Docekt No. 94-2035-03
PacifiCorp Exhibit No. 1R (RW-1R)
Witness: Rodger Weaver

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR AN ORDER APPROVING ITS AVOIDED COST RATES	DOCKET NO. 94-2035-03 PREFILED REBUTTAL TESTIMONY OF RODGER WEAVER

December 19, 1994

Q. Please state your name, business address and present position with PacifiCorp (the Company).

A. My name is Rodger Weaver. My business address is 825 N. E. Multnomah, Portland, Oregon 97232. My present position is Power System Regulation Manager.

Q. Are you the same Rodger Weaver who has already prefiled testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I will present the Company's position regarding several recommendations made by Division of Public Utilities (Division) witness Rebecca L. Wilson in her direct testimony.

Q. How is your testimony organized?

A. My testimony has two sections: Section 1 discusses the Division's tariff and short-run avoided energy cost recommendations and Section 2 discusses the Division's proposal to calculate avoided costs using the Company's RAMPP-4 IPM model.

Tariff and Short-Run Avoided Energy Costs

Q. The Division recommends that the Company file a tariff for purchases of power from qualifying facilities ("QF") smaller than one megawatt. What is the Company's position on that proposal.

A. The Company is willing to develop, in conjunction with the Division and any other interested parties, a draft tariff for submission to the Commission. The Company's goal would be to submit a joint draft of that tariff to the Commission within seven days after the Commission issues its order approving prices in this docket. That tariff would include, much like existing electric service schedules in this jurisdiction, prices and eligibility criterion.

Q. The Division also recommends that short-run avoided energy costs be based on 10 MWa of QF generation rather than the 50 MWa of QF generation used by the Company. What is the Company's position on that proposal.

A. The Division's recommendation is "intended to reflect the decrement of resources that will be avoided by QF's under one MW in a period of resource sufficiency." Thus, despite Ms. Wilson's recognition that administratively determined avoided cost rates "are commonly referenced with respect to, or form the basis for" other applications, including the "value of demand side resource benefits" and "review of resource acquisition decisions", and her assertion that "it is important that the method reflects reality as much as is practicable", the Division's approach is based on exclusion of QF resource additions larger than one megawatt. The Division has provided no support for that approach as it relates to these other applications and, although the Division's assumption does not materially impact the avoided cost results, the Company believes the Commission should adopt the 50 MWa approach.

Q. Have you recalculated the Company's short-run avoided energy costs based on the Division's 10 MWa QF assumption?

A. Yes. The recalculated rates, together with workpapers, are shown in PacifiCorp Exhibit 1R.1, which was prepared under my direction and supervision. I would note that the revised rates are not materially different from the Company's proposed rates.

IPM-Based Avoided Cost Rates

Q. On page 4 of Ms. Wilson's testimony she states that part of the Commission's avoided cost policy is to set prices for QF capacity and energy which reflect market conditions. Do you believe her proposal to base avoided costs on the Company's IRP process would result in avoided cost rates that reflect market conditions?

A. No. Despite the fact that an IRP-based proposal would be based on the Company's own plans, the proposal falls short of keeping pace with the changing generation supply market and utility information that is available. The Division's proposal will likely not reflect the most recent generation supply information as well as the Company's proposed method. The IRP-based approach would be scheduled in accordance with the IRP schedule. The Company's proposed method can be updated as conditions dictate. IRP is a long process that generally lasts over 2 years. By the time plans, which are based on a snapshot in time, are acknowledged by Commissions, many changes have taken place and the plans do not reflect current conditions. The changes which occurred during the RAMPP-3 process, as discussed in my direct testimony, provide an excellent example of this. However, this does not diminish the value of the IRP for the purposes it was intended. It simply means that the IRP is not a good solution for determining avoided costs.

Q. Are there other potential problems with using the Company's IRP process as the basis for determining avoided cost rates?

A. Yes. The Company believes the Division's proposal could result in a litigious process that would slow down an already long IRP process. This would be particularly problematic for a utility like PacifiCorp which provides service in seven jurisdictions. Differing avoided cost and QF development policies and objectives among the states could further burden the IRP process if that process were utilized to determine avoided cost rates.

Q. Does the Company have other concerns with Ms. Wilson's proposal to use the IPM model to calculate avoided cost rates?

A. Yes. The Company has four concerns. The first is a common major drawback of all differential revenue requirement approaches including one based on the IPM model. This is the inability to properly classify costs between capacity and energy. The differential revenue requirement method calculates a lump sum of avoided costs irrespective of whether the avoided costs represent capacity or energy. This lump sum would have to be divided subsequently into energy and capacity components, because not all QFs have the same operating characteristics as the assumed zero cost QF increments. The differential revenue requirement method provides no guidance on how this classification should be done. Failure to properly classify the lump sum of avoided costs would result inappropriate avoided cost rates. Second, the IPM model does not have the ability to provide peak and off-peak information and would require substantial modification in order to provide seasonal information. Ms. Wilson's request for such information in this case could not be met using the IPM model as it is presently structured. Third, as explained above, a differential revenue requirement approach would not generate avoided cost rates that reflect market conditions because of the lag between the start and completion of the IRP process. Fourth, reliance on very long-range forecasts also make the differential revenue requirement approach more subject to forecasting errors.

In addition, as a result of the industry's trend towards deregulation of generation resources, the Company believes it is very important to use a method which is flexible, provides reasonable results, and can be updated quickly to reflect changes in the marketplace. The differential revenue requirement approach especially if explicitly tied to the IRP process, does not meet these requirements. For these reasons the Company believes its proposed method is the right method for calculating avoided cost rates and recommends its adoption.

Q. On pages 10 and 11 of Ms. Wilson's testimony she states that the energy component developed by the Company's proposed proxy method is based on the variable running costs of the selected unit. Do you agree with that statement?

A. No. Running cost is only one part of the energy component, the other is the capital energy part. Since the selected avoidable baseload unit provides both capacity and energy, the fixed cost of that unit must be classified into capacity and energy components. The fixed cost of a simple cycle combustion turbine (SCCT) peaking unit, which due to its higher operating costs would be dispatched as a capacity resource, defines the portion of the fixed cost of the avoidable resource that is classified as capacity cost. The difference in fixed cost between the CCCT avoidable resource and the SCCT peaking unit is classified as energy related fixed cost and added to the variable production cost noted by Ms. Wilson to determine the total avoided energy cost.

Q. On page 11 of Ms. Wilson's testimony she states that the proxy method does not capture the contribution towards the displacement of baseload energy generation, cycling and peaking at any given point in time. Do you agree with this statement?

A. No. The proxy method provides a proper classification of capacity and energy prices, therefore, a QF is credited for what it allows the Company to avoid. If the developer operates its QF at a base load-like high capacity factor, it will avoid base load-like costs and be paid accordingly. If its operation is like that of either a peaking or cycling resource, its payment will be for the peaking or cycling-like costs it allows the Company to avoid. This illustrates the importance of the proper classification of costs. The differential revenue requirement method, since it produces a single lump sum price is itself unable to properly reflect the baseload/cycling/peaking nature of the costs an individual QF allows the Company to avoid. It therefore will tend to send the wrong price signals to potential QF developers.

Q. On page 11 of Ms. Wilson's testimony she states that the total output from QFs may not be sufficient to fully avoid the proxy plant, and thus result in inappropriate prices for the QF power. Does the IPM model properly deal with deferral of resources?

A. No. The IPM does not recognize lumpiness, it treats resource units as infinitely divisible and assumes they are available in any size required. However, resources can not be acquired in any imaginable size, they can be acquired only in certain sizes. Thus the IPM model does not deal with deferral of resources in a manner appropriate for avoided cost determination.

Q. On page 17 of Ms. Wilson's testimony she makes several statements regarding the determination of avoided cost rates in Idaho. Are those statements correct?

A. They are a little confused. Published avoided cost rates in Idaho are based on a surrogate avoided resource (SAR) methodology --- a form of proxy method. The rates are all-in energy rates, meaning they are not broken down into capacity and energy components. The determination of resource sufficiency/ deficiency is based on the energy requirements of the Company. Capacity is not included in the determination. The current published rates are based on a surrogate coal fired resource located in the Powder River Basin. Those rates were adopted almost four years ago by the Idaho Commission and have been suspended pending the outcome of the recently completed hearings on avoided costs. It is expected that the new surrogate resource adopted by the Idaho Commission will be a combined cycle combustion turbine and that the results will be consistent with those proposed by the Company in Utah. The Company is not proposing to change the SAR method adopted in Idaho.

Q. Does this conclude your rebuttal testimony?

A. Yes.

CERTIFICATE OF MAILING

I hereby certify that on December 19, 1994, a true and correct copy of the attached Rebuttal Testimony of Rodger Weaver was mailed, postage prepaid, to the following:

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PacifiCorp
1994 AVOIDED COSTS
Utah -10 MWa
Summary

	Year	Avoided Firm Capacity Costs ($/kW-mo) (1)	Avoided Energy Costs $/MWh (2)	Total Avoided Costs 75% CF $/MWh (3)	Total Avoided Costs 80% CF $/MWh (4)	Total Avoided Costs 95% CF $/MWh (5)
1	1994	0.00	15.86	15.86	15.86	15.86
2	1995	0.76	16.32	17.71	17.62	17.42
3	1996	0.00	17.46	17.46	17.46	17.46
4	1997	0.00	17.89	17.89	17.89	17.89
5	1998	0.96	19.49	21.24	21.13	20.87
6	1999	1.00	22.24	24.07	23.96	23.69
7	2000	5.04	30.56	39.76	39.18	37.82
8	2001	5.21	32.04	41.55	40.96	39.55
9	2002	5.39	33.60	43.44	42.82	41.37
10	2003	5.57	35.25	45.43	44.79	43.28
11	2004	5.76	37.00	47.52	46.87	45.31
12	2005	5.95	38.86	49.73	49.05	47.44
13	2006	6.16	40.82	52.07	51.36	49.70
14	2007	6.37	42.90	54.52	53.80	52.08
15	2008	6.58	45.09	57.12	56.37	54.59
16	2009	6.81	47.42	59.85	59.07	57.23
17	2010	7.04	49.88	62.74	61.93	60.03
18	2011	7.28	52.49	65.78	64.95	62.98
19	2012	7.52	55.25	68.99	68.14	66.10
20	2013	7.78	58.17	72.39	71.50	69.39
21	2014	8.05	60.79	75.49	74.57	72.39
22	2015	8.32	63.54	78.73	77.78	75.53
23	2016	8.60	66.42	82.13	81.15	78.82
24	2017	8.89	69.44	85.68	84.67	82.26
25	2018	9.20	72.61	89.41	88.36	85.87
26	2019	9.51	75.94	93.31	92.22	89.65
27	2020	9.83	79.43	97.39	96.27	93.61
28	2021	10.17	83.09	101.66	100.50	97.75
29	2022	10.51	86.94	106.14	104.94	102.10
30	2023	10.87	90.97	110.83	109.58	106.65
31	2024	11.24	95.21	115.73	114.45	111.41
32	2025	11.62	99.65	120.88	119.55	116.41
33	2026	12.02	104.31	126.26	124.89	121.64
34	2027	12.43	109.21	131.90	130.48	127.12

Column Notes:

(1) Based on a 3 month (June-August) summer capacity purchase for the years 1995, 1998 and 1999 and the fixed cost of simple cycle combustion turbine beginning in the year 2000.

(2) Based on production cost model results through 1999. Beginning in the year 2000, combined cycle fuel cost and capitalized fixed cost of combined cycle combustion turbine which is in excess of a simple cycle combustion turbine.

(3) Combined costs, assuming 75% Capacity Factor.

(4) Combined costs, assuming 80% Capacity Factor.

(5) Combined costs, assuming 95% Capacity Factor.

PacifiCorp
1994 AVOIDED COSTS
Utah -10 MWa
Calculation of Avoided Capacity and Capitalized Energy Costs

Cost of capital	10.43%
Discount Rate	8.81%
Inflation rate	3.40%
Real Discount Rate	5.23%

Simple cycle CT		Combined cycle CT		
1994 Capital	$462 /kW	1994 Capital	$663 /kW	
Carrying Charge	9.50%	Carrying Charge	9.50%	(assume 30 year book life)
Non-Fuel O&M	5.60 /kW	Non-Fuel O&M	17.01 /kW	

	Year	Simple Cycle Fixed Costs ($/kW-yr) (1)	Simple Cycle Fixed Costs ($/kW-mo) (2)	Combined Cycle Fixed Costs ($/kW-yr) (3)	Combined Cycle Fixed Costs ($/kW-mo) (4)	Capitalized Energy Cost ($/kW-mo) (4) - (2) = (5)	Capitalized Energy Cost 80% CF ($/MWh) (6)
1	1994	49.47		79.92		0.00	0.00
2	1995	51.15		82.63		0.00	0.00
3	1996	52.89		85.44		0.00	0.00
4	1997	54.68		88.35		0.00	0.00
5	1998	56.54		91.35		0.00	0.00
6	1999	58.47		94.46		0.00	0.00
7	2000	60.45	5.04	97.67	8.14	3.10	5.31
8	2001	62.51	5.21	100.99	8.42	3.21	5.49
9	2002	64.64	5.39	104.42	8.70	3.32	5.68
10	2003	66.83	5.57	107.98	9.00	3.43	5.87
11	2004	69.11	5.76	111.65	9.30	3.55	6.07
12	2005	71.45	5.95	115.44	9.62	3.67	6.28
13	2006	73.88	6.16	119.37	9.95	3.79	6.49
14	2007	76.40	6.37	123.43	10.29	3.92	6.71
15	2008	78.99	6.58	127.62	10.64	4.05	6.94
16	2009	81.68	6.81	131.96	11.00	4.19	7.17
17	2010	84.46	7.04	136.45	11.37	4.33	7.42
18	2011	87.33	7.28	141.09	11.76	4.48	7.67
19	2012	90.30	7.52	145.88	12.16	4.63	7.93
20	2013	93.37	7.78	150.84	12.57	4.79	8.20
21	2014	96.54	8.05	155.97	13.00	4.95	8.48
22	2015	99.82	8.32	161.28	13.44	5.12	8.77
23	2016	103.22	8.60	166.76	13.90	5.30	9.07
24	2017	106.73	8.89	172.43	14.37	5.48	9.38
25	2018	110.36	9.20	178.29	14.86	5.66	9.69
26	2019	114.11	9.51	184.35	15.36	5.85	10.02
27	2020	117.99	9.83	190.62	15.89	6.05	10.36
28	2021	122.00	10.17	197.10	16.43	6.26	10.72
29	2022	126.15	10.51	203.81	16.98	6.47	11.08
30	2023	130.44	10.87	210.73	17.56	6.69	11.46
31	2024	134.87	11.24	217.90	18.16	6.92	11.85
32	2025	139.46	11.62	225.31	18.78	7.15	12.25
33	2026	144.20	12.02	232.97	19.41	7.40	12.67
34	2027	149.10	12.43	240.89	20.07	7.65	13.10

Column Notes:
(1) Real levelized annual cost of simple cycle CT, represents the capacity portion of fixed avoided costs.
(2) Columm (1) divided by 12.
(3) Real levelized annual cost of combined cycle CT.
(4) Columm (3) divided by 12.
(5) Column (4) minus Column (2), represents the portion of fixed costs assigned to energy.
(6) Equal to Column (5), converted to $/MWh assuming the stated capacity factor.

PacifiCorp
1994 AVOIDED COSTS
Utah -10 MWa

	Year	Avoided Fuel or Purchase Cost ($/MWh) (1)	Updated Gas Price ($/MBtu) (2)	CCCT Energy Costs 7518 Btu/kWh ($/MWh) (3)	Variable Avoided Energy Cost ($/MWh) (1) + (3) =(4)	Capitalized Energy Cost 80% CF ($/MWh) (5)	Total Avoided Energy Cost ($/MWh) (4) + (5) =(6)
1	1994	15.86	2.41		15.86		15.86
2	1995	16.32	2.55		16.32		16.32
3	1996	17.46	2.69		17.46		17.46
4	1997	17.89	2.85		17.89		17.89
5	1998	19.49	3.01		19.49		19.49
6	1999	22.24	3.18		22.24		22.24
7	2000		3.36	25.25	25.25	5.31	30.56
8	2001		3.53	26.54	26.54	5.49	32.04
9	2002		3.71	27.92	27.92	5.68	33.60
10	2003		3.91	29.38	29.38	5.87	35.25
11	2004		4.11	30.93	30.93	6.07	37.00
12	2005		4.33	32.58	32.58	6.28	38.86
13	2006		4.57	34.33	34.33	6.49	40.82
14	2007		4.81	36.18	36.18	6.71	42.90
15	2008		5.08	38.15	38.15	6.94	45.09
16	2009		5.35	40.24	40.24	7.17	47.42
17	2010		5.65	42.46	42.46	7.42	49.88
18	2011		5.96	44.82	44.82	7.67	52.49
19	2012		6.29	47.32	47.32	7.93	55.25
20	2013		6.65	49.97	49.97	8.20	58.17
21	2014		6.96	52.31	52.31	8.48	60.79
22	2015		7.28	54.77	54.77	8.77	63.54
23	2016		7.63	57.35	57.35	9.07	66.42
24	2017		7.99	60.06	60.06	9.38	69.44
25	2018		8.37	62.92	62.92	9.69	72.61
26	2019		8.77	65.91	65.91	10.02	75.94
27	2020		9.19	69.06	69.06	10.36	79.43
28	2021		9.63	72.38	72.38	10.72	83.09
29	2022		10.09	75.86	75.86	11.08	86.94
30	2023		10.58	79.51	79.51	11.46	90.97
31	2024		11.09	83.36	83.36	11.85	95.21
32	2025		11.63	87.40	87.40	12.25	99.65
33	2026		12.19	91.65	91.65	12.67	104.31
34	2027		12.78	96.11	96.11	13.10	109.21

Column Notes:
(1) Avoided energy costs from PD/Mac Production Cost Studies.
(2) Gas commodity prices are based on futures prices as quoted in the Wall Street Journal January 12, 1994, adjusted for the Henry Head basis differental, escalated at 2.75% real (avg. of RAMPP 3 low & medium) per year through 2013, and escalated at 1.7% real (RAMPP-3 low)thereafter. In addition to the commodity price, firm transportation and shrinkage costs have been added consistent with RAMPP 3.
(3) Fuel cost of large combined cycle combustion turbine.
(4) Total avoided variable energy costs, Column (1)+column(3)+ Column(4)
(5) Fixed energy costs, fixed cost of CCCT less fixed cost SCCT
(6) Total avoided energy costs, Column(5) + Column (6)

PacifiCorp
Utah -10 MWa
Comparison of Proposed Avoided Cost Rates
to Authorized Avoided Cost Rates

		Utah Proposed Avoided Cost Rates 75% CF (¢/kWh)	Utah Authorized Avoided Cost Rates 75% CF (¢/kWh)	Difference
		(1)	(2)	(3)
1	1994	1.59	1.68	-0.10
2	1995	1.77	1.81	-0.04
3	1996	1.75	2.97	-1.23
4	1997	1.79	3.23	-1.44
5	1998	2.12	3.50	-1.38
6	1999	2.41	3.82	-1.41
7	2000	3.98	4.00	-0.02
8	2001	4.15	4.22	-0.07
9	2002	4.34	4.48	-0.14
10	2003	4.54	4.56	-0.01
11	2004	4.75	4.92	-0.17
12	2005	4.97	5.87	-0.89
13	2006	5.21	5.91	-0.70
14	2007	5.45	6.60	-1.15
15	2008	5.71	7.31	-1.60
16	2009	5.99	8.20	-2.21
17	2010	6.27	8.59	-2.31
18	2011	6.58	9.09	-2.51
19	2012	6.90	9.61	-2.71
20	2013	7.24	10.17	-2.93
21	2014	7.55	10.77	-3.22
22	2015	7.87	11.39	-3.52
23	2016	8.21	N/A	N/A
24	2017	8.57	N/A	N/A
25	2018	8.94	N/A	N/A
26	2019	9.33	N/A	N/A
27	2020	9.74	N/A	N/A
28	2021	10.17	N/A	N/A
29	2022	10.61	N/A	N/A
30	2023	11.08	N/A	N/A

20 Year Net Present Value:	32.64	40.79	
20-year Nominal Levelized	3.53	4.41	-0.88
20-year Real Levelized	2.67	3.34	-0.67
22 Year Net Present Value:	35.15	44.40	
22-year Nominal Levelized	3.67	4.63	-0.97
22-year Real Levelized	2.73	3.44	-0.72

PacifiCorp

Avoided Cost Prices for Purchase Power
Utah - 10 MWa
Summary of PD/Mac Avoided Cost Output
Mills/kWh

Without Special Sales Credit

Mills/kWh

OPER-YR	31 Jul	31 Aug	30 Sep	31 Oct	30 Nov	31 Dec	31 Jan	28 Feb	31 Mar	30 Apr	31 May	30 Jun	OPER-YR AVG
1993-94	18.42	18.60	20.29	20.42	19.48	17.88	15.37	15.04	15.59	13.28	10.72	10.70	16.33
1994-95	15.79	20.12	21.61	17.58	17.11	17.72	15.70	14.50	15.71	14.29	11.54	11.77	16.13
1995-96	16.25	20.72	22.45	18.19	17.65	17.37	16.80	15.39	17.91	14.18	11.51	12.31	16.74
1996-97	17.84	22.16	24.64	18.31	18.21	20.63	15.47	15.40	16.21	14.16	12.43	12.35	17.33
1997-98	21.58	23.92	27.41	19.07	18.98	18.07	16.73	16.39	17.34	17.58	13.56	13.62	18.70
1998-99	24.63	25.33	29.20	20.22	20.12	19.44	19.13	17.98	19.61	18.47	13.51	15.02	20.23
1998-99	26.78	31.44	30.98	31.12	22.05	21.60	20.92	19.49	20.88	19.63	14.27	15.63	22.94

Without Special Sales Credit

Cal -YR	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	OPER-YR AVG
1994	15.37	15.04	15.59	13.28	10.72	10.70	15.79	20.12	21.61	17.58	17.11	17.72	15.86
1995	15.70	14.50	15.71	14.29	11.54	11.77	16.25	20.72	22.45	18.19	17.65	17.37	16.32
1996	16.80	15.39	17.91	14.18	11.51	12.31	17.84	22.16	24.64	18.31	18.21	20.63	17.46
1997	15.47	15.40	16.21	14.16	12.43	12.35	21.58	23.92	27.41	19.07	18.98	18.07	17.89
1998	16.73	16.39	17.34	17.58	13.56	13.62	24.63	25.33	29.20	20.22	20.12	19.44	19.49
1999	19.13	17.98	19.61	18.47	13.51	15.02	26.78	31.44	30.98	31.12	22.05	21.60	22.24

Based on RAMPP-3 Avoided Costs