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**Some Issues Related to Possible
Power Generation as a By-Product of
Special Nuclear Materials Production**

University of California



LOS ALAMOS SCIENTIFIC LABORATORY

Post Office Box 1663 Los Alamos, New Mexico 87545

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Edited by Lidia Morales, S-DO

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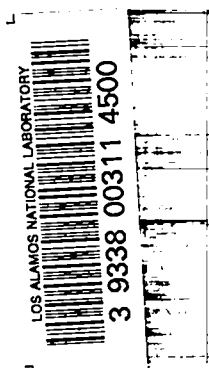
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Some Issues Related to Possible Power Generation as a By-Product of Special Nuclear Materials Production

S. V. Jackson



SOME ISSUES RELATED TO POSSIBLE POWER GENERATION
AS A BY-PRODUCT OF SPECIAL NUCLEAR MATERIALS PRODUCTION

by

S. V. Jackson

ABSTRACT

Various nontechnical issues that may arise for electric power generation by a Replacement Production Reactor project are explored and evaluated based on the possible introduction of impediments to the reactor construction and operation. The problems of a new production facility as a major power consumer are also evaluated. There are definite advantages for the power-generation case whereas the power-consumption case introduces significant barriers to the project. For the power-generation case, a system in which the reactor and generator are separate facilities minimizes the barriers to the construction of the total production facility.

EXECUTIVE SUMMARY

For a future Replacement Production Reactor (RPR) located either in the Pacific Northwest at the Hanford Reservation or in the Southeast at the Savannah River Plant, the following conclusions are reached.

- o Issues arising from net power generation by an RPR introduce no major impediments to an RPR.
- o Electric power generation by an RPR is likely to increase its societal acceptance.
- o A definite need exists in either region for electricity produced by an RPR.
- o Making distribution and marketing arrangements for RPR electric power should not prove difficult.

- o The probable RPR scenario will follow the N-reactor precedent at Hanford of separately owned and operated reactor and generator.
- o The siting of an RPR that would be a major power consumer in either region would probably be relatively difficult.

In reaching these conclusions, various issues associated with net electric generation or net electric consumption by a future RPR were explored. These include the projections of regional electric power supply, demand, and cost; the issue of who might build, own, and operate any generating facilities associated with an RPR; and the possible introduction of any legal or social constraints by making an RPR a net power producer or consumer. For the purposes of this study, only the Hanford Reservation and the Savannah River Plant were considered as possible sites for an RPR.

I. INTRODUCTION

A. Energy Related Issues

The US Department of Energy (DOE) is planning the design and construction of one or two new Replacement Production Reactors (RPRs) that will supply special nuclear materials for the nation's defense needs. In addition, the proposal has been made that any future RPR should operate in a dual-purpose mode if possible, producing net electric power from otherwise wasted heat as well as producing special nuclear materials. However, it is imperative that electric generation by an RPR not significantly delay construction nor hinder operation of that RPR. The purpose of this report is to examine the issues that arise as an RPR is made a net power producer (or possibly a major power consumer) and identify impediments that may be introduced.

A variety of issues arise for an RPR that is a net power producer or consumer. For example, power production may not be worth the added construction cost if there is no need for or market for the power produced. In addition, power production could introduce added environmental and regulatory proceedings that could delay construction of an RPR. In the case of an RPR that would be a major power consumer, issues such as power supply adequacy and system vulnerability to power supply interruptions could negatively impact the siting and operations of an RPR.

The issues treated in this study fall into four main categories and are explored by answering the following associated questions.

- (1) Is there a demand for any electric power produced by an RPR, and what is the associated value of that power?
- (2) Who will build, own, and operate the generating facilities, and what will be the associated power marketing arrangements?
- (3) If the RPR is a net consumer of power, how is the vulnerability of special nuclear materials production affected?
- (4) What are the social and institutional issues introduced by power generation or consumption by an RPR, and are they significant?

B. Background

Special nuclear materials (plutonium and tritium) for nuclear weapons needs are produced at four nuclear reactor facilities in the United States under the purview of DOE. The P, K, and C reactors, which are located at the Savannah River Plant at Aiken, South Carolina, are low-temperature, heavy-water-moderated reactors that are net consumers of electrical energy. The fourth reactor (N reactor), which is located on the Hanford Reservation near Richland, Washington, is a high-temperature, graphite-moderated reactor that exports just less than 4000 MW of thermal energy to a nearby generating plant, which produces 800 MW of electric power. The four reactors were designed and are operated specifically for the production of defense related special nuclear materials.

Recently, there has been concern whether the existing facilities will continue to meet the US defense nuclear stockpile needs in the late 1980s.¹ The N reactor at Hanford will reach the end of its operating life in the early-to-mid 1990s. The Savannah River Plant production facilities, although not lifetime limited, will be over forty years old by the mid-1990s. In addition to the possibility of loss of all production facilities by 2000, it is increasingly probable that operational and maintenance difficulties of these aging production plants will preclude the US from meeting production goals for special nuclear materials. At the very least, the production costs can be expected to increase greatly. There is also concern that the DOE production capability is "single threat, that is, not sufficiently redundant

to be able to handle technical problems, and lacking an expansion capability..." (Ref. 1, p. 9).

In light of the probability of a shortfall in defense materials production capability, DOE is studying the design and construction of one or two RPRs to satisfy the national need for special nuclear material through the early twenty-first century. The time span for construction of an RPR is such that, if construction was started immediately, an RPR would not be operational before about 1992-93. Therefore, it is imperative that no unnecessary delays be introduced in planning and constructing an RPR.

Seven RPR facility concepts are currently undergoing technical design review. These are

- o ACCEL Accelerator Neutron Generator
- o LMFBR Liquid Metal, Fast-Breeder Reactor (high temperature)
- o LWR Light-Water Reactor (high temperature)
- o LTHWR Low-Temperature, Heavy-Water Reactor (Savannah River type)
- o HTGR High-Temperature Gas Reactor
- o HTHWR High-Temperature, Pressurized, Heavy-Water Reactor
- o RNR Replacement N Reactor (designed to meet modern environmental and safety regulations; high temperature)

In net energy generation or consumption, these concepts have been presented in scenarios ranging from a net generation of 1000-1100 MW electric (high-temperature reactors) to a net consumption of 200-300 MW electric (accelerator). In the design review, a credit is given for the production of electrical energy; first, from the point of view of assurance of an energy supply for the RPR and second, from the point of view of net product cost of the plutonium and tritium produced.² The RPR concept scenarios generally include the equipment for recovery of by-product energy, and in the design review, any net electric energy generated and sold has been assigned a value of 23 mills/kWh in 1981 dollars.*

*M. R. Shay, private communication, United Nuclear Corporation, Richland, Washington, March 27, 1981.

C. Study Approach and Assumptions

This study examines some of the issues associated with power generation or consumption by an RPR. It is one of several studies treating nontechnical issues (that is, issues not directly related to the RPR technical design) of a future RPR. An RPR that generates only its own station power was presupposed as a base line for examining the power related issues. The base-line RPR is therefore connected to the power grid only for start-up power or for emergency backup power. This study then focused on issues that arise as the base line is changed to make the RPR a net energy producer or net energy consumer. In light of the need for an RPR to assure an adequate supply of defense special nuclear materials, any issues that would delay construction or hinder operation of an RPR were considered to be most significant.

As a limitation on this study, the assumption was made that an RPR will be located with the existing production facilities and fuel processing facilities at the Hanford Reservation and/or the Savannah River Plant. Furthermore, in view of the N-reactor precedent as a dual-purpose reactor and because of the very detailed electric power planning information readily available for the Pacific Northwest region, the location of an RPR at the Hanford Reservation was analyzed in greater detail. The Savannah River Plant location was then examined on a general comparison basis with Hanford.

Although the RPR concept scenarios generally include energy recovery facilities in designs and costs, it was assumed that the electric power generating facilities need not necessarily be directly part of the RPR. Total energy dump facilities are a required part of each design scenario; furthermore, this assumption is consistent with the N-reactor precedent in which steam is sold to the Washington Public Power Supply System (WPPSS) for generation of electric power. Indeed, the issue of who builds, owns, operates, and markets power from the generator is one of the more important energy related issues examined in this study. The assumption can be made, however, that all RPR concepts have been optimized as much as practicable for electric power cogeneration, subject to maintaining sufficiently high quality and quantity of special nuclear materials production.

The four categories of questions noted in Sec. I.A. are explored in the next four sections.

II. ELECTRIC POWER PROJECTIONS

A. General Criteria

The principal electric power projections that will have impacts on an RPR project are the projections of (1) peak and average electric load growth, (2) changes in the level of generation resources, and (3) future electric generation costs or electricity value. Clearly, if there is no demand for additional electric power in the region of the RPR or if the electricity has very little value there, it would be uneconomic to add generation capability to the RPR over and above station power. However, reliably projecting these factors is made difficult by the long lead-time before earliest operation of an RPR in 1992-93.

Forecasting of peak and average electric load growth is difficult because of numerous variables, including weather, population growth, economic conditions, price and availability of fuels, consumer behavior and lifestyle, technological change, and changes in government regulatory policies. The evaluation of these variables may be done on a model basis or on a historical basis. The inherent uncertainties of forecasting are compounded as the time frame for the forecast is extended. To apply to an RPR project, any forecasts must extend through at least 1990 to give some idea of conditions near the time of RPR start up and should perhaps extend for ten to twenty years beyond. For a thirty-year forecast, growth rates in power demand ranging from 2.0% per year to 5.1% per year³ result in demand increases that range from a factor of 1.81 to 4.45, which is clearly a large uncertainty. Therefore, a range of growth rates was examined, including a "most likely" growth rate (picked by a consensus) examined in detail.

Projections of changes in future electric generation resources are fairly clear-cut for a short-term time frame. They can be made on the basis of construction plans. However, as will be shown, the situation of plants with long lead-times, particularly nuclear plants, is far from clear. In addition, the long-term load growth uncertainties, various financial uncertainties, and regulatory uncertainties, all cause resource predictions to be sparse and of little use after the early 1990s.

Predictions of electrical generation costs and electricity values were made based on electric generation plants currently in operation or under construction. However, uncertain future economic conditions and uncertain

construction schedules can cause significant errors in predicted electric generation costs. Future technological changes can also introduce uncertainties. In addition, the fact that electrical energy will be a cogeneration by-product of special nuclear materials production by an RPR will have an effect on the value of power from an RPR.

As noted earlier, the Pacific Northwest region was analyzed in detail. The situation in the southeastern region of the Savannah River Plant will be examined in relation to the Pacific Northwest.

B. Electric Load Growth

The Pacific Northwest is unique in many aspects of electricity generation and use. In 1979, slightly over 70% of all electricity in the Pacific Northwest was hydroelectric power.⁴ This hydroelectric capacity has resulted in the nation's least expensive electricity and a per capita electric energy consumption for the region of almost double the national average (although the regional consumption of all energy forms is actually slightly less than that for the nation).⁵ The region's hydroelectric potential has now been developed essentially to the limit of its capacity, and the system is in a state of transition to a mixed hydro and thermal generating system. As this takes place, the electricity rates in the region will increase dramatically (for example, a 53% rate increase was recently proposed by the Bonneville Power Administration, the regional electric power pool coordinator⁶). The rate increases will probably slow the load growth in the Pacific Northwest, and this certainly leads to some uncertainty in predicting future load growth in the region. In addition, it is presently unclear how load growth will be affected by the emphasis placed on conservation measures in the recent Pacific Northwest Electric Power Planning and Conservation Act (Public Law 96-501).

The principal organization performing electric load forecasting is the Pacific Northwest Utilities Conference Committee (PNUCC). They predict the regional average and peak electric load growths and publish the results yearly along with a compilation of projected resources in both a West Group Forecast^{7,8} covering ten years and a "Blue Book"⁹ covering twenty years. Predictions of load growth are made by using a regional econometric load forecasting computer model as well as by using a compilation of individual

forecasts made by each of the electric utilities in the West Group Area.* Historically, the PNUCC forecasting methods have been quite successful, with a deviation usually about 5% on the high side between the actual and estimated 12-month average firm loads. It is generally thought that forecasting the loads slightly on the high side is advantageous because the consequences of being in error are much greater if power shortages occur than if excess capacity is available.

The PNUCC projected electrical energy use growth rates are presented in Table I along with projected growth rates from several other recent studies of the region. The regions covered by the studies are not precisely the same although they overlap to a large extent. The Washington Public Power Supply System (WPPSS) estimate is from a compilation of forecasts by 88 utilities participating in Washington Nuclear Projects (WNP) numbers 4 and 5. The National Electric Reliability Council (NERC) projection is from a compilation of forecasts of electric utilities in the Northwest Power Pool (NWPP) subregion. This subregion consists of Washington, western Oregon, the Idaho panhandle, and western Montana. The Northwest Energy Policy Project (NEPP) study results presented are from a report sponsored by the Pacific Northwest Regional Commission (Ref. 5, p. 7).

The projected growth rates are significantly lower than the historical growth rates (Table I). There has been a general downward trend in the annual growth rate: from approximately 7.5% through the 1960s, to 6% during the early 1970s, to a current rate of approximately 3.8%. The reductions probably have resulted from such factors as greater conservation efforts, more efficient energy use, and higher electricity prices. The NEPP and PNUCC studies have considered additional conservation in their projections. The general consensus is that conservation and improved efficiencies will not continue to lower significantly this load growth rate. Significant factors in this consensus are the population distribution and the continued influx of people into the Pacific Northwest. The Pacific Northwest states have an abnormally large number of young people in their populations. This and the

*The West Group Area includes the state of Washington; the panhandle of Idaho; Oregon, except for the southeastern part of the state; a portion of northern California; Bonneville Power Administration (BPA) and Pacific Power and Light Company services in Montana; and BPA loads and Water and Power Resources Service resources in southern Idaho.

TABLE I
 PACIFIC NORTHWEST AVERAGE ANNUAL ELECTRIC ENERGY CONSUMPTION GROWTH RATES

State or Region	Historical ^a (1964-1974)	PNUCC ^b Model (1980-2000)	PNUCC ^b Forecast (1980-2000)	WPPSS ^c Participants (1980-1992)	NERC ^d NWPP (1979-1989)	NEPP ^a (1974-2000)		
						Low	Moderate ^e	High
Washington	5.79	----	----	----	----	1.44	2.94	4.32
Oregon	5.95	----	----	----	----	1.27	2.97	4.54
Idaho	6.66	----	----	----	----	1.72	2.80	4.24
Pacific Northwest ^f	5.94	2.8	3.1	4.4	4.1	1.43	2.93	4.38

^aRef. 5, p. 7.

^bRef. 9, pp. 4-9.

^cRef. 10, p. 10.

^dRef. 11, pp. 34-44.

^eThis scenario is considered to be most probable.

^fThis region is not precisely the same for all studies. See Sec. II.B.

population influx will ensure the need for new homes and facilities, mitigating increased conservation efforts.

The moderate NEPP projection of 2.93% growth rate is very close to the two values currently projected by PNUCC. Therefore, it is of interest to examine the assumptions underlying the NEPP moderate projection, which was labeled as "most probable." The detailed assumptions given in the NEPP report (Ref. 5, pp. 1-36) may be summarized as follows.

- (1) Energy consumption growth (2.93% per year) will be faster than population growth (1.3% per year) and somewhat faster than income growth (2.6% per year, expressed as per capita gross regional product).
- (2) Electricity prices will rise to the price of replacement thermal power by 1990.
- (3) All new demand through 2000 will be met by a 50:50 mix of coal-fired and nuclear thermal plants.
- (4) Total electric conservation reductions by 2000 will be 12%.
- (5) At best, only 8-10% of total residential energy requirements will be supplied by unconventional (that is, solar and renewable) resources by 2000.

The effects of various projections of electric load growth rates on total average electric demand are illustrated in Fig. 1. The projected resources are also indicated and will be discussed in the next section on resource projections. The projected resources are based on a 42-1/2-month multiple-year critical period of stream flow for hydroelectric generation, based on historical data. Under high water flow conditions, excess power (secondary energy) is exported by means of three high-voltage tie-lines to California, replacing oil-fired thermal generation, and is also sold to regional aluminum production plants.

In addition to the average electric power load, the peak power load, which occurs in midwinter in the Pacific Northwest, is also important. In general, large-thermal-plant power will be used to meet baseload requirements whereas hydroelectric power will be used to meet power peaks. The peak-load power requirement for the Pacific Northwest, defined as the peak power needed for some one-hour period during the year, is projected by PNUCC to increase at an annual rate of 3.7%. This is conservative when compared to recent growth

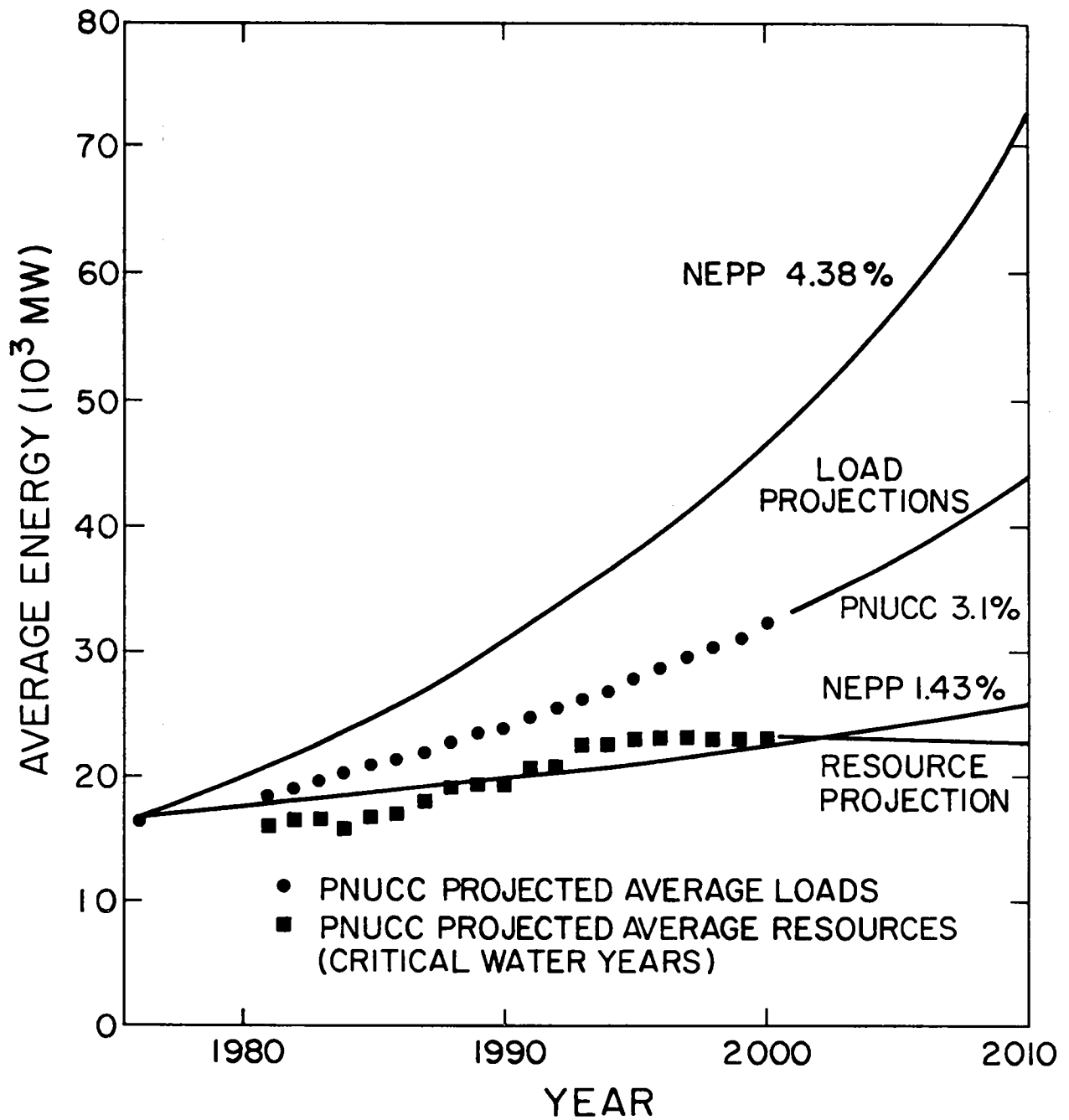


Fig. 1. Energy forecasts for the Pacific Northwest load growth and resource projections.

rates exceeding 4%. The results of a 3.7% per year increase in peak-load requirement accompanied by the projected peak resources are illustrated in Fig. 2. The total feasible generating capacity of a region should be equal to the peak load plus some percentage of reserves to cover possible plant outages.

The situation in the southeastern United States in the region of the Savannah River Plant* is similar in terms of load growth. The historical load growth has been above the national average and is projected at an average of 4.8% per year for the next decade (Ref. 11, p. 44). The peak-load growth is also projected at 4.8% (Ref. 4, p. XI.7.3). These figures may be somewhat high because significant contributions from conservation have not been considered although they are lower than the historical growth rates of 8.9% per year and 6.5% per year respectively. In terms of other loads, the region lacks the major tie-line capability equivalent to the 4000-MW capacity tie-line between the Pacific Northwest and California, and it has a much smaller secondary electric load (142 MW vs 1200 MW) of secondary power that may be interrupted to handle system emergencies or power supply shortfalls (Ref. 4, p. XI.7.51 and Ref. 7, p. 7).

C. Electric Generation Resource Forecast

Resource forecasting for the short term is reasonably clear cut in most cases because it can be based on operating plants, planned outages, and construction plans. For the long term, resource planning is somewhat tentative because it must be based on uncertain predictions of load demand. In the midterm, long lead-time plants such as large coal-fired and nuclear thermal plants must be considered in the resource projections. In this case, uncertainties in financial climate, regulatory policies, and load growth can all contribute to uncertainty in resource projections. However, it is precisely the long lead time needed for construction of large thermal plants (9-12 years) that makes midterm forecasting important.

In the Pacific Northwest, the forecasting of electric generating resources is further complicated because the resources have a very large hydroelectric component. Because of the necessity of meeting firm electric loads, resource

*In general, this analysis will consider the Virginia and Carolina Subregion (VACAR) of the Southeastern Electric Reliability Council (SERC) that includes South Carolina, North Carolina, and eastern Virginia.

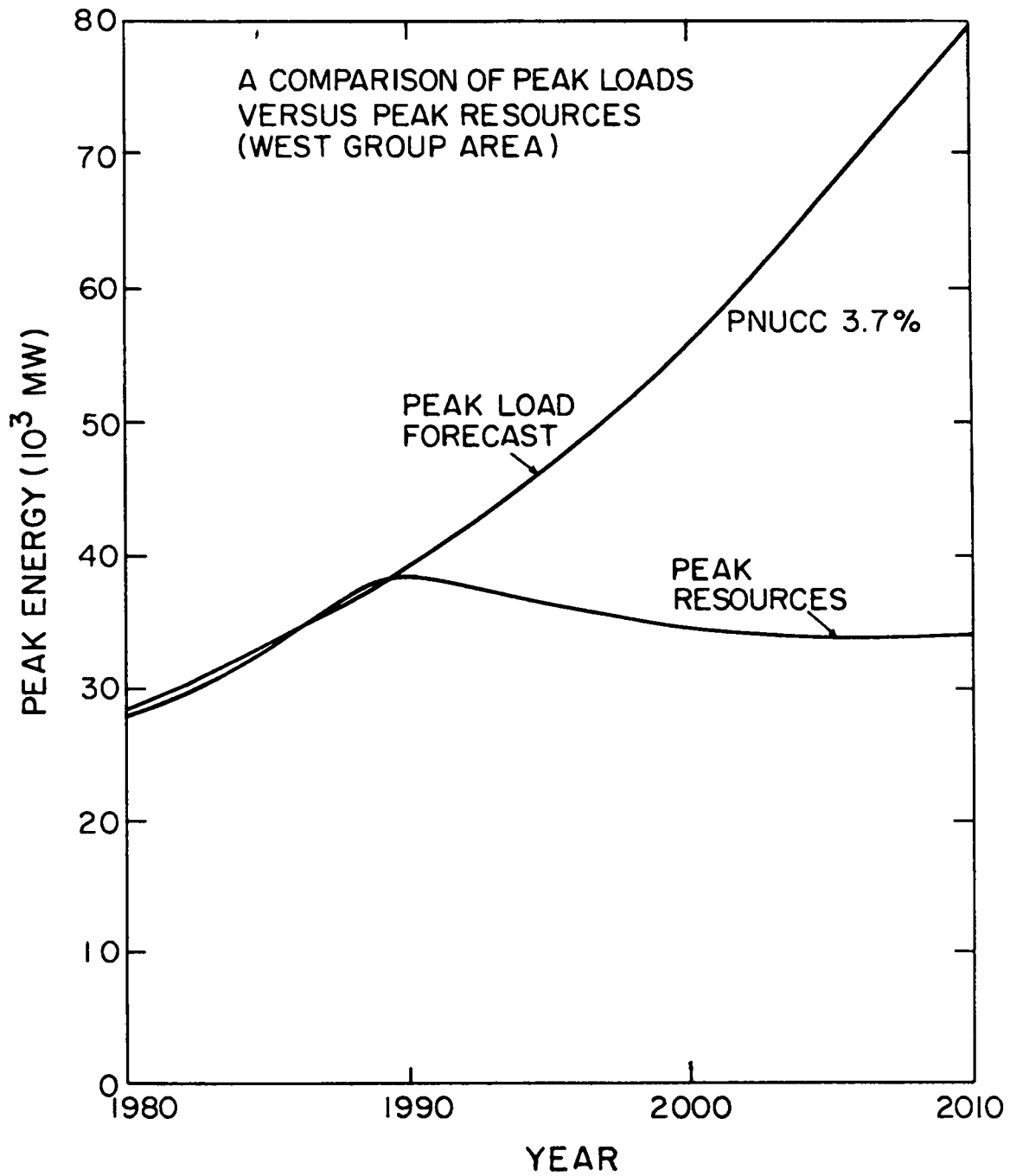


Fig. 2.
Peak load and resource forecast for the Pacific Northwest.

planning is based on adverse water flow. The firm hydroelectric power available is assumed to be that which could be generated under minimum recorded river flow. In the Pacific Northwest, this is the 1936-37 period centered in a 42-1/2-month period (Ref. 9, pp. 4-9), which is chosen on the basis of low water flow and system storage capacity. In normal or high water flow years, there may be an excess of capacity that gives rise to the notion of secondary (surplus) power. In the Pacific Northwest, this power is treated in three principal ways. (1) It may be used to replace more expensive thermal power, (2) it may be sold at a lower rate to interruptible users (in the Northwest it is sold principally to aluminum plants), and (3) it may be exported to some other region; in this case by three large tie-lines (4000-MW capacity) to California to replace oil-fired electric generation.

In Fig. 1, the West Group Area electric generation resources (under adverse water flow) have been shown along with projected average electric load for the next 30 years (Ref. 9, pp. 4-9). All anticipated delays in thermal plant construction as of December 1980 have been included in the projections. The dip at 1983-84 reflects the possible loss of the Hanford Generating Plant at the N reactor because of environmental problems. The loss is 515 MW (average); however, it is likely that this plant will continue operation into the early 1990s. There is a leveling off of the resource projection after the mid-1990s because there are no firm plant orders for after this time. At present, the long-term resource planning is very tentative because there is sufficient time to alter the plans significantly when the load forecasts become more reliable.

To illustrate the composition of the resources, Fig. 3 presents the load and resource forecasts through 1991 for the West Group Area (Ref. 7, p. 3), but does not reflect all known thermal project delays as of December 1980. It shows the planned startup of several major thermal power plants and the transition of the Pacific Northwest power system from a chiefly hydroelectric system to a more balanced hydroelectric-plus-thermal electric system. The figure also illustrates the problems that arise with delays in construction of major thermal plants. When originally ordered, all five of the WNP plants were due online by early 1983; Skagit 1 was due in mid-1981, and two plants at Pebble Springs were due online by mid-1983.¹² Clearly, had these plans materialized, the possibility of a resource shortfall would have been eliminated at least through the late 1980s. Presently, water flows above

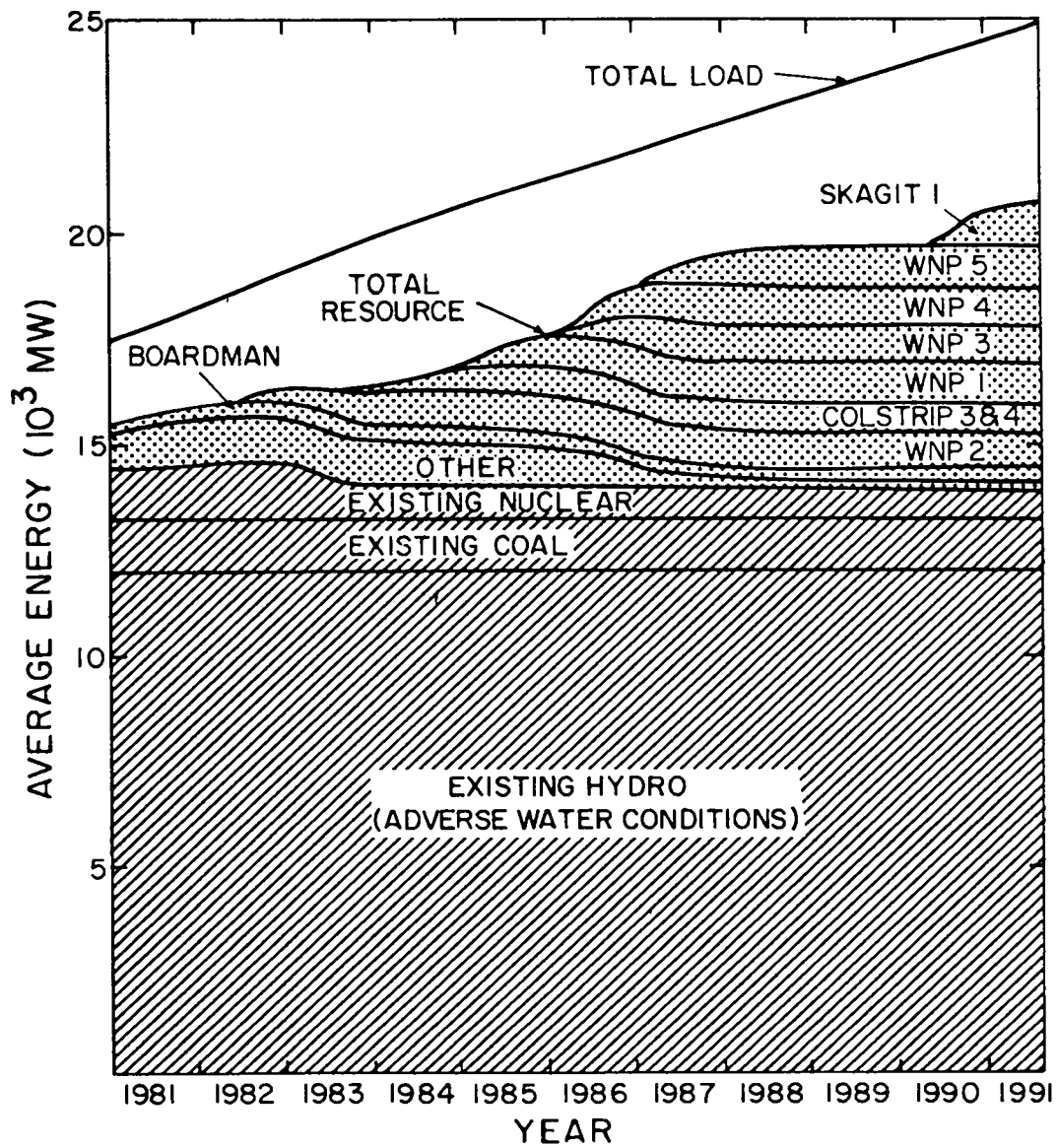


Fig. 3.
West Group forecast of energy loads and resources.

critical levels would possibly prevent the severe shortfalls indicated in Figs. 1-3; however, drought conditions in 1977 and 1979 did lead to severe problems involving power curtailments on a voluntary basis (Ref. 4, pp. XI.9.21-23).

The shortfalls indicated in Figs. 1-3 can only be aggravated by further delays in the construction of large thermal plants. The expected operation dates of the major thermal plants in the Pacific Northwest as revised over a recent 20-month interval are presented in Table II. The most recent projections must be regarded as optimistic in light of both the continued delays and the present uncertain regulatory regime under the Nuclear Regulatory Commission (NRC). The current uncertain financial climate can also contribute to delays or possible plant cancellations. WPPSS estimated that the 30 reactor-month delay from September 1980 to December 1980 will cost them approximately \$1.1 billion (Ref. 10, p. 23).

Further plant delays can only increase the likelihood of a serious shortfall in electric power in the Pacific Northwest with consequent brownouts/blackouts or the importation of expensive oil-generated electric power from California, if available. The PNUCC has analyzed the probability that resources will be insufficient to meet firm energy demand for at least one four-month period. Their analysis was based on the two assumptions of full reservoirs in July 1980 and thermal power plant operations dates predicted in July 1980, as well as the use of standard risk analysis and statistical techniques applied to plant operations and predicted water flow. The results indicated that a one-period insufficiency had a probability of 85% by 1984-85 and 100% by 1990-91 (Ref. 7, p. 7).

Clearly, because the Pacific Northwest is in a situation in which it needs more power, an additional 1000-1100 MW of generating capacity from an RPR would be welcomed. This would be the case even if, as with the current N reactor, the power would not be counted towards firm peaking power but only as average energy capacity. (This is due to the reactor running primarily to produce special nuclear materials with electricity as a by-product.)

In the Virginia and Carolinas Region (VACAR), the resource planning is greatly simplified because hydroelectric generation makes up only 6.9% of the capacity and 4.9% of the generation (Ref. 4, p. XI.7.48). Sufficient power plants exist or are planned in order to meet load growth; however, in South Carolina, North Carolina, and Georgia, significant delays in nuclear power

TABLE II

MAJOR PACIFIC NORTHWEST THERMAL ENERGY PROJECTS

Project	Ownership		Capacity (MWe)	Energy Date		
	Private	Public		as of 11/79 ^a	as of 9/80 ^a	as of 12/80 ^b
WNP 2	---	100 ^c	1100	9/81	1/83	9/83
WNP 1	---	100 ^c	1250	12/83	6/85	2/86
WNP 3	30	70 ^c	1240	3/85	6/86	9/86
WNP 4	---	100	1250	6/85	6/86	2/87
WNP 5	10	90	1240	6/86	6/87	9/87
Skagit 1	100	--	1288	11/86	7/90	--- ^d
Pebble Springs 1	90	10	1260	3/87	7/92	--- ^d
Skagit 2	100	--	1288	11/88	7/92	--- ^d
Pebble Springs 2	100	--	1260	4/89	7/94	--- ^d
Colstrip 3	100	--	490	7/83	1/84	--- ^e
Colstrip 4	100	--	490	5/84	11/84	--- ^e

^aRef. 9, Table 5.

^bRef. 10, pp. 22-26.

^cProject is net-billed to the Federal System (Bonneville Power Administration).

^dNot yet licensed for construction. Pebble Springs plants will not be licensed before 1982.¹³

^eCoal-fired plant.

plants have occurred. These have led to the prediction of dangerously low generation reserves in some cases. In the case of Duke Power Co., reserves are expected to slip "from an uncomfortable 17.6% in summer 1988 to a downright dangerous 9.8% in the winter of 1989-90."¹⁴

Original expected in-service dates for seventeen nuclear reactors located in the Savannah River Plant region (generally VACAR except that Georgia has been substituted for eastern Virginia) along with revisions have been listed in Table III. Catawba 2 is likely to be made indefinite¹⁴ and, furthermore, many of the units put into indefinite status may be cancelled if spent monies can be recouped through regulatory rate relief.¹⁴ By comparison with Table II, delays in nuclear reactor construction appear to be as bad, if not worse, in the Southeast as in the Pacific Northwest.

Most of the reactors were categorized as indefinite in Table III because of financial reasons, not because of changes in projected load growth. This is apparent from the Duke Power Company's projected reserves.¹⁴ Further slippage of nuclear plant construction can only result in a decrease in reserve capacity with a resulting decrease in system reliability. Although no power shortfalls are foreseen for the late 1980s to early 1990s for VACAR, it has been noted that (Ref. 4, p. XI.7.55):

Based on practical expectations and/or historical records, there will always be a dependence on oil/gas units to meet unusual load conditions, a dependence that increases with in-service date slippage. Such a condition is contrary to the national commitment to reduce oil consumption.

Thus, in the Southeast as in the Pacific Northwest, a large block of power from an RPR would be welcomed even though actual severe power shortages are not foreseen for the Southeast.

D. Electric Generation Costs and RPR Electricity Value

In the current RPR design review, a credit of 23 mills/kWh (in 1981 dollars) is given for net electricity generated and sold by the RPR. The question then is how this compares with predicted electric generation costs in the early 1990s. In the Pacific Northwest, the current wholesale rate for firm electricity is under 10 mills/kWh although this is expected to rise quite rapidly as thermally generated power becomes a greater percentage of the total

TABLE III

NUCLEAR POWER PLANTS PLANNED FOR THE SOUTHEASTERN US

Project	Capacity (MWe)	Energy Date		
		as of order ^a	as of 8/80 ^a	Most recent projection
McGuire 1	1180	3/76	8/80	Zero power testing ^f
McGuire 2	1180	3/77	4/82	--/83 ^f
Catawba 1	1145	3/79	7/83	--/84 ^f
Catawba 2	1145	3/80	1/85	--/85 ^f
Perkins 1	1280	1/81	indefinite	indefinite
Perkins 2 ^b	1280	1/82	indefinite	indefinite
Perkins 3	1280	1/83	indefinite	indefinite
Cherokee 1	1280	9/82	1/90	indefinite ^f
Cherokee 2	1280	9/83	1/92	indefinite ^f
Cherokee 3	1280	9/84	indefinite	indefinite
Harris 1	900	3/77	8/85	no change
Harris 2 ^c	900	3/78	3/88	no change
Harris 3	900	3/79	3/94	no change
Harris 4	900	3/80	3/92	no change
Vogtle 1	1100	2/78	--/85	--g
Vogtle 2 ^d	1100	2/79	--/85	--g
Summer 1 ^e	900	10/77	6/81	--h

^aRef. 12.

^bDuke Power Co.

^cCarolina Power and Light.

^dGeorgia Power.

^eSouth Carolina Electric and Gas.

^fSee Ref. 14. McGuire 1 is now delayed until at least 6/82 (Ref. 15).

^gFirst concrete has not been poured (Ref. 16).

^hDelayed until at least 6/82 (Ref. 15).

regional resource.* The 1980 net generation cost at the WPPSS Hanford Generating Plant at the N reactor was 13.51 mills/kWh (Ref. 17); however, this plant is over 15 years old. The most recent nuclear plant in the Pacific Northwest, Trojan, will produce power* in 1981 for 20-21 mills/kWh.

As the RPR will be a new generating facility in 1992-93, perhaps the best cost comparison can be made with the cost of replacement (or new) thermal power as projected for 1992. The Bonneville Power Administration (BPA) has performed such an estimate for WPPSS nuclear units 1, 2, and 3, which are net-billed (that is, committed in their entirety) to BPA.¹⁸ The estimate was required by Sec. 210 of the Public Utilities Regulatory Policies Act of 1978 (PURPA). WPPSS has estimated power costs for combined units 4 and 5 (Ref. 10, p. 29). These estimates are presented in Table IV. Although PURPA does not apply to large generation plants, it sets guidelines for purchasing replacement power from small renewable and cogeneration systems. The WPPSS estimates assume no further delays in units 4 and 5. Furthermore, the recent Pacific Northwest Electric Power Planning and Conservation Act of 1980 establishes a Pacific Northwest Electric Power and Conservation Council that shall oversee BPA in coordinating power loads and resources for the Pacific Northwest and rates for that power. Thus, there is some uncertainty in the value of electric power until this council is appointed and in operation. Nevertheless, Table IV indicates that 20-25 mills/kWh for electricity from an RPR is a conservatively low figure for the Pacific Northwest.

In the Southeast, this price would also be expected to be conservatively low. Any nuclear plant going into service in the early 1990s should have similar generating costs throughout the US. Furthermore, the electric costs in the Southeast are already much higher than those in the Pacific Northwest because over 90% of the generation is from thermal plants. In 1979, the average costs of power sold for resale (wholesale power) were (in 1981 dollars):** 27.8 mills/kWh for Duke Power Co., 29.1 mills/kWh for Carolina Power and Light Co., and 25.6 mills/kWh for South Carolina Electric and Gas

*Conversations with Arlee Holm of the Division of Power Resources, Bonneville Power Administration, Portland, Oregon, February 6-7, 1981.

**Data are revenues from sales for resale divided by kilowatt-hour sales for resale times 1.081 (GNP deflator, 1979 to 1980) times 1.10 (assumed inflation to 1981).¹⁹

TABLE IV
 WASHINGTON NUCLEAR PROJECTS (WNP) GENERATING COSTS
 IN 1981 DOLLARS

Project	Assumed Availability Factor (%)	Costs as Quoted (mills/kWh)	Dollar Year	Yearly Inflation Rate Assumed (%)	Costs in 1981\$ (mills/kWh)
WNP 1 ^a	67	39.47	1982	12	35.2 ^c
WNP 2 ^a	67	44.53	1982	12	39.8 ^c
WNP 3 ^a	67	45.23	1982	12	40.4 ^c
WNP 4 ^b }	65	75.5	1992	8	32.4 ^d
WNP 5 ^b }					

^aRef. 18.

^bRef. 14.

^cThese are long-run average costs. A 1992 cost present-valued to 1981 would be somewhat lower.

^dThis is the 1992 cost. It assumes no further delays beyond those noted in December 1980 by WPPSS.

Co. Against these prices, an RPR generation cost of 23 mills/kWh (1981 dollars) would look good, especially if escalation above inflation for fuels is applied to the current costs and if the marginal cost of power from new plants rises (as expected, especially for nuclear plants).

The question arises whether 23 mills/kWh is too low a price for by-product electricity from an RPR. The answer rests on discounts that will be applied to the power precisely because it is a cogeneration by-product of defense special nuclear materials production.

Many of the discounts have been applied in the history of the Hanford N production reactor.²⁰ Viewed as a producer of electricity, the N reactor has been unreliable, inflexible, and subject to some operating risks. In the last ten years, the N reactor met its production goal of 4.5×10^9 kWh/yr only once (1973). Because of the quality requirements of the special nuclear materials produced, scheduled N-reactor outages are relatively frequent and inflexible. Therefore, the PNUCC considers the N reactor to be a source of average energy but not of firm peaking energy. And as an operating risk, the government may shut the reactor down at any time that production of special nuclear materials is not needed for some period. On several occasions in the past 15 years, the N reactor has been threatened with proposed shutdowns. Furthermore, as a production facility for defense special nuclear materials, the reactor is not held liable for interruptions in electricity production or for any damages to the generating station resulting from reactor outages.

A comparison of the N-reactor 1980 generation cost¹⁷ of 13.5 mills/kWh (which includes the negotiated price of steam) to the Trojan nuclear plant's 1980 cost* of approximately 18 mills/kWh indicates a discount of 25%. Applying this to the WNP projections of 32-40 mills/kWh in 1992 (Table IV) results in a range of 24-30 mills/kWh for an RPR that operates equivalently to the N reactor. On this basis, a value of 23 mills/kWh (1981 dollars) is considered reasonable or perhaps slightly conservative.

For the currently proposed RPR concepts, however, the outage rate and outage flexibility have been considerably improved over the N reactor.** The

*Conversations with Arlee Holm of the Division of Power Resources, Bonneville Power Administration, Portland, Oregon, February 6-7, 1981.

**M. R. Shay, private communication, United Nuclear Corporation, Richland, Washington, March 27, 1981.

RPRs have been more highly optimized for electricity production. In addition, certain RPR concepts propose very high availability factors through such things as online refueling (in an RNR) or twin reactors (in an HTGR). Because of these factors, the N-reactor discount of 25% should be a maximum discount, and the 23 mills/kWh figure indeed does seem low. This is probably also the case in the Southeast where 23 mills/kWh is below the 1979 cost of wholesale power (both costs in 1981 dollars). It therefore seems that the credit for electric power should be examined in more detail in the RPR design review and perhaps be allowed to vary according to factors in each design that affect outage scheduling and the reactor availability factor.

III. ELECTRIC GENERATION AND MARKETING

A. The Electric Generation Facilities

The disposition of by-product energy from the production of special nuclear materials is specifically covered by statute in Sec. 44 of the Atomic Energy Act of 1954 as amended. The section reads as follows.²¹

Sec. 44. Disposition of Energy.--If energy is produced at production facilities of the Commission or is produced in experimental utilization facilities of the Commission, such energy may be used by the Commission, or transferred to other Government agencies, or sold to publicly, cooperatively, or privately owned utilities or users at reasonable and nondiscriminatory prices. If the energy produced is electric energy, the price shall be subject to regulation by the appropriate agency having jurisdiction. In contracting for the disposal of such energy, the Commission shall give preference and priority to public bodies and cooperatives or to privately owned utilities providing electric utility services to high cost areas not being served by public bodies or cooperatives. Nothing in this Act shall be construed to authorize the Commission to engage in the sale or distribution of energy for commercial use except such energy as may be produced by the Commission incident to the operation of research and development facilities of the Commission, or of production facilities of the Commission.

The Commission referred to in Sec. 44 has been superseded by DOE.

The proposed RPR concepts have generally included the generation facilities for production of net electrical energy as an integral part of the

total production facility, with DOE building, owning, and operating the generation facilities. This is simpler and more efficient from an engineering standpoint. However, there are institutional problems with this general scenario.*

The main problem is that Sec. 44 of the Atomic Energy Act has been strictly interpreted as not giving specific authorization to DOE to expend funds to build or operate an electric generator as part of the construction of a production facility. This was also at issue in the early 1960s during proposal of the N reactor, as is indicated by a quote from a 1962 opinion written by the Assistant Comptroller General of the United States.²²

... (1) The legislative history of the Atomic Energy Act of 1954 shows an intent by the Congress that no electric generating facility should be built by AEC without congressional authorization.

An attempt to add generating facilities to the N reactor was defeated in Congress although the N reactor was specified by law to be built capable of conversion to electricity production. The conversion was proposed by WPPSS, who specified that WPPSS would build and operate the generation facilities. At that time, approval of the WPPSS proposal also required specific authorization by Congress.**

In general, there are political difficulties in proposing a Federal electric generating project that would compete with or preclude non-Federal (public or private) projects. This has been especially true of Federal hydroelectric projects,²⁶ but is also recently seen in the Pacific Northwest Electric Power Planning and Conservation Act that states in Sec. 3(1)

"Acquire" and "acquisition" shall not be construed as authorizing the Administrator to construct, or have ownership of, under this act or any other law, any electric generating facility.

Thereby, the BPA is forbidden from building or owning an electric generating plant. In consideration of this indication of congressional intent and in

*Conversations with Harold Heacock of United Nuclear Corp., and with Oscar Elgert and Richard Haynes of DOE, Richland, Washington, February 4, 1981.

**The legislative history is covered in detail in Refs. 22-25.

view of the precedent of relatively satisfactory operation of the N reactor as separate reactor and generator, it seems unlikely that Congress will authorize DOE to build, own, and operate a net surplus electric generating plant as part of a future RPR.

Because all the current design concepts for an RPR include electric generating facilities if possible, the change to separate facilities will be relatively easy although it may cost an additional \$100 million.* Close coordination will be necessary in constructing separate facilities to ensure timely completion of an RPR. Environmental problems are expected to be minimal because all the RPR proposed designs are subject to current environmental regulations.

In considering who will build, own, and operate the electric generating facilities, the N-reactor precedent may be considered. Certainly, WPPSS is a prime candidate in the Pacific Northwest. They already own and operate the generating plant at the N reactor; they may especially need the power if any of their five nuclear projects is further delayed or cancelled; and they satisfy the preference condition in Sec. 44 of the Atomic Energy Act of 1954 that priority be offered to "public bodies and cooperatives." Virtually all of the public utilities in Washington are members or participants in WPPSS.

In the Southeast, the situation is much less clear. The major portion of electric utilities in Georgia, South Carolina, and North Carolina that might build an RPR generating station are private investor-owned utilities. The entire region probably does not satisfy the "... high cost areas not being served by public bodies ..." criterion of Sec. 44. To illustrate the situation, Table V presents a comparison of public and private utilities for the Pacific Northwest and for the Southeast. It is clear that WPPSS, representing nearly all of the public utilities in the Pacific Northwest as a Municipal Corporation and a Joint Operating Agency of the State of Washington, is in a good position to purchase thermal power from an RPR and still satisfy the preference condition of Sec. 44. In the Southeast, only South Carolina has a high proportion of public utilities, and this proportion is artificially inflated because the operations of Carolina Power and Light Co. are listed totally under North Carolina.

*Conversation with Harold Heacock, United Nuclear Corp., Richland, Washington, February 4, 1981.

TABLE V
PUBLIC AND PRIVATE UTILITIES^a BY STATE^b

State	1979 Electric Sales			1979 Operating Revenues		
	Public (10 ⁶ kWh)	Ratio	Private (10 ⁶ kWh)	Public (10 ⁶ kWh)	Ratio	Private (10 ⁶ kWh)
Washington	42.5	65:35	22.4	435.2	50:50	440.2
Oregon	6.0	14:86	37.6	70.0	7:93	875.3
Idaho	0.5	4:96	11.2	7.0	3:97	208.2
Montana	0	0:100	7.0	0	0:100	148.2
North Carolina ^c	3.9	5:95	81.3	147.9	6:94	2450.8
South Carolina ^c	6.6	36:64	11.6	160.5	27:73	443.3
Georgia	4.7	9:91	45.4	153.5	9:91	1621.1

^aThis does not include Rural Electric Cooperatives, which represent a small fraction of electric generation. For instance, the 25 Pacific Northwest cooperative listed as participants in WNP 4 and 5 had total sales of \$85.2 million and generated 5.3×10^9 kWh in 1979.¹⁴

^bSee Refs. 19 and 27.

^cA very large private utility, Carolina Power and Light Co., operates in both North and South Carolina but is included only under North Carolina in this compilation.

No entity similar to WPPSS exists in the Southeast, and the largest public utility in the three-state region, South Carolina Public Service Authority, had a total 1979 generating capacity²⁷ of only 1279 MWe. Such a system could not accept 1000-1100 MW of additional capacity and still maintain system stability and reliability. Distribution of the power is complicated by the fact that "... VACAR does not operate as a power pool or dispatch economy energy on a coordinated basis ... " (Ref. 4, p. XI.7.50). Sale of the power is complicated by the fact that without congressional exemption, a public utility may sell no more than 25% of the power from a facility to private investor-owned utilities or risk losing tax-free status for the bonds issued to build the facility (IRS ruling). Thus, in the Southeast, the generating facilities would probably have to be built by a private investor-owned utility (for example, South Carolina Electric and Gas Co., which already serves the Savannah River Plant). This could require specific congressional approval.

B. Electric Distribution and Marketing

In the Pacific Northwest, regardless of how the power is marketed, it will be distributed through the BPA power network. This is the current situation with Hanford Generating Plant power that is produced by WPPSS from steam purchased from the N reactor. The precise manner in which BPA will distribute power depends on which of two possible marketing arrangements are made and on the effects of the recent Pacific Northwest Electric Power Planning and Conservation Act.

Under this act, a Pacific Northwest Electric Power and Conservation Council will be established. The duties of the Council are to prepare, adopt, and participate in the implementation of a Regional Electric Power and Conservation Plan. The Council shall be established in 1981 [Sec. 4(a)] and then shall have two years to "prepare, adopt, and promptly transmit to the (BPA) Administrator" the Plan [Sec. 4(d)]. Basic principles and guidelines for the Plan are described in detail in the Act. In general, the Plan shall deal with matters concerning load forecasting, resource acquisition (especially through conservation), power distribution to customers, establishment of rates, and protection and enhancement of fish and wildlife resources. Of particular importance to an RPR, the Plan provides for the acquisition of major resources and also provides that excess power may be exported from the region.

The first of two possible marketing arrangements involves the RPR becoming a "major acquisition" of the BPA system. As such, all or most of the power would be committed to BPA on a long-term basis. This would be done on a net-billed basis, similar to the case currently with WNP 1, 2, and 3. The participants in the WPPSS project commit all of their share of the power from the project to the BPA power pool. They then draw on the power pool for their needs. The "net bill" is their charge from BPA minus the monies paid for their share of the WPPSS project generation. The RPR is in a good position to be acquired by the BPA because the Act provides that the Plan shall give the following specific priority for system acquisitions.

Section 4(e)(1)--The plan shall, as provided in this paragraph, give priority to resources which the council determines to be cost effective. Priority shall be given: first, to conservation; second, to renewable resources; third, to generating resources utilizing waste heat or generating resources of high fuel conversion efficiency; and fourth, to all other resources.

The RPR will produce power as a by-product of special nuclear materials production using otherwise wasted heat. The RPR therefore falls into the third category of resource acquisition and, furthermore, will be classified as "long term" (> 5 years) and "major resource" (> 50 MW), which will make it a very valuable system acquisition for BPA. It is probable that there will be few major acquisitions in the first three priority categories.

The second marketing arrangement is similar to that for WNP 4 and 5. The power would be committed to participants in the project by shares according to costs paid. The participants will then use the power directly as part of their own resources, with BPA still distributing the power and charging a distribution charge. That this marketing situation will occur is problematic. Under the Northwest Power Act, the utilities may contract with BPA to provide their total load. In this case, their resources may be committed to BPA, which results, in effect, in the first marketing arrangement.

A system already exists in the Pacific Northwest for distribution of electric power with a high degree of coordination between loads and resources. Furthermore, the market exists for either firm or secondary power, and the distribution network is equipped for long-term export in the event of excess power-generating capacity in the region.

In the Southeast, the situation is more difficult. There is no formal power pool to smooth out the fluctuations in load/generation balance. Tie-line capacity for export/import of power is also smaller than in the Pacific Northwest. Power exchange agreements will have to be negotiated, and system stability and reliability must be preserved with this large an addition of generating capacity. This latter concern should be minor for any of the four largest private investor-owned utilities in the region, each of which will have large nuclear plants online in the early 1990s. However, distribution by "public bodies" may prove to be exceedingly difficult.

IV. THE RPR AS A NET ENERGY CONSUMER

If the RPR does not generate at least station power or if it is a net consumer of energy even with an energy recovery system (the accelerator), then the RPR becomes vulnerable to interruptions in energy supply. If electric power is purchased, then the RPR must be a priority user. Interruptions, such as would occur with secondary power, could not be tolerated for strategic reasons (assurance of special nuclear materials supply) and for reasons of quality control (weapons-grade plutonium is defined to contain no more than 6% ^{240}Pu). If a separate power plant, dedicated to supplying power to the RPR, was built, then the RPR would still be vulnerable to interruptions in the fuel supply although a long-term fuel storage capacity would minimize the problem.

As a possible user of firm priority electric power, the RPR would be competing for a limited amount of available energy that would be guaranteed to rise in price. Indeed, the conclusions in Sec. II.C. of this report indicate that firm power might not be available at any price. It is difficult to conceive of an RPR, which consumes 300 MW of power, operating while the regional residents are without power.

In the Pacific Northwest, the Pacific Northwest Electric Power Planning and Conservation Act specifies that any new large single load that increases the total power requirements by more than 10 MW (average) over a 12-month period must be consistent with the Regional Electric Power and Conservation Plan. In addition, Sec. 5(b)(3) of the Act authorizes sale of electric power to Federal agencies in the region although they will continue to be nonpreference customers.²⁸ Without a plan currently in force, there is no

guarantee that the RPR will be accepted as a power customer; if it is accepted, it would have to use nonfirm power. In addition, even if power is provided, it will be very expensive because it is anticipated that, even for preference customers, the rate for power to new single loads will be the marginal cost of power (that is, power from new resources).²⁹ With a regional plan possibly three years away, it is doubtful that an RPR, which uses grid electric power, should be planned for Hanford.

The situation is much the same at the Savannah River Plant. Indeed, it is made worse by the lack of a formal, large power pool in the region and the fact that a single company would have to supply the large increase in power load. To ensure power supply, added tie-lines would probably be needed (perhaps from the Tennessee Valley Authority) although these would then be points of high vulnerability to an RPR.

If electricity from the grid is not purchased, then the RPR would have to rely on an on-site power station. National policy and fuel supply vulnerability would seem to preclude an oil- or gas-fired power plant. This would leave a coal-fired power plant as the only option. This option would seem unlikely at Hanford because of the lack of nearby coal. The nearest large supply of coal is nearly 1000 miles away, and transportation resources are very unsure²⁹ unless a special rail-line and unit train were constructed as was the case for the Boardman coal-fired plant in Oregon. In any event, this coal-fired generation would be very expensive. This option has more credibility at the Savannah River Plant.

The Savannah River Plant has several coal-fired power plants in operation to supply on-site power. It is probable that a new, large, 300-MW plant could be planned, constructed, and ready for operation in the early 1990s, even with uncertainties of the environmental regulations for coal burning. It would seem easier and cheaper, however, to generate at least station power for every concept scenario except for the accelerator. It is likely that the only possible location of the accelerator RPR would be the Savannah River Plant (an assumption of this study is that an RPR will be located at either Hanford or Savannah River). The problem of fuel supply vulnerability still exists, however, for any system needing an on-site coal-fired generator for power.

V. SOCIAL AND INSTITUTIONAL ISSUES

Social and institutional issues that are of major concern are those that would prevent or hinder the timely construction and operation of an RPR. Under consideration herein are those issues that arise if the base case RPR, supplying only its own station power, is changed to be a net producer or consumer of electric power. Although the base-case RPR is assumed to meet all current safety and environmental regulations, it will not be licensed by the NRC. This is pursuant to Sec. 110 of the Atomic Energy Act of 1954 as amended that, in part, reads (Ref. 21, p. 38):

Nothing in this chapter shall be deemed--(a) to require a license for (1) the processing, fabricating, or refining of special nuclear material, or the separation of special nuclear material, or the separation of special nuclear material from other substances, under contract with and for the account of the Commission; or (2) the construction or operation of facilities under contract with and for the account of the Commission; ...

It is assumed that this base-case RPR will require an environmental impact statement.

It seems clear that by making an RPR a net power consumer, no additional regulatory problems would be introduced. However, it would be more difficult and costly, and perhaps impossible, to site a major electric load in the Pacific Northwest. The uncertainties under the regional power legislation could easily impede the planning, construction, and operation of a power-consuming RPR. At either location, the addition of a major power load could instigate intervenor actions based on additional environmental impacts arising either from the increased electric load itself or from the required coal-fired generating facilities. In any event, there would likely be additional social pressures against an RPR that would add a major electric load in an area already short of power or deficient in reserve power.

If the RPR is made a major power producer, a great many issues arise. Some areas in which congressional action may be needed have already been indicated. Congress would have to make specific authorization if DOE is to construct, own, and operate the power generating facilities. And if someone else builds, owns, and operates the facilities, specific authorization may be

needed at the Savannah River Plant location for steam to be sold to a private investor-owned utility.

The addition of electric generating facilities either by DOE or by some other body introduces no difficulties. That the RPR need not be NRC licensed merely because it also generates electric power is clearly indicated in Sec. 271 of the Atomic Energy Act of 1954 as amended (Ref. 21, p. 86), which reads:

Sec. 271. Agency Jurisdiction.--Nothing in this Act shall be construed to affect the authority or regulations of any Federal, State, or local agency with respect to the generation, sale, or transmission of electric power provided through the use of nuclear facilities licensed by the Commission: Provided, That this section shall not be deemed to confer upon any Federal, State, or local agency any authority to regulate, control, or restrict any activities of the Commission.

On an environmental basis, the Hanford Generating Plant at the N reactor will experience difficulties in 1983 because of thermal discharges not allowed under the National Pollution Discharge Elimination System (NPDES). As the proposed RPR concepts are assumed to meet all environmental regulations, this problem should not arise for a separate RPR generating plant. However, the separated facilities will require good coordination of separate Environmental Impact Statements to avoid delays from separate intervenor actions. With good coordination on construction, a generating plant delay should not jeopardize an RPR, as all concepts incorporate total energy dump facilities that must meet NPDES criteria. Therefore, an RPR can operate without the generating plant in operation.

With the sale of by-product energy, there would probably be interaction with the Federal Energy Regulatory Commission concerning rates for sale of steam or electric energy. This would be appropriate because of the "... reasonable and nondiscriminatory prices" mentioned in Sec. 44 of the Atomic Energy Act of 1954 as amended.²¹ The interaction is not expected to impede operation of an RPR. As noted in Sec. 271 above, state public utility rate regulations will not apply to the RPR.

In general, the addition of electric generation facilities does not seem to have any significant impacts beyond those of the base-case RPR in the areas of siting, payments in lieu of taxes, and health and safety regulations. Power distribution issues do not directly affect the operation of the reactor

and are probably not significant. Although tax questions do not arise because of a Federal reservation location, there are some net benefits for the Hanford location because of Washington State's power-generation tax.

As for social implications, the immediate areas of both sites benefit strongly from the economic impacts of nuclear weapons work. There is little likelihood of any strong local opposition to even the base-case RPR. The generation of much needed electric power from otherwise wasted heat energy can only help to mitigate any local or regional opposition to the RPR. In fact, if the power is not generated and the heat energy is dumped, opposition to an RPR might be expected to increase. In either regional area, the ability to acquire a source of 1000-1100 MW of electric power on a relatively firm schedule (no NRC regulatory delays) and at a relatively modest utility investment (in just the generators) is a major plus for a power-generating RPR.

VI. CONCLUSIONS

In both the Pacific Northwest and the Southeast, there is a demand for electric power from a future RPR. Shortfalls in average electric-generating capacity are predicted for the Pacific Northwest throughout the 1980s and 1990s, and initial shortfalls in firm peaking energy generation are predicted for the early 1990s. In the Southeast, dangerously low reserve margins are predicted by the late 1980s, with emergency power probably supplied by oil- or gas-fired generation. These problems can be expected to worsen in both regions with further delays in nuclear power plant construction.

Thus, in both regions there would be serious difficulties in siting an RPR that would be a major power consumer. However, both regions would be expected to welcome the 1000- to 1100-MW resource that an RPR would represent. The projected cost of 23 mills/kWh should be further analyzed, however, because it is probably too low relative to future projected electric costs.

It is likely that a future RPR would follow the N-reactor precedent of physically separate reactor and generating facilities. The generating plant would be built, owned, and operated by some body other than DOE, probably WPPSS in the Pacific Northwest and some private investor-owned utility in the Southeast. Obtaining needed power at a relatively low investment and on a

relatively firm schedule would be definite advantages to whoever owned the generating facilities.

Power distribution and marketing present no major problems in the Pacific Northwest. The situation is less clear in the Southeast; however, any of the large private utilities could probably absorb the resource without creating major electric system instabilities.

In an N-reactor-type scenario, there appear to be no major additional impediments to a power-producing RPR that arise from social or institutional concerns. As long as construction of the generating facilities is closely coordinated with construction of the special nuclear materials production facility, no significant delays are expected to be introduced by adding net power generating facilities to an RPR.

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026-050	6.00	A03	176-200	12.00	A09	326-350	18.00	A15	476-500	24.00	A21
051-075	7.00	A04	201-225	13.00	A10	351-375	19.00	A16	501-525	25.00	A22
076-100	8.00	A05	226-250	14.00	A11	376-400	20.00	A17	526-550	26.00	A23
101-125	9.00	A06	251-275	15.00	A12	401-425	21.00	A18	551-575	27.00	A24
126-150	10.00	A07	276-300	16.00	A13	426-450	22.00	A19	576-600	28.00	A25
									601-up	†	A99

†Add \$1.00 for each additional 25-page increment or portion thereof from 601 pages up.