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

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