ORDER NO. 11 435

ENTERED NOV 04 2011

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 227

In the Matter of PACIFICORP, dba PACIFIC POWER 2012 Transition Adjustment Mechanism.	ORDER

DISPOSITION: STIPULATION ADOPTED

I. INTRODUCTION

This order addresses PacifiCorp, dba Pacific Power's (Pacific Power) 2012 Transition Adjustment Mechanism (TAM). In this order, we adopt the stipulation filed by Pacific Power, the Public Utility Commission of Oregon Staff, the Citizens' Utility Board of Oregon (CUB), and Noble Americas Energy Solutions, LLC (Noble Solutions) (collectively, the Joint Parties). The Industrial Customers of Northwest Utilities (ICNU) objected to the stipulation. For reasons provided below, we dismiss ICNU's objections, and find that the stipulation will result in rates that are fair, just and reasonable. This order results in an increase of approximately $50.7 million to Pacific Power's revenue requirement, an overall rate increase of approximately 4.4 percent.

II. BACKGROUND

Pacific Power is an electric company and public utility in the State of Oregon within the meaning of ORS 757.005. Pacific Power provides electric service to approximately 550,000 retail customers within the state, and is subject to the Commission's jurisdiction with respect to the prices and terms of electric service for its Oregon retail customers.

On March 17, 2011, Pacific Power filed Advice No. 11-005, an application for revised tariff schedules related to its 2012 TAM. Pacific Power's annual TAM filing updates the company's net power costs (NPC) to set transition adjustments for customers wishing to move to direct access service.[1] Pacific Power originally requested a $61.6 million increase to its Oregon NPC, an overall rate increase of 5.2 percent.

III. PROCEDURAL HISTORY

On April 18, 2011, a prehearing conference was held and a procedural schedule was adopted. During the course of the proceeding, ICNU and Noble Americas were granted leave to intervene as parties. CUB intervened in the proceedings as a matter of right under ORS 774.180.

On June 24, 2011, Commission Staff and intervenors filed testimony responding to Pacific Power's filing.[2] On July 29, 2011, Pacific Power filed additional testimony and updated its NPC in accordance with the TAM guidelines.[3] Staff and intervenors filed rebuttal testimony on August 16, 2011, and Pacific Power filed surrebuttal testimony on August 30, 2011. A hearing was held in Salem, Oregon, on September 8, 2011. At the hearing, Stefan Bird and Gregory Duvall testified on behalf of Pacific Power. Donald Schoenbeck testified on behalf of ICNU.

On September 20, 2011—after the hearing, but before briefs were due—the Joint Parties filed a stipulation that, if adopted, would resolve all issues in the docket. On October 5, 2011, ICNU filed objections to the stipulation. The parties filed simultaneous briefs addressing the stipulation on October 5, 2011, and October 12, 2011.

IV. DISCUSSION

A. Overview of the Stipulation

As noted above, Pacific Power originally requested a $61.6 million increase to its Oregon NPC, an overall rate increase of 5.2 percent. Pacific Power explained that the request is driven primarily by increases in total system load, changes to its portfolio of wholesale purchase and sales contracts, and increases in coal costs.

As the testimony developed, Pacific Power accepted approximately $7 million in reductions proposed by other parties. At the same time, the company updated its NPC in accordance with the TAM guidelines. The update increased the company's NPC projections and partially offset the accepted reductions. At the time of hearing,

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[1] Under OAR 860-038-0275, each electric company must announce by November 15 the prices to be charged for electricity services in the next calendar year. (For a more thorough discussion of the TAM *see, e.g.,* Order No. 05-1050 (establishing TAM) (Sept 28, 2005); Order No. 09-274 (adopting the TAM guidelines) (Jul 16, 2009); and Order No. 09-432 (refining TAM guidelines) (Oct 30, 2009).

[2] ICNU filed additional confidential testimony on June 28, 2011 and July 5, 2011.

[3] The basic guidelines for Pacific Power's TAM filings were established in Appendix A of Order No. 09-274 (the "TAM Guidelines"). Under the guidelines, the company updates its initial TAM filing with a "rebuttal update" during the course of the proceedings, then a "final update" at least five days prior to the direct access window beginning November 15.

Pacific Power's request for a rate increase had been reduced to $58.7 million, including both the agreed adjustments and the company's updated NPC.

The stipulation was filed after the hearing was completed. It addresses all issues in this docket, and would result in an additional $8 million reduction to the company's position at the time of hearing, resulting in a stipulated increase of $50.7 million, or approximately 4.4 percent in overall revenue requirement. The Joint Parties do not detail the reasons for the additional $8 million reduction or break down the $8 million into specific adjustments. They simply assert that the stipulated rate increase as a whole is supported by the evidence and would result in just and reasonable rates.

B. Legal Standard

The Commission has broad powers to set just and reasonable rates.[4] When considering a stipulation, we have the statutory duty to make an independent judgment about whether the settlement constitutes a reasonable resolution of the issues. We may adopt a non-unanimous settlement agreement so long as we make an independent finding, supported by substantial competent evidence in the record as a whole, that the settlement will result in just and reasonable rates.[5]

When considering a stipulation, we need not evaluate each individual adjustment, theory, or methodology proposed by the parties, but may review "the reasonableness of the overall rates," recognizing that a stipulation may represent a compromise of different positions.[6]

As the proponent of the rate increase, Pacific Power bears the burden of showing that its proposed rate change is just and reasonable.[7]

C. ICNU's Objections to the Stipulation

ICNU proposes a number of reductions to Pacific Power's surrebuttal position, listed in the table below.

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[4] *See* ORS 756.040.
[5] *See, e.g., In re PacifiCorp,* Docket No. UM 995, Order No. 02-469 at 75 (Jul 18, 2002); *In re PacifiCorp,* Docket No. UE 210, Order No. 10-022 at 6 (Jan 26, 2010); *In re Portland Gen. Elec. Co.*, Docket Nos. DR 10, UE 88, UM 989, Order No. 08-487 at 7-8 (Sept 30, 2008).
[6] *See* Order NO. 10-022 at 5.
[7] *See* ORS 757.210. *See also,* Order No. 02-469 at 4; *In re Northwest Natural Gas Co.,* Docket No. UG 132, Order No. 99-697 at 3 (Nov 12, 1999).

	Issue	Adjustment ($M)
1.	Retail Revenue Sales Offset	$30.8
2.	Gas Financial Hedging	$16.2
3.	Forward Price Curves	$ 1.7
4.	Sales Activity – Market Sales Limits	$ 1.4
5.	Sales Activity – ISO Charges	$ 1.1
6.	Sales Activity – DC Intertie Charges	$ 1.2
7.	Gadsby Units 4-6 – Wind Integration	$ 0.8
	Total Adjustments	**$53.2**

As noted above, Pacific Power's requested rate increase at the surrebuttal stage was $58.7 million. ICNU's objections, if granted, would result in a $5.5 million increase. We will address ICNU's objections in turn.

1. Retail Revenue Sales Offset

a. Parties' Positions

One of the drivers for Pacific Power's TAM request is increased retail load growth in the company's service territory. ICNU argues that if the Commission allows increased load growth to drive increased NPC, it should require Pacific Power to recognize $30.9 million in increased revenues associated with sales of that increased load.

ICNU argues that this adjustment helps balance out the fairness of an otherwise one-sided TAM mechanism. A stand-alone TAM filing allows the utility to charge ratepayers all of the NPC-related increases associated with projected high load growth, without accounting for the additional fixed cost recovery gained from higher corresponding sales. According to ICNU, this creates an incentive for the utility to inflate its load-growth forecasts and an opportunity for gaming.[8] "A reasonable remedy that is used in many power only proceedings," ICNU argues, "is to incorporate a revenue credit associated with fixed costs when loads differ from the amount forecast in a previous [general rate case]."[9]

Requiring the utility to recognize the revenue associated with additional load would not only make the TAM more even-handed, ICNU argues, it would also improve the ability of other parties to analyze the company's filings. ICNU argues that other parties have a difficult time analyzing the company's complex load-growth forecasts within the

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[8] When a TAM filing is made with a general rate revision proceeding, by contrast, all of the company's costs and revenues are reviewed simultaneously, so, according to ICNU, the incentive to inflate load growth is minimized. *See* ICNU/100, Schoenbeck/9.

[9] ICNU Opening Brief at 16 (citing ICNU/110, Schoenbeck/14).

confines of the short, streamlined, stand-alone TAM process.[10] If the Commission were to adopt ICNU's proposed approach, the company's incentive to game the TAM proceedings with inflated forecasts would be minimized.

Pacific Power asserts in response that its load-growth estimate is demonstrably reasonable. In any case, the company argues (with Staff's support), ICNU's proposal violates the Commission-approved TAM guidelines. These guidelines make clear that only specific net power accounts established by the Federal Energy Regulatory Commission may be updated through the TAM.[11] ICNU's proposal would update certain non-NPC accounts not included in the established list.[12]

Updating these non-NPC accounts not only violates the TAM guidelines, Pacific Power argues, it also violates the Commission's long-standing policy of matching costs and revenues. Pacific Power contends that if the Commission were to update all non-NPC revenues associated with increased sales, as ICNU proposes, the matching principle would require the Commission to also update *all* non-NPC *costs* on the other side of the ledger.[13]

In essence, Staff and Pacific Power argue, ICNU's proposal would reinvent the structure of the TAM. Under the TAM guidelines, parties are not permitted to propose modifications to the TAM in a stand-alone TAM proceeding; they may only do so in a general rate revision or other proceeding.[14]

In reply, ICNU argues that the failure of the TAM guidelines to identify a potential retail sales revenue offset does not mean that such an offset is barred by the TAM guidelines. It is possible, ICNU argues, that such an offset was simply not considered by the parties. In any event, ICNU concludes, the offset is an appropriate correction to the current one-sided nature of the TAM.

As an alternative approach to simplifying intervenors' analysis of load forecasts, ICNU suggests, the Commission could simply require Pacific Power to use in a stand-alone TAM the same load levels it used in its last TAM proceeding.

Pacific Power responds that using a load forecast from a prior period undermines the goal of accurately projecting NPC in the rate effective period. Moreover, the company argues, ICNU's proposal to use forecasts from prior dockets is inconsistent with the TAM

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[10] Moreover, ICNU argues, Pacific Power did not provide enough information to allow opposing parties to meaningfully analyze the forecasts until very late in the proceedings, in the company's rebuttal and surrebuttal filings.

[11] PPL/600, Griffith/2-5.

[12] Pacific Power also argues that the Commission recently ruled in PGE's net power cost update proceedings that such updates are limited to net variable power costs and should not cover fixed generation or other non-NPC-related costs (citing TAM Guidelines at 9).

[13] Pacific Power and Staff Reply Brief at 5.

[14] *See* TAM Guidelines at 9.

guidelines, which require use of the "most recent * * * forecast load."[15] Finally, Pacific Power argues, ICNU has in recent years made the *opposite* argument, insisting that updated data be used in connection with utilities' requested rate increases.[16]

b. Resolution

Over the past several years, the parties involved in Pacific Power's TAM proceedings have raised issues with the way the proceedings are conducted. In docket UE 199, a docket resolved two years ago, a number of issues were raised and addressed by stipulation. Most of the parties in this docket are signatories to that stipulation, including Pacific Power, Staff, CUB, and ICNU. The Commission adopted that stipulation in Order No. 09-274, thereby implementing the agreed-upon parameters for future TAM proceedings.[17] These TAM guidelines undermine ICNU's argument that Pacific Power's retail revenues should be recognized as an offset to the company's increased NPC.

The established guidelines make clear that the purpose of the TAM is to "update [Pacific Power's] *forecast net power costs* to account for changes in market conditions," and to identify the amount for the transition adjustment for direct access customers.[18] In other words, the stipulation makes clear that the TAM filing focuses on the NPC side of the equation. Nothing in our prior orders or approved guidelines suggests that an adjustment to the revenue side is within the scope of a TAM.

We agree with Pacific Power and Staff that ICNU is advocating a fundamental revision to the TAM process itself. While ICNU may certainly advocate for changes to the TAM, such as the changes proposed here, the TAM guidelines make clear that such changes are to be appropriately addressed in a general rate revision docket or other proceeding, not part of a stand-alone TAM proceeding.[19]

We also reject ICNU's alternative proposal that Pacific Power be required in a stand-alone TAM proceeding to use the load forecasts from its last TAM proceeding. The TAM guidelines state that the company's NPC update should be "based on the Company's most recent official forward price curve, forecast load and allocation factors."[20] While using forecasts from prior dockets may be simpler, it is not clear to us that it would appropriately serve the purpose of updating the company's NPC.

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[15] *Id.*

[16] Pacific Power and Staff Reply Brief at 6 (citing *In re PacifiCorp,* Docket No. UE 199, Order No. 08-543, Appendix A at 7 (Nov 12, 2008)).

[17] The TAM Guidelines were further refined by stipulation adopted in Docket No. UE 207.

[18] TAM Guidelines at 9 (emphasis added).

[19] The TAM guidelines state, "Nothing in this agreement prevents any Party, including the Company, from advocating in a future general rate case or other proceeding *other than a stand-alone TAM,* that the TAM should be eliminated or revised." TAM Guidelines at 9 (emphasis added).

[20] *Id.*

2. *Gas Financial Hedging Strategy*

Pacific Power's requested NPC includes the cost of a number of electric and natural gas hedges included in the company's 2012 test year. ICNU argues that the Commission should disallow $16.2 million of the company's natural gas hedges because they were imprudently executed.[21] According to ICNU, the company locked in "far too much gas far too quickly."[22]

ICNU challenges various hedges executed in 2007 and 2008 under Pacific Power's 2006 Risk Management Policy, for two reasons.[23] First, ICNU argues, a number of hedges included in the company's test year were purchased in violation of Pacific Power's own risk management policy.[24] ICNU proposes that all hedges beyond 48 months be disallowed. Second, ICNU argues, the company's hedging targets were "overly risky and aggressive" and resulted in unnecessary losses.[25] ICNU proposes new, less aggressive targets, and suggests that the Commission disallow all hedges that caused Pacific to exceed ICNU's proposed yearly targets.

We address these issues separately. First, we address the overall prudence of the company's hedging policy and its execution of that policy. Then, we address ICNU's assertion that the company's hedges beyond 48 months violated that policy.

a. Commission Review of Hedging Contracts

To evaluate the prudence of a hedging contract, we will first examine the utility's hedging strategy. If the strategy is prudently designed (for example, it includes sound hedging goals, methodology, and targets, among other things), we will next examine whether the utility executed its strategy prudently.

If a particular transaction is inconsistent with the strategy, or parties have raised issues that appropriately call the transaction into question, such as lack of market liquidity, we will then examine whether the utility provided adequate and contemporaneous analysis and documentation and a sound justification to support the transaction.

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[21] ICNU's adjustment would reduce the mark-to-market cost of Pacific Power's system-wide gas hedging amounts by $64.8 million, or $16.2 million on an Oregon basis.
[22] ICNU/100, Schoenbeck/3.
[23] This policy governed the transactions, along with the company's Front Office Procedures and Practices. *See* PPL/400, Bird/5.
[24] ICNU actually calculates its disallowance by first removing the hedges it believes violate the Risk Management Policy, then imposing its targets on the remaining hedges. For purposes of this order, we believe it is more logical to address the issues in a different order.
[25] ICNU Opening Brief at 17.

b. Pacific Power's Hedging Targets

i. Parties' Positions

Pacific Power's 2006 Risk Management Policy established natural gas hedging targets for filling the company's future net open position (NOP)[26]. The policy provided a target range for each year in advance of a prompt year,[27] and so long as the various requirements of the Risk Management Policy were met, traders were permitted to trade within the prescribed limits without prior management approval.

ICNU concedes that Pacific Power's Risk Management Policy was in certain respects consistent with industry standards, but it argues that certain trades made within the company's prescribed targets should be disallowed because the targets themselves were simply too aggressive. ICNU argues that this is illustrated by the fact that other utilities did not hedge as much gas as early as Pacific Power, and experienced fewer losses.[28]

ICNU contends that there are good reasons not to lock in gas too early. Pacific Power's natural gas is used for generation facilities that are dispatched to meet the last increment of load. Because prices and conditions change quickly, ICNU argues, these facilities may not actually need to be dispatched. A utility should therefore minimize the amount of gas transactions executed long before the gas is actually needed.[29] Moreover, ICNU believes, the longer a company's hedging horizon, the less liquid the market and the higher the financial and price risk to customers.[30] ICNU asserts that most of the losses Pacific Power experienced were due to gas hedges entered into a significant period of time before the gas was needed, and proposes more limited hedging targets.

According to ICNU, the company has failed to explain why its targets were so aggressive. Instead, it simply provides after-the-fact explanations of its hedging practices and the markets at the time the trades were executed, as well a generic discussion of the benefits of hedging. ICNU argues that such evidence is insufficient to demonstrate the prudence of the policy.

ICNU also dismisses Pacific Power's assertion that the company's hedging policy has, over time, decreased power cost volatility and customer rates.[31] Though Pacific Power argues that it "would be unfair to accept" the past benefits of its hedging practices and disallow costs in this case "when nothing material has changed in the Company's

[26] The NOP is the difference between Pacific Power's needs and its resources. Pacific Power's 2006 Risk Management Policy hedging targets are designated confidential. The company has since updated its hedging strategies and targets.
[27] The prompt year for purposes of this docket is 2012.
[28] ICNU/100, Schoenbeck/14-15.
[29] *Id.* at 13-14.
[30] ICNU Opening Brief at 20 (citing CUB/100, Jenks-Feighner/13-15). ICNU's proposed targets are 18.1percent in year 1, 36.3 percent in year two, 54.4 percent in year three, and 72.5 percent in year four.
[31] PPL/400, Bird/11; PPL/105, Duvall/5-8.

approach or circumstances,"[32] ICNU argues that something did materially change in the company's approach: it modified its Risk Management Policy in 2006 in a significant way.[33]

Pacific Power defends its hedging practices. In response to ICNU's assertion that the company hedged too much, too soon, Pacific Power notes that its normalized natural gas open position in the 2012 GRID[34] study is actually *lower* than ICNU's own targets would recommend.[35] It is therefore inappropriate to argue that the company hedged too much, too soon.

Moreover, the company argues, the evidence in the record does not support ICNU's assertion that Pacific Power hedges more aggressively than other utilities. ICNU cited favorably to Northwest Natural Gas Company's (NW Natural) hedging program, yet that company was hedged at 77 percent for the 2010-2011 prompt year—a higher percentage than Pacific Power is hedged for the 2012 test year in the instant docket. Pacific Power also argues that its hedging horizon appears to be shorter than either NW Natural's or Portland General Electric Company's.[36] In short, Pacific Power contends, the evidence does not show that it hedges more aggressively than other utilities.

Pacific Power challenges two elements of ICNU's objections: ICNU's assertion that its hedging policy was imprudent, and the calculation of ICNU's disallowance.

Reasonableness of Pacific Power's Hedging Policy

Pacific Power argues that the company established appropriate hedging targets, and hedged in a deliberate, continuous, and programmatic manner, consistent with its Risk Management Policy.[37] Its hedging program was reasonable, it argues, and even ICNU concedes that it was sound in many respects. For example, Pacific Power argues, ICNU agrees that Pacific Power's hedging program was appropriately diversified in terms of length and type of hedges, and that Pacific Power's natural gas hedges were well timed to meet its natural gas supply needs.[38] ICNU also concedes that the goal of Pacific Power's hedging strategy was appropriate: to reduce price volatility and provide price certainty, a goal that customers value, but which comes at a cost.[39]

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[32] *See* PPL/105, Duvall/7.
[33] *See* PPL/400, Bird/8.
[34] GRID (Generation and Regulation Initiatives Decision tool), is a power cost model used by Pacific Power to establish power costs included in cost of service rates.
[35] PPL/400, Bird/18.
[36] *Id.* at 24.
[37] PPL/406, Bird/4-5.
[38] Tr. at 155-156.
[39] Tr. at 158.

Pacific Power also points out that the company's hedging practices were reviewed by Staff several years ago. Staff determined that the company's hedging program resulted in substantial benefits for customers.[40]

Pacific Power argues that it has provided voluminous contemporaneous documentation supporting each hedge included in the test year. It provided detailed information on every natural gas hedge in the case, including the transaction type, counter-party, date of execution, delivery start and end dates, quantity, delivery market, market price, fixed price, and mark-to-market value so that each could be evaluated.

In sum, Pacific Power argues that ICNU is unfairly using a hindsight analysis to challenge the company's hedging program. Had prices continued to rise as projected in 2007 and 2008 as expected, the company argues, the hedges in this case would have substantially increased the company's NPC.[41] ICNU's restrictive targets would have left the company with a much larger NOP exposure in the face of the escalating forward prices and high price volatility that reigned in 2007 and 2008. Pacific Power notes that during the Western Energy Crisis, ICNU argued that Pacific Power was insufficiently hedged against the markets.[42] Now that prices have gone the other direction, ICNU asserts the opposite.

The company contends that it is unfair to ignore the significant reduction in price volatility achieved by the hedging program. Moreover, its customers have experienced a total net benefit of $118 million from the company's hedges since 2008, even taking into account the hedging costs in this case.[43]

Calculation of ICNU's Adjustment

In addition to defending its own hedging practices, Pacific Power challenges ICNU calculation of recommended disallowances. First, Pacific Power argues, ICNU intended to recalculate Pacific Power's NPC by removing hedges that exceed ICNU's target hedging levels for each month, but it did so incorrectly. Pacific Power argues that ICNU removed certain multi-year hedges, but then failed to add hedges back in later months

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[40] *See* PPL/400, Bird/10-11. According to Pacific Power, the Commission's 2005 study showed an 82 percent reduction in price volatility and a 15 percent decrease in prices; a more recent analysis of the 2005-2010 timeframe shows a 50 percent reduction in volatility associated with power hedges, and 52 percent associated with gas hedges. *See* PPL/403, Bird/11-12; PPL/400, Bird/11. Pacific Power also points to a 2009 third-party audit commissioned by the Utah Division of Public Utilities specifically found that the subject company's hedging program was "well-documented and controlled" and that the company's hedging program had "well-stated goals and strategy that is aimed at mitigating price volatility," among other things. *See id.* at 12. ICNU states that the company's policy has been criticized in Utah in other respects.

[41] PPL/400, Bird/30. Additionally Pacific Power states that approximately 20 percent of the multiyear hedges that ICNU proposes removing are already reflected in rates.

[42] Pacific Power and Staff Reply Brief at 13 (citing Order No. 02-469 at 16).

[43] PPL/105, Duvall/7.

when Pacific Power's total hedges fell *below* ICNU's proposed hedging targets. At the hearing, Pacific Power notes, Mr. Schoenbeck acknowledged that this error resulted in a hedge percentage for the prompt year that fell far short of his own 72.5 percent target. Mr. Schoenbeck also acknowledged that if hedges were added back in to bring Pacific Power back up to his own hedging target, his proposed adjustment would be reduced by approximately 50 percent.[44] Thus, Pacific Power states, ICNU's proposed adjustment is simply inaccurate.

Moreover, the company argues, ICNU calculated its adjustment by applying fixed targets to Pacific Power's hedges. Yet witness Schoenbeck testified that hedging parameters should be applied flexibly to respond to current conditions, within a range of 15 to 25 percent for both volume and length. This flexibility should have been included in ICNU's proposed adjustment, but was not.[45]

ii. Commission Resolution

We deny ICNU's objections. We find that Pacific Power has demonstrated that its hedging program and policies were objectively reasonable, and that the company executed its policies in a prudent manner.

Reasonableness of Pacific Power's Hedging Policy

The company's Risk Management Policy includes sound hedging goals, methodologies, and targets. Its policies and procedures were well articulated, and its specific hedging targets were made clear in advance to the company and its traders.

Moreover, the company's hedging program appears to be robustly designed and well documented. The company provided ample contemporaneous documentation of the policies and procedures in effect at the time the hedges were executed, including its method of identifying, measuring, and managing risk, its hedging targets, its credit policies and procedures, and its approved portfolio structures, as well as detailed procedures governing company enforcement of these policies. Indeed, ICNU's witness agreed that the company's hedging program was appropriate in many respects. The company appears to have hedged in a reasonably deliberate manner, consistent with these policies.[46]

While the company's hedging targets may have been more aggressive than ICNU considers ideal, we cannot conclude under the evidence before us that they were unreasonable. The company provided detailed information about each hedge included in the 2012 test year, allowing parties to challenge each hedge on grounds of cost or market

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[44] Tr. at 162-185.
[45] Tr. at 187-188.
[46] We address the subset of hedges that ICNU argues fell outside the company's Risk Management Policy in the next section.

liquidity, but ICNU seems only to argue that the targets and time horizons are *per se* unreasonable.[47] The company's hedging horizon does not appear to be unduly long,[48] nor are there specific allegations that the markets were illiquid for any of the longer-dated hedges.

Moreover, the company's hedging strategy allowed for some NOP going into the prompt year, and the evidence indicates that the company did, in fact, have a measure of NOP going into the prompt year, an important factor, in our view, in the sound execution of a hedging strategy. We note that Pacific Power's percentage of NOP for the 2012 test year is higher than ICNU's own target percentage, and higher than the NOP of utilities cited by ICNU as useful exemplars. Given these facts, we do not conclude that the company hedged too much, too soon. We therefore decline to impose an adjustment based on ICNU's proposed targets.

We encourage Pacific Power to work with Staff and stakeholders in workshops, as the company has committed to do, to address any stakeholder concerns about the company's present and future hedging strategies. The company states that it welcomes *ex ante* direction from the Commission on the company's risk management policy and hedging program,[49] which we believe should start with stakeholder involvement.

Calculation of ICNU's Adjustment

We also briefly address the calculation of ICNU's proposed adjustments. As Pacific Power notes, ICNU's witness conceded during the hearing that his calculations failed to ensure that his hedging targets were properly applied to each year, and that if he were to correct the calculations, his proposed adjustment would be reduced by approximately 50 percent. We find this to be an accurate representation of the testimony made during the hearing. Thus, even if we were to apply ICNU's hedging adjustment, we would apply a much smaller adjustment than ICNU proposes.[50]

c. *Alleged Violation of Risk Management Policy*

i. Parties' Positions

ICNU also challenges a number of hedges that it argues violate the company's 2006 Risk Management Policy. ICNU argues that the company's Risk Management Policy

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[47] For each hedge, Pacific Power provided information on the transaction type, counterparty, date of execution, delivery start and end dates, quantity, delivery market, market price, fixed price, and mark-to-market value of the transaction.
[48] Pacific Power points out that PGE's recent Integrated Resource Plan reveals that it has a longer hedging horizon than Pacific Power does.
[49] *See* PPL/400, Bird/14.
[50] Based on the evidence presented, we believe ICNU's adjustment, properly calculated, would be approximately $8.1 million (for all of its hedging challenges).

contemplated hedges up to a 48-month tenor. A number of hedges in the company's 2012 test year extended beyond this time horizon. These hedges, ICNU contends, should be disallowed.

ICNU concedes that the Risk Management Policy allowed for hedges beyond 48 months in certain circumstances, but it argues that the company failed to provide "*any* contemporaneous documentation of its unusual and aggressive approach of locking in huge amounts of gas well before it was needed."[51] The company simply offered the statement of the company's Senior Vice President of Trading (Mr. Bird) that he "personally pre-approved these transactions," and a post hoc analysis of the market data it could have considered in 2007 and 2008.[52] This evidence, ICNU argues, is insufficient to demonstrate that the transactions were reasonable. Moreover, ICNU argues, the volume of hedges beyond the 48-month tenor was excessive.

In response, Pacific Power argues that the hedges ICNU challenges were prudent and properly executed under the company's Risk Management Policy. The company points out that the Risk Management Policy explicitly permitted the company to execute transactions that extended beyond 48 months when it made financial sense to do so. The policy simply required the company's Senior Vice President of Trading to review and approve each one of them. In this case, the company's Senior Vice President of Trading testified that he personally approved each of these hedges because each was the least-cost option available to the company at the time.[53]

By way of further explanation, Pacific Power asserts that its Risk Management Policy set absolute limits on short positions for natural gas for each forward month or quarter through 48 months. At the time, large open positions rolled into the period within 48 months of delivery. The Risk Management Policy required the company to fill these positions.[54] It could fill them by purchasing products for individual months, but at the time there was greater liquidity in standard tenor products such as November-March or April-October than for individual months. Rather than pay higher prices for the single-month products, the company argues, it opted to purchase the more cost-effective standard market products. In short, Pacific Power explains that it was able to decrease the costs of company-required hedging by hedging with more standard strips as they rolled into the policy-defined hedging horizon.[55]

Pacific Power points out that these types of hedges were expressly permitted by the company's policies, and that the hedges at issue were, on average, only 2.3 months

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[51] ICNU Opening Brief at 21-22.
[52] *E.g.*, PPL/400, Bird/9-10, 28-33; PPL/406, Bird/8; ICNU/110, Schoenbeck/11; Tr. at 119-122.
[53] Tr. at 60-61. Pacific Power argues that contemporaneous written documentation of this analysis is not a prerequisite to establishing the prudence of its decision-making process. The correct legal standard is an objective standard of reasonableness (citing Order No. 02-469 at 5-6).
[54] PPL/400, Bird/9-10.
[55] *Id.*

beyond the 48-month tenor.[56] This 2.3-month average illustrates that the longer hedges were largely based on the purchase of more standard tenor products, and it is also well within the 15-25 percent range of flexibility that ICNU's witness testified he supported for both hedging length and volume targets.[57]

In short, the company argues, it prudently entered into hedges longer than 48 months in compliance with its internal risk management policy.

ii. Commission Resolution

We find no basis for disallowing the hedges ICNU challenges here. As we noted above, if a particular transaction is inconsistent with utility's hedging strategy, or parties have raised issues that appropriately call a particular transaction into question, we will next ask whether the utility provided adequate and contemporaneous analysis and documentation for the transaction and a sound justification to support it. In this case, we find that the transactions at issue were consistent with the company's policies, and that the company, in any event, provided a sound justification to support them.

First, it is clear that Pacific Power's Risk Management Policy, coupled with the company's Front Office Procedures and Practices, explicitly allowed it to execute hedges that extended beyond 48 months for specific, legitimate reasons. The mere fact that a hedge extended beyond the 48-month timeframe was not, itself, a violation of the company's written policies.

More specifically, hedges beyond 48-months were contemplated by the company's policies in certain instances, such as when it was more cost effective to purchase specific types of products rather than others to fill NOP requirements.[58] Mr. Bird explained that he personally approved each of the hedges at issue for precisely this reason. Consequently, the hedges appear to be consistent with the company's own policies.

We agree with ICNU that contemporaneous written documentation of Mr. Bird's reasons for approving each of the hedges would have been helpful, as it would illustrate with greater certainty that the company's decision to approve the hedges was appropriate. But such evidence is not strictly required,[59] particularly when the hedges appear, by other objective measures, to be appropriate under the company's own policies.

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[56] Tr. at 124.
[57] Tr. at 188.
[58] *See, e.g.,* Tr. at 124-125; ICNU/103, Schoenbeck/4.
[59] While contemporaneous written documentation is among the most persuasive types of evidence a utility can present, we have held that in most instances it is not strictly required. The question is whether the utility has demonstrated through evidence the objective reasonableness of its actions at the time the company acted. *See* Order No. 02-469 at 4.

Here, the fact that the hedges at issue extend, on average, 2.3 months beyond the 48-month hedging horizon is also relevant. It further supports Mr. Bird's explanation that the hedges extended beyond the 48-month timeframe not because the company was trying to beat the market, but because the company elected to purchase standard tenor products (such as November-March or April-October strips) rather than hedging for single months. Mr. Bird explained that at the time, this was the least expensive way to meet the requirements of the Risk Management Policy.[60] Under the evidence presented, we find the company's explanation persuasive.

3. *Use of Internally Generated Forward Price Curves*

ICNU objects to Pacific Power's use of internally developed forward price curves to develop its NPC. ICNU argues that Pacific Power should instead be required to use independent, third-party pricing data, which would allow intervenors to better evaluate the company's data within the context of a streamlined TAM proceeding. ICNU also challenges the company's use of scalars to convert monthly forward pricing to hourly GRID values.

a. *Source of Forward Price Curves*

i. *Parties' Positions*

ICNU argues that the company's reliance on complex internal forward price projections is unnecessary and limits other parties' ability to meaningfully analyze the company's forward price curve. Review of the company's forward price curve is complex, ICNU argues, making it a challenge to review in the context of the streamlined TAM process. This challenge is compounded by the fact that the company's internal data was designated "highly confidential" in this docket, making it difficult for ICNU to access and review the information.

ICNU argues that the company's use of internal data is unnecessary because the goal of the company's methodology is, essentially, to approximate third-party projections. The only purpose achieved by the company's use of "a secretive and byzantine internal derivation process is to inhibit [intervenor participation]"[61] The company should be required to rely instead on independent, third-party forward pricing projections and designate them as public or confidential.

With respect to the confidentiality issue, ICNU argues that the company initially withheld responses to data requests on the ground that the responses were "highly confidential."[62] Even when ICNU finally obtained the responses, the company failed to provide complete

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[60] Also relevant to our consideration is the fact that, of the set of hedges beyond 48 months, ICNU challenges no specific hedge on the grounds that it failed to meet the company's criteria described above, or on any other specific grounds such as market illiquidity.
[61] ICNU Opening Brief at 32.
[62] ICNU argues that the company did this even when no "highly confidential" protective order was in place.

formulaic data for ICNU's review, forcing ICNU to seek a change in the schedule to file supplemental testimony. Requiring Pacific Power to use third-party data would eliminate the company's need to use information Pacific Power considers "highly confidential," ICNU argues, and streamline parties' analyses.

ICNU asserts that Pacific Power could use third-party sources (specifically Intercontinental Exchange or "ICE" forward pricing data) wherever possible instead of the company's prices. This would not only streamline the process and avoid issues with "highly confidential" designations, it would also allow parties to monitor the forward price movement through the TAM process and eliminate surprises in the final update.

Pacific Power disputes ICNU's assertions. Regarding ICNU's argument that the company should use a publicly available forward price curve rather than a company-generated price curve, Pacific Power states there is no publicly available forward price curve for all of the market hubs in which Pacific Power transacts.[63] Historical price curves, which ICNU argues could be used for missing market hubs, are not a suitable replacement for forward price spreads because they are less accurate and not always available.[64] In short, Pacific Power argues, the evidence shows there is no publicly available forward price curve that can accurately replace the company's internally developed forward price curve.

With respect to the confidentiality issue, Pacific Power notes that the TAM guidelines require it to provide certain workpapers to the parties within a certain timeframe. This includes workpapers containing the official forward price curve used to develop the company's filing. The company states that it gave ICNU and other parties this information in a timely manner under the Commission's general protective order.[65] Thus, the information used to develop the official forward price curve was provided to the qualified parties in a timely manner and designated "confidential," not "highly confidential."

The company states that confidentiality issues arose when ICNU requested other forward price curve information, information *not* used to develop the official forward price curve, in discovery. The information at issue, however, was not the official forward price curve and not the information used to develop the NPC requested in the filing. Thus, the company argues, ICNU's argument about the highly confidential nature of the information used to develop its forward price curve is misleading.[66]

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[63] PPL/500, Link/6.
[64] *Id.* Moreover, Pacific Power explained, data for these market hubs are not always available in any instance.
[65] *Id.* at 3. Pacific Power explains that the official forward price curve is developed by the company for a given quote date. The quote date for the initial filing's forward price curve was December 31, 2010, and the quote date for the rebuttal update was June 30, 2011.
[66] *Id.*

Pacific Power also contests ICNU's assertion that the company's use of an internal forward price curve creates a gaming opportunity. The company points out that ICNU concedes after review that the company did not appear to game the company's forward price curve.[67] In fact, ICNU observed an insignificant difference between the company's internally generated forward prices and those reported by ICE.[68] Finally, Pacific Power argues, the methodology it uses to develop the forward price curve for its TAM is the same methodology it uses in daily operations and financial reporting.[69]

Staff also weighed in on this issue, arguing that the company-generated forward price curve is reasonable and consistent with forward price projections that Staff found from outside, independently available price sources.[70]

ICNU criticizes Staff's assertion that Pacific Power's forward price curve is reasonable on the ground that Staff conducted only limited discovery of Pacific Power's method of calculating the forward curves and encountered no difficulties gaining access to the information. ICNU states that it is the only party in this proceeding, as well as prior Commission proceedings, that has actually sought to review the data underlying the company's forward price curve.

ii. Resolution

After review of the evidence before us, we deny ICNU's objections. With respect to the company's use of an internally generated forward price curve, the company explained that no publicly available source of forward price curves exists for all of the market hubs in which Pacific Power transacts, nor are there any suitable replacements for the sources that are missing. As a result, the company explains, it must develop its own forward price curve. We find Pacific Power's explanation convincing on this point.[71]

With respect to the confidentiality of the company's forward price curve, Pacific Power explained that the forward price curve used to develop its proposed rate increase in this docket was provided to the parties in a timely manner under the Commission's general protective order, an order that would not have unduly limited ICNU's review.[72] ICNU

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[67] The company explains that the TAM guidelines also require it to provide, as part of its final update, the risk management validation that shows how the official forward price curve compares to broker quotes. *See* TAM Guidelines at 19 (Section D(2)).
[68] *See* ICNU/100, Schoenbeck/19.
[69] PPL/500, Link/8.
[70] Staff/300, Durrenberger/12.
[71] ICNU chose not to respond to the company's argument in its reply testimony. *See* ICNU/110, Schoenbeck/3.
[72] The TAM guidelines require Pacific Power to provide parties with various types of workpapers under specific time deadlines. *See* TAM Guidelines at 15-19.

has not disputed this assertion. It is unclear from the testimony why this information was insufficient to enable ICNU to analyze the company's forward price curve.[73]
In the end, we find Pacific Power's rebuttal testimony on this issue to be convincing. Our conclusion is further supported by the testimony of Pacific Power, Staff, and even ICNU that Pacific Power's forward price curves were consistent with data from third-party sources, evidence that the company's internal information was developed in a reasonable manner.

b. Conversion of Monthly Forward Pricing to Hourly GRID Values

i. Parties' Positions

ICNU also argues that the company's use of scalars, which are applied to a forward price curve to yield an hourly market price profile, is inappropriate. ICNU recommends use of an alternative method that would reduce NPC by $1.7 million.

ICNU explains that the GRID model is structured to simulate dispatch of the company's resources on an hourly basis to determine the company's NPC. ICNU states that the model contains data for the company's resources. Pricing information at major interconnection points in the western United States must be input into the model so that GRID can determine economic purchases or sales at these market hubs. Currently, ICNU notes, there is no third-party provider of forward or projected hourly prices for these hubs. Consequently, the company must input into GRID its own projections of 2012 hourly prices at these trading hubs.

To do so, the company uses a confidential set of hourly data to convert monthly forward price curves into hourly values to input into GRID. ICNU argues that the company's method for developing the hourly pricing data is overly complex, that it fails to replicate the way the company actually purchases in the market, and that it relies on a subset of data that is insufficiently robust to yield accurate hourly values.[74]

ICNU recommends the company be required to rely on certain, day-ahead pricing from a third-party source rather than its variable hourly data. This would reduce the variability of the hourly values—for example, the price of all on-peak hours for a given day in a month would be the same, which is less granular than Pacific Power's approach. ICNU argues that the Pacific Power trades most often in markets such as the forward and day-

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[73] We note that ICNU failed to challenge the highly confidential designation of any of the company's discovery requests during the course of these proceedings. While we understand ICNU's frustration with such designations, the Commission's protective orders provide avenues for relief parties seeking access to information that is improperly designated as confidential or highly confidential. To the extent parties believe information is improperly designated confidential or have other discover disputes, they should pursue relief for such issues in a timely manner, not at the end of a case. By the same token, Pacific Power must take steps to ensure that information sought in discovery, including highly confidential information, is provided to ICNU in a timely manner.

[74] ICNU/108, Schoenbeck/3.

ahead markets, so there is no need to calculate the hourly value in the manner Pacific Power does.[75] Simplifying the calculation would also facilitate intervenor participation in TAM proceedings.

In the alternative, ICNU argues that the company should use data from a different time period than it currently uses to ensure the underlying data is sufficiently robust to yield accurate results.[76] ICNU argues that for the years the company has chosen to create its data set, certain years lack sufficiently robust data. ICNU argues that only the years with more robust data should be used.

Finally, ICNU complains about the company's "highly confidential" designation of its scalars. ICNU argues that this designation, as well as the company's delay in providing ICNU with the full set of information needed to replicate the company's calculations, greatly impaired ICNU's timely review of the company's scalars. ICNU concedes that the information is confidential, but should not be treated as "highly confidential."

Pacific Power responds that methodology used by the company is very detailed, but is intended to yield hour-to-hour prices consistent with historical price data. ICNU's recommended methodology would simplify things, but it would yield hourly price profiles that deviate from known market trends, making the results less realistic.[77] ICNU's methodology would, for example, result in the same price for all on-peak hours for a given day type in a month (such as all Mondays), which is simply inconsistent with verifiable historical data.[78]

With respect to the confidentiality issue, the company argues that its scalars are extremely commercially sensitive. A counterparty could use the company's detailed pricing information to derive important market data that would affect the company's negotiation position to the detriment of ratepayers.

ii. Resolution

We find the company's use of hourly scalars derived from its historical data set to be appropriate. Pacific Power explained that its scalars are developed from reliable sources and are intended to yield hourly price profiles consistent with known market trends. While we acknowledge the challenges involved in analyzing this data, we find that the company has adequately explained that its use of hourly scalars is intended to develop results consistent with historical price data.

While use of more simplified data may be a reasonable method of valuing the company's short-term market purchases and sales, a key purpose of the GRID model is to determine

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[75] *Id.* at 11-12.
[76] *Id.* at 3-12.
[77] The company argues that its source of price index data is widely recognized as reliable. *See* PPL/500, Link/13.
[78] PPL/500, Link/14.

the economic dispatch of Pacific Power's resources on an hourly basis. The parties did not adequately address the impact of changing the scalar methodology on plant dispatch and we are unwilling to adopt this adjustment based on partial analysis. With respect to the scope of historical data used to develop the scalars, we find no reason to modify the scope of data Pacific Power has chosen to include in its analysis.

We acknowledge ICNU's frustration with the designation of relevant data as highly confidential. But we note once more that ICNU failed to challenge the highly confidential designation of this information during the course of these proceedings. Parties should pursue relief for discovery issues in a timely manner, not at the end of a case.

4. Remaining Issues (GRID Modeling)

ICNU proposes four additional adjustments. Each proposes modifications to Pacific Power's GRID modeling. They are as follows:

1.	Sales Activity – Market Sales Limits	$1.4
2.	Sales Activity – ISO Charges	$1.1
3.	Sales Activity – DC Intertie Charges	$1.2
4.	Gadsby Units 4-6 – Wind Integration	$0.8
	Total Remaining Adjustments	**$4.5 Million**

In addressing these modeling issues, we note that we have two goals. The first is to determine whether ICNU's objections undermine the reasonableness of the stipulated rates. The second is to provide some guidance on these issues for future TAM proceedings, which occur on an annual basis (either as part of a general rate revision or as a stand-alone TAM proceeding).

As to our first goal, we conclude at the outset that, given our previous findings in this order, ICNU's remaining objections would not undermine the reasonableness of the stipulation, even if sustained. As we have noted, in reviewing a contested stipulation, we may focus on the reasonableness of the overall stipulated rates. Were we to grant all of ICNU's remaining objections, which total $4.5 million in adjustments, it would reduce Pacific Power's requested revenue requirement increase from $58.7 million to $54.2 million. The stipulation proposes an even lower increase: $50.7 million.

For this reason, there is no need to address ICNU's remaining objections, as we can determine that, based on the record as a whole, the stipulated rate increase is reasonable, and the stipulation should be adopted on that basis.[79]

[79] ICNU's proposes a total of $53.2 million in reductions to Pacific Power's requested rate increase of $58.7 million (surrebuttal stage). Of that $53.2 million, we have denied ICNU's recommended $30.8 million reduction related to revenue sales offsets, and its proposed $16.2 million disallowance for

Nevertheless, to fulfill our second goal, we will address each of ICNU's remaining objections to provide guidance on these issues for future proceedings. We initially observe, as a general matter, that a stand-alone TAM is intended to be a streamlined proceeding. Review and verification of the company's complex modeling presents a serious challenge, particularly in the context of a stand-alone TAM proceeding, when the Commission is presented with limited information and a short timeframe for decision.

a. Sales Activity – Market Sales Limits

Pacific Power includes certain "market caps" in GRID that limit GRID's ability to model unlimited sales during certain periods. These market caps have proven to be controversial. Making things more controversial, the company has changed its methodology for modeling market caps since its last TAM filing. Pacific Power explains that the change is appropriate because the company has developed a more comprehensive approach to modeling market depth that more accurately portrays the company's ability to sell generation. Rather than applying market caps only for graveyard hours, as it had in the past, the company's modeling now specifies market depth during all hours.[80]

ICNU challenges Pacific Power's use of market caps.[81]

i. Parties' Positions

ICNU explains that Pacific Power imposes upon GRID various sales limits at each of the company's trading hubs.[82] These caps limit the amount of sales the company can make at each hub in any given hour. The caps limit sales based on the average energy sold by the company at these hubs over the last 48-month on-peak and off-peak periods.[83] Because the caps reduce the energy that can be sold in *all* hours based on these broad averages, there are "many hours in the historical period when the actual hourly sales amount exceeded the average sales value."[84] ICNU argues that the company's market caps

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hedging. ICNU's remaining objections total $4.5 million. We also make the following observations about the Joint Parties' positions at the surrebuttal stage: at that point, Staff proposed a total of about $2 million in additional reductions ($1.5 million for market caps—a GRID modeling issue that will be addressed later in this order—and $0.4 million for affiliate mine issues). CUB proposed a reduction of approximately $3.8 million for natural gas hedges beyond a 48-month tenor, objections that overlap with ICNU's objection to natural gas hedges beyond a 48-month tenor.

[80] *See* PPL/100, Duvall/9-10.

[81] Staff objected to the company's new market caps modeling on the ground that the modeling change was too substantial for a streamlined, stand-alone TAM proceeding. Staff recommended that the company revert to the methodology used in its last TAM proceeding. *See* Staff/100, Durrenberger/5. Pacific Power argues that reverting back to the company's prior methodology would actually *increase* system-wide NPC by approximately $10 million. *See* PPL/105, Duvall/18. Staff maintained its objection ($1.5 million) until it reached the stipulation with the Joint Parties.

[82] ICNU/100, Schoenbeck/24.

[83] *Id.* at 22. The market caps reduce the energy that can be sold in all hours based on four-year averages, including hours in which no transactions were executed; ICNU/110, Schoenbeck/7.

[84] ICNU/100, Schoenbeck/22.

inappropriately ensure that the company's sales levels will always be lower than actual operations.

ICNU asks the Commission to remove the caps entirely. Even if they are removed, ICNU argues, the company's sales volume modeled in GRID would still be lower than its actual historical sales.[85]

If market caps are imposed, ICNU recommends that GRID should model the maximum number of transactions the company actually entered into at each hub.[86] This would remove the artificial hourly constraints that drive sales in the model well below actual sales at certain times and certain hubs. Otherwise, ICNU argues, the model artificially constrains Pacific Power's sales when the company has marketable surplus capacity.

Pacific Power responds that market caps are appropriate and necessary. Without market caps, the company argues, GRID allows for unlimited sales in every market at all times. But historical data shows that Pacific Power's ability to sell in certain markets is sometimes limited. The caps appropriately reflect limitations related to market depth and other constraints. The company argues that the market cap values equal the actual transactions the company has executed at each trading hub on an energy basis, an appropriate constraint.[87]

Pacific Power argues it is meaningless that the number of sales transactions modeled by GRID is lower than the company's actual historical transactions. This is a characteristic of any dispatch model that balances and optimizes a forecast test year on an hourly basis with perfect foresight. Pacific Power notes that the Commission has already acknowledged this modeling issue in prior dockets.[88] Pacific Power also notes that market caps have been used in every past TAM proceeding, and that their removal would be a departure from historical practice. The company also disputes ICNU's assertion that the market caps substantially limit sales transactions modeled in GRID.

Moreover, Pacific Power argues, elimination of market caps would result in a double counting of short-term firm trading transactions. If market caps are removed, the company's calculations show that 90 percent of the increased sales that result are associated with offsetting purchases, and are thus attributable to arbitrage. The company already includes in its NPC calculation a trading margin adjustment, which would result in double-counting of such transactions if the caps were removed.[89]

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[85] ICNU/110, Schoenbeck/8.
[86] *Id* at 7-8. ICNU argues that Pacific Power is the only utility in the Pacific Northwest that attempts to model its inability to sell generation as part of its power cost modeling.
[87] PPL/110, Duvall/9-10.
[88] PPL/105, Duvall/20 (citing to Docket No. UE 191).
[89] PPL/110, Duvall/12.

In response, ICNU continues to point to results of the GRID model, which it argues reveal substantial artificial constraints on the company's sales. ICNU attributes this not to inherent characteristics of the model's dispatch optimization, but to artificial caps. ICNU argues that the company does not impose caps on purchases, only on sales, evidence that the caps are not justifiable.[90] And despite the company's assertion that eliminating market caps would result in double-counting of a short-term trading market adjustment, ICNU argues, the modest impact on the company's sales would be so limited that no double-counting would actually occur.[91]

ii. Resolution

As we noted above, our decision on this issue will not affect the reasonableness of the stipulation, so we address it only for the purpose of providing the parties with future guidance.

It is difficult in the context of a stand-alone TAM proceeding to determine whether a certain modeling technique is reasonably representative of the company's actual operations. We note however, that Pacific Power is the party that designed the GRID model, and it has the most familiarity with all of the data and assumptions used in the model. Because the company has control of the complex modeling and better access to the details and choices behind it, we expect the company to provide excellent reasons for its modeling choices. Here, the company provides a reasonable explanation for imposing market caps, but ICNU also raises legitimate concerns about whether the caps are truly necessary and whether they might be better designed to achieve fairer results.

We will accept Pacific Power's modeling of market caps here on a non-precedential basis. We direct Staff to conduct workshops with the parties to address the market caps issue, with the goal of determining whether agreement can be reached on a fair and reasonable method for modeling (or excluding) market caps in the future. If no agreement can be reached, we will expect Pacific Power to provide clear and robust evidence justifying its modeling of market caps in the company's next TAM proceeding. We will also ask Staff to present in the next TAM docket its own technical analysis of this issue.

b. Sales Activity – ISO Charges

i. Parties' Positions

ICNU states that Pacific Power engages in a significant number of transactions at several major trading points, including the Mid-Columbia and Palo Verde trading hubs, Four Corners, California Oregon Border, Mead, Mona, and the California market (Cal ISO).

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[90] ICNU/110, Schoenbeck/9.
[91] *Id* at 8.

ICNU notes that GRID models transactions at all of these hubs *except* the Cal ISO,[92] but nevertheless includes in its NPC $4.2 million (system-wide) in Cal ISO service and wheeling fees for spot transactions undertaken by the company with the Cal ISO during the historical period.[93] ICNU argues that these transactions should be removed from NPC because GRID does not include the offsetting benefits from these transactions. Pacific Power would not have engaged in these transactions, ICNU argues, unless it received a profit from them, but ratepayers are saddled with only the cost side of the transaction. As a result, Oregon NPC should be reduced by $1.1 million.

Pacific Power argues that Cal ISO system capability is not modeled in GRID because the company does not use the Cal ISO system capability. The Cal ISO fees are incurred when the company transacts with the Cal ISO at market hubs that *are* modeled in GRID, such as the California Oregon Border, Four Corners, Mona, and Palo Verde. The benefit of wholesale sales and purchases at these locations, the company argues, are already reflected in GRID.[94]

The company explains that it enters into transactions with the Cal ISO to serve load, not to earn a margin.[95] The benefits of the Cal ISO purchases are captured by GRID as follows: The company enters into transactions with the Cal ISO if the Cal ISO is identified as the most economic option for serving load at a given time. If the company were forced to forego these transactions, the company argues, it would limit the Company's ability to fully utilize the market and cause NPC to increase. "The retooling of GRID that would be required to remove Cal ISO as a counterparty would result in increased costs elsewhere, because the Company would need to find a way to replace the transactions it makes with the Cal ISO."[96] The result, Pacific Power argues, would be higher NPC. For this reason, the company argues, including Cal ISO costs here is just and reasonable.

Pacific Power also points out that Staff initially proposed the same adjustment as ICNU, but later agreed with the company that the Cal ISO fees were appropriate.[97]

ii. Resolution

We believe the company has provided persuasive evidence that the Cal ISO transactions provide customer benefits. It is not clear, however, whether the total level of benefits of these transactions justifies including all of the Cal ISO fees and costs in the company's

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[92] ICNU/100, Schoenbeck/21.
[93] *Id* at 25.
[94] PPL/105, Duvall/24.
[95] *Id* at 25.
[96] *Id* at 25. Pacific Power points out that ICNU does not dispute that the company engages in Cal ISO transactions. The transactions are reflected in GRID in the "system balancing sales and purchases where no counterparties are explicitly identified." *Id.* at 26.
[97] PPL/112 (Staff data request response, conceding that Cal ISO adjustment is unnecessary).

NPC. We expect to see evidence in future TAM proceedings that more precisely quantifies the level of benefits from Cal ISO transactions, as well as evidence demonstrating that the Cal ISO is a counterparty at these market hubs.

c. Sales Activity – DC Intertie Charges

Pacific Power executed a contract with Bonneville Power Administration in 1994 to provide deliveries of 200 MW of DC Intertie transmission capacity for energy deliveries associated with a contract with Southern California Edison (SCE).[98] Although Pacific Power's contract with SCE ended in 2002, the company retains the 200 MW of transmission capacity under the DC Intertie contract. ICNU argues that $1.2 million in contract costs should be excluded from GRID.

i. Parties' Positions

ICNU argues that charges related to the DC Intertie are not justified by corresponding benefits in GRID. It also argues that the company has not demonstrated the DC Intertie's continued usefulness, because its "extraordinary low level of activity does not justify the inclusion of the substantial wheeling costs" in NPC.[99] ICNU argues that the capacity of the wheeling agreement is seldom used by Pacific Power. For this reason, ICNU recommends disallowing $1.2 million.

Pacific Power argues that the DC Intertie contract benefits Oregon customers. Even though GRID does not model transactions at the Nevada Oregon Border, the company has made over 200 power purchase transactions there each year for the past five years (taking advantage of load diversity between control areas). The DC Intertie is used to transfer this power to load. Pacific Power explains that the cost of the contract is $1.99 per kilowatt-month, compared to $8 per kilowatt-month the company paid to BPA under a peak purchase contract. Without the contract, Pacific Power argues, the company would need to acquire a new 200 MW resource, which "would cost customers significantly more than the cost of the DC Intertie."[100]

The company argues that ICNU should not take an energy-only view of the contract. The contract provides assurance that the company can reliably serve its retail loads, and "[t]he costs associated with this contract are modest in light of the benefit to the Company's overall transmission strategy and hedge against changes in the market."[101]

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[98] The deliveries were from SCE at the Nevada Oregon Border market hub to PacifiCorp's western control area.
[99] ICNU/100, Schoenbeck/26.
[100] PPL/105, Duvall/22-23. The company also argues that its rights under the contract were prudently acquired 17 years ago and should not be challenged now.
[101] PPL/105, Duvall/23.

Pacific Power also points out that Staff initially proposed the same adjustment ICNU proposes here, but later agreed with the company that inclusion of the DC Intertie costs was appropriate.[102]

ICNU dismisses the company's argument that the contract provides capacity that would need to be replaced if the contract did not exist. ICNU also states that the Washington Utilities and Transportation Commission (WUTC) recently adopted ICNU's recommendation on this point.[103]

ii. Resolution

We believe the company has provided persuasive evidence that the DC provides some customer benefits. As with the Cal ISO fees, however, we expect to see evidence in future proceedings more precisely quantifying the level of benefits from the DC Intertie contract versus the cost of the resource.[104] We note that this is a long-term contract. In our view, the company has a continuing obligation to analyze the benefits of the contract; at the same time, the prudence of a long-term contract should be viewed in broader terms than a snapshot of benefits in any particular year.

d. Gadsby Units 4-6 – Wind Integration

ICNU also takes issue with Pacific Power's modeling of three natural gas turbine generators, Gadsby units 4, 5, and 6, as "must-run" facilities.[105] The company argues that the units must be designated as must-run units to support wind integration.[106]

i. Parties' Positions

ICNU argues that modeling Gadsby units 4-6 as must-run facilities is inappropriate because Pacific Power is not actually planning to operate the units in this manner. The units are inefficient and costly, especially when designated as must-run facilities.[107] Moreover, operating data from the twelve months ending June 30, 2011, demonstrates that the facilities were operated at a much lower capacity factor than the 32 percent used

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[102] Staff/100, Durrenberger/5-6; PPL/112.

[103] ICNU/100, Schoenbeck/26-27 (citing WUTC Docket No. UE 100749, Order 06 at ¶¶ 148-151 (Mar 25, 2011).

[104] The company states that the cost of the DC Intertie contract is $1.99 per kilowatt-month, which compares to "over $8 per kilowatt-month that the Company paid to BPA under the peak purchase contract," (PPL/105, Duvall/22) but without more, it is not clear whether this is a current apples-to-apples comparison or whether other options may be available.

[105] ICNU explains that Pacific Power's wind integration study is controversial, and that the must-run status of Gadsby is related to the company's wind integration. Rather than challenge the complex wind integration study in the context of a TAM, however, ICNU is challenging only the must-run status of Gadsby. *See, e.g.,* ICNU/100, Schoenbeck/30-31.

[106] PPL/110, Duvall/14-15

[107] ICNU/100, Schoenbeck/30-31; ICNU/110, Schoenbeck/4.

in the GRID model, demonstrating that they have not actually been operated as must-run facilities.

In fact, ICNU argues, if the must-run designation were removed, GRID would efficiently dispatch the facilities at a much lower capacity factor—one consistent with actual operations.[108] The must-run designation, ICNU argues, is simply inappropriate. The units should be modeled consistently with expected operations, which would reduce the company's NPC by $0.8 million.

Pacific Power argues that the facilities are properly modeled. The company takes issue with ICNU's reliance on the twelve months ended June 30, 2011 as a representative time period. This time period, the company argues, was marked by high levels of hydroelectric and wind generation and low market prices, conditions under which the Gadsby units would be expected to operate at a lower capacity factor than usual.[109] According to Pacific Power, later operational data show that the units have operated with as high as a 39 percent capacity factor. The 32 percent must-run setting applied in GRID "results in generation that is consistent with actual operational practice."[110]

Moreover, Pacific Power argues, ICNU concedes that it has not evaluated the company's overall wind integration costs. Having failed to do so, it should not selectively remove the must-run designation of Gadsby used to support wind integration.

The company also points out that Staff initially opposed the must-run designation of Gadsby, but later conceded that the designation was appropriate.[111]

ii. Resolution

We believe the company has provided some evidence that the Gadsby units are operated as must-run facilities, but the evidence on this issue is conflicting. In the company's next TAM proceeding, when more data is available, we expect to see clear evidence that the modeling of the units in GRID is reflective of actual operations.

V. CONCLUSION

We have reviewed the stipulation, which is set forth in Appendix A, and find that it will result in rates that are fair, just and reasonable. We adopt the stipulation.

[108] ICNU/110, Schoenbeck/4.
[109] PPL/110, Duvall/16.
[110] PPL/105, Duvall/31.
[111] PPL/112.

VI. ORDER

IT IS ORDERED that:

1. Advice No. 11-005 is permanently suspended.

2. The stipulation by and among PacifiCorp, dba Pacific Power; the Citizens' Utility Board of Oregon; Noble Americas Energy Solutions LLC; and the Staff of the Public Utility Commission of Oregon, attached as Appendix A, is adopted.

3. PacifiCorp, dba Pacific Power, must file new tariffs consistent with this order to be effective no earlier than January 1, 2012.

Made, entered, and effective NOV 04 2011.

John Savage
Commissioner

Susan K. Ackerman
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 227

In the Matter of: PACIFICORP, dba PACIFIC POWER 2012 Transition Adjustment Mechanism	**STIPULATION**

This Stipulation is entered into for the purpose of resolving all issues among certain parties to UE 227, PacifiCorp's (or the Company) 2012 transition adjustment mechanism (TAM).

PARTIES

1. The parties to this Stipulation are PacifiCorp, Staff of the Public Utility Commission of Oregon (Staff), the Citizens' Utility Board of Oregon (CUB), and Noble Americas Energy Solutions LLC (Noble Solutions) (together, the Parties). The Industrial Customers of Northwest Utilities (ICNU), the only other party to this docket, participated in the settlement conferences but declined to join and be a party to the Stipulation.

BACKGROUND

2. On March 17, 2011, PacifiCorp filed revised tariff sheets for Schedule 201, Net Power Costs, Cost-Based Supply Service, to be effective January 1, 2012, which implements PacifiCorp's 2012 TAM. The purpose of the TAM filing is to update net power costs (NPC) for 2012 and to set transition adjustments for Oregon customers who choose direct access in the November 2011 open enrollment window.

3. The March 17, 2011 TAM filing (Initial Filing) reflected total forecasted normalized system-wide NPC for the test period (12 months ending December 31, 2012) of approximately $1.56 billion. On an Oregon-allocated basis, the forecasted normalized NPC in the Initial Filing were approximately $382.3 million. This amount is approximately $79.0

million higher than the $303.3 million included in rates through the NPC baseline established in the 2011 TAM (Docket UE 216), or $61.6 million adjusting for the forecasted load increase in 2012. The Initial Filing would have resulted in an overall increase to Oregon rates of approximately 5.2 percent.

4. Staff, CUB, ICNU, and Noble Solutions filed opening testimony responding to the Company's Initial Filing on June 24, 2011. In addition, ICNU filed supplemental opening testimony on the issue of hourly scalars for forward price curves on July 5, 2011.

5. The Company filed reply testimony on July 29, 2011 (Rebuttal Filing). In the Rebuttal Filing, the Company updated NPC from the Initial Filing consistent with the TAM Guidelines and accepted certain adjustments proposed by Staff and intervenors. These changes resulted in 2012 Oregon-allocated NPC for 2012 of $384 million, or a $1.8 million increase to Oregon-allocated NPC included in the Initial Filing.

6. Staff and intervenors responded to the Company's Rebuttal Filing in rebuttal testimony on August 16, 2011. The Company filed surrebuttal testimony on August 30, 2011. The Company's surrebuttal testimony reflected Staff's proposal to update the load forecast based on the Company's July 2011 forecast, which reduced the Oregon-allocated NPC included in the surrebuttal filing by $15.9 million. The surrebuttal filing reflected 2012 Oregon-allocated NPC of $374.4 million, or a $7.9 million decrease to Oregon-allocated NPC included in the Initial Filing. The requested TAM increase included in the Company's surrebuttal filing was $58.7 million.

7. A hearing was held in this proceeding before Administrative Law Judge Lisa Hardie on September 8, 2011.

8. Prior to the hearing in this docket, all parties to the docket participated in settlement conferences on July 14, 2011 and August 5, 2011. All parties to the docket participated in an additional settlement conference on September 14, 2011.

9. The Parties have reached a comprehensive settlement of all issues raised in this case. The settlement establishes the baseline 2012 TAM NPC in rates, subject to the TAM Final Update, and addresses various TAM-related policy issues. ICNU is not a party to this Stipulation.

AGREEMENT

10. 2012 NPC. The Parties agree that the total-Company NPC for 2012 will be $1.46 billion, subject to the Final Update described in Section 11. The Parties agree that this is an Oregon-allocated NPC of $366.4 million or a TAM increase of $50.7 million, including the load change adjustment, as shown in Exhibit A. This results in an overall price increase of 4.4%, as shown in Exhibit B. This reflects the Parties' agreement that Oregon-allocated NPC presented in the surrebuttal filing shall be reduced by $8.0 million. The $8.0 million reduction reflects additional consideration of the issues in the testimony of Staff, ICNU, CUB and Noble Solutions. These adjustments resolve all issues related to NPC among the Parties.

11. NPC Baseline and Final Update. The Company shall file its Indicative Filing on November 8, 2011 and the Final Update on November 15, 2011 (collectively the Indicative Filing and the Final Update are referred to as the Final Update), consistent with the schedule adopted in this proceeding and as specified in the TAM Guidelines, adopted in Order No. 09-274 and modified in Order No. 09-432. The Final Update will reflect the $8 million decrease in Oregon-allocated NPC by using a base Oregon-allocated NPC of $50.7 million, and the update may increase or decrease the base NPC. The Final Update will also be used for purposes of calculating the transition adjustments.

12. Adjustments to NPC. The Parties agree that the stipulated $8 million reduction to the baseline NPC is for settlement purposes only and does not imply agreement on the merits of any adjustment, nor does it imply that the Parties have accepted any elements of the Company's NPC study.

13. Hedging Policy. PacifiCorp agrees to enter into a series of workshops with interested parties to review PacifiCorp's going-forward hedging policy in detail and seek input from the interested parties on how the policy is implemented and whether the policy should be revised to better reflect customer risk tolerances and preferences. While all Parties agree that this is not, and will not be, stated to be a pre-approval process in any future prudence review, the Company agrees to implement appropriate policy changes on a going-forward basis that result from agreement in the collaborative process.

14. Bonneville Power Administration (BPA) Transmission Credit for Direct Access. PacifiCorp agrees to increase the Schedule 294 transition adjustment by $(0.75)/MWh for the 2012 TAM for Schedule 747 and 748 customers to reflect the potential value associated with reselling BPA Point-to-Point wheeling rights from Mid-C to the Company's Oregon service territory that are freed-up as a result of customers choosing direct access. Nothing in this agreement obligates PacifiCorp to sell any transmission rights to an electricity service supplier.

15. Tariff. Upon approval of this Stipulation and concurrent with the filing of the Final Update, PacifiCorp will file revised Schedule 201 rates, new Schedule 205, Schedule 220 consistent with the Final Update and Exhibit C and revised transition adjustment Schedules 294 and 295 as a compliance filing in Docket UE 227 to be effective January 1, 2012, reflecting rates as agreed in this Stipulation. The Parties agree that the line losses in Schedule 220 and which are used in calculating the Schedule 294 and 295 transition adjustments will be consistent with the Real Power Losses that appear in Schedule 10 of PacifiCorp's OATT for the PacifiCorp Zone that are approved to be in effect for the test year.

16. This Stipulation will be offered into the record as evidence pursuant to OAR 860-001-0350(7). The Parties agree to support this Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Stipulation at hearing, if needed, and recommend that the Commission issue an order adopting the Stipulation.

17. If this Stipulation is challenged by any other party to this proceeding, the Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation. The Parties reserve the right to cross-examine witnesses and put in such evidence as they deem appropriate to respond fully to the issues presented including the right to raise issues that are incorporated in the settlements embodied in this Stipulation.

18. The Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material portion of this Stipulation or imposes additional material conditions in approving this Stipulation, any Party shall have the right to withdraw from the Stipulation, along with any other rights provided in OAR 860-001-0350(9), including the right to present evidence and argument on the record in support of the Stipulation, and shall be entitled to seek reconsideration pursuant to OAR 860-001-0720.

19. By entering into this Stipulation, no Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Party in arriving at the terms of this Stipulation, other than as specifically identified in the body of this Stipulation. No Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Stipulation.

20. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Stipulation is entered into by each Party on the date entered below such Party's signature.

PACIFICORP

By: Andrea L. Kelly

Date: 20 Sept 11

STAFF

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

Noble Solutions

By: ______________________

Date: ______________________

ORDER NO. 11 435

PACIFICORP

By: ____________________

Date: ____________________

STAFF

By: Paul A. Graham for Jason Jones

Date: 9/20/11

CUB

By: ____________________

Date: ____________________

Noble Solutions

By: ____________________

Date: ____________________

PACIFICORP

By: ______________________________

Date: ______________________________

STAFF

By: ______________________________

Date: ______________________________

CUB

By: Bob Jenks

Date: 9-20-11

Noble Solutions

By: ______________________________

Date: ______________________________

PACIFICORP

By: ______________________________

Date: ______________________________

STAFF

By: ______________________________

Date: ______________________________

CUB

By: ______________________________

Date: ______________________________

Noble Solutions

By: ______________________________

Date: 9-19-11

PacifiCorp
CY 2012 TAM (Settlement Agreement)

		Total Company									Oregon Allocated				
	ACCT.	UE 216 Final TAM CY 2011	Filed TAM CY 2012	July Update CY 2012	Surrebuttal (August 2011) CY 2012	**Settlement Agreement CY 2012**	Factor	Factors CY 2011	Factors CY 2012	Surrebuttal Factors CY 2012	UE 216 Final TAM CY 2011	Filed TAM CY 2012	July Update CY 2012	Surrebuttal (August 2011) CY 2012	**Settlement Agreement CY 2012**
Sales for Resale															
Existing Firm PPL	447	25,965,364	26,081,862	25,857,080	25,857,080	**25,857,080**	SG	26.177%	25.623%	26.314%	6,796,976	6,682,858	6,625,263	6,804,026	**6,804,026**
Existing Firm UPL	447	25,490,589	25,490,583	25,490,583	25,490,583	**25,490,583**	SG	26.177%	25.623%	26.314%	6,672,694	6,531,357	6,531,357	6,707,586	**6,707,586**
Post-Merger Firm	447	425,569,012	479,326,113	432,331,358	450,655,477	**450,655,477**	SG	26.177%	25.623%	26.314%	111,401,573	122,815,936	110,774,646	118,585,377	**118,585,377**
Non-Firm	447	-	-	-	-	**-**	SE	24.283%	24.336%	24.796%	-	-	-	-	**-**
Total Sales for Resale		477,024,966	530,898,559	483,679,022	502,003,141	**502,003,141**					124,871,243	136,030,151	123,931,266	132,096,989	**132,096,989**
Purchased Power															
Existing Firm Demand PPL	555	50,413,276	2,798,086	3,057,680	3,057,680	**3,057,680**	SG	26.177%	25.623%	26.314%	13,196,727	716,943	783,458	804,597	**804,597**
Existing Firm Demand UPL	555	46,845,802	46,946,386	46,965,905	46,965,905	**46,965,905**	SG	26.177%	25.623%	26.314%	12,262,866	12,028,897	12,033,898	12,358,597	**12,358,597**
Existing Firm Energy	555	57,920,075	24,844,458	24,712,774	24,712,774	**24,712,774**	SE	24.283%	24.336%	24.796%	14,064,911	6,046,166	6,014,120	6,127,708	**6,127,708**
Post-merger Firm	555	353,358,225	573,790,087	572,860,870	533,749,221	**533,749,221**	SG	26.177%	25.623%	26.314%	92,498,892	147,020,087	146,781,997	140,450,645	**140,450,645**
Secondary Purchases	555	-		-	-	**-**	SE	24.283%	24.336%	24.796%	-	-	-	-	**-**
Seasonal Contracts	555	-		-	-	**-**	SSGC	0.000%	0.000%	0.000%	-	-	-	-	**-**
Other Generation Expense	555	38,906,526	3,726,876	3,636,631	3,636,631	**3,636,631**	SG	26.177%	25.623%	26.314%	10,184,595	954,924	931,800	956,942	**956,942**
Total Purchased Power		547,443,905	652,105,892	651,233,861	612,122,212	**612,122,212**					142,207,992	166,767,016	166,545,273	160,698,490	**160,698,490**
Wheeling Expense															
Existing Firm PPL	565	40,049,244	27,034,359	27,034,359	27,034,359	**27,034,359**	SG	26.177%	25.623%	26.314%	10,483,726	6,926,913	6,926,913	7,113,815	**7,113,815**
Existing Firm UPL	565	259,960	-	-	-	**-**	SG	26.177%	25.623%	26.314%	68,050	-	-	-	**-**
Post-merger Firm	565	102,100,510	102,329,448	102,898,595	102,898,595	**102,898,595**	SG	26.177%	25.623%	26.314%	26,726,940	26,219,492	26,365,322	27,076,712	**27,076,712**
Non-Firm	565	104,176	2,893,180	2,886,131	2,899,820	**2,899,820**	SE	24.283%	24.336%	24.796%	25,297	704,087	702,371	719,031	**719,031**
Total Wheeling Expense		142,513,890	132,256,988	132,819,085	132,832,774	**132,832,774**					37,304,013	33,850,491	33,994,606	34,909,558	**34,909,558**
Fuel Expense															
Fuel Consumed - Coal	501	631,194,105	711,634,271	712,588,017	708,843,890	**708,843,890**	SE	24.283%	24.336%	24.796%	153,274,821	173,183,855	173,415,959	175,762,891	**175,762,891**
Fuel Consumed - Coal (Cholla)	501	55,439,077	56,618,412	57,709,222	57,629,949	**57,629,949**	SSECH	24.812%	24.910%	25.371%	13,755,347	14,103,650	14,375,371	14,621,343	**14,621,343**
Fuel Consumed - Gas	501	5,410,856	10,850,156	8,735,448	7,499,287	**7,499,287**	SE	24.283%	24.336%	24.796%	1,313,935	2,640,502	2,125,865	1,859,502	**1,859,502**
Natural Gas Consumed	547	365,117,219	484,957,536	443,183,136	438,533,308	**438,533,308**	SE	24.283%	24.336%	24.796%	88,662,546	118,019,633	107,853,384	108,737,457	**108,737,457**
Simple Cycle Comb. Turbines	547	8,178,179	36,248,503	36,351,436	36,589,196	**36,589,196**	SSECT	22.403%	24.329%	24.788%	1,832,173	8,818,918	8,843,960	9,069,661	**9,069,661**
Steam from Other Sources	503	3,540,887	3,893,567	3,760,489	3,760,489	**3,760,489**	SE	24.283%	24.336%	24.796%	859,844	947,542	915,155	932,440	**932,440**
Total Fuel Expense		1,068,880,323	1,304,202,446	1,262,327,747	1,252,856,120	**1,252,856,120**					259,698,666	317,714,100	307,529,695	310,983,294	**310,983,294**
Net Power Cost		1,281,813,152	1,557,666,766	1,562,701,671	1,495,807,965	**1,495,807,965**					314,339,428	382,301,456	384,138,307	374,494,353	**374,494,353**
Liquidated Damages Adjustment					(405,489)	**(405,489)**	SG			26.314%				(106,700)	**(106,700)**
UE 216 Settlement Adjustment		(44,855,794)									(11,000,000)				
UE 227 Settlement Adjustment						**(31,954,098)**									**(8,000,000)**
Total Net of Adjustments		1,236,957,358	1,557,666,766	1,562,701,671	1,495,402,475	**1,463,448,377**					303,339,428	382,301,456	384,138,307	374,387,653	**366,387,653**
Increase Absent Load Change												78,962,027	80,798,879	71,048,225	**63,048,225**
Oregon-allocated NPC Baseline in Rates from UE 216											303,339,428			303,339,428	**303,339,428**
$ Change due to load variance from UE-216 forecast											21,080,116			15,855,962	**15,855,962**
2012 Recovery of NPC in Rates											324,419,544			319,195,390	**319,195,390**
Increase Including Load Change												57,881,911	59,718,763	55,192,263	**47,192,263**
Add Other Revenue Change												3,745,661	3,745,661	3,508,274	**3,508,274**
Total TAM Increase												61,627,572	63,464,424	58,700,537	**50,700,537**
Variance from Surrebuttal															***(8,000,000)***

ORDER NO. 11 435

Docket UE 227
Exhibit A to Stipulation

APPENDIX A
PAGE 10 OF 12

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
Forecast 12 Months Ended December 31, 2012

Line No.	Description	Pre Sch No.	Pro Sch No.	No. of Cust	MWh	Present Revenues ($000) Base Rates	Present Revenues ($000) Adders[1]	Present Revenues ($000) Net Rates	Proposed Revenues ($000) Base Rates	Proposed Revenues ($000) Adders[1]	Proposed Revenues ($000) Net Rates	Change Base Rates ($000)	Change Base Rates %[2]	Change Net Rates ($000)	Change Net Rates %[2]	SETTLEMENT ESTIMATE Net Rates ($000)	SETTLEMENT ESTIMATE Net Rates %[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) (6) + (7)	(9)	(10)	(11) (9) + (10)	(12) (9) - (6)	(13) (12)/(6)	(14) (11) - (8)	(15) (14)/(8)	(14) (11) - (8)	(15) (14)/(8)	
	Residential																	
1	Residential	4	4	478,578	5,588,220	$560,344	$11,511	$571,855	$585,376	$11,511	$596,887	$25,032	4.5%	$25,032	4.4%	$21,629	3.8%	1
2	**Total Residential**			478,578	5,588,220	$560,344	$11,511	$571,855	$585,376	$11,511	$596,887	$25,032	4.5%	$25,032	4.4%	$21,629	3.8%	2
	Commercial & Industrial																	
3	Gen. Svc. < 31 kW	23	23	74,901	1,053,146	$111,984	($1,745)	$110,239	$116,707	($1,745)	$114,962	$4,723	4.2%	$4,723	4.3%	$4,081	3.7%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,000	2,072,210	$159,821	$7,564	$167,385	$169,083	$7,564	$176,647	$9,262	5.8%	$9,262	5.5%	$8,003	4.8%	4
5	Gen. Svc. 201 - 999 kW	30	30	803	1,326,831	$94,782	$1,911	$96,693	$100,614	$1,911	$102,525	$5,832	6.2%	$5,832	6.0%	$5,039	5.2%	5
6	Large General Service >= 1,000 kW	48	48	212	2,886,720	$183,684	($10,248)	$173,436	$195,861	($10,248)	$185,613	$12,177	6.6%	$12,177	7.0%	$10,522	6.1%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	5	232,367	$15,090	($910)	$14,180	$16,039	($910)	$15,129	$949	6.6%	$949	7.0%	$820	6.1%	7
8	Agricultural Pumping Service	41	41	6,131	123,013	$14,091	($1,964)	$12,127	$14,617	($1,964)	$12,653	$526	3.7%	$526	4.3%	$455	3.8%	8
9	Agricultural Pumping - Other	33	33	2,007	104,951	$6,348	$66	$6,414	$6,348	$66	$6,414	$0	0.0%	$0	0.0%	$0	0.0%	9
10	**Total Commercial & Industrial**			94,059	7,799,238	$585,800	($5,326)	$580,474	$619,270	($5,326)	$613,944	$33,470	5.7%	$33,470	5.8%	$28,920	5.0%	10
	Lighting																	
11	Outdoor Area Lighting Service	15	15	7,020	9,991	$1,293	$261	$1,554	$1,336	$261	$1,597	$43	3.3%	$43	2.8%	$37	2.4%	11
12	Street Lighting Service	50	50	247	9,314	$1,047	$228	$1,275	$1,080	$228	$1,308	$33	3.1%	$33	2.6%	$28	2.2%	12
13	Street Lighting Service HPS	51	51	726	17,431	$3,116	$678	$3,794	$3,212	$678	$3,890	$96	3.1%	$96	2.5%	$83	2.2%	13
14	Street Lighting Service	52	52	50	1,147	$130	$28	$158	$135	$28	$163	$5	3.7%	$5	3.1%	$4	2.7%	14
15	Street Lighting Service	53	53	263	9,017	$572	$134	$706	$588	$134	$722	$16	2.9%	$16	2.3%	$14	2.0%	15
16	Recreational Field Lighting	54	54	105	1,012	$87	$18	$105	$90	$18	$108	$3	3.6%	$3	3.0%	$3	2.6%	16
17	**Total Public Street Lighting**			8,411	47,912	$6,245	$1,347	$7,592	$6,441	$1,347	$7,788	$196	3.1%	$196	2.6%	$170	2.2%	17
18	**Total Sales to Ultimate Consumers**			581,048	13,435,370	$1,152,389	$7,532	$1,159,921	$1,211,086	$7,532	$1,218,618	$58,697	5.1%	$58,697	5.1%	$50,718	4.4%	18
19	**Employee Discount**				18,151	($450)	($9)	($459)	($471)	($9)	($480)	($21)		($21)		($18)		19
20	**Total Sales with Employee Discount**			581,048	13,435,370	$1,151,939	$7,523	$1,159,462	$1,210,616	$7,523	$1,218,139	$58,677	5.1%	$58,677	5.1%	$50,700	4.4%	20
21	AGA Revenue					$2,886		$2,886	$2,886		$2,886	$0		$0		$0		21
22	**Total Sales with Employee Discount and AGA**			581,048	13,435,370	$1,154,825	$7,523	$1,162,348	$1,213,502	$7,523	$1,221,025	$58,677	5.1%	$58,677	5.1%	$50,700	4.4%	22

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Klamath Dam Removal Surcharges (Sch. 199), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).

[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

50,700

ORDER NO. 11 435

Docket UE 227
Exhibit B to Stipulation

APPENDIX A
PAGE 11 OF 12

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 220

STANDARD OFFER SUPPLY SERVICE

Return to Cost-Based Supply Service

The Consumer's return to Cost-Based Supply Service is restricted under the provisions of Schedule 201, Cost-Based Supply Service.

Loss Adjustment Factor

The loss adjustment shall be included by multiplying the above applicable Energy Charge ~~Option~~ by the following adjustment factors where the Real Power Losses Factors are as set forth for service in the PacifiCorp Zone in Schedule 10 of the Company's ~~currently effective~~ FERC Open Access Transmission Tariff (OATT) approved at the time of the announcement date defined by OAR 860-038-270 to be in effect for the election period:

~~Transmission Delivery Voltage~~	~~1.0361~~
~~Primary Delivery Voltage~~	~~1.0577~~
~~Secondary Delivery Voltage~~	~~1.0918~~
Delivery Voltage >= 46 kV	~~1 + Transmission System Real Power Losses Factor~~1.0500
Delivery Voltage < 46 kV	~~1 + Combination of the Transmission System and Distribution System Real Power Losses Factor~~1.0856

~~The Company's currently effective OATT can be found at www.oasis.pacificorp.com.~~

In addition to this energy charge, all customers purchasing this service are required to pay for ancillary services at the rates determined by the appropriate pro forma transmission tariffs.