Electricity

Rising demand for electricity and an aging energy infrastructure in New Jersey have led to discussions about how best to meet the future electricity needs of the state. Policy makers, electricity providers, utilities, environmental groups, and the public must determine the most prudent, cost-effective, and environmentally responsible choices about New Jersey's future of electric energy supplies. This discussion should include a balanced assessment of the potential for renewable energy resources to supply electricity to the State.

Electric power and the energy to generate, transmit, and distribute it are vital to New Jersey's well-being. While the regulation, management and planning in the electric power industry over the last decade have changed, the industry continues to combine heavily regulated components with competitive markets and aspects of it continue to be directly influenced by New Jersey policymakers and public.

The terms "energy" and "electricity" are often used interchangeably, but electricity is only a type of energy consumed by residences, businesses, and industries that is generated from several fuels. New Jersey is part of a regional electric power market that spans the Mid-Atlantic region and is part of the Eastern interconnection or grid. The grid's design and regulation, management of its wholesale power market, and the regional reliability requirements depend both on the objectives, economics, and policies of the organizations that monitor and manage it and on the peer states within its region.

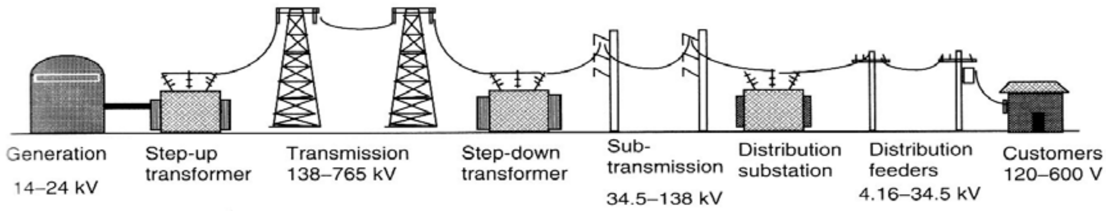
Moreover, since electricity flows throughout the region, the energy supply portfolio of the entire region affects which energy types are consumed here. The discussion herein is intended to address the specific problems facing New Jersey as it strives to meet future demand.

The State's current generation capacity will be affected by whether Oyster Creek nuclear facility and other generation units are retired or relicensed. The New Jersey Board of Public Utilities (BPU) adopted a Renewable Portfolio Standard (RPS) in 1999 to encourage the use of renewable energy in the production of electricity. In 2006, the BPU raised the RPS requirements for Class I Renewable Energy resources from 4% by 2008 to 20% by 2020. Class I Renewable Energy resources include: solar photovoltaics (PV), solar thermal electric, wind, geothermal, fuel cells, landfill gas recovery, and sustainable biomass. With a potential loss of significant generation capacity within the State, and the RPS, meeting future demand may come in significant part from renewable sources.

Overview of the Electric Power Industry, Electricity Markets, and Regional Regulatory and Management Organizations

The basic three functions within the electric power industry are generation, transmission, and distribution. Figure 1 illustrates the relationship between these components. Generation has traditionally consisted of large-scale plants, such as nuclear or coal-fired. Distributed generation[1] and renewable resources are assuming a more significant role in power generation, especially in back-up generation. Transmission lines are almost exclusively alternating current (AC), transformers, and other components. At different points in the transmission process, these lines have differing voltage, ranging from approximately 69 kV wires in sub-transmission situations to as much as 765-769 kV lines for main transmission lines. Distribution refers to the local facilities that feed power directly into the site where it is used, such as a home or office.

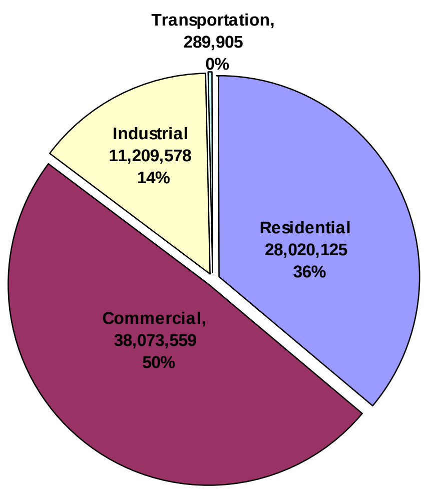
Figure 1: The Electric Power Industry



Source: Gilbert M. Masters, *Renewable and Efficient Electric Power Systems*, Wiley, 2004

In the electric power industry, the volume of electricity distributed for direct customer use is known as the *load*. Densely populated and other areas of high demand are known as load centers. The load[2] in New Jersey breaks down as shown in Figure 2, with the commercial sector purchasing the largest amount of electricity at 50% followed by the residential sector with 36%, and the industrial sector at 14%.

Figure 2: 2004 Total Sales of Electricity in MWH



Source: EIA, State Electricity Sales by Sector, 1990-2004.

[1] Distributed generation refers to smaller or localized electric generating units such as solar panels, fuel cells, or backup generators located near consumers. Backup generators are often run on diesel fuel.

[2] The term load herein refers to sales and does not include on site generation consumed onsite. In 2004 the total sales was 77,593,167 MWH

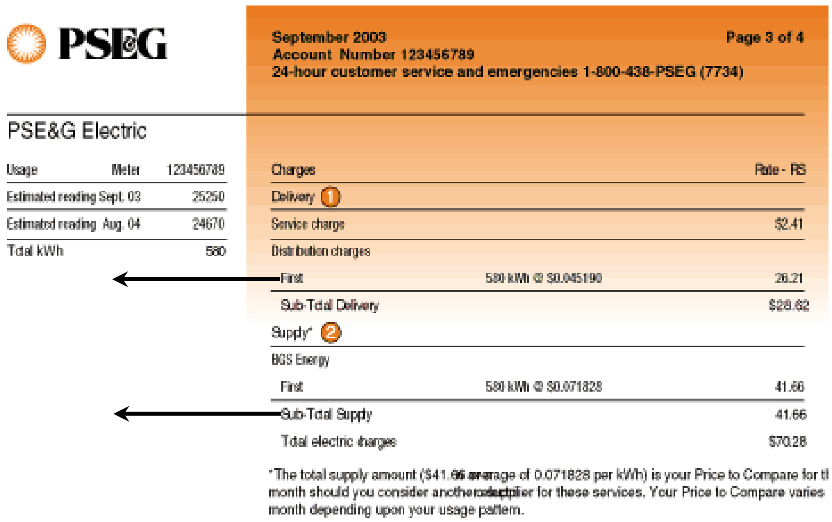
Prior to 1999, New Jersey's electric power industry like those throughout the nation was vertically integrated and regulated. This meant that utilities generated, transmitted, and distributed electricity themselves rather than having three separate firms responsible for one task. Each utility had a designated service territory, or franchise area, that only it could serve, which made it a regulated monopoly. The price of electricity was based on the utility's cost of service as determined by the BPU and by the Federal Energy Regulatory Commission (FERC). A utility's cost included fixed and operating costs, the cost of borrowing money from shareholders and bondholders. The BPU would review utility expenditures and allow utilities to recover prudently incurred costs from customers.

In 1999 New Jersey and other states "restructured" the electric power industry in conjunction with federal policies. New Jersey deregulated the generation of electricity and established wholesale markets for "electrons." Power plant owners apply to FERC to charge "market-based rates" for the sale of wholesale electricity. FERC grants market-based rates if the generator does not have "market power" -- the ability to raise prices above competitive levels – in the wholesale market. Generator owners that cannot satisfy FERC's market power test must sell their electricity at cost-of-service based rates.

The transmission and distribution of electricity, however, continues to be regulated under a cost-of-service regulatory framework. Utilities continue to be responsible for the transmission and distribution of electricity. In New Jersey there are four investor-owned utilities: Public Service Electric and Gas (PSE&G), Jersey Central Power & Light Company (JCP&L), Atlantic City Electric Company, and Rockland Electric Company. Their service areas are shown in Figure 3. These companies serve the vast majority of customers in New Jersey, although nine public entities and one cooperative also transmit and distribute electricity. Monthly electric bills reflect the changes in the way charges are configured. Bills, an example shown in Figure 4, include "delivery charges" and "supply charges," which represent different parts of the electric power industry. Delivery charges are for transmission and distribution of electricity and supply charges are for the generation of electricity.

Figure 3: New Jersey's Investor-Owner Utilities

Figure 4: Sample PSE&G Bill Reflects the Deregulated Industry Structure



PSEG

September 2003 Page 3 of 4
Account Number 123456789
24-hour customer service and emergencies 1-800-436-PSEG (7734)

PSE&G Electric

Usage	Meter	123456789
Estimated reading Sept. 03		25250
Estimated reading Aug. 04		24670
Total kWh		580

Charges		Rate - RS
Delivery 1		
Service charge		$2.41
Distribution charges		
First	580 kWh @ $0.045190	26.21
Sub-Total Delivery		$28.62
Supply* 2		
BGS Energy		
First	580 kWh @ $0.071828	41.66
Sub-Total Supply		41.66
Total electric charges		$70.28

*The total supply amount ($41.66 average of 0.071828 per kWh) is your Price to Compare for th month should you consider another electric supplier for these services. Your Price to Compare varies month depending upon your usage pattern.

Source: PSE&G Website

Location of New Jersey within the region's Power Grid and Markets

New Jersey's regional electricity market and regional power grid are the Mid-Atlantic Area Council (MAAC), which serves as the regional reliability organization, and Pennsylvania-New Jersey-Maryland Interconnection (PJM), the regional transmission organization (RTO) operating the wholesale market. They have different but overlapping roles with respect to grid reliability. PJM ensures the reliability of the largest centrally dispatched electric grid in the world by coordinating the movement of electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

Figure 5 shows the geographic boundaries of MAAC. Figure 6 shows the boundaries of PJM. PJM covers additional areas further to the south and west than MAAC. The regional nature of the power system and what happens in neighboring or nearby states can have important implications on the reliability, cost, and environmental impacts on New Jersey electricity consumers and residents. Any policy enacted in New Jersey is subject to the reality that electricity and air emissions flow across the regional grid and air shed based on the location and types of power plants, the location of the demand for electricity, and regional weather patterns.

Figure 5: MAAC Situated in the NERC Network of Regional Reliability Councils

The MAAC is part of the North American Electric Reliability Council (NERC), which was formed in 1968 to coordinate, standardize and formalize reliability requirements across regions of the country. The map below illustrates the geographic boundaries of MAAC and the other reliability councils that are part of NERC.

Source: adapted from NERC Webpage

Figure 6: PJM Geographical Scope

PJM encompasses 51 million people in 13 states and the District of Columbia. The region has a peak demand is over 130,000 MW, which is served by over 163,000 MWs of generation capacity. The region includes more than 56,000 miles of transmission lines.

Source: PJM Webpage

To understand the region's electricity markets, one must recognize the two types of markets within the electricity market. The first is for capacity or mega\watts, and the second is for energy or megawatt-hours (MWh). Capacity is a reliability product that ensures sufficient available generation units to satisfy demand even on the peak day of the year. For example, if a load center demands 20 MW of electricity, adequate capacity would mean that the generators supplying that electricity to meet the load have the ability to generate at least 20 MW, as well as a reserve margin of extra capacity to meet demand in the event of outages. Energy, on the other hand, is the product that lights buildings, runs motors, and powers computers. (A typical consumer is billed in kilowatt-hours (kWh), which is 1,000 times smaller than an MWh.) A typical house consumes approximately 10,000 kWh per year, which means that a large, 1000 MW power plant serves about 700,000 households, assuming this power plant has a capacity factor of approximately 80%.

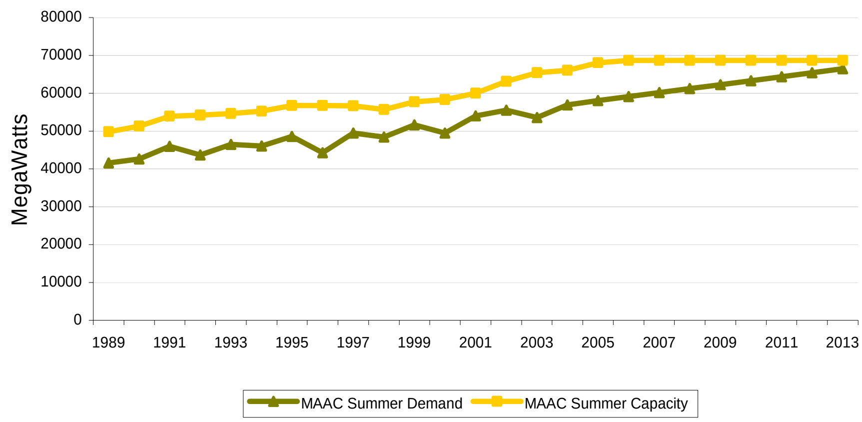
The amount of capacity available in the State depends on the required level of reliability determined by PJM based upon MAAC reliability requirements. Presently, reliability requirements are set based on general industry standards and enforced via voluntary agreement, but they will be mandatory as the federal Energy Policy Act (EPACT) of 2005 takes effect. One of the drivers for mandatory reliability requirements was the extensive blackout on August 14, 2003, which originated in Ohio and spread to Canada and at least eight other states including New Jersey. The EPACT makes compliance by electric utilities and other companies with reliability standards mandatory and enforceable under federal law. In addition, FERC has taken numerous other steps to reduce the chances of future blackouts.

The regional electricity grid and wholesale market is operated and administered by PJM, the Pennsylvania-New Jersey-Maryland Interconnection. PJM staffs the control room that dispatches generation units, monitors power flows on transmission lines, and ensures that the grid is operated reliably. It also conducts reliability studies, plans the transmission system, and generally responsible for the reliability of the region's grid.

In the PJM region demand for electricity is increasing at roughly 1.4 % per year. The *capacity margin* is the amount of additional capacity above peak demand. Currently, the region has a slight surplus, but according to MAAC estimates, the margin is expected to tighten over the next several years. This narrowing margin shown in Figure 7 suggests that new generation facilities or significant energy efficiency will be needed in the future and this need should be anticipated by policymakers.

The timeline for planning and developing new generation capacity can be lengthy. Figure 8 shows how different phases of the electricity capacity planning process take vastly different amounts of time. Planning for and building new generation can take up to 10 years, while determining the source of the next hour's electricity may happen in five-minute intervals throughout the day.

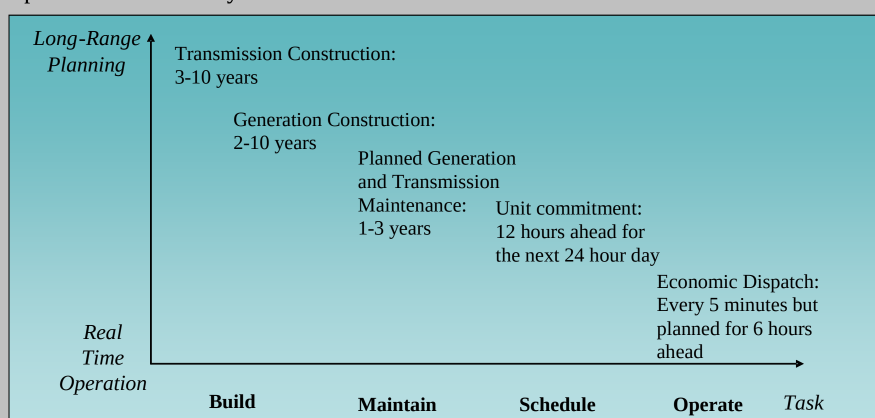
Figure 7: MAAC Regional Summer Electricity Capacity and Demand, Historical from 1989 to 2003, Projections from 2004 to 2013



Source: NERC Historical Capacity and Demand 2004 Reports, available at http://www.nerc.com/~esd/esddoc.html

Figure 8: Project Timeline and Planning for New Generation

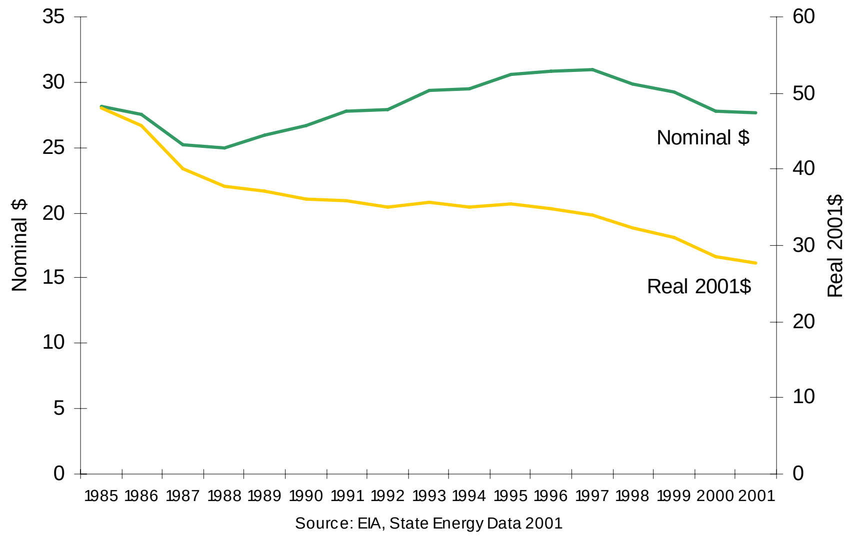
Planning and operating a power system requires decisions to be made years ahead of time and seconds before electricity is transmitted to the load (vertical axis) The different planning tasks (horizontal axis) also take place in different elements of the electric power industry, requiring the decisions to be integrated within both the competitive and regulated portions of the industry.



Load Fluctuations, Peak Pricing and Locational Marginal Pricing

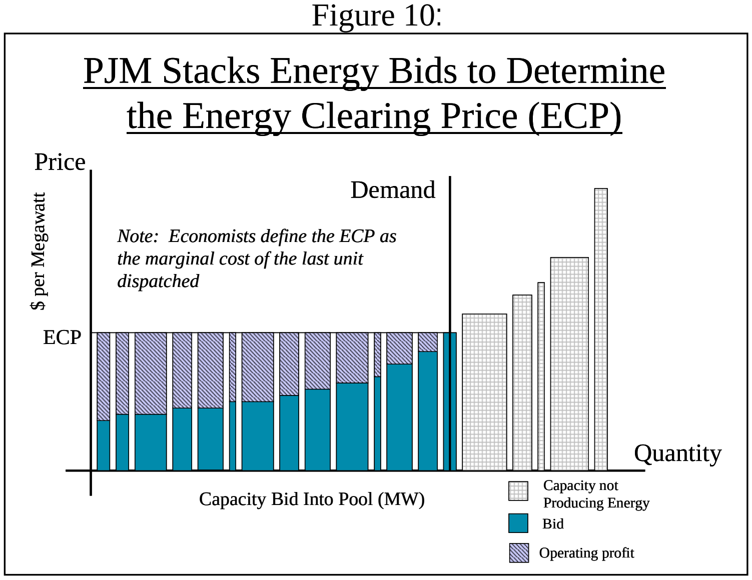
The rationale for the restructuring of the electricity markets is to harness the efficiency of competition. Indeed, the real prices paid by consumers in 2001 were 11% lower than in 1999 (see Figure 9). One major function of PJM is to administer the wholesale electricity markets. Every day owners of generation units submit bids or offers stating the minimum price they are willing to be paid to produce electricity. PJM takes all of this bid information and determines the least-cost dispatch of generation to meet forecasted demand given the operational limitations of generation units, transmission constraints, and reliability requirements. There are provisions to accommodate distributed generation and dispatchable demand in which consumers that can adjust their electricity demand based on changes in wholesale electricity prices.

Figure 9: Real and Nominal Electricity Prices in New Jersey, 1985-2001



Generation units are paid the energy clearing price ($/MWh) when they are dispatched not their bid price. For instance, if a generation unit offers to provide energy at $20/MWh and the energy clearing price is $30/MWh, the generation unit is paid $30/MWh, which results in an operating margin of $10/MWh. Figure 10 illustrates how the energy clearing price is determined. In PJM the prices that generators are paid depend on the location of the generation unit on the transmission system and the condition of the transmission (constrained or not). The energy clearing price is referred to as the locational marginal price (LMP).

Figure 10:



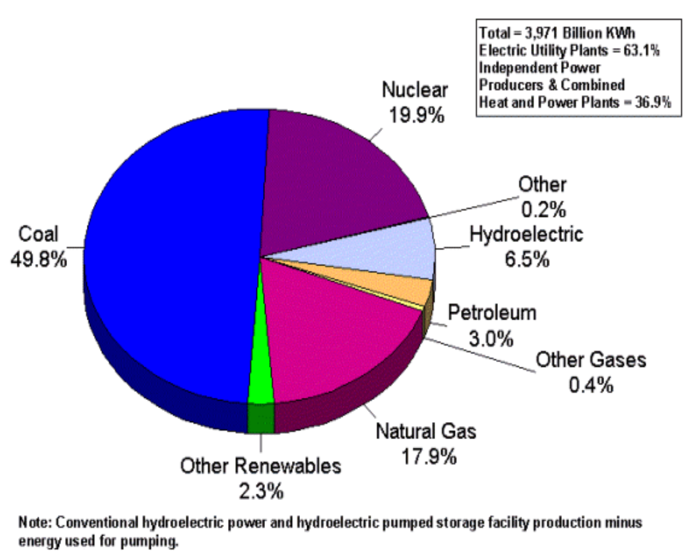
Locational Marginal Price helps wholesale market participants react rationally to congestion by investing in new generation and/or transmission in geographic areas that would help reduce congestion, or by implementing demand response programs. LMP also helps in long-term regional transmission and generation planning by signaling where new resources—generation, transmission, and demand reductions—should be located.

Electricity prices in PJM vary by hour and by location. Since more demand occurs at 2 pm than at 2 am, prices are higher in the afternoon than late at night. This is due to the need to purchase energy from more generating units to meet the higher demand. As demand increases, the least-cost generator's capacity reaches it's maximum and the additional energy must be purchased from generators producing energy at a higher cost and therefore bidding in at a higher price. In addition, times of high demand also face the limitations of the transmission system (transmission wires have a given ability to transport electricity, which cannot be surpassed). If lines reach their capacity, energy from more expensive sources that are not constrained by transmission may need to be purchased. Transmission constraints may limit the amount of energy that can be transferred into an area, referred to as a load pocket, requiring more expensive generation to be dispatched. This results in higher LMPs in these areas, including significant parts of New Jersey.

Fuel Consumption in the United States Electric Power Sector

In the United States, bulk of electric power is derived from coal, with significant contributions from nuclear energy and natural gas (see Figure 11). Ninety percent of coal consumed in the US annually is used for the generation of electrical power, with the result that, in 2004, coal-fired power provided 49.8 percent of electricity generation.

Figure 11 U.S. Electric Power Industry Net Generation, 2004



The US possesses plentiful, steady coal resources. High capital costs, lengthy construction periods and environmental concerns associated with coal limited construction of new coal-fired plants in the past decade. These concerns also have caused a transition to coal mined in the American West, which contains lower sulfur content than coal from Eastern deposits.

Nuclear energy represents a large portion of total electricity production at 19.9 percent. Nuclear energy once held promise to become the predominant source of power in the United States. Since the Three Mile Island incident in 1979, however, no additional nuclear power plants have been ordered. Nevertheless, output from nuclear plants has increased due to improvements to the existing nuclear power plants which resulted in higher operating capacity factors. Interest in nuclear power has enjoyed a renaissance in recent years as the U.S searches for ways to lower emissions of greenhouse gases (GHGs), reduce dependence on expensive natural gas, and limit reliance on imported fuels from unstable countries.

In 2004, natural gas supplied 17.9 percent of electricity generation in the US. Because of its clean-burning nature and the relative affordability of plant construction, natural gas has satisfied many of the emerging requirements for electric power. The attractiveness of new gas-fired plants, however, has been significantly reduced due to the significant increases in prices for natural gas experienced over the past few years.

Oil represents a relatively modest amount of power generation in the United States: three percent. Power generation by oil-fired plants has declined substantially over the past several decades following the oil shocks in the 1970s.

The majority of renewable energy resources currently support the electric power sector. The contribution of renewables to the national electricity mix is small (approximately nine percent) and is dominated by hydroelectric power, which accounts for 6.5 percent.
The use of hydroelectric power varies substantially by region, with New York and the Pacific Northwest deriving much more of their energy needs from hydroelectric power than do other regions of the country. Hydropower is desirable for its emissions-free electricity and protection to ratepayers from price volatility. Although new hydroelectric projects involve conflicts over the protection of natural resources and many of the best hydroelectric sites in the United States have already been utilized, the nation's hydropower capacity nonetheless has not been fully tapped. A study by the Idaho National Laboratory (formerly the Idaho National Engineering and Environmental Laboratory)[3] estimates that about 4,300 MW (approximately 0.05 quadrillion BTUs per year, assuming a 45 percent capacity factor) can be procured merely through efficiency improvements and capacity additions at existing hydroelectric facilities. Retrofitting non-hydropower dams with generators will yield an additional 17,000 MW (0.28 quadrillion BTUs). While these figures are not large in a national context, they would be significant in the regions in which hydroelectric power is most prevalent.

Non-hydroelectric power renewable resources constitute the fastest-growing sector of the energy economy, although they are developing from a small base. Biomass supplies most of

[3] Conner, Alison, James Francfort and Ben Rinehart. "US Hydropower Resource Assessment – Final Report," Idaho National Engineering and Environmental Laboratory, December. 1998.

the non-hydroelectric renewable power in the United States. Generation capacity totals 9,799 MW, installed primarily at pulp and paper installations to generate steam and electricity using wood and wood wastes. Biomass has the potential for use in gasification systems similar to that of integrated gasification combined cycle plants (IGCC) for coal. Some of the more interesting developments in the utilization of biomass have come in the form of "biorefining," which refers to facilities that have the capability to convert biomass into fuels such as ethanol, generate electric power, and produce commercial-grade chemicals.[4]

Wind recently emerged as the strongest candidate to provide additional capacity in the United States, and has an installed capacity of roughly 10,000 MW.[5] Geothermal plants, which draw energy from underground hot water sources, currently contribute about 2,300 MW of capacity, most of which is located in California. Solar – both photovoltaic and thermal – provides about 397 MW of power to the grid. Solar is particularly useful in off-grid applications, but it remains prohibitively expensive in all but the most specialized grid-based applications. Renewable energy technologies are highly dependent on policy, and policy incentives have been key in stimulating their use. Several states have enacted renewable portfolio standards (RPS) that require a specified percentage of energy delivered by utilities to be derived from renewable sources.[6] Congress has reauthorized several times a production tax credit of 1.9 cents/kilowatt-hour for defined renewable energy facilities, which has resulted in significant investments in those technologies. The 1.9 cent tax credit was most recently extended as part of the Energy Policy Act of 2005.[7]

Electricity Sales and Consumption in New Jersey

On a longer term historic basis, total electricity sales grew from 62,856 GWH in 1990 to 77,593 GWH in 2004, an annual growth rate of 1.52% (See Figure 12). During this period the fastest growing sector was the commercial sector with electricity sales increasing from 26,838 GWH in 1990 to 38,073 GWH in 2004, an annual growth rate of 2.53%. The growth in the residential sector was not as much as the commercial sector, but was substantial. Electric sales grew from 20,498 GWH in 1990 to 28,020 GWH in 2004, an annual growth rate of 2.26%. However, the industrial sector saw a substantial decline in total sales. Sales declined from 15,040 GWH in 1990 to 11,209 GWH in 2004, an annual decline of 2.08%.

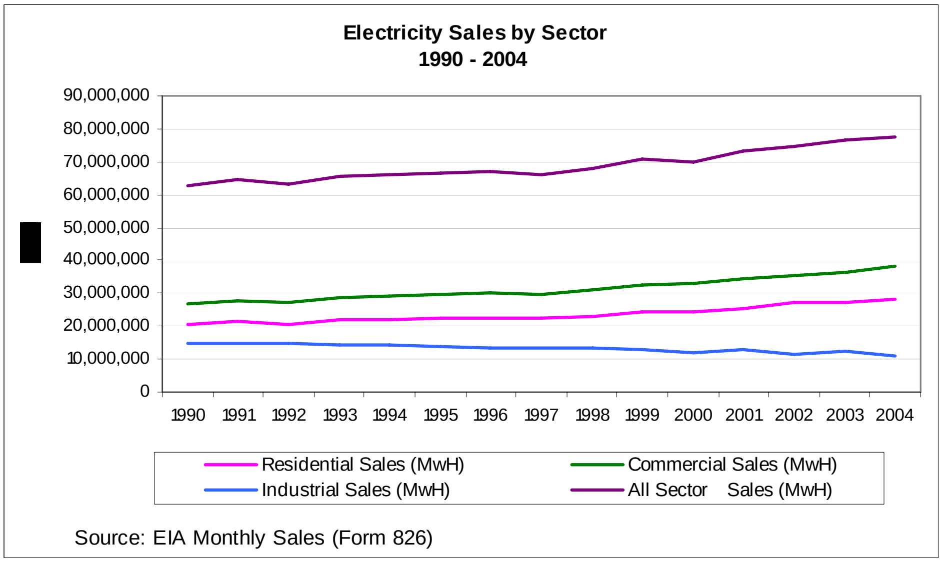
However if we look at the electric sales in the State since the passage of EDECA, we find that there was a significant escalation in the growth of electricity. In fact, total electric sales grew

[4] See National Renewable Energy Laboratory Biomass Research site at http://www.nrel.gov/biomass/biorefinery.html.
[5] American Wind Energy Association, "Wind Energy Fact Sheet," at www.awea.org

[6] For an overview on state activity, see Thomas Petersik, "State Renewable Energy Requirements and Goals: Status Through 2003," Energy Information Administration, available online at http://www.eia.doe.gov/oiaf/analysispaper/rps/index.html.
[7] Adjusted annually for inflation, the REPC provides a tax credit of 1.5 cents/kWh for wind, closed-loop biomass and geothermal. The adjusted credit amount for projects in 2005 is 1.9 cents/kWh. Electricity from open-loop biomass, small irrigation hydroelectric, landfill gas, municipal solid waste resources, and hydropower receive half that rate which is currently 0.9 cents/kWh. *Database of State Incentives for Renewable Energy*, www.dsireusa.org accessed: February 14, 2006.

from 68,162 GWH in 1998 to 77,593 GWH in 2004, an annual growth rate of 2.18%. Residential sales grew from 23,190 GWH in 1998 to 28,020 GWH in 2004, an annual growth rate of 3.20 %. Similarly the commercial sector grew from 31,127 GWH in 1998 to 38,073 GWH in 2004, an annual growth rate of 3.41%. The industrial sector during this time period saw an annual decline of 2.86%.

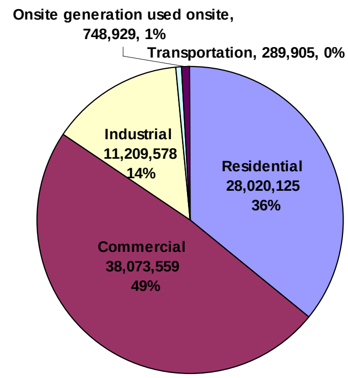
Figure 12



In the last few years we have seen increased on site generation of electricity. In most cases, particularly the larger facilities electricity is fed in to the power grid. However, a large portion of onsite generation is consumed on site. While historic data is not available on onsite generation for on site consumption, efforts are under way at the EIA and the BPU to capture this information. This data will be increasingly important in the future as more and more onsite PV and other alternative generation is relied upon by consumers. Based on EIA data we estimate that in 2004 some 749 GWH were consumed by facilities that also sold part of the electric generation to the grid and reflected in the electric sales data. So while the total electric sales in 2004 was 77,593 GWH the total electric consumption by New Jersey residents and businesses was 78,342 GWH , when we add the portion of the onsite generation consumed onsite.

Figure 13 provides a breakdown of electricity consumption for 2004 by sectors. The commercial sector consumed 38,073 GWH or 49% of the total, the residential sector consumed 28,020 GWH or 36% of the total and the industrial sector purchased 11,209 GWH or 14% of the total. The onsite generation used onsite (749 GWH) is predominantly in the industrial sector and accordingly the industrial consumption is estimated to be 11,958 GWH or 15 % of the total.

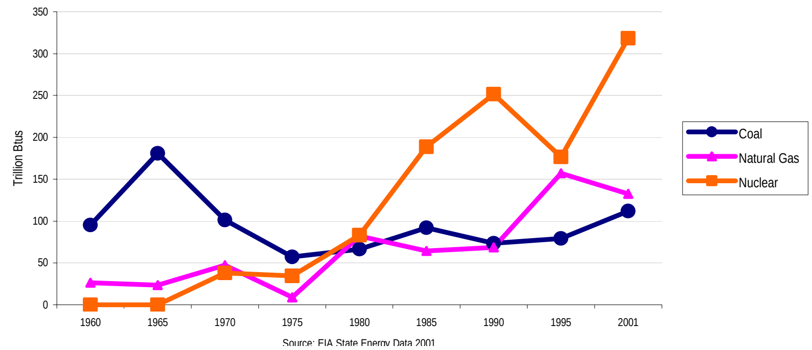
Figure 13: 2004 Electricity Consumption by Sector



Fuel Mix in the New Jersey Electric Power Sector

Nuclear, natural gas, and coal are the three largest sources of fuel to generate electricity in New Jersey. These fuels are heavily relied upon due to their reliable and/or domestic supplies. In recent years, as seen in Figure 14, the proportion of natural gas used by the electric power industry has increased.   The economic down-turn between the mid-1990s and 2001 has ended and the amount of natural gas is increasing. Natural gas has been supplied mostly by North American sources although this proportion is declining as more natural gas and liquefied natural gas in imported. The price of natural gas is often volatile, and this volatility is reflected in the cost of generating electricity from natural gas. The figure also shows an apparent dip in the amount of nuclear electric power generated. This is due however, to unavailability of the in-state nuclear generating plants and not to structural changes in the nuclear generation capacity within the State.

Figure 14: Three Main Fuels Used in the New Jersey Electric Power Industry, 1960-2001



Historically, between 15 to 25% of the electricity used in the State is imported from neighboring states, thus making the electricity generation fuel mix of the region also relevant to the total composition of New Jersey's electricity mix. As Figure 15 shows, the fuel mix in the entire MAAC region contains a larger percentage of coal than in New Jersey alone, and this amount is projected to increase in the future. It is infeasible to determine exactly how the imports impact the total fuel sources for electricity consumed in the State since at the point of transmission it is impossible to differentiate between electricity generated from coal versus electricity generated from nuclear energy. However, generation within New Jersey now and in the future affects the total amount of electricity that needs to be imported to meet demand.

Figure 15: Fuel Mix in the MAAC region

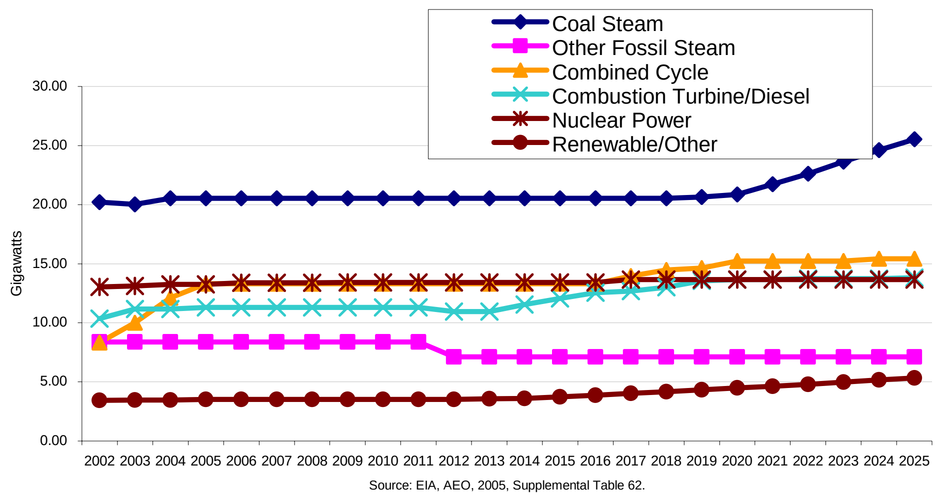


Figure 16 provides a snap shot of the fuel mix used to produce electricity consumed in New Jersey in 2004. Of the total electric consumption of 78,342 GWH, about 21,711 GWH or 27.71 % of the electricity was imported from the PJM and came from facilities located out side New Jersey, and the balance 56,631[8] GWH or 72.29 % were produced in facilities located in New Jersey. About 45% of the electricity consumed in the State is produced by nuclear plants, about 23% from natural gas, 28% from coal and slightly over 2% from renewable energy.

[8] 749 GWH or 0.96% was produced on site for on site consumption

Figure 16

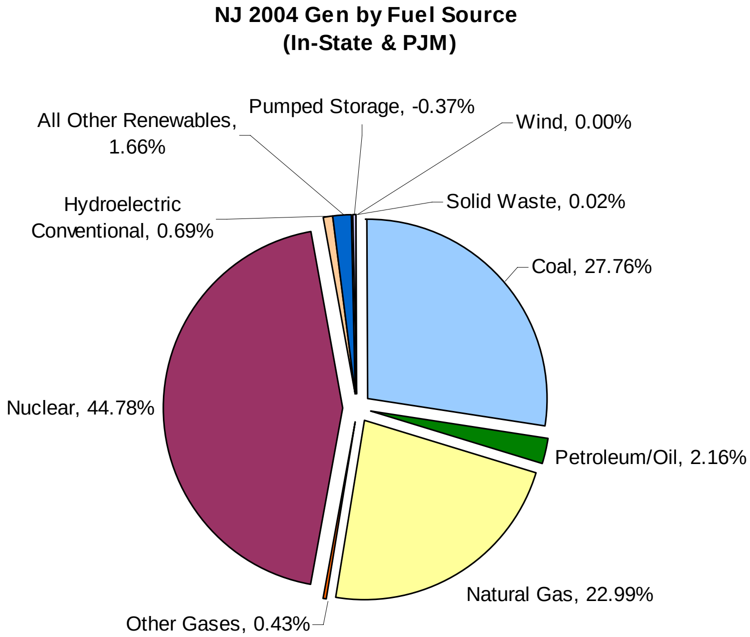
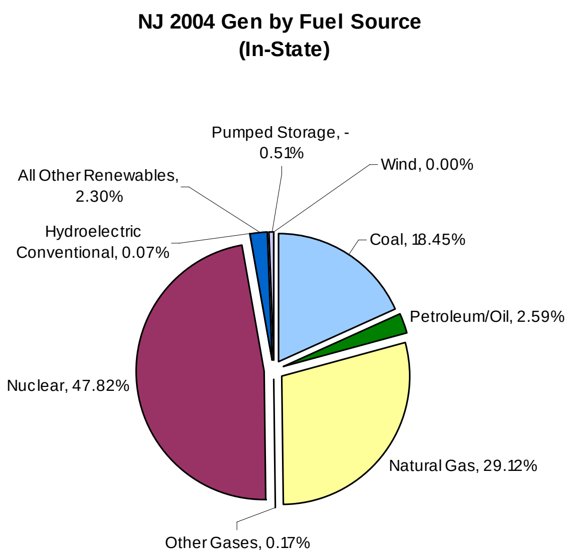


Figure 17 provides a snap shot of the fuel mix used to produce electricity generated by facilities located in New Jersey and sold to New Jersey consumers in 2004. About 48% of the electricity generated in the State is produced by nuclear plants, about 29% from natural gas, 18% from coal and slightly over 2% from renewable energy.

Figure 17



Peak Load and Load factor

In New Jersey and PJM as a whole, load demand is growing. Figure 18 shows the peak summer and winter load demands for PJM since 1989.

Figure 18: PJM Peak Loads (1989-2001)

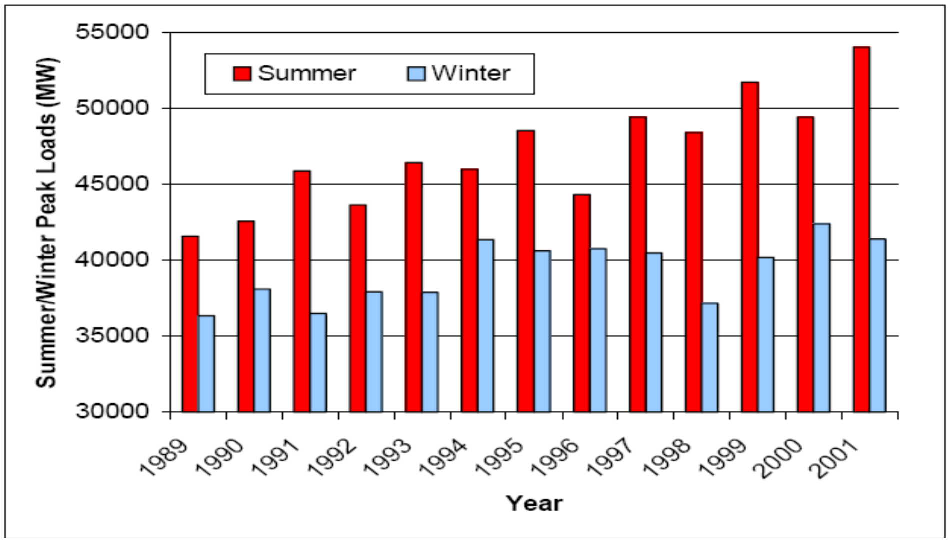


Figure 19 shows the PJM Load profile for the summer of 2001. The bold line shows load levels at 3 pm and the lower line at 6 am. The three-month period from June through August show load levels far beyond what was encountered during other months.

Figure 19: PJM Load Profile from April 1 through September 30 (2001)

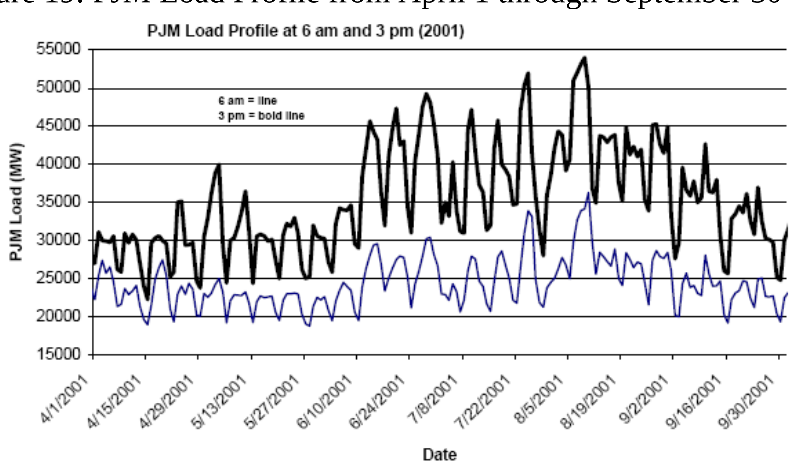


Figure 20 provides a histogram of PJM high load high demand operations in 2001. The number of hours of operation with load in excess of 40,000 MW was significant in June through August due primarily to air conditioning demand. The PJM load exceeded 50,000 MW in July during 12 hours and in August during 40 hours.

Figure 20 Histogram of PJM high load operations in 2001

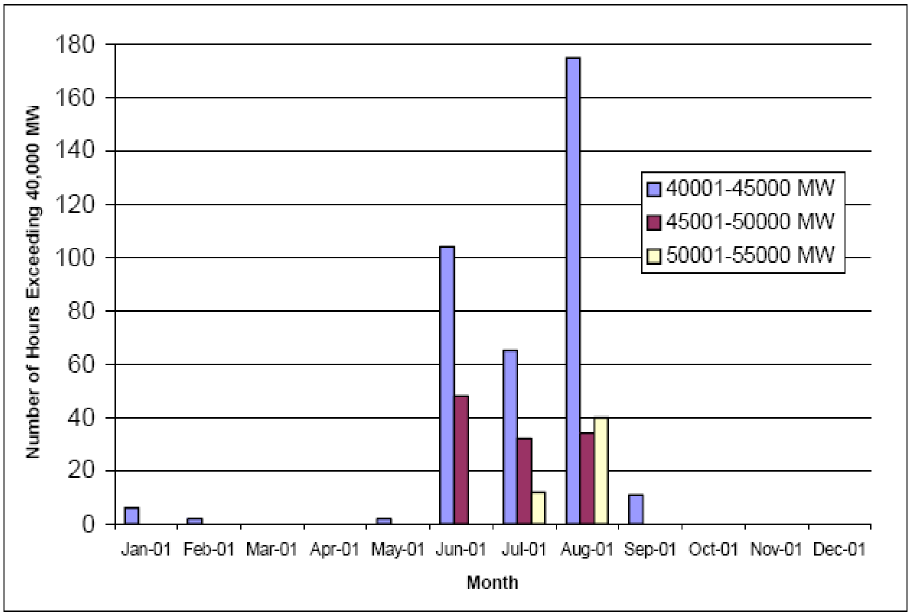
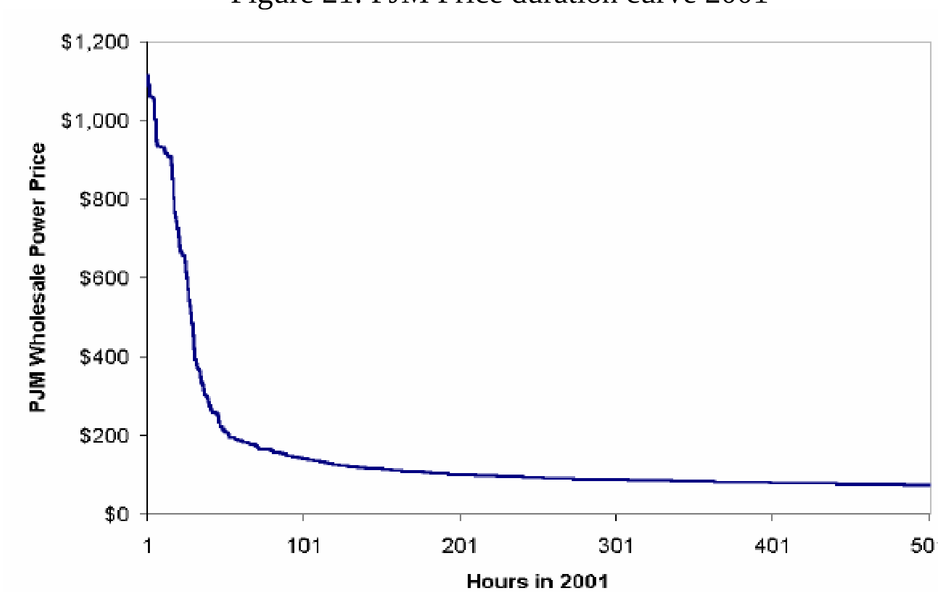


Figure 21 provides a price duration curve for 2001. It shows the very high price spiking that occurred in the PJM market during the summer of 2001. The figure shows that the PJM wholesale price was above $100/MWH for only about 200 hours during the year and above $200/MWH for about 50 hours.

Figure 21: PJM Price duration curve 2001



The high price periods generally coincide with the peak periods and accordingly the importance of peak load management. Reduction of the peak load has a direct correlation in reducing the marginal cost of electricity. In addition, peak load reduction can play a major role in reducing harmful environmental emissions. One commonly used measure of performance or efficiency of electricity use is the load factor. Load Factor is calculated as a ratio of the average load to the peak load during the period. The peakier the peak the worse the load factor. Since poor load factors coincide with peakier peaks it is clear that improvement of load factor should go a long way in reducing the marginal cost of electricity production. Load factor can be affected by numerous variables, e.g., demographics, end uses, etc. While a number of load management techniques can be employed to increase the load factor, those that reduce the peak without increasing overall energy use are preferable. Table 1 provides the summer peak load of major New Jersey utilities.

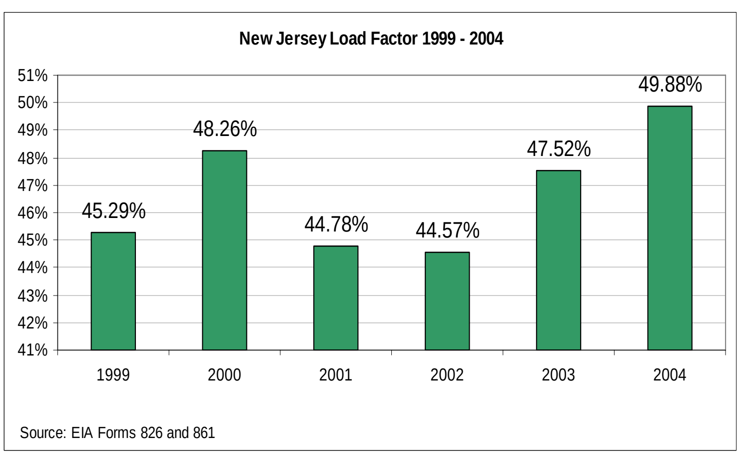
Table 1 Peak Load in MW

Year	PSE&G	JCP&L	ACE	RECO	STATEWIDE
1999	9,804	5,180	2,430	406	17,820
2000	9,369	4,483	2,329	371	16,552
2001	10,060	5,592	2,590	412	18,654
2002	10,188	5,820	2,677	424	19,109
2003	9,855	5,645	2,485	363	18,348
2004	9,429	5,457	2,454	417	17,757

Source: EIA Form 861

Figure 22 provides the statewide load factor from 1999 to 2004. It should be noted that the 1991 Energy Master Plan alluded to the fact that the average load factor for New Jersey utilities was well below the national average of over 60%. In 1990 the average load factor was 53%. As shown in the figure, the average load factor in New Jersey has deteriorated to below 50%.

Figure 22



Energy and Peak Load Projections

Projecting electricity needs through 2020 is a difficult exercise since there are many variables that will affect the eventual outcome. Even a single new piece of legislation such as the Energy Policy Act of 2005 could have profound effects on energy systems, fuels infrastructure, and rate of technological development responding to emerging needs. Unanticipated acts of nature can cause major fluctuations in price and supply, as demonstrated by the hurricanes that hit the Gulf Coast in 2005. Geopolitical events around the world can and will impact the US fuel supply decisions. Notwithstanding the variables involved, we have made a reasonable attempt to project electricity consumption and peak load through the planning period. **Continuation of current policies and consumer behavior is implied in our projections. Accordingly, substantial reduction in energy use from those projected herein will require major changes in current energy policies at the State level**. Even with the uncertainty of projecting the future, there are a number of important reasons for undertaking the exercise: (1) devising an estimate of New Jersey's projected electricity needs can establish an anchor by which policy makers can evaluate current policies to determine their long-term implications; (2) evaluating long-term projections can instill thinking in terms of long-term strategies; (3) examining why the projections could be wrong in the future can assist in focusing on potential variables that will impact the energy infrastructure; and finally, (4) projecting electricity needs to 2020 can help envision how new technologies that seem cutting edge today could be part of the mainstream energy infrastructure by the end of the planning period. In this context, we thought it was appropriate to start with the national outlook on electricity demand as developed by the Energy Information Administration.

United States Electricity Demand Projections

The Annual Energy Outlook 2006[9] (AEO2006) presents a forecast and analysis of US energy supply, demand, and prices through 2030. The projections are based on results from the Energy Information Administration's National Energy Modeling System. The AEO2006 projects the annual growth rate of electricity at 1.6% between 2005 and 2030. Total electricity sales increase by 50 percent in the AEO2006 reference case, from 3,567,000 GWH in 2004 to 5,341,000 GWH in 2030. The largest increase is in the commercial sector, as service industries continue to drive economic growth. By customer sector, electricity demand grows by 75 percent from 2004 to 2030 in the commercial sector, by 47 percent in the residential sector, and by 24 percent in the industrial sector. Efficiency gains are expected in both the residential and commercial sectors as a result of new standards in EPACT2005 and higher energy prices that prompt more investment in energy-efficient equipment. In the residential sector, the increase in electricity demand that results from a trend toward houses with more floor space, in addition to population shifts to warmer regions, is mitigated by an increase in the efficiency of air conditioners and refrigerators. In the commercial sector, increases in

[9] **Report #:DOE/EIA-0383(2006)**
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demand as a consequence of larger building sizes and more intensive use of electrical equipment is offset by increases in the efficiency of heating, cooling, lighting, refrigeration, and cooking appliances. Personal computers become more energy-efficient on average as residents and companies replace monitors that use cathode ray tubes with new models that use more efficient flat screens. New telecommunications technologies and medical imaging equipment increase electricity demand in the “other” commercial end-use category, which accounts for one-half of the increase in commercial demand. In the industrial sector, increases in electricity sales are offset by rapid growth in on-site generation.

With growing electricity demand and the retirement of 65 GWs of inefficient, older generating capacity, 347 GWs of new capacity (including end-use CHP) will be needed by 2030. Most retirements are expected to be oil- and natural-gas-fired steam capacity, along with smaller amounts of oil- and natural-gas-fired combustion turbines and coal-fired capacity, which are not cost-competitive with newer plants. Capacity decisions depend on the costs and operating efficiencies of different options, fuel prices, and the availability of Federal tax credits for investments in some technologies. Natural gas plants are generally the least expensive capacity to build but are characterized by comparatively high fuel costs. Coal, nuclear, and renewable plants are typically expensive to build but have relatively low operating costs and, in addition, receive tax credits under EPACT2005. Coal-fired and natural-gas-fired plants account for about 50 percent and 40 percent, respectively, of the capacity additions from 2004 to 2030. Coal-fired capacity is generally more economical to operate than natural-gas-fired capacity, because coal prices are considerably lower than natural gas prices. As a result, new natural-gas-fired plants are built to ensure reliability and operate for comparatively few hours when electricity demand is high. About 8 percent of the expected capacity expansion consists of renewable generating units. New nuclear capacity additions total 6 GWs (1.7% of new capacity), but no additional new nuclear plants are built after 2020, when the EPACT2005 production tax credit expires.

New Jersey Energy and Peak Load Projections

In order to project the electricity demand to 2020, we have used data from two historic periods 1) 1990 to 2004 and 2) 1998 to 2004. In New Jersey, electricity sales[10] to all sectors grew from 62,856 GWH in 1990 to 77,593 in 2004, an average annual growth rate of 1.52%. However, since the passage of Electric Discount and Energy Competition Act (EDECA) of 1998, electricity sales has grown at an annual rate of 2.18%.

Figure 23 provides projection of electricity consumption[11] to 2020 based on 1) 1.52% annual compound growth rate and 2) the continuation of a 14 year trend line between 1990 and 2004. The first projection estimates the total consumption in 2020 at 99,728 GWH. Continuation of the last fourteen year trend line projects the 2020 consumption at 92,703 GWH.

[10] The EIA data on sales data does not include on site use of electricity produced by on site generation. In 2004 onsite use from on site generation was 749 GWH.

[11] The consumption projections include on site generation used onsite and begins with 2004 consumption at 78,342 GWH rather than 77,593 GWH.

Figure 23

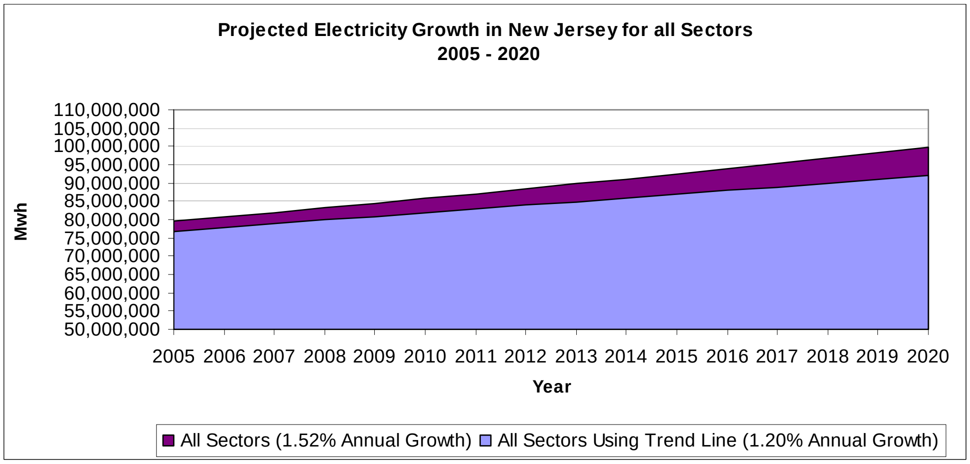


Figure 24

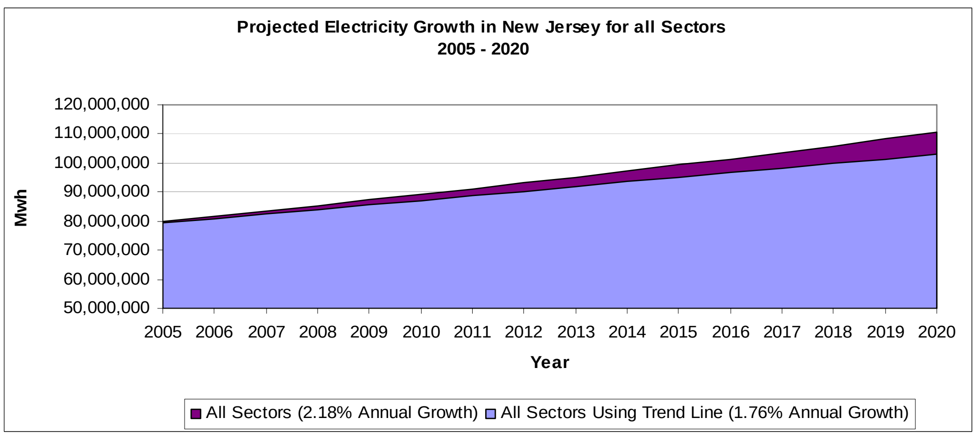


Figure 24 provides projection of electricity consumption to 2020 based on 1) 2.18% annual compound growth rate and 2) the continuation of a 6 year trend line between 1998 and 2004. The first projection estimates the total consumption in 2020 at 110,624 GWH. Continuation of the last six years trend line projects the 2020 consumption at 103,738 GWH.

The electricity growth rate in the last six years has been very high primarily driven by the lower average prices of electricity immediately after the implementation of price caps under EDECA as well as the recent trend for larger homes in most suburban areas of the State. Can this high rate of electricity growth in New Jersey be sustained in the future over the planning horizon? Or is it likely that the future growth will trend down to the historic growth between 1990 and 2004 (1.52% per year), a growth rate that is in the same range as that is currently projected for the total US electricity demand in the AEO2006 (1.55% per year)? We are of the opinion that for a long term planning horizon of 2020, the electricity growth will likely be in line with the AEO2006 and the longer term historic growth rate we have experienced in NJ. **Accordingly, we are projecting the electricity consumption of 99,728 GWH in 2020, a 1.52% annual growth rate**.

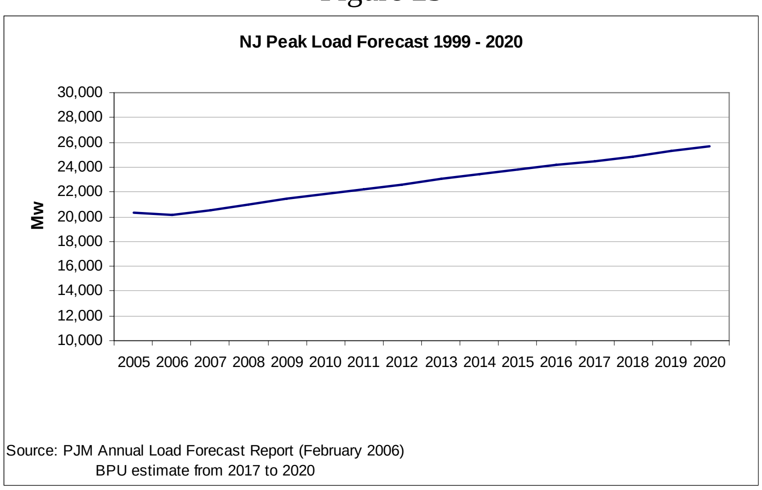
For peak load projection we have relied on the 2006 PJM load forecast issued in February 2006. Table 2 provides the summer peak loads for the major NJ utilities. Since the PJM forecast provides the summer peak loads up to 2016, we have trended the NJ utility related data to provide 2020 projection.

Table 2: Summer Load Forecast (MW)

	Year	PSE&G	JCP&L	ACE	RECO	Total
PJM Projection	2005	10,815	6,279	2,838	435	20,367
	2006	10,701	6,335	2,679	417	20,132
	2007	10,841	6,509	2,736	421	20,507
	2008	11,121	6,676	2,788	429	21,014
	2009	11,304	6,839	2,837	433	21,413
	2010	11,485	7,002	2,890	438	21,815
	2011	11,662	7,164	2,935	442	22,203
	2012	11,791	7,341	2,984	447	22,563
	2013	12,044	7,491	3,032	453	23,020
	2014	12,246	7,658	3,076	457	23,437
	2015	12,401	7,801	3,121	462	23,785
	2016	12,566	7,944	3,158	466	24,134
BPU Projection	2017	**12,732**	**8,116**	**3,186**	**468**	**24,502**
	2018	**12,909**	**8,274**	**3,227**	**472**	**24,882**
	2019	**13,086**	**8,433**	**3,267**	**476**	**25,263**
	2020	**13,263**	**8,591**	**3,308**	**480**	**25,643**

Figure 25 provides a graph of the summer peak load projection to 2020. By 2020 the total NJ peak load is projected to be 25,643 MW. With the projected energy demand of 99,728 GWH in 2020 the statewide load factor is projected to be 44.4%.

Figure 25



Irrespective of the accuracy of the projections, it is important from a planning perspective to understand the magnitude of the supply requirements to meet the projected demand. The current energy supplies that meet today's demands will not meet the future demand without additional supplies (both conventional and renewable) and energy efficiency measures. The need for more generation in the future will depend in part on how much energy demand is curbed by energy efficiency measures implemented now and in the future. Meeting this growth in demand requires policymakers to consider additional electric energy supply within New Jersey, and possibly additional investments in infrastructure and energy efficiency. Concerns such as public health, environmental stewardship, volatile and increasing fossil fuel prices, national security, and economic development need to be addressed in formulating prospective energy policies. New energy investments require significant time and capital. Investments in new power plants or transmission lines, for example, are essentially commitments to current technologies and facilities for many decades. As the energy landscape changes, the electric energy industry will have to strive to remain as flexible as possible. Nevertheless, making new infrastructure investments may be necessary to provide the reliable energy services required for New Jersey's well-being. Infrastructure investments, whether in generation, transmission, or distribution, require some sort of permitting or regulatory approval and ultimately acceptance from the public both for the type and site for the new infrastructure. Most siting decisions are made at the local or State level, which often leads to community opposition at grassroots levels and possibly also in the judicial system.[12] Due to several factors in New Jersey including environmental, safety, and health concerns related to nuclear energy and fossil fuels, desire to protect the integrity of forest and wildlife areas, and the challenge of locating new infrastructure in a State with the densest population in the country, this public acceptance should not be taken for granted by policymakers in the State. New Jersey and the region have a variety of renewable energy resources that should be considered a potential part of its electricity fuel mix.

In summary, key elements for an understanding of the issues facing New Jersey are manifold.

- Electricity usage is projected to increase from 78.342 million MWhs in 2004 to 99.728 million MWhs in 2020, without additional energy efficiency efforts. Under Governor Corzine's campaign proposal to reduce total projected demand by 20 % by 2020, a reduction in annual usage of 19.946 million MWhs will be required in 2020 to reach the target of 79.782 million MWhs.

- The New Jersey Board of Public Utilities has made a commitment to renewable energy resources with the adoption of a Renewable Portfolio Standard. Under the current RPS, by 2020, 20% of the LSE[13] sales must come from Class I Renewable Energy Resources and 2.5% of the LSE sales must come from Class II Renewable Energy Resources. Under the current solar carve out provisions[14] some 2% of the LSE sales must come from Class I Solar Electric Generation. The 2020 projected sales imputed after accounting for onsite use (0.953 million MWhs) of onsite generation is estimated at 78.829 million MWhs. The 2020 projected requirement for

[12] Park, Hyunsoo and Clinton Andrews. City Planning and Energy Use. Encyclopedia of Energy, Volume 1. 2004. 1-14.
[13] LSE means Load Serving Entity
[14] See http://www.bpu.state.nj.us/wwwroot/secretary/14-8-2rps.pdf

Class I Renewable Energy Resource is 15.766 million MWhs. Of the 15.766 million MWhs of Class I generation, some 1.5766 million MWhs must be procured from solar electric generation. To meet this solar electric generation requirement some 1577 MW of solar capacity[15] will have to be installed by the end of 2019. The projected Class II Renewable Energy Resource is 1.971 million MWhs for a total RPS requirement of 17.737 million MWhs.

- The balance of the electricity requirements, including non renewable onsite generation for onsite use, of some 62.045 million MWhs, must then be procured from conventional sources including imports from PJM. Electricity is generated from a variety of fuels and sources. In New Jersey, the single largest component of the supply mix being nuclear, the potential retirement of the Oyster Creek Nuclear Plant and other plants will affect the generating capacity within the State, requiring more energy to be imported from other states within the PJM region, and possibly necessitating new generation and transmission capacity to be constructed. Transmission of electricity requires infrastructure that is subject to limitations in the amount of electricity it can transport. Load pockets, within which LMPs are often higher due to congestion in transmission, are common in New Jersey, especially in the eastern portion of the State and need to be addressed. Renewable energy resources can often be installed in or near load pockets, thus lessening the impact of long transmission distances and costs associated with congestion.

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[15] Based on 1000MWh/MW solar electricity production.