Exhibit No.___(HS-1T)
Docket No. UE-09___
Witness: Hui Shu

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. PACIFICORP dba Pacific Power Respondent.	)))))))))))	Docket No. UE-09______

PACIFICORP

DIRECT TESTIMONY OF HUI SHU

February 2009

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

A. My name is Hui Shu, my business address is 825 N.E. Multnomah, Suite 600, Portland, Oregon 97232. My present position is Manager of Net Power Costs.

Qualifications

Q. Briefly describe your educational and professional background.

A. I received an undergraduate degree in Electrical Engineering and finished training in the program for a Masters in Business Administration from University of Shanghai for Science and Technology. I received a PhD degree in Systems Science with a focus on Econometrics from Portland State University. I have worked for PacifiCorp since 1992 and have held positions in the commercial and trading and regulatory areas. I accepted my current position in February 2008.

Q. Please describe your current duties.

A. I am responsible for the coordination and preparation of net power cost studies and related analyses used in retail price filings. In addition, I represent the Company on various net power cost related issues with intervenor and regulatory groups associated with the six state regulatory commissions to whose jurisdiction the Company is subject.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. I present the proposed pro-forma normalized net power costs for the calendar year ending December 31, 2010. In addition, my testimony:

- Describes the primary reasons for the increase in net power costs as well as factors that mitigate the increase;

- Describes the modeling of net power costs under the West Control Area ("WCA") allocation method;
- Describes the changes to modeling net power costs in the west control area since the Company's last general rate case in Docket UE-080220 ("2008 Rate Case");
- Describes the determination of wind integration charges; and
- Discusses the impact of thermal ramping on net power costs and the modeling of ramping losses.

Net Power Cost Results

Q. What are the proposed pro forma normalized net power costs?

A. The proposed net power costs are approximately $514.9 million for the Company's west control area. As discussed in Company witness Mr. R. Bryce Dalley's direct testimony, the Washington-allocated net power costs are approximately $111.0 million prior to the application of the production factor adjustment.

Q. Were the net power costs settled in the 2008 Rate Case?

A. Yes. In the 2008 Rate Case, the all-party Stipulation approved and authorized by the Washington Utilities and Transportation Commission ("Commission") on October 8, 2008, established a net power cost baseline of approximately $430.9 million on a west control area basis and $96.8 million on a Washington-allocated basis. There was no specific finding about the components of the net power costs.

Q. What are the primary factors that are driving the increase in net power costs since the 2008 Rate Case?

A. The factors with the largest impact include the expiration of long-term firm purchase power contracts, increased firm wheeling expenses, addition of natural gas pipeline reservation fees and startup fuel costs, lower hydro generation at Company-owned facilities, and increases in coal costs. These factors are partially offset by reductions in net power costs associated with new renewable wind resources.

Q. Why do expiring purchase power contracts increase net power costs?

A. Purchase power contracts generally reflect wholesale electric market prices at the time they were executed. Generally, wholesale electric market prices have increased over time, and thus the cost of the replacement power has increased. Beginning in November 2009, the original contract between the Company and the Grant Public Utility District ("Grant PUD") for the generation from the Wanapum project expires. The cost increase from this contract is somewhat mitigated by the increase in revenues from the Reasonable Portion of the contract with the Grant PUD. In total, changes to the Mid-Columbia contracts cause net power costs to increase by approximately $13.7 million from what was filed in the 2008 Rate Case on a west control area basis. In addition, this filing reflects the expiration of the storage and integration contract with the Clark County Public Utility District ("Clark PUD"), which increases net power costs by approximately $3.1 million.

Q. What are the primary reasons for the increase in firm wheeling expenses?

A. Wheeling expenses increased due to a low priced formula power transfer ("FPT") wheeling contract with the Bonneville Power Administration ("BPA") that expires and will be converted to a higher priced BPA point-to-point ("PTP") contract. BPA is eliminating FPT contracts when they expire. Wheeling expenses also increased to reflect wheeling generation from the newly acquired Chehalis natural gas plant ("Chehalis Plant") to the Company's load center and market. Net of cost decreases associated with the removal of certain wheeling expenses from the filing, wheeling expenses increased in this case by approximately $11.4 million from what was filed in the 2008 Rate Case on a west control area basis.

Q. Are there other new costs associated with the Chehalis Plant included in net power costs?

A. Yes. Net power costs include the cost of transporting natural gas for the Chehalis Plant, approximately $13.1 million, and startup fuel costs of the plant.

Q. Please explain why the Company-owned hydro generation in the current filing is lower than the 2008 Rate Case.

A. The hydro generation data was updated to more closely reflect the actual operation of the hydro plants on a normalized basis. The update includes 48-month normalized maintenance and forced outages, removal of the Big Fork project from the west control area, expiration of the operating license for the Condit dam and updated inflow data. The update also includes a reduction in the capability of some hydro generation plants due to changes in contracts and relicensing. Particularly, changes in the Company's contracts for generation from the Mid-Columbia projects caused changes to the operational flexibility for hydro plants on the Lewis River. The total impact of the reduction in hydro generation from the Company-owned facilities increases west control area net power costs by approximately $15 million.

Q. Have coal costs increased from what was reflected in the 2008 Rate Case?

A. Yes. Overall, coal costs increase net power costs by approximately $45 million on a west control area basis from what was filed in the 2008 Rate Case. I understand that the increase in coal costs mirrors the significant cost increases experienced in the coal markets during this same time period. For example, the Company obtains one-third of the coal necessary to fuel the Bridger Plant from a coal purchase agreement with Black Butte Coal Company. This coal comes from a mine similar to Bridger Coal Company's ("BCC") surface mine in design and geology. The Company's contract with Black Butte for coal was recently renegotiated. Prices under the new contract, which are indexed to producer price indices, have increased by approximately 41 percent for the pro forma period. A significant portion of the coal cost increases reflected in the case can be attributed to increases under this contract and other coal supply contracts for the Colstrip 4 unit.

Q. Aside from market-driven increases in third-party coal supply contracts, what other factors are contributing to the coal cost increase included in this case?

A. I understand that the balance of the coal cost increase is attributable to cost increases at the Jim Bridger mine. The Jim Bridger mine consists of two different mining operations: an underground mine and a surface mine. Both are subject to cost increases in the pro forma period due to labor and commodity cost escalation. Additionally, both are subject to increased taxes and royalty payments due to higher valuations driven by higher market prices.

Q. What are the specific drivers increasing costs at the Bridger underground mine?

A. The mine went into production mode in 2007. BCC expects maintenance costs to increase in the pro forma period as the new equipment in the mine is scheduled for rebuilds, component exchanges, etc. Additionally, BCC expects the mine infrastructure to be fully completed and in service by 2010. Depreciation expense is higher with the addition of mine infrastructure as well as increasing production from the underground mine. Finally, BCC expects its costs in 2010 to continue to reflect the dramatic steel cost increases that occurred in 2007 and 2008.

Q. What are the specific drivers increasing costs at the Bridger surface mine?

A. For many years, BCC was able to extract coal at the Bridger surface mine using low-cost highwall mining. The mine has now reached the stage, however, where BCC has replaced this production method with higher-cost dragline mining to properly steward the resources of the mine. Additionally, current accounting pronouncement EITF 04-6 requires that production costs be assigned only to extracted coal, not coal that is uncovered but remains in the pit. This contributes to higher costs in the pro forma period because more coal is scheduled to be uncovered than will actually be extracted; the opposite will be true in a year when previously uncovered coal is ultimately extracted.

Net Power Cost Decreases

Q. Are the net power cost increases partially offset by the inclusion of additional resources during calendar year 2010?

A. Yes. The generation from the Chehalis Plant and Marengo II wind project, as well as additional generation from resources that have been in service previously, are included in the pro forma calendar year 2010 net power costs.

Q. What is the impact of the Chehalis Plant in the current filing?

A. The impact of not running the Chehalis Plant would increase the proposed net power costs in the test period by about $17 million. As discussed previously, increased wheeling expenses, pipeline transportation expenses, and startup fuel costs for the Chehalis Plant are also included in net power costs. Further details on the Chehalis Plant are provided in the direct testimony of Company witnesses Mr. Stefan A. Bird and Mr. Gregory N. Duvall.

Q. What additional renewable generation has been included in calendar 2010 as a reduction to net power costs?

A. The pro forma calendar year 2010 net power costs include a full year of operation of the 140.4-megawatt Marengo wind project located in Washington and placed in service in August 2007, the 94-megawatt Goodnoe Hills wind project located in Washington and placed in service in May 2008, and the new 70.2-megawatt Marengo II wind project located in Washington placed in service in June 2008. Because the Company owns these wind facilities, the "fuel" cost of these resources is zero. The variable cost of these facilities is limited to a $1.15 per megawatt hour charge for intra-hour integration of wind generation into the

Company's resource portfolio, and the wind integration charge of \$0.68 per kW-month by BPA for the generation from the Goodnoe Hills and Leaning Juniper projects. The net impact of these additional resources reduces west control area net power costs by approximately \$24 million.

Determination of Net Power Costs

Q. Please explain net power costs.

A. Net power costs are defined as the sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue.

Q. Please explain how the Company calculated pro forma calendar year 2010 net power costs.

Net power costs are calculated using the Generation and Regulation Initiatives Decision tools model ("GRID"). For each hour in the pro forma period the model simulates the operation of the power supply of the Company.

Q. Is the Company's general approach to the calculation of net power costs using the GRID model the same in this case as in the 2008 Rate Case?

A. Yes. The Company used the GRID model in this case consistent with the last case. Because none of the general background on GRID has changed, instead of including GRID background testimony, I have attached that information to my testimony as Exhibit No.___(HS-2). As I discuss below, the Company has made some changes to the assumption within the GRID model in response to concerns that were raised by parties in the 2008 Rate Case.

GRID Model Inputs and Outputs

Q. Please describe any updated inputs to GRID.

A. The inputs to the GRID model have been updated to reflect the information available at the time the net power cost study was prepared for the current filing. This includes the net west control area load, wholesale sales revenues and purchase power expenses, transmission capability and wheeling expenses, market prices for natural gas and electricity, fuel expenses, hydro generation, wind generation, thermal generating capability, thermal heat rates, thermal planned maintenance and forced outage.

Q. What reports does the GRID model produce?

A. The major output from the GRID model is the net power cost report. This is attached to my testimony as Exhibit No.___(HS-3). Additional data with more detailed analyses are also available in hourly, daily, monthly and annual formats by heavy load hours and light load hours.

Determination of Net Power Costs on a West Control Area Basis

Q. How does the Company model net power costs for the west control area?

A. The Company modeled net power costs using the WCA methodology adopted in Order 08, Docket UE-061546. The Company has two control areas, east and west, with limited transfers between the two control areas. Under the WCA allocation method, only the load and resources in the west control area are taken into consideration.

Q. What are the load obligations in the west control area?

A. The load in the west control area is composed of the retail load in the Company's service territories in the states of California, Oregon and Washington. The wholesale sales contracts that are included in the west control area net power costs are the ones that have delivery points in the Company's west control area.

Q. What are the Company-owned resources in the west control area?

A. The Company-owned resources in the west control area include:

Hydro resources – facilities on the North Umpqua River and Rogue River in Oregon, Lewis River in Washington, Klamath River in Oregon and California, and other small hydro facilities in the west control area;

Wind resources – Leaning Juniper in Oregon, Goodnoe Hills, Marengo and Marengo II in Washington; and

Thermal resources – Colstrip in Montana, Jim Bridger in Wyoming, Chehalis in Washington and Hermiston in Oregon.

The Colstrip and Jim Bridger plants are located outside the geographical area of the three western states. However, through owned and contracted transmission capabilities, the generation from the two plants is electronically interconnected with the Company's west control area.

The Company has shares in two units of the Colstrip plant. Because only Colstrip 4 is authorized by the Commission for rate setting purposes in Washington, only Colstrip 4 is included in the west control area net power costs. In addition, because there is a limitation on transmission capabilities, the generation from the Jim Bridger plant that can be wheeled into the west control area is approximately 96 percent of total Jim Bridger's capability. As such, the WCA allocation methodology only includes 96 percent of the costs and output of

Jim Bridger.

Q. Are there wholesale purchase contracts in the west control area?

A. Yes. The west control area net power costs include the Company's wholesale purchase contracts that have delivery points within the west control area, which include the contracts for the generation from the Mid Columbia river hydro projects.

Q. How are the Company's owned transmission capabilities and wheeling contracts treated under the WCA allocation method?

A. The Company-owned transmission capabilities and the rights from the wheeling contracts with third parties are included in the west control area modeling if they are used to transmit power from and to locations in the west control area.

Q. Does the Company use 40 water year normalized hydro generation in the WCA modeling?

A. Yes. As authorized by the Commission in Cause No. U-86-02 Second Supplemental Order, the Company continues to include the normalized hydro generation under the most recent 40 stream flow conditions. In the current filing, the 40 water years are from 1968 to 2007. The 40 net power cost results obtained from simulating the operations of these stream flow conditions are averaged and the appropriate cost data is applied to determine expected net power costs under normal stream flow for pro forma calendar year 2010.

Q. How is the WCA net power cost model constructed?

A. The WCA model starts from a model that calculates the net power costs for the total Company. The following five general steps are needed to set up the model to calculate the WCA net power costs. First, the transmission topology is defined for the west control area, which removes all the transmission areas and the transmission paths that are not applicable to the west control area, as well as the paths that connect the west control area with the east control area. Second, the retail load is revised to include only the retail load in the west control area. Third, the wholesale sales and purchase power contracts that are not delivered to any points within the west control area are removed, including the exchange contracts whose delivery and receipts are not limited to the west control area. Fourth, the Company owned thermal, hydro and wind resources that are not located in the west control area are removed. And finally, the parameters that are set for the purpose of simulating the operation of the total Company system are reset for the west control area.

Changes and Correction to West Control Area Modeling

Q. Has the Company made changes and corrections to the modeling of the west control area net power costs since the 2008 Rate Case?

A. Yes. In addition to the changes and updates discussed above, the Company modified its inputs of wheeling expenses in the west control area in this filing to: (1) remove half of the wheeling expense for the Colstrip plant to reflect that only Colstrip 4, half of the Colstrip plant, is authorized by the Commission for rate setting in Washington; (2) remove the wheeling expenses related to the Big Fork hydro project, consistent with the modeling of the generation which is assigned to the east control area of the Company's system; and (3) remove all California Independent System Operator charges from the west control area, based on the assumption that the majority of the charges are incurred due to market transactions in the east control area of the Company's system. In addition, a category for electric swaps has been added to the net power cost calculation, which is the mark to market value of the electric swaps that the Company uses as part of its portfolio to hedge the market risk.

Q. Are wind integration charges added to the net power cost calculation in this filing?

A. Yes. The pro forma calendar year 2010 net power costs include wind integration charges for the wind facilities located in the Company's west control area, as well as wind integration charges by BPA for the Company's wind facilities located in BPA's control area.

Q. Has the Company included a thermal ramping adjustment in this filing?

A. Yes. The adjustment is made to the Jim Bridger plant for the over-stated available generation when the plant comes back from being off-line due to outages. There is no adjustment to the Colstrip plant, which is the other coal plant in the Company's west control area, because the Company is not the operator of the plant and the data for such adjustment is not available.

Q. Have you discussed the changes to the WCA modeling with parties?

A. Yes. On January 29, 2009, the Company discussed these changes with the WCA Monitoring Committee.

Wind Integration Charges

Q. What are wind integration charges?

A. Wind integration charges intend to capture the costs above and beyond the five percent operating reserve requirement that the Company is obligated to carry. The reserve requirement has been modeled in GRID. The uncertain nature of wind generation not only makes it non-dispatchable, but also requires additional resources to be ready to follow its changes from time-to-time similar to following changes in load.

Q. How is the Company's wind integration charge calculated?

A. In the Company's Integrated Resource Plan ("IRP") analysis, the load-following reserve requirement was calculated based on the increased uncertainty of system net load in the next hour due to the volatility of the 2,000 megawatts of wind resources proposed in the IRP preferred portfolio. The study first considered the variability of the system load. Next it applied wind generation as a negative increment of load and then determined the variability of load net of wind. The difference between the variability of load and variability of load net of wind is a measure of the incremental load-following reserve requirement. The cost of holding incremental reserves was established by running multiple stochastic studies of the IRP power cost model with increasing reserve requirements and reporting the cost in terms of dollars per megawatt hour of incremental wind generation assuming a 33 percent capacity factor. The result of this analysis estimates the average incremental load-following cost attributed to the first 2,000 megawatts of wind resources to be $1.10 per megawatt hour in 2007 dollars. This value is adjusted for inflation to $1.15 per megawatt hour for the pro forma calendar year 2010.

Q, The Company is not yet integrating a full 2,000 megawatts of wind resources. Is the wind integration cost estimate in the IRP still applicable?

A. Yes. The analysis reflects an average charge calculated to cover the costs of integrating up to 2,000 megawatts. The analysis does not support reduced integration charges for a smaller portfolio of wind projects.

Q. Is this system-wide approach applicable to the Company's west control area?

A. Yes. The capacity of wind resources in the Company's west control area is less than 2,000 megawatts. However, a sensitivity study prepared by the Company in the IRP shows that at lower capacities, the costs to integrate the wind resources could be higher. The reason for the potentially higher costs is because the wind resources in the west control area have lower capacity factors than much of the wind additions in the east control area and other projected wind resources.

Q. How does the Company's wind integration charge compare with the wind integration charges determined by other utilities?

A. The Company compared its wind integration charge to those of BPA and Portland General Electric ("PGE") and determined that the Company's is significantly lower. Beginning in 2008, the wind integration tariff charged by BPA is $0.68 per kilowatt month for interconnected wind projects, which represents approximately $2.82 per megawatt hour for a wind project with a capacity factor of 33 percent. In a presentation on wind integration to the Oregon Public Utility Commission and parties, PGE has estimated its wind integration costs to be about $11.75 per megawatt hours in 2008 dollars, which is ten times the Company's cost. The Company continues to monitor developments across the industry to inform its approach to estimating wind integration costs.

Ramping Loss Adjustment

Q. Does the net power cost calculation include an adjustment for thermal ramping losses?

A. Yes.

Q. Please describe why the thermal ramping loss adjustment is incorporated in the net power cost study when the Commission rejected such adjustment in Docket UE-061546.

A. In the Commission order, it is stated that

> *"We find that PacifiCorp has not carried its burden to show the change in methodology that it proposes in this case is appropriate. Accordingly, we adopt ICNU's ramping adjustment."*

In my testimony below, I will introduce evidence that the ramping losses are not "phantom outages" as asserted by Mr. Randall J. Falkenberg in his direct testimony in UE-061546.

Q. What is the purpose of the ramping loss adjustment that the Company modeled in its normalized net power costs?

A. The ramping loss adjustment is designed to capture the impact of the generation from a thermal coal-fired unit as modeled in GRID but not available in actual operation when the unit is starting up after being offline.

Q. What is involved in starting up a thermal unit?

A. As stated in Steam, by Babcock & Wilcox[1],

> *"Operating procedures vary with boiler design. However, certain objectives should be included in the operating procedures of every boiler: 1) protection of pressure parts against corrosion, overheating, and thermal stresses, 2) prevention of furnace explosions, and 3) production of steam at the desired temperature, pressure, and purity."*

The actual time required for each unit to start up is largely dependent on the design of the unit and the temperature of the components. On average, for steam generating units, this period of time takes about eight hours if the unit can quickly be brought back online while still hot, or over 24 hours if the unit has been allowed to cool.

There are four events of note when discussing start-up:

1) Clearance Release – The cause of the outage has been addressed, and the unit is cleared for operations to begin warming the unit.
2) Synchronization to Electric Grid – Steam is flowing to the turbine which is spinning the generator at 3,600 revolutions per minute. At this time, the outage is complete for tracking purposes.
3) Unit Available for Dispatch – The unit load has increased to a point where generation can be dispatched based on customer demand.
4) Unit at Full Load – The unit load has increased to the maximum rated capacity.

[1] The Babcock & Wilcox Company. Steam. 40th ed. 1992, p. 43-4.

Q. Does the GRID model consider these procedures and events?

A. No. In GRID, all thermal units are modeled as if they can start up and be available at their full capabilities instantaneously when returning from offline. As a result, the energy output from the generating units is overstated for the duration when the units are starting up. Figure 1 depicts the difference in generation between what is modeled by GRID and what occurs in actual operation.

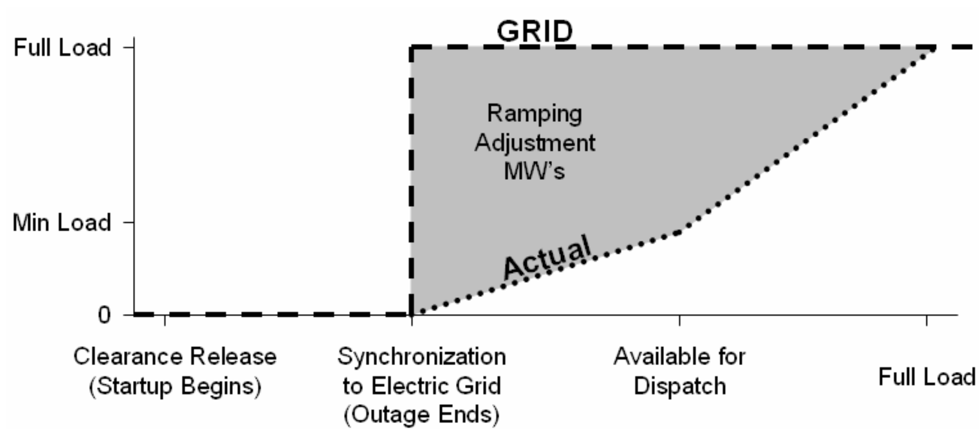

Figure 1. GRID vs. Actual Unit Ramping

Q. How does the Company estimate the ramping loss adjustments for the coal-fired units?

A. The ramping losses are calculated based on actual 48-month historical hourly data. Ramping loss is the difference between a thermal unit's availability and actual generation within a maximum of a twelve-hour window after the unit returns from being offline for any reason. The estimates are limited to only include the differences that are greater than ten percent of the availability. If the differences fall within ten percent of the availability in less than twelve hours, any differences after that time are also excluded from the estimates. That is, it is assumed that there are no ramping losses after twelve hours even if the unit still has not reached its availability, and it is also assumed that there are no ramping losses if the difference between the unit's availability and generation is less than ten percent of the unit's availability.

Q. Does the Company model ramping loss adjustments for the gas-fired units?

A. No. Although the gas-fired units may not be available instantaneously after returning from any offline period, the time for them to start up is much shorter. For an hourly model like GRID, the difference is not as significant.

Q. Does this conclude your direct testimony?

A. Yes.