Before the
Washington Utilities and Transportation Commission

Docket Nos.
UE-991255 (Avista)
UE-991262(PP&L)
UE-991409(Puget)

Direct Testimony of

Jim Lazar
Consulting Economist

On Behalf of
Public Counsel

December, 1999

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INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, address, and occupation, and summarize your utility regulation experience.

A. Jim Lazar, 1063 Capitol Way S. #202, Olympia, Washington, 98501. I am a consulting economist specializing in utility rate and resource issues. I have been engaged in utility rate consulting continuously since 1979. During that time, I have appeared before many local, state, and federal regulatory bodies, authored books, papers, and articles on utility ratemaking, and been a faculty member on numerous occasions at training sessions for utility industry analysts. I have appeared before this Commission on more than forty occasions in proceedings involving each of the gas and electric utilities regulated by the Commission. I have served as a consultant to this Commission on several occasions, including participation in BPA rate proceedings, assistance with technical studies, and staff training.

I have familiarity with the Centralia project through my work on rate proceedings involving each of the Applicants, beginning with Docket U-78-05 (1978), a generic rate proceeding which involved all of the applicants. I also have recent detailed familiarity with the Centralia project as a consultant to Mount Rainier National Park and the U.S. Environmental Protection Agency in their participation in the Collaborative Decision Making (CDM) process which led to the agreement for scrubbers to be installed on the two Centralia units in 2001/02. A copy of the "public" version of my report from that process is provided in Exhibit 502.

Q. What topics are you covering in your testimony?

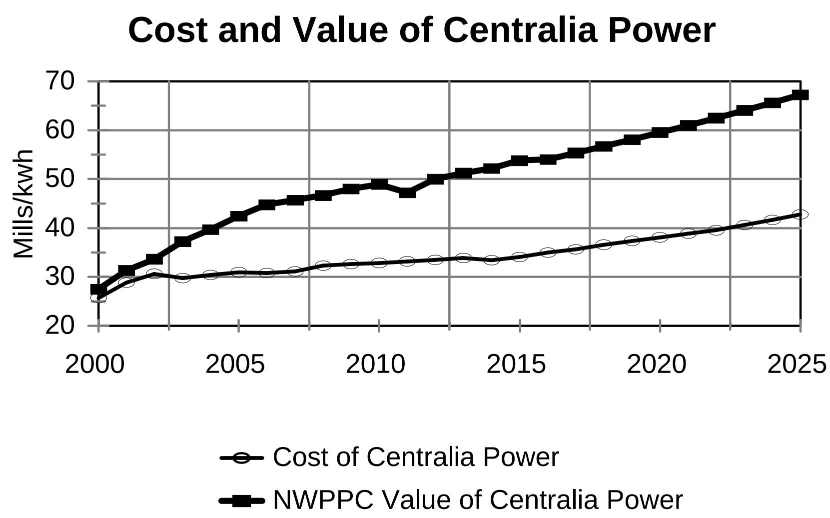
A. I address the economics of the Centralia project, compare the cost of ownership and operation of Centralia to recent forecasts of market prices for electric power, and present my conclusions as to why the sale of the plant is NOT consistent with the public interest. I also address some of the "qualitative" aspects of the Centralia project I considered in reaching this position.

SUMMARY OF FINDINGS

Q. Please summarize your findings?

A. Centralia is a cost-effective resource, combining a proven, reliable design, access to an adequate low-cost coal supply, and excellent strategic location. My analysis relies on two key assumptions: first, that the plant will last as long as the Applicants told the legislature it would when they sought the tax credit package, and second, that the most recent forecasts of the market value of power are the most applicable. Based on these key assumptions, the plant offers expected net benefits to regional ratepayers of $1.1 billion over and above the cost of ownership and operation in my base case analysis. With the installation of sulphur scrubbers now underway, the only "negative" is that, as a coal-fired steam plant, it is a major emitter of carbon dioxide. However, as my analysis shows, even with the potential cost of mitigation of the carbon emissions down to the level of a combined-cycle gas turbine, Centralia has very positive economics, and is worth more than the proposed selling price. None of the Applicants has prepared an Integrated Resource Plan examining the economic or technical aspects of replacing Centralia with market purchases or other resources. Based on my analysis, I recommend that the plant be retained as a generating resource by the Applicants and that the proposed sale of the Centralia coal plant be rejected as contrary to the public interest. The most likely result of the sale for electric consumers would be adverse, even if 100% of the gain on sale is credited to ratepayers.

At the time the proposed sale was conceived, expected future power prices were much lower than are forecast today. The cost of ownership of Centralia has remained stable. Thus, even if the proposed sale was consistent with the public interest when originally conceived, it is not consistent today, and the Commission should not approve the sale. The graph below compares the cost of power from Centralia as estimated by Pacificorp, the operator, with the value of that power as estimated by the Northwest Power Planning Council. As is evident, for most of the remaining life of the plant, the value of the power is expected to be much greater than the cost.



If the Commission does approve the sale, it should ensure that consumers are not adversely affected. The only way to do this with confidence that ratepayers will not be harmed is to require that each of the Applicants covenant that it will supply an amount of power equal to its share of the Centralia plant capability to ratepayers each year at the estimated cost of upgrade, ownership, and operation of Centralia. Merely crediting all of the gain on sale to ratepayers is not likely to provide an economic benefit of equal magnitude to the power, because the plant has value in excess of the selling price.

This conclusion is VERY different from that which I reached in 1997 as part of the CDM negotiations, where I concluded that the proposed tax credit package was important to assuring the future viability of the Centralia project. The reason for this change is that the market for power has moved towards equilibrium much more quickly than was forecast at that time. For example, Page 3 of Exhibit 501 compares the forecasts used by the Collaborative Decision Making group (Centralia owners, Environmental Protection Agency, Southwest Washington Air

Pollution Control Authority) at the time of the scrubber negotiation to that forecast by the Northwest Power Planning Council staff in November of this year. In the short run (first 10 years) the value of power has approximately DOUBLED from that forecast at the time of the scrubber negotiations.

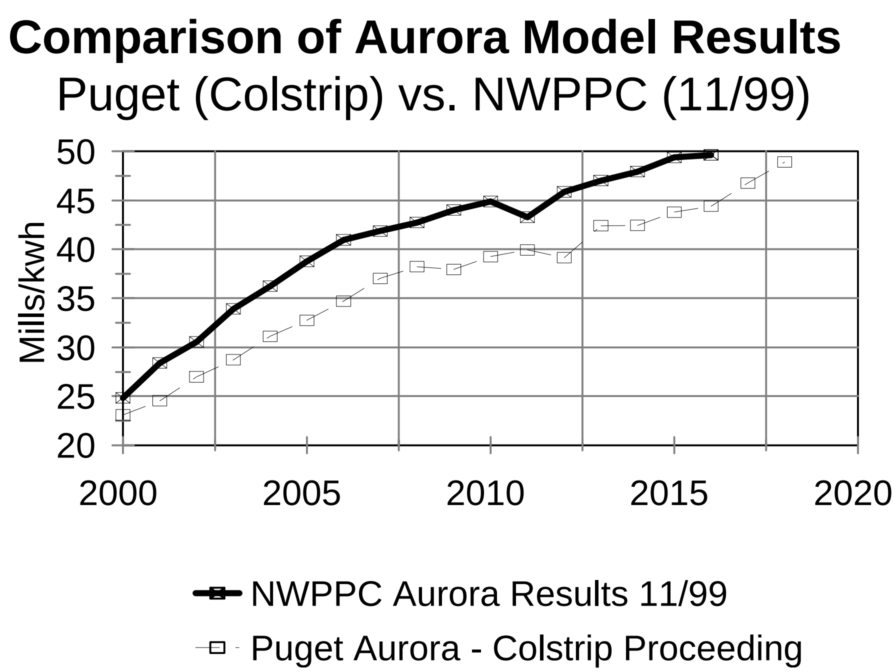
ECONOMICS OF CONTINUED OWNERSHIP OF CENTRALIA

Q. How have you analyzed the economics of continued ownership of the Centralia project?

A. I have compared the cost of continued ownership of Centralia to the cost of replacement power purchased at market prices. These calculations are presented in my Exhibit 501. The first calculation includes the current investment, the cost of installing scrubbers and low-NOx burners, operation and maintenance, and fuel costs for the remaining life of the plant. For my base case analysis, I assumed a 26 year remaining plant life and the costs of ownership estimated by Pacificorp. This plant life is consistent with the analysis that was used by the Centralia owners (including the Applicants) to justify the scrubber-related tax credits to the legislature. The second calculation, value of power, is based upon the Northwest Power Planning Council's November, 1999 power cost forecast for Western Washington / Oregon conservatively extrapolated to the estimated end of the plant lifetime. I also prepared alternative scenarios examining the impact of other assumptions on my conclusions.

Q. How does this analysis compare to the analysis you prepared in the PSE Colstrip proceeding, Docket No. UE-990269?

A. In the Colstrip proceeding, I relied upon Puget's forecast of market prices for power, since they were the best available to me at that time. Puget used the Aurora model to generate these forecast prices, the same model used by the Northwest Power Planning Council (NWPPC). The Puget results were generally consistent with the then most-recent results which I received from NWPPC, which had been prepared in September, 1998. In November, of 1999 NWPPC presented its most recent forecast results to its Regional Technical Forum on energy conservation, to which I was appointed earlier this year. The NWPPC forecast is superior to that prepared by Puget in the Colstrip proceeding (and used in this proceeding as well) because it is more recent, and because it separately measures the value of power in Western Washington / Oregon, where Centralia is located. The graph below compares the Puget Aurora results from the Colstrip proceeding to the more recent NWPPC Aurora results. I should note that a portion of the difference is related to location; the NWPPC forecast is for Western Washington / Oregon where Centralia is located, while the Puget forecast used for Colstrip was at a Mid-Columbia point of delivery, to which transmission costs from Montana to the Mid-Columbia region were added in the Colstrip proceeding. A copy of the 11/99 NWPPC presentation is provided in Exhibit 506.



Also, in the Colstrip proceeding, I relied on an "end-effects" analysis to estimate the value of power beyond the end of Puget's forecast period. In this proceeding, I have not done this, which I consider a conservatism. Instead, I have used Pacific's estimates of ownership and operating costs for the first 24 years of the entire 26-year remaining plant lifetime. I have then extrapolated the cost of power for the last two years of my analysis, based upon the 26 year analysis performed by Pacific as part of the scrubber negotiations.

I have used the 11/99 Northwest Power Planning Council's estimated value of power for Western Washington / Western Oregon through 2016 (the last year of this forecast), and extrapolated this through 2025.

Finally, there are two environmental calculations which were not a part of the Colstrip examination. First, there is the relative certainty of being able to market excess sulphur emissions credits once the scrubbers are installed. This adds approximately $43 million to the present value of Centralia. Second, there is the potential that carbon dioxide emissions regulations will be imposed, and I have estimated in one scenario what the cost of compliance with such regulations would be if imposed, to measure the exposure of ratepayers to such costs if ownership in the plant is retained. I have examined this as one of my scenarios. Both Pacificorp and PSE estimated carbon emissions costs; those assumed by PSE were approximately 9 times higher than those assumed by Pacificorp.[1] I used the higher PSE estimates as the basis for my analysis..

Q. Why have you selected a 26 year remaining plant life, and how does that compare with the Applicant's presentations?

A. I selected a 26 year remaining plant life, through 2025, for four separate reasons. First and foremost, that is the lifetime assumed by Pacificorp during the CDM negotiations, and that estimated lifetime was used to justify the decision to install scrubbers and to persuade the legislature to approve the tax package for Centralia which was approved in 1998. Exhibit 503

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[1] Puget assumed $10/ton beginning in 2008 in Scenario 3; Pacific assumed $1.10/ton beginning in 2009 in it's "Impact" analysis.

consists of excerpts from material presented by Pacificorp to the Washington State Legislature and material included in company press packets projecting the operating cost and tax revenue from the plant through the year 2025, the "30 YearLife of Plant" as it was described at that time.

Second, a contract to rewind the generators in 2001/02 (coordinated with downtime for scrubber installation) has been included in the Pacificorp forecast of costs, and since the original generators were installed in 1972 and have operated for 27 years, I thought it reasonable to assume that the rewinds would last until 2025, lifetimes of 23-24 years.

Third, the analysis prepared by the consulting engineer for the Applicants indicates that there are more than 50 years of coal reserves remaining at Centralia.

Finally, the Environmental Protection Agency has already granted sulphur dioxide emissions credits to the Centralia owners through at least the year 2027, as shown in Pacificorp's response to Public Counsel Data Request #32. It does not make sense to assume one plant lifetime when applying for sulphur emissions credits and then to use a shorter lifetime to justify the sale of the plant.

While Pacificorp assumed that Centralia would operate until 2025 in the CDM scrubber negotiations (26 years), it assumed only a 24 year remaining life (through 2023) in their application in this proceeding. Avista and PSE did not estimate a remaining lifetime for the plant, but used 21 and 19 year analyses (respectively) of the value of power in their submissions.

Q. What is the practical lifetime of the Centralia coal plant?

A. That is probably unknowable. There are coal plants operating in the United States which were originally commissioned over 50 years ago, but it is reasonable to assume that they have undergone major renovation and overhaul during that time, similar to that currently underway at Centralia. Given the difficulty of siting major energy facilities, it is common to employ life-extension measures to existing facilities. The scrubber installation is an example of this life extension, and the cost of the scrubbers is nearly the same as the original construction cost for the Centralia project itself. I consider the 26 year remaining life assumed by Pacificorp in the CDM negotiation to be reasonable; extending the life significantly beyond that time would probably require major overhaul expenditures which have not been included in the Company's estimated cost of ownership or operation.

Q. Has Pacificorp provided any support for your perspective that Centralia will likely be capable of operating for another 26 years?

A. Yes. In Pacificorp's power supply model, provided in response to PC Data Request #1, they show their estimates of the operating characteristics of virtually all thermal power plants in the western United States, together with estimated retirement data. Coal plants with vintages similar to Centralia, such as Jim Bridger, Colstrip 1 & 2, and Dave Johnston, are shown with no estimated retirement dates and no degradation of performance over the entire 19-year period of their analysis. In each case, annual capital improvements are included in the model, but the plants are assumed to operate throughout the analytical period. The Dave Johnston coal plant in Wyoming, for example, was commissioned in 1959, and is assumed to operate throughout the analytical period for a total life of 60 years.

Q. What data have you used in your base case analysis for the ownership and operating costs of Centralia?

A. I have relied primarily on Pacificorp's estimated cost of ownership and operation submitted in response to Staff data request #1 through 2023. For the last two years, I compared Pacificorp's estimated cost of operation for the last few years of the analysis submitted in this proceeding to those prepared for the CDM process. I determined that a conservative approach is to extrapolate the updated estimates for the last two years submitted in this proceeding, as these are newer and slightly higher (i.e., less favorable to the “keep” scenario) than the figures used in the CDM process.

Q. What data have you used in your base case analysis for the value of power from Centralia?

A. I relied primarily on the NWPPC Aurora model results through 2016 as the basis of my analysis, adjusted for the dispatch and location characteristics of Centralia. In my base scenario, I extrapolated that to the end of the 26-year analytical period. In other scenarios, I extrapolated the respective applicant’s estimates for Puget and Avista, and used Pacificorp’s RAMPP-5 Avoided Costs (which run through 2028) for the remaining years of the analysis.

The reason for choosing the Aurora model results for my base analysis is that I consider the Council staff and the Aurora model to be unbiased, technically competent, and up to date. The issue of what prices to use beyond the end of the Aurora model results and the end of the plant life required an assumption. In each scenario, I extrapolated these results for another ten years at a 2.5% inflation rate, which is the rate included in the NWPPC’s original model.

In an alternative scenario, I used Pacificorp’s filed avoided costs from RAMPP-5. The RAMPP-5 forecast is the only one that runs all the way to the end of the 26 years of my analysis. The RAMPP-5 forecast is slightly lower than the Aurora forecast for the years they cover in common, and I judged that using this forecast for the last years of the analysis was a conservative way to value power in those years.

Q. Are long-term forecasts of market prices speculative?

A. While the Aurora model is very sophisticated in modeling the west coast power system, it is inherently dependent upon assumptions as to natural gas prices, the cost of building new power plants, and evolution in power generation technology. The important thing I would note is the general congruence of the long-term forecasts prepared by Pacificorp, Puget (as used in the

Colstrip proceeding), Avista, and NWPPC; the big "differences" in the forecasts are in the period from 1999 to 2006, not in the later years. This difference between the older forecasts and the NWPPC Aurora model results reflects the fact that the region has moved into load/resource balance more quickly than previously assumed. This change is essentially confirmed by the newer forecast (November, 1999) provided by Avista in response to PC Data Request #19.

An important difference between Centralia and Colstrip should be noted here. Colstrip was a capital-intensive project, and in the Colstrip proceeding, the Commission concluded that the economic benefits of ownership could be expected to begin in the year 2005. Centralia, on the other hand, has much lower fixed costs, and is expected to provide economic benefits beginning immediately. Ratepayers have already paid for 27 years of capital costs at Centralia; we are beyond the "high cost" front-loaded years of its life. Even the scrubber additions are relatively modest in cost compared with the cost of a new power plant. For example, the cost of adding scrubbers to Centralia (1340 mw) is about $132/kw (1996$); the cost of Colstrip 3/4 (1400 mw) was $1,343/kw (1985$), plus transmission construction costs from Montana.

Under conditions of equilibrium, the short-term market price is approximately equal to the cost of a new combined-cycle gas turbine, around 30 mills/kwh, up from less than 15 mills/kwh in the 1995 - 1997 power market. Regional load growth, retirement of some generating plants, and a lack of new power plant construction are the basic causes of this increase. For example, in recent years, while the Trojan nuclear plant was retired, construction on the Tenaska / Fredrickson plant was halted by BPA. Other proposed generating plants, such as those approved by the Washington Energy Facility Site Evaluation Council for construction at Chehalis, Satsop, and Longview (totalling about 1500 megawatts, or more than the capacity of Centralia), have not been constructed.

Q. Why have you not relied exclusively upon the power market forecasts submitted by the Applicants?

A. As explained in the section below, COMMENTS ON THE PRESENTATIONS OF THE APPLICANTS, I found that each of their presentations suffered from either old or inappropriate data. I consider the NWPPC market forecasts to be the most unbiased, the most up-to-date, and the most complete. However, I have presented the results of multiple scenarios, including those resulting from use of the Pacificorp, Puget and Avista forecasts.

Q. Please summarize your findings on the economic effect of retaining Centralia?

A. Based on forecast ownership and operating costs, compared with the value of power as estimated in the Aurora model adjusted for the seasonal shape and location of the Centralia plant, I estimate that the plant would have to be sold for a total of <u>$1.4 billion, and 100% of the gain on that sale credited to ratepayers, in order for ratepayers to "break even"</u> compared with continued utility ownership of the plant. <u>This is nearly three times the proposed sale price.</u>

Based on other scenarios incorporating the NWPPC power cost forecast, the selling price would need to be $900 million - $1.3 billion. While some of the estimates presented by the applicants support lower selling costs, only the newest PSE forecast and Pacific's RAMPP-5 forecast seems to support a sale of the plant at the proposed price, and even if these lower forecasts were experienced, substantially all of the gain would need to be credited to ratepayers for consumers to "break even" for the period beginning in the year 2000, ignoring for the moment the huge ratepayer investment in the Centralia plant (payments in excess of market prices for power) in the past decade. I address the shortcomings of these other presentations later in my testimony.

In my analyses I have used the same discount rate of 7.16% that the Commission utilized in its Colstrip decision. This is based upon Puget's last-approved cost of capital, updated for changes in the cost of debt. Of the three Applicants, Puget has been before the Commission most recently for a cost of equity and capital structure determination. The table below presents the summary results of those scenarios which I think are most relevant for the Commission to consider. These analyses and other scenarios using other assumptions as to the cost and value of the power are developed and presented in greater detail in Exhibit 501.

Summary of Results

Scenario	**Minimum Required Selling Price** For Ratepayers to Break Even
Base - 26 Year Life	$1.4 billion
24-Year Life	$1.3 billion
$10/ton Carbon Tax in 2008	$914 million
Proposed Selling Price	$ 540 million

COMMENTS ON THE PRESENTATIONS OF THE APPLICANTS

A. Avista

Q. Please critique the assumptions made by Avista Corporation with respect to the cost and value of Centralia?

A. Avista has prepared a 21 year analysis of the cost and value of the power from Centralia. First of all, as previously explained, I have used a 26 year analysis to be consistent with the assumptions that went into the scrubber decision. I consider Avista's implied 21 year remaining plant life to be inappropriately conservative.

Avista's estimated value of power is, in my opinion, not of the caliber of those produced by others. The Company's estimate of the value of power presented in its direct testimony are obsolete, and the Company has prepared a new forecast which is much more consistent with the results of the Aurora model. That newer forecast was provided in response to Public Counsel data request #19, but the Company has not updated its testimony or exhibits. In general, compared with Avista's Exhibit 305, the new "medium" forecast is very close to the Company's old "high" forecast of market prices that appears in Exhibit 305.

In addition, rather than using a long-term model like Aurora, Avista has simply taken the most current market "quote" for a 5-year power product, and added 2 mill/kwh for the next 5 years. In Exhibit 305, they then extrapolated the later years at a 2.5% inflation rate. I have made the same extrapolation in my Exhibit 501, but using the newer forecast. While the inflation rate is the same as that used by NWPPC, Avista's approach completely ignores the expectation that regional markets will approach load/resource balance (i.e., increase in real terms as short-run marginal costs equal long-run incremental costs), and that natural gas fuel prices may well rise more rapidly than general inflation. The result, in my opinion, is a severe understatement of expected market prices in the Avista testimony.

Conversely, the Aurora model performs monthly analysis of West Coast loads and available resources, and new power plants are built when they are cost-effective for the plant owners to bring them into service. The combination of understated prices in the short run (i.e., not reflecting real market changes which have occured in the last year) and assuming only inflation-related increases thereafter makes the Avista value of power estimate inappropriate. Nonetheless, with the newer Avista forecast and even the shorter 24 year analytical period, the proposed selling price is insufficient to support a decision to sell the plant.

However, Avista has made two assumptions which I consider important, reasonable, and useful.

First, Avista has assumed that the power from Centralia is worth 1.71 mills/kwh more than generic year-round power at the Mid-Columbia point of delivery due to the dispatchability of the plant and the spring maintenance outage. This is consistent with past operating history at

Centralia and with the relationship between monthly costs which the Aurora model predicts and the projected operating costs of Centralia.[2]

Second, Avista assigns Centralia a value 1 mill/kwh more than generic power at the Mid-Columbia point of delivery due to its capacity value. The documents offering Centralia in the auction noted this value of Centralia in providing voltage support for the western part of the transmission grid. The Centralia Operating Committee minutes of March 24, 1998, estimated that a transmission reliability investment of $58.4 million would be required if Centralia were shut down, but did not indicate the value of additional transmission losses which would be experienced. A 1 mill/kwh benefit has a present value of $93 million, and is comparable to a $58.4 million avoided transmission investment plus some measure of additional system operating expenses associated with load following, voltage support, and losses.

I have included each of these benefits in my base case analysis and other analyses. In one case, PSE's newest analysis, the dispatch benefit was already embedded in the Company's (otherwise undocumented) Avoided Costs.

While I do not endorse the Avista analysis, due to the low and simplistic estimate of the value of power, the updated analysis, including the effect of the new power market forecast, suggests that the selling price would need to be at least $700 million in order to provide enough benefits to ratepayers to justify the sale.

B. Puget Sound Energy

Q. Turning to PSE, why should its estimate of the cost and value of power not be utilized?

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[2] The "equivalent availability" is a measure of the capability of the plant to produce power if dispatched. The "capacity factor" is the measure of power actually expected to be produced. The difference indicates that there are about 1500 hours per year when the value of the power would not exceed the variable running costs, and that the plant would be shut down to save money.

A. While PSE has used the Aurora model which I believe is the best available tool for estimating future power costs, there are two problems with PSE's analysis.

First and foremost, it is only a 19 year analysis, and Centralia is expected to last much longer.

Second, it does not adequately recognize the capacity and dispatch value of Centralia. The most recent NWPPC Aurora forecast separately estimates the value of power in Western Washington. It was not appropriate to make those adjustments for Colstrip, since Colstrip is located in Montana, and because the fuel costs at Colstrip are so low that it would seldom be subject to economic dispatch. To fail to account for these differences in the Centralia analysis is inappropriate, and I have modified the market forecast results used in the Colstrip case accordingly.

Third, there is no explanation whatsoever in PSE's evidence of why they present a LOWER forecast of future market prices than was submitted in the Colstrip proceeding. This new forecast is as much as 10 mills/kwh LOWER than the NWPPC Aurora results. For this reason, in my alternative scenarios, I have calculated the required minimum selling price using BOTH the forecast accepted by the Commission in the Colstrip proceeding as well as the newer, unsubstantiated PSE forecast.

PSE's estimate of the cost of keeping Centralia is generally reasonable, although it is a little bit high because it is based upon a cost of debt which has declined since the company's rate of return was last established.

Based on PSE's estimate of the cost of keeping Centralia, and the NWPPC estimate of the value of the power, the selling price would have to be at least $1.4 billion to provide enough benefit to ratepayers to justify the sale.

Using PSE's estimate of the cost of keeping Centralia, and the value of power adopted by the Commission in the Colstrip proceeding (adjusted to reflect the dispatch and locational value of Centralia), the selling price would have to be $651 million, or about 20% above that proposed.

Only if PSE's newest, lower forecast were used would the sale at the proposed price be justified, and even this would require that substantially all of the gain be credited to ratepayers to prevent harm.

C. Pacificorp

Q. Finally, what problems have you detected in Pacificorp's analysis of future costs and value of Centralia power?

A. I have relied heavily upon Pacificorp's estimate of the cost of owning and operating Centralia. The non-fuel and fuel costs are all provided in the Company's response to WUTC Staff Data request #1. In addition, a separate, higher forecast of fuel costs was provided in the workpapers to Mr. Miller's exhibits. I have used the fixed cost calculation and the higher fuel cost estimate (i.e., assumptions <u>less favorable</u> to the "keep" option) without modification for my analysis. I would also note that the fixed costs are probably too high, simply because Pacificorp has used a cost of capital consisting of 48% equity at 11.25%; in my 21 year career, the Commission has <u>**never**</u> allowed this high an equity capitalization ratio for an electric utility, and the most recent cost of equity decision for an electric utility was lower than 11.25%. Relying on what I consider slightly overstated "keep" costs, in my opinion, adds a measure of conservatism to my analysis.

On the value of power side of the equation, however, Pacificorp's analysis is seriously deficient. First, it does not rely on the Aurora model, but rather uses a proprietary model that has not been submitted for regional peer review. Second, embedded in this model is an apparent assumption that natural gas prices will decline in real terms over the entire forecast period, exactly the opposite of what NWPPC is assuming. Third, the Pacificorp model assumes that 22,000 megawatts of new combined cycle generation will be installed along the west coast over the next 15 years, without any analysis of whether those installations are cost-effective for the (assumed) owners; these capacity additions are hard-wired into the Pacificorp model, holding down the estimated market clearing price of the market. By contrast, the Aurora model “builds” new capacity if and when the market price reaches a point where an owner would recover their costs of constructing and operating a plant; no plant construction is “hard wired” into Aurora. I consider this an unacceptable shortcoming of the Pacificorp model.

In my exhibit 501, I have computed the value of the Centralia project, comparing the cost of power provided by the Company in the response to Staff Data Request #1 to a composite of the Aurora model results for the early years, and then extrapolated that result at the NWPPC’s assumed 2.5% inflation rate. This scenario indicates that a selling price of $1.497 billion would be required for ratepayers to break even. Even if I substitute Pacific’s now-obsolete “RAMPP-5" avoided costs, filed with the Oregon Commission in mid-1999, the minimum required selling price is $653 million, or about 20% higher than the selling price to TransAlta.

NO ANALYSIS OF POWER SUPPLY ALTERNATIVES

Q. Have any of the Applicants prepared an analysis of alternatives available to replace the power currently provided by Centralia?

A. No. The Commission’s Least Cost Planning rule requires each of the applicants to prepare an analysis every two years of alternatives for meeting future power needs. None of the Applicants have submitted a Plan in the last two years[3], and none of them have examined the sale of Centralia in any Plan ever submitted for review under the Commission’s rule.

[3] Pacificorp and Avista’s last filings were in 1997 and should not be considered seriously “delinquent.” PSE’s last electric least cost plan was filed in 1993.

The Commission noted the absence of this type of analysis in the Colstrip proceeding, stating:

> *"Although different kinds of power supply may be obtained, or shorter-term planning horizons may emerge, the Commission still considers it the responsibility of any utility to demonstrate what futures it sees as possible, and how it plans to meet its obligation to serve. The "new world" of power supply will, in all likelihood, require more planning rather than less."* [Docket UE-990267, 3rd Supp. Order, P. 21]

Q. What type of studies would be appropriate in examining an issue like the sale of Centralia?

A. The analysis should be resource-specific and should look at the life of the resource, life-extension options, and the potential for technological innovation. None of the Applicants have performed such a study.

Centralia has unique economic characteristics, including high reliability, a relatively short (30 days) annual maintenance interval, and the ability to be used in an economic dispatch scheme wherein it is shut down during periods when low-cost power is available, such as during the annual fish-flush operation on the Columbia River.

Alternative resources will have different, and equally unique characteristics. For example, a combined cycle gas plant would have a slightly higher availability than Centralia but be exposed to the vagaries of the natural gas market. Wind energy generators would have lower reliability and no dispatchability. Residential weatherization conservation measures would have higher reliability, provide additional savings on the transmission and distribution system, and have very different seasonal power supply impacts.

The tools that the region has developed in the past 14 years, since the Commission first ordered the preparation of Least Cost Plans in Cause U-85-53, allow for sophisticated comparison of resources with such distinct economic characteristics. The utilities have not used such tools in their evidence in this proceeding.

RATEPAYERS HAVE A HUGE INVESTMENT IN CENTRALIA

Q. How have the costs of Centralia been recovered in rates?

A. The current rates for each of the Applicants include the rate base, depreciation expense, and operating expenses for Centralia, based on their last rate proceedings.

Q. How does the cost of this power compare with the value in recent years?

A. The cost of power from Centralia is generally lower now than when rates were set for the owners, as the fixed costs have declined and the variable costs have been kept in check by aggressive cost containment and restructuring of the fuel supply contract.[4] In recent years, the return and operating expenses have generally been significantly greater than the market value of the power received from Centralia. Exhibit 504 compares the costs for Centralia power with the market value of power. To account for economic dispatch, I have excluded the month of May from these calculations, since Centralia is normally shut down for maintenance during the "fish flush" season when power prices are lowest.

Over the period 1986 through 1998, the cost of Centralia power was approximately $512 million MORE than the market value of that power. Using the 7.16% discount rate adopted by the Commission in the Colstrip proceeding, this totals $918 million in excess payments by ratepayers, expressed in 1999 dollars.[5]

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[4] Operating costs for Centralia were 24 mills/kwh in 1986, when WWP and PP&L last were before the Commission for rate cases. In 1998, this operating cost had declined to 20 mills/kwh.

[5] This calculation is prepared on the basis of Avista's allowed rate of return from 1986, updated once to reflect changes in the cost of capital in 1992. It is approximately accurate for the investor-owned utilities which are the subject of this proceeding. Different calculations would be applicable to the consumer-owned utilities.

In my opinion, this $918 million should be considered a ratepayer investment in Centralia, justifiable only because it was expected that over the long run, the plant would be cost-effective. The Aurora forecast now shows that this was probably a reasonable strategy, but in order for ratepayers to recover this investment, they must either enjoy the continued output of Centralia on a cost of service basis, or else receive compensation of $918 million if the plant is sold. It would be utterly unfair to have required <u>ratepayers</u> to have supported the Centralia investment for the past 13 years, when it was **uneconomic**, and then to allow <u>shareholders</u> to reap the benefits of a gain on the sale of the project now that it is more valuable..

In the Colstrip proceeding, the Commission noted the fact that baseload generating facilities are capital-intensive and that the costs are front-loaded, with an expectation of lower costs in the later years potentially justifying the high initial costs:

> *"Ratepayers have been funding the significant capital costs which occur early in the life of the asset [Colstrip.] It is likely that Colstrip will provide economic benefits after the facilities are fully depreciated."* Docket No. 990267, Third Supp. Order, P. 12

Based on this analysis of the payments by ratepayers in excess of market prices since 1986[6], the selling price of Centralia would have to be approximately $1.2 billion in order to reimburse ratepayers for their above-market payments for Centralia power since 1986 and provide a recovery of the undepreciated investment in the plant and mine for shareholders.

The point is that in order to make ratepayers indifferent either retrospectively or prospectively, the selling price would need to be much higher.

A PLAUSIBLE CARBON TAX DOES NOT CHANGE THE RESULTS

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6 Centralia began operation in 1972; if the analysis were taken back to the beginning of the plant's history, the "overpayment" by ratepayers, relative to market prices, would be even larger.

Q. Have you considered the effect that a carbon tax might have on the economic desirability of owning the Centralia project?

A. Yes. Both Pacificorp and PSE included carbon tax scenarios in their analyses, and I agree that this is a potential risk that should be considered. Because Centralia is a coal plant, it has greater exposure to a carbon tax than the "default" replacement resource I assumed, a gas turbine.

Q. How did you examine the potential of a carbon tax?

A. Pacificorp and PSE both assumed imposition of the tax in 2008. Pacificorp assumed a tax rate of $1.10/ton ($1996), while PSE assumed a tax rate of $10/ton. I used the higher figure in my analysis, because I consider Pacificorp's estimate to be trivial in magnitude.[7] However, I held this constant in nominal terms, because in my experience, taxes seldom have inflation adjustments built in. Even if a high carbon tax were imposed, it would likely be phased in over a long period of time.

Q. What does this analysis show?

A. With inclusion of a $10/ton carbon tax beginning in 2008, the minimum required selling price of the plant drops from $1.4 billion to $900 million. Centralia remains a very good deal for ratepayers even if such a carbon tax were imposed.[8]

Q. What if an even larger carbon tax were imposed?

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[7] Given Pacificorp's resource portfolio, including more than 4,000 mw of coal-fired generation, the Company clearly has an incentive to resist higher carbon taxes. This may influence the level of carbon tax which it considers acceptable to analyze.

[8] This analysis assumes that the carbon tax would be about three times as much per kwh on Centralia as on a gas turbine resource, because the carbon emissions are three times as great per kwh.

A. If the plant output become too expensive due to any factor, including a carbon tax, the option to shut it down in the future is always available to the owners. My analysis shows that the magnitude of a carbon tax would need to be VERY high before it would cause plant closure to be a cost-effective choice, and that it is highly likely that the value offered by TransAlta for the plant would be recovered long before a high carbon tax would be a plausible scenario. One option might be to impose a carbon tax on “new” resources, but to phase it in gradually for existing resources. Given the colossal political failure of President Clinton’s proposed energy tax in 1993-94, I consider the probability of a high carbon tax applied to existing resources to be fairly low.

Indeed, there is a possibility that a carbon incentive mechanism might be imposed in the same manner as the sulphur program now in effect, monetizing the pollution rights of existing polluters. Such an approach might well <u>enhance</u> the value of Centralia, and both Pacificorp and TransAlta considered such a possibility in the evaluation of the proposed sale.

QUALITATIVE FACTORS DO NOT JUSTIFY THE SALE OF CENTRALIA

Q. What are the qualitative reasons which have been offered as support for the sale of the Centralia project?

A. First, there is the issue of the awkward ownership structure, with eight different owners and a requirement for unanimous agreement on major decisions. Second, there is the issue of mine reclamation. Third, there is the issue of the the potential for technological evolution which would render the Centralia project uneconomic. Finally, there is the issue of the stability of the employment which the Centralia project provides in Thurston and Lewis Counties.

Q. Do you agree that the ownership structure is awkward and that this is a justification for the sale of the project?

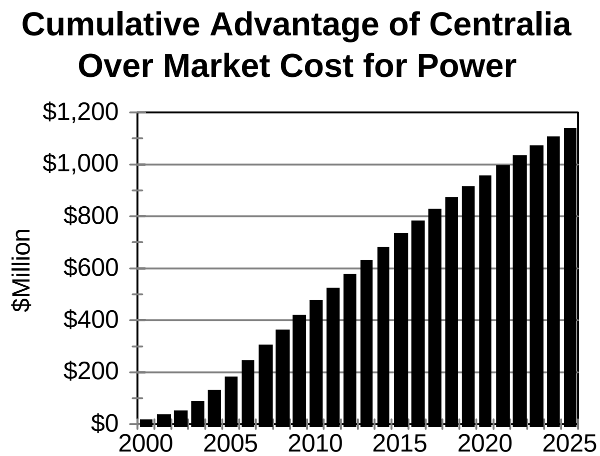
A. The ownership structure is awkward, because unanimous consent is needed for major decisions. However, this is being addressed in part by Avista entering into agreements to purchase shares currently held by PGE and Snohomish. If the fundamental economics of the plant are sound, there is no reason to expect that ownership issues cannot be overcome. Since my analysis shows that the economics of continued operation are very robust, there is little cause for concern. Exhibit 505 shows that the plant has operated with equivalent availability averaging around 90% for the past decade, even though the operational economics were fairly unfavorable due to a surplus wholesale power market. This is demonstrative proof that the plant is capable of being maintained and operated within the current ownership structure, but additional ownership consolidation is likely and probably desirable.

Q. Have the costs of mine reclamation been included in your analyses?

A. Yes. Each of the Applicants included the estimated cost of mine reclamation in their estimated fuel costs for the project in the “keep” scenarios, and I have included these costs in my analyses. It is admittedly unknowable whether actual reclamation costs will be higher or lower than the amounts being accrued into the reclamation fund through the fuel price, but I can only assume that these fuel costs include a “best guess” of these costs. The total amount flowing through the reclamation fund from 2000 through 2041 (when reclamation is assumed to be completed) is $510 million, as shown in Pacificorp’s workpapers. This amount is consistent with the estimated cost of reclamation.

Q. Do you agree that the Centralia technology is at risk to future technological evolution?

A. Yes, in fact for the benefit of the atmosphere and the planet, I sincerely hope so. For that reason, I examined the cumulative value of the plant to ratepayers over and above fixed and variable costs over the 26 years of my analysis. This analysis, shown in the graph below, shows that by 2008, the plant will have returned more value to ratepayers than the entire gain at the proposed sale price.



While it is likely that new technologies will evolve, the Aurora model is based upon the lowest cost currently-available technologies. I think it is unlikely that technologies significantly cheaper than these will be developed and deployed commercially in quantities significant enough to materially affect the power market in the next nine years.

Q. Finally, do you consider the preservation of employment at Centralia to be at risk?

A. No, I do not. The economics of operation are extremely robust, and my analysis shows that the existing owners will have every incentive to continue to operate the plant as long as it is economically competitive. While TransAlta may be a very highly qualified operator, this plant has 26 years of history of being operated successfully by the existing owners. This is evidence that if the economics are favorable, the plant will operate, and the employment will continue. I consider this to be a non-issue.

Conversely, TransAlta representatives indicated at a meeting with the Northwest Energy Coalition that it expected to be able to achieve considerable cost savings at the plant and mine. This would be consistent with the "aggressive cost containment" scenario prepared by Pacificorp.

It is logical that such cost containment would be accompanied by employment reductions. I have not included such cost containment as part of my base scenario analysis, but did examine it in an alternative scenario. Under this assumption of aggressive cost containment, the selling price would need to be $1.5 billion, and all of the gain credited to ratepayers, in order for the proposed sale to be acceptable.

THE AUCTION PROCESS DOES NOT DETERMINE A "FAIR" PRICE

Q. Does the fact that the proposed selling price was arrived at through an auction process mean that the proposed selling price is fair to ratepayers?

A. No. The auction, at best, could have determined the highest price that a willing buyer offered as of April, 1999, based on information provided beginning in September, 1998. My Exhibit 501 shows that forecasts of the value of power in the market increased significantly during this period, meaning that the value of the plant <u>today</u> is higher than it was at the time the bids were solicited.

More important, however, the value of the plant to regulated utilities, such as the Applicants, may be very different than it is to an Exempt Wholesale Generator (EWG). Utilities have access to low-cost capital with reasonable leverage. This low cost of capital reflects, in part, the societal discount rate of the utility's consumers. An EWG has much less certainty that they will be able to market the output of the project profitably, and therefore it should be expected to require a higher return on investment than a utility cost of capital. The bottom line is that an EWG should not be expected to pay as much as the plant is worth to the customers of a regulated utility.

For that reason, while the auction process may be a method to determine the value of the plant to TransAlta, it is not a method to determine the value of the plant to the ratepayers of Pacific Power, Puget Sound Energy, or Avista Utilities.

Q. Did the sellers accept the highest bid tendered in the auction?

A. No. There was one higher bid that was not accepted.[9]

AVISTA'S ARGUMENT FOR SHAREHOLDERS TO RECEIVE GAIN IS INAPPROPRIATE

Q. Mr. Dukich has proposed that shareholders should receive all of the gain on sale of Centralia, due to the low rates that Washington Water Power has charged. Is this a legitimate argument?

A. No. First and foremost, Mr. Dukich's exhibit 307 is utterly inappropriate. It appears to assert that Avista is entitled to a 10.67% return on rate base. That return was agreed to in Cause U-86-99, and that rate of return is now more than a decade out of date. If one were to attempt a meaningful analysis of this type, it would first be appropriate to update the allowed rate of return over the 13-year period since that docket. For example, in 1992, Puget was allowed a rate of return of 8.94% (and almost anyone would agree that Puget is a riskier utility than Washington Water Power). Avista has earned substantially in excess of 8.94% in the period since 1992.

Second, Mr. Dukich ignores the considerable investment that ratepayers made in keeping Centralia available over this same period since 1986. As shown in my Exhibit 505, this totals some $512 million, an investment justified only by the expectation that the plant would ultimately be cost-effective. As I explained earlier, reimbursing ratepayers for this investment should come before granting any windfall to shareholders.

Mr. Dukich's proposal also ignores the fact that the only logical way that a power plant under regulation can have a depreciated book value which is different from the market value is if the

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9 Public Counsel was allowed to "view" the alternative bids at Pacificorp's offices, but not to obtain copies or take any notes during this "viewing." It was not possible under these circumstances to perform any analysis of whether the technical and financial details of the high bid justified rejection, but even that higher bid amount would not fairly compensate ratepayers for the loss of Centralia.

depreciation expense allowed by the Commission in rates is too high. The fact that Centralia is being sold for MORE than the ORIGINAL book value of the investment suggests that the proper level of depreciation expense was ZERO. The plant, in fact, has APPRECIATED, not DEPRECIATED. Ratepayers should recapture excess depreciation contributions (and a deferred return on these contributions) prior to the calculation of any gain on sale which might then be divided between ratepayers and shareholders.

Finally, Mr. Dukich's proposal, if accepted, would require the Commission to completely revisit the notion of how allowed rates of return are computed. If a utility is allowed to reap the gains on the sale of plant which has been supported by ratepayers, the risk-adjusted rate of return would need to be computed in expectation of these windfalls due to appreciation of investments. Basically, acceptance of this proposal would seem to require that the allowed rate of return be computed without consideration of inflation in the calculation of the cost of capital. This is a radical notion which should not be considered in this proceeding.

CONCLUSION

Q. Please summarize your analytical results and your recommendation to the Commission?

A. The proposed sale of Centralia should be rejected. The proposed selling price is too low to compensate for the loss of the reliable, predictable-priced power than Centralia provides. The selling price would need to be nearly three times as high in order to make ratepayers whole.

The Centralia project should be expected to last for at least another 25 - 30 years once the scrubbers are installed and the generators rewound. This is longer than the analyses of the Applicants, and their shorter analyses ignore significant benefits of continued ownership.

In the event that the sale is to be approved, the Commission should take specific steps to ensure that ratepayers are held harmless. This would require that the selling utilities covenant that they will continue to supply power to ratepayers at costs no higher than ratepayers would experience from Centralia if it were not sold.

At a minimum, if the plant is sold, ratepayers should be reimbursed for the $512 million (plus interest, for a total of $918 million) that they have contributed over and above the value of Centralia power since 1986.

Q. Does this complete your prepared testimony?

A. Yes.