Forecasting Electricity Rates in a Liberalized Retail Market

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1. Introduction

In Japan liberalization of the electric utility industry is often considered from the stance of "lowering electricity rates." However, given that the electric utility industry is capital-intensive and that technology innovation capable of jolting the industry's overall efficiency is not yet available, changing the business environment, particularly the introduction of competition may have, among other things, a harmful effect on cost returns. Also liberalization incorporates negative factors of lower electricity rates as well. While "partial liberalization" which is currently in practice will be reviewed and discussed in around 2003 concerning the scope of retail liberalization, the mode of competition, etc., the systems that will be employed are still unclear. This is has led to an increase in the uncertainties within the electric utilities' business environment as well. What is worse, as symbolized by skyrocketing crude oil prices since the summer of 1999, primary energy prices are becoming increasingly volatile. The impacts on electricity rates under a changing business environment, in such areas as competitive systems and primary energy prices are a matter of great concern.

This study is designed to grasp what factors contribute to varying electricity rates in quantitative terms. We developed a model to calculate electricity rates, and then analyzed to what extent electricity rates were affected by such factors as the degree of retail liberalization, the size of scale of demand and crude oil spikes.[1]

2. General Description of the Model

2.1 Calculation targets

2.1.1 Forecast periods and targets

Electricity rates are forecast for FY2005 and FY2010, identical to the periods employed in the supply plan. Due to statistical restraints, FY1998 was taken as the latest year with actual records available. As for calculation targets, we picked out two companies, so that the model we prepared would not represent characteristics of any specific firm. Working

[1] It should be noted that this study, part of a consigned study project, was conducted in June 2000.

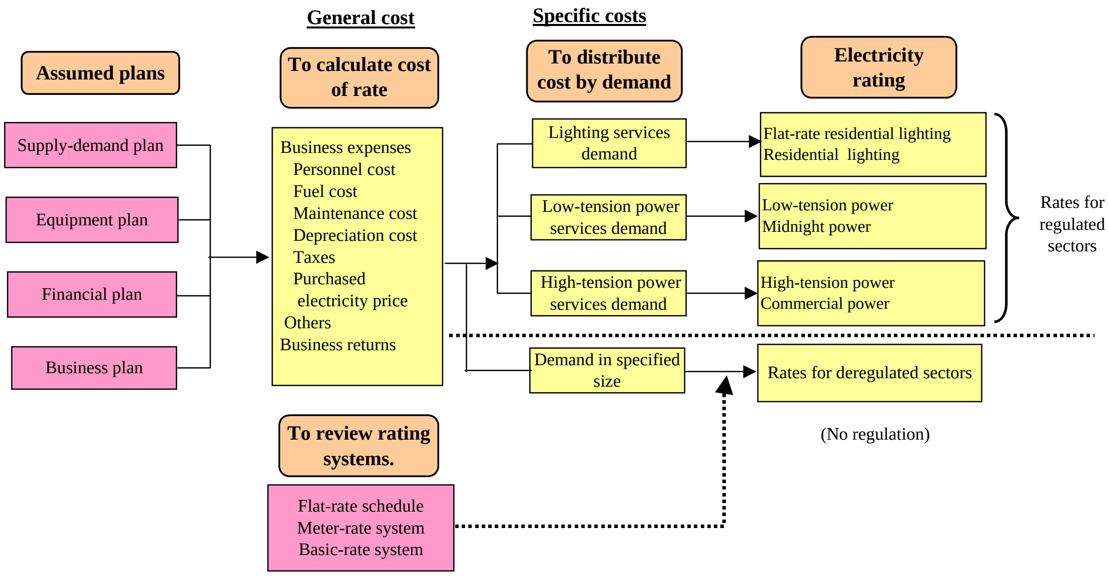
efficiency was taken into account as well.

2.1.2 General

Electricity rates are based on (1) cost principle, (2) fair return principle, and (3) equity-among-customers principle. The cost principle defines the cost as "that which is necessarily incurred when providing customers with good services under the efficient management of electric utility business". This is interpreted as a non policy-based price rating, but a rating determined by objective standards without a corporate mind strategy. Electricity rates have been calculated on this cost principle. However since March 21, 2000, when the retail market was partially freed, electricity rates applicable to special high voltage consumers were deregulated and freely set which became the standard. Fair returns are defined as those enabling electric utilities to raise the necessary funds to achieve a sustained development and to keep their profitability at an adequate level in order to cover interest payments, dividends, etc. They are calculated in cooperation with the cost, which provides the basis for the rating. Equity among customers is a principle that prevents electric utilities from favoring or disfavoring specific customers in their sales policy. This principle requires adequate cost distribution by demand area, based on which objective rating is secured.

Fig. 2-1 shows the actual rating processes following the three principles above.

Fig.2-1 Outline of Actual Electricity Rating Processes



(Source) Electricity Rating Study Group, "Electricity Rates for Citizens," Power News Co., December 1999

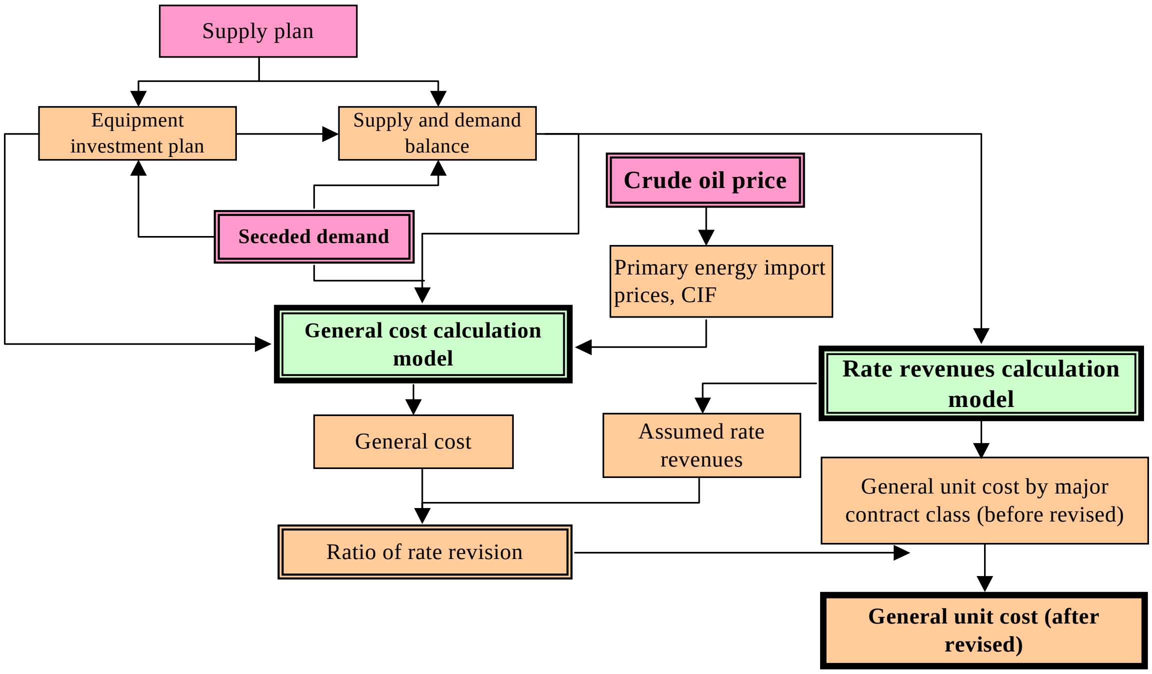
The cost principle is further divided into "general cost" and "specific cost." "General cost" is the balance after subtracting from the sum total of all costs incurred in electricity supply from generation to distribution, under efficient management and business returns. In addition to deducting profit and necessary costs for supplying freed sectors. For the calculation of total expenditure, by preparing a model pursuant to general-cost-method standards, we estimated the general cost from published data found in such forms as financial statements and the Electric Utility Industry Handbooks. Because we applied this calculation rule to the actual records period, the outcome was not in accordance with electric utilities' operating costs, etc. that can be found in their financial statements.

"Specific cost" is related to the third principle. To prevent disparity in demand area or differences among electricity consumers, this specific cost principle provides that electricity rates shall be set fairly and reasonably in accordance to the specific cost based on the standards that adequately reflect supply voltage and load characteristics of electricity consumption patterns.

Meanwhile, business returns, related to the second principle, are calculated by employing a rate base system, which requires the returns to be computed by multiplying invested values in business (real and effective assets) by a given rate of returns. We made our calculations conforming to this requirement.

Fig. 2-2 illustrates an overall flow of our electricity rate calculations. Based on the supply plan, we first assume various cases, then calculate the general cost for each target year utilizing the "general cost calculation model". Then, by comparing the outcomes with the "assumed rate revenues" (without rate revision) determined using a "rate revenues calculation model", we are able to calculate the "rate revision ratios." From the rate revision ratios, we then calculate the revised general unit cost after the rate revision.

Fig.2-2 Overall Flow

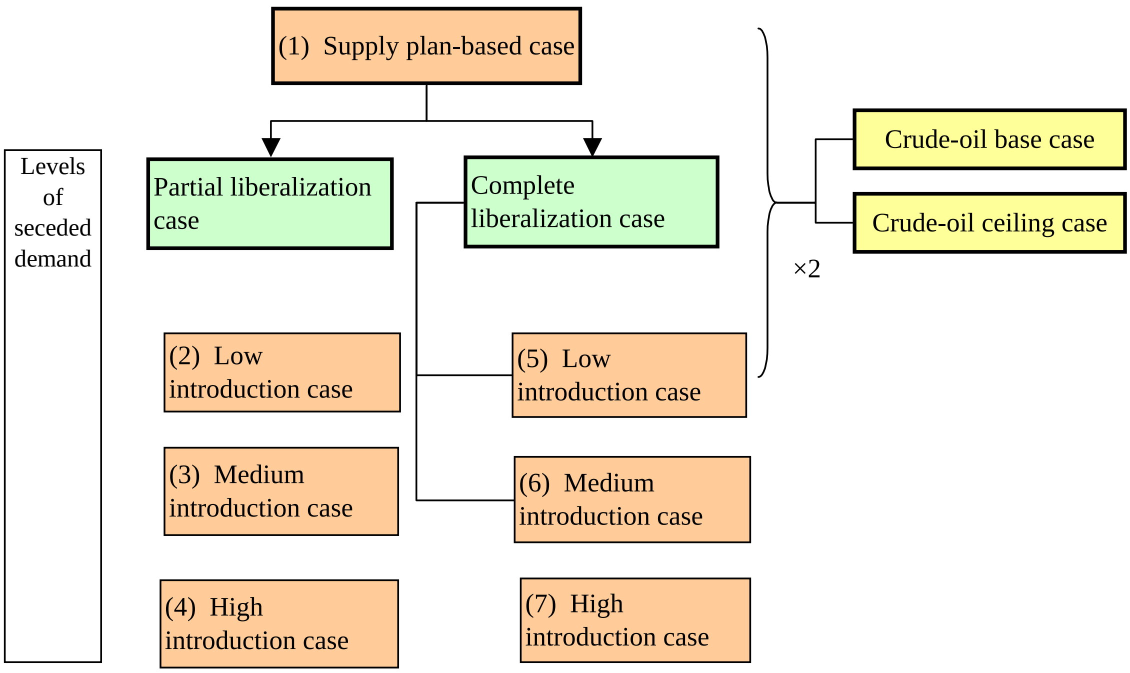


2.2 Assumptions and case establishment

2.2.1 Case establishment

Given the very hazy environment surrounding the electric utility industry, we prepared various cases before making calculations. In specific terms, we first set up two cases of “crude oil prices.” Then, we prepared a “supply plan-based case,” which was taken from individual utilities’ supply plans with the assumption that there was no retail liberalization. In accordance with this we prepared two additional cases differing in the “scope of retail liberalization” and three further cases differing in the “size of seceded demand.” In all, we prepared a total of 14 cases, 2 x (1+2 x 3).

Fig. 2-3　Cases Calculated in Our Forecast



2.2.2 Crude oil prices

The CIF price of crude oil imports in December 1998 hit a record low of \$9.30/bbl since the oil shock of 1974, and crude oil prices have continued to flag in recent years. More recently however, a series of OPEC agreements on production cuts from March 1998 have tightened the supply and demand, which has triggered a sharp upturn in the crude oil price starting in March 1999. As of February 2000, CIF import prices averaged \$26.97/bbl, which neared the levels during the second oil shock. Thus, crude oil prices have become extremely volatile in recent years. Accordingly, we prepared two cases concerning crude oil prices. One being the base case, where the crude oil price is assumed to have returned to an adequate level (\$22/bbl). The other being the high price case, where the present high price is assumed to continue in the foreseeable future (\$30/bbl).

2.2.3 Supply plan-based case

Based on the electric utilities' data concerning electricity sales amounts, equipment investment plans and so forth which are all contained in the "FY2000 Electricity Supply Plan" and "Management (Efficiency) Improvement Program" published in March 2000, we calculated electricity rates, which were organized as the "supply plan-based case." Because the utilities' supply plans assumed no seceded demand, the supply plan-based case assumes no demand detachment either. As derivatives from this case, we calculated various scenarios of demand secession, which are described below.

2.2.4 Scope of retail liberalization

The current system is subject to a review in three years time, with "expansion of the scope of partial liberalization," "complete liberalization" and "rights and wrongs of the creation of pool markets" which have been cited as the three major issues to be discussed. However, the extent of development of future institutional reforms remains unclear for the present. Therefore, in regard to the scope of liberalization of the retail sector, we have assumed two cases. The first being the partial liberalization case, where partial liberalization of the retailing area, currently limited to high volume demand (defined as receiving electricity through transmission lines of 20,000 V or more and having peak power demand of 2,000 kW or more) is assumed to continue. The other is the complete liberalization case, where the scope of retail liberalization is assumed to reach all customers, including residential customers. Meanwhile, regardless of the degree of retail liberalization, we basically assumed that no institutional reforms would take place if they should involve electric utilities' organizational changes.

Table 2-1 General Descriptions of Customers by Voltage (10 utilities total)

Voltage		Demand size	Commercial	Industrial	Total	Remarks
Extra-high tension	Over 20kV	Over 2,000kW	Some 2,200 contracts 26.3 TWh	Some 6,100 contracts 185.6 TWh	Some 8,300 contracts 211.9 TWh	Large-sized buildings, plants, etc.
High tension	6kV	50kW~ 2,000kW	Some 410,000 contracts 148.7 TWh	Some 290,000 contracts 139.5 TWh	Some 700,000 contracts 288.2 TWh	Small- and medium-sized buildings, plants, etc.
Low tension	100/200V	Under 50kW	Some 73 million contracts 283.3 TWh			Residential, retail shops
Total		Some 77 million contracts 799.0 TWh (100%)				

(Note) The numbers of contracts are as of late March 1998. Electric energy is as of FY1998.
In parenthesis are the shares with total electric energy taken as 100%.

2.2.5 Degree of seceded demand

We assumed the size of demand secession resulting from retail liberalization based on U.S. data was able to reveal how many customers in California changed their suppliers. California attracted keen attention across the world for its drastic reforms of the electric power market in 1998. We referred to California because the state completely freed retailing and published actual records of supplier changes by customer area. California's actual records are summarized in Table 2-2. In reference to the U.S. data, we determined the maximum rate of secession, and then prepared three cases of high, medium and low introduction cases.

Table 2-2 Actual Records of Supplier Changes in California (As of Late April 2000)

	Unit	Residential (Under 20kW)	Commercial (20-500kW)	Commercial (20-500kW)	Industrial (Over 500kW)	Agricultural	Total
No. of customers who changed(A)	Contracts	164,636	38,195	13,981	1,009	4,727	222,548
Total no. of customers(B)	Contracts	8,829,384	981,108	195,410	5,228	113,462	10,124,592
Ratio of change(A/B)	%	1.90%	3.90%	7.20%	19.30%	4.20%	2.2%
Demand changed(C)	MWh	1,275,706	747,013	7,277,693	15,843,329	669,800	25,813,541
Total demand(D)	MWh	56,380,993	14,222,592	50,261,097	45,832,601	6,769,254	173,466,537
Rate of change(C/D)	%	2.30%	5.30%	14.50%	34.60%	9.90%	14.88%

(Source)California Public Utility Commission

Table 2-3 Rates of Demand Change in Our Forecast

	California's contract category		Partial liberalization			Complete liberalization		
			Low introduction	Medium introduction	High introduction	Low introduction	Medium introduction	High introduction
Lighting service	Residential		-	-	-	1%	2%	3%
Commercial(high tension)	Commercial	(20 - 500kW)	-	-	-	5%	10%	15%
Commercial(extra-high tension)	Industrial	(Over 500kW)	10%	20%	30%	10%	20%	30%
Low tension	Commercial	(Under 20kW)	-	-	-	2%	4%	6%
High tension A	Commercial	(20 - 500kW)	-	-	-	5%	10%	15%
High tension B	Industrial	(Over 500kW)	-	-	-	10%	20%	30%
Extra-high tension	Industrial	(Over 500kW)	10%	20%	30%	10%	20%	30%

2.3 Major assumptions

In preparing these cases, we set major economic variables as shown in Table 2-4. GDP, the national bond yield and the exchange rate were assumed to be common to all cases. The macro economic outlook employed the values forecasted by the Japan Economic Research Center in its “Restart of the Japanese Economy II – Impact of IT Innovation and Its Assessment.” While the Center estimated sections of FY2005 and FY2015, we came up with the theoretical estimates for FY2010 by correcting the Center’s figures by the growth rate for a given period.

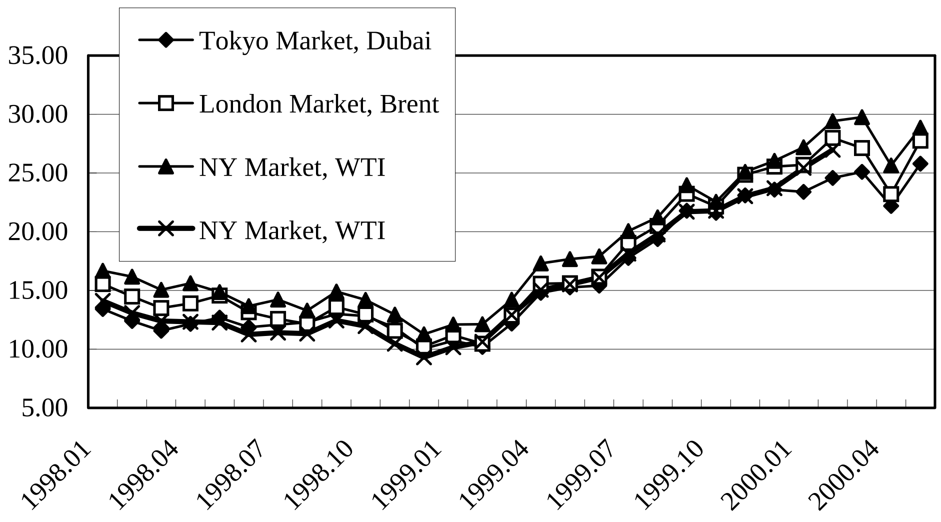
Table 2-4 Major Assumptions

	Unit	1990	1998	2005	2010	98/90	05/98	10/05
GDP	1 billion yen in 1990 price	436,044	480,165	531,807	600,518	1.2%	1.5%	2.5%
National bond yield	%	6.8%	1.6%	2.6%	2.9%	-16.5%	7.3%	1.8%
Exchange rate	yen/$	141.52	128.25	128.25	128.25	-1.2%	0.0%	0.0%
Base case								
Crude oil import price, CIF	$/bbl	23.34	12.81	22.00	22.00	-7.2%	8.0%	0.0%
LNG import price, CIF	$/ton	202.39	150.33	201.18	199.22	-3.6%	4.3%	-0.2%
Coal import price, CIF	$/ton	50.76	37.61	38.25	38.41	-3.7%	0.2%	0.1%
Residual oil price	yen/kl	25,027	17,189	24,750	24,750	-4.6%	5.3%	0.0%
High price case								
Crude oil import price, CIF	$/bbl	23.34	12.81	30.00	30.00	-7.2%	12.9%	0.0%
LNG import price, CIF	$/ton	202.39	150.33	254.83	252.88	-3.6%	7.8%	-0.2%
Coal import price, CIF	$/ton	50.76	37.61	38.99	39.15	-3.7%	0.5%	0.1%
Residual oil price	yen/kl	25,027	17,189	31,332	31,332	-4.6%	9.0%	0.0%

2.3.1 Crude oil prices

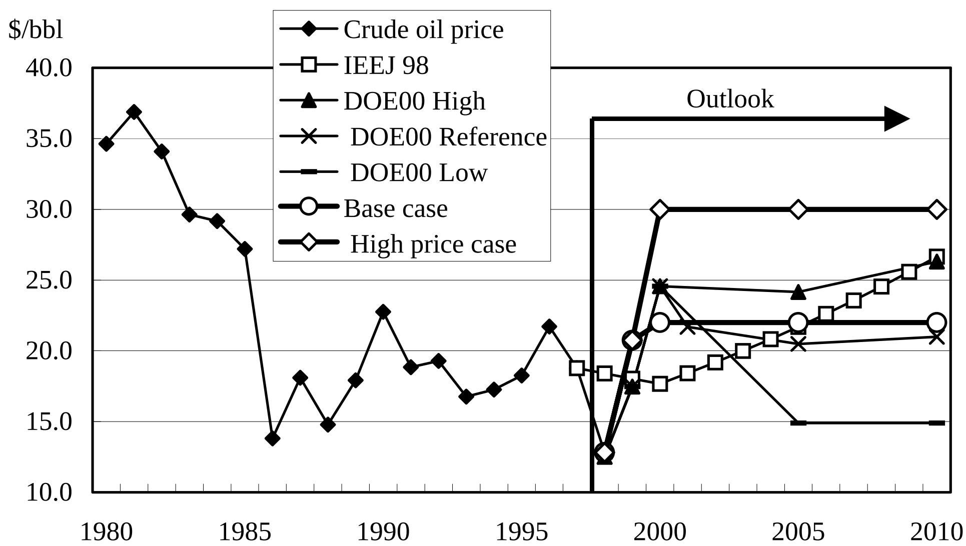
Dubai, the benchmark crude oil price index on the Tokyo Market, was once priced at a record low of $9 per barrel in December 1998, and spiked to the $28 mark in March 2000 due to OPEC’s cooperative production curtailments, etc., thus remaining highly volatile these last few years. Hence, we put the crude oil price at $22/bbl for the standard case, and $30/bbl for the high price case, while referring to the Reference Case of the DOE/EIA Outlook.

Table 2-4　Major Assumptions



(Source) Energy Data and Modelling Center, IEEJ, "EDMC Energy Trend"

Fig. 2-5　Crude Oil Price Outlook

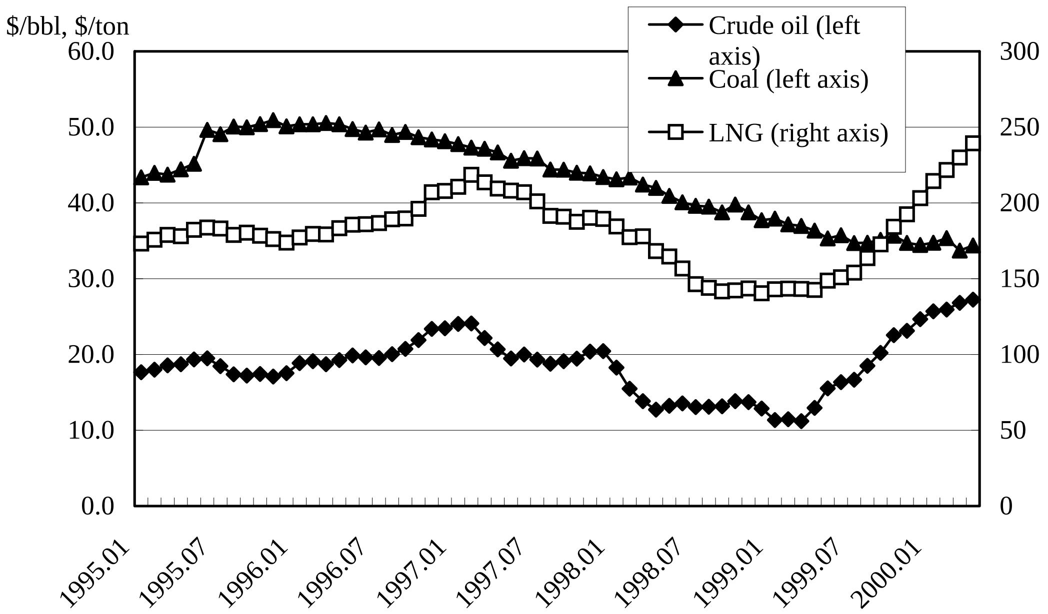


(Source) DOE00 is from DOE/EIA, "International Energy Outlook 2000" (March 2000), and IEEJ98 from IEEJ, "Japan's Long-term Energy Supply and Demand Outlook and Challenges" (December 1998).

2.3.2 CIF prices for other primary energy imports

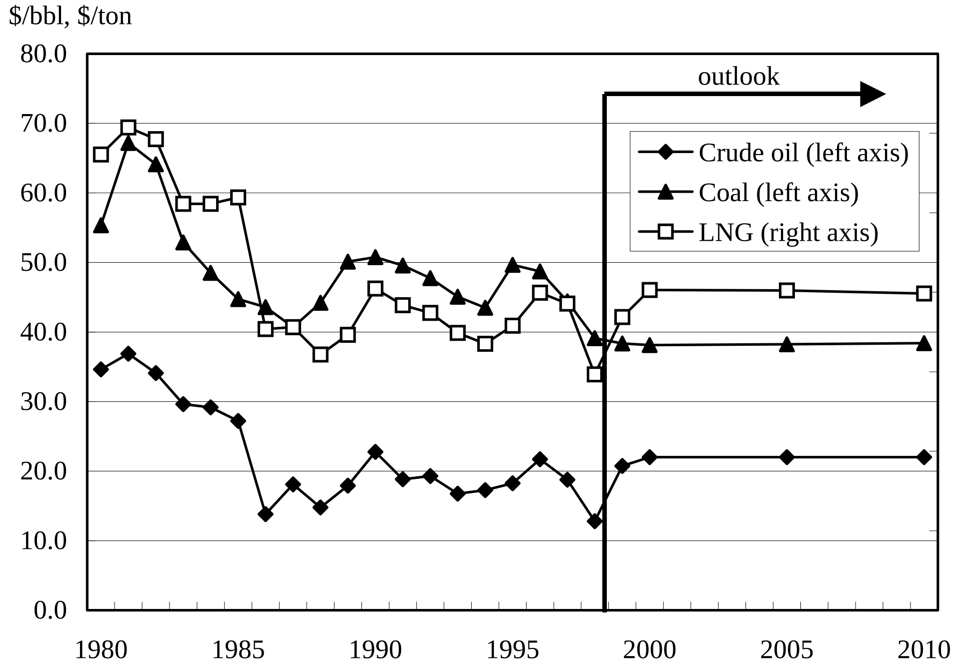
The prices for LNG and coal were also estimated in relation to crude oil in both the base and high price cases. However, with coal, we found that the prices were only superficially connected to oil prices and instead rather heavily dependent on Australia's exchange rates. As a result, coal price rises remained modest even when crude oil prices rose to their highest level.

Fig. 2-6 Changes in Primary Energy Import Prices, CIF



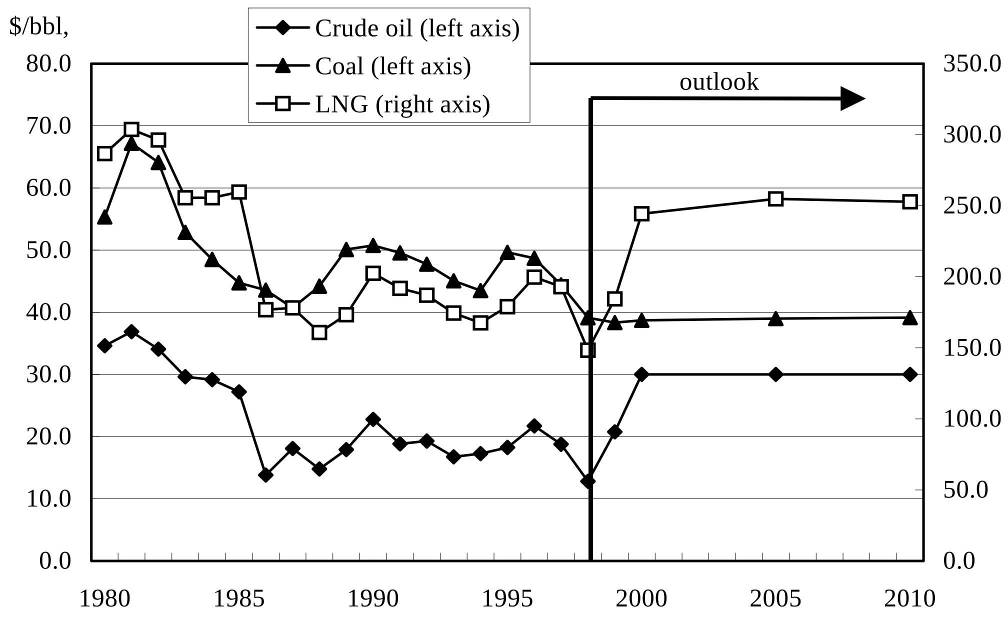
(Source) Ministry of Finance, "Monthly Statistical Report on Japanese Trades"

Fig. 2-7 Price Outlook for Primary Energy Imports, CIF – Crude Oil Base Case



(Source) Actual records from the Ministry of Finance, " Monthly Statistical Report on Japanese Trades." Forecast by IEEJ.

Fig. 2-8 Price Outlook for Primary Energy Imports, CIF – Crude Oil Ceiling Case



(Source) Actual records from the Ministry of Finance, "Monthly Statistical Report on Japanese Trades." Forecast by IEEJ.

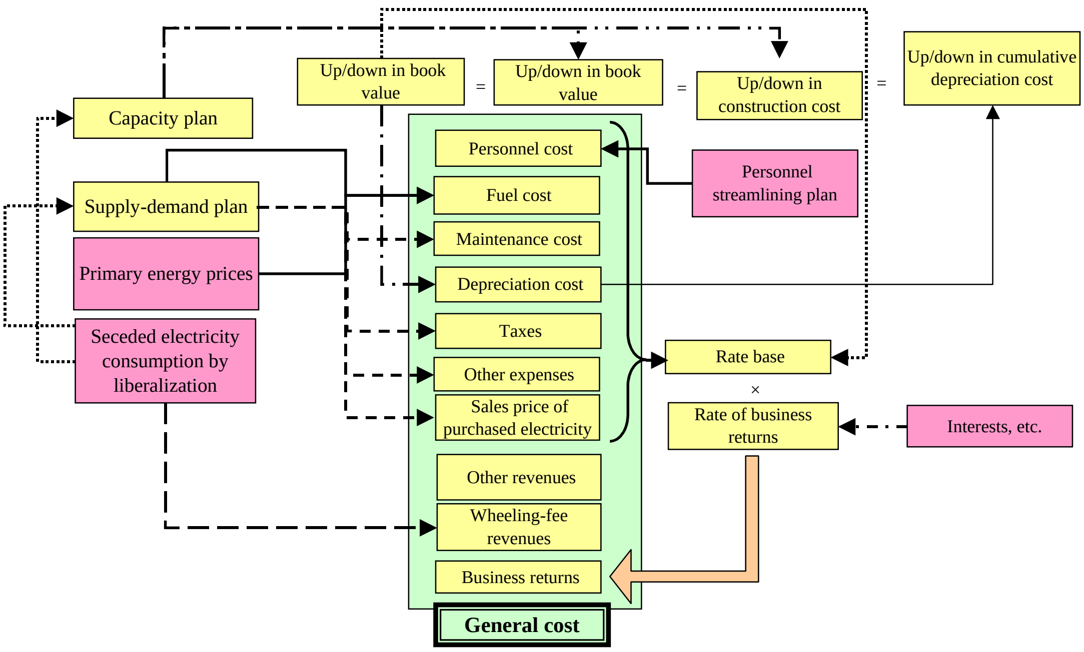
2.4 General cost calculation model

At this juncture we have employed a general cost method in calculating the costs incurred in electric utilities. General cost consists of:

General cost = personnel cost + fuel cost + maintenance cost + capital cost + Taxes + purchased power + other expenses – revenues from inter-company power sales + business returns

In constructing the model, we estimated each of these cost items from published data, typically those in financial statements for FY1980 – 1998. The model is outlined in Fig. 2-9. Meanwhile, we prepared the model according to the company, while using the same model in all cases. The criteria on how each cost item was calculated are described below.

Fig. 2-9 Flow of General Cost Calculation Model



2.4.1 Personnel cost

First by subtracting severance benefits from total personnel cost, then dividing the balance by the number of employees, we obtained per capita personnel cost. Personnel cost was estimated in relation to per capita compensation of employees.

2.4.2 Fuel cost

Dividing the fuel consumption amount by generated power output of each type of fuel (oil, gas, coal and nuclear), each fuel's consumption rate is established. The rates are assumed to remain unchanged in the future. Future fuel consumption is estimated by multiplying the rates by fuel-specific generated output stated in the supply and demand balance.

Subsequently, cost items are divided into different kinds of fuel. Each fuel cost is divided by each consumption amount which is established as the unit fuel cost. Then this unit fuel cost is calculated presumably in relation to CIF prices for each kind of fuel imports. By multiplying the resultant unit fuel cost by fuel consumption each of the fuel costs can be calculated.

2.4.3 Maintenance costs

First, the repair costs are divided into a portion of fossil fuel, nuclear, hydro and other generating facilities and a segment of others (distribution and general administration sectors). The repair costs involved in the generating capacities are calculated by multiplying installed capacities by unit cost, while others involve multiplying the sum total of electricity sales amount and seceded electricity demand by unit cost. As a result, the repair cost turns out to be the same in all cases. Particularly in regard to the distribution sector, due to the assumption that without affected transmission/distribution capacities, electricity demand (electricity sales amount + seceded demand) within a service area proves to be the same in all cases.

2.4.4 Depreciation cost

Depreciation cost is calculated by multiplying average book values at the beginning of a term and the end of a term by an average depreciation ratio.

Depreciation cost = average book values at a term's beginning and end X average depreciation ratio

Period's end book value = Period's beginning book value + incremental value (completed portion) – declined value (scrapped portion) + increase/decrease in construction cost burdens

The period's end book value is calculated by assuming an increase/decrease in capacities, respectively. The incremental value in book cost is calculated by adding up specific large-scale projects out of the actual and planned equipment and facility investments, and assumes the other depreciation costs are calculated together. The declined value in book cost is calculated by assuming scrapped facilities combined into one category.

2.4.5 Taxes

Public charges represent the sum total of property taxes, miscellaneous taxes, power development promotional taxes, business taxes, corporate taxes, and water concession charges. Property taxes are estimated from book values. Miscellaneous and business taxes are estimated from gross revenues (revenues from lighting/power services + delivery costs). The power development promotional tax is estimated from electricity sales amounts. Water concession charges are given as an exogenous variable. Meanwhile, the corporate tax employed in cost calculation is a theoretical value calculated back from stock dividends, which we employ in our calculation as well.

2.4.6 Electricity purchase and sales prices

This item covers electricity purchase and sales prices when traded among electric utilities under area-to-area sharing agreements, as well as electricity purchase and sales prices applicable when electric utilities deal with wholesale power producers, wholesale power suppliers and IPPs. These are calculated by multiplying the average unit purchase and sales prices by electricity amounts purchased and sold, respectively. Meanwhile, the unit purchase price from IPPs is estimated from an average rate of decoupling between the ceiling price posted by electric utilities when inviting bidders and the ceiling price unveiled by the MITI after successful bidding has been completed.

2.4.7 Other expenses

This item consists of rent, outsourcing fees, waste disposal cost, reprocessing cost, decommissioning cost, retirement cost, miscellaneous expenses and others. Waste disposal-related costs are estimated from generated output. The remainder is given exogenously.

2.4.8 Other revenues

Other revenues represent the sum total of additional charges for arrears, electric-utility miscellaneous earnings, and deposit interest. These are given exogenously. In the case where seceded demand is assumed to result from liberalization, wheeling-fee revenues are calculated and included in this item. Wheeling-fee revenues are calculated by multiplying wheeling fees by the amount of seceded demand. In the partial liberalization case, the wheeling fee is set at the standard unit charge published by individual utilities. In the complete liberalization case, wheeling fees applicable to low and high volume customers, respectively, are calculated on top of the standard one. The wheeling fees applicable to low and high volume customers are calculated by taking distribution and general administration costs which are actually recorded as the standard fees.

2.4.9 Business returns

Business returns are calculated by multiplying the rate base by the rate of business returns[2].

Rate base = electric utilities' properties + assets under construction + nuclear fuels + specified investments + working capital + deferred assets

Working capital is counted as equivalent to the basic concept of 1.5 months' operating cost plus a 1.5-month amount from annual payments for fuels and other stored goods. Here, the operating cost includes the fuel, personnel, repair and other costs, while not covering such things as the depreciation cost and public charges. Of these items, electric utilities' properties and working capital are determined endogenously, and the remainder is given exogenously.

We calculated the rate of business returns by assuming an average interest on interest-bearing debts outstanding, by putting the interest rate on future borrowing at the national bond yield, which is one of the major assumptions that has already described, and by taking payments of existing debts into account. Declines in outstanding interest-bearing debts, thanks to more efficient management were also interwoven.

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2 The rate of business returns is calculated as follows:

Rate of business returns

= Rate of returns to owned capital X 0.3 + Rate of returns of borrowed capital

- Rate of returns of owned capital is calculated by setting the upper limit equivalent to the rate of returns of owned capital actually recorded by all industries except general electric utilities, and the lower limit to the actual yields of such public bonds as national and municipal bonds. (When the rate of returns of owned capital actually recorded by all industries except general electric utilities stands below the actual yield of public bonds, the rate of returns of owned capital is calculated based on the yields of the public bonds.)
- Rate of returns of borrowed capital is calculated depending on general electric utilities' actual amount of interest-bearing debts by producing a weighted average of interest rates involved in actual records of interest-bearing debts thereof.

(Source) "Supply Agreement Rating Rules"

3. Forecast Results

3.1 General cost

To forecast electricity rates, we first calculated, as the benchmark, the general cost (cost of rate) from specific data in the supply-demand plans, equipment investment plans, etc., all under the “FY2000 Electricity Supply Plan” and the “Management Efficiency Improvement Program” released March 2000 by electric utilities. Later, we calculated the impact of opening the electricity market in the form of retail liberalization which would increase seceded demand. That is, we forecast the impact of seceded demand on the cost of electricity supply by calculating its impact on the cost and revenues. The forecast results are expressed in a two-target-utility average in exponential terms.

The forecast results of the supply plan-based case, or the benchmark, showed that the cost of rate would go down. It reflects shrinking capital cost due to a falling rate of business returns, on top of utilities’ curtailments in equipment investments and repair works, as well as further increased management efficiency by personnel cuts, etc. (Figs. 3-1 & 3-2).

3.1.1 Partial liberalization cases

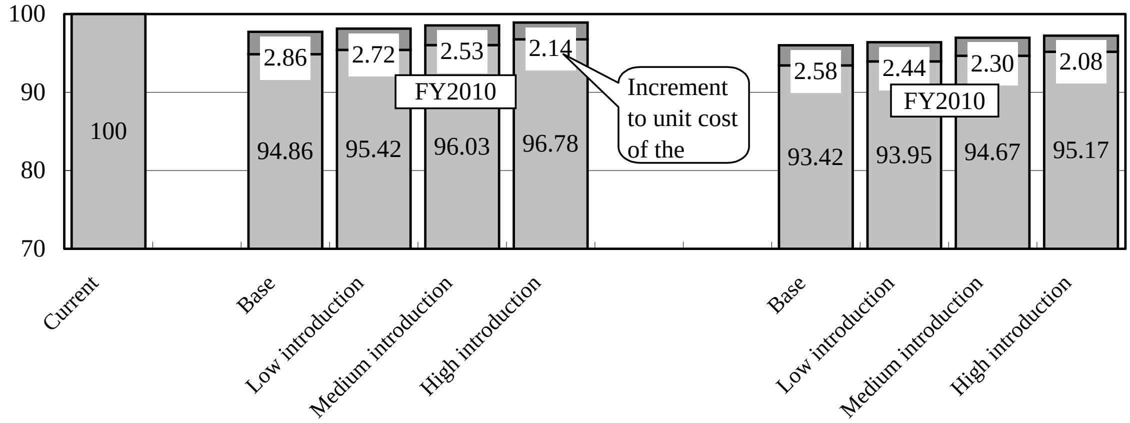
Based on the rates of secession assumed, we counted electricity sales amounts seceded from the target demand (commercial power services, extra-high tension, extra-high tension power services), then adjusted electricity supply amounts by halting or closing existing plants and correcting utilization factors.

It appears the Electricity Supply Plan, the basis for our forecast, originally assumed halts and closures of aging oil-fired power plants to some extent. Therefore, as a response measure to demand secession due to partial liberalization (if any), we assumed halts and closures of LNG-fired power plants as well.

Forecast results of specifically preconditioned cases of partial liberalization are illustrated in Fig. 3-1. In general, the unit cost of electricity sold is found swelling in proportion to increasing demand secession, because the burden of such fixed costs as the repair and depreciation costs would set to rise if electricity sales revenues fell due to larger demand secession.

In order to illustrate the impact of rising crude oil prices, Fig. 3-1 presents not merely the base case of crude oil price ($22/bbl), which is among our major assumptions, but the high price case ($30/bbl) that is an incremental unit cost.

Fig. 3-1 Forecast Results with Current Rate Levels Taken as 100 (Partial liberalization cases)

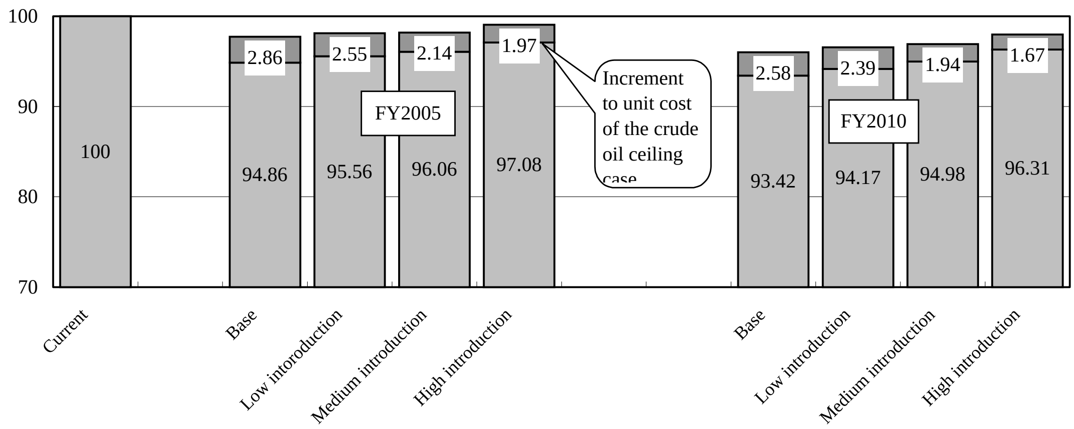


3-1-2 Complete liberalization cases

From the rates of secession assumed, we counted the electricity sales amounts seceded from the target demand (commercial power services, extra-high tension, extra-high tension power services). Complete liberalization leads to greater demand secession rather than partial liberalization. Therefore, we adjusted the amount of electricity supply by taking additional measures to the halts and closures of existing plants and correction of utilization factors. They included deferring commission of newly developed captive power sources and slashing the amount of purchased electricity by deferring commission of wide-area power sources developed by other electric utilities and wholesale power producers.

Forecast results of the specifically preconditioned complete liberalization cases are shown in Fig. 3-2. Overall, the unit cost of electricity sold proved to be higher than in partial liberalization cases. This is because the burden of such fixed costs such as the repair and depreciation costs would further rise as electricity sales revenues plunged sharply. Along with this seceded demand swelling would nearly double the size of partial liberalization cases.

Fig. 3-2 Forecast Results with Current Rate Levels Taken as 100
(complete liberalization cases)



3.2 Impacts of different assumptions and forecasting methods on rate levels

By conducting sensitivity analyses, this section considers the "rate of business returns" and "unit purchase price of electricity from outside." in order to learn to what extent rate levels should vary when different assumptions and forecasting methods were employed from those taken in our forecast.

Also of note, the projected electricity rate levels, given in the preceding sections, should be taken into account because they are heavily preconditioned to such points as the size of seceded demand and the crude oil price.

Table 3-1 Impacts on Rate Levels When Crude Oil Cost Varies by $1/bbl

	2005	2010
Impacts on supply cost (yen/kWh)	0.09	0.07
Impacts on ratio of rate revision (%)	0.50%	0.40%

(Source) Prepared by IEEJ from our forecast results.

3.2.1 Rate of business returns

Given the nature of public utility charges, big profits are taken through unfair earnings of monopolies at the expense of customers, while electric utilities must live on their mediocre profits. In both of these cases, electric utilities lose out on doing sound business. Thus, adequate business returns are imperative, which should be the principle of fair returns. As a system to put this principle into effect, the rate base system is currently employed, under which business returns are calculated by multiplying the value of real and effective electric utilities' assets by an adequate rate of returns. The electricity rate cuts, in practice since 1996, have seen a reduction of electric utilities' successful efforts in increasing their management efficiency. The lower rate of business returns that reflects falling interests is also contributing somewhat to this.

In the days ahead, the rate of business returns is expected to be on a moderate decline unless interest rates should otherwise be abruptly raised to a considerable extent (Table 3-2). This is because the electric utilities' fund borrowing period (corporate-bond redemption term) generally spans 5 – 10 years, and because the average interest on interest-bearing borrowing is likely to fall judging from low interest rates in the last few years.

As a result, in our forecast, the falling rate of business return is taken as a contributing factor in pushing electricity rates down. Yet some may argue that the rate of business returns would become an element unrelated to calculating the cost rate, once the principle of competition is fully introduced into the electricity market. This in turn would dissipate the concept of the heavy burden of general cost (= necessary costs + business returns). And yet, for electric utilities saddled with a huge amount of interest-bearing debts outstanding, unless the debts are reduced considerably, interest itself should remain unchanged as an element highly influential on interest payment, which forms part of the cost of rate (Table 3-3).

Table 3-2 Past Rates of Business Returns and Our Forecast

1960	1988 revision	1996 revision	1998 revision	2000 revision	2005 (forecast)	2010 (forecast)
8.00%	7.20%	5.25%	4.40%	3.80%	2.80%	2.80%

(Note) The 1998 revision put the rate of business returns for Kansai Electric Power at 3.7%.
(Source) "Theory and Practice of Electricity Supply Agreement" and others

Table 3-3 Impacts on Rate Levels When Business Returns Rate Varies 1%

	2005	2010
Impacts on supply cost (yen/kWh)	0.39	0.36
Impacts on supply cost (yen/kWh)	2.20%	2.00%

(Source) Prepared by IEEJ from our forecast results.

3.2.2 Electricity purchase price from outside

There are two kinds of electricity purchase price. One is "area-to-area electricity purchase price" payable for electricity received from other general electric utilities. The other is "electricity purchase price from other producers" payable for electricity received from wholesale power producers and wholesale power suppliers.

The “area-to-area electricity purchase price” is applied to electricity purchased under an electricity sharing agreement signed among general electric utilities to secure reliable electricity services. This agreement has been signed among the nine electric utilities and aims at supply-demand stabilization, wide-area power development, equipment investment curtailments, fuel cost reductions, etc. It is available in various forms, such as nationwide sharing and two-utility sharing.

The “electricity purchase price from other producers” has generally represented the price for electricity purchased from such wholesale power producers as Electric Power Development Co. and Japan Atomic Power Co., as well as wholesale Electric Utilities like joint-Ventured Power Utilities and Municipal Electric Utilities. Now that a bidding system has been introduced, electricity purchases from IPPs are covered as well, and a quantitative growth of this type is likely to proceed.

To forecast the unit purchase price involves various elements are interwoven. First, partial liberalization of the electricity retail market can be cited as a factor to send the unit purchase price down. If newcomers become fully active on the retail market and thus intensify price competition, electric utilities are likely to seek lower purchase conditions at price negotiations with other utilities and wholesale producers. Larger electricity purchases from IPPs whose unit prices are relatively low would contribute to reducing the electricity purchase cost. On the other hand, electricity purchase plans from newly developed sources, which generally involve high generating cost, and greater use of renewable energy sources can be cited as the factors to cause the unit purchase price to rise. This is the area that can be debated when designing specific systems of electricity liberalization.

As purchased electricity strongly carries the nature of negotiated transactions, forecasting the unit purchase price for electricity is very difficult. In our forecast, it is calculated back from actual unit prices in recent years. Yet, now that purchased electricity is expected to continue to grow in the future, it should be taken into account that differences in estimated purchased prices can greatly affect the assumed cost of purchased electricity (Table 3-4).

Table 3-4 Impacts on Rate Levels When Electricity Purchase Price Varies ¥1/kWh

	2005	2010
Impacts on supply cost (yen/kWh)	0.2	0.22
Impacts on rate revision ratio (%)	1.10%	1.20%

(Source) Prepared by IEEJ from our forecast results.