Ex.T-400 (KLE-T)
Docket No. UE-991255, UE-991262, UE-991409
Witness: Kenneth L. Elgin

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

AVISTA CORPORATION for Authority to Sell its Interest in the Coal-Fired Centralia Power Plant	DOCKET NOS. UE-991255
In the Matter of the Application of PACIFICORP for an Order Approving the Sale of its Interest in (1) the Centralia Steam Electric Generating Plant, (2) the Rate Based Portion of the Centralia Coal Mine, and (3) Related Facilities; for a Determination of the Amount of and the Proper Rate Making Treatment of the Gain Associated with the Sale, and for an EWG Determination.	UE-991262
In the Matter of the Application of PUGET SOUND ENERGY, INC. for (1) Approval of the Proposed Sale of PSE's Share of the Centralia Power Power and Associated Transmission Facilities, and (2) Authorization to Amortize Gain Over a Five-Year Period.	UE-991409

DIRECT TESTIMONY OF

KENNETH L. ELGIN

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

DECEMBER 8, 1999

Q. Please state your name and business address.

A. My name is Kenneth L. Elgin. My business address is Chandler Plaza Building, 1300 South Evergreen Park Drive SW, Olympia, Washington, 98504-7250.

Q. By whom are you employed and in what capacity?

A. I am employed by the Regulatory Services Division of the Washington Utilities and Transportation Commission as its Case Strategist.

Q. Would you describe your education and relevant employment experience?

A. I received a Bachelor of Arts from the University of Puget Sound in 1974 and a Master of Business Administration from Washington State University in 1980. In January, 1985, I was employed as a Utilities Rate Research Specialist for the Utilities Division. In that capacity, I was responsible for many diverse aspects of natural gas regulation including rate design, cost of service, purchased gas costs, and least cost planning. I was also responsible for financial analysis and rate of return issues for all regulated utilities. In December 1989, I was promoted to the position of Assistant Director for Energy. In that capacity, I was responsible for the policy direction of the Utilities Division's electric and natural gas programs. In 1995, I assumed my present position as Case Strategist for the Division. In my current assignment I consult with or represent Staff on all aspects of energy cases presented to the Commission in the context of litigation.

I have testified before the Commission on many occasions as outlined in Exhibit 401 (KLE-1). Most recently, I presented policy testimony for Staff in Docket UE-990267 involving Puget Sound Energy's (PSE) application to sell its entire investment in the Colstrip generating station and related transmission facilities. I have testified before the Federal Energy Regulatory Commission on issues related to rate design and risk for interstate pipelines. I have also testified on several occasions in Superior Court regarding the regulation of investor-owned utilities pursuant to Washington's public service laws. I have been the lead analyst for numerous tariff filings and in this capacity I have presented Staff recommendations to the Commission at its regular open public meeting.

I also participated in Docket UE-960195 concerning the merger of Puget Sound Power & Light Company and Washington Energy Company (Merger). This complex docket required a comprehensive analysis of many diverse issues. I was responsible for coordinating Staff's recommendation to the Commission. Following the evidentiary phase of the case, I also led the Staff effort in negotiating a Stipulation with the Companies and Public Counsel. I testified for Staff in support of the Stipulation, which was adopted by the Commission.

During my fifteen years of experience working on energy and financial issues, I have developed a thorough working knowledge of both the operations and financial profiles of all three electric utilities operating in Washington.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. In addition to my qualifications in Exhibit 401 (KLE-1), I sponsor Exhibit 402 (KLE-2).

Q. Would you please summarize the proposal in this Docket?

A. Avista, PacifiCorp, and PSE propose to sell their representative shares of the Centralia steam plant, associated transmission facilities, and related property to a subsidiary of TransAlta Corporation (TECWA), a Canadian company headquartered in Calgary, Alberta. The proceeds exceed the net book value of the Centralia steam plant and related transmission facilities. The utilities have also agreed that the sales price of the mine will be at net book value.

Each of the applicants present a slightly different accounting and ratemaking treatment. Avista requests that the entire gain be given to shareholders. PacifiCorp requests a sharing of the gain between ratepayers and shareholders based upon the depreciation reserve balance. PSE seeks to amortize the gain over a five-year period, which is identical to the treatment it sought for Colstrip.

Q. Please summarize your recommendation in these proceedings?

A. The Commission should authorize the sale of Centralia for each of the applicants, but only upon condition that each utility defer the entire gain on the sale and return the gain to ratepayers in a general rate case. The utilities should also be required to provide to ratepayers all near-term power supply benefits that arise from the sale. Since Avista and PacifiCorp each have a general rate case pending before the Commission, the Commission will be able to capture both the near-term power supply benefits and determine the precise method for returning the gain to ratepayers in those proceedings. PSE should receive identical treatment to what was ordered by the

Commission in Colstrip. As a condition of approval in Colstrip, PSE was ordered to defer the gain and all the near-term power supply benefits of the transaction, and return them to ratepayers in a general rate case to be filed no later than March 29, 2002. These same conditions should be applied to PSE's sale of its interests in Centralia.

Q. **Why does Staff recommend that the Commission reserve to a general rate proceeding the precise method to reflect the gain in rates, rather than resolving that issue in the current case?**

A. As a policy matter, it is appropriate to consider the disposition of the gain from the sale of utility property in a rate proceeding because that is the only time when all issues surrounding the utility's operations are under review. RCW 80.28.010(1) requires that the Commission fix rates that are fair, just, reasonable, and sufficient. The rate case process is the only arena where all relevant information is reviewed by the Commission in order to make the required statutory finding. In a transfer of property proceeding, the Commission does not have sufficient information to make such a finding, nor are all parties that might be impacted by such a finding adequately represented.

Q. **How is your testimony organized?**

A. My testimony is divided into three main topics. First, I discuss the economic and qualitative factors offered by the applicants in support of the sale, in light of the public interest test established in the Commission's recent decision concerning PSE's sale of its Colstrip interests. My testimony on these issues does not distinguish between any applicant. Next, I discuss the underlying rationale for requiring all of the gain on the sale of any large central station generation and transmission facilities to be returned to ratepayers. I demonstrate that to do otherwise would provide excessive compensation to shareholders. I also explain why shareholders are treated fairly by receiving book value from the sale. Finally, I respond to the testimony offered by Avista and PacifiCorp, which argues that shareholders receive some or all of the gain from the sale, and I respond to PSE's proposal to amortize the gain on sale within five years.

Q. Are there any other Staff witnesses testifying in this case?

A. Yes. Mr. Martin discusses accounting issues for each company and Mr. Buckley provides a calculation of the near-term power supply savings that PSE should be able to achieve from the sale of Centralia. This calculation provides the basis for the amount of near-term power supply savings that should be deferred between closing and the time PSE files its next general rate case.

I <u>STANDARD FOR APPROVAL</u>

Q. What public interest standard did the Commission require for PSE in order to sell its investment in the Colstrip generation and transmission facilities?

A. The Commission relied upon a four factor test to determine whether a sale or transfer of utility property is in the public interest. Briefly summarized, these standards are: (1) the transaction should not harm ratepayers by causing rates or risks to increase; (2) the transaction should strike a balance between shareholders, ratepayers, and the broader public preserving affordable, efficient, reliable, and available service; (3) the transaction should not impair the development of competitive markets for the delivery of service; and (4) the transaction should not shift jurisdiction to another forum where Washington ratepayers may be adversely affected. In Colstrip, the Commission also affirmed its finding in Docket UE-981627 involving PacifiCorp and Scottish Power PLC, that the proper standard for approving the transfer of utility property is whether there is "no harm" to the public interest resulting from the sale. The test I relied upon is the Commission's "no harm" test in the context of the four standards just described. Many of these concepts were repeated in the Commission's Prehearing Conference Order in this case which states that the examination should consider how ratepayers, shareholders and the general public would be impacted by the sale, as compared to no sale.

Q. What specific analysis did you rely upon in evaluating whether the sale of Centralia meets the first and second criteria of the Commission's no harm test?

A. The first element of the analysis requires a review of the underlying economics of the transaction. Therefore, I relied upon the testimony and studies each company submitted to support their belief that ratepayers are best served if Centralia is sold and removed from rate base. (PSE: Exs. T-101, 105; PacifiCorp: Exs. T-209, 210, 211, 212; and Avista: Exs. T-303; Exs. No. T-303, 304, 305.) These studies focus specifically upon a comparison of the cost of energy from continued ownership of Centralia and the cost of a reasonable alternative energy supply if Centralia is sold.

Q. What do these economic studies of the applicants show?

Avista testifies to a twenty year study supporting a net present value of $7.7 million. PacifiCorp supports a twenty-three year study with a net present value of $10 million. Finally, PSE presents a series of studies. Its nineteen year study, which I would describe as the "base case" scenario, shows a net present value of $7 million from the sale.

Each applicant produced a different study based upon the unique operating characteristics of its respective resource portfolio. It is also critical to note that the applicants treat the gain from the sale differently in their analyses. This is necessary to capture the unique accounting and ratemaking treatment proposals of each applicant. PSE's study includes the impact of its proposal to amortize the gain over a five year period beginning in 2000. PacifiCorp includes in its calculation of future revenue requirements its proposal to offset regulatory assets with the gain. Finally, Avista does not include any consideration of the gain in its study since it proposes to return all of the gain to shareholders.

Q. Do you have any observations about these analyses?

A. Yes. Each of the analyses use a different time horizon, all of which appear to be too short, and none of the applicants offer testimony supporting the period for which costs and benefits are studied. The applicants state that extending the time horizon over a longer period subjects their analysis to additional uncertainty, but this testimony does not justify the specific time frame utilized in the analysis. PSE and PacifiCorp reference a ten-year net present value benefit of $17.7 million and $39 million, respectively. (Ex. T-101, p. 6; Ex. T-209, p. 5.) Even though there is uncertainty in extending any analysis, I believe it is still reasonable to justify the time period upon which each company actually relies.

Q. What factors and considerations determine the proper time horizon for evaluating the economics of the sale?

A. New pollution control equipment is being installed. It makes little sense for the majority of the plant owners to justify the installation of pollution control equipment at Centralia, which is a significant capital expenditure with an estimated thirty-year life, and not base the economic analysis over the same time horizon. At a minimum, this discrepancy should be thoroughly explained and justified. Moreover, PacifiCorp should explain why it used a twenty-three year time frame in this case but supported a thirty-year analysis of the same facility in seeking tax concessions from the Washington legislature for the purchase of the pollution control equipment. I believe a thirty-year time frame is reasonable for such an analysis despite the added uncertainty.

Q. What impact would lengthening the time frame have upon each of the studies?

A. I have not done that specific analysis. However, based upon the underlying assumptions of the models used by the applicants, extending the period of evaluation would favor keeping Centralia in rate base. This conclusion is based on the scenarios presented by the applicants which all show that the cost of keeping Centralia is less than the market price of replacement power under a medium price scenario. (PSE:

Ex. 105; PacifiCorp: Exs. 211, 212; Avista: Ex. 304)

Q. What other observations do you have about the analyses presented by the applicants?

A. First, each of the applicants uses different models and forecasts of future market prices for replacing Centralia energy and capacity, and all of the models rely upon very similar costs for Centralia. As it did in Colstrip, PSE relies primarily on AURORA for future market prices and it replaced Centralia with energy purchases that match the delivery of energy from Centralia. PacifiCorp's analysis estimates future revenue requirements based upon future market prices and an economic dispatch of its system. Avista also relies upon a similar re-dispatch of its system, but with lower estimates of future market prices that produce results that favor a decision to sell. In comparison to the AURORA estimates of future market prices for replacement energy, Avista's estimates appear aggressive. Therefore, its testimony that the transaction produces a net benefit to ratepayers is suspect. In fact, in response to Public Counsel Data Request No. 19, Avista provides new higher estimates of future energy prices, which further undermines its testimony that the economics of the transaction benefit ratepayers.

Second, with the exception of PSE, the studies show that there are near-term benefits of selling Centralia. In the intermediate-term, the studies show that replacement power is also likely to approximate the cost of Centralia, and at some point in the 2004-2008 time frame market prices are forecasted to exceed the cost of Centralia. In the long-term, the studies all show that Centralia will cost less than alternate energy supply available in the market. Therefore, the net benefit of the sale is clearly a function of how aggressively an analyst estimates longer-term future energy prices and how far into the future the analyst studies the benefit of keeping Centralia in rate base. Looking at the economics of power supply costs and benefits, the sale of Centralia does not produce a net benefit to ratepayers.

Q. Do you have any other comments about the studies offered by the applicants?

A. Yes. As I previously stated, PSE's study assumes that it will replace Centralia with "in kind" market-based purchases with energy shaped to match the loss of this resource.

Q. Is this assumption valid?

A. No. It is unreasonable to expect PSE to purchase replacement power with the same characteristics as Centralia. Mr. Gaines recognizes this fact. On page ten of his direct testimony he discusses the flexibility PSE will have in replacing Centralia purchases. On page eleven he states, "Replacing (Centralia) . . . will allow PSE to achieve a better match between . . . resources and the demands of its customers." He also testifies on page nine that PSE's 93.8 MW share of Centralia's output, ". . . is a minuscule portion of PSE's peak load of 5,146 MW." It is, therefore, very unlikely that PSE will actually purchase power to replace Centralia. It is necessary to correct this flaw in PSE's presentation to ensure that ratepayers receive the near-term benefits of the expected reductions in power supply expense from the sale. Mr. Buckley estimates these benefits which should be deferred under Staff's recommendation.

Q. What conclusions have you reached from the economic analyses presented by the applicants?

A. None of the economic studies demonstrate clearly that ratepayers will benefit from selling Centralia. The analyses show that Centralia should be sold only if long-term market prices for replacement energy remain in the low to medium forecast scenarios. If, on the other hand, long-term energy prices rise and begin to exceed the medium case scenario, the analyses support a decision to keep the resource.

In conclusion, the studies demonstrate that the sale of Centralia is, at best, a "push" and that the sale exposes customers to the risk of paying higher energy costs in the future.

Q. Does this conclusion mean that the sale of Centralia fails the Commission's public interest test because it harms ratepayers?

A. Standing alone, these economic studies support a conclusion that the sale of Centralia will expose ratepayers to increased risks of higher future energy costs. Therefore, the studies themselves warrant a conclusion that Centralia should not be sold. However, there are other factors that should be considered in determining whether the sale harms ratepayers.

Q. What other factors should be considered?

A. These are the qualitative factors discussed by the applicants' policy witnesses, Messrs. Miller, Gaines, and Ely. First and foremost, the future cost of the Centralia steam plant is highly uncertain. Second, there are future environmental remediation costs related to the mine. Selling Centralia removes these uncertainties for <u>both</u> shareholders and ratepayers. Furthermore, Centralia is a highly valuable resource because of its location. Selling Centralia to TECWA provides certainty to the region that the pollution control equipment will be installed, the plant will continue to operate, and the region will continue to benefit from Centralia's strategic position in the Pacific Northwest grid.

Next, I would refer the Commission to testimony offered by Mr. Gaines of PSE. He states, ". . . the analyses do not reflect the significant potential technological or political changes that may occur within the planning horizon, including retail access, increased benefits from wholesale competition . . ." (Exhibit T-101, p.13) This is a critical element of the decision-making process. I do not believe that forecasting models can fully account for technology changes or efficiency improvements, or fully capture all of the anticipated benefits from increased wholesale competition.

Q. **Are there any other factors that you believe should be considered in the context of evaluating the sale of Centralia?**

A. Yes. The decision to sell Centralia relates directly to the issue of open access and whether the Commission believes it is in the long-run best interests for consumers to purchase power in wholesale competitive markets, rather than to continue to rely upon the utilities to make those purchases or make new investments in power plants. In other words, the decision to sell Centralia concerns whether it is appropriate for the Commission to regulate electric companies as distribution companies. In Colstrip, I testified that at the end of the current rate plan PSE should be regulated as a distribution company. I would also note, as a policy matter, that the Commission's third criteria evaluates the impact of a sale of utility property on competition and the ability to deliver affordable, reliable and, efficient electricity service. Competitive wholesale electric markets, I believe, will provide the public with better, lower-cost services. If the Commission agrees, then the sale of Centralia fits clearly within that policy framework. On the other hand, if the Commission believes that it is in the public interest to continue to regulate electric companies as vertically integrated utilities, then the economic studies do not support the sale of Centralia.

Q. Do these qualitative factors lead you to conclude that the sale of Centralia meets the Commission's public interest test?

A. The qualitative factors do support the decision to sell Centralia. However, as demonstrated by the economic analyses, there are long-term risks to ratepayers of higher energy costs if Centralia is sold. Therefore, in order for the public not to be harmed from the transaction, <u>all</u> of the gain and <u>all</u> of the near-term power supply benefits must accrue to ratepayers. This conclusion is very similar to that reached by the Commission in its analysis of Colstrip.

Q. The fourth criteria of the Commission's public interest test is whether the transaction may adversely affect Washington ratepayers by shifting jurisdiction to another forum. Would the proposal to sell Centralia shift jurisdiction to another forum adversely affecting ratepayer's interests?

A. No. The Commission would either continue to regulate the fully bundled rates of the applicants or, in an open access environment, the Commission would rely upon competitive markets to determine the reasonableness of power supply costs.

Q. Please summarize your testimony regarding whether the sale of Centralia meets the Commission's public interest test?

A. The economic studies do not demonstrate long-term economic benefits of the transaction. The decision to sell Centralia is heavily weighted by consideration of non-monetary factors and near-term benefits that are very likely to occur. I also believe the decision to sell is supported by the potential long-term benefits of moving regulated utilities to an environment where ratepayers receive the benefits of wholesale competition in electric commodity markets. In order for ratepayers to assume the risk of capturing these potential benefits of access to competitively priced power supplies, the near-term benefits of the transaction must be returned to ratepayers. Therefore, the Commission should approve the sale of Centralia for each applicant, but only on condition that ratepayers receive all of the gain and all of the near-term power supply benefits which result from the sale. The Commission will be able to capture the near-term power supply benefits for PacifiCorp and Avista customers in their pending rate cases. PSE should defer the near-term power supply benefits of the sale due to its operation under the Merger rate plan. Each company's proposed accounting and ratemaking treatment should, therefore, be rejected.

II. SOUND REGULATORY POLICY SUPPORTS RETURNING THE GAIN TO RATEPAYERS

Q. Are there other reasons for requiring that all of the gain goes to ratepayers from the sale of Centralia?

A. Yes. It is reasonable and sound regulatory policy to return the gain to ratepayers under any circumstance.

Q. Why is that?

A. The Commission's use of rate base, rate of return regulation provides shareholders an opportunity to earn a fair rate of return on utility investment. The policy is consistent with the seminal Supreme Court cases of *Hope & Bluefield.* In a rate case, the Commission evaluates <u>all</u> used and useful utility property and provides a market based return as compensation to investors for the public's use of the facilities. At all times investors are allowed an opportunity to earn a fair return <u>on</u> and <u>of</u> these investments. Furthermore, embedded in the calculation of compensation to investors is a return on equity component which compensates shareholders for the risk of ownership. Therefore, whenever the Commission sets rates, it makes a prospective determination that shareholders will be compensated fairly. Anytime a utility believes it is not receiving adequate compensation with respect to its investments, including the Centralia property, it may seek to change rates. This prospective look at market based returns on net book value is the time-honored test for measuring fair compensation to shareholders.

Q. What happens to shareholders once a utility sells property, such as Centralia?

A. Once the utility sells its remaining investment and receives the net book value of the facility at the time of closing, shareholders are treated fairly based upon management's decision to use the cash from the proceeds. There are two choices: (1) management may return the cash to shareholders; or (2) management may reinvest the proceeds in other assets. In the first instance, shareholders re-invest the cash dividend and seek a fair rate of return on any alternate investment. In the second instance, management must make decisions to re-invest in new projects that presumably will provide a fair return to investors. Indeed, if any of the gain is kept by the utility, shareholders will be provided excessive returns through accretion in the utility's book value.

Q. Are there any other ways in which the Commission's prior rate treatment of these facilities requires that ratepayers receive the entire gain from the sale?

A. Yes. As I testified in the Colstrip proceeding, these generation and transmission facilities were expected to produce long-term benefits to customers. Since rates reflect early year capital costs, rather than levelized costs, the benefits to ratepayers of Centralia must be considered over the entire life of the resource. The effect of traditional rate base regulation causes ratepayers to incur the high cost of these facilities in the early years and the lower costs in later years as these facilities are depreciated over time. Therefore, it is very important that the Commission insure that ratepayers receive all of the benefits from the transaction since consumers have paid in the early years of Centralia the significant portion of the total life-cycle cost of these facilities. Now, and for the remaining life of Centralia as it becomes fully depreciated, the benefits of lower fixed capital costs begin to accrue to ratepayers. The applicants studies in this proceeding all demonstrate this fact.

Q. Are there any other factors that support the decision to provide ratepayers all of the gains from this transaction?

A. Yes. RCW 80.04.350 requires the Commission to determine the depreciation rates to apply to all utility property used to serve the public. This ensures that shareholders are provided a return of capital over the economic life of all utility property. Setting depreciation rates is a prospective process, and the Commission is never able to accurately determine the depreciation rate of long-lived assets like Centralia. It is reasonable to consider the gain as the inability to accurately provide for the depreciation reserve. In other words, Centralia was depreciated too quickly. Therefore, ratepayers paid excessive depreciation expense and shareholders benefitted since capital was returned too quickly. Returning the gain to ratepayers establishes equity.

Q. Are there any final elements concerning the gain that warrants Commission consideration?

A. Yes. Each of the applicants presented testimony that the continued ownership of Centralia exposes both shareholders and ratepayers to considerable risk. This testimony stands for the proposition that, without the sale, it is possible that Centralia would no longer continue to be a viable source of power. If that is the case, the owners should be pleased with a transaction that returns the net book value from the remaining investment. If Centralia is not sold and later a decision is reached to abandon the facility, shareholders are faced with the prospect of asking ratepayers to continue to pay for an abandoned facility. If these risks are real, management has a fiduciary responsibility to sell Centralia now and return to shareholders the net book value of the facilities or reinvest the proceeds in other capital projects.

III. RATEMAKING PROPOSALS

Q. Do you have any comments about the specific proposals of PacifiCorp and Avista to allow shareholders to receive some or all of the gain?

A. Yes. My comments should be considered in the broader context of whether these proposals are reasonable for all applicants. The Commission's treatment of the gain should be uniformly applied to each applicant.

Q. Would you please summarize Avista's justification for its proposal to return the gain to shareholders?

A. First, Avista argues that it is fair and equitable to give shareholders the entire gain given the historical balance between ratepayers and shareholders. (Ex. T-306, p. 4.) Second, Avista argues that shareholders receive asymmetrical treatment from the Commission when it comes to evaluating resource decisions, and that a more equitable outcome is for shareholders to benefit from occasional gains rather than exclusive losses from developing new resources.

Avista presents Exhibit 307. This exhibit is a comparison of Company "earnings" and "authorized rate of return." On the basis of this exhibit, Avista asserts that its actual rate of return for its Washington electric operation is more often than not below what is considered fair and reasonable and authorized return during the period of time Centralia has been in service to the public. (Exhibit T-306, p. 4.) This argument should be rejected by the Commission.

Q. Why should this argument be rejected?

A. Exhibit 307 is based upon several false premises. First, Avista assumes incorrectly that the authorized rate of return adopted by the Commission in a rate case is synonymous with a fair rate of return until changed by the Commission in a subsequent rate order. However, an authorized rate of return may or may not be a fair rate of return, depending upon market conditions as they change over time.

Exhibit 307 demonstrates this problem. The Commission has not determined a fair rate of return for Avista since 1986 in Cause U-85-36. In early 1987 in Cause U-86-99, the Commission accepted a settlement establishing a revenue deficiency for the Company's investment in WNP-3. That $15.5 million revenue deficiency was based primarily upon a 10.67% rate of return applied to 64.1% of the Company's investment in WNP-3.

It is unreasonable to consider the Commission's acceptance of an 10.67% rate of return in 1987 as representative of a fair return for Avista each and every year through 1998. A 10.67 % rate of return for Avista has not been reasonable for many years.

Second, Avista assumes incorrectly that the column representing the achieved rate of return would have been accepted by the Commission as a fair representation of the Company's earnings for ratemaking purposes. What the exhibit does show clearly is that Avista's electric operations have not been fully reviewed since 1985 and its decision not to seek rate relief is *prima facie* evidence that existing rates provided adequate compensation to shareholders throughout the time period.

B. **Do you have any preliminary evidence regarding Avista's earnings during the past ten years?**

A. Yes. Exhibit 402 (KLE-2) shows Avista's market-to-book ratio and return on common equity for the period 1989-1998. Even though these figures are summary figures for the total company, they support the exact opposite conclusion: Avista was over-earning.

Q. **Do you have a preliminary estimate of what would be a fair rate of return for Avista during the 1990's?**

A. Yes. The cost of capital declined dramatically during the 1990's. For example, in the early 1990's, the Commission determined that 10.5% was a fair return for shareholders for both an electric and gas utility. Applying a 10.5% return on common equity to Avista, and assuming a reasonable capital structure consistent with prior rate decisions for the Company, produces an overall rate of return in the 8.75% to 9.25% range. I would also note that a 10.5% return on equity itself may be too high for Avista under current market conditions.

Q. Please summarize your conclusions regarding Exhibit 307?

A. Avista's exhibit and corresponding testimony that shareholders have not enjoyed the efficiency gains achieved by management is incorrect. An accurate study of the Company's earned returns for the 1990's would show that shareholders have captured the efficiency gains achieved by management during this last decade.

My previous testimony in this regards still stands: the Commission's use of rate of return regulation principles is fair to shareholders. At any time Avista determines that its rates provide inadequate compensation from the public's use of its utility property, it may seek rate relief from the Commission. The Commission will then evaluate all the facts and circumstances, and establish rates in accordance with the statutory principles of fairness and equity.

Q. Avista also discusses the fact that it has experienced substantial disallowance of prior investments in generation facilities. (Ex. T-306, pp. 5-7.) Would you please comment on this testimony that returning the gain to shareholders from the sale of Centralia restores equity because Avista was denied full recovery of these prior investments?

A. The 1970's and early 1980's were a period of time when ratepayers and shareholders suffered losses due to significant problems in the electric industry and the inability of the industry to develop efficient resources at that time. The testimony fails to mention that some of these investments were for resources that never reached commercial operation. Ratepayers lost because they paid for resources that never were developed.

The testimony leaves a false impression that only shareholders lost from the development of these resources. This is not the case. Furthermore, all three electric utilities have experienced losses from prior investments in developing new resources. It is also critical to note that prior Commission decisions regarding these "losses" were based upon substantial evidentiary records in order to develop public interest findings that treated all parties fairly. The Commission grappled with the consequences of these resource decisions and the impacts to all parties. It is simply incorrect to consider the Commission's prior treatment of Avista, or any other utility during this period, as asymmetrical and exclusively burdening shareholders with losses. Any attempt to "re-establish equity" by giving the gain from Centralia to shareholders, in essence, undermines these prior decisions of this Commission.

Q. Are there any other issues related to Avista's testimony which you would like to discuss?

A. Yes. The testimony fails to recognize that investors in utility equities are compensated for accepting the risk of developing new resources. In particular, during the periods when utilities were making investments in new resources, the market recognized these risks and discounted utility stocks accordingly. Shareholders were compensated for accepting the risk of developing new resources through equity risk premiums. Returning any of the gain from the sale of Centralia to shareholders amounts to excessive compensation for shareholders.

Q. Please summarize your conclusions about the policy discussion contained in Avista's testimony as it applies to all of the applicants?

A. Avista's arguments should be rejected. The testimony stands for the proposition that prior Commission decisions and current practices create unfair treatment to shareholders: all downside with no upside. I disagree. Prior decisions by this Commission evaluated all relevant evidence and treated all parties fairly. Unfortunately, all parties suffered losses due to the failure of utilities to develop these resources during this period. It would be inequitable and unfair to the parties in those prior rate proceedings to revisit those prior decisions. Finally, returning the gain to shareholders would provide excessive compensation to shareholders.

Q. If the Commission accepts Avista's arguments and decides to return the gain to shareholders, should this treatment be applied only to Avista?

A. No. If the Commission is persuaded by the arguments offered by Avista and decides to return the gain to shareholders, Staff believes the results of this policy decision should apply equally to all of the applicants. Avista is no different in this regard than any other applicant.

Q. Avista also provides testimony regarding the Company's low rates and high quality service in an effort to support the proposal that all the gain on the sale be returned to shareholders. Do you have any comments regarding this testimony?

A. Yes. The comparison of rates between utilities is not a relevant factor for the Commission in its consideration of the sale of Centralia or whether electric rates meet the standard under RCW 80.28.010 (1), which requires rates to be fair, just, reasonable and sufficient. Indeed, comparing the electric rates in Washington to national averages leads one to conclude that all Washington ratepayers enjoy low electric rates. However, low rates are the function of many diverse factors, which may include efficient management. Furthermore, section 2 of the this same statute requires Avista to deliver efficient electric service. Management should be pleased with the results of the customer surveys and continue its efforts to provide high quality service to customers. These results go a long way to demonstrate the reasonableness of the Company's expenses for customer service, but for purposes of determining the treatment of the gain from the sale of Centralia, this fact is irrelevant.

Q. PacifiCorp proposes to share the gain based upon the reserve depreciation methodology. Would you please describe this proposal?

A. This method treats the undepreciated amount of the original investment as "at risk," and, since shareholders continue to bear the risk of recovery of the undepreciated amount, they are entitled to that portion of the gain.

Q. Please summarize Staff's position regarding this proposal?

A. The Commission should also reject this methodology. My prior testimony discusses the reasons why this proposal is not acceptable. I think it fair to say that both shareholders and ratepayers bear the risk of ownership. Shareholders are compensated for accepting this ongoing risk of prudently managing the resource while it is in rate base, and as long Centralia continues to produce power, ratepayers will pay rates that reflect the ongoing reasonable costs of power produced by the plant. These costs include compensation to shareholders for the risks of ownership.

Q. Is your conclusion about PacifiCorp's proposed treatment of the gain applicable to all applicants?

A. Yes. The Commission's ratemaking practices provide shareholders an opportunity to earn a return on and of used and useful utility property. This policy is fair and equitable. If there is a gain on the transaction, such as with Centralia, the gain should be returned to ratepayers. The proposed treatment of Avista and PacifiCorp would provide excessive compensation to shareholders for the public's use of utility property and should be rejected.

Q. Please summarize your conclusion regarding PSE's ratemaking proposal to amortize the gain over a five year period?

A. PSE's proposal suffers from the same problems identified by Staff in the prior Colstrip proceeding and should also be rejected by the Commission.

Q. Would you briefly summarize the problems Staff identified in Colstrip which apply equally to PSE's proposal to sell Centralia?

A. PSE, similar to its testimony in Colstrip, asserts that the sale of Centralia is consistent with its commitment to reduce power supply costs in the context of the Merger commitment to achieve "power stretch" goals. The sale of Centralia, however, is not a "power stretch" goal. The Commission ruled that the sale of Colstrip was not contemplated in the Merger and it did not grant PSE permission to sell used and useful generation to achieve power stretch goals. The same conclusion should be apply here. The second problem is the interaction of the Merger rate plan with the savings resulting from the transaction. The rate plan was based upon a premise that PSE's thermal resources were included in prospective power costs and justified annual rate increases for PSE. If near-term power supply savings are not deferred, ratepayers are harmed since the rate plan precludes the Commission from recognizing in PSE's rates the lower costs of selling the resource.

Q. Does this conclude your direct testimony?

A. Yes.

Ex. 401 (KLE-1)
Docket No. UE-991255, UE-991262, UE-991409
Witness: Kenneth L. Elgin

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

AVISTA CORPORATION for Authority to Sell its Interest in the Coal-Fired Centralia Power Plant	)	DOCKET NOS. UE-991255
In the Matter of the Application of PACIFICORP for an Order Approving the Sale of its Interest in (1) the Centralia Steam Electric Generating Plant, (2) the Rate Based Portion of the Centralia Coal Mine, and (3) Related Facilities; for a Determination of the Amount of and the Proper Rate Making Treatment of the Gain Associated with the Sale, and for an EWG Determination.	)	UE-991262
In the Matter of the Application of PUGET SOUND ENERGY, INC. for (1) Approval of the Proposed Sale of PSE's Share of the Centralia Power Power and Associated Transmission Facilities, and (2) Authorization to Amortize Gain Over a Five-Year Period.	)	UE-991409

EXHIBIT OF

KENNETH L. ELGIN

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

DECEMBER 8, 1999

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 401
ADMIT ☑ W/D ☐ REJECT ☐

WUTC DOCKET NUMBER	COMPANY NAME	ISSUE
U-85-23	Telephone/Access Charges	Rate of Return
U-86-41	Northwest Natural Gas	Rate of Return,Rate of Design
U-86-100	Cascade Natural Gas	Rate of Return, Competitive Pricing
U-86-117	Washington Natural Gas	Purchased Gas Policy
U-87-640	Continental Telephone	Rate of Return
U-87-1338	Pacific Power & Light	Merger Policy
U-87-1532	Washington Natural Gas	Rate Design, Cost of Service
U-88-2126/2127	Northwest Natural Gas	Competitive Pricing
U-88-2173	Yelm Telephone Company	Return of Equity
U-88-2380-T	Washington Water Power	Policy, Purchased Gas, Rate Design, Services, Transportation
U-89-3105	Washington Water Power	Prudence, Excess Capacity
UE-901183	Puget Sound Power & Light	Regulatory Reform
UE-901459	Washington Water Power	Policy, Rate Design
UG-920630	Puget Sound Power & Light	Regulatory Reform
UG-920840	Washington Natural Gas	Policy
UE-921262 et al	Puget Sound Power & Light	Policy, Prudence
UE-971422	Washington Water Power	Banded Rates, Price Discrimination
UE-981149	Washington Water Power	Service Territory Agreements
UE-981410	Puget Sound Energy	Tariff Interpretation
UE-990267	Puget Sound Energy	Policy, Transfer of Property - Colstrip

FERC DOCKET NUMBER	COMPANY NAME	ISSUE
RP 95-409	Northwest Pipeline Corporation	Capital Structure, Rate Design, Risk

Ex. 402 (KLE-2)
Docket No. UE-991255, UE-991262, UE-991409
Witness: Kenneth L. Elgin

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

AVISTA CORPORATION for Authority to Sell its Interest in the Coal-Fired Centralia Power Plant	DOCKET NOS. UE-991255
In the Matter of the Application of PACIFICORP for an Order Approving the Sale of its Interest in (1) the Centralia Steam Electric Generating Plant, (2) the Rate Based Portion of the Centralia Coal Mine, and (3) Related Facilities; for a Determination of the Amount of and the Proper Rate Making Treatment of the Gain Associated with the Sale, and for an EWG Determination.	UE-991262
In the Matter of the Application of PUGET SOUND ENERGY, INC. for (1) Approval of the Proposed Sale of PSE's Share of the Centralia Power Power and Associated Transmission Facilities, and (2) Authorization to Amortize Gain Over a Five-Year Period.	UE-991409

EXHIBIT OF

KENNETH L. ELGIN

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

DECEMBER 8, 1999

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 402
ADMIT ☑ W/D ☐ REJECT ☐

Avista Corporation
Value Line Analysis
1989-1999

Line No.		1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1	High	15.7	15.5	16.9	18.4	21.0	18.9	18.1	19.9	24.8	24.9
2	Low	13.0	13.4	14.2	15.9	17.4	13.6	13.5	17.1	17.4	16.1
3	Average	14.35	14.45	15.55	17.15	19.20	16.25	15.80	18.50	21.10	20.50
4	Book	10.61	10.84	11.11	11.54	12.02	12.45	12.82	12.7	13.38	11.76
5	Market to Book	1.35	1.33	1.40	1.49	1.60	1.31	1.23	1.46	1.58	1.74
6	Return on Common Equity	12.7%	12.7%	11.5%	11.1%	11.7%	10.1%	10.9%	10.6%	14.6%	14.7%

Source: The Value Line Investment Survey, Dated August 20, 1999

Ex.T-403 (RCM-T)
Docket No. UE-991255, UE-991262, UE-991409
Witness: Roland C. Martin

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

AVISTA CORPORATION for Authority to Sell its Interest in the Coal-Fired Centralia Power Plant	DOCKET NOS. UE-991255
In the Matter of the Application of PACIFICORP for an Order Approving the Sale of its Interest in (1) the Centralia Steam Electric Generating Plant, (2) the Rate Based Portion of the Centralia Coal Mine, and (3) Related Facilities; for a Determination of the Amount of and the Proper Rate Making Treatment of the Gain Associated with the Sale, and for an EWG Determination.	UE-991262
In the Matter of the Application of PUGET SOUND ENERGY, INC. for (1) Approval of the Proposed Sale of PSE's Share of the Centralia Power Power and Associated Transmission Facilities, and (2) Authorization to Amortize Gain Over a Five-Year Period.	UE-991409

DIRECT TESTIMONY OF

ROLAND C. MARTIN

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

DECEMBER 8, 1999

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 403
ADMIT ☑ W/D ☐ REJECT ☐

Q. Please state your name and business address.

A. My name is Roland C. Martin; my business address is 1300 South Evergreen Park Drive SW, Olympia, Washington 98504.

Q. By whom are you employed and in what capacity?

A. I am employed by the Washington Utilities and Transportation Commission (WUTC) as a Regulatory Consultant in the Electric Section.

Q. Have you prepared an exhibit which describes your educational background and professional experience?

A. Yes, I have. Exhibit No. 403 (RCM-1) is that exhibit.

Q. What is the purpose of your testimony in these consolidated proceedings?

A. I address the accounting and ratemaking proposals by PacifiCorp, Avista and Puget Sound Energy relating to the gain from the sale of their interests in the Centralia facilities. My testimony is composed of individual sections devoted to each utility because of variations in their respective proposals.

<u>I - PacifiCorp</u>

Q. What aspects of PacifiCorp's application are you addressing?

A. I address PacifiCorp's calculation of the gain from the sale of its share in the Centralia Plant, the proposed sharing of the gain between shareholders and customers, and the proposed ratemaking treatment related to the portion of the gain allocated to customers.

Q. Please describe your understanding of the gain as calculated and presented by the Company.

A. Mr. Miller presents in Exhibit No. 208 the calculation of an estimated net book gain of $82,662,795 from the sale of PacifiCorp's 47.5% share of the Centralia facilities. This is an estimate because a number of elements and assumptions in the calculation may change, such as the amounts of plant balances and expenses associated with the sale. PacifiCorp should be directed to refile the details of the transaction after closing based on known facts for further Commission review and consideration.

Q. Does Staff have specific exceptions regarding the Company's gain calculation presented in Exhibit 208?

A. Yes. First, the Company included in the gain calculation accruals for plant and mine environmental liabilities in the amounts of $2,000,000 and $3,000,000, respectively. These amounts represent expenses PacifiCorp may incur in the future as a result of previous ownership of the plant and mine. These costs are unknown and speculative, and should be excluded from the gain calculation. Exclusion of these amounts is consistent with the Commission's decision in Docket No. UE-990267 involving the sale of PSE's share of the Colstrip facilities. The Company may file for a petition seeking the appropriate regulatory treatment to be accorded the environmental remediation costs when they become known.

Second, PacifiCorp has not included in the gain analysis the excess deferred federal income taxes related to Centralia which is estimated to be $5.9 million. If PacifiCorp is able to obtain a favorable ruling from the Internal Revenue Service permitting pass-through of excess deferred taxes as part of the net gain, the gain will be higher by the same amount. Staff recommends that Commission direct the Company to seek such a ruling from the IRS, consistent with the directive given PSE in Docket No. UE-990267.

Q. Please describe briefly PacifiCorp's proposal with respect to disposition of the net gain of approximately $83 million.

A. PacifiCorp proposes to assign approximately 36% of the net gain to shareholders and 64% to customers. The 64% is the percentage relationship between depreciation reserve to gross plant, while the 36% is the relationship of net plant to gross plant. The 64% allocation to customers equates to approximately $53 million, which the Company proposes be used to offset booked generation-related regulatory assets. This treatment effectively reduces rate base.

Q. What is Staff's recommendation with respect to the net gain from the sale of PacifiCorp's share of Centralia?

A. Staff recommends rejection of the Company's proposed assignment of a portion of the gain to shareholders. Instead, the Commission should pass through the entire net gain to ratepayers, for the reasons explained in Mr. Elgin's testimony. The precise method to flow-through the entire gain to ratepayers would be determined in PacifiCorp's pending general rate proceeding, Docket No. UE-991832.

Q. In addition to Mr. Elgin's testimony, what other guidelines support the Staff proposal for full flow-through of the gain to ratepayers?

A. The parties to the Stipulation and Order of Dismissal dated May 26, 1992, in Washington Court of Appeals No. 29404-1 embraced the Commission's adoption of an adjustment in Docket U-89-2688-T involving Puget Sound Power & Light Company (Puget), that gave the property sales gain/loss to the customer, based on an allocation reflecting the time the property was included in ratebase. Specifically, paragraph 6 of that Stipulation provided in part: "The amount to be allocated to the customer in future rate cases will be based on the amount of time the property was included in ratebase in relationship to the total time the property was held by the Company." Consistent with this principle, ratepayers deserve the full benefit of the gain because ratepayers have supported the Centralia facilities in rates through the date of sale.

Q. Are there prior Commission decisions that support the Staff proposal?

A. Yes. In Docket No. 87-1533-AT involving the sale of The Washington Water Power Company's (WWP) combustion turbine generator, the Commission authorized the sale based upon the premise that 100 percent of the after-tax gain was returned to the ratepayers. WWP, which is Avista's predecessor, was ordered to defer the gain on the sale into a deferred credit account until final disposition of the gain was determined in its next general rate case.

Q. Included in the Company's proposal is the use of the customer portion of the gain to write-off generation-related assets. Please comment on this aspect of the proposal by the Company.

A. Staff does not necessarily disagree with the idea that the portion of the gain accruing to ratepayers (100% under Staff's recommendation) may be used to offset certain regulatory assets that are determined to be recoverable in rates. The application of the gain as an offset to regulatory assets is one of the many potential methods of disposition of the gain that will accomplish flow-through of benefits to customers. To ensure that all of the broader aspects of ratemaking are considered, however, the determination of the appropriate benefit pass-through methodology, as well as the recoverability of regulatory assets to be potentially offset by the gain, are best addressed in the general rate proceeding.

<u>II- Avista Corp.</u>

Q. What aspects of Avista's application are you addressing?

A I address Avista's proposal to retain all of the book gain from the sale of its share of the Centralia facilities. I also address Avista's alternative proposal to offset certain costs with the gain allocated to customers under a gain-sharing approach similar to PacifiCorp's.

Q. Please describe your understanding of the gain as calculated and presented by the Company.

A. Mr. McKenzie presents in Exhibit No. 312 the calculation of an estimated net book gain of $29,605,503 from the sale of Avista's 15% share of the Centralia facilities. Similar to PacifiCorp, this is an estimate because a number of elements and factors in the calculation may change, such as the closing date of the sale, and the true up of estimates to actuals once actual information is available, as explained in his testimony. Avista should also be directed to refile the details of the transaction after closing based on known facts for further Commission review and consideration.

Q. Please describe briefly Avista's proposal with respect to the net gain of $29,600,000.

A. Avista proposes to assign all of the gain to shareholders. However, if the Commission were to allocate a portion of the gain to customers based on the method proposed by PacifiCorp, Avista proposes to offset the gain allocated to customers against the costs of storm damage resulting from Ice Storm 1996. Any remaining gain would be applied against the transition obligation under accounting standards for post-retirement benefits other than pensions.

Q. What is Staff's recommendation with respect to the net gain from the sale of Avista's share of Centralia?

A. Staff recommends rejection of the Company's proposed assignment of the entire gain to shareholders. Staff further recommends rejection of the proposal to allocate the gain between customers and shareholders. Staff proposes to pass through the entire net gain to ratepayers, for the reasons explained in Mr. Elgin's testimony. Consistent with the Staff recommendation for PacifiCorp, the method to flow-through the gain to ratepayers would be determined in Avista's pending general rate proceeding, Docket No. UE-991606.

Q. **In addition to Mr. Elgin's testimony, what other guidelines support the Staff proposal for full flow-through of the gain to ratepayers?**

A. In my testimony concerning PacifiCorp, I discussed the principle embodied in the Stipulation and Order of Dismissal dated May 26, 1992, in Washington Court of Appeals No. 29404-1 and Docket No. 87-1533-AT involving the sale of The Washington Water Power Company's (WWP) combustion turbine generator. These same principles support Staff's recommendation concerning Avista's proposal to flow the entire gain to shareholders.

Q. **Anticipating that the Commission rejects Avista's proposal for full assignment of the gain to shareholders, Avista claims that shareholders, at a minimum, should retain a portion of the gain that is proportional to the un-depreciated amount of the Centralia investment. Please comment on this proposal by the company.**

A. As I stated earlier for PacifiCorp, Staff opposes the depreciation-based methodology because it does not give the entire gain to the ratepayers. However, Staff does not necessarily disagree that the portion of the gain accruing to ratepayers (100% under Staff's recommendation) may be used to offset certain regulatory assets that are determined to be recoverable in rates. This is one of the many potential methods of disposition of the gain that will flow the benefits to customers. However, all aspects of ratemaking should be considered simultaneously. Therefore, the appropriate benefit pass-through methodology, as well as the recoverability of regulatory assets to be potentially offset by the gain, are best addressed in Avista's pending general rate proceeding.

III- PSE

Q. What aspects of PSE's application are you addressing?

A. I address PSE's request to amortize the gain from the sale of Centralia for ratemaking purposes over the five-year period commencing on January 1, 2000. Staff recommends rejection of the Company's amortization proposal. Instead, PSE should defer the entire gain, with a return equal to 7.16% compounded annually, until its next general case to ensure that the gain from the disposition of the facilities accrues to ratepayers.

Staff witness Alan Buckley presents testimony and exhibits demonstrating that there are short-term power cost benefits of the sale. Similar to Staff's proposal in Docket No. UE-990267 regarding the sale of Colstrip facilities, Staff recommends that the benefits identified by Mr. Buckley be deferred for ratepayers without true-up, with a return accruing on the balance compounded annually.

Q. Please describe your understanding of the gain as calculated and presented by the Company.

A. Mr. Karzmar presents in Exhibit No. 109 the calculation of an estimated book gain of $13,520,313 from the sale of PSE's share of the Centralia facilities. This is an estimate because a number of elements in the calculation may change, including the amounts of plant balances and expenses, as explained in his testimony. The $13.5 million is an estimate based on a closing date of December 31, 1999. PSE should also be directed to refile the details of the transaction based on known facts for further Commission review and consideration.

Q. Please describe briefly PSE's proposal with respect to the net gain of $13,520,313.

A. PSE proposes to amortize this gain over a five-year period commencing January 1, 2000, to Account 421.1, Gain on Disposition of Property. The taxes associated with the gain would be amortized to Account 410.2, Provision for deferred income taxes, other income and deductions. These are both below-the-line accounts. The proposal ensures that approximately 40% of the net gain is amortized during the Merger rate plan period for the benefit of shareholders.

Q. Is Staff's recommendation with respect to the net gain from the sale of PSE's share of Centralia consistent with the Merger rate plan that was approved by the Commission in Docket UE-960195?

A. Yes. The Merger Stipulation and Order specifically provided that associated gains or losses from property transactions during the rate plan period that are a direct result of the Merger, shall be included in PSE's current earnings (rather than deferred).

The properties presented in the Merger proceeding which were contemplated to be disposed of to achieve Merger synergies did not include production and transmission facilities in general, or the Centralia facilities in particular. It included distribution facilities and general plant such as headquarter assets, service centers and warehouses. The sale of the Centralia facilities, therefore, is not a direct result of the merger. Furthermore, at page 18 of the Commission's 3rd Supplemental Order in Docket UE-990267 involving the sale of PSE's share of Colstrip facilities, the Commission made it explicit that "its order approving the merger did not grant PSE permission to sell used and useful generation assets as a power cost savings".

Q. Does Staff propose a deferral mechanism with respect to the power supply benefits, similar to the mechanism proposed in Docket No. UE-990267 involving the sale of PSE's share in the Colstrip facilities?

A. Yes. The amounts of power cost benefits measured by Mr. Buckley would be deferred in a regulatory liability account and would not be subject to true-up. The lack of a true-up is different than the Commission's directive for Colstrip, for the reasons explained by Mr. Buckley in his testimony. The balance will accrue an annual return equal to the 7.16% determined to be an appropriate rate for PSE in the Colstrip sale, compounded annually. Similar to the deferral of the gain, the deferred benefits will be passed through to the ratepayers using an appropriate method determined in the next rate proceeding.

Q Do you have additional comment and recommendation with respect to the proposals of PacifiCorp, Avista, and PSE?

Q. Yes. If for some reason the Commission finds that there is a basis for gain sharing based on a method such as depreciation-based methodology or Merger rate plan period amortization, the Commission should limit the amount of benefit that is subject to such sharing. The gain subject to sharing should exclude an amount equal to the utilities' respective share of the accrued reclamation balance at closing date. That reclamation amount should be assigned in full to ratepayers. The estimated reclamation balances prior to tax considerations, projected to December 31, 1999, for PacifiCorp, Avista, and PSE which are subject to true-up, are $25.3 million, $10.3 million, and $4.1 million, respectively. These amounts in the reclamation trust funds are fuel costs included in Centralia operating costs and, thus, a component embedded in rates paid by the customers. Because the reclamation liability is transferred to the buyer, the benefit of reversal of the reclamation liability should not be subject to sharing. It should accrue to ratepayers who shouldered the reclamation cost accruals.

Q. Does that conclude your direct testimony concerning the applications of PacifiCorp, Avista, and PSE?

A. Yes.

Ex. 404 (RCM-1)
Docket No. UE-991255, UE-991262, UE-991409
Witness: Roland C. Martin

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

AVISTA CORPORATION for Authority to Sell its Interest in the Coal-Fired Centralia Power Plant	)	DOCKET NOS. UE-991255
In the Matter of the Application of PACIFICORP for an Order Approving the Sale of its Interest in (1) the Centralia Steam Electric Generating Plant, (2) the Rate Based Portion of the Centralia Coal Mine, and (3) Related Facilities; for a Determination of the Amount of and the Proper Rate Making Treatment of the Gain Associated with the Sale, and for an EWG Determination.	)	UE-991262
In the Matter of the Application of PUGET SOUND ENERGY, INC. for (1) Approval of the Proposed Sale of PSE's Share of the Centralia Power Power and Associated Transmission Facilities, and (2) Authorization to Amortize Gain Over a Five-Year Period.	)	UE-991409

EXHIBIT OF

ROLAND C. MARTIN

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

DECEMBER 8, 1999

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 404
ADMIT ✓ W/D ☐ REJECT ☐

Q. Please state your name and business address.

A. My name is Roland C. Martin; my business address is 1300 South Evergreen Park Drive SW, Olympia, Washington 98504.

Q. By whom are you employed and in what capacity?

A. I am employed by the Washington Utilities and Transportation Commission (WUTC) as a Regulatory Consultant in the Electric Section.

Q. Would you please describe your educational background and professional experience?

A. I received a Bachelor of Science in Business Administration, major in marketing management, from the University of the Philippines in April, 1975. I am also a graduate of the University of Pangasinan where I received a degree of Bachelor of Science in Commerce, major in accounting, in March, 1980. On an ongoing basis, I attend educational seminars on regulation and ratemaking.

I have been employed by the Commission since May, 1982. I have performed various phases of accounting and financial analysis of regulated utility and transportation companies both independently and jointly with other specialists, either as a lead or member of a team. During the course of my employment, I have been a Commission Staff witness in numerous formal contested proceedings before this Commission. Most recently, I was a Staff witness in Docket No. UE-990267 regarding Puget Sound Energy's (PSE) application to transfer its Colstrip facilities. I also presented testimony in Cause Nos. U-84-28, U-88-2380-T and UG-900190 concerning The

Washington Water Power Company's (now Avista Corp.) filings for general rate increases. I also testified in Cause No. U-85-32 concerning the general rate increase filing of Continental Telephone Company of the Northwest, Inc. and in Cause No. U-86-02 regarding Pacific Power and Light Company's (PacifiCorp) filing for a general rate increase. I have participated in a number of rate proceedings involving Puget Sound Power & Light Company (Puget) including the past energy cost adjustment clause (ECAC) filings, the general rate increase filing in Docket No. U-89-2688-T, the proceeding that dealt with Puget's cost recovery proposals in Docket Nos. UE-901183-T and UE-901184-P, the Periodic Rate Adjustment Mechanism (PRAM) implementation proceedings in Docket Nos. UE-910626, UE-920630, UE-940728, and UE-950618. I was the lead revenue requirement specialist in Puget's consolidated filings including a petition for accounting of residential exchange benefits, rate design case, and general rate change (Docket Nos. UE-920433; UE-920499; UE-921262), and Puget's filing to transfer revenues from PRAM rates to general rates (Docket No. UE-951270). I was a member of the Staff team in the proceeding regarding the merger of Puget and Washington Natural Gas Company into Puget Sound Energy (PSE) in Docket No. UE-960195 .

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

AVISTA CORPORATION for Authority to Sell its Interest in the Coal-Fired Centralia Power Plant	DOCKET NOS. UE-991255
In the Matter of the Application of PACIFICORP for an Order Approving the Sale of its Interest in (1) the Centralia Steam Electric Generating Plant, (2) the Rate Based Portion of the Centralia Coal Mine, and (3) Related Facilities; for a Determination of the Amount of and the Proper Rate Making Treatment of the Gain Associated with the Sale, and for an EWG Determination.	UE-991262
In the Matter of the Application of PUGET SOUND ENERGY, INC. for (1) Approval of the Proposed Sale of PSE's Share of the Centralia Power Power and Associated Transmission Facilities, and (2) Authorization to Amortize Gain Over a Five-Year Period.	UE-991409

DIRECT TESTIMONY OF

ALAN P. BUCKLEY

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

DECEMBER 8, 1999

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 405
ADMIT ☑ W/D ☐ REJECT ☐

Q. What is your name and business address?

A. My name is Alan P. Buckley. My business address is Chandler Plaza Building, 1300 South Evergreen Park Drive S.W., Olympia, Washington 98504-7250.

Q. By whom are you employed and in what capacity?

A. I am employed by the Washington Utilities and Transportation Commission as a Senior Policy Strategist. I am responsible, among other duties, for the analysis of power supply issues relating to the Commission's jurisdictional electric utilities.

Q. Would you describe your education and relevant employment experience?

A. I received a B.S. degree in Petroleum Engineering from the University of Texas at Austin in 1981. In 1987, I received a Masters of Business Administration degree in Finance from the University of California at Berkeley. From 1981 through 1986, I was employed by Standard Oil of Ohio (now BP America) in San Francisco as a Petroleum Engineer working primarily on Alaskan North Slope exploration drilling and development projects. From 1987 through 1988, I was employed as a Rates Analyst at Pacific Gas and Electric Company in San Francisco. Beginning late in 1988 until late 1992, I was employed by R. W. Beck and Associates, an engineering and management consulting firm in Seattle Washington, conducting cost-of-service and other rate studies, carrying out power supply studies, analyzing mergers, and analyzing the rates of the Bonneville Power Administration and Western Area Power Administration.

I came to the Commission in December 1993, where I have held a number of positions including Utilities Analyst, Electric Program Manager, and the position that I presently hold. I have provided testimony in numerous proceedings before the WUTC. I have also testified in proceedings at the Federal Energy Regulatory Commission and at the Bonneville Power Administration.

Q. **What is the purpose of your testimony?**

A. I provide an alternative estimate of <u>near-term</u> power supply savings that Puget Sound Energy ("PSE") should be able to achieve from the sale of Centralia. By near-term, I am referring to the 2000 and 2001 timeframe. My testimony focuses on the "market cost" portion of the savings calculation that represents the replacement power supply costs.

Q. **Did you prepare any exhibits in this docket in support of your direct testimony?**

A. Yes. I prepared Exhibit 406 (APB-1).

Q. **Would you please summarize PSE's proposal in this Docket in regard to near-term power supply savings?**

A. Yes. PSE bases its power supply savings on the difference between the costs of operating Centralia and the market cost of providing "in-kind" replacement power. PSE then netted the gain on sale against this difference to derive annual power cost savings. The Company ran several scenarios representing various discount rates, plant availabilities, and levels of CO_2 taxes.

Q. **Can you explain what is meant by replacement "in-kind"?**

A. Yes. By replacing Centralia energy "in-kind", the Company assumes it will replace the entire Centralia power production amount with power shaped in the same fashion as what has been historically produced by the plant. This was the only form of replacement power analyzed by PSE.

Q. How did the Company determine a market cost for in-kind replacement power?

A. Under several scenarios, PSE derived estimates of market costs using market prices as predicted from AURORA model runs or based on forward looking futures contracts. High-, medium-, and low-price assumptions were incorporated in the AURORA model runs. These market prices were applied "in-kind" to the total energy production expected for Centralia. A "shaping" factor was applied to the market prices to adjust for the shape of Centralia power. Market price estimates using forward looking futures contracts were used for the medium- or "expected" price sensitivities for the years 2000 through 2004.

Q. Please summarize your recommendations.

A. PSE's estimates of market costs based on replacing the Centralia power "in-kind" generally overstates the near-term replacement cost of energy and results in lower estimates of power supply savings during this period. PSE's analyses rely too heavily on a high cost replacement alternative and do not reflect the increased flexibility available to the Company as a result of the Centralia sale. The Commission, in its recent Order Granting Reconsideration in Docket No. UE-990267, clearly states that PSE will need "whatever analysis is required to make an informed decision". This statement is contained in the Commission's discussion of least cost planning efforts in resource decisions such as sales. The

Company's analysis is not supported by any least cost planning efforts which would address some of the concerns expressed above.

In order to develop a conservative estimate of near-term power supply savings, I recalculated the market costs of replacement power (under PSE's Scenario No.1) using estimates of spot market prices coupled with firming purchases. I believe that near-term power supply savings (without the gain on sale impact) could reasonably be approximately $1.5 million and $2.6 million for the years 2000 and 2001, respectively. This represents a conservative estimate of the level of power supply savings that PSE should be able to obtain in the near-term.

Q. What is the problem with using "in-kind" replacement power?

A. I believe PSE's own testimony says it very well:

" PSE may find that it will not need to replace its share of the output of Centralia in kind. If replacement is necessary, PSE can replace it with any one of a variety of options, including spot market purchases, shorter fixed-term purchases, DSM, renewable energy or cost-effective distributive generation." (Gaines: Ex. T-101, pp. 5-6)

In other testimony, PSE states that:

Q. How does PSE plan to replace its share of the Centralia Power?

A. It is not entirely clear that PSE will have to replace the power in kind, but, in any event, PSE intends to take advantage of market resources to the extent it needs to replace the resource. PSE is also analyzing other flexible power replacement products,

> *including, for example, winter-only energy supplies and capacity and load-factoring products. The opportunity for distributed generation and BPA in-lieu power is being considered. (Gaines: Ex. T-101, pp. 8)*

PSE's own testimony not only suggests that in-kind replacement power may not be necessary, but also questions whether replacement power may actually be needed at all. This is an important consideration, particularly during the near-term period addressed in my testimony.

Q. Does PSE's testimony describe other options for acquiring replacements power?

A. Yes. Regarding the improved flexibility in power supply strategy, PSE states:

> *Q. How will the sale provide PSE with increased flexibility in managing its power supply?*
>
> *A. ... PSE will have the flexibility to replace Centralia with spot-market purchases, shorter fixed-term purchases, DSM, renewable energy, or cost-effective distributed generation. In light of the uncertain industry structure and the potential technological advancements, this approach has value. The increased flexibility will allow PSE to pursue the benefits of the emerging robust wholesale market for new generation, which FERC predicts will reduce generation costs.*
>
> *The sale will also position PSE to accommodate the uncertainties in future demand for energy. It may not be necessary for PSE to replace the entire*

Centralia resource – especially for its forecasted life. (Gaines: Ex. T-101, p.10)

Q. PSE mentions analyzing other power replacement options. Were any such analyses provided to the Commission?

A. No. The testimony is inconsistent with the analyses PSE used to derive power supply savings. Market costs were based solely on in-kind replacement power priced using forward looking futures contracts or market price estimates from AURORA runs. The prices were then adjusted using a factor to represent the effect of purchasing the energy with the same shape as Centralia generation. No attempt at resource re-dispatch or developing other resource combinations was made.

Q. What analyses do you believe would have been appropriate?

A. Nothing more than what PSE itself suggests. PSE should have carried out an analysis utilizing a model that could compare post-Centralia sale power supply costs with those costs including Centralia, by allowing PSE's system to be re-dispatched to meet load. Alternative power supply options could be modeled to derive a least cost alternative for replacing Centralia, if appropriate. This kind of analysis would address much of the flexibility that PSE promotes, not only by identifying a range of replacement options, but also by taking advantage of whatever displacement capabilities exist in PSE's existing portfolio.

Q. Did other Companies involved in the sale of Centralia do such an analysis?

A. Yes. Pacificorp carried out that kind of analysis for its system.

Q. Did Staff carry out such an analysis?

A. No. At the present time, Staff does not have the tools to model PSE's system in such a manner.

Q. Can you comment further on the analysis that PSE did carry out?

A. Yes. As I stated earlier, PSE used in-kind replacement power to develop its market cost estimate. For the "expected" or mid-price range, annual strips of forward prices were used in the calculation of market costs for the period 2000 through 2004. These prices represent averages of monthly or quarterly futures contracts for firm energy. These are applied to the total Centralia production amount with a shaping adjustment. Other price scenarios (high- and low-price) utilize AURORA model results for price estimates. In any case, PSE's methodology results in market cost estimates on the high end of the scale, particularly for the mid- or "expected" market price scenario.

Q. Why are PSE's market cost estimates on the high side?

A. For three reasons. The first reason is due to the assumption that the price forecast for replacement power should be applied to the total equivalent amount of Centralia production. This assumes that all the power produced by Centralia is required to be replaced. This is counter to PSE's own testimony. Any analysis should account for potential differences in how much power is likely to be replaced. This would include not only the amount of energy, but also the use of alternative resources such as suggested by PSE, including spot market purchases combined with capacity, seasonal exchanges, or other least cost resources.

The second reason is that all of the energy is assumed to be acquired in the same shape (including off-peak and on-peak hours) as was produced by Centralia. This, again as suggested by PSE, would most likely not be the case. Centralia is essentially a base load plant that operates fairly constant throughout the day and year. PSE's market cost methodology does not take into account the potential for replacement market energy to be purchased in off-peak or low-load hours, which would result in reduced costs as compared to purchasing energy in the same shape as Centralia. Nor does it take into consideration that other resource alternatives such as capacity purchases or seasonal exchanges may best meet PSE's needs. Finally, PSE's analyses (for the "expected" price scenario and in the near-term) are based on strips of forward futures contracts for firm power. These prices represent the high end of energy replacement costs. The actual "expected" AURORA prices for the same near-term period are lower than the strips used by PSE and best represent potential "spot-market" prices of energy which, under any number of scenarios, could represent all or a portion of the price of replacement energy for Centralia.

Q. Can you recommend a better methodology to derive acceptable market cost estimates for the near-term?

A. Lacking access to the appropriate models previously discussed, I believe that a proper analysis should better match the testimony of PSE's own witness. In order to estimate near-term market costs for comparing savings, I would investigate a number of possible replacement possibilities, rather than use a single "in-kind" methodology.

Q. Please continue.

A. In carrying out an analysis such as this, it is appropriate to begin with a range of estimates. For example, the Company's methodology of "in–kind" replacement using prices based on firm futures contracts results in estimates toward the high end of the replacement cost scale and thus minimizes expected savings.

Assuming the Company's Scenario No. 1 with "expected" market prices, and not including the "gain on sale" amount, near-term power supply costs are actually estimated to increase about $1.7 million in 2000 and then are about equal in 2001. Exhibit 406, Alternative I, shows the summary calculation using this methodology.

On the other hand, a scenario in which PSE did not replace any Centralia energy would most likely result in the largest savings. In this case, the net savings would be equivalent to the fixed cost savings associated with the Centralia plant, net any net margins (revenues that exceed the variable cost of operating the plant) that may be collected through market sales of Centralia energy. To estimate this amount, I subtracted the variable operating costs of operating Centralia from the full embedded cost to obtain the fixed cost of Centralia. I then credited a margin on market sales equal to the difference between market price forecasts and the variable operating costs. This results in savings of around $2.9 million and $3.6

million for the years 2000 and 2001, respectively. Exhibit 406, Alternative II, shows the calculation of these estimates.

Q. **You said that the options described above would most likely bracket the expected sale effects. What other possibilities are there?**

A. As stated by PSE's own witness, there are numerous possibilities for replacing the energy from Centralia, if necessary. These include combinations of short-term firm market transactions, spot-market purchases backed by PSE's own generation or other capacity purchases, seasonal exchange arrangements, or simple re-dispatching of PSE's existing resources. PSE also identified other alternatives such as DSM and distributed generation opportunities as potential replacements. Determining which combination of these options that would be projected to best serve load and meet a least cost standard is impossible without the modeling effort which was not carried out by the Company.

Q. **Can you make a more representative estimate of near-term power supply savings?**

A. Yes. A reasonable method to estimate potential savings would be to replace the annual strip of forward prices used by PSE for 2000 and 2001 with the actual "expected" AURORA results to represent estimated spot market prices. To provide an additional level of firmness, a charge could be added to represent the market costs associated with firming the spot market purchases. This method results in a conservative estimate of market costs for replacement power within the range of costs identified above. It relies on spot power and ancillary firming markets for replacement power, rather than the firm, forward futures contract prices represented in PSE's analyses.

Q. What are the market costs and savings utilizing your method?

A. By using an approach that attempts to represent the use of the spot market, with firming, for replacement power rather than futures contracts, I calculate a market cost of $14.9 million and $15.4 million for 2000 and 2001, respectively. This assumes full replacement of the total expected Centralia production and other Scenario No. 1 assumptions. Comparing this to the costs of Centralia for those years results in estimated power supply savings of approximately $1.5 million for 2000 and $2.6 million in 2001. Exhibit 406, Alternative III, shows the calculation of these estimates.

Q. You mention that this represents a conservative estimate of market costs. Can you please explain why?

A. Yes. This estimate is conservative for several reasons. The first reason is that I assume, as did PSE, that the entire amount of energy from Centralia is replaced and is done so on a relatively firm basis. Also, this method does not take into account the potential for shaping the energy into even lower cost off-peak hours, nor does it represent re-dispatching of existing or alternative resources to meet the load requirements. Finally, I firmly believe that there are combinations of alternative resource options that would result in even lower costs for whatever amount of energy is ultimately needed. This could include the ability to meet all near-term energy needs with existing, very low-cost hydro generation during favorable water years.

Q. In your analysis you used AURORA market prices that were used in both the Colstrip and Centralia PSE filings to represent the spot market. There are some indications that the prices for market energy may be on the increase. Do you wish to comment?

A. Yes. My testimony addresses only the near-term (2000 and 2001) power supply savings potential. This period is approximately the same as the remainder of PSE's rate freeze period per the Merger agreement. There is less price uncertainty associated with this period than the post-rate freeze period. In addition, the best opportunity for power supply savings is not dependent on relatively small changes in market forecasts, but lies in the flexibility to utilize or acquire a combination of resources to meet load if it is necessary to replace the energy from Centralia. This can only be captured through more extensive modeling of power supply alternatives that should take place in preparation for future rate cases. To the extent that recent market price forecasts change significantly, Staff would fully expect PSE to re-evaluate the Company's decision to sell Centralia or the price being received.

Q. In its Order Granting Reconsideration in Docket No. UE-990267, the Commission ordered PSE to track the actual costs of replacement power for purposes of determining future true-ups. Is this Staff's recommendation in this proceeding?

A. No. Staff is proposing no true-ups related to the near-term power supply costs.

Q. Please explain why not.

A. It is virtually impossible to specifically calculate the actual true costs of replacement power on a resource by resource basis without some kind of modeling. The potential for cost savings is in the coordinated dispatch of all utility-owned resources and other resource options. The very basis for my testimony in this proceeding is that it is incorrect to simply apply an "in-kind" substitute to derive replacement costs. While in-kind replacements are easier to price and true-up, PSE must, as stated in its testimony, economically re-dispatch available resources to meet load and most likely not rely on a single, trackable transaction. Re-dispatching will affect the costs of other resources, but it is the difference in total aggregate costs that are important and the only way to properly track replacement costs. Unfortunately, given differences in resource availability, weather, load, and other factors, a comparison of costs without a particular resource can only be carried out by comparing actual costs against modeled performance with the resource included based on actual dispatch conditions. This results in the same uncertainties that exist when simply trying to model dispatch efficiencies based on a "test-year".

Q. What is your recommendation?

A. With the problems inherent in properly deriving amounts to be trued-up, I recommend that the Commission adopt a single, conservative estimate for power supply savings for purposes of measuring any amounts that should be deferred in order to capture near-term benefits for ratepayers. For purposes of Centralia, the estimated power supply savings of $1.5 million and $2.6 million for 2000 and 2001 respectively, (Alternative III), meet that requirement.

Q. Does this conclude your testimony?

A. Yes.

Ex. 406 (APB-1)
Docket No. UE-991255, UE-991262, UE-991409
Witness: Alan P. Buckley

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

AVISTA CORPORATION for Authority to Sell its Interest in the Coal-Fired Centralia Power Plant	)	DOCKET NOS. UE-991255
In the Matter of the Application of PACIFICORP for an Order Approving the Sale of its Interest in (1) the Centralia Steam Electric Generating Plant, (2) the Rate Based Portion of the Centralia Coal Mine, and (3) Related Facilities; for a Determination of the Amount of and the Proper Rate Making Treatment of the Gain Associated with the Sale, and for an EWG Determination.	)	UE-991262
In the Matter of the Application of PUGET SOUND ENERGY, INC. for (1) Approval of the Proposed Sale of PSE's Share of the Centralia Power Power and Associated Transmission Facilities, and (2) Authorization to Amortize Gain Over a Five-Year Period.	)	UE-991409

EXHIBIT OF

ALAN P. BUCKLEY

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

DECEMBER 8, 1999

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 406
ADMIT ☑ W/D ☐ REJECT ☐

Estimated Near-Term Power Supply Savings

	YR 2000	YR2001
I. PSE - Scenario 1/Forward Contracts		
Centralia Cost	$16,444	$18,043
Market Cost	18,148	18,045
Savings (000's)	**($1,704)**	**($ 2)**
II. STAFF - No Replacement Energy		
Centralia Cost	$24.98/MWh	$27.41/MWh
Variable Dispatch Cost	14.03	14.38
Fixed Cost Savings	$10.95/MWh	$13.03/MWh
Less Credit for Sales Margin	$ 6.67/MWh	$ 7.73/MWh
(market less variable dispatch)		
Net Savings	$ 4.28/MWh	$ 5.30/MWh
Total Savings (000's)	**$ 2,872**	**$ 3,556**
@ 671 GWhs		
III. STAFF - Spot Market + Firming		
Centralia Cost	$16,444	$18,043
Market Cost	14,919	15,445
("expected" AURORA+1mill firm)		
Total Savings (000's)	**$ 1,525**	**$ 2,598**

Ex.T-407 (KLE-Supplemental)
Docket No. UE-991255, UE-991262, UE-991409
Witness: Kenneth L. Elgin

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

AVISTA CORPORATION for Authority to Sell its Interest in the Coal-Fired Centralia Power Plant	)	DOCKET NOS. UE-991255
In the Matter of the Application of PACIFICORP for an Order Approving the Sale of its Interest in (1) the Centralia Steam Electric Generating Plant, (2) the Rate Based Portion of the Centralia Coal Mine, and (3) Related Facilities; for a Determination of the Amount of and the Proper Rate Making Treatment of the Gain Associated with the Sale, and for an EWG Determination.	)	UE-991262
In the Matter of the Application of PUGET SOUND ENERGY, INC. for (1) Approval of the Proposed Sale of PSE's Share of the Centralia Power Power and Associated Transmission Facilities, and (2) Authorization to Amortize Gain Over a Five-Year Period.	)	UE-991409

SUPPLEMENTAL TESTIMONY OF

KENNETH L. ELGIN

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

JANUARY 4, 2000

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 407
ADMIT ☑ W/D ☐ REJECT ☐

Q. Please state your name and business address?

A. My name is Kenneth L. Elgin. My business address is Chandler Plaza Building, 1300 South Evergreen Park Drive SW, Olympia, Washington, 98504-7250.

Q. Have you previously provided direct testimony in these consolidated proceedings?

A. Yes.

Q. Please describe the purpose of this supplemental testimony?

A. Following the prefiling of the Staff direct case, PacifiCorp submitted revisions to the direct testimony and exhibits of Roger Weaver. The essence of Mr. Weaver's revisions correct the Company's financial analysis supporting its decision to sell the Centralia generating facility.

Q. Please summarize these corrections to the analysis?

A. The Company's revised analysis increases the expected benefits of the proposed transaction from a net present value of $10 million to a net present value $42 million.

Q. Does this change have any impact on your recommendation in these proceedings?

A. No.

Q. Please explain why the expected $32 million increase in net present value benefits of the transaction does not impact your recommendation in this proceeding?

A. On page 11 of my direct testimony I state, "None of the economic studies clearly demonstrate that ratepayers will benefit from the transaction." I still believe this to be the case. First, the revision to Mr. Weaver's analysis does not alter the fact that ratepayers would swap a known fixed cost resource for future unknown energy prices if the sale occurs. Furthermore, PacifiCorp's revised analysis continues to rely upon a twenty-three year time horizon. Extending the analysis to thirty years, the expected life of the new scrubbers, would diminish the $42 million net present value figure. Therefore, the original conclusion I reached on page 10 of my direct testimony still stands: the net benefit is clearly a function of how aggressively one estimates long-term future energy prices and how far into the future one extends the analysis.

I would also note that the $42 million net present value benefit produced by the revised analysis is still relatively small (0.42%) considering the magnitude of total costs for Pacific's Centralia operations during the period of analysis. Exhibit 212 shows a $10.468 billion net present value revenue requirement if Centralia is not sold compared to a $10.426 billion net present value revenue requirement if Centralia is sold under a medium market price forecast for replacement power.

Therefore, I conclude that this revised financial study is insufficient to support a conclusion that the sale of the Centralia facilities is in the public interest. As I concluded in my direct testimony, the transaction is a "push," at best. In order to determine whether the sale is in the public interest other factors must be considered, as I stated on page 11 of my direct testimony.

Q. Does that conclude your supplemental testimony?

A. Yes.

Docket No. UE-991409
Exhibit 408

Application For Approval of the Proposed Sale of the Centralia Power Plant
Docket No. UE-991409, et. al.

PSE's Data Request No. 2 to Staff

Request:
With regard to the testimony of Ken Elgin, page 8, lines 7-15, provide all documents that justify your proposed 30-year expected life for the Centralia facilities.

Response by Mr. Elgin:
The referenced testimony does not propose a thirty year life for Centralia. The testimony asserts that new pollution control equipment is being installed with an estimated life of at least thirty years. Please see supporting documents Exhibits 105 and 503. A thirty year analysis, despite the added uncertainty, appears reasonable given the fact that the majority of the owners support the installation of the new scrubbers.

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 408
ADMIT ☑ W/D ☐ REJECT ☐

409

Application For Approval of the Proposed Sale of the Centralia Power Plant
Docket No., UE-991409, et. al.

Public Counsel Data Request No. 1 to WUTC Staff

Request:
PacifiCorp has operations in multiple states. Provide the percentage of the gain on sale of PacifiCorp's share of Centralia that Staff proposes be ascribed to Washington operations, and the percentage of that Washington-allocated gain which staff proposes be flowed through to Washington electric consumers in rates.

Response:
Staff proposes to pass through the entire net gain to ratepayers. Consistent with Staff's proposal that the precise method to flow-through the entire net gain to ratepayers would be determined in PacifiCorp's pending general rate proceeding, the issue of inter-jurisdictional allocation of the net gain will be addressed in the general rate proceeding.

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 409
ADMIT ☑ W/D ☐ REJECT ☐

Docket No. UE-991409
Exhibit 410

Revised Exhibit 406
"Estimated Near-Term Power Supply Savings"
Updated Market Forecast

		2000	2001
II.	**STAFF** – ***No Replacement Energy***		
	Centralia Cost	$24.98/MWh	$27.41/MWh
	Variable Dispatch Cost	14.03	14.38
	Fixed Cost Savings	$10.95/MWh	$13.03/MWh
	Less Credit for Sales Margin	$12.96	$12.67
	(market less variable dispatch)	(26.99 – 14.03)	(27.05 – 14.38)
	Net Savings	-$2.01	$0.36
	Total Savings @ 671 GWhs	**-$1,349**	**$242**

Docket No. UE-991409
Exhibit 411

Application For Approval of the Proposed Sale of the Centralia Power Plant
Docket No. UE-991409, et. al.

PSE's Data Request No. 8 to Staff

Request:
With regard to the testimony of Alan Buckley, page 10, lines 18-20, please explain how the proposed firming charge would be calculated and how market data could be used to verify it.

Response by Mr. Buckley:
Staff is not aware of a standard, traded firming product exchanged on public exchanges. For purposes of estimating a market price for firming charges, a Northwest region trader and marketer confirmed that an adder of \$1/mWh to \$2/mWh would be appropriate in today's market to firm either the Dow Jones Mid C or COB indexes. This range is for a high-load factor transaction and is based on over- the- counter negotiations.

In previous discussions in other dockets, Staff discussed with regional traders physical firming products priced around \$0.50/kW-mo. for 100% load factor transactions.

The estimate of a \$1.00/mWh adder for firming is conservative for purposes of developing a reasonable replacement power price because it has been applied to the total Centralia amount and for all periods of the year. Actual purchases of this product may not be in those amounts or for the entire period.

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 411
ADMIT ☑ W/D ☐ REJECT ☐

Docket No. UE-991409
Exhibit 412

Application For Approval of the Proposed Sale of the Centralia Power Plant
Docket No. UE-991409, et. al.

PSE's Data Request No. 9 to Staff

Request:
With regard to the testimony of Alan Buckley, pages 13-14, lines 1-22, 1-3, please provide any and all precedent that supports your contention that PSE should have to defer an estimated amount of savings rather than actual savings achieved.

Response by Mr. Buckley:
Mr. Buckley does not address whether PSE should have to defer an amount. The testimony addresses the difficulty and accuracy of developing an "actual" amount of power supply savings and recommends that there be no attempt to true-up given the inherent problems. The testimony states that while actual power supply costs can be determined for a particular period, these costs would have to be compared to what "actuals" would have been with Centralia present using models to carry out the coordinated economic dispatch of PSE's system. A dispatch model must be used to estimate the power supply costs of a portfolio including Centralia given actual load, load shape, weather, market prices, and other factors so that a comparison to real actuals can be made. Given the continued uncertainties in deriving an "actual" savings amount, Mr. Buckley's recommendation is that a single, conservative estimate for power supply savings be used for purposes of measuring any amount that should be deferred.

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 412
ADMIT ☑ W/D ☐ REJECT ☐

Application For Approval of the Proposed Sale of the Centralia Power Plant
Docket No. UE-991409, et. al.

PSE's Data Request No. 10 to Staff

Request:
With regard to the testimony of Alan Buckley generally, provide copies of all workpapers, in paper and electronic format.

Response by Mr. Buckley:
See attachments. The workpapers are printouts of portions of PSE's Exhibit No.__(WAG-4) Excel Spreadsheet PSEWAG1.XLS.

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 413
ADMIT ☑ W/D ☐ REJECT ☐

Centralia - A... of Revenue Impacts

1 Scen. (NERC availability)

Row		Item	Unit	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
		OPERATION																				
5		Plant Capacity	MW	93.8	93.8	94.3761	94.9522	94.9522	94.9522	94.9522	94.9522	94.9522	94.9522	94.9522	94.9522	94.9522	94.9522	94.9522	94.9522	94.9522	94.9522	94.9522
6		Availability - NERC	%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%
7		Energy at Plant	GWH	658	658	662	666	666	666	666	666	666	666	666	666	666	666	666	666	666	666	666
8	0.00%	Energy at BPA Tono	GWH	658	658	662	666	666	666	666	666	666	666	666	666	666	666	666	666	666	666	666
9	0.0%	Energy to PSE	GWH	658	658	662	666	666	666	666	666	666	666	666	666	666	666	666	666	666	666	666
10		Heat Rate	BTU/kWh	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485
12		**CENTRALIA COSTS:**																				
13		Carrying Costs on Existing and Incremental																				
14		Generation, Common and Transmission Plant																				
15		Return on Ratebase	$(000)	550	940	1,489	1,561	1,424	1,291	1,160	1,030	902	775	649	547	473	399	325	252	179	106	33
16		Depreciation	$(000)	684	857	1,110	1,196	1,202	1,209	1,217	1,224	1,232	1,239	1,247	594	596	604	613	622	631	640	649
17		Federal Tax	$(000)	463	806	1,589	1,691	1,618	1,548	1,479	1,410	1,341	1,273	1,205	794	750	710	671	633	594	554	515
18		Property Tax	$(000)	273	291	299	301	304	307	310	313	316	319	322	325	329	332	336	339	343	347	351
19			$(000)																			
20		Insurance	$(000)	14	15	15	15	15	15	15	16	16	16	16	16	16	17	17	17	17	17	17
21		Subtotal Return & Capital Costs	$(000)	1,984	2,909	4,502	4,765	4,563	4,371	4,181	3,993	3,807	3,623	3,439	2,277	2,164	2,062	1,962	1,864	1,765	1,665	1,565
22		Ending Balance Recovery	$(000)	-	-	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593
23		Operating Costs (Fuel O&M, Gen Tax)																				
24		Fuel & Reclamation	$(000)	10,552	10,816	11,144	11,481	11,768	12,062	12,364	12,673	12,990	13,315	13,647	13,989	14,338	14,697	15,064	15,441	15,827	16,223	16,628
25		Mine Reclamation	$(000)	945	945	945	945	945	945	945	945	945	945	945	945	945	945	945	945	945	945	945
26		Non-Fuel O&M	$(000)	1,447	1,897	2,035	1,795	2,224	2,280	2,337	2,395	2,455	2,516	2,579	2,644	2,710	2,777	2,847	2,918	2,991	3,066	3,142
27		CO2 Tax	$(000)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28		Subtotal Operating Costs	$(000)	12,944	13,658	14,124	14,221	14,937	15,287	15,646	16,013	16,390	16,776	17,172	17,577	17,993	18,419	18,856	19,304	19,763	20,233	20,716
29																						
30		SO2 Allowances (Cr)	$(000)	694	712	143	(455)	(467)	(479)	(490)	(503)	(515)	(528)	(541)	(560)	(574)	(588)	(603)	(618)	(633)	(649)	(665)
31																						
32		Transmission	$(000)																			
33		Trans. O&M BPA Paul	$(000)	32	32	33	33	33	34	34	34	35	35	35	36	36	37	37	37	38	38	38
34		Trans. Credits and Exchange	$(000)	(437)	(440)	(443)	(445)	(448)	(451)	(454)	(457)	(459)	(462)	(465)	(468)	(471)	(474)	(477)	(480)	(483)	(487)	(490)
35		BPA IR Charges	$(000)	1,200	1,200	1,800	1,800	1,800	1,800	1,800	2,036	2,036	2,036	2,036	2,036	2,302	2,302	2,302	2,302	2,302	2,604	2,604
36		IR - Losses at Market		300	332	337	343	349	355	383	407	432	447	443	460	469	454	495	496	512	521	544
37		Total Transmission	$(000)	1,095	1,124	1,727	1,731	1,734	1,738	1,763	2,021	2,043	2,056	2,049	2,063	2,336	2,318	2,357	2,355	2,369	2,676	2,697
38		Rev. Req. Legislative Tax Savings	$(000)	(273)	(360)	(290)	(236)	(206)	(206)	(206)	(206)	(206)	(206)	(206)	(206)	(206)	(206)	(206)	(206)	(206)	(206)	(1,034)
39		Rev Req. Plant & Mine Closure	$(000)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,641
40		**Subtotal Centralia Cost**	$(000)	16,444	18,043	20,799	20,619	21,155	21,304	21,486	21,911	22,111	22,313	22,505	21,745	22,306	22,599	22,959	23,292	23,650	24,312	29,512
41	7.69%	Discount Factor		0.9636	0.8948	0.8309	0.7716	0.7165	0.6653	0.6178	0.5737	0.5327	0.4947	0.4594	0.4266	0.3961	0.3678	0.3416	0.3172	0.2945	0.2735	0.2540
42																						
43		**PV Centralia Cost**	$(000)	15,846	16,145	17,283	15,910	15,157	14,174	13,274	12,570	11,779	11,038	10,338	9,275	8,835	8,312	7,842	7,387	6,965	6,649	7,495
		PV Lump Sum Recovery Ending Book	$(000)																			
45		**Accum. PV Centralia Cost**	$(000)	15,846	31,991	49,274	65,184	80,341	94,515	107,789	120,359	132,139	143,177	153,515	162,790	171,626	179,938	187,780	195,167	202,132	208,781	216,276
46		**MARKET COSTS:**																				
47		Mid Point Forecast																				
48	1	AURORA w/ NWPPC	$/MWh	21.70	23.11	27.46	27.93	28.40	30.60	32.56	34.53	35.74	35.42	36.77	37.47	36.27	39.57	39.62	40.96	41.64	43.54	45.76
49	0.019	Energy at Mid-C	GWH	~~671~~	~~671~~	675	679	679	679	679	679	679	679	679	679	679	679	679	679	679	679	679
50		Cost of Energy at Mid-C	$(000)	14,559	15,505	18,535	18,969	19,290	20,783	22,110	23,451	24,276	24,058	24,974	25,448	24,636	26,874	26,911	27,819	28,278	29,569	31,078
51		Trans. Credits on PSE Line	$(000)	(840)	(1,260)	(1,890)	(1,890)	(1,890)	(1,890)	(1,890)	(2,138)	(2,138)	(2,138)	(2,138)	(2,138)	(2,418)	(2,418)	(2,418)	(2,418)	(2,418)	(2,734)	(2,734)
52		Transmission Mid-C to PSE	$(000)	1,200	1,200	1,800	1,800	1,800	1,800	1,800	2,036	2,036	2,036	2,036	2,036	2,302	2,302	2,302	2,302	2,302	2,604	2,604
53		Subtotal	$(000)	14,919	15,445	18,445	18,879	19,200	20,693	22,020	23,349	24,174	23,956	24,872	25,346	24,521	26,759	26,796	27,704	28,163	29,439	30,948
54		Rev. Req. Gain or (Loss)	$(000)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55		**Total Market Cost**	$(000)	14,919	15,445	18,445	18,879	19,200	20,693	22,020	23,349	24,174	23,956	24,872	25,346	24,521	26,759	26,796	27,704	28,163	29,439	30,948
56																						
57		**PV Market Cost**	$(000)	14,376	13,820	15,326	14,567	13,757	13,768	13,605	13,395	12,878	11,851	11,425	10,812	9,713	9,843	9,152	8,787	8,294	8,051	7,859
58		**Accum. PV Market**	$(000)	14,376	28,197	43,523	58,090	71,847	85,614	99,219	112,614	125,493	137,344	148,769	159,581	169,294	179,136	188,288	197,075	205,369	213,420	221,280
60		**PV Centralia Cost - Market Costs**		1,470	3,794	5,751	7,094	8,494	8,901	8,570	7,745	6,646	5,833	4,746	3,210	2,332	802	(509)	(1,908)	(3,237)	(4,639)	(5,004)
61																						
62																						
63		**Cost Centralia @ PSE**	$/MWh	24.98	27.41	31.41	30.95	31.75	31.98	32.25	32.89	33.19	33.49	33.78	32.64	33.48	33.92	34.46	34.96	35.50	36.49	44.29
64		**Cost Alternative @ PSE**	$/MWh	22.67	23.47	27.85	28.34	28.82	31.06	33.05	35.04	36.28	35.96	37.33	38.04	36.80	40.16	40.22	41.58	42.27	44.19	46.45

w/ 1 mill adder for firming

Forward Prices AURORA per NWPPC assumptions
High/Low = +/- [redacted]

Frem COLSTRIP
AURORA - Not replaced.

		50% of May	23											
		Expected w/o												
Expected AURORA	Flat	Average RTC	__% May	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1999	19.04	19.35	22.67	20.95	18.27	15.81	11.95	13.93	19.76	21.67	21.41	18.76	20.09	23.22
	2000	20.70	20.99	24.65	22.90	20.49	16.83	13.99	15.28	21.32	22.56	22.61	20.63	22.12	25.02
	2001	22.11	22.40	26.06	24.61	22.09	18.48	15.40	15.22	21.90	24.47	25.22	22.22	23.31	26.30
	2002	23.65	23.95	27.89	26.36	22.98	19.84	16.56	16.67	23.26	26.19	28.03	23.14	25.00	27.84
	2003	25.29	25.68	29.49	27.99	24.53	19.96	16.44	17.99	24.43	29.26	32.29	24.76	26.76	29.59
	2004	27.58	28.02	31.02	30.16	26.03	21.02	17.37	20.15	26.96	34.07	37.80	26.48	28.44	31.41
	2005	29.14	29.61	32.46	30.89	27.38	22.09	18.51	20.71	29.02	37.51	40.45	28.11	29.47	33.13
	2006	31.01	31.51	33.68	32.45	28.18	23.26	19.29	21.67	32.58	42.46	43.67	29.35	30.71	34.75
	2007	32.88	33.50	34.45	33.11	28.97	23.99	18.81	20.71	32.37	55.36	50.94	29.84	30.92	35.15
	2008	34.04	34.66	35.48	33.90	29.76	24.63	19.82	20.89	34.91	57.01	53.41	30.58	32.00	36.13
	2009	33.74	34.37	36.33	34.16	30.18	25.13	19.23	20.16	29.01	58.65	51.11	31.23	32.64	37.02
	2010	35.02	35.65	37.42	35.15	30.28	25.75	20.49	22.33	35.93	58.22	51.34	31.55	33.72	38.07
	2011	35.69	36.35	38.68	35.69	30.96	26.50	20.38	22.07	36.36	60.41	50.51	32.64	34.66	39.35
	2012	34.55	35.18	38.82	35.59	30.54	27.06	20.00	21.56	31.79	56.44	46.71	30.83	35.16	40.06
	2013	37.69	38.37	40.17	38.27	32.59	27.96	21.88	22.72	35.91	63.68	59.01	33.18	36.14	40.71
	2014	37.74	38.42	41.90	38.84	31.55	27.54	22.08	22.86	38.47	62.52	54.76	33.24	36.96	42.11
	2015	39.01	39.72	43.45	39.33	32.12	28.11	22.58	23.45	39.02	65.47	57.68	35.20	38.00	43.71
	2016	39.65	40.35	46.65	43.48	32.33	27.54	23.62	26.25	38.69	60.02	53.04	35.99	41.42	46.82
	2017	41.46	42.22	48.44	45.01	33.76	28.55	24.16	26.81	43.01	64.87	54.15	37.82	43.06	47.94
	2018	43.58	44.34	49.27	46.36	35.26	30.59	26.09	28.07	43.44	69.88	64.00	38.34	41.91	49.76

			High w/o __%												
High AURORA	Flat	Average RTC	May	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1999	22.79	23.10	27.33	25.63	20.98	16.81	15.69	16.38	23.35	26.32	26.21	22.83	24.24	27.70
	2000	25.34	25.70	30.41	28.52	24.81	18.14	17.07	18.86	25.77	28.12	29.09	25.15	27.53	30.58
	2001	28.29	28.78	33.89	32.24	28.20	20.82	17.04	20.01	26.92	31.71	36.00	28.05	30.67	33.88
	2002	31.91	32.48	37.39	34.79	32.20	23.63	18.76	22.39	30.73	37.90	42.69	31.92	33.61	36.92
	2003	34.95	35.59	40.01	37.69	34.08	25.52	20.38	23.78	34.42	45.08	48.20	34.08	36.38	39.83
	2004	37.87	38.54	42.92	39.02	35.53	26.60	22.50	26.81	38.59	51.46	54.35	35.68	38.14	42.89
	2005	40.52	41.21	45.61	41.52	36.97	27.85	24.48	28.38	41.83	56.52	57.79	38.27	40.84	46.14
	2006	41.21	41.89	46.08	41.96	37.93	28.82	25.48	29.20	44.30	57.16	58.87	38.24	40.59	45.84
	2007	44.03	44.78	46.83	44.73	39.86	30.52	26.62	29.42	43.94	67.45	69.71	40.31	41.74	47.17
	2008	43.83	44.57	48.55	44.16	40.55	30.33	26.78	30.06	45.48	60.57	67.63	41.30	42.18	48.32
	2009	45.13	45.87	49.84	44.99	41.63	31.47	27.97	31.19	47.73	62.75	67.77	42.63	43.81	49.75
	2010	45.93	46.71	50.98	46.90	41.45	32.68	28.01	31.87	50.24	61.79	68.36	43.09	44.72	51.07
	2011	48.22	49.03	55.84	49.03	41.02	33.37	29.65	33.56	52.34	67.85	67.84	44.44	47.97	55.80
	2012	49.60	50.46	57.24	50.50	43.12	34.74	29.80	34.38	53.85	69.13	70.15	46.10	49.41	56.73
	2013	50.44	51.29	57.70	52.27	43.66	37.02	30.93	33.34	51.72	71.22	76.85	44.84	48.37	57.38
	2014	52.86	53.82	61.91	55.33	45.89	38.78	30.96	34.76	54.79	71.69	78.30	47.97	52.51	61.48
	2015	53.67	54.60	64.08	55.56	46.97	39.57	32.17	35.66	55.13	74.31	75.13	48.14	52.93	64.37
	2016	55.19	56.13	65.77	56.13	48.61	40.99	33.52	37.47	57.07	77.61	74.68	49.24	54.17	67.02
	2017	57.46	58.38	68.48	60.16	51.61	42.82	36.35	39.91	58.99	77.87	75.68	50.89	56.94	69.83
	2018	58.19	59.13	68.07	62.60	53.56	45.27	36.52	39.61	55.69	74.84	84.82	51.53	56.40	69.39

2

Forward Prices AURORA per NWPPC assumptions

High/Low = +/- 20% 20

	Flat	Average RTC	50% of May Low w/o __% May	Jan	23 Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Low															
AURORA	1999	16.41	16.61	17.68	17.22	16.04	14.61	11.93	12.44	17.40	18.15	19.06	16.75	16.80	18.87
	2000	16.65	16.85	18.59	16.95	16.17	15.15	12.15	12.59	17.44	18.32	19.16	16.81	17.13	19.34
	2001	17.11	17.27	18.75	18.02	16.21	15.52	13.38	12.58	17.69	19.31	19.71	17.19	17.38	19.55
	2002	17.82	17.98	19.68	18.89	16.63	15.65	13.93	13.62	18.07	20.07	20.85	17.73	18.35	20.30
	2003	18.24	18.44	19.98	19.59	17.68	15.78	13.68	13.75	18.64	20.98	21.55	17.91	18.75	20.64
	2004	18.78	18.98	21.15	19.52	17.99	15.66	14.23	14.79	19.08	21.74	22.91	18.42	19.09	20.76
	2005	19.29	19.52	21.63	19.87	18.21	16.05	13.86	14.75	19.60	22.61	23.65	18.64	20.54	22.07
	2006	21.41	21.66	24.31	21.96	19.16	17.22	15.79	17.23	20.60	24.65	27.16	20.82	23.05	25.01
	2007	21.86	22.09	22.96	23.33	20.44	18.23	16.56	16.57	20.88	26.44	29.54	20.19	22.11	25.03
	2008	22.64	22.89	24.19	23.19	20.83	18.62	16.78	16.99	22.05	28.45	31.47	20.73	23.01	25.34
	2009	22.50	22.76	24.66	22.68	21.15	18.93	16.55	16.06	21.51	30.71	30.68	20.33	21.96	24.80
	2010	22.72	23.07	25.04	23.22	21.57	19.45	14.72	14.72	22.26	29.30	34.13	20.23	22.39	25.67
	2011	23.01	23.35	24.63	23.22	21.99	19.76	15.10	14.63	20.98	31.84	34.68	21.38	22.75	25.13
	2012	24.65	25.07	25.48	23.56	21.93	20.19	14.95	15.97	22.73	40.42	36.92	22.31	24.39	26.99
	2013	25.12	25.57	25.14	24.32	22.55	20.63	14.95	16.25	22.17	41.12	42.07	22.01	23.74	26.54
	2014	23.30	23.72	24.99	23.47	22.94	20.37	13.79	15.81	21.38	28.40	37.96	21.27	23.28	25.97
	2015	23.43	23.85	25.51	23.85	22.86	20.55	13.66	14.45	21.83	28.70	39.77	21.08	23.03	25.83
	2016	22.60	22.98	25.49	24.58	22.79	19.54	13.92	14.94	21.89	25.79	32.15	20.87	23.11	26.09
	2017	23.32	23.72	25.83	25.04	22.84	19.73	14.02	15.88	21.70	26.39	35.85	21.52	23.65	27.36
	2018	23.20	23.59	25.13	24.38	22.65	18.58	14.14	15.42	21.07	27.00	38.75	21.46	23.47	26.29

Medium Price + 20 Pct

Flat	RTC	Plus x Percent
1999	22.79	23.10
2000	24.84	25.19
2001	26.53	26.88
2002	28.38	28.75
2003	30.35	30.81
2004	33.09	33.62
2005	34.97	35.53
2006	37.21	37.82
2007	39.46	40.20
2008	40.85	41.59
2009	40.48	41.24
2010	42.02	42.78
2011	42.82	43.62
2012	41.46	42.22
2013	45.22	46.05
2014	45.28	46.10
2015	46.81	47.67
2016	47.59	48.42
2017	49.76	50.66
2018	52.30	53.21

Medium Price - 20 Pct

Flat	RTC	Minus X Percent
1999	16.41	16.61
2000	16.56	16.79
2001	17.68	17.92
2002	18.92	19.16
2003	20.23	20.54
2004	22.06	22.42
2005	23.32	23.69
2006	24.80	25.21
2007	26.31	26.80
2008	27.23	27.73
2009	26.99	27.49
2010	28.02	28.52
2011	28.55	29.08
2012	27.64	28.14
2013	30.15	30.70
2014	30.19	30.73
2015	31.21	31.78
2016	31.72	32.28
2017	33.17	33.77
2018	34.86	35.47

3

Replaced w/ forward prices

Market Prices at Mid-C

1 Scen. (NERC availability)

Price Scenario ----> 1 **AURORA with NWPPC Assumptions**

		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
5	Selected Scenario																				
6																					
7	Scenario Medium	-	26.51	26.99	27.46	27.93	28.40	30.60	32.56	34.53	35.74	35.42	36.77	37.47	36.27	39.57	39.62	40.96	41.64	43.54	45.76
8	Scenario High	-	26.60	29.70	33.51	36.70	39.77	42.54	43.27	46.23	46.02	47.39	48.23	50.64	52.07	52.96	55.51	56.35	57.95	60.33	61.10
9	Scenario Low	-	17.48	17.96	18.71	19.16	19.72	20.25	22.48	22.95	23.77	23.63	23.86	24.16	25.88	26.38	24.47	24.60	23.73	24.48	24.36
10	Medium Price + 20 Pct	-	26.60	29.70	32.95	33.52	34.08	36.72	39.07	41.43	42.89	42.51	44.13	44.96	43.53	47.48	47.55	49.15	49.96	52.25	54.91
11	Medium Price - 20 Pct	-	21.21	21.59	21.97	22.34	22.72	24.48	26.04	27.62	28.60	28.34	29.42	29.98	29.02	31.66	31.70	32.77	33.31	34.83	36.61
14	AURORA with CO2																				
15	AURORA + CO2 Medium	-	26.51	26.99	27.46	27.93	28.40	30.12	31.75	33.26	38.84	39.84	40.79	41.43	42.34	44.15	43.91	45.49	45.67	46.97	48.78
16	AURORA + CO2 High	-	26.66	29.74	33.34	36.62	39.09	42.06	42.46	44.95	49.11	51.81	52.24	54.59	58.14	57.55	59.79	60.88	61.98	63.77	64.12
17	AURORA + CO2 Low	-	17.66	17.74	18.30	18.70	19.05	19.45	20.00	20.34	28.14	27.21	27.78	27.68	28.16	28.83	28.83	29.30	30.03	30.41	31.12
18																					
19	AURORA with NWPPC Assumptions																				
20	AURORA Medium	-	26.51	26.99	27.46	27.93	28.40	30.60	32.56	34.53	35.74	35.42	36.77	37.47	36.27	39.57	39.62	40.96	41.64	43.54	45.76
21	AURORA High	-	26.60	29.70	33.51	36.70	39.77	42.54	43.27	46.23	46.02	47.39	48.23	50.64	52.07	52.96	55.51	56.35	57.95	60.33	61.10
22	AURORA Low	-	17.48	17.96	18.71	19.16	19.72	20.25	22.48	22.95	23.77	23.63	23.86	24.16	25.88	26.38	24.47	24.60	23.73	24.48	24.36

4

Forward Prices AURORA per NWPPC assumptions

High/Low = +/- 20% 20

105% adjust annual average for shape of Centralia Power

Replace AURORA forecast 2000-2004 with annual strip of forward prices obtained 7/31/99 by PSE trading.

Expected AURORA	Flat	Average RTC	Expected w/ Shape	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1999														
	2000	25.25	26.51												
	2001	25.70	26.99												
	2002	26.15	27.46												
	2003	26.60	27.93												
	2004	27.05	28.40												
	2005	29.14	30.60	32.46	30.89	27.38	22.09	18.51	20.71	29.02	37.51	40.45	28.11	29.47	33.13
	2006	31.01	32.56	33.68	32.45	28.18	23.26	19.29	21.67	32.58	42.46	43.67	29.35	30.71	34.75
	2007	32.88	34.53	34.45	33.11	28.97	23.99	18.81	20.71	32.37	55.36	50.94	29.84	30.92	35.15
	2008	34.04	35.74	35.48	33.90	29.76	24.63	19.82	20.89	34.91	57.01	53.41	30.58	32.00	36.13
	2009	33.74	35.42	36.33	34.16	30.18	25.13	19.23	20.16	29.01	58.65	51.11	31.23	32.64	37.02
	2010	35.02	36.77	37.42	35.15	30.28	25.75	20.49	22.33	35.93	58.22	51.34	31.55	33.72	38.07
	2011	35.69	37.47	38.68	35.69	30.96	26.50	20.38	22.07	36.36	60.41	50.51	32.64	34.66	39.35
	2012	34.55	36.27	38.82	35.59	30.54	27.06	20.00	21.56	31.79	56.44	46.71	30.83	35.16	40.06
	2013	37.69	39.57	40.17	38.27	32.59	27.96	21.88	22.72	35.91	63.68	59.01	33.18	36.14	40.71
	2014	37.74	39.62	41.90	38.84	31.55	27.54	22.08	22.86	38.47	62.52	54.76	33.24	36.96	42.11
	2015	39.01	40.96	43.45	39.33	32.12	28.11	22.58	23.45	39.02	65.47	57.68	35.20	38.00	43.71
	2016	39.65	41.64	46.65	43.48	32.33	27.54	23.62	26.25	38.69	60.02	53.04	35.99	41.42	46.82
	2017	41.46	43.54	48.44	45.01	33.76	28.55	24.16	26.81	43.01	64.87	54.15	37.82	43.06	47.94
	2018	43.58	45.76	49.27	46.36	35.26	30.59	26.09	28.07	43.44	69.88	64.00	38.34	41.91	49.76

High AURORA	Flat	Average RTC	Expected w/ Shape	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1999														
	2000	25.34	26.60	30.41	28.52	24.81	18.14	17.07	18.86	25.77	28.12	29.09	25.15	27.53	30.58
	2001	28.29	29.70	33.89	32.24	28.20	20.82	17.04	20.01	26.92	31.71	36.00	28.05	30.67	33.88
	2002	31.91	33.51	37.39	34.79	32.20	23.63	18.76	22.39	30.73	37.90	42.69	31.92	33.61	36.92
	2003	34.95	36.70	40.01	37.69	34.08	25.52	20.38	23.78	34.42	45.08	48.20	34.08	36.38	39.83
	2004	37.87	39.77	42.92	39.02	35.53	26.60	22.50	26.81	38.59	51.46	54.35	35.68	38.14	42.89
	2005	40.52	42.54	45.61	41.52	36.97	27.85	24.48	28.38	41.83	56.52	57.79	38.27	40.84	46.14
	2006	41.21	43.27	46.08	41.96	37.93	28.82	25.48	29.20	44.30	57.16	58.87	38.24	40.59	45.84
	2007	44.03	46.23	46.83	44.73	39.86	30.52	26.62	29.42	43.94	67.45	69.71	40.31	41.74	47.17
	2008	43.83	46.02	48.55	44.16	40.55	30.33	26.78	30.06	45.48	60.57	67.63	41.30	42.18	48.32
	2009	45.13	47.39	49.84	44.99	41.63	31.47	27.97	31.19	47.73	62.75	67.77	42.63	43.81	49.75
	2010	45.93	48.23	50.98	46.90	41.45	32.68	28.01	31.87	50.24	61.79	68.36	43.09	44.72	51.07
	2011	48.22	50.64	55.84	49.03	41.02	33.37	29.65	33.56	52.34	67.85	67.84	44.44	47.97	55.80
	2012	49.60	52.07	57.24	50.50	43.12	34.74	29.80	34.38	53.85	69.13	70.15	46.10	49.41	56.73
	2013	50.44	52.96	57.70	52.27	43.66	37.02	30.93	33.34	51.72	71.22	76.85	44.84	48.37	57.38
	2014	52.86	55.51	61.91	55.33	45.89	38.78	30.96	34.76	54.79	71.69	78.30	47.97	52.51	61.48
	2015	53.67	56.35	64.08	55.56	46.97	39.57	32.17	35.66	55.13	74.31	75.13	48.14	52.93	64.37
	2016	55.19	57.95	65.77	56.13	48.61	40.99	33.52	37.47	57.07	77.61	74.68	49.24	54.17	67.02
	2017	57.46	60.33	68.48	60.16	51.61	42.82	36.35	39.91	58.99	77.87	75.68	50.89	56.94	69.83
	2018	58.19	61.10	68.07	62.60	53.56	45.27	36.52	39.61	55.69	74.84	84.82	51.53	56.40	69.39

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Centralia - A... of Revenue Impacts

1 Scen. (NERC availability)

#	Item	Unit	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	OPERATION											
5	Plant Capacity	MW	93.8	93.8	94.3761	94.9522	94.9522	94.9522	94.9522	94.9522	94.9522	94.9522
6	Availability - NERC	%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%
7	Energy at Plant	GWH	658	658	662	666	666	666	666	666	666	666
8	0.00% Energy at BPA Tono	GWH	658	658	662	666	666	666	666	666	666	666
9	0.0% Energy to PSE	GWH	658	658	662	666	666	666	666	666	666	666
10	Heat Rate	BTU/kWh	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485
12	**CENTRALIA COSTS:**											
13	Carrying Costs on Existing and Incremental											
14	Generation, Common and Transmission Plant											
15	Return on Ratebase	$(000)	550	940	1,489	1,561	1,424	1,291	1,160	1,030	902	775
16	Depreciation	$(000)	684	857	1,110	1,196	1,202	1,209	1,217	1,224	1,232	1,239
17	Federal Tax	$(000)	463	806	1,589	1,691	1,618	1,548	1,479	1,410	1,341	1,273
18	Property Tax	$(000)	273	291	299	301	304	307	310	313	316	319
19		$(000)										
20	Insurance	$(000)	14	15	15	15	15	15	15	16	16	16
21	Subtotal Return & Capital Costs	$(000)	1,984	2,909	4,502	4,765	4,563	4,371	4,181	3,993	3,807	3,623
22	Ending Balance Recovery	$(000)	-	-	593	593	593	593	593	593	593	593
23	Operating Costs (Fuel O&M, Gen Tax)											
24	Fuel & Reclamation	$(000)	10,552	10,816	11,144	11,481	11,768	12,062	12,364	12,673	12,990	13,315
25	Mine Reclamation	$(000)	945	945	945	945	945	945	945	945	945	945
26	Non-Fuel O&M	$(000)	1,447	1,897	2,035	1,795	2,224	2,280	2,337	2,395	2,455	2,516
27	CO2 Tax	$(000)	-	-	-	-	-	-	-	-	-	-
28	Subtotal Operating Costs	$(000)	12,944	13,658	14,124	14,221	14,937	15,287	15,646	16,013	16,390	16,776
29												
30	SO2 Allowances (Cr)	$(000)	694	712	143	(455)	(467)	(479)	(490)	(503)	(515)	(528)
31												
32	Transmission	$(000)										
33	Trans. O&M BPA Pool	$(000)	32	32	33	33	33	34	34	34	35	35
34	Trans. Credits and Exchange	$(000)	(437)	(440)	(443)	(445)	(448)	(451)	(454)	(457)	(459)	(462)
35	BPA IR Charges	$(000)	1,200	1,200	1,800	1,800	1,800	1,800	1,800	2,036	2,036	2,036
36	IR - Losses at Market		300	332	337	343	349	355	383	407	432	447
37	Total Transmission	$(000)	1,095	1,124	1,727	1,731	1,734	1,738	1,763	2,021	2,043	2,056
38	Rev. Req. Legislative Tax Savings	$(000)	(273)	(360)	(290)	(236)	(206)	(206)	(206)	(206)	(206)	(206)
39	Rev Req. Plant & Mine Closure	$(000)	-	-	-	-	-	-	-	-	-	-
40	**Subtotal Centralia Cost**	$(000)	16,444	18,043	20,799	20,619	21,155	21,304	21,486	21,911	22,111	22,313
41	7.69% Discount Factor		0.9636	0.8948	0.8309	0.7716	0.7165	0.6653	0.6178	0.5737	0.5327	0.4947
42												
43	**PV Centralia Cost**	$(000)	15,846	16,145	17,283	15,910	15,157	14,174	13,274	12,570	11,779	11,038
	PV Lump Sum Recovery Ending Book	$(000)										
45	**Accum. PV Centralia Cost**	$(000)	15,846	31,991	49,274	65,184	80,341	94,515	107,789	120,359	132,139	143,177
46	**MARKET COSTS:**											
47	Mid Point Forecast											
48	1 AURORA w/ NWPPC	$/MWh	26.51	26.99	27.46	27.93	28.40	30.60	32.56	34.53	35.74	35.42
49	0.019 Energy at Mid-C	GWH	671	671	675	679	679	679	679	679	679	679
50	Cost of Energy at Mid-C	$(000)	17,788	18,105	18,535	18,969	19,290	20,783	22,110	23,451	24,276	24,058
51	Trans. Credits on PSE Line	$(000)	(840)	(1,260)	(1,890)	(1,890)	(1,890)	(1,890)	(1,890)	(2,138)	(2,138)	(2,138)
52	Transmission Mid-C to PSE	$(000)	1,200	1,200	1,800	1,800	1,800	1,800	1,800	2,036	2,036	2,036
53	Subtotal	$(000)	18,148	18,045	18,445	18,879	19,200	20,693	22,020	23,349	24,174	23,956
54	Rev. Req. Gain or (Loss)	$(000)	4,160	4,160	4,160	4,160	4,160	-	-	-	-	-
55	**Total Market Cost**	$(000)	13,988	13,885	14,285	14,719	15,040	20,693	22,020	23,349	24,174	23,956
56												
57	**PV Market Cost**	$(000)	13,479	12,424	11,870	11,357	10,776	13,768	13,605	13,395	12,878	11,851
58	**Accum. PV Market**	$(000)	13,479	25,903	37,773	49,130	59,906	73,673	87,278	100,673	113,552	125,403
60	**PV Centralia Cost - Market Costs**		2,367	6,088	11,501	16,054	20,435	20,841	20,511	19,686	18,587	17,774
61												
62												
63	**Cost Centralia @ PSE**	$/MWh	24.98	27.41	31.41	30.95	31.75	31.98	32.25	32.89	33.19	33.49
64	Cost Alternative @ PSE	$/MWh	21.25	21.10	21.57	22.09	22.57	31.06	33.05	35.04	36.28	35.96

#	Item	2010	2011	2012	2013	2014	2015	2016	2017	2018
5	Plant Capacity	94.9522	94.9522	94.9522	94.9522	94.9522	94.9522	94.9522	94.9522	94.9522
6	Availability - NERC	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%
7	Energy at Plant	666	666	666	666	666	666	666	666	666
8	0.00% Energy at BPA Tono	666	666	666	666	666	666	666	666	666
9	0.0% Energy to PSE	666	666	666	666	666	666	666	666	666
10	Heat Rate	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485
15	Return on Ratebase	649	547	473	399	325	252	179	106	33
16	Depreciation	1,247	594	596	604	613	622	631	640	649
17	Federal Tax	1,205	794	750	710	671	633	594	554	515
18	Property Tax	322	325	329	332	336	339	343	347	351
20	Insurance	16	16	16	17	17	17	17	17	17
21	Subtotal Return & Capital Costs	3,439	2,277	2,164	2,062	1,962	1,864	1,765	1,665	1,565
22	Ending Balance Recovery	593	593	593	593	593	593	593	593	593
24	Fuel & Reclamation	13,647	13,989	14,338	14,697	15,064	15,441	15,827	16,223	16,628
25	Mine Reclamation	945	945	945	945	945	945	945	945	945
26	Non-Fuel O&M	2,579	2,644	2,710	2,777	2,847	2,918	2,991	3,066	3,142
27	CO2 Tax	-	-	-	-	-	-	-	-	-
28	Subtotal Operating Costs	17,172	17,577	17,993	18,419	18,856	19,304	19,763	20,233	20,716
30	SO2 Allowances (Cr)	(541)	(560)	(574)	(588)	(603)	(618)	(633)	(649)	(665)
33	Trans. O&M BPA Pool	35	36	36	37	37	37	38	38	38
34	Trans. Credits and Exchange	(465)	(468)	(471)	(474)	(477)	(480)	(483)	(487)	(490)
35	BPA IR Charges	2,036	2,036	2,302	2,302	2,302	2,302	2,302	2,604	2,604
36	IR - Losses at Market	443	460	469	454	495	496	512	521	544
37	Total Transmission	2,049	2,063	2,336	2,318	2,357	2,355	2,369	2,676	2,697
38	Rev. Req. Legislative Tax Savings	(206)	(206)	(206)	(206)	(206)	(206)	(206)	(206)	(1,034)
39	Rev Req. Plant & Mine Closure	-	-	-	-	-	-	-	-	5,641
40	**Subtotal Centralia Cost**	22,505	21,745	22,306	22,599	22,959	23,292	23,650	24,312	29,512
41	7.69% Discount Factor	0.4594	0.4266	0.3961	0.3678	0.3416	0.3172	0.2945	0.2735	0.2540
43	**PV Centralia Cost**	10,338	9,275	8,835	8,312	7,842	7,387	6,965	6,649	7,495
45	**Accum. PV Centralia Cost**	153,515	162,790	171,626	179,938	187,780	195,167	202,132	208,781	216,276
48	1 AURORA w/ NWPPC	36.77	37.47	36.27	39.57	39.62	40.96	41.64	43.54	45.76
49	0.019 Energy at Mid-C	679	679	679	679	679	679	679	679	679
50	Cost of Energy at Mid-C	24,974	25,448	24,636	26,874	26,911	27,819	28,278	29,569	31,078
51	Trans. Credits on PSE Line	(2,138)	(2,138)	(2,418)	(2,418)	(2,418)	(2,418)	(2,418)	(2,734)	(2,734)
52	Transmission Mid-C to PSE	2,036	2,036	2,302	2,302	2,302	2,302	2,302	2,604	2,604
53	Subtotal	24,872	25,346	24,521	26,759	26,796	27,704	28,163	29,439	30,948
54	Rev. Req. Gain or (Loss)	-	-	-	-	-	-	-	-	-
55	**Total Market Cost**	24,872	25,346	24,521	26,759	26,796	27,704	28,163	29,439	30,948
57	**PV Market Cost**	11,425	10,812	9,713	9,843	9,152	8,787	8,294	8,051	7,859
58	**Accum. PV Market**	136,828	147,640	157,353	167,195	176,347	185,134	193,428	201,479	209,339
60	**PV Centralia Cost - Market Costs**	16,687	15,150	14,273	12,743	11,432	10,033	8,704	7,302	6,937
63	**Cost Centralia @ PSE**	33.78	32.64	33.48	33.92	34.46	34.96	35.50	36.49	44.29
64	Cost Alternative @ PSE	37.33	38.04	36.80	40.16	40.22	41.58	42.27	44.19	46.45

Embedded Costs

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Co. t O&M

line	Scen. (NERC availability)		Actual 1995	Actual 1996	Actual 1997	Actual 1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
4	*Centralia - PSE*															
5	Net MW (including station use)	MW	93.8	93.8	93.8	93.8	93.80	93.80	93.80	94.38	94.95	94.95	94.95	94.95	94.95	94.95
6	Scrubber Station Use						0.00	0.00	0.00	-0.58	-1.15	-1.15	-1.15	-1.15	-1.15	-1.15
7	Net Output after Scrubber Use		93.8	93.8	93.8	93.8	93.80	93.80	93.80	93.80	93.80	93.80	93.80	93.80	93.80	93.80
8	Net Plant Heat Rate (Btu/kWh)		10,554	10,475	10,503	10,418	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485
9	PSE's Energy/Capacity	%	42.2%	61.8%	66.6%	84.5%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%	80.1%
10	Total MMBtu Requirement		3,661,548	5,334,781	5,746,179	7,235,923	6,900,934	6,900,934	6,900,934	6,943,318	6,985,703	6,985,703	6,985,703	6,985,703	6,985,703	6,985,703
11	MWh - Gross Generation		346,931	509,281	547,117	694,593	658,172	658,172	658,172	662,214	666,257	666,257	666,257	666,257	666,257	666,257
12	Incremental Scrubber Use						0	0	0	(4,042)	(8,085)	(8,085)	(8,085)	(8,085)	(8,085)	(8,085)
13	Total MWh - Generation	MWh	346,931	509,281	547,117	694,593	658,172	658,172	658,172	658,172	658,172	658,172	658,172	658,172	658,172	658,172
14	0.0% Energy at BPA Tono	MWh	346,931	509,281	547,117	694,593	658,172	658,172	658,172	658,172	658,172	658,172	658,172	658,172	658,172	658,172
15	0.0% Energy to PSE	MWh					658,172	658,172	658,172	658,172	658,172	658,172	658,172	658,172	658,172	658,172
16																
17			Actual	Actual	Actual	Actual	|-----> Forecast									
18	Fuel w/o Reclamation	$000	5,461	8,778	10,414	11,258	10,295	10,552	10,816	11,144	11,481	11,768	12,062	12,364	12,673	12,990
19	Reclamation Accrual	$000	368	368	368	368	368	945	945	945	945	945	945	945	945	945
20	Non Fuel O&M	$000	2,197	1,424	1,785	2,286	1,363	1,447	1,897	2,035	1,795	2,224	2,280	2,337	2,395	2,455
21	Total Fuel and Non-Fuel O&M	$000	8,026	10,570	12,567	13,912	12,026	12,944	13,658	14,124	14,221	14,937	15,287	15,646	16,013	16,390
22	CO2 Tax															-
23	Total Cost: Fuel Reclamation O&M and CO2		8,026	10,570	12,567	13,912	12,026	12,944	13,658	14,124	14,221	14,937	15,287	15,646	16,013	16,390
24	Total Unit Cost:	$/MWh	23.14	20.75	22.97	20.03	18.27	19.67	20.75	21.46	21.61	22.70	23.23	23.77	24.33	24.90
25	year to year % change			-10.3%	10.7%	-12.8%	-8.8%	7.6%	5.5%	3.4%	0.7%	5.0%	2.3%	2.3%	2.3%	2.4%
26												WSST Exemptions starts				
27																
28	<u>Calculation of Variable Dispatch Cost</u>															
29																
30	External Coal Variable Cost	$/MWh					13.18	13.51	13.85	14.20	14.55	14.92	15.29	15.67	16.06	16.46
31	2.5% Variable O&M - estimate	$/MWh					0.50	0.51	0.53	0.54	0.55	0.57	0.58	0.59	0.61	0.62
32	Total Variable Dispatch	$/MWh					13.68	14.03	14.38	14.74	15.10	15.48	15.87	16.27	16.67	17.09

Variable Dispatch Cost.

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