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]

[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.