- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application for an Order Approving the Sale of its Interest in (1) the Centralia Steam Electric Generating Plant, (2) the Ratebased Portion of the Centralia Coal Mine, and (3) Related Facilities; For a Determination of the Amount of and the Proper Ratemaking Treatment of the Gain Associated with the Sale; and for an EWG Determination	)	DOCKET NO. 99-2035-03 REPORT AND ORDER

ISSUED: March 14, 2000

SHORT TITLE

Sale of Centralia Plant and Mine

SYNOPSIS

The Commission approves the sale subject to conditions concerning the distribution of the gain on the sale. The gain is to be shared 95 percent to ratepayers and 5 percent to shareholders. The sharing reflects future risk. Utah's share of the gain is determined using the allocation factors of the Rolled-In Interjurisdictional Allocation Method. The ratemaking treatment of Utah's share of the gain is to include the gain as an offset to ratebase in the next rate case.

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APPEARANCES:

Michael L. Ginsberg Assistant Attorney General	For	Division of Public Utilities
Douglas C. Tingey Assistant Attorney General	"	Committee of Consumer Services
John M. Eriksson George M. Galloway Attorneys at Law - Stoel Rives	"	PacifiCorp
Gary A. Dodge Attorney at Law Parr, Waddoups, Brown, Gee & Loveless	"	Large Customer Group

I. PROCEDURAL HISTORY

On August 12, 1999, PacifiCorp ("PacifiCorp" or "the Company") filed its Application for an order approving the sale of its interest in (1) the Centralia steam electric generating plant, (2) the ratebased portion of the Centralia coal mine, and (3) related facilities; for a determination of the amount of and proper ratemaking treatment of the gain associated with the sale; and for an EWG determination. C. Alex Miller, Managing Director of Planning, Rodger Weaver, Director, Regulatory and Strategy Support, and Anne E. Eakin, Vice President of Regulation, filed testimony and exhibits with the Application.

Following a duly noticed hearing held September 21, 1999, the Commission issued a Scheduling Order on September 29, 1999.

On November 23, 1999, PacifiCorp filed a Motion for EWG Determinations, containing a draft order and the attestation of Michael Ginsberg, Attorney for the Division of Public Utilities ("the Division"), and Douglas C. Tingey, Attorney for the Committee of Consumer Services ("the Committee"), that each agency approves the draft order as to both form and substance. The Commission issued its Order on December 20, 1999, concluding that operation of the plant, as an eligible facility, subject to approval of the Application and following consummation of the sale, will benefit consumers, is in the public interest, and does not violate state law.

On January 7, 2000, Rebecca L. Wilson, Nancy L. Kelly and Paul Chernick, and Richard M. Anderson filed direct testimony for the Division, the Committee, and the Large Customer Group ("LCG").

PacifiCorp filed the rebuttal testimony and exhibits of Matthew R. Wright, Vice President of Regulation, who adopted the direct testimony of Anne E. Eakin, C. Alex Miller, and Rodger Weaver, on January 18, 2000.

The Commission held hearings January 19, 20, and 21, 2000.

Post-hearing briefs were filed January 31, and February 1, 2000, by PacifiCorp, the Division, the Committee, and LCG.

II. POSITIONS OF THE PARTIES

A. PACIFICORP

PacifiCorp applies for approval to sell its 47.5 percent, 636.5 Mega-Watt, interest in the Centralia steam generating plant and the ratebased portion of the Centralia coal mine to affiliates of TransAlta Corporation. Centralia is a 1,340 MW coal-fired generation station located in Washington state. It is owned by seven northwest utilities, and operated by PacifiCorp. The adjacent mine, which PacifiCorp owns, supplies coal to the plant under contract. The sale price for these properties is about $554 million, an amount which produces a gain on the sale. PacifiCorp's share of the gain is approximately $83 million.

A net revenue requirement analysis employing forecasts of the market price of replacement power is used by the Company to show that ratepayers, based on an expectation that revenue requirement will be lower if the plant is sold than otherwise, benefit from the sale. Its testimony is that all risk, whether borne by ratepayers or shareholders, is reduced by the sale. Based on its "depreciation reserve" method, the Company would apportion 64 percent of the gain to ratepayers and 36 percent to shareholders. Allocation of the ratepayer share of the gain to state jurisdictions would distribute 4.8 percent, or $2.6 million, to Utah. PacifiCorp prefers to use Utah's share of the gain to offset the premium earlier paid to acquire the Yampa plant, thus amortizing it as a reduction in rate base. The Company also seeks an order from the Commission allowing the Centralia generating plant to be considered an "eligible facility" so that the purchaser can operate it as an exempt wholesale generator (EWG) under federal law.

B. DIVISION

Given these PacifiCorp terms, the Division testifies that sale of the plant and mine is not in the public interest. The Division states that the sale fully compensates shareholders for their capital investment in the plant and mine, and reduces any going-forward risks they might face; ratepayers, on the other hand, risk, without adequate compensation, a revenue requirement that might be substantially higher due to the cost of power purchases than if the plant and mine were retained. The share of the gain Utah ratepayers require if they are to benefit from the sale ranges, according to Division calculations, from $3.8 million to $81.9 million, depending on the market price of replacement power and other assumptions. The Division recommends that the entire gain benefit ratepayers, and would determine the Utah ratepayer share using this jurisdiction's currently approved allocation method. This would give Utah approximately 35 percent of the gain, or about $31.6 million. Even with this recommendation, the Division questions whether ratepayers are fully compensated for the future risk they will bear when the plant is sold. If the Commission approves the sale, the Division recommends either deferral of decisions about the ratemaking treatment of the gain until an appropriate record can be developed in a general rate case or amortization as a rate base reduction not tied to the Yampa premium.

C. COMMITTEE

The Committee testifies that the sale is not in the public interest because ratepayers are not protected from the substantial risk that sale of the plant will increase revenue requirement. The gain required to protect ratepayers from the harm of higher rates due to the need to purchase replacement power is calculated by the Committee at $18 million to $117 million, depending on forecast market price of replacement power. The Company's proposal to allocate $2.6 million of the gain on the sale to Utah ratepayers is, the Committee states, inadequate. The Committee urges denial of the sale because risks far outweigh any benefit ratepayers might receive. This might be different if PacifiCorp were to share the going-forward risks of higher replacement power costs, which it refuses to do, or if compensation to Utah ratepayers were large enough, which the gain on the sale is insufficient to permit. If the Commission approves the sale, the Committee supports the Division's position on the treatment of the gain.

D. LARGE CUSTOMER GROUP

The Large Customer Group testifies that PacifiCorp's proposal to split the $83 million gain between shareholders and ratepayers fails to comply with the principle that "benefits follow risks" and thereby would produce an undeserved windfall for shareholders. The rates paid for electric service, if the properties were retained, would allow shareholders to recover their investment and to earn a reasonable return on it. Sale of the plant and mine, states LCG, makes shareholders whole, but ratepayers face the risk of higher cost replacement power. The sale truncates a flow of benefits that ratepayers had reason to expect would continue for the economic life of the plant. Because the sale price is the implied market value of the assets, the gain on the sale places a market value on this flow of economic benefits. Ratepayers would be adequately compensated for the loss of these benefits if the full amount of the gain were returned to them. LCG does acknowledge, however, that shareholders may continue to bear a small amount of risk, and would not object if a small part of the gain, though much less than the 36 percent the Company proposes, were allocated to them. The gain returned to ratepayers, adjusted for taxes and other savings, and amortized over two years with interest, should be allocated to customer classes on the same basis as currently used for purchased power costs. It should be returned promptly to ratepayers either by refund or billing credit.

III. DISCUSSION, FINDINGS, AND CONCLUSIONS

We first determine whether, and under what conditions, sale of the Centralia plant and associated mine is in the public interest. Given the testimony of the parties, we cannot reach this conclusion without first considering the disposition of the gain on the sale. We take up the sharing of the gain on the sale between ratepayers and shareholders and the proper allocation of the ratepayer share to the Utah jurisdiction. Following decisions on these subjects, we decide the ratemaking treatment of the Utah ratepayers' share.

A. PUBLIC INTEREST EVALUATION OF THE SALE DECISION

As presented by the Company and the parties, the public interest issue turns on an analysis of risk. The record shows that risks are generally categorized as qualitative and quantitative. The quantitative risk borne by ratepayers and shareholders is revealed by comparing keep-the-plant versus sell-the-plant cases. The cases are analyzed for the difference in net present value of revenue requirement between them over the remaining life of the plant (through 2023), under various assumptions about plant cost control, pollution control investment, coal supply, and sale of the California service territory. The important factor in this comparison is the forecast for market prices of replacement power over 23 years into the future. Ratepayers, who will bear the risk of replacing the power generated by Centralia, are considered better off if the sale reasonably can be expected to reduce net revenue requirement. This measure of ratepayer benefit, a reduction in revenue requirement, is a reduction in quantitative risk. The Company identifies qualitative risks as those associated with the management difficulty posed by joint ownership of the plant, possible early closure of the plant, whether temporary or permanent, required investment in pollution control equipment, possible environmental cleanup costs, and the more immediate incurrence of reclamation costs should the mine close early.

PacifiCorp's position is that sale of plant and mine benefits ratepayers and shareholders by reducing the quantitative and qualitative risks each faces. Quantitative risk, the likelihood that power purchased on the market to replace that generated by the plant will be more costly, is almost wholly borne by ratepayers, though the Company argues shareholders face some risk because regulators might not allow full recovery in rates of higher cost replacement power. Its analysis of this risk is said by the Company to produce a "wash," meaning, in net revenue requirement terms, ratepayers should be indifferent to sale or retention of the plant. In PacifiCorp's view, retention of the plant and mine risks early, temporary or perhaps permanent closure of the plant, the accompanying need to purchase replacement power, and more immediate incurrence of mine reclamation costs and, possibly, environmental cleanup costs. After the sale, the Company claims ratepayers will no longer face these unmeasured, qualitative risks and these risks will be substantially reduced for shareholders. This is what, the Company asserts, clearly tips the balance in favor of sale.

The Division, the Committee, and the Large Customer Group come to a quite different conclusion. They generally assert that, after the sale, shareholders would face little or no risk but ratepayers would be greatly exposed because the important risk is the "going-forward" risk of higher cost replacement power. We assess these positions in the following, beginning with quantitative risk.

1. QUANTITATIVE RISK

As an integral part of PacifiCorp's production system, the Centralia plant would generate power during its 23-year remaining life at a cost, which includes the cost of meeting air quality requirements, that can be estimated. Once the plant is sold, this power will have to be replaced with purchases on the wholesale market. The likelihood that this replacement power will be more expensive than that generated by the plant is termed on this record quantitative risk, and it is a risk almost wholly borne by ratepayers. PacifiCorp relies on forecasts of the market price of replacement power that minimize estimates of this risk and, correspondingly, are the basis for its position that ratepayers will benefit from a slightly lower revenue requirement when the plant and mine no longer are part of the production system. By contrast, parties present the case for higher market prices and on this basis assert that the sale poses substantial and, under the terms proposed by the Company, uncompensated risk for ratepayers.

The Company estimates quantitative risk by comparing the revenue requirement impacts, in net present value terms, of sell-the-plant (gain on the sale is treated as a revenue requirement reduction) versus keep-the-plant (includes installation of pollution control equipment to meet air emission requirements and continued operation of the plant through 2023) scenarios. These scenarios are analyzed using forecasts of the market price of replacement power the Company identifies as low, medium, and high. A variation of the medium forecast traces the effect of "aggressive" control of operations and maintenance costs at the mine. Using the medium forecast as the base case, the Company testifies that the present value of system revenue requirement associated with selling the plant is about $10 million lower than the present value of the revenue requirement if the plant is retained. The scenario using low market prices gives greater benefit. Benefits disappear in the high price scenario and a ratepayer burden is indicated.

The Division and the Committee testify that the Company's low, medium and high market price forecasts fail to describe the relevant range. The three Company forecasts approximate only the lower half of the range of forecast prices supported by the other parties, and thus the Company's high case is better regarded as a medium case because it is lower than other credible medium case forecasts. The Committee argues that PacifiCorp's low price forecast is implausible, its medium case is more credible as a low case, while its high case makes a better medium or base case. The Division and the Committee argue that forecasts of higher market prices, such as those produced by the Northwest Power Planning Council, more accurately suggest the risk the sale may create for ratepayers. Moreover, the Committee contends that the Company employs other assumptions in its forecasts that tend to reduce ratepayer risk, in all leading the Committee to conclude that the amount required to compensate ratepayers could exceed $117 million.

Forecasts of market prices of replacement power principally depend on assumptions about future natural gas prices, the installation cost of new capacity, and plant operating efficiencies. Such assumptions, states the Company, are the critical factors in the evaluation of projections. Parties critique the particular assumptions employed by the Company and offer alternatives. Witnesses emphasize forecast natural gas prices because these prices have the greatest effect on forecasts of electricity prices. In our judgment, an assumption that future gas prices will be as low as that in the Company's low case faces telling criticism on this record, and this low case is the only case, the Company acknowledges, that unambiguously generates a ratepayer benefit. As well, its assumptions about plant operating efficiencies and plant installation costs must be evaluated in view of credible arguments showing other plausible values for them that damage the Company's case. At the high end of the range, the forecast of high prices authored by the Northwest Power Planning Council and supported by the Division rests on an assumed role for demand-side resources that the Company regards as unrealistic. Thus, key assumptions in the low- and high-case forecasts are disputed. Because the record does not permit us to resolve these disputes, we will place somewhat less reliance on the forecasts that depend on them.

Some cases also depend on assumptions about the pending sale by the Company of its California distribution system properties. The newly enacted legislation in Oregon which intends a restructured electric industry there after 2001 may affect the net revenue requirement analysis by suggesting loss of load, a diminished capacity requirement, and, in the Company's view, enhanced benefits of sale. The effect of the California sale assumption is best seen as a variation of the Company's medium-case scenario, where it gives rise to a larger ratepayer benefit from sale than the scenario otherwise shows. The Committee argues that this potential loss of load is a problem only in the Company's low market price scenario because when higher price forecasts are used the sale into the wholesale market of power made available by loss of load will provide compensation, making it incorrect to assert an increase in revenue requirement from retaining the plant in loss of load circumstances. The California and Oregon matters, we note, are presented in conclusory terms rather than with analytical rigor. Resultant ambiguity prevents us from drawing specific conclusions about their role in determining the ratepayer impacts the sale might occasion. As we show below, however, it is most unlikely that these effects would change our overall assessment of quantitative risk.

In considering the role of forecasts, we are aware that a forecast is simply a projection of the implications of a set of assumptions. It follows that the more acceptable the assumptions, the more cogent the forecast. But even if experts agree on the appropriate assumptions, which is not the case on this record, forecasts do not tell the future; the future is uncertain. Unforeseen occurrences will render forecasts inaccurate. In other words, we know of no basis by which it might be held that Forecast A is a more probable portrayal of the future than is Forecast B. Capable forecasts are equally likely, and the witnesses treat them so.

To work around these limitations when a forecast must be the basis for a decision, we believe that we must consider a range of plausible, forecast outcomes broad enough to cover the implications of all assumptions experts today think worth considering. Further, we should consider best those forecasts which form the basis for decisions and actions that minimize the harm that might occur when the future unfolds differently than expected. The record shows that the Company's low forecast is the subject of much criticism and other, higher forecasts reveal growing ratepayer risk. From these observations, we conclude that forecasts based on disputed assumptions about which we are unable to reach informed judgment or forecasts which define the low and high boundaries of the reasonable range of projected market prices are a less satisfactory basis for regulatory decisions than is a well-founded medium-case forecast.

Record evidence on assumptions reveals no basis upon which we might either reject assumptions that some witnesses question or select a set of more plausible ones to use for a new base case. Rather than a specific forecast, we will look for a plausible range of forecast market price values, and from reasonable medium cases will draw the inferences about quantitative risk we consider appropriate.

Witnesses do not claim to have reviewed all market price forecasts that might have been produced recently, yet each is comfortable with the range - narrow and lower in PacifiCorp's case, broader and higher in that of the others - described by the forecasts they submit. No witness argues for a lower forecast than the Company's low case; all but the Company argue for forecasts higher than its high case while characterizing the Company's high case as in reality a medium case. In view of this testimony and record evidence on the assumptions underlying forecasts, including those introduced by the Division and the Committee, we conclude that the Company's forecasts cover but the lower half of a reasonable range. The range we accept is defined at the low end by the Company's low case and at the high end by the Northwest Power Planning Council forecast submitted by the Division. We agree with the Division and the Committee that in this wider range the Company's high case appears rather as a medium case.

We are influenced in reaching this conclusion by record evidence showing that small differences in forecast power prices result in disproportionately large changes in the net present value of the difference in revenue requirement between the keep and the sell cases. These small differences in market price swing what is characterized by the Company as a small ratepayer benefit in its medium case to a large detriment as forecasts of higher prices are used. For example, the Division's analysis of the Company's medium and high market price cases indicates *Utah* revenue requirement, depending on assumptions, would be $2 million higher in the medium case if the sale occurs (contrasting with the Company's estimate of a *total system* gain of $10 million, the difference in direction of impact due to the Company's proposed method of sharing the gain and allocating it to states) but $100 million higher in the high case. We agree with the Division that the big difference in the revenue requirement results of the two cases is a good indication of quantitative risk. We also agree with LCG's argument that a market evaluation of the replacement power risk is indicated by the $83 million gain on the sale. This discussion means, and we so conclude, that a case nearer the Company's high case best suggests the quantitative risk ratepayers will face after sale of the plant and mine.

2. QUALITATIVE RISK

PacifiCorp urges acceptance of the proposition that the proposed sale minimizes and balances quantitative and qualitative risks for ratepayers and shareholders, making both groups better off. Qualitative risk should be key, the

Company avers, even as we consider the record on quantitative risk, which is subject to an analytical treatment not possible for qualitative considerations. Sale of the plant and mine minimizes qualitative risk, and this, testifies the Company, is what makes the sale worthwhile. This emphasis is necessary to the Company's position, as is evident in the Company's acknowledgment that its analysis of quantitative risk, based as it must be on "uncertain assumptions" and forecasts, does not, except in select cases, show positive benefits for ratepayers from the sale. As our conclusions thus far reveal, we have rejected the Company's position that quantitative analysis reveals little ratepayer risk if the sale occurs, but it is with the Company's repeated emphasis on the importance of the qualitative risk factors in mind that we now consider them.

Qualitative risks include installation of scrubbers, possible plant closure, reclamation costs, relationship of these to restructuring, and joint ownership problems. These risks are interrelated. For example, the Company testifies that the decision to invest in scrubbers to control air emissions is the economically correct one, but it is not supported by the public entities which share in plant ownership. Joint ownership agreements, however, require unanimous capital budgeting decisions. If disagreement delays scrubber installation beyond predetermined dates, the plant may be forced to close temporarily, or perhaps permanently, and replacement power will have to be purchased on the wholesale market. Moreover, both the scrubber investment and potential reclamation costs arise in an environment of industry, and therefore regulatory, restructuring, which the Company asserts threatens recovery of these expenditures. Nonrecovery is the risk for shareholders; that for ratepayers is the recovery in rates of higher cost replacement power if the plant closes.

There is no dispute that sale of the plant and mine removes these qualitative risks, and it is on this basis that the Company asserts sale under the proposed terms is in the public interest. The Company also asserts, however, that shareholders will continue to bear aspects of these qualitative risks even after sale and this is one, though not the only, reason shareholders have a claim to a portion of the gain on the sale. The Division and the Committee disagree, arguing that the risk remaining after sale is the "going-forward" risk that sale of the plant may require purchase of more costly replacement power. This risk is essentially borne by ratepayers. LCG generally supports the Division and Committee argument but is willing to acknowledge that shareholders may continue to bear some risk though much less than would require compensation anywhere near the 36 percent share of the gain proposed by the Company. As identified by the Company, shareholder risk remaining after sale is the chance that regulators might not allow full recovery of high-cost replacement power or of reclamation costs should the new owner default and the mine reclamation obligation reverts to PacifiCorp.

a. Installation of Scrubbers/Threat of Plant Closure

Regulatory practice permits recovery of expenditures made at generating plants to meet clean air requirements. Under present circumstances, however, restructuring initiatives raise doubt about the continuation of the practice, as some states may not allow full recovery of new investment in scrubbers; scrubbers may not be deemed a stranded cost; and the power produced by the plant, more costly because of the added scrubber expenditures, may be less marketable in a restructured market. These are points in the Company's argument favoring sale: sale eliminates these risks.

If the sale does not occur, the Company informs us that, since not all owners agree to the necessary investments, the scrubber contract will terminate, and installation of the scrubbers will be delayed. Negotiations, requiring time, would be necessary to recommence scrubber installation or to consolidate ownership in order to remove objections to the investment. As a result, deadlines will not be met, and in the short term the plant will be forced to close. This is the Company's argument, which concludes with the assertion that, owing to environmental opposition to the plant, the longer the plant is closed the more likely it will remain closed permanently. Closure for any length of time will require purchase of replacement power, while permanent closure in addition will move forward the incurrence of mine reclamation expenditure. The result, the Company believes, would be costly to ratepayers and a poorer alternative for them than sale of the plant under proposed terms.

We must assess the risk to ratepayers if the sale of the plant and mine fails. The Division and the Committee dispute the plant closure assertions. Centralia, argues the Division, is a "must run" plant - there are times it must run for system reliability - and a valuable plant: it is, absent the coal issue, an efficient plant; it is strategically located; there are no barriers to movement of the power it produces; and its closure would immediately require large voltage support investments by others, notably the Bonneville Power Administration, in the northwest. BPA studies are cited to support the point. PacifiCorp presents no studies or claims to the contrary. Moreover, both the Division and the Committee assert that new generation plants are not coming on line fast enough to meet expected demand. Both parties conclude PacifiCorp is mistaken to argue permanent closure. Nor do we know how Washington state regulators might attempt to resolve a dispute among owners, which include political subdivisions of the state, over the means of bringing the plant into compliance with the state's air quality standards, particularly in light of the value of the plant and its apparent economic benefits to that state. We conclude there is little risk the plant will close permanently, though temporary closure is possible.

The Division conducts an analysis, contested by the Company for failure to consider material facts, purporting to show that permanent closure of the plant and mine have a net present value effect on revenue requirement that is less than the risk ratepayers will bear of higher cost replacement power when the plant and mine are sold. Because we have concluded that permanent closure is unlikely, we need not reach a conclusion on the merits of this dispute. The relevant remaining case is premature closure of the mine. In this case, the Division's analysis shows an effect that is much smaller than that of permanent closure, and much smaller than the risks we have determined ratepayers must bear after the sale of the plant and mine.

Complete replacement of Centralia mine coal with Powder River Basin coal is a suggested alternative to planned scrubber installation. Though full replacement of coal supply has not been presented to us with adequate analytical rigor, the Company reports that its studies support scrubber installation as the least-cost air quality compliance strategy. The economics, it asserts, of an alternative coal supply are not favorable and scrubbers would still be required. The record also shows that TransAlta had the option to choose another alternative but chose to continue with the scrubber installation as planned and to continue operating the mine. We conclude scrubbers, as planned, are reasonable for the continued operation of the plant.

In summary, we conclude the risk of permanent closure of the Centralia plant in the event the sale fails is low. Temporary closure, however, is possible. Should that occur, its adverse effects on ratepayers will be considerably less than the quantitative risks we have determined they will bear if the plant and mine are sold under the Company's proposal. This being so, our obligation is to determine what is necessary to compensate ratepayers for the risk they will bear following the sale.

We conclude that the qualitative risks posed by scrubber investment are of concern only to the extent that shareholders may not be adequately compensated for making the investment in an environment affected by restructuring initiatives, if the sale fails. We return to this below.

b. Reclamation Costs

The direct liability for reclamation costs is removed when the sale occurs, but PacifiCorp claims shareholders will nonetheless face some risk for reclamation after the sale should TransAlta default. While this risk has not been quantified, reclamation costs, the record suggests, could reach $200 million or more. Yet only $52 million has been accrued to date. The record does not suggest why apparently little, compared to the potential cost, has been accrued. Though reclamation cost is recoverable in rates, shareholder risk arises, the Company argues, not simply because it is underfunded, but, should the sale fail, and the plant is closed, incurrence of the reclamation cost is accelerated. The risk is that regulators might not approve full and timely recovery in rates. There is also a risk the other owners of the plant may default on their contract share of reclamation costs.

The record is clear that such risk is eliminated by the sale, leaving only the question whether an indirect liability, which is said to arise if the purchaser defaults, is a risk for shareholders, and if so, whether it is adequately compensated by the opportunity to earn the allowed rate of return. We return to this below. If the sale fails, however, we must consider the asserted risk that restructuring may adversely affect potential recovery of reclamation (and also scrubber) expenditures.

c. Relationship to Restructuring

The Company is concerned that required expenditure at the plant and mine occurs during a time when restructuring is under active consideration around the nation. In its view, this threatens recovery. The decision to sell the plant and mine, however, has nothing to do, the Company avers, with restructuring legislation in Oregon, which is merely coincident in time with the move to sell these properties. Sale does not indicate a Company policy, and one does not exist, states the Company, either to dispose of generation facilities or to vertically disaggregate its operations. Nevertheless, LCG urges us to carefully consider the approval decision which is the subject of this Docket because it could set a precedent for Utah regulatory treatment of stranded costs. LCG desires symmetry in regulatory consideration when asset sales yield a gain or yield a loss. PacifiCorp argues that we can and should reach a decision about the Centralia sale independent of this concern. The relevant issue restructuring raises, according to PacifiCorp, is that it is under active consideration today, even in Utah, that as a result utilities are avoiding ratebase additions, and it is the necessity of making capital expenditures in this uncertain environment that led PacifiCorp to sell Centralia.

The Committee argues that restructuring is not a certainty; many factors, such as changes in electricity prices, can affect what occurs. The Committee's general policy position is that ratepayers' interest is in retention, not sale of PacifiCorp plant, and that, in this Docket, the Company's assertion that Centralia is too risky to retain is an overstatement.

We believe restructuring may pose new concerns for regulatory treatment of investment. In this Docket, however, the decision to sell the plant and mine is a voluntary one. The risk associated with such a sale appears to be an ordinary business risk for which the opportunity to earn a reasonable rate of return is the necessary and adequate compensation. For this reason, shareholders are adequately compensated for any indirect liability that may remain after the sale is consummated.

By contrast, in light of the restructuring movement, future sales of plant may not be voluntary. The Company might also face an argument that in such an environment investment undertaken today may not be fully recoverable in rates. Though the question why a state would require an investment but disallow recovery would have to be addressed, this consideration may be germane if the Centralia sale fails. One aspect of it would be whether the allowed rate of return would, under restructuring circumstances, be adequate compensation for the risk of possible underrecovery of the scrubber investment and reclamation costs.

We have no record upon which to consider these matters and reach no conclusions with respect to them. If the sale fails, the risk of recovering reclamation costs and the investment in scrubbers may have to be considered in light of restructuring. Any such risk is on this record speculative, and the possibility of it does not alter our conclusion that the voluntary sale, with the regulatory treatment proposed by the Company, poses greater risks for ratepayers than if the plant and mine are retained, and far greater risks for ratepayers in either case than for shareholders. As we have stated, this means we must determine whether ratepayers can be compensated for bearing this risk. But the fact that a buyer is willing to purchase Centralia, pay a premium for it, and make the investments necessary to meet state air quality standards, is evidence that one entity, whose interests are material, believes cost recovery in a restructured environment is likely.

d. Joint Ownership Risks

PacifiCorp argues that conditions of management under joint ownership is a shareholder problem and risk. Public entities participate in plant ownership, and this requires specific governing provisions. Capital budgeting decisions must be unanimous, and current owners do not all agree to support the scrubber investment. The Committee and the Division both point to a standing offer by Avista, an owner of the plant, to buy out owners that oppose scrubber installation in the event the sale does not go forward, as an indication that joint ownership problems may be reduced if sale is not consummated. What is unambiguous on this record is the elimination of this risk when the sale takes place. If the sale does not occur, we believe plant management risk, even in the face of the joint ownership difficulty, is a business risk compensated by the allowed return on equity. We conclude there is no reason to pursue the Company's claim of joint ownership risk further: it is eliminated if the sale occurs and compensated if it does not.

In summary, our conclusions with respect to asserted qualitative and quantitative risks are as follows. If the sale occurs, qualitative risks are eliminated for ratepayers and for shareholders. We reject the Company's assertion that, after the sale, shareholders will bear a continuing, uncompensated, risk for reclamation costs because we believe any such risk is compensated as a business risk through the opportunity to earn a reasonable rate of return. If the sale fails, we find record support for a conclusion that the risks of joint ownership of the plant can be reduced if not eliminated. We cannot fully assess, though we do not dismiss, the Company's assertion that, in the event the sale fails, recovery of scrubber and reclamation expenditures are put at unusual and uncompensated risk by industry and regulatory restructuring. We do conclude, however, that any such additional risk is today a matter of speculation and does not rise to the level of importance and materiality that we find with respect to the risk ratepayers will bear following sale. There is only a possibility that recovery of these expenditures would ever be threatened or would ever arise as a shareholder problem. Aside from the possible effects on risk posed by restructuring, we conclude the risk that any such expenditures may not be fully recoverable in rates is a risk normally faced by the utility when regulators review expenditures for legitimacy and reasonableness, and one that is fully compensated by the opportunity to earn a reasonable return.

On the basis of the foregoing, we conclude that sale of the plant and mine, under the terms proposed by the Company for sharing the gain, is not in the public interest because the going-forward risks are almost entirely borne by ratepayers. All other risks, including those borne by shareholders, are either eliminated by the sale or substantially reduced by it. Under the Company's proposal, going-forward risks to ratepayers are substantial and unmitigated.

B. SHARING THE GAIN ON SALE BETWEEN RATEPAYERS AND SHAREHOLDERS

Our conclusion that quantitative risks are large and are borne almost exclusively by ratepayers, while qualitative risks are either eliminated by the sale, substantially reduced by it, or compensated as normal business risk by the opportunity to earn an allowed rate of return on investment, means that we must reject the Company's proposal to split the gain 36 percent to shareholders and 64 percent to ratepayers.

This proposed split has an appearance of objectivity through the use of the depreciation reserve method, an historical bookkeeping approach that splits the gain based on the percent of gross plant recovered from depreciation versus the percent of gross plant remaining undepreciated. Shareholders, argues the Company, own the assets, front the capital for them, and therefore have borne the risk of the investment in the plant and mine. Pacificorp believes shareholders are entitled to 100 percent of the gain, but, in the spirit of compromise, knowing such a position would be opposed, propose to split it. The proposal acknowledges that customers, over time, have repaid shareholders a portion of the up-front investment, but shareholders still bear the risk of recovering the undepreciated portion of the plant. In the Company's view, allocation of the gain between ratepayers and shareholders turns on which of them has borne and will bear risk.

As we recount above, the Division, the Committee, and LCG all testify that the only important risk after the sale is that associated with the cost of replacement power, and that this risk overwhelms any risk shareholders may continue to bear after the sale. All testify that the depreciation reserve method is flawed, that it produces an inequitable result, and that it should not be employed in this Docket. Though corrections to the Company's application of the depreciation reserve method are proposed by the Division and the Committee, in case we should accept the method, we find good reason on this record to reject it. It is therefore unnecessary to comment on the proposed corrections. Whether or not the method is flawed, our conclusions about risk make its use inappropriate in this Docket. We note that the gain is positive, the undepreciated value of the plant is recovered, and shareholders are made whole. There is no loss on the sale. What remains is the treatment of the amount in excess of that necessary to fully compensate shareholders.

Contrary to PacifiCorp's description of risk-bearing, record evidence leads to the conclusion that the important remaining risk occasioned by the sale is the going-forward risk of high-cost replacement power. The Company's assertions about large continued ownership risks associated with installation of scrubbers, reclamation costs, and plant closure have been examined. These risks are either eliminated or substantially reduced by sale. All considered, the principal burden of uncompensated future risk falls on ratepayers.

Therefore, given the facts in this Docket and as pertains to the purposes of this Docket, we reject the assertion that the undepreciated portion of book investment is a relevant risk measure. Based on the risk analysis discussed herein, we conclude that 95 percent of the gain on the sale should be given to ratepayers. This acknowledges some continued shareholder risk after the sale. We also note that the possibility of substantial gain for shareholders may provide an improper incentive to a regulated utility to sell assets valued above book value, to the detriment of ratepayers. Our analysis of the record suggests that 5 percent of the gain adequately compensates shareholders for risks they may continue to bear following the sale.

C. AMOUNT OF THE GAIN: PROPOSED CORRECTIONS AND MODIFICATIONS

Adjustments increasing the size of the gain are proposed by the Division and the Committee. The Division proposes three: correction of an arithmetic error, exclusion of transactions costs, and exclusion of an amount set aside for environmental contingencies.

PacifiCorp agrees to correct a computational error discovered by the Division. The error understates the gain by about $3.1 million. The proper figures for the correction and the gain itself await the completion of the sale. At that time, we will require PacifiCorp and the parties to submit a final calculation of the gain on the sale which includes the accepted correction.

PacifiCorp reduces the amount of the gain by the costs of bringing the sale to fruition, the transactions costs, for which among owners PacifiCorp bears 75 percent responsibility. The Division opposes this treatment unless it is shown that ratepayers materially benefit from the sale, and recommends exclusion of $4.2 million in transactions costs from the gain. Only the gain, argues the Division, is available to compensate ratepayers for the risk of high-cost replacement power. In the Company's view, this is at odds with the recommendation that shareholders receive none of the gain, and with its position that beneficiaries should proportionately bear transactions costs. We have concluded that the going-forward risk of high-cost replacement power, borne almost wholly by ratepayers, is the important risk engendered by the sale and accordingly award 95 percent of the gain to them. The equitable result, which we adopt, is recovery of transactions costs in proportion to shares in the gain on the sale. Hence, 95 percent of such costs will be recovered from the ratepayers' share of the gain, and 5 percent from shareholders'.

The final correction proposed by the Division is the exclusion of accruals for environmental contingencies. The Company would reduce the amount of the gain by about $5 million to establish a contingency fund intended to address a potential liability for cleanup of environmental problems which arise during a 15-year period and which have a cause traceable to the period of its ownership of the plant and mine. Shareholders, the Company testifies, take the risk if the amount required is greater than $5 million; the risk ratepayers bear is capped at the $5 million. Otherwise, contends the Company, ratepayers would face an open-ended liability during the 15-year period. The Division does not support this proposal. In its view, which it states is backed by Company studies suggesting that environmental cleanup risk is low, any future claims for recovery should be addressed if and when they arise. PacifiCorp notes that if this position is accepted, an adjustment must be made to exclude accruals made for environmental liabilities associated with the unregulated portion of the mine. Exclusion of the accruals should only affect the 47.5 percent of the mine that is in ratebase. Consistent with our decisions thus far, we conclude that 95 percent of the $5 million contingency fund amount, rather than 100 percent as proposed by the Company, should reduce the gain on the sale.

The Committee argues that any benefits of excess deferred taxes triggered by the sale should pass back to ratepayers. To do so, the Company responds, would violate rulings of the Internal Revenue Service, and on this basis it opposes the Committee's proposal. In past dockets, the Commission has stated an intention to return excess deferred taxes resulting from the transfer of assets if it can be accomplished without violating law or federal regulations. We will defer a decision on this issue to an appropriate future proceeding. We will require the Division to pursue this issue in that proceeding.

D. SHARING THE GAIN AMONG STATE JURISDICTIONS

Our conclusion that 95 percent of the gain on the sale must come to ratepayers as compensation for the future risks the sale imposes on them means that the Company's proposal to allocate just 5 percent of the ratepayers' share of the gain to Utah is inadequate. A 5 percent share of the gain is wholly inadequate given record evidence that this jurisdiction will bear approximately 35 percent of the going-forward risks.

PacifiCorp's proposal to allocate but 5 percent of the gain to Utah follows from its view of the importance of history. By its calculation, Utah customers have paid just 5 percent of the accumulated depreciation on Centralia. This calculation is based on interjurisdictional allocation methods employed since the merger between Pacific Power and Utah Power occurred in 1989, plus the application of the fully rolled-in method for the period following its adoption in April 1998 by Utah Commission order. Regardless of such history, and without according it decisionmaking significance, the Division argues that the 5 percent proposal is unfair. Five percent of the gain cannot compensate Utah ratepayers who must bear 35 percent of the risk. The Committee regards this as the crucial issue if sale is permitted, arguing that the

Commission should support the conclusions of the April 1998 Order on interjurisdictional allocations and allow Utah the benefits of the fully rolled-in method. Shareholders, the Committee recalls, agreed to bear all risk of interjurisdictional allocation disagreement as a condition of merger approval in 1989.

As we have repeatedly held, historical cost causation is an improper basis for interjurisdictional allocation of system revenue requirement. In the April 1998 Order, we reaffirmed that current, not historical, characteristics of cost causation are what count. That Order also explicitly rejects other allocation methods, particularly Modified Accord, which figure prominently in the Company's proposed allocation of the gain to states. Beyond this, a 5 percent share of the gain for Utah is not adequate compensation for the risk this jurisdiction's ratepayers must bear. On this basis, we reject the Company's proposed allocation. The Utah jurisdictional share will be about 35 percent, the precise amount to be determined by application of the fully rolled-in allocation method.

E. RATEMAKING TREATMENT OF THE GAIN ON SALE

Both the method and timing of ratemaking treatment of the gain are in dispute. The Company proposes to use the gain to offset the Yampa acquisition premium associated with the Company's purchase of Colorado-Ute generation plants. This is said to match the gain on sale against a premium paid for steam generation plants, to match the remaining life of Centralia to the undepreciated life of the Yampa assets, and to provide accounting ease with regard to interjurisdictional allocation issues. The result of the Company's proposal is an amortization of the gain by means of a reduction in rate base.

The Committee proposes to amortize the entire gain at the system level as a regulatory liability, by means of a reduction in rate base, and to allocate it in proportion to the allocation of generation plant in service. Although the Division recommends deferring the ratemaking treatment of the gain, if we decide to return the gain to ratepayers as an amortized ratebase reduction, like the Committee, the Division opposes tying it to the Yampa acquisition premium. LCG proposes to return the gain over a two-year period as a billing credit to Utah customers to mitigate both the Company's proposed rate increase in Docket No. 99-035-10 and any future increases. LCG argues that long-term amortization of the gain provides insufficient certainty that benefits will flow to Utah ratepayers.

To adopt the LCG position advocating a billing credit is to prejudge the outcome of current and future rate cases. We will not do so. Because ratepayers bear the risk of purchasing replacement power over the remaining life of the Centralia plant after it is sold, we conclude that amortizing the gain over the remaining life of the plant best implements the matching principle we employ in ratemaking. We further conclude that the gain must not be associated with a premium on previously acquired plant as the Company proposes, but should be separately recorded on a system basis in the year the transaction closes. Should restructuring issues such as stranded costs ever arise, the gain thus is readily identifiable. We expect to obtain in a future proceeding a complete record regarding final values, tax consequences, and other factors which are necessary to determine the amount of the gain subject to ratemaking treatment.

F. EWG STATUS

During the course of this proceeding, we issued an Order on December 20, 1999, granting PacifiCorp's Motion For EWG Determinations. This Order concluded, subject to approval in this Docket of the sale of Centralia plant and mine, that EWG status benefits consumers, is in the public interest, and does not violate state law. We now conclude that sale of the Centralia plant and mine is in the public interest, subject to the treatment of the gain on the sale we herein order, and should be approved. The December 20, 1999 Order granting EWG status is therefore final.

VI. ORDER

Wherefore, pursuant to our previous discussion, and the findings and conclusions made herein, we order:

- PacifiCorp's Application for approval of the sale of its interest in the Centralia plant and mine is hereby approved, subject to the conditions that follow.

2. The calculation of the gain and the associated accounting entries will be filed with the Commission upon completion of the sale.

3. The Division will pursue the excess deferred taxes issue in the next appropriate proceeding.

4. The gain is to be shared 95 percent to ratepayers and 5 percent to shareholders.

5. The Utah ratepayers' share of the gain will be determined using the rolled-in interjurisdictional allocation method.

6. The gain is to be amortized as an offset to ratebase not associated with any previous acquisition adjustment.

7. Implementation of the gain in rates is deferred to the next applicable proceeding.

8. The grant of EWG status is final upon completion of the sale.

9. Within 30 days of the issuance of this order, an aggrieved party may file a written request for review by the Commission. If such request is denied in writing within 20 days, or deemed denied by failure to grant review, the aggrieved party then has 30 days following such denial within which to petition the Supreme Court for review.

DATED at Salt Lake City, Utah, this 14th day of March, 2000.

/s/ Stephen F. Mecham, Chairman

/s/ Constance B. White, Commissioner

/s/ Clark D. Jones, Commissioner

Attest:

/s/ Julie Orchard, Commission Secretary