BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PACIFICORP for Approval of an IRP-Based Avoided Cost Methodology For QF Projects Larger than One Megawatt	)))))	Docket No. 03-035-14

REBUTTAL TESTIMONY OF RODGER WEAVER

May 6, 2004

Q. Please state your name and business address.

A. My name is Rodger Weaver. My Business address is 825 NE Multnomah, Suite 800, Portland, Oregon 97232.

Q. Are you the same Rodger Weaver that filed testimony earlier in this case?

A. Yes.

PURPOSE OF TESTIMONY

Q. What is the purpose your rebuttal testimony in this case?

A. I will be responding to issues set forth by Philip Hayet (CCS) and Roger Swenson (Desert Power LP and US Magnesium LLC).

Q. Would you explain the Company's goals in this docket?

A. Yes. The primary goal of the Company in this docket is to assist the Commission in establishing an avoided cost pricing mechanism to provide large QFs with price offers that are just and reasonable to the Company's customers, the QF and the Company. The method adopted by the Commission must take account of the specific characteristics of the specific large QF. It is those peculiarities that determine the costs the Company would have to incur but for the power provided by the large QF. This is the appropriate basis upon which to determine avoided cost-based prices for the QF power and meet PURPA's ratepayer indifference standard.

Q. Does the avoided cost methodology proposed by the Company in this case meet these criteria?

A. Yes. The proposed methodology in this case is based on the methodology traditionally used by the Commission to establish avoided costs for small QF projects covered by Schedule 37. Recall that this method is to be applied directly only to small QFs. It does not attempt to recognize the specific capabilities and operational characteristics of the individual small QF. The decision to exclude such considerations from small QF pricing is one of expediency and materiality. The Commission has decided, due to the relatively minor cost impact of small QFs on overall revenue requirement and due to the process difficulties detailed analysis would impose on small QFs, that the generic Schedule 37 rates will be available to the small QFs without adjustment.

Q. So the Schedule 37 avoided cost prices are not directly available to large QFs?

A. That is correct. Rather, Schedule 37 provides a starting point that allows the large QF and the Company to tailor the QF's contract to the specific capabilities of the QF resource to ensure compliance with PURPA's ratepayer indifference standard. Thus, different large QFs would and should require different contract terms, including different prices, to reflect the costs the QF allows the Company to avoid. For example, a wind project, that provides intermittent power, should have different contract terms and different prices than a CCCT cogeneration plant whose operational characteristics are controlled by a different technology and fuel availability and market and also by the operational requirements of the steam host industrial facility.

Q. The Company's direct testimony was based on the Company's Schedule 37 filing. Do any of the adjustments proposed by CCS and DPU in the Schedule 37 proceeding that the Company agreed to apply in this docket as well?

A. Yes. As a result of the Schedule 37 process, the Company has agreed to several changes to the methodology that would also be applicable to Schedule 38. A copy of the Company's comments on Schedule 37 is attached as Exhibit UP&L ___(RW-1R).

US Magnesium LLC (US Magnesium) and Desert Power LLC (Desert Power)'s NDP Methodology

Q. Does the Company have concerns with US Mag and Desert Power's proposed

methodology?

A. Yes. The proposed methodology has numerous problems which make the approach unsuitable. These problems include:

i. The Desert Power and US Magnesium plants would not displace the West Valley resource

ii. The West Valley plant is a dispatchable resource while the Desert Power and US Magnesium plants would be scheduled resources

iii. The NDP methodology is an extremely complex approach which would require complex and manual billing

Q. Would you explain why the Desert Power and US Magnesium plants would not displace the West Valley plant?

A. There are several reasons. The first is that the combined capacity of the Desert Power and US Magnesium facilities is insufficient to displace the West Valley units. A second reason is that those facilities don't provide the operating benefits associated with the West Valley plant. A third reason is the Company's need for resources ensures that the West Valley plant will continue to operate.

Q. Please explain the first reason.

A. The West Valley units are under a lease arrangement dated March 2002. The provisions of the lease allow the Company to withdraw from the lease in the third and sixth year of the lease. This exit provision allows the Company to terminate the lease in its entirety. If the Company chooses to exercise this option, the Company would return to the plant's owner the entire 200-MW capacity of the plant. However, the combined capacity of the Desert Power and the US Magnesium plants do not match or exceed the 200-MW capacity of the West Valley plant. Indeed, the incremental energy that they offer which is not already available to the system is smaller than the total volume of their application as PacifiCorp already takes power from both facilities. Should the Company withdraw from the lease, some portion of the capacity of the West Valley power plant would not be displaced by the Desert Power and US Magnesium plants.

Q. What is the capacity of the Desert Power and US Magnesium plants?

A. As best we can infer from information provided by these developers, their total capacity is on the order of 138.6 MW consisting of 46.8 MW at US Magnesium plus 90 MW at Desert Power, including planned and existing upgrades.

Q. Would all this capacity constitute new resource available to the system?

A. No. The existing US Magnesium facility is currently under contract to the Company and is delivering power under the terms of that contract. Also, the Company is purchasing from Desert Power, although not on a long-term firm basis. However, even if all the Desert Power capacity is added to the proposed expansion of US Magnesium capacity, the total being offered for new long-term firm capacity is 102 MW, or only half of the total West Valley Plant capacity. The West Valley lease is on an all-or-nothing basis and does not allow for displacement of the 102 MW of new firm capacity being offered. This new capacity is not able to defer West Valley at its lease decision date so West Valley should not serve as the NDP.

Q. Would you please explain the second reason the Desert Power and US Magnesium facilities would not displace the West Valley plant?

A. As I discuss later in my testimony, the West Valley units are dispatchable, but as proposed by Mr. Swenson, the Desert Power and US Magnesium are only schedulable. The terms of the West Valley lease provide PacifiCorp with complete operational control over these units. Each of the five units can be dispatched at PacifiCorp's discretion to produce energy for our customers at the best cost/risk balance the Company can achieve. The Company also has complete control over the maintenance schedules of the West Valley units. Neither Desert Power nor US Magnesium offer this level of operational flexibility.

Q. Would you please explain the third reason?

A.. The Company's L&R study clearly shows that the Company is capacity deficit during five months of the year through 2006. There is little likelihood that PacifiCorp will elect to terminate the 200 MW West Valley lease and replace that resource with a 136.6 MW QF purchase of which, as discussed earlier in my testimony, not more than 102 MW can be viewed as a new firm resource on the system. Further, as I explain below the QFs are existing resources and would not displace other resources.

Q. If the West Valley plant is not the next deferrable plant than what plant is?

A. The least cost source of capacity during the period 2004 through June 2007 would be a wholesale purchase during the specific months in which the Company is capacity deficit.

Q. What would be the next deferrable plant after June 2007?

A. The Company's L&R study shows that the Company is both capacity and energy deficit beginning in June 2007. The next deferrable plant would need to provide the Company both capacity and energy and should provide those at least cost to the Company and the Company's customers. Thus, the next deferrable plant would be a CCCT located in the Utah "bubble".

Q. Isn't what you have just described the Company's Proposed Approach?

A. Yes. The West Valley plant is not the next deferrable plant. Rather, but for power delivered from other sources such as QF suppliers, the Company is most likely to acquire capacity in the wholesale market until June 2007 and would then acquire capacity and energy from a new CCCT located in the Utah bubble.

Q. Is all of the capacity being offered by Desert Power and US Magnesium new resource?

A. No. As indicated above, both the Desert Power and US Magnesium plants are existing resources that are currently either selling power into the market, to the Company or being utilized to serve existing industrial load. Therefore, these resources will not displace another existing resource.

Q. On page 18, lines 11-14, and page 19, line 1-4, and again on page 26, lines 6 - 8, of his testimony, Mr. Swenson asserts that the Company's method of computing capacity cost during the long-run resource shortage period as "having no rational economic basis." Do you agree with this assessment?

A. No. In simplest terms, Mr. Swenson is wrong because he confuses the capacity cost a QF facility would allow the Company to avoid with the capital cost a QF developer must incur to construct its facility. Avoidable capacity cost and QF facility capital cost are, in fact, two distinct concepts. I explain the Company's long standing and widely accepted approach to long-run avoided capacity cost determination on page 7 of my direct testimony. Capacity is the firm ability to stand ready to deliver electric energy on demand. The lowest initial cost resource capable of meeting this requirement is typically considered to be a SCCT. Thus, the capital cost of constructing this resource, and that amount of capital cost only, is the appropriate basis for computing avoided capacity cost. Additional capital cost invested in a plant, such as the additional investment required to add steam cycle and duct firing capability to convert a SCCT to a CCCT, is incurred for the purpose of allowing the plant to produce energy more efficiently; to "wring" more megawatt hours out of the same MMBtu of fuel input. Thus, this additional investment –

capital cost – is properly classified as a component of energy cost, as it is in the Company's method. Note finally, that the focus is on the costs the QF facility allows the Company to avoid imposing on its customers, not on the capital cost the QF developer incurs to construct its facility.

Q. Mr. Swenson refers to the West Valley NDP variously (see page 12, line 22, page 16, line 13, and page 19, line 17) as a scheduled or a dispatchable resource. Would you explain the difference between a dispatchable resource and a scheduled resource?

A. Yes. A dispatchable resource is one that the Company has total control over such that the Company can increase or reduce the plant's generation from the Company's control center on a real time basis. The West Valley plant is a good example of a dispatchable resource, the Company can elect to start the plant at any time, operate the plant for a period of time, ramping output up and down as economics dictate, and then shut down the plant when the plant is no longer needed. A scheduled resource is a resource whose generation needs to be preplanned in advance of generation and must be taken regardless of market conditions. Naturally the value to the Company of a dispatchable resource is significantly greater than the value of a scheduled resource. The West Valley NDP methodology proposes that the Company should pay a QF as if it would allow the Company to avoid the level of costs associated with a dispatchable resource.

Q. Would the Desert Power and US Magnesium resources be dispatchable?

A. Mr. Griswold is the best witness on the Company's view of the operating characteristics being offered by these two facilities. My understanding is that based on the testimony of Mr. Swenson, neither Desert Power nor US Magnesium offer dispatchability, rather they are offering the ability to pre-schedule their output.

Q. What is the implication for the appropriateness of the West Valley NDP approach?

A. To the extent that these facilities do not match the degree of operational control the Company enjoys with any dispatchable resource, they would have the ability to require the Company to take energy at any time that they decide to generate. This would be equivalent to the Company purchasing a high load hour product in the wholesale market but being required to take any additional energy the seller opts to deliver, conceivably up to all hours, regardless of whether the Company needs such power, or stated differently, regardless of whether the QF power requires the Company to back down lower cost resources. This results in higher net power costs and is therefore in violation of the ratepayer indifference standard.

Q. Would you explain what you meant by asserting that the West Valley NDP methodology is an extremely complex approach which would require complex and manual billing?

A. Yes. The NDP methodology has two billing components. The first component consists of scheduled energy that would be paid avoided costs. The second component would consist of unscheduled energy that would be paid at either firm or non-firm market prices. In order to bill the QF accurately, the Company would have to make an hourly analysis to compare scheduled generation to actual generation in order to determine the level of scheduled and unscheduled generation. If there is unscheduled generation in a given hour, the Company would then need to do a second hourly analysis to determine if the Company is a net buyer or a net seller in the market. If the Company is a net seller in the market, then the Company would need to do a third hourly analysis to determine if the Company needed the QF resource as operating reserve. Having completed these three hourly studies, the Company would then have sufficient information to calculate the QF's payment for that hour. This level of detail and complexity would require manual billing and is likely to result in constant disputes.

Committee of Consumer Services

Q. In Exhibit CCS 2.2 the Committee suggests several changes to the Company's Proposed Approach. Would you explain these adjustments?

A. Yes. The Committee recommends that the Commission revise the definition of the summer season to June through September. The Company agrees that the summer season June through September has significantly higher avoided cost than the other eight months of the year. The Company would accept this recommendation.

The Committee recommended that the capacity payment currently based on a three month capacity purchase should be increased to six months. The Company agrees that the three-month capacity purchase could be viewed as being conservative. However, during the period 2004 to 2007, the Company is capacity deficit in five months in 2005 and 2006, six months in 2007, and seven months in 2004. In 2004, we have already passed one of the deficit months and we are almost through a second deficit month. Therefore, only five deficit months remain in 2004. In 2007, the Company is transitioning over to the proxy resource in July 2007. During the period January to June 2007 the Company is only resource deficit in May and June. The Company therefore considers it reasonable that the capacity payment be increased from 3 months to 5 months per year.

Q. The CCS puts forth two gas pricing options. Would you please describe them and state whether the Company agrees that the options should be used?

A. The Committee proposed two gas pricing options in their comments: (1) if the Commission prefers fixed energy pricing for QFs, the CCS recommended adoption of the Committees alternative gas price forecast which appears to be based on the Committee's combination of the Company's forecast and those provided by NYMEX and the Energy Information Administration (EIA) with a negative $0.40 per MMBtu basis adjustment to produce Utah market gas prices; or (2) if the Commission prefers QF energy prices to vary with the gas markets, the CCS recommends tying the cost calculation to an indexed fuel price at the time the energy is delivered to the Company.

The NYMEX and EIA index approach should be rejected. The Committee forecast is not adequately substantiated and cannot be taken as representative of Utah gas prices. As shown in Exhibit UP&L____(RW-2R), the historical difference between the NYMEX and EIA indexes on one hand and Opal prices on the other is highly volatile. More significantly, on average the data indicate a negative basis adjustments of approximately $1.02/MMBtu and $1.57/MMBtu for NYMEX and EIS, respectively. Therefore, the Committee's proposed basis adjustment would result in an overpayment to QFs.

In contrast, the Company uses PIRA Energy Group's long term natural gas forecast as the basis for the Company's long term price projection appropriate for the Utah area (the OPAL gas market). This means that PIRA provides the Company with a direct price projection for OPAL. PIRA is a credible and respected forecasting firm within the energy industry. In developing their long term forecast for the OPAL market, PIRA takes into account plans and forecasts of regional supply, demand and pipeline capacity expansions. At this point, the Company does not believe that Mr. Hayet as adequately substantiated why his proposed gas forecast is superior to the Company's. From a policy perspective, the Company believes that the Commission should rely on the gas forecast being used by the Company for any long-term avoided cost method.

Q. What is your response to the Committee's second option, tying the energy price

through time to a fluctuating natural gas price index.

A. The Company believes this recommendation should be adopted as an option that can be used for specific QFs as appropriate. For example, wind resources would probably prefer the certainty of a fixed price while a gas fired resource would probably prefer the risk mitigation of the fuel indexed mechanism. By allowing the Company the option to offer either a fixed price or a fueled indexed price, the Company and QFs would be able to tailor their payment stream to best serve their needs while continuing to meet PURPA's ratepayer indifference standard.

Q. Does this conclude your testimony?

A. Yes.

April 19, 2004

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84111

Attn: Julie P. Orchard
Commission Secretary

RE: Docket No 03-035-T10
Schedule 37 - Avoided Cost Purchases From Qualifying Facilities

The Company has reviewed the comments of the Division of Public Utilities and The Committee of Consumer Services and would like to comment on their proposals.

Division of Public Utilities

Size Limit Recommendation

The Company is willing to adopt the DPU's experimental size limit recommendation of 5 MW for two years with a maximum 25 MW contracted for new small QF projects before the rates and size limitation must be updated. However, because of the increase in size limit, the pricing design should be changed to a volumetric basis with on and off-peak pricing where the capacity payment is built into the on-peak pricing as opposed to capacity and energy payments to avoid overpaying intermittent projects such as wind.

Price Design

Schedule 37 currently allows a QF to select either a capacity and energy payment or seasonally differentiated on-peak / off-peak volumetric prices. Previously it was envisioned that QF's with high capacity factors would be indifferent between the two pricing options. However, with the increased interest in intermittent resources, this price design is problematic. An intermittent resource, such as a wind project projected to have an annual capacity factor between 30% and 40%, would certainly select the capacity and energy design. Thus, in this example, the intermittent resource would receive a capacity payment based upon the full name plate capacity despite the intermittent nature of the resource. This would result in an overpayment.

The Company recommends eliminating the capacity and energy price option from the filed tariff to resolve the possibility of overpayment. All QFs, regardless of fuel type, would be entitled to the on-peak / off-peak pricing provided in the tariff.

Other Division Comments
The Division makes four other minor recommendations all of which the Company considers reasonable. The fourth recommendation, related to variable and fixed O&M costs is the same adjustment recommend by the CCS.

Committee of Consumer Services
Summer Peak Defined as June through September
The Company agrees with this recommendation. An analysis of the Company's avoided costs clearly shows that the prices during the June through September period are higher than the other eight months of the year. Adjusting the summer peak season to only four months would send a more accurate price signal to QFs.

This revision will only impact those QFs that elect to take the seasonally differentiated on-peak / off-peak volumetric prices mention in the price design section of this letter.

Capacity Payment based on three months
The Committee recommended that the capacity payment currently based on a three month capacity purchase should be increased to six months. The Company agrees that the three-month capacity purchase could be viewed as being conservative. However, during the period 2004 to 2007, the Company is capacity deficit in five months in 2005 and 2006, six months in 2007, and seven months in 2004. In 2004, we have already passed one of the deficit months and we are almost through a second deficit month.

Therefore, only five deficit months remain in 2004. In 2007, the Company is transitioning over to the proxy resource in July 2007. During the period January to June 2007 the Company is only resource deficit in May and June. The Company therefore puts forth, in response to the CCS recommendation, that the capacity payment could prudently be increased from 3 months to 5 months on a yearly basis.

Gas Pricing Proposal
The Committee proposed two gas pricing options in their comments: 1) if the Commission prefers fixed energy pricing for QFs, the CCS recommended adoption of the Committees alternative gas price forecast which appears to be based on the Committee's combination of the the Company's forecast and those provided by NYMEX and the Energy Information Administration; or 2) if the Commission prefers QF energy prices to vary with the gas markets, the CCS recommends tying the cost calculation to an indexed fuel price at the time the energy is delivered to the Company.

The CCS recommendation described above as "Option 1" for a gas price forecast developed by the Committee should be rejected by the Commission. The Committee forecast is not adequately substantiated and appears to rely on the Committee's view, in part, on future gas prices at Henry Hub. As such, it is not representative of Utah gas prices. The Committee also states that the gas price forecast it developed has been made to include an undocumented $.40/mmBTU "basis adjustment" to account for the difference in prices between OPAL and Henry Hub.

In contrast, the Company uses PIRA Energy Group's long term natural gas forecast as the basis for the Company's long term price projection appropriate for the Utah area (the OPAL gas market). This means that PIRA provides the Company with a direct price projection for OPAL. PIRA is a credible and respected forecasting firm within the energy industry. In developing their long term forecast for the OPAL market, PIRA takes into account plans and forecasts of regional supply, demand and pipeline capacity expansions. Consequently, the Company recommends to the Commission that the gas price forecast being used by the Company be utilized.

The Company believes that the CCS recommendation described above as "Option 2" should be rejected. The Company believes that the conversion to a new avoided cost methodology is best reviewed formally and is inconsistent with the Commissions previous finding in this particular docket with respect to fixed energy prices for "small" QFs.

The Company believes that the issue of variable avoided cost pricing will receive formal debate in Docket # 03-035-14 and, depending on the outcome of that proceeding, the Commission may or may not wish to revisit avoided cost pricing methodologies with respect to "small" QFs.

Other CCS comments
The Company agrees that the Company's original filing included an error related to variable and fixed O&M costs and should be corrected.

Based on the Committee's recommendation to change the seasonal definitions, the method of calculating average annual energy prices should be revised.

If you have any questions, please call me at (503) 813-5541 or via email at Mark.Widmer@PacifiCorp.Com.

Sincerely,

/s/ Mark Widmer

Mark Widmer
Manager, Regulation

Enclosures

PacifiCorp
NYMEX / Opal Price Index

Month	NYMEX	Opal	Difference
Jan-01	9.98	7.80	2.18
Feb-01	6.21	5.51	0.70
Mar-01	5.05	4.77	0.28
Apr-01	5.34	4.53	0.81
May-01	4.87	3.25	1.62
Jun-01	3.73	2.50	1.23
Jul-01	3.11	2.35	0.76
Aug-01	3.19	2.44	0.75
Sep-01	2.34	1.67	0.67
Oct-01	1.86	2.05	(0.19)
Nov-01	3.15	1.90	1.25
Dec-01	2.31	2.25	0.06
Jan-02	2.61	1.98	0.63
Feb-02	2.04	2.01	0.03
Mar-02	2.40	2.74	(0.34)
Apr-02	3.41	1.82	1.59
May-02	3.36	1.78	1.58
Jun-02	3.38	1.26	2.12
Jul-02	3.26	1.32	1.94
Aug-02	2.95	1.31	1.64
Sep-02	3.27	1.08	2.19
Oct-02	3.72	2.13	1.59
Nov-02	4.13	3.04	1.09
Dec-02	4.13	3.13	1.00
Jan-03	4.96	3.12	1.84
Feb-03	5.66	4.74	0.92
Mar-03	9.11	4.33	4.78
Apr-03	5.14	3.41	1.73
May-03	5.12	4.73	0.39
Jun-03	5.95	4.82	1.13
Jul-03	5.29	4.42	0.87
Aug-03	4.69	4.61	0.08
Sep-03	4.43	4.32	0.11
Oct-03	4.45	4.26	0.19
Nov-03	4.86	4.23	0.63
Dec-03	6.15	5.41	0.74
Jan-04	5.76	5.53	0.23
Feb-04	5.15	4.82	0.33
Mar-04	5.37	4.79	0.57

-0.341
4.775238

PacifiCorp
EIA US Natural Gas City Gate / Opal Price Index

Month	EIA	Opal	Difference
Jan-00	3.27	2.23	1.04
Feb-00	3.48	2.38	1.10
Mar-00	3.54	2.58	0.96
Apr-00	3.72	2.69	1.03
May-00	4.15	3.09	1.06
Jun-00	5.19	3.73	1.46
Jul-00	5.20	3.39	1.81
Aug-00	4.63	3.25	1.38
Sep-00	5.21	4.11	1.10
Oct-00	5.66	4.58	1.08
Nov-00	5.20	5.26	(0.06)
Dec-00	6.64	8.26	(1.62)
Jan-01	8.91	7.80	1.11
Feb-01	7.08	5.51	1.57
Mar-01	6.10	4.77	1.33
Apr-01	6.30	4.53	1.77
May-01	5.77	3.25	2.52
Jun-01	5.38	2.50	2.88
Jul-01	4.03	2.35	1.68
Aug-01	4.32	2.44	1.88
Sep-01	3.66	1.67	1.99
Oct-01	3.37	2.05	1.32
Nov-01	4.02	1.90	2.12
Dec-01	3.90	2.25	1.65
Jan-02	3.79	1.98	1.81
Feb-02	3.76	2.01	1.75
Mar-02	3.84	2.74	1.10
Apr-02	4.21	1.82	2.39
May-02	4.07	1.78	2.29
Jun-02	4.15	1.26	2.89
Jul-02	3.95	1.32	2.63
Aug-02	3.67	1.31	2.36
Sep-02	3.99	1.08	2.91
Oct-02	4.32	2.13	2.19
Nov-02	4.65	3.04	1.61
Dec-02	4.74	3.13	1.61
Jan-03	5.31	3.12	2.19
Feb-03	5.86	4.74	1.12
Mar-03	7.60	4.33	3.27
Apr-03	5.61	3.41	2.20
May-03	5.66	4.73	0.93
Jun-03	6.40	4.82	1.58
Jul-03	5.82	4.42	1.40
Aug-03	5.48	4.61	0.87
Sep-03	5.58	4.32	1.26
Oct-03	5.25	4.26	0.99
Nov-03	5.53	4.23	1.30
Dec-03	5.91	5.41	0.50

-1.62
3.265238

PacifiCorp
NYMEX / Opal Natural GasPrice Index $/MMBtu

Month - year	NYMEX	Opal	Difference	% Diff from Opal
average 1-01 to 3-04	**4.41**	**3.39**	**1.02**	**42.59%**
Jan-01	9.98	7.80	2.18	28.02%
Feb-01	6.21	5.51	0.70	12.66%
Mar-01	5.05	4.77	0.28	5.86%
Apr-01	5.34	4.53	0.81	17.80%
May-01	4.87	3.25	1.62	50.01%
Jun-01	3.73	2.50	1.23	48.94%
Jul-01	3.11	2.35	0.76	32.58%
Aug-01	3.19	2.44	0.75	30.67%
Sep-01	2.34	1.67	0.67	40.47%
Oct-01	1.86	2.05	(0.19)	-9.23%
Nov-01	3.15	1.90	1.25	65.48%
Dec-01	2.31	2.25	0.06	2.88%
Jan-02	2.61	1.98	0.63	31.75%
Feb-02	2.04	2.01	0.03	1.33%
Mar-02	2.40	2.74	(0.34)	-12.44%
Apr-02	3.41	1.82	1.59	87.22%
May-02	3.36	1.78	1.58	88.91%
Jun-02	3.38	1.26	2.12	167.72%
Jul-02	3.26	1.32	1.94	147.86%
Aug-02	2.95	1.31	1.64	124.96%
Sep-02	3.27	1.08	2.19	203.62%
Oct-02	3.72	2.13	1.59	74.79%
Nov-02	4.13	3.04	1.09	36.02%
Dec-02	4.13	3.13	1.00	31.89%
Jan-03	4.96	3.12	1.84	58.90%
Feb-03	5.66	4.74	0.92	19.41%
Mar-03	9.11	4.33	4.78	110.16%
Apr-03	5.14	3.41	1.73	50.84%
May-03	5.12	4.73	0.39	8.27%
Jun-03	5.95	4.82	1.13	23.38%
Jul-03	5.29	4.42	0.87	19.77%
Aug-03	4.69	4.61	0.08	1.63%
Sep-03	4.43	4.32	0.11	2.64%
Oct-03	4.45	4.26	0.19	4.51%
Nov-03	4.86	4.23	0.63	15.01%
Dec-03	6.15	5.41	0.74	13.59%
Jan-04	5.76	5.53	0.23	4.15%
Feb-04	5.15	4.82	0.33	6.82%
Mar-04	5.37	4.79	0.57	11.96%

Source: Bloomberg Power and Gas Prices

PacifiCorp
EIA US Natural Gas City Gate / Opal Price Index $/MMBtu

Month - year	EIA	Opal	Difference	% Diff from Opal
average 1-00 to 12-03	**4.96**	**3.39**	**1.57**	**66.28%**
Jan-00	3.27	2.23	1.04	46.64%
Feb-00	3.48	2.38	1.10	46.19%
Mar-00	3.54	2.58	0.96	37.23%
Apr-00	3.72	2.69	1.03	38.35%
May-00	4.15	3.09	1.06	34.40%
Jun-00	5.19	3.73	1.46	39.02%
Jul-00	5.20	3.39	1.81	53.19%
Aug-00	4.63	3.25	1.38	42.48%
Sep-00	5.21	4.11	1.10	26.87%
Oct-00	5.66	4.58	1.08	23.49%
Nov-00	5.20	5.26	(0.06)	-1.16%
Dec-00	6.64	8.26	(1.62)	-19.61%
Jan-01	8.91	7.80	1.11	14.29%
Feb-01	7.08	5.51	1.57	28.44%
Mar-01	6.10	4.77	1.33	27.87%
Apr-01	6.30	4.53	1.77	38.98%
May-01	5.77	3.25	2.52	77.74%
Jun-01	5.38	2.50	2.88	114.83%
Jul-01	4.03	2.35	1.68	71.80%
Aug-01	4.32	2.44	1.88	76.95%
Sep-01	3.66	1.67	1.99	119.72%
Oct-01	3.37	2.05	1.32	64.46%
Nov-01	4.02	1.90	2.12	111.19%
Dec-01	3.90	2.25	1.65	73.70%
Jan-02	3.79	1.98	1.81	91.32%
Feb-02	3.76	2.01	1.75	86.77%
Mar-02	3.84	2.74	1.10	40.09%
Apr-02	4.21	1.82	2.39	131.15%
May-02	4.07	1.78	2.29	128.83%
Jun-02	4.15	1.26	2.89	228.71%
Jul-02	3.95	1.32	2.63	200.33%
Aug-02	3.67	1.31	2.36	179.86%
Sep-02	3.99	1.08	2.91	270.47%
Oct-02	4.32	2.13	2.19	102.98%
Nov-02	4.65	3.04	1.61	53.15%
Dec-02	4.74	3.13	1.61	51.37%
Jan-03	5.31	3.12	2.19	70.11%
Feb-03	5.86	4.74	1.12	23.63%
Mar-03	7.60	4.33	3.27	75.33%
Apr-03	5.61	3.41	2.20	64.63%
May-03	5.66	4.73	0.93	19.69%
Jun-03	6.40	4.82	1.58	32.71%
Jul-03	5.82	4.42	1.40	31.77%
Aug-03	5.48	4.61	0.87	18.75%
Sep-03	5.58	4.32	1.26	29.28%
Oct-03	5.25	4.26	0.99	23.30%
Nov-03	5.53	4.23	1.30	30.87%
Dec-03	5.91	5.41	0.50	9.16%

Source: Bloomberg Power and Gas Prices