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POTENTIAL FEDERAL REGION IX ELECTRICITY PRICES

Jayant Sathaye, Panos Cavoulacos and John Tsitsiklis

May 1980

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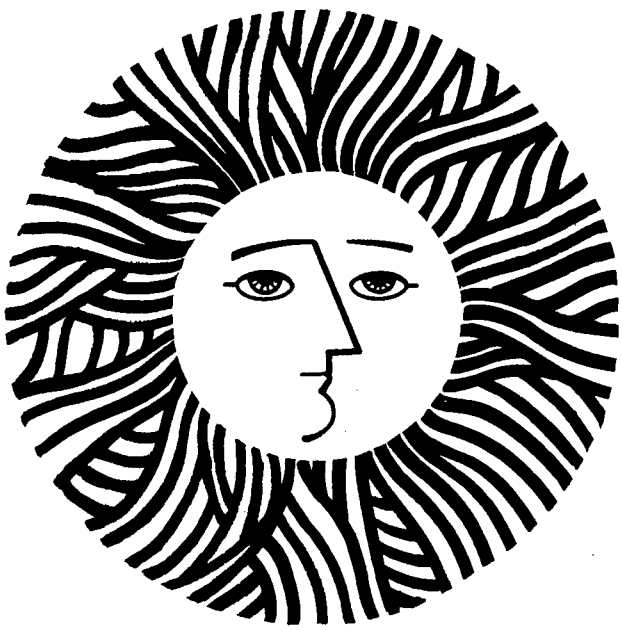

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POTENTIAL FEDERAL REGION IX ELECTRICITY PRICES

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Energy Analysis Program
Lawrence Berkeley Laboratory
Berkeley, California

May 1980

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INTRODUCTION

Each year the Energy Information Administration (EIA) submits an Annual Report to Congress[1]. The report includes several projections of future energy demand and supply alternatives for each of the ten federal regions in the country. In arriving at these energy demand and supply alternatives several assumptions are made regarding fuel prices. Each fuel type is priced separately by each region. Electricity prices by customer class are derived from fuel price assumptions and from capital operation and maintenance costs and other financial data assumed to reflect utility averages in the region.

This study was designed to provide an independent estimate of average electricity prices and to evaluate the sensitivity of average prices to the financial and other cost variables. The price estimate was derived for seven EIA scenarios. The concept of average price was formulated to represent the average burden that consumers will have to bear in Region IX if the power plants and fuels were brought on line as projected in the scenario. Average price for an individual utility may vary from an estimate if the utilities' mix of power plants or fuels were different. During the 1977-78 California drought average electricity prices increased by 25 percent due to the heavy dependence on oil-fired power plants which were used as substitutes for hydroelectric supplies.

For the projected energy demand and supply alternatives EIA has estimated an average busbar price, exclusive of transmission and distribution costs for each federal region. As part of our analysis we estimated two sets of prices, one assuming EIA capital costs and a second set assuming the capital costs provided in the widely used Energy Supply Planning Model[2] developed by Bechtel Corporation. The two sets of results are tabulated and compared with EIA estimates. The results are also compared with 1977 actual prices for Pacific Gas and Electric Company, a major utility in Northern California.

AVERAGE PRICE MODEL AND DATA BASE

The average price model was used to calculate the levelized busbar cost of electricity in 1978 dollars. The levelized busbar cost of electricity for each plant type may be expressed as the sum of three types of costs.

$$C_j = (\text{Levelized Capital Cost})_j + \text{Operations and Maintenance Cost})_j + (\text{Fuel Cost})_j$$

where j = plant type.

The overall levelized cost of electricity for the region in any year is then the weighted average of the costs for each plant type (the weighting factor being the amount of energy produced by each type of plant).

$$C = \frac{\sum_{j=1}^{M} C_j E_j}{\sum_{j=1}^{M} E_j}$$

where E_j = Energy generated by plant type j during the year under consideration; and C = levelized busbar cost of electricity or the average price in 1978 mills/kwh.

Levelized Capital Costs

Levelized capital cost may be expresses as a function of initial capital cost (CC), the energy generated each year (E), the total rated capacity of plants (PW), the fixed charge rate (FCR), and the escalation rate for capital costs (EESC). For a power plant of type j the levelized capital cost is:

$$\text{Levelized Capital Cost} = CC_j \; EESC_j \; PW_j \; FCR_j / E_j$$

Capital Costs

In validating the projections of average busbar electricity prices, two sets of capital cost data were used. The first data set was derived from the Bechtel ESPM Model[2,3] whereas the second set included data obtained from EIA[4,5]. The two data sets are not entirely compatible, requiring some changes and

approximations in the ESPM data set. Solar thermal electric power plants, photovoltaics, wind, biomass-electric and ocean thermal conversion (OTEC) technologies, all categorized as new and renewable, were excluded from consideration, primarily because their contribution to installed capacity in Region 9 will be very small, less than one percent. Table 1 shows the correspondence established between the twenty-three plant types used in EIA projections and the twelve plant types with scrubbers used as a separate unit in ESPM.

Table 2 shows the comparable capital and operation and maintenance (O&M) costs for the EIA and the ESPM data bases. Capital costs in the EIA data were in 1975 dollars per kilowatt of installed capacity, whereas the ESPM costs were in 1978 dollars per kilowatt of installed capacity. The EIA cost estimates were converted to 1978 dollars using an inflator of 1.2. This value was based on the construction cost inflation indices of 1.19 used by DOE/EIA[4,5] and the 1.22 Boeckh commercial/factory index.

The EIA capital costs include interest during construction calculated with a real weighted cost of capital of 4.3 percent. For the ESPM data the interest during construction (IDC) was included at the same rate. The effect of IDC depended both on the construction time and the distribution of capital expenditures during that time. For example, nuclear power plants (LWR) require 9 years for construction and IDC is about 17 percent of the direct costs. IDC is assumed to form part of the capital thus the costs would not be recovered till the plant starts generating electricity (AFUDC accounting). Escalation rates and working capital are excluded in both data bases.

As can be seen in Table 2 on a comparable basis the Bechtel-ESPM estimates are much lower than the DOE/EIA figures except for pumped storage and geothermal plants.

EIA distinguishes between new, deferred and committed power plants and uses different capital costs especially for nuclear power plants with uncertain regulatory proceedings, long lead times and generally rising escalation rates. The capital costs also include the IDC calculated with a real weighted cost of capital and the postulated construction times.

Costs for plants converted from oil or gas to coal were assumed the same as for coal-fired plants. Although oil and gas plants are cheaper than coal plants, the conversion costs are high enough so that the total costs are likely to exceed the coal plant costs.

Table 1

EIA and ESPM Power Plants Correspondence

EIA/MEFS	Bechtel/ESPM
Nuclear	Light-water reactor (1100 MWe)
Residual oil-steam fired	Oil-fired (800 MWe)
Coal Fired Plants	
Bituminous high-sulfur with scrubbers	Coal-fired, high-BTU plus SO_x removal (800 MWe)
Bituminous medium-sulfur with scrubbers	
Bituminous low-sulfur with scrubbers	
Subbituminous medium-sulfur	Coal-fired, low-BUT plus SO_x removal (800 MWe)
Subbituminous low-sulfur	
Liguite medium-sulfur	
Liguite low-sulfur	
Bituminous high-sulfur	Coal-fired, high-BTU (800 MWe)
Bituminous medium-sulfur	
Bituminous low-sulfur	
Subbituminous medium-sulfur	Coal-fired, low-BTU (800 MWe)
Subbituminous low-sulfur	
Liguite medium-sulfur	
Liguite low-sulfur	
Distillate turbines	Gas turbines (133 MWe)
Combined cycle (distillate)	Combined cycle (400 MWe)
Gas turbines	Gas turbines (133 MWe)
Gas-steam fired	High-BTU gas-fired (800 MWe)
Hydro	Dam and hydro (200 MWe)
Pumped storage	Pumped storage (1000 MWe)
Hydrothermal (step I)	Geothermal (200 MWe)

Table 2

Capital and O&M Costs of Power Plants

	Bechtel/ESPM		DOE/EIA	
Plant Type	Capital (1978 $/kw)	O&M (1978 $/kw)	Capital (1978 $/kw)	O&M (1978 mills/kwh)
Nuclear	670	14.91	1062	1.98
Residual Oil	325	14.47	438	1.08
Coal-Fired Plants				
Bit HS Scr	540	27.13	672	5.38
Bit MS Scr	540	27.13	660	4.28
Bit LS Scr	540	27.13	600	2.40
Sub MS Scr	610	29.71	684	4.40
Sub LS Scr	610	29.71	624	2.52
Lig MS Scr	610	29.71	708	4.40
Lig LS Scr	610	29.71	648	2.52
Bit HS	400	14.10	600	2.40
Bit MS	400	14.10	600	2.40
Bit LS	400	14.10	600	2.40
Sub MS	470	16.68	624	2.52
Sub LS	470	16.68	624	2.52
Lig MS	470	16.68	648	2.52
Lig LS	470	16.68	648	2.52
Distillate turbines	175	6.03	174	3.30
Combined Cycle	235	13.73	318	1.50
Gas trubines	175	6.03	174	3.30
Gas steam	195	11.68	324	0.60
Hydro	725	8.56	804	1.00
Pumped Storage	370	3.48	228	1.00
Geothermal	880	47.82	700	13.94

Fixed Charge Rate

The ratio of the levelized annual costs to the total investment is defined as the fixed charge rate.[6,7] Levelized annual cost is the constant amount that would have to be paid annually over the book life of the power plant. In general the fixed charge rate depends on factors such as the weighted cost of capital, property taxes, insurance costs, the method used for depreciation, state, local and federal taxes, tax preference allowances, whether normalized or flow through accounting is used and on the projected lifetime of the plant.

For example, PG&E calculates the fixed charge rates as follows:[8]

FCR = Required return on new investment + Ad Valorem tax + Insurance + Federal, state and local Taxes + Depreciation

The fixed charge rate will therefore be a function of technical and financial parameters specific to that plant, the utility that owns it and the general macroeconomic environment.

The EIA scenarios assume a fixed charge rate between 10 and 13 percent varying with the type of plant.[5] These numbers are significantly different from the usually quoted numbers which range from 15 to 20 percent.[6] The difference arises because EIA figures are based on the real cost of capital at 4.28 percent whereas generally the nominal cost of capital at 10 percent is assumed. The real cost of financing is assumed by EIA to be 3 percent for debt, 3.5 percent for preferred equity and 6.5 percent for common equity. A fixed financial structure is also assumed at 55 percent debt, 10 percent preferred equity and 35 percent common equity.

Table 3 shows the fixed charge rate for different types of power plants used in our estimates of future average prices. These fixed charge rates are generally those assumed by EIA for Region 9, which are slightly lower than the national averages. Fixed charge rates for utilities using flow through accounting, other factors remaining constant, are smaller than for those using normalized accounting procedures. Utilities in California and Arizona which account for 88 percent of the generation in Region 9 are required to use flow through accounting thus accounting for the lower fixed charge rates.

Table 3

Fixed Charge Rates by Plant Type

Plant Type	FCR Scenarios A, B, C, D, E, N	FCR Scenario H
Nuclear	.118	.148
Resid. Oil	.111	.164
Bit. HS. Scr.	.131	.169
Bit. MS. Scr.	.131	.169
Bit. LS. Scr.	.131	.169
Sub MS. Scr.	.131	.169
Sub LS. Scr.	.131	.169
Lig. MS. Scr.	.131	.169
Lig. LS. Scr.	.131	.169
Bit. HS	.131	.169
Bit. MS	.131	.169
Bit. LS	.131	.169
Sub. MS	.131	.169
Sub. LS	.131	.169
Lig. MS	.131	.169
Lig. LS	.131	.169
Dist. Trbns.	.103	.130
Comb. Cycle	.111	.161
Gas Trbns.	.103	.130
Gas Steam	.111	.163
Hydro	.104	.161
Pumped Str.	.104	.161
Geothermal	.081	.086

The fixed charge rate for geothermal power plants is extremely low since it was considered an emerging technology which would be subsidized thus lowering its levelized costs. However, geothermal plants are already in commercial operation in California without any special studies. The resulting higher or normal fixed charge rate does not affect the total capital costs significantly since the level of geothermal development is fairly small.

The EIA fixed charge rates for coal fired units are higher than for any other type of plant in Region 9. In contrast the fixed charge rates for PG&E for coal fired and nuclear units are about alike with nuclear slightly higher reflecting the tax life of 22 years and 16 years for coal and nuclear plants respectively. It is difficult to justify the higher values used by EIA for coal units even considering the interim investment for pollution control such as scrubbers or the different tax schemes, pollution control equipment is not eligible for tax credit. Furthermore, EIA uses the same FCR for both power plants with or without scrubbers.

Escalation of Costs

Except for the analysis conducted for scenarios B and E, no cost escalation was assumed. Since the oil embargo, capital costs of power plants escalated sharply and then slowed down in the past couple of years. Based on this short history of cost escalations, it is not clear if a trend can be established for future escalation of costs.

For scenarios B and E, a 12 percent cost escalation from 1977 to 1985 was assumed in accordance with EIA projections.

Since cost escalation would apply to new power plants only an effective escalation rate was used, to account for old plants already in line before 1977, in order to estimate the average future prices accurately. The effective escalation rate:

$$EESC_j = \frac{(\text{existing capacity}) + 1.12\ (\text{new capacity})}{(\text{existing capacity} + \text{new capacity})}$$

Furthermore, plants coming on line after 1978 but before 1985 were also assumed to have a 12 percent escalation rate. The average prices will be slightly on the higher side.

Operation and Maintenance Costs

Cost data on operation and maintenance (O&M) of power plants are shown in Table 2. The EIA data were in 1975 miles per kilowatt-hour of electricity generation. The ESPM data were in 1978 dollars per kilowatt of installed capacity. In estimating average prices, the ESPM data were converted into mills/kwhe using the figures for capacity in place and total generation projected in the scenario.

Fuel Costs

All the fuel costs used in this analysis are based on EIA projections except for geothermal power plants. The fuel costs and the respective efficiencies of power plants are shown in Table 4. Geothermal costs are based on the cost of oil, coal and nuclear fuels. In 1979 the average cost of steam sold to geothermal plants was 17 mills/kwhe, which is the price assumed in this report. Since the amount of natural gas consumed by peaking units is very small, all peaking units including combined cycle and combustion turbines were assumed to burn distillate oil.

AVERAGE PRICES

Average future price of electricity was calculated for scenarios A, B, C, D, and E and for two sensitivity cases, H and N. Case H assumes higher fixed change factors and case N is the nuclear moratorium scenario.

In validating the EIA price estimates, two analyses were conducted. The first analyses used EIA assumptions regarding capital cost data, fixed charge factors and fuel costs, whereas the second analysis was based on ESPM cost data.

To provide a perspective to the concept of average prices, we have estimated an average price for 1977 and compared that with prices charged by PG&E in 1977.

Average electricity prices or busbar costs for 1977 were 38 mills/kwhe in 1978 dollars. Fuel costs for coal, oil and gas varied between utilities and during the year in 1977. Fuel costs were assumed as 7 mills for nuclear fuel, 29 mills for oil, 18 mills for gas, 14 mills for coal and 13 mills for geothermal per kilowatt hour of generation.

Table 4

Estimates of Region 9 Electricity Prices in 1978 mills/kwh

SCENARIO	1985			1990			1995		
	LBL Estimate		EIA Estimate	LBL Estimate		EIA Estimate	LBL Estimate		EIA Estimate
	With ESPM Data	With EIA Data		With ESPM Data	With EIA Data		With ESPM Data	With EIA Data	
A	29.39	31.41	33.25	31.45	33.17	33.00	31.43	33.10	34.28
B	35.22	37.24	45.09	36.92	39.18	45.45	41.76	43.89	51.70
C	29.48	31.40	33.00	32.06	34.01	37.25	36.28	37.99	39.36
D	27.56	29.65	29.09	28.94	30.95	32.77	30.95	33.14	33.48
E	32.47	34.48	38.28	35.45	37.91	44.56	38.20	40.68	45.77
H	33.58	36.52	35.93	36.89	39.86	46.89	38.81	41.76	48.53
N	29.48	31.40	33.01	32.25	34.04	37.36	36.79	38.43	40.04

Average electricity prices for PG&E during 1977 were 42 mills/kwhe inclusive of transmission and distribution charges. Comparing this figure with average busbar electricity prices estimated for 1977 using the LBL model, 38 mills/kwhe, are slightly on the higher side assuming an average 30 percent contribution of T and D to the prices.

Our estimates based on EIA and ESPM cost estimates are for power plants which would be constructed in the future. These costs are generally higher for most types of plants than the costs of plants already in place especially before 1973 since the escalation rates were lower before 1973. Our estimates are likely to be higher than the actual future prices.

In calculating the average prices for 1977 as well as for future years, it was assumed that all the existing power plants were still being paid off. Clearly all the plants which are older than 30 years and some which are more recent have been paid off and would not form part of the rate base. To assess their impact on 1977 prices, plants older than 30 years were deducted from the rate base and the prices were recomputed. The overall impact was small, of the order of 1 or 2 mills, thus reducing the 1977 estimated average price to 36 mills per kilowatt hour.

Table 4 shows the average price of electricity for the 7 Scenarios A through N. For each scenario and each year 1985, 1990 and 1995, the three estimates of prices are presented, prices based on ESPM capital cost data, prices based on EIA cost data and finally the EIA estimates.

A comparison of the first two sets of prices reveals the sensitivity of prices to variations in capital costs. Capital costs between the two data sets vary from 15 to 35 percent for the base load power plants with smaller differences for peaking units (see Table 2). In all cases, except pumped storage and geothermal plants, the EIA cost estimates are higher than the ESPM cost estimates.

The estimate of average prices for all scenarios and all years differs by only 2 to 3 mills or roughly 7 to 10 percent. As compared to the differences in base load capital costs, the differences in prices are significantly smaller. The main reason for the smaller differences in prices is the large contribution of fuel costs which increases with time. Also in five of the seven scenarios capital costs are not allowed to change with time thus increasing the effect of fuel costs contribution. Variations in capital costs of future power plants

either because of lack of sufficient knowledge of future pollution control technology or for security reasons will have a relatively small impact on electricity prices so long as fuel costs dominate the equation. Variations in capital costs for solar or renewable technologies with little or no fuel costs may introduce significant changes in overall electricity prices if their contribution to the generating mix were large.

The EIA estimated prices compared with LBL estimates of prices based on EIA data show wide variations among the scenarios. Price differences between Scenarios A, C, D and N show little or no change between EIA and LBL estimates. Maximum difference is of the order of 3 mills/kwh or roughly 10 percent of the estimated prices (see Table 5). There are, however, larger differences between the two estimates for Scenarios B, E and H, of the order of 7 to 8 mills/kwh or roughly 20 to 25 percent.

The large price differences in scenarios B and E arise mainly because of the different costs of escalation assumed by EIA and LBL. EIA assumes a 38 percent escalation in costs between now and 1985 to account for potential changes in capital costs, in pollution control expenditures and other uncertainties. LBL estimates assume only a 12 percent escalation for capital costs with no escalation for stricter environmental standards since the scrubber costs already assumed a 90 percent removal rate.

Price estimates for Scenario H, a sensitivity analysis of the effect of high fixed charge factors on Scenario C estimates, seem to change in an inconsistent fashion from 1985 to 1995. High fixed charge factors would raise the electricity prices, as can be seen in LBL estimates for Scenario H where prices increase 4 to 6 mills as compared with Scenario C for 1985, 1990 and 1995. EIA estimates are also higher for Scenario H but the difference increases from 2 mills/kwh in 1985 to 10 mills/kwh in 1990 and 1995. It is not clear what causes this sudden change in estimated differences. One possible explanation may be that the higher fixed charge rates apply to future plants coming on line after a certain date. The difference in absolute terms would still remain inexplicable.

Table 5

Differences between EIA and LBL Estimates Based on EIA Cost Data

	SCENARIO						
YEAR	A	B	C	D	E	H	N
1985	1.8	7.9	1.6	-0.6	3.8	-0.6	1.6
1990	-0.2	6.3	3.2	1.8	6.7	7.0	3.3
1995	1.2	7.8	1.4	0.3	5.1	6.8	1.6

CAPITAL COSTS AND FINANCING

Among the seven electricity projections described in Scenarios A through N, Scenario A calls for the maximum amount of new capacity additions primarily in the construction of coal power plants. Between 1985 and 1995, a period during which scenarios exhibit significant differences, net additional capacity requirements vary from roughly 25.3 GWe in Scenario D to 42.7 GWe in Scenario A including refinements. Total additional capacity requirements are, as one would expect, the largest for Scenario N, the nuclear moratorium case, 48.0 GWe. Surprisingly enough Scenario C with the mid-mid projections also calls for a large total additional capacity of 46.4 GWe during the same period.

Scenario B with the highest world oil price assumptions shows a far smaller addition of new capacity, 38.1 GWe during the same period. A large fraction of the present energy supply is derived from oil power plants in this region. An increase in world oil price would encourage utilities to construct new coal fired capacity to meet additional demand and to replace some existing oil power plants. Furthermore, the larger the increase in WOP, the more conversions are likely to occur. However, projections in Scenario C, with smaller increases in WOP than in Scenario B, show a larger amount of capacity additions. Demand in Scenario B is assumed higher than in Scenario C. An interesting item in Scenario C is the potential construction of 6.7 GWe of distillate turbines during 1985 to 1990 and a subsequent retirement of 10.7 GWe of these turbines in the following five year period from 1990 to 1995.

Focusing on Scenario C, the most likely case, the projected additions of 67.4 GWe of capacity would call for roughly $39.2 billion for power plants coming on line between 1978 and 1995. This figure is in real 1978 dollars and does not include any factors adjusting for inflation. An inflation rate of ten percent with the consequent higher cost of borrowing money could increase this figure by more than one hundred percent. Raising a capital of roughly $100 billion in nominal dollars within an eighteen year period would pose a formidable task for Region 9 utilities. At the end of 1977, all the private and public utilities in Region 9 had total assets worth $27.5 billion.

Certainly compared with these assets, the amount of difficulty in raising $100 billion of capital in the eighteen years will depend on the capital markets and the regulated nature of the utilities. The nature of the electric utility industry has changed dramatically in the last ten years. Plant expansion and capital investments in the 1960's were supported to a large extent by a phenomenal growth rate in electricity consumption. During the 1970's, however, the competitive position of the utilities in raising capital has declined as compared to other industries. The forecasted capital requirements at least for the forseeable future will be financed in an unfavorable economic environment.

Construction expenditures at 10 percent or less of total capitalization are typically associated with AA rated utilities[10] with growth rates approaching 15 percent generally associated with lower rated utilities. With the construction expenditures projected above for Region IX utilities, it is likely that the utilities bond rating will be adversely affected.

The other major factor in assessing the utilities' financial ability to raise capital is the attitude of regulatory commissions. Each state has a different attitude towards the allowable rate of return that utilities are permitted. In California the PUC has opposed the normalization of income tax benefits and the inclusion of construction work in progress in the rate base. A change in this policy could substantially increase the utility internal cash flow. The regulatory climate would also affect the utilities' standing in the capital markets. On a long term basis, utilities may face a capital financing problem if the present trend in regulatory and economic climate continues.

This work was supported by the U. S. Department of Energy under Contract W-7405-ENG-48.

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