, while PacifiCorp may ask the Commission for changes in the PCAM to be made at an earlier date, rates implemented under a modified PCAM could not become effective prior to April 1, 2009, unless the parties agree that a change is necessary and jointly ask the Commission to approve a change to be reflected in rates before April 1, 2009. This provision affords the parties a degree of certainty as to how total net power cost recovery will occur through at least March 2009. (Tr., p. 59-60.) The Commission notes that this provision does not divest the Commission of jurisdiction to order other rates into effect should the public interest require it prior to that date.

48. MacRitchie explained that, under ¶¶17 and 18 of the Stipulation, the parties agreed to implement a sharing mechanism tracking the costs and risks associated with changes in PacifiCorp's total net power cost. Under this arrangement, PacifiCorp agrees that a change of up to $40 million either up or down from the baseline (the Dead Band) will not be reflected in the annual rate change under the PCAM. For changes in total net power costs greater than $40 million annually, PacifiCorp and its customers share in the costs and benefits of those changes on the sliding scale of Sharing Bands set out in ¶18. Under the Stipulation, interest would apply symmetrically to over and under recoveries. PacifiCorp would pay interest on over recoveries and would be permitted to charge interest on under recoveries. (Tr., pp. 61-66.)

49. MacRitchie noted that ¶21 of the Stipulation provides for a collaborative review of the operation of the PCAM by the parties to determine whether modifications should be made to the current PCAM mechanism. In addition, the parties agreed, under ¶22 of the Stipulation, to initiate a collaborative process to review PacifiCorp's energy risk management strategies and determine which, if any, financial hedging program costs and benefits should be allowed into PCAM applications. (Tr., pp. 67-69.)

50. MacRitchie stated "we will achieve east/west rate parity for the major customer classes, which was first begun in Docket Number 20000-ER-00-162" on implementation of the rate changes provided for in this case. He also said the integrated rate schedules will have common features, drawing the example that Schedule 46 did not previously contain a force majeure clause but that the counterpart large power service Schedule 217 did. Upon merger of the two, both will be subject to such a clause. (Tr., pp. 72-75.)

51. MacRitchie briefly described the non-rate related changes described at ¶27 of the Stipulation. In ¶28 of the Stipulation, PacifiCorp agreed not to make another general rate case application which would result in new rates becoming effective before August 1, 2007. The parties further agreed in ¶29 that, in PacifiCorp's next general rate filing, the parties would support on a one-time trial basis only, the principle of a forecast test year that extends 20 months past the date of actual historic data included in the application. In return, PacifiCorp agreed to provide fully normalized and adjusted historic 12 month results of operations reports for the time period 6 months beyond the date of actual data included in the general rate case as soon as that information is available. According to MacRitchie, PacifiCorp would also make certain fully normalized and adjusted historic results are provided to the Commission and parties on a semi-annual basis when that information becomes available. (Tr., pp. 75-78.)

52. In ¶30 of the Stipulation, the parties agreed to begin a collaborative process to consider whether AFOR concepts may be applicable to PacifiCorp's Wyoming operations. In ¶31, they agreed to begin talks on an evaluation of new and existing demand side management programs for possible application in Wyoming. At ¶32, PacifiCorp agreed to begin a Wyoming-specific load research program for irrigation loads. At ¶33, it agreed to make a one-time contribution of $30,000 from shareholder funds to Energy Share of Wyoming for purposes of providing emergency energy assistance to Wyoming utility customers. This contribution, MacRitchie stated, "is in addition to the approximately $52,000 which PacifiCorp employees and customers contribute every year, including in that a dollar-for-dollar match from the company." (Tr., p. 78-84.)

53. MacRitchie commented on the advantages of the Stipulation, stating the various agreements in the Stipulation serve the public interest; and the proposed PCAM, Dead Band, and Sharing Bands will result in some commodity risks and costs continuing to be borne by PacifiCorp. He observed that the $25 million in new revenue provided in the Stipulation is below the $40.2 million sought in the Application. He said the Stipulation removes the AFOR proposal from immediate consideration and leaves the currently authorized rate of return on equity of 10.75% in place (less than the 11% PacifiCorp requested in its application). He pointed out that Wyoming East/Wyoming West parity has been largely achieved in this case and that, under the Stipulation, rates will be based generally on cost of service principles. MacRitchie stated that the implementation of the PCAM could reduce "somewhat" the frequency of general rate cases. In his opinion, the package of stipulated agreements would result in just and reasonable rates. He further opined that the stipulated revenue increases are fully supported by the Application. (Tr., pp. 84-86 and 90-91.)

54. MacRitchie noted that there is no stipulated return on equity or capital structure in the Stipulation or as an element of the PCAM. That effectively leaves in place the Commission-approved return on equity and capital structure from PacifiCorp's last rate case going forward. (Tr., pp. 105 and 171.) The Commission's Order of February 28, 2004, in Docket No. 20000-ER-03-198, the last general rate case, provided, at ¶34 b5:

> "We conclude that the overall authorized rate of return for PacifiCorp in this case should be 8.415%, determined as follows:

Component	Ratio	Cost	Weighted Cost
Debt	48.66%	6.60%	3.212%
Preferred Stock	6.39%	5.80%	0.371%
Common Equity	44.95%	10.75%	4.832%
TOTAL	100.00%		8.415%

55. MacRitchie stated that the forecast test year in the Application produces an increased revenue requirement of about $40.2 million. With a somewhat more traditional test year ending March of 2006, the revenue requirement in this case would be about $32 million. The $660 million baseline for total net power costs for PCAM purposes is the adjusted total net power cost for the year ending March 2006 as presented in the Application. He stated that the PCAM in the Stipulation is a modification of what is contained in the Application. It is in substance a modification of a portion of the AFOR described in the Application. (Tr., p. 113-115 and 117-118.)

56. Asked whether power costs could dip below the $660 million, MacRitchie found that to be somewhat unlikely, stating:

> "In the theoretical basis, yes, that's correct. Let me just say our power costs are not going down in total. There are clearly fluctuations and that's part of what the PCAM is addressing, the volatility piece in it.
>
> "But the power costs are continuing to rise. We have continuing obligations. We have growth in Wyoming. We have contracts that are coming up for renewal that were placed many years ago when power costs were significantly lower and now need to be replaced at market rates, which are considerably

higher. Our coal production costs are higher than they were and continue to be. Our spot coal price has risen considerably and looks as if it will continue to track other energy costs.

"So you're right. If you're picking out one element of our power costs has stabilized to a point that it was last summer, but, you know, who knows where it's going to go. At the beginning of last year, we had no idea where the power costs were and the gas prices were going.

"I would say generally, power costs are rising and we're continuing to see that." (Tr., p. 119.)

Even though PacifiCorp has long term power sales contracts, it will be renegotiating those also. MacRitchie stated the proportion is far heavier toward purchase contracts and that, on balance, its wholesale contract power costs will be increasing, noting "the contracts that were more favorable to us that have to be replaced at higher price." (Tr., pp. 119-120.)

57. MacRitchie explained that the PCAM will cover net power costs and those costs include all of PacifiCorp's purchases and sales of energy in the market. Net power costs also include wholesale contracts and wheeling and fuel costs, including gas and coal costs and the Company's own coal production costs. The PCAM would not, however, in his opinion, extinguish regulatory lag or go a long way toward resolving it. The more comprehensive AFOR would be more likely to do so because it addresses more than power costs. Forecasted test periods would be another way to address the situation. (Tr., pp. 133 and 141-142.)

58. MacRitchie assured the Commission that the Stipulation, if approved, would be binding upon PacifiCorp regardless of whether or not it was purchased by MidAmerican Energy Holdings Company. (Tr., pp. 176-177.)

59. J. Ted Weston, Revenue Requirement Manager in PacifiCorp's Regulation Department, testified for himself and adopted the prefiled testimony and exhibits of Erich Wilson and Reed C. Davis, and a portion of the prefiled testimony and exhibits of David L. Taylor. (Tr., pp. 290-297.)

60. In preparing the Application, Weston consulted with his staff and with business controllers of each of PacifiCorp's business units to identify changes in employee wages, pension and benefit costs, tree trimming and pole treatment cycles, and other known and measurable changes to be normalized into the Application. Prior to filing the Application, Weston also met with representatives of the OCA on several occasions to assist OCA in becoming familiar with the rate filing. PacifiCorp gave all parties copies of the data contained in Weston's Exhibit 2, supporting a $34 million increase based on an historical test year ending March 2005, updated for "known and measurable adjustments out through March 2006". Weston met in Portland, Oregon, with Denise Parrish of the OCA and David Peterson, a WIEC consultant, to review PacifiCorp's books and records and to assist with discovery in this case. (Tr., pp. 299-301.)

61. Weston identified a number of operating changes that have occurred since the last rate filing which was based on an historical test year ending September 2002, updated with known and measurable changes to September 2003. Weston stated that the Company made significant new plant investments thereafter, stating that, by September 2006, PacifiCorp will have invested over $3 billion in infrastructure, of which $300 million will have been invested in

Wyoming. He stated that over $150 million of capital investment has been made in the four major power plants in Wyoming, Jim Bridger, Dave Johnston, Naughton, and Wyodak. In addition, $59 million was invested in its transmission system since the last general rate case. An additional $45 million was invested in the distribution system in Wyoming. PacifiCorp has also invested an additional $33 million to convert its Jim Bridger mine from an open pit to an underground long-wall mining operation. He detailed an additional $12 million invested in such items as communication equipment, vehicles and other general operations needs. As a result, Wyoming depreciation expense has increased by $8 million annually. (Tr., pp. 301-303.)

62. He stated that, since the last rate filing, PacifiCorp has averaged over $59 million in contributions to its pension plan and an additional amount of post-retirement benefits amounting to $34 million. These items account for a $9 million annual increase in the Wyoming cost of service. Finally, medical costs have increased by over $14 million, with about $2 million being attributable to Wyoming. (Tr., pp. 303-304.)

63. Overall, new plant investment and depreciation expense account for $21.6 million of the $40.2 million increase requested in this case. Wyoming's share of PacifiCorp's increased net power costs since the last rate case, net of the rate relief obtained in PacifiCorp's last pass-on filing, is about $20 million. Increases in salaries account for approximately $8.5 million in increased costs; and the increase in the Company's equity ratio to 50.8% and the requested increase in the return on equity from 10.75% to 11%, taken together, result in a $6 million share of the initially requested revenue increase. (PacifiCorp Ex. 8, p. 3.)

64. The increases in costs since the last Wyoming general rate are partly offset by some cost reductions. Application of the MSP (Multi-State Process) Revised Protocol interjurisdictional allocation methodology (the Revised Protocol) has benefited Wyoming in the amount of $6.2 million. Because of comparatively higher growth levels in other jurisdictional states, costs allocated to Wyoming have been decreased by about $13 million. Nevertheless, in Weston's opinion, the net effect is shown in the Application and accompanying testimony and exhibits to be a revenue shortfall of $40.2 million. (Tr., pp. 306-307.)

65. Weston testified that, under these circumstances, the $25 million rate increase provided in the Stipulation is in the public interest and should be approved by the Commission. Weston explained that, given PacifiCorp's current level of earnings (a 5.9% return on equity), the $25 million revenue increase would bring earnings up by approximately 300 basis points, resulting in a return on equity of approximately 9%. (Tr., p. 308.)

66. Mark T. Widmer, Director of Net Power Costs in the Commercial and Trading Department, testified on behalf of PacifiCorp. Widmer adopted the prefiled testimony of Mark Tallman. (Tr., pp. 322-325.) He explained in detail the operation of the PCAM tariff, describing how monthly adjusted actual net power costs are determined by summing a number of specific FERC account entries. (Tr., p. 326.)

67. Widmer noted that a number of adjustments are made in calculating monthly actual net power costs. First, prior period accounting adjustments are removed so costs outside of the appropriate comparison period are not included. Second, actual costs are adjusted to be

consistent with costs modeled in PacifiCorp's GRID model. Third, Commission ordered cost disallowances are factored in. Then a revenue variation adjustment is made to true-up the net power cost baseline for the actual level of revenues collected relative to the net power cost base. He explained that Wyoming's allocated share of total net power cost is then calculated using the Revised Protocol. The Wyoming embedded cost differential (ECD) base is the sum of the ECD adjustments included in PacifiCorp's last general rate case. The Wyoming adjusted actual ECD is a recalculation of the Wyoming ECD base for the comparison period adjusted only for the accounts that are included in the adjusted actual net power costs. Widmer explained:

> "The ECD adjustment is the calculation we will go through at the end of each comparison period cycle to determine if there has been an incremental change from the ECD adjustment that's already included in base rates, and that total, if one is calculated for the ECD, gets added to the monthly deferral balance calculation to equal the total deferred calculation balance." (Tr., p. 330.)

Stating that "The deferred formula is the formula that we will use on a monthly basis to measure whether or not there is a deferral accrual each month," Widmer explained that the deferred net power cost adjustment is a monthly adjustment equal to adjusted actual net power costs minus the base net power cost, applying a revenue variation adjustment, plus or minus the total-company Dead Band times the customer sharing proportion, times the Wyoming allocated share. Symmetrical interest would be applied to the overall deferred balance once the monthly deferred net power cost adjustment is determined. Not all of these calculations would be completed every month if PacifiCorp's total net power costs remain within the $40 million Dead Band. Widmer also explained that, at the end of the comparison period, if there is a balance in the deferred net power cost (NPC) account, they would also perform an ECD adjustment. The ECD adjustment is equal to the actual adjusted ECD amount minus the ECD base adjusted for the revenue variation adjustment. (Tr., pp. 326-331.) Widmer undertook, on behalf of PacifiCorp to educate the Commission staff in the use of the GRID model so that the workings of PacifiCorp's net power costs, for which the GRID model is of great importance, can be better understood by the Commission in the future. (Tr., pp. 360-361.)

68. Widmer stated that Commission approval of the proposed PCAM is not being requested under Commission Rules 249 and 250 but under W.S. § 37-2-121 as a non-traditional rate making method. Widmer stated his opinion that one of the reasons the PCAM mechanism is in the public interest is because it will help PacifiCorp to remain financially healthy and because it creates a sharing of risk. Through the PCAM mechanism, as proposed, he stated, the parties and the Commission would have the same rights and abilities to review the information included in PCAM filings as they would in any other proceeding before the Commission. Widmer noted that the proposed PCAM does not include a forecast of net power costs for a future year but rather will utilize measurements of net power costs incurred on an historic basis. (Tr., pp. 331-332.)

69. Widmer stated the net power costs included in the case have been thoroughly reviewed by the parties and that the OCA has carefully reviewed PacifiCorp's power costs and the major drivers of those costs. In addition, Widmer noted, net power costs are determined on a total-company basis. As such, the components of those costs are also extensively reviewed in all of the other states in which PacifiCorp provides service. (Tr., pp. 335-336.)

70. Widmer pointed out that the proposed PCAM includes a sharing mechanism through the implementation of the Dead Band and Sharing Bands. The PCAM therefore does not provide a direct pass through of costs, which would place all of the risk of increases of net power costs on customers. Rather, as proposed, the PCAM provides a sharing of risk between PacifiCorp and its customers. (Tr., pp. 340-341.)

71. Widmer offered that the Company would be willing to provide the Commission with periodic reports showing the monthly deferred balance calculations and to track various PCAM components. (Tr., pp. 342-343.)

72. Widmer agreed, from a credit rating point of view, a utility that does not have a mechanism to track its purchased power costs is at greater risk of a credit downgrade than one that does. He noted the financial sector view expressed by Standard & Poor's: "Because about 21 percent of PacifiCorp's power in 2003 came from purchases, the lack of an FPPA is a credit concern." Both Fitch and Standard & Poor's expressed concern. (Tr., pp. 379-380 and exhibits cited there; FPPA is an S&P acronym for "fuel and purchased-power adjustment mechanism".)

73. William R. Griffith, PacifiCorp's Director of Pricing and Cost of Service, with responsibilities for retail rate design and implementation, testified and adopted a portion of the pre-filed direct testimony of David L. Taylor and the pre-filed testimony and exhibits of Carole H. Rockney. (Tr., pp. 381-384.)

74. Griffith explained the rate mitigation provisions in ¶23 of the Stipulation. They are designed to lessen the impact of the agreed rate increases on Schedule 33 customers by assigning a small proportion of cost responsibility to Schedule 25. Griffith noted, after including the rate mitigation provisions, Schedule 33 customers will experience a rate increase of about 10.88% which is significantly above the 6.84% average increase experienced across all customer classes. At the same time, Schedule 25 customers, even given the rate mitigation increase, will experience an increase of only 4.4%, the least of any major customer class. In Griffin's opinion, the rate mitigation process outlined in ¶23 is fair and does not detract from the Stipulation's overall fairness. (Tr., pp. .391-394.)

75. Griffith described the non rate-related changes to PacifiCorp's rules and regulations addressed in ¶27 of the Stipulation. First, there are a number of housekeeping amendments to the rules which are not substantive and are made only to improve clarity and readability. Second, the charge for service disconnection and reconnection visits would be increased from $15 to $20, bringing the charge in line with the cost of the visits. Third, the line extension allowance for transmission level service would be eliminated. Fourth, the Company will implement a new charge for meter verification at multiple meter locations such as multiple family dwellings and apartment houses. (Tr., pp. 398-400.)

76. Griffith explained PacifiCorp's undertakings to assist the Irrigators, found at ¶32 of the Stipulation:

> "Traditionally, the company has used long established load research information from our Idaho irrigation loads. Idaho is our largest -- has the largest irrigation load on our system. We've used the load research information from Idaho in our cost-of-service studies for Wyoming irrigators.

"What happens here is that these Wyoming peak loads are then weighted by the actual Wyoming irrigation consumption in order to develop load factors for the Wyoming irrigators. The question is do Wyoming irrigators have the same timing relationship to the company's system peak as Idaho irrigators do, and to answer this question and to answer the concerns of our Wyoming irrigation customers, we agree that not later than July 1, 2006, we'll implement a collaborative with Wyoming irrigators for a statewide load research program that would give Wyoming irrigation its own load research program rather than using the modeling or the load shapes from Idaho.

* * *

"So if we include the effect of the current proposed price change, these Wyoming west irrigation rates -- customers' rates will remain about 4 percent lower than they were in March of 2004 and about 20 percent lower than they were in March of 2003.

"And I think this helps somewhat to point out the kind of inconsistent nature and the variability in irrigation loads and how that can be reflected in cost-of-service results. And so through the stipulation, the parties have agreed that due to this inconsistent nature of irrigation and of weather and irrigation characteristics, the time and cost to install metering, to collect load research and to evaluate load research results, it may take several years to understand and complete a Wyoming load research program, because we do see a lot of variability in irrigation loads from year to year.

"We will make reasonable attempts to install data-gathering metering for the 2007 irrigation season, and once this data is available that represents the long- term average irrigation loads in Wyoming, we will utilize the Wyoming-specific irrigation load data in our cost-of-service studies in future general rate cases."

"We also agree we will continue to monitor the effectiveness of the alternative rate design that was approved by this Commission last spring at the beginning of the 2005 irrigation season." (Tr., pp. 400-402.)

77. Griffith stated his opinion that the stipulated rate increases have several positive aspects: [i] rate parity will be achieved throughout all major customer classes; [ii] as of July 1, 2006, net power cost rates will be unbundled from base rates; [iii] the rates will observe cost of service principles; and [iv] the rate mitigation proposal for Schedule 33 customers will serve to spread price increases fairly while still reflecting the different costs of serving different customers. Griffith testified that rates under the Stipulation are very close to cost of service for all customer classes, ranging "between 98 and 102 percent of cost of service by the various class[es]". (Tr., pp. 402-405.)

78. Jeffrey K. Larsen, PacifiCorp's Managing Director of Regulatory Affairs, testified and adopted the pre-filed testimony of David M. Mosier. Larsen testified about the impact of changes in net power costs under the PCAM on the Company's earnings. He stated that, because of the nature of the Sharing Bands in the PCAM mechanism, even very large changes in total net power cost would not result in over earning. Because PacifiCorp would absorb a portion of any power cost under recovery, an increase in net power cost over the baseline amount results in a decrease in PacifiCorp's overall earnings and return on equity. However, even with a $600 million increase over the baseline net power cost, earnings would be reduced by about 200 basis points from 9.1% to about 7%. Likewise, in the event that power costs decrease, even if total net power costs were to decrease by as much as $600 million, earnings (viewed against return on equity) would increase by only about 200 basis points from 9.1% to about 11% -- the return on

equity sought in the Application. Such a large decrease in power costs is so unlikely that it is unreasonable to give it consideration. In his opinion, there is no realistic opportunity for PacifiCorp to over earn as a result of implementation of the PCAM. (Tr., pp. 426-441.)

79. The PCAM does not have a separate return on equity measurement; and the overall impact of PCAM cost recovery can be measured through PacifiCorp's semi-annual earnings reports to the Commission. Those reports show the bundled revenue requirement and associated return on equity, which can be compared to the authorized return on equity. In Larsen's opinion, return on equity would not be a good indicator of the operation of the PCAM. He thought the best indicator of the operation of the PCAM (and of the need to reset the baseline or otherwise modify the PCAM) is the status of the deferral account, which can be monitored by the Commission. (Tr., pp. 445-446.)

Party Positions: The Office of Consumer Advocate

80. Deputy Administrator Denise K. Parrish presented the case of the OCA. She explained the negotiations which led to the Stipulation as a long-term process starting with discussions of alternative forms of regulation beginning in the fall of 2004. Parrish testified that:

> ". . . we had a potential of continuing back-to-back rate cases and even some indication from the company that we could start looking at pancaking of rate cases, rate cases filed on top of the other one, before the prior one was done." (Tr., p. 195.)

She described other aspects of the context of the negotiations, including the need for more capital investment in Wyoming, PacifiCorp's concern with its power costs, the pressure for future test years, and "a great deal of potential upward pressure in rates and new mechanisms that were beginning to potentially shift risk to customers." These discussions stemmed from a desire to mitigate some of the pressures while being fair to the company without putting all of the risk "on the back of the ratepayers." Parrish recommended the Stipulation because it shares the risk of purchase power cost volatility, it does not force parties who are not yet comfortable with the AFOR to litigate the issue at this time, and it continues discussions of ways to mitigate and share risk. Parrish described the Stipulation as a package assembled from many compromises among PacifiCorp and the parties. She urged the Commission to view it as a package and a remarkable one, stating:

> "It was a beautiful thing because it was a meeting of the minds. It was a way to get so many issues on the table and have so many customer groups represented, and it was with that that I would encourage you to consider it in the public interest." (Tr., p. 198.)

The Stipulation, in her opinion, meets the needs of each of the parties. (Tr., pp. 190-199.)

81. Parrish pointed out the differences between the PCAM and a traditional pass-on under Sections 249 and 250 of the Commission's Rules. The traditional pass-on [i] does not provide for sharing between the utility and its customers, [ii] does not include Company-controlled costs, and [iii] generally does not provide for interest on both under and over collections. On this basis, she agreed with MacRitchie that the PCAM could be thought of "as the first step toward some alternative-type regulation that's being presented to you." The PCAM

does not treat over and under earnings as they would be treated under Section 249 but views them in terms of the sharing of costs and risks. Later, Parrish testified that PacifiCorp's operations would not fit well under a Section 249/250 model because of their "mix of self-generation and purchased generation, a mix of very stable fuel supply and less stable fuel supply." (Tr., pp. 199 and 278.)

82. Parrish testified that the Stipulation does not affect the Commission's authority over PacifiCorp's earnings levels and the Commission will retain all of its statutory jurisdiction and authority to address earnings issues as appropriate. While the PCAM establishes a formula for power cost rate adjustments, those adjustments are not automatic and must be approved by the Commission. They would simply be dealt with by a new mechanism. (Tr., pp. 200-201.) She stated:

> "There has to be an application made. We would anticipate notice to allow parties to participate. There could be hearings. There could be disallowances in the end. All of those options are still there under this mechanism. It is simply a formula that lays out what the rate would be rather than being -- it's a little less subjective than some of the ratemaking that's done." (Tr., pp. 201-202.)

83. Parrish described the nature of the compromise and the $25 million revenue requirement that it produced:

> "The parties have chosen not to break down the 25 million between power costs and net power costs. We have chosen not to break down that 25 million between return and rate base and increasing expenses, and there is a reason for that. The reason being is that with six parties, you'd have seven different answers as to how we got there. I would have different adjustments to rate base than WIEC would, than AARP might, than the company would, and so we didn't need to.
>
> "There was a general consensus that all past [*sic*] lead to 25 million. Is that however we got there in our own mind, whether we were looking at what the Commission might have given if we had gone to a contested case, if we were looking at past history of percentages, of grants, if we were looking at whatever it might be, we decided that that 25 million was reasonable." (Tr., p. 204.)

84. Parrish explained that, during the OCA's investigation of PacifiCorp's case, she spent one week at PacifiCorp's offices conducting a regulatory audit. She ultimately concluded that the $25 million increase contained in the Stipulation "is in a range of reasonableness based on the case that was filed by the company." (Tr., pp. 204-205.) Overall, she found the level of investigation by the various parties to be satisfactory. She said:

> "I don't think that you need to have the scratch paper or the spreadsheets that get you to that rate base and that rate of return in this case. I think that it's enough to have the company's initial filing. It's a filing that supports 35 million -- 34 million on a traditional basis, 42 million on a slightly less traditional basis, and it's enough for the parties to come in and say we've all looked at it, we've done our analysis, we understand this case and 25 million works.
>
> We think that that is a record for you. That beyond that that the parties do not have a common mind-set, but it's not out of the air either. There was work done. There were discussions. There was discovery. There was investigation." (Tr., pp. 205-206.)

Based on the work of the OCA, including her audit, she concluded that the $25 million number "is within the range of what I would have testified to in a contested case." (Tr., p. 251.)

85. Regarding the possibility of Commission staff presence at later meetings provided for in the Stipulation to discuss, for example, the development of an AFOR, Parrish testified that she would prefer not to have any Commission staff present because such sessions are essentially negotiations and they should not be privy to the "positioning . . . being done by parties, early positioning, late positioning, on an issue that you may be asked to decide and upon which they may be asked to advise." She thought the Commission could have sufficient information given to it in meetings or reports, and the parties could conduct status briefings on topics on which negotiations are taking place. Regarding the greatly truncated time frame which developed in this case, Parrish's suggested solution was for the Commission simply to tell parties that "no more" such situations should occur in the future. (Tr., pp. 206-207 and 241-243.) Later in the hearing, counsel for WIEC described technical conferences which take place in Utah and Colorado prior to the formal hearing on the case when an all party settlement is presented to the regulators. He opined that such a process would have served well in this case. (Tr., pp. 269-270.)

86. Parrish explained why she felt the PCAM proposed in this case was acceptable even though OCA had previously opposed implementation of a PCAM by PacifiCorp. (*See*, Docket No. 20000-ET-03-205, Order of June 21, 2004.) She observed that, in its prior filing, PacifiCorp requested implementation of a PCAM in a docket separate from a general rate case -- essentially a single-issue general rate case examining certain costs which are going up and ignoring those going down. In this proceeding, the PCAM was proposed in the context of a general rate case. Parrish pointed out that this PCAM, as agreed to by the parties, contains a sharing mechanism with Dead Bands and Sharing Bands described in ¶17 of the Stipulation and as advocated in the past by parties to the former PCAM case. She concluded that, while this was not her ideal PCAM, this PCAM is more reasonable than the PCAM previously proposed by PacifiCorp. She stated she considers the PCAM established in the Stipulation also to be better than the proposed UCAM because this PCAM implements a better sharing mechanism than that which would be included in a UCAM. With the UCAM, she noted, there is a potential for gaming. PacifiCorp could, at least theoretically, have a disincentive to utilize its own generation as an alternative to wholesale power purchases even though its own generation might be more cost effective. This could occur because the UCAM guarantees recovery of wholesale power purchase costs but does not provide a guarantee that PacifiCorp could cover the cost of its own generation. (Tr., p. 220-223.)

87. Parrish notes that projections have been approved in a rate case for another utility (MDU) and that projections are routinely used in the net power cost element of PacifiCorp general rate cases. She noted the Commission has in the past allowed plant in service updates to the time of the rate hearing. The $660 million figure used here for the power cost baseline contains an element of projection; but she concluded it would not be extraordinary for the Commission to use the $660 million baseline net power cost amount in the PCAM, derived from a test year updated through March 2006. (Tr., p. 227-229.)

88. Parrish advised the Commission of her view, that with respect to PacifiCorp's coal mining operations and contracts, the Commission has the ability, through its normal

authority, to examine the books and records of PacifiCorp and "sister companies" to adequately scrutinize and investigate coal costs. (Tr., pp. 237-238.)

89. The PCAM established in the Stipulation provides a better result for customers, in Parrish's opinion, than would a conventional pass-on and balancing account mechanism under Commission Rules 249 and 250 because of the PCAM's risk sharing provisions. (Tr., p. 253.)

90. Parrish explained the revenue variation adjustment in the PCAM tariff as a mechanism to true-up actual levels of sales and load with those estimated in establishing the PCAM rate. The tariff also contains a deferred NPC adjustment which is a mechanism used to true up the calculated deferred NPC adjustment sales volumes with actual sales volumes to ensure that PacifiCorp recovers only an appropriate amount of costs in its rates. (Tr., pp. 271-272.)

91. Parrish testified to her view of the most important aspects of the Stipulation:

[i] it allows PacifiCorp an opportunity to deal with "truly unexpected volatile net power costs";

[ii] it includes some risk sharing between the utility and its customers and is not entirely one-sided in that regard;

[iii] it allows a rate increase needed to allow operation and investment "but without having an excessive profit level" (She found the original application in this case "asked for an amount of revenue requirement that included profit levels that were higher than reasonable or necessary to continue operating safely and reliably." (Tr., p. 275.))

[iv] there is a known time line for increases in the near future, with a brief general rate stayout period;

[v] it continues the AFOR discussions which she termed very beneficial even if no AFOR ultimately comes to fruition;

[vi] it explored possibilities for improving rate making and provided for demand side management discussions (in which Wyoming has been ignored in the past); and

[vii] rates are now generally in the range of cost of service, avoiding some risk of uneconomic self generation and bypass which occur when subsidies persist.

Finally, Parrish opined that the entire package is "very good for customers and in the public interest." (Tr., pp. 274-277.)

92. In summary, Parrish stated:

> I believe that this stipulation has a great number of benefits versus what might otherwise have been offered and I believe the result of this is an agreement that has many facets of the public interest and as a package, as a total package, should be approved as being in the public interest."
> (Tr., pp. 289-290.)

Party Positions: The Irrigators

93. Richard McKamey testified on behalf of the Irrigators, "a fairly large group of irrigators, farmers, investors that are also the majority owners in the Wyoming Sugar Company." McKamey testified that the Big Horn Basin Irrigators believe that the Stipulation is "well done, professional and in the public interest." He stated that the Irrigators still have concerns going forward, but that the Stipulation addressed them. Irrigator rates have gone up by 65% to 85% in recent years and this led to their involvement in this case. McKamey testified that the study provided for in the Stipulation should address the level of Irrigator contribution to the cost of service. Given the heavy energy use by the Irrigators, McKamey reiterated their interest in demand side management and the irrigation load study that will be undertaken pursuant to the Stipulation. McKamey concluded that the Irrigators were comfortable with the Stipulation and their ability to work with PacifiCorp, the OCA and others on their issues. (Tr., pp. 185-188.)

Party Positions: WIEC and AARP

94. Although both parties were present at the hearing and participated through counsel, neither WIEC nor AARP presented evidence at the hearing. Counsel for both parties did, however, make statements in support of the Stipulation. (Tr., *passim.*)

95. Counsel for WIEC found that the interests of WIEC in this case do not differ significantly from those of other customers; and WIEC approached its analysis of this case "from the standpoint is this good for all consumers?" He identified six elements of the Stipulation as having value for consumers:

[i] the PCAM is a significant improvement over the AFOR, the UCAM and the originally proposed PCAM in this case, (as well as an improvement of the previously proposed PCAM);

[ii] it provides a degree of rate certainty for consumers "well into 2007";

[iii] possible implementation of an AFOR is deferred to at least 2009;

[iv] a rate increase of $25 million is a significant reduction from the $40.2 requested in the Application;

[v] avoiding an "unduly harsh" rate increase for Schedule 33 customers; and

[vi] the Pass-On Case and a litigation matter will be withdrawn.

In return, WIEC would accept the PCAM, an earlier increase in rates, the use of a future test year in upcoming rate cases ("on a trial basis" and with comparative historical data being furnished by PacifiCorp), and the study of an AFOR. (Tr., pp. 19-25.)

96. Counsel for AARP stated its position that the Stipulation represents just and reasonable rates and rate making methodology. AARP asked that the Commission approve the Stipulation, stating: "We believe it is in the public interest and serves as a model, if you will, for what can result from a diligent negotiated process." One advantage for AARP members is that the rate increase is phased and does not begin until March 1, 2006. AARP was pleased that the

AFOR filed in this case "will no longer be a part of what is approved in this case." Counsel appreciated the additional contribution to Energy Share of Wyoming. (Tr., pp. 27-30.)

Party Positions: Kinder Morgan

97. Kinder Morgan did not appear at hearing, and although not a party to the Stipulation, did not oppose it. (Tr., *passim.*)

Pro se testimony: Richard Innes

98. Richard Innes of Casper, Wyoming, appeared and testified on his own behalf, expressing the hope that the PCAM will be of assistance. In the overall context of PacifiCorp's legal dealings with the Commission, he is pleased with the Stipulation, the rate change, the PCAM and other elements of the Stipulation. Innes states that he believes the outcome of this proceeding with the Stipulation in place "might come out to the public benefit." (Tr., pp. 136-138.)

Legal Standards Applicable in this Case

99. W.S. § 37-2-121 provides the standard which rates must meet and allows utilities to propose innovative rate making procedures for Commission consideration:

> "If upon hearing and investigation, any rate shall be found by the commission to be inadequate or unremunerative, or to be unjust, or unreasonable, or unjustly discriminatory, or unduly preferential or otherwise in any respect in violation of any provision of this act, the commission, within the time periods provided under W.S. 37-3-106(c) may fix and order substituted therefor a rate as it shall determine to be just and reasonable, and in compliance with the provisions of this act. The rate so ascertained, determined and fixed by the commission shall be charged, enforced, collected and observed by the public utility for the period of time fixed by the commission. The rates may contain provisions for incentives for improvement of the public utility's performance or efficiency, lowering of operating costs, control of expenses or improvement and upgrading or modernization of its services or facilities. Any public utility may apply to the commission for its consent to use innovative, incentive or nontraditional rate making methods. In conducting any investigation and holding any hearing in response thereto, the commission may consider and approve proposals which include any rate, service regulation, rate setting concept, economic development rate, service concept, nondiscriminatory revenue sharing or profit-sharing form of regulation and policy, including policies for the encouragement of the development of public utility infrastructure, services, facilities or plant within the state, which can be shown by substantial evidence to support and be consistent with the public interest."

In accord is W.S. § 37-2-122(b) regarding services and service regulations. It states, in part:

> If, upon hearing and investigation, any service or service regulation of any public utility shall be found by the commission to be unjustly discriminatory or unduly preferential, or any service or facility shall be found to be inadequate or unsafe, or any service regulation shall be found to be unjust or unreasonable, or any service, facility or service regulation shall be found otherwise in any respect to be in violation of any provisions of this act, the commission may prescribe and order substituted therefore such service, facility or service regulation, as it shall determine to be adequate and safe, or just and reasonable, as the case may be and otherwise in compliance with the provisions of this act, including any provisions concerning the availability or reliability of service."

100. Under W.S. § 37-2-112, the Commission has "... general and exclusive power to regulate and supervise every public utility within the state in accordance with the provisions of this act." It has broad powers of inquiry into utilities and their business. *See, e.g.*, W.S. § 37-2-116, *Ordering production of records;* W.S. § 37-2-117, *Commission may initiate investigation; and* W.S. § 37-2-119, *Matters to be considered and determined in investigation.*

101. Under Section 119, *Settlements*, in the Commission's Rules, "Informal disposition may be made of any hearing by stipulation, agreed settlement, consent order or default, upon approval of the Commission."

102. In *PacifiCorp v. Public Service Commission of Wyoming*, 2004 WY 164, 103 P.3d 862 (2004), the Wyoming Supreme Court discussed the basic standard of review for Commission decisions. In PacifiCorp, 2004 WY 164, ¶13, the Court quoted with favor *Sinclair Oil Corp. v. Wyoming Public Service Comm'n*, 2003 WY 22, ¶9, 63 P.3d 887, ¶9 (Wyo. 2003):

> "Speaking specifically of PSC, we have said that PSC is required to give paramount consideration to the public interest in exercising its statutory powers to regulate and supervise public utilities. The desires of the utility are secondary. *Tri County Telephone Ass'n, Inc. v. Public Serv. Comm'n*, 11 P.3d 938, 941 (Wyo. 2000) (citing *Mountain Fuel Supply Co. v. Public Serv. Comm'n*, 662 P.2d 878, 883 (Wyo. 1983)). Additionally, in recognition of the limited nature of our review, we have explained that the judicial function is exhausted when we can find from the evidence a rational view for the conclusions of the PSC. *Tri County Telephone Ass'n*, at 941 (citing *Telstar Communications, Inc. v. Rule Radiophone Serv., Inc.*, 621 P.2d 241, 246 (Wyo. 1980))."

Construing W. S. § 37-3-101, which requires rates to be reasonable, the Court in *Mountain Fuel Supply*, 662 P.2d at 883, commented that:

> "This court cannot usurp the legislative functions delegated to the PSC in setting appropriate rates, but will defer to the agency discretion so long as the results are fair, reasonable, uniform and not unduly discriminatory."

Later, 662 P.2d at 885, the Court in *Mountain Fuel* stated that:

> "We agree that if the end result complies with the 'just and reasonable' standard announced in the statute, the methodology used by the PSC is not a concern of this court, but is a matter encompassed within the prerogatives of the PSC."

In accord are *Great Western Sugar Co. v. Wyo. Public Service Comm'n and MDU*, 624 P.2d 1184 (Wyo. 1981); and *Union Tel Co. v. Public Service Comm'n*, 821 P.2d 550 (Wyo. 1991), wherein the Supreme Court stated, 821 P.2d at 563, that it "... has recognized that discretion is vested in the PSC in establishing rate-making methodology so long as the result reached is reasonable."

103. W.S. § 37-2-120 requires the Commission to afford due process in its cases, stating that:

> "No order, however, shall be made by the commission which requires the change of any rate or service, facility or service regulation except as otherwise specifically provided, unless or until all parties are afforded an opportunity for a hearing in accordance with the Wyoming Administrative Procedure Act."

104. The Wyoming Administrative Procedure Act, at W.S. § 16-3-107, sets parameters for due process in Commission cases, including the giving of reasonable notice. In accord are W.S. §§ 37-2-201, 37-2-202, and 37-3-106. *See also*, Sections 106 and 115 of the Commission's Rules.

Findings

105. Many of the facts necessary to the Commission's decision are set forth above and will not be repeated here.

106. The Commission finds the rate increase called for in the Stipulation in the amount of $25 million to be reasonable and supported by the expert analyses testified to by the parties herein. It is lower than the $40.2 million sought by PacifiCorp based on a September 2006 forecast test year, and it is below the $32 million described in the Application using a forecast test year ending March 2006. Under the Stipulation, PacifiCorp's rates would increase by $25 million per year which would result, depending on circumstances, in a return on equity of approximately 9.1%.

107. The evidence here shows that PacifiCorp has experienced cost increases since its last general rate case, including, *inter alia*, new capital investment, increased labor and employee medical expenses and pension costs, and increased total net power costs, all of which contribute to an increase in PacifiCorp's overall cost of service. In addition to supporting the Stipulation, PacifiCorp provided witnesses sponsoring the entire filed general rate case, offering testimony on general policy and business matters, revenue requirements, cost of capital, the filed cost of service study, rate spread and rate design. This traditional and comprehensive showing forms the basis for our examination of the Stipulation and the acceptability of its provisions.

108. It appears to the Commission that the PCAM mechanism is capable of functioning in the public interest, to fairly share power cost risks and to produce just and reasonable rate results. Although it has not been tested in actual operation, in Wyoming, the Commission has sufficient oversight responsibility and power to act with respect to the PCAM should it produce other than a just and reasonable result. On the evidence before us now, the PCAM proposed in the Stipulation is in the public interest and should be approved. We base this finding in part on PacifiCorp's undertaking to educate the Commission's staff on the GRID model which is central to the determination of net power costs.

109. Neither the AFOR nor the alternative UCAM has been supported here; and neither will be approved.

110. The PCAM will help PacifiCorp to obtain more rapid collection of net power costs and will help to protect PacifiCorp from the possibility of losses resulting from unexpectedly large and volatile increases in net power costs. At the same time, the Company is required under all circumstances to absorb significant portions of any increase in those costs, a result which we may accept as in the public interest. Adoption of a Wyoming PCAM is not in itself sufficient to help PacifiCorp maintain an advantageous credit rating and lower its cost of debt, but it could do so if a significant number of other PacifiCorp jurisdictions approve PCAMs or similar mechanisms. This would be to the advantage of the Company and customers alike.

111. We do not expect the implementation of the PCAM as proposed to result in over earning by PacifiCorp. However, if it were to occur, the public will be protected because the Commission has at its disposal all Wyoming regulatory powers to identify and deal with the problem. We will require PacifiCorp to provide us with a quarterly informational filings showing the status of the working of the PCAM, including the deferred power cost balance.

112. The Stipulation generally achieves the East-West rate parity we have asked for and worked toward since 2000. It will establish rates on the basis of cost of service principles. With all service classes experiencing rates in the range of 98% to 102% of their respective costs of service, the spread of rates is reasonable and based on an appropriate methodology. The mitigation proposed for Schedule 33 customers is also a fair way to approach the otherwise steep increase they would face. These facts favor our approval of the Stipulation.

113. We approve of the continuing engagement by PacifiCorp and the parties in a variety of ongoing issues such as the irrigation rate study and the continuing discussion of the AFOR concept, all as provided in the Stipulation. They clearly serve the interests of the Company and its customers. Even if they do not lead to agreement on the issues, such ongoing activities promote understanding and permit concerned persons and entities to contribute to solutions which will enhance the quality of later presentations to the Commission. The knowledge and understanding developed will likely be of assistance in the future in ensuring that PacifiCorp's rates and services will be in a form and at levels consistent with the public interest.

114. We understand the desire of PacifiCorp and the parties to keep their negotiations out of the public eye so that the free flow of ideas in negotiation will not be compromised. It is acceptable to us that such meetings be kept closed for these reasons. Negotiations are a reasonable method for parties to identify potential compromises and settlement terms. Since Commission staff members will not be privy to negotiations, the parties must work seriously on the timing of cases and stipulations in the future to accommodate the need for Commission examination of cases and their proposed solutions. If a very short timeline is actually necessary for the resolution of a case, the company and parties should work diligently with the Commission and its staff to ensure that there is sufficient time to gather all of the facts on the record and to make an informed decision. Among the techniques which may be employed are periodic informational meetings and technical conferences described above. Should it appear to the

Commission that PacifiCorp or the parties to this case are in continuous "negotiations" in the absence of a filed case and this impedes the normal flow of relevant information, we will revisit this subject formally to insure a fair, full and timely flow of information to the Commission.

115. The two stage rate increase provided for in the Stipulation will lessen the rate shock experienced by consumers, and this is an important advantage of the Stipulation. Even though they will only operate for a relatively short time, we find the short moratorium will promote near term rate stability and predictability to the benefit of consumers.

116. The stipulated agreement by PacifiCorp to dismiss the Pass-On Case in Docket No. 20000-233-EP-05 is an advantage as it makes for administrative efficiency in terminating a redundant proceeding.

117. We believe that the genuinely differing needs and positions of PacifiCorp and the parties contributed to a sufficient examination of PacifiCorp's case and led to sincere and fruitful negotiations. The negotiations among the parties, who have differing interests and who brought to the negotiations a recognized high degree of insight and experience in regulatory issues, shows clearly in the Stipulation they produced. The Stipulation is supported adequately in the record by the parties and provides for a number of distinct benefits, as presented in the discussion of "Party Positions," *infra*.

118. For all of these reasons we find that the Stipulation taken as a whole results in rates, terms and conditions of service that are just, reasonable and not unduly discriminatory, and that the Stipulation should be approved as it was presented to us.

Conclusions of Law

119. PacifiCorp is an electric public utility as defined in W.S. § 37-1-101(a)(vi)(C); and, as such, under W.S. § 37-2-112, the Commission has the general and exclusive jurisdiction to regulate PacifiCorp as a public utility in Wyoming. PacifiCorp is duly authorized by the Commission to provide retail electric public utility service in its Wyoming East and Wyoming West service territories under certificates of public convenience and necessity issued and amended by the Commission.

120. All proper public notices in these proceedings were given in accordance with the Wyoming Administrative Procedure Act, W. S. § 37-2-203 and the Commission's Rules, especially Section 106 thereof. The public hearing was held pursuant to the provisions of W. S. §§ 16-3-107, 16-3-108, 37-2-203, and applicable sections of the Commission's Rules. Pursuant to the order of the Commission under W.S. §§ 37-2-102 and 16-3-112, a hearing examiner conducted and presided over the hearing in these cases. The interventions of the various parties were properly granted, and the entities and persons who intervened became parties to the case for all purposes.

121. The great preponderance of the evidence presented to the Commission in this case supports our approval of the Stipulation and the disposition of the captioned case on the basis thereof. The ability of utilities to bring innovative rate making proposals to the Commission for review and approval, including the PCAM and other elements of the Stipulation, is provided for in W.S. § 37-2-121; and the Stipulation resolves the captioned cases fully within the ambit of this statute.

122. PacifiCorp's current retail electric utility service rates in Wyoming are inadequate and unremunerative and should be increased, but only to the extent provided for in this Order.

123. The PCAM set out in the Stipulation serves the public interest and should be approved pursuant to the Commission's authority under W.S. § 37-2-121 to authorize the use of nontraditional rate making methods.

124. We conclude that our decisions set forth above, when given effect accurately and in accordance with this order, will, with the ordered increases, produce rates that are just and reasonable; they will produce no undue discrimination among customers; they are adequate and remunerative; and they are in the public interest. The allocation, rate design and rate spread proposals of PacifiCorp approved hereinabove are fair and reasonable and in the public interest. The rates approved herein will allow PacifiCorp to continue to provide adequate and reliable service and to make needed investments in Wyoming. Likewise, the tariff modifications approved herein are just and reasonable and produce no undue discrimination among customers.

125. The jurisdiction of the Commission cannot be widened or narrowed by agreement of the parties to this or any other case. We conclude that the case in general, the Stipulation, and our approval of it do not limit or change the powers or jurisdiction of the Commission. We will continue to act in the public interest at all times.

NOW, THEREFORE, IT IS ORDERED THAT:

1. The Stipulation and Agreement, in the form attached to this Order, marked as Attachment A and made a part hereof by reference, is approved.

2. PacifiCorp is authorized to increase its rates as and to the extent set forth in the Stipulation and to implement the other provisions of the Stipulation. PacifiCorp shall file appropriate tariffs prior to the effective date of any changes in rates, terms or conditions of service authorized by this Order.

3. The parties shall promptly hereafter deal with all confidential information in their possession in accordance with and at the time specified in ¶5(e) of the Confidentiality Agreement approved by the Commission in the Order Granting Motion for Approval of Confidentiality Agreement entered herein on November 4, 2005.

4. This order is effective immediately.

MADE and ENTERED at Cheyenne, Wyoming, on March 24, 2006.

PUBLIC SERVICE COMMISSION OF WYOMING

Steve Furtney

STEVE FURTNEY, Chairman

Kathleen A. Lewis

KATHLEEN A. LEWIS, Deputy Chair

Mary Byrnes

MARY BYRNES, Commissioner

(SEAL)

PUBLIC SERVICE COMMISSION OF WYOMING OFFICIAL SEAL

Attest:

Stephen Oxley

STEPHEN G. OXLEY, Secretary and Chief Counsel

Attachment A to the Wyoming Public Service Commission Order Approving Stipulation of March 24, 2006, in Docket No. 20000-230-ER-05.

RECEIVED

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Service Commission
Wyoming

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC UTILITY SERVICE RATES IN WYOMING, CONSISTING OF A GENERAL RATE INCREASE OF APPROXIMATELY $40.2 MILLION PER YEAR AND FOR APPROVAL OF AN ALTERNATIVE FORM OF REGULATION OR IN THE ALTERNATIVE FOR APPROVAL OF AN UNCONTROLLABLE COST ADJUSTMENT MECHANISM.	Docket No. 20000-230-ER-05 (Record No. 10196)

STIPULATION AND AGREEMENT

This Stipulation and Agreement (Stipulation) is entered into between PacifiCorp, the Wyoming Office of Consumer Advocate (OCA), AARP, the Wyoming Industrial Energy Consumers ~~Customers~~ (WIEC) and the Big Horn Basin Irrigators, collectively referred to as the Parties.

I. RECITALS

1. On October 14, 2005, PacifiCorp (Company) filed an Application with this Commission in Docket No. 20000-230-ER-05 requesting approval of a general rate increase of approximately $40.2 million per year. The application also requested approval of an alternative form of regulation (AFOR) mechanism. Alternatively, if the Commission did not approve the AFOR mechanism, PacifiCorp sought approval of an Uncontrollable Cost Adjustment Mechanism (UCAM). Both the AFOR and the UCAM were sought in conjunction with and in addition to the requested increase of $40.2 million in base rates.

2. On October 28, 2005, the Commission issued a Notice of Application in Docket No.

Parties Joint Exhibit 1

20000-230-ER-05. Pursuant to W.S. § 37-3-106, the Commission entered a Suspension Order in Docket No. 20000-230-ER-05 on November 2, 2005, suspending the proposed filing for purposes of investigation. Requests for intervention were to be filed with the Commission on or before November 23, 2005. The following parties were granted intervention status: OCA, AARP, WIEC, Kinder Morgan, Inc., Kinder Morgan Interstate Gas Transportation LLC, Canyon Creek Compression Company and the Big Horn Basin Irrigators.

3. On November 18, 2005, the Commission issued its Order on Motion for Approval of Procedural Schedule in Docket No. 20000-230-ER-05 denying the Company's request for an expedited procedural schedule absent an all-party agreement. In addition, the Commission reminded the parties that they may, at any time, bring to the Commission a stipulation, a settlement, suggested modifications to the procedural schedule, or other motions for relief.

4. On December 16, 2005, the Company filed an Application with this Commission in Docket No. 20000-233-EP-05 requesting approval of a net wholesale purchase power cost increase of approximately $16.1 million per year for net wholesale purchase power costs.

5. The Parties have engaged in discussions regarding PacifiCorp's general rate increase request and wholesale purchase power cost pass-on request. The Parties have reached an agreement that resolves all outstanding issues to their satisfaction.

II. AGREEMENTS REGARDING RESOLUTION OF ISSUES

6. PacifiCorp agrees that, immediately upon approval by the Commission of this Stipulation and Agreement, the Company shall file a request with the Commission to dismiss the pass-on application filed in Docket No. 20000-233-EP-05 and further, the Company agrees that it will not otherwise pursue this application.

7. The Parties stipulate that PacifiCorp will be allowed to increase rates $15 million per year effective March 1, 2006 pursuant to the application filed in Docket No. 20000-230-ER-05.

8. The Parties stipulate that the $15 million March 1, 2006 increase shall be allocated among all service schedules on the basis of cost of service relationships and rate impact mitigation provisions as described further in paragraph 23. A summary illustrating the increase to be effective March 1, 2006 for each rate schedule is included in Stipulation Exhibit 1.

9. The Parties stipulate that PacifiCorp should be allowed to increase rates an additional $10 million per year in Docket No. 20000-230-ER-05, effective July 1, 2006. The Parties agree that the July 1, 2006 increase shall be in addition to the increase effective March 1, 2006. A summary illustrating the effect of the July 1, 2006 increase for each rate schedule is included in Stipulation Exhibit 1.

10. The Parties stipulate that the March 1, 2006 and July 1, 2006 revenue increases will result in an annual ongoing revenue increase of $25 million effective on and after July 1, 2006. The total ongoing annual revenue increase effective July 1, 2006 shall be $25 million in comparison to the revenues in effect on the date that this Stipulation is signed.

11. The Parties stipulate that the $25 million ongoing revenue increase effective July 1, 2006 shall be proportionally assigned to the service schedules using the cost of service relationships proposed in the general rate case application in Docket No. 20000-230-ER-05 as well as on the basis of rate impact mitigation provisions as described further in paragraph 23. A summary illustrating the cumulative $25 million general rate case revenue increase and the percentage increase for each rate schedule is included in Stipulation Exhibit 1.

12. The Parties stipulate that effective July 1, 2006, total net power costs shall be unbundled from other base costs and recovered on an on-going basis through a Power Cost Adjustment Mechanism (PCAM), as an agreed modification of the power cost recovery mechanisms proposed by PacifiCorp in its application in Docket No. 20000-230-ER-05. The costs tracked and included in the PCAM shall be as identified in the NPC PCAM Tariff attached hereto as Stipulation Exhibit 2.

13. The Parties stipulate that any cost included in a PCAM application may be challenged by any Party or the Commission and it shall be the Company's responsibility and obligation to demonstrate to the Commission that rate adjustments proposed in PCAM applications are just and reasonable. The Parties agree that a PCAM application challenge shall not delay implementation of the proposed PCAM rates, but that those rates shall be implemented on an interim basis, subject to final determination by the Commission after opportunity for hearing. If the Commission determines that the interim rates are not just and reasonable, any excess charges shall be refunded with interest at the rate established

by the Commission pursuant to Section 241 of the Commission's Rules and Regulations for Customer Deposits. In the alternative, if interim rates are authorized by the Commission at a level below that requested in the PCAM application, and the Commission determines after investigation that the interim rates were insufficient; the Company shall be entitled to recover the Commission approved rates with interest at the rate established by the Commission pursuant to Section 241 of the Commission's Rules and Regulations for Customer Deposits.

14. The Parties stipulate that PacifiCorp shall file a PCAM application annually beginning on or before February 1, 2007 and on or before each February 1st thereafter subject to the provisions of Paragraph 15 of this Stipulation. The PCAM application shall be based on a historic 12 month test period beginning December 1st and ending the November 30th preceding each filing date except as provided in Paragraph 16 of this Stipulation. The PCAM annual rate effective date shall be on April 1, 2007 and on April 1st each year thereafter subject to Paragraph 15 of this Stipulation.

15. The Parties stipulate that, unless all of the Parties jointly petition the Commission to implement a change or changes, the PCAM established by Commission approval of this Stipulation and Agreement shall remain in effect and shall be utilized without modification except as set forth in Paragraph 21, for purposes of determining all total net power cost adjustments to PacifiCorp's rates that are to be effective prior to April 1, 2009. The Parties agree that the Company may file applications with the Commission that if approved by the Commission, will allow the Company to track and recover net power

costs after November 30, 2007, differently than in the current PCAM provided that any rate changes resulting therefrom do not occur until on or after April 1, 2009, provided however, that nothing herein obligates any party to support, or waives any Party's right to object to, any such application filed by the Company.

16. The Parties stipulate that the first PCAM application filed on or before February 1, 2007, shall compare adjusted actual total net power costs for the time period July 1, 2006 through November 30, 2006 to base total net power costs which for purposes of this specific one-time period, shall be $336 million on a total Company basis as identified in Stipulation Exhibit 3. The Parties further agree that for PCAM applications filed on or before February 1, 2008 and beyond, subject to the provisions of this agreement, base total net power cost shall be $660 million (total Company) as reflected in the Company's application in Docket No. 20000-230-ER-05 until the Commission authorizes and the Company implements a change in base net power costs through a general rate case. The Parties further agree, however, that in the event that PacifiCorp files a new general rate case on or before February 1, 2007, then the base total net power costs beginning December 1, 2006 shall be $700 million annually for purposes of the deferral calculation only, as shown in Stipulation Exhibit 3, and shall remain in effect at that level until the Commission authorizes a change in base net power costs through a general rate case. The Parties stipulate and agree that the PCAM base total net power costs shall be reset at each general rate case.

17. The Parties stipulate that the PCAM shall utilize a symmetrical annual dead band of plus

or minus $40 million on a total Company basis that shall be applicable on either side of the base total net power cost. The Parties further agree that if less than an annual PCAM comparison period is used, then the dead band shall be computed on the pro rata share of $40 million to the applicable months in the comparison period. Actual total net power costs that fall outside the dead band and within the Customer Proportion shall be recoverable or refundable subject to a symmetrical sharing proportion.

18. The Parties stipulate that the total Company symmetrical sharing proportion of the PCAM shall be computed in a layered manner under the following conditions:

Actual Total Net Power Cost Layer	Customer Proportion	Company Proportion
Over $200 million above Base	Company recovers 90% from Customers	Company absorbs 10%
Over $100 million and up to $200 million above Base	Company recovers 85% from Customers	Company absorbs 15%
Over $40 million and up to $100 million above Base	Company recovers 70% from Customers	Company absorbs 30%
$40 million above Base (Dead Band)	Company recovers 0% from Customers	Company absorbs 100%
$40 million below Base (Dead Band)	Company returns 0% to Customers	Company retains 100%
Over $40 million and up to $100 million below Base	Company returns 70% to Customers	Company retains 30%
Over $100 million and up to $200 million below Base	Company returns 85% to Customers	Company retains 15%
Over $200 million below Base	Company returns 90% to Customers	Company retains 10%

The Parties further stipulate that there will be no deferral or accrual of interest for costs which are included in the Company Proportion. Additionally, if less than an annual

PCAM comparison period is used, the thresholds between the various layers shall be prorated based on the number of months in the comparison period.

19. The Parties stipulate that the PCAM shall generally measure the difference between adjusted actual total net power costs and the corresponding Commission approved base total net power cost on a monthly basis as set forth in more detail in the NPC Tariff attached hereto as Stipulation Exhibit 2. The Parties agree that interjurisdictional allocation provisions shall be included in the calculation of the PCAM pursuant to the terms of the NPC PCAM Tariff.

20. Interest shall apply to over and under recoveries in a symmetrical manner (paid to customers if actual total net power costs are less than base total net power costs and charged to customers if actual total net power costs are more than base total net power costs) after the dead band threshold is met and the sharing provisions have been applied. The symmetrical interest rate shall be established by the Commission pursuant to Section 241 of the Commission's Rules and Regulations for Customer Deposits. Interest shall continue to accrue as long as there is a net balance in the NPC deferred account. Interest shall also be appropriately included in the deferred cost amortization and recovery period. Any deferred net power cost balance that is collected through a change of rates shall be amortized over a 12 month period and recovered or refunded in a deferred net power cost adjustment, unless the Commission approves a longer or shorter amortization period for good cause to recognize extraordinary circumstances. The Parties agree that if the Commission approves a longer amortization period, interest shall be calculated based on

the Company's most recent authorized weighted average cost of capital. Further, the Parties agree that to ease the administrative burden of preparing and processing a PCAM application for very small cost changes, the Company may elect to defer recovery of a NPC under collection at its discretion and the Company may elect to defer refund of a NPC over recovery if the balance in the deferred account is less than $1 million on a Wyoming jurisdictional basis.

21. The Company agrees that not later than September 1, 2006, it will initiate a collaborative process with the Parties to review how PCAM revenues are tracked and explore whether a more refined method of calculating the revenue variation adjustment can be developed, or an alternative revenue tracking mechanism implemented, for the net power cost comparison period beginning December 1, 2006.

22. The Company agrees that not later than March 15, 2006, it will initiate a collaborative process with the Parties to review the Company's energy risk management strategies and to endeavor to determine which, if any, financial hedging programs, costs and benefits would be supported in PCAM applications. The Company may determine the level of financial hedging costs and associated benefits to include in each PCAM application to manage risk in the best interest of its customers which may be challenged by the Parties when PCAM applications are filed with the Commission, unless the parties previously agreed to the level of financial hedging costs and associated benefits that they would support in the PCAM. The Parties agree that energy risk management programs do not necessarily reduce costs. Upon completion of the collaborative review of its energy risk

management strategies, the Company will file an energy risk management plan with the Commission if requested by the Parties or if the Company, in its sole discretion, chooses to make such a filing. The Parties agree that energy risk management programs may include highly sensitive and confidential information that could jeopardize the Company's interests if revealed to the public or competitive suppliers, and to respect the Company's reasonable need to protect highly sensitive and confidential information.

23. The Parties stipulate to implement one-half of the Schedule 46 Load Size Charge to Schedule 33/218 in rates implemented pursuant to this agreement effective on July 1, 2006. The annualized revenues representing the remaining one-half of the Load Size Charge shall be collected from Schedule 25/206 on a rate impact mitigation basis effective on March 1, 2006. The Parties stipulate that they will support at the next general rate case, implementation of the full Load Size Charge for Schedule 33/218 provided however, that the Load Size Charge shall be supported by cost of service principles. PacifiCorp agrees that not later than July 1, 2006, it will initiate a collaborative process with Wyoming partial requirements customers and other interested Parties, to attempt to reach an agreement on an appropriate cost of service methodology for back-up facilities and back-up demand charges for partial requirements service. If an agreement is not reached in the collaborative process, the Parties shall be free to propose alternative cost of service methodologies and that nothing herein obligates any party to support, or waives any Party's right to object to, any such methodologies in any application filed by the Company. The Stipulation approved by the Commission in

Docket No. 20000-ER-02-184 effective March 6, 2003, shall remain in effect for all aspects of Schedule 33/218 with the exception of back-up facilities and back-up demand charges unless otherwise agreed to by the participants in the collaborative.

24. The Parties stipulate to a one-time opportunity for Schedule 33/218 customers to change the contract level of Supplemental demand with only 3-months notice, if such notice is provided to the Company in writing by Schedule 33/218 customers on or before March 31, 2006, after which the then-current tariff provision with respect to notice shall apply.

25. The Parties stipulate that the rates implemented pursuant to this agreement effective on March 1, 2006 and July 1, 2006, shall include the rate design changes proposed in Docket No. 20000-230-ER-05 to: 1) achieve East-West rate parity for the major customer classes first begun in Docket No. 20000-ER-00-162; 2) eliminate the Short Term Interval Demand billing adjustment for Schedule 46; and 3) to revise the monthly minimum kW charge for Schedule 46.

26. The Parties stipulate that a Force Majeure provision has historically been included in Schedule 217 and that Schedule 217 shall be eliminated as a result of the Rate Parity Plan first begun in Docket No. 20000-ER-00-162. The Parties agree that in rates implemented pursuant to this agreement effective on ~~July~~ March 1, 2006, Schedule 217 (primary voltage) customers shall be served under Schedule 46 and Schedule 217 (Transmission voltage) customers shall be served under Schedule 48T. The Parties agree that the same historic Force Majeure provision in Schedule 217 shall be incorporated in Schedules 46 and 48T unless and until that provision is modified in a general rate filing or other formal

proceeding before the Commission.

27. The Parties stipulate that rates implemented pursuant to this agreement effective on July 1, 2006, shall include each of the proposed corrections, revisions and modifications to PacifiCorp's Rules and Regulations as proposed by the Company in Docket No. 20000-230-ER-05. These include: 1) several housekeeping changes to provide more clarity, 2) increase the charge for disconnection and reconnection visits to reflect cost, 3) elimination of line extension allowance for transmission level service, and 4) implementation of a new charge for meter verification at multiple meter locations. Tariff sheets implementing these corrections, revisions and modifications are sponsored by William Griffith and included as Exhibit PPL__.1 (WRG-1) in the Company's application in Docket No. 20000-230-ER-05.

28. The Parties stipulate that in its next general rate case application, the Company shall request that new rates be effective only on or after August 1, 2007, provided, however, that nothing in this Stipulation in a future general rate case will prohibit all the Parties from stipulating and agreeing to support an earlier rate effective date.

29. The Parties stipulate on a one-time trial basis only that in the first general rate case filed by the Company following Commission approval of this Stipulation the Parties to this agreement shall support the principle of a forecast test year that extends 20 months past the date of actual historic data included in the general rate case application. The Company agrees to file for informational purposes with the Commission, the Parties and any other parties to such general rate case, as soon as such information becomes

available, actual normalized costs on a total Company basis for the time period six months beyond the date of actual data included in the general rate case application. Nothing herein shall be construed to limit any Party's right to challenge the forecast methodology, assumptions or data in that case. The Company agrees to file with the Commission and the Parties, fully normalized and adjusted historic twelve month results of operations reports on a semiannual basis as soon as such information becomes available for informational purposes.

30. The Parties stipulate that they will work cooperatively in collaborative meetings that shall begin no later than March 15, 2006, on AFOR issues to discuss and consider whether AFOR concepts may be applicable to the Company's operations in Wyoming. The Parties stipulate that the initial AFOR model to be considered in the first collaborative meeting shall be a draft proposal offered by the Company and provided to the Parties no later than March 1, 2006. The Company shall implement an AFOR tracking mechanism that results from the collaborative process for test purposes only and will share information with the Parties regarding the AFOR tracker as that information is developed, subject to reasonable requirements for the protection of confidential information. The Company agrees that any future request it may make for Commission approval of an AFOR will be structured such that no adjustment to rates resulting from approval of the AFOR will occur prior to April 1, 2009. Nothing herein obligates any Party to support, or waives any Party's right to object to, any AFOR application filed by the Company. If all of the Parties to this stipulation agree to an AFOR mechanism, nothing herein restricts the

Company from filing an AFOR application with the Commission and a stipulation that would support the implementation of an AFOR prior to April 1, 2009.

31. The Company agrees that it will meet with the Parties no later than March 15, 2006, to begin dialogue on and evaluation of new Demand Side Management programs and the possible extensions of existing Demand Side Management programs offered by PacifiCorp in other states that could be prudent and cost effective for Wyoming. All classes of service shall be considered in the Demand Side Management evaluation. PacifiCorp agrees to make a best-efforts attempt to file an application with the Commission prior to December 31, 2006, to implement prudent and cost-effective Demand Side Management programs in Wyoming that can be shown to be in the public interest and to propose in the application an appropriate cost recovery mechanism.

32. The Company agrees that not later than July 1, 2006 it will initiate a collaborative process with Wyoming Irrigators for a state specific load research program regarding Wyoming irrigation loads. The Parties agree that due to the inconsistent nature of weather and crop dependent irrigation, the time and cost to install metering to collect load research data, and the time necessary to evaluate and include the load research results in cost of service studies, it may take several years to complete the Wyoming irrigation load research program. PacifiCorp will make reasonable attempts to install data gathering metering for the 2007 irrigation season and once data is available that represents average long-term irrigation load conditions in Wyoming, to utilize Wyoming specific irrigation load data in its cost of service studies in future general rate cases in a reasonable time frame. The

Company agrees that it will continue to monitor the effectiveness of and make adjustments if necessary to the alternative irrigation rate design that was approved by the Commission in Docket No. 20000-ET-04-217.

33. The Company agrees that on or before April 1, 2006, it will make a one-time contribution of $30,000 from shareholder funds to Energy Share of Wyoming for purposes of providing emergency energy assistance to Wyoming utility consumers.

III. GENERAL TERMS AND CONDITIONS

34. The Parties stipulate to support all elements of this Stipulation as being in the public interest in proceedings before the Commission. The Parties agree to advocate and defend the position that this Stipulation should be heard by the Commission on an expedited basis because it is in the public interest.

35. The Parties stipulate that this Stipulation represents a compromise in their respective positions and is a result of settlement negotiations. As such, evidence of conduct or statements made in the negotiation and discussion phases of this Stipulation shall not be admissible as evidence in any proceeding before the Commission or court.

36. The Parties stipulate that the positions and agreements of the Parties set forth herein cannot be used to bind or estop any party from arguing any position in a future docket before this Commission.

37. In the event the Commission declines to approve this Stipulation or makes a material change to this Stipulation, or it is otherwise disapproved in whole or in material part by any court of competent jurisdiction, then any Party adversely affected by such action shall

have the right to withdraw from this Stipulation and no Party to this Stipulation shall be prejudiced by its terms and each Party shall be entitled to file any application, testimony and tariffs it chooses, to cross-examine witnesses and, in general, to put on such case as it deems appropriate. The withdrawing Party shall notify the Commission and all other Parties in writing of its intent to withdraw, such notice to be given by mail, e-mail or fax, to be received within three business days of the Commission or court decision. The Parties will meet within five business days of the notice of withdrawal for purposes of determining whether an alternative agreement can be reached or whether Commission proceedings in the captioned dockets should go forward for hearing to the Commission.

38. All negotiations relating to this Stipulation are privileged and confidential, and no Party shall be bound by any position asserted in the negotiations, except to the extent expressly stated in this Stipulation. Execution of the Stipulation shall not be deemed to constitute an acknowledgment by any Party of the validity or invalidity of any particular method, theory or principle of regulation, and no Party shall be deemed to have agreed that any principle, method or theory of regulation employed in arriving at this Stipulation and Agreement is appropriate for resolving any issue in any other proceeding.

39. The Parties stipulate to the submission of the Company's direct prefiled testimony and exhibits in Docket No. 20000-230-ER-05 and the Parties waive the filing and submission of testimony and exhibits from intervenors. The Parties waive cross examination of Company witnesses regarding general rate case prefiled testimony and exhibits. It is the Parties' intent to make (a) four Company witnesses available to explain the proposed

Stipulation and to address general business and policy matters, revenue requirement, power cost, PCAM mechanics, rate spread, rate design and tariff matters and (b) one OCA witness available. The Parties request notice from the Commission in advance of the hearing if the Commission would request additional witnesses.

40. The Parties stipulate and agree that this Stipulation and Agreement is in the public interest and that all of its terms are reasonable.

41. The Parties shall advocate in good faith that the Commission approve this Stipulation in its entirety. They shall make attorneys or witnesses available to explain and support this Stipulation in whatever level of detail may be desired by the Commission.

DATED this _____ day of February, 2006.

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41. The Parties shall advocate in good faith that the Commission approve this Stipulation in its entirety. They shall make attorneys or witnesses available to explain and support this Stipulation in whatever level of detail may be desired by the Commission.

DATED this 2nd day of February, 2006.

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STIPULATION EXHIBIT 1

STIPULATION EXHIBIT 1
PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICES
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS IN WYOMING
DISTRIBUTED BY RATE SCHEDULE
HISTORIC TEST PERIOD 12 MONTHS ENDED MARCH 2005
FORECAST TEST PERIOD 12 MONTHS ENDED SEPTEMBER 2006

Line No	Description	Present Schedule Number	Proposed Schedule Number	Average No of Customers Forecast	KWH (000) Forecast	Present Revenues Forecast ($000)	Proposed for March 1: Revenues ($000)	Proposed for March 1: Adjustment ($000)	Proposed for March 1: March 1 Change ($000)	Proposed for March 1: Percent	Unbundled Proposed Revenues - July 1: Base Revenues ($000)	Unbundled Proposed Revenues - July 1: NPC Revenues ($000)	Unbundled Proposed Revenues - July 1: Total Revenues ($000)	Proposed for July 1: July 1 Change ($000)	Proposed for July 1: Total Change ($000)	Proposed for July 1: Total Change Percent	Avg. Cents/kWh Proposed	Avg. Cents/kWh Present
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(16)/(5)	(6)/(5)
									(7)-(6)	(9)/(6)	(6)+(15)-(12)			(15)-(9)	(13)-(6)	(15)/(6)		
	Residential																	
1	Residential Service	2/18	2/18	86,326	709,998	$50,355	$53,314	$0	$2,958	5.87%	$45,747	$9,429	$55,175	$1,862	$4,820	9.57%	7.77	7.09
2	Residential Service (Optional)	3/18	2/18	5,159	109,995	$6,857	$7,378	$0	$521	7.60%	$6,199	$1,461	$7,659	$282	$802	11.70%	6.96	6.23
3	**Total Residential - East**			91,485	819,994	$57,212	$60,691	$0	$3,479	6.08%	$51,945	$10,890	$62,835	$2,143	$5,622	9.83%	7.66	6.98
4	Residential Service	201	2/18	9,389	74,212	$5,510	$5,612	$0	$102	1.85%	$4,821	$986	$5,807	$195	$297	5.39%	7.82	7.42
5	Residential Service (Optional)	205	2/18	2,254	40,461	$2,673	$2,752	$0	$79	2.95%	$2,318	$537	$2,856	$104	$183	6.84%	7.06	6.61
6	**Total Residential - West**			11,642	114,673	$8,183	$8,364	$0	$181	2.21%	$7,139	$1,523	$8,662	$299	$479	5.86%	7.55	7.14
7	**Total Residential**			103,127	934,667	$65,395	$69,055	$0	$3,660	5.60%	$59,085	$12,412	$71,497	$2,442	$6,102	9.33%	7.65	7.00
	Commercial, Industrial & Irrigation																	
8	General Service	25	25	21,799	1,151,952	$72,249	$74,813	$1,266	$2,564	3.55%	$59,944	$15,512	$75,455	$643	$3,207	4.44%	6.55	6.27
9	Partial Requirements Service	33	33	4	813,814	$31,805	$33,147	($1,450)	$1,342	4.22%	$24,929	$10,337	$35,266	$2,119	$3,460	10.88%	4.33	3.91
10	Agricultural Pumping Service	40	40	380	15,057	$1,067	$1,099	$0	$32	2.95%	$901	$219	$1,120	$21	$52	4.91%	7.44	7.09
11	Large General Service kW>1,000	46	46	85	2,030,687	$84,599	$87,747	$0	$3,149	3.72%	$63,576	$26,265	$89,841	$2,094	$5,243	6.20%	4.42	4.17
12	Large General Service - Transmission	48	48	13	2,062,018	$67,421	$70,816	$0	$3,395	5.04%	$46,642	$25,932	$72,574	$1,757	$5,152	7.64%	3.52	3.27
13	Recreational Field Lighting	54	54	57	577	$41	$44	$0	$3	7.65%	$39	$7	$46	$2	$5	12.75%	8.00	7.10
14	**Total Commercial, Industrial & Irrigation - East**			22,338	6,074,105	$257,182	$267,666	($184)	$10,484	4.08%	$196,031	$78,271	$274,301	$6,635	$17,120	6.66%	4.52	4.23
15	General Service	206	25	2,725	169,780	$10,393	$10,784	$183	$391	3.76%	$8,595	$2,282	$10,877	$93	$484	4.65%	6.41	6.12
16	General Service - High Voltage	209	48	0	0	$0	$0	$0	$0	0.00%	$0	$0	$0	$0	$0	0.00%	0.00	0.00
17	Agricultural Pumping Service	210	210	20	1,905	$118	$131	$0	$12	10.35%	$111	$28	$139	$8	$20	17.23%	7.28	6.21
18	Large Power Service - Primary	217	46	1	9,166	$389	$397	$0	$8	2.11%	$288	$118	$406	$9	$18	4.52%	4.43	4.24
19	Large Power Service - Transmission	217	48	12	832,562	$27,853	$28,126	$0	$274	0.98%	$18,400	$10,416	$28,816	$690	$963	3.46%	3.46	3.35
20	Partial Requirements Service	218	33	2	1,200	$347	$338	$0	($9)	-2.70%	$324	$16	$340	$2	($7)	-2.02%	28.37	28.95
21	**Total Commercial, Industrial & Irrigation - West**			2,759	1,014,613	$39,101	$39,776	$183	$676	1.73%	$27,719	$12,860	$40,579	$802	$1,478	3.78%	4.00	3.85
22	**Total Commercial, Industrial and Irrigation**			25,097	7,088,719	$296,283	$307,443	($1)	$11,160	3.77%	$223,750	$91,131	$314,879	$7,438	$18,598	6.28%	4.44	4.18
	Lighting																	
23	Outdoor Area Lighting Service	15	15	3,144	4,286	$572	$615	$0	$44	7.65%	$593	$52	$645	$29	$73	12.77%	15.04	13.34
24	Street Lighting Service	51	51	181	3,909	$755	$812	$0	$58	7.64%	$804	$47	$851	$39	$96	12.78%	21.77	19.30
25	Street Lighting Service	53	53	287	4,421	$491	$529	$0	$38	7.72%	$501	$53	$554	$25	$63	12.75%	12.53	11.12
26	Street Lighting Service	57	57	34	600	$104	$112	$0	$8	7.64%	$110	$7	$118	$5	$13	12.75%	19.61	17.40
27	Street Lighting Service	58	58	53	1,437	$81	$87	$0	$6	7.65%	$74	$17	$91	$4	$10	12.74%	6.33	5.62
28	**Total Lighting - East**			3,698	14,653	$2,003	$2,156	$0	$153	7.66%	$2,082	$176	$2,258	$102	$256	12.76%	15.41	13.67
29	Security Area Lighting	207	207	256	400	$126	$132	$0	$6	4.66%	$131	$5	$136	$4	$10	7.77%	33.95	31.50
30	Street Lighting - Company	211	211	91	1,340	$441	$462	$0	$21	4.66%	$460	$16	$476	$14	$34	7.76%	35.51	32.95
31	Street Lighting - Customer	212	212	14	90	$15	$16	$0	$1	4.62%	$15	$1	$16	$0	$1	7.75%	17.86	16.57
32	Traffic Signal Systems	212	212	16	76	$3	$3	$0	$0	2.21%	$2	$1	$3	$0	$0	3.60%	3.63	3.50
33	Metered Outdoor Night Lighting	212	212	3	49	$3	$4	$0	$0	2.13%	$3	$1	$4	$0	$0	3.53%	7.39	7.14
34	**Total Lighting - West**			380	1,955	$588	$616	$0	$27	4.63%	$610	$24	$634	$18	$45	7.72%	32.43	30.11
35	**Total Lighting**			4,078	16,607	$2,591	$2,772	$0	$181	6.97%	$2,692	$200	$2,892	$120	$301	11.62%	17.42	15.60
36	AGA (Revenue Credit)			0	0	$1,111	$1,111	$0	$0	0.00%	$1,111	$0	$1,111	$0	$0	0.00%		
37	Total Sales to Ultimate Consumers - East			117,521	6,908,752	$317,508	$331,625	($184)	$14,117	4.45%	$251,169	$89,337	$340,505	$8,881	$22,998	7.24%	4.93	4.60
38	Total Sales to Ultimate Consumers - West			14,781	1,131,242	$47,872	$48,756	$183	$884	1.85%	$35,468	$14,406	$49,875	$1,119	$2,003	4.18%	4.41	4.23
39	**Total Sales to Ultimate Consumers**			132,302	8,039,993	$365,380	$380,380	$0	$15,000	4.11%	$286,637	$103,743	$390,380	$10,000	$25,000	6.84%	4.86	4.54

STIPULATION EXHIBIT 2

NPC PCAM Tariff
Schedule 94

Available

In all territory served by the Company in the State of Wyoming.

Applicable

All retail tariff rate schedules shall be subject to two normally scheduled rate elements, a Base Net Power Costs (NPC) charge and Deferred NPC Adjustment that together recover total net power costs including fuel, purchased power (including NPC financial hedges), wheeling, and sales for resale for natural gas and electricity and excluding other NPC costs not specifically modeled in the Company's production cost model.

Definitions and Basic Concepts:

NPC Rate Effective Period shall be the 12-month period beginning April 1, 2007 and extending through March 31, 2008 in the first PCAM application filed on or before February 1, 2007. In each succeeding PCAM application, the NPC Rate Effective Period shall be the 12-month period beginning April 1st and extending through March 31st following the NPC Comparison Period. The Company may file and the Commission may approve PCAM applications with amortization periods for deferred amounts longer than 12 months to reflect extraordinary circumstances.

NPC Comparison Period shall be the five-month historic period beginning July 1, 2006 through November 30, 2006 in the first PCAM application filed on February 1, 2007. In each succeeding PCAM application, the NPC Comparison Period shall be the historic 12-month period beginning December 1st and extending through November 30th prior to the NPC Rate Effective Period.

Base NPC is calculated by taking the sum of the monthly total Company NPC as approved by the Commission in a stipulated agreement or as a result of the most recent Wyoming general rate case (GRC). The Base NPC shall be recovered from all retail tariff rate schedules through the unbundled rate elements as set forth in this Schedule. The Base NPC shall not reflect an Embedded Cost Differential (ECD) adjustment.

Adjusted Actual NPC: Adjusted Actual NPC is the annual sum of the monthly total Company amounts properly recorded in FERC Account Numbers: 501 (Steam Power Generation – Fuel), 503 (Steam Power Generation -- Steam from other Sources) and 547 (Other Power Generation -- Fuel) for coal, steam and natural gas purchased and or sold; 555 (Purchased Power), 565 (Wheeling); and 447 (Sales for Resale). Adjustments shall be made to actual costs that are consistent with the Company's production dispatch model, to remove prior period accounting entries made during the accrual period, and to include applicable Commission-adopted adjustments from the most recent general rate case. Hydro normalization, forced outage and other operational volatility circumstances shall be excluded from adjustment because these unpredictable events result in net power cost volatility that the PCAM captures for rate making purposes.

Deferred NPC Adjustment is a charge applicable to all retail tariff rate schedules as set forth in this schedule. The Deferred NPC Adjustment is calculated by taking the sum of the monthly differences between the Adjusted Actual NPC and the corresponding monthly Base NPC adjusted for the Revenue Variation Adjustment, and adjusted to reflect the prorated total Company Dead Band, Sharing Proportions, and Wyoming Allocated Share and include Symmetrical Interest accrual on the Customer Proportion of net Deferred NPC Adjustment balances outside of the Dead Band.

TABLE 1

Adjusted Actual Total NPC Layer	**Customer Proportion**	**Company Proportion**
Over $200 million above Base	Company recovers 90% from Customers	Company absorbs 10%
Over $100 million and up to $200 million above Base	Company recovers 85% from Customers	Company absorbs 15%
Over $40 million and up to $100 million above Base	Company recovers 70% from Customers	Company absorbs 30%
$40 million above Base (Dead Band)	Company recovers 0% from Customers	Company absorbs 100%

$40 million below Base (Dead Band)	Company returns 0% to Customers	Company retains 100%
Over $40 million and up to $100 million below Base	Company returns 70% to Customers	Company retains 30%
Over $100 million and up to $200 million below Base	Company returns 85% to Customers	Company retains 15%
Over $200 million below Base	Company returns 90% to Customers	Company retains 10%

Dead Band is illustrated in Table 1 above and is a total Company annual symmetrical range of plus $40 million above the base and $40 million below the base. There will be no deferral or accrual of interest for costs which fall within the Dead Band. If the NPC Comparison Period is longer or shorter than an annual period, the Dead Band shall be prorated on the basis of the applicable monthly NPC Base included in the NPC Comparison Period.

Sharing Proportion is also illustrated in Table 1 above and is the symmetrical proportion of Deferred NPC Adjustment eligible for recovery from, or repayment to customers. The Sharing Proportion shall be layered to reflect a Customer Proportion and a Company Proportion. There will be no deferral or accrual of interest for costs which are included in the Company Proportion. If the NPC comparison period is longer or shorter than an annual period, the thresholds between the various layers shall be prorated based on the number of months in the comparison period.

Revenue Variation Adjustment is equal to the ratio of actual Wyoming monthly kilowatt-hours sold divided by the Wyoming monthly kilowatt-hours assumed in the load forecast used to calculate the Base NPC rate elements.

Symmetrical Interest shall be computed on the net accumulated Deferred NPC Adjustment balance monthly at the rate determined by the Commission pursuant to Rule 241, Customer Deposits. Interest shall be paid to the Company on net Deferred NPC under–collections and interest shall be paid to Customers on net deferred NPC over-collections. Appropriate provisions for interest during the amortization period shall be included in the calculation of Deferred NPC

Adjustments in the NPC Rate Effective Period. If the Commission implements a proposed Deferred NPC Adjustment on an interim basis, any excess charges or under charges shall be refunded to or collected from customers with interest at the rate established by the Commission pursuant to Rule 241. If the Commission approves an amortization period for a Deferred NPC balance of longer than 12 months, interest on any balance not recovered within 12 months shall be calculated based on the Company's most recent authorized weighted average cost of capital.

Wyoming Allocated Share shall be calculated using Wyoming Allocation Factors. Wyoming Allocation Factors are Wyoming's percent of total system factors prescribed for allocation of net power costs pursuant to the Revised Protocol or current Commission approved interjurisdictional allocation methodology as approved in the most recent general rate case.

Wyoming Actual Adjusted ECD is recalculated for each NPC Comparison Period. The Wyoming Actual Adjusted ECD will be calculated in the same manner that the Wyoming ECD Base was calculated except the only values that will be updated in the recalculation are the amounts from the FERC accounts included in the definition of Adjusted Actual NPC and associated megawatt hours for the NPC Comparison Period.

Wyoming ECD Base is the sum of the ECD adjustments included in the Wyoming revenue requirement as most-recently approved by the Commission either in a stipulated agreement or as a result of a GRC.

Timing

The Company shall file Deferred NPC Adjustment applications on or before February 1st of each year under normal circumstances. The implementation and effective date of the Deferred NPC Adjustment shall be April 1st of each year under normal circumstances. Nothing shall prevent the Company from filing out-of-period PCAM applications to reflect extraordinary circumstances. The Company may elect to defer recovery of a NPC under collection at its discretion and the Company may elect to defer refund of a NPC over recovery if the balance in the deferred account is less than $1 million on a Wyoming jurisdiction allocated basis.

Deferred NPC Adjustment:

Deferred NPC for the Comparison Period shall be calculated monthly and recorded on the Company's books, based on the following formula:

Deferred NPC Adjustment = ((((Adjusted Actual NPC – (Base NPC x Revenue Variation Adjustment)) +/- Dead Band) x Sharing Proportion) x Wyoming Allocated Share) + Symmetrical Interest.

At the end of each comparison period, the Deferred NPC Adjustment may also include an ECD Adjustment. An ECD Adjustment shall be included in the Deferred NPC Adjustment if the value of the Deferred NPC Adjustment is not zero. The ECD adjustment formula is as follows:

ECD Adjustment = (Wyoming Actual Adjusted ECD – (Wyoming ECD Base x Revenue Variation Adjustment))

The initial Base NPC will be set at $660 million on an annual basis. For purposes of the first comparison period from July 1, 2006 through November 30, 2006 an adjustment will be made in the deferral calculation, which increases the Base NPC for those months from $321 million to $336 million. If the Company has not or will not file a new general rate case prior to February 1, 2007, the Base NPC will remain $660 million for the new NPC Comparison Period starting December 1, 2006 and shall remain at that level until rates are set in the Company's next general rate case. Otherwise, the Base NPC will be revised to $700 million on an annual basis on December 1,2006 for purposes of the deferral calculation only.

Base NPC and the Deferred NPC Adjustment shall be allocated to all retail tariff rate schedules and, where applicable, to the demand and energy rate components within each schedule based on the applicable allocation factors and cost of service study relationships established in the Company's last GRC. The allocated and classified costs shall then be divided by appropriate billing determinants to calculate the specific rates set forth in this schedule for the Base NPC and Deferred NPC Adjustment. As such, the Deferred NPC adjustment will be spread to customer classes and rate elements in the same proportion as Base NPC.

Monthly Billing

All charges and provisions of the applicable rate schedule will be applied in determining a Customer's bill except that the Customer's total electric bill will be increased or decreased by an amount equal to the product of all kilowatt demand multiplied by the following dollar per kilowatt rate plus all kilowatt-hours of use multiplied by the following cents per kilowatt-hour rate:

Schedule	Delivery Voltage	Billing Units	Base NPC	Deferred NPC Adj.
2	**	Demand per kWh	0.148¢	0.000¢
		Energy per kWh	1.180¢	0.000¢
15	**	Demand per kWh	0.017¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
25	Secondary	Demand per kW	$0.89	$0.00
		Energy per kWh	1.185¢	0.000¢
	Primary	Demand per kW	$0.87	$0.00
		Energy per kWh	1.159¢	0.000¢
33	Primary	Demand per kW	$0.78	$0.00
		Energy per kWh	1.160¢	0.000¢
	Transmission	Demand per kW	$0.77	$.000

		Energy per kWh	1.135¢	0.000¢
40	**	Demand per kW	$0.74	$0.00
		Energy per kWh	1.210¢	0.000¢

Monthly Billing (continued)

Schedule	Delivery Voltage	Billing Units	Base NPC	Deferred NPC Adj.
46	Secondary	Demand per kW	$0.79	$0.00
		Energy per kWh	1.186¢	0.000¢
	Primary	Demand per kW	$0.78	$0.00
		Energy per kWh	1.160¢	0.000¢
48T	Transmission	Demand per kW	$0.77	$0.00
		Energy per kWh	1.135¢	0.000¢
51	**	Demand per kWh	0.017¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
53	**	Demand per kWh	0.017¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
54	**	Demand per kWh	0.017¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
57	**	Demand per kWh	0.017¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
58	**	Demand per kWh	0.017¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
207	**	Demand per kWh	0.013¢	0.000¢

		Energy per kWh	1.186¢	0.000¢
210	**	Demand per kW	$0.73	0.000¢
		Energy per kWh	1.209¢	0.000¢

Monthly Billing (continued)

Schedule	Delivery Voltage	Billing Units	Base NPC	Deferred NPC Adj.
211	**	Demand per kWh	0.013¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
212-1	**	Demand per kWh	0.013¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
212-2	**	Demand per kWh	0.076¢	0.000¢
		Energy per kWh	1.189¢	0.000¢
212-3	**	Demand per kWh	0.076¢	0.000¢
		Energy per kWh	1.189¢	0.000¢

** Rates will be applicable for all Delivery Voltage levels.

Rules

Service under this Schedule is subject to the General Rules contained in the tariff of which this Schedule is a part, and to those prescribed by regulatory authorities.

STIPULATION EXHIBIT 3

Stipulation Exhibit 3

Month	July to November 2006	Dead Band (+/-)	Baseline $660 M	Dead Band (+/-)	Baseline $700 M	Dead Band (+/-)
January			41,644	2,524	44,168	2,524
February			42,936	2,602	45,538	2,602
March			40,536	2,457	42,993	2,457
April			46,069	2,792	48,861	2,792
May			44,195	2,679	46,874	2,679
June			65,327	3,959	69,286	3,959
July	89,930	5,207	85,922	5,207	91,129	5,207
August	79,930	4,628	76,369	4,628	80,997	4,628
September	61,507	3,562	58,766	3,562	62,328	3,562
October	55,885	3,236	53,394	3,236	56,630	3,236
November	49,330	2,857	47,132	2,857	49,989	2,857
December			57,705	3,497	61,202	3,497
Total	**336,582**	**19,490**	**659,995**	**40,000**	**699,995**	**40,000**

OCS Data Request 27.5

Please provide the distribution planning criteria used by the Company to size transformers, such as the assumed coincidence factor(s) and how load estimates are formulated.

Response to OCS Data Request 27.5

Please refer to Attachment OCS 27.5 which provides a copy of the Company's distribution engineering standard DA 411.

DA 411 General—Residential Electrical Demand

Scope

This document provides guidance on electrical demand estimation and service transformer sizing for single- and multi-family residential dwellings. Covered topics include residential load estimation, load factor, coincidence factor, and service transformer sizing.

Refer to PacifiCorp Engineering Policy 19, *Residential Subdivision Design Policy,* for additional information on design.

Load Estimation

Several factors must be known or assumed in order to accurately estimate peak electrical demand. Even with accurate information or profile metering, changes in the number of occupants, life style, major appliances, or remodels can result in significant changes. In the absence of unusual conditions such as temperature extremes or large block loads the demand estimates provided below are appropriate for sizing transformers across the company's service territory.

Table 1 and Table 2 below show estimated peak demands for single-family homes.

Table 1—Summer Peaking, Single-Family, Ducted Heat Source: Gas, Heat Pump, Other Estimated Peak Demand (kVA) per Residence

Home Size (Effective/Total ft.²)		< 1300 ft.²		1300-2000 ft.²		2001-3500 ft.²		3501-4500 ft.²		4501-6000 ft.²	
Number of Customers	CF	Peak Load	XFMR Size	Peak Load	XFMR Size	Peak Load	XFMR Size	Peak Load	XFMR Size	Peak Load	XFMR Size
1	1	8	**25**	10	**25**	14	**25**	17	**25**	22	**25**
2	0.9	15	**25**	18	**25**	26	**50**	31	**50**	40	**50**
3	0.86	21	**25**	26	**50**	37	**50**	44	**50**	57	**75**
4	0.82	27	**50**	33	**50**	46	**50**	56	**75**	73	**75**
5	0.78	32	**50**	39	**50**	55	**75**	67	**75**	86	**100[1]**
6	0.76	37	**50**	46	**50**	64	**75**	78	**100[1]**	101	**167[1]**
7	0.74	42	**50**	52	**75**	73	**75**	89	**100[1]**	114	**167[1]**
8	0.72	47	**50**	58	**75**	81	**100[1]**	98	**100[1]**	127	**167[1]**
9	0.71	52	**75**	64	**75**	90	**100[1]**	109	**167[1]**	141	**167[1]**
10	0.7	56	**75**	70	**75**	98	**100[1]**	119	**167[1]**	154	**167[1]**
11	0.7	62	**75**	77	**100[1]**	108	**167[1]**	131	**167[1]**	170	*
12	0.7	68	**75**	84	**100[1]**	118	**167[1]**	143	**167[1]**	185	*
13	0.7	73	**75**	91	**100[1]**	128	**167[1]**	155	**167[1]**	201	*
14	0.7	79	**100[1]**	98	**100[1]**	138	**167[1]**	167	**167[1]**	216	*
15	0.7	84	**100[1]**	105	**167[1]**	147	**167[1]**	179	*	231	*
16	0.7	90	**100[1]**	112	**167[1]**	157	**167[1]**	191	*	247	*
17	0.7	96	**100[1]**	119	**167[1]**	167	**167[1]**	203	*	262	*
18	0.7	101	**167[1]**	126	**167[1]**	177	*	215	*	278	*
19	0.7	107	**167[1]**	133	**167[1]**	187	*	227	*	293	*
20	0.7	112	**167[1]**	140	**167[1]**	196	*	238	*	308	*

[1] Consult with engineering prior to installing transformers 100 kVA or greater for single-phase, residential services.

* Multiple service transformers required.

ROCKY MOUNTAIN POWER

PACIFIC POWER

Table 2—Winter Peaking, Single-Family, Ducted Heat Source: Resistive Electric Estimated Peak Demand (kVA) per Residence

Home Size (Effective/Total ft.²)		< 1300 ft.²		1300-2000 ft.²		2001-3500 ft.²		3501-4500 ft.²		4501-6000 ft.²	
Number of Customers	CF	Peak Load	XFMR Size	Peak Load	XFMR Size	Peak Load	XFMR Size	Peak Load	XFMR Size	Peak Load	XFMR Size
1	1	13	**25**	17	**25**	20	**25**	25	**25**	30	**50**
2	0.77	21	**25**	27	**25**	31	**50**	39	**50**	47	**50**
3	0.70	28	**50**	36	**50**	42	**50**	53	**50**	63	**75**
4	0.67	35	**50**	46	**50**	54	**50**	67	**75**	81	**75**
5	0.64	42	**50**	55	**50**	64	**75**	80	**75**	96	**100[1]**
6	0.62	49	**50**	64	**75**	75	**75**	93	**100[1]**	112	**167[1]**
7	0.60	55	**50**	72	**75**	84	**100[1]**	105	**100[1]**	126	**167[1]**
8	0.59	62	**75**	81	**75**	95	**100[1]**	118	**167[1]**	142	**167[1]**
9	0.58	68	**75**	89	**100[1]**	105	**100[1]**	131	**167[1]**	157	**167[1]**
10	0.57	75	**75**	97	**100[1]**	114	**167[1]**	143	**167[1]**	171	**167[1]**
11	0.57	82	**75**	107	**100[1]**	126	**167[1]**	157	**167[1]**	189	*
12	0.57	89	**100[1]**	117	**167[1]**	137	**167[1]**	171	**167[1]**	206	*
13	0.57	97	**100[1]**	126	**167[1]**	149	**167[1]**	186	*	223	*
14	0.57	104	**100[1]**	136	**167[1]**	160	**167[1]**	200	*	240	*
15	0.57	112	**167[1]**	146	**167[1]**	171	**167[1]**	214	*	257	*
16	0.57	119	**167[1]**	156	**167[1]**	183	**167[1]**	228	*	274	*
17	0.57	126	**167[1]**	165	**167[1]**	194	*	243	*	291	*
18	0.57	134	**167[1]**	175	**167[1]**	206	*	257	*	308	*
19	0.57	141	**167[1]**	185	*	217	*	271	*	325	*
20	0.57	149	**167[1]**	194	*	228	*	285	*	342	*

[1] Consult with engineering prior to installing transformers 100 kVA or greater for single-phase, residential services.

* Multiple service transformers required.

Supplemental Calculations

1.Square Footage and Heat Source Based Model:

Conservative estimates for peak residential demand are provided in Table 3 and Table 4. Estimates vary with the ducted heat source and total square footage, in all cases ducted air conditioning is assumed. Quick reference tables are provided to assist in sizing service transformers with multiple residences in the same classification. Peak demand estimates may also be made using load factor conversions with a nearby comparable or historical meter data.

Table 3—Multi-Family / Apartment
Estimated Peak Demand (kVA) Per Residence

Ducted Heat Source	< 800 ft.^{2}	801 - 1000 ft.^{2}	1001 - 1500 ft.^{2}
Gas, Heat Pump, Other	5	6	7
Resistive	8	9	11

Table 4—Single-Family
Estimated Peak Demand (kVA) Per Residence

Ducted Heat Source	< 1300 ft.^{2}	1300-2000 ft.^{2}	2001-3500 ft.^{2}	3501-4500 ft.^{2}	4501-6000 ft.^{2}
Gas, Heat Pump, Other	8	10	14	17	22
Resistive	13	17	20	25	30

2.Load Factor (Energy to Demand Conversion)

Load factor (LF) can be used to estimate peak electrical demand or energy consumption when one of the factors is unknown. Load factors vary seasonally and are highly dependent on the types of major appliances in use and their duty cycle. Typical load factors for residential dwellings are provided in Table 5. For a fixed amount of energy consumption the estimated peak demand will increase as the load factor decreases as shown in Figure 1.

Load factor calculations may be used to estimate peak electrical demand by pulling historical usage for the customer in question or comparable sites nearby. For the residential load class an average power factor (PF) of 0.95 may be assumed. Equations and examples are provided to assist in manual calculations.

Table 5—Typical Residential Load Factor

Season	Ducted Heat Source	Load Factor
Shoulder	Minimal Heat/Cooling	30% to 45%
Summer	Evaporative Cooling	30% to 45%
	Air Conditioning	30% to 40%
Winter	Non-Resistive Heat	30% to 40%
	Resistive Heat	25% to 40%

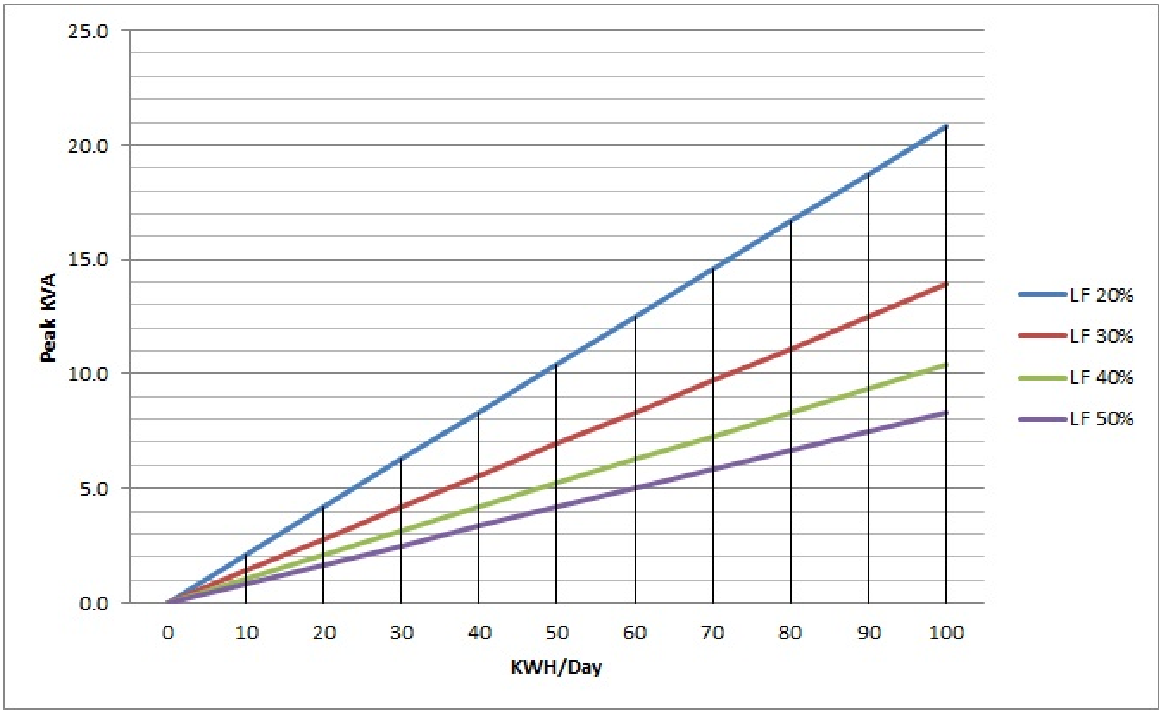

Figure 1—Estimating Load with Historical Usage

$$LoadFactor(LF) = \frac{kWh}{\left(Peak\ kW\right) \times Number\ of\ Days \times 24\frac{hrs}{day}}$$

$$Peak\ kW = \frac{kWh}{LF \times Number\ of\ Days \times 24\frac{hrs}{day}}$$

$$Peak\ kVA = \frac{PeakkW}{PF}$$

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PACIFIC POWER

Example Calculating Load Factor (LF)

1. Total kWh in billing period = 975 kWh
2. Peak demand registered = 5.6 kW
3. Number of days in billing period = 29

$$Load\,Factor\,(LF) = \frac{975\;kWh}{5.6\;kW \times 29\;days \times 24\,\frac{hrs}{day}} = 0.25\;or\;25\%$$

Example Calculating Peak kW and kVA

1. Total kWh in billing period = 975 kWh
2. Load factor = 40%
3. Assumed power factor (PF) = 0,95
4. Number of days in billing period = 29

$$Peak\;kW = \frac{975\;\;kWh}{0.4 \times 29\;days \times 24\,\frac{hrs}{day}} = 3.5\;kW$$

$$Peak\;\;kVA = \frac{3.5\;kW}{0.95\;\;PF} = 3.68\,kVA$$

3.Block Loads, Climate Adjustment, and Flicker Sources

Limitations on block load size for residential services are addressed in the PacifiCorp *Electric Service Requirements Manual* under load requirements. In general adjustments are not necessary for infrequently used loads with limited duty cycles commonly associated with home shops for wood/metal working or electric lifts. Adjustments to demand estimates may be necessary for uncommon conditions, some of which some of the most common are discussed below.

3.1. Heating and Cooling

Heating and cooling loads are accounted for in the demand estimates in Table 3 and Table 4. These estimates are valid for all climate zones assuming the loads fall at or below the median ranges shown Table 6 and Table 7. Climatic adjustments may be necessary for older homes with less insulation, unique floor plans, or in the extremes of climatic conditions. These adjustments should be made in coordination with load sheets provided by the customer.

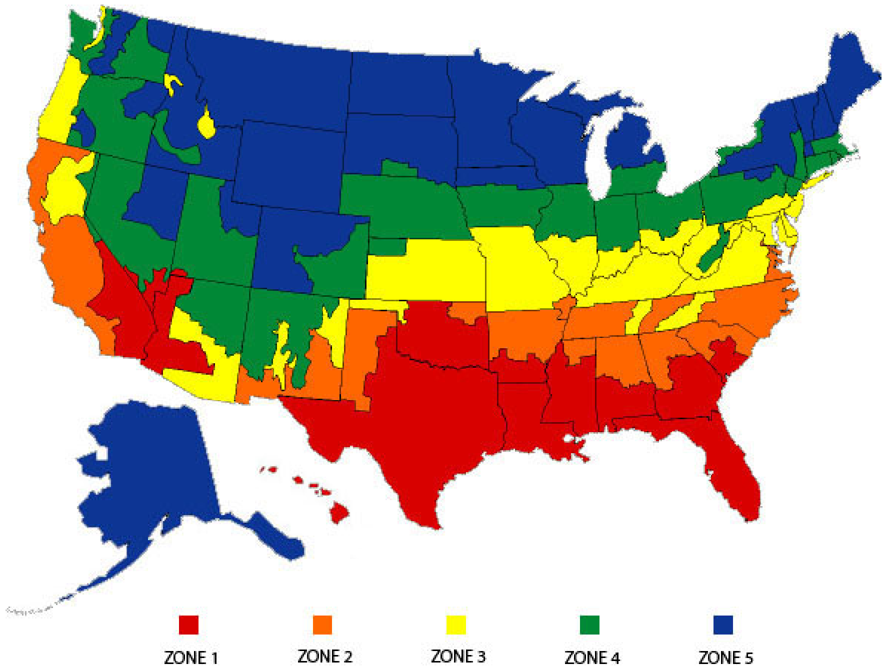

Figure 2—U.S. Climate Zones

Table 6—AC Tonnage vs. Finished Square Footage

	ZONE 1	ZONE 2	ZONE 3	ZONE 4	ZONE 5
1.5 Tons	600 - 900 ft²	600 - 950 ft²	600 - 1000 ft²	700 - 1050 ft²	700 - 1100 ft²
2 Tons	907 - 1200 ft²	951 - 1250 ft²	1001 - 1300 ft²	1051 - 1350 ft²	1101 - 1400 ft²
2.5 Tons	1201 - 1500 ft²	1251 - 1550 ft²	1301 - 1600 ft²	1351 - 1600 ft²	1401 - 1650 ft²
3 Tons	1501 - 1800 ft²	1501 - 1850 ft²	1601 - 1900 ft²	1601 - 2000 ft²	1651 - 2100 ft²
3.5 Tons	1801 - 2100 ft²	1851 - 2150 ft²	1901 - 2200 ft²	2001 - 2250 ft²	2101 - 2300 ft²
4 Tons	2101 - 2400 ft²	2151 - 2500 ft²	2201 - 2600 ft²	2251 - 2700 ft²	2301 - 2700 ft²
5 Tons	2401 - 3000 ft²	2501 - 3100 ft²	2601 - 3200 ft²	2751 - 3300 ft²	2701 - 3300 ft²

Note: Assume multiple AC units for residences for AC loads larger than 5 Tons

Table 7—Resistive Heat Load vs. Finished Square Footage

kW per 1000 ft²	ZONE 1	ZONE 2	ZONE 3	ZONE 4	ZONE 5
Lower Range	4.4 kW	5.9 kW	8.8 kW	10.3 kW	11.8 kW
Median	7.4 kW	8.8 kW	11 kW	12.5 kW	14.7 kW
Upper Range	10.3 kW	11.8 kW	13.2 kW	14.7 kW	17.6 kW

3.2. Electric Vehicle (EV) Chargers

Electric vehicle chargers are considered a unique load and not accounted for in standard estimates. While the adoption of electric vehicles is increasing throughout the company's service territory the technology is evolving rapidly with customer behavior, charge rates and durations varying significantly. Isolated electric vehicle chargers are not expected to cause problems, however multiple electric vehicle chargers connected to the same set of secondary conductors or transformers may result in equipment overloads.

If the presence of an electric vehicle is known at the time of construction or service upgrade, 6 kVA should be added to the peak demand estimate for that residence. Table 8 provides peak charge rates for standard electric vehicle chargers currently on the market, however most vehicles are not currently capable of charging at the peak rates listed.

Table 8—Electric Vehicle Peak Charge Rates

Type	Voltage	Peak Charge Rate	Demand Adder per Dwelling
Level 1	120 V	1.92 kW / 16 A	1.5 kVA
Level 2a	240 V	7.68 kW / 32 A	6 kVA
Level 2b		19.20 kW / 80 A	18 kVA

4.Coincidence Factor

Coincidence factors are applied when more than one customer is served by a single transformer or set of conductors. Since all customers generally do not reach peak load at the same moment, the total load on cables or on the transformer is generally less than the sum of the individual peak loads.

Coincidental peak demand is determined by adding up the individual peak demands and multiplying by a coincidence factor. Coincidence factor varies with number of customers. The numbers provided in Table 9 apply to single-and multi-family construction.

Table 9—Coincidence Factor

Number Of Customers	1	2	3	4	5	6	7	8	9	10	11 or more
CF for Summer Loads	1.0	.90	.86	.82	.78	.76	.74	.72	.71	.70	.70
CF for Winter Loads	1.0	.77	.70	.67	.64	.62	.60	.59	.58	.57	.56

Example

Determine the coincidental peak demand for the group of single-family homes below assuming summer peaking with natural gas as the primary heat source.

Home Size	1500 ft.^{2}	2500 ft.^{2}	3000 ft.^{2}
Number of Homes	1	2	2 w/ 1 EV

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Step 1:

1. Determine the estimated peak demand for each residence using Table 3 and Table 4.
2. Add the estimated peak demands for each residence.
3. Determine coincidence factor based on number of residences and peaking using Table 9.

Size of House	Individual Demand	Number of Homes	Sum of Demands
1500 ft²	10 kVA	1	10 kVA
2500 ft²	14 kVA	2	28 kVA
3000 ft²	14 kVA	1	14 kVA
3000 ft² w/ EV	20 kVA	1	20 kVA
	Totals	**5**	**72 kVA**

Step 2:

1. Determine the coincidental demand by multiplying the sum of demands by the coincidence factor.

$$CoincidentalDemand = CF \times Sum\ \ of\,Demands\ = 0.78 \times 72\,kVA\ = 56.1\ kVA$$

5.Service Transformer Sizing

Service transformers are sized to serve peak coincidental load while limiting voltage drop and flicker to acceptable levels. Service transformer size also impacts the maximum available fault current at the customer's service entrance. The short-circuit current rating (SCCR) of the customer's service entrances may limit the size of transformer that may be selected.

For new construction and service upgrades service transformers should be sized to serve the estimated coincidental peak load without exceeding limits defined in Table 10. Summer peaking should be assumed for most residential services unless a ducted resistive heat source is present or the area is known to be winter peaking. Table 11 should be used in determining whether or not an in-service transformer is overloaded.

Table 10—Conservative Transformer Loading Guidlines

100% Summer Loading, 110% Winter Loading					
Transformer Size	25 kVA	50 kVA	75 kVA	100 kVA	167 kVA
Summer Range	0-25	26-50	51-75	76-100	101-167
Winter Range	0-28	29-55	56-83	84-110	111-184

Table 11—Maximum Transformer Loading Guidelines

130% Summer Loading, 150% Winter Loading					
Transformer Size	25 kVA	50 kVA	75 kVA	100 kVA	167 kVA
Summer Range	0-33	34-65	66-98	99-130	131-218
Winter Range	0-38	39-75	76-113	114-150	151-251

Example

Determine the required service transformer size to serve the group of single-family homes below assuming summer peaking with natural gas as the primary heat source.

Size of House	Individual Demand	Number of Homes	Sum of Demands
1500 ft²	10 kVA	1	10 kVA
2500 ft²	14 kVA	2	28 kVA
3000 ft²	14 kVA	1	14 kVA
3000 ft² w/ EV	20 kVA	1	20 kVA
	Totals	**5**	**72 kVA**

$$Coincidental\ Demand = CF \times Sum\ of\ Demands = 0.78 \times 72\ kVA = \ 56.1\ kVA$$

$$Required\ Transformer\ Size = 75\,kVA\,(kVA\ Range = 51 - 75)$$

Table 12—Summer Peaking, Multi-Family, Ducted Heat Source: Gas, Heat Pump, Other

Home Size (Effective/Total ft.²)		< 800 ft.²		801-1000 ft.²		1001-1500 ft.²	
Number of Customers	CF	Peak Load	XFMR Size	Peak Load	XFMR Size	Peak Load	XFMR Size
1	1	5	**25**	6	**25**	7	**25**
2	0.9	9	**25**	11	**25**	13	**25**
3	0.86	13	**25**	16	**25**	19	**25**
4	0.82	17	**25**	20	**25**	23	**25**
5	0.78	20	**25**	24	**25**	28	**50**
6	0.76	23	**25**	28	**50**	32	**50**
7	0.74	26	**50**	32	**50**	37	**50**
8	0.72	29	**50**	35	**50**	41	**50**
9	0.71	32	**50**	39	**50**	45	**50**
10	0.7	35	**50**	42	**50**	49	**50**
11	0.7	39	**50**	47	**50**	54	**75**
12	0.7	42	**50**	51	**75**	59	**75**
13	0.7	46	**50**	55	**75**	64	**75**
14	0.7	49	**50**	59	**75**	69	**75**
15	0.7	53	**75**	63	**75**	74	**75**
16	0.7	56	**75**	68	**75**	79	**100[1]**
17	0.7	60	**75**	72	**75**	84	**100[1]**
18	0.7	63	**75**	76	**100[1]**	89	**100[1]**
19	0.7	67	**75**	80	**100[1]**	94	**100[1]**
20	0.7	70	**75**	84	**100[1]**	98	**100[1]**

[1] Consult with engineering prior to installing transformers 100 kVA or greater for single-phase, residential services.

Table 13—Winter Peaking, Multi-Family, Ducted Heat Source: Resistive Electric Estimated Peak Demand (kVA) per Residence

Home Size (Effective/Total ft.²)		< 800 ft.²		801-1000 ft.²		1001-1500 ft.²	
Number of Customers	**CF**	**Peak Load**	**XFMR Size**	**Peak Load**	**XFMR Size**	**Peak Load**	**XFMR Size**
1	1	8	**25**	9	**25**	11	**25**
2	0.77	13	**25**	14	**25**	17	**25**
3	0.70	17	**25**	19	**25**	24	**25**
4	0.67	22	**25**	25	**25**	30	**50**
5	0.64	26	**25**	29	**50**	36	**50**
6	0.62	30	**50**	34	**50**	41	**50**
7	0.60	34	**50**	38	**50**	47	**50**
8	0.59	38	**50**	43	**50**	52	**50**
9	0.58	42	**50**	47	**50**	58	**75**
10	0.57	46	**50**	52	**50**	63	**75**
11	0.57	51	**50**	57	**75**	69	**75**
12	0.57	55	**50**	62	**75**	76	**75**
13	0.57	60	**75**	67	**75**	82	**75**
14	0.57	64	**75**	72	**75**	88	**100[1]**
15	0.57	69	**75**	77	**75**	95	**100[1]**
16	0.57	73	**75**	83	**75**	101	**100[1]**
17	0.57	78	**75**	88	**100[1]**	107	**100[1]**
18	0.57	83	**75**	93	**100[1]**	113	**167[1]**
19	0.57	87	**100[1]**	98	**100[1]**	120	**167[1]**
20	0.57	92	**100[1]**	103	**100[1]**	126	**167[1]**

[1] Consult with engineering prior to installing transformers 100 kVA or greater for single-phase, residential services.

OCS Data Request 27.7

Reference Witness Meredith rebuttal at lines 1157-1158 stating, “It is also very conservative relative to interruptible programs offered by other utilities around the country.” Please provide all other utilities around the country that Witness Meredith is referring to and any pricing comparison that RMP conducted to support this statement. Where applicable provide your response in a live, unlocked Excel spreadsheet with all link and formula intact.

Response to OCS Data Request 27.7

Please refer to Attachment OCS 27.7 which provides copies of interruptible program tariffs from other utilities. All of these tariffs contain capacity credit prices higher than the $1 per kilowatt-month ($/kW-month) proposed by the Company.

ELECTRIC SCHEDULE E-BIP Sheet 1
BASE INTERRUPTIBLE PROGRAM

APPLICABILITY: This rate schedule is available until modified or terminated in the rate design phase of the next general rate case or in another proceeding. The E-BIP (Program) is intended to provide load reductions on PG&E's system. Customers enrolled in the Program will be required to reduce their load down to their Firm Service Level (FSL).

Pursuant to Decision 10-06-034, which placed a Megawatt (MW) cap on emergency demand response programs, the Program may at any time be subject to a cap for new participants.

TERRITORY: The Program is available throughout PG&E's electric service area.

ELIGIBILITY: Schedule E-BIP is available to PG&E customers receiving bundled-service, Community Choice Aggregation (CCA) service, or Direct Access (DA) service and being billed on a PG&E commercial, industrial, or agricultural electric rate schedule. Each customer, both directly enrolled and those enrolled in a DR aggregator's portfolio, must take service under the provisions of a demand time-of-use rate schedule to participate in the Program and have at least 100 kilowatt (kW) or higher maximum demand during the summer on-peak or winter (T) partial-peak for at least one month over the previous 12 months. Eligible (T) customers include those receiving partial standby service or services pursuant to one or more of the Net Energy Metering Service schedules except NEMCCSF. Customers participating in Peak Day Pricing (PDP) rate option or (T) Scheduled Load Reduction Program (SLRP) are eligible to participate in Schedule E-BIP.

Customers receiving power from third parties (other than DA and CCA) and (N) customers billed by full standby service are not eligible for Schedule E-BIP. (N) Customers may participate with third-party aggregators in Schedule E-BIP; however, neither those third-party aggregators nor the customers themselves may be the Demand Response Provider (DRP) of record for those customers and may not bid the associated capacity from those customers into the CAISO market. Also, customers are prohibited from participating in Schedule E-BIP if the customer is participating in another capacity-based program, even if PG&E is the DRP such as the Capacity Bidding Program.

(D)

PG&E, acting as a Demand Response Provider (DRP), must be able to register (N) customers who are participating in the Schedule E-BIP into the California Independent System Operator's (CAISO) Demand Response Registration System (DRRS), which requires Load Serving Entity (LSE) approval. To the extent that PG&E is unable to register the customer and/or the customer's LSE does not allow the customer to be registered, the customer will be ineligible to participate in the Schedule E-BIP. (N)

A customer may enroll directly with PG&E or with a DR aggregator. A DR aggregator is an entity, appointed by a customer, to act on behalf of said customer with respect to all aspects of the Program, including but not limited to: a) the receipt of notices from PG&E under this Program; b) the receipt of incentive payments from PG&E; and c) the payment of Excess Energy Charges to PG&E.

(Continued)

ELECTRIC SCHEDULE E-BIP Sheet 2
BASE INTERRUPTIBLE PROGRAM

ENROLLMENT: Each customer, both directly enrolled and those in a DR aggregator's portfolio, must designate a FSL of kW to which it will reduce its load down to or below during a Program curtailment event. The FSL must be no more than 85 percent of each customer's highest monthly maximum demand during the summer on–peak and winter partial-peak periods over the past 12 months with a minimum load reduction of 100kW. During the enrollment process, customers must demonstrate their ability to meet the designated FSL by participating in a curtailment test. The curtailment test will last up to the maximum event duration and will take place prior to enrollment being completed. (L)(T) (L) (L)(T) (L) I (L)(N) (N)

As part of its application, each new applicant is required to submit an event action plan detailing specific actions taken to reduce its load down to or below the applicant's proposed FSL within the 30-minute response time and for the maximum event duration.

An applicant's effective start date shall be determined by PG&E and shall be set after PG&E has determined the application has met the eligibility rules, the load reduction demonstration was successful and PG&E has approved the applicant's load reduction plan. (N)

Customers on the Program may not have, or obtain, any insurance for the purpose of paying Excess Energy Charges for willful failure to comply with requests for curtailments. Customers with such a policy will be terminated and required to pay back any incentives received for the period covered by the insurance. If the period cannot be determined, the recovery shall be for the entire period the customer was on the Program. (L)(T) (L)

Customers who are deemed essential under the Electric Emergency Plan as adopted in Decision 01-04-006 must acknowledge that they are voluntarily electing to participate in the Program for part or all of their load based on adequate backup generation or other means to interrupt load upon request by PG&E, while continuing to meet its essential needs. In addition, an essential customer may commit no more than 50 percent of its average peak load to the Program. (L) (L)(T) (L) (L) (L)(T)

Customers participating directly with PG&E must enroll using PG&E's demand response enrollment website. DR aggregators must enroll customers by submitting a fully executed Notice to Add or Delete Customers Participating in the Base Interruptible Program (Form 79-1080). (T) (T)

Directly-enrolled customers will be responsible for maintaining their notification contacts through PG&E's Inter-Act system. DR aggregators submit their notification contact(s) with their Add or Delete Customers Participating in the Base Interruptible Program (Form 79-1080) form and maintain them through Inter-Act. (N) (N)

(Continued)

ELECTRIC SCHEDULE E-BIP Sheet 3
BASE INTERRUPTIBLE PROGRAM

METERING EQUIPMENT:

Each Service Agreement (SA) must have an MV90 or SmartMeter ™ interval meter capable of recording usage in 15-minute intervals installed that can be read remotely by PG&E. A Meter Data Management Agent (MDMA) may also read the customer's meter on behalf of the customer's Electric Service Provider (ESP), if a customer is receiving DA service. Metering equipment (including telephone line, cellular, or radio control communication device) must be in operation for at least 45 days prior to participating in the Program in order to meet the CAISO requirement that customers comprising a Reliability Demand Response Resource provide 45 days of historical meter data to the CAISO. If required, PG&E will provide and install the metering equipment at no cost to the bundled service or CCA service customer. The installation of an interval meter for customers taking service under the provisions of DA is the responsibility of the customer's ESP, or Agent, and must be installed in accordance with Electric Rule 22. (T) (T) (N) I I (N) (T)

Customers receiving an MV90 interval meter at no charge from PG&E through the Program must remain enrolled for a minimum period of one year. Customers who received an MV90 interval meter through the Program but who later elect to leave prior to the one-year anniversary date, or is terminated for cause, must reimburse PG&E for all expenses associated with the installation and maintenance of the meter. Such charges will be collected as a one-time payment pursuant to Electric Rule 2, Section I. Customers who leave the Program after one year may continue their use of the MV90 meter at no additional cost. (T) (T) (T) (D)

Direct Access Service Customers – If PG&E is the MDMA, no additional fees will be required from the customer. If PG&E is not the MDMA, the customer will be responsible for any and all costs associated with providing the interval data into the PG&E system on a daily basis. This includes any additional metering or communication devices that may need to be installed and any additional fees assessed by the customer's ESP. Prior to a customer's participation in the Program, the customer must be able to successfully transfer meter data within PG&E's specification on a daily basis for a period of no less than 10 days to establish its baseline. (T)

Until all necessary equipment is installed and all requirements have been met, new customers will not receive incentive payments or be assessed Excess Energy Charges or be obligated to participate in curtailment events.

DISPATCH / NOTIFICATION SYSTEMS:

PG&E's demand response operations website, located at https://inter-act.pge.com, will be used to communicate all curtailment events to the customer. (T) (T)

Directly-enrolled customers and DR aggregators, at their expense, must have access to the internet and an e-mail address to receive notification via the internet. In addition, they must have, at their expense, a cellular telephone that is capable of receiving a text message sent via the internet. Customers cannot participate in the Program until all of these requirements have been satisfied. (D)(T) (T) I (T)

In the event of a Program curtailment, directly-enrolled customers and DR aggregators will be notified using one or more of the above-mentioned systems. Receipt of such notice is the responsibility of the directly-enrolled customer and DR aggregator. PG&E does not guarantee the reliability of the e-mail system or Internet site by which notification is received. (T) (T)

(Continued)

PROGRAM DETAILS:

PG&E will register each customer at the CAISO for the purposes of bidding into its market as a Reliability Demand Response Resource (RDRR) product. PG&E will assign each customer, both directly enrolled and through a DR aggregator, to a CAISO sub-Load Aggregation Point (sub-LAP), CAISO sub-LAP may change over time, and will be disaggregated by LSE.

Directly-enrolled customers and DR aggregators will be given at least 30 minutes notice before each curtailment.

A program curtailment event will be limited to a maximum of one (1) event per day and six (6) hours per event. The Program will not exceed 10 events during a calendar month, or 180 hours per calendar year. (T)

All customers will be placed on a calendar billing cycle and their regular electric service bills will continue to be calculated each month based on actual recorded monthly demands and energy usage.

The Program will be operated throughout the year.

PG&E may terminate the Program, as directed by the Commission, upon 30 days written notice to all directly-enrolled customers and DR aggregators.

(Continued)

ELECTRIC SCHEDULE E-BIP Sheet 5
BASE INTERRUPTIBLE PROGRAM

PROGRAM TESTING: PG&E may call two (2) test events per year at its or the CAISO's discretion. These test events will be operated, paid, and counted as Program events. (N)

PG&E may conduct a monthly notification test to test its notification system. The monthly notification test will not count toward the Program event limits. No actual load curtailment is required. (N)
|
(N)

INCENTIVE PAYMENTS: Incentives will be paid on a monthly basis based on the directly enrolled customer's or DR aggregator's CAISO sub-LAP portfolio monthly Potential Load Reduction (PLR) amount: (N)

Potential Load Reduction	Incentive
1 kW to 500 kW	$8.00/kW
501 kW to 1,000 kW	$8.50/kW
1,001 kW and greater	$9.00/kW

The PLR (described below) will be multiplied by the appropriate incentive level to determine the monthly incentive payment.

Summer Season (May 1 through October 31): The difference of the directly enrolled customer's or DR aggregator's CAISO sub-LAP portfolio average monthly on-peak period demand (on-peak kWh divided by available on-peak hours), excluding days participating in a DR program event, and its designated FSL. (N) (T)

Winter Season (November 1 through April 30): The difference of the directly enrolled customer's or DR aggregator's CAISO sub-LAP portfolio customer's average monthly partial-peak period demand (partial-peak kWh divided by available partial-peak hours), excluding days participating in a DR program event, and its designated FSL. (N) (T)

The customer's interval data is available through PG&E's Inter-Act system The data may not match billing quality data. All incentive payment calculations uses billing quality data. (N)
|
(N)

ELECTRIC SCHEDULE E-BIP Sheet 6
BASE INTERRUPTIBLE PROGRAM

EXCESS ENERGY CHARGES:	Excess Energy is any energy (kWh) consumed during a curtailment event that is in excess of the customer's FSL. The energy usage is measured in 15-minute intervals. Customers will be assessed an Excess Energy Charge at $6.00 per kilowatt-hour (kWh). PG&E will evaluate and apply Excess Energy Charges for directly-enrolled customers' and DR aggregators' CAISO sub-LAP portfolio no later than 90 days after each curtailment event. The incentive payments will be reflected on the directly-enrolled customers' regular monthly bills as an adjustment. PG&E will adjust DR aggregators' payments based on performance no later than 90 days after a curtailment event. PG&E may elect to evaluate and assess the Excess Energy Charges associated with several curtailment events as a single adjustment.
PROGRAM RETEST:	If a customer fails to reduce its load down to or below its FSL throughout the curtailment event, including test event, PG&E may require a re-test that will not count toward the Program event limits. The Excess Energy Charge will increase to $8.40 per kilowatt-hour (kWh) for the re-test and will continue at this level for the remainder of the calendar year. If the customer fails to reduce its load down to or below its FSL during the re-test, the customer has the option to either: a) de-enroll from the program, b) be re-tested at the current FSL, or c) modify its FSL to an achievable level that meets Program requirements. PG&E may require the customer be re-tested at the new FSL. If the customer does not modify its FSL, de-enroll from the Program, or successfully comply with the re-test, then PG&E will either: a) set the customer's FSL to the highest FSL that meets the Program requirements and require a re-test, b) re-test the customer at its current FSL, or c) terminate the customer's participation. There is no limit to the number of re-tests to which a customer is subject. The customer will be subject to an additional Excess Energy Charge for each failed re-test. For aggregators who fail to comply with a curtailment event, the methodology specified above will be applied at the DR aggregator's CAISO sub-LAP portfolio. In the event an aggregation within an (N) aggregator's CAISO sub-LAP portfolio fails a load curtailment test, only the I customers in the failed aggregation that failed to reduce their loads below I their FSL will be retested. (N)

(Continued)

PROGRAM TRIGGERS:

1) The CAISO issues a market award or dispatch instruction by CAISO sub-LAP pursuant to CAISO Operating Procedure 4420. (N)
(N)

(D)
I
I
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(D)

2) PG&E in its sole discretion may dispatch one or more customers to address transmission or distribution reliability needs. (T)
(T)

(Continued)

ELECTRIC SCHEDULE E-BIP Sheet 8
BASE INTERRUPTIBLE PROGRAM

CONTRACTS:	Customers, both directly-enrolled and those in a DR aggregator's portfolio, may re-designate their FSL or discontinue participation in the Program once annually by providing a 30-day written notice during the month of November. Cancellation will be effective January of the following year. Customers may de-enroll prior to the end of the first year if they do so to participate in the 2016 Demand Response Auction Mechanism Pilot, as directed by the California Public Utilities Commission in Resolution E-4728.	(T)
	DR aggregators must submit a signed Agreement For Aggregators Participating in the Base Interruptible Program (Form 79-1079).	(T)
AGGREGATOR'S PORTFOLIO:	DR aggregators must submit a Notice to Add or Delete Customers Participating in the Base Interruptible Program (Form 79-1080) signed by the aggregated customer to add or delete a customer from its portfolio. PG&E will review and approve each SA before enrollment under the aggregator's portfolio. Each SA may be included in only one portfolio at a time.	(T)
	PG&E will only add a new customer to a DR aggregator's portfolio after all necessary equipment is installed and all requirements have been met. Metering equipment (including telephone line, cellular, or radio control communication device) must be in operation for at least 45 days prior to participating in the Program.	(T) (N) I I (N)
	The terms and conditions of the agreement governing the relationship between the DR aggregator and a customer, with respect to such customer's participation in the Program through such a DR aggregator, are independent of PG&E. Any disputes arising between DR aggregator and such customer shall be resolved by the parties.	(T) I (T)
SPECIAL CONDITIONS FOR COMMUNITY CHOICE AGGREGATION SERVICE (CCA SERVICE) CUSTOMERS AND DIRECT ACCESS (DA) CUSTOMERS:	DA/CCA Service customers enrolling directly with PG&E must make the necessary arrangements with their ESP/CCA before enrolling in this Program.	
	Aggregators must make the necessary arrangements with the ESP and CCA before enrolling DA or CCA Service customers in this Program. Aggregators must notify the ESP/CCA of its DA/CCA Service customers.	(T) (T)
INTERACTION WITH CUSTOMER'S OTHER APPLICABLE PROGRAMS AND CHARGES:	Customers who participate in a third party sponsored interruptible load program must immediately notify PG&E of such activity.	
	Customers enrolled in the Program may also participate in one of the following PG&E DR programs: Scheduled Load Reduction Program (Schedule E-SLRP), or the Peak Day Pricing (PDP) rate option.	(T) (T) (D)

(Continued)

UNDER-FREQUENCY RELAY PROGRAM: Only directly-enrolled customers may participate in PG&E's Underfrequency Relay (UFR) Program. The UFR Program is not available to customers enrolled through DR aggregators. Under the UFR Program, the customer agrees to be subject at all times to automatic interruptions of service caused by an underfrequency relay device that may be installed by PG&E. Please note that PG&E may require up to three years' written notice for termination of participation in the UFR Program. (T)

1) **Details on Automatic Interruptions:** If a customer is participating in the UFR Program, service to the customer will be automatically interrupted if the frequency on the PG&E system drops to 59.65 hertz for 20 cycles. PG&E will install and maintain a digital underfrequency relay and whatever associated equipment it believes is necessary to carry out such automatic interruption. Relays and other equipment will remain the property of PG&E. If more than one relay is required, PG&E will provide the additional relays as "special facilities," at customer's expense, in accordance with Section I of Rule 2.

   In addition to the underfrequency relay, PG&E may install equipment that would automatically interrupt service in case of voltage reductions or other operating conditions.

2) **Metering Requirements for UFR Program:** If a customer is participating in the UFR program in combination with firm or curtailable-only service, the customer will be required to have a separate meter for the UFR service. PG&E will provide the meter sets, but the customer will be responsible for arranging customer's wiring in such a way that the service for each service agreement can be provided and metered at a single point. NOTE: Any other additional facilities required for a combination of curtailable with firm service will be treated as "special facilities" in accordance with Section I of Rule 2.

3) **Communication Channel for UFR Service:** UFR Program customers are required to provide an exclusive communication channel from the PG&E-provided terminal block at the customer's facility to a PG&E-designated control center. The communication channel must meet PG&E's specifications, and must be provided at the customer's expense. PG&E shall have the right to inspect the communication circuit upon reasonable notice.

4) **Rate for UFR Service:** Customers participating in the UFR Program will receive a $0.67/kW demand credit on a monthly basis based on their average monthly on-peak period demand in the summer and the average monthly partial-peak demand in the winter.

SCHEDULE 26
NONRESIDENTIAL DEMAND RESPONSE PILOT PROGRAM

PURPOSE

This schedule is an optional supplemental service that provides participating Large Nonresidential Customers incentives for reducing a committed amount of load at the request of the Company. Under this tariff, the Customer provides a Firm Load Reduction Commitment that the Company calls at any time according to the conditions listed below. The pilot is expected to be conducted from December 1, 2017 through September 30, 2020.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To qualifying Nonresidential Customers served under Schedules 32, 38, 47, 49, 75, 83, 85, 89, and 90. Participating Customers must execute a Schedule 26, Firm Load Reduction Agreement (Agreement) to participate in this program. The Agreement specifies the Customer's Firm Load Reduction Commitment and selected Firm Load Reduction Options.

CUSTOMER ENROLLMENT

Qualified Customers must have enrolled and completed enablement at least 5 business days prior to the Participation Month.

At the time of enrollment, the Customer chooses the participation option, the maximum event hours per season option, the advance-notice option and the event windows for which they want to participate. The load reduction amount is agreed to by the Customer and the Company or its representative. First-time participants can also opt-in for a commissioning test.

Within five business days of enrollment, the Company will confirm receipt of the Service Point Identification (SPID) the Customer intends to enroll under this schedule and the Company or its **(C)**
representatives will send a signed Agreement to the Customer's representative. The Customer **(C)**
may choose to aggregate SPIDs. **(C)**

Each Agreement will automatically renew for successive annual terms on January 1st of subsequent calendar years unless the Customer elects to terminate such Agreement by notifying PGE prior to January 1st or this Schedule is withdrawn, revoked or otherwise terminated.

SCHEDULE 26 (Continued)

CUSTOMER PARTICIPATION OPTIONS

Customers are offered three participation options: Option 1 provides that the Customer participates for all eight months of the contracted program year. Options two and three offer the Customer summer or winter seasonal participation. In the second option the Customer participates for four months in the summer – June, July, August and September. The third option is the Customer participates for four months in the winter – November, December, January and February. Customers select one of the three options at the time of enrollment.

Customer Option	Participation Months	Number of Months Participating
1	Nov, Dec, Jan, Feb, Jun, Jul, Aug, Sep	Eight-month – both seasons
2	Jun, Jul, Aug, Sep	Four-month seasonal – summer
3	Nov, Dec, Jan, Feb	Four-month seasonal – winter

FIRM LOAD REDUCTION OPTIONS

Several firm load reduction options are available to Customers in the Reservation Price Section: Options include differing maximum event hours per season, notification periods, and event windows. For each season only one 'maximum hours' selection and one 'notification period' selection can be chosen for all event windows in which the Customer chooses to participate.

RESERVATION PRICE

20 Event Hours Maximum per Season
Monthly Payment per kW

	Notification Period		
	18 hours	**4 hours**	**10 minutes**
Summer (June - September)			
11 am -4 pm	$1.68	$1.80	$1.91
4 pm - 8 pm	$1.95	$2.08	$2.22
8 pm - 10 pm	$0.39	$0.42	$0.45
All summer windows	$4.02	$4.30	$4.57
Winter (November - February)			
7 am - 11 am	$1.27	$1.35	$1.44
11 am -4 pm	$0.73	$0.78	$0.83
4 pm - 8 pm	$2.07	$2.22	$2.36
8 pm - 10 pm	$0.73	$0.78	$0.83
All winter windows	$4.80	$5.13	$5.46

SCHEDULE 26 (Continued)

RESERVATION PRICE (Continued)

40 Event Hours per Season
Monthly Payment per kW

	Notification Period		
Windows	**18 hours**	**4 hours**	**10 minutes**
Summer (June - September)			
11 am -4 pm	$2.52	$2.69	$2.87
4 pm - 8 pm	$2.92	$3.12	$3.32
8 pm - 10 pm	$0.59	$0.63	$0.67
All summer windows	$6.04	$6.45	$6.86
Winter (November - February)			
7 am - 11 am	$1.90	$2.03	$2.16
11 am -4 pm	$1.09	$1.17	$1.24
4 pm - 8 pm	$3.11	$3.32	$3.54
8 pm - 10 pm	$1.09	$1.17	$1.24
All winter windows	$7.20	$7.70	$8.19

80 Event Hours Maximum per Season
Monthly Payment per kW

	Notification Period		
	18 hours	**4 hours**	**10 minutes**
Summer (June - September)			
11 am -4 pm	$3.35	$3.58	$3.81
4 pm - 8 pm	$3.89	$4.16	$4.42
8 pm - 10 pm	$0.79	$0.84	$0.89
All summer windows	$8.03	$8.58	$9.12
Winter (November - February)			
7 am - 11 am	$2.53	$2.70	$2.87
11 am -4 pm	$1.46	$1.56	$1.65
4 pm - 8 pm	$4.14	$4.42	$4.70
8 pm - 10 pm	$1.46	$1.56	$1.65
All winter windows	$9.58	$10.23	$10.89

SCHEDULE 26 (Continued)

COMMITTED LOAD REDUCTION

If a Customer has completed a test event, but not participated in actual events, their Committed Load Reduction will be based on nominated load identified in the agreement. If a Customer has completed only one event, their Committed Load Reduction will be the higher of either their nominated load or their first event performance. If a Customer has participated in more than one event, their Committed Load Reduction will be based on an average of actual load reductions during event hours. The Customer, at its discretion, may choose to increase its nomination above the levels described above.

QUALIFIED LOAD REDUCTION

If no events are called in a Participation Month, the Customer qualifies for the full Reservation Payment; the Qualified Load Reduction is the Committed Load Reduction.

In order to qualify for the full Reservation Payment during a month with events, the Customer must provide a minimum of 90% of the Committed Load Reduction on average over each event for which the Customer is enrolled during events in that month. If the Customer qualifies for the full Reservation Payment; the Qualified Load Reduction is the Committed Load Reduction.

To qualify for a proportional reservation payment during a month with events, the Customer must deliver a minimum of 70% of the Committed Load Reduction on average over each event for which the Customer is enrolled during events in that month. If the Customer qualifies for a reduced reservation payment; the Qualified Load Reduction is the average load reduction percentage for all event hours during that month.

If the Customer fails to deliver a minimum of 70% of the Committed Load Reduction on average during an event for which the Customer is enrolled during events in that month, the Customer is not eligible for the Energy Reduction Payment for that Event and the Reservation Payment for that month. If other Load Reduction Events are called in the same month, and the Customer complies, the corresponding Energy Reduction Payments are paid for each event that the Customer delivers a minimum of 70% of the Committed Load Reduction on average over each event for which the Customer is enrolled during events in that month.

RESERVATION PAYMENTS

The Reservation Payment is the Customer’s Qualified Load Reduction (kW) multiplied by the sum of each applicable Reservation Price ($/kW) based on the Options selected by the Customer adjusted for losses based on the Customer’s delivery voltage. For each event window (time period for an event) per season, only one price is applicable. The Reservation Payment is made to the Customer no later than 60 days after the month in which they participated.

SCHEDULE 26 (Continued)

ENERGY PAYMENTS

The Energy Payment is the Mid-Columbia Electricity Index (Mid-C) as reported by the Powerdex, adjusted for losses based on the Customer's delivery voltage. The Firm Energy Reduction Amount can be up to 120% of the commitment.

The monthly energy prices (per MWh) for the months in which the events are called* are: **(C)**

Nov 2018	Dec 2018	Jan 2019	Feb 2019	Jun 2019	Jul 2019	Aug 2019	Sep 2019
$25.75	$31.25	$31.25	$26.25	$15.64	$28.94	$32.52	$30.04

The Firm Energy Reduction Payment rates will be updated annually by October 1st for the next calendar year beginning in November. Evaluation and settlement of the Firm Energy Reduction Payment will occur within 60 days of the Firm Load Reduction Event. **(C)**

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* PGE will not call events on Saturdays, Sundays, or Holidays. Holidays are New Year's Day (January 1), President's Day (third Monday of February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). If a holiday falls on Saturday, Friday is designated a holiday. If a holiday falls on Sunday, the following Monday is designated a holiday. **(C)** **(C)**

LINE LOSSES

Losses will be included by multiplying the applicable price by the following adjustment factors:

Subtransmission Delivery Voltage	1.0356
Primary Delivery Voltage	1.0496
Secondary Delivery Voltage	1.0685

LOAD REDUCTION MEASUREMENT

Load Reduction is measured as a reduction of Demand from a Customer Baseline Load calculation during each hour of the Load Reduction Event. Although the Firm Load Reduction Agreement shall specify the Customer Baseline Load calculation methodology to be used, PGE generally uses the following baseline methodology:

Baseline Load Profile

The Baseline Load Profile is based upon the average hourly load of the five highest load days in the last ten Typical Operational Days for the Event period. For Customers choosing the four-hour or 10-minute notification options there is an adjustment to the amounts above to reflect the day-of operational characteristics leading up to the Event if the Event starts at 11 am or later. This adjustment is the difference between the Event day load and the average load of the five highest days used in the load profile above during the two-hour period ending four hours prior to the start of the Event.

SCHEDULE 26 (Continued)

LOAD REDUCTION MEASUREMENT (Continued)

Typical Operational Days

Typical Operational Days exclude days that a Customer has participated in a Firm Load Reduction Event or pre-scheduled opt-out days as defined in the Special Conditions. Typical Operational Days for the baseline calculation are defined as the ten applicable days closest to the Load Reduction Event. Typical Operational Days may include or exclude Saturdays, Sundays and **(C)**
Western Electricity Coordinating Council (WECC) holidays. **(C)**

The Company may decline the Customer's enrollment application when the Company determines the Customer's energy usage is highly variable and the Company is not able to verify that a reduction will be made when called upon.

FIRM ENERGY REDUCTION

The Firm Energy Reduction amount is the difference between the Customer's Baseline Energy profile and the Customer's measured hourly energy usage during the Load Reduction Event.

LOAD REDUCTION EVENT

The Company, at its discretion, initiates a Load Reduction Event by providing the participating Customer with the appropriate notification consistent with the Customer's selected Firm Load Reduction Option. The Customer reduces its Demand served by the Company, for each hour of the Load Reduction Event to achieve its Committed Load Reduction. Each load reduction event will last from one to five hours in duration. For pilot purposes, the Company will call at least one event per season.

The Company initiates Load Reduction Events during January, February, June, July, August, September, November, and December.

EVENT NOTIFICATION

The Company notifies the participating Customer of a Load Reduction Event using a mutually agreed upon method at the time of enrollment. The Company's notification includes a time and date by which the Customer must reduce the committed Demand for each period of the Load Reduction Event.

The Customer is responsible to notify the Company if the Customer's contact information specified at the time of the enrollment changes as soon as such change occurs.

FIRST-TIME PARTICIPANT OPTIONAL COMMISSION TEST

A commissioning test is available to Customers who are participating on this schedule for the first time. Interested participants will work with the Company to learn the details of this process.

SCHEDULE 26 (Continued)

SPECIAL CONDITIONS

1. Customers cannot use on-site diesel, pipeline natural gas or propane or other carbon emitting generation equipment for load reductions to meet load reduction commitments under this tariff. **(C)**

2. Customers that choose to take service under Schedules 86, 485, 489, 490, 532, 538, 549, 575, 583, 585, 589, or 590 will be withdrawn from this program.

3. Firm Load Reduction by Schedule 75 Customers will not exceed the Customer's Baseline Demand as specified in the written service agreement between the Customer and the Company. Customer cannot use purchases under Schedule 76 to meet load reduction commitments under this tariff. In the case of Customers participating on Schedule 76R – Partial Requirements Economic Replacement Power Rider – at the time of the event, the energy imbalance will not apply during event hours and for the event energy amount.

4. The Company is not responsible for any consequences to the participating Customer that results from the Firm Load Reduction Event or the Customer's effort to reduce Energy in response to a Firm Load Reduction Event.

5. This tariff is not applicable when the Company requests or initiates Load Reduction affecting a Customer SPID under system emergency conditions described in Rule N or Rule C(2)(B).

6. The Company will not cancel or shorten the duration of a Firm Reduction Event once notification has been provided.

(D)

7. Participating Customers are required to have interval metering and meter communication in place prior to initiation of service under this schedule. The Company will provide and install necessary equipment which allows the Company and the Customer to monitor the Customer's energy usage. **(T)**

8. If the Customer experiences operational changes or a service disconnection that impairs the ability of the customer to provide the Firm Load Reduction as requested under this schedule, the agreement will be terminated. **(T)**

9. If the Company is not allowed to recover any costs of this program by the Commission, the Company may at its option terminate service under this agreement with 30-day notice. **(T)**

SCHEDULE 26 (Concluded)

SPECIAL CONDITIONS (Continued)

10. The Customer may pre-schedule four opt-out days per season as indicated in the Agreement. If the Company calls a Load Reduction Event on a pre-scheduled opt-out day, the Customer is exempt from providing load reduction and receives no Firm Energy Reduction Payment, whether or not they choose to operate. The Customer will receive the Reservation payment if otherwise eligible. An opt-out day will not be included in the calculation of the Baseline Demand Profile. **(T)**

11. Customers who opt for this Schedule may be placed on a calendar monthly billing cycle. **(T)**

TERM

This pilot term is December 1, 2017 through September 30, 2020.

Schedule TOU-BIP Sheet 1

TIME-OF-USE-GENERAL SERVICE
BASE INTERRUPTIBLE PROGRAM

APPLICABILITY

This Schedule is optional for General Service customers and Aggregators who have monthly Maximum Demands or aggregated monthly Maximum Demands reaching or exceeding 200 kW. Customers, both directly enrolled and those in an Aggregator's portfolio, must take service under the provisions of a Time-of-Use (TOU) or Real Time Pricing (RTP) rate schedule to participate in the Program, and must commit to curtail at least 15 percent of their Maximum Demand, which shall not be less than 100 kW, per Period of Interruption. Additionally, this Schedule is optional for customers with load served under the maintenance and/or backup service provisions of Schedules S, TOU-8-S, or TOU-8-RTP-S as well as supplemental and excess supplemental load of that Schedule.

Participant must choose Participation Option A or Participation Option B, as defined in Special Condition 2 of this Schedule. Customers directly enrolling must make such selection in the Interruptible Service Agreement (Form 14-315) and Aggregators in the Time-of-Use Base Interruptible Program Aggregator Agreement (Form 14-780) prior to receiving service under this Schedule. Participation Option B is the default option for participants who make no selection.

For the purpose of this Schedule a participant is defined as either a customer directly enrolling in this Schedule or an Aggregator.

This Schedule is not applicable to customers served under Schedules GS-APS-E, AP-I, and CBP.

Pursuant to Decision 10-06-034 and Decision 18-11-029, this Schedule is subject to resource allocation every April to administer the Megawatt (MW) cap on emergency demand response programs for new participants and new participating loads. (C)(N)

Pursuant to Decision 18-11-029, except for the customers grandfathered to continue the existing dual participation in accordance to Special Condition 17, all customers served under this Schedule are not eligible to dually enroll with Option CPP of an applicable TOU rate schedule. (N)

TERRITORY

Within the entire territory served.

RATES

All charges and provisions of the customer's Otherwise Applicable Tariff (OAT) shall apply.

(Continued)

Schedule TOU-BIP Sheet 2
TIME-OF-USE-GENERAL SERVICE
BASE INTERRUPTIBLE PROGRAM
(Continued)

RATES (Continued)

Directly Enrolled Customer:
In accordance with the terms and conditions of this Schedule and the applicable contract(s) a customer is eligible for interruptible bill credits on their monthly bill. The bill credits will be based on the kW demand difference between the customer's monthly average kW demand recorded during each TOU period (on-peak and mid-peak during the Summer Season, and mid-peak during the Winter Season), and the customer's Firm Service Level (FSL). The kW demand difference, as described above, will be multiplied by the applicable bill credit amounts differentiated by the selected Participation Option (A or B), by voltage levels, by season, and by TOU period, as listed in this Section. The bill credit(s) for each applicable TOU period is then summed to arrive at the total credit for the month. (D)

Example – Monthly BIP Credit Calculation for Customers during Summer Season:

MASO = Monthly Average Summer On-Peak Demand
MASM = Monthly Average Summer Mid-Peak Demand
FSL = Firm Service Level
SOPC = Summer On Peak Credit amount depending on Participation Option A or B and Voltage Level
SMPC = Summer Mid Peak Credit amount depending on Participation Option A or B and Voltage Level

Step 1: Total Monthly Summer On-Peak kWh / Total Monthly Summer On-Peak Hours = MASO
Step 2: (MASO – FSL)* = Summer On-Peak Interruptible kW
Step 3: Summer On-Peak Interruptible kW x applicable SOPC = monthly bill credit for Interruptible kW for Summer On-Peak Interruptible kW
Step 4: Total Monthly Summer Mid-Peak kWh / Total Monthly Summer Mid-Peak Hours = Monthly Average Summer Mid-Peak Demand (MASM)
Step 5: (MASM – FSL)* = Summer Mid-Peak Interruptible kW
Step 6: Summer Mid-Peak Interruptible kW x applicable SMPC = monthly bill credit for Summer Mid-Peak Interruptible kW
Step 7: The sum of Steps 3 and 6 = Monthly Summer Season Bill Credit

* Value must be 0 or above.

(Continued)

Schedule TOU-BIP
TIME-OF-USE-GENERAL SERVICE
BASE INTERRUPTIBLE PROGRAM
(Continued)

Sheet 3

RATES (Continued)

Aggregator:
In accordance with the terms and conditions of this Schedule and the applicable contract(s), an Aggregator is eligible for monthly payments. The payments will be based on the kW demand difference between each Aggregated Group's total monthly average demand of all of its service accounts as recorded during each TOU period (on-peak and mid-peak during the summer season, and mid-peak during the winter season), and the Aggregated Group's Firm Service Level (FSL). The kW demand difference, as described above, is then multiplied by the applicable payment amount differentiated by the selected participation option (A or B), by voltage level, by season, and by TOU periods, as listed in this Section. The BIP payment(s) for each applicable TOU period is then summed to arrive at the total payment for the month.

MASO = Monthly Average Summer On-Peak Demand
MASM = Monthly Average Summer Mid-Peak Demand
FSL = Firm Service Level
SOPC = Summer On Peak Credit amount depending on Participation Option A or B and Voltage Level
SMPC = Summer Mid Peak Credit amount depending on Participation Option A or B and Voltage Level

Step 1: Total Monthly Summer On-Peak kWh for all service accounts in the aggregated group/ Monthly Summer On-Peak Hours = Aggregated Monthly Average Summer On-Peak Demand (Aggregated MASO)
Step 2: (Aggregated MASO – Aggregated FSL)* = Aggregated Summer On-Peak Interruptible kW (T)
Step 3: Aggregated Summer On-Peak Interruptible kW x applicable SOPC = Aggregated monthly payment for Summer On-Peak Interruptible kW
Step 4: Total Monthly Summer Mid-Peak kWh for all service accounts in the aggregated group/ Monthly Summer Mid-Peak Hours = Aggregated Monthly Average Summer Mid-Peak Demand (Aggregated MASM)
Step 5: (Aggregated MASM – Aggregated FSL)* = Aggregated Summer Mid-Peak Interruptible kW (T)
Step 6: Aggregated Summer Mid-Peak Interruptible kW x applicable SMPC = Aggregated monthly payment for Summer Mid Peak Interruptible kW
Step 7: The sum of Steps 3 and 6 = Aggregated Monthly Summer Season Payment

* Value must be 0 or above. (T)

(Continued)

Schedule TOU-BIP — Sheet 4

TIME-OF-USE-GENERAL SERVICE
BASE INTERRUPTIBLE PROGRAM
(Continued)

RATES (Continued)

The interruptible bill credits or payments are differentiated by voltage levels as follows:

Participation Option A:

SERVICE METERED AND DELIVERED AT VOLTAGES BELOW 2 KV

$/kW per Meter per Month:

Summer Season	- on peak	$ (21.76)(I)
	mid-peak	$ (1.70)(I)
Winter Season	- mid-peak	$ (9.14)(R)

SERVICE METERED AND DELIVERED AT VOLTAGES FROM 2 KV THROUGH 50 KV

$/kW per Meter per Month:

Summer Season	- on peak	$ (21.76)(I)
	mid-peak	$ (1.42)(I)
Winter Season	- mid-peak	$ (8.55)(R)

SERVICE METERED AND DELIVERED AT VOLTAGES ABOVE 50 KV

$/kW per Meter per Month:

Summer Season	- on peak	$ (14.87)(I)
	mid-peak	$ (0.72)(I)
Winter Season	- mid-peak	$ (5.38)(R)

Participation Option B:

SERVICE METERED AND DELIVERED AT VOLTAGES BELOW 2 KV

$/kW per Meter per Month:

Summer Season	- on peak	$ (19.62)(I)
	mid-peak	$ (1.25)(I)
Winter Season	- mid-peak	$ (7.56)(R)

SERVICE METERED AND DELIVERED AT VOLTAGES FROM 2 KV THROUGH 50 KV

$/kW per Meter per Month:

Summer Season	- on peak	$ (19.28)(I)
	mid-peak	$ (1.25)(I)
Winter Season	- mid-peak	$ (7.56)(R)

SERVICE METERED AND DELIVERED AT VOLTAGES ABOVE 50 KV

$/kW per Meter per Month:

Summer Season	- on peak	$ (12.81)(I)
	mid-peak	$ (0.61)(I)
Winter Season	- mid-peak	$ (4.62)(R)

(Continued)

Schedule TOU-BIP Sheet 5
TIME-OF-USE-GENERAL SERVICE
BASE INTERRUPTIBLE PROGRAM
(Continued)

RATES (Continued)

Excess Energy Charges:
For both Participation Option A and Participation Option B, a charge for Excess Energy may apply under certain conditions, as set forth in Special Condition 6.

Excess Energy Charges ($/kWh):

	Option A	Option B
Voltages below 2 kV	$12.48488(R)	$11.26027(R)
Voltages from 2 kV to 50 kV	$12.24444(R)	$11.01982(R)
Voltages above 50 kV	$11.82401(R)	$10.59939(R)

SPECIAL CONDITIONS

1. Interruptible Load: The Interruptible Load is the measured difference between the Customer's (T) or Aggregated Group's demand, at the time of interruption, and the Customer's or Aggregated (T) Group's Firm Service Level.

2. Participation Option A and Participation Option B:

   a. Participation Option A: 15-Minute Participation Option requires a Customer or (T) Aggregated Group to reduce its demand imposed on the electric system to its Firm Service Level within 15 minutes of a Notice of Interruption from SCE, as defined in Special Condition 4 of this Schedule.

   b. Participation Option B: 30-Minute Participation Option requires a Customer or (T) Aggregated Group to reduce its demand imposed on the electric system to its Firm Service Level within 30 minutes of a Notice of Interruption from SCE, as defined is Special Condition 4 of this Schedule.

3. Load Zone: SCE will assign each participant to a load zone. The assigned Load Zone may be at SCE's system or subsystem level which may change over time. Participant may be direct enrolled Customer or Customer in an Aggregated Group. (T)

(Continued)

Schedule TOU-BIP Sheet 6
TIME-OF-USE-GENERAL SERVICE
BASE INTERRUPTIBLE PROGRAM
(Continued)

SPECIAL CONDITIONS (Continued)

4. Firm Service Level (FSL): FSL is the Maximum Demand SCE is expected to supply and/or deliver during any Period of Interruption. The FSL shall be specified by the customer and by the Aggregator for each of its Aggregated Groups. During a Period of Interruption, the participant is expected to interrupt load to its specified FSL. Except for the participants who are verified with the status of Non-Performance as described in Special Condition 10, and the participants with a change in the Prohibited Resource Attestation as described in Special Condition 11, increases or decreases in FSL may be made no more often than once per year, upon written request by the participant and execution of an Interruptible Service Agreement (D)
(Form 14-315) for customers, and Attachment E to the Time-of-Use Base Interruptible Program Aggregator Agreement (Form 14-780) for Aggregators to increase or decrease the participant's FSL. Participants served under this Schedule shall establish a FSL of zero or greater. Increases in FSL may be made as described in Special Condition 14. Decreases in (N)
FSL may only be made during the resource allocation process. (N)

Default Adjustment Value (DAV) is the nameplate capacity value of the participant's Prohibited Resource provided at the time of attestation. If a participant has multiple units of Prohibited Resource at the same site, then the DAV is the sum of the nameplate capacity values from all Prohibited Resource units at the same site. For participants who do not use their Prohibited Resource to reduce load during a Demand Response event, as described in Special Condition 11, b. (1) ii, the DAV will not affect the participant's FSL. For participants electing to use its Prohibited Resource to reduce load during a Demand Response event on the same site for the same service account, as described in Special Condition 11, b. (1) iii, the direct enrolled participant must set the FSL at no less than the DAV, and the Aggregators must set the FSL for their Aggregated Group at no less than the sum of the DAV for all participants attested to Special Condition 11. b. (1) iii.

5. Notice of Interruption: A Notice of Interruption will be sent to customer designated contacts. Customers must ensure the notification delivery method is functional and be responsible to pay for all charges associated with the notification delivery service. Failure to provide at least one valid notification contact or functional notification delivery service may result in Excess Energy Charges being applied. SCE may give a Notice of Interruption under this Schedule:

   a. After the California Independent System Operator (CAISO) has (i) publicly declared a Warning, Stage 1, Stage 2, Stage 3, or Transmission Emergency and (ii) has taken all necessary steps to prevent the further degradation of its operating reserves according to Operating Procedure 4420; or

   b. Upon determination by SCE's grid control center of the need to implement load reductions in SCE's service territory; or

   c. At the discretion of SCE for program evaluation or system contingencies.

(Continued)

Schedule TOU-BIP
TIME-OF-USE-GENERAL SERVICE
BASE INTERRUPTIBLE PROGRAM
(Continued)

Sheet 7

SPECIAL CONDITIONS (Continued)

5. Notice of Interruption (Continued):

   Once SCE sends a Notice of Interruption to a participant's contact(s), the participant shall reduce the demand imposed on the electric system to its FSL in accordance with Special Condition 4 above. Upon receiving a Notice of Interruption, participant is responsible for determining they are located in the affected Load Zone (block) and shall respond accordingly. SCE will not be responsible for notifying the customers within an Aggregated Group of an interruption. The Aggregator will be solely responsible for notifying the customers within its Aggregated Group of an interruption. (T)

6. Period of Interruption: A Period of Interruption is a time interval which commences 15 minutes after Notice of Interruption for participants on Participation Option A and 30 minutes after a Notice of Interruption for participants on Participation Option B. For Participation Option A and Participation Option B participants, a Period of Interruption ends for participants upon notification by SCE of the end of a Period of Interruption.

7. Excess Energy: Excess Energy is the number of kWh consumed in each Period of Interruption which exceeds the product of the FSL kW multiplied by the total number of hours within the Period of Interruption.

8. Charges for Excess Energy: For each Period of Interruption during which the participant has Excess Energy, the applicable Excess Energy Charge shall be added to the customer's bill or charged to the Aggregator.

9. Noncompliance: The customer's noncompliance with any of the terms and/or conditions of this Schedule and/or the associated contract(s), except for the terms and conditions relating to failure to interrupt load, may result in the suspension of the interruptible credits and charges pursuant to the customer's otherwise applicable tariff. However, the customer remains subject to all other terms and conditions of this Schedule and the applicable contract(s). The interruptible credits of this rate schedule will be applied effective the next meter read date after SCE determines the customer is in compliance.

10. Non-Performance: If a participant fails to reduce demand to its FSL during a Period of Interruption, SCE may give written notice to that participant that a repeated failure to reduce demand to its FSL during a Period of Interruption may result in removal from the Schedule. Following the written notice, if the participant fails to reduce demand to its FSL during another Period of Interruption, SCE may direct the participant to revise its FSL to a level designated by SCE. Such participant may be subject to removal from this Schedule if its FSL is not timely adjusted to the level designated by SCE. Any participant removed from this Schedule for multiple failures to reduce demand to its FSL during a Period of Interruption over the contract term is not eligible to participate in this Schedule during the subsequent 12 month term.

(Continued)

Schedule TOU-BIP Sheet 8
TIME-OF-USE-GENERAL SERVICE
BASE INTERRUPTIBLE PROGRAM
(Continued)

SPECIAL CONDITIONS (Continued)

11. Use of Prohibited Resources:

a. Prohibited Resources.

Effective January 1, 2019, the following list of resources are prohibited in providing load reduction during demand response events: distributed generation technologies using diesel, natural gas, gasoline, propane, or liquefied petroleum gas, in topping cycle Combined Heat and Power (CHP) or non-CHP configuration ("Prohibited Resources"). The following resources are exempt from the prohibition: pressure reduction turbines and waste-heat-to-power bottoming cycle CHP, resources powered by fuel (e.g., renewable gas, renewable diesel, or biodiesel) that has received renewable certification from the California Air Resources Board, as well as energy storage resources not coupled with fossil fueled resources.

b. Attestation of Prohibited Resources

(1) Participant must attest to one of the following conditions in order to participate in this Schedule
   i. Participant does not have a Prohibited Resource onsite
   ii. Participant does have a Prohibited Resource onsite and will not use the resource to reduce load during any demand response event. Participant must provide the number of unit(s) of Prohibited Resource onsite, and the DAV for the Prohibited Resource onsite (as defined in Special Condition 4).
   iii. Participant does have a Prohibited Resource onsite and may have to use the resource(s) during demand response events for safety, health, or operational reasons. Participant must provide the number of unit(s) of Prohibited Resource onsite, and the DAV for the Prohibited Resource onsite (as defined in Special Condition 4).

(2) Form Requirement for Attestation of Prohibited Resources: The direct enrolled participants must sign Form 14-315. The aggregator enrolled participants must sign Form 14-980, Authorization for Participation in Aggregated Demand Response Programs Form, (Form 14-780, Attachment C). For participants enrolled with an Aggregator prior to January 1, 2019, the Aggregator may use its own attestation form. Participant with multiple accounts enrolled through an Aggregator may submit one form for all accounts with same attestation condition as described in Special Condition 11.b.(1). Each aggregator is responsible for submitting the completed attestation form(s) for each participating accounts of their participants on this Schedule to SCE in a machine readable format, such as a comma-separated value (.csv) file or other format acceptable by SCE. Customer signature for the participating accounts may be in an electronic format, including a "click." Each Aggregator with active participating account(s) on this Schedule must re-execute and submit Time-of-Use Base Interruptible Program Aggregator Agreement (Form 14-780) to SCE, after October 1, 2018 and no later than December 10, 2018.

(Continued)

Schedule TOU-BIP Sheet 9
TIME-OF-USE-GENERAL SERVICE
BASE INTERRUPTIBLE PROGRAM
(Continued)

SPECIAL CONDITIONS (Continued)

11. Use of Prohibited Resources (Continued):

b. Attestation of Prohibited Resources (Continued):

(3) Initial Attestation: All existing participants must attest prior to December 10, 2018, and all new participants must attest at the time of enrollment.

(4) Update of the Attestation: Participants may update their attestation(s) with any of the following changes, if the change is supported by documentation that confirms the operational change, and can be verified by SCE or a Verification Administrator. Update of the Attestation may be subject to SCE's approval.

i. Add, remove, or modify an onsite Prohibited Resource
ii. Change the status of the use of Prohibited Resource(s) to reduce load during any demand response event.
iii. Change the DAV.

c. Verification of Attestation of Prohibited Resources:

The Verification Administrator is an independent contractor responsible for verifying the Prohibited Resource attestations.

(1) Participant's compliance and participation may be subject to verification performed by a Verification Administrator and consequences associated with non-compliance.
(2) Participation in this Schedule is contingent on complying with possible verification requests and facility access for site visits, as deemed necessary by the Verification Administrator. Compliance with Verification Administrator requests will be determined by the Verification Administrator
(3) If directed by the Verification Administrator, SCE may pay for the installation of monitoring equipment for purpose of verification of attestation in the test year 2019.
(4) All participating accounts may be required to provide the Verification Administrator with written operating manifest(s), date and time stamped photo(s) of the Prohibited Resource unit(s), load curtailment plan(s), single line diagram(s), permit copy(ies), or other information and/or documentation about their onsite Prohibited Resource unit(s).

(Continued)

Schedule TOU-BIP Sheet 10
TIME-OF-USE-GENERAL SERVICE
BASE INTERRUPTIBLE PROGRAM
(Continued)

SPECIAL CONDITIONS (Continued)

11. Use of Prohibited Resources (Continued):

c. Enforcement of Prohibition of Resources:

The Verification Administrator is responsible for enforcing the prohibition.

(1) Type I Violation

i. Invalid Attestation: This type of infraction includes mistakes on the attestation that may be reasonably found to be clerical or administrative in nature, such as reporting a higher than actual nameplate capacity value of a Prohibited Resource or not including an onsite Prohibited Resource on the attestation, as long as the resource is not used to reduce load during a DR event. These instances of “Type I” infractions may be subject to a 60-day cure period for customer correction and aggregator validation. SCE or its Verification Administrator will notify the direct enrolled participants or the aggregators of any identified Invalid Attestation. Once notified, if the violation is not cured within 60 days, the participant will be removed from this Schedule at the next regularly scheduled meter read date. Once removed from this Schedule, if the participant or the participant’s aggregator is able to provide SCE with a valid attestation at the time of re-enrollment, the participant may re-enroll at any time.

ii. No Attestation: Any active participant that does not agree to the prohibition, by submitting an attestation by December 10, 2018, will be removed from this Schedule on the participant’s next regularly scheduled meter read date, but will be eligible to re-enroll subject to the submittal of the attestation.

(Continued)

Schedule TOU-BIP Sheet 11
TIME-OF-USE-GENERAL SERVICE
BASE INTERRUPTIBLE PROGRAM
(Continued)

SPECIAL CONDITIONS (Continued)

11. Use of Prohibited Resources (Continued):

d. Enforcement of Prohibition of Resources (Continued):

(2) Type II Violation - Non-Compliance with the Prohibition: A Type II Violation is defined as a violation of the term(s) of its attestation when (a) the participant that did not attest to any use of any Prohibited Resource, but is using a Prohibited Resource to reduce load during a demand response event, or (b) a participant submits an invalid nameplate capacity value that is lower than the actual capacity value on the nameplate. SCE or its Verification Administrator will notify the direct enrolled participants or the aggregators of any identified Type II Violation. A participant identified with a single instance of a Type II Violation shall be removed from this Schedule for one year, and must wait 12 months to be eligible to re-enroll in this Schedule and all other “affected DR programs.” A participant with two or more instances of Type II Violation shall be removed from this Schedule for a period of three years, and must wait 36 months to be eligible to re-enroll in this Schedule and all other “affected DR programs.” “Affected DR programs” are all DR programs and pilots subject to the prohibition requirements in Decision 16-09-056 and Resolution E-4906.

e. Dispute Resolution:

Participants disputing a Type I or Type II Violation shall be permitted to engage in a dispute resolution process with the Verification Administrator, SCE, the California Public Utilities Commission (Commission), and, if applicable, the aggregator. The participants, the aggregators, and SCE shall follow the Commission Alternative Dispute Resolution (ADR) and Formal Complaint processes to resolve disputes over verification issues.

(Continued)

Schedule TOU-BIP
TIME-OF-USE-GENERAL SERVICE
BASE INTERRUPTIBLE PROGRAM
(Continued)

SPECIAL CONDITIONS (Continued)

12. Direct Access (DA) and Community Choice Aggregation (CCA): A customer receiving DA or CCA service shall notify its Energy Service Provider (ESP) or Community Choice Aggregator (CCA), as applicable and Scheduling Coordinator that it is subject to interruption under this Schedule. In addition, if a customer receiving DA or CCA service owns its own meter or has a meter provided by an ESP, the meter must be capable of providing the proper pulse data interface between the customer's metering system and SCE's data recorder. Where SCE is the MDMA and MSP for participating service accounts which do not have the required IDR metering, SCE will provide and install such equipment.

13. Meter Requirements: Interval data recorder (IDR) metering is required for all customers providing interruptible load for purposes of this Schedule, whether the load is provided directly by the customer or through an Aggregator.

14. Contracts: A contract is required for service under this Schedule. A participant with a valid contract may not be required to execute a new contract for account changes if the participant's Federal Tax Identification Number remains the same. To be served under this Schedule, eligible Participants shall comply with all provisions of the contract and this Schedule.

    Except for the conditions listed in Special Condition 14. d. below, participants shall have a one month window each year between November 1 and December 1, to provide written notice to SCE for the following options, a through c, with all changes becoming effective on the next regularly scheduled meter read date on or after December 1.

    a. Terminate service under Schedule TOU-BIP and return to the OAT.

    b. Change the Participation Option. Changes in Participation Option with timely receipt of the signed Interruptible Service Agreement (Form 14-315) or Attachment D to the Time-of-Use Base Interruptible Program Aggregator Agreement (Form 14-780).

    c. Increase the FSL. Increases in the FSL with timely receipt of the signed Interruptible Service Agreement (Form 14-315) or Attachment E to the Time-of-Use Base Interruptible Program Aggregator Agreement (Form 14-780). (D)

    d. A participant may provide written notice to SCE and request for any of the options a through c above outside of the November 1 to December 1 period, if the customer is changing its attestation of the Prohibited Resource(s). All changes become effective on the next regularly scheduled meter read date on or after SCE's approval of the participant's written notice. In addition, SCE may, at its sole discretion, initiate additional window(s) throughout the year with a duration of a specified period, due to any change which may affect customer's participation on this Schedule. A participant may be removed from this Schedule at any time if the participant has incurred one or more instances of Type II Violation as described in Special Condition 11. d. (2).

(Continued)

SPECIAL CONDITIONS (Continued)

14. Contracts: (Continued)

Participants with a verified status of Non-Performance as described in Special Condition 10, may be removed from this Schedule. Termination of Service under Schedule TOU-BIP due to Non-Performance will become effective upon participant's next regularly scheduled meter read date following SCE's notification of service termination to the participant. (T)

Aggregators are required to complete a Time-Of-Use Base Interruptible Program Aggregator Agreement (Form 14-780) including the attachment thereto.

Customers shall not be permitted to prematurely terminate service hereunder unless changes in electrical demand require a change in the customer's Otherwise Applicable Tariff (OAT) is not eligible for this Schedule.

Failure to meet minimum applicability requirements due to changes in demand or connected load for 12 or more consecutive months will result in the customer being removed from this Schedule. Removal from this Schedule will occur once per year on the next regularly scheduled read date after December 1.

(Continued)

Schedule TOU-BIP
TIME-OF-USE-GENERAL SERVICE
BASE INTERRUPTIBLE PROGRAM
(Continued)

SPECIAL CONDITIONS (Continued)

15. Number and Duration of Interruption: The number of Periods of Interruption will not exceed one (1) per day, ten (10) in any calendar month, and a total of 180 hours per calendar year. The duration of each Period of Interruption will not exceed 6 hours.

16. Customer Electrical Generating Facilities:

a. Where customer electrical generating facilities are used to meet a part or all of the customer's electrical requirements, service shall be provided concurrently under the terms and conditions of Schedule S or TOU-8-S, whichever is applicable, and this Schedule. Parallel operation of such generating facilities with SCE's electrical system is permitted. A generation interconnection agreement is required for such operation.

b. Customer electrical generating facilities used solely for auxiliary, emergency, or standby purposes (auxiliary/emergency generating facilities) to serve the customer's load during a period when SCE's service is unavailable and when such load is isolated from the service of SCE are not subject to Schedule S or Schedule TOU-8-S. However, upon approval by SCE, momentary parallel operation may be permitted in order for the customer to avoid interruption of load during a Period of Interruption or to allow the customer to test the auxiliary/emergency generating facilities. A generation interconnection agreement is required for such momentary parallel operation.

17. Relationship to Other Demand Response Programs. Unless otherwise permitted herein, participants on this Schedule may not be served under any other demand response program. Aggregated Groups may not include TOU-BIP directly enrolled customer service accounts. With limitations, customers participating directly (not through an Aggregator) in TOU-BIP may (D)
also participate in Schedules SLRP, OBMC, or an applicable RTP rate schedule. Customers' (D)
service accounts participating in SLRP will not receive a SLRP incentive payment during (N)
hours where there is an overlapping TOU-BIP event. Only customers dually participating in |
this Schedule and Option CPP of an applicable TOU rate schedule prior to October 26, 2018 |
are grandfathered to continue the existing dual participation. All other customers served |
under this Schedule are not eligible for service to dually participate with CPP. In addition, |
customer's service accounts on this Schedule may also participate in other SCE resource (N)
contracts, provided specific contract provisions allow for such dual participation. Customer's service accounts on this Schedule shall not participate in the CAISO's Ancillary Services Load Program.

For customers' service accounts grandfathered to continue to dually participate with Schedule (C)
CPP or Option CPP of an applicable TOU rate schedule, the sum of credits provided by (C)
TOU-BIP and CPP will be capped. The capped credit amount, also known as the Maximum Available Credit, is listed per the customer's OAT in the applicable rate section of Schedule CPP or Option CPP. These grandfathered customers are capped at the megawatt level as of (N)
December 10, 2018. (N)

(Continued)

Schedule TOU-BIP Sheet 15
TIME-OF-USE-GENERAL SERVICE
BASE INTERRUPTIBLE PROGRAM
(Continued)

SPECIAL CONDITIONS (Continued)

18. Insurance. Insurance may not be used to pay non-compliance penalties for willful failure to comply with a Notice of Interruption. Existing and new participants will not be eligible for continued service or new service under this Schedule unless a declaration is signed under penalty or perjury which states that the participant does not have, and will not obtain, any insurance for the purpose of the insurance paying non-compliance penalties for willful failure to comply with Notices of Interruptions. Continued eligibility and new eligibility under this Schedule will require that each participant execute a declaration stating that it does not have, and will not obtain, such insurance. For any participant with such insurance after the effective date of this Special Condition, service under this Schedule will be terminated and such participant will be required to pay back the interruptible rate discounts for the period covered by the insurance. If the period cannot be determined, the recovery shall be for the entire period the participant was on this Schedule. (T)

19. Aggregators: Pursuant to Decision 06-11-049, Aggregators may participate under this Schedule. The Aggregator may aggregate the load of customers whose load falls below the minimum load requirements, as defined in the applicability section of this Schedule, into one or more Aggregated Groups as long as the total load of each Aggregated Group meets the minimum load requirements. SCE will provide the Aggregator with a monthly payment in accordance with the terms and conditions of Time-Of-Use Base Interruptible Program Aggregator Agreement (Form 14-780). Payments will remain at the Aggregated Group level, providing for interruptible payments and Excess Energy Usage Charges based on each Aggregated Group's Firm Service Level (FSL) and monthly average peak demand. Existing TOU-BIP customers wishing to join an Aggregated Group may only do so after opting out of this Schedule during the annual window from November 1 through December 1. (T)

(Continued)

Schedule TOU-BIP
TIME-OF-USE-GENERAL SERVICE
BASE INTERRUPTIBLE PROGRAM
(Continued)

SPECIAL CONDITIONS (Continued)

20. Aggregated Groups: Aggregators may group their Customers into one or more Aggregated Groups as they require. All Customers in an Aggregated Group must be served under the same voltage level, and the same Participation Option A or B, the same load zone, and the Aggregated Group must meet the minimum load requirements of this Schedule. In addition, an Aggregated Group will be comprised wholly of either Bundled, DA, or CCA Customers. Once established, the addition or removal of Customers from an Aggregated Group is not permitted until the annual window from November 1 to December 1. An exception applies to allow removal of a Customer's service account when electric service with SCE is discontinued for that service account. In an Aggregated Group, if a Customer service account's voltage level changes to a level different from that of the other Customers in the Aggregated Group, then such Customer service account must be removed from the Aggregated Group during the annual window, but will remain in the Aggregated Group until such time. Each Aggregated Group must maintain the minimum requirements as outlined within this Schedule. (T) (T) (T) (T) (T) (T) (T) (T)

21. For the purposes of participation under Schedule TOU-BIP, time periods are defined as follows:

(N)

TOU Period	Weekdays		Weekends and Holidays	
	Summer	Winter	Summer	Winter
On-Peak	4 p.m. - 9 p.m.	N/A	N/A	N/A
Mid-Peak	N/A	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.
Off-Peak	All other hours	9 p.m. - 8 a.m.	All other hours	9 p.m. - 8 a.m.
Super-Off-Peak	N/A	8 a.m. - 4 p.m.	N/A	8 a.m. - 4 p.m.

(N)

Holidays are New Year's Day (January 1), Presidents' Day (third Monday in February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Veterans Day (November 11), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25).

When any holiday listed above falls on Sunday, the following Monday will be recognized as a holiday. No change will be made for holidays falling on Saturday. The summer season shall commence at 12:00 a.m. on June 1 and continue until 12:00 a.m. on October 1 of each year. The winter season shall commence at 12:00 a.m. on October 1 and continue until 12:00 a.m. on June 1 of the following year. (T)

22. Event for Program Evaluation: At SCE's discretion, Customers may be requested to participate in a program evaluation event demonstrating their ability to reduce load to their contracted FSL. A BIP program evaluation event will be counted as an actual curtailment event and excess energy charges will apply. (T)

(Continued)

Schedule TOU-BIP Sheet 17 (N)
TIME-OF-USE-GENERAL SERVICE
BASE INTERRUPTIBLE PROGRAM
(Continued)

SPECIAL CONDITIONS (Continued)

23. Reliability Cap: D. 18-11-029 established a new reliability cap management process, a Commission-enforced annual cap designed to limit the capacity from reliability-based demand response programs to two percent of the recorded all-time coincident CAISO peak load (reliability cap or cap). (T) (T)

When the available capacity (headroom) is below 50% of an individual utility's allocated portion of the two-percent reliability cap, increase in participation through new enrollment or decrease in FSL is based on a first-come; first-served approach. When the available capacity ("headroom") is between 50%-95% of an individual utility's allocated portion of the two-percent reliability cap, a lottery will be held in April of each year, after which new enrollments and decreases in the Firm Service Level would occur after the results of the lottery are determined. (T) (T) (T) (T) (T) (T)

When SCE utilizes the lottery, it will apply the following prioritization:

A. Third-party resources from Local Capacity Areas that have local capacity deficiencies pursuant to CAISO,
B. Utility resources from Local Capacity Areas that have local capacity deficiencies pursuant to CAISO; (N)
C. All other third-party resources, and
D. All other utility resources

(N)

(T)

(T)

(Continued)