Response of Public Counsel Witness Jim Lazar
To Data Request of Puget Sound Energy

7) With regard to the testimony of Jim Lazar at page 4, lines 13-20, provide all documents that refer or relate to any public statements by you regarding the estimated life of coal plants generally or the Centralia facilities specifically.

Response:

See exhibit 502

See Lazar testimony in Colstrip, Docket UE-990267

a.) A copy of Mr. Lazar's testimony in Cause U-83-57 is attached; page 6 addresses the lifetime of Colstrip.

b.) A copy of Mr. Lazar's 1976 paper, entitled "Electricity for Washington State: The Relative Costs of Power Production -- Nuclear, Coal, and Oil" is attached. Page 12 addresses the life of plants.

c.) A copy of Mr. Lazar's 1984 paper, entitled "Should Utility Conservation Efforts Continue During a Surplus" is attached. Page 13 addresses the life of coal-fired power plants.

Due to Mr. Lazar's 23-year career in examining energy facility costs, there may be additional documents which are responsive to this request. If such are located prior to the hearing, they will be supplied as a supplemental response to this request.

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 507
ADMIT ☑ W/D ☐ REJECT ☐

SHOULD UTILITY CONSERVATION EFFORTS CONTINUE DURING A SURPLUS?

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Olympia, Washington
May 3, 1984

I
OVERVIEW

Between 1977 and 1983, most major Northwest electric utilities undertook programs to assist their consumers in installing and financing energy conservation measures. The efforts were largely initiated due to a perception that the region was facing probable electricity supply shortages, and conservation was determined to be an available, cost-effective, environmentally acceptable, and quickly obtainable resource.

As a result of greater than expected electrical price increases, lower than anticipated economic expansion in the region, and numerous other factors, the supply shortfall predicted by the regional utilities as recently as 1980 have been transformed into a regional surplus. The 1980 utility forecast for the region projected a shortfall of 3152 average MW for the operating year 1984-85 (1); in the 1984 utility forecast, this has transformed into a projected surplus of 1286 Average MW. (2)

This shift is even further underscored by inclusion of the assumption in 1980 that the WPPSS nuclear plants would contribute 1313 average MW during the 1984-85 operating year. (3) The 1984 forecast reduces this expectation to only 570 average MW. (4) The overall shift including the resource reductions, totals some 4816 average MW. Now, instead of promoting unconventional resources, the region is seeking export markets for massive amounts of excess power.

As a result of the transformation of shortfall into surplus, many regional policymakers have suggested that the conservation efforts initiated over the past five years should be slowed down or aborted altogether. This paper seeks to review some of the economic factors which should be considered if conservation efforts are to be reduced in the near future and to explore some of the underlying policy changes which have brought on the perceived surplus.

II

HOW DID THE DEFICIT TURN INTO A SURPLUS?

The entire discussion of the role of conservation during a surplus cannot exclude a discussion of where the so-called surplus came from. The region geared for energy deficits for a decade -- developing conservation programs, paying hundreds of millions of dollars in rate increases for thermal power plants, approving the regional act, and adopting electrical energy curtailment plans. Then, one morning in 1982, the utilities suddenly started projecting energy surplusses.

The startling turnaround in the regional load/resource balance was the result of a combination of important factors. Some of these are economic, while others are the result of changes in utility philosophy. Most had been predictable at the time that the 1980 utility forecast was made; critics of utility forecasting made their concerns known in many forums.(5)

Between 1980 and 1984, the nation and the region went through a very severe recession. The reduction in industrial development, population growth, residential construction, and commercial expansion all contributed to the reduction in load growth during this period. Record high interest rates were considered responsible for the underperformance of the major regional industries -- forest products, transportation equipment, and nonferrous metals.

In addition, electrical rates during this period soared dramatically. In 1979, the Bonneville Power Administration was selling wholesale power to public utilities and aluminum companies for 4 mills/kwh; by January of 1984, this had increased to 23 mills/kwh and 26 mills/kwh respectively, increases of 475% and 550% respectively. (6) At the retail level, rates for public and private utilities also soared; in the case of Puget Power, the largest electric utility in Washington, average residential rates rose from less than 1.8 cents/kwh to 4.4 cents/kwh, an increase of 26 mills/kwh, or a larger absolute increase than even the aluminum industries received. (7)

Most of the increase in power rates was predictable -- resulting from expenditures as planned in the utility construction budgets. In fact, the private utilities continually reduced their construction budgets during this period, due to both the deferral of the Skagit and Pebble Springs projects, and to the lower rate of distribution system expansion needed to serve the lower than predicted customer growth.

Had construction on new nuclear plants gone forward as scheduled, rate increases would have been even larger than we have experienced. Puget Power, for example, anticipated having not only the Skagit and Pebble Springs plants under construction, but planned eight additional nuclear plants as well. (8) However, the utility forecasts of the period did not anticipate rate increases of nearly the magnitude which has been observed, and consequently, these forecasts underpredicted the level of price response.

One of the more significant changes, however, is a simple change in how the load/resource balance is computed. In 1980, the "doom and gloom" predictions of shortages offered by the utilities always looked at the difference between total resources of the region, measuring hydro output under critical water conditions, and the projected total load, including a "planning reserve." By 1984, two changes had occurred: the "energy reserves" included in the projected load have been cut in half, and the "non-firm" or interruptible portion of the regional load has been excluded from the projected load/resource balance.

The impact of these two changes is fairly significant. In 1980, the projected load for 1984-85 included 299 MW of energy reserves, and 1331 MW of interruptible load. (9) By 1984, the energy reserve had dropped to 142 MW, and the interruptible load (no longer included in calculating the load/resource balance) was down to 739 MW. (10)

Absent these two calculation changes, the PNUCC forecast would still be predicting the region to be facing shortfalls. If the past projection of interruptible load, plus the difference between the former and current reserve requirements are added to the regional load for the 1984-85 operating year, the surplus of 1286 MW quickly becomes a deficit of 202 MW. Even if the current interruptible load is used, the surplus is reduced to 390 average MW, which is to be considered near load/resource balance.

The changes in analytical technique are probably improvements over past policies, given the reality that providing energy from new expensive resources to serve interruptible load is far from cost-effective. On the other hand, if that load can be served with low-cost energy sources, then it may be logical to still treat this load as a portion of overall regional requirements. However, the change from deficit to surplus must be looked at as being at least partly semantics; if the arithmetic were still being done as it was in the past, the surplus would not exist.

Another major change is that the PNUCC is no longer the only forecast which the utility and regulatory community rely upon. Bonneville and the Regional Council both now prepare independent forecasts of regional requirements. (11)

Untenable Assumptions Included in the Utility Surplus Forecast

The forecast of a firm power surplus is based upon several untenable assumptions. First, the long-term surplus now being used as the basis for persuing long-term surplus sales agreements with utilities outside the region, is based on the assumption that WPPSS nuclear plants #1 and #3 are completed, in 1991 and 1989 respectively. (12) Even if this were possible financially, it might not be advantageous economically, if conservation or other resources are available at lower cost.

If, as is expected, revenue from surplus power sales outside the region, or from non-firm sales of power within the region fail to recover the incremental cost to complete and operate the WPPSS plants, then completion must be considered uneconomic.

Present plans call for operating the Hanford N-reactor through 1993. The cost of fuel for this plant is extremely expensive -- as much as 50 mills/kwh. The bulk of this cost, however, is paid by the Department of Defense, as the plutonium produced in the N-reactor is owned by DOD. Whether this plutonium production should be considered an economic benefit, or an environmental cost, is beyond the scope of this paper. If, in fact, the plutonium does not have economic value, then early displacement of the N-reactor by lower-cost conservation would be beneficial.

In addition, the utility forecast assumes that the thermal plants which are completed operate at capacity factors of 70-75% after the initial years of operation. While this may be justified for coal plants (13), it cannot be justified on the basis of historical experience for nuclear plants.

The overoptimism of the utility forecasts of thermal plant performance is offset to some extent by the fact that this forecast is based upon hydro capability under critical water conditions. Numerous analyses have questioned the wisdom of planning baseload resources to meet rare water conditions (14), and this conservatism, compared with an analysis of shortage costs, may well not be economically justifiable. This paper is not intended to address this crucial issue; the Author, however, is a member of the Northwest Power Planning Council's Options Evaluation Task Force, which is looking at shortage costs in comparison with the cost of resource planning certainty.

If the N-reactor, together with WPPSS #1 and #3 plants are removed from the utility load/resource balance, and the performance of the remaining nuclear projects is rerated to the 65% availability assumed by the Northwest Power Planning Council, the region faces deficits much sooner than under present assumptions. With these adjustments, the region would face deficits compared with total load in 1987-88, and compared with firm load in 1988-89, as tallied by PNUCC, a surplus of only 4-5 years. This compares with projections of up to a 15 year surplus without these adjustments.

The removal of WPPSS #1 and #3 are economic questions: can the region provide this energy at lower cost from other alternatives. The capacity factor adjustment is one which has been around for many years; PNUCC has reduced their expectation for large nuclear plants from 75% prior to 1983 to 70% in the current forecast; Actual performance of large nuclear plants to date has been far lower. Through 1981, nuclear plants over 1000 MW averaged only 58% capacity factors (15).

III

HISTORY OF UTILITY INVOLVEMENT IN CONSERVATION

In the second half of the 1970's, many studies were undertaken by the Northwest energy community to determine the amount of non-traditional resources which were economically feasible to develop. Without exception, these studies showed that massive amounts of conservation were possible, ranging up to the equivalent of 11 nuclear plants worth of power. (16) Most of these studies indicated that it would be possible to displace much of the thermal power plant construction which the utilities had programmed for the ensuing decade, including the Skagit, Pebble Springs, and the later WPPSS nuclear plants, Colstrip coal plants 3&4, and other projects which had not yet received names.

In response to these studies, and the utility forecasts of energy deficits, the major investor owned utilities, with the approval of the Public Utility Commissioner of Oregon, and the Washington Utilities and Transportation Commission, initiated residential conservation loan programs during 1978. The programs initially took the form of interest-free loans, with the utilities permitted to treat the investment during the loan period as any other investment -- included in rate base, with a rate of return on the investment allowed in the rates from all ratepayers.

Legislation followed in both Washington and Oregon to permit consumer-owned utilities to initiate similar programs. In addition, legislation in Washington was approved in 1980 to allow the private utilities a higher rate of return on conservation and renewable resource programs than for other supply sources, as an incentive to the development of these short lead time resources.

In December of 1980, Congress passed the Pacific Northwest Electric Power Planning and Conservation Act, which made conservation the resource of first priority in meeting the regions electrical energy requirements. With only a few exceptions, passage of the Act was endorsed by public and private utilities alike.

Under the Act, BPA developed conservation financing programs which were made available to all regional utilities willing to execute contracts with Bonneville. The terms of the contracts offered were attractive to most of the smaller "requirements" customers of BPA. The Regional Plan, as developed in 1983, includes some 5000 average MW of conservation to meet regional needs under high load growth conditions.

IV

CURRENT PROPOSALS TO DIMINISH CONSERVATION ACTIONS

Major utilities, together with both Bonneville and the Regional Power Council created by the 1980 Act, have advocated some reductions in current conservation efforts. The Regional Council, in their Regional Power Plan (17) has supported increased efforts to develop conservation capability in the commercial, industrial, and agricultural sectors, but diminished residential conservation. Bonneville's conservation budget over the next several years is significantly lower than would be needed to achieve all of the conservation in the regional plan.

The Public Utility Commissioner of Oregon has initiated proceedings to consider whether conservation programs should be reduced or eliminated, and whether rate design changes which encourage conservation should be reversed. These follow from a staff working paper, which suggests:

> "Now, however, the region faces a projected surplus of electric power and natural gas and relatively stable energy prices into the 1990's. As a result, there are several issues that need to be reexamined if efficient energy use and resource development are to be promoted in Oregon. These include: How actively should conservation be encouraged, and how should conservation programs be financed?" (18)

Puget Power, one of the first utilities to initiate an active conservation program, has shifted its advertising effort from marketing of conservation, to "image building" marketing of the "benefits provided by electricity." Bonneville, ostensibly in the name of "equity" declined to provide incentives to generating utilities sufficient to get them to join the regionally-financed BPA conservation programs; as a result, some 75% of the consumers in the region do not have these programs available, although the larger utilities are continuing to provide their own programs in many instances.

Perhaps most challenging to the role of conservation as a resource are the analyses suggesting that the region is entering a period of perpetually declining demand for electricity. These analyses, supported by short-run data indicating significant demand reductions, are being used by some as conclusive evidence that a "death spiral" has begun. The death spiral results when rising fixed capital costs caused by new power plant construction results in sufficient price response that diminished demand fails to provide needed revenues, forcing additional price increases, with accompanying further demand reductions, until a point is reached where the revenue requirement cannot be met at any price. (19)

The treatment recommended by death spiral theorists in most cases is aggressive marketing, discriminatory pricing, and conservation program cancellation. An analysis of the death spiral by the Northwest Power Planning Council staff has concluded that a regional utility death spiral is unlikely, and can be made even more unlikely by using the type of flexible planning incorporated in the regional plan. (20)

V

WHAT CONSERVATION PROGRAMS ARE STILL COST-EFFECTIVE?

If in fact the region is no longer facing the type of deficits previously forecast, we must inquire as to what types of conservation programs are still cost-effective. Clearly programs developed when BOTH new power plants AND conservation were thought to be required to meet regional power needs may no longer be appropriate. The cost which can be avoided by implementing conservation measures is no longer the total cost of a new power plant, but only the costs which can be saved by either terminating a plant under construction, or by deferring operation of a plant which has been completed.

Four types of conservation measures must be analyzed in the context of the current load/resource balance. First are those with extremely low costs, which are cost-effective compared with the operating costs of existing power plants. Second are resources with extremely long lives, such as building construction standards. Third are perishable resources -- those which will become unavailable if development is delayed. Finally, there are the "marginal" conservation resources -- those with relatively high costs. The following sections of this paper will examine each of these in turn.

Low Cost Measures

A conservation measure which is less expensive than the operating costs alone of a plant already in operation is clearly cost-effective. An example of such a measure -- retrofit ceiling insulation where none exists -- costs less than 10 mills/kwh in 1980 levelized dollars (21) and is therefore less expensive than the 10-30 mills/kwh fuel, variable O&M, and environmental costs for the region's coal plants. From a social perspective, it is beneficial to develop such resources, even if the coal plants remain idle, and no use of subsequent them is made at any point in time.

Retrofit resources falling into this category, based upon the analyses undertaken by the Regional Council in development of the Plan, include such residential retrofit measures as attic, wall, and floor insulation, water heat wraps, appliance efficiency standards, commercial building HVAC improvements, and certain irrigation system improvements.

Prospective measures meeting this test include most of the measures included in the Regional Council's Model Conservation Standards for residential structures -- with the exception of R-27 walls in zone 1, triple glazing in zones 1&2, and multifamily ceiling insulation over R-30 in zone 1. Most of the retrofit measures identified in the Council studies for commercial structures also meet this test.

Long Lifetime Measures

Conservation measures with extremely long lifetimes, where the majority of savings will occur beyond the currently projected surplus period, will likely retain their life-cycle cost-effectiveness, even though in the short-run the costs will exceed benefits. Potentially, any resource with an initial cost exceeding the variable operating costs of existing coal plants may fall into this category, so long as the lifetime of the measure significantly exceeds the duration of the projected surplus. Those which can most cost-effectively be developed now should be continued.

The best example of long life measures are the remaining Model conservation standards included in the Regional Plan. The cost of meeting these additional standards may well exceed the benefits to the region in the early years of implementation. However, residential structures have typical lifetimes of 50-80 years, and the benefits of efficient construction will far outlive the current surplus (and in fact, will outlive power plants now entering operation, based upon the assumed 30-35 year operating lifetimes). The determination of cost-effectiveness for these measures, however, was calculated by the Council using an assumed 30 year structure lifetime (22), so the life-cycle cost-effectiveness is likely to be even greater than assumed.

As-yet undeveloped standards for commercial structures, industrial processes, irrigation equipment, appliance efficiency, water heating systems, and utility transmission and distribution efficiency improvements are also among those which fall into the category of long-life measures. Whenever new construction is undertaken, in any sector of the economy, the decisions affecting electrical energy efficiency should be based upon the life-cycle costs involved, looking both at the short-term period of surplus, and the long-term period when expensive new resources can be displaced.

Perishable Resources

There are some resources which must be developed as soon as possible, or the opportunities for ever developing them will be lost permanently. Most such measures fall into one of the two previous categories as well, but the special characteristics of such resources should be identified. Those measures which are both perishable and cost-effective should be developed now; obviously those which are not cost-effective should be allowed to perish quietly.

Foremost in this category are residential conservation retrofits. Families faced with high electric bills will respond to those bills in whatever manner appears best to them. Some will make relatively poor investments, in measures offered by unscrupulous businesses, which provide either comparatively poor economic benefits or create adverse health consequences. Included in this category are heat pump retrofits, wood stoves, kerosene heaters, and various technological contraptions which provide little or no benefit at all (23). There is a clear regional benefit to minimizing the amount of money spent unwisely on such measures; regional conservation financing for measures which are dependable, cost-effective, and environmentally benign, may obviate much of the inefficient allocation of capital resources associated with certain relatively poor conservation investments.

In addition, many consumers, responding to high electric bills, will purchase suboptimal conservation measures in the marketplace. The research of the Regional Council indicates that residential retrofit levels of up to R-38 ceilings, R-30 floors, and triple glazing are cost-effective over their lifetimes, compared with new generating resources. However, a family looking only at their own benefits (rather than the regional savings), and utilizing a comparatively high individual discount rate, may choose to install lower levels of weatherization. Some in the region have advocated exactly this laissez-faire approach to regional conservation, entirely avoiding the need for utility investments in conservation.

There are two major problems with "allowing the marketplace to work." First, experience with utility conservation programs clearly indicates the need to provide quality control over contractors, to insure that consumers actually receive what they pay for. Second, and probably more important, is the fact that the "market" for conservation is far from perfect. Consumers are not buying undifferentiated products with perfect information.

The problem with an imperfect market is that consumers will tend to "cream skim" the most cost-effective measures, which may not be optimal from a regional long-run perspective. The installation of "halfway measures" in response to price may permanently deprive the region of certain amounts of cost-effective conservation. A consumer installing R-30 ceiling insulation, or single glazed storm windows may be taking a cost-effective step to reduce their own heating bill. From a regional perspective, however, it would be even more cost-effective to have installed R-38 ceiling insulation, or double-glazed storm windows. As an example, research for the Power Council showed that the incremental cost of installing double-glazed storm windows over single glazed storm windows as $256, while the cost of going back to do a second retrofit would be $756. As a result of these cost differences, it may never be cost-effective to return to the structure a second time to make the incremental upgrades in the future. As a result, the region will lose the potential resource permanently.

In addition, both the Regional Council and Bonneville have supported the notion of "capacity building," the development and testing of new conservation programs in limited scale, in order to work out the bugs before wide-scale implementation efforts begin in a few years. Furthermore, it is recognized as important to continue efforts in order to prevent the deterioration of the conservation infrastructure which has been developed in recent years, consisting of auditors, contractors, material suppliers, and inspectors.

The magnitude of consumer-initiated conservation is very substantial. Two major studies of residential structures in the region have concluded that initial conservation measures have taken place in the absence of regional financing incentives. (24)

The table below shows the amount of conservation in each cost range identified by the Regional Council for retrofit measures in electrically heated residences constructed prior to 1980:

TABLE 1
RESIDENTIAL RETROFIT POTENTIAL BY COST STRATA (25)
(costs in levelized 1980 mills/kwh)

COST RANGE (MILLS)	ENERGY SAVINGS AVAILABLE (AVERAGE MEGAWATTS)
0-10	631
10-20	386
20-30	152
30-40	109
40-50	45

Most of the measures which consumers have typically invested in fall into the first cost strata. This cost range for zone 1 (where most of the region's population lives) includes wall insulation, ceiling insulation up to R-30, and floor insulation up to R-11.

Of all the measures which consumers have typically installed in response to price, only single glazed storm windows fall into the next cost strata, at 19 mills/kwh. However, consumers installing all of the measures in the first cost strata will make it difficult, if not impossible, for the region to ever justify returning to the structure to make the upgrades to the maximum level which is regionally cost-effective prior to the beginning of the retrofit process. One requirement of the Regional Plan was that consumers install all measures which are cost-effective to the region and structurally feasible in order to obtain any financial assistance. (26) This provision is aimed directly at reducing the amount of "cream skimming" which results when suboptimal conservation measures are installed.

For example, where a home in zone 1 has already installed storm windows, the cost of upgrading from double to triple glazing is 64 mills/kwh (1980 levelized), or more than the cost of completion of WPPSS #3; however, if an installation from single to triple glazing is made at one time, under a regional program, the cost of the incremental pane of glass above double glazing is only 17 mills/kwh. (27)

In developing the Regional Plan, the Council assumed that 56% of the conservation in the 0-10 mills/kwh category had already been developed by consumers, along with 34% of available 10-20 mill/kwh conservation, and 10% of the 20-30 mill/kwh measures. (28) This suggests that nearly all of the conservation in the upper cost stratas may be lost as a result of inaction by the region to secure these resources, as halfway measures make subsequent development uneconomic. As much as 400 MW in residential retrofit conservation alone may be at stake -- enough to displace a 1240 MW nuclear plant operating at a 65% capacity factor, assuming 10% line losses.

Another kind of resource perishability exists in certain parts of the commercial, industrial, and agricultural sectors. The failure to improve the efficiency of certain of our employers may make them uneconomic in the marketplace. While other manufacturers in other parts of the country may have financial incentives to implement conservation measures, lower retail electricity costs in this region may not justify these types of investments. Since the Northwest has much higher average labor costs than other parts of the United States (29), the mix of labor and energy costs is different.

However, looking at the marginal cost of additional resources, this region is little different from any other. As a result, regional cost-effectiveness tests may be much different that those of individual industries. As with residential consumers, businesses will typically apply a much higher implied discount rate to their decisions than the region does in constructing generating plants.

By making regional investments in energy productivity, the region may be able to preserve employment opportunities, in addition to providing a cost-effective source of power for the region as a whole.

The issue of perishability is perhaps the most important reason that the region should consider investing in conservation in spite of any perceived surplus.

Wood Stoves and Other "Quick Fixes"

Some consumer actions in response to price may not be cost-effective, either to the consumers or to the region. An aggressive program developing resources which are cost-effective can help prevent inefficient allocation of resources by less-than-knowledgable consumers. This may be termed the "consumer protection" role of utility conservation programs.

Many consumers in the region have installed wood stoves or other measures which provide at least a perception of significant savings on heating costs. Wood stoves in particular are credited with significant amounts of substitution for electric heat use. The problem with such measures, from a resource planning perspective, is that the energy savings produced can disappear even more quickly than they appeared.

During the recent recession, the price of wood dropped in real terms. In 1980, Western Washington newspaper advertisements carried typical prices of $55/cord of wood ($2.75/MMBTU). By 1983-84, the price had risen only to $60/cord ($3.00/MMBTU). Applying a consumer price deflator to the 1984 figure, the 1984 price of wood was $50/cord in 1980$ ($2.50/MMBTU).

However, with rising employment and real per capital income, and stabilizing electric rates, as forecast by both the utilities and the Regional Council, the attractiveness of wood heat will diminish. In addition to changing perceptions of cost, the time required to feed a wood stove, the inconvenience and mess, and the less controllable heat provided, make wood heat a potentially less attractive energy source over time.

In the event that consumers choose to return to using electric heat, they may do so at any time without warning to the utility. The distribution facilities are in place, as are the electric furnaces or baseboard heaters. As a result, it is possible for wood stoves to have the effect of reducing power demand during the period of the surplus, and then have the demand quickly return after the surplus is over, creating compound problems for utilities. The unprecedented peak load in this region during the December, 1983 may have been due in part to wood heat users supplementing their primary energy source with electric heat in underinsulated homes.

Implementing conservation measures during the surplus has two advantages for utilities. First, once homes are insulated, consumers may have less incentive to use wood heat, thereby preserving the electric heating load (albeit at a lower level) during the period of surplus. Second, it will insure that if and when the electric heat load returns to the system, the load will be more predictable and manageable.

Other "quick fixes" may fall into the same-category. Thermostat setbacks, shorter showers, and other lifestyle changes which result in lower electricity consumption are all subject to deterioration over time. In recognition of this factor, the Regional Council recommended that inverted electric rates be implemented in order to "minimize thermostat creep." (30) Supplemental charges for increased usage in dry years could also serve to keep thermostats down and wood heat users off of the system in a more predictable manner. (31)

By substituting technological improvements for quick fixes, the region can insure that loads which "disappear" from the system do not reappear without warning. This issue is discussed further in the section below on "Planning Certainty."

VI

HIGH COST CONSERVATION MEASURES -- CANDIDATES FOR CUTBACKS

Some of the conservation measures included in the Regional Plan, or advocated by other conservation analyses (32) are comparatively high in cost. For example, in the residential sector, heat pump retrofits, heat pump water heaters, and solar water heaters, have much higher costs per unit of energy saved than most of the conservation measures included in utility conservation programs. In the commercial sector, triple glazing and resizing of ducts may fall into this category. The cost-effectiveness of these measures were initially determined by comparison with the total cost of new power plant construction. In light of current circumstances, these measures are appropriately subject to renewed scrutiny.

As an example, heat pump water heaters were determined by the Council to be cost-effective for larger households, but not for smaller units, as the greater hot water consumption of large households justified the higher capital costs of the units. In all household sizes, however, the cost of energy saved was greater than 20 mills/kwh saved. Such measures cannot be justified solely on the basis of short-run variable cost savings from leaving coal plants idle.

In addition, heat pump water heaters have relatively short life expectancies, of between 8 and 15 years. As a result, the long-run savings that come from programs like the Model Conservaton Standards, are not present for all conservation measures.

Measures with relatively high cost, and short lifetimes, such as street lighting retrofits, may also be non-competitive. The current BPA program for street lighting is particularly subject to such criticism, as it allows conversion to high pressure sodium lighting, when in fact, over the long run, low pressure sodium retrofits may be most cost-effective. The existing program may be viewed as implementing a halfway measure.

Such high cost conservation measures can be justified economically only if the benefits of implementation in the current time frame exceed the costs. Since this is not likely to be true from a strictly short-run analysis, it is critical that the region investigate the long-run savings due to displacement of the operation of existing thermal power plants. Such savings include not only variable fuel and O&M costs, but also extended plant lifetimes, environmental costs, and the benefits of planning certainty. The next section of this paper seeks to quantify some of these benefits.

VII

ADDITIONAL CONSIDERATIONS FOR CONSERVATION DURING A SURPLUS

Long Run Savings Due to Thermal Plant Displacement

When additional conservation measures are implemented during a period when existing power plants are capable of meeting current demand, the operation of themal plants can be displaced. Such displacement allows either of two options for utilities. Either the plants can be allowed to sit idle, or else the plants can be operated for the export market.

Currently, utilities generally make the decision between these two options by looking strictly at short run incremental running costs. If the export market will support a price which exceeds the running costs of the power plants, they are operated, and the power exported. This behavior appears to be contrary to sound economic principles.

Power plants have finite lifetimes. The generally accepted lifetime of a coal plant is about 35-40 years. Many thermal plants have operated for much longer periods of time than this. This is due in part to the fact that they are used only sporadically. For example, Puget Power's Shuffleton oil-fired plant, located at Renton, was built in 1930, but is currently in "excellent condition" according to the Company. (33) The Black Hills Power and Light Company operates three coal-fired units at their Osage plant, all built more than thirty years ago; in 1983, these units operated at a combined capacity factor of over 62%. (34) The availability of surplus energy from the Northwest, frequently at costs lower than the price of coal, has enabled Black Hills to displace operation of these units from time to time.

The same theory is not likely to apply for nuclear plants. First of all, nuclear plant lifetimes are expected to be limited due to radiation-induced problems, including the potential that radiation levels may become too high for plant maintenance workers to perform needed tasks. In addition, metal embrittlement may limit the lifetime of nuclear plants regardless of the period of operation. Finally, regulatory uncertainties make it speculative to suggest that leaving a nuclear plant idle will extend the plant lifetime. The Regional Council has treated nuclear units as "nondispatchable" for the purpose of their economic evaluations; this paper does not suggest any other action is appropriate.

Presently, regional utilities typically operate their coal-fired plants at any time that the market will sustain a price which covers variable costs and provides any positive return at all to fixed costs. Individuals faced with the opportunity to allow their own capital facilities to be used for the benefit of others in exchange for payment of little more than variable running costs alone generally do not exercise the opportunity.

For example, if I take a week-long business trip by air, and leave my car idle during that period, am I likely to allow a stranger to take a cross-country trip in my car, even if she agrees to pay for all the gas, and buy me a couple of tapes for the cassette deck in addition? Obviously not. I am relatively unconcerned by the fact that my capital investment in the automobile sits idle.

This is because I know that the car will last only 100,000 or so miles, and must be replaced at the end of that lifetime, and in addition, I know that there are certain periodic maintenance costs, such as tires and tune-ups, which may not coincide in time with the stranger's use of the car. I have both fixed maintenance costs and replacement costs to consider, in addition to variable running costs.

Frankly, I'd rather let it sit in the driveway until I need it, and then use it myself to meet my own transportation needs. The same theory may apply to a coal plant.

For a utility, however, regulatory incentives work against this approach. Since a utility's captive ratepayers are generally paying for the capital costs of a power plant, but the utility's profits are determined on the basis of current revenues, the incentive for the utility is to operate the plant whenever a short-run profit results. A change in regulatory incentives could change this result. For example, if the state commissions allowed recovery of the fixed plant costs only when resources were either needed to meet native load, or else taken out of operation entirely to save the plant lifetime, then utilities would have an incentive to minimize long-run costs, by extending plant lifetimes.

If, for example, a coal plant can last 60 years if operated only two-thirds of the time, rather than 40 years operating to the limit of its availability, then the region has the opportunity to delay the need to replace the plant by 20 years. Due to real cost escalation in power plant construction, the future savings, even after adjustment for inflation, may exceed the current marginal cost of power.

Assume, for example, if the replacement costs of a coal plant are currently 50 mills/kwh, of which 40 mills are capital-related. Also assume that real escalation for coal plant construction is running at 2% annually. With this information, we can calculate that the future savings due to plant life extension by current non-opertion are approximately 60 mills/kwh, subject to any real discount rate which may be applied. We should not operate the plant unless we can recover our opportunity costs.

If implementation of conservation programs during a perceived surplus results in the opportunity to displace coal plant operations, the savings to the region may be much greater than the variable operating costs alone. Some credit, whether large or small, must be granted to reflect the extension of plant life. This credit, however, is subject to substantial uncertainties.

If the expectation is that the resource will eventually have to be replaced by another coal plant, and real escalation is expected, it may be appropriate to use more than the current replacement cost of the plant as the "opportunity cost" of running the plant to meet current load, either local or export. If, on the other hand, technological innovation is expected to make the ultimate replacement costs lower (fluidized bed combustion, photovoltaics, or other possibilities), then it is appropriate to apply a real discount factor to the current replacement costs.

In any event, however, unless technological innovation is expected to make ultimate replacement equal or lower in cost (in constant dollars) than the variable running costs alone, then some value must be assigned to the capital depletion which can be avoided through the implementation of conservation measures during a surplus.

In addition, substitution of conservation for generation brings environmental benefits to the region. These benefits, of 2 to 200 mills/kwh compared with coal generation, may be thought of more properly as short-run benefits, to be added to the displaced variable costs, in determining which conservation measures are cost-effective even in a strictly short-run analysis. (35) Inclusion of these costs in any analysis, either short-run or long-run, will enhance the attractiveness of conservation during the current perceived surplus.

Planning Certainty Benefits

One benefit to utilities and energy planners of the implementation of conservation measures on an accelerated schedule is the planning certainty which results. The cost of uncertainty has been observed in the region, through the cancellation of some $3 billion in unfinished power plants, and the mothballing of yet another $4 billion of investment.

With aggressive programmatic conservation implementation, the region will be spared the need to estimate how much conservation will result from price response. The evidence from Hood River, from the water heater wrap program, and from other efforts in this region and elsewhere, is that consumers willingly participate in fully funded conservation programs. Therefore we can be assured of having certain resources on line, and the measure of planning uncertainty we currently face will be reduced.

The amount of conservation which is available in the residential space heat sector alone, which has not yet been obtained through price response, is equal to the projected delievered output of WPPSS #3. (36) The capital cost of that conservation has been estimated at approximately $2.5 billion (1980$); this is significantly lower than the present value of the remaining capital and operating costs for completion WPPSS #3, of approximately $4 billion. (37) The economic savings alone from that planning certainty are worth paying for.

With respect to conservation standards for new construction, the benefits from planning certainty are even more valuable. For example, assume that the region expects between 500,000 new homes and 2,000,000 new homes over the next 20 years (the approximate range of the Regional Council's forecasts). Assume further that with current efficiencies, the average refrigerator in those homes will use 1200 kwh/year, but with appliance efficiency standards in place, they will use only 600 kwh/year.

Without the appliance efficiency standards, the region is looking at an additional load for refrigerators of somewhere between 600 million kwh/year and 2.4 billion kwh/year (68-274 average MW); with the appliance efficiency standards in place, this range drops to between 300 million kwh/year and 1.2 billion kwh/year (34-137 average MW). The range of uncertainty, for which other resources must be planned or optioned, drops from 206 average MW to 103 average MW. The reduction in the band of uncertainty greatly reduces the probability that expensive long lead-time resources will be initiated, but not needed. The currently projected 5 year surplus period represents 25% of the planning period in the above example.

With the inclusion of other energy-consuming appliances, the reductions in the range of uncertainty will obviously be much greater -- refrigerators use only about 8-10% of average home electricity usage. Building shell standards, water heater standards, and other measures promise even greater benefits.

Perhaps the greatest planning certainty comes from the fact that conservation measures are far more reliable that power plants. The probability of all of the attic insulation, storm windows and water heater wraps in the region failing simultaneously is nonexistent. One the other hand, a large nuclear plant can be expected to be forced out of service without warning from time to time. The contribution of each to our energy supply is approximately equal.

This additional planning certainty is valuable and quantifiable.

Capacity and Energy Analysis --Seasonal Characteristics

Most conservation analyses by Bonneville, the Regional Council, and others have focused narrowly on the annual average energy savings associated with such measures. Conservation measures bring another set of benefits: most of the savings are obtained during the period when electricity use is highest, i.e. during the Winter heating season. As a result, both the seasonality of energy savings, and the reductions in capacity requirements, should be considered in evaluating the cost-effectiveness of conservation resources.

The conservation measures in the Model Plan of the Northwest Conservation Act Coalition for new residential structures were estimated to reduce peak load by 4 kw for each average kw of energy reduction.(38) In the Regional Plan, the seasonality of energy savings were clearly shown, ranging from 100 kwh/month in July to 2000 kwh/month in January. (39)

The capacity savings of some measures are smaller than others. Irrigation system improvements, while potentially cost-effective, provide only Summer savings; heat pumps, solar water heaters, and commercial HVAC improvements may provide less valuable savings. Residential weatherization, however, provides very significant capacity savings. Woodstoves may provide excellent seasonal savings, but may be displaced by electric heat when weather conditions are extremely adverse.

The peak capacity and seasonal benefits of most conservation measures are twofold. First, there are the direct reductions to the costs of meeting power supply requirements which result from the fact that conservation reduces capacity requirements by a greater amount than energy requirements, thereby improving the system load factor, reducing the need for construction of peakload generators, and reducing transmission and distribution costs. These economic savings are above and beyond the savings associated with the energy requirements which are displaced.

In addition, however, the reduction in seasonality of regional loads assists the region in meeting the requirement in the Regional Act to protect, mitigate, and enhance the region's fisheries. By reducing winter loads by a much greater amount than summer loads, and displacing thermal plant construction, the ultimate result is greater dependence upon hydro-generated electricity during the spring and summer months. By maintaining river flows at higher levels, downstream migration of juvenile salmon is enhanced. (40) To quantify these benefits would require extensive analysis; however, it is evident that these savings are not insignificant.

Finally, most of the region's major utilities are projecting expenditures for transmission and distribution system improvements which exceed their expenditures for generation over the next decade. The capacity-related reductions in these expenditures which could be achieved through conservation

VIII

EQUITY IMPACTS OF CONSERVATION PROGRAMS
The "No Losers Test" - - - Low Income Effects

One reason often given for reducing utility contributions for conservation are so-called "equity" considerations. During the current surplus, one customers conservation reduces the utility's revenue by a greater amount that it reduces cost. As a result, other consumers must face rate increases. During the last Bonneville rate proceeding, the allocation of the "unrecovered cost of the surplus" was a hotly contested issue.

The staff of the Public Utility Commissioner of Oregon raises these equity issues in their discussion of potential changes to current conservation policy. They suggest that the "marginal cost" to be used in determining conservation resource cost-effectiveness should be reduced to reflect a melding of short-run marginal costs for the duration of the surplus, and long-run marginal costs thereafter. (41)

Traditionally, the conservation programs of the private utilities have utilized a so-called "no losers test" in which the amount of financial assistance provided to a consumer to conserve is no more than the difference between the present value of the cost of new resources to serve a load, and the present value of the anticipated retail revenues from doing so. This approach is said to ensure that non-participants are made no worse off as a result of the programs. However, in observing this so-called "no losers test," the incentives provided have typically been significantly smaller than the total cost of the programs, and participation has been less than enthusiastic in many cases. (42)

Low participation rates mean that conservation is underdeveloped as a resource. The result must be the development of higher-cost generating resources, resulting in a misallocation of society's scarce capital resources. Even during the surplus, since most of the retrofit measures in utility programs are lower in cost than the running costs of coal plants, or the replacement costs associated with operation of those plants, there is a misallocation of resources.

The potential benefits in equity from the "no losers test" have been demonstrated to be minor in comparison with the massive losses in economic efficiency which results from underdevelopment of conservation. As a result of this analysis, one study by a consumer group of low income and senior citizen ratepayers renamed the underlying criteria used by utilities as the "hardly any winners test." That analysis concluded by stating:

> "The potential for billions of dollars worth of efficiency improvements through providing adequate conservation incentives must not be compromised to save a few million (or even a few hundred million) dollars worth of equity." (43)

One regional example of aggressive conservation, the Hood River demonstration project supported by Bonneville, has shown that consumers will willingly participate in fully financed programs. The fact that nearly 100% of consumers need some sort of conservation retrofit suggests that all consumers do share in the benefits of aggressive implementation.

There are additional macroeconomic benefits. A society with lower energy costs will be able to reinvest a larger amount in its own economic vitality. Conservation programs are relatively labor-intensive, relative to the construction of generating plants, leading to more pronounced multiplier effects within the local economy.

Bonneville claims to have bypassed the "no losers test" in establishing their conservation programs; however, the incentive which BPA provides, of some 29.2 cents/annual kwh, is only about one third of the incremental cost to complete and operate WPPSS #3, which is the obvious "marginal resource" for their analysis. One can only conclude that BPA is holding down the incentive in order to assure some kind of equity.

The equity which results, however, is of a very dubious nature. Partial financing means that the recipient of the conservation must provide some "up front" capital when the measures are installed. In the absence of utility financial assistance, low income ratepayers and renters will have essentially no access to conservation. Even with partial financing, such measures are typically unavailable to low income individuals or to renters. Innovative programs by Puget Power and Snohomish PUD have attempted to address the problems of low-income homeowners, but in spite of directives in the Regional Plan, Bonneville has failed to create workable programs for renters.

Since low income and renter ratepayers must share in the cost of new thermal resources, their electric rates have increased significantly in recent years. Their inaccessibility to conservation programs means that they have been unable to combat those higher rates with lower consumption. If, in fact, there is an "unrecovered cost of surplus" being allocated to electric power purchasers, those costs, together with thermal power plant costs, are being disproportionately borne by low income ratepayers and renters.

At present, low income and renter ratepayers have the lowest levels of insulation in this region, although only about 2.5% of all residential consumers have totally exhausted all available cost-effective conservation opportunities.(44) As a result, they are the best candidates for cost-effective conservation investment. However, present policies deny these ratepayers access to capital for conservation; their own high implied discount rates make direct investment impossible; for renters, their short time horizons make the investment unjustifiable. The burden of policies developed to promote so-called "equity" appear to be falling on those who are least able to bear the burden.

Equity considerations have been, and are continuing to be misapplied in the determination of what energy conservation programs should be made available. The present surplus must not be used as a excuse to deny weatherization assistance to those who, for whatever reasons, have been unable or unwilling to participate in the limited programs offered to date.

IX

CONCLUSION

Utilities have expressed concern that the region is in a lengthy period of energy surplus. This analysis presupposes the continued operation of the Hanford N-reactor and the completion of WPPSS nuclear plants 1&3, none of which may be economically sound. A better economic choice may be to abandon these projects, and develop lower cost conservation in their place. Further, the surplus is to some extent a result of a change in calculation methodology, looking only at the regional firm load, rather than include interruptible customers in the load/resource balance.

The current trend of utilities to reduce their conservation investments is inconsistent with the long-range goal of minimizing regional energy cost. Most conservation measures are lower in cost that the opportunity costs which are incurred in their absence -- operation of existing coal-fired power plants, or completion and operation of new power plants, either soon or in the distant future.

Additional research is required to better estimate the opportunity costs associated with current operation of a coal plant. It is important to determine to what extent plant lifetime can be extended through deferred operation. If, in fact, the life of a coal plant is primarily determined by the number of equivalent years of operation, the region may be better served by removing coal plants from service, and substituting conservation.

Conservation resources which are of particularly low cost, are perishable, have long-operating lifetimes, or particularly good seasonal and peak load characteristics should go forward without delay. As much as 500 average MW of low-cost residential retrofit conservation may be permanently lost to the region as a result of halfway measures being installed by consumers in response to price, making subsequent additional retrofit uneconomic.

Some reassessment of higher-cost measures is appropriate under current circumstances, but any efforts to abandon cost-effective conservation programs due to a temporary supply surplus is likely to be counterproductive over time.

FOOTNOTES

1 Pacific Northwest Utilities Conference Committee; West Group Forecast, Table I-1 (March, 1980) [PNUCC, 1980]

2 Pacific Northwest Utilities Conference Committee; Northwest Regional Forecast, Table II-1 (March, 1984) [PNUCC, 1984]

3 PNUCC 1980; Table III-2

4 PNUCC 1984; Table II-7

5 See e.g. Natural Resources Defense Council, Choosing an Electrical Energy Future for the Pacific Northwest: An Alternate Scenario, January, 1977, and Comptroller General, Region At The Crossroads: The Pacific Northwest Searches for New Sources of Electric Energy, EMD-78-76, (August, 1978); Other studies critical of the utility forecasts were published in 1975 by Washington State University, 1976 by Seattle City Light, 1977 by Washington Public Interest Research Group, 1978 by Northwest Energy Policy Project, and 1980 by NRDC.

6 Bonneville Power Administration, 1983 Wholesale Power Rate Final Environmental Impact Statement, (September, 1983)

7 Exhibits of John Ellis and Bill Baker, Washington Utilities and Transportation Commission v. Puget Sound Power and Light Company, Cause U-83-58 (April, 1984)

8 Testimony of R. E. Olson, Corporate Treasurer, Atomic Safety and Licensing Board, July, 1979.

9 PNUCC 1980, Tables III-2; VII-20

10 PNUCC 1984, Tables II-5; IV-12

11 Northwest Power Planning Council, Northwest Conservation and Electric Power Plan, Chapter 4 (April, 1983) [Regional Plan]
Bonneville Power Administration, Forecasts of Electricity Consumption, (July, 1983)

12 PNUCC 1984, Table II-6

13 Actual capacity factors for Northwest coal plants have reached levels as high as 80% for smaller plants, and 70% for larger plants, as reported in Form 759 reports to the U.S. DOE Energy Information Administration for the years 1978-83;

14 People's Organization for Washington Energy Resources, Critical Water Planning and Northwest Electric Power Development, 1982

15 Northwest Conservation Act Coalition, WPPSS Nuclear Plant #3: Where Now?, Table V-4 (October, 1983)

16 See, e.g. GAO (op. cit) Tables IV-1c and IV-2c; also Northwest Energy Policy Project, Energy Futures Northwest, Final Report, Table 9 (1978)

17 Regional Plan, page 5-11

18 Economic Research Division, Public Utility Commissioner of Oregon, Cost-Effective Fuel Use and Resource Development in Oregon, (February, 1984)

19 See, e.g. Arlon R. Tussing, WPPSS Costs, the Price-Elasticity of Demand for Electricity and the 'Utility Death Spiral' in the Pacific Northwest, presented to the Conference on Utility Rate Economics, June 10-11, Seattle.

20 Northwest Power Planning Council, Issue Briefing: The Utility Death Spiral, Page 1 (April, 1984)

21 Battelle Pacific Northwest Laboratories, Assessment of Electric Power Conservation and Supply Resources in the Pacific Northwest, Volume 1, Residential Conservation, Table 2.9 (1983)

22 Regional Plan, appendix K;

23 The author is aware of an available "Molecule Energizer," which for only $199.95 provides an elegantly crafted anodized ducted aluminum box with four 75 watt light bulbs, an electric fan, and a deflector plate, which promises to "fill your house with energized air molecules," and somehow reduce heating costs. The device, obviously, is nothing but an entropy box, providing the same efficiency as any electric resistance heater.

24 Seattle City Light, Residential Consumer Characteristics Survey, (October, 1983) and Bonneville Power Administration, The Pacific Northwest Residential Energy Survey, (July, 1980)

25 Battelle, op. cit. Table 2.9

26 Regional Plan, Page 10-7, Item 1C

27 Regional Plan, page K-3; Battelle, op. cit., Table 2.9

28 Regional Plan, Page K-9

29 Washington State average manufacturing wages are 30% higher than the national average; Oregon and Idaho wages are 13% and 1% higher than average: Federal Reserve Bank of San Francisco, Western Economic Indicators, Number 4, 1983, page B-5

30 Regional Plan, page 7-14

31 Washington State Energy Office, A Provisional Power Plan, page 61 (November, 1982)

32 See, e.g. Northwest Conservation Act Coalition, Model Electric Power and Conservation Plan for the Pacific Northwest, Page 99 (November, 1982) [Model Plan]

33 Testimony of R.G. Bailey, Washington Utilities and Transportation Commission Cause No. U-83-58

34 Black Hills Power and Light Company, Form 10-K Report to the Securities and Exchange Commission, page 9 (December, 1983)

35 Environmental costs associated with major thermal plants remain under study. The results of the major analyses lie in the 2 to 300 mills/kwh range. See: Model Plan, Appendix 2 for an extensive discussion of environmental costs of thermal plant operation.

36 Regional Plan, table K-12

37 Northwest Conservation Act Coalition, WPPSS Nuclear Plant #3: Where Now?, Table VII-1 (October, 1983)

38 Model Plan, page 109

39 Regional Plan, figure 7-2

40 See: Romer Associates, Northwest Electric Load Shaping For Fish Enhancement, (November, 1981) included in: Recommendations for Fish and Wildlife Program under the Pacific Northwest Electric Power Planning and Conservation Act, Volume 2 (1982)

41 Public Utility Commissioner of Oregon, op. cit., Table 4

42 Montana Power Company reports that only one in four of their customers obtaining conservation audits has accepted conservation financing; Testimony of Pete Antonioli, Montana Public Service Commission Docket 83.9.67 (April, 1984)

43 People's Organization for Washington Energy Resources, The No-Losers Test is Really a "Hardly Any Winners" Test, (1982)

44 Bonneville Power Administration, The Pacific Northwest Residential Energy Survey, (1980)

ELECTRICITY FOR WASHINGTON STATE

THE RELATIVE COSTS OF POWER PRODUCTION

Nuclear, Coal, and Oil

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October, 1976

Selected Findings

1. If all types of electric power generators were able to operate at 100% of capacity at all times, nuclear power generators would provide electricity at lowest total cost.

2. If we attempt to measure the total cost of producing electricity, including the extra capacity required to insure output during operating failures, the cost of Coal produced electricity is unquestionably lower than that for nuclear plants.

3. Nuclear plants have much higher capital costs than do fossil fuel facilities, and the cost of providing the required additional capacity required for reliable power production are correspondingly higher.

4. Since most cost estimates for producing electricity were made, the cost of all types of fuel have skyrocketed. In the past five years, the price of uranium has increased by 500%, coal by 200%, and oil by 150%. This has driven the price of all three types of generation up substantially, but the effect has been relatively greater for nuclear generation than for fossil fuel plants.

5. Publicly owned utilities are permitted to raise their capital requirements through the issue of tax-free bonds. This serves to increase the attractiveness of capital-intensive production methods, as they are able to raise the necessary funds at rates considerably below fair-market rates. The difference between these lower rates and market rates is paid for by the taxpayers in general. As nuclear plants are more capital-intensive, this serves to bias the decision of such utilities in favor of this mode of generation, even if the total real costs are greater than for other available options.

6. Privately owned utilities operate as governmentally sanctioned and regulated monopolists. As a rule, the rate of return (profit) permitted to a privately owned utility is calculated as a percentage of invested capital. Therefore, in best representing the interests of its stockholders, the privately owned utility will prefer to choose methods of generation which are most capital-intensive. This decision is not necessarily the method which provides power at the lowest total cost. As this study discovers, the real cost of power generated by fossil fuel plants is lower than that produced by the more capital-intensive, and therefore more attractive, nuclear generation stations.

This study attempts to measure the relative costs of electrical power generation from three different types of generating facilities. Barring massive energy conservation, we shall have to increase our total supply of electricity in the Pacific Northwest during the next decade. We have several possibilities open to us; nuclear power is most often suggested by the utilities as the most feasible and least expensive alternative. Coal and oil fired power plants are both available as possibilities. Some persons have advocated the increasing use of wind and solar power, or, alternatively, disrupting power service to the electroprocess industries in this region as the need for electrical energy in other areas increases.

For the purposes of this study, it shall be assumed that nuclear, coal, and oil offer our only real alternatives. These technologies are all at a much higher stage of development than wind or solar generation. The possibility of disrupting power service to those industries holding firm and binding contracts must be dismissed as morally irresponsible, legally unfeasible, and economically counterproductive.

This study assumes that the demand for additional energy exists, and only attempts to measure relative costs. Most estimates of the relative costs of power generation assume that everything works perfectly at all times. Some modify this to some extent; very few actually evaluate real performance of generating units. The California Public Utilities Commission model[1] assumes that hydroelectric power plants operate perfectly at all times, while other methods are less reliable. Those of us in the Northwest, who depend upon hydro for nearly all of our power needs can clearly remember years of drought in which our power consumption had to be greatly reduced.

Nuclear power, the newest technology under consideration, has the worst reliability record of the available alternatives. As the figure 1 on page 14 shows, if all three alternaitives were perfectly reliable, and no sudden increases in prices were observed, the cost of nuclear power would be the lowest of the group. Unfortunately, the average output of operating nuclear generators is only 52.3% of rated capacity.[2] If we consider only the ten newest units, those installed since June, 1974, this figure goes up to 58%[3] of rated capacity. The ten most reliable units have an average output equal to 72% of capacity. This means that, on the average, we must build 1912 megawatts (MW) of capacity in order to have an expected output of 1000 MW. If we assume we are capable of duplicating the performance of our most recently built plants, this need goes down to 1724 MW. If we are able to duplicate our ten most reliable plants, this figure would decline even further, to 1382 MW. There is not a direct relationship between the most recent and the most reliable technology. It seems that nuclear plants have relatively low reliability for their first years of operation, then build up to a higher level, and finally decline after ten years of operation. A typical case is that of the Dresden #1 plant, built in 1960. In 1961, this plant produced 33% of rated capacity. By 1966 this had increased to 80%. In 1974, the plant produced only 20% of its rated capacity.[5]

Coal and oil plants also suffer from reliability problems. These technologies have been with us for over a century, however, and technical refinement has improved their reliability into the 80% to 90% range. At an 80% reliability factor[6] we would need to build 1250 MW of capacity in order to have an expected output of 1000 MW. At 90% reliability, this would drop to 1111 MW. If for some reason, the reliability of a coal plant dropped to that of our best nuclear plants, 72%, we would have to provide 1382 MW of generating capacity to provide 1000MW of output.

Obviously, the requirement to build capacity in excess of rated capacity causes the capital requirements for construction to be increased. The price of borrowing money has increased rapidly in recent years. Estimates of the interest rates which must be paid by utilities range from 8%[7] to 14%.[8] These estimates vary, in part, due to federal subsidies to public utilities, which will be discussed later. For the purposes of this study, a rate of time preference of 12% will be used. This figure was utilized by Wilson and Thor[9] in the study conducted by the Bank of America[10] in January, 1976. These high interest rates tend to penalize those investments having a high capital cost, and make feasible projects which have lower capital costs and high operating costs. For this reason, the advantage in operating costs which nuclear plants hold is diminished when the entire cost of building and operating a plant is discounted to a common year. The high capital cost will add greatly to the discounted present value of the plant, while the fuel costs become relatively less important over the lifetime of the plant. Coal and oil plants have higher operating costs, but once these are discounted, they may be sufficiently low to make the total cost of a fossil fuel plant competitive with those for a nuclear plant.

ENVIRONMENTAL CONSIDERATIONS

We find environmentalists on both sides of the debate over nuclear power. The utilities argue that nuclear power offers the best way to meet the stringent requirements of the Clean Air Act, while their opposition stresses fear about the potentially catastrophic consequences of a major nuclear accident, as well as concern over the disposal of nuclear waste. While concern over reactor safety continues, according to Edward Mason, member of the Nuclear Regulatory Commission:

> "There is not enough money in the U.S. to raise man's other activities to the safety level already achieved by nuclear power." [11]

According to industry spokesmen, the chance of a major nuclear accident is on the order of one in one million reactor-years. According to government figures, such an accident, if it did occur, could cause up to $19 billion[12] in damage. In economic terms, such a risk could be provided for by an insurance payment of $20,000 per reactor-year.

Present insurance payments, under the limited liability provisions of $125 million as provided by the Price-Anderson act, are already considerably in excess of this figure, and are included in the operation costs for nuclear power in this study.

The environmental consequences of fossil fuel generating plants are more clearly understood. The imposition of air pollution standards has forced the capital and operating costs of these types of facilities up substantially. There has recently been an increasing concern over the amount of carbon dioxide in the atmosphere. This increasing concentration of CO_2 was not thought to be an environmental concern at the time the Clean Air Act was written, but may prove to be as dangerous as the pollutants which have been controlled. The process of burning fossil fuel for power generation inevitably leads to the release of vast quantities of CO_2. At the present time, the long term effect of this is as uncertain as the problems potentially facing us from radioactive wastes; probably miniscule, but potentially catastrophic. As far as other harmful emissions are concerned, the cost estimates included in this study include the cost of abatement to meet all currently enacted standards for environmental quality.

Due to the fact that all of the cost estimates used in this study do include all legally required pollution control measures, no further consideration will be given to these environmental concerns.

COST ESTIMATES

All of these aggregate cost estimates are the sum of the capital costs for each project with interest to 1981 and the discounted present value of the fuel and operation and maintenance costs, also in 1981. This formula can be shown formally as:

$$\text{Total cost} = \sum_{a=1}^{4} (K_a + k_a) \cdot (1+i)^{(5-a)}$$
$$+ \sum_{b=1}^{33} F \times (1+f)^{(b-1)} / (1+i)^{(b-1)}$$
$$+ \sum_{c=1}^{33} M \times (1+m)^{(c-1)} / (1+i)^{(c-1)}$$

Where: K is Capital requirements for year 'a' in 1977 prices

k is the capital escalator for year 'a' in dollars

F is fuel cost for one year operation in 1981 prices

f is fuel cost escalator in percent

M is operation and maintenance cost for one year in 1981 prices

m is O&M cost escalator in percent

i is the opportunity cost of capital

For nuclear power plants, four years construction is anticipated. Therefore, construction costs have been evenly distributed over the four year period 1977 to 1980. Fossil fuel plants are expected to require half this construction time, and capital costs are therefore spread over a two year period from 1979 to 1980. By doing so, all facilities are anticipated to become operational in 1981. Fuel and O&M costs are figured from a 1981 base, escalated according to the formulae on page 9, then discounted at 'i' to 1981 dollars. Capital costs are all figured with interest to 1981. This formula, therefore, gives a total figure for building and operating a power plant measured at a common point in time. While it would be possible to construct a price schedule for the power thus generated, based upon this data, this study will make no such attempt. The intention of calculating these figures is to provide a ready comparison between the costs for various forms of generation.

Capital Costs

The capital costs for all types of generating facilities has increased in recent years. Part of this increase is due to increasing construction and raw material costs, part due to increasingly stringent environmental and safety regulation, and part due to inflation. In 1970, by one estimate, it was possible to build a 1000MW nuclear unit for $150 million.[13] By 1975, the estimate had risen to $755 Million.[14] All of the estimates for capital costs used in this study are based upon the 1976 Bank of America study conducted by Wilson and Thor.

Nuclear: $755/kilowatt of capacity in 1975
9.3% escalation from 1975 to 1979
6.5% escalation from 1980 to 1984

Nuclear, high rate of capital cost escalation:
$755/kilowatt of capacity in 1975
11.1% escalation 1975 to 1979
8.3% escalation 1980 to 1984

Coal $595/kilowatt of capacity in 1975
9.3% escalation in 1975 to 1979
6.5% escalation in 1980 to 1984

Oil: $473/kilowatt in 1975
9.3% escalation in 1975 to 1979
6.5% escalation in 1980 to 1984

Wilson and thor allowed for the possibility that construction costs for nuclear generating facilities would increase at a more rapid rate than for other types of facilities. This is based upon the dramatic rise in construction costs which have been observed in the period 1970 to 1975 for nuclear plants. All of the estimates, including those for coal and oil generating facilities, include a substantial factor of cost escalation for the late 1970's, and assume that the rate of escalation will ease by 1980.

Fuel Costs

Fuel costs for all types of generating facilities have all skyrocketed in the last five years. Prior to the Arab oil embargo of 1973, uranium was available at $6 to $8 per pound, a rate which held relatively constant for the 20 previous years. Coal had been selling at $10 to $12 per ton, and oil for less than $5 per barrel. Since that time, the price of uranium has shot up to $47-$50/lb., coal to $30/ton, and oil to $12.50/bbl. In terms of energy content, one lb. of uranium is equal to eight barrels of oil or two tons of coal.[15] The fact that uranium prices have shot up by 500%, while coal has increased by a more moderate 200%, and oil by only 150%, has made nuclear fuel lose about half the advantage in cost it once had over fossil fuels.

The fuel requirements for the different types of generation, therefore, vary substantially if out of date prices are used for calculation. At the time of the Wilson and Thor study, uranium had seemingly stabilized at about $32/lb. Since that time, however the price has increased by an additional 50% to the $50/lb. range. This study will use the prices used by Wilson and Thor, as well as more recent prices which have appeared in the market for uranium.

Nuclear:	$.42/million BTU in 1975 $.66/million BTU in 1976 escalation at 6.5% from 1975 to 1979 escalation at 6.0% from 1980 to 2013
Nuclear, rapid fuel price increase:	
	$.42/million BTU in 1975 $.66/million BTU in 1976 escalation at 9.3% from 1975 to 1979 escalation at 8.3% from 1980 to 2013
Coal:	$1.25/million BTU in 1975 escalation at 6.5% in 1975 to 1979 escalation at 6.0% from 1980 to 2013
Oil:	$2.62/million BTU in 1975 escalation at 6.5% from 1975 to 1979 escalation at 6.0% from 1980 to 2013
Oil, rapid fuel price escalation:	
	$2.62/million BTU in 1975 escalation at 9.3% from 1975 to 1979 escalation at 8.3% from 1980 to 2013

No provision has been made in these figures for a rapid escalation of coal prices, as U.S. coal reserves are not expected to be appreciably depleted during the anticipated 33 year operating lifetime of these generators, while the supplies of oil and uranium are not nearly as secure.

One third of fuel costs for nuclear power units is fixed, and will not be affected by reliability. This occurs because some degradation of nuclear fuel occurs whether the reactor is in operation producing electricity, or standing idle. This means that a plant operating at 66% of capacity will consume 79% of the fuel required by a plant of similar size operating at 100% of capacity. Alternatively, this means that a plant operating at 52% of capacity (the average for all plants) will consume 129% of the fuel which would be required by a plant of lesser capacity providing the same output at 100% of capacity.

Operations and Maintenance Costs

Operation and Maintenance costs for nuclear and oil plants are far lower than for coal fired generating stations. Presumably this is due to the reduced throughput of fuel; if one pound of uranium equals two tons of coal, it is reasonable to expect lower operating costs with a fuel of reduced mass and inherently cleaner handling characteristics. According to Wilson and Thor, O&M costs for the three types of generating facilities are as follows:

Nuclear: $9.47/kilowatt of capacity in 1981
Coal: $24.22/kilowatt of capacity in 1981
Oil: $9.75/kilowatt of capacity in 1981

escalation for all of these at 7% per year

THE EFFECTS OF GOVERNMENT SUBSIDIES

Nearly every step of the power generation process, whether by nuclear power, coal or oil is subsidized in some way by governmental participation. Publicly owned utilities are able to raise their capital requirements by issuing tax-free bonds, which result in much lower interest rates than the market would provide for a profit-oriented privately owned utility. Privately owned utilities operate as government-sanctioned monopolists, and their rate of profit is regulated, in part to protect consumers, but also to insure continuing corporate liquidity. Through the Energy Research and Development Agency, the federal government underwrites most of the innovative research programs for nuclear, geothermal, solar, and wind generation. Through the depletion allowance, the price of all mined material, whether uranium, oil or coal, is subsidized by the taxpayer. Federal controls on the price of oil have kept U.S. oil prices below prevailing world prices. Delays and variances in the implementation of environmental regulations have reduced direct costs of power generation for existing utilities. An attempt to evaluate the total empact of all of these forms of market interference would be a monumental (and possibly facinating) task. This study will make only one provision for this maze of governmental interference. As provided in the B of A study, the interest rates for new capital are computed at a free-market rate of 12.0%, rather than at the subsidized rate which a publicly

Owned utility would be able to issue bonds. Once the effects of these subsidies is taken into account, the net cost of new capital to the public will be the same or higher than the market rate. For example, a bond issued by a publicly owned utility at an interest rate of 6.3% to an investor in a 70% income tax bracket will cost the public a total of 20.01%. 6.3% of this will appear in the accounting of their utility; the remainder is foregone income tax which would have been paid to the government had the bond provided taxable income.

THE COST OF A GENERATING PLANT

The data which follows in figures 1 through 4 attempt to show the entire cost of building and operating a power generating unit capable of providing a reliable 1000 MW of electricity. These costs all assume that no unanticipated delays in construction are encountered. All figures show the total cost in 1981 of building and operating a plant with a 33 year lifetime. For nuclear plants, capital expenditures are spread over a four year period from 1977 to 1980, with escalation as shown on page 7. For fossil fuel plants, capital costs are divided over a two year construction period, from 1979 to 1980, again, with the escalation figures provided earlier. The total figures include capital costs, together with escalation and interest to 1981, and the discounted present value of all fuel and operation and maintenance costs, including escalation, for the 33 year operating lifetime of the plants.

By calculating these values, it is possible to compare which type of generation is least expensive economically, given the assumptions about the price of fuel, capital, operating costs, and the reliability of the various generatint facilities which have been provided.

Figure '1' shows a hypothetical case in which all types of generating facilities are operating at 100% of capacity at all times. This type of reliability does not occur in practice, but it is this type of analysis which is utilized in reporting the relative costs of various types of facilities in the popular press. It should be noted in this example, however, that nuclear plants hold a clear advantage in costs over other types of facilities.

Figure '2' shows relative costs of power production if we presume that we are capable of duplicating the most reliable technology which we currently employ for each type of facility. Since our most reliable nuclear plants operate at a lower factor of capacity that our most reliable fossil fuel plants, allowance has been made for the extra capital and fuel costs incurred when sufficient capacity is constructed to provide an equal anticipated output. Under this scenario, coal holds an advantage in total cost over nuclear power, but oil remains as a less attractive alternative, unless the [illegible] unanticipated increase in uranium prices which took place in 1976 are taken into account, and these higher prices continue to increase at the higher 8.3% escalator. In such a case, oil would begin to become competitive with nuclear power, but would remain at a distinct disadvantage

Type	% Capacity	Cap Δ	Fuel Δ
Nuclear	100%	normal	normal
Coal	100%	normal	normal
Oil	100%	normal	normal
Oil	100%	normal	rapid
Nuclear	100%	normal	rapid
Nuclear	100%	rapid	normal
Nuclear	100%	rapid	rapid
Nuclear	100%	normal	76 normal
Nuclear	100%	normal	76 rapid
Nuclear	100%	rapid	76 normal
Nuclear	100%	rapid	76 rapid

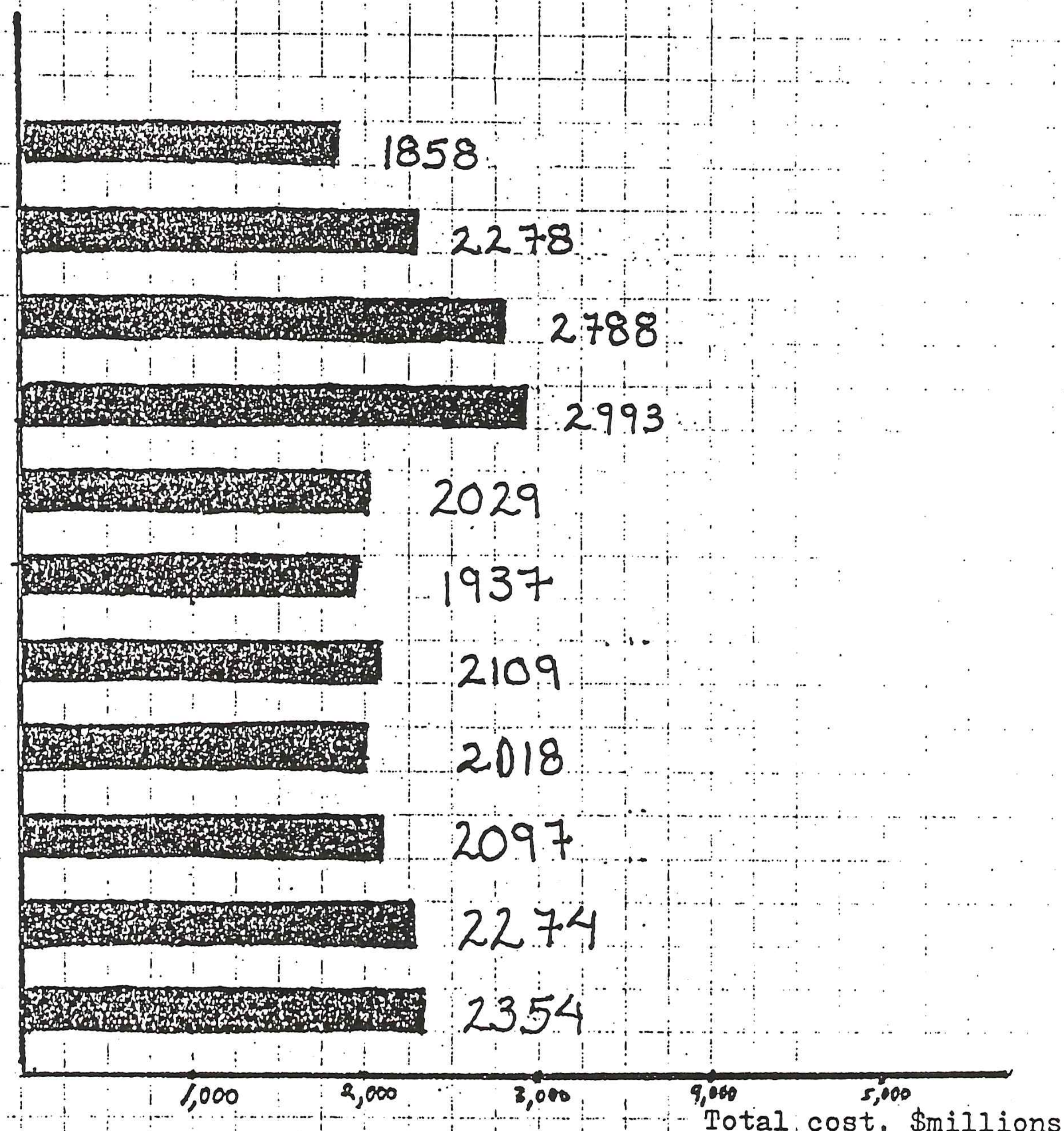

Figure 1, All types of units operating with perfect reliability

Type	% Capacity	Cap Δ	Fuel Δ
Coal	90%	normal	normal
Oil	90%	normal	normal
Oil	90%	normal	rapid
Nuclear	72%	normal	normal
Nuclear	72%	normal	rapid
Nuclear	72%	rapid	normal
Nuclear	72%	rapid	rapid
Nuclear	72%	normal	76 normal
Nuclear	72%	rapid	76 normal
Nuclear	72%	normal	76 rapid
Nuclear	72%	rapid	76 rapid

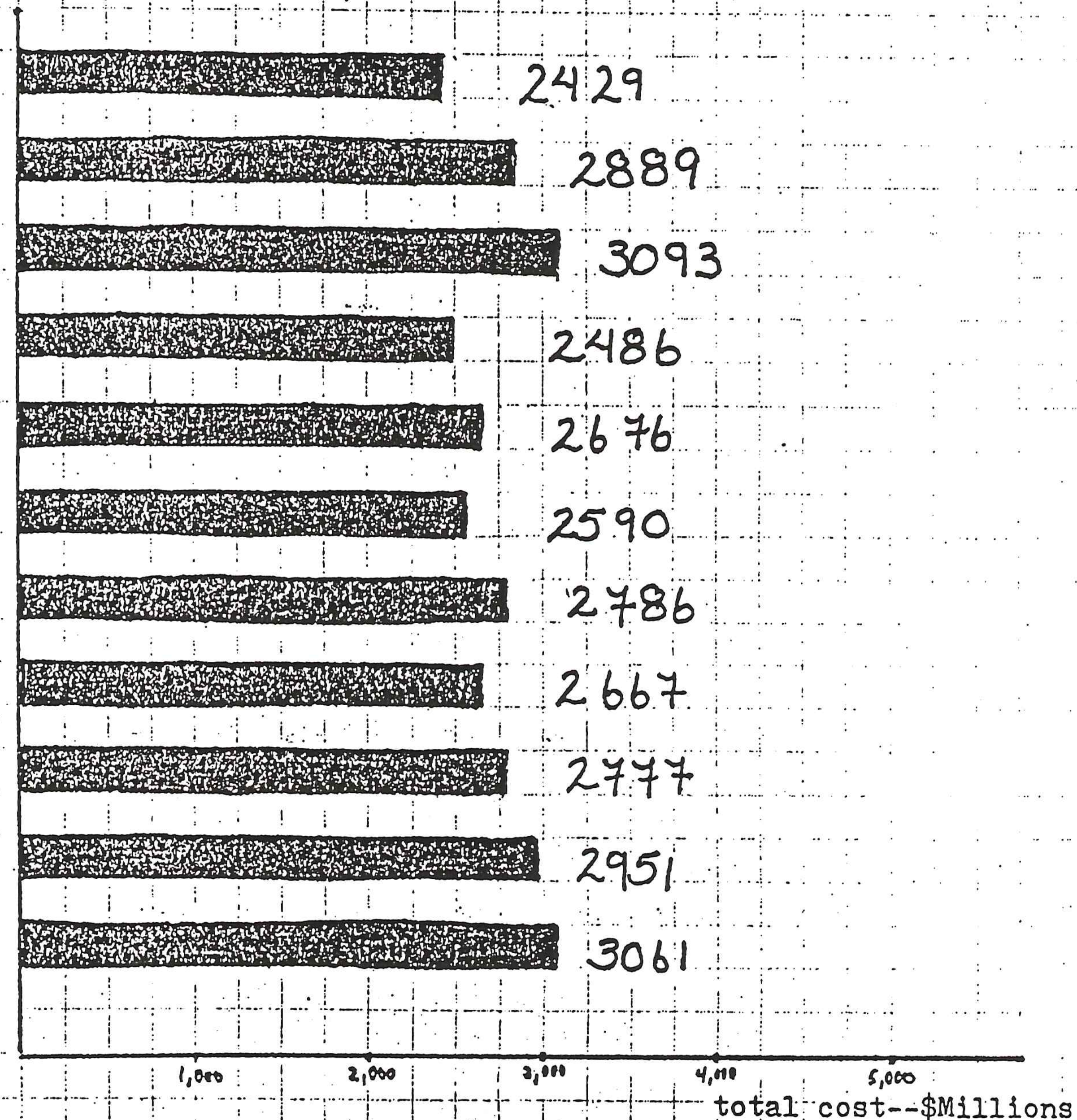

Figure 2 Most reliable units now in operation

Type	% Capacity	Cap Δ	Fuel Δ
Coal	80%	normal	normal
Oil	80%	normal	normal
Oil	80%	normal	rapid
Nuclear	58%	normal	normal
Nuclear	58%	normal	rapid
Nuclear	58%	rapid	normal
Nuclear	58%	rapid	rapid
Nuclear	58%	normal	76 normal
Nuclear	58%	rapid	76 normal
Nuclear	58%	normal	76 rapid
Nuclear	58%	rapid	76 rapid

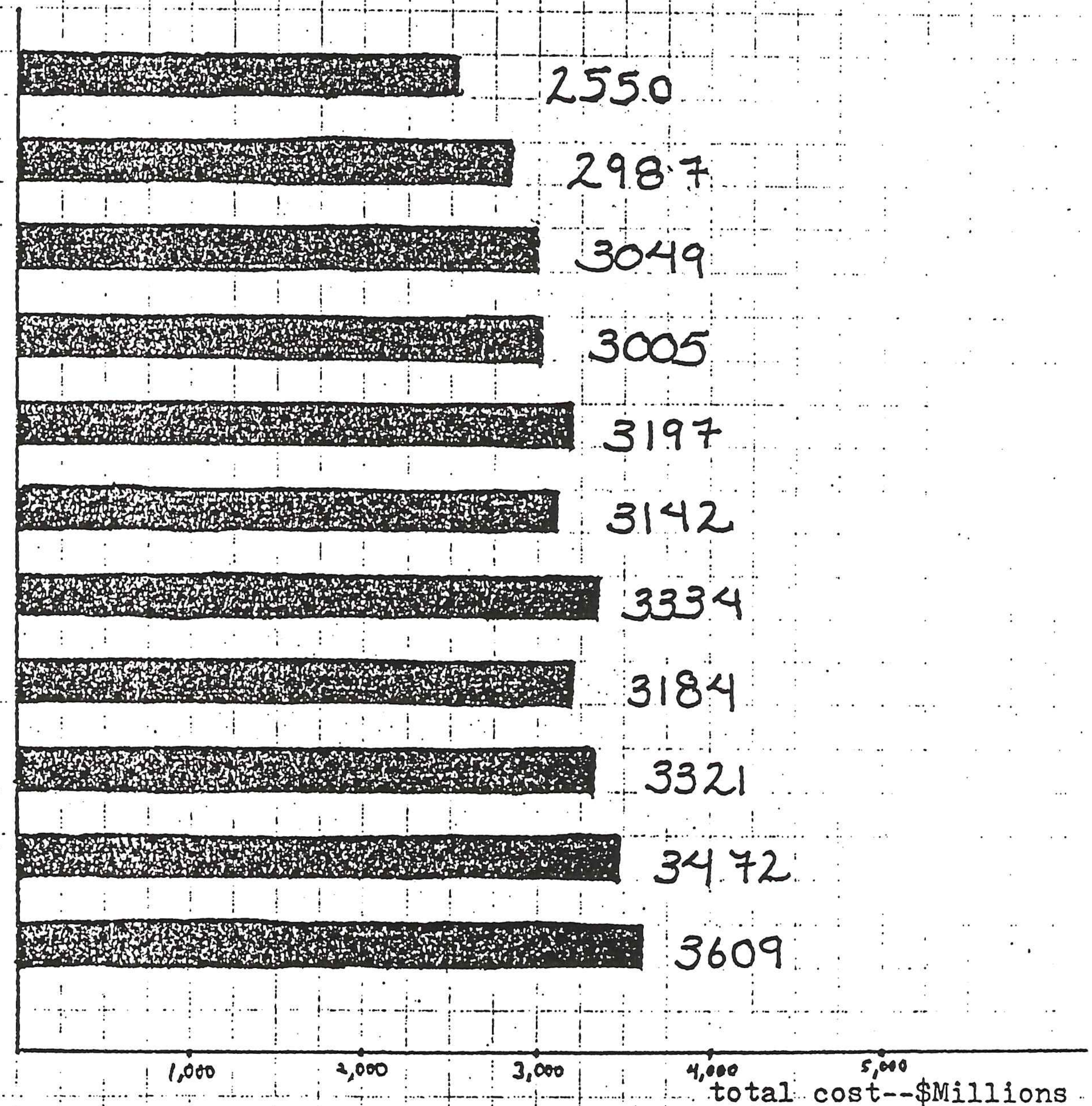

Figure 3 Most recently installed units

to coal.

Figure three shows a more likely probability of the relative costs of power generation. This data assumes that we are able to duplicate the performance of our most recently installed power plants. If we are able to do this, that is, to maintain the performance record of plants installed since June, 1974, nuclear power will not be competitive with power produced by coal regardless of abnormal price increases which affect the 1975 market for uranium. If 1976 prices are included, or any rapid rate of fuel price increases occur, oil would also become competitive.

Figure '4' shows a pessimistic scenario, in which only average reliability in our new plant construction. Comparable figures for coal generation are provided, and it is evident that a drastic drop in the reliability of coal generators would be required before the cost of coal generated power would become as great as for a new plant of average reliability. No additional projections have been provided for oil fired plants, as it is evident that coal fired plants hold a distinct advantage in total costs over oil plants.

THE TENDENCY OF PUBLIC UTILITIES TO OVERCAPITALIZE

The tendency of public utilities to overcapitalize has long been known to economists. Because the privately owned utilities are government regulated monopolists, the rate of return (profit) permitted for utilities has been calculated as a percentage of invested capital.[16] For this reason, utilities have always preferred capital-intensive productive methods to those having relatively higher operating costs and lower capital requirements. The preference of privately owned utilities for nuclear plants, in spite of the increasingly obvious disadvantage which these plants have in terms of total costs, follows this long established pattern. For the privately owned utility, the high capital requirements are compensated by the increase in profits permitted by the regulating agency. For the publicly owned utility, the subsidization of capital bond issues through tax-exemption provides an unrealistically low rate of interest. The subsidy provided by taxpayers for these tax-exempt bonds are never figured into the benefit:cost analysis conducted by the individual utility.

Any national program of economization in the production of electrical power would certainly take the total cost, including that of government subsidy, into account. It can be said, however, that the individual utilities are acting in their own self-interest, as well as that of their stockholders, in pursuing these capital-intensive generating methods. At the same time, however, we can easily see that the real costs of producing electricity by capital intensive methods, such as nuclear plants, are much higher than would result from less capital-intensive sources such as coal and oil.

Special Consideration for Washington State.

Washington State currently enjoys some of the lowest electric rates in the nation. This is due to the tremendous base of power provided by the hydroelectric capability of our river systems. The Bonneville Power Administration (BPA) provides the vast majority of this power from dams constructed with federal funds for the joint purposes of flood control and power production. The sale of electricity by BPA, therefore, is not required to generate revenue to pay the full cost of these dams, as a part of the cost is paid for by the enourmous flood control benefits which these dams provide. Consequently, our electric rates are approximately one-third of those which prevail over most of the nation, and our per capita consumption is correspondingly higher.

As we begin to consider additional generating units, we must consider the marginal cost of this power with relation to the average which we already enjoy. Any form of thermal generation will be at a cost of from three to ten times the present average cost for hydro produced power. Because this power will be added into the existing stream of electricity, we should only add this power capability if the benefits of this additional, marginal power will exceed the costs of providing such power. Present utility rates do not discriminate in this fashion.[17] The lack of a marginal pricing policy encourages additional demand at average prices, while imposing the much higher marginal cost on the system as a whole. Utilities in other parts of the country do not face this problem, since the majority of their power is already derived from such thermal generating units, and therefore, marginal cost is not greatly different from average cost. In 1975, additional thermal generating plants in the U.S. produced power at a cost between $.026/kwh and $.053/kwh. This is between four and ten times the cost of hydro produced power from BPA. The introduction of additional thermal power can only be justified at the marginal cost, rather than at the much lower current average price for electricity in the Northwest.

An additional problem facing Washington State is a legal constraint on BPA. BPA must, by law, sell power to publicly owned utilities preferentially before it can contract with private companies. As the needs of publicly owned utilities, such as the Okanogan PUD, increase, less power is available for sale to privately owned utilities, such as Puget Power. Privately owned utilities, therefore, will be forced to depend upon thermal generation for an increasing proportion of their power in coming years. As mentioned previously, privately owned utilities increase their profits by increasing their capital investment. It is therefore logical to expect a privately owned utility to choose a method of thermal generation which tends to maximize capital costs, rather than one which minimizes total costs, including fuel, and operations and maintenance. In this case, with the greater capital costs of nuclear power, the profit-maximizing decision of a privately owned utility would be biased in favor of this option. The relatively higher operating costs of coal or oil generation would not increase their profits, although it is evident from figure '3' that these options provide electricity at a lower total cost.

The argument has been made that nuclear power plants would provide more employment than other options. The higher construction costs would, over the short run, provide additional employment for persons involved in reactor manufacturing, as well as for those in the building trades. In terms of total contribution to the state, however, it is likely that coal or oil plants would provide equal or greater employment. There are presently no manufacturers of nuclear reactors in the state, and these pieces of equipment will therefore, be manufactured in other areas by out-of-state workers. Fossil fuel plants, being relatively less sophisticated, would use a greater proportion of locally available technology.

In terms of fuel, coal offers the most attractive possibilities for job creation. The state has no presently developed sources of either oil or uranium with which to fuel such power plants, and these fuels would have to be brought in from outside, thus providing jobs out-of-state. Coal reserves in the state are substantial, however, and the formations located near Centralia, Chehalis, and Glacier could all provide fuel for electric generators, and jobs for Washington miners.

CONCLUSION

This study has provided a comparison of the cost of electric generation from nuclear power plants with those for coal and oil fired plants. No provision has been made for the different postures which have been taken by environmentalists, although all cost estimates have included a provision for pollution abatement equipment which would meet all present regulations. Similarly, no provision has been made for the pleas of conservationists, who argue against increasing energy production. This study does not attempt to show a need for power. All which has been attempted is to show the real costs of generating electricity from three alternatives, based upon the best available information of the costs of the required inputs.

If we try to honestly compare the costs of power generation, based upon present performance, we are forced to conclude that nuclear power generation is not competitive in cost with coal generation. The introduction of government subsidies and profit regulation into these decisions may alter the monetary costs borne by the utilities, or their respective profits, but the real costs of generation are higher as a result of this governmental interference. If the capital requirements for nuclear generation can be reduced, or the reliability can be increased, obviously this competitive disadvantage can be ameliorated. Until this is done, we can expect the divergence between the higher utility profits from nuclear generators with the obviously lower total cost of fossil fuel generators to continue.

FOOTNOTES

1 Willey, W.R.Z., Eletricity Consumption and Investment Finance in California, in California Energy, Federal Reserve Bank of San Francisco, 1976

2 Operating Units Status Report, Federal Energy Administration, Energy Research and Development Agency, Federal Power Commission, Nuclear Regulatory Commission, April, 1975

3 Ibid.

4 Ibid.

5 Ibid.

6 Willey, Op. Cit.

7 Ibid.

8 Comey, D. The Uneconomics of Nuclear Energy, The Skeptic, July, 1976

9 This study is based, to a considerable extent, on work done (see footnote 10) by John Oliver Wilson, Vice President and Senior Economist, and Eric P. Thor Jr., associate economist, Bank of America, San Francisco, CA.

10 Wilson, J.O., and Thor, E.P., The Future of Nuclear Energy in California, in California Energy, Federal Reserve Bank of San Francisco, 1976

11 Bethe, H.A., The Case for Nuclear Power, The Skeptic, July, 1976

12 Reactor Safety Study, WASH 1400, U.S. Nuclear Regulatory Commission, October 1975

13 Temple, Barker, and Sloan, The Economic Impact of EPA's Air and Water Regulations on the Electric Utility Industry, EPA Office of Planning and Evaluation, Washington, D.C., November, 1975

14 Wilson and Thor, Op. cit.

15 Comey, Op. Cit.

16 For a full discussion of the overcapitalization of utilities, see Averch and Johnson, "Behavior of the Firm Under Regulation," or Wellisz, "Regulation of Natural Gas Pipeline Companies."

17 For a fuller discussion of the marginal pricing problem in the Northwest, See Barton, et. al. or Christey.

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Exhibit # T-20

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

VS.

PACIFIC POWER AND LIGHT COMPANY

CAUSE U-83-57

DIRECT TESTIMONY OF

JIM LAZAR
Consulting Economist

ON BEHALF OF THE PUBLIC

DIRECT TESTIMONY OF JIM LAZAR, CONSULTING ECONOMIST
ON BEHALF OF THE PUBLIC

Q. Please state your name, address, and occupation?

A. Jim Lazar, 317 E. 17th Ave, Olympia, Washington. I am an independent consulting economist specializing in utility rate and resource planning issues.

Q. What is your educational and professional background in the area of utility rate and resource analysis?

A. I hold a degree in economics from Western Washington University, and have undertaken graduate studies at that institution and at the University of Washington Graduate School of Public Affairs. My academic work has centered on the economics of regulated industries, including particularly the electric energy market.

I worked on the staff of the Washington State Senate between 1977 and 1982, first in the transportation field, and later as an energy aide to a state senator. I was employed by the People's Organization for Washington Energy Resources as Research Director during most of 1982, during which time I served as the lead author of POWER's book on electric utility ratemaking, The People's Power Guide. I began doing consulting work in 1979, and have continued that work since that time. During 1981, I served as a member of the faculty of the Western Consumer Utility Training Center, centered in San Francisco. I have been an invited speaker at numerous utility-sponsored forums on resource planning and pricing issues.

My consulting clients have included the Northwest Power Planning Council, local, state, and federal agencies, including the Idaho Public Utilities Commission, the National Marine Fisheries Service, and Island County, Washington, industrial trade associations, consumer groups, and electric utilities. I have appeared as an expert witness on numerous occasions before this Commission, before the Idaho and Oregon Commissions, before the Bonneville Power Administration, and before the regulatory bodies governing numerous consumer-owned utilities. I have recently been appointed a member of the Options Evaluation Task Force of the Northwest Power Planning Council, which is involved in evaluating numerous alternative means of providing for the region's energy future.

Q. What is the purpose of your testimony in this proceeding?
A. I have been asked by the Office of Public Counsel to discuss what Colstrip-related facilities are currently useful for providing service to Pacific's customers, to identify for the Commission certain apparent inconsistencies in Pacific's application for ratemaking treatment of the Colstrip project, and to review the impact of the recent contract with Black Hills Power and Light on Pacific's consumers.

Q. Please begin by discussing which of the Colstrip facilities for which Pacific has requested ratemaking treatment are actually available for service at this time?
A. Pacific is requesting inclusion in rate base of their

investment in Colstrip unit #3, of the facilities considered "common" to Colstrip units 3&4, and of the investment in the two 500 kv transmission lines between Colstrip and Townsend, Montana. The breakdown of each of these elements is shown on page 1 of Exhibit ___(JL-1), derived from the Company's response to Public Counsel Data Request #13. The total amount of investment on which Pacific has based this request is $136 million. The Washington allocated share is $20,341,000, as shown on line 21, Table 4-4, exhibit 6.

Two problems must be addressed. First, the Colstrip project is clearly excess capacity, and the Commission should make a determination on how excess capacity should be treated for ratemaking purposes. Second, even if Colstrip is to be included in rate base, this particular request includes facilities which are not providing service at this time, and facilities which could not do so, even if there were a need. This includes a portion of the capacity of Colstrip #3, and a portion of the transmission facility. In addition, the Company has included in their request 100% of the "common facilities" between Colstrip 3&4 at this time, in spite of the fact that project #4 will receive half of the benefits of these expenditures.

Q. On what do you base the conclusion that Colstrip #3 represents excess capacity?

A. First of all, Mr. Steinberg's testimony (TR. 18) indicated that Pacific has a surplus of energy in the current year of 511 average MW; the 42 MW in first year energy from Colstrip (60% capacity factor; 70 MW capacity) is clearly excess to the needs of Pacific's customers. In addition, Pacific has committed output in excess of the capability of Colstrip #3 to Black Hills Power and Light Company. To ask that Pacific's captive ratepayers also support this investment would seem to be double-recovery.

Q. Has Pacific been aware of their energy surplus for an extended period of time?

A. Yes, in February, 1981, Pacific indicated to Bonneville that they had an energy surplus through the year 1990 without the Company's share of Colstrip #3&4, and without WPPSS #3&5. If the projected output of these plants were included, the projected surplus in 1989-90 would still have been 212 average MW, again, based on the 1981 estimate. In the company's March, 1984 estimate, provided in response to RR. #1, the Company shows an energy surplus through 1992-93, after accounting for the Black Hills sale, and excluding any potential production from WPPSS #3. The letter to Bonneville and the response to RR #1 are included in my exhibit as appendices A-1 and A-2.

Q. How does Pacific's surplus compare with that estimated for the region as a whole?

A. Pacific's surplus appears to be larger than average. Bonneville is projecting a surplus through approximately 1990, but appears to be including output from WPPSS #3 in that estimate. The region as a whole, as detailed on page 6-3 of the Northwest Conservation and Electric Power Plan, has a substantial surplus through at least 1988 under the medium-high or medium-low forecasts. It is safe to say that the region has a surplus throughout the period when the Black Hills contract is below the ultimate capacity of 75 MW.

Q. What aspects of the Black Hills contract (exhibit 2) should the Commission look at in considering Pacific's request in this proceeding?

A. While PP&L is not obligated to serve the Black Hills contract exclusively with Colstrip-generated energy, the Black Hills contract should not be considered as anything less than a commitment of the Colstrip energy, and really is a commitment of much more. If Black Hills had been an owner of Colstrip, they would have paid a full share of the costs, and accepted the actual output. As the contract is written, Black Hills is assured of the ability to receive power at up to an 80% capacity factor 52 weeks of the year, without any provision for scheduled or unscheduled outages, and is required to pay only a portion of the total costs of the project.

The price is clearly based on Colstrip, and the tariff could not be supported except for the completion of Colstrip #3 under FERC policies now applied to this region, which limit sales for resale to no more than the fully allocated cost of the plant on which the sale is based. It is my understanding that FERC has allowed an exception to this policy in the Southwest, on an experimental basis, but Pacific has not apparently requested an exception.

Second, the Commission must recognize the 40 year nature of the sale to Black Hills. The expected lifetime of Colstrip is in the 30-35 year range; the Black Hills contract is for a 40 year term, with fixed payments only in the first 35 years, and 5 years of those at reduced prices. For the first 5 years Black Hills will receive a 50% discount on the fixed cost portion of their purchases, and for the last five years Black Hills will receive power from Pacific, apparently without any payment whatsoever for capital costs. If a new power plant is required at that time to meet the obligation under the contract, the cost to Pacific could be very large indeed.

In the words of Black Hills, in a February 10 letter to FERC, "Black Hills' customers achieve long term firm power and energy at a substantial reduction from the cost of new construction." The FERC filing, including the Black Hills letter, are included in my exhibit as Appendix B.

As exhibit 3 shows, had Black Hills proceeded with participation in Wyodak 2, as they had originally planned, their costs would have been far higher than the cost of Colstrip energy under the contract with Pacific.

As indicated in their letter to FERC (Appendix B), the capital costs of building their own 75 MW plant would have been $2560/kw, compared with a payment to Pacific under the contract of only $1695/kw. In this proceeding, Pacific is asking their captive ratepayers to pick up the cost of Colstrip energy, while Black Hills ratepayers receive the benefits. As a minimum, the amount of Colstrip dedicated to Black Hills should be deducted from the amount to be carried by Pacific's customers.

Third, it is important to realize that Black Hills' share of Colstrip #3 increases, from the present 15 MW of capacity and associated energy, up to 75 MW of capacity and associated energy by 1988. By 1990, when the Colstrip energy would begin to be useful in Pacific's system, Black Hills will be entitled to more capacity than Pacific's share of Colstrip #3.

Ratepayers will have made a contribution when the capacity is excess, but will not be entitled to benefits if and when the capacity is needed.

Fourth, Pacific has not apparently offset the costs associated with Colstrip #3 by the revenues to be received from sale of the power. If, in fact, Colstrip #3 is used and useful for service to Washington consumers, then the power will be sold, and revenues derived. Since Colstrip comes into the system at a cost greater than the average revenue, there would still be a residual revenue requirement. I have detailed on line 43 of page 2 of exhibit ___(JL-1) that this adjustment would reduce the Pacific request by $1.84 million, after adjusting for the 10% loss factor assumed by the company in Exhibit 3.

This short run revenue, however, must be considered in light of the fact that much of the Colstrip energy ceases to be available on January 1, 1985, when the next increment of the Black Hills contract takes effect. This further reduces the cost which Pacific's captive ratepayers can be considered responsible for under any circumstances.

Finally, Black Hills receives the benefits of a levelized fixed charge factor, which normally is not made available to ratepayers. While the Company's response to the request for the first year cost of Colstrip #3 (PC-3) shows a levelized fixed cost recovery, the actual rate request in Exhibit 6 does not appear to track the mathematics of the Company's response to the data request.

Q. Turning to the issue of shared costs between Colstrip #3 and #4, please describe the problem with the Company's proposed treatment?

A. The Company has proposed including 100% of the shared costs between Colstrip #3&4 in the rate base addition for Colstrip #3. The amount of shared costs, at December, 1983, was $38,487,880. There are several problems with this approach.

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First, Pacific has offered its share of Colstrip #4 for sale (at least to Bonneville as shown in Appendix A to my exhibit), and it would be appropriate to include half of the shared costs as part of the investment in Colstrip #4 in any price negotiations with a potential purchaser. The Company refused to provide copies of documents associated with any offers to sell their share of the Colstrip 3/4 output or the Company ownership in the projects to other parties in their response to PC-5.

Second, at least a portion of these costs would not have been incurred were Colstrip #4 not being built. Third, the total investment in shared costs cannot be used, or become useful, until Colstrip #4 is complete, and until sufficient transmission has been built to transmit that power to Pacific's Washington service area.

Q. How have other participant utilities treated the shared costs of Colstrip?

A. Puget Power has proposed splitting the shared costs (and the transmission) 50% to Colstrip #3, and 50% to Colstrip #4 in their pending request before this Commission in Cause U-83-54. This is similar to the treatment I recommend in this proceeding if any portion of the pending request is to be granted, for reasons which will become clear. Washington Water Power made the same proposal as Pacific; in Idaho, only 75% of WWP's shared costs and transmission were allowed in the recently completed rate case, in that Commission's order #18679 page 7. In Washington, WWP's request was not contested to the best of my recollection.

Portland GE and Montana Power allocated approximately 75% of the shared costs to Colstrip #3, based on an analysis of which costs were increased by the decision to build two plants instead of one; the Montana case is being aggressively contested, and it is my understanding that a challenge of both the PGE and the PP&L proposals are being made in Oregon as well.

Q. Is there an inconsistency in considering both the Common facilities and the transmission investment used and useful at this time?

A. Yes. If in fact 75% (or more) of the common facilities were needed in order for Colstrip #3 to come into service, and those costs therefore should be assigned to Colstrip #3, then one would have to look at the capacity of each of the two lines of the 500 kv transmission system, and determine if both of those were needed for Colstrip #3 to come into service. The only conclusion to be reached is that both are not. Only one line would be needed to support the combined capacity of Colstrip units 1, 2, and 3. Therefore, if a common facility cost allocation is used which is based on the investment in common facilities needed to support a single plant, the same logic should carry through to the transmission system cost allocation.

Q. What is the capacity of currently available Colstrip generation, and of the associated transmission system?

A. Colstrip 1 and 2 have capacity of 330 MW each; Colstrip #3 is a 700 MW unit; the combined generating capacity at Colstrip presently is 1360 MW.

Montana Power, owner of 540 MW of Colstrip 1-3 generating capacity, has several transmission lines of 69 kv to 230 kv leading from Colstrip, which serve its own system, in addition to the 500 kv system. These have a combined carrying capacity of approximately 400 MW. The 500 kv system has been estimated at various levels of capacity. The Colstrip EIS indicated that a single 500 kv line would be expected to have a capacity of 1500 MW, and a dual line capacity of 5000 MW. Page 3.7-9 of the Colstrip EIS is included in Appendix C-1 of my exhibit.

The Colstrip-Pacific Northwest Study, provided by the Company in response to Public Counsel request 9, shows the two circuits with 3850 MW of capacity, and a single line with 2100 MW of capacity, sufficient to carry the output of all four Colstrip projects. The Colstrip Pacific Northwest Study, is included as Appendix C-2 to my testimony.

Even at the lower rating in the EIS, half of the system would have a capacity of 1500 MW, which would greatly exceed the output of the three operating Colstrip generating plants. Even without consideration of the Montana Power lines, a single line would appear to have capacity exceeding the ability of the BPA system now in place to deliver power to the West.

Q. Does the manner in which the Colstrip transmission is built allow for a segregation of one line from the other for ratemaking purposes?

A. Yes. Unlike most of the BPA dual circuit 500 kv lines, which consist of two sets of conductors strung on a single set of towers, the Colstrip line is two separate transmission lines, each with its own set of towers. This construction is substantially more expensive than the type of dual circuit construction BPA is using for the portion of the Colstrip transmission system they are building, from Townsend, Montana to Spokane. As testified by Mr. Steinberg, the BPA segment from Garrison to Taft, necessary for operation of Colstrip #4, will not be in service until July/August, 1985. The BPA system is scheduled for completion to Spokane in 1987.

Because the private utility Colstrip transmission is really two independent lines, the accounting has been separate for the "A" and "B" lines. The "A" line was less expensive to build, as a portion of it was converted from a 230 kv line formerly owned by Montana Power. According to the Company response to Public Counsel request #13, Pacific's investment through December, 1983 in the "A" line totalled $9,549,500. The investment at December, 1983 in the "B" line totalled $19,399,300, or approximately twice as much as the "A" line. Had Colstrip #4 not been planned, it is unlikely that the "B" line would have been built; there is no apparent justification for treating the "B" line as a part of the cost of Colstrip #3.

In any event, it is clearly inconsistent to include all of the common facility expenses as a part of Colstrip #3 (when not even the sponsoring utility has argued that all of these costs were needed for a single project), and at the same time include the second transmission line ("B" line) which is clearly not needed to transmit the output of the three existing projects. Pacific's existing Midpoint-Malin transmission line, essentially equal in design characteristics to the "A" line, has carried in excess of 1250 MW of capacity, and there is no reason to doubt that the "A" line could do the same, particularly in light of the various studies rating this capacity of a single 500 kv line at up to 2100 MW.

Q. Pending the completion of the BPA portion of the transmission system, is there a bottleneck which precludes the movement of the full output of Colstrip 1, 2, and 3 to the West?

A. Yes. While the private utility transmission system is overbuilt relative to present generating capacity (sufficient to carry the output of 4 plants and sell surplus capacity to others), the BPA system is inadequate to carry the full output of Colstrip 1, 2, and 3.

According to the minutes of the Colstrip Transmission Committee of August 18, 1983, September 22, 1983, and November 17, 1983, the BPA bottleneck precludes the movement of 135 MW of Colstrip capacity to the West. The relevant portions of the Transmission Committee Minutes, provided in response to PC-14, are included in Appendix D to my exhibit.

While Colstrip #3 was operated at full capacity during much of the week of December 20-26, Colstrip units 1&2 were backed off by 65 MW per unit or more during the period when Colstrip #3 was operated at full capacity.

Q. Is the Company aware of the excess capacity which exists in the 500 kv system, after the BPA segment is completed?

A. Yes. In a contract dated April 17, 1981, the 5 utilities owning the Colstrip transmission project agreed to allow BPA to have access to 185 MW of transmission capacity on the Colstrip lines. This amount is in excess of the needs of the Colstrip participants. BPA plans to use this capacity in order to wheel power from Basin Electric Cooperative in North Dakota to Malin, Oregon, for delivery to the Western Area Power Authority for ultimate use in California.

The revenues from ~~this~~ the potential sale of excess transmission capacity to BPA or other parties should be reflected as an offset to the Company's revenue requirement for the Colstrip transmission system. However, these revenues cannot logically begin until the capacity of the "B" line can

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be used, i.e., until the BPA transmission segment is complete, and Colstrip #4 can be placed in service, at which time the Commission should address the investment in Colstrip #4 and the "B" line, as well as the revenues associated with the projects which become useful at that time.

Q. What is your recommendation to the Commission for this proceeding?

A. The addition of Colstrip #3 to Pacific's system compounds the long-existing problem of excess capacity. It is clearly inappropriate to grant a full rate of return on excess capacity. Doing so would totally eliminate any incentive for the Company to carefully match loads and resources.

Further, since the output of Colstrip, or its equivalent, is committed to Black Hills for a 40 year term, the energy will not be available if and when it may be needed in the future. The plant offers neither short-run or long-run benefits to Pacific's customers. Given the lack of benefits, it appears difficult to justify any increase in rates whatsoever.

Although this is not my Recommendation, the Commission could determine that the available Colstrip capacity is used and useful. Under such an assumption, it would be possible to compute the appropriate level of rate relief for the portion of the output which is available to PP&L's system.

The Commission could adopt a strictly short-run analysis, and assume that the power not committed to Black Hills is useful on Pacific's system. For such an analysis, it would be important to exclude the common facility and transmission costs which are not actually associated with Colstrip #3, and should be assigned to Colstrip #4, to BPA, or to future projects.

This is particularly important so long as Pacific is continuing efforts to sell its share of this project. In addition, the Commission should exclude entirely that portion of Colstrip #3 output, and the capacity required to generate that output, which is committed to Black Hills from Washington rates. For this amount of power, there is not even short-run availability, even if one assumed that the power, if available, would find a current market on Pacific's system.

Q. Have you prepared an exhibit which details the adjustments you recommend if the Commission determines the currently available capacity to be used and useful?
A. Yes, page 2 of my exhibit shows the development of a rate proposal based solely on the assumption that the Washington allocated share of power from Colstrip #3 (including 50% of the common facilities and the "A" transmission line) which is not committed to Black Hills is used for Pacific's customers, and that this power is sold at the average revenue per kwh on the Washington System.

Q. Please discuss each adjustment on page 2 of your exhibit?

A. Line 9 shows the Company investment, as shown on Page 2 of Record Response #4. Line 11 shows the first year cost/kwh of 65.3 mills as provided by the Company in their response to data request PC-3, which is reproduced as Appendix E to my exhibit. The levelized cost, provided in response to PC-3, is 78 mills/kwh. I am uncomfortable with these estimates, but have used the Company-provided figures in my analysis.

Lines 14 and 15 remove, respectively, the investment at December, 1983, associated with the "B" transmission line, and 50% of the production facilities common to Colstrip 3&4. Line 17 shows the net investment in plant which is currently available for service, some $39 million less than the Company has proposed on a systemwide basis.

Line 19 applies the fixed charge rate of 12.21%, provided by the Company in response to the request for the first year cost of Colstrip (PC-3), to the adjusted investment. Line 20 adds depreciation at a 35 year straight line rate, producing the annual capital cost (systemwide) on line 21.

The Company calculated production costs assuming a 70% capacity factor in response to RR-2. I have adjusted the variable fuel cost portion of this to reflect the first year capacity factor of 60%, as testified to by Mr. Steinberg (TR 25).

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Line 27 shows the total first year cost, consisting of the annual capital cost in line 21, plus the variable fuel, and fixed production costs in lines 24 and 25.

Line 29 shows the first year output, and line 31 the cost of that output at 65.97 mills/kwh. Using the Company's 70% capacity factor assumption in the response to PC-3, the cost/kwh would drop to 57.6 mills. Line 33 shows the amount of energy committed to Black Hills, based upon the 80% capacity factor assumed by Black Hills in their FERC submittal included in Appendix B of my exhibit. Subtracting this from the total output leaves the residual first year output available to Pacific's system in line 35 of 262,800 MWH.

Line 36 adjusts this using the Company's Washington allocated share. I should point out that this allocator, of 16% to Washington is based on the state contribution to Pacific's system peak. If an energy, or peak-credit allocator were used, recognizing that Colstrip was built primarily for energy, rather than peak, the Washington share would be much lower. For example, the weighted average cost of capital for measuring the cost of Colstrip in the Black Hills Contract is determined using an energy allocator. I believe the Commission should initiate an investigation into the interstate allocators used by Pacific, as a peak-based allocator simply fails to recognize the primarily energy-related purpose of the baseload plants and transmission lines which form the basis of the need for interstate allocation. In my analysis, I have used the Company's allocator.

Line 37 adjusts the Washington share for 10% losses, taken from the estimate in Exhibit 3; this was neglected by the Company in their response to PC-3. Line 39 shows the revenue requirement (systemwide) based on the cost/kwh in line 31, and the output available to the system in line 35. Line 41 shows the Washington allocated share of that systemwide revenue requirement, again using the peak allocator Pacific has used in this proceeding. It would be possible to conduct this allocation using the jurisdiction-specific rates of return, but the differences would be insignificant.

The resulting amount, $2.776 million, must then be adjusted to recognize the revenue that will be received from the sale of the additional kilowatt-hours produced by Colstrip #3, before a residual rate increase can be determined.

If in fact the Washington allocated share output of Colstrip is used in Pacific's Washington system, it will be sold at the currently effective retail tariffs; the average revenue at present rates from these Washington tariffs is 4.86 cents/kwh (Tr. 79). The sale of this power would thus produce an offsetting revenue of $1.84 million. This leaves a residual revenue requirement of $935,000 for this proceeding. If the

Commission finds that the output of Colstrip #3 is used and useful in the Company's Washington service area, this is the maximum revenue requirement adjustment that would appear justified. Absent the capacity factor reduction in lines 24 & 29, the residual revenue requirement would be $722,000.

However, I recommend that the application be rejected on the basis that the excess capacity provided by Colstrip #3 provides no short-run benefits to Pacific's ratepayers, and the Black Hills contract commits the output over the long-run, so that there are no long-run benefits available either. The exercise above is based solely on a short-run analysis which assumes that the Colstrip capacity which is available to the Company is, in fact, used and useful.

Q. Does this complete your prepared testimony?

A. Yes.