Q. Please state your name, business address and present position.

A. My name is Stefan A. Bird. My business address is 825 NE Multnomah, Suite 600, Portland, Oregon, 97232. I am Senior Vice President, Commercial and Trading, PacifiCorp Energy.

Qualifications

Q. Please describe your business and educational background.

A. I hold a B.S. in mechanical engineering from Kansas State University. I joined PacifiCorp Energy and assumed my current position in January 2007. From 2003 to 2006, I served as president of CalEnergy Generation U.S., an owner and operator of Qualifying Facility and merchant generation assets, including geothermal and natural gas-fired cogeneration projects across the United States. From 1999 to 2003, I was vice president of acquisitions and development for MidAmerican Energy Holdings Company ("MEHC"). From 1989 to 1997, I held various positions at Koch Industries, Inc., including energy marketing, financial services, corporate acquisitions, project engineering and maintenance planning in the United States, Latin America and Europe.

In my current position I oversee the Company's Commercial and Trading organization which is responsible for dispatch of the Company's owned and contracted generation resources, procurement of natural gas and electricity wholesale purchases and sales to balance the Company's load and resources. I am responsible for acquisition of power resources for utilization in the Company's east and west balancing authorities (the "System") by means that include the negotiation of power purchase agreements ("PPAs") and the acquisition of generation resources through the requests for proposals ("RFP") process. My organization is also responsible for the Company's load and revenue forecast, integrated resource plan ("IRP") and net power costs ("NPC") modeling.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to demonstrate the prudence of, and provide information regarding, the Dunlap I wind-powered generation resource, associated 230 kilovolt (kV) transmission and all of the necessary facilities to interconnect the resource to the transmission network and operate the Dunlap I resource (collectively, the "Wind Project"). Specifically, my testimony provides a description of the Wind Project and describes the economic analysis and selection of the Wind Project as a supply side resource for which the Company is seeking cost recovery in this proceeding.

Q. Would you please summarize your testimony in this proceeding?

A. The Wind Project has not been acquired to satisfy any state's renewable portfolio standard but is, instead, a prudent system resource that contributes to PacifiCorp's diverse and cost-effective portfolio of resources. It was acquired through a fair, transparent and robust competitive bidding process, namely the 2009R RFP, which was overseen by an independent evaluator ("IE"). Specifically, my testimony covers the following:

- A general description and overview of the Wind Project;
- A general overview of the 2009R RFP;
- A description of the economic analysis and selection of the Initial Short

List and Final Short List in the 2009R RFP;

- A detailed description of the site and all the facilities that are essential components of the Wind Project.

Overview of the Wind Project

Q. Please describe the Wind Project.

A. The Wind Project is a 111 megawatt (MW) wind project consisting of:

- seventy four wind turbine generators (WTGs),
- a 34.5 kV electrical collector system,
- a 34.5 kV to 230 kV collector substation (known as the Dunlap Substation),
- a 230 kV transmission line (approximately 11.6-miles in length) from the Dunlap Substation to a transmission interconnection substation,
- a 230 kV transmission interconnection substation (known as the Shirley Basin Substation),
- 230 kV breakers,
- 230 kV take off structures,
- metering,
- line switches,
- facilities necessary to route the Company's 230 kV Miners-Difficulty 230 kV transmission line into and out of the Shirley Basin Substation, and
- access roads, an operations & maintenance (O&M) building and required communication and control facilities (e.g., hardware, software, and associated communication circuits and other equipment).

Q. What costs related to the Wind Project are included in the revenue requirement in this case?

A. The case includes a capital investment of $264.5 million total Company for the Wind Project ($108.8 million on a Utah basis). Of this amount, $253.7 million total Company ($104.4 million on a Utah basis) is associated with generation plant. The remaining investment of $10.8 million total Company ($4.4 million on a Utah basis) is related to transmission plant required to interconnect the generation plant to the Company's network transmission system at the Shirley Basin Substation. The case also includes O&M costs associated with the Wind Project of $2.4 million (total Company) for WTG maintenance, permitting obligations, local levy tax and ongoing land use payments. The investment and operating costs are offset by $1.3 million (total Company) in renewable energy credit (REC) revenues forecast through 2011 and by $8.0 million (total Company) NPC savings due to the Wind Project. Dr. Hui Shu's testimony addresses the NPC savings and Mr. Brian S. Dickman's testimony reflects the impacts of all of these components on the Company's Utah revenue requirement and resulting rate relief necessary to recover the cost of the Wind Project.

Q. Please describe the difference between the generation plant costs and the transmission plant costs.

A. Generation plant costs include those costs associated with the wind-powered generation resource and the facilities necessary to deliver the output from the resource to the point of interconnection ("POI") with the Company's transmission system. Generation plant costs generally include the O&M building, the WTGs, the 34.5 kV collector system, the Dunlap Substation, the 230 kV transmission line from the Dunlap Substation to the Shirley Basin Substation and any costs determined by a Federal Energy Regulatory Commission ("FERC") compliant Large Generator Interconnection Agreement ("LGIA") study process to be directly associated with interconnecting the generation resource to the Company's transmission network at the POI. Transmission plant costs generally include costs associated with the Shirley Basin Substation and constitute the "Interconnection Facilities". Transmission plant costs are considered network upgrades and are utilized by other PacifiCorp wholesale customers.

Q. Who will operate the generation plant facilities and who will operate the transmission plant facilities?

A. The Company's transmission function will have operational responsibility for the transmission plant facilities (e.g., Shirley Basin), and the Company's generation group (aka PacifiCorp Energy) will have operational responsibility for the generation plant (e.g., the WTGs, the collector system, the Dunlap Substation and the 11.6 mile 230 kV transmission line from the Dunlap Substation to the Shirley Basin Substation). The point of demarcation between the transmission plant facilities and the generation plant facilities is outside the Shirley Basin Substation fence. This point of demarcation is typically described in FERC-compliant LGIA studies as the "point of change in ownership" between the interconnection customer and the transmission provider.

Q. What is the cost in this case associated with interconnection facilities classified as network facilities?

A. $10.8 million total Company ($4.4 million on a Utah basis) is related to Interconnection Facilities classified as network facilities pursuant to the FERC-compliant LGIA process. The Shirley Basin Substation comprises the majority of these costs.

Q. Please provide additional details on the REC related revenues included in Mr. Dickman's revenue requirement calculation.

A. The REC sale price is estimated based on the Company's current understanding of REC market liquidity and information obtained from broker quotes when available. See Exhibit RMP___(SAB-1). The estimated volume of RECs available for sale from the Wind Project in this case is approximately 188,703 MWh per year resulting in estimated revenues of $1.3 million per year (total Company).

Q. What is the projected commercial operation date for the Wind Project?

A. September 30, 2010.

Q. Is this project consistent with the Company's IRP?

A. Yes. Although the economic recession has slowed load growth in the Company's service areas, the 2008 IRP, as amended by the 2008 IRP Update, continues to indicate a need for additional supply to serve growing load, replace expiring contracts, and the on-going obligation to serve customers energy needs. Under current market conditions, the Company's cost-effective long-term supply options are primarily limited to natural gas fueled generation and wind-powered generation resources. The Company's addition of the Wind Project to its portfolio is consistent with the 2008 IRP action plan, as amended by the 2008 IRP Update.

Q. Did the Company obtain a Certificate of Public Convenience and Necessity for the Wind Project?

A. Yes. The Wyoming Public Service Commission issued an order approving the Company's request for a Certificate of Public Convenience and Necessity ("CPCN") for the Wind Project in Docket No. 20000-348-EA-09 (Record No. 12223), Order Granting a CPCN, issued December 21, 2009, attached hereto as Exhibit RMP___(SAB-2).

2009R RFP

Q. How did the Company acquire the Wind Project?

A. The Wind Project was selected through a competitive bidding process in the 2009R RFP.

Q. Please describe the 2009R RFP.

A. The 2009R RFP targeted acquisition of up to 500 MW of system-wide renewable resources with commercial operation dates between 2010 and 2012 and where no single resource exceeding 300 MW would be acquired.[1] Eligible resources were also required to: (1) meet an expected annual output of at least 25,000 megawatt hours ("MWh") after accounting for planned and unplanned outages; (2) include associated RECs; and (3) comply with renewable portfolio standard ("RPS") requirements in the Company's six-state service area. The 2009R RFP also

[1] 300 MW is the upper limited permitted by Utah Code Ann. § 54-17-502. Qualifying facilities that are at least 10 MW are eligible, pursuant to Guideline 6 in Order No. 05-446.

allowed for the submission of a Company cost-based benchmark alternative (the "Benchmark").

Q. Was an Independent Evaluator hired to oversee the 2009R RFP?

A. Yes. On May 22, 2009, the Oregon Public Utility Commission selected, and the Company contracted with, Boston Pacific to be the IE.

Q. Did the Utah Commission retain a consultant in the 2009R RFP?

A. No. The Utah Commission had retained a Utah consultant (the "Utah Consultant") for the 2008R-1 RFP. The 2008R-1 and the 2009R RFPs both took place in calendar 2009. As such, the Utah Consultant reviewed, commented and oversaw the 2008R-1 RFP.

Q. Was the 2009R RFP approved by a commission?

A. Yes. The Oregon Public Utility Commission approved the 2009R RFP at its Public Meeting on July 7, 2009.

Q. Who was the Utah Consultant?

A. Merrimack Energy reviewed and provided comments to the format and structure of the 2008R-1 RFP. See Confidential Exhibit RMP___(SAB-3) for a copy of the Utah Consultant's comments in the 2008R-1 RFP Final Report.

Q. Did the Utah Consultant provide any comments on the transmission assumptions and if so what?

A. Yes, the Utah Consultant acknowledged the Company held two workshops focused on transmission related costs, requirements and assumptions in both the 2008R-1 RFP and the 2008 All Source RFP. The workshops explained the costs and assumptions of those costs in each of the referenced RFPs.

Q. What was the Utah Consultant's conclusion regarding the 2008R-1 RFP?

A. The Utah Consultant concluded:

> *"The solicitation process was undertaken in a fair, consistent and equitable manner by the Company with the oversight of the Oregon IE and the Utah Consultant at all stages of the process. While we did have some concerns about potential biases in the evaluation of PPA vs. BOT options, the Company was responsive to our requests to conduct analysis to assess the potential bias, which led to a fair selection process.*" [2]

Q. Did the Utah Consultant provide any comments regarding the models, assumptions and or methodologies used in the evaluation in the 2008R-1 RFP?

A. Yes, the Utah Consultant commented that:

> *"the models and methodologies used are very detailed and comprehensive, accurately accounting for all costs associated with the evaluation. The modeling methodologies are state of the art and are among the most comprehensive and effective methodologies utilized in all the solicitation process in which we have participated. PacifiCorp provided the quantitative and qualitative evaluation results, all model outputs, and the qualitative evaluation to the IE and Utah Consultant in a timely manner, which allowed for a through review and assessment by the IE and Consultant*".[3]

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[2] Final Report of the Utah Consultant (RFP 2008R-1), December, 2009, p. 36.
[3] Id., at p. 38 – 39.

Q. Were the same models and methodologies used in the 2008R-1 RFP also used in the 2009R RFP?

A. Yes.

Q. Please describe the timeline associated with the 2009R RFP process.

A. The 2009R RFP was issued to the market July 8, 2009, with the Company's Benchmark submittal due no later than September 3, 2009. Proposals from the market were due September 10, 2009. Following review by the IE, the Benchmark was formally submitted to the IE on September 3, 2009. The price and non-price analysis of the Benchmark was completed by the Company and reviewed by the IE prior to the Company opening proposals from the market on September 10, 2009. The IE provided a memo on the Benchmark to the Company on September 11, 2009 (the "Benchmark Memo"), attached hereto as Confidential Exhibit RMP___(SAB-4).

Q. Describe the market response to the 2009R RFP.

A. The Company received 82 bids from 26 bidders on September 10, 2009.

Q. Please explain how the IE conducted its analysis and established the conclusions set forth in the Benchmark Memo.

A. The IE undertook a detailed examination of the Benchmark by reviewing the submittal and detailed cost backup sheets and through conversations with the Company's resource development personnel. The IE's stated primary concern was the potential omission of capital costs. Accordingly, the IE focused on ensuring that appropriate capital costs were included in the Benchmark. As an additional check, the IE compared the Benchmark capital costs and estimated capacity factor to proposals from the 2008R-1 RFP[4] the IE considered comparable.

Q. What did the Benchmark Memo conclude with respect to the estimated capital costs for the Benchmark?

A. The Benchmark Memo concluded that all capital costs were properly included and that the level of the Benchmark's estimated capital costs were appropriate. The IE also found that the Benchmark capital costs were within the range of comparable costs as indicated by proposals in the 2008R-1 RFP. Finally, the IE found that the estimated Benchmark capacity factor was within the range of capacity factors from proposals associated with potential resources in the nearby vicinity.[5]

Q. Why did the Company submit a Benchmark and what role did it play in the RFP process?

A. The Benchmark played an important role in the 2009R RFP process by providing a cost-based alternative for the benefit of customers. The Company received proposals in the 2009R RFP under a multitude of structures with varying terms and conditions. The proposals received were compared to the Benchmark and consisted of PPAs and the BOT of an asset. Including a Benchmark provides a benefit for customers because it serves as a check on market-based proposals, provides a resource alternative the Company is prepared to undertake, and it shields customers from 100 percent market exposure.

[4] The 2008R-1 RFP was issued to request and evaluate proposals to fulfill a portion of the renewable resource generation identified in the Company's 2007 Integrated Resource Plan.

[5] *See* Benchmark Memo at p. 11-12.

Economic Analysis and Resource Selection

Q. Please describe the 2009R RFP initial shortlist selection process.

A. The Company's analysis of the 2009R RFP proposals focused on determining which resources would provide the best value to customers on a system-wide planning basis to meet customer requirements at the least cost and on a risk adjusted basis. To achieve these objectives, the Company evaluated alternatives in a two step process. First, the Company selected three initial shortlists: (a) west wind; (b) east wind; and (c) all other renewable resources. The purpose of first selecting three separate Initial Shortlists was to capture location resource diversity and the different sources of renewable resources.

The IE agreed with the Company's goal to select groups of proposals to comprise each of the three initial shortlists. The criteria used by the Company in selecting shortlisted proposals were to:

(1) select proposals with the greatest net benefit in terms of price and non-price benefits;

(2) select a diversity of proposals and projects;

(3) select a mix of PPAs and BOTs;

(4) determine a relatively clear split between the score of the last proposal included and the next proposal that was not selected; and

(5) achieve the RFP goal that each category contain up to 500 MW or five proposals.

See The Oregon Independent Evaluator's Final Closing Report on

PacifiCorp's 2009R Renewables RFP (November 5, 2009) ("Final Report") at p.12, attached hereto as Confidential Exhibit RMP___(SAB-5).

Each proposal received up to a maximum of 100 points. The three initial shortlists were comprised of the highest scoring proposals in each of the three respective segments, based on price (up to 70 points) and non-price factors (up to 30 points). The price factor was derived by using the Company's proprietary RFP base model. The RFP base model determines the top performing proposals on the basis of the net present value revenue requirement ("Net PVRR")/kW-mo. The Net PVRR component views the value of the energy and capacity as a positive and the offsetting costs of the proposal as a negative. The higher the Net PVRR, the more valuable a given resource is to the Company's customers as compared to undifferentiated alternatives from the market.

Non-price factors evaluated were negative or positive as applicable, based on the following criteria: (a) conformity with 2009R RFP proposal requirements; (b) conformity with the *pro forma* PPA or BOT documents and/or Asset Acquisition and Sale Agreement attached as exhibits to the 2009R RFP; (c) feasibility of the alternative; (d) site control or permitting of the alternative; and (e) operational viability. Based on the application of the price and non-price factors, the Company selected proposals to comprise the initial shortlists containing a total of 14 resource alternatives (13 proposals from the market and the Company Benchmark). The 14 alternatives contained five east wind resources, four west wind resources and five other renewable resources.

Q. Did the IE agree with the Company's selection of alternatives contained in the three initial shortlists?

A. Yes. The IE agreed with the Company's selection of the three initial shortlists.[6]

Q. Please describe the 2009R final shortlist selection process.

A. After the Company selected the three initial shortlists, it moved to step two of the evaluation process – selection of the final shortlist. To select the final shortlist, the Company applied its next highest alternative cost for compliance ("ACC") analysis methodology for renewable resources to each of the three initial shortlists. This resource-specific analysis allows the Company to compare a resource against the potential next highest alternative cost for renewable resource compliance. In essence, the result of the ACC analysis shows how the resource compares to the undifferentiated power market. The ACC analysis also incorporates a resource's risk-adjusted system benefit, using the Company's IRP stochastic production cost model. A negative ACC indicates that the resource is valued below undifferentiated market alternatives; whereas a positive ACC indicates that the resource is valued above undifferentiated market alternatives. Upon completion of the ACC analysis the Company selected two alternatives for inclusion in the final shortlist. One of the alternatives was the Benchmark.

Q. Did the IE concur with the selection of the Wind Project on the final shortlist?

A. Yes. The IE concurred with the selection of the final shortlist

[6] *See* Final Report at pp. 11-14.

Q. Did the Company obtain a qualified third party expert evaluation of the wind potential at the Site?

A. Yes. Wind potential studies were performed by the Company's consultant in support of the Company's Benchmark submittal. In addition, as part of the 2009R RFP process, the Company retained a separate consultant to perform an independent wind study for the Benchmark and the other final shortlist bids. The second study confirmed the Site's suitability for the Wind Project. The second study also supplied an independent estimate of the annual capacity factor forecast for the Wind Project. The independent study was used in the RFP analyses of the Benchmark.

Q. Please describe the qualifications and experience of the technical consultants utilized to assess the estimated annual capacity factor of the Wind Project.

A. The first technical study was completed by the Company consultant, Black & Veatch supported by V-Bar, attached hereto as Confidential Exhibit RMP___ (SAB-6). The second technical study was conducted by Global Energy Concepts ("GEC"), a Det Norske Veritas ("DNV") company. DNV-GEC provided a report on the expected capacity factors of the four final shortlisted bidders, attached hereto as Confidential Exhibit RMP___(SAB-7).

Q. What factors did Black & Veatch take into account in formulating its technical study expected annual capacity factor of the Wind Project?

A. Black & Veatch took into account Site details including: Site topology; factors affecting the Site wind speeds; surface roughness; terrain features; air density;

meteorological data (on-Site data and off-Site reference data); data correlations; the WTG power curve; WTG layout; and ten energy production loss factors. The Black & Veatch technical study resulted in an annual fifty percent probability ("P50") capacity factor estimate over the life of the project; meaning that there is a 50 percent chance the actual production in any given year will be higher or lower than the P50 estimate. The Company generally regards the P50 estimate akin to the normalized estimations the Company makes associated with run of river hydro resources and retail load. In a subsequent report, Black & Veatch reported on the expected annual exceedence levels associated with the Wind Project on a 1-year, 10-year and 20-year basis. For example, Black & Veatch estimated, for any given year, there is a 90 percent chance that energy production will be 34.75% or greater in any given year whereas there is a 10 percent chance production will exceed 42.77 % or greater and a 5 percent chance production will be 43.90 % or greater.

Q Did DNV-GEC perform a similar evaluation regarding estimated exceedence levels?

A. Yes. DNV-GEC roughly estimated that for any given year there is a 90 percent chance that energy production will be 30.7% or greater.

Q Were the results of the DNV-GEC report different than the Black & Veatch report?

A. Yes, the DNV-GEC report reduced the expected annual capacity factor for all final shortlisted bidders, including the expected capacity factor for the Wind Project. The attached Confidential Exhibit RMP___(SAB-8) provides a comparison of the expected capacity factors and underlying assumptions provided by the four final shortlisted proposals as compared to the assumptions utilized in the DNV-GEC report. The report compares the key areas where DNV-GEC assumptions differed from that of the original proposals. Generally, DNV-GEC utilized more conservative energy production loss factors due to: availability, wakes, turbine performance, electrical and environmental.

Q. Please describe any safeguards or controls that have been put in place to guard against the possibility that the actual costs to construct the Wind Project generation plant will exceed the costs assumed in the RFP bid evaluations.

A. At the time of submittal into the RFP 2009R process, a large majority of the costs associated with the Wind Project generation plant could reasonably be forecasted on the basis of then-current contractual commitments or actual expenditures up until that time. For example, property costs were materially known and major equipment in the form of WTGs, switch gear and the Dunlap Substation step-up transformer were subject to contract. In addition, the balance of plant construction costs was contractually established at that point in time. In total, at the time of submittal into the RFP 2009R process, approximately 95 percent of the Wind Project generation plant costs could reasonably be forecasted on the basis of contractual commitments or actual spend to date.

Q. What expected costs were evaluated in RFP 2009R for the Benchmark?

A. The Benchmark costs submitted and used in the 2009R RFP evaluation were $261,183,699.

Q. What is the currently forecasted cost associated with the Benchmark?

A. The current forecast for the Benchmark costs is $253,401,317.

Q. Does the current Benchmark cost forecast include the Interconnection Facilities?

A. No. As described earlier in my testimony, the Interconnection Facilities are expected to cost $10.8m. My testimony later addresses why transmission interconnection costs are not included in the RFP process of evaluating alternative long-term supply-side resources.

Q. Please describe the primary reason the estimated costs used to evaluate the Benchmark in the 2009R RFP are higher than the actual costs currently being forecasted by the Company.

A. The primary reason for the forecasted reduced cost is a reduction in the need to use planned contingency.

Q. Is contingency a valid assumption to include in capital project planning?

A. Yes. Including contingency dollars as part of a planned wind construction project is a reasonable and standard construction practice that constitutes a prudent industry practice to predict and address unknown project costs. In fact, a number of functional organizations recommend including contingency in establishing project estimates.

Q. What functional organizations are you referring to?

A. Two examples include the Association for the Advancement of Cost Engineering ("AACE") and the Project Management Institute ("PMI").

Q. Is the Company's practice with respect to estimating contingency consistent with that put forth by AACE and PMI?

A. Yes.

Q. Does federal law establish that contingency is part of eligible project costs?

A. Yes, a reference is included in Part 80 of Title 49[7].

Q. What do you mean by "prudent industry practices"?

A. Prudent industry practices include those practices, methods, standards and acts (including those engaged in or approved by a significant portion of the power industry for similar facilities in the United States) that, at a particular time, in the exercise of good judgment, would have been expected to accomplish the desired result in a manner consistent with applicable laws, safety, environmental protection, economy and expedition.

Q. What did the IE conclude in its 2009R RFP Final Report on the final shortlist?

A. First, the selected alternatives represented the resources with the greatest net

[7] Eligible project costs mean amounts substantially all of which are paid by, or for the account of, an obligor in connection with a project, including the cost of:

(1) Development phase activities, including planning, feasibility analysis, revenue forecasting, environmental review, permitting, preliminary engineering and design work, and other pre-construction activities;

(2) Construction, reconstruction, rehabilitation, replacement, and acquisition of real property (including land related to the project and improvements to land), environmental mitigation, *construction contingencies*, and acquisition of equipment; and

(3) Capitalized interest necessary to meet market requirements, reasonably required reserve funds, capital issuance expenses, and other carrying costs during construction.

(emphasis added)

benefits to customers as determined by the ACC. Second, the alternatives represented the top options from a competitive process where the Company received proposals from 26 suppliers offering a total of 39 projects. Some of these projects offered multiple options for a total of 82 proposal options and over 9,400 MW. Third, the IE's report states:

> *"[i]ndependent analysis confirmed that the selected bids represent the lowest cost alternatives for ratepayers, with an accounting for risk. Our independent analysis included the creation of our own cost annuity models for each bid option, a review of PacifiCorp's models, and a thorough review of the terms and condition of each bid*".[8]

Fourth, The RFP aligns with the Company's IRP process. The initial and final shortlist analyses used current assumptions from the IRP. In addition, the ACC analysis uses a model from the Company's IRP process to calculate the benefit of renewable resources. Fifth, the Company Benchmark is included in the final shortlist and the IE took special care to confirm that selection, noting:

> *"[w]e confirmed the accuracy of the Benchmark costs and scoring and provided the Commission with a complete review of all costs of the project prior to bid receipt. We also confirmed the Benchmark's status by; (a) reviewing the project's initial and final shortlist scores and models, (b) independently scoring the project's non-price characteristics, (c) comparing the cost and output of the project to recent third-party bids, and (d) evaluating the bid costs in our own cost model".*[9]

Sixth, while there were two bids targeted for acquisition, the shortlist also includes two 'back-up' bids which provides some assurance that, should negotiations fall through with a bidder, the RFP may still result in a winner in

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[8] Id. at p. 3.
[9]Final Report at p. 3.

addition to the Benchmark.[10]

Q. Does the record developed in the RFP process show that the Wind Project is a prudent and cost-effective resource?

A. Yes.

Q. Is the Wind Project cost-effective and more attractive than the alternative market bids received in the 2009R RFP because of a favorable capacity factor or because of favorable capital costs?

A. Both. The Wind Project is competitive and cost-effective because of both favorable capital costs and a favorable expected capacity factor.

Q. What is the effect of reduced capital cost on the nominal levelized ACC as compared to an increase in expected annual capacity factor?

A. A $100 per kilowatt reduction in capital cost has the effect of reducing the nominal levelized ACC by approximately $3.05 per megawatt hour, whereas a 1 percent (1%) increase in annual capacity factor (i.e. moving from 36.4% capacity factor to 37.4% capacity factor) has the effect of reducing the nominal levelized ACC by approximately $2.58 per megawatt hour.

Q. What is the Company's current forecast for cost reduction of the Wind Project generation plant versus the cost evaluated in the RFP 2009R process?

A. The Company is currently forecasting an actual cost for the Wind Project generation plant that is approximately $7.8 million, or $70 per kilowatt, lower than the estimated cost evaluated in the 2009R RFP process.

[10] Id. at p. 4.

Q. Is the acquisition of the Wind Project consistent with PacifiCorp's renewable resource commitments resulting from the MEHC acquisition?

A. Yes.

Q. Please describe the MEHC transaction commitments to which you refer.

A. As part of the regulatory approvals related to the acquisition of the Company, MEHC and the Company committed to:

- Bring at least 100 MW of cost-effective wind resources in-service within one year of the close of the transaction;
- Have 400 MW of cost-effective new renewable resources in the Company's generation portfolio by December 31, 2007; and
- Reaffirm the Company's commitment to acquire 1,400 MW of cost-effective new renewable generation resources.

The Wind Project was acquired consistent with these commitments.

Wind Project Site and Facilities

Q. Where will the Wind Project WTGs be located?

A. The WTGs associated with the Wind Project will be located approximately eight miles north of Medicine Bow, Wyoming in Carbon County on property primarily owned by the Company (the "Site").

Q. Why is the Site an appropriate place to construct Wind Project?

A. The Site is appropriate for Wind Project for three primary reasons: (1) studies indicate the Site will result in a desirable wind resource; (2) the Site is located in close proximity to the Company's transmission system and another Company-owned wind project; and (3) the Company owns the majority of the Site land, thereby avoiding third-party royalty payments at a benefit to customers.

Q. Please explain the division of land ownership within the Site and land associated with the Shirley Basin Substation.

A. The Company owns the vast majority of the Site land. The Bureau of Land Management ("BLM") owns two sections, the state of Wyoming owns approximately two and one half sections and one section is held by a private third party. The Shirley Basin Substation also resides on fee land owned by the Company.

Q. Please explain if any of the Wind Project facilities will be located on land not owned by the Company.

A. The Wind Project does not have WTGs on land not owned by the Company. Although the Company installed electrical facilities on the third-party lands, no WTGs were placed on those lands. The Company holds a lease for the state lands within the Site boundaries and has utilized those rights to cross one section with the 230 kV transmission line from the Dunlap Substation to the Shirley Basin Substation. The Company additionally holds easements to other state sections that the 230 kV transmission line from the Dunlap Substation to the Shirley Basin Substation crosses and transmission facilities required to route the Miners-Difficulty 230 kV transmission line into and out of the Shirley Basin Substation cross. The remainder of the 230 kV transmission right-of-way from the Dunlap Substation to the Shirley Basin is on land leased from a private entity. Likewise, the remainder of the 230 kV transmission right-of-way from the Miners-Difficulty 230 kV line into and out of the Shirley Basin Substation is leased from a private entity. See the map attached hereto as Confidential Exhibit RMP___(SAB-9).

Q. Does the Company own the subsurface rights to the fee lands it holds?

A. No. The Company does not own any of the subsurface rights to fee lands associated with the Wind Project.

Q. Is there an inferred risk that future mineral development on the land could displace the Interconnection Facilities before the end of their useful life?

A. No. The Company does not believe that any subsurface right holder will be able to unreasonably displace any portion of the Wind Project.

Q. What precaution is the Company taking to mitigate the risk that customers could pay for an asset that may be removed before the end of its useful life due to the interests of subsurface right holders?

A. The Company has done prudent legal research on its rights as a surface right holder, as compared to those of subsurface right holders, and is comfortable that the law does not allow subsurface right holders to unilaterally displace the Company's facilities and that any given subsurface right holder would be required to enter into good faith negotiations to reasonably accommodate their subsurface extraction objective.

Q. Who will supply the towers, WTGs and control systems for the Wind Project?

A. The towers, WTGs and control systems will be supplied by the General Electric Company ("GE").

Q. How was GE selected as the turbine supplier?

A. The Company solicited offers from multiple turbine suppliers, and GE was determined to provide the lowest cost and risk to customers.

Q. Is GE a proven supplier of WTG equipment?

A. Yes. GE is one of the leading and most creditworthy WTG suppliers in the market and has an established track record of manufacturing wind generation components.

Q. Will GE supply a warranty?

A. Yes. GE will provide a two year warranty.

Q. Who will supply contracted O&M services for the Wind Project?

A. GE will provide O&M services for the WTGs and related Wind Project facilities located at the Site. GE will not be providing O&M services associated with the Shirley Basin Substation, any 230 kV transmission facilities or the Shirley Basin Substation.

Q. How was GE selected as the O&M provider?

A. The Company solicited offers from multiple O&M providers and GE was determined to provide the lowest cost and risk to customers.

Q. Please explain how the Wind Project will interconnect to the Company's transmission system.

A. The Wind Project will interconnect to the Company's transmission system via the new 230 kV Shirley Basin Substation and associated facilities. The Interconnection Facilities are essential components of the Wind Project.

Q. Please further describe the Interconnection Facilities.

A. The Interconnection Facilities will generally consist of the Shirley Basin Substation, associated switching and protective equipment and all associated work required to safely interconnect the Wind Project to the Company's transmission system. More specifically, the Interconnection Facilities will consist of:

- a new three breaker ring bus interconnection substation;
- 230 kV take off structures;
- revenue metering;
- line switches;
- facilities necessary to route the Company's 230 kV Miners-Difficulty transmission line into and out of the Shirley Basin Substation; and,
- communication facilities and associated communication programming or other work on Company facilities to enable the safe operation of the interconnected generation.

Q. On what analysis or process did the Company base its determination that the Interconnection Facilities are needed?

A. As per procedures outlined in PacifiCorp's Federal Energy Regulatory Commission regulated OATT (the Tariff), the Company's PacifiCorp Energy division filed an application for generator interconnection. Under the Tariff defined study process, a facility study was completed for the Wind Project. Included with my testimony is Exhibit RMP___(SAB-10), a copy of the facility study. The study identifies a need for the Interconnection Facilities to connect the Wind Project to the Company's network transmission system. Following completion of the facility study, an LGIA was executed.

Q. Why is the Shirley Basin Substation considered transmission plant instead of generation plant?

A. Under the FERC compliant LGIA study process, the Shirley Basin substation is considered an enhancement to the Company's network transmission system and, as such, is accounted for as transmission plant instead of generation plant. This means that that the Shirley Basin Substation becomes part and parcel to the network transmission system that is made available on a non-discriminatory basis to the Company's transmission customers under currently established rate tariffs for network transmission service or point-to-point transmission service.

Q. Are there other recent examples of transmission interconnection substations associated with new wind-powered generation facilities?

A. Yes. The Company is purchasing all of the output and associated attributes from the 99 MW Three Buttes, LLC wind project as delivered to their POI with the Company's network transmission system. The substation constructed to enable interconnection of that third-party owned and operated generation resource to the Company's Dave Johnston to Casper 230 kV transmission line is the Latigo Substation, a 230 kV substation with a 3 breaker ring bus configuration. The Windstar Substation represents another example. The Windstar Substation was constructed to interconnect the Company's Glenrock wind-powered generation resource to the transmission network. Subsequently, because the Windstar Substation was in place and classified as a network facility, it is being used as the POI for the Top of the World Wind Energy, LLC project, a 200.2 MW wind-powered generation resource for which the Company has entered into a PPA and is purchasing all of the generation output and associated attributes. Knowing it had multiple LGIA applications in and around the Dave Johnston 230 kV area, the Company's transmission function specified the Windstar Substation footprint and design to accommodate that expected future need.

Q. How are interconnection facilities classified as network facilities funded?

A. Under the FERC compliant non-discriminatory LGIA process followed by the Company, the transmission provider generally has the option to fund the construction itself or ask the interconnection customer to fund the construction; subject to refund. If the interconnection customer funds the construction then it is refunded an amount based on the actual costs to construct the interconnection facility or provided transmission credits that can be used to take transmission service. Once a generator is interconnected to the transmission network, it can then apply for and take transmission services (e.g., network transmission service or point-to-point transmission service). Point-to-point transmission service is the type of service a generator would use to wheel out of, or through, the Company's transmission system. Network transmission service is the type of service a generator would use to meet retail load service obligations interconnected to the Company's transmission system. Transmission credits are subject to a FERC determined interest rate and, if unused, the value of the transmission credit account is ultimately returned to the interconnection customer after a period of time.

Q. In the example cited above involving the interconnection of the Three Buttes, LLC resource at the new Latigo Substation, did the interconnection customer refuse, pass back or otherwise forfeit their LGIA related refund?

A. No. The Three Buttes, LLC reference is an example of a PPA. Under the PPA approach, the generation owner is typically afforded any refunds associated with the LGIA process. However, when the Company is considering the BOT structure in a RFP process, the Company will typically seek a three-way agreement between the interconnection customer, the Company's transmission function and the Company's generation group (aka PacifiCorp Energy). The three-way agreement, or other form of agreement, is typically intended to define that any refunds shall be assigned to PacifiCorp Energy as part of the LGIA assignment. This is done because, under a BOT structure, the Company is typically acquiring an asset and all of its associated rights (including the LGIA) for a negotiated price. This is to be distinguished between a PPA structure where the asset is owned by a third party, including all associated rights (including the LGIA).

Q. In the Company's Renewable RFP process, how are costs associated with interconnection facilities treated?

A. Because the FERC LGIA process allows a generator to non-discriminatorily interconnect to the transmission system, but not directly bear the costs associated with facilities classified as network transmission facilities (typically the interconnection substation), the Company evaluates the cost associated with the generation resource as delivered to the POI.

Q. Why does the Company not include the cost of the interconnection faculties in its RFP analysis?

A. There are three important reasons the Company focuses on the generation costs as delivered to the POI. First, the Company does not include the cost associated with the interconnection facilities because those costs for all bidders are typically not known at the time a RFP is being processed. Second, notwithstanding anything else, the interconnection cost recovery process is set by FERC. Finally, because it is reasonable to expect that any new long-term supply-side resource will result in new generation asset construction and new or upgraded network interconnection facilities, the costs associated with those facilities can be expected to be capital costs borne by the Company and will become part and parcel to the revenue requirement policies established by FERC for transmission expense recovery.

Q. As it relates to interconnection facilities, does the Company's Renewable RFP process distinguish between who the generation owner will be?

A. No. In an RFP process where third party owned and operated generation supply is being compared to generation supply that could be owned by the Company, the RFP process applies the same analytical approach to all considered resource alternatives, regardless of potential ownership. This is done to create a fair, transparent and non-discriminatory RFP process.

Q. How were bidders notified of their transmission interconnection obligation?

A. The Company provided the following statement in its RFP document issued to the market:

> "*This RFP requires that all Bidders must enter into a separate Interconnection Agreement if their facilities are located within the PacifiCorp footprint in accordance with PacifiCorp's Open Access Transmission Tariff.*"
>
> See Section 5.E of the Company RFP issuance at http://www.pacificorp.com/content/dam/pacificorp/doc/Suppliers/RFPs/RFP2009R_MainDocOnly_7-8-09.pdf.

Q. Did the IE review the treatment of interconnection costs as part of its overall RFP responsibilities?

A. Yes.

Q. Please explain why the Wind Project is in the public interest?

A. The Wind Project is in the public interest because: (1) it is an important piece to the resource portfolio that is needed (as demonstrated by the 2008 IRP); (2) it is a resource that is desirable due to its location-specific attributes; and (3) the project will benefit customers as clearly demonstrated through the competitive procurement process of the 2009R RFP. The Wind Project will also make it possible for the Company to meet a portion of the Company's network load service obligation including Rocky Mountain Power's obligation to serve its Utah customers.

Q. Does this complete your testimony?

A. Yes.