Exhibit T-500

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

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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?

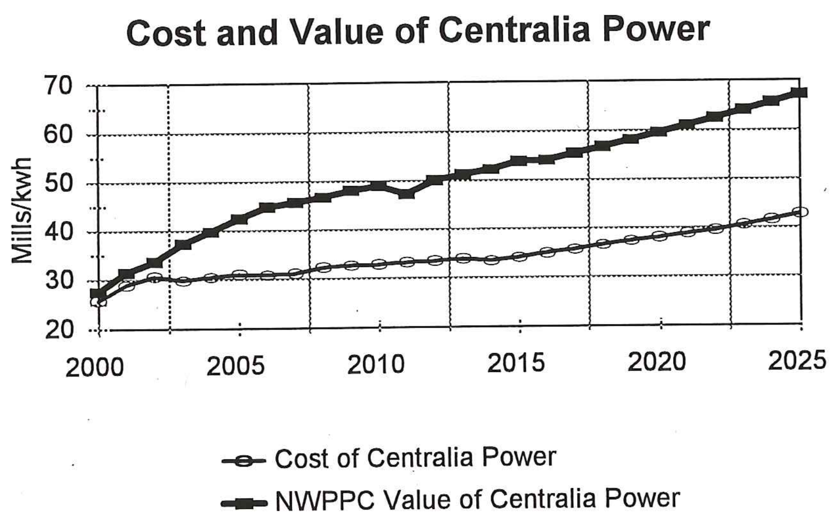
A. I address the economics of the Centralia project, compare the cost of ownership and operation of Centralia to recent forecasts of market prices for electric power, and present my conclusions as to why the sale of the plant is NOT consistent with the public interest. I also address some of the "qualitative"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

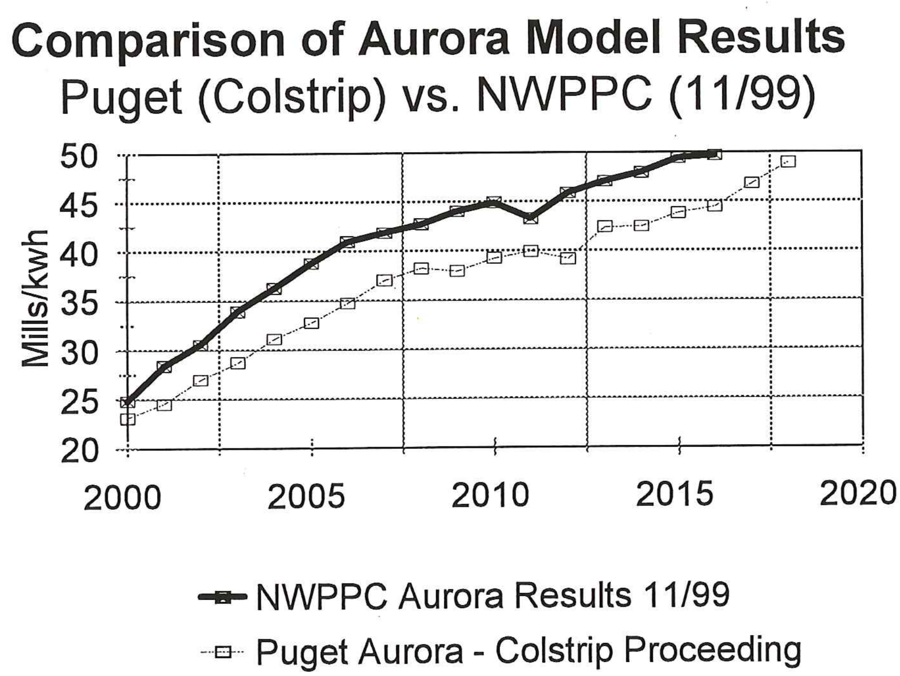
ECONOMICS OF CONTINUED OWNERSHIP OF CENTRALIA

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 consists of excerpts from material presented by Pacificorp to the Washington State Legislature

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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.

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 $1.4 billion, and 100% of the gain on that sale credited to ratepayers, in order for ratepayers to "break even" compared with continued utility ownership of the plant. This is nearly three times the proposed sale price.

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.

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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.

A PLAUSIBLE CARBON TAX DOES NOT CHANGE THE RESULTS

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]

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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.

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

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 enhance 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?

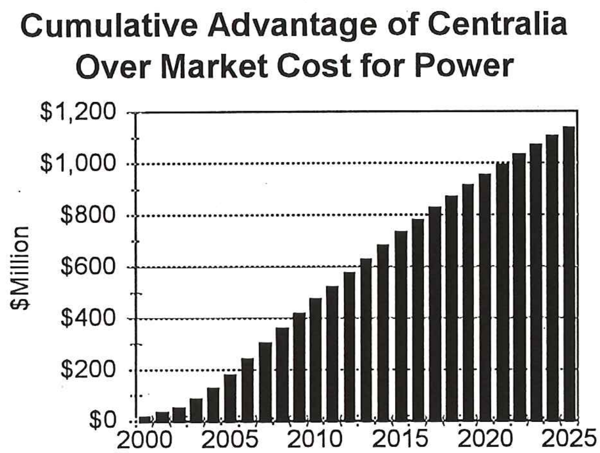
A. The ownership structure is awkward, because unanimous consent is needed for major decisions. However, this is being addressed in part by Avista entering into agreements to purchase shares currently held by PGE and Snohomish. If the fundamental economics of the plant are sound, there is no reason to 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.

Christine O. Gregoire
ATTORNEY GENERAL OF WASHINGTON
900 Fourth Avenue #2000 • Seattle WA 98164-1012

January 3, 2000

Carole Washburn
WUTC
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PO Box 47250
Olympia, WA 98504-7250

RE: ***UE-991255 Avista/Centralia***
UE-991262 PacifiCorp/Centralia
UE-991409 PSE/Centralia

Dear Ms. Washburn:

Please find enclosed a revised Exhibit 501 (12/31/99), which replaces the prefiled exhibit, and a list of revisions to Mr. Lazar's testimony (Exhibit T-500) which reflects the revisions that he has made to Exhibit 501. These revisions were previously referenced in Public Counsel's letter to the Commission dated December 30, 1999. These revisions are being faxed to the Commission and parties today, and the workpapers in hard copy and electronic format will be provided tomorrow.

Thank you for your assistance.

Very truly yours,

Charles F. Adams
Assistant Attorney General
(206) 464-6446

CFA/ca
Enclosures
Cc: Parties

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 500
ADMIT ☑ W/D ☐ REJECT ☐

Revised Exhibit 501 and Related Testimony

The following corrections are a result of errors identified since the testimony and exhibits were prefiled and also new information which has become available subsequent to Public Counsel's filing:

1) Revisions filed by Pacificorp to its exhibits on 12/28/99.
2) Errors identified in Mr. Lazar's exhibit in response to PSE and Pacificorp data requests.
3) Additional error identified in calculation of value of sulphur credits 12/28/99.
4) New forecast released by Northwest Power Planning Council as part of 12/8/99 report on regional reliability; the forecast was obtained on 12/29/99.

Corrections to the testimony of Jim Lazar (Exhibit T-500).

Page 2, line 10	*$1.1 billion* should read **$800 million**
Page 11, line 8	*$1.4 billion* should read **$1.0 billion**
Page 11, line 10	"*three*" should be "**two**"
Page 11, line 13	*$900 million - $1.3* billion should read **$625 million - $1.2 billion**
Page 12, Lines 1-11	*$1.4 billion* should read **$1.0 billion** *$1.3 billion* should read **$1.0 billion** *$914 million* should read **$625 million**
Page 15, line 26	*$1.4 billion* should read **$1.0 billion**
Page 16, line 3	*$651 million* should read **$734 million**
Page 16, line 3	"*20%*" should be "**35%**"
Page 17, line 12	*$1.497 billion* should read **$1.166 billion**
Page 17, line 15	*$653 million* should read **$557 million** *or about 20%* should be deleted
Page 21, line 22	*$1.4 billion to $900 million* should read **$1.0 billion to $625 million**
Page 25, line 4	*$1.5 billion* should read **$1.2 billion**
Page 27, line 22	*three* should read **two**

Exhibit 501 has been revised in its entirety. Revisions are dated 12/31/99.

Before the
Washington Utilities and Transportation Commission

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

Exhibit of

Jim Lazar
Consulting Economist

On Behalf of
Public Counsel

Exhibit 501
Keep vs. Sell Analyses

Revised 12/31/99

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 501
ADMIT ☑ W/D ☐ REJECT ☐

Summary of Results
Centralia Cost and Value of Power
2000-2025

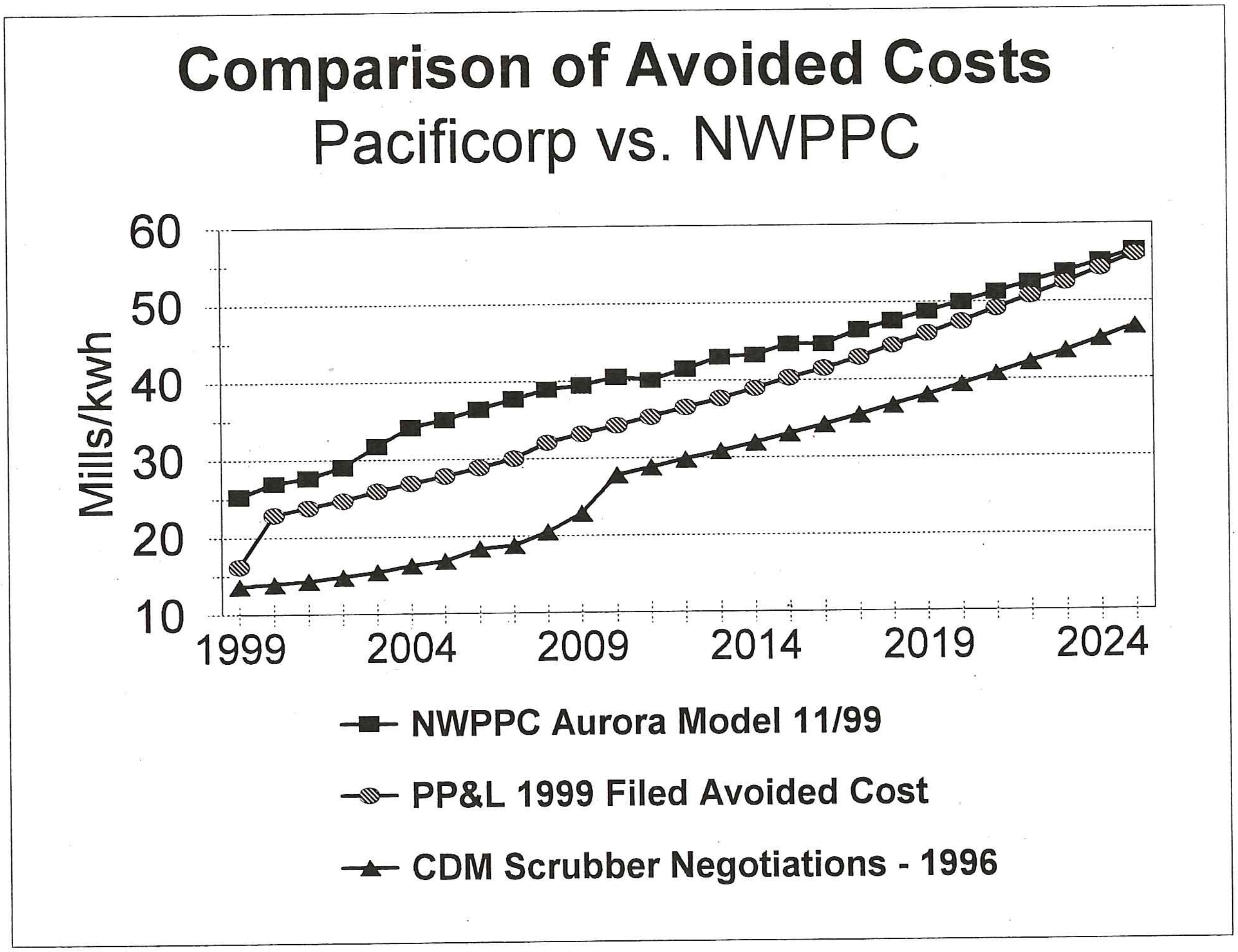
Scenario		Cost of Power	Value of Power	Years Analyzed	Minimum Required Sell Price	Sale Price to TransAlta	Gain on Sale to Make R/P Whole	Total Gain On Sale to TransAlta
1	Base Analysis	Pacificorp	NWPPC (11/99)	26	$1,030	$540	$807	$317
	Sensitivity Analyses							
2	24 Year	Pacificorp	NWPPC (11/99)	24	$981	$540	$758	$317
3	PSE / Aurora	PSE	NWPPC (11/99)	26	$1,014	$540	$791	$317
4	Aggressive Cost Containment	Pacificorp	NWPPC (11/99)	26	$1,166	$540	$943	$317
5	Pacific RAMPP-5	Pacificorp	RAMPP-5	26	$557	$540	$334	$317
6	Colstrip Equivalent	PSE	WUTC-Colstrip	26	$734	$540	$511	$317
7	PSE 26	PSE	PSE	26	$501	$540	$278	$317
8	Avista 26	Avista	Avista (new)	26	$744	$540	$521	$317
9	CO2 Tax	Pacificorp	NWPPC (11/99)	26	$625	$540	$402	$317

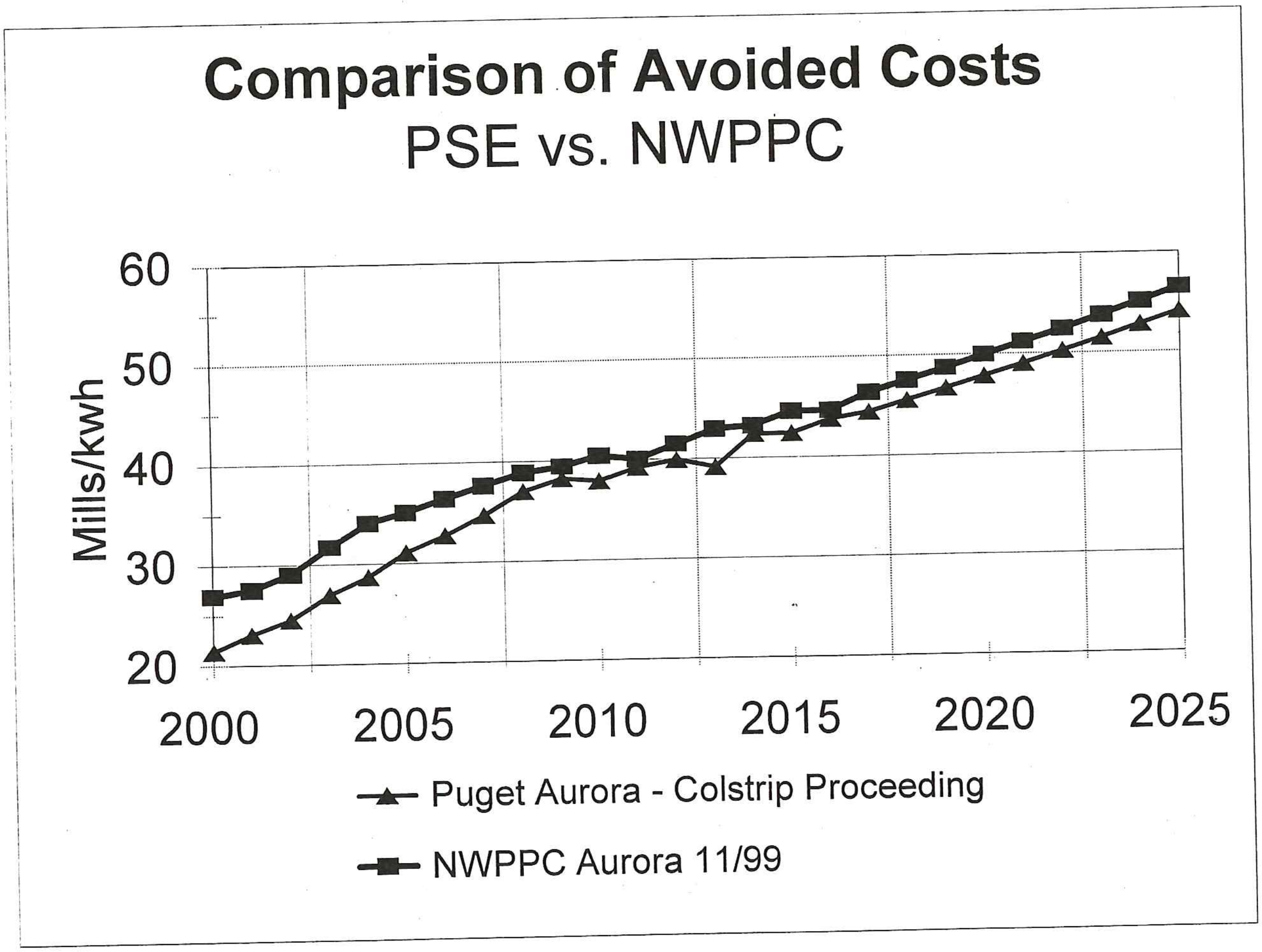
Note: All scenarios include dispatchability and capacity adders if not included in underlying forecasts

Comparison of Avoided Cost Estimates

Forecast:	RAMPP-4 PP&L	RAMPP-5 PP&L	Aurora Colstrip PSE	Centralia PSE	Centralia Avista	11/99 Avista	NWPPC 1998 Plan	NWPPC 11/99	Used In Scrubber Negotiation
Vintage:	1997	1999	1999	1999	1999	1999	1998	1999	1996
Year									
1999	14.6	16.2			22.5	21.9	25.3	25.3	13.6
2000	14.7	22.9	21.4	26.5	22.8	26.5	27.0	26.9	13.9
2001	15.1	23.8	23.1	27.0	23.8	27.0	28.1	27.6	14.3
2002	15.7	24.7	24.6	27.5	24.3	27.3	29.8	29.0	14.8
2003	16.3	25.9	27.0	27.9	25.0	27.5	30.6	31.7	15.4
2004	17.6	26.9	28.8	28.4	25.6	27.8	31.9	34.1	16.3
2005	18.1	27.8	31.1	30.6	26.2	28.0	32.7	35.1	16.8
2006	20.7	28.9	32.8	32.6	26.9	28.3	34.1	36.4	18.4
2007	21.0	30.0	34.7	34.5	27.5	30.3	35.1	37.7	18.8
2008	23.7	32.0	37.1	35.7	28.2	32.3	36.2	38.9	20.5
2009	27.9	33.1	38.3	35.4	28.9	34.3	38.6	39.4	22.9
2010	37.1	34.2	38.0	36.8	29.7	36.3	39.0	40.5	27.8
2011	38.4	35.3	39.3	37.5	30.4	*37.2*	40.4	40.0	28.8
2012	39.7	36.5	40.0	36.3	31.2	*38.1*	42.2	41.5	29.8
2013	41.1	37.6	39.2	39.6	31.9	*39.1*	43.4	43.0	30.8
2014	42.5	38.9	42.4	39.6	32.7	*40.1*	45.4	43.2	31.9
2015	43.9	40.2	42.5	41.0	33.6	*41.1*	46.1	44.6	33.0
2016	45.5	41.5	43.8	41.6	34.4	*42.1*	48.6	44.6	34.2
2017	47.0	42.9	44.4	43.5	35.3	*43.1*	*49.8*	46.4	35.4
2018	48.7	44.4	*45.5*	45.8	36.1	*44.2*	*51.1*	*47.5*	36.7
2019	50.4	45.9	*46.7*	*46.9*	37.0	*45.3*	*52.3*	*48.7*	38.0
2020	52.1	47.4	*47.8*	*48.1*	38.0	*46.5*	*53.6*	*49.9*	39.3
2021	53.9	49.1	*49.0*	*49.3*	*38.9*	*47.6*	*55.0*	*51.2*	40.7
2022	55.8	50.7	*50.3*	*50.5*	*39.9*	*48.8*	*56.4*	*52.5*	42.1
2023	57.8	52.4	*51.5*	*51.8*	*40.9*	*50.0*	*57.8*	*53.8*	43.6
2024	59.8	54.2	*52.8*	*53.1*	*41.9*	*51.3*	*59.2*	*55.1*	45.2
2025	61.9	56.0	*54.1*	*54.4*	*43.0*	*52.6*	*60.7*	*56.5*	46.8

Note: All Figures in italics are extrapolated at 2.5% assumed inflation
All estimates for "flat" power without ancillary service or locational adders


Comparison of Avoided Costs
Pacificorp vs. NWPPC
Mills/kwh
60
50
40
30
20
10
1999
2004
2009
2014
2019
2024
NWPPC Aurora Model 11/99
PP&L 1999 Filed Avoided Cost
CDM Scrubber Negotiations - 1996


Comparison of Avoided Costs
PSE vs. NWPPC
Mills/kwh
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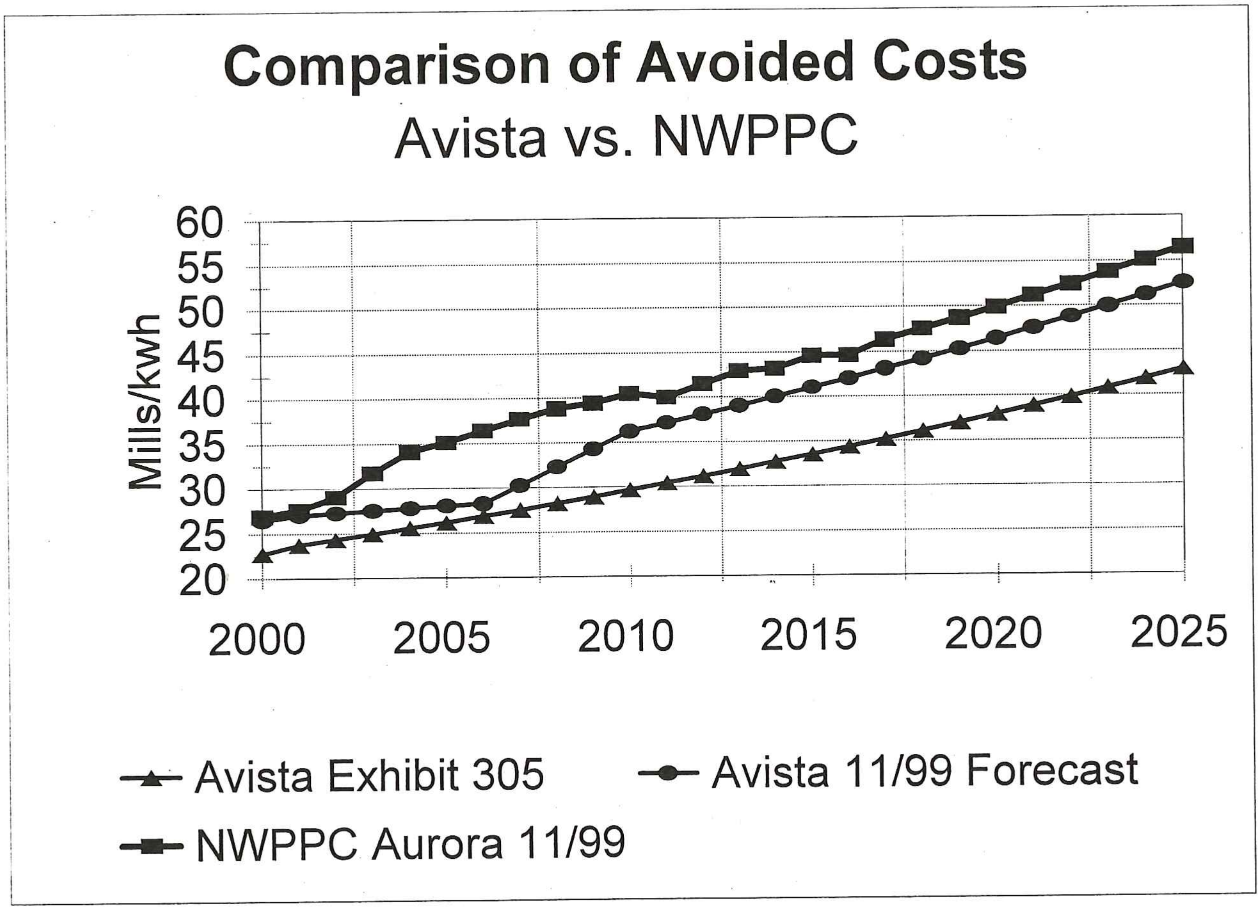
Puget Aurora - Colstrip Proceeding
NWPPC Aurora 11/99


Comparison of Avoided Costs
Avista vs. NWPPC
Mills/kwh
60
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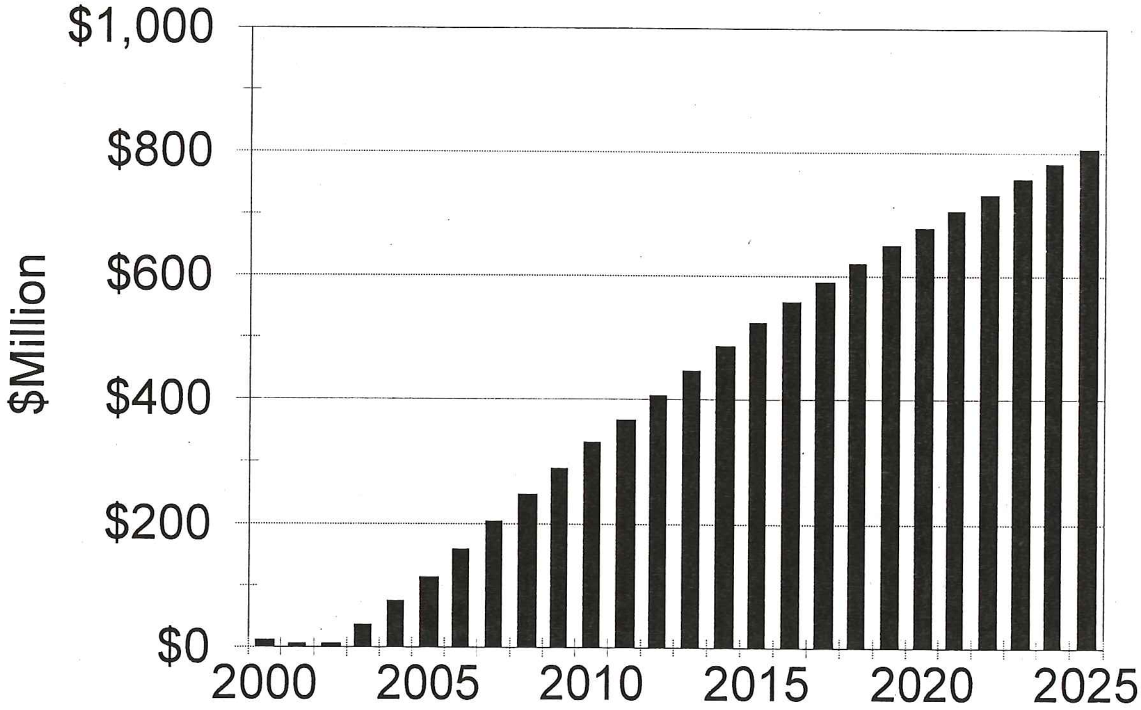
2020
2025
Avista Exhibit 305
Avista 11/99 Forecast
NWPPC Aurora 11/99

Cumulative Advantage of Centralia Over Market Cost for Power



BASE ANALYSIS

NWPPC Aurora Value of Power Revised 12/29/99	Source	2000	2001	2002	2003
Non-fuel Revenue Requirement	PP&L	$34,328	$44,764	$49,658	$45,177
Unit 1 Fuel	PP&L	$33,114	$33,651	$33,973	$34,734
Unit 2 Fuel	PP&L	$32,939	$33,604	$34,565	$35,549
Total		$100,380	$112,019	$118,196	$115,460
PP&L Share of Output	PP&L	3,873,072	3,877,197	3,867,687	3,893,872
Ownership / Operating cost mills/kwh	PP&L	25.92	28.89	30.56	29.65
Aurora Forecast from NWPPC	11/29	26.92	27.59	29.05	31.74
Extrapolation Beyond Forecast @ 2.5%					
Value of Power Before Shaping:		26.92	27.59	29.05	31.74
Add Dispatch @ 1.71 proportioned		1.71	1.75	1.84	2.02
Value with Dispatch Benefit	Avista	28.63	29.34	30.89	33.76
Add 1.00 mills capacity benefit	Avista	29.63	30.34	31.89	34.76
Output mwh @ 100% of Plant	PP&L	8,153,836	8,162,520	8,142,498	8,197,625
Cost of Power ($Millions)	3252.515	$211.33	$235.83	$248.83	$243.07
Value of Power ($Millions)	4016.321	$233.47	$239.50	$251.55	$276.71
Cost/Value of Sulphur Credits	-42.749	$9.78	$10.10	$1.99	($6.61)
Net Value of Plant vs. Market:	721.0568	$12.36	($6.43)	$0.72	$40.25
	806.5548				
Present Value @	0.0716	$11.53	($5.60)	$0.59	$30.52
Cumulative Present Value:		$12	$6	$7	$37

		24 Years	26 Years
Gain on Sale Required for Breakeven:		$757.52	$806.57
Book Value, Plant:	Avista	$116.51	$116.51
Book Value, Mine:	PP&L	$107.20	$107.20
Total Sale Price Required:		**$981.24**	**$1,030.28**
Actual Sale Price:	PP&L	$554.00	$554.00
Minimum % Gain On Sale To Ratepayers		**229.35%**	**244.20%**

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Exhibit 501 (Revised 12/31/99)
Page 8

NWPPC Aurora Value of Power Revised 12/29/99	2004	2005	2006	2007	2008
Non-fuel Revenue Requirement	$47,159	$46,646	$46,435	$46,180	$49,845
Unit 1 Fuel	$35,273	$36,059	$38,322	$39,114	$40,280
Unit 2 Fuel	$35,143	$36,551	$38,331	$39,010	$40,971
Total	$117,575	$119,257	$123,088	$124,304	$131,096
PP&L Share of Output	3,870,048	3,845,230	3,977,927	3,962,682	4,016,576
Ownership / Operating cost mills/kwh	30.38	31.01	30.94	31.37	32.64
Aurora Forecast from NWPPC	34.10	35.11	36.44	37.69	38.90
Extrapolation Beyond Forecast @ 2.5%					
Value of Power Before Shaping:	34.10	35.11	36.44	37.69	38.90
Add Dispatch @ 1.71 proportioned	2.17	2.23	2.31	2.39	2.47
Value with Dispatch Benefit	36.27	37.34	38.76	40.08	41.38
Add 1.00 mills capacity benefit	37.27	38.34	39.76	41.08	42.38
Output mwh @ 100% of Plant	8,147,469	8,095,221	8,374,583	8,342,488	8,455,950
Cost of Power ($Millions)	$247.53	$251.07	$259.13	$261.69	$275.99
Value of Power ($Millions)	$295.49	$302.24	$324.58	$334.36	$349.87
Cost/Value of Sulphur Credits	($6.82)	($7.03)	($6.96)	($6.97)	($6.94)
Net Value of Plant vs. Market:	$54.78	$58.20	$72.41	$79.64	$80.82
Present Value @	$38.77	$38.44	$44.62	$45.80	$43.37
Cumulative Present Value:	$76	$114	$159	$205	$248

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepaye

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NWPPC Aurora Value of Power Revised 12/29/99	2009	2010	2011	2012	2013
Non-fuel Revenue Requirement	$49,860	$49,954	$50,084	$50,289	$50,524
Unit 1 Fuel	$41,380	$42,684	$44,373	$46,681	$47,999
Unit 2 Fuel	$41,805	$43,503	$45,034	$46,545	$47,562
Total	$133,045	$136,140	$139,491	$143,516	$146,085
PP&L Share of Output	4,026,506	4,077,035	4,131,729	4,204,368	4,216,136
Ownership / Operating cost mills/kwh	33.04	33.39	33.76	34.13	34.65
Aurora Forecast from NWPPC	39.45	40.46	40.03	41.51	42.96
Extrapolation Beyond Forecast @ 2.5%					
Value of Power Before Shaping:	39.45	40.46	40.03	41.51	42.96
Add Dispatch @ 1.71 proportioned	2.51	2.57	2.54	2.64	2.73
Value with Dispatch Benefit	41.95	43.03	42.57	44.15	45.69
Add 1.00 mills capacity benefit	42.95	44.03	43.57	45.15	46.69
Output mwh @ 100% of Plant	8,476,854	8,583,231	8,698,377	8,851,300	8,876,077
Cost of Power ($Millions)	$280.09	$286.61	$293.67	$302.14	$307.55
Value of Power ($Millions)	$355.64	$369.30	$370.31	$390.76	$405.56
Cost/Value of Sulphur Credits	($6.94)	($6.91)	($6.94)	($6.91)	($6.90)
Net Value of Plant vs. Market:	$82.49	$89.60	$83.58	$95.52	$104.91
Present Value @	$41.31	$41.88	$36.45	$38.88	$39.84
Cumulative Present Value:	$289	$331	$368	$407	$446

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepaye

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NWPPC Aurora Value of Power Revised 12/29/99	2014	2015	2016	2017	2018
Non-fuel Revenue Requirement	$46,504	$47,201	$47,996	$48,854	$49,854
Unit 1 Fuel	$49,231	$50,587	$52,241	$53,914	$55,720
Unit 2 Fuel	$48,785	$50,115	$51,780	$53,184	$54,958
Total	$144,521	$147,903	$152,016	$155,952	$160,532
PP&L Share of Output	4,216,437	4,216,856	4,216,546	4,229,946	4,234,950
Ownership / Operating cost mills/kwh	34.28	35.07	36.05	36.87	37.91
Aurora Forecast from NWPPC	43.21	44.62	44.65	46.38	*50.1*
Extrapolation Beyond Forecast @ 2.5%				45.76	46.91
Value of Power Before Shaping:	43.21	44.62	44.65	45.76	46.91
Add Dispatch @ 1.71 proportioned	2.74	2.83	2.84	2.91	2.98
Value with Dispatch Benefit	45.95	47.46	47.48	48.67	49.89
Add 1.00 mills capacity benefit	46.95	48.46	48.48	49.67	50.89
Output mwh @ 100% of Plant	8,876,710	8,877,591	8,876,939	8,905,149	8,915,685
Cost of Power ($Millions)	$304.25	$311.37	$320.03	$328.32	$337.96
Value of Power ($Millions)	$407.90	$421.32	$421.50	$433.41	$444.77
Cost/Value of Sulphur Credits	($6.90)	($6.90)	($6.90)	($6.89)	($6.89)
Net Value of Plant vs. Market:	$110.54	$116.84	$108.37	$111.98	$113.70
Present Value @	$39.18	$38.64	$33.45	$32.25	$30.56
Cumulative Present Value:	$486	$524	$558	$590	$620

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepaye

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NWPPC Aurora Value of Power Revised 12/29/99	2019	2020	2021	2022	2023
Non-fuel Revenue Requirement	$51,028	$52,013	$52,367	$52,034	$52,607
Unit 1 Fuel	$57,113	$58,541	$60,005	$61,505	$63,042
Unit 2 Fuel	$56,332	$57,740	$59,184	$60,664	$62,180
Total	$164,474	$168,295	$171,556	$174,203	$177,830
PP&L Share of Output	4,234,950	4,234,950	4,234,950	4,234,950	4,234,950
Ownership / Operating cost mills/kwh	38.84	39.74	40.51	41.13	41.99
Aurora Forecast from NWPPC	*51.3*	*52.6*	*53.9*	*55.3*	*56.7*
Extrapolation Beyond Forecast @ 2.5%	48.08	49.28	50.51	51.78	53.07
Value of Power Before Shaping:	48.08	49.28	50.51	51.78	53.07
Add Dispatch @ 1.71 proportioned	3.05	3.13	3.21	3.29	3.37
Value with Dispatch Benefit	51.13	52.41	53.72	55.07	56.44
Add 1.00 mills capacity benefit	52.13	53.41	54.72	56.07	57.44
Output mwh @ 100% of Plant	8,915,685	8,915,685	8,915,685	8,915,685	8,915,685
Cost of Power ($Millions)	$346.26	$354.30	$361.17	$366.74	$374.38
Value of Power ($Millions)	$455.89	$467.29	$478.97	$490.94	$503.22
Cost/Value of Sulphur Credits	($6.89)	($6.89)	($6.89)	($6.89)	($6.89)
Net Value of Plant vs. Market:	$116.52	$119.87	$124.69	$131.09	$135.73
Present Value @	$29.22	$28.06	$27.23	$26.72	$25.82
Cumulative Present Value:	$650	$678	$705	$732	$758

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepaye

NWPPC Aurora Value of Power Revised 12/29/99	2024	2025
Non-fuel Revenue Requirement	$53,923	$55,271
Unit 1 Fuel	$64,619	$66,234
Unit 2 Fuel	$63,735	$65,328
Total	$182,276	$186,833
PP&L Share of Output	4,234,950	4,234,950
Ownership / Operating cost mills/kwh	43.04	44.12
Aurora Forecast from NWPPC	*58.1*	*59.5*
Extrapolation Beyond Forecast @ 2.5%	54.40	55.76
Value of Power Before Shaping:	54.40	55.76
Add Dispatch @ 1.71 proportioned	3.46	3.54
Value with Dispatch Benefit	57.85	59.30
Add 1.00 mills capacity benefit	58.85	60.30
Output mwh @ 100% of Plant	8,915,685	8,915,685
Cost of Power ($Millions)	$382	$390
Value of Power ($Millions)	$516	$529
Cost/Value of Sulphur Credits	($7)	($7)
Net Value of Plant vs. Market:	$140.51	$145.45
Present Value @	$25	$24
Cumulative Present Value:	$782	$807

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepaye

Before the
Washington Utilities and Transportation Commission

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

Exhibit of

Jim Lazar
Consulting Economist

On Behalf of
Public Counsel

Exhibit 502
Analysis Prepared in 1997 Examining
Centralia Scrubber Decision

Economics of the Centralia Target Solution

Jim Lazar, Consulting Economist

INTRODUCTION

This report summarizes key economic issues and findings surrounding the work of the Collaborative Decision Making (CDM) task force which was formed to evaluate emission alternatives for the Centralia Power Plant. I was retained by Mount Rainier National Park, as a contracting authority for the federal agency participants in the CDM, which included the Environmental Protection Agency, National Park Service, and U.S. Forest Service.

The Centralia Power Plant is a 1300 megawatt mine-mouth two-unit pulverized coal power plant located near Centralia, Washington. There are eight owners, including four investor-owned utilities (IOU) and four consumer-owned utilities (COU) as shown below:

Table 1
Centralia Plant Owners[1]

Pacific Power and Light Company	IOU	47.5%
Washington Water Power	IOU	15.0%
Seattle City Light	COU	8.0%
Tacoma Public Utilities	COU	8.0%
Snohomish PUD	COU	8.0%
Puget Power	IOU	7.0%
Grays Harbor PUD	COU	4.0%
Portland General Electric	IOU	2.5%

The plant became operational in 1972, and was not fitted with pollution abatement technology to reduce sulphur dioxide emissions at that time. The plant is fueled with coal from an adjacent surface mine owned and operated by a subsidiary of Pacificorp. Pacificorp also owns Pacific Power and Light Company, an electric utility serving seven Northwest states, which is the largest owner of the power plant, and the plant operator. Because of the adverse air quality impacts resulting from SO_2 emissions from the Plant which burns coal from the adjacent mine, federal and state regulatory agencies have determined that reductions in sulphur emissions may be necessary.

The CDM group was made up of plant owners, Washington state air regulators, federal air regulators, and affected land management agencies including the U.S. Forest Service and the National Park Service.

Three generic alternatives to reduce sulphur emissions were considered:

> **Target Solution**: Install scrubber technology to reduce sulphur emissions while allowing use of high-sulphur coal to continue;

External Coal Option: Close the surface mine at Centralia and utilize only low-sulphur coal from mines in Wyoming delivered via rail.

Plant Closure: Close the Centralia Power Plant and mine, relying on the electricity trading market and potential future new resources to meet regional power demands.[2]

This report covers analysis up to the signing of the CDM workgroup report, as well as incorporating additional information became available after the CDM agreement was executed.

The CDM group has recommended that the Target Solution be pursued, with a package of tax preferences to mitigate the financial impact of that option. If the economic assumptions underlying the analysis presented to the CDM task force by Pacificorp[3] prove accurate, the economics of installing scrubbers would not be justified without the tax package. The most likely outcome if the tax package is not approved would be either the External Coal option (closure of the mine and loss of some 500 jobs under the assumed conditions) or Combined Mine and Plant Closure (loss of over 700 jobs).

Because of Pacificorp's perception of changing market conditions, the analysis prepared by Pacificorp uses assumed values for the power the plant will produce which are lower than those formally filed by Pacificorp with the Washington Utilities and Transportation Commission (WUTC) on March 5, 1996. I have independently prepared an economic analysis applying Pacificorp's filed avoided costs as an alternative measure of the value of power, but otherwise relying on Pacificorp's analysis. This independent analysis, presented in Section IV below, shows that the retrofit would be cost-effective even if the tax incentive package is not approved.

The Centralia mine and steam plant represents the single largest industrial employer in Lewis County. The annual payroll is approximately $36 million, and approximately $70 million per year is spent by the plant and mine owners on goods and services from vendors within the state of Washington. While some of the major vendors have relatively little local impact (e.g., fuel suppliers and railroads); closure of either the mine or the plant would cause a loss of property taxes, sales taxes (on materials and supplies), business gross revenue taxes, and employment taxes to the state of Washington and to Lewis County and the affected school districts, port districts, and other special taxing districts.

This report will summarize the economics which underlie the Target Solution without conducting any specific analysis of whether this option meets economic conditions of actual or potential Pareto optimality.[4] Because some of the data I have had access to is identified as confidential, proprietary, and/or commercially sensitive by the source, this report will discuss certain findings in general terms. The numerical results presented in this report rely entirely on data which is not subject to confidentiality, and it is my belief that the entire contents of this report can be released without restriction. Signatories to specific confidentiality agreements have access to the underlying assumptions, data, and analysis.

I. Centralia Economics

The Centralia power plant has among the highest operating costs among baseload powerplants in the Pacific Northwest region. In the twelve months ended May, 1996, the amount of operation, maintenance, and fuel cost charged to owners was 2.17¢/kwh.[5]

During the same period, power traded on the Pacific Northwest electricity market averaged less than 1.1¢/kwh[6], about half the cost of operating the Centralia plant, calling the economic viability of several power plants, including Centralia, into serious question. Aggressive market operations by electricity brokers in the Pacific Northwest suggest that these low prices will continue for an indefinite period: five-year firm power offers at prices well under the operating cost of the Centralia plant have been rejected by regional utilities in favor of continued reliance on the spot market.[7]

In addition to the competitive spot market, new gas-fired power production technology has become very cost-competitive with continued operation of the Centralia power plant. Compared with the retrofit of the Centralia power plant, a new combined-cycle combustion turbine (CCCT) would have lower fuel costs at current gas prices, lower operation and maintenance costs, greater dispatching flexibility, higher reliability, and only modestly more expensive construction costs.[8] Three siting processes have already been initiated and/or completed before the Energy Facility Site Evaluation Council of Washington for CCCT plants in the Centralia vicinity at Longview, Chehalis, and Satsop. If built, these three proposed facilities would exceed the capacity of the Centralia Power Plant.

Any strategy to reduce the emissions of the Centralia plant will cause increased costs of ownership and/or operation. Use of external low-sulphur coal would require construction of rail handling facilities and new track. The external coal, while cheaper to buy, has a higher total cost than the higher-sulphur Centralia coal when transportation expense is included. Constructing scrubbers adds capital costs and operating costs, and also slightly reduces the output of the power plant.[9] Given the aggressive spot power market and the opportunities to construct new gas-fired resources at low costs, the future of the Centralia power plant is in question even without the additional costs of emission controls.

Given the fragile economics of the plant under current conditions, the additional costs of the scrubber option pose challenging obstacles. The plant and mine are two of the largest family-wage employers in Lewis County, a county which has been adversely affected by contractions in forest products industry employment. Preserving employment provided by the plant and mine and the tax flows from the employers and their employees has been an objective of the CDM work group, subject to the constraint that the air pollutant emissions of the plant must be reduced to acceptable levels.

II. Key Analytical Assumptions

This report relies primarily on modeling analyses prepared by Pacificorp, which in turn has been modified in response to comments which I provided during the CDM process. I have also prepared some independent analysis, and where it suggests different results from that prepared by Pacificorp, the differences are identified below.

The studies prepared by Pacificorp are based on specific assumptions, many of which are best guesses due to the uncertainties of long-run cost and market conditions. The key assumptions include:

Cost of retrofit (rail facilities for External Coal; Scrubbers for the Target Solution)
Annual utilization of plant (Pacificorp assumed a 70% plant capacity factor in all analyses)
Cost of coal -- Centralia and External
Cost of coal transportation (External Coal)
Value of SO2 credits
Value of Power / Cost of Replacement Power under shutdown scenario

Of these assumptions, the value of power clearly drives all of the results. Under higher value of power conditions, retrofit and external coal options are clearly cost-effective. Under low value of power conditions, Plant Closure is clearly the economic choice. Under the mid-range value of power conditions relied upon in the Pacificorp analysis, the economics of the three options are fairly close, and the other assumptions affect which option is most attractive. The higher value of power filed by Pacificorp with the WUTC is clearly sufficient to support the cost of the retrofit without causing a significant risk of plant closure.

III. Pacificorp Economic Analysis

The most recent Pacificorp Analysis, dated November 21, 1996, shows that Plant Closure is the most economic option. While the complete analysis was not distributed by Pacificorp to the CDM Task Force Economic Committee, this result is consistent with previous analyses presented to the CDM work group by Pacificorp[10], which were reviewed in detail. The table below compares the cost of the Target Solution to the cost of replacement power in the market under Plant Closure:

Table 2
Estimated 30-Year Present Value Per Pacificorp
1996 $ Millions
(Source: Pacificorp Press Release 11/21/96)

	Per Pacificorp
Scrubber Installation:	$ 172
Scrubber Operation:	$ 49
Plant Renewals and Replacements:	$ 192
Plant Operation and Fuel:	$ 1,495
Total 30-Year Present Value:	$ 1,908
Value of Power (Shutdown Scenario)	$ 1,721
Net Value of Plant (Loss):	($ 187)
Tax Package:	$ 130

The External Coal alternative was discarded by Pacificorp late in the analytical process, as the cost of this alternative was determined to be greater than the cost of the Target Solution. As shown above, however, even the Target Solution is believed by the owners to be slightly more expensive than Plant Closure and purchase of replacement power.

IV. Independent Review of Pacificorp Economic Analysis

During the CDM process, I identified certain areas of potential cost savings to the owners from close-coupling the construction of the two scrubbers, from lower fuel costs resulting from the continued use of Centralia coal under close-coupling, and from certain other elements. At the time these potential savings were identified, I presented them to the CDM Task Force, and the owners acknowledged and recognized these areas of potential savings. These cost savings have generally been incorporated by Pacificorp in the November analysis. In addition, I have prepared certain independent analysis of some of the underlying assumptions in the Pacificorp analysis which have not been incorporated by Pacificorp.

VALUE OF POWER -- PACIFICORP ANALYSIS VS. FILED AVOIDED COSTS

First, I have compared the value of power estimates prepared by Pacificorp to it's "official" avoided costs filed with the WUTC, and to other projections prepared by the Bonneville Power Administration[11], Puget Power[12], and JBS Energy[13], (a California consultant to regulators and power plant developers). The value of power over a period time far into the future is extremely uncertain. In my professional opinion, the range of estimates of power cost defined by the level used by Pacificorp in the analyses prepared by it for the CDM workgroup and the level contained in the filed avoided costs used by me in my sensitivity analysis are a reasonable range of probable outcomes in a highly uncertain market environment. The level used by Pacificorp in its analyses is about 20% lower than the filed avoided cost, but is still slightly higher than that used by some other analysts. This in turn means that the economics of continued plant operation (with external coal or scrubbers) is possibly more favorable or less favorable than estimated by Pacificorp or my sensitivity analysis, but the result is probably within this range.

The key analytical assumption is the value of the power produced by the Centralia plant. Pacificorp's analysis relies on an estimate of the value of power which is significantly lower than the avoided costs which the Company filed with the WUTC in March, 1996.[14]

It is important to understand the purpose for which the avoided costs are computed and filed with regulatory bodies in order to better interpret the economic viability of the Centralia project. Avoided costs are computed to assist in determining what level of payments could be made by a utility to an independent power producer offering a small increment of electricity to augment the utility's supply without adversely affecting the utility's customers. The Company computes its anticipated costs of meeting loads with its existing and available resources, and then recomputes these with a hypothetical 50 megawatt additional resource operating. The savings which occur to the utility from having an additional non-owned resource-producing energy for its system is the "avoided cost" (quite literally, the cost the utility would "avoid" on other power plants if the hypothetical new power plant were operating).

Under the set of assumptions used by Pacificorp to calculate avoided cost, Pacificorp has a surplus of capacity until at least 2004, and the avoided cost assigns zero value to additional capacity until that time, counting only the fuel and other operating cost savings which would occur with a small additional power supply added to the system until that time. Between 2004 and 2011, the Pacificorp assumptions include a small amount for additional generating capacity; after 2011, these assumptions include half (not all) of the cost of additional generating capacity, on the theory that peaking capacity would be available at that time for a price lower than the actual cost of building new peaking power plants. In addition, the Pacificorp analysis assumes that off-peak energy will be available at a price somewhere between the running cost of an efficient new powerplant and the full cost of such a plant. This is a novel approach which has not been widely discussed in the resource planning field, and which, to my knowledge, has not be embraced by the regulatory bodies. It assumes that investors will fund new power plant construction in the future even though they will not be allowed to recover the full cost of their investment. In my opinion, this is a very speculative set of assumptions, leading to a relatively low set of avoided costs.

The closure of Centralia would have a very different impact on the power system than the addition of a 50 megawatt independent power producer. If the Centralia plant were closed, the region would be faced with an immediate loss of 1300 megawatts of capacity, of which 617 would be lost to Pacificorp based on its 47.5% share. This would accelerate the time of a capacity deficit by approximately 4 years, and this would significantly raise the avoided cost calculation. For this reason, the avoided cost calculation based upon a surplus of capacity until the year 2004 understates the value of the capacity provided by the Centralia project. In addition, the loss of the Centralia project due to Plant Closure would be a large enough regional impact to affect the market value of on-peak and off-peak energy, undoubtedly raising these above the levels shown by Pacificorp. Simply stated, a cost estimate based on a change of 50 megawatts in resource supply tends to understate the economic costs associated with losing a 1300 megawatt generating plant.

I believe that the "avoided cost" (however measured) is the minimum value which should be assigned to the output of Centralia. During certain market conditions, the Company can sell power for more than the cost of operating existing power plants, and during those periods, the "value" of the power is the price at which it can be sold, not the cost of producing the power. Under adverse market conditions, Pacificorp can always shut down a plant, and that is precisely what the "avoided cost" measures. Pacificorp recognizes this fact in the design of its conservation programs,[15] but has not included this in the economic evaluation of Centralia plant economics.

The sensitivity analysis prepared at the filed Washington avoided costs (which reflects the full costs, not partial costs, of replacement capacity) may present a more accurate picture of the value of power from Centralia, simply because it includes the full costs of additional generating capacity after the end of the surplus period. In fact, even the filed avoided cost may understate the value of power from Centralia, because it has not been adjusted to reflect the acceleration of the time of anticipated deficit which would result from closure of Centralia.

Table 3 compares the analytical result presented by Pacificorp as part of the CDM process to an otherwise identical analysis computed using the avoided costs filed with the WUTC. Attachment 1 shows the detailed calculation of the information in Table 3, and contains a graphical presentation of the Pacificorp and WUTC filed avoided costs.

Table 3
Estimated 30-Year Present Value Per Pacificorp
Compared with Filed WUTC Avoided Costs
1996 $ Millions

	Per Pacificorp	At Filed Avoided Cost
Scrubber Installation:	$ 172	$ 172
Scrubber Operation:	$ 49	$ 49
Plant Renewals and Replacements:	$ 192	$ 192
Plant Operation and Fuel:	$ 1,495	$ 1,495
Total 30-Year Present Value:	$ 1,908	$ 1,908
Value of Power (Shutdown Scenario)	$ 1,721	$ 2,068[16]
Net Value of Plant (Loss):	($ 187)	$ 160
Tax Package:	$ 130	$ 130
Net Value (Loss) With Tax Package	$ (57)	$ 290

As is evident, use of the higher filed avoided costs to compute the value of power significantly changes the analysis prepared by Pacificorp. At the avoided costs used in the Pacificorp analysis, even with the tax package, the plant retrofit is not economically viable. Using the filed WUTC avoided costs, the plant retrofit is cost-effective even without the tax package.

REDUCED DISPATCH OF CENTRALIA WITH HIGHER-PRICED EXTERNAL COAL

Entirely separate from the avoided cost issue, I also have identified one methodological shortcut relied upon by Pacificorp in its analysis which tends to overstate the economic attractiveness of the scrubber option. In each of the three analyses, and regardless of expected value of power, the Pacificorp analysis assumes that the plant will operate at a 70% capacity factor. In fact, the plant is placed on "economic dispatch" status (shut down to save money when the power is worth less than the short-term variable operating costs) from time to time. In the "low" value of power cases, this would occur more frequently. In addition, the variable operating costs under the External Coal option are higher than the Target Solution (the scrubbers are capital-intensive way of reducing emissions, while external coal involves lower capital costs and higher operating costs). Therefore, the choice of External Coal would mean more frequent economic dispatch, a lower average capacity factor, and lower total costs (since by definition the economic dispatch means that the replacement power costs less than the avoided operating costs of the plant).[17]

IMPACT ON OWNERS OTHER THAN PACIFICORP

Pacificorp's analysis looks only at the economics of the plant operation, not at the profitability of the mine to Pacificorp. Under the Target Solution, the mine continues to operate (at a presumed profit to Pacificorp) while under Plant Closure or External Coal options the mine does not operate and Pacificorp has no revenue stream associated with this investment. Because Pacificorp receives 100% of the revenue from the mine, but bears only 47.5% of the operating cost of the plant, the Target Solution is more financially attractive to Pacificorp than to the other plant owners. In addition to this major factor, each of the owners have unique financial and geographic characteristics which may affect the economics of continued plant operation. The key differences are as follows:

> **Pacificorp (47.5%):** Is the owner and operator of the mine, and it earns a return on the mine investment if it is operating, and makes no return if the mine is closed (Plant Closure or External Coal). Because the mine is profitable when the plant operates using local coal, Pacificorp is much more favorable to continued Plant operation (Target Solution) than the other owners. While the Pacificorp economic analysis shows that the Target Solution (even with the tax package) is more expensive than Plant Closure, the Target Solution is more desirable than Plant Closure from the perspective of Pacificorp.
>
> **Other Investor-Owned Utilities (24.5%):** These utilities have approximately the same cost of capital as Pacificorp, and therefore have relatively high costs (compared with consumer-owned utilities discussed below) to pay for a capital-intensive option such as the Target Solution. The alternatives, External Coal and Plant Closure involve primarily higher operating costs rather than capital costs, and affect investor-owned and consumer-owned utilities equally. The Pacificorp economic analysis is a reasonable presentation of the effect on this group of owners, subject to the other elements of independent review addressed above.
>
> **Consumer-Owned Utilities (28%):** These utilities have access to tax-exempt bonding authority and can finance their share of retrofit capital costs at significantly lower cost than the investor-owned utilities. The Pacificorp analysis tends to overstate the cost of the Target Solution for this group of owners.

To summarize, the analytical assumptions used by Pacificorp are generally reasonable, although the value of power assumptions are highly uncertain. In my opinion, the assumptions <u>other than value of power</u> tend to bias the results very slightly in favor of continued operation with scrubbers and/or continued operation with external coal. If I were to prepare an independent analysis using the most recent value of power assumptions relied upon by Pacificorp, it would probably show that Plant Closure is slightly more preferable than the analysis prepared by Pacificorp, and that External Coal is significantly more preferable than the analysis prepared by Pacificorp.[18] This conclusion tends to support the contention of the owners that some sort of cost mitigation, in this case a tax package, is an important element of the decision to implement the Target Solution; however, as stated earlier, the most important assumption is the value of power, for which I have prepared a sensitivity analysis using the Company's filed avoided costs which concludes that plant retrofit is cost-effective even without a tax incentive package.

V. Replacement Power In Event of Plant Closure

Closure of the Centralia Power Plant would remove 1300 megawatts of baseload capacity from the Western Washington load center. At Pacificorp's estimate of a 70% capacity factor, this would require replacement of 1300 megawatts of peaking capacity and about 8 billion kilowatt-hours per year of energy. While the economic cost of replacing this power is addressed by the Pacificorp analysis, the capacity constraints and environmental effects are not addressed.

Western Washington is the location of the majority of the state's population, but relatively little of the power generation. In 1990, the Bonneville Power Administration announced that a "voltage collapse" was possible due to limited power supply west of the Cascades. BPA initiated a project to upgrade transmission facilities to ensure adequate transmission capacity to Western Washington, and Puget Power acquired some 700 megawatts of cogenerated power from developers in Whatcom and Skagit counties. These efforts restored reliability to the westside power grid, but the loss of the 1300 megawatt Centralia project coupled with continued population and load growth in Western Washington would eventually create a need for peaking capacity construction and/or transmission capacity construction which are not reflected in the Pacificorp analysis. However, the Pacificorp analysis does anticipate incurrence of costs equivalent to a portion of the cost of constructing new gas-fueled capacity in the 2005- 2008 time frame; however, inclusion of the full costs of new capacity would move the avoided costs closer to those in the sensitivity analysis based upon the filed Washington avoided costs If new facilities were constructed in Western Washington, the capacity loss would be mitigated at the time of that construction.

In addition, while the closure of the Centralia plant would eliminate the air pollutant emissions from the plant, the same amount of energy would be required, and output of other existing or new power plants would be increased to fill the void. This increase in output would have associated environmental effects. The simplified table below identifies the major types of resources which would likely provide this replacement power, and generally characterizes the air emissions of those alternatives relative to the Centralia plant operating under the Target Solution:

Table 4
Estimated Emissions of Alternative Resources Relative to Target Solution

Type of Resource	CO_2	SO_2	Other Emissions
Northwest Coal	Same	Same	Same / Worse
Northwest Gas	Lower	Lower	Lower
Canadian Gas	Lower	Lower	Lower
California Gas	Lower	Lower	Same / Lower
Southwest Coal`	Same	Same / Worse	Same / Worse
Renewable Resources	Much Lower	Much Lower	Much Lower

While renewable resources, such as wind, geothermal, and solar, can provide replacement power at much lower emissions rates than other alternatives, the costs for such resources remain far above the cost of gas and coal resources. Unless the fundamental economics of such resources change, through tax preferences, internalization of environmental costs through taxes or fees, or technological evolution, it is unlikely that renewable resources would provide more than a token level of replacement power in the event that Centralia is closed. Implementation of emission taxes on CO_2 could change this financial reality, but the failed efforts to impose a broad-based energy tax in the early years of the first Clinton administration suggest that such a tax would be a difficult legislative proposition.

VI. Financial Risk to Owners

The Pacificorp analysis shows a moderate loss associated with the Target Solution compared with Plant Closure, even with the tax incentive package. The sensitivity case shows a modest net value to the plant without the tax package. These analyses, however, do not consider certain specific risks the owners accept in pursuing this option.

Most important of these risks is that the value of power is extremely uncertain. Gas prices drive the wholesale power market, and can be very erratic. If gas prices remain low, the value of power will be lower than assumed in the Pacificorp analysis, and the choice to install scrubbers will clearly be uneconomic. Conversely, if gas prices rise more than assumed, scrubber installation will be cost-competitive even without a tax package. My evaluation of these assumptions is discussed in section IV above, including the sensitivity case using the (higher) filed Washington avoided costs.

Imposition of any sort of carbon dioxide tax, energy tax based on fuel input, or other environmental tax not assumed in the Pacificorp analysis would also adversely affect the economics of the plant. A carbon tax of $20/ton (a level well within the range proposed by several states for evaluation of power options) would approximately <u>double</u> the operating costs of the Centralia plant, while having a much more modest impact on gas-fired resources and almost no effect on renewable resources. Such a tax, which is a long-run possibility as the nation struggles to balance the federal budget and comply with the Rio Accords on carbon dioxide emissions, would make scrubber installation an expensive mistake.

Since External Coal involves a smaller capital commitment, and Plant Closure implies a shift to less carboniferous fuels, both of the other options would be less adversely affected by a CO_2 tax than the Target Solution. If the owners choose to implement the Target Solution, they are implicitly accepting this risk. While I think the probability of such a tax being imposed in the short-run is very small (as discussed above), it remains a long-run financial risk which is unique to the Target Solution.

Finally, as the utility industry is becoming more competitive, utilities face a level of market risk they have not previously encountered. In California, utilities will be offering their customers a choice of power suppliers within a few years, and it is expected that this type of customer choice will spread to other regions. Several northwest utilities already have pilot programs underway, with large industrial customers choosing to buy power at spot market prices or negotiated contract rates from vendors other than the local utility. If the Centralia owners lose market share to lower cost or more customer-oriented competitors, they will face surplus capacity problems, and the value of power will be diminished. Investment of nearly $200 million in scrubbers at the Centralia plant poses additional risks in the face of such market uncertainties.

None of these risks changes the underlying economics in any certain or predictable fashion. However, all of these are risks which the owners will face with or without a decision to install scrubbers at Centralia, and uncertainty should be expected to hinder the commitment of capital by these owners. It is entirely possible that the plant owners could pursue the Target Solution, invest some $200 million in scrubber technology, then face a loss of the current markets for power and face emission taxes on CO_2, leaving them with an uneconomic investment and no assured market for the relatively high-cost power.

VII. Summary and Conclusion

The Pacificorp economic analysis reflects application of a set of assumptions regarding the financial viability of the Centralia power plant which is relatively favorable to retrofit as compared with plant closure, but measures this against a newly reduced estimate of the value of the power the plant produces. With this particular set of assumptions (see Note 3), the Pacificorp analysis shows that retrofit of the plant with scrubbers is at a slight disadvantage of Plant Closure and purchase of power in the market. The proposed tax package is believed by Pacificorp to be a key element to the Target Solution, since it closes much (but not all) of this gap between the costs the owners would incur under Plant Closure and the Target Solution. If the value of power assumptions used by Pacificorp are accepted, I concur that the tax incentive package is an important element of the Target Solution.

A previous analysis by Pacificorp favored delayed construction of the second scrubber. Revisions to the analysis to take into account construction efficiencies, operating efficiencies, and the market for the scrubber waste product have eliminated the financial advantage to delay. Similarly, once these economies were taken into account, the use of external coal became less attractive than scrubber installation. The logical remaining alternatives are full scrubbing of both units on a close-coupled construction schedule (the Target Solution) and Plant Closure.

If the revised Pacificorp avoided cost presented to the CDM group accurately measures the value of power from the Centralia power plant, it is my opinion that without the tax package it is extremely unlikely that the owners will pursue the emission retrofits to the Centralia steam plant. Under this scenario, even with approval of the tax package, the economic costs and financial risks associated with retrofit and continued operation of the Centralia steam plant are challenging.

The tax package brings the economic costs of the Target Solution relatively close to that of Plant Closure, based on the Pacificorp analysis. Even with the tax package, there remain significant economic risks to the Centralia plant owners if they choose to pursue the retrofit program. These risks include price risks, market risks, and environmental regulation risks. These risks must be considered by the owners as they evaluate the choice between Plant Closure, External Coal, and the Target Solution.

My own economic sensitivity analysis uses the filed Washington avoided costs as the proxy for the value of power from Centralia. This analysis, which does not consider the business risk associated with a major investment in an older power plant, indicates that the tax package is not necessary, as the value of the power is sufficient to justify the additional capital and operating costs of the scrubbers. While the avoided costs are the key assumption in the analysis, they are clearly not the only risks which the Centralia power plant owners face in deciding whether to invest in emission controls. If the higher filed avoided costs accurately measure the value of power from Centralia, the tax package may be viewed as offsetting the business risk (other than the uncertainty in avoided cost) associated with the scrubber investment.

Endnotes

1. Source: The Centralia Power Project -- An Overview; This material provided to the CDM group by Pacificorp erroneously reported that Portland General Electric's share is 2.0%; actual ownership of PGE is 2.5% as confirmed from the 1993 PGE Form 1 report to the Federal Energy Regulatory Commission.

2. As a practical matter, this would mean relying on existing power plants (primarily coal and gas-fueled) in the short run, and cause the construction of new power plants (most likely gas-fueled in the current economic environment) in the long-run.

3. The key economic assumptions are the cost of the retrofit, the future operating costs of the power plant, the future generation from the power plant, and the value of power produced by the power plant. The last of these, the value of power, is the only assumption upon which this report performs any sensitivity analysis.

4. Pareto Optimality: when no market participant can be made better off without making another market participant worse off. A "potential" improvement in Pareto Optimality exists if the "winners" could compensate the "losers" for their losses and still be better off. The concept is named for Italian-born Swiss economist Wilfredo Pareto.

5. Puget Sound Power and Light Company, response to Public Counsel Data Request #94, Washington Utilities and Transportation Commission Docket No. UE-960195

6. Puget Sound Power and Light Company response to WUTC Staff Data Request No. 3, Docket No. UE-960696 before the Washington Utilities and Transportation Commission.

7. The long-term price offers by power vendors to clients of Jim Lazar are confidential.

8. I have assisted with evaluations of new CCCT installations at Coyote Springs and Hermiston, Oregon, and reviewed an evaluation of a CCCT for Clark PUD. Combined capital and operating costs for new units ranges from 2.0¢/kwh to 3.0¢/kwh.

9. Initially, the Pacificorp analysis indicated a net cost associated with disposal of the waste product from the scrubbers, which made external coal a more attractive alternative. Subsequent analysis determined that net revenue could be obtained from marketing this effluent as a building product, which caused the Pacificorp analytical result to be changed to show the scrubber option to be of lower cost than the external coal option.

10. Previous economic analyses prepared by Pacificorp were provided on June 18, July 15, August 2, and August 20. These contain confidential data on project retrofit costs and operating cost forecasts. The prior analyses were reviewed in detail, and an independent alternative cost analysis model was prepared to examine various alternative scenarios. The independent model confirmed the general accuracy of the Pacificorp analyses of June, July, and August, and was used to verify the change in results in the November analysis based upon the changes in assumptions with respect to retrofit cost and operating costs contained in the November analysis.

11. BPA Technical Work Group on WNP-2 Evaluation, November 1, 1995

12. Long-Run avoided costs presented to the Conservation Collaborative, December, 1996.

13. Testimony of William Marcus before the Washington Utilities and Transportation Commission, Docket No. UE-951270, November, 1996

14. The avoided costs relied upon by Pacificorp were similar to those presented to the CDM group and to the Pacificorp Resource and Market Planning Process (RAMPP) Advisory Group, but have not been formally submitted to, reviewed by, nor approved by the Washington or Oregon regulatory authorities. Pacificorp has filed avoided costs in Oregon which are <u>lower</u> than those used by the Company in its Centralia analysis. The Company's December, 1996 "RAMPP-4 Update" report indicates that the cost of new resources has declined about 20% since the RAMPP-4 estimates were prepared, a level which is consistent with the avoided costs used by the Company in its Centralia analysis. However, as discussed, these calculations are based on the costs <u>saved</u> as a result of a small capacity <u>addition</u>, not the costs which would be incurred if a large generating plant such as Centralia were closed.

15. Telephone conversation, Andrea Kelly, Pacificorp, 1/8/97

16. The present value of the power from Centralia based on filed avoided costs is computed in Attachment A. All other figures in this table are calculated from the Pacificorp press release of 11/21/96 announcing the CDM agreement.

17. This shortcut tends to overstate the economic attractiveness of the Target Solution by up to $100 million on a present value basis, relative to the External Coal option, because the plant will operate fewer hours per year if the External Coal option is selected than if the Target Solution is implemented. This is an important finding: While Pacificorp ranks the order of the economic alternatives (without any tax breaks) as Plant Closure, Target Solution, and External Coal, with this methodological shortcut corrected, I would rank the alternatives in a different order: Plant Closure, External Coal, Target Solution.

18. The key changes in an independent analysis would be to recognize lower plant dispatch under External Coal, and lower costs of capital for the consumer-owned utilities. The first would tend to make External Coal more attractive, and the second would partially mitigate this by creating a slightly improved economic result of the Target Solution. Because the plant owners have elected to support the Target Solution (with the tax package), I have not prepared this independent analysis.

Before the
Washington Utilities and Transportation Commission

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

Exhibit of

Jim Lazar
Consulting Economist

On Behalf of
Public Counsel

Exhibit 503
Material Submitted to the Legislature Indicating
a 30-year Lifetime for Centralia

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 503
ADMIT ☑ W/D ☐ REJECT ☐

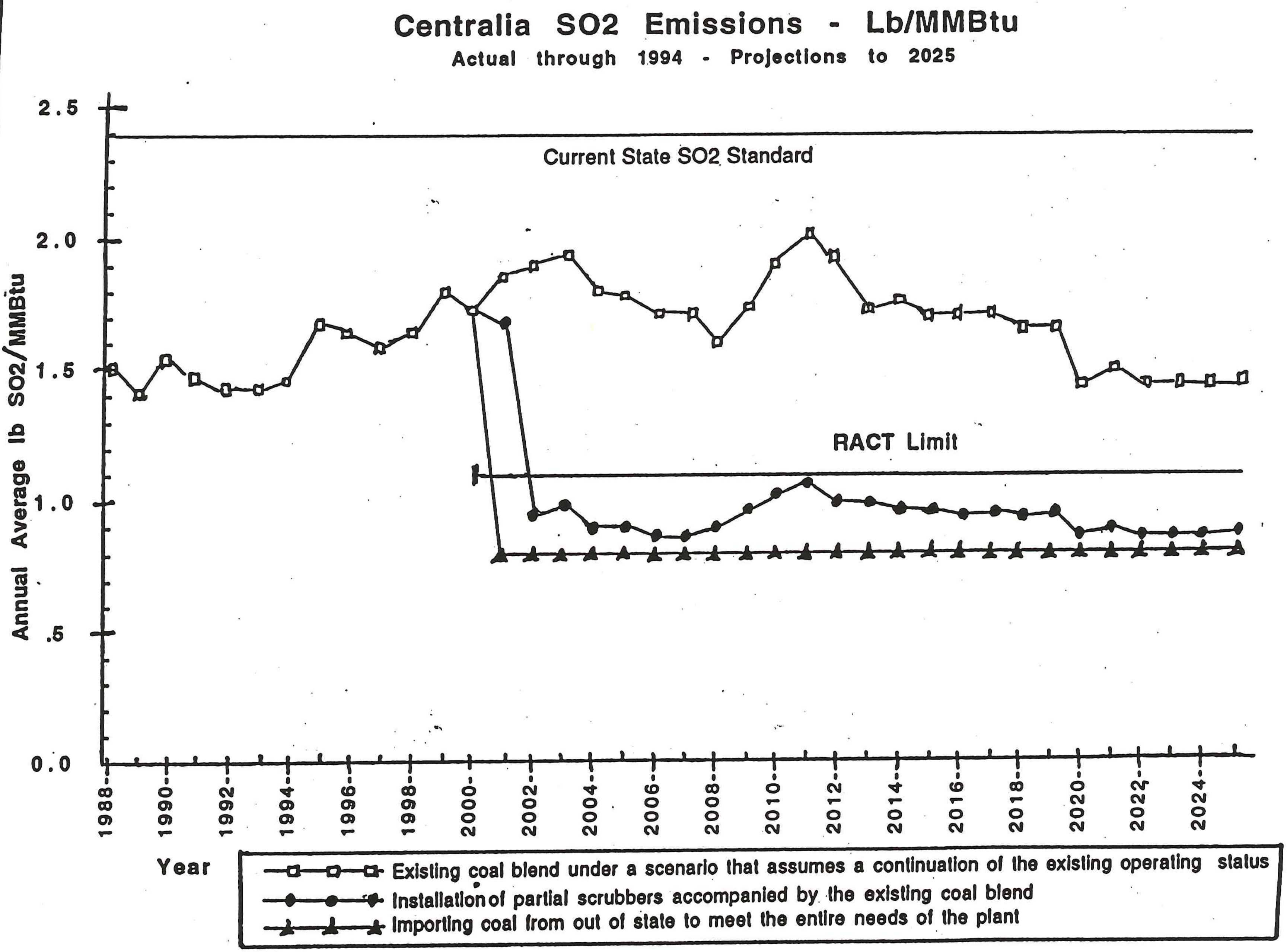
Public Counsel Data Request No. 6:

Provide copies of all materials supplied to members of the Washington legislature in support of tax package.

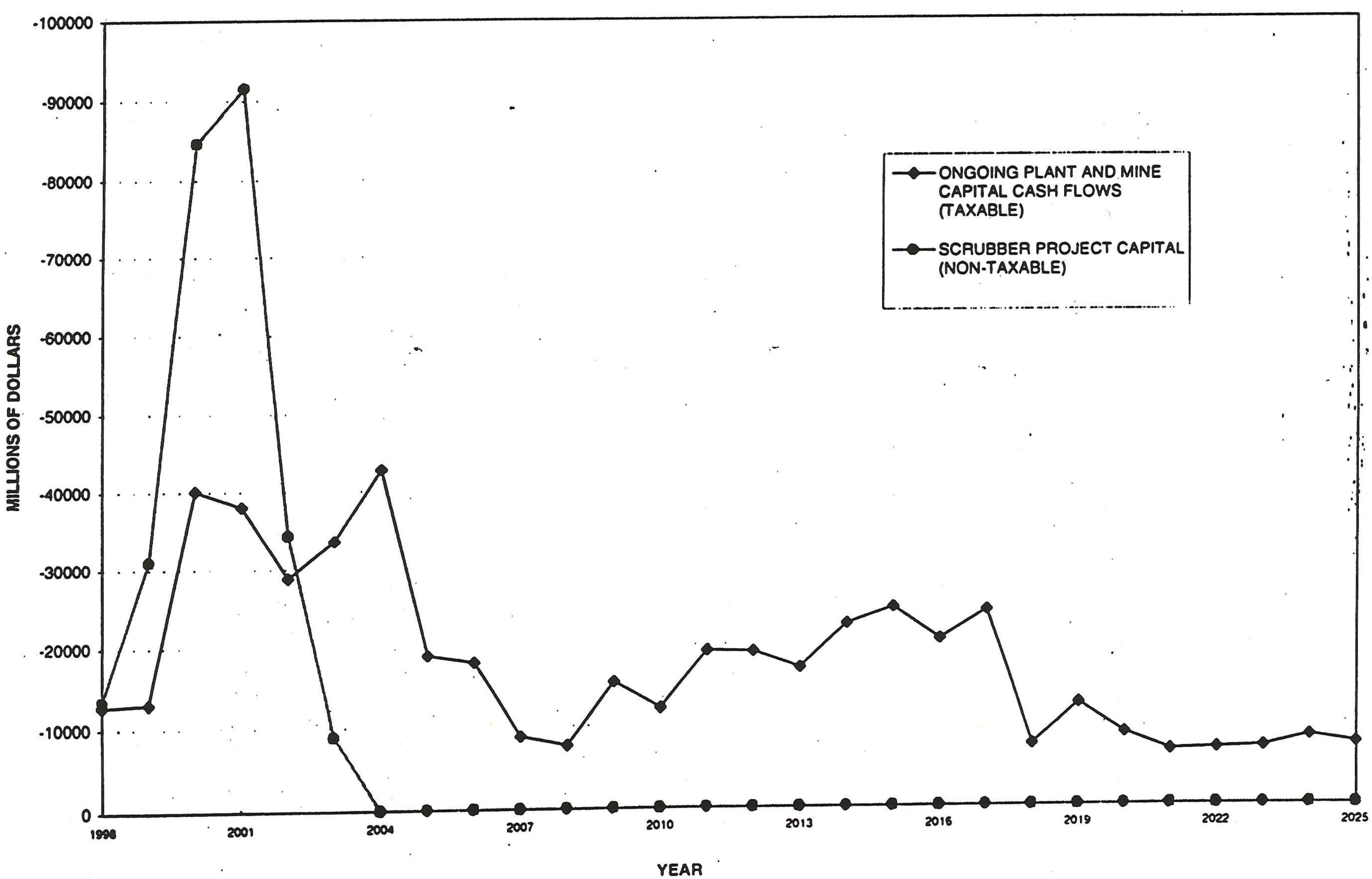
Response to Public Counsel Data Request No 6:

The requested materials are included as Attachment Response PC 6.

Exhibit of Jim Lazar
Exhibit 503
Page 2



CENTRALIA PLANT CAPITAL CASH FLOW



2/19/97

Centralia Power Plant Option 6g
Annual Projected Cost and Value of Power

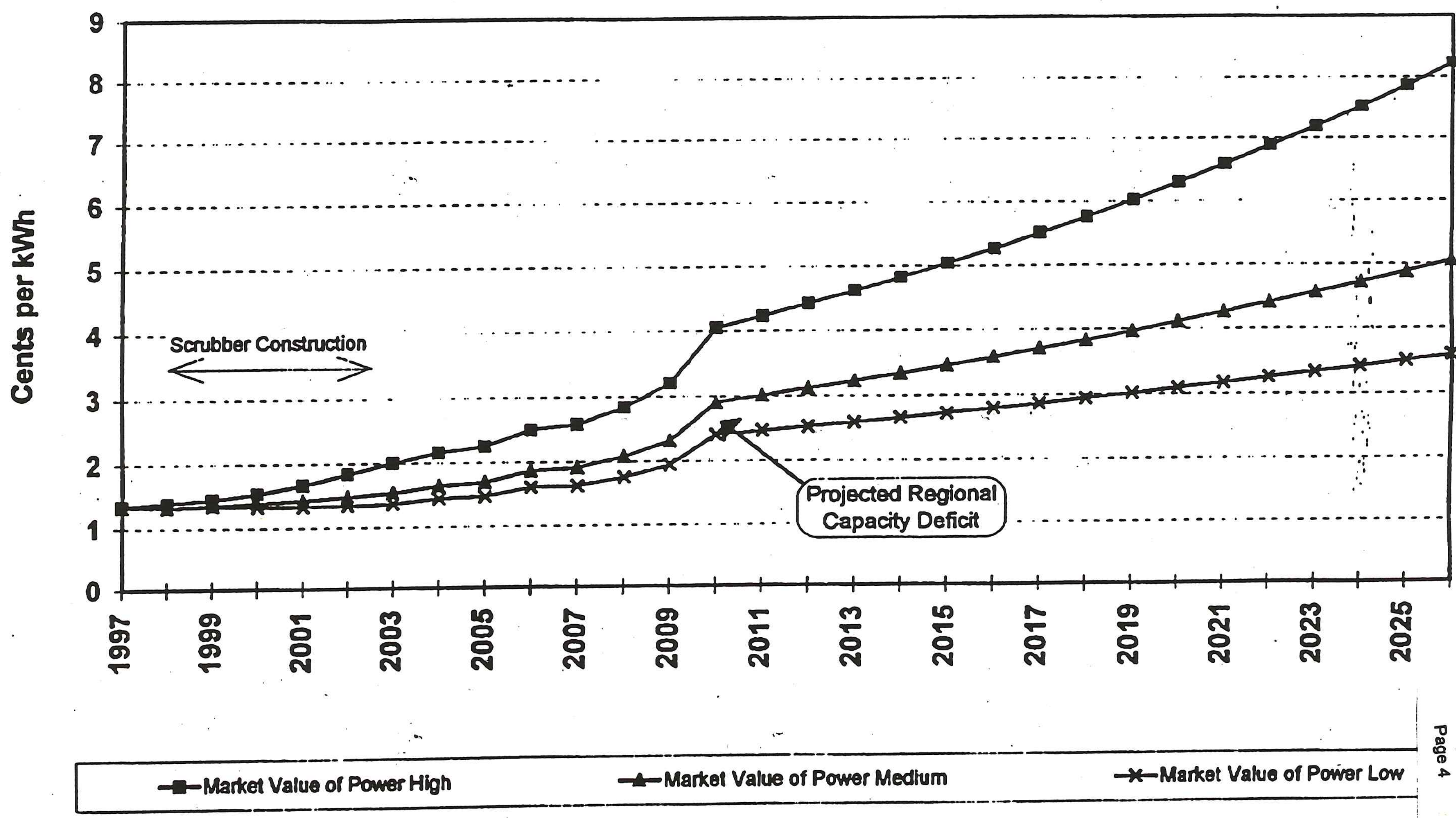


Exhibit of Jim Lazar
Exhibit 503
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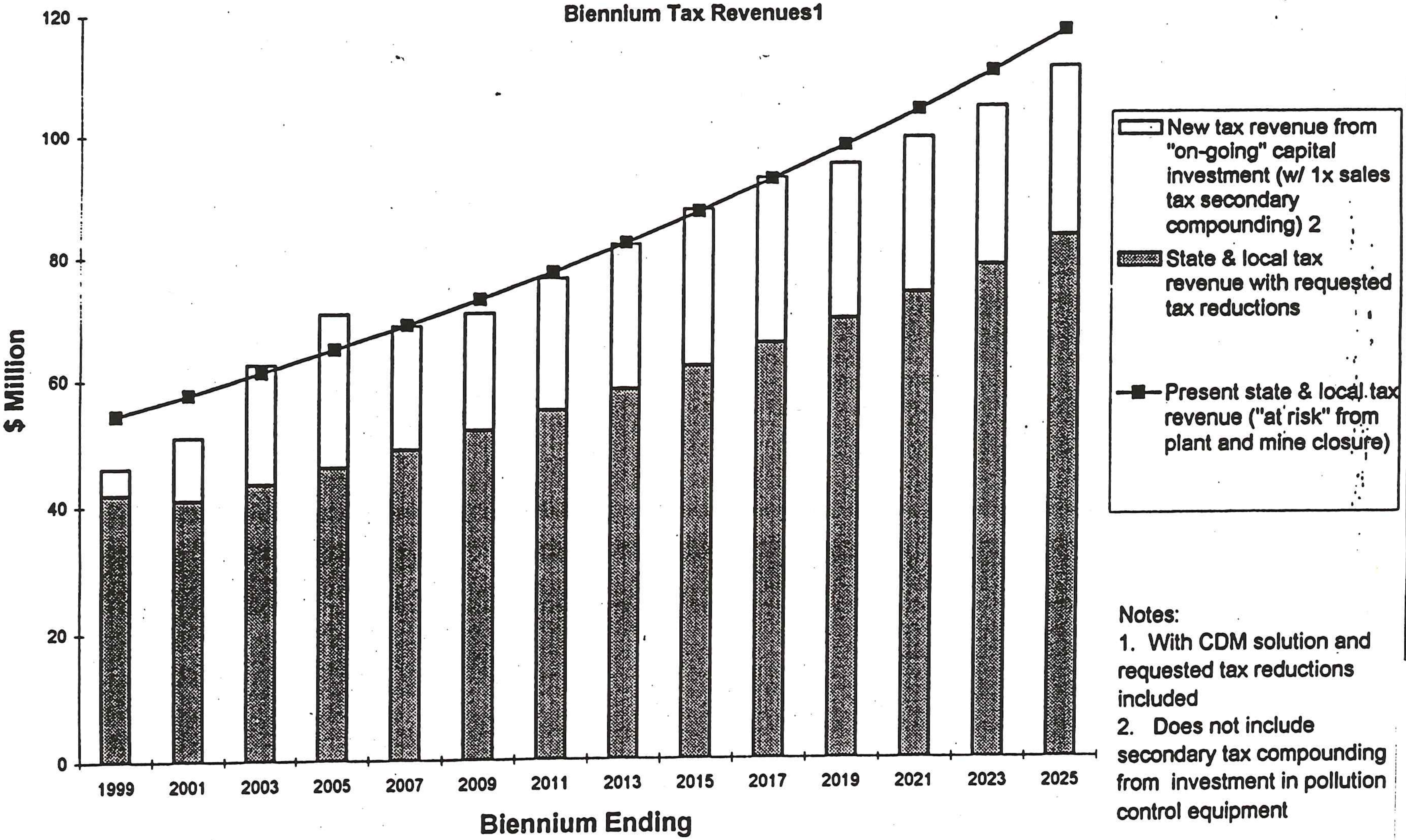
1/28/97

Power Supply Analysis

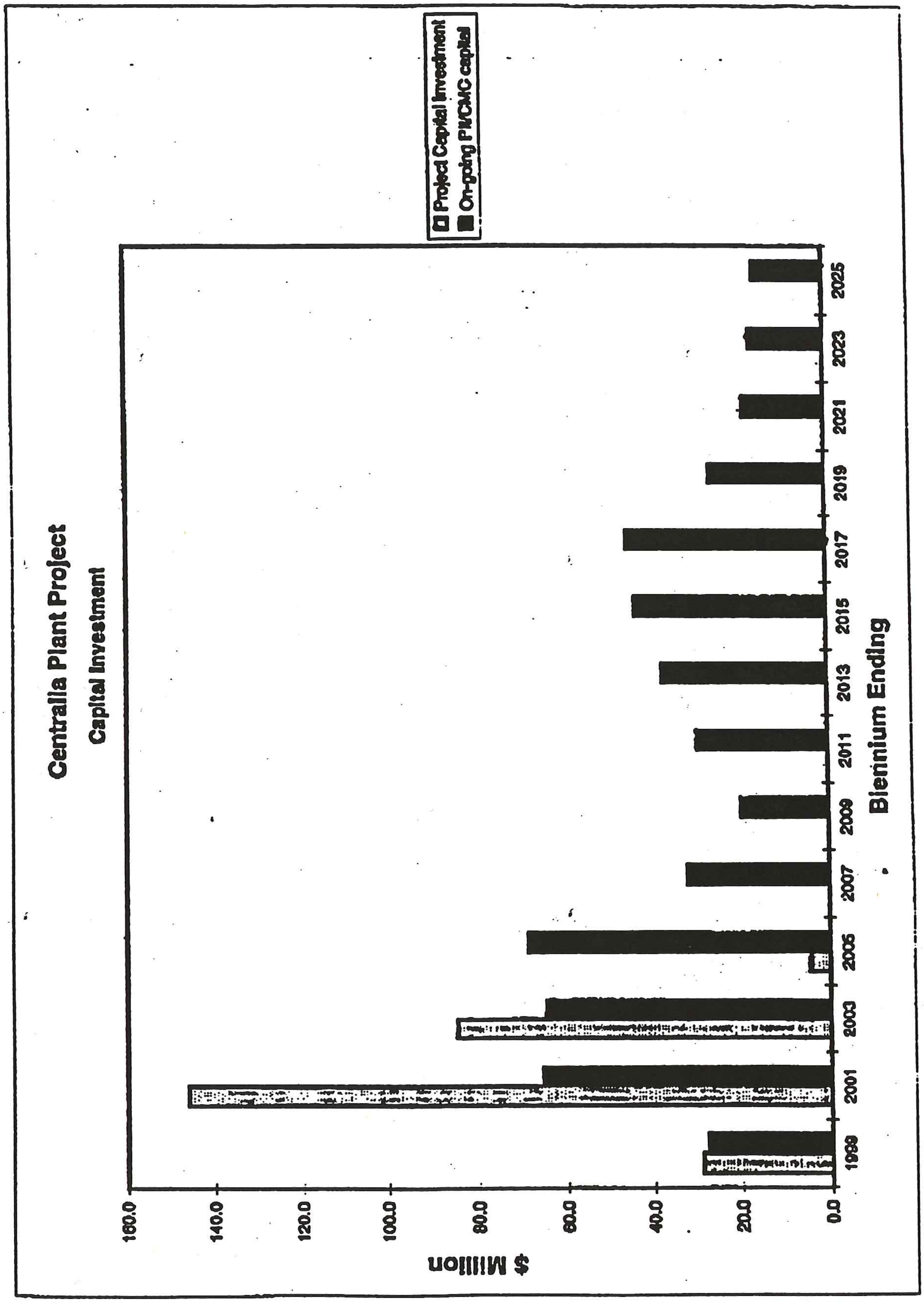
Centralia Plant Project

State and Local
Biennium Tax Revenues1



Notes:
1. With CDM solution and requested tax reductions included
2. Does not include secondary tax compounding from investment in pollution control equipment

3/3/97


Centralia Plant Project
Capital Investment
Project Capital Investment
On-going PI/CMC capital
$ Million
180.0
140.0
120.0
100.0
80.0
60.0
40.0
20.0
0.0
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023
2025
Biennium Ending

2/27/97

THE CENTRALIA POWER PROJECT - AN OVERVIEW

CENTRALIA POWER PLANT - Shared Ownership - Managed by Pacificorp

Customers who Benefit -

Owner	Ownership Share	Customers in Pacific NW
Pacificorp	47.5%	550,000
Wash. Water Power	15.0%	285,000
Seattle City Light	8.0%	335,000
Tacoma Public Utility	8.0%	140,000
Snohomish Co. PUD	8.0%	220,000
Puget Power	7.0%	830,000
Grays Harbor PUD	4.0%	40,000
Portland Gen. Elect.	2.5%	620,000
	Total	2,430,000

Generation Capacity - Two coal fired units able to produce 1,300,000 kilowatts

Production Level (1994) - Enough energy to serve Seattle (9,775,391,000 KWH)

Coal Consumed (1994) - 6 Million Tons/yr (1.2 million tons imported)

Completion Date - Sept. 1972

Original Const. Cost - $250 Million (includes $66 million in pollution control equip.)

CENTRALIA MINING CO. (CMC) - Owned by Pacificorp

Mining Capacity - 4.8 to 5.3 million tons/year

Coal Reserves - 150 million tons

Mining Methods - Surface mine (80 million cubic yards/yr moved)
3 drag lines and 3 shovel operations

Unusual Mining Costs - A. CMC coal lies far below the surface - averaging 500 feet deep and often reaching depths of 600 feet
B. Clay impurities in coal requires washing before use

BTU Content of Coal - 7888 BTU/lb average for Centralia mine
9829 BTU/lb average for imported coal

Fuel Cost Comparisons - CMC mined coal = $22 to $24/ton delivered at plant
Import coal = $3.50 to $4/ton + $15/ton ave. transp. cost

Excerpt from Centralia Owners Committee Minutes

January 2, 1997

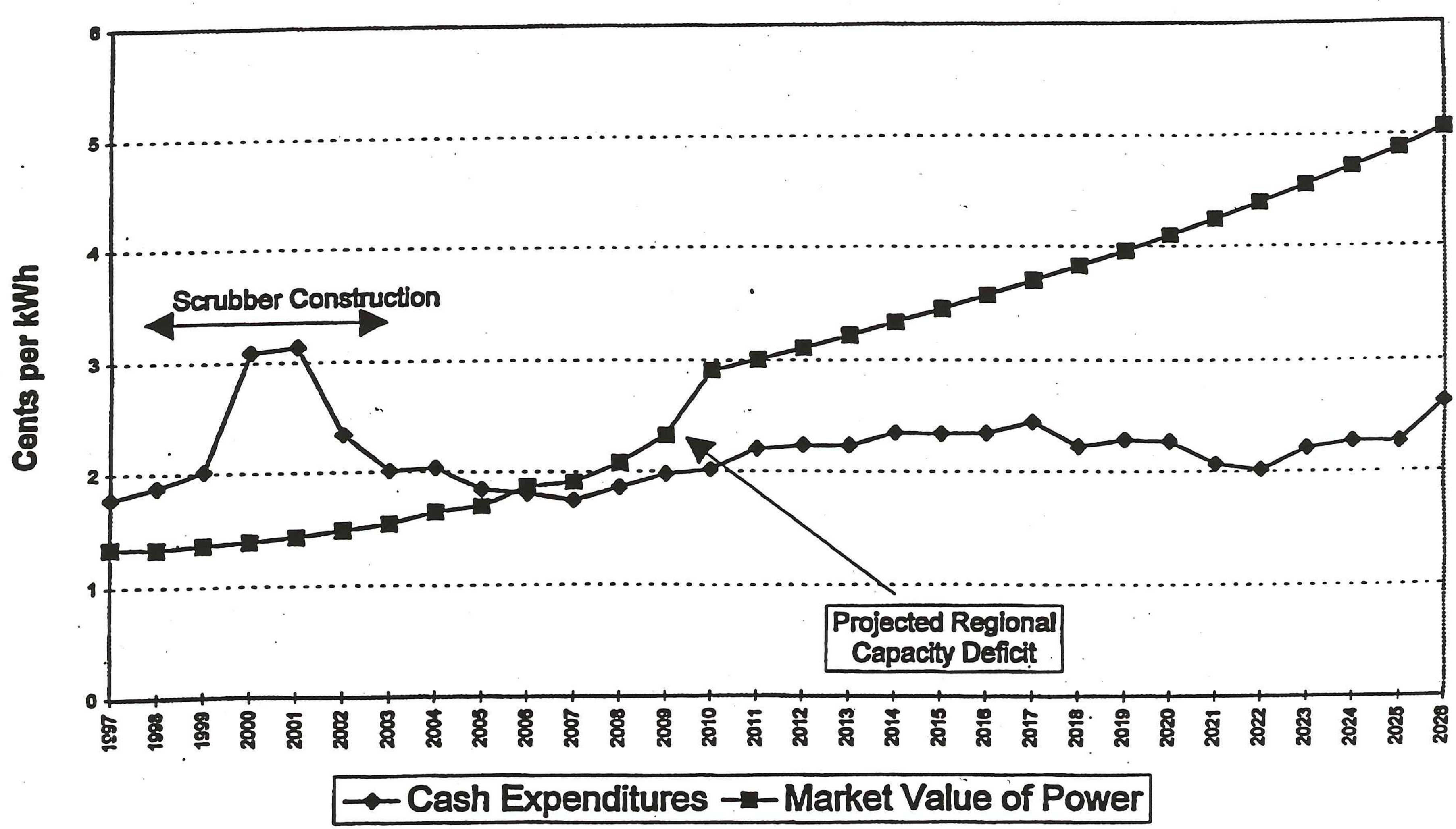
Part of the Approved Press Release Package and Legislative Proposal

CDM Target Solution - Centralia Power Plant
Estimated Costs for 30 - Year Life of Plant

	Present Value Dollars ($million)('96 equivalent)			Nominal Dollars ($million)(1996 - 2026)		
	w/out incentives	tax incentives	w/ incentives	w/out incentives	tax incentives	w/ incentives
Target Solution(8)						
Capital Investment	$ 172	$ 12 (1)	$ 160	$ 264	$ 19 (1)	$ 245
Operating Costs ($ops)	$ 49	$ 16 (2)	$ 33	$ 225	$ 70 (2)	$ 155
$ops/year('96)(4)		2.7 - 3.1				
Sub-Total (1997 - 2026)	$ 221	$ 28	$ 193	$ 489	$ 89	$ 400
On-Going Plant & Mine Operations (not including Target Solution)						
Capital Investment	$ 192	0	$ 192	$ 526	0	$ 526
Operating Costs ($ops)	$ 1495	$ 102 (3)	$ 1393	$ 4882	$ 331 (3)	$ 4551
$ops/year('96)(4)		7.5 - 8.1				
Sub-Total (1997 - 2026)	$ 1687	$ 102	$ 1585	$ 5408	$ 331	$ 5077
Total (1997 - 2026)	$ 1908	$ 130	$ 1778	$ 5897	$ 420	$ 5477
Projected Wholesale Value of electricity(9)			$ 1721(5)			
Surplus(Loss) (1997 - 2026)			$ (57) (7)			

notes:
(1) Sales and Use Tax on new pollution control equipment, not currently in tax revenue budgets
(2) Property Tax on new pollution control equipment, not currently in tax revenue budgets
(3) Sales and Use Tax reduction on coal
(4) Applies to only the Operating Costs, for reference purposes only, expressed as $/yr. (1996 equivalent)
(5) All revenue applied to on-going costs, no return on existing capital investment
(6) Present Value Dollars is the equivalent amount if all cash was expended today, (discounting at the appropriate rate for each Owner) - economic tool to evaluate different cash flows on the same basis
(7) Target Solution plus On-Going Operations of the Plant/mine are positive only in later years, making the Target Solution capital investment very risky as a "stranded investment"
(8) The Target Solution is the proposed product of the Collaborative Decision Making Group (CDM), this product will be a recommended input to the public regulatory order process by SWAPCA, scheduled for the summer of 1997. The Target Solution includes SO2 and NOX controls
(9) Confidence in costs projections are higher than for revenue in future years

Centralia Power Plant Option 6g
Annual Projected Cost and Value of Power



Before the
Washington Utilities and Transportation Commission

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

Exhibit of

Jim Lazar
Consulting Economist

On Behalf of
Public Counsel

Exhibit 504
Calculation of Ratepayer Investment (Loss)
on Centralia 1986 - 1998

Centralia Historical Cost and Value of Power

1986 - 1998
Scaled up to 100% Ownership

Year	Fixed Costs Mills/kwh	O&M Costs mills/kwh	Total Cost	Value Of Power	Gain/Loss Per kwh	Total Million Kwh	$Millions Ratepayer's Loss	$Millions Ratepayer's Loss $1999
1986	8.54	23.98	32.52	11.71	-20.81	4.09	($85.04)	($208.96)
1987	4.01	21.36	25.37	15.49	-9.88	8.85	($87.38)	($200.35)
1988	4.10	19.66	23.75	19.44	-4.32	8.29	($35.80)	($76.61)
1989	4.02	20.16	24.18	22.95	-1.22	8.63	($10.54)	($21.04)
1990	4.16	22.49	26.65	19.17	-7.48	7.29	($54.52)	($101.59)
1991	4.38	18.20	22.58	15.98	-6.60	7.75	($51.12)	($88.90)
1992	3.54	17.82	21.36	21.70	0.33	8.85	$2.95	$4.79
1993	3.76	18.72	22.48	25.75	3.27	8.37	$27.41	$41.51
1994	2.96	17.90	20.86	22.34	1.47	9.53	$14.02	$19.80
1995	5.80	21.00	26.80	12.46	-14.34	5.14	($73.70)	($97.19)
1996	3.06	20.70	23.76	13.80	-9.96	8.45	($84.11)	($103.51)
1997	3.87	21.80	25.67	13.41	-12.26	6.81	($83.44)	($95.82)
1998	2.94	20.00	22.94	24.02	1.07	8.55	$9.17	$9.83
					Total:		($512.11)	($918.03)

Before the
Washington Utilities and Transportation Commission

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

Exhibit of

Jim Lazar
Consulting Economist

On Behalf of
Public Counsel

Exhibit 505
Historical Performance of Centralia Coal Plant

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 505
ADMIT ☑ W/D ☐ REJECT ☐

Public Counsel Data Request Attachment Response 51

Year	Availability Factor	Equiv. Availability Factor	Forced Outage Rate	Capacity Factor
1974	56.30	56.30	15.00	37.06
1975	71.53	71.53	11.69	53.92
1976	70.49	66.47	21.34	53.74
1977	79.67	73.16	7.58	71.60
1978	69.90	64.06	20.92	55.99
1979	77.32	68.50	15.78	67.05
1980	79.76	72.54	7.38	64.01
1981	90.38	83.55	4.14	62.87
1982	84.46	79.90	5.57	48.77
1983	79.79	75.31	6.65	55.02
1984	74.50	71.65	3.11	57.81
1985	87.96	85.38	1.03	70.91
1986	86.43	85.38	3.19	45.53
1987	94.07	93.22	2.64	73.46
1988	89.34	86.76	3.29	77.79
1989	83.69	80.76	4.69	76.64
1990	89.43	89.20	5.49	65.66
1991	90.92	90.35	2.81	68.77
1992	92.90	92.50	2.03	83.45
1993	83.37	82.55	12.49	76.48
1994	90.43	86.93	3.54	83.28
1995	87.32	85.49	2.94	49.87
1996	96.87	95.41	2.41	68.48
1997	92.18	88.76	2.68	59.30
1998	92.37	91.22	1.61	79.16
1999	93.17	91.42	4.21	69.96

Before the
Washington Utilities and Transportation Commission

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

Exhibit of

Jim Lazar
Consulting Economist

On Behalf of
Public Counsel

Exhibit 506
Northwest Power Planning Council
November, 1999 Presentation to
Regional Technical Forum

Proposed RTF Economic Valuation Process

Regional Technical Forum

Goal of the Process

- Establish the "value to the region's power system" of conservation and direct application renewable resources

Regional Technical Forum

Primary Inputs

- PNW Avoided Power Costs
- Conservation and Renewable Resource costs, savings/output, load shapes & lifetimes
- Non-energy benefits (particularly those that can be monetized)
- Financial Assumptions (finance life, interest and discount rates)

REGIONAL TECHNICAL FORUM

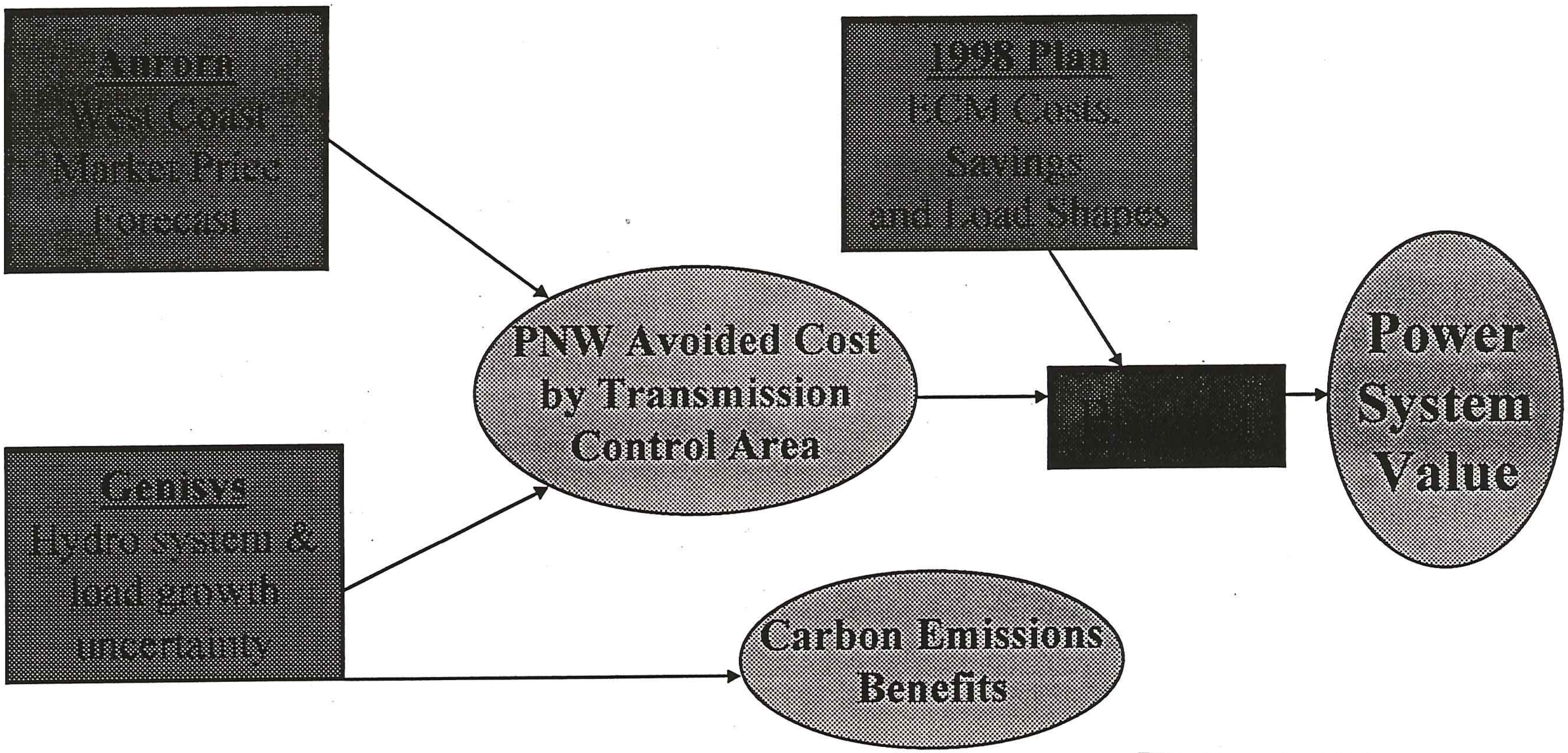
Exhibit of Jim Lazar
Exhibit 506
Page 3

RTF Input in Valuation Process

- Establish ECM cost, measure life and savings estimates
- Establish financial assumptions (discount rate, finance terms, etc.)
- Assign "non-energy" values to ECM's where appropriate
- Identify ECM's which may have additional "local benefits" (e.g. distribution system savings)

REGIONAL TECHNICAL FORUM

Proposed Economic Valuation Process



REGIONAL TECHNICAL FORUM

Exhibit of Jim Lazar
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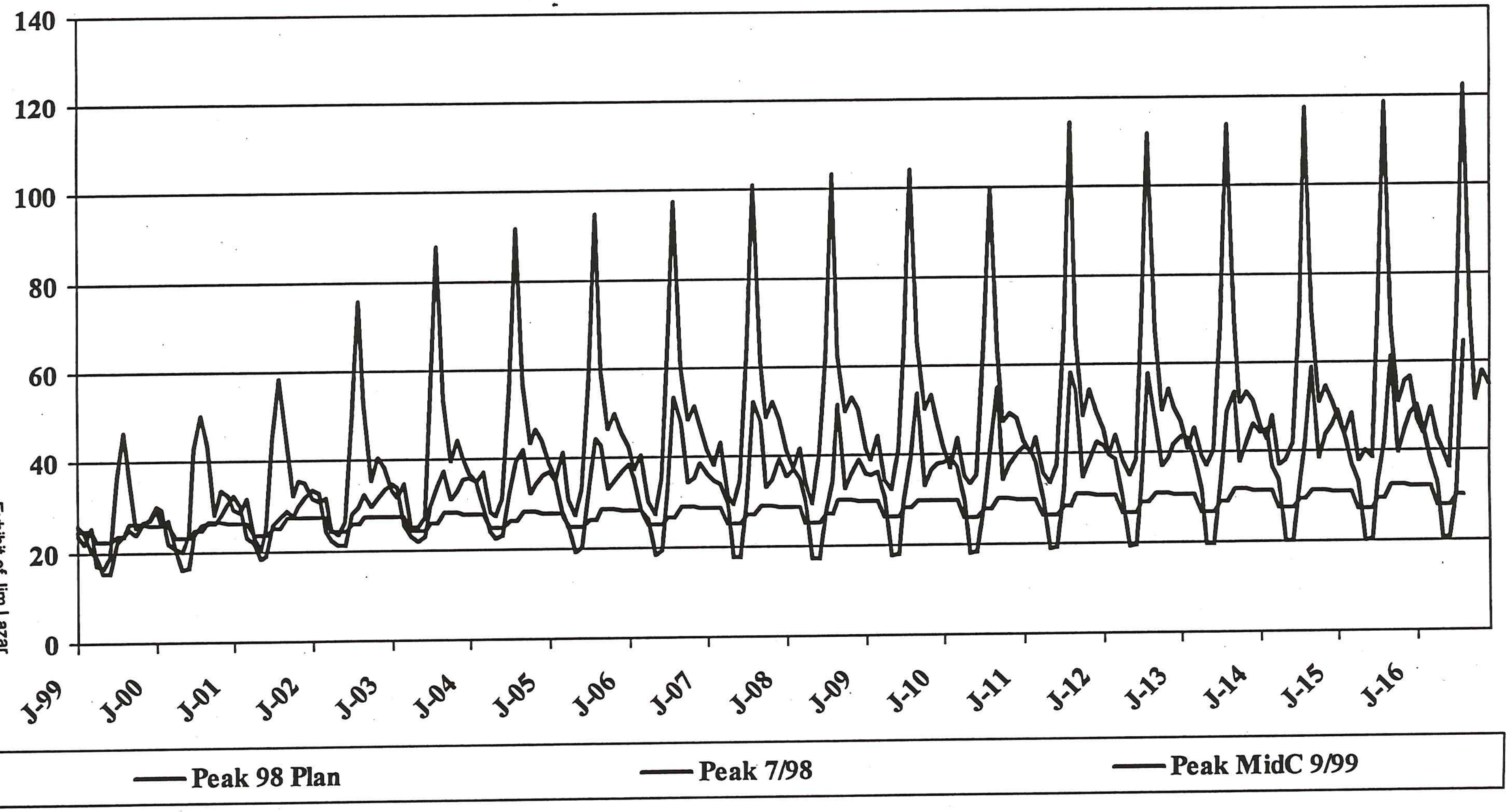
Page 5

On-Peak Period Price Forecasts



Off-Peak Price Forecasts

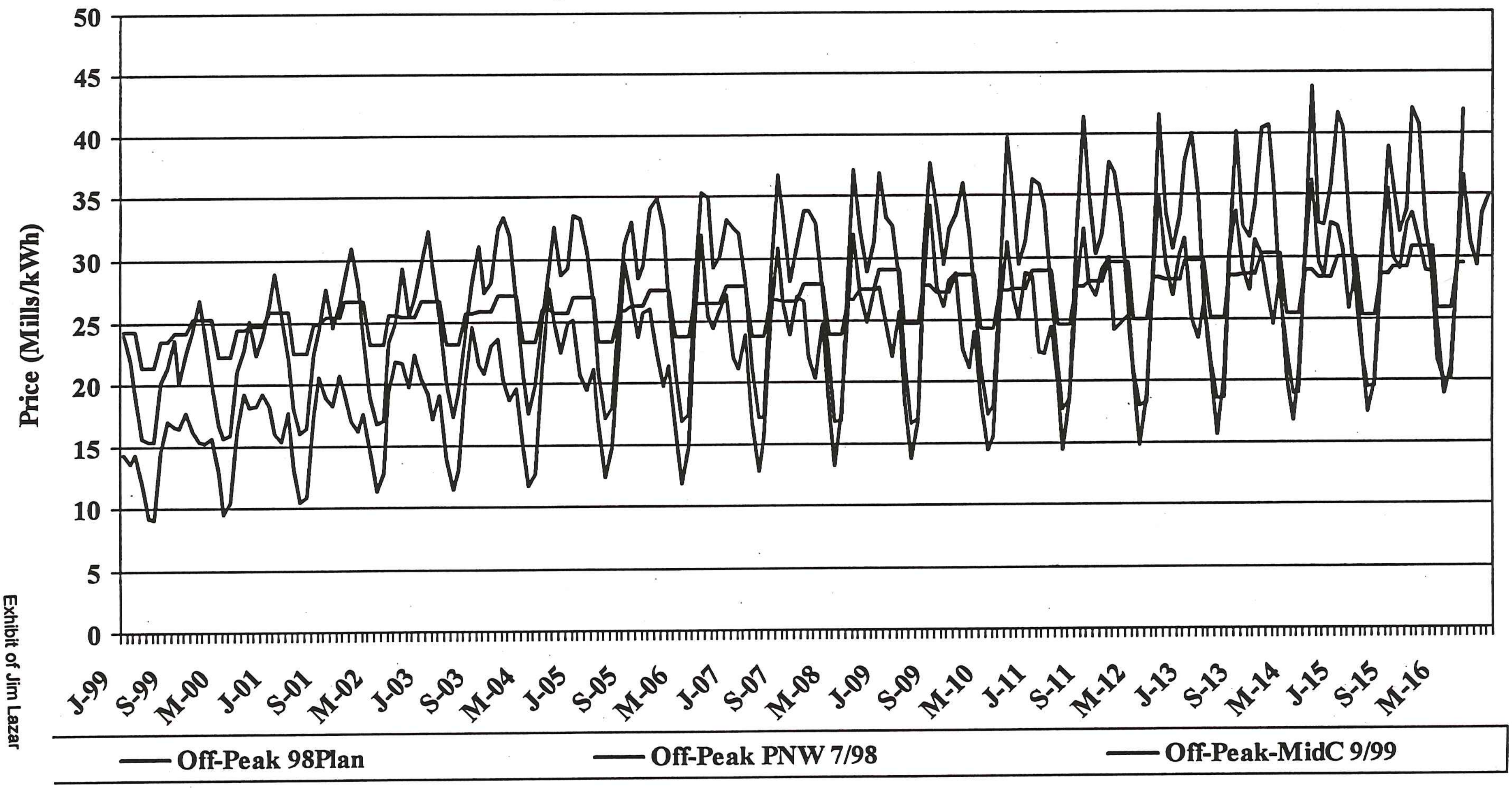


Exhibit of Jim Lazar
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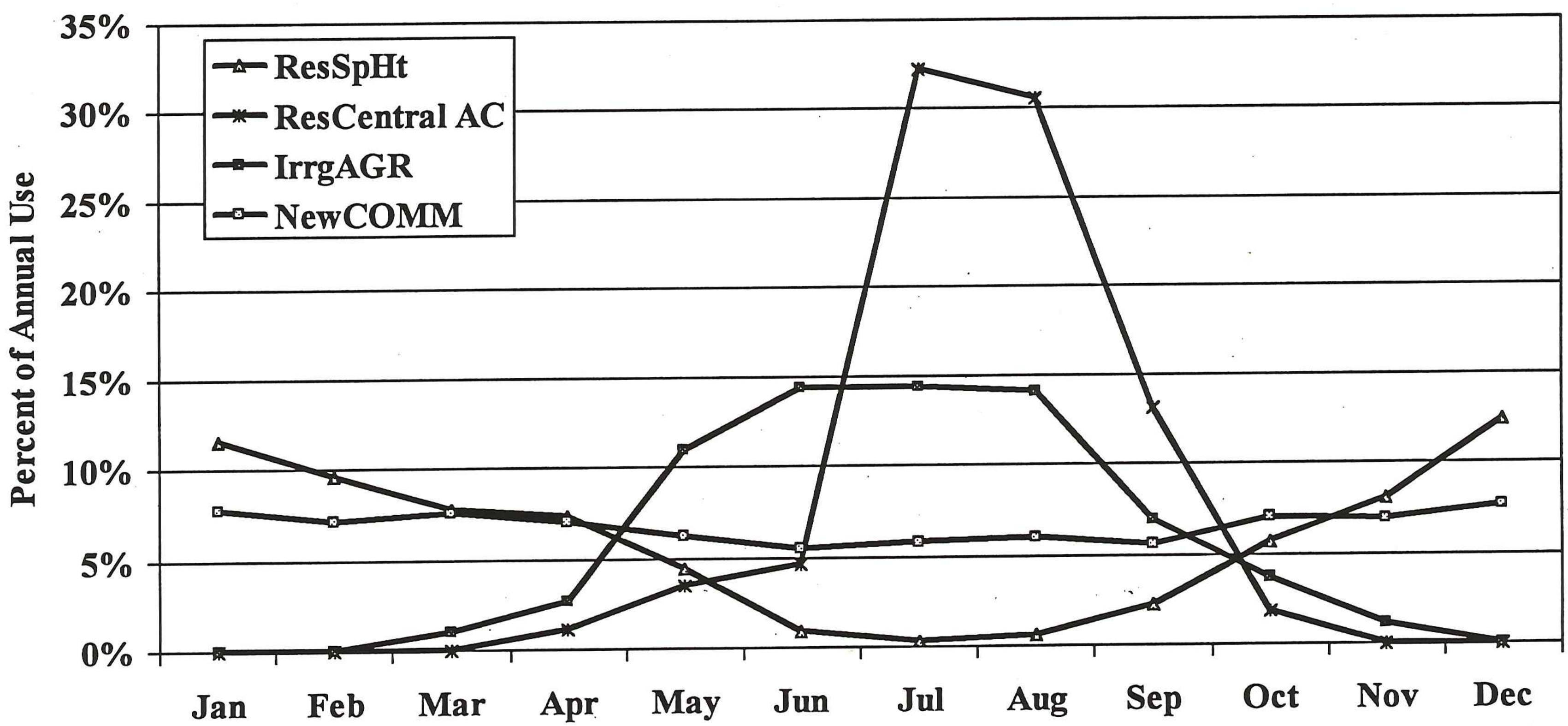
Typical On-Peak Load Shapes



REGIONAL TECHNICAL FORUM

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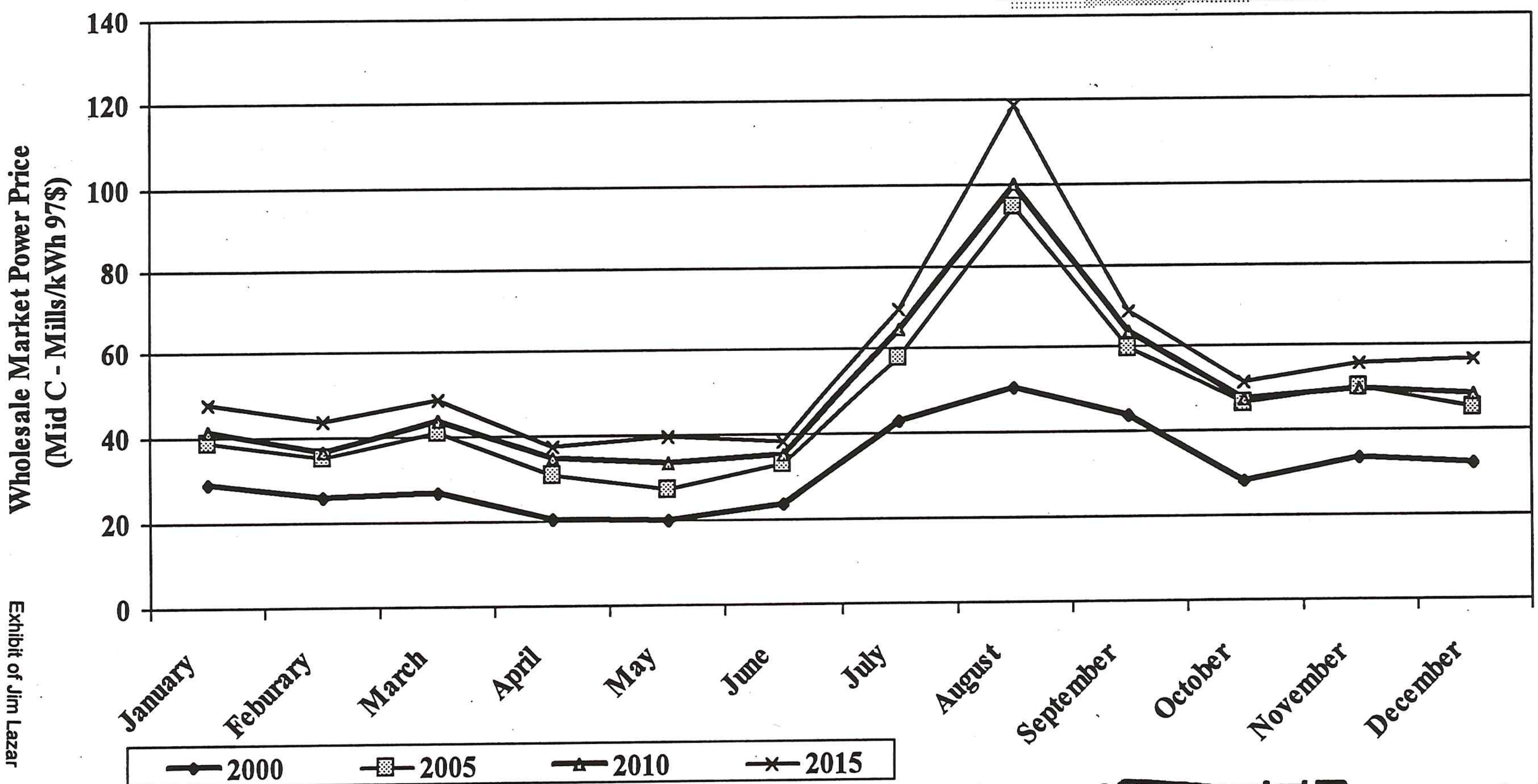
Exhibit of Jim Lazar
Exhibit 506
Page 8

Forecast On-Peak Market Power Price by Month and Year



Regional Technical Forum

Exhibit of Jim Lazar
Exhibit 506
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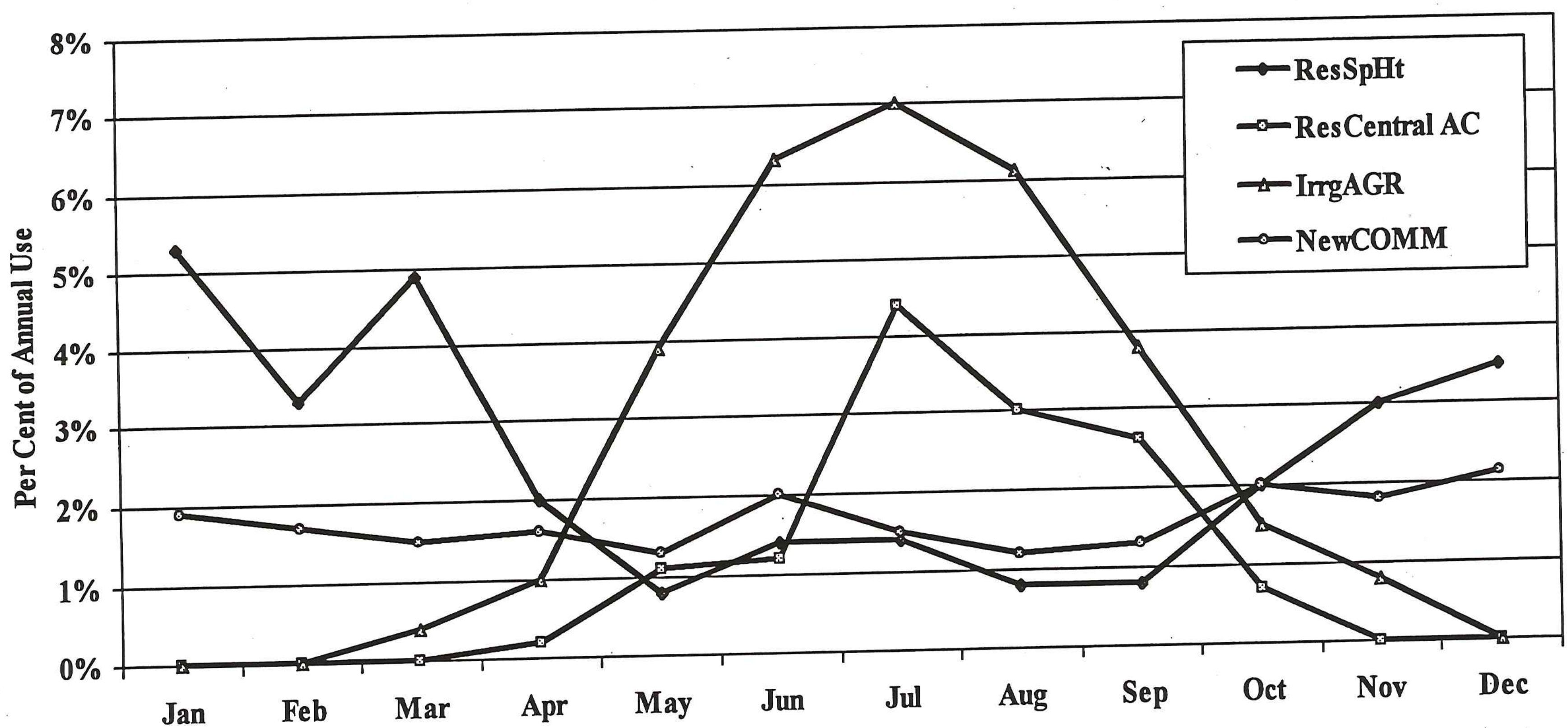
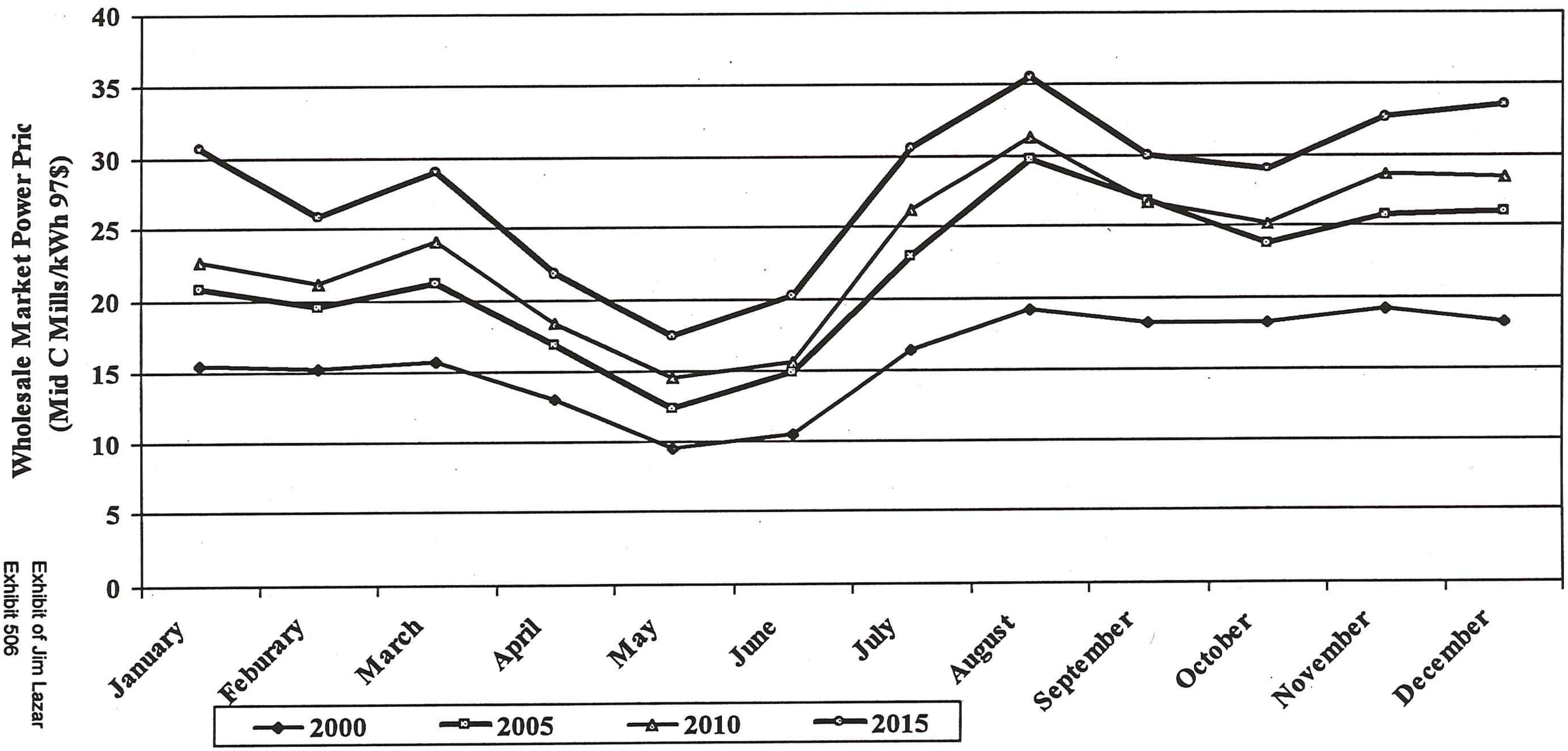
Typical Off-Peak Load Shapes



REGIONAL TECHNICAL FORUM

Forecast Off-Peak Market Power Price by Month and Year



REGIONAL TECHNICAL FORUM

Exhibit of Jim Lazar
Exhibit 506
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Impact of Load Shape & Price Forecast on Cost-Effectiveness

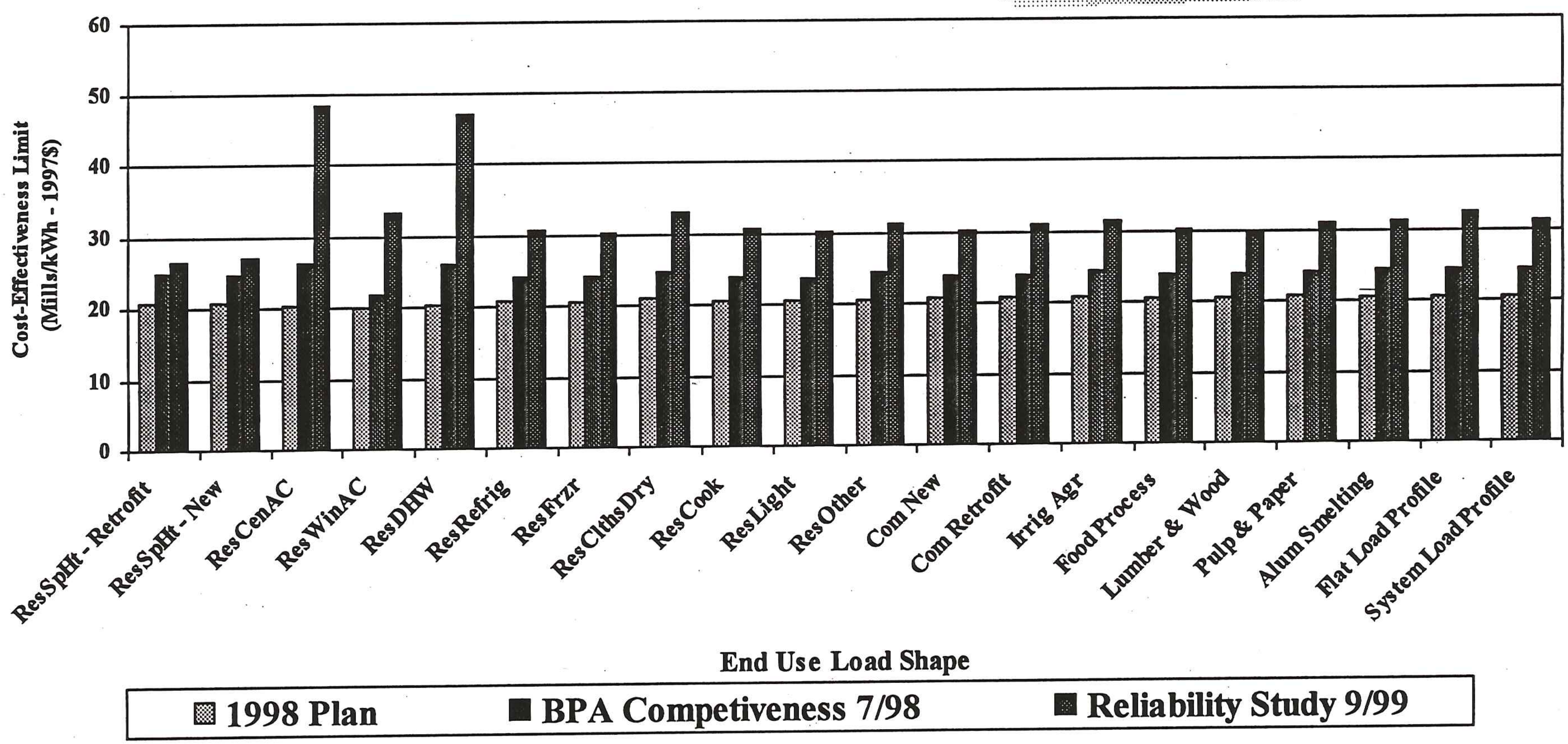

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Exhibit of Jim Lazar
Exhibit 506
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Procost Inputs

Program Parameters	
Program Life (yrs)	20
Program Start Date	2000
Present Value Time Zero	1999
Cost Reference Yr	1997
Real Discount Rate	4.75%
Inflation Rate (Currently NA)	0.0%
Capital Real Escalation Rt	0.0%
Sponsor Share of First Cost	100%
Sponsor Share of Replace Cost	100%
Sponsor Share of O&M	100%
Last Sponsor O&M Yr	20
Loss Factor	7.5%
T&D Credit ($/kw-yr)	5.00
Externalities Credit (m/kwh)	0.0
Regional Act C/E Credit (%)	10%
Admin Cost (% of First Cost)	0%
Cost Coeff of Variation	25%
Marg Cost / Save Shape File	C:\My Documents\Tom's Docs\Procost\MC and LoadSha
Marginal Cost Tab	98Plan Medium
Savings Shape Tab	Conservation Load Shapes

Sponsor Parameters	Spon 1	Spon 2	Spon 3	Cust
Real AT Cost of Cap	7.00%	5.00%	4.75%	5.00%
Financial Life (yrs)	10	10	20	1
Weight	0.0%	0.0%	100.0%	

Run Tabs:	Reset
FLAT	✓
SysLoad	✓
ResCAC	
ResDryer	
ResDHW	
ResFRIG	
NewCOMM	
ExCOMM	
IrrgAGR	
SIC 26	

On / Off

Browse

Run ProCost

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