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June 6, 2012

Via Electronic Filing and U.S. Mail

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

RE: **Docket No. UE 245 – In the Matter of PACIFICORP, dba PACIFIC POWER 2013 Transition Adjustment Mechanism.**

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

/s/ Mark Brown
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c: UE 245 Service List (parties)

PUBLIC UTILITY COMMISSION OF OREGON

UE 245

STAFF REPLY TESTIMONY OF Stephen Schue

In the Matter of
PACIFICORP, dba PACIFIC POWER
2013 Transition Adjustment Mechanism.

REDACTED VERSION

June 6, 2012

CASE: UE 245
WITNESS: Stephen Schue

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 100

Reply Testimony

June 6, 2012

PAGES 6-11, 14-16, AND 29 IN

STAFF EXHIBIT 100

ARE CONFIDENTIAL

AND SUBJECT TO PROTECTIVE

ORDER NO. 10-069 IN UE 245.

YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER

TO RECEIVE THE

CONFIDENTIAL VERSION.

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

A. My name is Stephen Schue. I am a Senior Economist in the Electric and Natural Gas Division of the Oregon Public Utility Commission (OPUC). My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to summarize and critique various parts of PacifiCorp's opening testimony, PAC/100, sponsored by Company witness Greg Duvall. I then recommend reductions of $19.6 million (system basis) to the Company's net power cost request.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

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I. INTRODUCTION

Q. PLEASE SUMMARIZE PACIFICORP'S 2013 TRANSITION ADJUSTMENT MECHANISM (TAM) FILING.

A. The Company's February 29, 2012, filing requested an increase in Oregon-allocated net power costs (NPC) of $9.9 million.[1] This translates into an average rate increase of 0.8 percent. The increase in NPC on a system basis is $41.1 million, or the difference between $1.4631 billion, the basis for current rates, and $1.5042 billion, the summary figure for this filing. Increases in coal costs and the effect of increased purchases from small power producers required by the Public Utility Regulatory Policies Act (PURPA)[2] more than offset a significant decrease in hedging losses.

Q. DID PACIFICORP CHANGE MODELS FOR THIS FILING?

A. No. This filing is based on the Company's Generation and Regulation Initiative Decision Tools (GRID) model, the same model that served as the basis for the 2012 TAM filing. Given various restrictions and input assumptions, the model runs PacifiCorp's system-wide resources on an hourly basis in a way that minimizes NPC for the test year. Important GRID inputs include plant operating characteristics, fuel costs, market price forecasts at various trading hubs, long- and short-term firm contract parameters, expected hydro and wind conditions, and opportunities for short-term non-firm sales and purchases.

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[1] This takes into consideration a slight load decrease. The $9.9 million is the difference between collections under 2013 rates requested in this filing and under current rates, both applied to forecast 2013 loads.

[2] The new PURPA contracts are at prices substantially greater than PacifiCorp's overall 2012 unit power costs. Therefore, the new PURPA contracts increase 2013 unit power costs (relative to 2012).

Q. DID THE COMMISSION DIRECT THE COMPANY AND OTHER PARTIES TO RESEARCH AND DISCUSS ANY ISSUES PRIOR TO THE 2013 TAM FILING?

A. Yes. Order No. 11-435 (in UE 227, the 2012 TAM docket) directed PacifiCorp to make a presentation on its hedging policies and strategy at a workshop. The Order also directed all parties to participate in one or more workshops devoted to the market cap issue.

Q. DID THE COMPANY MAKE A WORKSHOP PRESENTATION ON ITS HEDGING POLICIES AND STRATEGY?

A. Yes. Stefan Bird, a PacifiCorp Senior Vice President who directs the Company's hedging program, made a presentation at the Commission's March 19, 2012, Hedging Workshop. Mr. Bird also answered related questions from the Commissioners.

Q. DID THE COMPANY AND OTHER PARTIES HOLD A WORKSHOP ON THE MARKET CAP ISSUE?

A. Yes. Staff organized a workshop in Salem on January 11, 2012. Industrial Customers of Northwest Utilities (ICNU) outlined a possible approach to the market cap issue. However, given that much work would be required to complete analysis of that approach, parties decided to wait until this proceeding to present complete analyses and recommendations on the market cap issue. Staff's implementation of the approach suggested by ICNU at the workshop is included in the next section of this testimony.

Q. DOES ANOTHER RECENT COMMISSION ORDER SIGNIFICANTLY IMPACT THE CALCULATION OF NPC?

A. Yes. Order No. 10-414 (Docket UM 1355) prescribes the methodology to be used in modeling forced outages at coal plants. Given that many of the Company's coal plants have low variable (mostly fuel) costs, forced outage rate assumptions significantly impact the NPC calculation made by the GRID model.

Q. DID THE COMPANY COMPLY WITH ORDER NO. 10-414 IN THIS FILING?

A. Yes. Staff examined the documentation that PacifiCorp provided for its coal plant forced outage rate calculations and determined that the methodology used in this filing is consistent with Order No. 10-414.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. In the remaining sections, I discuss and make recommendations on market caps, hydro plant outages, margins at the Chehalis gas-fired plant, and the relationship between certain issues in this docket and PacifiCorp's request for a power cost adjustment mechanism in Docket UE 246.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. I recommend reductions of $19.6 million on a system basis. Approximately 80 percent of the overall reduction is related to the elimination of market caps. Most of the remainder is due to recommended changes in the Company's modeling of outages at its hydro plants.

II. MARKET CAPS

A. INTRODUCTION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION ON THE MARKET CAP ISSUE.

A. Market caps are an unrealistic restriction which inappropriately increases NPC by $15.5 million on a system basis. Therefore, this amount should be subtracted from the GRID model run as filed, or the model should be run without market caps.

Q. PLEASE DESCRIBE MARKET CAPS.

A. The Company imposes limits on short-term sales in its GRID modeling. These sales limits are imposed on an on- and off-peak monthly basis at six different trading hubs. Four years of historical data, taken from July 2007 through June 2011 are used. Each specific limit is applied to an on- or off-peak period at a particular trading hub during a particular month during the 2013 test period. That specific limit is the average of four years of average data for that on- or off-peak month and location. This "average of the averages"- based limit is applied to every hour of the relevant 2013 test period modeling.

Q. PLEASE PROVIDE A HYPOTHETICAL EXAMPLE FOR AN ON- OR OFF-PEAK PERIOD ASSOCIATED WITH A PARTICULAR MONTH AND LOCATION.

A. Assume that the limit applies to the on-peak period of November 2013 at the Mona hub. The Company has compiled average on-peak hourly sales at Mona for each of the years 2007, 2008, 2009, and 2010. Assume that these averages are 200, 350, 425, and 225 MW. The average of these averages is 300 MW. In other words, over the four on-peak November periods at Mona the average hourly sales were 300 MWh. (Then 300 MWh per hour is equivalent to 300 MW.) In some hours, sales were much higher; in some hours, there were no sales. However, on average, sales were at the 300 level. For modeling purposed, this average level, 300, would then be applied to each November 2013 on-peak hour at Mona.

<u>B. EVIDENCE FOR AND AGAINST THE COMPANY'S APPROACH</u>

Q. HOW DOES THE COMPANY SUPPORT THE USE OF MARKET CAPS?

A. On Pages 18 and 19 of PAC/100, the PacifiCorp asserts that without market caps, GRID would make much higher levels of economic[3] sales than is reasonable, given that both the Company and potential counterparties might have transmission constraints. Also, the Company asserts that large transactions might impact market prices, and that this is not included in the GRID logic.

Q. IF THE COMPANY WERE CORRECT, WOULD REMOVING MARKET CAPS RESULT IN MUCH HIGHER SHORT-TERM SALES IN GRID?

A. Yes.

Q. IF MARKET CAPS ARE REMOVED FROM THE GRID INPUTS, DO SHORT-TERM SALES INCREASE DRAMATICALLY?

A. No. The relevant short-term sales increase from approximately [redacted] Gigawatt-hours (GWh) to approximately [redacted] GWh, or approximately [redacted]

[3] Costs less than sales revenue, net of transmission and any other transaction costs. Resulting positive margins then lower the NPC forecast.

GWh. To put this into context, the Company's system-wide 2013 load forecast is approximately 60,000 GWh.

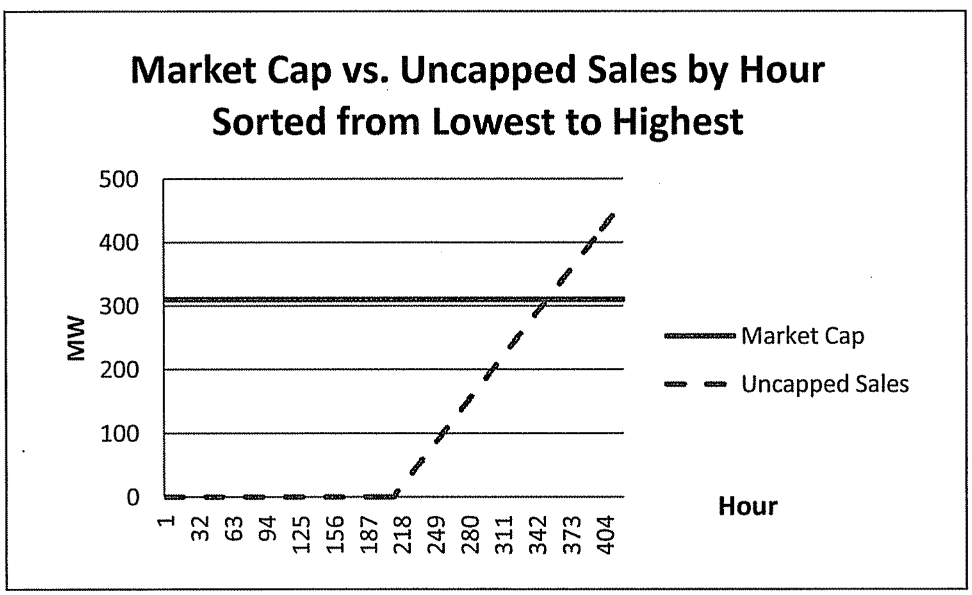
Q. IF SHORT-TERM SALES IN EACH HOUR WITHIN EACH CAPPED ON- OR OFF-PEAK MONTHLY PERIOD AT A PARTICULAR TRADING HUB WERE AT THE RELEVANT MARKET CAP, WHAT WOULD BE THE OVERALL TEST PERIOD SHORT-TERM SALES?

A. Approximately [redacted] GWh.

Q. THE [redacted] GWH CHANGE IN SHORT-TERM SALES RESULTING FROM MARKET CAP REMOVAL SEEMS SMALL COMPARED TO THIS [redacted] GWH FIGURE. PLEASE EXPLAIN.

A. An illustration can explain the results. Graph 1 below illustrates what takes place when market caps are imposed in the GRID modeling process.

Graph 1



For illustrative purposes, the hours in a hypothetical monthly on-peak period at a particular trading hub are arranged from left to right in order of sales. With no market caps, some hours have no sales, and among hours which do have sales, these sales vary substantially. Imposing the market cap, which is the same for every hour, reduces sales in hours which have uncapped sales greater than the cap. In other words, imposition of the market cap eliminates the block of sales in the upper right corner of the graph, above the market cap line and below the (dotted) uncapped sales line. This block is small relative to the area beneath the uncapped sales line, consistent with the overall GRID results of [redacted] and [redacted] GWh cited above. The block eliminated by market cap imposition is very small relative to the area underneath the (solid) market cap line, consistent with the overall GRID results of [redacted] and [redacted] MWh cited above.

Q. DO ACTUAL SHORT-TERM SALES VARY CONSIDERABLY FROM HOUR TO HOUR LIKE THE UNCAPPED SALES IN GRAPH 1, OR ARE THEY GENERALLY FLAT LIKE THE MARKET CAP LINE?

A. Actual short-term sales vary greatly from hour to hour.

Q. WHAT IS AN INDICATION OF THIS VARIANCE AMONG HOURLY SALES?

A. Ratios of the highest to the average hourly sales within monthly on- and off-peak periods at particular trading hubs are indicative of whether sales are generally flat or substantially vary. Ratios significantly above 1.0 indicate variation.

Q. DO YOU HAVE DATA DEMONSTRATING THAT THE COMPANY'S HISTORICAL ACTUAL DATA HAVE RATIOS OF PEAK TO AVERAGE SALES SUBSTANTIALLY GREATER THAN 1.0?

A. Yes. The Company's work papers provided hourly historical data for the one-year period beginning July 2010 for both the Four Corners and California-Oregon Border (COB) trading hubs. This information can then be parsed into 48 on- and off-peak monthly blocks. Ratios vary between [redacted] and [redacted]. When weighted by average sales, an overall ratio of approximately [redacted] would result. In other words, actual data indicate that short-term sales look much more like the uncapped sales line in Graph 1 than like a flat line.

Q. PLEASE PROVIDE A REPRESENTATIVE GRAPHICAL ILLUSTRATION.

A. Actual August 2010 on-peak short-term sales at Four Corners are representative. Hourly sales peak at [redacted] MWh and average [redacted] MWh, resulting in a ratio of [redacted].

Graph 2

[redacted]

Graph 2 above illustrates the principle that there is much variation in hourly sales.

Q. DID PARTIES DISCUSS THE FACT THAT HISTORICAL DATA INDICATE THAT SALES VARY CONSIDERABLY AMONG HOURS WITHIN MONTHLY ON- AND OFF-PEAK PERIODS AT PARTICULAR TRADING HUBS AT THE WORKSHOP ON JANUARY 11, 2012?

A. Yes. ICNU presented data from Confidential Exhibit ICNU/111 in Docket UE-227. Pages 1 and 2 of this Exhibit provide monthly off-peak data for the 2006-2009 period on a monthly basis at each of the Company's six principal trading hubs. These data indicate that monthly maxima were almost always substantially greater than the corresponding monthly averages, often more than ten times greater. Confidential Exhibit ICNU/111 from Docket UE-227 is included with this testimony as Confidential Exhibit Staff/102.

Q. IF MARKET CAPS ARE REMOVED FROM GRID, DO MODELED HOURLY SALES FOR THE 2013 TEST PERIOD EXHIBIT THE SHAPE AS THE UNCAPPED HOURLY SALES IN GRAPH 1 AND THE ACTUAL SALES IN GRAPH 2?

A. Yes. Without market caps, there is substantial variation in modeled hourly sales within on- and off-peak monthly blocks at the Company's various trading hubs. Graph 3 on the next page illustrates uncapped July on-peak market sales at COB in a GRID run not subject to market caps. Hourly sales vary from [redacted] up to [redacted] MWh. Wide variation in hourly sales occurs for other months and trading hubs as well.

Graph 3

[redacted]

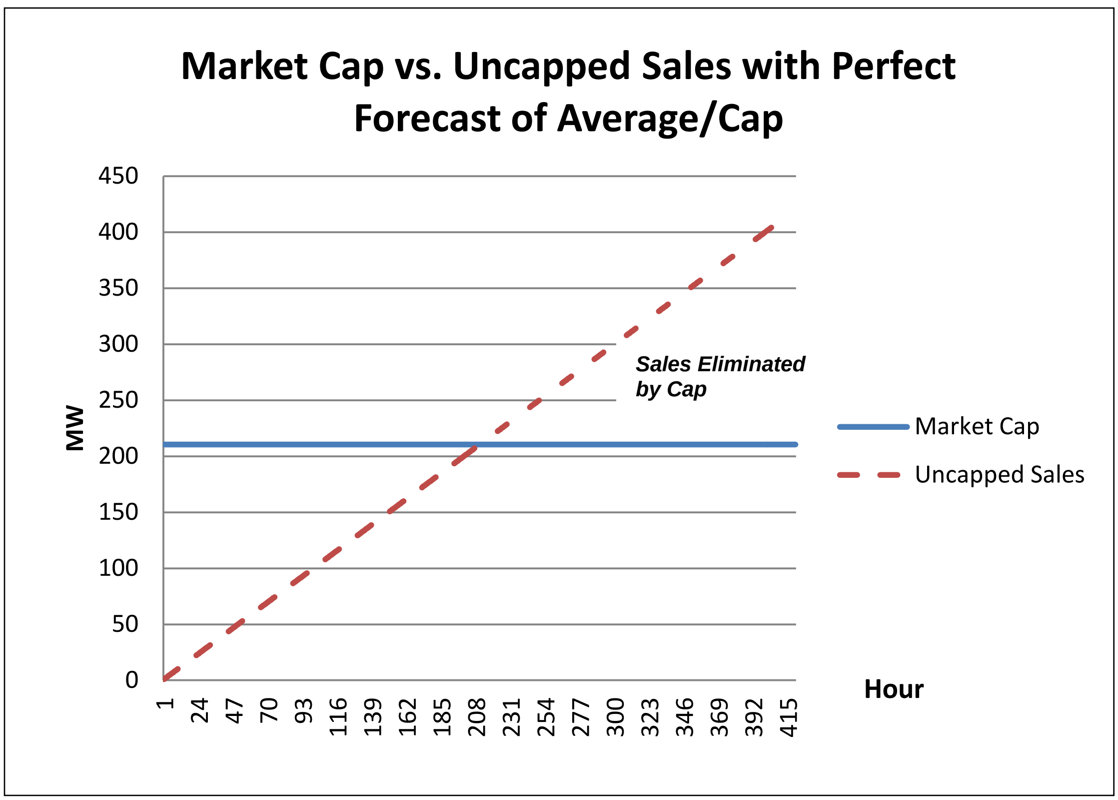
Q. GRAPHS 2 AND 3 SHOW THAT BOTH ACTUAL AND GRID FORECAST SALES DATA INDICATE WIDE VARIATION AMONG HOURS. GIVEN THIS WIDE VARIATION, DO THE FLAT (ACROSS ALL HOURS) MARKET CAPS IMPOSED IN THE GRID RUN SUPPORTING THE COMPANY'S NVP REQUEST MAKE SENSE?

A. No. This construct will systematically result in GRID unrealistically cutting off sales which are higher than average.

Q. PLEASE ILLUSTRATE THIS POINT GRAPHICALLY.

A. Graph 4 on the next page shows the block of realistic sales that the Company's market cap methodology cuts off, thereby increasing NPC on a system basis by more than $15 million. The area in the upper right between the average and sorted hourly sales lines is eliminated in GRID by the market caps. Note that Graph 4 assumes that the forecast average which serves as the cap is equal to the average of the widely varying hourly sales figures, i.e. the market cap is based on a perfect forecast. In this perfect forecast example, the cap reduces total sales by 25 percent. The mismatch between the actual shape of (sorted) sales across hours and the average-based cap results in substantial reductions in GRID as well.

Graph 4



Q. DOES THIS SAME MISMATCH BETWEEN REALISTIC VARIATION IN SALES ACROSS HOURS AND AVERAGE-BASED CAPS RESULT IN THE

$15.5 MILLION DIFFERENCE BETWEEN GRID RUNS WITH AND WITHOUT MARKET CAPS?

A. Yes. The caps used in GRID are based on four year historical averages and are not perfect forecasts in the sense that the uncapped GRID monthly on- and off-peak sales at various trading hubs in the 2013 test year are not necessarily exactly equal to the historical averages. However, the general principle illustrated in Graph 4 affects GRID sales. Specifically, in each of the 144 different sales blocks modeled in GRID (on/off peak, 12 months, and 6 trading hubs), imposition of a market cap unrealistically cuts off sales, thereby increasing the NPC result by $15.5 million on a system basis.

Q. PLEASE PROVIDE A GRAPHICAL EXAMPLE FROM THE 2013 INITIAL FILING GRID RUN OF THE PHENOMENUM ILLUSTRATED IN GRAPH 4.

A. Graph 5 on the next page shows on-peak sales at COB during July of the test year under the relevant market cap. It compares with Graph 3, which shows uncapped sales at COB for the same period. Compared to Graph 3, Graph 5 slices off a block of sales in the upper right section of the graph, i.e. confirms the point made by Graph 4. Note that Graphs 3 and 5 line up closely, except for the “sliced off by the cap” sales evident in Graph 5. However, they do not line up perfectly, as the two graphs come from GRID runs which had either all market caps eliminated (Graph 3) or all market caps active (Graph 5), and there are interactive effects in GRID.

Graph 5

[redacted]

Q. ON PAGES 20 AND 21 OF EXHIBIT PAC/100, THE COMPANY MAKES THE CLAIM THAT GRID HAS OVER-FORECAST SALES BY LARGE AMOUNTS IN RECENT YEARS AND THAT MARKET CAPS ARE A PARTIAL SOLUTION TO THIS ISSUE. PLEASE FURTHER DESCRIBE THIS ARGUMENT.

A. Table 5 on Page 20 of Exhibit PAC/100 shows that GRID sales forecasts were substantially lower than actuals for the 2007 through 2011 period. Annual over-forecasts averaged approximately 9,300 GWh, and were as high as approximately 23,700 GWh. PacifiCorp then states that "Removing market caps would cause GRID to further over forecast wholesale power sales."

Q. DO YOU AGREE WITH THIS ARGUMENT?

A. No. As noted above, imposition of market caps reduces sales by approximately [redacted] GWh in GRID's modeling of the 2013 test year. If the Company is concerned that GRID can over-forecast annual sales by as much as 23,700 MWh, imposing market caps is far from a complete offset. If the Company has concerns about GRID's model logic, it should improve the model logic. It should not, instead, try to impose unrealistic constraints, such as market caps. Market caps are poorly designed, as they confuse averages with widely varying hourly sales, and are not justified as an off-set to what the Company feels is a large problem.

C. ALTERNATIVE APPROACHES

Q. HAVE YOU ANALYZED ANY ALTERNATIVE MARKET CAP STRUCTURES WHICH MIGHT SERVE AS A COMPROMISE BETWEEN STAFF'S RECOMMENDATION THAT THE CAPS BE ELIMINATED ENTIRELY AND THE COMPANY'S POSITION THAT THE CAPS AS FILED SHOULD BE RETAINED?

A. Yes. Staff has analyzed two possible alternative market cap structures, an equal percentage basis relaxation of the caps and a structure suggested at the workshop on January 11, 2012.

Q. WHAT HAPPENS TO THE GRID RESULTS IF MARKET CAPS ARE LOOSENED RATHER THAN ELIMINATED?

A. As caps are loosened on an equal percentage basis (Company's caps multiplied by 1.5, 2.0, 2.5, 3.0, etc.), the relevant sales gradually increase from [redacted] GWh to [redacted] GWh and overall NPC decrease gradually from $1.5042 billion to $1.4887 billion. There are no discontinuities or "breakpoints." Therefore, the analysis did not find any potential compromise market cap structures. However, the analysis did clear up a possible point of disagreement concerning the prices received by the increased sales resulting from relaxation of the market caps.

Q. ARE THE MODELED PRICES RECEIVED ON THE INCREASED SALES ALLOWED BY RELAXING THE MARKET CAPS SIGNIFICANTLY HIGHER THAN PRICES RECEIVED ON THE SALES ALLOWED UNDER THE MARKET CAPS?

A. No. There might be a concern that without the caps, GRID would be able to unrealistically take advantage of very high market prices in some circumstances, thereby understating NPC. However, this concern is unfounded. The market cap relaxation analysis indicates that the prices received on the additional sales allowed as the caps are increased are not significantly higher. The average price received for the [redacted] GWh of the relevant (designated as system balancing) sales allowed under the caps is $[redacted] per MWh, whereas the average price received for the [redacted] GWh that result with no market caps is $[redacted] per MWh.

Q. PLEASE SUMMARIZE THE POSSIBLE COMPROMISE MARKET CAP STRUCTURE DISCUSSED AT THE JANUARY 11, 2012, WORKSHOP.

A. ICNU mentioned a possible structure under which the cap for a particular on- or off-peak month at a particular trading hub would be the highest of the four most recently available relevant averages, rather than the average of the four averages.

Q. PLEASE GIVE AN EXAMPLE WHICH CONTRASTS THE COMPANY'S CURRENT METHODOLGY AND THIS ALTERNATIVE APPROACH.

A. Subsection A above contains a hypothetical example concerning the construction of a cap for November on-peak sales at the Mona trading hub. The example assumes that historical averages for on-peak November sales at Mona for 2007, 2008, 2009, and 2010 are 200 (MW), 350, 425, and 225. The Company's current methodology calculates the average of these four averages, which is 300, and uses this 300 figure as the November on-peak Mona cap for GRID modeling of the 2013 test year. The alternative approach would select the highest of the four historical averages, which is 425, and use this 425 figure as the cap, rather than 300.

Q. HAVE YOU ANALYZED THE EFFECT THIS ALTERNATIVE APPROACH WOULD HAVE ON CALCULATION OF THE 2013 TEST YEAR FORECAST IN GRID?

A. This alternative approach would result in system wide NPC of $1.4965 billion for the 2013 test year. The contrasts with the Company's approach which results in $1.5042 billion and the no cap approach which results in $1.4887 billion. Stated in terms of differences, the alternative "maximum of the four historical averages" approach results in NPC approximately $7.8 million more than the no cap approach, and approximately $7.7 million less than the Company's "average of the four historical averages" approach. In other words. the alternative approach would effectively "split the difference" between the Company's approach and Staff's recommended no cap approach.

Q. WHAT ARE THE ADVANTAGES AND DISADVANTAGES OF THE ALTERNATIVE APPROACH?

A. If the Commission were to find the arguments of Staff and the Company to both have some merits, the "maximum of the four historical averages" approach does represent a sort of middle ground, and it results in a 2013 NPC forecast approximately half way between the results the approaches advocated by the Company and by Staff. The primary disadvantage is that it still applies average-based caps to sales which do vary substantially across the relevant on- and off-peak monthly periods at the six trading hubs modeled. This mismatch still makes the approach questionable on theoretical grounds.

<u>D. OTHER CONSIDERATIONS</u>

Q. DOES THE COMPANY PROPOSE A RELATED CHANGE IN METHODOLGY IN ITS INITIAL FILING?

A. Yes. The Company no longer includes an adjustment for wholesale arbitrage and trading opportunities. In the final 2012 GRID run, this adjustment decreased NPC by $3.0 million (system basis).

Q. HOW MUCH WOULD THIS ADJUSTMENT DECREASE THE INITIAL 2013 GRID NPC CALCULATION?

A. This adjustment would decrease 2013 NPC by $2.3 million. This figure is from the Company's response to ICNU Data Request No. 2.14. That response is included in this testimony as Confidential Exhibit Staff/103.

Q. HOW DOES THE COMPANY JUSTIFY EXCLUSION OF THIS ADJUSTMENT IN ITS 2013 CALCULATIONS?

A. On Page 22 of PAC/100, the Company bases its decision to discontinue the adjustment on the fact that, in recent years, GRID has overestimated wholesale sales. This reasoning is vague, but the relevant Order does not provide a detailed modeling prescription.[4]

Q. WHAT DO MARKET CAPS AND THE TRADING AND ARBITRAGE ADJUSTMENT HAVE IN COMMON?

A. They are controversial adjustments to GRID's basic modeling of NPC. They also introduce volatility into the results.

Q. PLEASE JUSTIFY THE ASSERTION THAT MARKET CAPS AND THE TRADING AND ARBITRAGE ADJUSTMENT INTRODUCE VOLATILITY INTO THE GRID MODELING RESULTS.

A. In the 2012 NPC calculations, market caps increased NPC by $5.5 million and the arbitrage and trading adjustment decreased NPC by $3.0 million, for a net effect of a $2.5 million increase in NPC. In the Company's initial 2013 filing, market caps increase NPC by $15.5 million, and there is no arbitrage and trading adjustment, resulting simply in a $15.5 million increase in NPC. This is too much volatility from controversial adjustments.

Q. WHAT IS YOUR RECOMMENDATION FOR DEALING WITH THESE TWO ISSUES?

[4] Order No. 07-446 stated on Page 11 that GRID model results should be "adjusted as necessary" to incorporate wholesale arbitrate and trading opportunities.

A. Staff recommends that both be eliminated. The Company is allowed to discontinue the arbitrage and trading adjustment, but also must discontinue use of the market cap structure. Then the combined effect of a $2.5 million increase in 2012 would become zero in 2013, a small year-to-year change in combined effects. More importantly, the volatility from these adjustments would be eliminated going forward.

E. SECTION SUMMARY

Q. PLEASE SUMMARIZE THIS SECTION OF YOUR TESTIMONY.

A. Market caps are an arbitrary construct based on confusion between average sales (the basis for the caps) and both actual and uncapped modeled sales, which vary substantially among hours in the relevant periods. Elimination of the caps does not lead to unrealistic results. In GRID, sales increase, but not dramatically. Prices received for sales increase very little. Therefore, the caps should be eliminated.

The arbitrage and trading adjustment is also a source of controversy, and should be eliminated, as the Company has done in its initial filing

The effect of Staff's recommendation for this section is then a $15.5 million reduction in NPC on a system basis. This figure will vary somewhat between now and the final GRID run in mid-November 2012, as forward curves and contracts change.

Q. WHAT IS AN ALTERNATIVE TO YOUR RECOMMENDATION FOR COMMISSION CONSIDERATION?

A. If the Commission did not want to entirely eliminate market caps, it could adopt the "highest of the four averages" approach discussed in subsection C. If the Commission were to take this approach, Staff recommends that the arbitrage and trading adjustment then be retained as well. The overall effect of this alternative recommendation is a decrease of $7.7 million associated with changing from the "average of the four averages" to the "highest of the four averages" market cap structure, combined with a decrease of $2.3 million associated with continuing the arbitrage and trading adjustment. The combined effect on the initial filing 2013 GRID NPC forecast is then $10.0 million.

III. HYDRO PLANT OUTAGES

Q. PLEASE SUMMARIZE THIS SECTION OF YOUR TESTIMONY.

A. In this section, I discuss the Company's approach to modeling outages, both planned and forced, at its hydro facilities. This discussion results in two recommendations: 1) related to forced outages, the 2013 test year NPC should be reduced by $1.36 million on a system basis, 2) related to planned outages, the 2013 test year NPC should be reduced by $2.60 million on a system basis, and 3) GRID should simply assume actual test year planned outages in the future, beginning with its 2014 TAM filing.

Q. IS THE COMPANY'S INCLUSION OF OUTAGES AT ITS HYDRO FACILITIES A CHANGE FROM PREVIOUS FILINGS?

A. Yes. On Page 14 of PAC/100, the Company states that "In the partial stipulation in Docket UM 1355, the Company agreed to remove hydro forced outages from Docket UE 207 but reserved the right to include hydro forced outages in a future TAM proceeding."

Q. WHAT IS YOUR GENERAL VIEW OF INCLUDING HYDRO OUTAGES IN THIS PROCEEDING?

A. To the extent that the Company's modeling reflects costs that are realistically expected to occur in the 2013 test year, inclusion is acceptable. However, Staff disagrees with the Company's modeling of both forced and planned hydro outages.

Q. HOW DOES THE COMPANY MODEL FORCED HYDRO OUTAGES?

A. The Company first performs a detailed analysis of historical forced outage data from the four-year period beginning in July 2007. The results of this detailed analysis are then used in GRID. The resulting decreases in hydro output increase NPC by $2.0 million on a system basis.

Q. WHY DO YOU DISAGREE WITH THE COMPANY'S MODELING OF FORCED HYDRO OUTAGES?

A. Although the Company carefully performed a detailed analysis, which was included in the work papers supporting the initial filing, the approach has a serious flaw. The flaw is that the results are driven by a small number of "outlier" events. Of the 1,120 outage days at various plants included in the analysis, 457 days are associated with only two events, each lasting more than half a year. Another 297 days are associated with a related series of outages at several facilities on the Umpqua River, all lasting at least 18 days, and all beginning on the same date. These "outlier" events comprise 754 of the total 1,120 days, or 67 percent. In Order 10-414 (Docket UM 1355), the Commission provides a methodology under which "outlier" events are excluded from the calculation of forced outage rates at coal plants. Extreme events should also be excluded from hydro forced outage rates.

Q. WHAT IS YOUR RECOMMENDATION FOR EXCLUDING "OUTLIER" EVENTS FROM THE COMPANY'S 2013 TEST YEAR NPC CALCULATION?

A. I recommend disallowance of 67 percent of the overall $2.0 million effect of hydro forced outages, or $1.34 million on a system basis.[5]

Q. HOW DOES THE COMPANY MODEL PLANNED OUTAGES AT ITS HYDRO PLANTS?

A. The Company bases its 2013 planned outage assumptions on four years of historical data, beginning in July 2007.

Q. ARE THE RESULTS SUBSTANTIALLY DRIVEN BY "OUTLIER" EVENTS?

A. Yes. Of a total of 2,561 outage hours included in the analysis, 1,455 (or 57 percent) are related to events lasting more than 28 days.

Q. DO YOU HAVE A MORE FUNDMENTAL DISAGREEMENT WITH THE COMPANY'S APPROACH TO HYDRO PLANNED OUTAGES?

A. Yes. It is not sensible to base planned outages in 2013 on what happened in the past. In theory, the Company should simply use the outages it plans during 2013 in its modeling.

Q. WHAT IMPACT WOULD THIS HAVE ON THE 2013 NPC CALCULATION?

A. Calculation of the impact of various planned outage assumptions requires running the Company's Vista Decision Support System (Vista) model. The Vista model output must then be run through GRID. Staff does not have the ability to run Vista. Staff also does not know the Company's actual planned outages for 2013. Hence, Staff cannot estimate the impact of replacing the historical-based hydro planned outages with actual 2013 planned outages.

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[5] The Company provided GRID input information sufficient to calculate the overall effect of hydro forced outages. However, calculation of the exact effect of removing extreme events from the NPC calculation would be complex. If the Company feels that Staff's "linear" approach is insufficiently exact, it can perform the complex calculation and suggest a somewhat different figure.

Q. IS THERE A PRACTICAL PROBLEM WITH REQUIRING THE COMPANY TO USE ITS ACTUAL 2013 HYDRO PLANNED OUTAGES?

A. Yes. The Company could implement this methodology in its rebuttal testimony. However, given the "only three rounds of testimony" schedule in this docket, other parties would not have an opportunity to reply.

Q. WHAT IS YOUR RECOMMENDATION ON HYDRO PLANNED OUTAGES?

A. Beginning in its 2014 TAM filing, the Company should assume the outages it actually plans at its hydro facilities during the test year. For 2013, the Company's NPC calculation should be reduced to remove the effect of "outliers" included in the historical data-based approach. The hydro forced outage discussion above established that 1,120 outage days are associated with a $2.0 million increase in NPC. Removing the effect of the 1,455 days associated with "outlier" planned outages would then decrease NPC by approximately $2.6 million.[6]

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS ON HYDRO OUTAGES.

A. First, the NPC forecast should be lowered by $1.34 million to remove the effect of "outliers" from the forced outage calculations. Second, the NPC forecast should be lowered by $2.60 million to remove the effect of "outliers" from the planned outage calculations. Finally, in future TAM filings, the Company should assume actual test year hydro facility planned outages in its modeling, rather than relying on historical data.

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[6] Note that 1455/1120 x $2.0 million = $2.6 million. As with the forced outage calculation, the Company might suggest a more exact figure, based on detailed modeling.

IV. MARGINS AT THE CHEHALIS GAS-FIRED PLANT

Q. PLEASE SUMMARIZE THIS SECTION OF YOUR TESTIMONY.

A. The modeling logic concerning the operation of the Company's Chehalis gas-fired plant is incorrect in certain blocks of the 2013 test year. A disallowance of $174,000 is necessary to correct for the resulting errors on a system basis.

Q. WHAT OCCURS IN GRID DURING THE BLOCKS IN QUESTION?

A. These blocks of several hours occur at the end of periods in which margins are positive until the block in question, at which point the margins turn negative. After the blocks in question, GRID no longer dispatches the Chehalis plant for many hours. Not ending dispatch before the hours in question, during which the value of the power produced is less than the cost to run the plant, simply does not make sense, given that the plant is not simply running a few hours before it will again have positive margins.

Q. DID YOU INVESTIGATE OTHER POSSIBLE REASONS WHY IT MIGHT MAKE SENSE FOR THE PLANT TO RUN AT NEGATIVE MARGINS DURING THE BLOCKS IN QUESTION?

A. Yes. I looked at the GRID hourly output to see if GRID assigned Chehalis to carry reserves during these blocks.

Q. DID GRID ASSIGN RESERVES TO CHEHALIS DURING THESE BLOCKS?

A. No.

Q. IS YOUR RECOMMENDATION FOR THIS SECTION THEN A DISALLOWANCE OF $174,000 ON A SYSTEM BASIS?

A. Yes.

V. RELATIONSHIP WITH REQUEST FOR POWER COST ADJUSTMENT MECHANISM IN DOCKET UE 246

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

A. This section provides a discussion of elements in this 2013 TAM filing which are also relevant to the Company's request for a power cost adjustment mechanism (PCAM) in Docket UE 246.

Q. DOES PACIFICORP CURRENTLY HAVE A PCAM IN OREGON?

A. No. However, in Docket UE 246, the Company has submitted testimony requesting a PCAM. (See PAC/900, Pages 14-36, in that docket.)

Q. PLEASE DESCRIBE VERY BROADLY HOW A PCAM WOULD WORK.

A. A PCAM would compare forecast power costs which are incorporated into rates paid by customers with actual power costs, on an annual basis. If actuals were higher than forecast, then the Company would be allowed to collect the difference from customers.[7] If actuals were lower than forecast, then the Company would be required to refund the difference to customers.[8]

Q. WOULD 2013 BE THE FIRST YEAR OF OPERATION OF THE COMPANY'S PROPOSED PCAM?

A. Yes. The mechanism's first annual comparison would be between the forecast 2013 net power costs set in this docket and actual 2013 power costs. This

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[7] This collection would be subject to a dead band, sharing, and an earnings test, if the PCAM were structured like those of Portland General Electric Company (PGE) and Idaho Power Company (Idaho). It would be a straight collection from customers under PacifiCorp's proposal.

[8] This refund would be subject to a dead band, sharing, and an earnings test, if the PCAM were structured like those of PGE and Idaho. It would be a straight refund to customers under the Company's proposal.

comparison would take place in 2014, after actual 2013 power costs are known.

Q. DOES THE COMPANY BASE ITS PCAM REQUEST IN PART ON THE UNPREDICTABILITY OF GROWING WIND INTEGRATION COSTS?

A. Yes. Exhibit PAC/900 includes a lengthy discussion of issues associated with integrating substantial quantities of intermittent power from increased wind resources.

Q. DOES THE GRID MODELING OF 2013 NPC IN THIS DOCKET INCLUDE THE COST OF WIND INTEGRATION?

A. Yes. The 2013 NPC estimate in the initial filing includes $[redacted] million in wind integration costs. This figure is the difference between GRID runs with and without the cost of wind integration. The cost of wind integration is introduced into GRID by imposing a requirement to hold reserves adequate to cover the fluctuations of wind resource output. The Company then divides the $[redacted] million total into inter- and intra-hour integration costs. Inter-hour costs of $[redacted] million come from the Company's 2010 Wind Integration Study, included in its 2011 Integrated Resource Plan. The difference, $[redacted] million, is designated as intra-hour. Intra-hour, inter-hour, and total wind integration costs can also be expressed as $3.87, $2.98, and $0.89 per MWh.

Q. DOES THE COMPANY STATE THAT ITS MODELING OF WIND INTEGRATION COSTS IN THIS DOCKET IS APPROPRIATE?

A. Yes. The Company states that it "continues to believe that the level of reserves required to integrate wind generation net of system load, as identified in the Wind Study, is appropriate." (See PAC/100, Duvall/15, Lines 13-15.)

Q. DO YOU WANT TO DISCUSS ANY OTHER ELEMENTS OF THE COMPANY'S INITIAL FILING IN THIS DOCKET THAT ARE RELEVANT TO THE PCAM REQUEST IN DOCKET UE 246?

A. No.

VI. SUMMARY

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend that :

1) market caps be eliminated, reducing system NPC by $15.5 million.

2) the Company be allowed to discontinue the arbitrage and trading adjustment, consistent with the initial filing.

3) the effect of “outliers” be removed from the hydro forced outage calculations, reducing system NPC by $1.36 million.[9]

4) the effect of “outliers” be removed from the hydro planned outage calculations, reducing system NPC by $2.6 million.

5) actual planned hydro plant outages be used in future TAM proceedings.

6) the effect of the incorrect Chehalis plant dispatch logic be disallowed, reducing system NPC by $174,000.

Q. WHAT IS THE TOTAL IMPACT OF YOUR RECOMMENDATIONS?

A. In summary, I recommend disallowances which total $19.634 million.

Q. IF MARKET CAPS WERE NOT ELIMINATED, BUT RATHER CALCULATED ON A “HIGHEST OF THE FOUR AVERAGES” BASIS, AND THE ARBITAGE AND TRADING ADJUSTMENT WERE CONTINUED AS IN PREVIOUS TAM FILINGS, WHAT WOULD THE SUMMARY RESULT BE?

A. The market cap-related reduction of $15.5 million would be replaced by the combination of a decrease of $7.7 million associated with the change in market

[9] Both recommendations 3 and 4 implicitly allow the Company to include hydro outages in its NPC calculation, which represents a change from prior TAM filings.

cap approaches, and a decrease of $2.3 million associated with continuation of the arbitrage and trading adjustment (a credit to customers), or a total of $10.0 million. Then the summary reduction would be $14.134 million, rather than $19.634 million.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 245
WITNESS: Stephen Schue

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

June 6, 2012

WITNESS QUALIFICATION STATEMENT

NAME:	STEPHEN SCHUE
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	SENIOR ECONOMIST, ELECTRIC AND NATURAL GAS DIVISION
ADDRESS:	550 CAPITOL ST. NE, SALEM, OR 97308-2148
EDUCATION:	Bachelor of Science, Economics, University of Oregon Master of Arts, Economics, University of Minnesota Master of Business Administration, University of Leuven (Belgium)
EXPERIENCE:	I have been employed at the Oregon Public Utility Commission (Commission) since August of 2011. My current responsibilities include research, analysis and technical support for electric cost recovery proceedings, with an emphasis on variable power costs. I was previously employed at Portland General Electric Company (PGE) for 18 years. At PGE, I performed analysis and sponsored testimony related to net variable power costs, resource planning, and purchases (both transmission and power) from the Bonneville Power Administration. I was the project manager for PGE's 2000 Integrated Resource Plan. During 1986 and 1987, I worked at the Commission, specializing in economic evaluation of utility conservation programs.

CASE: UE 245
WITNESS: Stephen Schue

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Reply Testimony

June 6, 2012

STAFF EXHIBIT 102

IS CONFIDENTIAL AND SUBJECT TO MODIFIED

PROTECTIVE ORDER NO. 10-069. YOU MUST HAVE

SIGNED APPENDIX B OF THE MODIFIED

PROTECTIVE ORDER IN

DOCKET UE 245 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

CASE: UE 245
WITNESS: Stephen Schue

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support
Of Reply Testimony

June 6, 2012

UE 245
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CERTIFICATE OF SERVICE

UE 245

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 860-001-0180, to the following parties or attorneys of parties.

Dated this 6th day of June, 2012 at Salem, Oregon.

Mark Brown
Public Utility Commission
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Salem, Oregon 97301-2551
Telephone: (503) 378-8287