The Ability to Meet Future Gas Demands from Electricity Generation in New York State

Final Report

Prepared for

New York State Energy Research and Development Authority

and

New York Independent System Operator

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EXECUTIVE SUMMARY

ES 1. BACKGROUND, STUDY FRAMEWORK, AND ASSUMPTIONS

This report documents the results of the analysis undertaken by Charles River Associates (CRA) as part of the New York State Energy Research and Development Authority (NYSERDA)/New York State Independent System Operator (NYISO) Gas and Electric Study. The study was initiated to address concerns about the adequacy of the New York gas delivery infrastructure for simultaneously meeting traditional gas demands and future gas demands for electric generation. These concerns have stemmed from existing delivery constraints in the downstate region, forecasted demand growth among traditional gas consumers, and the expectation that gas demands among the electric generation sector will grow rapidly as new gas-fired power plants are built to support increasing electric demands.

- Prior to autumn 2001, no substantial pipeline expansions had been built in New York since the Iroquois addition in 1991. The Energy Information Administration (EIA) has noted that, as a result of this limited supply expansion and substantial gas demand growth, downstate gas deliveries in the New York City area have approached their throughput limits.[1]

- At the same time, substantial amounts of new gas-fired electric generation capacity have been proposed for New York; complete applications for siting approval have been filed for new generation projects totaling almost 10,000 MW.[2]

This study has examined the ability to meet electric loads under a range of pipeline expansion and new generating capacity scenarios, in light of this potential mismatch between total gas demands for electric generation and the adequacy of the gas delivery infrastructure for meeting those demands. A few key aspects of the New York gas and electric systems are important for understanding how future gas and electric demands will be met in each of these scenarios.

- Substantial expansion of the New York pipeline infrastructure is already underway. With projects that have recently been completed or are expected to be completed by the end of 2003, a total of 465 thousand dekatherms (MDT) per day of new delivery capacity will be available into the downstate region. This additional capacity represents a 7 percent increase in delivery capacity to the State and a 16 percent increase into the downstate region, and exceeds forecasted growth in nongeneration gas demands through at least 2005.

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1 "Status of Natural Gas Pipeline System Capacity Entering the 2000-2001 Heating Season," EIA *Natural Gas Monthly*, October 2000; *Natural Gas Transportation—Infrastructure Issues and Operational Trends*, EIA Natural Gas Division, October 2001.

2 New York Department of Public Service, Summary of Article X Cases, 7 June 2002. Available at http://www.dps.state.ny.us/xtable.PDF

- In addition to the 465 MDT per day of expansions already being added, the Federal Energy Regulatory Commission (FERC) has provisionally approved projects that could provide a total of approximately 800 MDT per day, primarily to the downstate region.

- Gas-fired, combined-cycle (CC) plants account for almost 90 percent of the new electric generating capacity proposed for New York. These CC units are substantially more efficient than existing gas-fired steam units. For each British thermal unit (Btu) of gas, a new CC unit can produce about 50 percent more electricity than a steam unit. Hence, the presence of these units will increase gas demands only if generation from existing units burning other fuels or imports from other regions are displaced; if generation from less efficient gas-fired units is displaced, gas demands will *decrease*, ceteris paribus. New units are most likely to displace non-gas-fired generation during winter periods when gas delivery capacity has been unavailable to generators and steam units have opted to burn residual oil. In the summer, when more gas has been used for generation historically, new gas-fired units are more likely to replace generation from less-efficient, existing gas-fired units.

- The ability to burn oil in electric generators has been and continues to be important to the reliable operation of the New York electric system. A substantial amount of oil has been used to meet electric loads both in the winter months when gas supplies to electric generators have been limited, and in the summer to comply with reliability rules (in order to protect against the sudden loss of gas supply to New York City). The importance of oil is that it provides an alternative, locally stored fuel option, or "local Btu storage," that can be used when gas is unavailable or uneconomic for electric generation. The ability to store and burn oil is and will be important, even in the absence of any electric load growth and/or generating capacity additions. Although the combination of oil and gas pipeline capacity has allowed current and historical electric demands to be met, pipeline capacity would not have been sufficient if the ability to store and burn oil for electric generation had been substantially diminished.

Recognizing the importance of local Btu storage, we have assumed that electric generators will be able to burn oil at a scale comparable to historical levels. We are then able to estimate gas use and the extent to which oil needs to be burned in various electric capacity addition and pipeline expansion scenarios. This approach identifies a range of combinations of local Btu storage and gas delivery capacity that are sufficient to meet the fuel supply needs of the electric system and illustrates the resulting trade-off between local fuel storage and pipeline capacity.

Our analytical approach involves estimating both what we have termed "maximum potential gas demands for electric generation," and gas and oil use among electric generators under a range of pipeline expansion scenarios. The maximum potential gas demands are calculated by assuming that there are no deliverability constraints limiting the amount of gas used for electric generation. These demands represent the amount of gas generators would choose to consume if gas were always available at an attractive price relative to residual and distillate oil. For each pipeline scenario, estimated gas use, which accounts for gas delivery constraints to generating units, is calculated by assuming that generators will always burn gas if the pipeline system is able to deliver it. Correspondingly, the amounts of oil used for electric generation are calculated by assuming generators will only burn oil during those periods when the gas delivery capacity has been fully utilized. Hence, these estimates are not a prediction of expected fuel use.

Our analysis has focused primarily on the year 2005. Our scenarios for that year are defined by electric capacity additions and gas pipeline expansions:

- On the electric side, our analysis includes three generation capacity addition scenarios. All scenarios include 527 MW of new capacity assumed to come on line during summer 2002. Additionally the three scenarios include 1,030 MW, 1,780 MW, or 4,435 MW of net capacity additions over the 2003-2005 time period (4,435 MW is an amount corresponding to the assumptions used in the analysis supporting the December 2001 Draft New York State Energy Plan (NYSEP), updated to reflect changes in the status of some projects[3]). Total installed capacity in each of the addition scenarios is sufficient to satisfy New York Control Area (NYCA) installed capacity requirements (including locational requirements).

- On the gas side, all of our scenarios include the 465 MDT per day of pipeline capacity created by projects that will be in place by the end of 2003. In addition to this capacity, our pipeline cases include expansions that provide between 0 and 800 MDT per day into downstate New York (800 MDT per day represents the approximate total of the pipeline expansions into downstate New York with provisional FERC approval).

In addition to 2005, we have also examined cases for the years 2002 and 2010. Our 2002 case, which provides a baseline characterization of the gas and electric system performance, includes only new generation and pipeline capacity that is already operating or is under construction with expected completion dates in 2002. Our 2010 cases cover the same range of pipeline expansions as the 2005 scenarios (described above), and all 2010 cases include new generating capacity additions during the 2003–2010 period totaling 5,015 MW.

A few additional key assumptions were imposed in the integrated gas and electric analysis.

- Our analysis evaluated the *physical adequacy* of the New York gas delivery infrastructure for supplying the natural gas needs of both traditional gas users and electric generators, assuming liquid markets exist for both gas supplies and pipeline capacity.[4]

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3 In addition to the planned new electric generating units included in the Draft NYSEP assumptions, additional units that, as of April 2002, had either received Article X approval, or involved repowering or expansion of units on existing plant sites were included in the 4,435 MW case. The set of units included in each of the electric capacity cases was selected with the guidance of NYSERDA and the NYISO.

4 The defined scope of work for this project was to assess the adequacy of the gas delivery infrastructure to support future natural gas demands (both for electric generation and nonpower needs). However, actual gas deliveries to power plants depend on the generators' willingness and ability to purchase their desired level of gas supply and pipeline/LDC delivery service through contractual commitments (either daily/spot, short-term, or long-term). It is possible that another party (either within New York or outside of the State) could contract for the pipeline capacity needed by the New York electric generators. If that party places a higher value on the

- Gas demands for electric generation were assumed to be supplied only after nonpower demands were met.

- Since several of the pipelines serving New York also serve New England, it was necessary to account for the capacity on those pipes used to serve New England gas demands. For each year analyzed, pipeline flows between New York and New England were estimated starting with historical flows, and adjusting for expected future supply and demand conditions in New England. In our analysis, the capacity required for meeting New England demands was accounted for and could not be reduced for the purpose of meeting gas demands in New York.

- Pipeline capacity and other delivery limits within individual local distribution companies (LDCs) were not modeled.

- Normal winter weather was assumed for the purpose of estimating the amount of pipeline capacity needed to serve nongeneration demands for gas. A design winter scenario was also analyzed to assess the impact of an extremely cold winter.

- We assumed fuel demands for dual-fueled electric generators would be met with natural gas when delivery capacity is available, and oil would only be burned in these units if pipeline capacity were fully utilized.

- As noted above, we examined a range of electric generation capacity addition and retirement scenarios. We did not explicitly model the economic decisions of generation owners and developers to build new capacity or retire existing units. Hence, existing gas- and/or oil-fired steam units were retired only if they were replaced as part of repowering projects at existing sites (*e.g.*, Astoria and Albany units).

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capacity (in either daily/spot, short-term, or long-term markets) than the New York generators do, the capacity may no longer be available to meet the requirements of the New York generators.

ES 2. PRINCIPAL FINDINGS AND ANALYTICAL RESULTS

Our analysis has generated three principle conclusions. First, with the addition of 465 MDT per day of pipeline capacity assumed to be in place by November 2003, New York will have sufficient gas delivery capacity to supply the amounts of gas required for generation under all 2005 generation and post-2003 pipeline addition scenarios, provided the existing ability to burn oil is maintained. For each new generation capacity scenario, there is a range of feasible combinations of gas pipeline additions and oil burning capability that allows the fuel needs of electric generators to be met. This range of combinations illustrates the trade-off between gas pipeline capacity and local Btu storage. There are advantages and disadvantages associated with each.

- Pipeline capacity additions of between 300 MDT per day and 800 MDT per day (beyond the 465 MDT per day) would provide additional benefits to the electricity and natural gas systems, including enabling the use of larger quantities of cleaner-burning natural gas and the potential for better contingency protection.

- The more natural gas pipeline capacity built and used to serve electricity generation, the more dependent the electric system is on natural gas availability and the more exposed it is to natural gas price volatility.

Second, as noted above, the ability to burn oil for electric generation has been and continues to be an important substitute for natural gas in the operation of the electric system in New York. The ability to burn oil requires having oil-capable units available (either steam units or combined-cycles), along with sufficient local storage capacity and environmental/operating permits (that allow units to run on oil). If the ability to burn oil is substantially diminished, more pipeline capacity will be needed to support the needs of electric generators. Similarly, if pipeline capacity is not expanded, the ability to burn oil will remain critical for meeting electricity demands. Policies that affect either the ability to burn oil in electric generators or the ability of pipelines to expand delivery capacity need to recognize this trade-off.

Finally, for the range of generation addition scenarios analyzed in this study, there is enough proposed new pipeline capacity with provisional FERC approval to allow the maximum potential gas demands of generators to be delivered. Additionally, under the pipeline scenarios in which the maximum potential gas demands could not be fully met, a substantial portion of this maximum potential amount could still be delivered, but the use of fuel oil would continue to be required to meet electric demands. However, the total projected 2005 NYCA oil burn, in all cases analyzed, would be less than the historical amount actually burned in either 2000 or 2001. The amount of this new pipeline capacity that will be needed for electric generation needs depends on the amount of gas-fired generating capacity that is actually built and the extent to which the ability to burn oil is maintained.

The integrated gas and electric analysis produced several key analytical results.

- The statewide maximum potential gas demand for electric generation is higher in all 2005 cases than in the corresponding cases for 2002. This result is due to growth in electric loads as well as the presence of more base-load, gas-fired generation.

- Comparing the projected fuel use across capacity-addition scenarios shows that for a given level of pipeline capacity, gas deliveries typically decrease when a larger amount of new electric generation capacity is added. As more CC units are added in the downstate area, the limited amount of gas available in those areas is able to support more generation due to the relative efficiency of the new units. Hence, less electric generation is needed from other areas, and less total gas is consumed.

- The efficiency advantage of new CCs also lowers the need for generation from steam units fueled by residual oil. As a result, oil use generally also declines as more new generators are added.

- Pipeline expansions totaling 800 MDT per day into the downstate area are sufficient to meet the maximum potential demands of generators (*i.e.*, gas deliveries to generators are never restricted, so there is no need to burn oil) in the case with the most new electric capacity (4,435 MW). Fewer pipeline expansions are needed to meet the maximum potential demands if less new generation capacity is added. In the case with 1,780 MW added, only 500 MDT per day is required; in the case with 1,030 MW, 400 MDT per day is sufficient to meet the maximum potential gas requirements.

- Our case for 2010 shows that annual fuel demands among gas-fired and dual-fueled generators will increase approximately 20 percent between 2005 and 2010. This substantial increase in generation reflects the fact that existing base load units (nuclear, coal, and hydro) are already operating near full capacity in 2005. Hence, incremental electric load growth will need to be met either by new CCs or by existing steam units that have traditionally operated at low annual utilization levels. The 2010 maximum potential gas demand of generators can be met with 800 MDT per day of pipeline expansions into the downstate region.

- In an unusually cold winter in which nongeneration gas demands reached the design day requirements of the LDCs, less gas would be available for electric generation. As a result, either more oil would need to be burned by electric generators, or additional pipeline capacity would be required to meet electric loads. In a design winter, for gas-fired generators to be able operate at a level similar to what we have estimated for a normal 2005 winter, between 100 and 160 MDT per day of additional pipeline capacity would be required.[5]

[5] The exact amount would depend on the amount of interruptible gas transmission capacity that would be curtailed.

ES 3. GAS AND ELECTRIC SYSTEM RISKS AND UNCERTAINTIES

While our analysis indicates that the gas and electric systems can reliably meet their future loads under a range of electric generation and gas pipeline expansion scenarios, oil use by electric generators remains a key substitute for gas during times of peak gas demands (*e.g.*, cold winter days). This is particularly true during extreme winter weather conditions. For example, in 2005 under normal winter weather conditions, if 4,435 MW of generation capacity is added along with 300 MDT per day of post 2003 pipeline expansion, gas pipeline capacity into the downstate market is adequate to satisfy 89 percent of the total potential winter gas demand for electric generation.[6] Under design winter conditions, where the temperature sensitive gas load can increase between 10 and 20 percent (depending on the LDC), the gas available for electric generation declines substantially. In this case, only 70 percent of total potential winter gas demand for electric generation is met, compared to 89 percent in the normal weather case. Lower levels of gas use will require offsetting increases in oil-fired generation to ensure that electricity demands are fully met. Alternatively, as noted above, gas-fired generators could operate at a level similar to what we have estimated for a normal 2005 winter if between 100 and 160 MDT per day of additional pipeline capacity were added.

As discussed above, dual-fueled electric generators regularly switch from gas to oil in response to high gas prices and/or the unavailability of gas. This switching capability is an economic alternative to building fixed pipeline capacity to fully meet peak gas loads that only occur on a limited number of winter days (*e.g.*, 10–15 days per heating season). Fuel switching by electric generators provides the same type of relief to the gas system as do the interruption of deliveries to interruptible customers and the use of liquefied natural gas (LNG) by LDCs. Hence, maintaining that capability is critical to ensuring that the electric and gas systems can reliably meet the future needs of their customers. To the extent that residual oil-capable steam units are removed from service as new, more efficient combined-cycle generating units are added, one of two things will need to take place to ensure that gas and electric customer needs are met. Either pipeline capacity will need to be expanded, or the new combined cycles will need to be capable of burning oil at a scale comparable to the historical burn levels of oil-capable steam units.

Higher than expected electric demands pose another potential risk to the gas and electric system. However, our finding that the gas and electric systems can reliably meet their future loads across the range of scenarios included in our analysis holds true, even with higher electric loads. In a 2005 case with extreme weather loads (defined as an increase in both peak demand and annual energy requirements consistent with the extreme weather peak forecast reported in the NYISO Gold Book[7]) and 4,435 MW of new capacity, electric loads can be met under all pipeline addition scenarios. However, slightly more oil needs to be burned by electric generators in each corresponding pipeline scenario.

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6 As explained above, oil-fired generation is used to for the remaining 11% of total fuel needs to ensure that electric needs are fully met.

7 See New York Independent System Operator, *2001 Load and Capacity Data* (Gold Book), pp. 4–5.

Our analysis has not attempted to identify the amount of pipeline expansion that is likely to occur in New York. However, our results do illustrate how seasonality in electricity demands and nongeneration gas loads may limit the incentive for generators to contract for firm capacity. The willingness of generators to enter firm contracts is critical for pipeline/LDC expansions, as regulatory approval for these projects will require sufficient contractual commitments from purchasers of capacity to cover the pipeline construction costs.

Our analysis has shown that gas deliveries to electric generators may be constrained often in the winter, but only rarely in the summer. The resulting dilemma facing owners of new CC units as they consider their gas supply options is that the entire year-round cost of firm gas delivery contracts would need to be justified by their desire to secure gas supplies in the winter. In order for the generators to be willing to enter into firm gas transmission capacity contracts, winter prices in the electricity market would need to be high enough to fully compensate the generators for the cost of securing firm capacity. Given that electricity prices and spark spreads[8] are typically lower in the winter than in the summer, and electricity prices may be in-effect capped by the generation cost of steam units burning residual oil during the winter, owners of combined-cycle units may not have an incentive to contract for firm, year-round capacity.

8 The spark spread is the difference between the cost of electricity and the cost of converting natural gas to electricity.

INTRODUCTION

This report documents the results of CRA's analysis of the ability of the natural gas delivery system to meet future electricity generation requirements in New York State. The analysis, which has been undertaken as part of the NYSERDA/NYISO Gas and Electric Study, integrates the modeling of the gas demands of New York electric generators, with the modeling of available gas supply and delivery capacity to the State. By integrating gas demand estimates from a detailed model of the electric system with a characterization of gas supplies from a detailed model of the gas delivery system, we are able to characterize the location, extent, and duration of New York gas and oil use under a variety of conditions.

The study was initiated to address concerns about the adequacy of the New York gas delivery infrastructure for simultaneously meeting traditional gas demands and future gas demands for electric generation. These concerns have stemmed from existing delivery constraints in the downstate region, forecasted demand growth among traditional gas consumers, and the expectation that gas demands among the electric generation sector will grow rapidly as new gas-fired power plants are built to support increasing electric demands.

- Prior to autumn 2001, no substantial pipeline expansions had been built in New York since the Iroquois addition in 1991. The Energy Information Administration (EIA) has noted that, as a result of this limited supply expansion and substantial gas demand growth, downstate gas deliveries in the New York City area have approached their throughput limits.[9]

- At the same time, substantial amounts of new gas-fired electric generation capacity have been proposed for New York; complete applications for siting approval have been filed for new generation projects totaling almost 10,000 MW.[10]

In light of the potential mismatch between total gas demands for electric generation and the adequacy of the gas delivery infrastructure for meeting those demands, this study has examined the ability to meet electric loads under a range of gas pipeline expansion and new electric generating capacity scenarios.

The report begins with a discussion of the conceptual framework for assessing pipeline adequacy. The discussion focuses on the determinants of generators' gas demands, the determinants of the gas supply available to meet those demands, and the potential causes of gas shortages stemming from supply and demand imbalances.

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9 "Status of Natural Gas Pipeline System Capacity Entering the 2000–2001 Heating Season," EIA *Natural Gas Monthly*, October 2000; *Natural Gas Transportation—Infrastructure Issues and Operational Trends*, EIA Natural Gas Division, October 2001.

10 New York Department of Public Service, Summary of Article X Cases, 7 June 2002. Available at http://www.dps.state.ny.us/xtable.PDF

The integrated electric and gas modeling approach is described in the second chapter of this report. Our approach utilizes separate models for the electric and gas systems. Consistent equilibrium solutions are obtained by iterating between the two models. The third chapter contains a detailed discussion of the basic factors that drive our integrated modeling efforts. The scenarios are defined along with the institutional and regulatory structure that provides the basis for the analysis.

The fourth and fifth chapters present the results of the analysis. The total fuel demands by gas capable electric generating capacity are outlined in chapter four. These total fuel demands represent the initial outputs from the electricity model and were calculated assuming no restrictions on gas deliveries. As such they represent the maximum potential gas demand for electric generation and are inputs to the gas system model. Chapter five presents the results of the integrated gas and electric modeling. Gas and oil use for electricity generation is presented for each of the cases and years analyzed. Historical usage patterns are presented as a reference point and reliability considerations are identified.

1. CONCEPTUAL FRAMEWORK FOR ASSESSING PIPELINE ADEQUACY

Assessing the ability of the gas delivery infrastructure to meet future gas demands for electricity generation requires understanding:

- The range of potential gas requirements for electric generation under various electric load conditions.
- How this range is affected by electric load growth and the addition of new electric generation capacity.
- The extent to which potential gas requirements for electric generation can be met with various levels of gas delivery capacity.
- The economic determinants of generators' fuel use decisions.
- The economic determinants of available gas deliverability and future pipeline capacity expansions.
- Potential causes of gas shortages stemming from supply and demand imbalances that prevent the minimum gas demand needed to meet electric load from being supplied.

This chapter begins with a conceptual discussion of each of these issues and then outlines the framework with which each is addressed in this study. For readers unfamiliar with the gas and electricity infrastructure in New York State, background information is provided in Appendix A.

1.1 DETERMINANTS OF GENERATOR GAS DEMANDS

Gas is burned by several different types of electric generators in the NYCA:

- Steam Generators – which use either gas or residual oil to fire boilers (approximately 11,000 MW). The majority of gas-capable NYCA steam units have the ability to burn gas or residual oil (commonly referred to as "dual-fuel" units), while a small portion (approximately 560 MW) are only capable of burning natural gas.
- Combustion Turbines – which use either gas or distillate oil (approximately 2,800 MW).
- Combined Cycle Gas Turbines – which use either gas or distillate oil (approximately 3,100 MW).

The generators and their primary and secondary fuels are listed in the *Load & Capacity Data* Report, commonly referred to as the "Gold Book."[11]

The extent to which gas-capable generators (either those units that can only burn gas, or units that can burn either gas or oil) will be dispatched to meet electric loads and their resulting gas demands are determined primarily by the mix of generators available to sell into the electric market, fuel prices facing each type of generator, operative environmental regulations including the cost of emissions allowances, and the demand for electricity. These factors combine to form a demand curve, or range of potential gas demands for each generator. Where in that range the actual demand will fall is a function of the gas price (including both commodity and transportation costs), the price of residual oil, the price of distillate oil and the resulting economic decision of the generation owner.

To illustrate this decision, consider the following simple example. If a generator is able to obtain delivered gas at a relatively low price, it will be willing to sell into the electric market at a correspondingly low output price, which is reflected in the generator's bid into the market. If electric demand is such that this bid is below the market clearing electric price, the generator will be dispatched and, as a result, contribute to the aggregate demand for gas. If delivered gas is only available at a much higher price such that if the unit burns gas, its dispatch cost will be above the dispatch cost of other, nongas units that are available as substitutes, the owner will not be willing to sell its output at the market clearing price and the generator will either not run or will burn a lower-cost fuel.

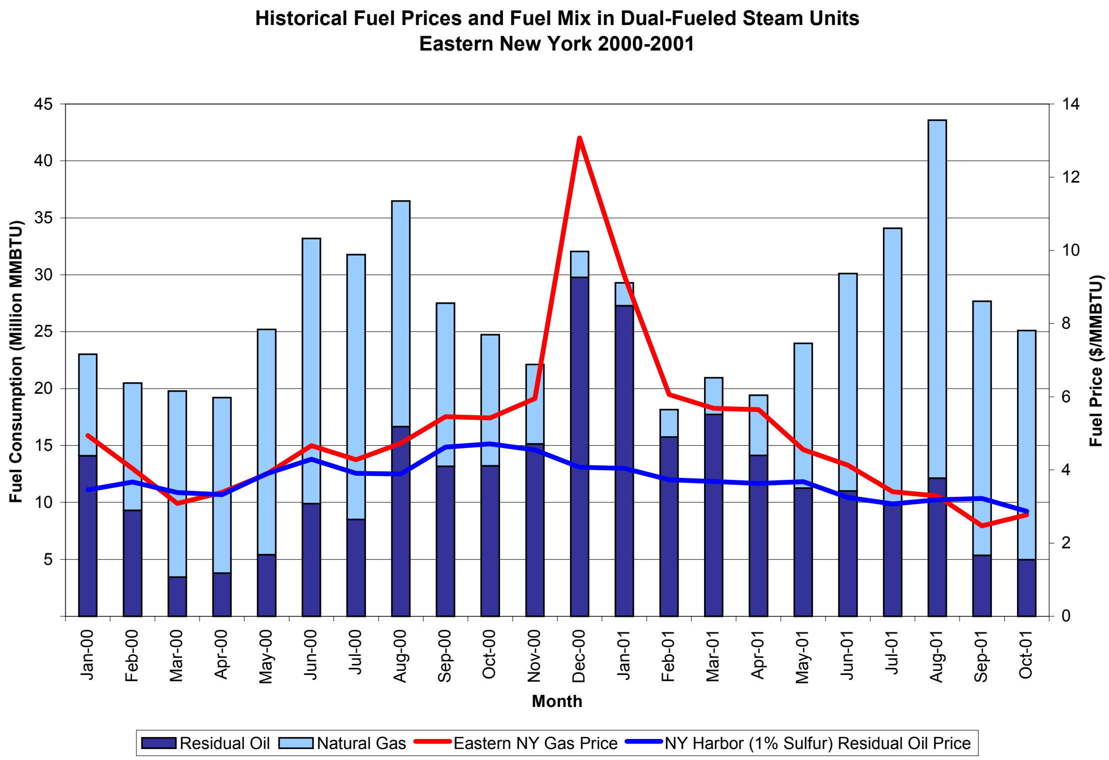
This example shows the two types of decisions made by the operators of gas-capable generators. First, they will choose to burn whatever fuel is available at the lowest cost. Second, they will choose whether or not to sell into the electric market at the market-clearing price. If delivered gas prices are low, more gas-fired generators will run and dual-fueled units will opt to run on gas. When the gas price is high relative to oil, dual-fuel units will opt to burn oil to the extent it is available and gas-fired units without the ability to burn alternative fuels may be displaced by oil-burning units.

Such economic decisions by generators in New York have led to substantial variation in the mix of gas and oil used for generation. This variation in fuel mix is illustrated in Figures 1 and 2, which show fuel prices and the corresponding amount of gas and oil burned by dual-fueled steam units in eastern New York. The red line on Figure 1 represents the gas price and the blue line represents the oil price. Each bar shows the total amount of gas and oil burned; the dark portion on the bottom represents oil and the lighter portion on top represents gas. These data show two interesting facts. First, these units have burned substantial amounts of both gas and oil during all seasons of the year, implying that some gas has been available in the winter and that oil has been economically attractive during some summer months. Second, the graph shows that when gas

[11] This report is prepared by the NYISO and filed with the New York State Energy Planning Board in compliance with the regulations pursuant to Section 6-106 of the New York State Energy Law.

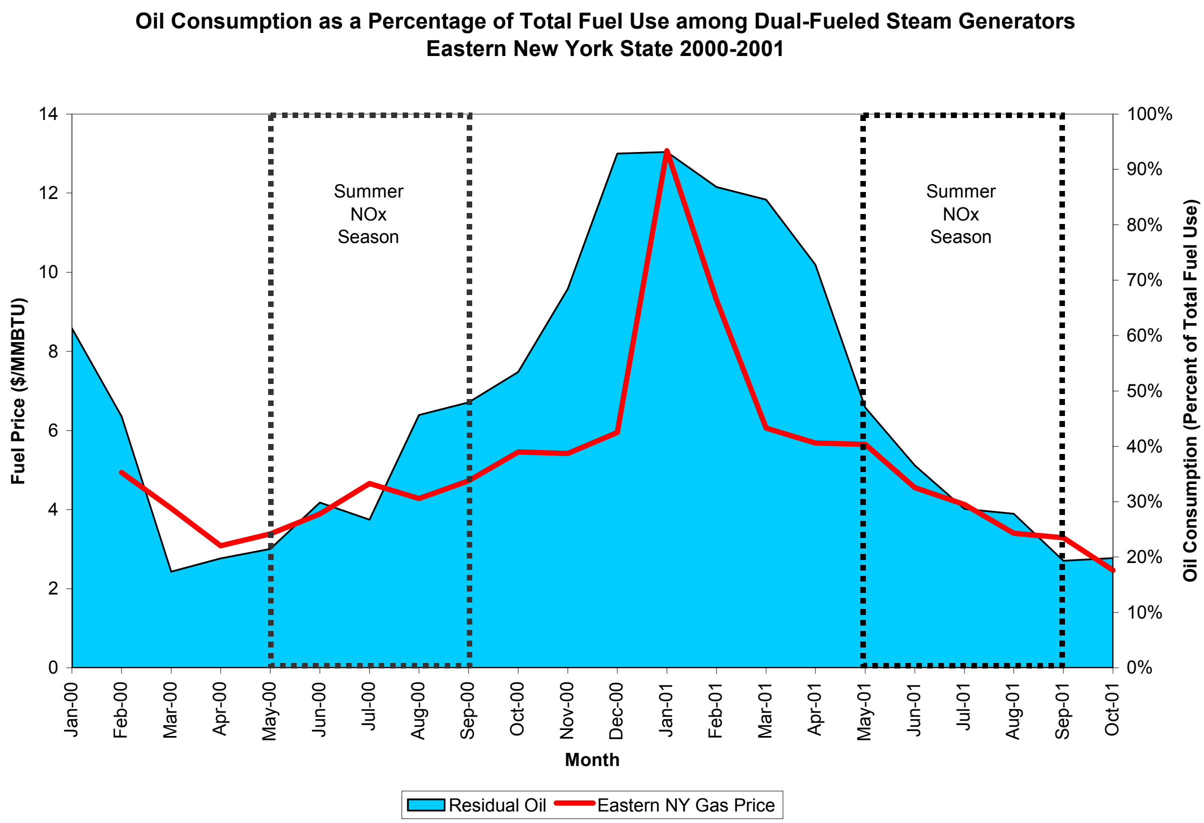
prices have risen, as in late 2000 and early 2001, generators have made the economic decision to burn oil.

Figure 1



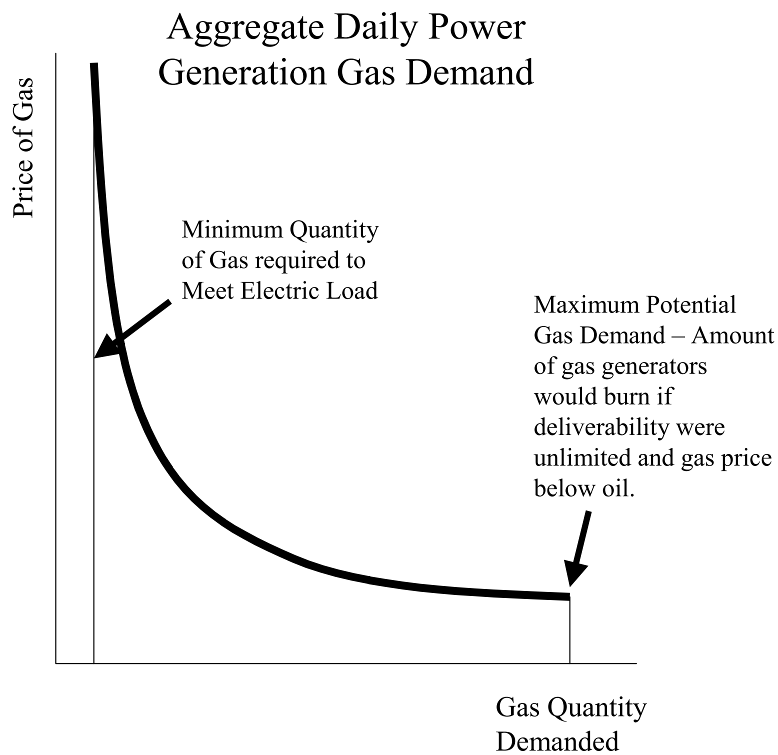
This economic decision to burn oil when gas prices rise can be clearly seen in Figure 2, which shows oil as a percentage of total fuel burn in dual-fuel units. These historical data illustrate that New York generators have made economic decisions to burn oil when gas prices have been high, even during periods when environmental regulations make it costly to burn oil. When gas prices were at their highest level at the end of 2000, more than 90 percent of the fuel used in dual-fueled steam units was residual oil. Furthermore, substantial amounts of oil were burned even during the summer months, when nitrogen oxides (NO_X) regulations apply.

Figure 2



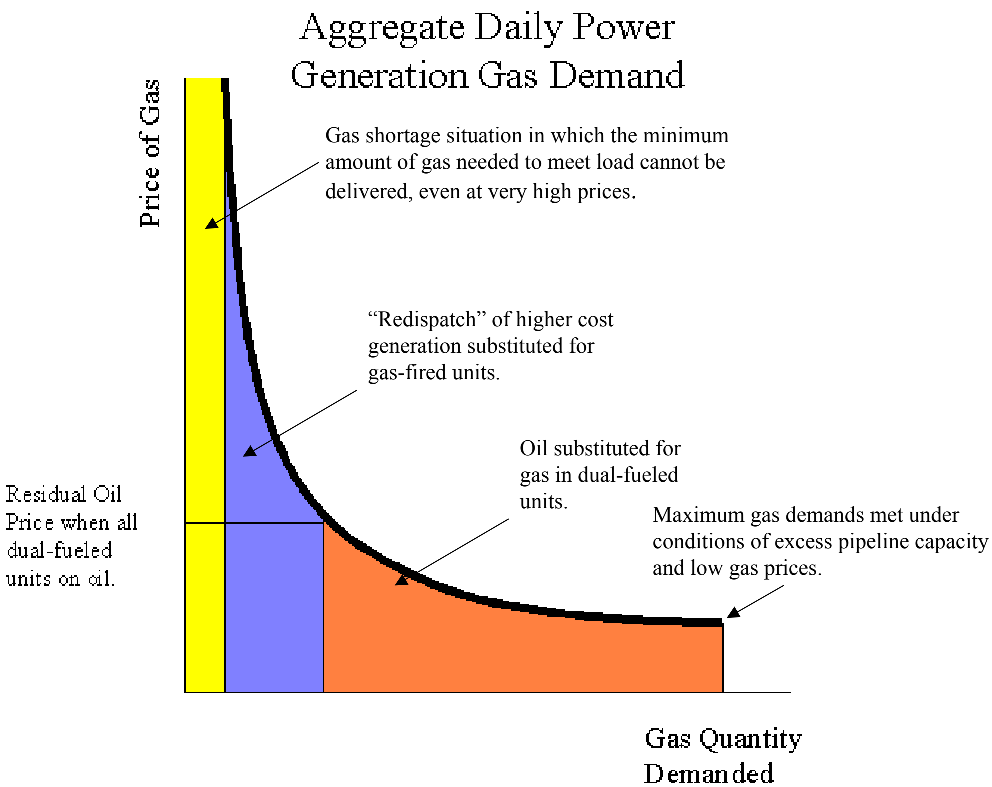
The range of potential gas demands among generators and the economic decisions about fuel use made by plant operators can be conceptualized in a demand curve, as depicted in Figure 3.

Figure 3



The end points of the demand curve define the range of potential gas use. The point at the far right corresponds to a situation where the delivered gas price is relatively low, so that gas-fired generators are dispatched before oil-burning units and dual-fueled units opt to burn gas. Throughout this report, we refer to this point as "maximum potential" or "unrestricted" gas demand. The far left end of the demand curve represents the minimum amount of gas that is needed to meet electric loads. If electricity supply is sufficiently tight that load cannot be met without gas-fired units, the owners of these units will be willing to pay a higher price for gas, which they can then recover through higher electric prices (*e.g.*, California gas and electricity markets in the winter of 2000–2001). As delivered gas prices rise, substitutes become more attractive and the quantity of gas demanded by generators drops from its maximum potential level. This substitution is depicted in Figure 4.

Figure 4



First, when the gas price rises to the cost of burning residual oil (including any related environmental costs), dual-fueled steam units will substitute residual oil for gas. If the gas price increases enough, residual-oil-burning steam units will become more economic than gas-fired, combined-cycle units (CCs) and gas demands will be further reduced as these units are displaced. This displacement represents a different form of substitution; buyers in the electric market turn to substitutes for gas-fired generation. Additional substitution occurs if the gas price rises above the level at which all residual-fired units are dispatched, as higher-cost, non-gas-fired units, such as oil-fired peakers or imports from other areas (which may include high fees for losses or wheeling), will be more economic than gas-fired CCs and displace additional gas demands.

If the delivered gas price rises very high and the quantity demanded by generators still exceeds the available supply of gas, a shortage exists and electric loads will not be met. A sustained imbalance between gas supply and generators' demand occurs when gas demands are in or near this region for some period or periods during the year, even under normal electric and gas operating conditions (extreme circumstances that lead to such shortages will be addressed in a later, contingency analysis, phase of this study). Note, however, that the economic responses of generators to changes in the gas price may create periods when generating units, which would run on gas if supply were abundant and the price low, either do not run or switch to oil. Such periods do not represent shortages or sustained mismatches between supply and demand. Rather, they simply reflect the market outcome and the economic decisions made by competitive generators—the type of market response illustrated by New York generators in the historical data shown in Figures 1 and 2.

The amount of gas-fired generation that is needed to meet electric loads, and for which a shortage in the gas market will occur if its gas requirements are not met, will vary with load and generator availability. During high load times, the minimum amount of gas-fired generation required will be higher, which means more gas supply is needed to avoid shortages (*i.e.*, the size of the yellow area in Figure 4 is highest in peak load periods). During lower load periods, it may be the case that no gas-fired generation is needed, so that the demand curve for gas actually touches the price axis (y-axis) and the yellow region disappears. Similarly, minimum gas requirements will increase and decrease with the amount of nongas generation that is on outage.

Because this study is focused on the ability to meet future gas demands, which occur in years when new power plants are expected to be in operation, it is also important to understand how new gas-fired, CC units will affect the range of potential gas demands. As CC units are added, they have two counteracting effects on gas demands. First, because theses units are predominantly fueled by gas and are relatively efficient, they will tend to displace more costly generation, some of which is not gas-fired. As a result, under many load conditions, new CCs will increase maximum potential gas demands. For example, consider the summer peak period in eastern New York. Much of the installed generating capacity is needed, including oil-fired steam units and many oil-fired gas turbines (GTs). When more CC capacity is in place and gas is available at a low price, the oil-fired steam units and GTs will not need to run as much, meaning their generation, which is oil-fired, will have been replaced by gas-fired CCs, increasing both the total potential gas demand for electric generation. If the high-cost, oil-fired units whose generation is displaced by new CCs are retired, the minimum gas requirements for the electric generation sector will also increase.

The second effect of adding new CCs is a consequence of their relative efficiency. Because CCs are able to generate at a lower heat rate than steam units or simple cycle turbines (peaking units), if all else is equal, having them available may lower the minimum gas requirements for meeting electric load. For example, suppose that 100 MW of gas-fired generation is needed to meet electric demands for an hour. If a GT with a 10,500 Btu/kWh heat rate supplies this 100 MW, 1,050 MMBtu of gas will be needed for that hour. However, if a CC with a 7,000 Btu/kWh heat rate is available, it can supply the necessary 100 MW while burning only 700 MMBtu of gas.

1.2 DETERMINANTS OF GAS SUPPLY AND TRANSMISSION CAPACITY FOR GENERATION

The economic decisions by generators purchasing fuel provides a means by which gas suppliers can effectively ration limited delivery capacity. If delivery is not constrained, competition among gas transportation suppliers will keep prices relatively low so that generators (and other gas purchasers) will be able to buy as much gas as they want at a relatively low price that reflects only the commodity and incremental transportation costs of gas (but no additional margin). However, if pipeline capacity is fully utilized so that deliverability to additional gas customers is constrained, delivered gas prices will rise to ration limited delivery capacity. The market will reach equilibrium when the delivered price is just high enough that gas demands fall to the level that can be supplied when the gas delivery system is fully utilized.

Several factors, including the economics of building pipeline expansions, seasonal variation in nonpower gas demands, and institutional and regulatory factors make it unlikely that maximum potential gas demands for electric generation will always be fulfilled. Generators could contract for firm delivery capacity and avoid fluctuations in the availability and price of transportation. However, the existing incentives for generators generally do not favor buying firm gas transportation capacity. The lack of incentive for generators to buy firm transportation capacity in turn prevents pipelines from building the full amount of additional capacity that would be needed to serve generators' full potential demands.

Although the largest driver of forecasted growth in natural gas demand over the next decade is the electric power generation sector, the economic interests of the owners of new power plants are not always aligned with the pipelines' interest in expanding pipeline capacity. Clearly, in the long run, new power plants will require new pipelines (or pipeline expansions) to supply their fuel. However, in the short term, many generators can acquire adequate capacity in the active secondary market, at a cost that is often much lower than the costs of firm capacity on a pipeline expansion or new pipeline.

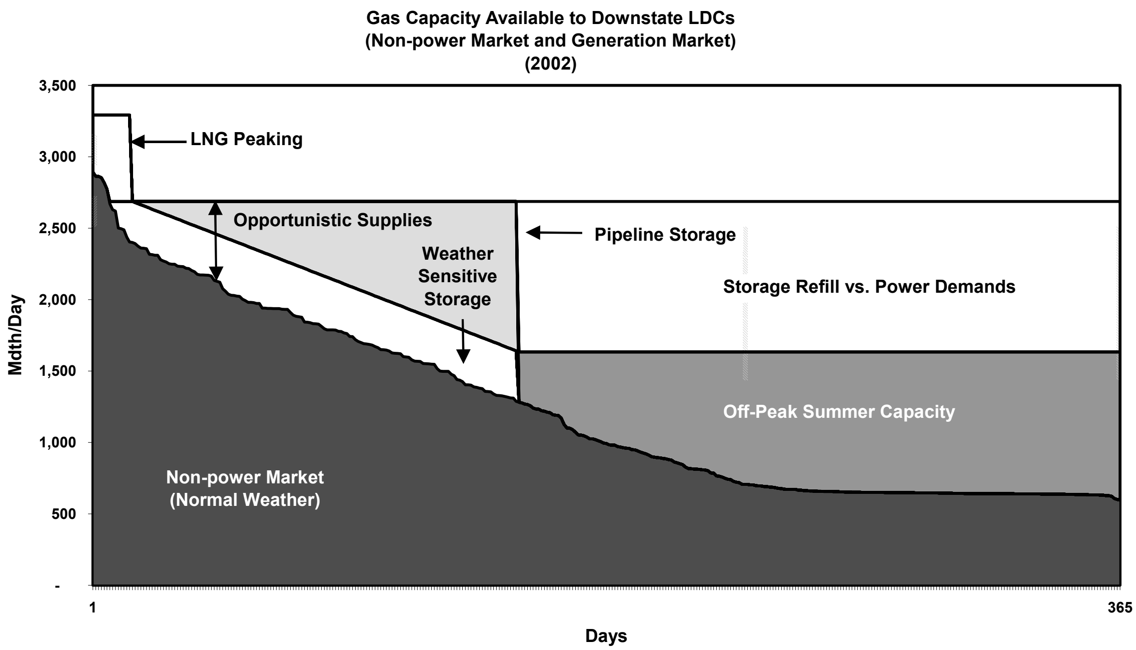
The traditional dual-fuel steam electric generation units in New York have burned gas when it was available and the price was economic. Experience indicates that gas has been readily available in the summer and randomly available in the winter (depending on weather). As discussed in the previous section, these units have switched between gas and oil as dictated by economic conditions.

In contrast, the new CC units being installed throughout the Northeast have been designed to be primarily fired by gas (with occasional distillate oil backup for some projects and no backup capability for others). The plants that have environmental permits to burn distillate oil as an alternate fuel to gas are typically restricted to no more than 720 hours of distillate operation per year. As New York (and the Northeast in general) is a winter-peaking gas area, there is generally substantial surplus pipeline capacity in the summer, although some of this capacity is necessarily used to fill winter storage needs. Given their operational efficiency, the CCs would reasonably expect to be dispatched ahead of the large installed base of steam electric units as long as their efficiency advantages (generally around 50 percent) were not offset by a price disadvantage relative to residual fuel oil (the same 50 percent).

There are different "risks" associated with relying on the secondary market for pipeline capacity instead of contracting for firm gas transportation service. The secondary released capacity market is often not firm, with capacity being subject to recall by its longer-term owner. In the primary pipeline direct market, the firm contract holder is the primary owner. However, the time when the power plant may be most interested in assuring that it is dispatched (and thereby requiring fuel) is in the peak summer months when it is likely that the spark spread or "profit" for a MWh would be the highest. This is the same time that the pipeline capacity is most likely to be available and at lowest cost. During the peak winter months, electric prices are typically lower, gas pipeline capacity is more expensive (if available at all), and the generator's MWh "profit" will be at its lowest.

This seasonal fluctuation in pipeline utilization and available capacity is illustrated in Figure 5.

Figure 5



The chart shows a load duration curve for the nonpower generation market.[12] The relatively steep initial portion of the curve is due to the short period of very cold weather that occurs in a normal winter. Over the course of the winter, the daily demands for gas rise as the temperature falls. Utilities plan for this seasonal increase in load by purchasing storage services. Such storage services provide supplies that are much closer to the market than general pipeline supply by virtue of the supplies having been transported from the production areas to the market areas during the lower demand periods in the summer. During a normal weather year, LDCs in New York serve their firm customers and transportation customers[13] with firm pipeline supplies supplemented by winter storage services and local LNG supplies.[14]

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[12] A load duration curve represents the daily deliveries to a market segment (in this case, the entire market, excluding power generation), ranked from the peak day send-out to the lowest daily delivery.

[13] Transportation customers are those customers that elect to only purchase delivery services from an LDC for gas that they have independently purchased from a third party. Either the third party or the customer is responsible for getting the gas delivered to the LDC's city gate facilities, where the LDC accepts the gas and delivers it to the customer's facility.

[14] The LNG supplies in NY are liquefied from pipeline supplies in the summer and placed into storage for the winter. It represents a very high deliverability source for a short period of time (approximately five days at the maximum withdrawal rates). Given the long time it takes to refill the storage tanks, it is generally only available for one cycle during the year.

The utilization of storage is a function of the weather and the relative economics of the cost of gas in storage compared to other alternate sources of supply. As such, LDCs must contract for sufficient gas to meet extreme weather conditions (*i.e.*, a "design winter") in order to meet their "obligation to serve." Given that design winters are rare occurrences, some of the capacity planned for use in such circumstances may then be "available" at other times. During random days in the winter, the weather may be relatively mild. Under such conditions, the pipeline capacity that would normally have carried the storage gas to market may alternatively be used to bring spot gas purchases to power plants if the economics are favorable. In very mild winters such as that in 2001–2002, these conditions may emerge quite often. We have labeled this capacity as "opportunistic supplies" for the power markets. It is important to note that power generators are not the only candidate for this capacity, as an LDC may elect to inject gas into storage to extend their storage supplies, sell the capacity and gas to "off-system" customers, or to interruptible customers within the LDC.

For generators that have dual-fuel capability (and the environmental permits to burn oil), the randomness of these supplies does not constitute a problem (except for a possible economic one). However, there is risk associated with counting on these supplies because the occurrence of a design winter[15] could effectively remove all such supplies from the spot market for the winter's duration. While electric generators face the risks that they will be unable to generate since these "opportunistic" supplies would not be available on the spot market, their "lost profits" are likely to be small. Relatively high delivered gas prices coupled with relatively low electricity prices result in winter spark spreads that are typically small.

When the winter season is over, two blocks of potential pipeline capacity open up for power generators—off-peak summer capacity and storage refill capacity. The off-peak summer capacity is typically available for most of the summer at prices that are often quite favorable. This capacity provides a substantial portion of the capacity that is used by generators for the summer. In addition, there is the capacity that is typically used to refill storage fields in the summer. The availability of this capacity is not assured but rather depends on several conditions.

If the previous winter was quite cold, then the storage fields (or local LNG facility) may be effectively depleted—requiring a substantial amount of injection over most of the summer (as injection rates are lower than withdrawal rates). Given the need for LDCs to have adequate supplies to meet their firm delivery obligation in the winter, low storage inventories in the spring create considerable pressure on the market to utilize a portion of the gas transmission capacity to refill the storage fields. High gas and transportation prices may create some reluctance to do this, but as the summer wears on, the need to replenish the supplies becomes stronger.

High storage inventories at the end of the winter heating season (such as currently exist) can free up the pipeline capacity market a great deal, augmenting the off-peak market substantially. This same situation occurs whenever the storage market slows down. It is the availability of this

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[15] A design winter is a winter that is significantly colder than a normal winter (*i.e.*, 10 to 15 percent colder on average than the normal winter. The normal winter is generally based on 30-year averages.

transportation capacity at very low costs (when gas prices are also often low) that supports the high demand for gas by generators in the summer. The fact that gas prices and gas transportation costs are often at their lowest when electric prices are at their peak allows generators to earn substantial margins without the need to contract for firm gas pipeline capacity.

Since gas transmission capacity is typically available at low costs when it is most valuable to generators (summer) and typically unavailable when it is least valuable (winter), there is little incentive for the generator to contract for firm gas transmission capacity. However, without firm capacity contracts in hand, a pipeline is unlikely to receive FERC approval for the project. It is only when a generator perceives that the pipeline market will be sufficiently "tight" when it would be profitable for the generator to run, that the generator would enter into a firm agreement for its overall gas transmission capacity. Otherwise, a generator would likely opt to rely heavily on the secondary market or, as is the case for one of the new generation projects in New York, contracting for less than 50 percent of their total gas requirements.

This divergence of interests makes pipeline expansion projects problematic, particularly in the Northeast where there is substantial existing oil-fired electric generating capacity that would be available to meet electricity demand when gas prices are high and/or gas deliverability is restricted. In the event that the contracts are in hand, most pipeline projects can be in place in a timely fashion. Thus, over the long term, there is unlikely to be any systemic shortages of gas for the power sector, from an economic perspective. However, we would expect that this "economic" amount of gas transmission capacity would, necessarily, result in situations where the delivered price of gas rises to levels that make it economic to meet electricity demands with oil-fired generation instead of gas-fired generation.

Given that gas transmission capacity is available on a short-term spot basis (*i.e.*, released capacity), merchant electric generators have little incentive to purchase firm gas transmission capacity unless the expected costs are similar (adjusting for the relative risks). To date, in the NYCA, market-released capacity during the summer months has been readily available at costs below those that would be paid to obtain firm service directly from the pipeline. For example, for the first quarter of 2002, the average discount on Tennessee Gas pipeline was 36 percent of the full tariff rate.[16]

1.3 Framework for Analysis

Because both generator gas demands and pipeline/LDC deliverability are determined to a large extent by the amount of new generating capacity that is added and the extent of pipeline expansions, we have modeled a range of electricity and gas expansion cases. Because of the economic and regulatory uncertainty surrounding the addition of new gas and electric infrastructure, this study does not explicitly address the amount of new gas or electric capacity

[16] Source: Tennessee Gas pipeline Web site for released capacity.

that is needed or is likely to be built in New York.[17] Rather we determine whether any of the scenarios analyzed leads to a sustained imbalance between gas demand by electric generators and gas delivery capacity.

Our study framework also recognizes that the ability to burn oil in electric generators has been and continues to be important to the reliable operation of the New York electric system. A substantial amount of oil has been used to meet electric loads both in the winter months, when gas supplies to electric generators have been limited, and in the summer to comply with reliability rules (in order to protect against the sudden loss of gas supply to New York City). The importance of oil is that it provides an alternative, locally stored fuel option, or "local Btu storage." Even in the absence of any electric load growth and/or generating capacity additions, pipeline capacity would not be sufficient to allow electric demands to be met if the ability to store and burn oil for electric generation were substantially diminished.

Recognizing the importance of local Btu storage, we have assumed that electric generators will be able to burn oil at a scale comparable to historical levels. We are then able to estimate gas use and the extent to which oil needs to be burned in various electric capacity addition and pipeline expansion scenarios. This approach identifies a range of combinations of local Btu storage and gas delivery capacity that are sufficient to meet the fuel supply needs of the electric system and illustrates the resulting trade-off between local fuel storage and pipeline capacity.
The goal of our analysis of generator gas demands and the corresponding deliveries by pipelines and LDCs is to identify:

- For each generating capacity scenario, the range of potential gas demand for generation and where in that range actual deliveries will fall under various pipeline expansion scenarios.

- Whether conditions exist under which gas delivery capacity is so limited that a shortage results because minimum gas requirements for meeting electric load cannot be fully supplied.

- The number of days on which the maximum potential gas demands for electric generation can be met and the percentage of the total annual potential demands that are met.

Our approach utilizes separate models for the electric and gas systems. Consistent equilibrium solutions are obtained by iterating between the two models. The General Electric Multi-Area Production Simulation (GE MAPS) model is used to simulate operation of the Northeast regional electric system.[18] The New York gas transportation system is modeled using a GRIDNET-based

[17] All of the electric capacity expansion scenarios exceed the NYCA locational and statewide installed capacity requirements. In addition, the MAPS modeling accounts for required spinning and non-spinning operating reserves.

[18] The GE MAPS model is a Multi-Area Production Simulation (MAPS), which simulates the hourly operation of the electric generation and transmission system, including the impacts of transmission constraints and operating reserve requirements. The model minimizes the total system cost of meeting forecasted electricity demands given key economic and engineering assumptions (*e.g.*, fuel costs, heat rates, etc.) for electric generating units.

model. The appendices to this report provide more detailed descriptions of both models, along with an overview of the gas and electric infrastructures serving New York.

Our iterative modeling approach begins with estimating the maximum potential gas demands for each day of the year using the GE MAPS model. The MAPS model performs an hourly commitment and dispatch of the electric system, assuming that gas-fired generators are able to purchase gas at a relatively low price (below that of residual oil) and obtain their full, or maximum potential, unrestricted demands.

The hourly fuel demands for each electric generating unit are summed by day to obtain the corresponding daily demands, which are fed into the gas model. The gas model is then dispatched to see what portion of the maximum total potential gas demands can be met, given pipeline and LDC deliverability. If the maximum potential gas demands cannot be met, generating units are recommitted and/or redispatched using the GE MAPS model or, in the case of dual-fuel steam units, simply switched to oil until the level of gas demands matches available gas supplies for each gas delivery node.

If there are any days when the gas system is unable to meet the minimum gas requirements for generation (*i.e.*, if all non-gas-fired generating capacity is in operation and gas-fired generation must then operate to meet electric load in any electric load pockets), those days are identified as a shortage situation in which electric load cannot be met.

This approach allows us to identify:

- Maximum potential amount of gas that generators would consume if deliverability were never constrained.

- Days on which these full, unrestricted demands will not be met and some redispatch to oil-fired units or units in another location will be required.

- The total amount of gas and oil burned in each pipeline/capacity addition scenario.

- The amount of pipeline capacity expansion needed to fully meet maximum potential gas demands.

- The number of days during which CCs are likely to run on gas under various levels of pipeline expansion.

The detailed modeling results for each generating unit can be aggregated (over time and by geographic area) to characterize overall gas and electric system performance.

2. INTEGRATED ELECTRIC/GAS MODELING METHODOLOGY

We describe our integrated modeling approach in this chapter. The description includes a discussion of key assumptions and a description of the analytical steps that we employed. The chapter closes with an overview of the integrated model structure.

2.1 ANALYTICAL FRAMEWORK AND ASSUMPTIONS

Our analyses are designed to evaluate the physical ability of the electric and gas systems to simultaneously meet their demands. Electricity demands were analyzed on an hourly basis, while gas demands were analyzed on a daily basis. Hourly fuel demands (gas or oil) for each individual generating unit were summed to provide total daily fuel demand. Total daily gas demands for electric generation were added to total daily gas demands for nonelectric generation to obtain the combined total simultaneous daily gas requirements.

The gas system's ability to meet the total daily gas delivery requirements (the sum of nonelectric and electric requirements) was then evaluated. The ability of the gas infrastructure to meet normal hourly fluctuations in electric system fuel requirements, as well as rapid ramp-ups and ramp-downs, was not explicitly modeled in this phase of the analysis. Nor was analysis performed on the ability of the gas infrastructure to handle peak hour demands. However, as will be discussed in section 4.3 of this report, hourly fluctuations in future electric system fuel requirements are similar to historical fluctuations that have been met by the existing gas pipeline and LDC systems. Likewise, future peak hourly demands are assumed to be similar to those experienced in the recent past. Hence, we believe that the results from the daily analyses are representative of the results that would be obtained from a more detailed hourly gas system analysis.

We have not addressed the price and cost implications of various outcomes. For example, we do not attempt to estimate the level of future locational electric energy prices and associated locational capacity prices that would result under various electric generation expansion cases and/or gas system expansions. Hence, our analysis does not support conclusions about the economic feasibility of the cases, or the overall impacts on the costs to meet statewide electric and gas demands.

Our integrated analysis relies on a few key assumptions and simplifications.

- Our analysis evaluates the *physical adequacy* of the New York gas delivery infrastructure for supplying the natural gas needs of both traditional gas users and electric generators, assuming liquid markets exist for both gas supplies and pipeline capacity.[19]

[19] The defined scope of work for this project was to assess the adequacy of the gas delivery infrastructure to support future natural gas demands (both for electric generation and nonpower needs). However, actual gas deliveries to power plants depend on the generators' willingness and ability to purchase their desired level of gas supply and pipeline/LDC delivery service through contractual commitments (either daily/spot, short-term, or long-term). It is possible that another party (either within New York or outside of the State) could contract for the pipeline capacity needed by the New York electric generators. If that party places a higher value on the

- Traditional LDC gas demands to meet traditional gas customer requirements (residential, commercial, industrial, and transportation) have priority over gas demanded for electric generation. Hence, those LDC demands are always met first in our modeling.

- We have not modeled the interaction between gas and oil prices directly in a single integrated model of electricity and gas markets. Rather, we have modeled the interactions using an iterative process that models gas demands for electricity generation under a set of simplifying assumptions:

  – Gas is always preferred to distillate as a generating fuel in new combined cycles.

  – Gas is preferred to residual oil in dual-fuel steam units.

  – Given the heat rate advantage of new combined cycles, their gas demands are met before competing gas demands from higher heat rate steam units.

- Similarly, we have not modeled the interaction between residual oil and distillate. As an alternative, we assume that the relative prices for distillate and residual oil make residual oil in steam units a lower-cost option than distillate fired in a new combined cycle. (Historical data indicate that this condition is generally true.)

- We assume fuel demands for dual-fueled electric generators would be met with natural gas when delivery capacity is available, and oil would only be burned in these units if pipeline capacity were fully utilized and gas was not available.

- Since several of the pipelines serving New York also serve New England, it was necessary to account for the capacity on those pipes used to serve New England gas demands. For each year analyzed, pipeline flows between New York and New England were estimated starting with historical flows, and adjusting for expected future supply and demand conditions in New England. In our analysis, the capacity required for meeting New England demands was accounted for and could not be reduced for the purpose of meeting gas demands in New York.

- Pipeline capacity and other delivery limits within individual LDCs have not been modeled.

- Normal winter weather is assumed for the purpose of estimating the amount of pipeline capacity needed to serve nongeneration demands for gas. A design winter scenario is also analyzed to assess the impact of an extremely cold winter.

As noted above, we examined a range of electric generation capacity addition and retirement scenarios. We did not explicitly model the economic decisions of generation owners and

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capacity (in either daily/spot, short-term, or long-term markets) than the New York generators do, the capacity may no longer be available to meet the requirements of the New York generators.

developers to build new capacity or retire existing units. Hence, existing gas- and/or oil-fired steam units were retired only if they were replaced as part of repowering projects at existing sites (*e.g.*, Astoria and Albany units).

Our approach establishes a clear hierarchy for assessing the feasibility of simultaneously meeting electric and gas system demands. Traditional gas demands are met first. Remaining available gas supplies, if deliverable, are used for electric generation at the units, as determined from the GE MAPS modeling. If there is insufficient gas to meet the locational demand for gas from those units, substitution options are evaluated. We consider the options in the following priority:

- Step 1—Fuel switching at those dual-fuel steam units that were operating in the MAPS dispatch. These units are assumed to switch to residual oil. If switching these units to residual oil reduces the gas requirements to a level that can be met by the gas system, we have a solution that meets electric load (since these units were running in the MAPS dispatch) with available gas supplies.

- Step 2—If Step 1 does not reduce gas demand sufficiently (*i.e.*, the total demand from gas-only steam units and combined cycles cannot be met) available, uncommitted oil-capable steam units are brought on line to meet electricity requirements.[20] Since the MAPS model accounts for transmission constraints, rerunning the model with the oil-capable units on line establishes whether those units can feasibly meet locational electricity demands.[21] If the uncommitted oil-capable capacity can meet electric requirements, we have a feasible outcome.

- Step 3—In Steps 1 and 2, we limit substitute units to those located in the NYCA. If there is insufficient non-gas-fired capability in the NYCA, we are left with two options for meeting NYCA electricity requirements:

  - Replacement generation from neighboring regions. Since we have not modeled gas system performance in neighboring regions, we assume that replacement generation must come from available units that do not use gas. We limit the replacement generation to non-gas-fired units as the most restrictive assumption. This would be the case when the constraints affecting gas delivery in the NYCA also affect marginal deliveries to adjacent markets. Further, the electric transmission system must be capable of delivering the replacement generation to meet NYCA loads.

  - The substitution of distillate oil for gas at those new combined cycle units that have that capability.

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[20] While we recognize that several of the new combined cycle units are being constructed with oil-backup capabilities, given our simplifying assumptions, oil-fired steam units are a preferred option to the use of backup by these units (historical oil price data indicate that this option would have been lower cost in most months).

[21] For example, oil-capable units outside of New York City could not feasibly replace in-city, gas-fired capacity when there is congestion into the city. The transmission constraints in the MAPS model ensure that replacement generation can, in fact, meet locational demands.

2.2 Overview of Integrated Model Structure

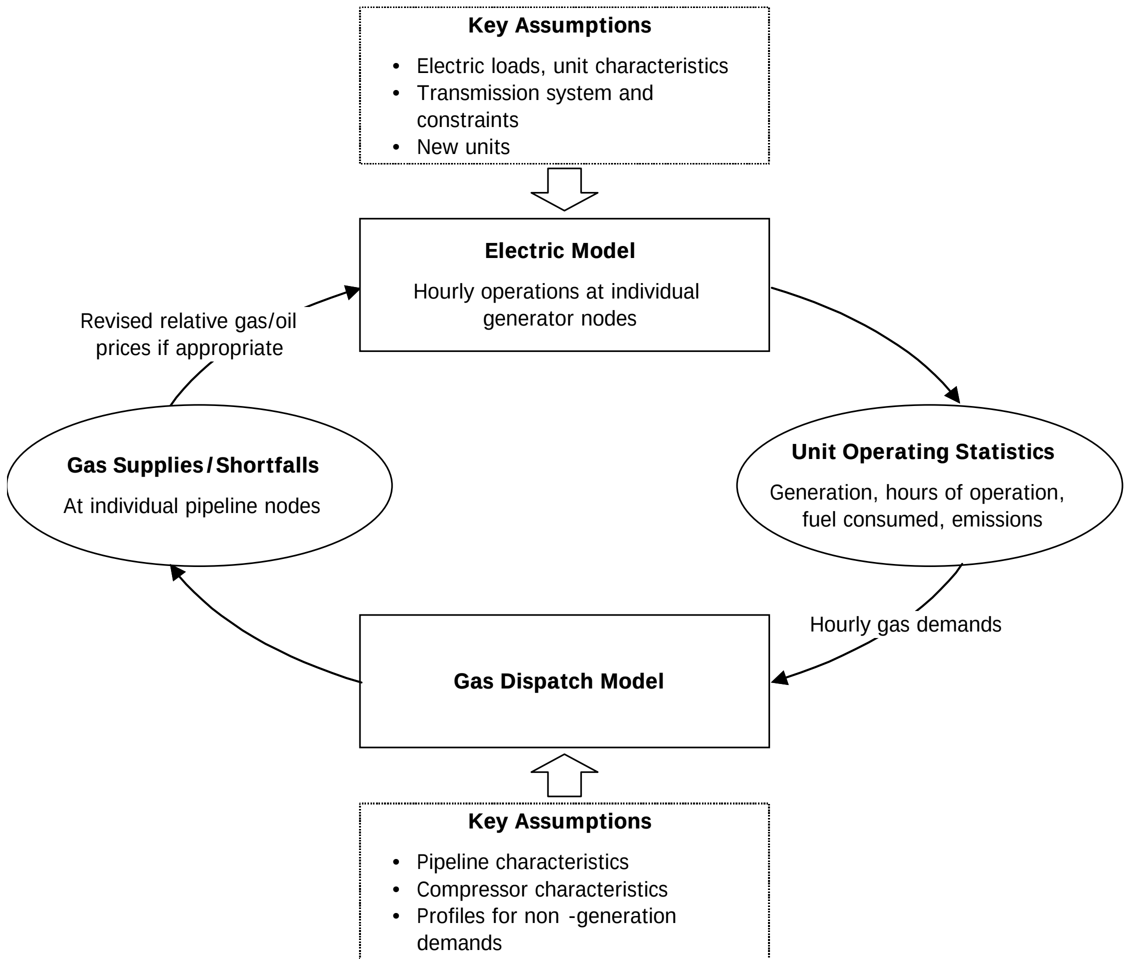
Our integrated electric/gas modeling takes selected outputs from the GE MAPS model and feeds them into our gas system dispatch model. As illustrated in Figure 6 below, for a given set of assumptions, the electricity model determines the operating profiles for all generating units, including the hourly demands for fuel. Hourly demands are summed to create daily totals for each generating unit, which are input to the gas model.

The total daily demands for fuel by gas capable units are used in the gas dispatch model, which matches daily gas supplies to traditional gas LDC demands and the demands for gas to fire electric generators. Daily gas supplies and shortfalls are identified for each appropriate pipeline node. If the gas system cannot meet the demands of electric generators, the electric generating resources are recommitted—removing those units that would not be able to receive gas—and redispatched to meet electric loads.

The recommitment and redispatch are accomplished through iterations between the gas model and the MAPS electric system model. The results of the gas dispatch model (*i.e.*, those gas units whose daily fuel demands cannot be met by the gas system) are incorporated as inputs to the second iteration of the MAPS model. The MAPS model is rerun to see if electric loads can be met, given restricted gas availability, by recommitting and redispatching the entire electric system subject to the same transmission constraints and operating requirements used in the initial MAPS run.

Figure 6

Overview of Modeling Approach



3. DESCRIPTION OF ELECTRIC AND GAS SYSTEM ANALYSES

This chapter outlines the structure of our approach to the integrated electric/gas system analysis. In addition, it provides an overview of the institutional and regulatory factors affecting electric and gas market behavior. The chapter closes with a discussion of how the market fundamentals (*i.e.*, electric load growth and generation technology) must necessarily drive the results of our analyses.

3.1 DEFINITION OF SCENARIOS

Our integrated analyses have been designed to identify and characterize sustained imbalances between total gas demand (for electric generation and all other uses) and the ability of the gas delivery infrastructure to facilitate meeting those demands. The results of this analysis will provide a basis for identifying fundamental imbalances between energy demands and supplies—given assumed electricity and gas demands, electric and gas transmission system expansions, and new generation capacity additions.

Our gas and electric modeling has covered a range of potential electric and gas system conditions. Given that our analysis is conducted at a detailed level—utilizing hourly and daily analysis for individual locations throughout the NYCA and adjacent regions (electrically)—each analysis must be conducted independently for each modeling scenario and year.

Our analysis has focused primary on the year 2005. Our scenarios for that year are defined by electric capacity additions and gas pipeline expansions.

- On the electric side, our analysis includes three generation capacity addition scenarios. All scenarios include 527 MW of new capacity assumed to come on line during summer 2002. Additionally the three scenarios include 1,030 MW, 1,780 MW, or 4,435 MW of net capacity additions over the 2003–2005 time period (4,435 MW is an amount corresponding to the assumptions used in the analysis supporting the December 2001 Draft NYSEP, updated to reflect changes in the status of some projects). Total installed capacity in each of the addition scenarios is sufficient to satisfy NYCA installed capacity requirements (including locational requirements).

- On the gas side, all of our scenarios include 465 MDT per day of pipeline capacity created by projects that have recently been completed or will be in place by the end of 2003.[22] In addition to this capacity, our pipeline cases include expansions that provide between 0 and 800 MDT per day into downstate New York (800 MDT per day, represents the approximate total of the pipeline expansions into downstate New York with provisional FERC approval).

[22] These projects include (1) Transcontinental Gas Pipeline's Phase I Market Link project (completed in 2001) that added 115 MDT per day into the downstate market, (2) the 70 MDT per day Iroquois expansion to service the Athens project, (3) 50 MDT per day of additional capacity to the downstate market, and (4) the Iroquois Pipelines' Eastchester expansion of 230 MDT.

We have also examined cases for the years 2002 and 2010. Our 2002 case, which provides a baseline characterization of the gas and electric system performance, includes only new generation and pipeline capacity that is already operating or is under construction with expected completion dates in 2002. Our 2010 cases cover the same range of pipeline expansions as the 2005 scenarios, and all cases include new generating capacity additions during the 2003–2010 period totaling 5015 MW.

3.2 INSTITUTIONAL AND REGULATORY BACKGROUND

Market, institutional and regulatory factors will influence exactly how future gas and electric demands will be met, as described below. The extent to which new infrastructure will be added and existing infrastructure retired will depend on factors such as siting and environmental approvals, approval of tariff rates, and economic viability of projects. In addition, the rules and operating requirements of both the gas electric markets/systems must be understood before one can characterize how the gas and electric systems will be integrated to meet future electricity and gas demands. Several competing factors drive the expansion of the electric and gas systems.

- **Electric System Expansions—**Electric system expansion is taking place within the competitive wholesale market structure. It is being accomplished primarily through the addition of new generating capacity, with only limited expansion of electricity transmission capabilities almost solely through unregulated entities. New generating capacity is virtually all gas-fired, with only a portion of the new capacity having oil-fired back up capability. Independent merchant generators are responsible for the vast majority of new construction, particularly in the NYCA. Since new generation is being constructed outside of the traditional rate base regulated environment, the economic viability of this generation is driven by market forces within the context of local wholesale market rules (*e.g.*, NYISO, ISO-NE or PJM). Generators earn revenues through the sale of various electric products (*e.g.*, energy, capacity, and various forms of ancillary services).

- **Gas Transmission System Expansions—**Unlike electric generation, natural gas production is very concentrated geographically, necessitating long interstate transmission pipelines to deliver the gas to market, particularly to markets in the Northeast. These interstate and international gas pipelines are a highly regulated contract carriage business. Transmission rates (prices) in the United States, regulated by the FERC, are typically based on costs. As such, any pipeline expansion project is also subject to approval by the FERC. Because of the potential impact on the prices paid by existing pipeline customers, an expansion project must meet the traditional public necessity criteria. Essentially, FERC must determine that the project will be socially beneficial, a criteria that covers not only the costs to be born by existing and future customers, but also the environmental impacts on society.

  In order to pass muster on these issues, pipelines typically have had to "prove" the need for the pipeline by demonstrating customer willingness to contract for capacity provided by the project. These may be the existing customers, but more often today, they are new, "incremental" customers, often merchant power plants. Depending on the nature of the "beneficiaries" of the project, the costs may be rolled into existing rates where they are born by all customers or they are allocated to the "new" customers who must pay the incremental (marginal) costs of the expansion. The narrower the class of beneficiaries, the more heated the economic and environment debates are likely to be, making it more difficult to construct.

3.3 BASIC DRIVERS OF THE INTEGRATED ELECTRIC/GAS SYSTEM ANALYSIS

Future requirements for gas by electric generators in the NYCA will be driven by forecasted increases in electricity demands and the generators and fuel sources displaced by new capacity additions, including changes in NYCA electricity imports and exports.

- **Growth in Electricity Demand—**Given that NYCA electricity demands are forecasted to increase at modest rates over the next decade (*i.e.*, at annual rates of less than 1.5 percent) the amount of increase in gas requirements attributable to electric load growth, by itself, will be correspondingly small. For example, between 2002 and 2005 summer peak loads for the NYCA are forecasted to grow by approximately 1,000 MW, while annual energy requirements are forecasted to increase by 4,750 GWh. Given the amount of new CC capacity that will be built and the heat rate advantage that these units have over existing units, the growth in electricity demands is met almost completely by the new CCs. In this case, peak summer day gas requirements increase by .168 billion cubic feet (BCF) per day (the amount used by 1,000 MW of new CC capacity operating at full load for the day), and annual gas requirements would increase by 32.3 BCF per year. Put in context, the incremental requirements due to electric load growth represent only 2 percent of year 2005 total annual gas requirements in New York.

- **Heat Rate advantage of New CCs**—Given that the majority of downstate generation is currently supplied by gas-capable steam units (a total of 8,000 MW of existing gas-only and dual-fuel units), the heat rate advantage of new CCs is an important factor that drives future requirements for gas to meet electricity demands. New CCs have full load heat rates of approximately 7,000 Btu/kWh, while existing gas-fired steam units typically have heat rates between 10,000 and 11,000 Btu/kWh. Hence, new CCs will have a substantial cost advantage and will replace gas-fired and oil-fired steam units in the NYCA dispatch merit order. The variable generating costs of new CCs are slightly higher than those of existing coal-fired generation and substantially lower than those for existing steam gas and steam oil units.

The net impact of new CCs on future gas requirements in the NYCA results from the interaction of three factors:

- Increases in gas demands due to electricity load growth, as discussed above.

- Decreases in NYCA gas demand when new CCs replace generation that would have been supplied by existing, less-efficient units. When new CCs simply replace generation that would have been supplied by existing steam units using gas, daily gas requirements for electric generation will correspondingly be reduced. The heat rate advantage of new CCs relative to existing steam units allows them to generate approximately 50 percent more electricity with the same amount of gas.

- Increases in NYCA gas demands when new CCs replace generation from nongas fuel sources and/or imports. If new CCs replace generation that would have been supplied by any fuels (*e.g.*, oil or coal) or imports, gas requirements for electric generation in the NYCA would necessarily increase.

Hence the combined impact on future gas requirements of electricity load growth and the addition of new gas-fired electric generating capacity, cannot be determined without a detailed analysis of the competition among existing and new units in the electric marketplace, as discussed in the following chapter.

4. CHARACTERIZATION OF GAS DEMANDS OF ELECTRIC GENERATORS

The results of our electric system analysis are presented in this chapter. The discussion focuses on the fuel demands created by generators that burn either natural gas or oil (residual oil or distillate oil), or both gas and oil. For gas-capable units, these results represent the maximum potential demand for gas, as defined in the first chapter of this report. These maximum potential demands form the inputs to the gas model. As such, they are independent of the gas system's ability to deliver the desired amounts of gas. The results of our analysis of the gas systems' ability to meet total gas demands, and the resulting gas deliveries to electric generators are presented in Chapter 5.

In this chapter we outline how potential gas demands will change across years and scenarios. Electricity capacity additions are outlined in the first section of the chapter. The total fuel demands for gas and oil capable units, corresponding to each of the electricity capacity expansion scenarios, are presented next. The chapter closes with a discussion of the intra-day (hourly) gas demands created by the hourly operating patterns of gas-fired generation.

4.1 Electric Generation Capacity Expansion Scenarios

Our analysis has examined daily gas demands among electric generators and the corresponding ability of the gas system to meet those demands on a daily basis for five electric system conditions: three generation capacity addition cases for 2005, along with cases for 2002 and 2010. Our 2002 case includes all currently operating power plants along with new plants and upgrades to existing plants that are currently under construction and will commence operation during 2002. Our 2005 cases include 1,030 MW, 1,780 MW or 4,435 MW of new capacity, as shown in Table 1 below. For 2010, in addition to the new units included in the 2005 case with 4,435 MW, one additional CC plant was added on Long Island, for a total of 5,015 MW.[23]

The capacity additions in the 4,435 MW case correspond to those included in the new capacity assumptions used in the analysis supporting the December 2001 Draft NYSEP, updated to reflect the status of projects as of April 2002. This set of units includes all projects that have received Article X approval, as well as several repowering and/or expansion projects at existing sites. Merchant generating companies have encountered difficult economic conditions throughout the United States, and their financial performance has suffered substantially. The poor financial health of generating companies, coupled with relatively low futures prices for electricity, has lead companies to slow project development activities. This slowdown raises the likelihood that only a portion of those units receiving Article X approval will be constructed on their original schedule. To reflect the possibility that fewer units are constructed in the NYCA over the next few years, we also examined 2005 scenarios with fewer new generator additions. The set of units included in these cases is also shown in the table below. In the first of these cases, the

[23] Note that no additional capacity beyond the projects included in our 4,435 MW case is needed to meet the 2010 ICAP requirements.

Athens project (under construction) and East River project (interconnection facilities are under construction) were included along with the Ravenswood cogeneration facility and the planned expansion at the Poletti Station, for a total of 1,780 MW. The Ravenswood, East River, and Poletti projects were included to represent the proposed projects located in New York City. To date, these projects have not announced any delays in their planned in-service dates. Only the Athens and East River projects were included in the most restrictive case, for a total of 1,030 MW of net additions over the 2003–2005 period. Table 2 shows the NYCA load and reserve margin for each of these cases.

Table 1

Electric Generation Capacity Additions and Retirements

Unit Name	Status	Type	Installation Date	Retirement Date	Planned Summer Capacity (MW)	Capacity Included in 4,435 MW Case	Capacity Included in 1,780 MW Case	Capacity Included in 1,030 MW Case
Additions and Retirements Prior to 2003								
Astoria Unit 2	Operating	Steam (Oil)	6/1/00		171	171	171	171
Hudson Avenue 10/100 Unit	Operating	Steam (Oil)	6/1/01		60	60	60	60
Various Unit Upratings	Operating		6/1/01		165	165	165	165
NYPA Hell Gate	Operating	CT	6/1/01		80	80	80	80
NYPA Vernon	Operating	CT	6/1/01		80	80	80	80
NYPA Fox Hills	Operating	CT	6/1/01		44	44	44	44
NYPA 23rd Street	Operating	CT	6/1/01		80	80	80	80
NYPA Harlem Rail	Operating	CT	6/1/01		80	80	80	80
NYPA River Street	Operating	CT	6/1/01		44	44	44	44
Various Wind Projects	Operating	Wind	10/15/01		42	42	42	42
Carlson Addition	Under Construction	CT	1/15/02		39	39	39	39
NYPA Pilgrim State Hospital	Under Construction	CT	6/1/02		44	44	44	44
LIPA Additions	Under Construction	CT	6/1/02		360	360	360	360
Various Unit Upratings	Under Construction		6/1/02		123	123	123	123
Total Net Additions Prior to 2003						**1,412**	**1,412**	**1,412**
Additions and Retirements 2003-2005								
Miscellaneous Renewables	Planned	Wind	1/1/03		30	30	30	30
Ravenswood	Approved	CC	1/1/03		250	250	250	
Con Edison East River	Approved	Cogen	1/1/03		360	360	360	360
LIPA Additions	Under Construction	CT	6/1/03		160	160	160	160
Miscellaneous Renewables	Planned	Wind	6/1/03		45	45	45	45
Waterside 6, 8, 9	Retired with E River Addition	Steam (Oil)		1/1/03	(164)	(164)	(164)	(164)
Heritage (Independence)	Approved	CC	1/1/04		800	800		
Hudson Avenue 10/100 Unit	Planned Retirement	Steam (Oil)		1/1/04	(60)	(60)	(60)	(60)
Athens Generating Plant (Greene)	Under Construction	CC	1/1/04		1,080	1,080	1,080	1,080
Orion Astoria Repowering Phase I	Application Complete	CC	1/1/04		908	908		
Astoria Unit 5	Retired with Astoria Phase I	Steam (Dual)		1/1/04	(361)	(361)		
Astoria Unit 2	Retired with Astoria Phase I	Steam (Oil)		10/1/02	(171)	(171)		
Miscellaneous Renewables	Planned	Wind	6/1/04		45	45	45	45
Albany	Approved	CC	1/1/05		750	750		
Albany 1-4	Retired with Albany Repowering	Steam (Dual)		1/1/05	(363)	(363)		
SCS Queens (Astoria) 1	Approved	CC	1/1/05		900	900		
Orion Astoria Repowering Phase II	Application Complete	CC	1/1/05		908	908		
Asotria Units 3 and 4	Retired with Astoria Phase II	Steam (Dual)		1/1/05	(716)	(716)		
Poletti Expansion	Application Complete	CC	1/1/05		500	500	500	
Various Unit Retirements	Retirements			1/1/05	(511)	(511)	(511)	(511)
Miscellaneous Renewables	Planned	Wind	6/1/05		45	45	45	45
Total Net Additions 2003-2005						**4,435**	**1,780**	**1,030**
Additons After 2005								
Long Island CC		CC	1/1/10		580	580		
Total New Additions 2003-2010						**5,015**		

Table 2

NYCA Reserve Margins Under Various Capacity Addition Scenarios

		2002	2005 18% Reserve Margin	2005 4,435 MW Case	2005 1,780 MW Case	2005 1,030 MW Case	2010
NYCA	Existing Capacity	36,259	36,259	36,259	36,259	36,259	36,259
	2002 Planned Additions	522	522	522	522	522	522
	Additional New Capacity (Net of Retirements)	-	244	4,435	1,780	1,030	5,015
	Total Capacity	36,781	37,025	41,216	38,561	37,811	41,796
	Load	30,475	31,377	31,384	31,384	31,384	32,824
	Capacity/Load (%)	121%	118%	131%	123%	120%	127%
	Reserve Requirement (18%)	5,486	5,648	5,649	5,649	5,649	5,908
	Capacity in Excess of Requirement	821	-	4,183	1,528	778	3,064
NY City	Existing Capacity	8,707	8,707	8,707	8,707	8,707	8,707
	2002 Planned Additions	123	123	123	123	123	123
	Additional New Capacity (Net of Retirements)	-	(18)	2,353	904	136	2,353
	Total Capacity	8,830	8,812	11,183	9,734	8,966	11,183
	Load	10,665	11,015	11,015	11,015	11,015	11,453
	Capacity/Load (%)	83%	80%	102%	88%	81%	98%
	Locational Capacity Requirement (80%)	8,532	8,812	8,812	8,812	8,812	9,162
	Capacity in Excess of Requirement	298	-	2,371	922	154	2,021
Long Island	Existing Capacity	4,545	4,545	4,545	4,545	4,545	4,545
	2002 Planned Additions	360	360	360	360	360	360
	Additional New Capacity (Net of Retirements)	-	(380)	160	160	160	740
	Total Capacity	4,905	4,525	5,065	5,065	5,065	5,645
	Load	4,776	4,866	4,866	4,866	4,866	5,129
	Capacity/Load (%)	103%	93%	104%	104%	104%	110%
	Locational Capacity Requirement (97% 2002, 93% 2005)	4,633	4,525	4,525	4,525	4,525	4,770
	Capacity in Excess of Requirement	272	-	540	540	540	875

4.2 FUEL DEMANDS FOR ELECTRICITY GENERATION

Annual fuel demands among gas-fired and dual-fueled units increase only slightly, about 2 percent, between 2002 and the 2005 case with 4,435 MW of new capacity. This is shown in Table 3, below. In the winter months, generation from new CC units replaces generation from less-efficient gas-fired units and from some existing, nongas units, as well as some imports, for a net increase in winter gas demands. In the summer months, the shift in generation from steam units to more efficient CC units outweighs the shift from nongas units and imports to CCs, resulting in a slight decrease in total New York gas demand for power generation.

Table 3

Annual Maximum Potential Fuel Demands
For Gas-Fired and Dual-Fueled Electric Generation (Million MMBtu)

	Winter (Jan-Apr, Oct-Dec)			Summer (May-Sep)			Annual		
Year/Case	Combined Cycle and GT units	Dual-Fueled Steam Units	Total	Combined Cycle and GT units	Dual-Fueled Steam Units	Total	Combined Cycle and GT units	Dual-Fueled Steam Units	Total
2002	130	137	267	106	115	221	236	252	488
2005 -- 1,030 MW Case	153	121	274	119	110	229	271	231	503
2005 -- 1,780 MW Case	174	100	274	129	94	223	303	194	496
2005 -- 4,435 MW Case	243	38	281	177	40	217	420	78	498
2010	282	42	324	214	50	264	495	93	588

In addition to the change in overall gas demand among these units, there is also a shift in the types of units consuming the gas. In 2002, gas use is split almost evenly between gas turbine and cogeneration units, and steam units that can also burn residual oil. In 2005, the generation mix shifts to new CC units so that only a small portion of statewide electricity generation (and the associated gas demand) comes from steam units that are dual-fuel capable. To the extent that new CC units do not have storage, or resupply capabilities comparable to the existing dual-fuel steam units that they replace, NYCA generation will become increasingly dependent on receiving gas. However, as long as the steam units are not retired, they will remain available and can generate using residual oil in times when the CCs are unable to get their full, unrestricted gas deliveries.

The table also shows gas demands under each of the 2005 capacity addition scenarios. When new CC capacity is added, peaking units, many of which burn oil rather than gas, are displaced first. Hence, when fewer new CC units are added, many of the steam units are still needed to meet load in a significant number of hours. As a result, gas demands are higher when capacity additions are more limited, and decrease when enough CC units are added that a substantial portion of gas-fired steam generation is displaced (as in the 4,435 MW and 1,780 MW cases).

Between 2005 and 2010, power generation gas demands increase in both the summer and winter. Because almost no additional capacity needs to be added between 2005 and 2010 (to meet locational and statewide installed capacity requirements), increases in gas requirements between 2005 and 2010 attributable to electric load growth are not offset by a shift in generation to more efficient gas-fired units, as in 2005. Rather, both the new CC units, and older steam and GT units all run more in 2010, relative to their 2005 operating levels. Hence, total NYCA requirements for gas and/or oil increase by approximately 18 percent between 2005 (4,435 MW case) and 2010.

Table 4 shows fuel use on the summer and winter peak electric days. As with total annual gas demand, between 2002 and 2005, peak-day demand increases slightly in the winter and decreases slightly in the summer. Comparing the 2005 peak demands among the capacity addition scenarios shows that during peak periods, the steam units still generate substantial amounts if only limited combined-cycle capacity is added, as the new units displace mostly imports and generation from oil-fired units, including peakers.

Table 4

Peak (Electric) Day Maximum Potential Fuel Demands for Gas-Fired and Dual-Fueled Electric Generation (Million MMBtu)

	Winter Peak			Summer Peak		
Year/Case	Combined Cycle and GT units	Dual-Fueled Steam Units	Total	Combined Cycle and GT units	Dual-Fueled Steam Units	Total
2002	0.40	0.98	1.38	0.94	1.54	2.48
2005 -- 1,030 MW Case	0.50	0.94	1.39	1.04	1.52	2.57
2005 -- 1,780 MW Case	0.58	0.91	1.48	1.17	1.38	2.55
2005 -- 4,435 MW Case	0.91	0.50	1.41	1.52	0.94	2.46
2010	1.21	0.57	1.78	1.81	1.08	2.88

As described above, the addition of new combined-cycle capacity shifts the generating mix away from units that can also burn residual oil toward the CC units. If the gas delivery system is unable to supply the full gas demands of these units, one of two alternatives must be available: (1) the CC will substitute distillate for gas, or (2) the CC will go off-line and non-gas-fired, substitute generating units will need to be committed and dispatched to meet electricity load.

We note that a number of the new CC projects proposed for the downstate region (*i.e.*, East River Repowering, Ravenswood Cogeneration, Poletti Station Expansion, and Bowline Point 3) have barge resupply/backup capabilities, which would provide distillate resupply capability equal to the residual oil re-supply capability for dual-fuel units. If, however, the resupply/backup capability were not available, electric loads could still be met if substitute non-gas-fired generation was available.[24] Non-gas-fired generation would include available "green power" resources, as well as conservation and demand reduction resources. Table 5 shows the extent to which such substitute capacity is available for four electrical regions within New York: New York City, Long Island, Eastern NY (East of the Total East Interface, including New York City and Long Island), and New York State.

For 2002 and 2005 (4,435 MW Case), enough substitute capacity exists (*e.g.*, for winter 2005, 9,195 MW available statewide—3,288 MW of which is dual-fueled steam capacity in Eastern New York) to meet winter peak electric load even if no units are able to get gas deliveries. In 2010, only a small amount of gas-fired generation is needed to meet winter peak electricity load. If the winter peak electricity load were coincident with the peak day gas demand—making gas unavailable for electric generation—NYCA generation would need to be supplemented by imports from adjacent markets to meet NYCA electric loads.

By contrast, in summer 2005, under our 4,435 MW case, a substantial portion the gas-fired CC generation will be operated to meet peak loads, even if we assume that all available oil-capable units (*i.e.*, those units not out on maintenance or forced outages) are generating and on oil. For eastern New York, the 4,435 MW scenario includes 3,505 MW of new combined cycle capacity and the assumed retirement of approximately 2,200 MW of steam capacity.

Given assumed load growth and retirements, approximately 3,100 MW of the new capacity must operate to meet Eastern New York peak loads.[25] Given their high efficiency, however, these new CC will require only about 500 MDT of gas on the peak summer day, an amount substantially below historical summer daily deliveries.

Table 5

Available Substitute Capacity for Gas-Fired Generation, by Type
4,435 MW Capacity Additions Case

Winter Peak

		Peak Hour Gas-Fired Generation (MWh)		Available, Non-Gas (or Dual-Fueled) Substitute Capacity (MW)						
Year	Electrical Transmission Area	Dual-Fueled Units (Gas & Residual Oil)	Gas-Only Units (Distillate Backup Only)	Dual-Fueled Steam	Dual-Fueled Peakers	Oil-Fired Peakers	Oil-Fired Steam	Other	Total	Uncovered Gas-Fired Generation
2002	NYC	2,731	444	1,383		2,035	-	-	3,418	-
	Long Island	756	303	563	118	1,389	-	-	2,069	-
	Eastern NY	5,609	968	2,138	198	3,534	-	-	5,870	-
	NY State	5,609	2,990	2,138	198	3,557	800	53	6,746	-
2005	NYC	1,063	4,472	2,351		1,959		779	5,089	-
	Long Island	974	109	937	134	1,314	-	-	2,386	-
	Eastern NY	3,047	6,614	3,943	215	3,383	-	779	8,320	-
	NY State	3,047	6,735	3,943	215	3,406	800	832	9,195	-
2010	NYC	1,765	4,527	1,128		2,087		779	3,994	533
	Long Island	998	693	751	98	1,032	-	-	1,880	-
	Eastern NY	3,403	6,420	3,126	178	3,201	-	779	7,284	-
	NY State	3,403	8,431	3,126	178	3,224	1,605	832	8,965	-

Summer Peak

		Peak Hour Gas-Fired Generation (MWh)		Available, Non-Gas (or Dual-Fueled) Substitute Capacity (MW)						
Year	Electrical Transmission Area	Dual-Fueled Units (Gas & Residual Oil)	Gas-Only Units (Distillate Backup Only)	Dual-Fueled Steam	Dual-Fueled Peakers	Oil-Fired Peakers	Oil-Fired Steam	Other	Total	Uncovered Gas-Fired Generation
2002	NYC	4,919	900	-		1,289	-	-	1,289	-
	Long Island	1,591	696	389	-	853	-	-	1,242	-
	Eastern NY	8,372	2,295	1,367	71	2,233	-	-	3,671	-
	NY State	8,372	4,636	1,367	71	2,256	822	53	4,569	67
2005	NYC	2,957	4,671	-		1,966		-	1,966	2,706
	Long Island	1,467	573	389	108	913	-	-	1,410	-
	Eastern NY	5,890	7,299	1,070	143	2,969	-	-	4,182	3,116
	NY State	5,890	9,822	1,070	143	2,992	1,642	105	5,953	3,870
2010	NYC	3,462	4,755	-		1,882		-	1,882	2,872
	Long Island	1,448	1,031	389	-	500	-	-	889	143
	Eastern NY	6,484	8,130	1,070	71	2,473	-	-	3,614	4,516
	NY State	6,484	11,051	1,070	71	2,496	822	53	4,512	6,539

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24 We define substitute non-gas-fired capacity as capacity that is available to run (*i.e.*, not on maintenance or forced outage) but uncommitted for the day. If conditions required (*e.g.*, gas deliveries to gas-fired generators were restricted), this capacity could be committed to meet local area electric demands.

25 The minimum amount of required generation from gas-fired CC can be calculated by committing and dispatching all available non-gas-fired capacity before committing and dispatching the required amount of CC units. The gas deliveries resulting from this dispatch (where non-gas-fired units are dispatched first) establish the minimum amount of gas that would need to be delivered to meet peak NYCA electricity loads, holding imports from adjacent markets constant.

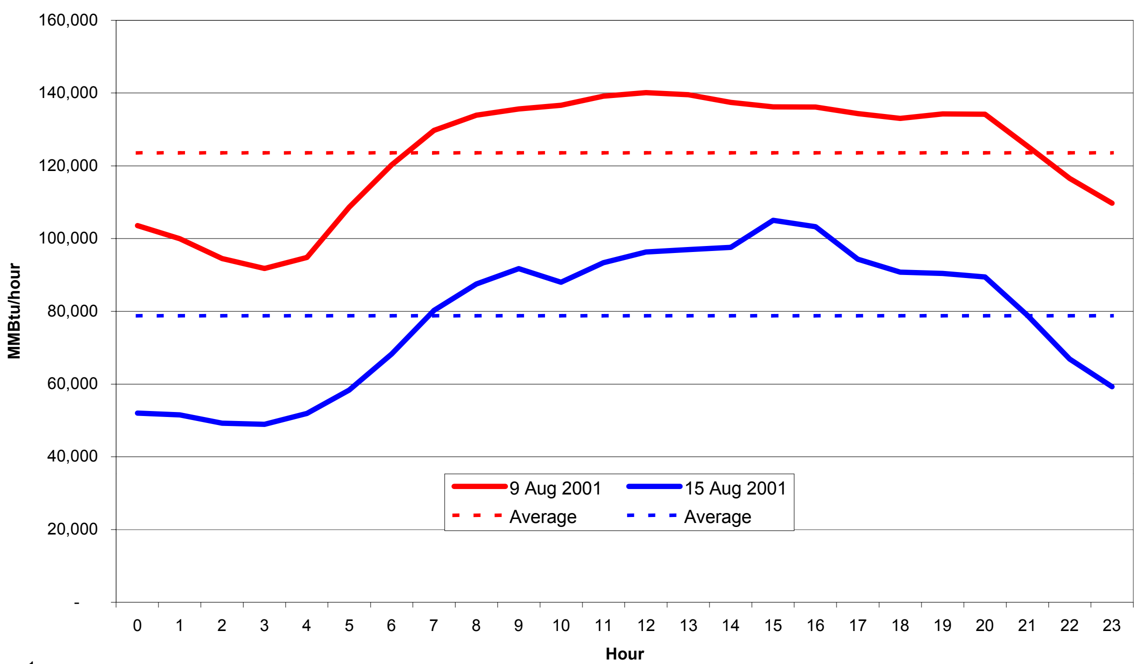
4.3 INTRADAY VARIATION IN GAS DEMANDS FOR ELECTRICITY GENERATION

The above analysis of electric generator gas and oil demands has addressed only total annual and daily fuel use. However, because the hourly electric load shape is not flat within a day, but rather increases substantially from off-peak to peak hours, the gas system may need to deliver substantially more gas in some hours than others. A gas model based on daily demands and delivery capacities does not test the ability of the system to meet either peak-hour demands or the ramp in deliveries that is required as generators ramp up their electric output. In order to better understand whether the intraday variation in gas use exhibited in hourly patterns of fuel use from our MAPS model are feasible, we have examined both historical data and hourly model results.

The gas pipeline and LDC infrastructure has been able to cope with hour-to-hour variation in gas delivery, as can be seen from historical data. Figures 7 and 8 show hourly gas use by New York generators on sample days during summer 2001.[26] As illustrated in the charts, historical gas use for generation has exhibited substantial intraday variation. On each of the days shown, gas deliveries fall well below the daily average during off-peak hours and rise substantially above the average as generators are ramped up during the higher electric load hours.

Figure 7

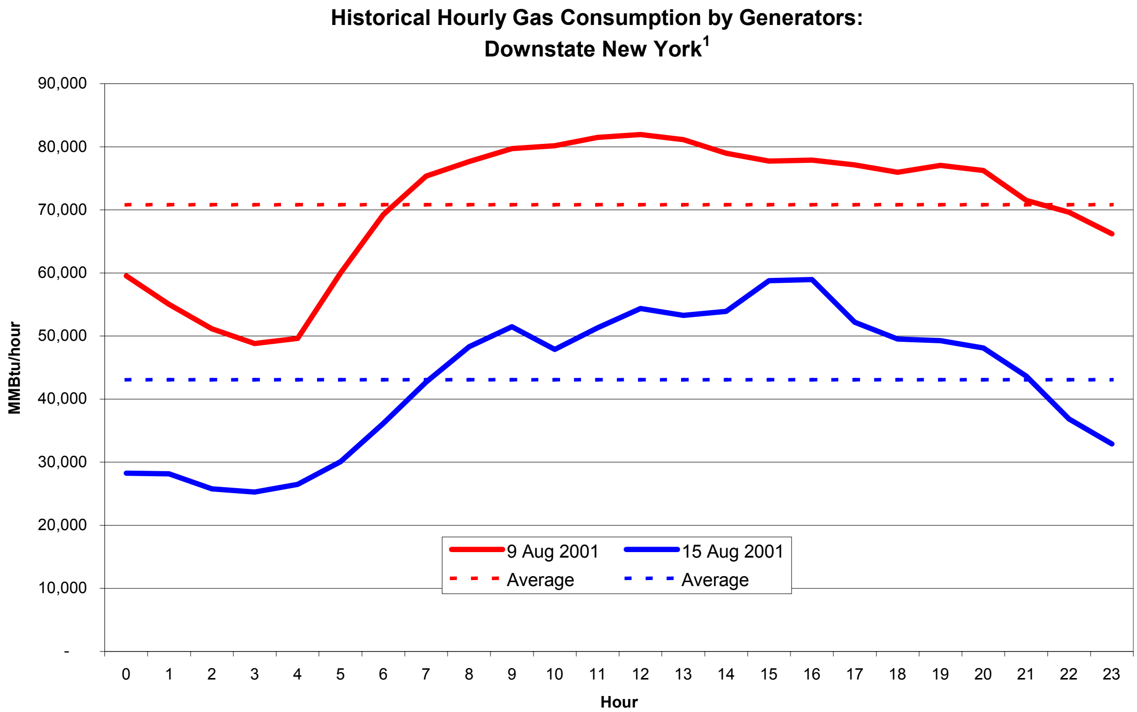
Historical Hourly Gas Consumption by Generators: New York State[1]



[1]Based on available hourly data for gas-fired units from the U.S. EPA Acid Rain Program. For some generators, either data were not available or the fuel mix was not known. Hence, the total may exclude the gas consumption of some units and/or include some oil consumption from.

[26] These graphs are based on available hourly data for gas-fired units from the U.S. EPA Acid Rain Program. The gas use shown is only approximate, because data were not available for a few generators and the exact fuel mix used in dual-fueled steam units was not known and could only be approximated using SO_2 emissions. Hence, the total may exclude the gas use of some units and include some oil.

Figure 8



[1]Based on available hourly data for gas-fired units from the U.S. EPA Acid Rain Program. For some generators, either data were not available or the fuel mix was not known. Hence, the total may exclude the gas consumption of some units and/or include some oil consumption.

As long as the gas system is able to continue to support this type of hourly variation in delivery, and the addition of new gas-fired generation does not increase the required daily ramp in gas deliveries, it is sufficient to analyze gas demands and delivery capabilities on a daily basis when testing for a sustained mismatch between gas demand and supply. Our MAPS results show that this is the case.

Figures 9 and 10 illustrate that the addition of CC units actually decreases intraday variation in fuel demands. Each chart shows the hourly fuel demands of gas-fired and dual-fueled generators on the peak (electric) summer day from the cases with 4,435 MW and 1,760 MW of additions. For both the downstate region and the State overall, off-peak demands are higher and on-peak demands slightly lower in the case with more CC capacity.

Figure 9

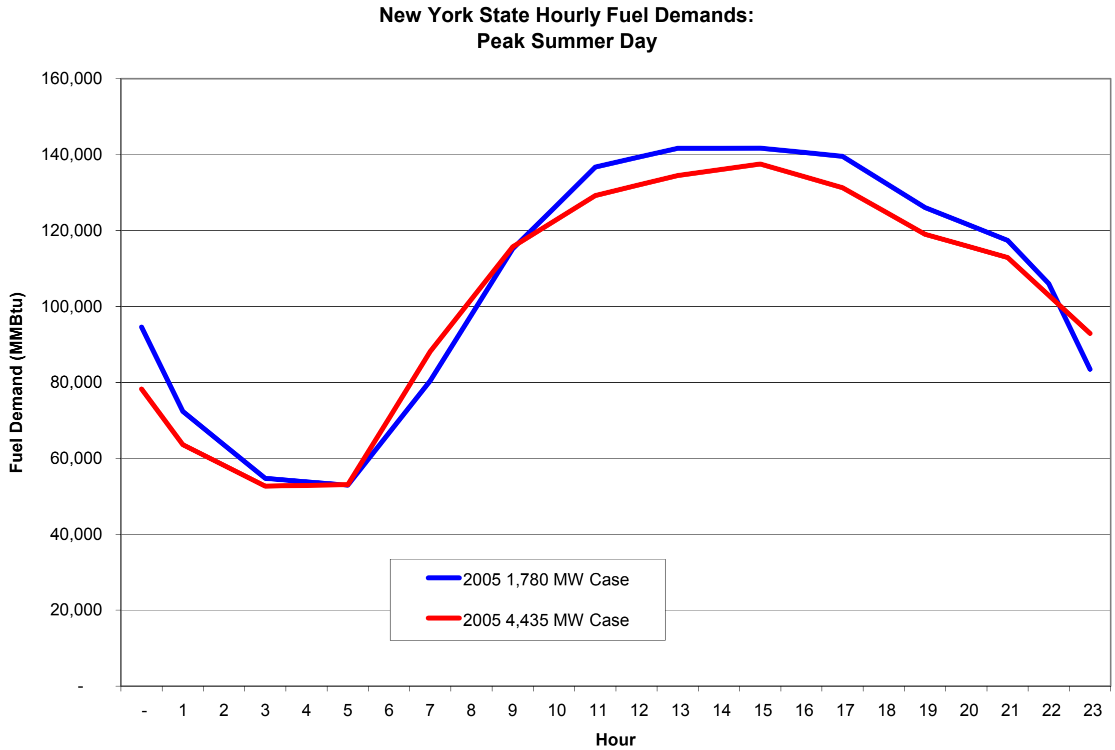
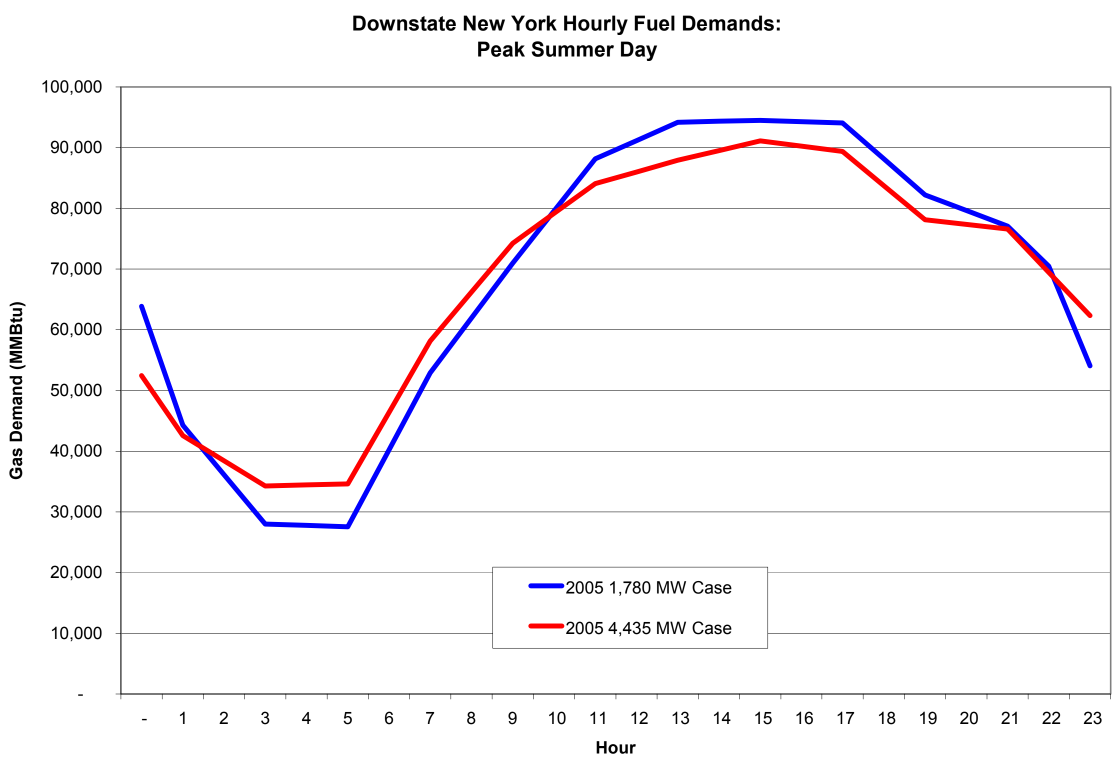


Figure 10



Figures 11 and 12 illustrate why the ramping requirements decrease when more CC units are added. Figure 11 shows downstate gas demands by generator type for the 1,780 MW case. The CC units run at a constant level throughout the day, while steam units and peakers ramp up to meet mid-day loads. As illustrated in Figure 12, in the 4,435 MW case, the combined cycle units still run at a nearly constant rate throughout the day. As a result, overall hourly gas demands are slightly flatter than in the 1,780 MW case.

Figure 11

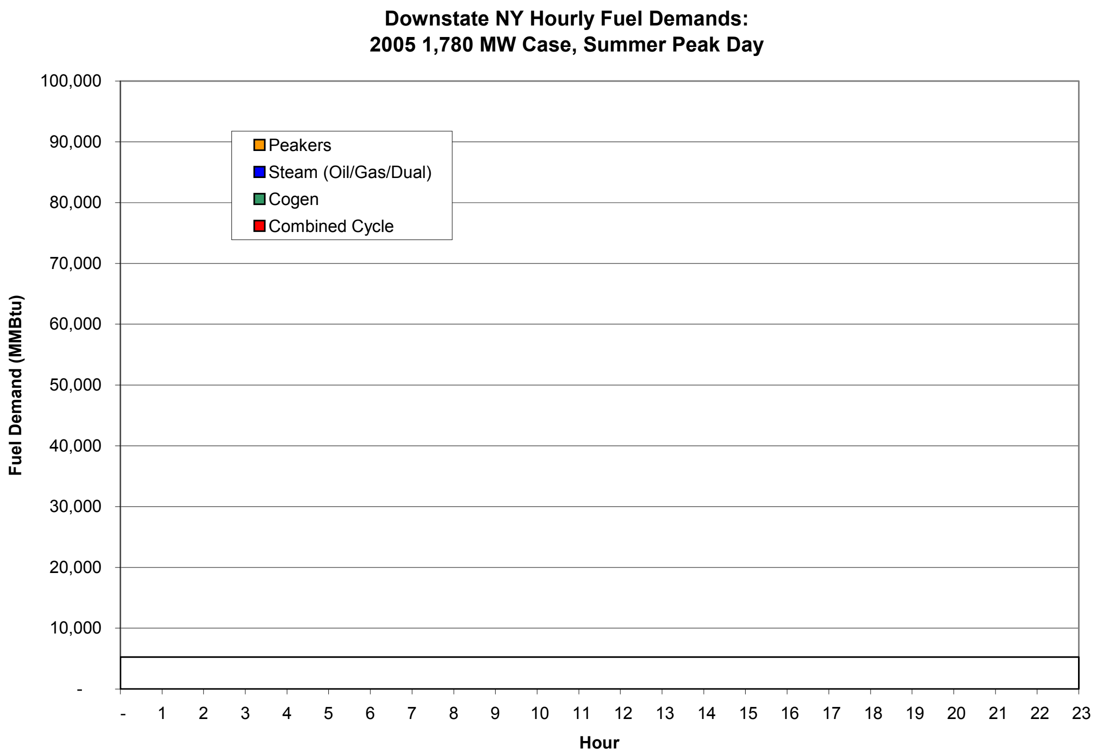
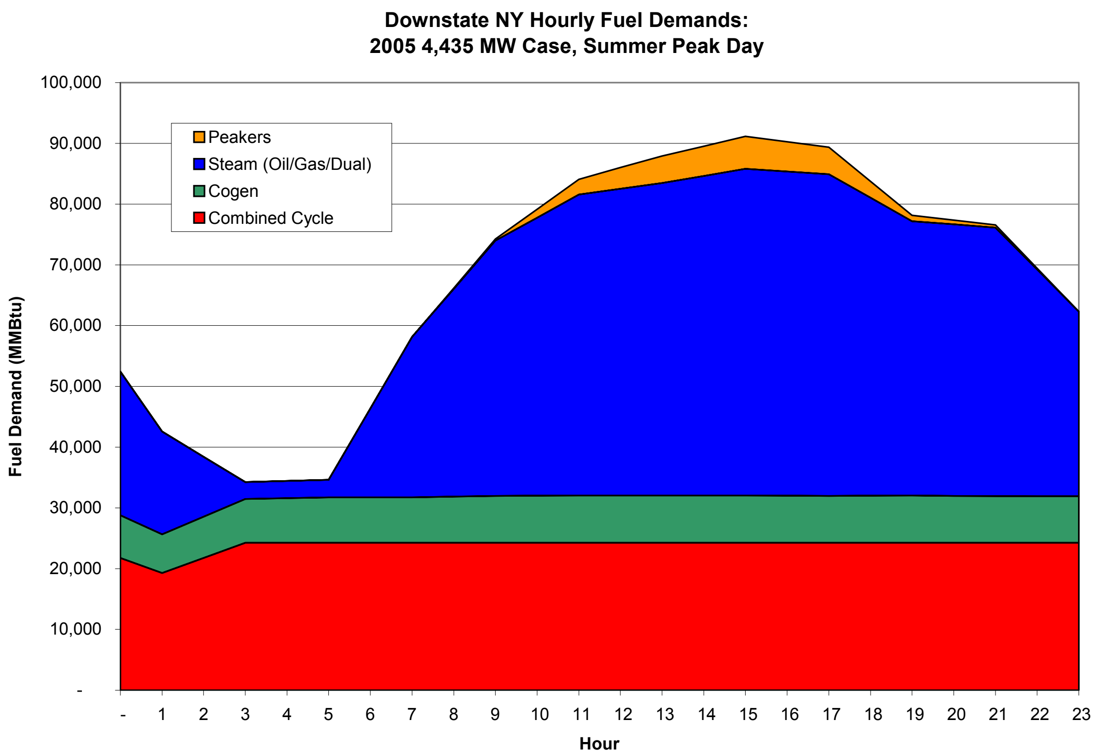


Figure 12



In the winter, when loads are lower, generator capacity additions increase intraday variation slightly, as shown in Figures 13 and 14. The increased intraday variation is not likely to cause hourly gas delivery problems, however, since steam units, which will be burning oil in the winter, do most of the ramping.

Figures 15 and 16 illustrate the generation mix and ramping pattern for the downstate region. In periods when gas delivery is constrained, most of the steam units will be burning oil and therefore will not rely on the gas system for their fuel needs for ramping up. The remaining ramping requirements are relatively small and would put a correspondingly small burden on the gas system if they were met by CCs. Alternatively, however, under constrained gas delivery conditions, many CC plants may be unable to obtain gas or choose not to run because of high gas prices. In those instances, oil-fired units would meet the ramp.

Figure 13

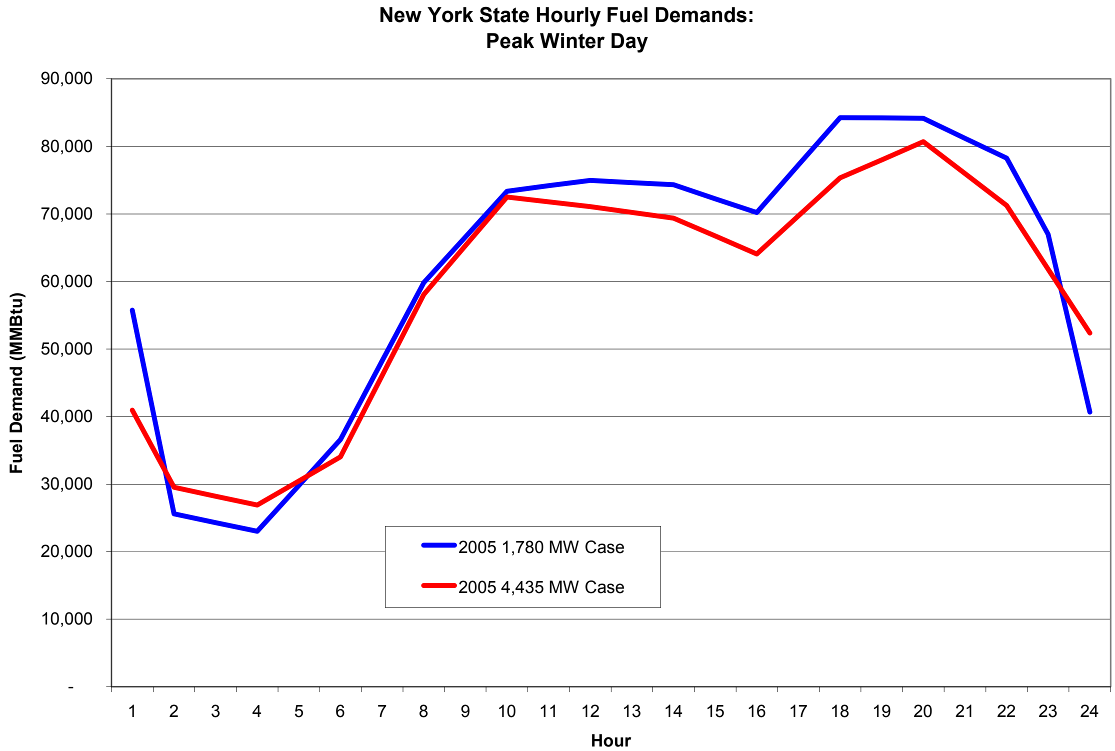


Figure 14

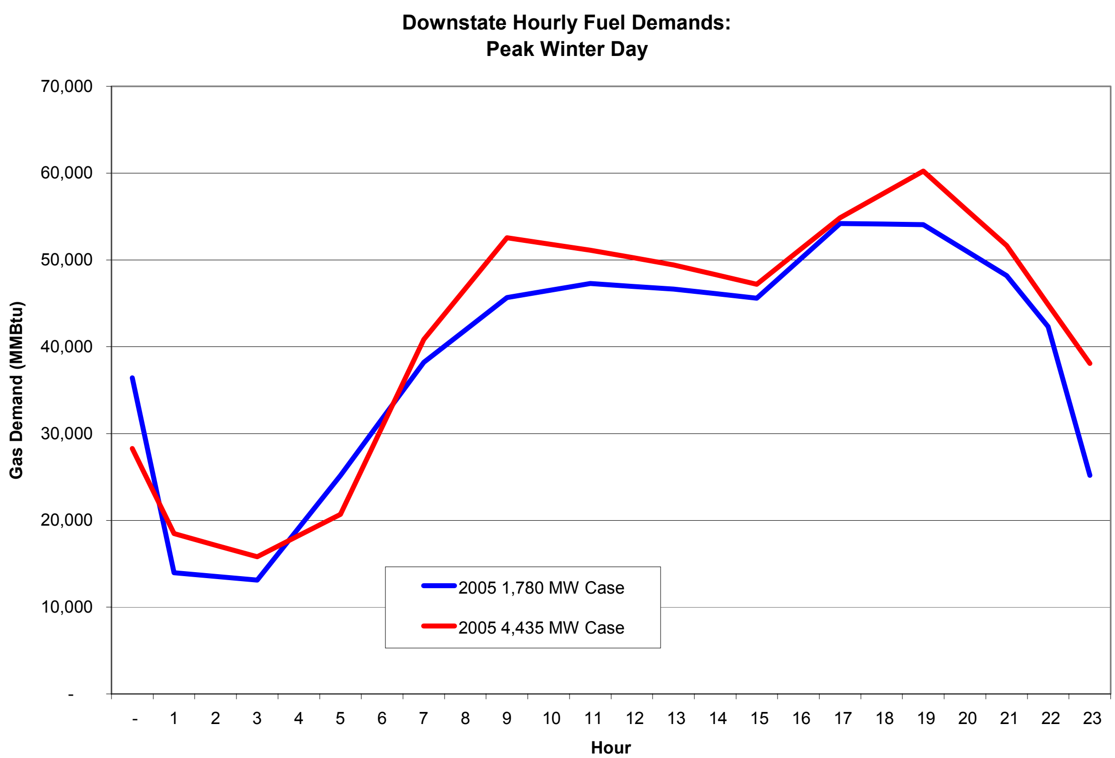


Figure 15

**Downstate NY Hourly Fuel Demands:
2005 1,780 MW Case, Winter Peak Day**

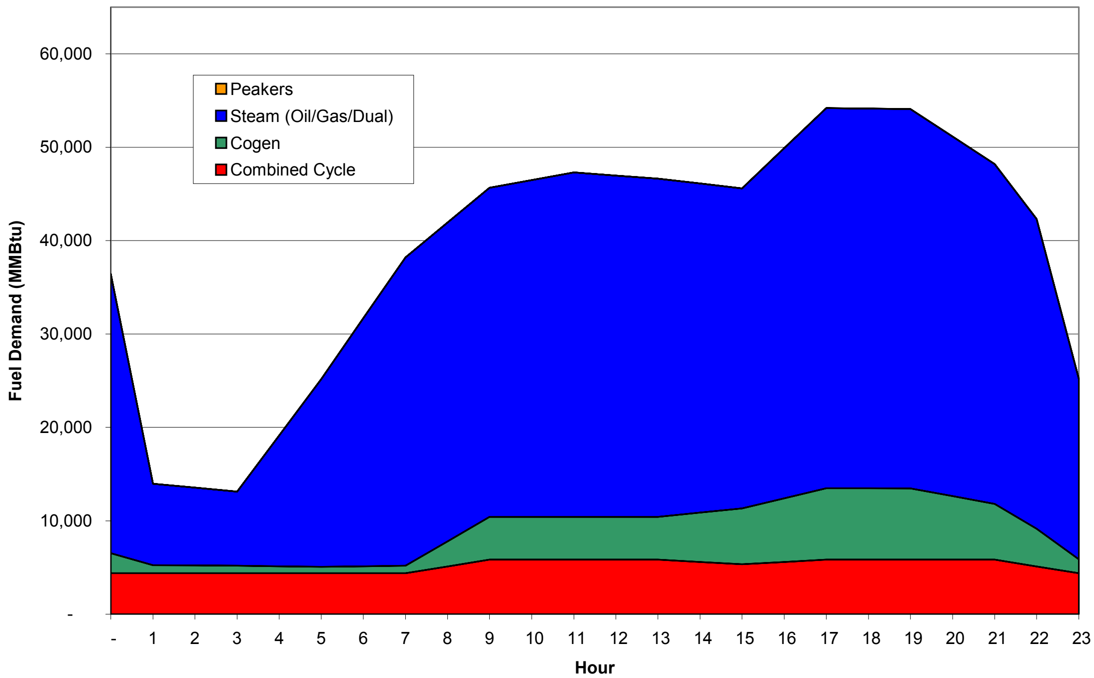
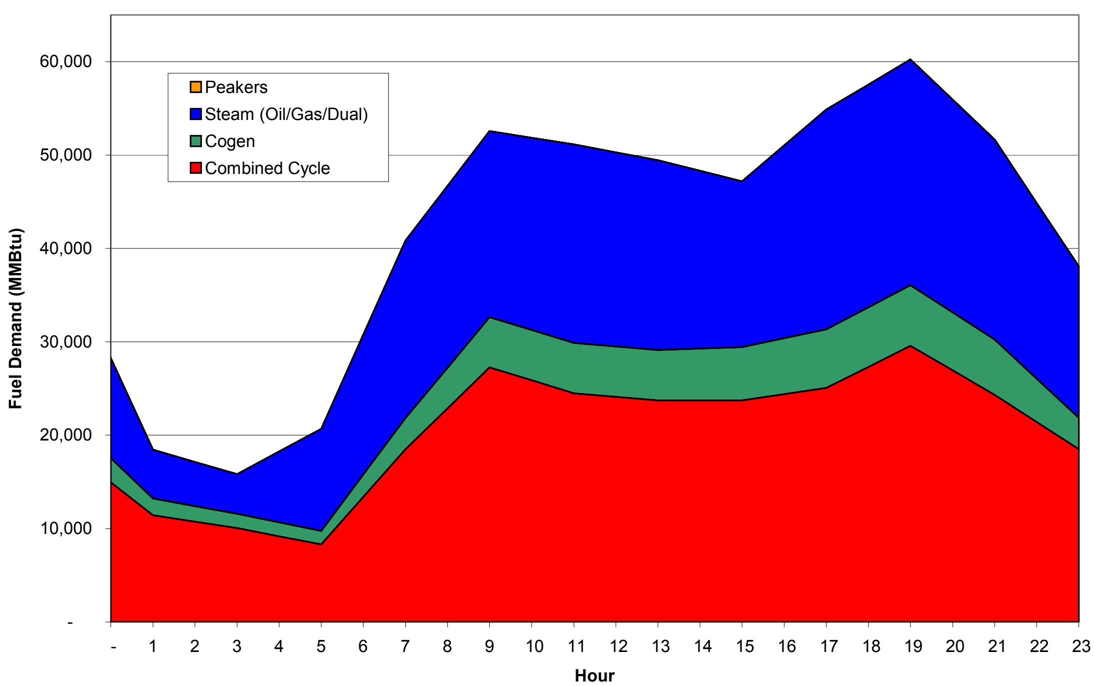


Figure 16

**Downstate NY Hourly Fuel Demands:
2005 4,435 MW Case, Winter Peak Day**



5. GAS DEMAND AND SUPPLY

5.1 PIPELINE CAPACITY ADDITIONS

Prior to the autumn of 2001, no substantial pipeline expansions had been built in New York since the Iroquois addition in 1991. The EIA has noted that, as a result of this limited supply expansion and substantial gas demand growth, downstate gas deliveries in the New York City area have approached their throughput limits.[27] However, substantial expansion of the New York pipeline infrastructure is already under way. With projects that have recently been completed or are expected to be completed by the end of 2003, a total of 465 MDT per day of new delivery capacity will be available into the downstate region, for an increase in delivery capacity of 16 percent. This additional capacity exceeds forecasted growth in nongeneration gas demands through at least 2005.

In addition to the 465 MDT per day of expansions already being added, there are numerous pipeline proposals for new and expanded capacity to serve New York, totaling more than one billion cubic feet per day of capacity. Not all of the projects will be built, as some are competing to effectively serve the same markets and some are seeking markets that will not evolve. A substantial portion of the proposed capacity has begun to clear regulatory hurdles; the FERC has provisionally approved projects that could provide a total of approximately 800 MDT per day, primarily to the downstate region (an increase in capacity of approximately 27 percent).

The set of the proposed pipeline projects are that have recently been added or will be in place before November 1, 2003, are included in all of our pipeline capacity expansion cases. These projects include the following:

- **Iroquois Athens** is an expansion that is designed to serve a 1,080 MW combined cycle power plant under development in Athens, New York. Under the plan, Iroquois will expand its existing capacity by 70 MDT per day by installing a 10,000 horsepower compressor on the existing system, with a start-up date of September 2003. In addition to increasing deliverability to the Athens plant, Iroquois believes that the new compressor will increase reliability on their system as a whole.

- **Iroquois Eastchester** received its FERC Certificate in December 2001, and is expected to go forward with an additional 230 MDT per day in April 2003. Thirty miles of new pipe will be laid from Northport, New York, under Long Island Sound into New York City. The new segment of pipeline will be accompanied by upstream additions and modifications to compression at Dover, Boonville, Wright, Athens and Croghan, New York.

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[27] Status of Natural Gas Pipeline System Capacity Entering the 2000–2001 Heating Season, EIA *Natural Gas Monthly*, October 2000; *Natural Gas Transportation—Infrastructure Issues and Operational Trends*, EIA Natural Gas Division, October 2001.

- **Transco MarketLink** was originally planned as a three-phase project to bring 700 MDT per day into the New York/New Jersey area from the Midwest. Over the past two years, the project has undergone significant revision, and is currently approved as a two-phase project. Phase I was completed in December 2001, and has a capacity of 166 MDT per day into the region. **Transco Leidy East** has been incorporated into Market Link Phase II and is expected to be in-service by November 2002. Of the 130 MDT per day of capacity from Phase II, 25 MDT per day are expected for New York State.

- **Other Projects** represent other expansions in the New York area, although they are not necessarily directed to New York. From all of this capacity, we have included 25 MDT per day of deliveries into downstate New York, to be in service by November 2003.

  – **Algonquin Hanover Compression** is expected to bring 135 MDT per day of capacity into the NJ/NY area on Texas Eastern.

  – **Stagecoach Storage** is a high-deliverability underground storage project in New York and Pennsylvania connecting to the Tennessee Gas Pipeline. It is planned to have up to 500 MDT per day of deliverability.

In total, we have included 465 MDT per day of capacity that was either recently installed or will be installed prior to November 2003. For the period after 2003 we have not selected any one proposed pipeline expansion or new pipeline project over another. Rather, we have accounted for the proposed projects through "generic" capacity expansions. By using generic pipeline expansions, we are able to reflect our fundamental assessment that new pipeline capacity will follow the commitments of power generators to contract for pipeline capacity to support their projects. As previously stated, it is unrealistic to hypothesize substantial new power generation capacity without assessing the incremental pipeline capacity that is being marketed to support that incremental load. Our generic expansion cases into the downstate area span the potential range of additional capacity that could be created by the proposed projects.

The pipeline expansion cases represent the following:

- No additional expansion after November 2003 (beyond the 465 MDT per day discussed above).

- Additional Pipeline capacity expansions (beyond the 465 MDT) into the downstate market of 300, 400, 500 and 800 MDT per day.

5.2 GAS DEMANDS FOR TRADITIONAL END USERS

The demand for gas by traditional end use gas consumers (*i.e.*, all gas demands except those for electricity generation) in New York is projected to grow a total of just over 6 percent between

2002 and 2005, with all of that growth effectively in the downstate region, as shown in Table 6.[28] This growth represents the New York LDCs' outlook that each LDC provides annually to the New York Public Service Commission.

Table 6
New York State Gas Market
2002 and 2005
Million DekaTherms

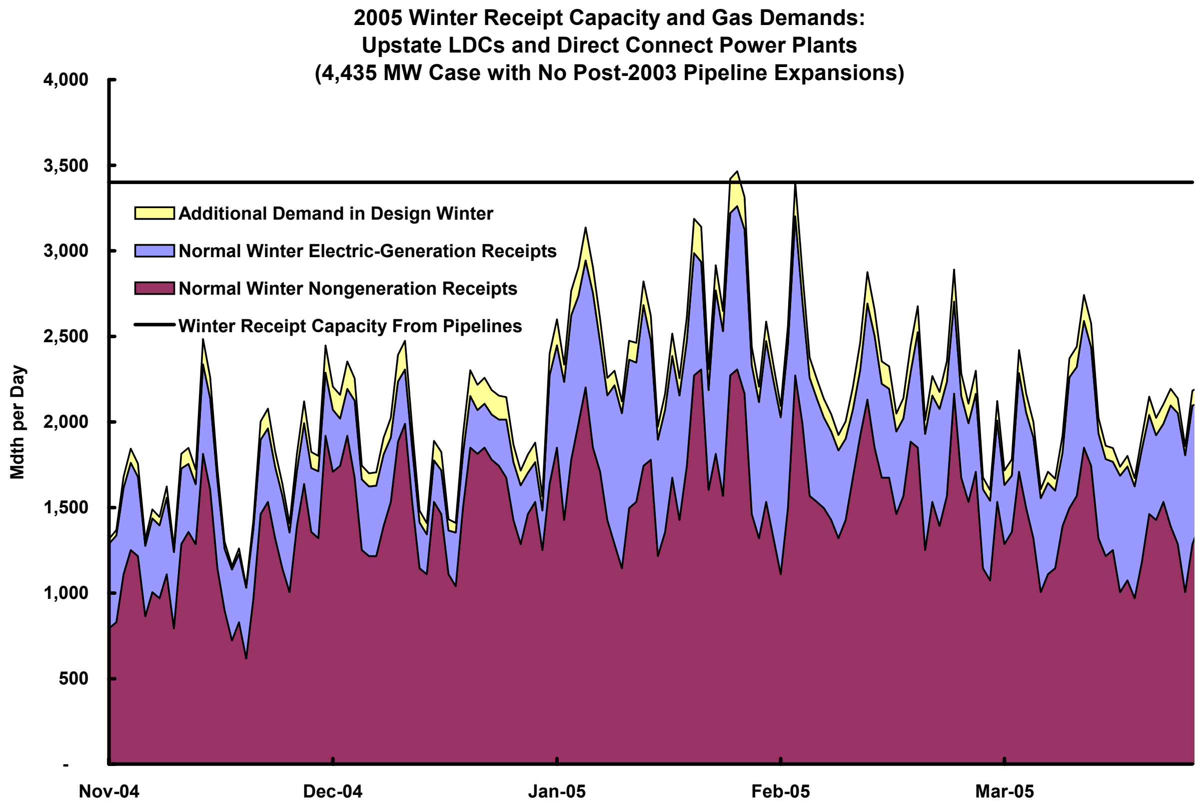
	Gas Market, Excluding Electric Generation (Normal Weather)		
Year	Downstate	Upstate	Total
2002	451	363	814
2005	500	367	867
Growth	**10.9%**	**1.1%**	**6.5%**
2002 Share	**55%**	**45%**	**100%**

The upstate and downstate markets are quite different. Historically, the upstate market has represented about 45 percent of the State's LDC demand, while the downstate market is about 55 percent of the State's demand. Projected growth in the nonpower sector over the next five years is significant in the downstate area.

In general, the infrastructure in the upstate area is relatively robust and there is a substantial cushion between peak gas demands and physical gas system deliverability during a year with normal winter weather. Our analysis shows that upstate capacity will remain adequate through at least 2005. This finding is illustrated in Figure 17, which depicts the upstate gas supply/demand balance, under both normal and extreme (design winter) weather conditions, for our case with the most electric generation additions (4,435 statewide) and no new pipeline capacity. This case represents a "worst case" scenario, since peak-day gas demands among generators are at their highest and deliverability is at its lowest. Given the low growth rate in traditional gas demand for this region and the amount of gas-fired capacity additions proposed for the area, the cushion between peak gas demands and winter deliverability in a normal winter will remain more than adequate over the forecast period. During a cold (design weather) winter, gas demands would approach physical capacity limits on a few days, and exceed capacity on one day. However, for this brief period when a small amount of the maximum potential gas demand cannot be fully supplied, the upstate area has more than sufficient substitute, oil and other non-gas-fired generating capacity to allow electric demands to be met.

[28] Traditional end users include residential, commercial, industrial, and transportation customers. Forecasted demand growth includes potential new uses among these consumers, such as expanded use of natural gas for transportation.

Figure 17



This is not meant to imply that there are no areas in the region where gas deliverability may be limited. We recognize that within individual upstate LDCs, there may be deliverability constraints in portions of the system. However, our analysis treats each LDC as a single node and we did not analyze deliverability conditions within the LDC.

Downstate conditions are substantially different than those found upstate. Peak gas demands in the downstate area have required interruptions in deliveries to interruptible customers in the winter. During the course of a typical winter, residual fuel oil is routinely substituted for gas in some large commercial and industrial boilers as well as steam electric power plants. When gas is higher priced than residual fuel oil, the decision is driven by economics—customers that can use either fuel choose the lower cost fuel. As discussed in section 1.1 earlier, historically this has been the case for dual-fueled electric generation in New York. When gas prices rise, reflecting its limited availability, the gas and electric markets clear by using substitute fuels (oil) for electric generation—leaving gas supplies for those consumers with limited/no options for substitution.

Downstate there is reasonably strong growth in the demand for gas outside of that used for electric generation—a total of almost 11 percent between 2002 and 2005. Our analysis shows a need for the pipeline capacity that is currently being added into the downstate area to serve this potential growth, even if the gas requirements for electric generation do not increase over historical levels. We expect that the downstate non-power-generation gas market growth itself increases the average daily demands that the LDCs must serve. If the LDCs maintain their full design winter reserve, then the daily capacity into this market would have to increase by 292 MDT per day.

In the future, gas deliverability in this area will be stressed by the forecasted growth in both traditional gas markets and the increased demand that would be created by new power plants. With the pipeline capacity that exists today, in both a normal and a design winter, the LDCs would need to limit deliveries to a portion of their interruptible gas load in 2002. As the interruptible loads are designed and priced in anticipation of interruptions, there is nothing unusual about such an event. It does point out, however, that the gas delivery capacity in the downstate area is tight during peak winter months.

For 2002 we only included 255 MDT per day out of the total of 465 MDT per day. This amount represents the approximate portion that was expected to be in service during the year at the time our analysis commenced. If the design winter increment on the downstate growth is excluded, then the additional capacity is just sufficient to meet the new load. Without further expansion (beyond the 465 MDT per day included in all cases), the current tightness in this market would remain not much different than it is today. Even with the additional capacity, under normal weather conditions, our analysis shows some minor interruptions of interruptible customers in the winter period, which is not an abnormal event. Given the very mild winter in the first quarter of 2002, the normal weather assumption that underlies our forecast is unlikely to occur. As a result, this capacity limitation may not emerge until next winter (albeit quite small, and manifested only with the interruptible customers).

5.3 Gas Demands For Electricity Generation

The maximum potential demand for gas by electric generators increases by 2 percent between 2002 and 2005. The relatively modest growth in maximum potential gas demands reflects a large shift downstate away from relatively inefficient steam gas units to the new, more efficient CCs, as shown in Table 7. As shown, the maximum potential downstate demand for gas by electric generators in 2002 is 305 MDT. This total represents the total demand for fuel (*i.e.*, Btus, irrespective of their source—gas or oil) by gas-capable generating units.

As shown in Table 7 most of the 2002 demand is from generators that take deliveries at relatively low pressures (*e.g.*, dual-fired gas/oil units). As many of these units burn oil routinely (sometimes due to better economics for oil, other times due to seasonal interruptions of gas), actual historical downstate gas use is well below any estimate of maximum potential fuel demands by these units. For example, as shown in Figure 1 in the first chapter of this report, gas accounted for approximately 50 percent of the total fuel burn of dual-fueled units in New York State during 2000 and 2001.

Table 7
Maximum Potential Gas Demands
Among Electric Generators
New York State
2002 and 2005
Million DekaTherms

	Gas/Oil Dual-Fueled Steam Plants	Combined Cycle Gas Turbine Gas-Only Steam Plants	All Plants with Gas Capability
Year	**Downstate**		
2002	273	32	305
2005	95	195	290
Growth			**-5.1%**
2002 Share	**56%**	**7%**	**63%**
2005 Share	**19%**	**39%**	**58%**
Year	**Upstate**		
2002	176	7	183
2005	68	140	208
Growth			**13.8%**
2002 Share	**36%**	**2%**	**38%**
2005 Share	**14%**	**28%**	**42%**
Year	**Total**		
2002	448	40	488
2005	163	335	498
Growth			**2.0%**
2002 Share	**92%**	**8%**	**100%**
2005 Share	**33%**	**67%**	**100%**

Absent any load growth, the 4,435 MW of new gas-fired, CC units (taking deliveries at high pressure) in our highest electric case, would simply substitute for existing steam electric plants and potential gas demand would go down. The substantial number of new combined cycles included in the 4,435 MW case effectively reduces the total potential gas demand between 2002 and 2005 even though the total downstate generation from gas increases.

It is important to note that satisfying the entire gas market year-round by pipeline is a very unlikely scenario as it would be economically unwise. A distinctly seasonal gas market will not produce high load factors for pipeline expansion projects if the expansions are sized to meet maximum potential winter peak demands, including demands by electric generators. Gas pipelines in the Northeast are typically sized to operate at very high load factors for the winter season. The extreme peaks are served at a lower cost by high-deliverability LNG and curtailing interruptible customers (if they have not already switched to their alternate fuel based on economics). The longer shoulder periods are served by winter storage services. If all winter peaks were served by year-round pipeline capacity, released capacity would be available at low prices for most of the year, making it extremely unattractive for those customers that purchased long term firm capacity.

5.4 Analytical Results: Gas and Oil Use for Electricity Generation

Our analysis shows that with the addition of 465 MDT per day of pipeline capacity assumed to be in place by November 2003, New York will have sufficient gas delivery capacity to supply the amounts of gas required for generation under all 2005 generation and pipeline addition scenarios, provided the existing ability to burn oil is maintained. For each new generation capacity scenario, there is a range of feasible combinations of gas pipeline additions and oil-burning capability that allows the fuel needs of electric generators to be met. This range of combinations illustrates the trade-off between gas pipeline capacity and local Btu storage. There are advantages and disadvantages associated with each.

- Pipeline capacity additions of between 300 MDT per day and 800 MDT per day (beyond the 465 MDT per day) would provide additional benefits to the electricity and natural gas systems, including enabling the use of larger quantities of cleaner-burning natural gas and the potential for better contingency protection.

- The more natural gas pipeline capacity built and used to serve electricity generation, the more dependent the electric system is on natural gas availability and the more exposed it is to natural gas price volatility.

The remainder of this section presents the analytical results underlying these basic conclusions from our electric and gas system modeling, beginning with annual generation among gas-fired power plants.

Tables 8, 9, and 10 illustrate the annual amount of electric generation produced by gas-fired and dual-fueled units, by fuel type. Each table shows annual generation for the downstate region under each pipeline additions scenario for one of our new generating capacity cases. Table 8 begins with the results from the 4,435 MW generation expansion case. The first column of the table shows how much each type of gas-capable unit would generate if its maximum potential gas demand were fully supplied. Note that in this unrestricted gas delivery case, 75 percent of the gas-fired generation comes from CCs. Because gas deliveries are not restricted, the maximum potential demand is supplied on every single day.

The second column of the table shows the gas-capable units' generation in the scenario with no additional pipeline capacity added into the downstate region post 2003. In this case, 25 percent of the generation from new CCs using gas would need to be replaced by generation from non-gas-fired units or increased imports into the downstate region (from either the upstate region or outside New York). Note that the total generation among the units represented in this table decreases when pipeline constraints are encountered. This is due to increased imports into the downstate region.

The remaining columns show the results from the pipeline expansion scenarios with 300, 400, 500, and 800 MDT per day of new capacity. As more pipeline capacity is added downstate, the CCs and gas-fired steam units receive an increasing portion of their maximum potential demands. In the 300 MDT per day case, 95 percent of the gas needed to allow CCs to operate on gas all of the times they wish to run can be supplied. In this case, there are 280 days with no restrictions in gas deliveries, and on most days when capacity is constrained, a large portion of the potential demand can be supplied. Incremental pipeline capacity of 400 MDT per day increases the number of operational days with no restrictions at all to 318 while allowing 98 percent of the gas power market demand to be served. For the case with 800 MDT per day, 100 percent of the maximum potential demand for gas is met.

Table 8
Generation by Gas-Fired and Dual-Fueled Units (GWh)
Downstate Region 2005
4,435 MW Generating Capacity Additions Case

	Maximum Potential Gas Demand	No Post 2003 Pipeline Expansions	300 MDT/day Expansion Into Downstate	400 MDT/day Expansion Into Downstate	500 MDT/day Expansion Into Downstate	800 MDT/day Expansion Into Downstate
Combined-Cycle Units Fueled by Gas	27,856	20,762	26,520	27,304	27,734	27,856
Other Units Fueled by Gas	9,003	8,217	8,656	8,748	8,786	9,003
Units Fueled By Oil	0	1,705	1,038	567	296	0
Total	36,858	30,684	36,214	36,618	36,816	36,858
# of Days When Maximum Potential Gas Demand is Supplied	365	140	280	318	342	363
% Served of Maximum Potential Gas Demand	100%	79%	95%	98%	99%	100%

Table 9 shows the analogous results from the case with 1,780 MW of new generating capacity. Looking at the generation mix in the unrestricted case shows that generation by CCs is more than 60 percent lower than in the 4,435 MW Case, as far less new gas-fired capacity is added. In the case where no pipeline capacity is added after November 2003, the generators' maximum potential gas demands can be met on 228 days of the year, and 91 percent of the potential demand is supplied. If an additional 300 MDT per day of pipeline capacity is added, 98 percent of the potential gas needs for generation can be met, with unlimited deliveries on 318 days.

Table 9
Generation by Gas-Fired and Dual-Fueled Units (GWh)
Downstate Region 2005
1,780 MW Generating Capacity Additions Case

	Maximum Potential Gas Demand	No Post 2003 Pipeline Expansions	300 MDT/day Expansion Into Downstate	400 MDT/day Expansion Into Downstate	500 MDT/day Expansion Into Downstate	800 MDT/day Expansion Into Downstate
Combined-Cycle Units Fueled by Gas	9,881	9,340	9,880	9,880	9,881	
Other Units Fueled by Gas	20,310	18,240	19,626	19,832	20,310	
Units Fueled By Oil	0	1,883	591	413	0	
Total	30,191	29,462	30,098	30,126	30,191	
# of Days When Maximum Potential Gas Demand is Supplied	365	140	280	318	365	
% Served of Maximum Potential Gas Demand	100%	91%	98%	98%	100%	

Table 10 shows downstate generation and deliveries for the 1,030 MW case. With the pipeline capacity remaining fixed after November 2003, 93 percent of generators' potential gas demands can be met, with deliveries unrestricted on for 248 days of the year. If an additional 300 MDT per day of pipeline capacity were added, unrestricted demands could be fully served 323 days of the year and 98 percent of the gas requirements would be fully met.

Table 10
Generation by Gas-Fired and Dual-Fueled Units (GWh)
Downstate Region 2005
1,030 MW Generating Capacity Additions Case

	Maximum Potential Gas Demand	No Post 2003 Pipeline Expansions	300 MDT/day Expansion Into Downstate	400 MDT/day Expansion Into Downstate	500 MDT/day Expansion Into Downstate	800 MDT/day Expansion Into Downstate
Combined-Cycle Units Fueled by Gas	4,682	4,641	4,679	4,682		
Other Units Fueled by Gas	24,045	21,993	23,458	24,045		
Units Fueled By Oil	0	2,093	589	0		
Total	28,727	28,727	28,727	28,727		
# of Days When Maximum Potential Gas Demand is Supplied	365	140	280	365		
% Served of Maximum Potential Gas Demand	100%	93%	98%	100%		

Table 11 presents a summary of the results from our electric and gas model analysis. For each generating capacity and pipeline expansion scenario, estimates of gas and oil use are shown. The maximum potential gas demands are shown first (in the fourth column of the table). The maximum potential gas demands are calculated by assuming that there are no deliverability constraints limiting the amount of gas used for electric generation. Columns six through ten list the projected amounts of gas, and the corresponding amounts of oil, that could be used for electric generation under each of the pipeline expansion cases. The amounts of gas consumed are calculated by assuming that generators will always burn gas if the pipeline system is able to deliver it. Correspondingly, the amounts of oil used for electric generation are calculated by assuming generators will only burn oil during those periods when the gas delivery capacity has been fully utilized. Note that estimated gas and oil use do not always sum to the maximum potential gas demand. The difference is attributable to changes in net imports and exports and changes in generation among units that burn other fuels.

Table 11
Summary of Gas and Electric Modeling Results
From All Gas and Electric Expansion Scenarios

All of New York

Year	Net Electric Generating Capacity Additions (Post 2002)	Fuel	Maximum Potential Gas Demand (MMDT)	Estimated Gas and Oil Consumption (MMDT)				
				No Post 2003 Pipeline Expansions	300 MDT/day Expansion into Downstate Region	400 MDT/day Expansion into Downstate Region	500 MDT/day Expansion into Downstate Region	800 MDT/day Expansion into Downstate Region
2002	N/A	Gas	488	453	N/A	N/A	N/A	N/A
		Oil	-	18	N/A	N/A	N/A	N/A
2005	1030 MW	Gas	503	478	495	503	503	503
		Oil	-	24	8	-	-	-
	1780 MW	Gas	496	468	487	489	496	496
		Oil	-	22	8	6	-	-
	4435 MW	Gas	498	439	484	491	494	498
		Oil	-	18	11	6	4	-
2010	5015 MW	Gas	588	517	570	576	580	588
		Oil	-	95	22	12	6	-

Downstate New York

Year	Net Electric Generating Capacity Additions (Post 2002)	Fuel	Maximum Potential Gas Demand (1,000 MMDT)	Estimated Gas and Oil Consumption (MMDT)				
				No Post 2003 Pipeline Expansions	300 MDT/day Expansion into Downstate Region	400 MDT/day Expansion into Downstate Region	500 MDT/day Expansion into Downstate Region	800 MDT/day Expansion into Downstate Region
2002	N/A	Gas	305	273	N/A	N/A	N/A	N/A
		Oil	-	16	N/A	N/A	N/A	N/A
2005	296 MW	Gas	285	263	279	285	285	285
		Oil	-	22	6	-	-	-
	1,046 MW	Gas	282	257	275	282	282	282
		Oil	-	20	6	-	-	-
	2,513 MW	Gas	290	232	277	283	286	290
		Oil	-	18	11	6	3	-
2010	3,093 MW	Gas	336	268	320	327	331	336
		Oil	-	94	21	11	5	-

The results presented in the table highlight several key findings.

- The statewide maximum potential gas demand for electric generation is higher in all 2005 cases than in the corresponding cases for 2002. This result is due to growth in electric loads as well as the presence of more base-load, gas-fired generation.

- Comparing the projected fuel use across capacity-addition scenarios shows that for a given level of pipeline capacity, gas deliveries typically decrease when a larger amount of new electric generation capacity is added. As more combined-cycle generating units (CCs) are added in the downstate area, the limited amount of gas available in those areas is able to support more generation due to the relative efficiency of the new units. Hence, less electric generation is needed from other areas, and less total gas is consumed.

- The efficiency advantage of new CCs also lowers the need for generation from steam units fueled by residual oil. As a result, oil use generally also declines as more new generators are added.

- Pipeline expansions totaling 800 MDT per day into the downstate area are sufficient to meet the maximum potential demands of generators in the case with the most new electric capacity (4,435 MW). Fewer pipeline expansions are needed to meet the maximum potential demands if less new generation capacity is added. In the case with 1,780 MW added, only 500 MDT per day is required; in the case 1,030 MW, 400 MDT per day is sufficient to meet the maximum potential gas requirements.

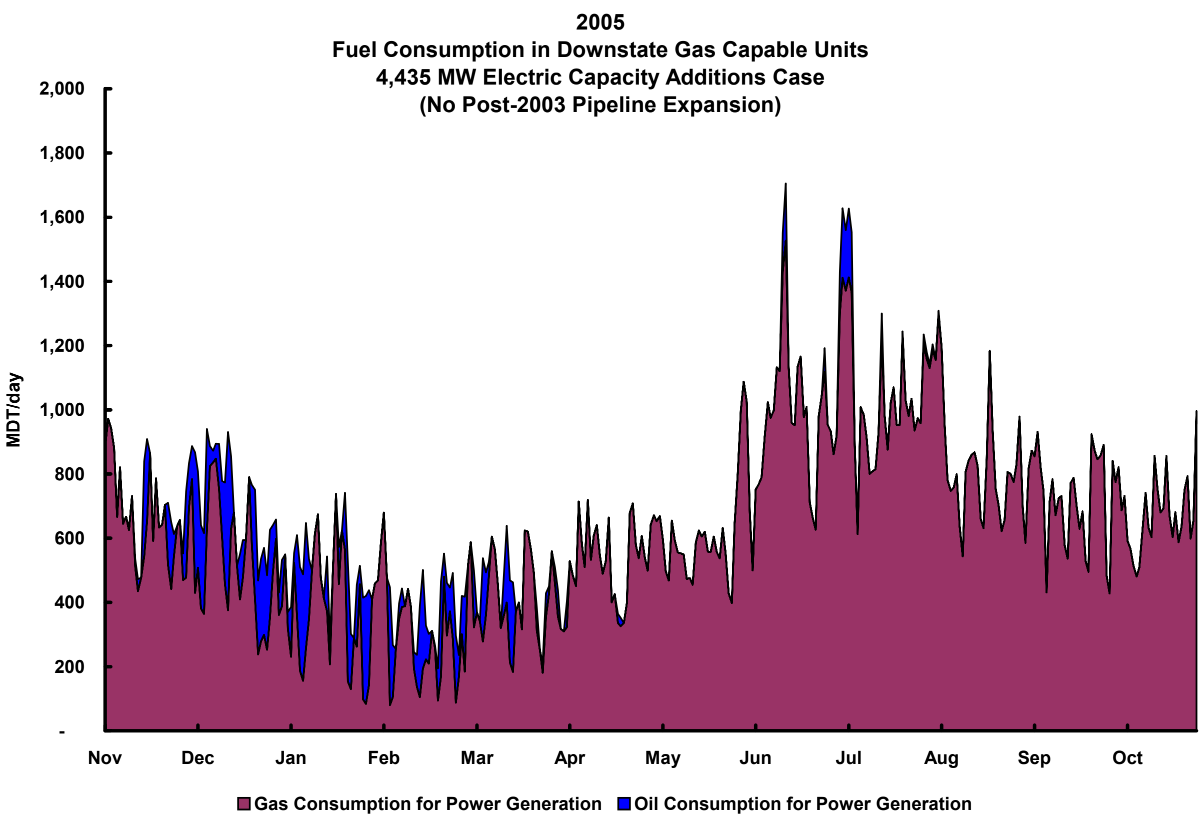
- Our case for 2010 shows that annual fuel demands among gas-fired and dual-fueled generators will increase approximately 20 percent between 2005 and 2010. This substantial increase in generation reflects the fact that existing base load units (nuclear, coal, and hydro) are already operating near full capacity in 2005. Hence, incremental electric load growth will need to be met either by new CCs or by existing steam units that have traditionally operated at low annual utilization levels. The 2010 maximum potential gas demand of generators can be met with 800 MDT per day of pipeline expansions into the downstate region.

As the issue of pipeline adequacy for the growth in the generation market is one of the principal areas of interest for this study, we have shown the daily deliveries of gas and oil to the Downstate electric generators for the 4,435 MW electric case under each of the pipeline expansion scenarios that we analyzed. The data are for the full year. Figures 18-22 illustrate the gas deliveries and the oil consumed (primarily residual fuel oil in dekatherm equivalents).

Figure 18 depicts gas (shown in maroon) and oil (shown in blue) usage for 2005 in the case where there are no post-2003 expansions in gas pipeline or LDC capacity. As illustrated, a substantial quantity of oil is consumed in this scenario during the winter, as well as on a few peak days in the summer.[29] Figure 19 depicts gas and oil usage with 300 MDT per day of additional pipeline/LDC capacity into the downstate region. Two things change as a result. The amount of oil used declines substantially. Oil is used in dual-fuel or oil-only units only in the winter. Additionally, as the high efficiency CCs are substituted for the older steam electric units, the total fuel use in the downstate area declines.

As shown in Figure 20, adding an additional 100 MDT per day (for a total of 400 MDT per day) has very little impact on the relative amounts of gas and oil burned to generate electricity in the downstate area, since there was very little oil burned in the 300 MDT per day case as a starting point. Oil is still used in dual-fuel units for a few days, even in the 500 MDT per day case shown in Figure 21. Figure 22 shows that, with the entire 800 MDT/d of incremental gas pipeline/LDC capacity expansions, oil use for electric generation is completely eliminated, even during the winter.

Figure 18



29 Projected oil usage is compared with historical levels in section 5.5 below.

Figure 19

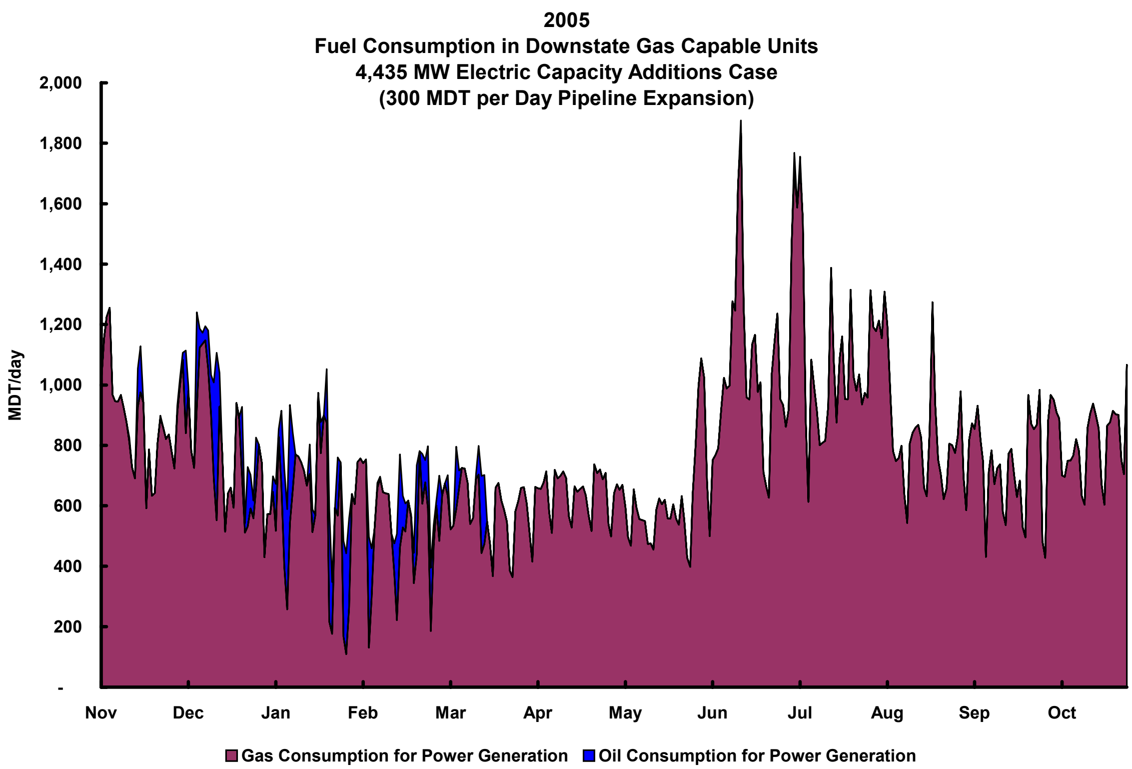


Figure 20

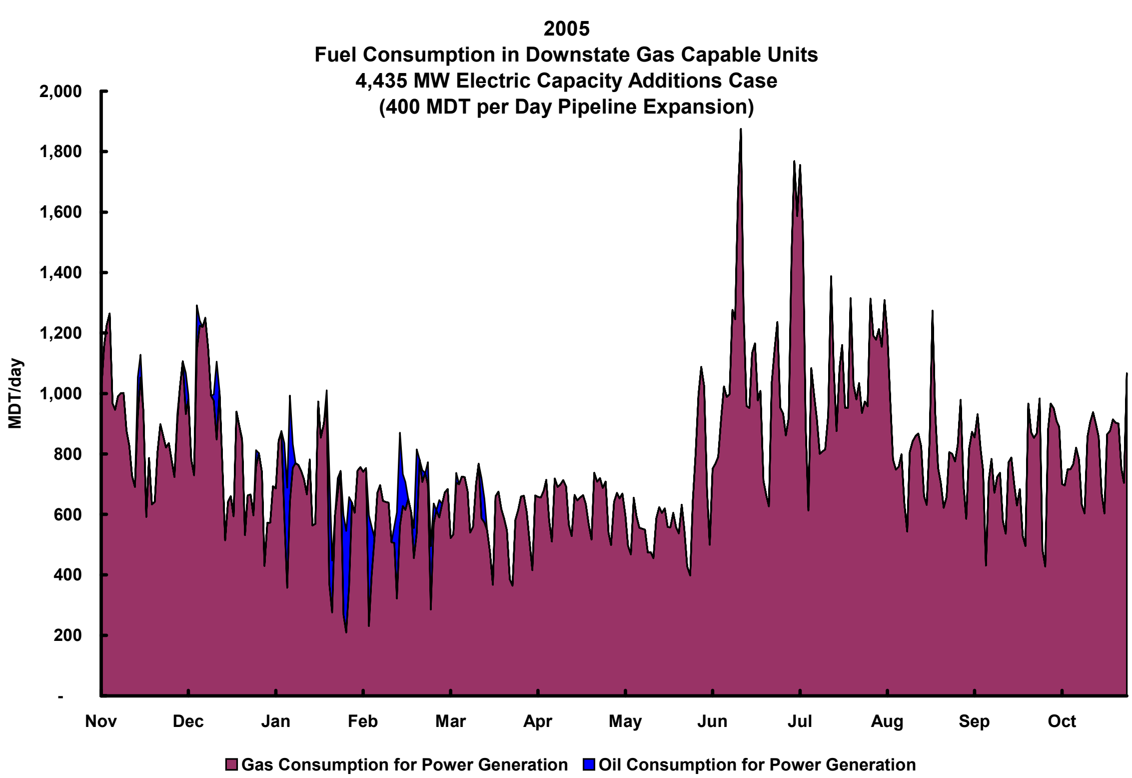


Figure 21

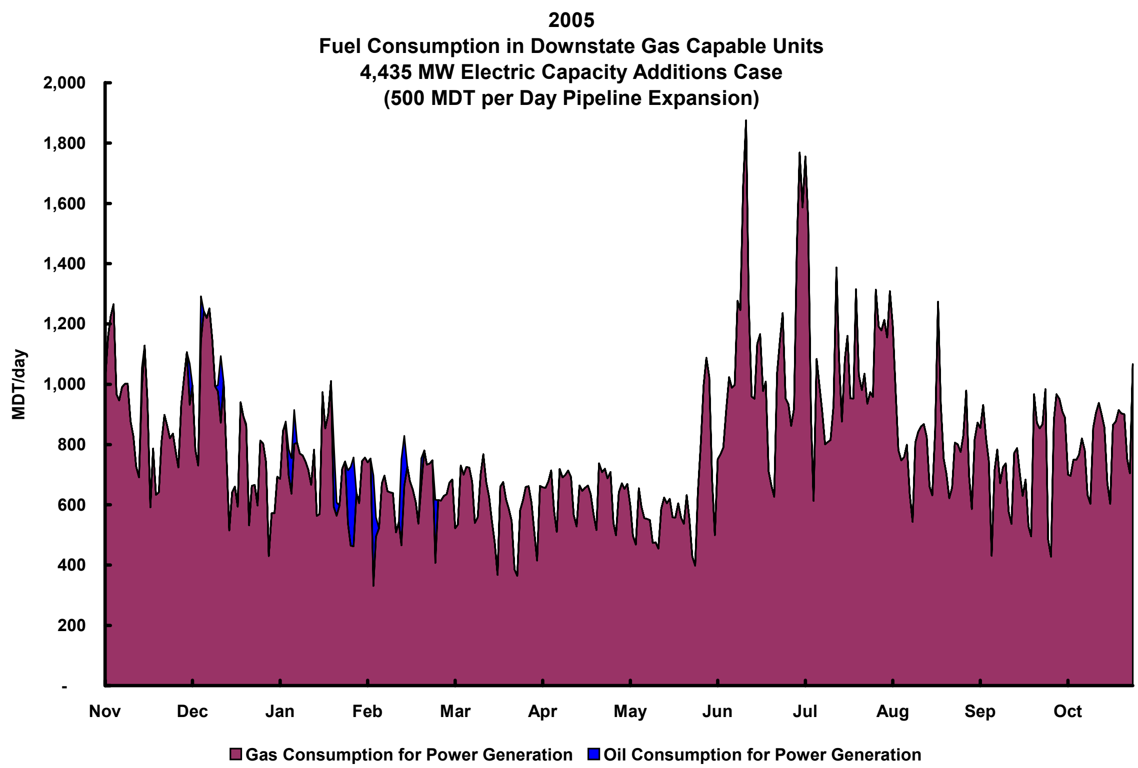
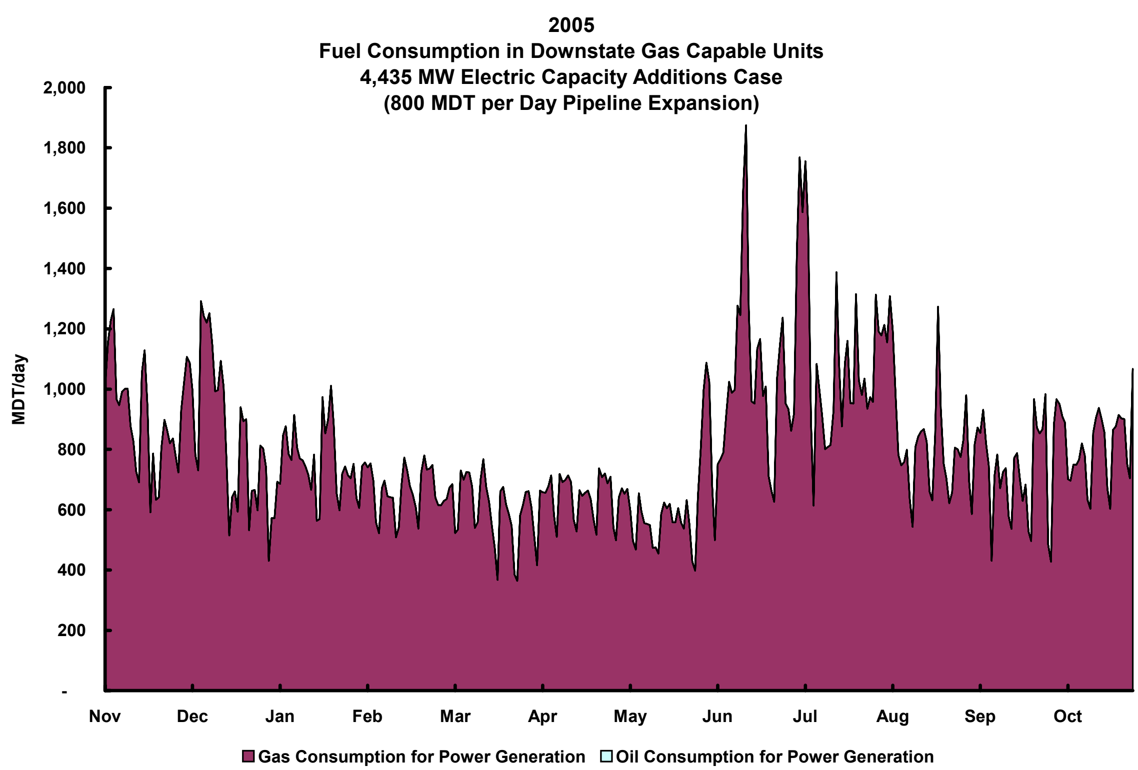


Figure 22



Figures 23, 24, and 25 show available and utilized capacity into an example gas load pocket in the downstate area under the case with 4,435 MW of capacity and various levels of pipeline expansion. For different levels of pipeline expansion, the charts illustrate chronologically over the year the utilization of gas delivery capacity and the periods when oil needs to be burned. The green shaded area represents the capacity available for deliveries to electric generators (after nonpower demands have been met). The maroon portion represents estimated deliveries to electric generators. During periods when delivery capacity is fully utilized, the green area is not visible behind the maroon. The yellow area illustrates the amount of oil that is burned by electric generators when gas pipeline capacity is fully utilized.

- If no pipeline expansions are added in the 2003–2005 period, the delivery capacity into the area is fully utilized on many days. As a result, some oil is burned during many days in the winter and a few days in the summer.

- If downstate pipeline capacity is increased by 300 MDT per day, the full capacity is required on substantially fewer days and less oil is burned.

Figure 23

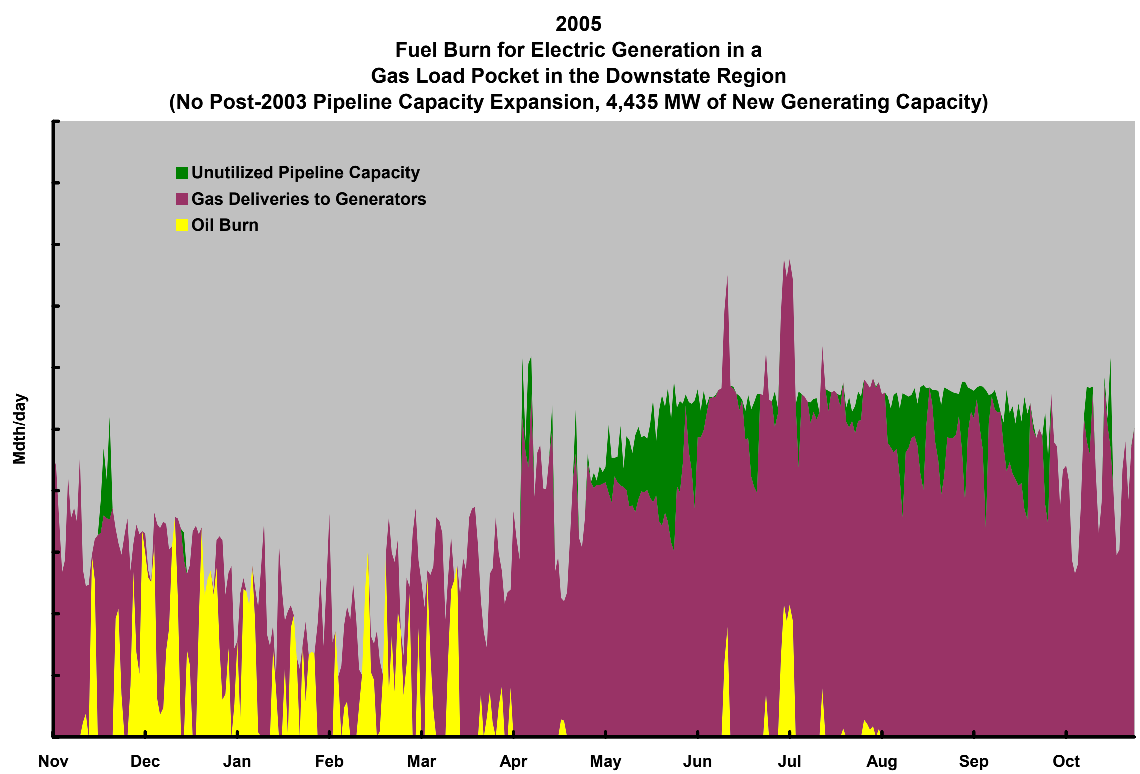


Figure 24

2005
Fuel Burn for Electric Generation in a
Gas Load Pocket in the Downstate Region
(300 MDT per Day Expansion, 4,435 MW of New Generating Capacity)

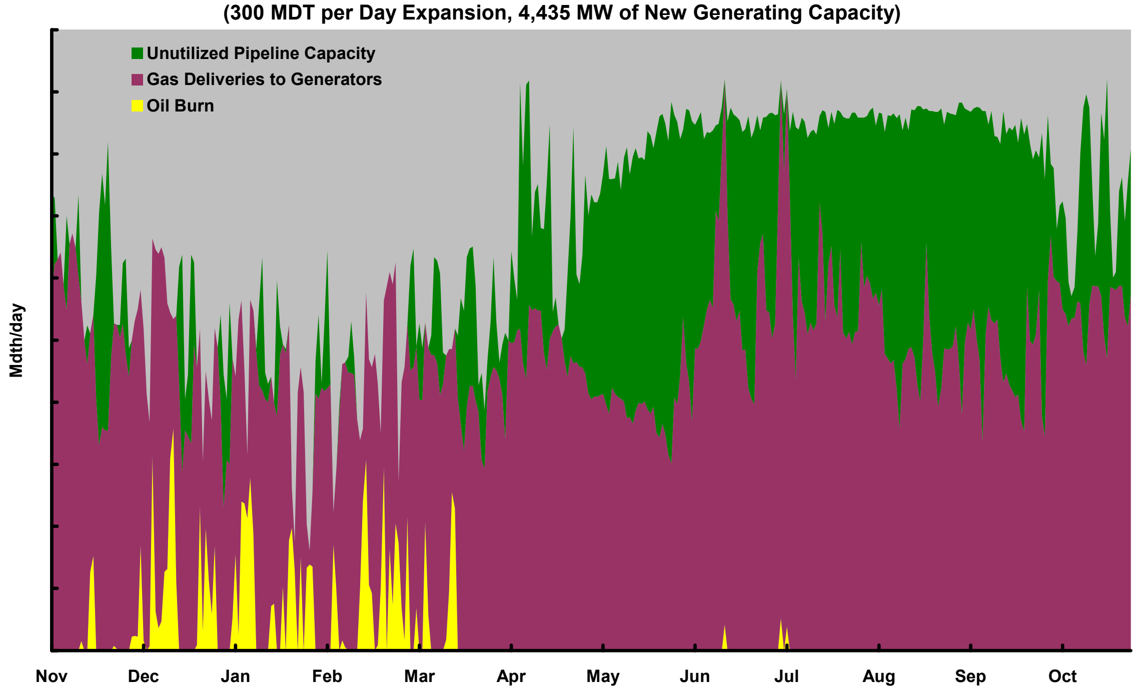
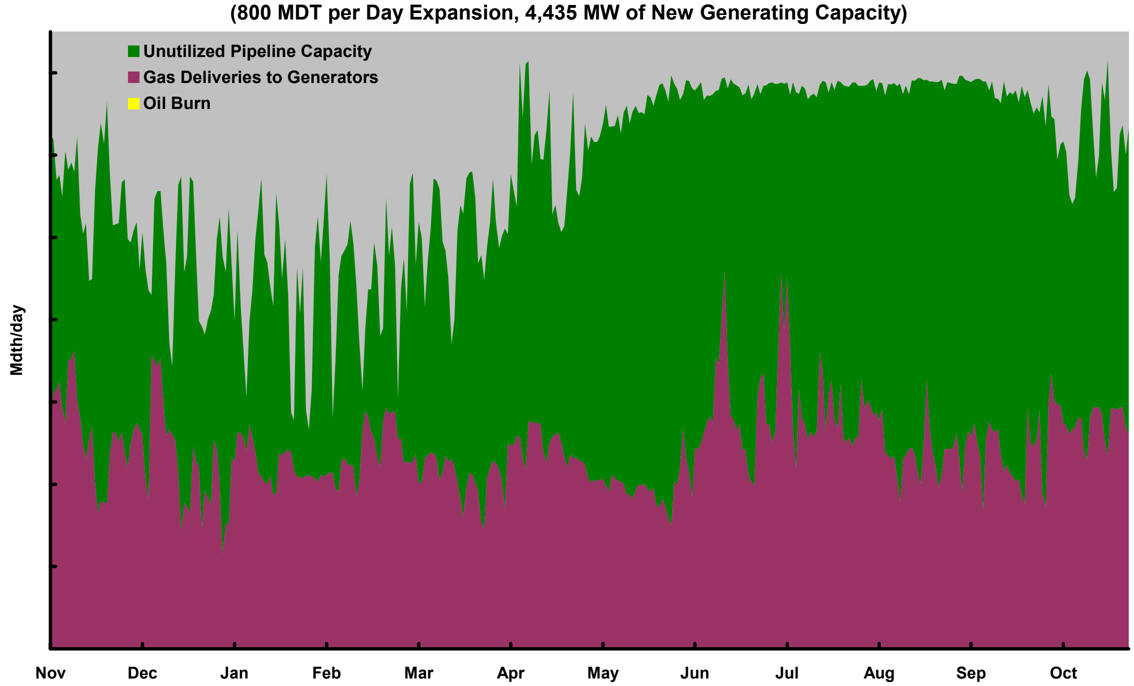


Figure 25

2005
Fuel Burn for Electric Generation in a
Gas Load Pocket in the Downstate Region
(800 MDT per Day Expansion, 4,435 MW of New Generating Capacity)



- When all proposed pipeline expansions are included (for an additional 800 MDT per day of capacity), generators' full, maximum potential gas demands can be met and there is substantial unutilized pipeline capacity throughout the year.

Figures 26 and 27 illustrate the seasonality in electric generators' potential gas demands and the amount of capacity available to meet those demands. The graphs depict load duration curves for winter and summer gas deliveries to electric generators in the downstate region in 2005. The bottom area of each graph, shaded blue, shows the projected gas deliveries to the electric generation market in 2005 for our case with 4,435 MW of new electric generating capacity and the most restrictive pipeline expansion scenario (only the 465 MDT per day currently being added). The jagged, yellow area on top of the load duration curve shows the portion of electric generators' maximum potential gas demands that would not be served, given the assumed pipeline capacity.

Figure 26 illustrates the situation for winter 2005 (covering November 2004 through March 2005). Some gas is available for electric generation in the downstate region everyday (after nonpower gas demands are fully met), just not enough to serve the entire potential requirements of gas-capable generators. There are only six days when the maximum potential demands of electric generators are fully met, and deliveries total 56 percent of maximum potential demand. When the maximum potential demands are not met, either the generators will burn oil in place of gas, or other non-gas-fired units will be dispatched in their place. Alternatively, pipeline capacity would need to be expanded if the unserved portions of winter demand were to be met.

The situation in the summer is very different, as shown in Figure 27. Electric generators' maximum potential demands for gas are fully met on 134 of 214 days. And, on those days when there are unmet demands, the shortfall is a relatively small portion of total maximum potential gas demands. As a result, deliveries total 93 percent of maximum potential demand. Hence, little expansion would be needed to meet unrestricted summer gas demands for electric generation.

The addition of 300 MDT per day into the downstate market has a significant effect on the proportion of unrestricted winter gas demands that can be served. Figure 28 shows the winter gas demands and deliveries from Figure 26, but with the additional portion of potential demand that can be met with the pipeline expansion in place shaded red. With the additional capacity, most (89 percent) of the winter maximum potential gas demands for electric generation could be served. In the summer, the additional 300 MDT per day of capacity would be utilized very little as the existing available capacity is very large relative to the maximum potential gas demands for electric generation. The result is that summer demand provides little economic support for the pipeline expansion.

These charts illustrate the dilemma facing owners of new CCs as they consider their gas supply options. Since a pipeline/LDC expansion will require electric generation owners to contract for firm capacity to compensate for its construction, the generators are faced with a situation where, effectively, the entire year-round cost of the pipeline expansion would need to be justified by their desire to secure gas supplies in the winter. In order for the generators to be willing to enter into firm capacity contracts, winter prices in the electricity market would need to be high enough to compensate the generators for the cost of securing firm capacity. Given that electricity prices and spark spreads are typically lower in the winter than in the summer and electricity prices may be, in effect, capped by the generation cost of steam units burning residual oil, owners of CC units may not have an incentive to contract for firm, year-round capacity.

Figure 26

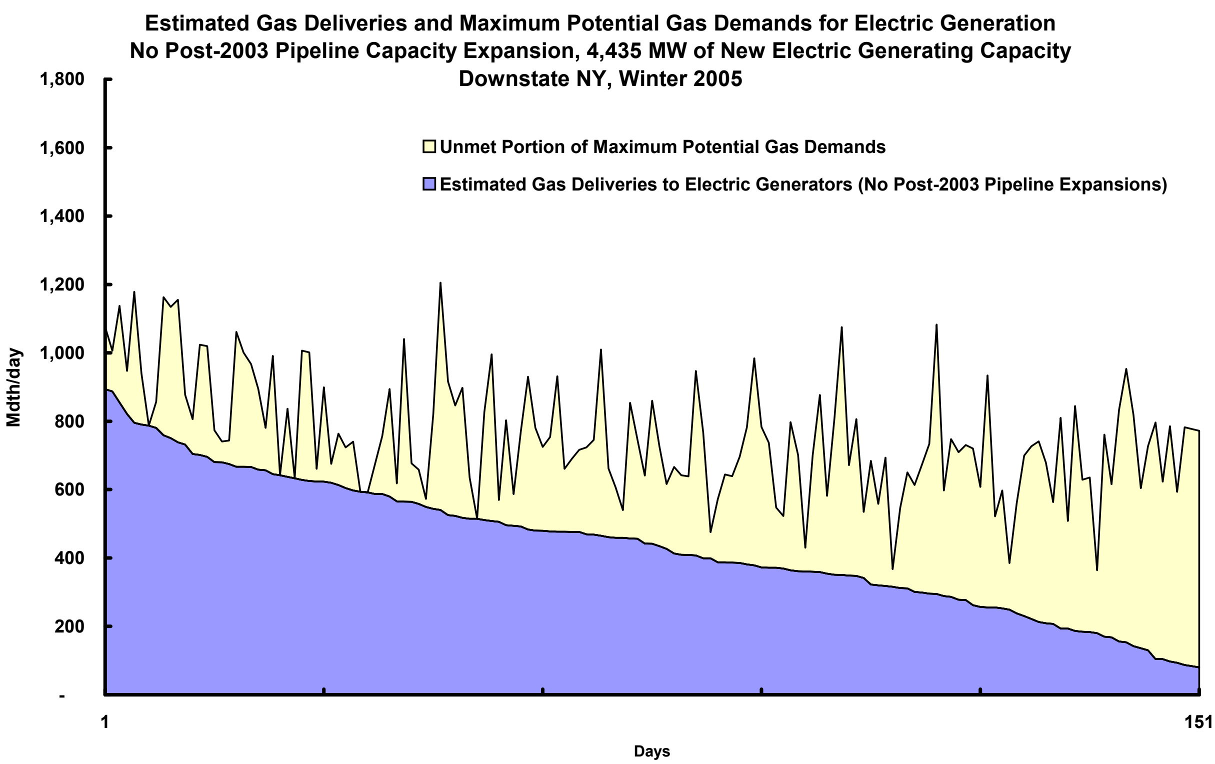


Figure 27

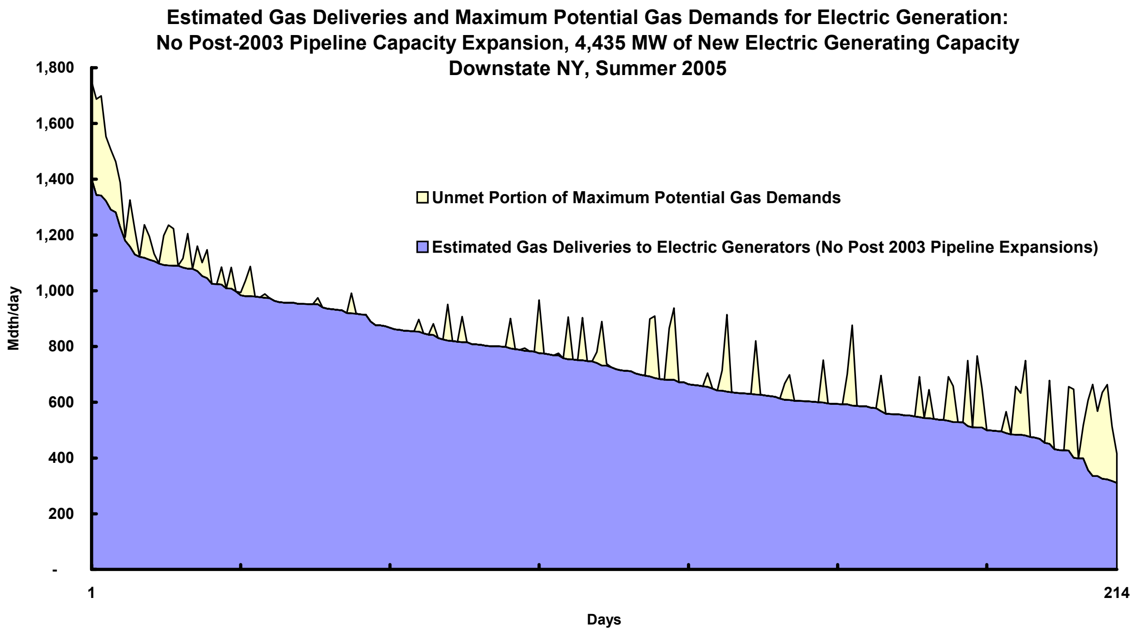
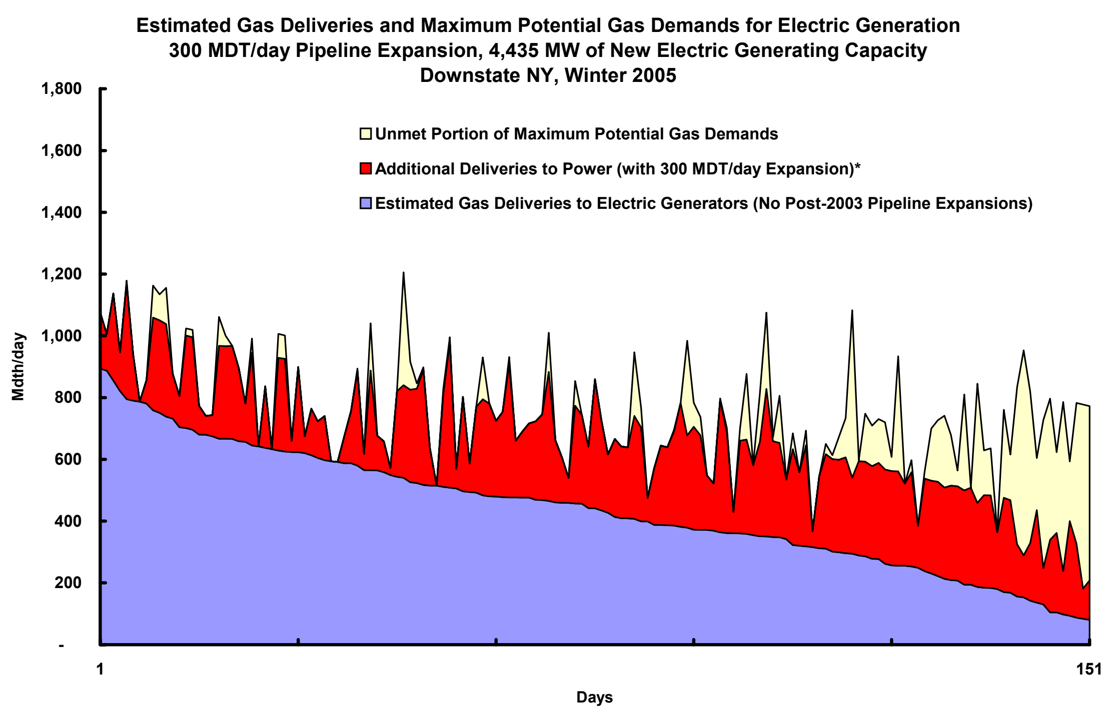


Figure 28



* Represents additional deliveries to the power markets from a 300 MMcf/d pipeline capacity expansion into the downstate region.

The risk to the electric industry is relatively low as long as the substantial overhang of oil-fired generation capacity that currently exists, as shown in Table 12, is not substantially diminished. A substantial decline in the available oil fired generation capacity would increase the probability that the lack of firm pipeline capacity would create a dilemma for the electric industry. As Table 12 illustrates, if no gas were available at all during the winter, the existing oil capable units can substitute completely for those generating units burning gas, allowing electricity demand to be met entirely. Interestingly, it is not actually the oil-fired steam electric capacity that is important here but rather the fuel storage and resupply capability inherent in that capacity.

If the predominately residual oil storage tank capacity were converted to distillate oil tanks, new combined cycle plants were located on sites where the tanks exist, and inventory volumes of distillate oil were maintained, then the issue of winter service gas availability would become moot, even for the CC units (as long as the facilities could burn oil for more than 720 hours and maintain inventory volumes of oil). In the event that the CCs do not install more than a few days of on-site distillate storage, the capacity to refill their tanks becomes important. For the repowering plants, there is often existing barge delivery that would allow refills without introducing substantial stress on the petroleum industry. However, waterways do occasionally freeze, affecting barge deliveries at oil terminals and/or power plant sites. Additionally, during periods of extremely cold weather, the combined demands of electric generators and heating customers have, on rare occasions, made the distillate oil market very tight.

Table 12
Available Substitute Capacity for Gas-Fired Generation, by Type
4,435 MW Electric Capacity Additions Case
Downstate New York
2005

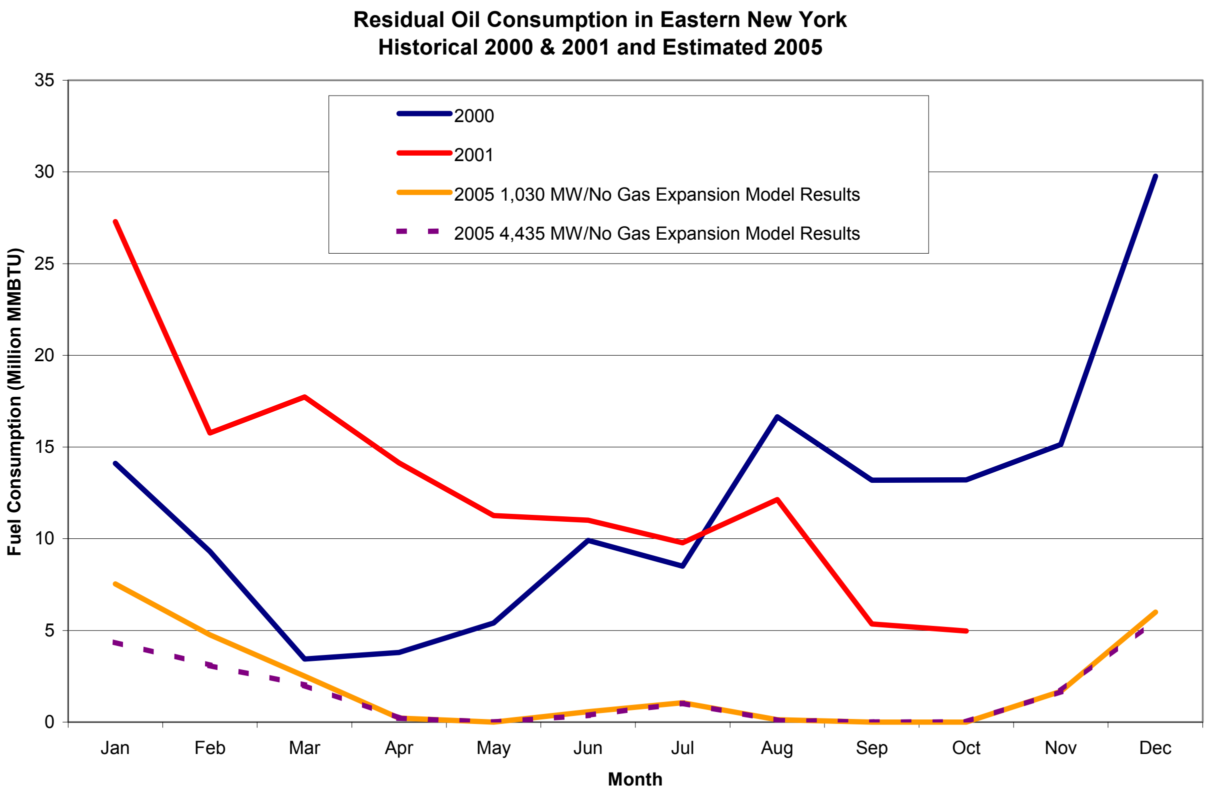
Period	Gas Committed				Available Uncommitted	
	Dual-Fueled Steam Electric Units		Combined Cycle & Combustion Turbine Units		Oil-Fired Peaking and Steam Electric Units	
	Peak Hour Gas-Fired Generation (MW)	Percent (%)	Peak Hour Gas-Fired Generation (MW)	Percent (%)	Peak Hour Oil-Fired Generation (MW)	Percent (%)
Winter Peak	2,037	14%	4,581	33%	7,475	53%
Summer Peak	4,424	34%	5,245	40%	3,376	26%

5.5 PROJECTED AND HISTORICAL OIL USAGE

We have compared our projected 2005 oil burn for electric generation in New York with historical data as a way of validating the reasonableness of our cases. Figure 29 shows 2000 and 2001 historical monthly oil use along with estimated 2005 oil use from two of our model scenarios: our 4,435 MW capacity additions case with no pipeline expansions and the case with 1,030 MW of new CCs and no pipeline expansions. The total amount of oil burned in each of these cases is below the historical levels from both 2000 and 2001. Because the results from the case with 1,030 MW show that more oil is burned than in any other case we have modeled, we can conclude that the amount of oil burned in each of our cases falls below historical levels.

This finding suggests that the levels of oil burn that we have estimated should be feasible under existing and expected future environmental restrictions.

Figure 29



5.6 EXTREME WEATHER SENSITIVITY CASES

While our analysis indicates that the gas and electric systems can reliably meet their future loads under a range of electric generation and gas pipeline expansion scenarios, oil use by electric generators remains a key substitute for gas during times of peak gas demands (*e.g.*, cold winter days). This is particularly true during extreme winter weather conditions. For example, in 2005 under normal winter weather conditions, if 4,435 MW of generation capacity is added along with 300 MDT per day of post-2003 pipeline expansion, gas pipeline capacity into the downstate market is adequate to satisfy 89 percent of the total potential winter gas demand for electric generation.[30] Under design winter conditions, where the temperature-sensitive gas load can increase between 10 and 20 percent (depending on the LDC), the gas available for electric generation declines substantially. As shown in Table 13, in this case, only 70 percent of total potential winter gas demand for electric generation is met, compared to 89 percent in the normal weather case. Lower levels of gas use will require offsetting increases in oil-fired generation to

[30] As explained above, oil-fired generation is used to for the remaining 11 percent of total fuel needs to ensure that electric needs are fully met.

ensure that electricity demands are fully met. Alternatively, gas-fired generators could operate at a level similar to what we have estimated for a normal 2005 winter if between 100 and 160 MDT per day of additional pipeline capacity were added.[31]

Table 13
Generation by Gas-Fired and Dual-Fueled Units (GWh)
Downstate Region 2005 Design Winter Case
4,435 MW Generating Capacity Additions Case

	Maximum Potential Gas Demand	No Post-2003 Pipeline Expansions	300 MDT/day Expansion Into Downstate	400 MDT/day Expansion Into Downstate	500 MDT/day Expansion Into Downstate
Combined Cycle Units Fueled by Gas	27,856	26,520	24,035	25,321	26,340
Other Units Fueled by Gas	9,003	8,656	8,302	8,370	8,440
Redispatched Units Fueled By Oil	0	1,038	1,632	1,509	1,072
Total	36,858	36,214	33,970	35,200	35,852
# of Days When Unrestricted Gas Market for Power Is Served	365	280	246	272	298
% Served of Unrestricted Gas Market for Power	100%	95%	88%	91%	94%

Higher than expected electric demands pose another potential risk to the gas and electric system. However, our finding that the gas and electric systems can reliably meet their future loads across the range of scenarios included in our analysis holds true, even with higher electric loads. In a 2005 case with extreme weather loads (defined as an increase in both peak demand and annual energy requirements consistent with the extreme weather peak forecast reported in the NYISO Gold Book[32]) and 4,435 MW of new capacity, electric loads can be met under all pipeline addition scenarios. In this case, slightly more oil needs to be burned by electric generators in each corresponding pipeline scenario, but total oil burn remains below historical levels and should therefore be available.

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[31] As shown in Figure 17, under design winter conditions there is one day when a very small portion of upstate gas demands for electric generation cannot be fully supplied. Hence, a very small amount of oil would also need to be burned in the upstate area.

[32] See New York Independent System Operator, *2001 Load and Capacity Data* (Gold Book), pp. 4–5.

5.7 ELECTRICITY GENERATION FUEL MIX AND RELIABILITY CONSIDERATIONS

With the addition of new CCs in the NYCA market, gas will fire an increasing amount of electric generation. The new, more efficient CCs will replace output from the less-efficient, gas-fired units, output from generators burning other fuels, and imports into NYCA from other regions. This substitution will increase the portion of NYCA electricity generated from gas.

Prior to the introduction of the gas-fired CC units, the gas used for power generation in the downstate market was in dual-fuel steam units. Whenever gas was not available for these units, they simply shifted to oil. As most of the new CCs do not have either firm delivery contracts for gas or oil backup for more than a short time (if at all), the reliability of the units is subject to gas availability, something that cannot be guaranteed under current conditions.

There are three ways that the electric system can broadly maintain, and possibly enhance, its reliability as the dependence on gas increases. First, if the new units were to contract for firm gas supply and delivery services, then absent a delivery system failure, the fuel would be available when the units were dispatched to run. Secondly, the units could install a backup fuel if they could be assured that they could switch on the fly should their gas supply be interrupted. Third, if the overall system (not the CC units themselves) could have adequate oil-fueled capacity that is capable of meeting the 10- and 30-minute response time requirements.

Each of these "solutions" comes with caveats. In the first case, where the CCs contract for firm gas, the CCs would have to absorb the price of firm pipeline capacity – a cost that is much higher than the released capacity or interruptible rates they would otherwise pay. Based on the limits to surplus pipeline capacity to New York, it is unlikely that a significant number of CCs could expect to operate with gas without committing to a firm pipeline contract (likely to be a pipeline expansion). The reluctance to enter into such an agreement by a CC operator is driven by short-term economics—the lack of compensation for being a "more reliable supply" and the limited profitability of selling into the electricity market during the winter periods when the high cost capacity would be unlikely to be obtained otherwise.

Even with a firm gas contract, the diversity of the gas supply plays a role in the reliability of the unit. Clearly, if all of the units were served by a single pipeline, should that pipeline suffer any major system failure that could not be addressed by other gas supplies, then the system would still need some oil-fired generation units. These could be the CCs if they had adequate short-term oil backup on site (useable for days, not hours) in which case the steam units may be retired. Alternatively, the existing oil-fired steam electric units could be provided incentives to remain in service to assure system reliability. This is an interesting aspect of the repowering situations where there are already large storage tanks on site. Converting one of these tanks to a distillate tank (with the environmental permits to utilize the fuel as needed) would provide a new CC unit with oil availability comparable to that of an existing dual-fuel steam unit.

If the units were to have backup fuel and permits to burn it for extended periods (weeks, not days), then the units' fuel reliability would be very high. Under these conditions, it is likely that the existing steam units would be dispatched so rarely, that their opportunity costs may exceed their value in the electricity market and they would be retired.

In the third case, where the CCs do not have a firm contract for gas or a sufficient backup fuel, it is unlikely that the pipelines would be constructed. The existing steam electric units would likely remain in service and run when gas was unavailable to the CCs. In this case, the CCs would have relatively low capacity factors, and less-efficient units with higher emission rates would run more often.

The disconnect between the gas industry and the electric industry is quite stark. If one analyzes the behavior of the merchant power sector, they have little incentive to either contract for a firm gas supply or to install any substantial oil backup in the current environment. First, there is a substantial amount of released pipeline capacity available in the summer to serve the downstate market. This capacity can be had at a sizable discount from filed pipeline tariffs, providing generous savings. Secondly, the backup fuel (or firm capacity) is primarily required during the winter months when the margin on generation has traditionally been low, so the penalty for not operating on any given winter day(s) is small. Finally, there is no compensation to the generators for acquiring any backup (*i.e.*, no differential consideration in a generator's ability to participate in capacity markets).

On the pipeline side, pipelines are required by the FERC to show a market need for new capacity. The only accepted showings are executed capacity contracts. Without a demonstrable market, the pipelines will not be built. And because the incremental market is largely a power generation market, the lack of incentives on the merchant generator side effectively delay the timing of the pipeline expansions until the generators sense that there will not be adequate surplus pipeline capacity for a sufficient number of months and they contract for the space. The incentives of the two players need to be realigned if the goal of greater electric efficiency, reliable generation, and better air quality at a reasonable cost is to be achieved.

APPENDIX A: NEW YORK GAS AND ELECTRIC SYSTEM INFRASTRUCTURE

A-1. GAS INFRASTRUCTURE

The gas industry infrastructure in New York consists of eight interstate US pipelines and one intrastate pipeline [33]; thirteen gas distribution companies [34] (commonly referred to as LDCs); and local gas production and storage facilities.

INTERSTATE PIPELINES SERVING NEW YORK

All of the pipelines in the state were included in the analysis. The geographic territories of the pipelines vary widely. By virtue of these pipelines, New York has a diversified supply mix, receiving gas from US production in the Southwest, the Gulf Coast and Appalachia as well as New York; Canadian supplies from both western and eastern basins; and small amounts of imported liquefied natural gas (LNG) from various foreign sources (delivered via exchange/displacement from New England).

Three of the pipelines serve only the upstate area, three serve only the downstate area and four serve both. The pipelines are listed below by the areas they serve.

Table A1
Pipelines Serving New York State by Region
(As of January 1, 2002)

Upstate Only	Both regions	Downstate Only
Dominion Transmission	Columbia Gas Transmission	Algonquin Gas Transmission
Empire Transmission	Iroquois Gas Transmission	Texas Eastern Transmission
National Fuel Gas Supply	Tennessee Gas Pipeline	Transcontinental Gas Pipeline
	Trans Canada Pipeline (at international borders)	

New York has a very limited amount of in-state storage, most of which comes from LNG facilities within the LDCs. The Stagecoach project will add some new high-deliverability, underground storage.

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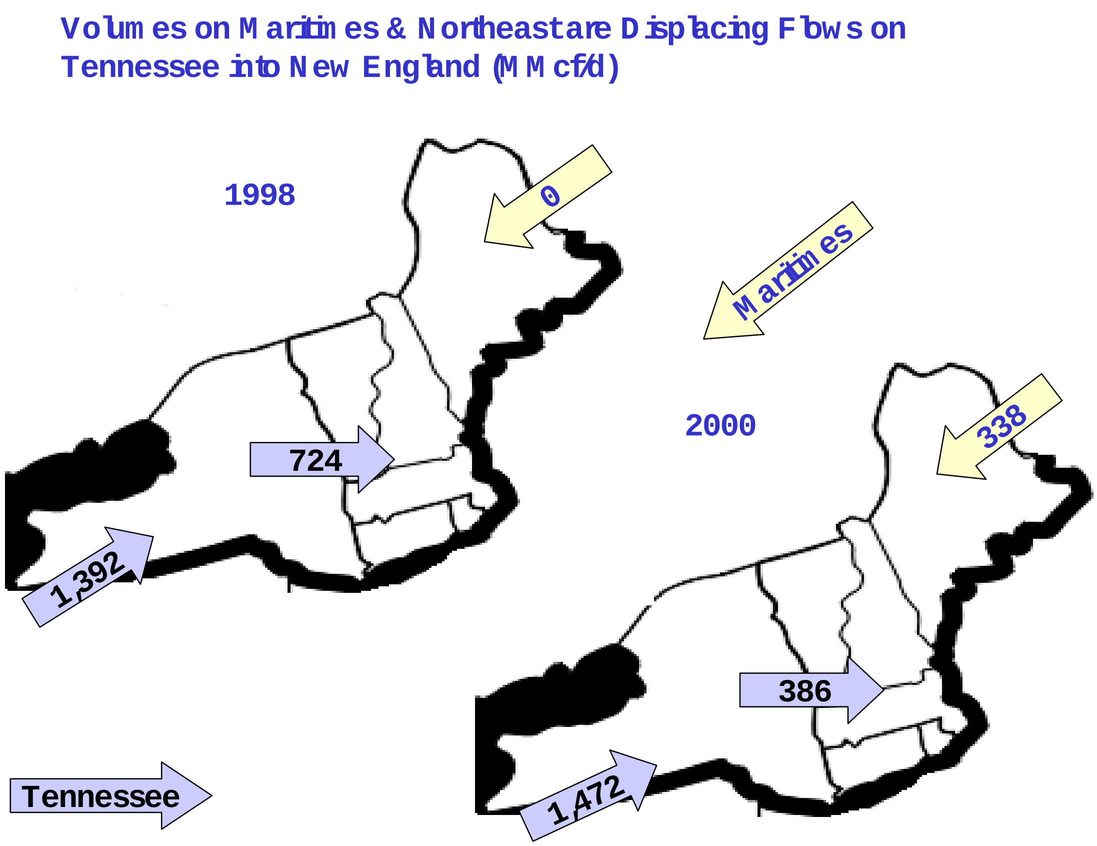
[33] A second intrastate pipeline, North Country Pipeline was excluded from the analysis. The power load served by North Country (Saranac) was included within our analysis as part of NYSEG.
[34] Three very small LDCs were excluded from the analysis, Woodhull and Filmore (both municipal companies) and Corning Natural Gas.

The pipelines serving New York and New England traditionally have been long haul transmission lines, with ultimate supplies coming from the U.S. Southwest and Gulf Coast as well as Western Canada (and some small quantities of Appalachian production). For this reason, the Northeast was always at the farthest end of the pipe, with the commensurate high cost and limited flexibility. All of the gas that entered the region stayed in the region. No other region's capacity could be diverted to the Northeast to provide even temporary relief for any "crisis." As a consequence, the capacity in the region was limited to what the region both needed and was willing to pay for.

With the advent of U.S. imports from the Sable Island production (offshore Nova Scotia), the Northeast finally had relatively short haul production from the north that greatly expanded both the pipeline delivery capacity, as well as the supply of gas in the region and enhanced the flexibility of pipeline deliveries. These incremental pipeline flows not only supplied new markets (*e.g.*, new combined cycle electric generators in New England), but also offloaded pipeline capacity coming from the south so that capacity might be used in other areas. Sable Island gas does reach into New York occasionally. Much more importantly, however, is the fact that it meets some of New England's market requirements, thereby allowing the pipeline capacity that flows through New York (to New England) to be utilized in New York, if needed. This displacement effect (illustrated in Figure A1) is of greater regional consequence than the actual volume itself.

Figure A1



A-2 ELECTRIC INFRASTRUCTURE

ELECTRICITY DEMAND AND SUPPLY SITUATION IN THE NORTHEAST

Table A2 shows New York summer and winter peak demands for the previous ten years, as reported in the NYISO Load and Capacity Data report for 2001 (the Gold Book). Summer peak loads in New York have grown to just over 30,000 MW. Winter peak loads are typically about 5,000 MW below the summer peak.

Table A-2

New York Summer and Winter Peak Demands

Year	Summer Peak (MW)	Winter Peak (MW)
1991	26,839	22,981
1992	24,951	22,704
1993	27,136	23,810
1994	27,062	23,343
1995	27,206	23,508
1996	25,587	22,728
1997	28,700	22,568
1998	28,160	23,879
1999	30,311	24,051
2000	28,138	23,764

According the NYISO Locational Installed Capacity Requirements Study for the 2002-2003 Capability Year (dated 14 March 2002), peak demand for 2002 is forecasted to be 30,475 MW. Peak summer electricity demand for NYCA is forecasted to grow at an annual rate of 1.3% between 2002 and 2005 – just under 400 MW per year. In contrast, winter peak loads are only forecast to grow at approximately 200 MW per year over the same period.

Similar growth rates are forecasted for surrounding markets:

- ISO-NE – Actual 2001 summer peak load in New England was approximately 25,000 MW, which translated to 23,790 MW on a weather-normalized basis. Summer peak loads are forecasted to grow at a rate slightly above those in New York—at 1.6% per year (or approximately 400 MW per year). Winter peak load is forecasted to grow at 1.3% (or 300 MW per year) for the next ten years.

- PJM—with an actual 2001 Summer peak load of approximately 54,000 MW, PJM loads are forecasted to grow at a rate comparable to loads in New York. Summer peak load is forecasted to grow at 1.5% per year (or approximately 800 MW per year) and Winter peak load is forecasted to grow at 1.4% (or 650 MW per year) for the next ten years.

Specific load forecasts for the ISO-NE and PJM markets are shown in Table A3.

Table A-3

Forecasted NEPOOL Peak Loads

Summer Peak Load (MW)												
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020
Load	23,650	24,140	24,493	24,860	25,308	25,718	26,012	26,377	26,724	27,075	36,300	37,870
Winter Peak Load (MW)												
	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2015-16	2020-21
Load	21,485	21,775	22,105	22,480	22,823	23,102	23,438	23,712	24,013	24,317	27,700	28,800

Source: 2001 CELT Report

Forecasted PJM Peak Loads

Summer Peak Load (MW)												
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020
Load	51,358	52,134	53,025	53,882	54,793	55,730	56,567	57,437	58,249	59,073	36,300	37,870
Winter Peak Load (MW)												
	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2015-16	2020-21
Load	43,110	43,763	44,378	45,025	45,669	46,283	46,903	47,533	48,120	48,749	27,700	28,800

Source: 2001 MACC Report

Growth in electricity generating capacity in ISO-NE and PJM will significantly outpace the growth in forecasted demands over the next several years. As listed in Table 2 below, this analysis includes approximately 10,300 MW of new capacity that is assumed to be added in ISO-NE between 1999 and 2003 and approximately 9,400 MW in PJM over basically the same time period. Virtually all of the units included in ISO-NE are either operating or currently under construction and nearly all of the additions listed for PJM are in operation or under construction. It is assumed that all of the units will finish construction and enter service as scheduled.

Table 2

ISO-NE New Capacity Additions

Unit Name	Installation Date	Winter Capacity (MW)
Dighton (CPN)	6/1/99	169
Bridgeport Harbor Station	7/1/99	520
Androscoggin Energy Center (Jay)	11/1/99	165
Maine Independent Station (Veazie)	5/1/00	520
Berkshire Power (Agawam)	6/1/00	272
Bucksport Cogen	6/1/00	174
Rumsford (CPN)	6/1/00	265
Tiverton Power Plant	6/1/00	265
Millenium Power Partners (Charlton)	11/1/00	360
Calpine Westbrook Power	3/1/01	540
Blackstone (AMNAPO)	5/1/01	580
Milford (EPPSCO) 2	5/1/01	272
Milford (EPPSCO) 1	5/1/01	272
Wallingford CC	6/1/01	250
Lake Road (Killingly)	10/1/01	792
Kendall Square (Cambridge)	12/1/01	263
ANP Bellingham	2/1/02	580
Mystic Station Expan CC8	3/1/02	775
Mystic Station Expan CC9	3/1/02	775
Fore River (Weymouth)	6/1/02	750
AES Londonderry	6/1/02	720
Newington CC (COEDDE)	6/1/02	525
RI Hope Energy (Johnston)	7/1/02	522
Total		**10,326**

PJM New Capacity Additions

Unit Name	Installation Date	Winter Capacity (MW)
AES CT in Accomac County 1	9/1/00	135
Burlington PSEG Power	10/1/00	186
Linden (PSEG)	10/1/00	160
Connectiv Hay Road Wilmington	1/1/01	333
AES Iron Wood NUG	1/1/01	700
AES CT in Accomac County 2	6/1/01	165
Hunlock Creek CT	6/1/01	44
Kraft Foods Cogen	6/30/01	88
Rockland Township	7/1/01	250
Archbald CT PEI Power	8/1/01	45
Liberty at Eddystone	10/1/01	170
AES Red Oak (Sayerville)	11/1/01	100
Calpine plant at Ontelanee	11/1/01	170
Williams Hazelton PA	1/1/02	568
Bergen PSEG Power	5/1/02	545
East Coast Power -- Linden	5/1/02	500
Kelson Ridge CC Phase 1	6/1/02	830
Linden CC1 PSEG Power	1/1/03	550
Linden CC2 PSEG Power	5/1/03	593
Marcus Hook Refinery	5/1/03	593
Cecil County	6/1/03	563
Hunterstown, Gettysbug PA	6/1/03	800
Marcus Hook Refinery	1/1/04	725
Hay Road Conversion to CC	1/1/04	550
Total		**9,363**

New capacity additions in New York State are not, in general, as far along the construction time line as those in the adjacent markets. Planned new capacity additions for New York are shown in Table 1 in the body of this report. Most of the capacity additions planned for the NYCA are scheduled for service beginning in 2004 or after – with only the NYPA combustion turbines and re-activated steam units currently in operation, and the LIPA "Powering Long Island" gas turbine projects scheduled to come on-line this summer.

Of the planned capacity additions, only the Athens project is currently under construction. However, several of the projects have met the requirements of Article X of the New York State Public Service Law. Article X sets forth a review process for consideration of any application to construct and operate an electric generating facility with a capacity of 80 megawatts or more. An applicant must meet Article X requirements to obtain the Certificate of Environmental Compatibility and Public Need (Certificate) that is needed before construction of such a facility can begin. Any application filed under Article X is evaluated by the New York State Board on Electric Generation Siting and the Environment (Siting Board).

Additional power will be available to New York via a 330 MW underwater HVDC cable between Connecticut and Long Island currently under construction.

APPENDIX B: OVERVIEW OF GAS DISPATCH MODEL

OVERVIEW

Our analyses are designed to evaluate the *physical* ability of the electric and gas systems to simultaneously meet their daily demands. For the gas industry, there are three distinct "capacities" that are important – contract firm capacity, physical capacity and takeaway capacity -- and each has implications for what may happen at a delivery point.

- The most common "capacity" reference is the **contractual firm capacity** of a pipeline. This is the volume that the pipeline has committed to deliver to a customer by virtue of a financially binding agreement. In the past, where long-term contracts dominated and the pipeline was limited to only building the capacity that customers had agreed to pay for, the contractual capacity and the physical capacity of a pipeline were often the same. With the advent of capacity pipeline restructuring, many customers have not renewed expiring contracts, thereby creating a spread between the physical and contractual capacity of a pipeline. In addition, pipelines have occasionally built expansions without contractual commitments for the entire volume and assumed the market risk of recovering their costs. In general, contractual capacity is less than the physical capacity of a pipeline.

- The second most common "capacity" reference is to the **physical capacit**y of a pipeline. This refers to the maximum amount of gas that can flow through any point given the size of the pipe, the ambient temperature and the maximum allowable pressure. While this term is widely used, it is often misinterpreted, since it varies with the actual pressure at a point. The pressure at a point can change as a result of what happens at another point in the pipeline system. For example, if a customer upstream of a given delivery point takes more gas, then the pressure at the downstream point will have declined and the pipeline's ability to deliver at the downstream point will be diminished. Conversely, early in the day, a pipeline may have increased their pressure and created some 'line pack' that would allow a customer to take more than they generally could at any given point. Any expectation that one could rely on these additional volumes without benefit of a contract may be questionable. Pipelines make day-ahead and hourly choices regarding what pressure they need to operate their pipe at, anticipating issues such as the volume requested by customers and temperature that may impose additional demands on the pipeline.

- The customer also imposes a limit on the volumes that may be delivered at a point known as the "**take-away capacity**." This is the maximum volume that the customer may receive at a point and it too is a variable, conditioned by the demand at that point. For example, a power plant near a pipeline/LDC city-gate may increase the delivery capacity of the station by virtue of its reducing the pressure on the receipt side of the point, thereby allowing more gas to flow.

Our analysis was based, in part, on the normal daily physical capacity of each pipeline. However, this is not the only "physical" capacity in the delivery network. Each of the capacities discussed above were addressed in our model design. Both the physical capacities along each pipeline and the take-away capacities at each delivery point to the LDCs have been assessed and included in the model. Where physical capacities exceed contracted volumes, the model was designed such that gas will preferentially flow at the contracted level. For example, if two pipelines serve an LDC, and pipeline A has physical capacity above its contracted capacity, the excess will not be utilized until pipeline B's contracted volumes have been filled. The limiting "constraint" at any point cannot be determined *ex ante*. Rather it must be determined within the context of the total system operations at each that point in time.

We have not addressed the price/cost implications of various outcomes to assess whether market participants would choose to pay for the gas deliveries. We have assumed that gas deliveries would be made if the physical delivery capacity existed, since the objective of our analysis was to assess the adequacy of the pipeline/LDC infrastructure. Given that the pipeline industry is based on a *contract carriage* paradigm, it is very important to understand that, absent commitments by customers to contract for new pipeline capacity, the physical flows we have characterized might not be realized in the market. While we have based our analysis on the physical capability of the pipeline industry to deliver the market volumes, there are several policy implications that may need to be addressed to deal with this distinction.

The gas model developed for this project is based on a network model (a variation on GRIDNET) that solves over a series of nodes (storage facilities, supply sources, demand sinks, pipeline interconnects) and arcs (pipelines) such that gas demand is met by supplies in an economically efficient manner. It does this through the use of EMNET, a linear programming algorithm that optimizes the gas pipeline system to maximize profit. The basic model has been modified in two significant ways to focus on New York State – first; we have represented the infrastructure and delivery systems within the state in great detail. Secondly, the model's aim has been changed from focusing on price differentials between market points to examine the feasibility of flow patterns. The model operates on a daily basis.

DATA SOURCES

In order to assure the quality of the model, a variety of sources have been used to obtain and verify data. Data were requested from pipelines, LDCs and federal and state government agencies as well as acquired from commercial vendors.

- Pipelines were asked to provide capacity data at the New York border, interconnects with other pipelines, interconnects with LDCs, and at other points along their systems (compressor stations, meter stations, or other points that may constrain the flows along the pipe).

- While most pipelines have complied with these requests, some have not—in these cases border capacities have been estimated using publicly available data from the Energy Information Administration's (EIA) "Natural Gas Pipeline State Border Capacity Database."

- LDCs have also contributed data regarding their off-take capacity from pipelines. Wherever possible, each interconnect has two volumes associated with it—a delivery capacity supplied by the pipeline, and a receipt capacity supplied by the LDC.

- The LDCs have also supplied data regarding storage contracts and usage patterns. These data include minimum and maximum inventory levels, maximum injection and withdrawal rates, must turn volumes, the geographic location of the storage fields behind the contracts, and the pipelines associated with the storage fields and contracts.

- Each LDC has also given information on expected demand volumes by category, over time and temperature variation. Demand categories include both firm and non-firm sales and transportation gas. Demand data are discussed in greater detail below.

INPUTS

Other than the physical attributes of the pipeline systems (interconnections, capacity, links, storage, etc.), the primary inputs to the model are the supply and demand parameters.

Demand

- Each LDC has provided estimates of their demand for non-power related gas for each year of the study. This includes firm sales gas, firm transportation gas, non-firm sales gas, and non-firm transportation gas. In addition, they have supplied us with normal-weather degree-day data, and we have broken out each demand category into "base" demand and temperature-sensitive demand.

- Power-related demand for fuel by each generating unit is provided by CRA's MAPS model of New York State's electricity grid. Since generating units have different abilities to burn gas and/or oil, we group the units in terms of their ability to substitute oil for gas:

  – Gas consumed by gas-only units, which includes both steam units taking gas at low pressures and some simple and combined cycle turbines that take gas high pressures. There is no ability for fuel switching at these units. Hence, if gas is unavailable to these units they will not operate and electricity demands will need to be met by other generating units.

– Fuel (either gas or oil) consumed by dual-fuel steam units. If gas is unavailable at these plants, their demand for fuel can be met by substituting oil in place of gas, and therefore will not represent a problem for the electricity grid.

– Fuel (either gas or oil) consumed by simple and combined cycle turbines that predominantly burn gas, but have some oil backup capability.

The total demand for fuel by gas capable units represents the maximum potential gas demand for electric generation. The maximum total gas demand is fed into the gas model to determine that portion of the demand receiving gas (since gas is assumed to be the preferred fuel) and, if gas supplies are insufficient, that portion of the total demand using oil.

- Each demand category is associated with a different price—the highest priced demand is served first, and the lowest price last. This allows us to assign relative priority in meeting demand. For example, residential customers will be served before generating units, and combined cycles will be served before steam gas units, since their efficiency advantage, generally makes them more profitable to serve.

- Several pipelines pass through NY and into New England states. The volumes for downstream markets were developed using data from the pipelines when they provided the data. In other instances, flows into New England have been estimated from the EIA's "Natural Gas Pipeline State Border Capacity Database."

Supply

- Supply is broken out into New York production, firm supply, storage withdrawals, and spot supply.

  – New York production and firm supply are assigned the lowest cost, and therefore will flow first.

  – Storage withdrawals have the next highest cost, and therefore meet the next level of gas demand.

  – Spot supplies are the highest cost, and therefore are only drawn when the other three categories have been exhausted.

- Firm supplies are allocated to each pipeline relative to the firm contracted volumes that each LDC holds. The sum of the firm supplies into the state is equal to the sum of the peak-day firm supplies of the LDCs.

- Spot supplies are limited by each pipeline's available unused daily capacity, and can flow to meet any demand, given that the pipeline capacity is available to move gas to the customer. We can make this key assumption because the project and this model are designed to test the robustness of the New York State pipeline infrastructure, not the overall productivity of the North American supply basins.

- Three pipeline capacity expansions were included as part of the base analysis. Details on the Athens expansion, Iroquois Eastchester and that portion of the Transco MarketLink Phase II that serves New York can be found in the "Pipeline Capacity Additions in the Base Case" section of this report.

OUTPUTS

While there are numerous outputs of the model, the following is a list of some of the more important ones for this study:

- Flow and capacity at each node.

- Customer receipts from each pipeline, and for each demand category.

- Supply types to pipelines (firm, spot, NY production, or storage).

- Storage use patterns (injections, withdrawals, and resulting inventory levels)

- Flows at interconnections between pipelines.

The resulting mix of gas and oil usage is of particular interest to NYSERDA/NYISO. In addition to characterizing the resulting fuel mix (*e.g.*, the amount of gas burn, the amount of oil burn, the number of days of oil burn, etc.) our analysis allows us to characterize the gas system's ability to meet the total potential demand for gas by electric generators. Again, we characterize the number of days that the gas system can not meet the maximum potential demand for gas and the amount of oil that must be burned (somewhere in the electric system) to produce substitute generation.

NEW YORK GAS SYSTEM STRUCTURE

The LDCs included in the study are listed by region in Table B1, below.

Table B1

New York State Gas Distribution Companies by Region (As of January 1, 2002)

Downstate LDCs	Upstate LDCs
•KeySpan New York	•Niagara Mohawk
•KeySpan Long Island	•New York State Electric & Gas
•Consolidated Edison	•National Fuel Gas Distribution
•Orange & Rockland	•St. Lawrence Gas
•Central Hudson	•Rochester Gas & Electric

APPENDIX C: OVERVIEW OF ELECTRIC DISPATCH MODEL

CRA used the GE Multi-Area Production Simulation (MAPS) model to "commit" and "dispatch" available electricity generating units to meet assumed electricity demands throughout the Northeast. The GE MAPS model simulates the hourly operation of the electric generation and transmission system, including the impacts of transmission constraints and operating reserve requirements. The model minimizes the total system cost of meeting forecasted electricity demands given key economic and engineering assumptions (*e.g.*, fuel costs, heat rates, etc.) for electric generating units.

Input Assumptions

- **Available Generating Capacity**. All generators listed in the 2001 Gold Book are included in our MAPS model runs. Additionally, new units that came on line during 2001 or are expected to come on-line in 2002 are included in all cases analyzed. Assumptions for capacity additions beyond 2002 vary by modeling scenario and are detailed in section 4 of this report. NEPOOL and PJM capacity includes all units listed in 2001 ISO-NE CELT Report and the 2001 MAAC EIA-411 Report, along with new capacity additions shown in Table A4 in Appendix A.

- **Electric Loads**. Table C1 shows our NYCA load assumptions for each year. The 2002 peak load is based on the forecast reported by the NYISO in their February 28, 2002 (Revised March 14, 2002) *Locational Installed Capacity requirements Study*. Loads for later years were estimated by growing the 2002 loads at the rate implied by the forecasts in the 2001 Gold Book. Load forecasts for NEPOOL are from the 2001 ISO-NE CELT Report and forecasts for PJM are from the 2001 MAAC EIA-411 Report.

Table C1

Load Assumptions for MAPS Electric Model
Summer Peak (MW)

Region	2002	2005	2010
NYCA	30,475	31,384	32,824
New York City	10,665	11,015	11,453
Long Island	4,776	4,866	5,129

- **Transmission Upgrades**. The 330 MW HVDC cable between Connecticut and Long Island is included in all of our modeling scenarios. No other transmission upgrades are included.

Overview of MAPS[35]

MAPS is a highly detailed model that calculates hour-by-hour production costs while recognizing the constraints on generation dispatch imposed by the transmission system. MAPS performs a transmission-constrained production simulation, which uses a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved ac load flow, to calculate the real power flows for each generation dispatch. This makes it possible to capture the economic penalties of redispatching the generation to satisfy transmission line flow limits and security constraints.

Because of its detailed electrical representation of the transmission system, MAPS can be used to study issues that cannot be adequately modeled with conventional production costing software. These issues include:

- **Locational Spot Pricing** - MAPS calculates the hourly spot price ($/MWh) at each bus modeled -- which is the cost of supplying an addition MW of load at the bus. The difference in spot prices at two buses is the short-run marginal wheeling cost between these buses. Hence, MAPS can be used to characterize the value of energy at different locations and the implied short-run value of transmission.

- **Transmission Bottlenecks** - MAPS can determine which transmission lines and interfaces in the system are bottlenecks and how many hours during the year they are limiting. MAPS can then be used to assess, from an economic point of view, the relative value of generation on each side of the interface and the feasibility of various methods, such as transmission line upgrades or the installation of phase-angle regulators, for alleviating the bottlenecks.

- **Power Wheeling** - MAPS can determine which transmission lines are actually carrying wheeled power, including lines that may not be part of the contract path. MAPS can also approximate the change in system losses due to a wheeling transaction.

- **Transmission Access** - The hourly spot price at each bus defines a key component of the total avoided cost that is used in formulating contracts for transmission access by non-utility generators and independent power producers.

- **Loop Flow or Uncompensated Wheeling** - The detailed transmission modeling and cost reconstruction algorithms in MAPS combine to identify which companies are

[35] This overview of MAPS, based on the similarly titled GE publication, has been prepared by CRA. The contents of the GE publication have been reorganized and the text has been edited.

contributing to the flow on a given transmission line and to defining the production cost impact of that loading.

APPENDIX D: GAS-FIRED GENERATION IN THE NEW YORK CONTROL AREA, BY LDC

List Includes: 1) All 2001 Gold Book units whose primary fuel is reported as NG; 2) All Dual Fuel Steam units listed in Gold Book; 3) Planned New Capacity.
LDC/Pipeline Match-ups based on CRA Research

LDC	Pipeline	Owner	Station/Unit	Zone	City	County	State	Summer Capacity (MW)	Winter Capacity (MW)	Type	Primary Fuel	Secondary Fuel	Tertiary Fuel
Existing Capacity													
Central Hudson Gas & Electric		Dynegy Power Inc.	Danskammer 1	G	Newburgh	Orange	NY	63	63	ST	FO6	NG	FO2
Central Hudson Gas & Electric		Dynegy Power Inc.	Danskammer 2	G	Newburgh	Orange	NY	66	64	ST	FO6	NG	FO2
Central Hudson Gas & Electric		Dynegy Power Inc.	Roseton 1	G	Newburgh	Orange	NY	607	590	ST	FO6	NG	FO2
Central Hudson Gas & Electric		Dynegy Power Inc.	Roseton 2	G	Newburgh	Orange	NY	608	589	ST	FO6	NG	FO2
Consolidated Edison		Orion Power Holdings, Inc.	Astoria 2	J	Queens	Queens	NY	171	190	ST	NG	FO6	
Consolidated Edison		Orion Power Holdings, Inc.	Astoria 3	J	Queens	Queens	NY	355	361	ST	FO6	NG	
Consolidated Edison		Orion Power Holdings, Inc.	Astoria 4	J	Queens	Queens	NY	362	375	ST	FO6	NG	
Consolidated Edison		Orion Power Holdings, Inc.	Astoria 5	J	Queens	Queens	NY	361	370	ST	FO6	NG	
Consolidated Edison		Orion Power Holdings, Inc.	Astoria GT 01	J	Queens	Queens	NY	12	15	GT	NG		
Consolidated Edison		New York Power Authority	Bronx Zoo	J	New York	Bronx	NY	3	3	IC	NG	FO2	
Consolidated Edison		Consolidated Edison Co. of NY	East River 6	J	Manhattan	New York	NY	131	137	ST	FO6	NG	
Consolidated Edison		Consolidated Edison Co. of NY	East River 7	J	Manhattan	New York	NY	178	162	ST	FO6	NG	
Consolidated Edison		New York Power Authority	Harlem Rail	J	New York	Bronx	NY	80	89	CT	NG		
Consolidated Edison		New York Power Authority	Hell Gate	J	New York	Bronx	NY	80	89	CT	NG		
Consolidated Edison		Mirant Corporation	Hillburn GT	G	Hillburn	Rockland	NY	37	47	GT	NG	KER	
Consolidated Edison		Orange and Rockland Utilities	Intl. Crossroads	G	Mahwah NJ		NJ	3	3	IC	NG	FO2	
Consolidated Edison		Orange and Rockland Utilities	Lederle	G	Pearl River	Rockland	NY	19	19	CC	NG	FO2	
Consolidated Edison		Mirant Corporation	Lovett 3	G	Tomkins Cove	Rockland	NY	69	69	ST	NG	FO6	BIT
Consolidated Edison			Misc. - NYC (NRG)	J	New York		NY	79	79	GT	NG		
Consolidated Edison			Other Misc. - NYC (JFK)	J	New York	Queens	NY	44	44	CC	NG		
Consolidated Edison		New York Power Authority	Poletti 1	J	Queens	Queens	NY	847	831	ST	FO6	NG	
Consolidated Edison		KeySpan - Ravenswood, Inc.	Ravenswood 1	J	Queens	Queens	NY	9	11	GT	NG		
Consolidated Edison		KeySpan - Ravenswood, Inc.	Ravenswood 1	J	Queens	Queens	NY	353	384	ST	FO6	NG	
Consolidated Edison		KeySpan - Ravenswood, Inc.	Ravenswood 2	J	Queens	Queens	NY	386	392	ST	FO6	NG	
Consolidated Edison		KeySpan - Ravenswood, Inc.	Ravenswood 3	J	Queens	Queens	NY	980	991	ST	FO6	NG	BIT
Consolidated Edison		Mirant Corporation	Shoemaker GT	G	Middletown	Orange	NY	35	33	GT	NG	KER	
Consolidated Edison		New York Power Authority	Vernon Boulevard	J	New York	Queens	NY	80	89	CT	NG		
Consolidated Edison		Consolidated Edison Co. of NY	Waterside 6	J	Manhattan	New York	NY	69	69	ST	FO6	NG	
Consolidated Edison		Consolidated Edison Co. of NY	Waterside 8	J	Manhattan	New York	NY	47	47	ST	FO6	NG	
Consolidated Edison		Consolidated Edison Co. of NY	Waterside 9	J	Manhattan	New York	NY	48	48	ST	FO6	NG	
Elizabethtown Gas Company (NJ)		Consolidated Edison of NY, Inc.	Cogen Tech-Linden	J	Linden NJ		NJ	720	779	CC	NG		
Keyspan Long Island		Long Island Power Authority	Barrett 1	K	Island Park	Nassau	NY	16	21	GT	NG	FO2	
Keyspan Long Island		Long Island Power Authority	Barrett 1	K	Island Park	Nassau	NY	192	186	ST	NG	FO6	
Keyspan Long Island		Long Island Power Authority	Barrett 10	K	Island Park	Nassau	NY	41	52	JE	NG	FO2	
Keyspan Long Island		Long Island Power Authority	Barrett 11	K	Island Park	Nassau	NY	39	51	JE	NG	FO2	
Keyspan Long Island		Long Island Power Authority	Barrett 12	K	Island Park	Nassau	NY	43	52	JE	NG	FO2	
Keyspan Long Island		Long Island Power Authority	Barrett 2	K	Island Park	Nassau	NY	16	19	GT	NG	FO2	
Keyspan Long Island		Long Island Power Authority	Barrett 2	K	Island Park	Nassau	NY	196	195	ST	NG	FO6	
Keyspan Long Island		Long Island Power Authority	Barrett 3	K	Island Park	Nassau	NY	16	19	GT	NG	FO2	
Keyspan Long Island		Long Island Power Authority	Barrett 4	K	Island Park	Nassau	NY	14	19	GT	NG	FO2	
Keyspan Long Island		Long Island Power Authority	Barrett 5	K	Island Park	Nassau	NY	16	19	GT	NG	FO2	
Keyspan Long Island		Long Island Power Authority	Barrett 6	K	Island Park	Nassau	NY	16	20	GT	NG	FO2	
Keyspan Long Island		Long Island Power Authority	Barrett 7	K	Island Park	Nassau	NY	14	19	GT	NG	FO2	
Keyspan Long Island		Long Island Power Authority	Barrett 8	K	Island Park	Nassau	NY	16	20	GT	NG	FO2	
Keyspan Long Island		Long Island Power Authority	Barrett 9	K	Island Park	Nassau	NY	41	50	JE	NG	FO2	
Keyspan Long Island		Long Island Power Authority	Far Rockaway 4	K	F Rockaway	Queens	NY	108	110	ST	NG	FO6	
Keyspan Long Island		New York Power Authority	Flynn	K	Holtsville	Suffolk	NY	136	165	CC	NG	FO2	
Keyspan Long Island		Long Island Power Authority	Glenwood 4	K	Glenwood	Nassau	NY	113	115	ST	NG		
Keyspan Long Island		Long Island Power Authority	Glenwood 5	K	Glenwood	Nassau	NY	113	110	ST	NG		
Keyspan Long Island		Long Island Power Authority	LI GT COOL	K			NY	60	0	GT	FO2		
Keyspan Long Island		New York Power Authority	Pilgrim State Hospital	K	Islip	Suffolk	NY	44	49	CT	NG		

LDC	Pipeline	Owner	Station/Unit	Zone	City	County	State	Summer Capacity (MW)	Winter Capacity (MW)	Type	Primary Fuel	Secondary Fuel	Tertiary Fuel
Keyspan Long Island		Long Island Power Authority	Port Jefferson 3	K	P Jefferson	Suffolk	NY	192	187	ST	FO6	NG	
Keyspan Long Island		Long Island Power Authority	Port Jefferson 4	K	P Jefferson	Suffolk	NY	195	189	ST	FO6	NG	
Keyspan Long Island		Long Island Power Authority	South Oaks Hosp	K	Amityville	Suffolk	NY	0	0	IC	NG		
Keyspan Long Island		Long Island Power Authority	SUNY Stony Brook	K	Stony Brook	Suffolk	NY	14	14	CC	NG		
Keyspan Long Island		Long Island Power Authority	TBG-Grumman	K	Bethpage	Nassau	NY	44	63	CC	NG	FO2	
Keyspan Long Island		Long Island Power Authority	Trigen-NDEC	K	Garden City	Nassau	NY	55	62	CC	NG	FO2	
Keyspan New York		New York Power Authority	23rd Street	J	Brooklyn	Kings	NY	80	89	CT	NG		
Keyspan New York		NRG Power, Inc.	Arthur Kill 2	J	Staten Island	Richmond	NY	349	351	ST	FO6	NG	
Keyspan New York		NRG Power, Inc.	Arthur Kill 3	J	Staten Island	Richmond	NY	507	501	ST	FO6	NG	
Keyspan New York		Consolidated Edison of NY, Inc.	Bkln Navy Yard	J	Brooklyn	Kings	NY	272	285	CC	NG	FO2	
Keyspan New York		Consolidated Edison Co. of NY	Hudson Avenue 10/100 Unit	J	New York	Kings	NY	60	67	ST	FO6		
Keyspan New York		New York Power Authority	KIAC (JFK)	J	New York	Queens	NY	105	110	CC	NG		
Keyspan New York		New York Power Authority	River Street (NYPA)	J	Brooklyn	Kings	NY	44	49	CT	NG		
Keyspan New York		New York Power Authority	Virginia Avenue	J	Staten Island	New York	NY	44	49	CT	NG		
Keyspan New York		Consolidated Edison of NY, Inc.	York-Warbasse	J	Brooklyn	Kings	NY	21	21	GT	NG	FO2	
National Fuel Gas Distribution		NFR Power, Inc.	American Brass	A		Erie	NY	63	0	CC	NG		
National Fuel Gas Distribution		PP&L EnergyPlus Co. (EPLUS)	Bethlehem Steel	A	Lackawanna	Erie	NY	22	21	CC	NG		
National Fuel Gas Distribution		Niagara Mohawk Power Corp.	Ellicotville Energy CC	A		Cattaraugus	NY	3	4	CC	NG		
National Fuel Gas Distribution		Niagara Mohawk Power Corp.	General Mills Inc	A		Erie	NY	3	4	CC	NG		
National Fuel Gas Distribution		Indeck-Yerkes LP	Indeck-Yerkes	A		Erie	NY	50	57	CC	NG		
National Fuel Gas Distribution		Connectiv / NEPA	NEPA Energy (Ripley)	A			PA	81	85	CC	NG		
National Fuel Gas Distribution		Niagara Mohawk Power Corp.	Oxbow Pwr- N.Tonaw	A		Erie	NY	56	60	CC	NG		
National Fuel Gas Distribution		Sithe Energies Inc.	Sithe-Batavia	B		Genesee	NY	57	61	CC	NG		
New York State Electric & Gas Corp		TransAlta	Binghamton Cogen	C	Binghamton	Broome	NY	48	48	CC	NG	FO2	
New York State Electric & Gas Corp		Niagara Mohawk Power Corp.	Hydrocarbon-Algny	A		Allegany	NY	0	1	IC	NG		
New York State Electric & Gas Corp		Indeck-Olean LP	Indeck-Olean	A		Cattaraugus	NY	76	87	CC	NG		
New York State Electric & Gas Corp		New York State Elec. & Gas Corp.	Indeck-Silver Spr 1	C	Silver Springs	Wyoming	NY	36	45	CC	NG	FO2	
New York State Electric & Gas Corp		New York State Elec. & Gas Corp.	Indeck-Silver Spr 2	C	Silver Springs	Wyoming	NY	15	18	CC	NG	FO2	
New York State Electric & Gas Corp		New York State Elec. & Gas Corp.	Lockport Cogen Pr	A	Lockport	Niagara	NY	187	205	CC	NG		
New York State Electric & Gas Corp		New York State Elec. & Gas Corp.	Saranac Energy Co	D	Plattsburgh	Clinton	NY	80	80	CC	NG		
New York State Electric & Gas Corp		New York State Elec. & Gas Corp.	Saranac Energy Co	D	Plattsburgh	Clinton	NY	80	80	CC	NG		
New York State Electric & Gas Corp		New York State Elec. & Gas Corp.	Saranac Energy Co	D	Plattsburgh	Clinton	NY	80	80	CC	NG		
Niagara Mohawk		PSEG Power	Albany 1	F	Bethlehem	Albany	NY	92	92	ST	NG	FO6	
Niagara Mohawk		PSEG Power	Albany 2	F	Bethlehem	Albany	NY	91	90	ST	NG	FO6	
Niagara Mohawk		PSEG Power	Albany 3	F	Bethlehem	Albany	NY	90	95	ST	NG	FO6	
Niagara Mohawk		PSEG Power	Albany 4	F	Bethlehem	Albany	NY	91	97	ST	NG	FO6	
Niagara Mohawk		Niagara Mohawk Power Corp.	Burrws-Little Falls 1	E	Little Falls	Herkimer	NY	1	2	CC	NG		
Niagara Mohawk		Niagara Mohawk Power Corp.	Burrws-Little Falls 2	E	Little Falls	Herkimer	NY	1	2	CC	NG		
Niagara Mohawk		Niagara Mohawk Power Corp.	Cal Ban Power	A			NY	0	0	IC	NG		
Niagara Mohawk		Constellation Power Source	Carr St.-E. Syr	C	Dewitt	Onondaga	NY	104	104	CC	NG		
Niagara Mohawk		NYSEG Solutions, Inc.	Carthage Paper	E		Jefferson	NY	60	66	CC	NG		
Niagara Mohawk		Central Hudson Enterprises Corp.	CHR-Syracuse	C		Onondaga	NY	95	95	CC	NG		
Niagara Mohawk		TransCanada Power Marketing, Ltd.	Fort Orange	F		Rensselaer	NY	64	71	CC	NG		
Niagara Mohawk		Niagara Mohawk Power Corp.	Fulton Cogn Assoc	C		Oswego	NY	44	48	CC	NG		
Niagara Mohawk		Niagara Mohawk Power Corp.	GPUI-Onondaga Cog	C		Onondaga	NY	74	80	CC	NG		
Niagara Mohawk		Indeck-Corinth LP	Indeck-Corinth 1	F	Corinth	Saratoga	NY	80	85	CC	NG	FO2	
Niagara Mohawk		Indeck-Corinth LP	Indeck-Corinth 2	F	Corinth	Saratoga	NY	54	58	CC	NG	FO2	
Niagara Mohawk		Indeck-Ilion LP	Indeck-Ilion	E		Herkimer	NY	57	62	CC	NG		
Niagara Mohawk		Indeck-Oswego LP	Indeck-Oswego	C		Oswego	NY	49	55	CC	NG		
Niagara Mohawk		Niagara Mohawk Power Corp.	Nottingham High S	C	Syracuse	Onondaga	NY	0	0	CC	NG		
Niagara Mohawk		NYSEG Solutions, Inc.	NSINS-S Glens Falls	F		Saratoga	NY	58	62	CC	NG		
Niagara Mohawk		Niagara Mohawk Power Corp.	Renns.Cogen, BASF	F		Rensselaer	NY	79	80	CC	NG		
Niagara Mohawk		Sithe Energies Inc.	Sithe-Sterling	E		Oneida	NY	54	64	CC	NG		
Niagara Mohawk		Niagara Mohawk Power Corp.	Syracuse Power Co.	C	Geddes	Onondaga	NY	0	3	CC	NG		

LDC	Pipeline	Owner	Station/Unit	Zone	City	County	State	Summer Capacity (MW)	Winter Capacity (MW)	Type	Primary Fuel	Secondary Fuel	Tertiary Fuel
Rochester Gas & Electric Corp		Rochester Gas and Electric Corp.	Allegany Cogen	B	Hume	Allegany	NY	59	63	CC	NG		
Rochester Gas & Electric Corp		Rochester Gas and Electric Corp.	Station 9	B	Rochester	Monroe	NY	14	14	GT	NG		
St Lawrence		Central Hudson Enterprises Corp.	CHR-Beaver Falls	E		Lewis	NY	87	88	CC	NG		
St Lawrence		Sithe Energies Inc.	Sithe-Massena	D		St. Lawrence	NY	78	91	CC	NG		
St Lawrence		Sithe Energies Inc.	Sithe-Ogdenbrg	E		St. Lawrence	NY	76	87	CC	NG		
	Columbia	Mirant Corporation	Bowline 1	G	W Haverstraw	Rockland	NY	605	605	ST	NG	FO6	
	Columbia	Mirant Corporation	Bowline 2	G	W Haverstraw	Rockland	NY	615	593	ST	NG	FO6	
	Iroquois	Long Island Power Authority	Northport 1	K	Northport	Suffolk	NY	383	375	ST	NG	FO6	
	Iroquois	Long Island Power Authority	Northport 2	K	Northport	Suffolk	NY	389	377	ST	NG	FO6	
	Iroquois	Long Island Power Authority	Northport 4	K	Northport	Suffolk	NY	393	387	ST	NG	FO6	
	TGP	Niagara Mohawk Power Corp.	Project Orange	C		Onondaga	NY	86	92	CC	NG		
	TGP	Selkirk Cogen Partners, L.P.	Selkirk-I	F	Selkirk	Albany	NY	90	102	CC	NG		
	TGP	Selkirk Cogen Partners, L.P.	Selkirk-II	F	Selkirk	Albany	NY	82	103	CG	NG	FO2	
	TGP	Selkirk Cogen Partners, L.P.	Selkirk-II	F	Selkirk	Albany	NY	82	103	CG	NG	FO2	
	TGP	Selkirk Cogen Partners, L.P.	Selkirk-II	F	Selkirk	Albany	NY	112	124	CG	NG	FO2	
	Empire	Sithe Energies Inc.	Sithe Independence	C	Scriba	Oswego	NY	960	1023	CC	NG	FO2	

Planned New Capacity													
Consolidated Edison		Astoria Energy, LLC	Astoria (SCS)	J	Astoria	Queens	NY	900	1000	CC	NG	FO2	
Consolidated Edison		Orion Power Holdings, Inc.	Astoria CC Phase I	J	Queens	Queens	NY	908	1009	CC	NG	FO6	
Consolidated Edison		Orion Power Holdings, Inc.	Astoria CC Phase II	J	Queens	Queens	NY	908	1009	CC	NG	FO6	
Consolidated Edison		Consolidated Edison Co. of NY	Con Edison East River	J	New York	New York	NY	360	400	CC	NG		
Consolidated Edison		NYPA	Poletti Expansion	J	Queens	Queens	NY	500	556	CC	NG		
Consolidated Edison		KeySpan - Ravenswood, Inc.	Ravenswood	J	Queens	Queens	NY	250	278	CC	NG	FO2	
Keyspan Long Island		International Power Plc	Brookhaven Energy	K	Brookhaven	Suffolk	NY	407	644	CC	NG		
Keyspan Long Island		Long Island Power Authority	LIPA Turbine 2002 1	K			NY	39	39	GT	NG		
Keyspan Long Island		Long Island Power Authority	LIPA Turbine 2002 2	K			NY	39	39	GT	NG		
Keyspan Long Island		Long Island Power Authority	LIPA Turbine 2002 4	K			NY	39	39	GT	NG		
Keyspan Long Island		Long Island Power Authority	LIPA Turbine 2002 5	K			NY	39	39	GT	NG		
Keyspan Long Island		Long Island Power Authority	LIPA Turbine 2002 6	K			NY	39	39	GT	NG		
Keyspan Long Island		Long Island Power Authority	LIPA Turbine 2002 7	K			NY	39	39	GT	NG		
Keyspan Long Island		Long Island Power Authority	LIPA Turbine 2002 8	K			NY	39	39	GT	NG		
Keyspan Long Island		Long Island Power Authority	LIPA Turbine 2002 9	K			NY	39	39	GT	NG		
Keyspan Long Island		Long Island Power Authority	LIPA Turbine 2003 1	K			NY	39	39	GT	NG		
Keyspan Long Island		Long Island Power Authority	LIPA Turbine 2003 2	K			NY	39	39	GT	NG		
Keyspan Long Island		Long Island Power Authority	LIPA Turbine 2003 3	K			NY	39	39	GT	NG		
Keyspan Long Island		Long Island Power Authority	LIPA Turbine 2003 4	K			NY	39	39	GT	NG		
National Fuel Gas Distribution		Jamestown, City of	Carlson	A	Jamestown	Chautauqua	NY	39	43	CT	NG		
Niagara Mohawk		PSEG	Albany	F	Albany	Albany	NY	750	833	CC	NG		
	Iroquois	Athens Generating	Athens Gen Plant (Greene)	G	Athens	Greene	NY	1080	1200	CC	NG		
	Empire	Sithe Energies Inc.	Heritage Station (Scriba)	C	Scriba	Oswego	NY	800	889	CC	NG		

Sources:
1) Existing Capacity is from NY ISO Gold Book 2001
2) Planned New Capacity is based on CRA/NYSERDA Assumptions.
3) LDC/Pipeline information is based on CRA's research.