NEW YORK STATE ENERGY PLAN

and

FINAL ENVIRONMENTAL IMPACT STATEMENT

New York State
Energy Planning Board

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1998

George E. Pataki, Governor

within New York State, and the potential for new generation capacity to be built closer to load centers in a competitive environment.[3]

In the forthcoming restructured utility environment, it is likely that transmission facilities will continue to be owned by regulated utilities. However, it is also likely that transmission planning and control will be a responsibility of the independent system operator (ISO), governed by system reliability considerations and the needs of the marketplace as perceived by risk-taking market participants, rather than by traditional long-term projections of electric demand needs.

Generation

Approximately 35,000 megawatts (MW) of generation are available within New York State to supply electric capacity needs, with another 436 MW under contract to New York's utilities to supply only energy without any firm capacity associated with the transaction[4]. Additionally, four municipal utility systems in New York own about 135 MW of generation. Under current conditions, this electricity capacity is more than adequate to meet the State's electricity needs now and for some period into the future. The "Load and Capability Analysis" section presented later in this Electricity Resource Assessment indicates that additional electric capacity may initially be needed at some point

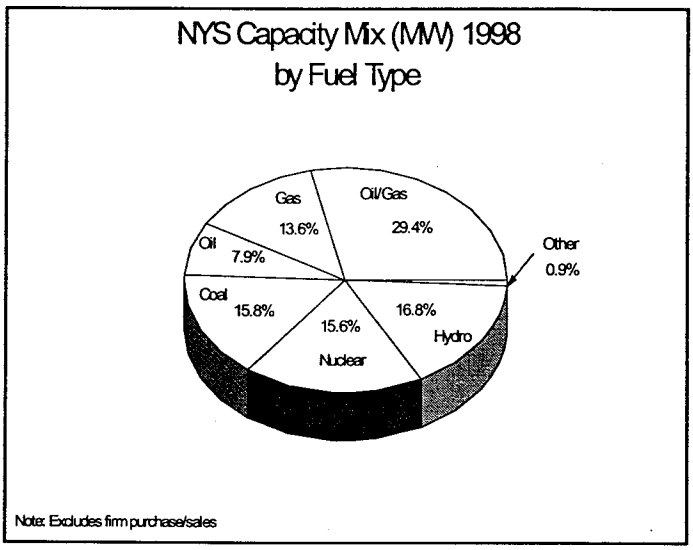

Figure 3-2

[3] In many instances it may be less expensive to construct gas-fired combined-cycle generation stations near the load centers than to build new transmission capacity.

[4] See the 1998 *Report of the Member Electric Systems of the New York Power Pool Load and Capacity Data* filed pursuant to Section 6-106 of State Energy Law. Additionally, there are many small generation units throughout the State that are not interconnected with the electric system. The capacity available from such generation is not significant enough at this time to be considered here, as competition unfolds, however, such generation could affect future generation requirements.

between 2001 and 2005 under current reliability criteria, or by 2010 or later, if the reliability criteria are modified.

The existing generation capacity mix, by fuel type, available in the New York State system is shown in Figure 3-2. As indicated, New York's existing capacity is dominated by oil and gas fired capability, with nearly equal shares of hydroelectric, nuclear, and coal-fired electric generating capacity.

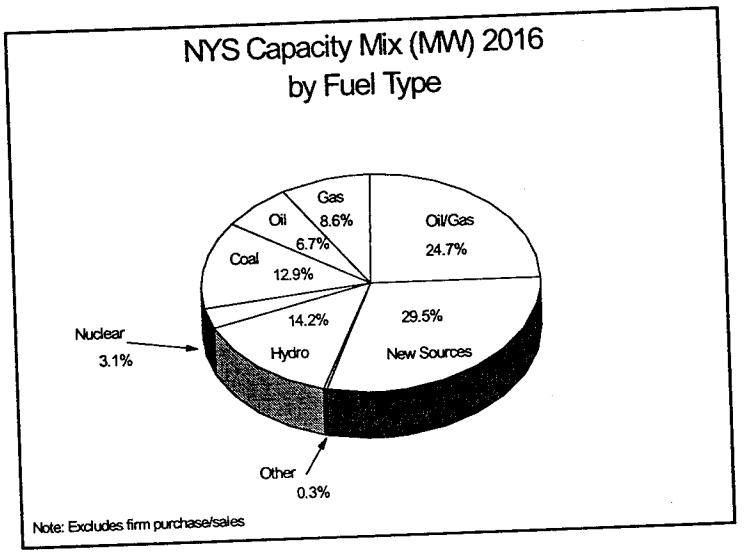

Figure 3-3

Similar information projected for 2016 is shown in Figure 3-3. In this illustrative analysis, it was assumed that all new capacity resources needed to meet future electricity demand (including maintenance of the existing 22% reserve margin criteria) are met by highly-efficient combined cycle natural gas facilities. However, this Electricity Resource Assessment recognizes that future capacity requirements will actually be met by a yet undefined combination of resources and fuel types, including among others increased energy efficiency, renewable resources, distributed generation, electricity imports, and other new technologies.

Table 3-4 illustrates one potential scenario for how the State's generation might operate through 2016, based on the forecast described in the Electric Sales Forecast section.[5] This projection assumes that all existing NYPP generating facilities continue to operate, with the exception of those that New York's utilities have identified will retire over the forecast period. They also assume that IPP facilities will continue to operate after current contracts with utilities expire. The projections assume that new, but unspecified supply sources are acquired to meet demand growth and reserve requirements (as currently

[5]Table 3-4 results from an extrapolation of the computer modeling of the electrical system used for the Draft State Energy Plan.

defined by the NYPP as discussed previously). [6]

Participants in a properly functioning market, with adequate information, should be able to determine when and where additional generation resources are needed to meet customer needs. Government should help to ensure that electricity supply, demand, and price information are available for market participants so that they are able to respond, in a timely manner, to maintain the reliability of the electric system. Planned generating facilities greater than 80 MW will continue to be subject to Article X of the Public Service Law (at least until the law sunsets in 2002). As in the case of transmission line certification, power plant certifications will require findings that the public interest can be served and environmental impacts are acceptable. To the extent that new generation facilities will promote or contribute to competition in electric markets, including the reduction of market power conditions, they will be consistent with the long-range plan for expansion of the electric power system in New York State envisioned by this SEP, and the public interest will likely be served so long as environmental and other impacts are also found to be within acceptable ranges or can be mitigated.

The previous discussion in this section focused on the amount and types of generation that may be available in the future. The reliability of that capacity, however, must also be ensured if electric system reliability is to be maintained at appropriate levels. Currently, New York State utilities own and control about 85% of the State's installed generating capacity with the remainder owned by IPPs. A significant percentage of the IOU generation, however, is in the process of being divested, or structurally separated from the T&D utility, and ultimately owned by autonomous operators. As New York's electricity system moves from having a regulated generation system to a competitive generation market, the oversight of generation performance will move from the PSC to market-driven performance standards. The ISO will be responsible for designing and operating a system that will offer appropriate economic incentives sufficient to maintain generation system reliability.

IPP facilities have operated reliably compared to other existing electricity generation because these newer facilities use the latest technology available and have contractual provisions that provide for purchase of

[6] The subsequent "Load and Capacity Analysis" indicates that new capacity resources will be needed during the planning period to ensure reliable service. Because of transmission system constraints, siting new capacity in specific load areas to avoid construction of electric transmission systems could be beneficial.

their electricity output when (and usually only when) they operate. These facilities make a significant contribution toward meeting overall system reliability. As long as economic incentives continue to be available, IPP facilities would continue to perform well.

Nuclear facilities provide a significant portion of New York's generation. They generate over one-fifth of the electricity consumed in the State. While these facilities may be considered simply as contributors to the State's generation supply, they must also be viewed in light of their unique characteristics, which include extremely large initial capital investments, high fixed operating costs, large decommissioning and spent fuel storage costs, low short-term variable costs, and significant nuclear safety requirements whose oversight is regulated by the federal Nuclear Regulatory Commission. Although nuclear power plant performance has improved over the past decade, and might continue to improve over time, the high cost of nuclear power and safety issues call into question whether nuclear power will be able to compete successfully in the future. Decommissioning a significant block of nuclear generation capability before the expiration of licenses, however, could alter the generation mix in the State. Later, in the "Load and Capability Analysis" section of this Electricity Resource Assessment, the impact of early retirement of two representative nuclear units is considered. The date when new resources might otherwise be required advances by four years in the most extreme case studied (*i.e.*, to 2001 instead of 2005).

PROJECTION OF ELECTRICAL ENERGY REQUIREMENTS BY SUPPLY SOURCE
(GWH)

	ACTUAL	<---------- ESTIMATED ---------->					
GENERATION SOURCE	**1996**	**1998**	**1999**	**2000**	**2003**	**2007**	**2011**	**2016**
NEW ENERGY SUPPLIES	N/A	0	0	0	4,779	19,941	38,407	65,163
RESIDUAL OIL	8,847	5,956	7,329	9,624	9,345	8,013	7,181	5,393
DISTILLATE OIL	409	38	38	44	87	64	60	31
COAL	26,585	31,338	30,326	28,897	28,894	28,846	28,782	28,911
NATURAL GAS	13,361	16,119	18,779	18,984	21,579	20,291	19,135	17,054
NUCLEAR	35,224	34,243	32,102	32,310	32,206	31,860	24,415	11,114
IPPS	33,120	34,839	35,217	36,479	36,267	35,692	35,408	35,242
CONVENTIONAL HYDRO	26,971	24,374	24,374	24,635	24,635	24,635	24,635	24,636
PUMP STORAGE LOAD	-2,506	-1,838	-1,492	-1,463	-1,126	-940	-765	-757
PUMP STORAGE OUTPUT	1,681	1,288	1,045	1,015	792	662	527	521
PURCHASES	13,875	8,162	8,922	8,250	6,330	2,040	793	589
SALES	-9,069	-4,729	-4,705	-4,753	-4,144	-3,951	-3,847	-3,714
TOTALS	148,498	149,791	151,935	154,023	159,643	167,153	174,732	184,182

Table 3-4

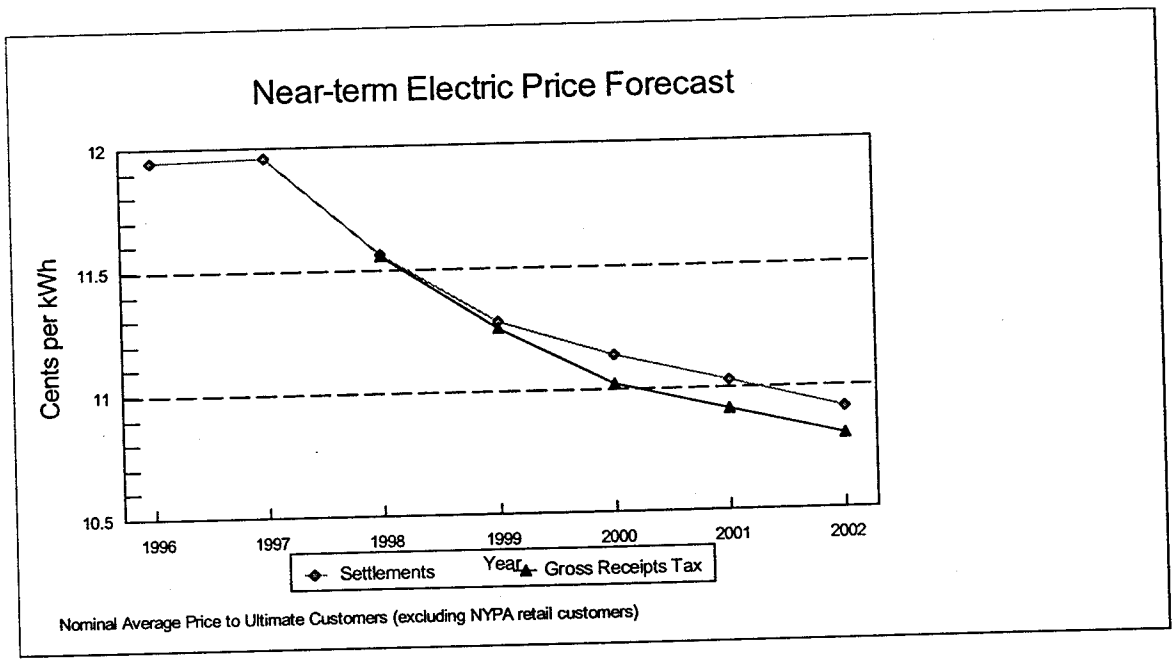

Figure 3-6

revenue concessions take the form of IPP buy-out costs, funding for retail access programs, funding for environmental programs, and funding for power for jobs programs. The foregone rate increases represent rates that would have otherwise been in effect. Some of the rate decreases were initiated prior to the final settlement agreements and thus pre-date the settlement agreements by as much as two years.

The total Statewide rate relief and revenue concessions represent a $6.7 billion savings during the period from 1995 to 2002. By the final year of the settlement agreements, New York State electricity consumers will, on average, experience a 10% revenue reduction as a result of PSC and LIPA negotiations. It should be noted that as the settlement agreements unfold and begin to take effect, many customers are anticipated to opt for retail access. For these customers, savings may be greater than indicated in the settlement agreements.

Long-Term Electric Price Forecasts

With the advent of greater consumer choice and retail access, the ability to forecast future electricity prices ultimately paid by consumers is increasingly more difficult because market forces will control prices rather than regulation. However, the development of a more national market for electricity sales will help assure

that New York's electricity prices become more competitive with electric prices in other states and regions. The methodology used to forecast long-term electric prices in this SEP required several major simplifications, with the results stated in a price band. A key component driving future electricity prices is the long-term equilibrium price of electricity generation in a competitive market. In the near term, however, future electricity prices will generally be determined by the settlement agreements reached among the IOUs, various parties, and Department of Public Service staff in the PSC's competitive opportunities case as discussed previously. As shown in Figures 3-6 and 3-7, electricity prices in the initial years (1998-2002) of the forecast period during the transition to competition are expected to decline in both real and nominal terms.

Developing a long-term forecast for electric prices first requires a forecast of the long-term equilibrium price of generation in a competitive environment. The long-term forecast assumes an equilibrium in competitive generation markets by the year 2006. The generation price estimate for 2006 is drawn from estimates of the total cost of constructing and operating state-of-the-art new generating units at that time. It was further assumed, as a simplification, that there would be no remaining ratepayer charges for generation-related strandable costs as of 2006 (except for the LIPA Shoreham regulatory asset and NYPA sales-for-resale benefits). However, because there is a reasonable probability that stranded cost charges might remain in rates at that time, the 2006 price could be considered somewhat understated.

To develop the 2006 cost estimate for generation, the 1997 capital cost of a new combined-cycle gas turbine generation unit was estimated and then inflated over time. A range of cost estimates was developed for 2006, with the high end based on an escalation rate equal to inflation and the low end assuming no escalation at all (except for gas prices). The low end reflects the potential that technological improvements would fully offset inflationary pressures. Two sets of gas prices, a high case and a low case, were used. Additional factors were applied to reflect line losses, the need for reserves, and the fact that not all generators will be base loaded. Generation costs were estimated to range from 6.0 cents per kWh for the high range and 5.2 cents for the low range in 2006 dollars.

A component to reflect transmission and distribution (T&D) charges was calculated to complete the long-term total electric price forecast. T&D was assumed to remain regulated, with costs comparable to current costs. For the high-range forecast, current T&D costs were assumed to increase at the rate of inflation (forecast to be about 2.5% annually), reaching 6.0 cents per kWh. For the low-range forecast, T&D costs

were assumed to remain constant in nominal terms at current levels, averaging 5.0 cents per kWh. These include LIPA's Shoreham-related costs and NYPA's sales-for-resale benefits, which are assumed to be the only stranded costs and benefits remaining in 2006.

For the early years of the long-term forecast, the price reductions set forth in Figure 3-6 as agreed to in rate settlements are assumed to occur. The settlement rate reduction impacts were assumed to begin phasing out in 2002 and expire in 2006, when electric prices would begin to experience the full effects of retail competition. From 2002 to 2006, overall rates (the sum of generation, T&D, and stranded costs) were assumed to move at a constant annual rate from the settlement values to the 2006 forecasts, decreasing slightly over time in the low case and increasing in the high case. Post-2006, the high-range forecast reflects an escalation rate of T&D costs equal to inflation, along with a "high" forecast of gas prices. The low-range forecast reflects constant T&D costs and fixed production costs with "low" gas prices (which increase at approximately the projected rate of inflation).

The long term forecasts were converted to constant 1996 dollars to provide forecasts of real electricity prices. The "high" forecast of real electricity prices increases at an average annual rate of 0.01 cents per kWh (0.1%) from 2002 to 2016. The "low" forecast of real electricity prices declines at an average annual rate of 0.2 cents per kWh (-2.4%) from 2002 to 2016. Figure 3-7 provides the "high" and "low" long-term

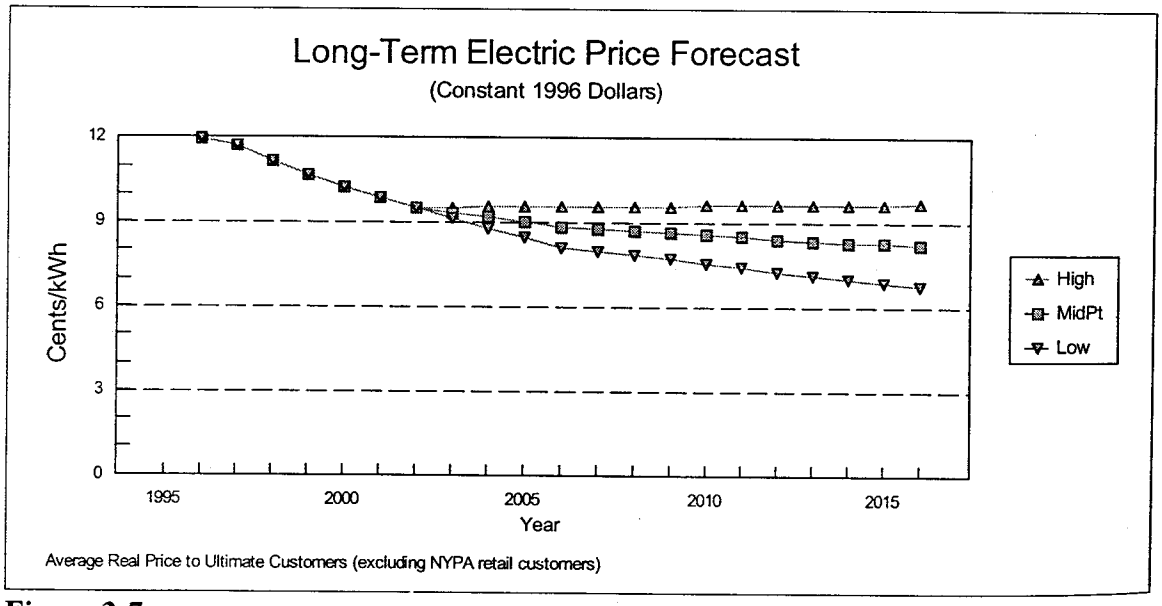

Figure 3-7

forecasts for real electricity prices during the planning period. The prices are Statewide average electricity prices to ultimate customers, excluding NYPA retail customers, expressed in constant 1996 dollars. Future electric generation prices should move closer to the national average since, over time competition will likely eliminate most market distortions, leaving only regional anomalies for state-to-state price differences. Thus, changes in generation prices should have no more impact on New York's competitive position than comparable changes in other states.

Electric Sales Forecast

Sales forecasts of total delivered electricity were prepared by the Department of Public Service staff for the service territories of the seven IOUs in New York State for the period 1996-2016. The sales forecast of the New York Power Authority, as it was reported by the NYPP in its 1998 Load and Capacity Data report, was added to the forecasts of the IOUs to derive a Statewide sales forecast over the planning period. Over this period, the electric utility industry will be undergoing major changes that will affect sales. Many of these changes, such as the price decreases forecast in Figures 3-6 and 3-7, and enhanced marketing activities, could increase sales. Other changes, such as enhanced load-management practices, may moderate sales, although economic conditions are and will be a major determining factor influencing the demand for electricity. The forecasts are presented in Figure 3-8 as a range between the high and low graphs shown.

The forecast reflects the uncertainties surrounding actual price levels for electricity in the future, the effect of price changes on sales, actual economic conditions and their impacts on sales, and other effects of competition. Estimates of the annual sales growth rates prepared by New York's seven IOUs and the NYPA fall into the middle of this range.

The midpoint annual sendout growth rates over the forecast period is 1.2%, with the high forecast showing a 1.6% average annual growth rate and the low forecast of sendout being 0.7%. From the early-to-late 1980s, the annual average growth rate for sendout in New York State was 2.3%, which by 1996 had dampened to 0.6%. At the same time, the nominal price of electricity had increased from approximately 9.5 cents per kWh in 1989 to 11.96 cents per kWh in 1996, a 3.3% average annual growth rate. This increase in electric prices affected demand for electricity and, ultimately, the economy of the State. The

competitive policies espoused in this plan could produce significant price reductions in the cost of electricity which, in turn, could stimulate growth in the State's economy.

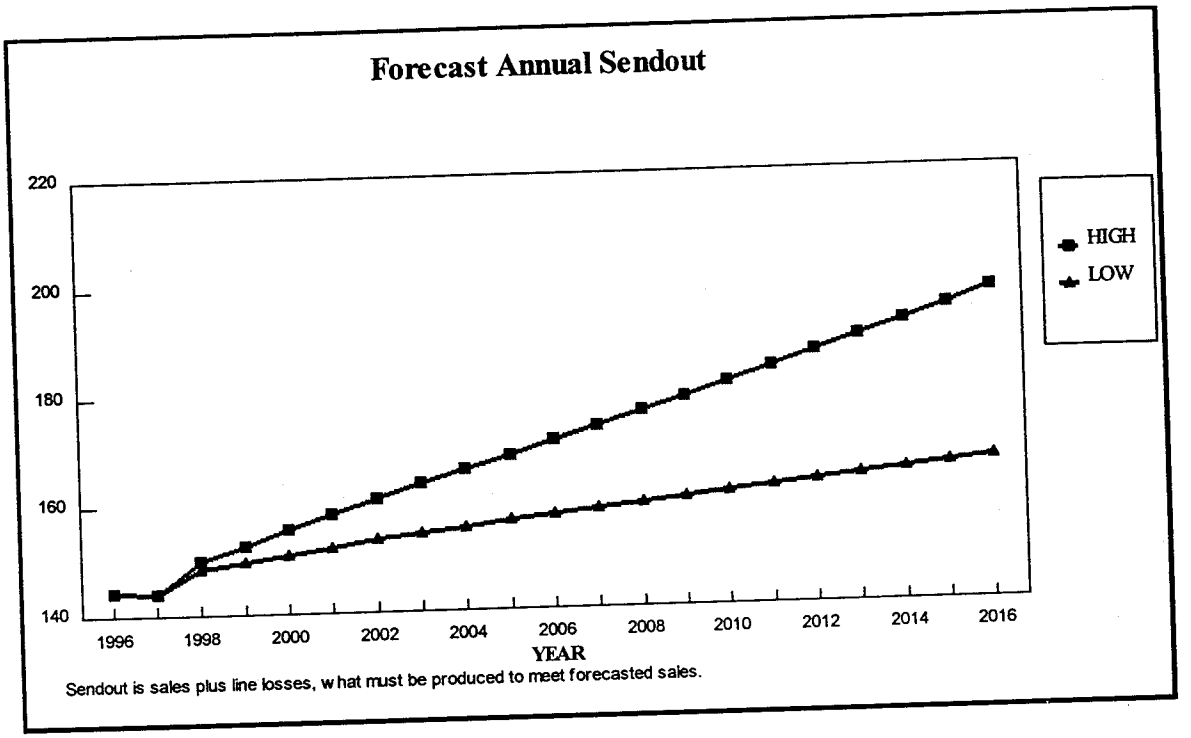

Figure 3-8

The midpoint average annual growth rate (outlook) for generation capacity requirements over the forecast period is 1.1%, and the high and low forecast growth rates are 1.5% and 0.6% respectively.