PACIFIC POWER
A DIVISION OF PACIFICORP

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November 16, 2012

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capitol Street NE, Ste 215
Salem, OR 97301-2551

Attn: Filing Center

RE: **UM 1182 – Direct Testimony and Confidential Exhibit of Stacey J. Kusters**

PacifiCorp d/b/a Pacific Power submits for filing an original and five copies of the direct testimony and confidential exhibit of Stacey J. Kusters.

Confidential material in support of the filing has been provided to parties under the protective order in this docket (Order No. 11-506).

PacifiCorp respectfully requests that all data requests regarding this matter be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
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Please direct any informal inquiries to Bryce Dalley, Director, Regulatory Affairs & Revenue Requirement, at (503) 813-6389.

Sincerely,

William R. Griffith /RBD

William R. Griffith
Vice President, Regulation

Enclosures

cc: Service List in UM 1182

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document, in Docket UM 1182, on the date indicated below by email and/or US Mail, addressed to said parties at his or her last-known address(es) indicated below.

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DATED: November 16, 2012

Amy Eissler
Coordinator, Regulatory Operations

Docket No. UM-1182
Exhibit PAC/100
Witness: Stacey J. Kusters

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Stacey J. Kusters

November 2012

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

A. My name is Stacey J. Kusters. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. I am Director of Origination in Commercial and Trading for the Company.

Qualifications

Q. Briefly describe your education and business experience.

A. I hold a Bachelor of Arts in political science from Simon Fraser University and an Executive Master of Business Administration from the University of British Columbia. I joined PacifiCorp Energy in January 2001 as a manager of origination and assumed my current position as Director of Origination in 2006. From 1996 to 2001, I was employed at Powerex, the marketing arm for BC Hydro in Vancouver, British Columbia, as the marketing manager to develop the Northwest and California regions. I held various positions at Powerex, which included business development, energy trading, and origination. I also represented Powerex on the board of both the California Independent Operator (CAISO) and the California Power Exchange (CalPX) from 1999 through January 1, 2001.

Q. Please explain your responsibilities as Director of Origination.

A. I manage the procurement of new generation resources, contract administration, the market forecast group, the integrated resource plan (IRP), and structuring and pricing. Most relevant to this docket, I am responsible for acquisition of power resources for the Company's east and west balancing authority areas through negotiated power purchase agreements (PPAs) and the acquisition of generation resources, including implementation of requests for proposals (RFPs) consistent with applicable law and guidelines.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

The purpose of my testimony is to provide recommendations to the Public Utility Commission of Oregon (Commission) regarding an analytic framework and methodologies to enable Independent Evaluators (IEs) to better compare power supply contracts between the Company and third parties to cost-based utility ownership resources during a Commission approved resource solicitation. My analysis is limited to those items identified by the Commission in Order No. 12-324 as those to be initially addressed in this phase of the docket: 1) wind capacity factor; 2) heat rate degradation; 3) construction cost over- under-runs; and 4) counterparty risk.

Q Please provide a summary of your testimony.

A. My testimony includes: 1) a description of the process used by the Company to ensure a fair evaluation of resource options in the context of the four factors listed above; 2) a discussion of how the risks and benefits associated with each of the four factors may be allocated; and 3) a recommendation for each factor for how IEs may evaluate resource options in future resource solicitations. In general, I conclude that, given the evolving utility and energy industry and the uniqueness of individual resource solicitations and evaluation processes, the adoption of pre-determined quantitative assumptions will not benefit customers nor result in mitigation of a perceived utility self-build bias. Furthermore, I conclude in all cases that a pre-deterministic quantitative tool, while not advisable as a policy matter, is also simply not possible in the context of evaluating unique bid solicitations. However, the adoption of specific methodologies and evaluation approaches could provide a framework under which an IE can fairly evaluate the risks and benefits associated with utility owned resources as compared to contracted resources. As will be explained further below, if the Commission does adopt such quantitative assumptions, the robustness of those assumptions, and whether any potential benefit is actually realized by customers, will depend on whether or not the Commission also adopts corresponding mandatory non-negotiable pro-forma contract terms that allocate risks and benefits in all cases that are tied directly to specific factors associated with each assumption. Non-negotiable pro-forma contract terms would be necessary to ensure that customers receive the risk allocation benefit intended by the Commission in establishing such quantitative assumptions and to prevent a bidder from attempting to shift risk toward customers once they have been selected for the final short list and have made it to the negotiation stage of a resource solicitation.

Background

Q. Please explain Guideline 10(d) of the Commission's competitive bidding guidelines (Order No. 06-446).

A. Guideline 10(d) states "if the RFP allows affiliate bidding or includes ownership options, the IE will independently score the utility Benchmark (if any) and all or a sample of the bids to determine whether the selections for the initial and final shortlists are reasonable. In addition, the IE will evaluate the unique risks and advantages associated with the Benchmark (if used), including the regulatory treatment of costs or benefits related to actual construction cost and plant operation differing from what was projected in the RFP." This guideline requires the IE, whose role is to help ensure that all offers are treated fairly through an independent review; to evaluate a utility cost-based ownership option on a comparable basis with other offers received.

Q. Please briefly explain the Company's process used to evaluate resource options received in response to a RFP solicitation.

A. The Company first performs an initial screening which results in an initial shortlist. The initial screening consists of both price and non-price scores. Bidders on the initial shortlist are then asked to submit best and final offers. The Company then evaluates the best and final offers and incorporates the results from the best and final offer into the models from the Company's most recently acknowledged IRP to produce a final shortlist of resource options.

Q. If the Company submits a cost-based benchmark resource, is a detailed price and non-price score completed?

A. Yes. The benchmark resource is submitted to the IE prior to the bid due dates set forth in the RFP. The IE conducts a review and independently scores the benchmark in accordance with Guideline 10(d).

Q. Briefly, please describe the non-price scores used in initial screening.

A. While each RFP is unique, the non-price score usually consists of 30 points out of 100 possible points. The remaining 70 points are the price score. The non-price score will typically depend on the unique nature of the resource for which the Company is soliciting proposals. Typical criteria include factors such as site control, permitting, schedule, fuel supply, guarantees offered, development risk, safety and environmental compliance, operational experience, and pro forma contract compliance.

Q. Who is responsible for the development of the non-price scores?

A. The Company is responsible for the development of the non-price scores. However, the Company files the RFPs with the Commission and ultimately requests approval under the Commission's competitive bidding guidelines. Stakeholders and the IE have the opportunity to be involved in the overall development of the RFP by providing comments throughout the development of the RFP. The IE files a report with the Commission on the design of the RFP prior to the Commission approval of the RFP. In addition, the IE evaluates the non-price scores and files an initial shortlist report with the Commission that assesses whether or not the Company applied the non-price scores fairly and in a manner consistent with the approved RFP methodology.

Q. Given this background, what is your understanding of reason for the current investigation regarding Guideline 10(d).

A. In Order No. 11-011, the Commission expressed a desire to improve the IE's evaluation of the comparative risks and advantages of utility benchmark resources in accordance with Guideline 10(d). The Commission indicated that it wanted a more comprehensive accounting and comparison of all relevant risks, including consideration of construction risks, operation and performance risks, and environmental regulatory risks. The Commission requested comment on the analytic framework and methodologies that should be used to evaluate and compare utility owned resources to contracting for power with a third party. My testimony provides recommendations regarding this analytic framework as it relates to the four risk factors listed above.

Capacity Factors for Wind-Based Renewable Resources

Q. Please explain the Company's current methodology for evaluating expected capacity factors associated with wind resources, regardless of ownership.

A. As described above, the RFP process has two key stages: (1) initial screening, and (2) developing the final shortlist. During the screening stage of the RFP process, all alternatives are evaluated using the expected capacity factor provided by the bidder or associated with the utility's cost-based benchmark. For example, the expected capacity factor associated with a PPA bid or Asset Purchase and Sale Agreement (APSA) bid will be utilized for analytical purposes until the initial shortlist stage of the RFP. After the initial screening is complete and an initial shortlist is developed the Company retains a qualified and independent third-party technical expert (the Capacity Factor Expert) to assess the expected wind resource capacity factor associated with each alternative on the initial short list, including the cost-based utility ownership benchmark resource. Due to the technical expertise required, the Capacity Factor Expert would not typically be the IE for the overall RFP, however; the IE reviews and evaluates the reports prepared by the Capacity Factor Expert.

Q. How does the Company ensure the Capacity Factor Expert is objective in its evaluation?

A. If a cost-based utility benchmark resource is one of the resource alternatives, the Capacity Factor Expert is not allowed to be the same technical expert the Company relied on in preparing its benchmark submittal to the IE. Likewise, the Capacity Factor Expert is required to disclose if it has any conflicts associated with any of the bidders or project bids on the initial shortlist.

Q. What information does the Capacity Factor Expert provide to the Company for all wind resources?

A. The Capacity Factor Expert provides the Company a report consisting of a capacity factor estimate for each resource on the initial shortlist. The Company then uses the capacity factor estimates for its final analysis of the initial shortlisted alternatives to determine the final shortlist.

Q. Has the Company always used a Capacity Factor Expert to assess the capacity factors in request for proposals?

A. No. The Company first retained a Capacity Factor Expert for the purpose of evaluating third party resources and the cost-based utility option resource in its 2009R RFP. A Capacity Factor Expert was utilized to ensure the capacity factor in each alternative was evaluated fairly, regardless of ownership, during the shortlist stage of a solicitation. The Capacity Factor Expert was instituted with the 2009R RFP because that represented the first time the Company provided a cost-based utility owned wind resource alternative for consideration during a RFP process.

Q. What is the capacity factor metric the Company currently uses during the RFP process to acquire a weather-dependent variable energy resource like a wind resource?

A. The metric is based on the estimated long-term annual capacity factor validated by the Capacity Factor Expert on an annual 50 percent probability (P50) basis; meaning there is a reasonable expectation that there is a fifty percent probability that the actual calendar year production in megawatt-hours (MWh) will be higher or lower than the long term predicted MWh production during any given calendar year. The use of a P50 estimate is commonly applied in the wind industry. The P50 estimate represents the net capacity factor associated with the project and is used to calculate annual MWh production that is then used for analysis purposes.

Q. Does the Company recommend that future renewable RFPs use a Capacity Factor Expert once the initial shortlist has been prepared to ensure a fair and balanced outcome between a utility benchmark resource and other proposals?

A. Yes. The Company's experience has been that employing a Capacity Factor Expert is an objectively reasonable method to compare alternatives, regardless of ownership.

Q. If a third party owned wind resource does not perform as predicted, what is the effect upon customers?

A. The effect upon customers is that they may not get the benefit of the bargain. The Company has attempted to negotiate a capacity factor guarantee (i.e. a Wind Guarantee) instead of a mechanical availability guarantee from wind resource

PPA counterparties. However, citing risk associated with tax laws, wind resource PPA counterparties have been unwilling or unable to provide such a guarantee. In contracts negotiated to date, if the wind resource performs worse than expected during a time period, the Company is only expected to purchase the MWh produced, and it may need to purchase replacement power in the market. If the wind resource performs better than expected during a time period, the Company is required to purchase the excess output of the PPA wind facility at the contract price which may be higher or lower than the market price. In this way, both the utility and PPA counterparty are responsible for the risks associated with over or under performance during a time period and therefore both are appropriately incented to accurately forecast production. The effect upon customers is determined by then-applicable regulatory rulings or rate making processes.

Q. If a utility owned wind resource does not perform as predicted, what is the effect upon customers?

A. The effect is similar to that associated with a third party owned wind resource. If the wind resource performs worse than expected during a time period, the Company only receives the energy produced, and it may need to purchase replacement power on the market. If the wind resource performs better than expected during a time period, the Company receives more energy than expected and as well as any associated benefits (e.g., tax benefits). Therefore, the Company is incented to accurately forecast production. The effect upon customers is determined by then-applicable regulatory rulings or rate making processes.

Q What does the Company recommend to the Commission with respect to analyzing wind resource capacity factors during an RFP process?

A. The Company recommends a continuation of the process described above, including the employment of a Capacity Factor Expert to evaluate all resource alternatives on the initial shortlist, regardless of ownership. The Company makes this recommendation for a number of reasons: 1) it ensures that wind capacity forecasts for third party owned wind resources and cost-based utility benchmark resources are evaluated on an objective, consistent and comparable basis; 2) it allows flexibility to continue to account for evolutions of the science of forecasting the production of weather-dependent variable resources; and 3) it maintains appropriate incentives for the utility and the third party that owns a wind resource, to the extent feasible, to produce the most accurate wind capacity factor forecasts as possible when bidding into a RFP and during the operational stage.

Q. Is it possible to incorporate pre-determined assumptions that will be utilized in all future RFP analyses to quantify costs, risks and benefits of third party owned wind resources versus utility benchmark resources?

A. No. The associated costs and risks associated with a third party owned wind resource versus a utility benchmark resource cannot be predetermined quantitatively in the context of an RFP. The appropriate regulatory treatment of an RFP outcome and selected resources should be handled as part of ratemaking proceedings. It is not possible to accurately quantify the costs and risks at the RFP stage because the regulatory treatment of the cost-based utility benchmark is cost-based and subject to the regulatory compact whereas the costs and risks of a contract are subject to the contract terms and conditions. While the Company is supportive of improvements to the evaluation process to ensure that it is as fair as possible, as discussed above, it firmly opposes any RFP evaluation process that would involve the predetermined *quantification* of risks and benefits of any resource. The Company recommends however, including application of methodologies that ensure a fair and reasonable evaluation process between third party bidders and cost-based utility ownership. The appropriate forum for evaluating actual costs and the prudency of the Company's resource decisions is a ratemaking proceeding.

Heat Rate Degradation

Q. Please explain the importance of heat rate as part of the Company's current methodology to evaluate thermal resources.

A. The heat rate is the convention used to represent the overall thermal efficiency of a resource. Fuel costs, especially for a natural gas-fired resource, are one of the major components of the total cost of electricity; the fuel cost of the total energy cost is directly proportional to the heat rate. Therefore it is important to correctly identify the expected heat rate of a thermal resource.

Q. Please explain where the heat rate information comes from that the Company uses to evaluate thermal resources, regardless of ownership.

A. For the cost based utility benchmark resource, and the asset purchase and sale agreement (APSA), the Company utilizes the "new and clean" heat rate information as provided by the engineer-procure-construct (EPC) contractor or the APSA bidder. These values are based on the performance information provided by the Original Equipment Manufacturer (OEM) as adjusted for site-specific characteristics and the third party's design. The heat rates are converted to a long term annual schedule of performance through the application of the heat rate degradation curve, which is supplied by the OEM. To ensure a common approach is used, the same degradation values are applied for proposals that use the same OEM equipment. For third party tolling services agreement (TSA) proposals the Company utilizes the heat rate information that is submitted in the bidder's proposal.

Q. Is the OEM the best source for heat rate degradation data?

A. Yes. The OEM has the most information about the expected performance over time of its equipment. However, actual plant performance is dependent on the maintenance of the plant. The Company enters into long-term maintenance contracts (LTP) for the major OEM equipment to ensure the equipment is maintained and overhauled according to the OEM's recommendations. The heat rate degradation schedule is prepared based on the OEM's recommended maintenance schedule and used in the evaluation process. This may or may not be accurate for a third party bidder as it may in fact do this work itself and choose not to have an LTP contract compliant with the OEM's recommended overhaul schedules or maintenance practices. These maintenance overhauls contribute significantly to recovering the degradation losses that affect the performance of the equipment over the life of the asset. Unless contracts terms exist to protect customers, third parties consistent with OEM maintenance guidelines could pose increased risks to customers.

Q. Does the IE assess the reasonableness of heat rate and degradation values used to evaluate resource proposals as it pertains to a Company owned benchmark resource or the third party bidder?

A. Yes. In general the IE assesses the reasonableness of the heat rate and degradation values used to evaluate the resource proposals. However, it would also depend on how the third party bidder proposal is structured and if the third party bidder intends to operate and maintain in the plant equipment. Without this information, it is difficult to determine a third party bidder's maintenance assumptions and therefore whether or not they are reasonable.

Q. Are customers typically protected from impaired performance versus the guaranteed heat rate provided in EPC and Asset Purchase and Sale (APSA) contracts?

A. Yes. The Company negotiates liquidated damages for impaired performance (i.e. higher heat rates than guaranteed) under an EPC or an APSA in the event the resource does not meet its guaranteed heat rate value at the completion of the project's commissioning period. For example, in the Company's most recent EPC contract for the Lake Side 2 resource, the EPC contains provisions to recover liquidated damages in the event the heat rate is greater than the guaranteed contract heat rate value.

Q. Can heat rates of utility owned resources improve over time?

A. Yes. The OEMs periodically make available mechanical and controls upgrades that can result in improved heat rates if purchased and installed. The Company has implemented these types of upgrades on its natural gas-fired combustion turbine resources. These prudent and cost-effective opportunities to upgrade generation assets are taken by the Company to benefit customers. These benefits are not factored into the economical analysis of either the Company utility benchmark or third party EPC or APSA proposals.

Q. Should one expect reported heat rates to be higher than full-load heat rates, even after a degradation factor is applied?

A. Yes. Typically. thermal generation resources are most efficient when they operate at full-load. However, reported heat rates are often higher than full-load heat rates. There are a number of factors that contribute to reported heat rate values being higher than the full load heat rates, including operation at reduced load, variations in ambient conditions and the effects of startups and shut downs. Many natural gas-fired facilities regularly operate at reduced load, which is less efficient, in order to hold reserves for system reliability and to integrate intermittent generation resources. In addition, fuel consumed during startups and shutdowns also contributes to reported heat rates being higher than the full load heat rates.

Q. What is the effect on customers if reported heat rates are higher than full load heat rates?

A. Customers are not affected. To illustrate, suppose the Company were considering purchasing a thermal unit versus entering into a tolling services agreement (TSA), which is a form of PPA, with a "guaranteed" heat rate, and the thermal unit's modeled full-load heat rate is equal to the TSA guaranteed heat rate. Inasmuch as the thermal unit would also be used to provide reserves, integrate wind, or track load, its realized heat rate will be higher than that of the TSA contract. However if the TSA is selected, the other requirements (reserve holding, etc.) do not disappear. The Company may need to operate other units less efficiently to meet these requirements, causing a similar economic impact to customers. However, ultimately the effect upon customers is determined by then-applicable regulatory rulings or rate-making processes.

Q. Does a "guaranteed" heat rate fully protect customers against performance fluctuations with respect to energy delivered under a TSA?

A. No. A guaranteed heat rate is a contractual concept in which regardless of the actual operational efficiency of the resource used to supply energy under the TSA, the price paid for that energy would be calculated based upon a the contract heat rate. Therefore the seller of the TSA is encouraged to ensure plant performance and is harmed in the case of poor plant performance. If performance is poor enough, the seller of the TSA may choose or be forced to default under the TSA, leaving the Company to either step into the poor performing project, or otherwise replace the power with market purchases (if available). For this reason, the value of a guaranteed heat rate is limited by the creditworthiness of the TSA contracting party and its guarantor. Often, these guarantees are capped which would minimize the overall harm to customers in the case of nonperformance.

Q. Is there an impact of a "guaranteed" heat rate to the seller of the TSA?

A. Yes. The Company would expect any seller of a TSA with a guaranteed heat rate to embed a risk premium into the price of the TSA in the form of a heat rate margin to address degradation. Therefore any benefit of a "guaranteed" heat rate the customer realizes is also paid for by customers.

Q. Does the Company currently address the fact that reserve requirements will need to be met regardless of the asset or product type chosen as a result of a resource solicitation?

A. Yes. In the initial screening process the costs and benefits of reserves are not captured. In the final shortlist, the IRP models capture the costs and benefits of reserves in the Company's planning and risk models when evaluating the performance characteristics of a utility asset versus the characteristics and performance of third party asset under a TSA. The Company assets are modeled with the heat rate degradation curves and part load performance curves. The costs associated with heat rate degradation are attributed to the Company assets as well as any benefits associated with holding operating reserves. The benefits, if any, of a TSA guaranteed heat rate are attributed to a TSA proposal, however, no additional benefits associated with a contribution to the operating reserve requirements of the system is attributed to a TSA proposal.

Q. What are the Company's recommendation for an analytical framework that may be applied by the IE to compare risks associated with heat rate degradation of utility benchmark resources and third party proposals?

A. As discussed above, a number of factors contribute to the appropriate allocation of risks and benefits associated with heat rate degradation. The Company proposes that the best method of ensuring parity among proposals is to apply the same or a similar methodology for estimating heat rate degradation in order to ensure that both the utility benchmark resource and the third party proposals are using reasonable assumptions. The current process of using OEM and proposal data could be established at the outset of the RFP as the method to be reviewed by the IE during the evaluation process.

Q. Is it possible to incorporate pre-determined assumptions that would be utilized in all future RFP analyses to quantify costs, risks and benefits of third party owned resources versus utility benchmark resources?

A. No. The costs and risks associated with a third party owned resource versus a utility benchmark resource cannot be predetermined quantitatively in the context of an RFP. The appropriate regulatory treatment of an RFP outcome and selected resources should be handled as part of ratemaking proceedings. It is not possible to accurately quantify the differing costs and risks at the RFP stage because the regulatory treatment of the utility benchmark resource is cost-based while the cost of a performance-based contract is the contract price. While the Company is supportive of improvements to the evaluation process to ensure that it is as fair as possible, as discussed above, it firmly opposes any RFP evaluation process that would involve the up-front *quantification* of risks and benefits of any resource. The appropriate forum for evaluating actual costs and the prudency of the Company's resource decisions is a ratemaking proceeding.

Construction Cost Over- and Under-Runs

Q. Please explain how the Company currently addresses cost over and under-runs as part of its resource solicitation process.

A. For third party proposals, the Company requests fixed-price bids. For a utility cost-based benchmark resource, the Company's current practice is to obtain fixed price proposals from EPC contractors, with fixed performance, scope and schedule. Cost contingency is included in the utility cost-based benchmark resource to account for potential EPC change orders, change in law provisions, required scope modifications and other unforeseen project costs. Contingency is included in the evaluation process, as more fully described below.

Q. How do utility benchmark resources differ from third party proposals with respect to construction costs?

A. By and large, the Company procures the design and construction of a new resource the same way a third party does, namely through qualified equipment suppliers and contractors.

Q. Has the Company always receive fixed price bids?

A. No. During the 2007-2008 time period, market conditions were such that materials, resources and equipment escalated at very high rates and many suppliers were only willing or able to provide firm prices with very limited validity periods. At the time, both the third party proposals and the utility benchmark resource required pricing from contractors for new resources whether in the form of a PPA, TSA, APSA or an EPC for the utility benchmark resource. Market participants at the time would not provide firm pricing that they were willing to hold for several months during a period of high cost uncertainty for materials, resources and equipment. Their proposals were not based on underlying firm fixed prices and therefore bidders indicated to the Company that the cost to receive a fixed price bid would require large premiums to account for a price risk to hold a bid firm for several months. To address this issue, some bidders provided proposals that had a portion of their bids indexed and a portion fixed. Although the RFP process allowed for a portion of the bids to be indexed to such indices as the PPI labor index, PPI metals index, CPI inflation index, etc., EPC contractors indicated that these indices did not adequately correlate to their actual cost risk. Since that period, because there is now less price volatility and uncertainty under current market conditions with respect to materials, resources, and equipment, firm fixed prices can currently be secured from market participants who are typically willing to hold pricing for several months without extraordinary price premiums.

Q. Is there flexibility within an RFP process to allow for non-fixed price proposals?

A. Yes. Although in the Company's EPC contracting experience this is not a desirable method, due to the increased risk to customers, the Company has provided this option in past RFPs for bidders to provide a portion of their proposed EPC prices to float and be re-priced at the earlier of the execution of the EPC contract but no later than two years from the execution of the contract with the Company. In prior RFPs, when the EPC market was significantly more volatile than it is today, the RFP process allowed bidders to fix the floating price portion of the EPC contract at a later date; that was the later of the execution of the EPC contract for new construction (APSA, PPA or TSA) but no later than two years from the execution of the APSA, PPA or TSA contract.

Q. Did the Company account for indexed cost risk being passed on to the Customer?

A. Yes. For a bid with any portion that is not provided as a fixed price, the Company applied an incremental risk adder that was calculated for each bid and the Company benchmark.

Q. How does the Company minimize cost uncertainty in its bid solicitation process?

A. In general terms, the Company requires bidders to provide fixed pricing for fixed scope, performance and schedule with liquidated damages for non-performance. Risk adjustments, if any, are imputed to the bidders or utility benchmark resource based on the risk associated with the unfixed capital portion in the proposals or the utility benchmark resource. These values are reviewed by the IE.

Q. How does the Company minimize cost uncertainty with respect to a utility benchmark or third party proposal?

A. The Company requires that bidders submitting third party proposals and utility cost-based benchmark EPC contracts provide fixed pricing for fixed scope, performance and schedule with liquidated damages for non-performance. For third party proposals or the utility cost-based benchmark resource, contingency reserves are applied to the proposal price consistent with industry practices.

Risk adjustments, if any, are imputed and reviewed associated with any unfixed portion of the utility benchmark resource or third party proposals. These values are reviewed by the IE.

Q. How does the Company ensure that customers are protected from imprudent cost overruns from change orders that may occur with EPC contracts associated with a utility benchmark resource?

A. Contingency reserves are applied to EPC as described above. EPC contractual terms are applied to minimize scope or project related events that could result in cost change orders. Additional costs or benefits not initially contemplated are subject to a prudence review before the Company may include those costs in customer's rates. It is proper that unforeseen but prudently incurred costs are recoverable, as they are incurred for the benefit of customers. However costs determined to be imprudently incurred should not be and are not recoverable. In this way, the current regulatory framework encourages utilities to be prudent with respect to the minimization of cost overruns and also to protect its customers from such cost overruns that are not in the Company's ability to control.

Q. Is there a potential for customers to benefit from cost under-runs that may occur with regard to EPC and APSA construction?

A. Yes. As reviewed by the IE, the Company also budgets reasonable contingency reserves in the total cost that is submitted to the Commission. Only the actual costs, plus any contingency reserves, are ultimately sought to be recovered from customers.

Q. Who is responsible for the risks associated with cost overruns associated with a third party developed resource?

A. In general, the Company seeks to protect its customers from cost overruns associated with a third party developer by ensuring that the third party developer is responsible for any cost overruns. If the Company is not successful in ensuring this during contract negotiations, customers may remain at risk for any cost overruns if the third party is unwilling to cap its costs or not pass through change orders. However, because the utility does not have control over the timing and schedule of the third party developed project, it does not have the same ability to ensure that controls are in place to address those issues that can result in cost overruns. Thus, unless the third party agrees to be responsible for all cost overruns, both the Company and its customers may be put at an unreasonable disadvantage because the Company is responsible for the cost overruns and yet has no control over those costs because they are not developing, engineering or constructing the resources. Furthermore, even if the third party agrees to bear the risk associated with cost overruns, it may not perform and customers may still be at risk if the third party defaults under the contract.

Q. Is it likely that customers will benefit from cost under-runs under PPA and TSA structures?

A. No. In the event there is a construction cost under-run for a third party PPA or TSA, any cost reductions would accrue to the owner of the project, not to customers.

Q. What are the Company's recommendation for an analytical framework that may be applied by the IE to compare risks associated with cost over- and under-runs for utility benchmark resources and third party developers?

A. The Company recommends that the risk adjusted methodology, described above, be applied (and reviewed by the IE) to compare the respective risks. This ensures that the utility benchmark resource is risk adjusted based on the unfixed capital costs from a cost over-run and a cost under-run and third party proposals are evaluated on a cost overrun basis only, because if the costs are below the contract prices the savings are not realized by the Company. This is appropriate because third party resource cost under-runs are not returned to customers. It is very difficult to compare the risks and benefits associated with cost over and under-runs between utility benchmark resources and third party bidders. This is because the cost recovery mechanism for each is fundamentally different – in the case of the utility benchmark, cost equals cost, in the case of the third party bidder, the cost equals a contract amount. Contracts are subject to contract law and third party resource developers are not subject to regulatory oversight in the same way as a public utility with an obligation to serve. This can only be changed with a change to the regulatory process – this fundamental difference cannot and should not be overlooked when looking for improvements to the bid evaluation process.

Q. Is it possible to incorporate pre-determined assumptions that will be utilized in all future RFP analyses to quantify costs, risks and benefits associated with cost over- and under-runs for third party bidders and utility benchmark resources?

A. No. The costs and risks associated with a third party bidder versus a cost-based utility benchmark resource cannot be predetermined quantitatively in the context of an RFP. The appropriate regulatory treatment of an RFP outcome and selected resources should be handled as part of rate-case proceedings. It is not possible to definitively quantify the costs and risks at the RFP stage because the regulatory treatment of the utility benchmark resource is cost-based while the cost of a performance-based contract is the contract price. While the Company is supportive of improvements to the evaluation process to ensure that it is as fair as possible, as discussed above, it firmly opposes any RFP evaluation process that would involve the up-front *quantification* of risks and benefits of any resource. The appropriate forum for evaluating actual costs and the prudency of the Company's resource decisions is a ratemaking proceeding.

Counterparty Risk

Q. Does the Company consider counterparty credit risk to be a significant item to be addressed in its competitive RFP process?

A. Yes. The Company's obligation is to procure the least-cost resource, as adjusted for risk. Counterparty credit risk is a risk to customers that must be taken into account as part of the resource selection process. The creditworthiness of the counterparty, as well as the entity providing adequate credit assurances on the counterparty's behalf, if applicable, are important because the selected counterparty's ability to perform its obligations under the contract can impact the overall cost for the customer. The Company's IRP models do not capture the risk associated with the counterparty credit requirements or default risk. The Company performs a credit evaluation on the counterparty (and the entity providing credit assurances on its behalf, as applicable) based on the counterparty's audited financial statements (as well as those of the entity providing credit assurances on the counterparty's behalf, as applicable), and assigns an internal credit rating to the counterparty (and the entity providing credit assurances on its behalf, as applicable), utilizing a proprietary credit scoring model developed in conjunction with a third party, if no external credit ratings exist.

Q. Does the Company require credit assurances of all bidders when the bidders submit their initial proposals?

A. No. Bidders have argued that providing credit assurances at the time of bid submission is costly and overly burdensome. The Company understands that these costs may burden bidders in the early stages of the process, however the Company does need to protect customers to ensure a resource is selected from a creditworthy counterparty and requires the commitment to provide credit assurances (if applicable) from those bidders selected for the final shortlist.

Q. Is credit evaluated in the initial shortlist process?

A. No. The RFP process from design to selection of a resource can take approximately eighteen months to complete. From the time the bidder submits a proposal until the time a bid is selected is approximately twelve months. Credit requirements are included in the RFP solicitation, and the evaluation of the credit quality of the bidder is completed at the time a bidder is selected for the final shortlist. During the period of time from the initial bid submission to the final short listing, a bidder's creditworthiness could deteriorate, which is not presently captured in the RFP evaluation process. A reasonable approach would be to use credit as a non-price score prior to the final shortlist determination. One method to establish a non-price score would be to determine, utilizing the bidder's credit rating (either a published rating or an internal credit rating if the bidder is not externally rated), the probability of a default between the time of the final shortlist and the on line date of the proposed resource. Moody's Investor Services, a public ratings agency, assigns default probabilities based on its ratings and the time horizon considered. These default probabilities could be utilized to make this determination for those counterparties that are rated by Moody's. As an example, the default probabilities from Moody's (as of 2011, which is the most recent data available) are attached as Confidential Exhibit PAC/101. Another method that could be employed to establish a non-price score would be to determine, utilizing the bidder's credit rating (either a published rating or an internal credit rating if the bidder is not externally rated), the inferred probability of default from corporate bond yield spreads over United States Treasury yields.

Q. Are all bidders currently rated by either Moody's or Standard and Poor's when they submit proposals?

A. No. The Company has historically seen a wide range in the creditworthiness of bidders. At one end of the spectrum are large, established, highly creditworthy EPC entities with published ratings from the rating agencies. At the other end are small, limited liability companies that do not have published ratings from the rating agencies and are not creditworthy, and who may eventually use the Company's credit as a means to finance the PPA or TSA that the Company enters into.

Q. Can the Company determine the probability of default in assessing a counterparty risk?

A. Yes. For example, using the information from Moody's in the Confidential Exhibit PAC/101 referenced previously, the Company could assign a probability of default based on the counterparty's credit rating and the period of time from the execution of the TSA or PPA to the commercial operation date (tenor). This would indicate the likelihood of defaulting during that period of time.

Q. How would default probabilities be used to differentiate bids?

A. As indicated previously, the Company performs a credit evaluation on the bidder/counterparty (and the entity providing credit assurances on its behalf, as applicable), and will assign an internal credit rating (for the counterparty and the entity providing credit assurances on its behalf, as applicable), utilizing external credit ratings or a proprietary credit scoring model developed in conjunction with a third party, if no external credit ratings exist. By definition, a credit rating implies a probability of default: the higher the credit rating, the lower the probability of default; the lower the credit rating, the higher the probability of default. The Company may also require the bidder provide credit assurances to support its performance under the contract, depending upon its credit rating and the project's time horizon. For those counterparties that are rated by Moody's, utilizing the credit rating (with its corresponding probability of default), for each bid, the Company could multiply the probability of default for the relevant tenor (e.g., four years), by the incremental cost to the customer (above the amount of any credit assurances posted), should default occur. If default is driven by cost overruns in a given RFP project, then those costs could be paid by the Company (if project completion remained prudent, and after utilizing any posted credit assurances from the counterparty) and ultimately be borne by the customer. This expected cost of default could then be added to each bid's cost.

Q. Does the Company require credit assurances from bidders on the final shortlist?

A. No. The Company requires the commitment to provide credit assurances (if applicable) from those bidders selected for the final shortlist. Specifically, all bidders are required to provide acceptable commitment letters to provide credit assurances (if applicable), within twenty business days of being notified that they have been selected for the final shortlist.

Q. Does the Company require credit assurances in the PPA and TSA in addition to a letter of credit, and/or a parental guarantee?

A. Yes. The Company may require additional terms and conditions in the contract that pertain to other forms of credit protection. However, in order to ensure these terms are included in the final contract, the Company would request that these terms be approved as part of the approval of the RFP and considered non-negotiable, so that when bidders submit their proposals they would not be allowed to change these terms.

Q. Does counterparty credit risk change over time?

A. Yes. As discussed above, the average timeframe for the RFP process is eighteen months, during which time a counterparty's financial standings may improve or worsen. Additionally, when a third party enters into a PPA or TSA with the Company, the third party will often establish a special purpose entity which relies on the PPA or the TSA and the Company's credit to finance the project. Furthermore, some sellers engage in "portfolio financing," in which a number of projects support a single bank loan. If the PPA or TSA does not specify a maximum debt-to-equity ratio in the contract, the seller could highly leverage the project, using the project as collateral to finance other projects, either initially or subsequently. Over time the seller may not be able to continue to profitably operate the other projects, and customers may be deprived of a well-functioning resource in order to satisfy deficiencies in a project seller's affiliated projects that do not serve the Company or its customers. The seller could also deplete the equity in the project serving the Company in order to collateralize other projects. If the seller defaults, the Company may be required to step into the contract and the seller's debt, which may be potentially entangled with the cross-collateralized projects. If the Company does not have alternative capacity choices at the point in time necessary to step into the project, the cost to the Company could be more than what the Company would pay under the PPA or TSA. This risk could be addressed with a non-negotiable contract term that requires the seller to maintain a specific debt-to-equity ratio in the project, so that in the event the Company is required to step into the contract, it steps into the asset with a certain level of equity. This could also be addressed with a non-negotiable term in the PPA to prohibit cross-collateralization. This would provide the Company with a subordinated security interest in the project.

Q. What is the Company's recommendation for an analytical framework that may be applied by the IE to compare risks associated with counterparty risk for utility benchmark resources and third party bidders?

The Company proposes the following evaluation framework. First, the Company would request that the Commission approve a template APSA, PPA, and TSA with non-negotiable credit terms as part of the RFP approval process. Second, in the initial evaluation, the non-price score would include scoring criteria for credit and the determination of the probability of default.

Q. Is it possible to incorporate an analysis into the RFP that will quantify costs, risks and benefits associated with counterparty risk?

A. No. The associated costs and risks associated with a third party bidder cannot be quantified in the context of an RFP. While the Company is supportive of improvements to the evaluation process to ensure that it is as fair as possible, as discussed above, it firmly opposes any RFP evaluation process that would involve the up-front *quantification* of risks and benefits of any resource. The Company would however, recommend that the third party bidder's credit evaluation be conducted at the initial shortlist phase from a non-price scoring perspective and, a credit rating be determined, along with its inherent probability of a default both at the time of the initial shortlist and as well as at the time the Company determines the final shortlist. This should be done and validated by the IE in order to ensure the credit rating and probability of the risk of default is continuously taken into account while evaluating the resources.

Further Recommendations

Q. Other than the foregoing, does the Company have any other proposals or recommendations regarding improvements to the resource evaluation process?

A. Yes. As noted in a number of places throughout my testimony, there are a number of instances whereby the institution of non-negotiable contract terms may serve to level the playing field between third party bidders and the cost based utility benchmark resources. In doing so, the Commission would essentially be incorporating some regulatory certainty into what is currently a completely negotiated process. Any risks and benefits associated with a third party resource versus a utility benchmark resource are dependent on the terms of the four corners of the contract governing the relationship between the utility and the third party. If the Commission assumes there is a benefit to customers associated with a third party project, that benefit will only be realized if the utility is able to negotiate that benefit in the contract. While it is true that third parties are asked to carry the risk of cost overruns, they typically do not do so willingly or voluntarily – to the extent they are able to negotiate away some of that risk, they are incented to do so. If the Commission adopts non-negotiable contract terms, it will eliminate the current uncertainty regarding the ability of a utility to negotiate benefits to customers in a contract with a third party.

Q. Does this conclude your testimony?

A. Yes.

CONFIDENTIAL
Docket No. UM-1182
Exhibit PAC/101
Witness: Stacey J. Kusters

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of Stacey J. Kusters

November 2012

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