Oregon

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June 30th, 2006

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 2148
SALEM OR 97308-2148

RE: **Docket No. UE 179** - In the Matter of PACIFICORP, dba PACIFIC POWER AND LIGHT COMPANY Request for a General Rate Increase in the Company's Oregon Annual Revenues.

Enclosed for electronic filing in the above-captioned docket is the Public Utility Commission Staff's Direct Testimony.

/s/ Kay Barnes
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c: UE 179 Service List - parties

PUBLIC UTILITY COMMISSION
OF OREGON

UE 179

STAFF DIRECT TESTIMONY OF

Bill Wordley

In the Matter of
PACIFICORP, dba PACIFIC POWER & LIGHT COMPANY
Request for a General Rate Increase in the Company's Oregon Annual Revenues.

June 30, 2006

CASE: UE 179
WITNESS: Bill Wordley

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Direct Testimony

June 30, 2006

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Bill Wordley. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301. I am a Senior Economist in the Economic Research & Financial Analysis Division of the Utility Program of the Public Utility Commission of Oregon (OPUC).

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE?

A. My witness qualification statement is found in Staff/101, Wordley/1.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. In this testimony I will describe staff's proposed adjustments to the power costs that PacifiCorp has included in its filed case. I will also describe limitations with the company's power cost modeling, and staff's recommendation that the company pursue stochastic power cost modeling.

Q. PLEASE SUMMARIZE STAFF'S ADJUSTMENTS TO POWER COSTS.

A. Staff proposes three adjustments to the power costs allocated to Oregon:

(1) A reduction of $1,096,400 to match the costs and revenues from contingency operating reserves that PacifiCorp provides to non-owned power generation plants on its system;

(2) A reduction of $13,253,202 to account for PacifiCorp's margin realized from wholesale market sales and purchase transactions that are not captured by the GRID power cost model used in this case; and

(3) A reduction of $7,068,361 to account for the extrinsic value associated with PacifiCorp's flexible purchase power contracts and gas-fired generating plants.

Q. WHAT IS STAFF'S RECOMMENDATION REGARDING PACIFICORP'S POWER COST MODELING?

A. The Commission should indicate a preference for stochastic power cost modeling. Modeling the uncertainty and interaction associated with system loads, electricity and natural gas market prices, hydroelectric generation, and thermal unit availability provides a more realistic simulation of PacifiCorp's system operations and produces a distribution of power costs that can be used to design a fair power cost adjustment mechanism.

Adjustment for Contingency Operating Reserves

Q. WHAT ARE CONTINGENCY OPERATING RESERVES?

A. The North American Electric Reliability Council (NERC) requires all entities with generation to carry contingency reserves to meet its most severe single contingency, or 5% for operating hydro and wind resources and 7% for operating thermal resources, whichever is greater. In the case of PacifiCorp, the company provides reserves for all generating plants, company-owned and non-owned, in its two control areas. The control areas are geographical areas for which PacifiCorp is responsible for providing load and resource balance and other associated electrical system services necessary to maintain the integrity of the electrical system. Contingency operating reserves are one of the services PacifiCorp provides.

Q. WHO OWNS THE POWER PLANTS FOR WHICH PACIFICORP PROVIDES RESERVES?

A. First, PacifiCorp has a number of joint-ownership power plants. The company provides reserves for the entire output of these jointly owned plants. Second, several other utilities own power plants located inside PacifiCorp's control areas. Third, some of PacifiCorp's large retail customers own generating plants for which PacifiCorp provides reserves. Finally, PacifiCorp provides reserves for all the QFs (qualifying facilities) in its control areas.

Q. HOW DID STAFF DETERMINE THAT AN ADJUSTMENT WAS WARRANTED, AND HOW WAS THAT PROPOSED ADJUSTMENT CALCULATED?

A. An adjustment is warranted because there is a mismatch between costs and benefits in the company's filed case. In response to staff discovery, the company provided the cost of providing contingency operating reserves to non-owned generating plants in its control areas; that amount was $12,566,679 (Staff DR 364)[1]. Also through discovery, the company provided estimates of the revenue in its filled case from providing reserves to other parties; which was $8,449,194 (Staff DR 348). The difference of $4,117,485 is the mismatch between costs and benefits identified by staff.

[1] Staff has used the company's responses to staff DRs 252,348, and 364 in this testimony. The responses are voluminous and staff believes that parties already have the responses. Therefore, staff is not providing additional copies with this testimony, but will provide records upon request.

The portion of the difference allocated to Oregon is the proposed adjustment of $1,096,400.

Power Cost Modeling

Q. DESCRIBE THE LIMITATIONS OF PACIFICORP'S POWER COST MODELING.

A. The company should be commended for committing resources and expertise to the development and improvement of its GRID power cost modeling capability. The concerns that staff has are not with the GRID model logic and structure but rather with the some of the primary inputs to the model.

Q. WHICH INPUTS TO GRID IS CONCERN STAFF?

A. The major variable inputs to GRID that cause concern to staff are retail system loads, market prices for electricity and natural gas, thermal power plant forced outages, and hydro generation availability. These are the primary driving variables to power costs in GRID.

Q. WHAT CONCERNS DOES STAFF HAVE WITH THESE VARIABLE INPUTS TO GRID?

A. The major inputs to GRID are normalized/smoothed, deterministic and assumed to be not correlated. In reality, these variables are not smooth, somewhat random and uncertain, and correlated to some extent. Unfortunately, the unrealistic representation of the major inputs in GRID yields a power cost estimate that is inconsistent with actual operation. Consequently, GRID's power cost estimate should not be included in rates without adjustment.

Q. CAN YOU PROVIDE SOME EXAMPLES OF THE PROBLEM WITH THE GRID INPUTS THAT YOU HAVE IDENTIFIED?

A. Yes. For example, the hourly system load used in GRID assumes "normal" weather, which yields a smooth load shape. This is not how loads (or weather) occur on an actual basis. The difference between the smooth loads in GRID and the bumpy actual loads contribute to a significant difference in the actual operation of the power system compared to what is modeled in GRID.

Power plant forced outages in GRID are assumed to be spread evenly over all hours of the test year. In actual operation plant forced outages are random. PacifiCorp simply "derates" or reduces the capacity available from all power plants in all hours, which means, even during profitable market conditions GRID prevents the maximum generation output from occurring in the modeling run, limiting profit margins and resulting in an increase to "modeled" power cost.

Much like the smoothed representation of system load, the power and natural gas prices inputs to GRID are also smoothed. Again, this is not how market prices occur on an actual basis. The smoothed representation of prices prevents GRID from capturing profitable market opportunities that occur in actual operation. Exhibit 102 is a comparison of the shape of actual Mid-Columbia power prices, on and off-peak, and Opal gas prices for May 2006 compared to the representation of these prices in GRID. These graphs illustrate the difference between actual and normalized prices. This difference contributes to a significant difference in the actual operation of the power system to what is modeled in GRID.

Another limitation related to the primary inputs variables in GRID is that there is no correlation assumed between the variables. Correlation is a measure of the extent to which two variables change together. It is likely that some level of correlation exists, for example, between loads and power prices, between hydro conditions and power prices, and between gas price and power price. By not capturing these correlations between variables, GRID is not accurately portraying the real world of power operations.

Q. WHAT DOES STAFF RECOMMEND REGARDING THE PROBLEMS YOU HAVE IDENTIFIED RELATED TO THE INPUTS TO GRID?

A. Staff recommends that the company actively pursue stochastic power cost modeling. Stochastic modeling can provide a more realistic simulation of PacifiCorp’s actual power system operations. It can provide a realistic representation of the variability, and any interactions, associated with retail loads, natural gas and electricity market prices, hydroelectric generation, and thermal unit availability. In addition, stochastic power cost modeling provides a distribution of power costs that can be used to design a PCA mechanism. This modeling will improve “normalization” of power costs and assessment of power cost risk.

Q. HAS STAFF RECOMMENDED STOCHASTIC POWER COST MODELING BEFORE?

A. Yes. In docket UE 165, staff testimony recommended stochastic power cost modeling for PGE. In docket UE 173, staff testimony recommended stochastic power cost modeling for PacifiCorp.

Q. WHAT COMMITMENT DID PACIFICORP MAKE IN ITS LAST GENERAL RATE CASE (UE 170) REGARDING STOCHASTIC POWER COST MODELING?

A. As part of a stipulation incorporated into Order 05-1050 in UE 170, PacifiCorp committed to work with staff to evaluate stochastic modeling of power costs for possible incorporation into rates. (Order 05-1050, Appendix A, at 3)

Q. WHAT IS THE STATUS OF THAT EVALUATION EFFORT?

A. While the company has made some progress, there is still quite a bit more work to do before a determination can be made regarding the use of stochastically modeled power cost in rates. Staff supports the company's efforts, and would like to see more progress on the company's part soon.

Q. ARE THERE INSTANCES WHERE STOCHASTIC POWER COST MODELING HAS BEEN USED IN PROCEEDINGS BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON?

A. Yes. PacifiCorp first used stochastic modeling of power costs in its 2003 Integrated Resource Plan (IRP, Docket LC 31). The Commission in Order No. 03-508 acknowledged PacifiCorp's 2003 IRP. PacifiCorp refined its stochastic modeling for its 2004 IRP (Docket LC 39). The Commission in Order No. 06-029 acknowledged PacifiCorp's 2004 IRP. PacifiCorp has modeled the uncertainty associated with retail system loads, natural gas prices, electricity prices, hydroelectric generation, and thermal unit availability. PacifiCorp's 2004 IRP can be located on PacifiCorp's web site (www.pacificorp.com). Relevant sections include: Chapter 4: Risks and Uncertainties (pp. 61-69); Chapter 8: Results (pp. 138-154); and Appendix G: Risk Assessment Modeling Methodology.

Q. IS IT APPROPRIATE TO TRANSFER THESE STOCHASTIC MODELING TECHNIQUES FROM THE RESOURCE PLANNING ARENA TO THE RATEMAKING ARENA?

A. Yes. The elements that PacifiCorp has modeled stochastically for purposes of IRP are the same elements that have traditionally been, and currently are, normalized in the determination of test year revenue requirements. Portfolio risk is an important consideration in both resource planning and ratemaking. In each arena, sound decision-making requires the best possible measurement and assessment of the relevant portfolio risks. In the IRP arena, the company and Commission evaluate the risks associated with alternative portfolios comprised of existing resources and resource additions. The goal is to select the least-cost and least-risk resource portfolio. In the ratemaking arena, the company and Commission need to consider the risks of the existing resource portfolio and evaluate alternative forms of regulation. The goal is to select ratemaking methods that allocate risk fairly and provide the company with the opportunity to earn the allowed rate-of-return. Staff recommends that the Commission employ a consistent approach when considering portfolio risk. It is inconsistent to use sophisticated risk modeling when making IRP decisions, only to revert to deterministic or point-estimate modeling when making ratemaking decisions.

Q. ARE STAFF'S PROPOSED MARGIN AND EXTRINSIC VALUE ADJUSTMENTS RELATED TO THE LIMITATIONS OF THE EXISTING GRID POWER COST MODELING YOU HAVE DISCUSSED EARLIER IN YOUR TESTIMONY?

A. Yes. If the company successfully implemented stochastic power cost modeling, there may no longer be a need for staff's proposed margin and extrinsic value adjustments. Stochastic power cost modeling would mitigate the concerns regarding the primary inputs to GRID discussed earlier, and would help capture the impact on power costs of the sales and purchase transactions currently not captured by GRID and the option (extrinsic) value of the undispatched capacity of PacifiCorp's flexible resources.

Q. IS THIS CASE THE FIRST TIME STAFF HAS PROPOSED THE MARGIN AND EXTRINSIC VALUE ADJUSTMENTS?

A. No. While this is the first case in which staff has presented written testimony recommending the margin and extrinsic value adjustments, it is not the first time staff proposed these adjustment. In settlement negotiations Staff has proposed the extrinsic value adjustment in the last three cases that included power costs (UE 147, UE 170, and UE 179). Staff has proposed the margin adjustment in the last five PacifiCorp rate cases (UE 116, UE 134, UE 147, UE 170, and UE 179). All these cases prior to this case (UE 179) were settled with stipulations approved by the Commission.

Adjustment for the Margin from Market Transactions Not Included in GRID

Q. PLEASE DESCRIBE WHAT MARKET TRANSACTIONS MEANS.

A. Market transactions are the short-term firm and non-firm sales and purchases the company makes in the wholesale power market. Short-term means less than 12-months ahead, however many of these transactions occur in the day-ahead and hour-ahead power markets.

Q. WHAT SPECIFIC MARKET TRANSACTIONS IS YOUR PROPOSED ADJUSTMENT FOCUSED ON?

A. Staff's margin adjustment is based on an analysis of the short-term firm and non-firm sale and purchases **not** captured by the GRID modeling.

Q. HOW DOES STAFF IDENTIFY THE MARKET TRANSACTIONS NOT CAPTURED BY GRID?

A. Short-term firm and non-firm sales and purchases are estimated in the GRID simulation of hourly system power operations for the future test year. After the test year has occurred, the actual MWh volume short-term firm and non-firm transactions are compared to the earlier GRID MWh estimate. The actual MWh volumes of sales and purchases consistently exceed the GRID forecast of sales and purchases volume. It is the MWh volume of actual sales and purchases **less** the volume forecast by GRID that the margin adjustment is based on.

Q. WHY DOESN'T GRID DO A BETTER JOB OF ESTIMATING THE VOLUME OF SHORT-TERM AND NON-FIRM TRANSACTIONS?

A. As discussed and illustrated in this testimony there is considerably more variation and interaction between the actual loads, market energy prices, thermal plant availability and hydro generation than what is included in GRID. This difference between what GRID is modeling and the actual operation of the system is what causes the actual volume of market sales and purchases to be consistently higher than what GRID estimates.

Q. IS THE FACT THAT GRID CONSISTENTLY UNDER ESTIMATES THE VOLUME OF SALES AND PURCHASES A REASON TO PROPOSE AN ADJUSTMENT TO THE COMPANY'S POWER COSTS?

A. No. It's the fact that the company makes a positive margin on actual transactions in additional of what GRID estimates that causes staff to propose the adjustment.

Q. WHY DOES THE COMPANY MAKE A POSITIVE MARGIN ON THESE ADDITIONAL SALES AND PURCHASES?

A. It's the advantageous characteristics of PacifiCorp system that allow the company to realize a positive margin on the additional sales and purchases not included in GRID. PacifiCorp's system is spread over six states, and has significant load diversity, power transmission capability and power resource flexibility. By using these valuable system characteristics the company is able to consistently realize a positive margin in actual operation from the additional sales and purchase transactions. Below is a comparison of system characteristics between PacifiCorp, PGE and Idaho Power Company. As can be seen, PacifiCorp is substantially more spread out and diversified than the other electric utilities in Oregon.

	PacifiCorp	PGE	Idaho PC
Transmission Lines - miles[1]	15,586	561	4,691
Service Territory - sq. mi.[2]	136,000	4,000	24,000
Number Customers - millions [2]	1.6	0.76	0.46
Generation - MW [2,3]	8,622	1,975	3,260
Hydro	1,084	509	1989
Coal	6,114	676	1026
Gas	1,368	790	245
Wind	33		
Geothermal	23		

[1] - Company's 2005 FERC Form 1
[2] - Company's Web Site
[3] - GRID detail

Q. HOW IS THE MARGIN ADJUSTMENT CALCULATED?

A. First, the MWh volume of sales and purchases not captured by GRID are determined by simple subtracting the GRID forecast MWh volumes from the actual MWh volumes, call these additional MWh. Second, the dollars associated with the additional volumes are determined by subtracting the actual sales and purchase dollars from the GRID forecast sales and purchase dollars, call these additional dollars. Third, the margin in $/MWh is determined by dividing the additional dollars by the additional MWh. Finally, the margin adjustment is determined by multiplying the $/MWh margin by the average of the additional MWh sales and additional MWh purchases.

Q. WHAT DATA DID STAFF USE TO CALCULATE THE MARGIN ADJUSTMENT?

A. Staff used the only data available, which is the GRID power cost forecasts from UE 134 and UE 147, and the actual cost power results from the test year in each of those cases. The only other case that included power costs since PacifiCorp began using GRID was UE 170, however the test period for that case was calendar year 2006, for which actual results are not available at this point.

Q. WHAT IS STAFF'S PROPOSED MARGIN ADJUSTMENT?

A. Staff's proposed margin adjustment, based on the two years of available data is a reduction of $13,253,202 to Oregon's allocated power cost.

Extrinsic Value Adjustment

Q. WHAT IS EXTRINSIC VALUE?

A. Extrinsic value is the dollar value associated with the capacity of the company's flexible power resources that is unused or not dispatched by GRID. During actual operation of the power system, depending on market conditions, PacifiCorp has the option to use this unused capacity and make a positive margin. The company runs its power plants and takes delivery from its flexible purchase power contracts whenever the market price for power exceeds the cost of producing power from its plants or the cost of contact power. This is called economic dispatch. Extrinsic value is inherent in the actual operation of the company's system due to the volatility of the primary inputs to GRID, and the correlation between these inputs, neither of which is included in GRID as discussed earlier in this testimony.

Q. WHY DOES GRID NOT USE OR DISPATCH ALL OF THE COMPANY'S RESOURCE CAPACITY?

A. Consistent with economic dispatch GRID runs the power plants and uses the purchase contracts when market power prices exceed the marginal cost of the plant or contract. As discussed earlier, the market prices in GRID are smooth and do not reflect the uncertainty inherent in today's wholesale energy market. Because of this limited representation of market energy prices, GRID does not use a significant part of the available gas-fired plant and flexible contract capacity. This unused capacity has a substantial extrinsic or expected value.

Q. HOW MUCH UNUSED POWER RESOURCE CAPACITY IS THERE IN THE COMPANY'S FILLED CASE?

A. All of the PacifiCorp's gas-fired generating plants, except Hermiston, have a lot of unused capacity in company's filled case. The Hermiston gas-fired plant is supplied by a low cost long-term contract, so the plant is dispatched to capacity by GRID. However, the Current Creek gas-fired plant has 39% unused capacity, the West Valley CTs 66%, the Gadsby CTs 81%, and Gadsby 82%. Two purchase power contracts also have significant unused capacity, Desert Power with 20% and APS Supplemental with 87%.

Q. HOW WAS STAFF'S EXTRINSIC VALUE ADJUSTMENT CALCULATED?

A. Staff based its calculation of extrinsic value in this case on PacifiCorp's estimate of extrinsic value used to justify the acquisition of the West Valley gas-fired power plant in UE 134. Staff used a five-year average of PacifiCorp's estimate to stabilize for any shorter term aberrations. This estimate of extrinsic value for West Valley was then used as the basis to develop extrinsic value estimates for each of the resources with unused capacity in the company's filled case that were identified above. The estimate for each resource was based on its specific MW capacity, heat rate (MMBtu/MWh), and unused capacity as estimated by GRID.

Q. WHAT IS STAFF'S PROPOSED EXTRINSIC VALUE ADJUSTMENT?

A. Staff's proposed extrinsic value adjustment is a reduction of $7,068,361 to Oregon's allocated power cost.

Addressing Anticipated PacifiCorp Arguments

Q. WHAT ARGUMENTS DO YOU EXPECT PACIFICORP TO RAISE REGARDING STAFF'S MARGIN AND EXTRINSIC VALUE ADJUSTMENTS?

A. Staff expects the following arguments:

- The margin and extrinsic value adjustments overlap so, there is double-counting;
- Staff is using old data to calculate the adjustments;
- The company does not use extrinsic value anymore to justify its power resource acquisition decisions; and
- These adjustments are inconsistent with "normalized rate-making" and that staff is "cherry picking".

Q. PLEASE ADDRESS THE COMPANY'S ARGUMENTS.

A. The overlap argument would be that the unused capacity from the company's gas-fired power plants and flexible purchase contracts, which is the source of the extrinsic value, is used in actual operations to make sales that are included in the margin adjustment. Staff examined the two years of data used to calculate the margin adjustment and found that the resources contributing to the extrinsic value adjustment actually provided less energy in the actual year than was forecast by GRID, consequently there is no overlap in the staff's calculation of the adjustments.

The company may argue that the data staff used to calculate the adjustments is old. Staff has used the most recent data available in calculating both of the adjustments. For the margin adjustment staff used the only two GRID forecasts from dockets for which the actual power cost data was available. Staff asked the company in Staff DR 252 to provide estimates of extrinsic value based on the GRID model run that supported the company's filing in this docket, but the company response was that "the company has not performed the requested analysis". So staff used the only estimate of extrinsic value it has, which was one developed and used by PacifiCorp to justify the acquisition of the West Valley gas-fired CTs in UE 134.

The company may argue that it does not use extrinsic value anymore to justify resource acquisition economics. This would be interesting, because without the extrinsic value included as a benefit in the company's West Valley economic analysis, the project would have had a negative net present value. With a negative net present value, staff would have proposed a prudence disallowance instead of the support for cost recovery it provided the company in the extension of UE 134 to reconsider the inclusion in rates of West Valley costs.

During the UE 170 proceeding, staff met with company personnel at the company's offices to review the cost/benefit evaluations of recent resource acquisitions. Staff was told by the company's expert in the area of power resource economic analysis, that extrinsic value should always be included when analyzing the costs and benefits of alternative resource choices.

Finally, the company may suggest that the adjustments are inconsistent with normalized rate-making. These adjustments improve normalized rate-making by recognizing characteristics of the company that provide value not captured by "traditional" normalized rate-making. The company, but not customers, have been benefiting from the extrinsic value of the resource capacity not dispatched by GRID and the additional sales and purchase transactions not captured by GRID. Customers are paying the full cost of the company's resources, and are entitled to all benefits derived from those investments. Staff's recommended adjustments remedy this mismatch between costs and benefits.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 179
WITNESS: Bill Wordley

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

June 30, 2006

WITNESS QUALIFICATION STATEMENT

NAME:	Bill Wordley
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist, Economic Research & Financial Analysis Division
ADDRESS:	550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.
EDUCATION:	All course work towards Masters in Economics Portland State University B.S. Portland State University Major: Mathematics
EXPERIENCE:	Since August 2000 I have been employed by the Public Utility Commission of Oregon. Responsibilities include research and providing technical support on a wide range of cost, revenue and policy issues for gas, electric and telephone utilities. Active participation in all primary PacifiCorp regulatory cases in Oregon during past six years, including providing testimony in UM 995, UE 116, UE 134, and UE 173. From March 1999 to August 2000 I worked as a consultant in the energy field working for electric utilities and utility organizations. Work included load forecasting and operations planning. From 1972 to 1999 I worked for PacifiCorp in various analytical and management positions dealing with long and short-term load, sales, and revenue forecasting, power operations planning, power contract optimization, merger and acquisition support, strategic planning support, market research, retail market planning, load-resource analysis, and power contract administration. Testified in some 30 regulatory proceedings in Oregon, Washington, Idaho, Montana, Wyoming, and California.

CASE: UE 179
WITNESS: Bill Wordley

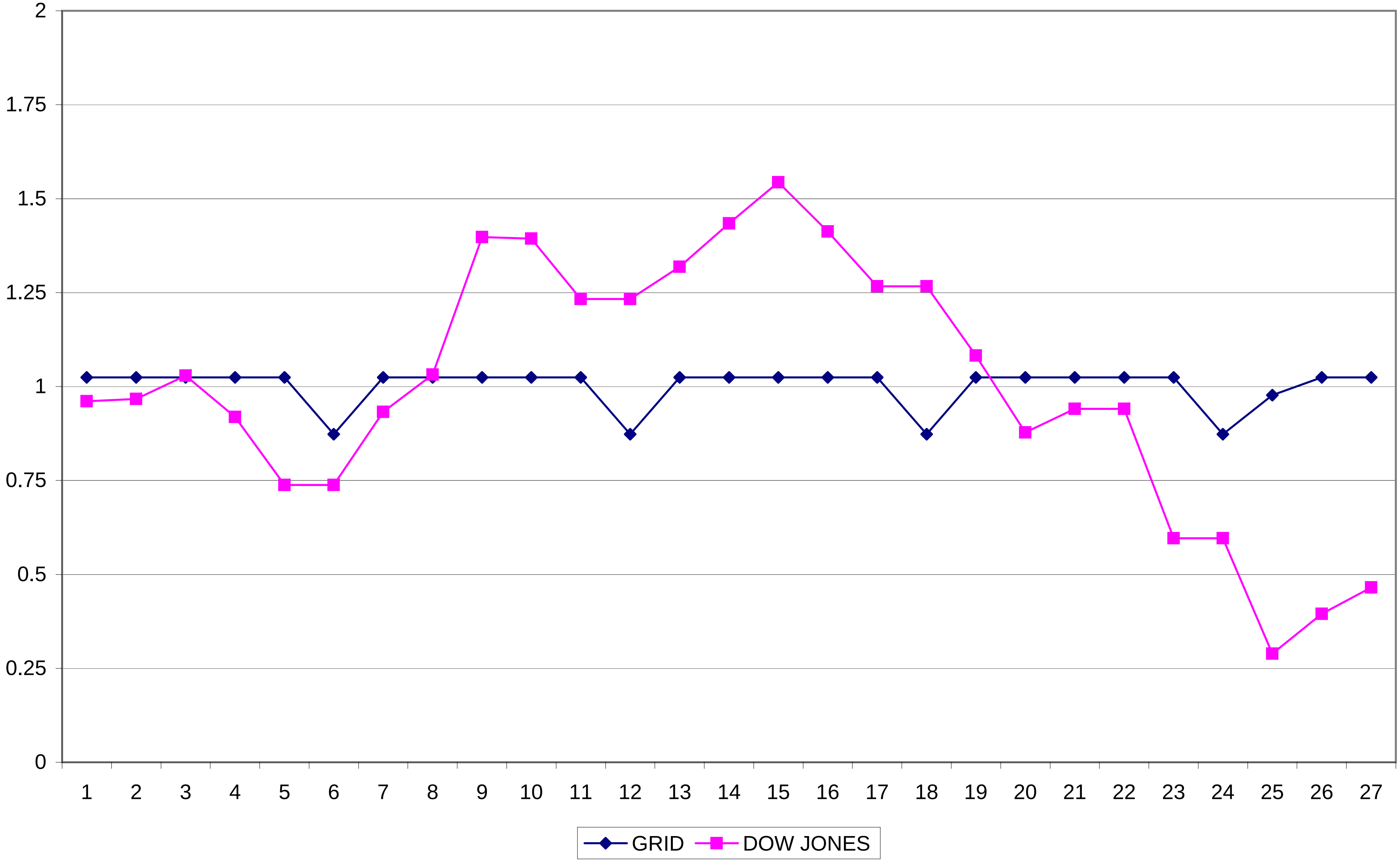
PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support of
Direct Testimony

June 30, 2006

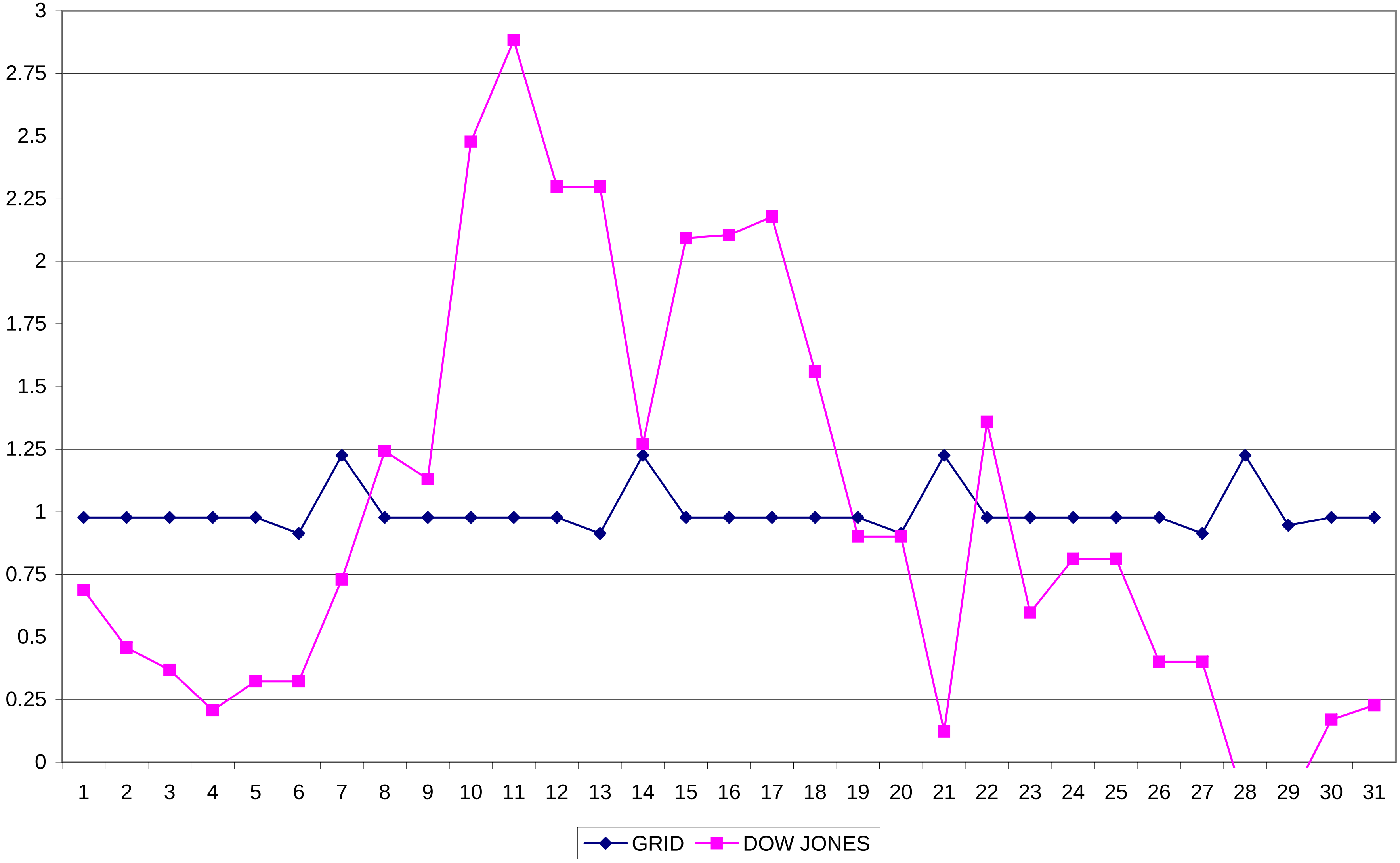
May On-Peak Electricity Price Shape (GRID v. 2006 Dow Jones Index)

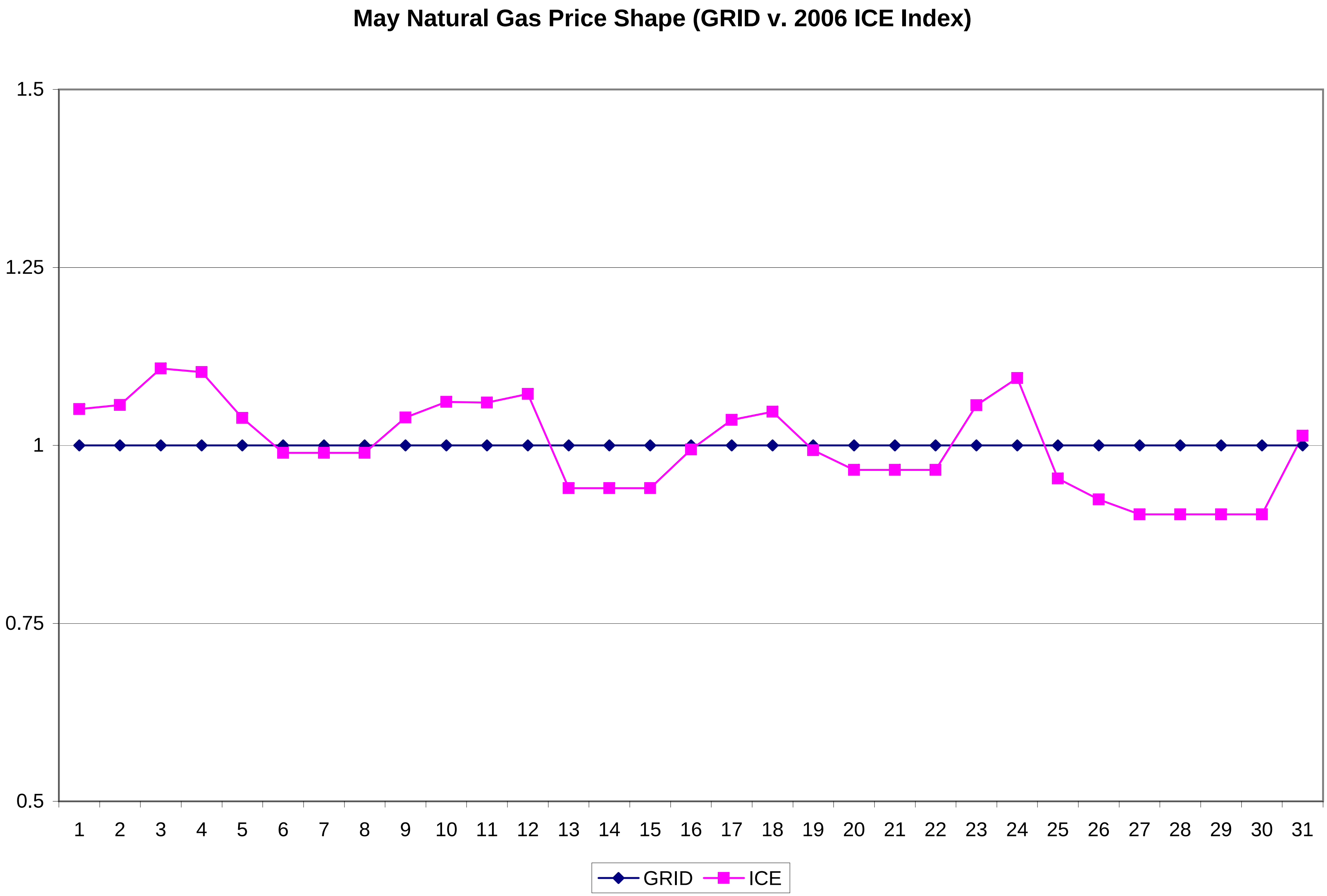


Note: May 2006 had 27 on-peak price days.

Staff/102
Wordley/1

May Off-Peak Electricity Price Shape (GRID v. 2006 Dow Jones Index)





May Natural Gas Price Shape (GRID v. 2006 ICE Index)
1.5
1.25
1
0.75
0.5
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
GRID
ICE

CERTIFICATE OF SERVICE

UE 179

I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-13-0070, to the following parties or attorneys of parties.

Dated at Salem, Oregon, this 30th day of June, 2006.

Jason Jones
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UE 179
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