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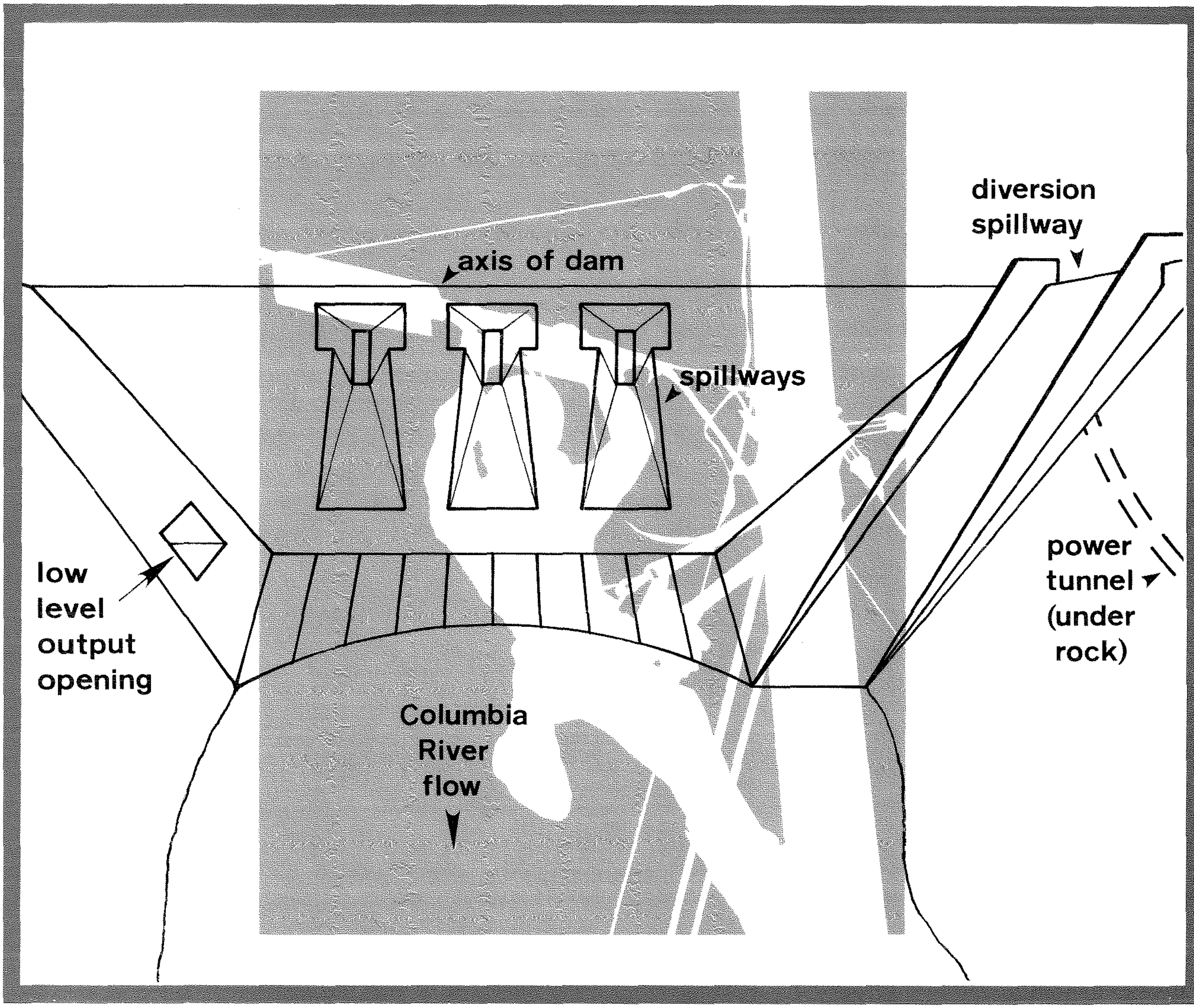

STUDIES IN LABOR MARKETS AND UTILITY PRICING

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Pricing Federal Power in the Pacific Northwest: An Efficiency Approach

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Recent forecasts of electric-power demand and supply in the Pacific Northwest suggest the possibility of serious shortages during the decade of the 1980's. The projected imbalance reflects the inefficient pricing policies prescribed by law and regulatory commissions for the Bonneville Power Administration (BPA) and other regional electric utilities.[1] Bonneville is the wholesale marketing agency for hydroelectric power generated at some 30 Federal dams along the Columbia River and for some purchased thermal (coal and nuclear) power supplies. Indeed, BPA is the wholesale supplier of over one-half of the total electricity consumed in the Pacific Northwest. Thus, its pricing practices profoundly influence the general level of electric rates faced by ultimate consumers in that region.

A conflict over BPA supplies has developed among Bonneville's various customer groups, with private utilities being denied contracts for firm Federal power—assured supplies—since the early 1970's. This reflects the agency's attempts to assure the needs of its statutory preference customers—the publicly-owned retail power agencies that have first priority for Federally-generated wholesale power. Private utilities have had to make up for that loss as well as meet the growth of demand on their own, generally from more expensive thermal supplies. The consequence is a wide disparity in retail rates to ultimate consumers served by the two classes of utilities. In recent months, Bonneville's industrial customers have suffered a loss of that portion of their contracted supplies subject to interruption. Moreover, these customers face a possible cutoff of all Federal supplies when their contracts expire in 1983. The industries involved employ about 15,000 persons with an annual payroll of about \$355 million, and supply 30 percent of the nation's primary aluminum, 100 percent of its ferronickel, and substantial quantities of other key materials.

The Pacific Northwest Electric Power Planning and Conservation Act, which has been introduced into Congress to deal with the allocation problem, would rely on new institutional arrangements to balance demand and supply. But by failing to address the fundamental cause of the disequilibrium—namely, the present inefficient pricing policies followed by Bonneville and other regional utilities—it is unlikely to provide a permanent solution to the region's electrical-supply problems.

In this article, we argue that Bonneville should base its power rates not on average cost but rather on long-run incremental cost. The former is total cost divided by the number of units to be sold; the latter is the cost of producing additional electricity, taking into account the need to add more fixed factors, namely plant facilities. Long-run incremental cost approximates the cost of electricity produced from new plant. This pricing approach would result in a more efficient allocation of resources, because rates would reflect the true cost of the resources expended to provide consumers with each additional block of power. It would significantly lower the future demand for Bonneville power because its price would be much higher than under the current average-cost pricing method. As a result, substan-

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tially less new generating capacity would be required than is currently forecast.

Section I discusses the economic-efficiency argument for pricing on the basis of long-run incremental cost. As noted there, electric utilities traditionally have not followed that method because their operations presumably have been characterized by decreasing long-run average and incremental costs due to economies of scale. Under such conditions, pricing on the basis of incremental cost would fail to recover average cost, resulting in a loss. But as Section II indicates, this long-run incremental cost in actuality is far higher than the average cost reported by Bonneville. In Section III, we attribute part of the gap between the two to present average-cost accounting methods, but also to rising long-run incremental costs resulting from the exhaustion of economies of scale. Section IV discusses some of the sub-optimal long-run incremental cost pricing methods that have been proposed to avoid surplus revenues, and argues that true long-run incremental cost pricing is preferable.

It is important to note that while Bonneville's pricing policies have been singled out for study in this article, the arguments advanced in favor of incremental-cost pricing apply to the entire electric-utility industry. To various degrees, the wide-spread use of average-cost pricing methods is holding electric-utility rates everywhere below those that would prevail under long-run incremental-cost pricing, spurring the growth of electrical consumption and causing too many resources to be devoted to power generation.

I. Rationale for Different Pricing Methods

Bonneville Power Administration—like other electric utilities throughout the nation—traditionally has followed an average-cost pricing method for establishing the level of its power rates.[2] Under this method, the utility first determines its *revenue requirement.* This refers to the total costs that must be recovered through rates during a given period to compensate the utility for all the expenses incurred in supplying the product, including a return on invested capital.[3] Under present statutes, total revenues must exactly equal total costs, a requirement known as the budgetary constraint. Dividing total costs by the number of units expected to be sold in a given period yields the average unit cost—and thus the price—of electricity.

Economic theory demonstrates that the price per unit should be equal not to average cost but to marginal cost. Marginal cost is the change in total cost resulting from an additional unit of output—that is, the cost of producing one more unit of a good or service, or alternatively, the cost that would be saved by producing one less unit.

In economic theory, the distinction between short and long-run is based on whether or not plant size is fixed. Short-run cost calculations show how a firm's costs will vary in response to variations in output within the limits of a given amount of fixed plant. Long-run cost calculations show how costs will vary during a planning period long enough to permit adjustment of the scale of productive facilities.

Electric-power rate decisions thus depend upon whether or not the scale of plant is to be increased. If new plant is scheduled during the planning period encompassed in the rate calculation, long-run incremental (marginal) cost is the appropriate basis for pricing, i.e., price per unit should be equal to long-run incremental cost.[4] Long-run incremental cost equals the cost of electricity produced from the next block of new generating facilities scheduled to be added. Under that pricing method, the price per unit thus reflects only the cost of electricity produced from new productive facilities—in contrast to average cost pricing, which also reflects the cost of electricity from older facilities.

The rationale for pricing on the basis of incremental cost is simply efficiency. A fundamental precept of economics states that optimum welfare and efficiency are achieved under conditions of perfectly competitive markets. A perfectly competitive firm, which by definition has no control over the price of its product, maximizes profits by selecting an output level where the price of its good or service equals its marginal cost. Under such conditions, resources would be channelled into their most efficient uses.[5] This is because each price would reflect the value of the resources required to supply each particular good or service, and because consumers therefore would be provided with the proper price signals to make the choices that would yield society the most efficient use of resources. If price were less than marginal cost, consumers would be induced to consume an additional unit, even if the benefits were less than the marginal commitment of society's resources to produce that unit.

Equality of price and marginal cost leads to optimal welfare and efficiency only if it applies to all goods and services throughout the economy. Pricing as many goods as possible at marginal cost does not necessarily provide a "second best" solution. It might actually make allocation less efficient, particularly in situations where close substitutes are priced above or below marginal cost. But while this problem complicates the application of marginal-cost pricing, it does not necessarily invalidate its use in particular situations. Care simply must be taken to consider the ramifications on both the market in question and the markets of other close substitutes and complementary products.

In the Pacific Northwest situation, electric power is being priced far below marginal cost, whereas close substitutes such as oil and natural gas are being priced closer to marginal cost. Given the relatively high cost of substitutes, adoption of long-run incremental-cost pricing by electric utilities probably would lead to a reduction in overall energy use rather than a shift to alternate fuels.

Note on Terminology

This article addresses the issue of the appropriate method to be followed by Bonneville in establishing the *level* of its electric-power rates. The level of rates determines the overall revenues to be realized by the agency in any given period, as distinguished from the structure of rates charged for various classes of customers or service. For that reason, the terms "demand" and "capacity" are used in a general sense as they are understood by economists, rather than in reference to peak operations alone as they are used by electric-utility rate makers. Demand refers to the total quantity that will be purchased at a given price at a particular period of time. Capacity refers to production potential, i.e., plant and equipment. "Additions to capacity" may be used in connection with the expansion of baseload as well as peak generation facilities.

Dilemma of incremental pricing

The goal of the regulatory authorities should be to price as close to the perfectly competitive model as possible. Why then haven't they done so? The reason is the regulators' assumption that electricity generation involves decreasing long-run average costs over the output range relevant to a given market. Decreasing long-run costs are the result of increasing returns to scale. These economies of scale, in the regulatory context, refer to a situation in which unit production costs decline for the individual firm as the size of its plant is increased. The economies are internal to the operation of the individual firm, in contrast to external economies which arise out of the growth of the entire industry.[6]

"Plant" in this context may consist of a single production facility or a group of production facilities comprising a system. In electric-power generation, regulators assume that the size of plant required to achieve lowest unit cost is so large that it justifies only one firm for any given market. Because of this assumed inherent tendency to decreasing long-run average cost over the relevant output range, the electric-generating industry traditionally has been characterized as a "natural monopoly." To enable consumers to benefit from these

Background on Bonneville

Functions

Bonneville Power Administration (BPA) was created by Congress in 1937 to market and transmit electric power from the Federally-owned Bonneville Dam. The agency's authority subsequently has been expanded to include the marketing of hydroelectric power from other Federal dams since constructed in the Pacific Northwest. As of the end of 1978, there were 30 Federal dams with an installed capacity of 16,441 megawatts under Bonneville's marketing authority (Figure 1).

BPA does not build dams or generating plants, but serves instead as a marketing agency for power generated at Federal facilities built and operated by the U.S. Army Corps of Engineers and Bureau of Reclamation. The agency, however, is responsible for designing and constructing the vast transmission network required to supply its market area. That area consists of Washington, Oregon, Idaho, Western Montana, plus small portions of adjacent states. The Federal power facilities in the Pacific Northwest, together with the transmission system, are known collectively as the Federal Columbia River Power System (FCRPS).

Role in hydro-thermal development

Until the 1960's, the Pacific Northwest depended on hydro-electric generation to meet nearly all of the region's electrical requirements. But by that time, most of the economically and environmentally feasible damsites had been developed, and it then became evident that thermal plants would have to be added to meet the growth of regional electrical requirements. As a result, BPA and over one hundred public and privately-owned utilities entered into an agreement—known as the Hydro-Thermal Program—to meet the projected growth of demand over the 1970–90 period. Under this program, the Federal government agreed to develop the remaining hydro-electric power potential of existing dams to meet the growth of peak demands. The government also agreed to construct the necessary high-voltage transmission lines to accommodate the growth in regional power deliveries. Non-Federal utilities in the region agreed to build and operate numerous new thermal (coal and nuclear) operating plants to meet the growth of baseload (steady) energy requirements. Thermal construction lagged during the 1970's, contributing to power "shortages," and Bonneville purchased small but increasing amounts of thermal power from non-Federal utilities.

Contribution to Pacific Northwest electric supplies

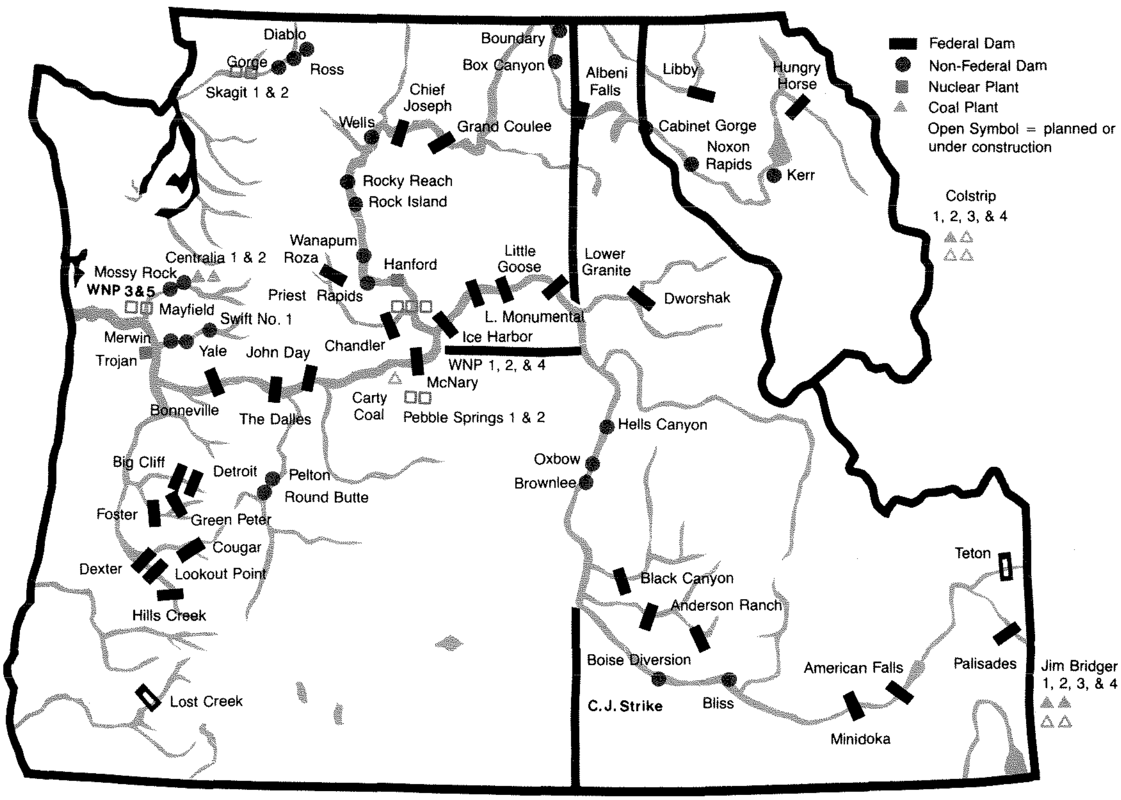
In fiscal 1978, BPA supplied about 87 billion kilowatt-hours of electricity, equivalent to about 54 percent of the total electric power generated in the Pacific Northwest. Private investor-owned utilities generated another 26 percent, while non-Federal publicly-owned utilities produced the remaining 20 percent.

BPA's customers

Bonneville Power Administration is a wholesale supplier of electricity. The agency's customer groups consist of publicly-owned utilities, private investor-owned utilities and direct-service industries. Under existing law, publicly-owned utilities—i.e., utilities owned by public entities such as municipalities, cooperatives and public utility districts—have preference or priority in the purchase of Federal power. Since the early 1970's, BPA has denied private investor-owned utilities access to all but small amounts of "firm" power—assured contract supplies—to enable Bonneville to meet the requirements of its preference customers.

Figure 1

Pacific Northwest Electric Generating Plants



Pacific Northwest Electric Generating Capacity and Output, 1978

Ownership	No. of Plants	Capacity[1] Megawatts	Capacity[1] Percent of Total	Output Billions of Kilowatt-Hours	Output Percent of Total
Federal Columbia River Power System	30	16,442	48.7	87.0[2]	54.2
Hydro	(30)	(16,442)	(48.7)		
Non-Federal Publicly-Owned Utilities	52	7,954	23.6	31.5	19.7
Hydro	(39)	(6,217)	(18.4)		
Thermal	(13)	(1,735)	(5.1)		
Privately-Owned Utilities	106	9,332	27.7	41.9	26.1
Hydro	(88)	(4,020)	(11.9)		
Thermal	(18)	(5,312)	(15.8)		
All Owners	188	33,728	100.0	160.4	100.0
Hydro	(157)	(26,679)	(79.1)		
Thermal	(31)	(7,047)	(20.9)		

1 Name-plate rating as of December 31, 1978; actual capability is about 12 percent higher on average than name-plate rating.

2 Includes power purchased from the Hanford and Trojan nuclear plants and the Centralia coal-fired plant owned by non-Federal utilities.

Source: Bonneville Power Administration, *Financial and Statistical Summary* (Fiscal year 1978), page 6, plus information supplied directly by agency.

economies of scale, governments have granted private firms exclusive franchises to serve given market areas, or have assumed direct public ownership of generation and transmission facilities. At the same time, governments have regulated utility rates to prevent the extraction of monopoly profits (Appendix A).

But this assumed tendency to decreasing long-run average cost also has provided the rationale for pricing on the basis of average cost. Under such conditions, if rates were to be established on the basis of long-run incremental cost, average cost would not be recovered, and the result would be an operating loss.

Chart 1 illustrates the concept of economies of scale as it applies to the individual firm. Here plant size is not fixed, and the comparison is between average production costs of plants of various capacity. Economies of scale in the electric-power industry refer to the fact that relatively larger generation and transmission systems have lower unit costs than relatively smaller systems. The concept is defined for a particular point in time, which means a given state of technology.[7] Economies of scale would exist if, say, the cost per kilowatt-hour associated with a 10,000 megawatt generating system were lower than the average production costs associated with a 7,500 megawatt system, with both alternatives being considered within the same planning period.

In Chart 1, the long-run average cost curve (LRAC) envelops a family of short-run cost curves, each short-run curve (SRAC) corresponding to a different plant scale. Each point on the LRAC curve, being a point of tangency with a SRAC curve, represents the least cost at which a given level of output can be achieved. The firm experiences increasing returns to scale—that is, lower average unit costs for plants of increased size—up to output level Q_3 corresponding to $SRAC_3$, after which diseconomies serve to increase unit costs.

Chart 1

Decreasing Long-Run Cost Curve for a Utility Facing Economies of Scale

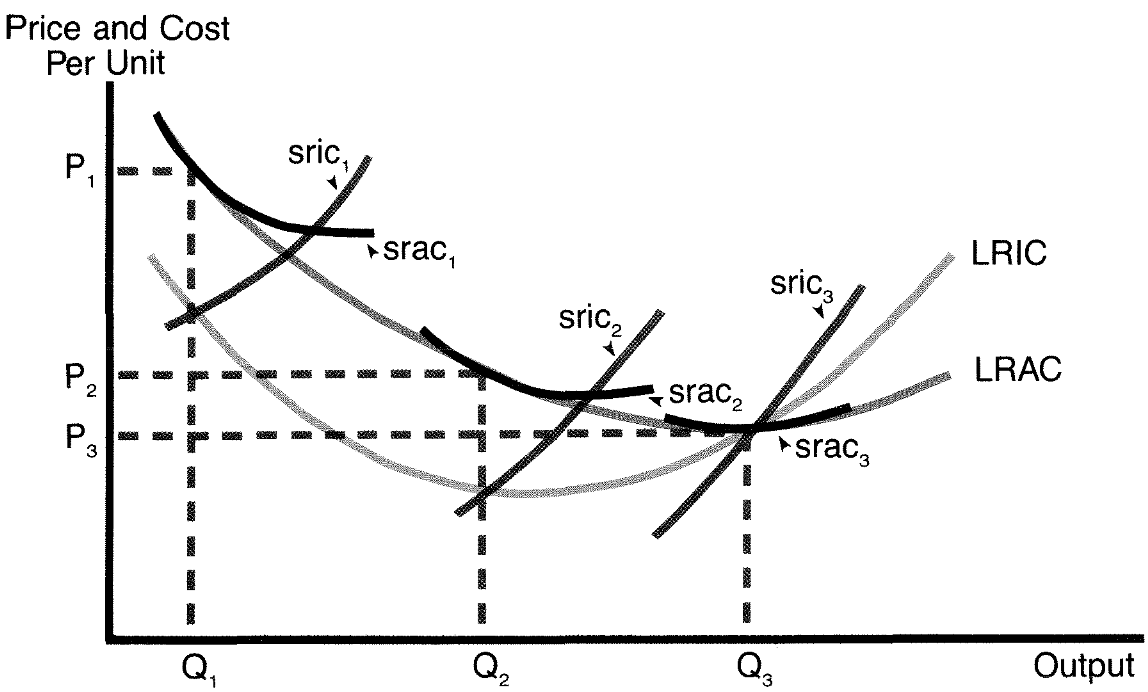


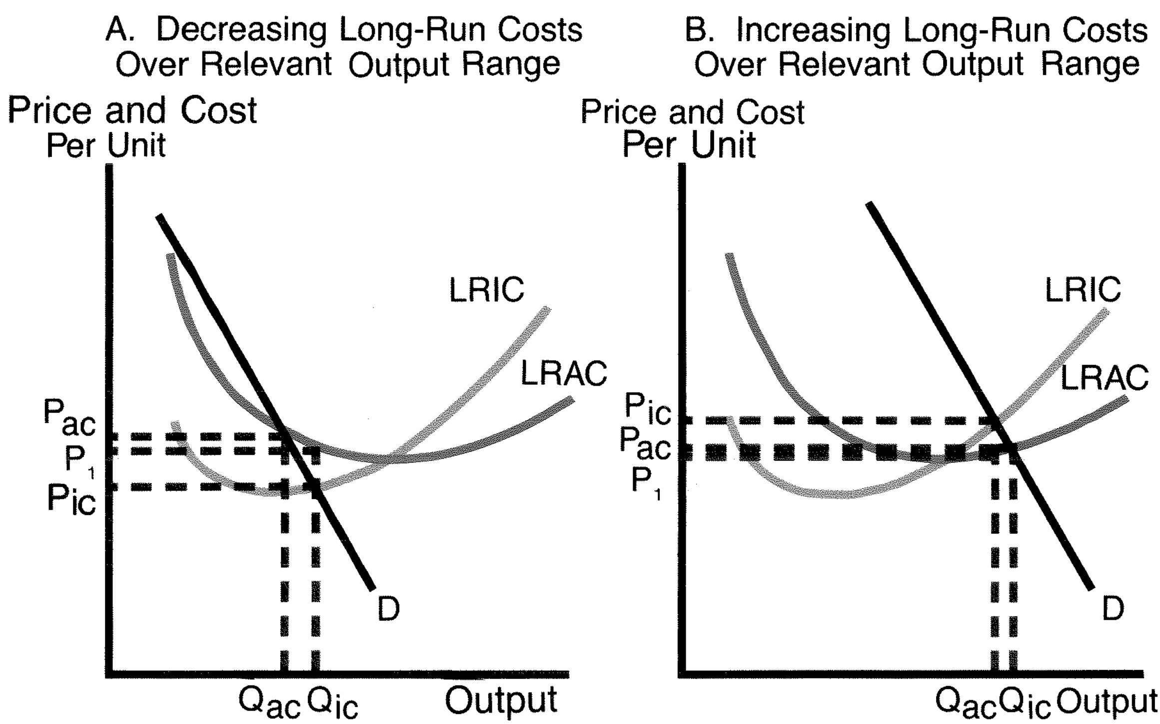
Chart 2-A shows the pricing alternatives facing regulatory authorities in a situation where the utility is operating in a range of decreasing long-run average costs. To achieve the most efficient allocation of resources possible under regulated-monopoly conditions, the regulatory authorities would have to mandate incremental-cost pricing. Under that method, the legal (ceiling) price (Pic) would be determined by the cost of production of the last unit, that is, by the intersection of the demand schedule (D) and the long-run incremental-cost curve (LRIC). But setting the unit price at Pic would generate losses for the regulated firm under conditions of decreasing long-run average costs, in that the cost of the last unit of output would be less than the average cost per unit. These losses would be represented by the area, (P_1 - Pic) × Qic.

To avoid the necessity for public subsidies to offset these losses, rate-setting commissions have followed an average-cost pricing method, incorporating in the average cost a rate of return on invested capital. Under this method, the maximum price per unit is set at (Pac), the intersection of the demand schedule (D) and the long-run average cost curve (LRAC). Under conditions of decreasing long-run average cost, this method of pricing results in a higher unit price and lower level of output than the more efficient long-run incremental cost method. This is because long-run average cost is above long-run incremental cost under such conditions.

Chart 2-B illustrates the price and output combinations that would result under alternative pricing methods if the utility were operating in a range of increasing long-run average

Chart 2

Pricing Alternatives in a Regulated Monopoly Situation



costs. Under such conditions, pricing on the basis of long-run incremental cost results in a price (Pic) and output level (Qic). That price would yield a profit beyond the return incorporated in average cost, in that the cost of the last unit of output would be more than the average cost per unit. The *excess profit* would be represented by the area, (Pic - P_1) × Qic. To avoid excess profits, regulators might prefer to follow the average-cost method, which would result in price (Pac) and output level (Qac). But average-cost pricing under conditions of increasing long-run average costs, results in an under-pricing of the product and a correspondingly greater and uneconomic amount of resources devoted to its production.

II. Bonneville's Long-Run Incremental Cost

The Pacific Northwest's electric-power system currently relies primarily on hydro-electric generation. But thermal (coal and nuclear) plants will have to provide most of the new energy or baseload requirements of regional consumers, i.e., electricity which is required on a steady basis. This is because the region contains few undeveloped dam sites. However, Congress has not authorized any Federally-built coal or nuclear plants in the region. Instead, under the Hydro-Thermal Program underway since the late 1960's, Bonneville has been purchasing increased amounts of thermal power from other publicly-owned utilities for transmission over Federal lines. In addition, Bonneville has been adding new hydro generating capacity at existing Federal dams to meet the peaks in demand that exceed its steady baseload requirements. To estimate the agency's overall long-run incremental cost of power, it is therefore necessary to include estimates of the cost of both new thermal baseload and hydro-peaking facilities.

In micro-economic theory, the concept of

Table 1
Incremental Baseload Capacity and Cost, Washington Public Power Supply System, Nuclear Plants 1, 2, and 3

	Scheduled Additions to Baseload Capacity[1]		Scheduled Additions to Output[2]		Levelized Total Costs[3]		Present Value (1980)[6]		
Year	**Annual**	**Cumulative**	**Annual**	**Cumulative**	**Annual[4]**	**Cumulative**	**Factor[5]**	**Annual Cost**	**Output**
1982	1,100	1,100	7,227	7,227	188.3	188.3	.834	157.0	6,027
1983	—	1,100	—	7,227	—	188.3	.762	143.5	5,507
1984	1,250	2,350	8,213	15,440	234.1	422.4	.696	294.0	10,746
1985	—	2,350	—	15,440	—	422.4	.635	268.2	9,804
1986	868	3,218	5,703	21,143	159.9	582.3	.580	337.7	12,263
							Total:	1,200.4	38,326

Incremental Unit Cost = (Σ present value total cost)/(Σ present value kwh generation) = 1,200.4/38,326 = 3.13 cents/kwh

1 Net to Bonneville Power Administration, in megawatts.

2 In millions of kilowatt hours. Based on annual capacity factor (operating rate) of 75 percent. Annual output = capacity × factor × hours in year (8,760).

3 In millions of dollars. Levelizing reduces a stream of unequal future costs over a period n to a series of n equal payments. (See Appendix B, Table 1).

4 Total costs (both fixed and variable).

5 Assumes a discount rate of 9.5 percent; discounted to 1980.

6 Annual cost in millions of dollars. Output in millions of kilowatt hours.

Source: Computed by the author on the basis of output and cost data provided by Bonneville Power Administration.

long-run has no specific time dimension. But in applying theory to rate determination, the utility is faced with the problem of defining the long-run. The length of that period determines the amount of new generating capacity to be included in the estimate of long-run incremental cost, and thus the amount of total revenues to be received. For relative stability in rates, the period selected should be long enough to prevent frequent rate changes.

Fortunately, it is not difficult to delineate the next well-defined block of baseload energy to be acquired by Bonneville. The agency has contracted with the Washington Public Power Supply System (WPPSS) to purchase nearly all of the output from three nuclear plants scheduled for completion over the 1982-86 period. We have defined that block as the next baseload increment, and have developed an estimate of the consequent long-run incremental cost of energy, discounted back to the year 1980 (Table 1).

Long-run incremental cost per kilowatt-hour may be defined for computational purposes as the present value of all future costs associated with the output from scheduled additions to capacity, divided by the present value of that incremental output.[8] Long-run incremental unit cost thus can be estimated by determining: 1) the scheduled additions to capacity and resultant output over the planning horizon, 2) total levelized annual costs, fixed and variable, associated with that output, and 3) the present value of these costs and additions to output.

"Levelizing" is a method for reducing a stream of unequal future costs over a given period to a series of equal costs. It eliminates the year-to-year fluctuations in costs to provide a more representative figure of the annual costs and revenues required to produce that increment of output. Application of that procedure to WPPSS nuclear-plant costs is shown in Appendix B, Table 1. The present-value calculation converts expected costs to their present value today. In the present case, we discount to the year 1980 at a 9.5-percent rate, in keeping with the practice of some of the investor-owned utilities in the region. Thus, we estimate the long-run incremental cost of power produced from these three nuclear plants at about 3.13 cents/kwh.

Power from the new hydro-peaking facilities will cost much less per kilowatt hour. But because thermal plants will account for the bulk of the new generation capability, the overall incremental unit cost of electricity still will approximate 3 cents/kwh.[9] This compares with the average cost of .412 cents/kwh recovered by Bonneville in 1979.

Bonneville's efficiency would improve if it priced its total power supplies on the basis of incremental cost. (This would require Congressional authorization, however.) In planning rates for any given future period, Bonneville would set the unit price equal to the long-run incremental cost of the appropriate block of scheduled capacity. If it did so, regulatory commissions might follow suit and encourage Bonneville's utility customers to make a similar switchover to long-run incremental cost pricing, thereby providing retail electricity customers with the price signals required to allocate available supplies more efficiently. In contrast, under BPA's present average-cost pricing method, the cost of the last and more expensive increment would be combined with the costs associated with the older facilities, so that wholesale and retail customers would not be aware of the economic value of the resources required to supply additional increments. Consequently, too many resources would be devoted to the production of electricity.

III. Differential Between Long-Run Incremental and Average Cost

As we have seen, the estimated long-run incremental cost of power to be acquired by Bonneville far exceeds its latest reported average-cost figure. Consequently, it seems doubtful that the introduction of long-run incremental cost pricing would fail to recover the agency's total costs. Several factors help explain this wide differential between estimated long-run incremental and reported average cost. First, Bonneville, in interpreting the laws governing its selling price, has failed to recover the true average costs—i.e., opportunity costs—actually incurred by the Federal government in producing, purchasing and transmitting electricity. Second, the average-cost methodology employed by the electric-utility industry *in general* fails to fully reflect inflation, because it determines capital charges on an original-cost basis, whereas long-run incremental cost reflects the present value of the future inflated costs associated with additional new plant. Third, the economies of scale associated with the Federal Columbia River Power System have been exhausted with regard to baseload generation, raising incremental cost in a static sense above average cost.

Understated average costs

Bonneville is required by law to set wholesale power rates so as to produce sufficient revenues to recover the cost to the Federal government of producing, purchasing and transmitting electricity.[10] Evidence suggests, however, that the agency has not been recovering its true total and average costs, because it is also required to set power rates sufficiently low "to encourage widespread use of electric energy and provide the lowest possible rates to consumers consistent with sound business principles."[11]

For more efficient resource allocation, Bonneville power rates should be based on long-run incremental rather than average-cost pricing methods. But if the latter method must be employed, the revenue requirement should be determined on the same basis as it is in the private-utility sector. That would call for an "opportunity-cost" approach—one that would assure the general taxpayer a rate of return on invested capital equal to that earned on average in the private-utility sector were investment there to be financed solely through long-term debt. This assumes little difference in risk between the Federal and private-utility sectors, since the latter is regulated to ensure a reasonable rate of return.

To show Bonneville's underestimation of the actual economic costs incurred by the Federal Columbia River Power System (FCRPS) over the 1947–79 period, the author re-estimated average unit costs incurred by that system on the basis of the methodology employed by privately-owned electric utilities.[12] The adjustments included the addition of imputed property and income taxes, as well as the recalculation of interest charges and amortization on Congressional appropriations for FCRPS investments. Other FCRPS costs were accepted as measured by Bonneville. Appendix C contains the computations, plus technical notes.

Taxes: Bonneville pays no taxes—other than payroll taxes—to Federal, state or local governments. In contrast, private utilities over the 1947–79 period paid annual property taxes averaging about 2.3 percent of their total investment in plant, and income taxes averaging about 9.0 percent of their operating revenues. Addition of imputed property and income-tax costs of that magnitude thus would have raised the total unit cost (and price) of FCRPS electricity by 1979 to .606 cents per kilowatt hour (Table 2). This represents a 47-percent increase over Bonneville's reported cost of .412 cents per kilowatt hour (Table 3).

Interest: Over the 1937–77 period, the interest rates on BPA borrowings ranged from 2½ to 6⅛ percent, with 3¼ percent being the 1977 weighted average for all debt outstanding.[13]

These interest rates appear to be inordinately low, however. Some critics claim that the appropriate interest rate to be applied to those Congressional appropriations should be the prevailing average yield on long-term Treasury bonds at the time the debt is incurred.[14] But the author would go even further and use the average rate paid by private electric utilities for new long-term borrowings in the bond market. The author contends, in other words, that the appropriate comparison should be between the Federal and private utility sectors, and not between the Federal utility sector and the Federal government sector in general. On that basis, the public would earn as great a return on funds invested in the Federal utility sector as it could earn from purchasing private-utility bonds. Over the 1947–79 period, the interest payments that should have been recovered through rates imputed on this basis would have raised the average unit cost for Bonneville-marketed power to .831

cents/kwh by 1979 (Table 2)—102 percent more than the cost and corresponding price actually calculated by Bonneville (Table 3).

Amortization: Bonneville is required by law to repay each dollar borrowed for investment in Federal generating projects within 50 years after the project becomes revenue producing, and each dollar investment in transmission equipment within 40 years after those facilities are placed in service. However, the agency has not repaid such borrowings on a systematic basis, as it would if it were operating as a private utility with a given depreciation schedule. In fact, BPA has set its rates so low that it was unable to pay anything back to the Treasury in the past three years, but instead only increased its outstanding debt.

With adjustments made for imputed taxes, interest and amortization costs, the Federal Columbia River Power System actually incurred an average unit cost of at least 1.018 cents/kwh in 1979 instead of the .412 cents/kwh actually reported. Had rates been raised to reflect true average costs, the price for Bonneville power in 1979 would have been 147 percent higher than the amount actually charged

Table 2
Reconciliation of Reported and Imputed Unit Cost, Federal Columbia River Power System, 1947–79
(cents per kilowatt hour)

	Unit Cost[1]	Plus Imputed Cost Differential Cumulatively Added[2]					Constant Dollar Unit Cost[6]	
Fiscal Year	As Reported By Bonneville +	Taxes +	Net Interest +	Net Amortization[3]	Unit Cost As Imputed By Author[4]	Wholesale Price Index[5]	As Reported	As Imputed
1947	.265	.356	.360	.289	.289	37.81	.701	.765
1949	.232	.315	.327	.247	.247	43.22	.538	.572
1951	.240	.337	.366	.274	.274	46.93	.511	.584
1953	.238	.340	.373	.330	.330	46.44	.512	.711
1955	.238	.360	.403	.382	.382	46.30	.514	.826
1957	.235	.353	.390	.383	.383	48.85	.481	.784
1959	.239	.375	.413	.445	.445	50.20	.476	.888
1961	.247	.393	.431	.488	.488	50.20	.491	.972
1963	.247	.463	.503	.550	.550	50.12	.493	1.097
1965	.242	.374	.409	.432	.432	50.50	.480	.855
1967	.256	.377	.415	.412	.412	52.98	.484	.778
1969	.265	.395	.486	.489	.489	53.23	.479	.886
1971	.270	.402	.524	.561	.561	59.35	.455	.945
1973	.273	.394	.512	.604	.604	66.41	.411	.910
1975	.361	.519	.721	.762	.762	90.16	.400	.845
1977	.362	.557	.838	1.027	1.027	100.00	.362	1.025
1979	.412	.606	.831	1.018	1.018	120.61	.497	1.228

1 Derived on the basis of average-cost pricing method. For derivation see Appendix C, Table 1.

2 For derivation of the various imputed-cost components, see Appendix C, Table 2. The differentials between the various imputed- and reported-cost components were derived, and then added to (or subtracted from) total unit costs (as reported by Bonneville) on a cumulative basis.

3 From 1947-57, Bonneville repaid more of its borrowings than would have been called for under the author's imputed-amortization schedule. Imputed amortization was less than the amount actually recovered, and thus reduced the unit cost.

4 Derived on the basis of average-cost pricing method. For derivation see Appendix C, technical notes and Table 2.

5 Fiscal year 1977 = 100.

6 Cents per kilowatt hour, in constant 1977 dollars.

(Table 3). As reported by Bonneville, the average cost of power remained virtually constant over the entire 1947–67 period, as sales rose from 8.3 to 51.9 billion kilowatt hours, but then began to increase in 1969–79 as sales rose from 51.8 to 72.0 billion kilowatt hours. On an imputed basis, in contrast, the average cost rose almost without interruption throughout the entire period, with the rate of increase accelerating during the sales expansion of the 1970's (Chart 3). In constant dollars, unit costs as reported by Bonneville trended downward over time, whereas imputed costs in real terms trended upward (Chart 4).

Low Federal power rates undoubtedly helped contribute to the periodic electrical shortages of the 1970's. During the 1947–70 period, with virtually stable BPA rates, the Pacific Northwest's electric-power consumption rose at a 7½-percent annual rate. In contrast, consumption growth slowed to a 3½-percent annual rate over the 1970–77 period as a result of the 1974–75 recession and supply problems—as well as rising rates. But during the past two years the growth rate accelerated once again. As a result, the region's per capita electrical-energy consumption continued to be almost double the national average.

Impact of inflation

The average-cost figure of 1.02 cents/kwh, as calculated here on an opportunity-cost basis, is still less than one-third as large as the estimated long-run incremental cost of 3.13 cents/kwh. Part, if not all, of this differential may be due to the failure of the utility industry's average-cost methodology to reflect the full effects of inflation.

The electric utility industry (including Bonneville) determines the capital costs to be recovered through revenues on the basis of the historical (original) cost of plant and equipment. These capital charges include such items as depreciation, interest, and property taxes. But during periods of rapid inflation, when rising prices push the cost of new equipment far beyond the original cost of equipment acquired in the past, the average-cost procedure yields much lower figures than the long-run incremental-cost procedure, which includes discounted future capital costs. In particular, if depreciation is calculated on a straight-line ba-

Table 3
Imputed Unit Cost as a Percent of Reported Unit Cost

Fiscal Year	Unit Cost as Reported by Bonneville	+	Plus Imputed Cost Differentials, Cumulatively Added: Taxes	+	Net Interest	+	Net Amortization[1]
1947	100.0		134.3		135.8		109.1
1949	100.0		135.8		140.9		106.5
1951	100.0		140.4		152.5		114.2
1953	100.0		142.9		156.7		138.7
1955	100.0		151.3		169.3		160.5
1957	100.0		150.2		166.0		163.0
1959	100.0		156.9		172.8		186.2
1961	100.0		159.1		174.5		197.6
1963	100.0		187.4		203.6		222.7
1965	100.0		154.5		169.0		178.5
1967	100.0		147.3		162.1		160.9
1969	100.0		149.1		183.4		184.5
1971	100.0		148.9		194.1		207.8
1973	100.0		144.3		187.5		221.2
1975	100.0		143.8		199.4		211.1
1977	100.0		156.6		231.8		283.7
1979	100.0		147.1		201.7		247.1

1 From 1947–57, Bonneville repaid more of its borrowings than would have been called for under the author's imputed-amortization schedule. Imputed amortization was therefore less than the amount actually recovered, and thus reduced the unit cost.

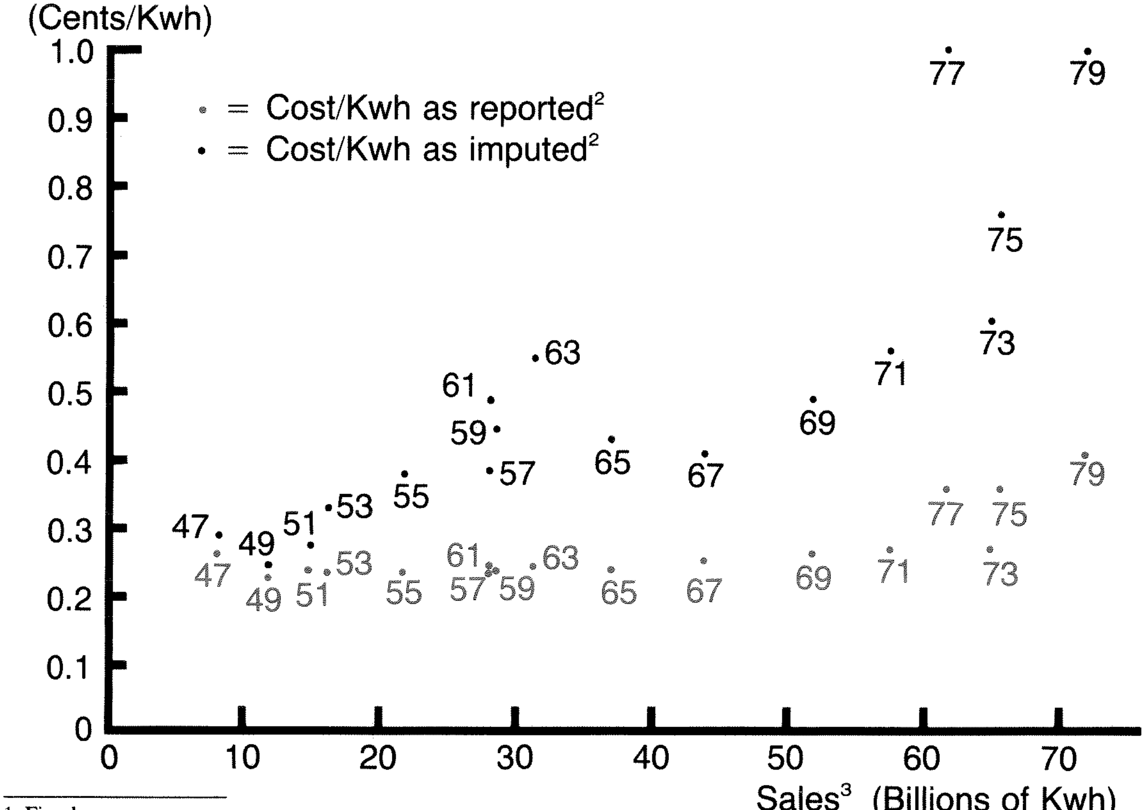
sis, the average-cost method overestimates the loss of value in the early life of the plant. An annual-average depreciation charge for plant and equipment of various ages calculated on an historic-cost basis bears no relation to current value. Similarly, interest rates used in calculating average cost are historic rates, whereas the incremental-cost procedure includes both current and future rates for long-term bond financing of scheduled plant and equipment.[15]

Decreasing returns to scale?

The above discussion relates to the behavior of costs *over time*. In contrast, the theoretical concepts of decreasing returns to scale and increasing long-run average cost depict cost and output alternatives facing a firm *at a moment of time* under the assumption of constant technology and factor prices (Chart 2-B). The average-cost concept as defined in economic theory is a statement of how average costs vary for systems of varied scale built today. A firm would be operating in an output range associated with increasing long-run average costs if expansion to a larger scale plant (or system) built from scratch today entailed higher average costs than a smaller plant built today.

Even in this static sense, the Federal Colum-

Chart 3
Federal Columbia River Power System Costs,
As Reported And On
An Imputed Private-Utility Cost Basis, Biennially 1947–79[1]
(Current Dollars)



1 Fiscal year

2 Determined on the basis of the average-cost pricing method. Under that method, total costs are divided by the number of units sold in a given period to obtain the unit cost and therefore the average price of electricity.

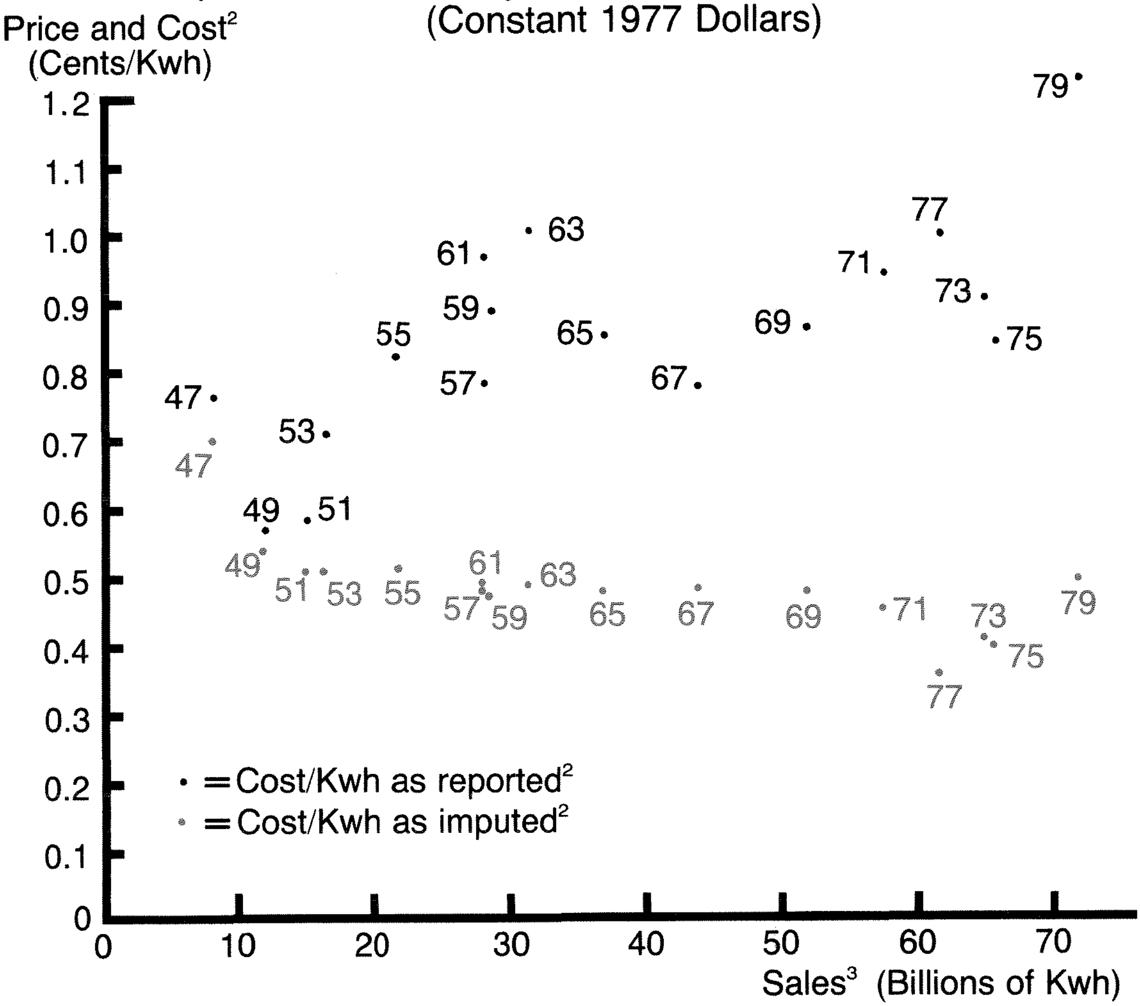
3 Sales equal the amount of power generated in a given period (output) minus transmission and other losses.

Source: See Appendix C, Tables 1 and 2.

bia River Power System may be facing increasing long-run average costs due to the exhaustion of economies of scale in baseload generation. Bonneville's decision to purchase thermal power rather than to develop the hydroelectric potential of the system to meet baseload growth suggests the exhaustion of such economies of scale. That is, even if the system were rebuilt from scratch today, long-run incremental cost might be higher than average cost. Some evidence also suggests that economies of scale for nuclear power at the plant level have been exhausted.[16]

Chart 4

Federal Columbia River Power System Costs, As Reported And On An Imputed Private-Utility Cost Basis, Biennially 1947–79[1] (Constant 1977 Dollars)



1 Fiscal year

2 Determined on the basis of the average-cost pricing method. Under that method, total costs are divided by the number of units sold in a given period to obtain the unit cost and therefore the average price of electricity.

3 Sales equal the amount of power generated in a given period (output) minus transmission and other losses.

Source: Table 2, developed from data shown in Appendix C, Tables 1 and 2.

IV. Strict Incremental or Sub-Optimal Incremental Pricing?

Whatever the reasons, Bonneville faces a situation where its long-run incremental cost is higher than its calculated current average cost. Strict application of long-run incremental-cost pricing would conflict with the agency's statutory requirement that total revenues equal total costs. One possible solution would be to utilize a sub-optimal approach to incremental-cost pricing known as the inverse-elasticity rule (IER), which involves price discrimination among customer groups with different price elasticities of demand. Under this method, prices charged certain customer groups closely approximate incremental cost, while prices charged other customers may be higher or lower than incremental cost, depending on the relationship of incremental and average cost.

Bonneville's current incremental cost is higher than its reported average cost. In this case, the proper approach would be to charge customers with higher price elasticities of demand higher rates, i.e., rates closer to incremental cost. Revenues from such customers would tend to decrease (as their demand is price elastic), lowering total revenues. Using the inverse-elasticity rule, customers with more elastic demand would be charged incremental cost, while customers with less elastic demand would be charged prices closer to average cost. The objective is to charge prices approximating long-run incremental cost to as many customers as possible.

The customer groups that ultimately determine the quantity of electricity demand in a region are the end-users, namely the residential, commercial and industrial customers. Therefore, in order to implement the inverse-elasticity rule, Bonneville would have to estimate the price elasticities of demand of these customer groups.[17]

Elimination of the legal budgetary restrictions on the use of long-run incremental cost pricing would remove the difficult practical problem of estimating these elasticities, and would also remove the need to discriminate among customer groups.[18] The price per unit for sales to all customer groups could then be set equal to long-run incremental cost, which would represent the most efficient way of allocating scarce resources.

Recent studies of the demand for electric power suggest that residential and commercial demand are price elastic, both over short- and long-term periods.[19] Since these groups consume about 60 percent of the Pacific Northwest's total electricity, sharply higher prices probably would reduce projected consumption significantly. A large number of the twelve nuclear and coal-fired generating plants scheduled for completion during the 1980's thus would not be needed.

Surplus funds collected by Bonneville either could be returned to the U.S. Treasury or could be used to finance conservation projects or research-and-development projects in the use of renewable resources for electrical generation in the Pacific Northwest. In the former case, regional consumers would be helping to repay the past subsidies they have received for Federal power in the past. In the latter case, regional consumers would be helping to finance their own conservation and electrical-supply programs.

As long as the price charged for electric power continues to be below the market-clearing price, apparent "shortages" are going to persist. The Pacific Northwest Electric Power Planning and Conservation Act will not provide an effective allocation mechanism, despite its establishment of a conservation program to reduce consumption. Consumers are not likely to be convinced of the need to conserve when the price they pay fails to provide proper signals regarding the true value of the resources required to bring them additional power. Efforts to shift available supplies among competing groups will not solve the fundamental problem of disequilibrium. The only lasting solution is through higher prices. Even with the sharp increase in power rates implemented by Bonneville in early 1980 as a result of the averaging in of the costs of scheduled thermal power, the agency's average price for power still remains far below the long-run incremental cost that would represent an efficient use of society's scarce resources.

V. Summary and Conclusions

Traditionally, the electric-power industry has presumably been characterized by decreasing long-run average costs over the output range relevant to a given market. To permit consumers to benefit from the assumed economies of scale inherent in electricity generation, governments have granted private firms monopoly status to serve given markets under regulated conditions. Social control also has taken the form of public ownership of generation and transmission facilities. Regulatory agencies, on the basis of this assumed characteristic of decreasing long-run average costs, also have prescribed the average-cost pricing method for setting the level of rates. Under such cost conditions, setting price equal to incremental cost would result in a financial loss.

For a more efficient allocation of resources, Bonneville should base its power rates on long-run incremental cost rather than average cost. Moreover, the agency should follow a strict, rather than sub-optimal, approach to long-run incremental cost pricing. Average price per unit should equal long-run incremental cost. The result is efficient resource allocation, because rates then reflect the true cost of the resources expended to provide consumers with each additional block of power.

The long-run incremental cost of the next block of power to be acquired by Bonneville is far above the agency's reported average cost. This may reflect 1) Bonneville's failure to recover the true average costs of the Federal system as determined on an opportunity-cost basis and 2) the failure of the utility industry's historical-cost accounting methods to fully reflect the impact of inflation. But it also may reflect the exhaustion of economies of scale.

Congress should remove legal budgetary restraints to enable Bonneville to set the average level of its rates equal to long-run incremental cost. By its sharp impact on power rates, that approach should significantly reduce Pacific Northwest electric-power consumption—and thereby reduce the need for many of the coal and nuclear generating plants now scheduled for construction during the 1980's. Surplus revenues could be returned to the U.S. Treasury or used for a loan program to foster regional electrical conservation and renewable electrical-energy development programs. Legislation designed to re-allocate available supplies among competing consumer groups will not correct the basic disequilibrium between demand and supply created by the average-cost pricing method. Instead, regulatory authorities must give increased emphasis to the role of price as a balancing mechanism.

APPENDIX A:
Natural Monopoly and Utility Regulation

The electric-power industry traditionally has been considered a "natural monopoly,"—an industry where free-market conditions allegedly lead to a structure which is both monopolistic and capable of achieving lowest production costs. Theorists argue that the technological conditions inherent in the generation and transmission of electricity favor the granting of monopoly status to firms serving given market areas. At the same time, legal authorities claim that it is proper for government regulatory commissions to regulate these "public utilities," where monopoly is considered as "natural" or inevitable due to "technical conditions," so as to prevent the extraction of monopoly profits.

Social control of these utilities has taken two forms: 1) establishment of public regulatory authorities with power to investigate utility finances and operations and to set "just and reasonable" rates; and 2) direct public ownership of generation and transmission facilities. On a nationwide basis, regulation of privately-owned enterprises is the more common form of organization, but in the Pacific Northwest, publicly-owned utilities play an important role, sharing the retail market almost equally with privately-owned utilities. Publicly-owned utilities not only own their own generating plants, but also purchase wholesale power from the Bonneville Power Administration.

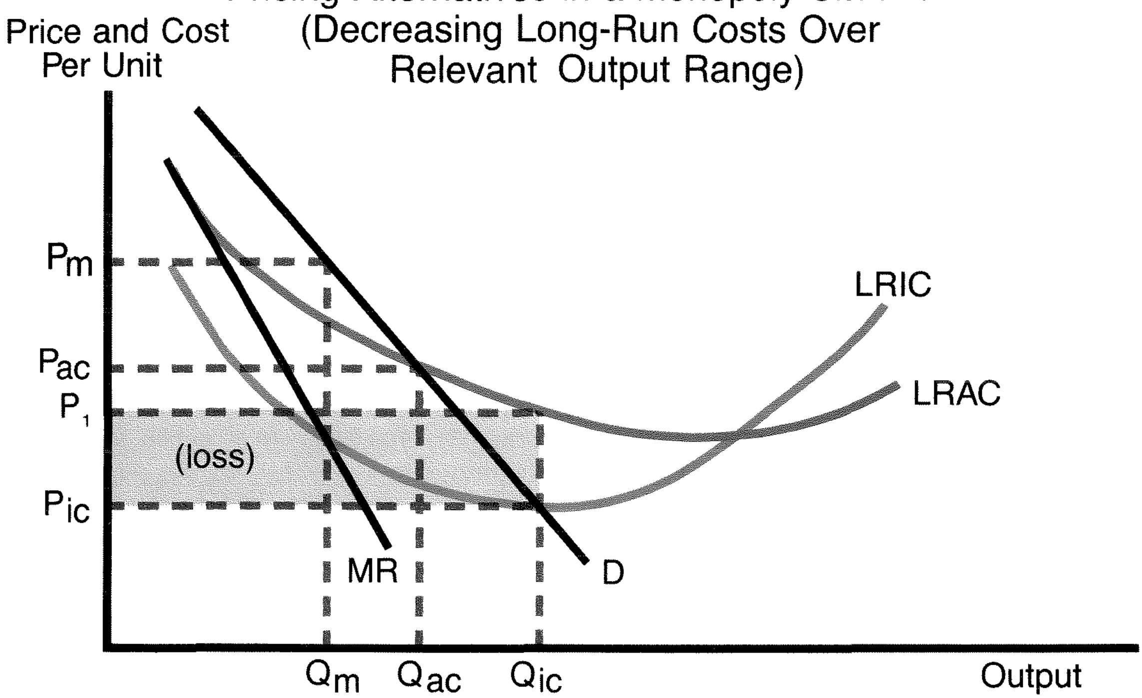
Legal justification for regulating certain privately-owned business firms developed from English common law, as modified in a series of landmark judicial decisions over the 1877–1943 period.[20] These decisions determined the legal criteria for a public utility to be: 1) a business whose activities are essential to the public welfare, i.e., in legal terms, "affected with a public interest;" and 2) one where regulation is required to protect the public. But economists have struggled for years to determine which characteristics qualify an industry as a natural monopoly and justify the granting of exclusive franchises under regulated conditions.

Some have mentioned heavy fixed costs as a necessary prerequisite.[21] They point out that supplying electricity requires very costly capital equipment, resulting in a high proportion of fixed to variable costs. Effective utilization of this equipment requires that the facilities be operated as close to full capacity as possible, thus dividing the total fixed cost of those facilities among the maximum number of units of output. Similarly, in this context, duplicate facilities—such as would be present in the usual competitive situation—would result in substantially higher unit costs. These characteristics translate into short-run declining average costs. That is, once the investment in plant is made and plant size is fixed over the short-run, average unit cost declines as output is expanded.

Other economists have argued that the incidence of heavy fixed costs is not a sufficient criterion for "natural monopoly." In industries with a heavy proportion of fixed to variable costs, production may still be carried on efficiently by a large number of firms. Duplication would be inefficient only in situations where there are economies of scale, or decreasing

Chart A.1

Pricing Alternatives in a Monopoly Situation (Decreasing Long-Run Costs Over Relevant Output Range)



P_m = Unregulated monopoly price under profit maximization
P_{ac} = Regulated monopoly price under average-cost pricing
P_{ic} = Regulated monopoly price under long-run incremental-cost pricing

long-run average costs, over the entire extent of the market. In such situations—but only in such situations—it would be inefficient for more than one producer to supply a given market. According to these economists, economies of scale are the indispensible feature of natural monopoly.[22]

Unregulated, the monopolist maximizes profits by equating marginal revenue (MR) to long-run incremental cost (LRIC) and pricing at a level P_m which corresponds to an output level Q_m (Appendix A, Chart I). Because price per unit exceeds average cost per unit, the monopolist enjoys a substantial economic profit. Moreover, because price exceeds long-run incremental cost—the cost of the last block of production—there is an under-utilization of resources, i.e., too few resources are devoted to this product. This socially undesirable option is normally prevented through the regulatory process, with the adoption of an average-cost pricing method. This approach results in a lower price, Pac, than the unregulated monopoly price, P_m. Similarly, it results in an output level, Qac, which is greater than the unregulated monopoly level of output, Q_m. It does not lead to as low a price and high an output level as would exist if price were determined by the cost of production of the last unit, that is, by the intersection of the demand curve and the long-run incremental cost curve. But under long-run decreasing average-cost conditions, the result is a price, Pie, that fails to cover average costs, so that without public subsidy the firm would be forced out of business.

APPENDIX B:
Table 1
Five-Year Levelized Annual Costs, Washington Public Power Supply System Nuclear Plants 1, 2, and 3
(cost data in thousands of dollars)

Year	Fixed Cost[2]	Variable Cost[2]	(Credits)[3]	Total Cost	Present Value Factor[4]	Present Value of Total Costs	Levelizing Factor[5]	Levelized Annual Cost
WPPSS #2								
1982[1]	163,320	23,670	(−4,280)	182,710	.913	166,814		
1983	164,860	25,190	(−4,280)	185,770	.834	154,932		
1984	167,940	27,440	(−4,280)	191,100	.726	138,739		
1985	169,690	30,410	(−4,280)	195,820	.696	136,291		
1986	172,460	32,640	(−4,280)	200,820	.635	127,521		
					Total	724,297	× (.26)	= 188,317
WPPSS #1								
1984[1]	192,550	37,750	(−4,910)	225,390	.913	205,781		
1985	198,180	38,660	(−4,910)	231,930	.834	193,430		
1986	200,170	42,830	(−4,910)	238,090	.726	172,853		
1987	203,840	46,190	(−4,910)	245,120	.696	170,604		
1988	203,480	49,560	(−4,910)	248,130	.635	157,563		
					Total	900,231	× (.26)	= 234,060
WPPSS #3								
1986[1]	133,410	26,800	(−3,750)	156,460	.913	142,848		
1987	132,540	29,700	(−3,750)	158,490	.834	132,181		
1988	133,420	33,180	(−3,750)	162,850	.726	118,229		
1989	134,340	34,930	(−3,750)	165,520	.696	115,202		
1990	135,320	36,120	(−3,750)	167,690	.635	106,483		
					Total	614,943	× (.26)	= 159,885

1 Initial year of full operation.
2 Costs include expected increases in input prices.
3 Interest earnings on reserves.
4 Assumes a discount rate of 9.5 percent.
5 Levelizing factor = $i/(1-v^m)$, where i = interest rate, m = number of periods, and $v^m = 1/(1+i)^m$.
Source: Computed by the author on the basis of cost data provided by Bonneville Power Administration.

APPENDIX C:
Adjustment of Bonneville's Reported Average Costs to Reflect Opportunity Costs

The following technical notes describe the methodology used by the author to adjust Bonneville's reported average unit costs for the 1947–79 period to include the major cost items and methodologies employed by private-owned utilities. The reported and imputed costs appear in Appendix C, Tables 1 and 2, respectively.

Taxes: Annual property-tax payments were imputed by applying the average property-tax rate for the U.S. private-utility sector in any given year to the Federal Columbia River Power System's total electrical plant in service as of that year, valued on an historical-cost basis. Income-tax payments for the system were imputed through a similar procedure, by applying the income-tax rate for the U.S. private-utility sector in any given year to the total electric-power revenues received by FCRPS as of that year.

Interest: Interest payments on an opportunity-cost basis were imputed for any given year n by the formula:

$$P_n = \sum_{y=1939}^{n} i_y A_y$$

Appendix C, Table 1
Federal Columbia River Power System Costs, 1947–79
As Reported by Bonneville[1]
(cost data in millions of dollars)

Fiscal Year	Variable Costs: Operation & Maintenance	Purchase and Exchange Power	Total	Fixed Costs: Interest	Amortization[2]	Total	Total Costs	Sales[3]	Unit Cost[4]
1947	6.01	.34	6.35	5.16	10.38	15.54	21.89	8.26	.265
1949	5.69	.74	6.43	5.86	15.53	21.39	27.82	11.97	.232
1951	8.11	.55	8.66	5.53	22.00	27.53	36.19	15.08	.240
1953	10.25	.76	11.01	9.34	18.60	27.94	38.95	16.39	.238
1955	12.01	.48	12.49	15.94	23.55	39.49	51.98	21.83	.238
1957	15.34	.49	15.83	24.02	26.42	50.44	66.27	28.21	.235
1959	18.39	.52	18.91	30.14	19.42	49.56	68.47	28.66	.239
1961	21.69	.70	22.39	32.82	14.49	47.31	69.70	28.28	.247
1963	23.17	1.28	24.45	34.63	18.62	53.25	77.70	31.49	.247
1965	27.05	1.62	28.67	35.22	26.22	61.44	90.11	37.20	.242
1967	28.98	9.64	38.62	35.55	38.66	74.21	112.83	43.99	.256
1969	34.09	12.53	46.62	43.32	47.34	90.66	137.28	51.88	.265
1971	44.59	12.81	57.40	59.14	39.14	98.28	155.68	57.61	.270
1973	53.44	48.26	101.70	69.32	6.32	75.64	177.34	65.04	.273
1975	71.32	19.35	110.02	89.18	37.95	127.13	237.15	65.73	.361
1977	94.79	23.72	118.51	118.49	− 13.41	105.08	223.59	61.75	.362
1979	123.15	25.20	148.35	168.00	− 19.79	148.21	296.56	72.02	.412

1 These costs reflect Bonneville's interpretation of its repayment responsibility. That is, they represent the amounts the agency believes it must recover in the form of revenues during any given year to cover all the costs incurred by the Corps of Engineers, the Bureau of Reclamation and the Bonneville Power Administration in purchasing, generating, transmitting and marketing electric power, including the amortization of the Government's investment in power facilities with interest. The repayment accounting method constitutes the basis for establishing the average power rate.

2 Amortization, unlike the other cost data, is not reported by Bonneville. Rather, it is a residual amount left over from total revenues after all other costs have been subtracted. This policy arises from the agency's interpretation of its repayment responsibility. Although it is required by law to repay in full all Congressional appropriations within fifty years after the investment becomes revenue producing, Bonneville does not interpret this requirement to mean that it must repay the borrowings on a straight-line or otherwise consistent basis. In fiscal years 1977 and 1979, total revenues were insufficient to permit any repayment of debt to the U.S. Treasury.

3 In billions of kilowatt hours.

4 In cents per kilowatt hour, derived on the basis of the average-cost pricing method. Unit cost equals total cost divided by the number of units (kwh) sold in a given period. Unit cost and average cost are thus synonymous under the average-cost pricing procedure.

Source: U.S. Department of Energy, Bonneville Power Administration, *Annual Report* (various issues) and *Financial and Statistical Summary*.

Appendix C, Table 2
Federal Columbia River Power System Costs, 1947–79, As Imputed on a Private-Utility Cost Basis[1]
(cost data in millions of dollars)

	Variable Costs			Fixed Costs							
Fiscal Year	Operation & Maintenance	Purchase and Exchange Power	Total[2]	Property Tax[3]	Income Tax[4]	Depreciation[5]	Reconciliation Depreciation & Amortization[6]	Interest[7]	Total	Total Costs	Unit Cost[8]
1947	6.01	.34	6.35	5.94	1.59	3.76	.75	5.49	17.53	23.88	.289
1949	5.69	.74	6.43	7.69	2.21	5.01	1.00	7.27	23.18	29.61	.247
1951	8.11	.55	8.66	10.36	4.23	6.80	1.36	9.89	32.64	41.30	.274
1953	10.25	.76	11.01	11.89	4.86	9.62	1.93	14.84	43.14	54.15	.330
1955	12.01	.48	12.49	20.28	6.24	15.86	3.18	25.39	70.95	83.44	.382
1957	15.34	.49	15.83	26.41	6.91	20.46	4.10	34.36	92.24	108.07	.383
1959	18.39	.52	18.91	32.44	6.43	23.91	4.79	41.20	108.77	127.68	.445
1961	21.69	.70	22.39	33.37	8.05	25.50	5.11	43.52	115.55	137.94	.488
1963	23.17	1.28	24.45	59.44	8.74	27.74	5.56	47.21	148.70	173.15	.550
1965	27.05	1.62	28.67	39.46	9.55	28.96	5.81	48.20	131.98	160.65	.432
1967	28.98	9.64	38.62	42.13	10.70	31.06	6.23	52.64	142.76	181.38	.412
1969	34.09	12.53	46.62	55.85	11.71	40.99	8.22	90.41	207.18	253.80	.489
1971	44.59	12.81	57.40	68.53	7.25	50.06	10.04	129.67	265.55	322.95	.561
1973	53.44	48.26	101.70	73.33	5.87	55.03	11.03	145.95	291.21	392.91	.604
1975	71.32	19.35	90.67	98.59	5.22	70.50	14.13	221.82	410.26	500.93	.762
1977	94.79	23.72	118.51	123.08	3.58	85.44	17.13	286.44	515.67	634.18	1.027
1979	123.15	25.20	148.35	134.66	5.25	95.87	19.22	329.79	584.80	733.15	1.018

1 These costs represent the author's interpretation of the amounts that should have been recovered by Bonneville in the form of revenues in any year had it been operating as a private investor-owned electric utility. These consist of the variable costs as actually measured and reported by Bonneville, plus recomputations of fixed costs to include imputed property and income-tax payments, interest charges reflecting the opportunity cost of capital in the private-utility sector, and a straight-line depreciation and amortization charge to repay all outstanding debt on a consistent and continuous basis.

2 The author took no exception to total system variable costs as measured by Bonneville. Variable costs are thus as reported in Appendix C, Table 1.

3 Derived by applying the average property-tax rate for the U.S. private-utility sector in any given year (property taxes paid as a percentage of total electric plant) to the Federal Columbia River Power System's (FCRPS's) total electric plant in service as of that year.

4 Derived by applying the average income-tax rate for the U.S. private-utility sector in any given year (Federal and other income taxes paid as a percentage of total revenues) to the total electric-power revenues received by the Federal Columbia River Power System as of that year. Income tax is considered a fixed cost by private investor-owned utilities in that some payment is assured by the regulatory process.

5 Private utilities recover their long-term borrowings for capital investment through their depreciation charges. Depreciation is usually calculated on a straight-line basis, by applying the average life of service of the equipment to the total value of the plant in service, measured on a historical (original) cost basis as is customary in the private-utility industry. Bonneville estimates the average service life of its plant to be 60 years. For any given year, depreciation thus has been calculated here as 1/60th of the total value of the plant in service, measured on an historical-cost basis.

6 Depreciation is calculated on an average 60-year basis, whereas Bonneville is required by law to amortize (pay back) its borrowings within 50 years after they become revenue producing. The "reconciliation" charges represent the difference between 1/50th and 1/60th of the value of plant in service.

7 Derived on an "opportunity cost" basis; total interest payments in each year equal the product of new debt and the current Moody's average Aaa interest rate for public (private investor-owned) utilities, plus the product of old unamortized debt and the interest rate in effect when that debt was incurred. Debt is reduced (amortized) on a straight-line basis by 1/50th each year after it is incurred. A consistent series showing Congressional appropriations to the FCRPS was not available. Total value of plant in service was used as a proxy in determining outstanding debt, under the assumption that borrowing was for capital investment.

8 In cents per kilowatt hour, derived on the basis of the average-cost pricing method. Unit cost equals total cost divided by the number of units (kwh) sold in a given period. Unit cost and average cost are thus synonymous under the average-cost pricing procedure.

Source: For data pertaining to the private-utility sector: Federal Power Commission, *Statistics of Privately-Owned Electric Utilities in the United States* and Moody's Investors Services, *Moody's Public Utilities Manual*. For reported data pertaining to the Federal Columbia River Power System: Bonneville Power Administration.

where: P_n = total interest payment in year n

i_y = Moody's Aaa interest rate on public (private investor) utility issues in year y

A_y = unamortized portion of appropriations received in year y as of year n

This formula simply states that total interest payments in any given year, P_n, equal the sum of all interest payments on outstanding FCRPS debt in that year. In other words, total interest payments equal new debt times the prevailing interest rate, plus any unamortized old debt multiplied by the rate(s) in effect when the debt was incurred. The first debt was assumed to be incurred in 1939, the earliest date for which data were available. Each increment in debt was amortized on a straight-line basis by 1/50 each year after it was incurred, in line with the 50-year payback period specified by law. Note that Moody's Investor Service refers to private investor-owned utilities as public utilities, using that term in a general sense.

A consistent series showing annual Congressional appropriations to the FCRPS was not available. A proxy for "new debt" was developed by taking the total value of plant in service; i.e., the capital stock, and calculating the annual change, or new investment added each year. That proxy was used under the assumption that borrowing was for capital investment.

Amortization: Amortization costs were imputed annually for the 1947–79 period by developing a systematic straight-line depreciation schedule. Depreciation was calculated by applying the average life of service of the equipment to the total value of the plant in service, measured on an historical (original) cost basis. This amortization procedure follows that used by most private utilities. Bonneville estimates the average service life of its plant and equipment to be 60 years. For any given year, depreciation thus was calculated as 1/60th of the total value of plant in service. Since depreciation is calculated on a 60-year basis, whereas Bonneville is required by law to amortize borrowings within 50 years, depreciation charges thus calculated would fall short of meeting Bonneville's repayment responsibilities. A reconciliation charge therefore was calculated, representing the difference between 1/50th and 1/60th of the value of the plant in service. (The fact that transmission investment must be paid back in 40 rather than 50 years was ignored, i.e., the payment period was assumed to be 50 years, the same as for generating investment.)

FOOTNOTES

1. Perhaps the most widely-used source is the long-term forecast of Pacific Northwest electric-energy loads and resources developed annually by the region's utilities. For a summary of the latest findings, see U.S. Department of Energy, Bonneville Power Administration, **Power Outlook Through 1989–90** (Portland: Bonneville Power Administration, May 1979). Bonneville's marketing area includes Washington, Oregon, Idaho and Western Montana.

2. For a description of the average-cost pricing methodology followed by private investor-owned utilities in establishing the level of rates, see Edison Electric Institute, **Economic Growth in the Future: The Growth Debate in National and Global Perspective** (New York: McGraw-Hill Book Company, 1975), pp. 259–266.

3. For Bonneville, the return on invested capital includes interest to be paid to the U.S. Treasury for long-term borrowings for investment in the Federal Columbia River Power System. These funds are acquired through Congressional appropriation and, for financing transmission facilities, through the sale of revenue bonds to the Treasury. For private investor-owned utilities, the return consists of three components: 1) interest payments on bonded indebtedness, 2) dividends on preferred stock, and 3) a return to common-equity holders, a residual amount which becomes available to these owners only after all other legitimate claims of the company have been settled. The first two are specified exactly on the bond indenture and the preferred-stock certificates.

4. In a perfect-competition model, there is one situation in which short and long-run marginal (incremental) costs are equal—that is, in long-run competitive equilibrium. In this situation, plant capacity has been adjusted to its optimum size for achieving a given level of output, as shown in Chart 2 at output Q_3. It is assumed that a firm starts from scratch in planning its optimal-size production facility. In reality, this optimum is never realized. Instead, firms operate with plants of various ages, and must make decisions with regard to adding new capacity, either for replacement or growth purposes. Pricing on the basis of short-run costs would not necessarily recover the capital costs associated with this new plant.

With regard to the distinction between marginal and incremental cost, marginal cost—strictly speaking—refers to the additional cost of supplying a single, infinitesimally small additional amount. Incremental cost refers to the average additional cost of a larger finite addition to production. Since rate changes are relatively infrequent, additions to output for which costs must be recovered are of an incremental rather than marginal magnitude.

5. For proof that marginal-cost pricing of all goods and services leads to optimum welfare, see Edward Berlin, Charles J. Cicchetti and William J. Gillen, **Perspective on Power, A Study of the Regulation and Pricing of Electric Power,** A Report to the Energy Policy Project of the Ford Foundation (Cambridge: Ballinger Publishing Company, 1975), pp. 127–130.

6. The cost curves for an individual firm are drawn under the assumption that the firm has no influence on the prices of the factors of production it uses. Internal economies therefore are those enjoyed by a firm apart from any change in factor prices. When an industry as a whole expands its output, the prices of factor inputs may be affected. External economies affect the slope of the industry supply curve.

7. For a discussion of the distinction between economies of scale, i.e., decreasing long-run average costs, and decreasing short-run average costs attributable to spreading of overhead, see Edward Berlin, Charles J. Cicchetti and William J. Gillen, **op. cit.,** pp. 6–7.

8. There are numerous studies devoted to the methodologies for determining long-run incremental costs and rates in the electric-utility industry. See, for example, Charles R. Cicchetti, William G. Gillen and Paul Smolensky, **The Marginal Cost and Pricing of Electricity: An Applied Approach** (Cambridge: Ballinger Publishing Company, 1977); Charles R. Scherer, **Estimating Electric Power System Marginal Costs** (Amsterdam: North-Holland Publishing Company, 1977); National Economic Research Associates, Inc., **A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States,** Topic 1.3, prepared for Electric Utility Rate Design Study (New York: National Economic Research Associates, Inc., 1977); and Ralph Turvey, **Optimal Pricing and Investment in Electricity Supply, An Essay in Applied Welfare Economics** (Cambridge: Massachusetts Institute of Technology, 1968). All of these studies are inordinately complex because they deal not only with the level of rates, but also with the structure, and the time and seasonal differentiation of rates.

9. According to Bonneville, thermal capacity will account for 92 percent of the total new generation name-plate capacity scheduled for the 1978–86 period. See U.S. Department of Energy, Bonneville Power Administration, **BPA Long-run Incremental Cost of Service and Rate Study** (Portland: Bonneville Power Administration, July 1979), Table 4. The author did not accept BPA's calculations of long-run incremental thermal and hydro-power costs, but did take into consideration that the agency's incremental-cost estimate for hydro-peaking capacity was far lower than its estimate for baseload thermal energy.

10. The legal requirement to recover costs is found in Section 7 of the Bonneville Project Act (50 Stat. 731, approved August 20, 1937); Section 5 of the Flood Control Act of 1944 (58 Stat. 887), which applies to the marketing of power from all Corps of Engineers' projects; and Section 9 of the Federal Columbia River Transmission Act (approved October 18, 1974; 88 Stat. 1376). See Bonneville Power Administration, **The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System, op. cit.,** Appendix C, pp. II–34–38.

11. Bonneville Power Administration, **The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System, ibid.,** Appendix C, p. II–9.

12. Major cost items were included only if appropriate. For example, the return to equity owners was excluded because Bonneville is financed solely through Congressional appropriations and sales of revenue bonds to the U.S. Treasury.

13. Bonneville Power Administration, **Interest Rate Policy** (Unpublished paper, February 15, 1978), p. 5.

14. See Edison Electric Institute, **A Study of the Bonneville Power Administration, The Marketing Agent for the U.S. Columbia River Power System** (New York: Edison Electric Institute, 1963), p. 2; and David L. Shapiro, "Bonneville Agency Pricing and Electric Power Utilization," **Quarterly Review of Economics and Business** (Winter 1976), p. 22. In these studies, the opportunity-cost principle for selecting the appropriate interest rate was not discussed.

15. Since Bonneville purchases power only from publicly-owned utilities, the sale of long-term bonds is the only method of funding. For private utilities, the return on equity capital is adjusted for inflation, since the regulatory process permits the return on old equity to equal the rate of return on new equity. However, this adjustment pertains only to the return on equity capital.

16. Numerous utility experts have noted the increased maintenance problems and higher forced outage rates associated with nuclear plants above about 600 MW capacity. See, for example, C. C. Boone, "The Financial Impact of Outages," paper presented at 31st Annual Meeting of the American Power Conference, April 1969; also, Louis H. Roddis, Jr., "Address to the 1972 Atomic Industrial Forum."

17. Since electricity is crucial to the aluminum industry—by far Bonneville's largest industrial user—and is presently priced very low relative to other regions, the industrial sector's demand schedule may be less elastic than that of the utility sector. If so, industrial users would pay less for power under the inverse elasticity rule than utility customers, although both groups would pay far more than they are paying under current average-cost pricing methods. Since industrial customers are willing to take a certain amount of interruptible power, that differential might be acceptable to all parties.

18. Strict long-run incremental-cost pricing also would eliminate the need for the preference clause, because with overall consumption declining, sufficient resources would be available to meet the quantity demanded by all customer groups.

19. See J. W. Wilson, "Residential Demand for Electricity," **Quarterly Review of Economics and Business** (November 1979), pp. 7–22; K. P. Anderson, "The Demand for Electricity: Econometric Estimate for California and the United States," **RAND R-905-NSF,** Santa Monica, Cali-

fornia, 1972; R. Halvorsen, "Residential Electricity: Demand and Supply," presented at the Sierra Club Conference on Power and Public Policy, Vermont, January 1972.

20. For a summary of the constitutional history and the criteria for regulation, see Alfred E. Kahn, **op. cit.,** pp. 3–8; also, Dexter Merriam Keezer and Stacy May, **The Public Control of Business** (New York: Harper and Brothers, 1930), Chapter 5.

21. Ely observed, for example, that natural monopolies will exist in the presence of the following three conditions: a high degree of price sensitivity by consumers, the technical and economical impracticality of a large number of producers, and a high proportion of fixed to variable costs. Clemens, many years later, listed the following necessary conditions: conditions of space and geography, large capital investments, economies of decreasing costs, technical limitations of the market, and exclusive franchises. Richard T. Ely, **Outlines of Economics,** 6th Ed. (New York: MacMillan Company, 1937), p. 628, Eli W. Clemens, **Economics and Public Utilities** (New York: Appleton-Century-Crofts, Inc., 1950), pp. 26–28.

22. For example, Kahn, in his analysis of natural monopoly, emphasizes that it is not the fact of "duplication alone that makes for natural monopoly, but the presence of economies of scale or decreasing costs in the provision and utilization of their facilities," and that this will be the case only "when the economies achievable by larger output are internal to the individual firm." See Kahn, **op. cit.,** Vol 2, pp. 119 and 121.

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