Critical Assessment of EDF's Workpaper on "Vertical Market Power in Interconnected Natural Gas and Electricity Markets"

prepared for

Eversource Energy

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Disclosure

This report has been commissioned by Eversource Energy (Eversource), the owner of Yankee Gas Services Company (Yankee), NSTAR Gas Company, and Public Service Company of New Hampshire. This study has been funded in full by Eversource. Levitan & Associates, Inc. (LAI) has performed an independent, critical assessment of the Environmental Defense Fund's (EDF's) "Vertical Market Power in Interconnected Natural Gas and Electricity Markets." No data or information has been provided by EDF. LAI has relied on Yankee for operating information of relevance at the local level in Connecticut. Pipeline data regarding throughput and delivery by location on the Algonquin and Tennessee pipelines are from their respective electronic bulletin boards. The methods, findings and recommendations set forth in this report are strictly that of LAI and do not reflect corporate recommendations from Eversource or any affiliates. This analysis is independent of any other work undertaken for the Connecticut Department of Energy and Environmental Protection or the Public Utilities Regulatory Authority.

Executive Summary

Levitan & Associates (LAI) has been asked by Eversource Energy (Eversource) to perform an independent, critical assessment of the October 2017 working paper sponsored by the Environmental Defense Fund (EDF), authored by Levi Marks, Charles F. Mason, Kristina Mohlin, and Matthew Zaragoza-Watkins ("EDF paper" or "EDF"). The EDF paper alleges that two energy companies that operate local distribution companies (LDCs) on the Algonquin Gas Transmission System (Algonquin) and also own generation resources in New England managed their pipeline capacity in such a way as to drive up natural gas prices in New England, directly or indirectly rendering the firms' electric generators more profitable. EDF's working paper relied on data from the three-year period, August 2013 through July 2016. In addition to the EDF paper, EDF has accused the Eversource and Avangrid companies of market manipulation before state and federal regulatory commissions and consumer advocates, as well as in the media, including the *Wall Street Journal*.

EDF alleges that Eversource's and Avangrid's behavior "increased average gas and electricity prices by 38% and 20% respectively, over the three-year period," resulting in customers paying "$3.6 billion more for electricity" (p. 1). However, the Critical Assessment performed by LAI demonstrates that the Eversource companies did not game the natural gas market for purposes of improving the capacity factors of its generation fleet in New Hampshire, or, for that matter, for any other reason. EDF's claimed wholesale price effects are false because there was no inefficient or manipulative "withholding" of natural gas. Because Connecticut LDCs did not manipulate gas deliverability or otherwise withhold capacity, we conclude that EDF's allegations are uninformed, baseless, and quixotic.

Simply put, EDF's allegations are preposterous.

➔ ***Overall Conclusions of LAI's Critical Assessment:***

- EDF's findings of the exercise of vertical market power by Yankee Gas Services Company (Yankee), located in Connecticut, and NSTAR Gas Company (NSTAR) located in Massachusetts, rest on false and misguided assumptions about gas utility operations, scheduling protocols and stringent reliability obligations. LAI finds that EDF's allegations about vertical market power are analytically corrupt.

- EDF asserts that the Eversource had indirect, but not direct, motivation to have its LDCs withhold capacity for purposes of sustaining rate-base regulation in New Hampshire. LAI finds that EDF's insinuation is both baseless and bizarre.

- EDF finds that the postulated capacity withholding by LDCs in Connecticut caused wholesale electricity costs in New England to be $3.6 billion higher over a three-year period than would otherwise have been the case absent the postulated withholding. LAI's technical review shows that Yankee's and NSTAR's reductions in scheduled quantities during the last three hours of the Gas Day – EDF's criterion – represented a sliver of New England's peak demand. Therefore, notwithstanding the absence of actions and motivation to manipulate gas prices, it is incomprehensible that the postulated withholding of a comparatively trivial amount of pipeline capacity on Algonquin could cause wholesale power costs in New England to be $3.6 billion higher.

➔ ***False Foundational Assumptions Identified by LAI***:

The EDF paper rests on critically false assumptions arising from the fact that EDF unreasonably simplified standard utility practice and ignored that LDCs are first and foremost responsible for supplying gas to their firm customers *without interruption*.

The false assumptions that most seriously corrupt the EDF analytical construct are as follows:

- EDF's empirical analysis is badly marred by failing to account for the fact that regulated gas utilities must serve their customers with the highest level of reliability, requiring the flexibility to maintain access to address weather and other uncertain demand uncertainties so that LDC customers do not experience a loss of supply in the coldest periods.

- EDF inexplicably failed to consider Yankee's Supplier of Last Resort (SOLR) obligation, which requires Yankee to backstop supply obligations of third-party suppliers in the event of a failure to deliver.

- EDF failed to account for the deliverability constraints along the Algonquin mainline that would have prevented the scheduling and delivery of any released capacity in Connecticut to the lion's share of direct connected generation in Massachusetts and Rhode Island.

- EDF did not account for the portfolio constraints associated with how Yankee balances system requirements in Connecticut across Algonquin, Tennessee, and Iroquois, requiring Yankee to rely on no-notice service as an operational hedge to assure reliability.

- EDF failed to recognize that Algonquin is prohibited from releasing unscheduled no-notice service entitlements to third parties, taking into account Yankee's scheduling and use of such entitlements.

- EDF failed to recognize, while praising the scheduling practices of other LDCs in New England with no generation portfolio, that these other LDCs are relying on reserved no-notice capacity to manage demand uncertainty, *with the same effect*.

➔ ***Critical Assessment – Key Findings Supporting LAI Conclusions:***

EDF's lack of transparency coupled with an array of fatal analytic flaws and lack of understanding of industry fundamentals renders the EDF paper and its alleged "findings" useless. LAI's Critical Assessment of the EDF paper produced the following key findings and conclusions:

1. **There was no market manipulation, nor did Eversource have "market power" in relation to natural gas pipeline capacity.**

   - EDF provided no valid analysis showing Eversource to have market power in the gas marketplace.

   - EDF inexplicably ignored the LDCs' state-imposed public-service obligations to maintain requisite levels of supply to deliver gas to firm customers with high reliability regardless of uncertainties in load variability due to weather or SOLR back-stop obligations for third-party delivery failures, and other reasons.

   - EDF fails to consider that NSTAR uses a third-party Asset Manager to handle the nomination and scheduling of its pipeline portfolio, which is not under the day-to-day control of the Eversource parent company. The Asset Manager is heavily incentivized to optimize the release of capacity and has complete control over that release after NSTAR has satisfied the needs of its firm customers. Any failure to release capacity would be to the financial detriment of the Asset Manager and would make no difference to NSTAR.

   - EDF has fictionalized both the market and operational consequences associated with constraints on pipeline delivery capability into and within New England. EDF either chose to ignore or does not understand the physical configuration of pipeline infrastructure affecting how Algonquin schedules non-firm flows west-to-east to gas-fired generators across pipeline bottlenecks in New England.

   - Interstate pipelines under FERC-approved tariffs would impose severe penalties for unauthorized gas use by an LDC in order to protect pipeline integrity. Although EDF recognizes that LDCs have an obligation to supply firm customers with gas, and that there is weather uncertainty, EDF's empirical analysis does not account for the supply reserve needed to cover uncertain weather and other uncertain demand fluctuations, while avoiding severe penalties for unauthorized use. Changing the operating principles and state regulations governing LDCs would threaten life and property in the event of customer disruptions.

   - EDF failed to correctly assess the role of no-notice service for Yankee. EDF contends that it was a combination of no-notice pipeline capacity and gas storage assets that Yankee used to drive up gas prices by withholding pipeline capacity. EDF either does not understand or chose to fictionalize the role that no-notice contracts play in the continued provision of reliable service for Yankee's firm customers. Together, no-notice service and rights to gas storage assets are an integral part of Yankee's supply portfolio to assure reliability to firm service customers, and was not used for raising gas prices.

- LAI's analysis of Yankee's scheduled gas on Algonquin indicates that both positive and negative adjustments are made over the course of the gas day's nomination cycles. Analysis of weather-forecast data used by Yankee supports the view that the amount of typical negative schedule adjustments near the end of the Gas Day to match actual cumulative receipts is consistent with the extent of day-ahead weather uncertainty during the heating season. Weather and other demand uncertainties continue through most of the gas day, thereby preventing more or earlier capacity releases without potentially harming the ability to serve firm customers. EDF either chose to ignore or does not understand that Algonquin, like other FERC jurisdictional pipelines, cannot liquidate the capacity underlying no-notice service as it is paid for and used day in, day out by its entitlement holders.

- EDF's claims gloss over the impact of forecast uncertainty in managing the portfolio to meet firm gas demand and spot market trading conventions in the natural gas industry.

    - EDF claimed that the largest negative schedule adjustments occurred on colder, or the coldest, days. In fact, we found that larger negative schedule changes more frequently occurred on forecasted and actual less-cold days. Such less cold days are associated with more moderate gas prices and less constrained capacity.

    - EDF did not quantitatively analyze weather forecast uncertainty, which is a major factor in explaining schedule adjustments during the winter. Our analysis, using Yankee's weather forecast data, found that larger negative adjustments are correlated with days that turn out to be milder than forecasted.

    - EDF focused on 37 days over the three-year data period when all shippers on Algonquin had a net total negative schedule change greater than 0.1 Bcf/d in the final three hours of the gas day. LAI's analysis of the types of days in the 37 days with large negative adjustments found that a disproportionately high number of those days occurred when the corresponding Next Day spot gas product included a multi-day delivery period and/or a deferred start of delivery.

    - Multi-day products of up to five days and deferred start date products both involve scheduling challenges. Lower demand on weekends and holidays and greater weather forecast uncertainty for multi-day and deferred start Next Day products are barriers to reducing some of the observed negative final schedule adjustments. Yankee, like other LDCs, sometimes needs to forecast three to five days ahead due to weekends and holidays, thus compounding the uncertainty associated with weather forecasts, operating conditions, customer loads and back-stop obligations, *i.e.*, SOLR.

  - EDF plays fast and loose in its characterization of which parties are responsible for the 0.1 Bcf/d of net scheduling reductions on 37 days changes throughout the report, at least once (pp. 3-4) allocating it only to the Connecticut LDCs, which is entirely inaccurate.

- EDF states on page 24 of the report that "large, consistently negative adjustments just before the end of the gas day are consistent with an LDC shipper that intentionally nominates capacity in excess of its predictions of its customers' daily demand." EDF implies that this behavior is irresponsible. In actuality, Yankee is operating responsibly in light of load uncertainty, potential operational constraints, and Yankee's core obligation to serve its firm customers no matter what.

- EDF's analysis appears sophisticated and rigorous through the use of equations, a large database, and academic references. In reality, the analysis is intrinsically flawed, overly simplistic and profoundly uninformed in regard to the operation of the spot gas trading market and operational practices for protecting against higher than expected demand.

  - The simple single equation regression models used to test aspects of EDF's vertical market power theory are insufficient to be taken as hard evidence. For the reasons cited above, the analysis is disproven before getting to the point in the modeling system of accepting that any portion of the observed negative schedule adjustments represents withholding. Hence, the rest of the EDF analysis is useless.

  - EDF did not use a sound statistical model for estimating gas demand price elasticity. Our analysis found that there appears to be no correlation between final schedule adjustments and Next Day gas prices. This is most likely due to weather and other demand uncertainties not being resolved until after gas trading closes.

- LDCs structure and manage their portfolios to ensure sufficient operational flexibility to maintain firm service to their customers under harsh weather and operating conditions. LDCs have no contractual obligation to serve pipeline-connected gas-fired generators in New England. Generators on interstate pipelines in New England, including those on Algonquin, have overwhelmingly elected <u>not</u> to secure their own firm capacity entitlements, thereby scheduling gas supply as a non-firm shipper throughout the year or relying on third parties for gas supply. Yankee's scheduling practices are entirely consistent with its obligation to serve its firm customers and are in strict accord with state and federal requirements

- EDF admits that withholding spare capacity instead of making spot capacity release sales to the market is a disincentive to market manipulation. While Yankee has little or no profit incentive to release capacity or engage in bundled commodity sales, it has ample incentive to engage in such transactions on the customers' behalf when it is sure such transactions are certainly surplus to support the needs of its firm customers. Revenues derived from capacity release are credited 100% to Yankee customers after funding a reserve account to fund LDC expansion.

2. **Eversource had no direct or indirect motivation to have its LDCs withhold capacity for purposes of sustaining rate-base regulation in New Hampshire.**

- Over the relevant three year period, PSNH owned only 1,177 MW, all of which was subject to divestment. This nameplate, which EDF describes as a "large portfolio of electric generation" (p. 3) represents only 3.5% of the 34,000 MW in ISO-NE.

- The Eversource LDCs had no motivation to withhold pipeline capacity from the market to increase gas prices for the sake of perpetuating the availability of its thermal fleet in New Hampshire. Under traditional cost-of-service regulation, Eversource makes no additional profit when gas and/or power prices are higher. Any increase in net margin derived from higher electric energy prices administered through ISO-NE's Day Ahead or Real Time market is credited to Public Service of New Hampshire's (PSNH's) customers, not its stockholders.

    - EDF did not allege that the energy company would profit from the sale of generation assets, only that it could continue to receive a rate-of-return on regulated assets. While not explicitly part of EDF's allegation, EDF's theory of abuse ignores the competitive option New Hampshire's customers have in addition to reliance on PSNH for standard service.

    - EDF chose to ignore or does not understand the market and regulatory dynamics affecting customer choice, in effect, hindering, if not precluding, PSNH's ability to compel its customers to foot the bill for economic obsolescence.

- The capacity supply obligations borne by PSNH's thermal fleet have little or nothing to do with gas prices in New England, but instead reflect region-wide constraints on gas deliverability, the need for resources that are available during cold snaps when gas-only units are typically constrained, the episodic delivery and regasification of imported LNG, and the basic lack of fuel diversity across ISO-NE.

- EDF alleges that a regulated electric utility would only benefit from the firm's affiliated LDC's effort to increase wholesale gas prices in a subtle, indirect way, by prolonging the time that its non-gas-fired generators appear to remain economic under rate base regulation. In PSNH's case, the New Hampshire Legislature had already required PSNH to sell its generation assets. The New Hampshire Public

Utilities Commission (NHPUC) Order in July 2016 approved PSNH's Settlement Agreement to divest its generation assets in conformance of state policy restructuring electricity markets. These agreements have been largely fulfilled as PSNH is now winding down the sale of its generation assets.

- Under the structure of the agreement formed under New Hampshire's legislative and regulatory authority, Eversource's investors were unaffected by a good or bad outcome through divestiture. Under the settlement agreement, PSNH's sale of its generation fleet was a precondition to the securitized financing of any remaining stranded costs. EDF's allegations about subtle, indirect profit motives are naïve and unfounded as they ignore the existence of the agreement shielding Eversource's investors from financial penalties if the divestiture did not yield sufficient capital to cover the net book cost of the PSNH generation fleet.

- EDF is selective and biased in its theory that the parent of a regulated electric utility has an incentive for its LDCs to increase gas prices so as to forestall a state legislature from requiring divestment. By that logic, the parent should also want to maximize its LDC rate base, which is furthered by efforts to keep gas prices as low as possible. This is a major internal contradiction of EDF's theory. In the current and recent market environment in New England, there is greater opportunity for expansion of LDC rate base to promote oil to gas conversions than for preserving old thermal generation assets under traditional cost of service regulation.

- EDF praises the behavior of LDCs that make bidirectional schedule changes during the day, failing to recognize that, due to constraints across Algonquin that happen on cold days, increases in scheduled volumes can normally only be made by utilizing no-notice capacity.

- When the analysis of scheduling behavior is expanded, we find that LDCs that do not own generation capacity in New England and were praised by EDF for efficiently allocating capacity on Algonquin engage in end-of-day nomination reductions on Tennessee similar to those associated with EDF's purported bad actors on Algonquin. Notably, Tennessee does not offer no-notice service that can be used for intraday schedule increases when the pipeline is otherwise scheduled full. Not initially nominating all of Yankee's no-notice capacity does not mean that any no-notice capacity entitlement not nominated should be released. On the contrary, demand uncertainty warrants the retention of the reserve margin Yankee relies on to meet firm customer demand. The absence of no-notice service on Tennessee heightens Yankee's reliance on the daily swing capability embedded in the Algonquin tariff to hedge against demand and operational uncertainties.

3. **Notwithstanding the absence of action and motivation to manipulate gas prices in New England, it is incomprehensible that the postulated withholding of a comparatively trivial amount could cause wholesale power costs to be $3.6 billion higher over a three-year period.**

   - EDF alleges that Eversource exercised vertical market power by directing Yankee and NSTAR to engage in "unusual scheduling practices" that resulted in "significant quantities of pipeline capacity" being unutilized (p. 3). A review of the data indicates that Yankee and NSTAR reduced their scheduled quantities during the last three hours of the gas day by up to a total of 0.07 Bcf/d, which represents a sliver of New England's peak demand of 4.5 Bcf, about 1.5%. In LAI's opinion, it is inconceivable that the postulated withholding of at most 0.07 Bcf/d, and on average 0.009 Bcf/d, an infinitesimal portion of average demand, could itself explain a significant fraction of the alleged $3.6 billion in alleged increased wholesale energy costs over the three-year period.

   - The methods EDF used to simulate the changes in gas and electric energy prices are not part of standard industry practice in the power industry. Deviations from standard practice sometimes make sense, but must be explained. EDF did not do this. Notwithstanding the lack of any reason to analyze the impact on energy prices of a change in gas prices in this analysis, it would have been far preferable to have used a more complete econometric model of gas-price formation. It also would have been far preferable to employ a standard production cost modeling software and data system for electric energy price simulation. Instead, EDF used ISO-NE bid curves coupled with numerous simplifying assumptions. Since EDF employed unproven techniques, it would have been far preferable if EDF had made its analysis transparent to enable validation.

   - EDF failed to account for the major regional issues that are occurring in New England that are recognized by industry experts. These major regional issues include the lack of pipeline infrastructure and fuel diversity for the large fleet of natural gas-fired generation, generation retirements, uncertain oil inventory and replenishment logistics during cold snaps, uncertain LNG imports, and the grim outlook for gas production from Atlantic Canada. EDF's allegations stand solely on the purported "downscheduling" of an insignificant portion of gas assets paid for by gas customers and utilized by LDCs to maintain operational flexibility and local system reliability. EDF's failure to account for these issues renders their allegations and findings useless.

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1 Introduction

The EDF sponsored October 2017 working paper by Marks, Mason, Mohlin, and Zaragoza-Watkins will be referred to throughout as "EDF" or the "EDF paper" despite the lack of its imprint on the unpublished paper. Each author is tied to EDF.[1] Moreover, EDF has been actively trumpeting the findings set forth in the EDF paper to state and federal regulatory bodies as well as the trade press, although it has been released only in draft form and has not been subject to academic peer review.

EDF has alleged that LDCs doing business in Connecticut have "regularly restricted capacity to [New England] by scheduling deliveries without actually flowing gas" (pp. 2-3), thereby withholding gas pipeline capacity from the secondary market and increasing wholesale energy prices over the three-year period from August 2013 to July 2016. EDF contends that this withholding has caused customers in New England to pay $3.6 billion more for electricity than would otherwise have been the case if such capacity were available to serve generators. EDF has alleged that Yankee and NSTAR have been motivated to withhold pipeline capacity despite the loss of off-system sales revenue to the LDCs in order to extend for a longer time rate-of-return regulated profitability of the generation fleet owned and operated by PSNH. The authors allege that this indicates vertical market power abuse. EDF alleges that the vertical market power abuse is exercised by Eversource in order to extract a stream of rate-of-return regulated asset profits for Eversource's investors by making older, less-efficient non gas-fired generation units appear more productive than they would be under competitive market conditions. In the media, EDF alleges that the Connecticut LDCs "booked large orders and then canceled at the last minute, which pushed electric prices up by 20%."[2]

LAI has been asked by Eversource to consider the existence of any economic motivation by its LDCs to withhold pipeline capacity for the purpose of keeping the generation assets of PSNH under rate-of-return regulation. LAI also addresses the conventional gas utility practices underlying the provision of firm service to the Eversource LDCs' customers in Connecticut and Massachusetts. As part of our review of conventional gas utility practice, emphasis has been

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[1] Levi Marks, Charles F. Mason, Kristina Mohlin, & Matthew Zaragoza-Watkins. 2017. Vertical Market Power in Interconnected Natural Gas and Electricity Markets. https://www.edf.org/sites/default/files/vertical-market-power.pdf, accessed 2017-10-11. On its website and in the press, EDF has represented the EDF paper as having been authored by EDF and a "team of economists at EDF, UC Santa Barbara, University of Wyoming and Vanderbilt University. Each author, however, has held or currently holds a position at EDF, rendering the EDF paper suspect in its viewpoint rather than an academic working paper subject to the traditional independent, objective peer-review process. Marks, currently a Ph.D. candidate at the University of California, Santa Barbara, previously worked as an intern and researcher at EDF from 2016 to 2017. Mason, currently a Professor of Oil and Gas Economics at the University of Wyoming, was listed in a May 2017 Forbes article as a Senior Contributing Economist at EDF. Mohlin is currently employed by EDF as a Senior Economist. Zaragoza-Watkins, currently an Assistant Professor in Economics at Vanderbilt University, previously worked as a Post-doctoral fellow and Senior Economist at EDF from 2014 to 2017. Notably, the paper does not state whether or not the authors other than Mohlin were paid for any of the research and travel associated with production of the paper and the authors' presentations at several conferences.

[2] "How Local Utilities Gamed the Natural-Gas Market," Fred Krupp, *Wall Street Journal*, November 16, 2017.

placed on the role "No-Notice Service" contracts play in providing a valuable operational hedge to ensure reliable service to firm customers. LAI has also addressed the analytic shortcomings and patent defects underlying EDF's allegations in relation to the Eversource LDCs's obligation to serve, scheduling practices, and industry conventions.

EDF alleges that the Eversource LDCs are engaging in "unusual scheduling practices [to tie] up capacity that, in a well-functioning market, should have been released, or would have otherwise [*sic*] made available, to other shippers" (p. 3). The Eversource LDCs have an obligation to serve firm customers on an economic and reliable basis. In this analysis, LAI explains the scheduling practices underlying Yankee's usage of its contracted Algonquin capacity. In particular, we explain how No-Notice Service is managed to sustain daily flexibility in the event that unanticipated gas sendout materializes when there is greater than forecast demand. Such demand forecast uncertainty is an inherent part of looking forward one to five days, rather than looking back at the relationship between expected and actual demand, as EDF has done. EDF fails to assess the role No-Notice Service plays in the assurance of reliable service, and in the effects of the differences in how No-Notice Service is utilized by LDCs on Algonquin. LAI explains the standard operating procedures supporting Yankee's daily nomination and confirmation process and how measurement error throughout the heating season, in particular, is managed to avoid potentially severe operational or economic consequences for Yankee's firm customers.

This report is organized as follows:

- In Section 2, we comment on the alleged profit motive underlying EDF's economic assessment. We also summarize other key economic framework and empirical analysis flaws in the EDF explanation of the alleged exercise of vertical market power.

- In Section 3, we explain the practices and principles of LDC operations, highlighting operational realities that have been misunderstood, mischaracterized, or ignored by EDF.

- In Section 4, we present an alternative interpretation of the pipeline data used by EDF as the basis for its conclusions.

- In Section 5, we analyze the relationships between final schedule adjustments and weather, weather forecasting errors, market imperfections in gas trading, and the impact on gas prices.

- In Section 6, we critique EDF's modeling of alleged gas price increases and report on our analysis of the relationship between final schedule changes and spot market gas prices.

- In Section 7, we provide our conclusions.

2 The EDF Market Power Analysis Framework is Flawed

Highlights

- EDF fictionalizes Eversource as a single actor pursuing corporate-level profit-maximizing behavior in the face of traditional state government utility regulation and corporate accountability standards. EDF presented no evidence that Eversource Energy directed or otherwise influenced its LDC operating affiliates to manipulate the market. EDF does not explain how this political and regulatory charade would be implemented. EDF did not present a calculus of benefits and costs to Eversource, nor does it mention downside risk.

- EDF's definition of "overschedule" ignores the key role of weather forecast and other demand uncertainties, and the resultant need for a supply buffer to meet firm demands.

- EDF did not use any weather forecast data to test whether the observed schedule adjustments were consistent with weather uncertainty and need to reserve capacity for colder than expected weather.

- EDF mischaracterizes release of pipeline capacity rights. LDCs will not typically release their rights without a recall provision or sell firm gas until close to delivery time. EDF did not perform any analysis of how the LDCs could know with assurance how much capacity is releasable until within a few hours before delivery.

- EDF's assertion in the paper's introduction that overscheduling occurs on the coldest days is contradicted by the more detailed description in the body of the report that the largest schedule adjustments were on cold days when the LDCs still had excess contract capacity.

- EDF concedes that a traditionally-regulated electric utility does not keep any extra profit when electricity prices are higher. Instead, EDF makes a "subtle" argument of an indirect motivation to give the appearance of more value for regulated non gas-fired generation assets, primarily coal and oil, in order to persuade the state legislature and regulatory commission to keep them as regulated rate-based assets.

- To test its theory of vertical market power, EDF relied on a flimsy econometric analysis that omits important variables, such as weather uncertainty, SOLR delivery uncertainties, interactions with other New England pipelines in the generation of electricity, and such scant data that indicator (dummy) variables were needed instead of continuous capacity (MW) variables to characterize vertical ownership of merchant and regulated generation assets.

2.1 EDF ignores the roles of utility regulation and corporate accountability

The purpose of this section is to explain the Eversource LDCs' obligation to serve in the context of the absence of any economic motivation to withhold pipeline capacity to enhance the profitability of the regulated generation fleet in New Hampshire.

EDF has alleged that Eversource has a profit motive to increase gas prices in New England in order to preserve rate-of-return regulation of the PSNH generation fleet. EDF has alleged that by withholding capacity and mismanaging the Yankee portfolio for its customers' use, gas prices in New England are higher than would otherwise be the case. EDF alleges that if the LDCs owned by Eversource and Avangrid had reduced their day-ahead scheduled volumes by an average of 9 MDth/d and 42 MDth/d, respectively, over the three-year period,– or roughly 0.2% and 0.9% of total New England pipeline capacity – the alleged $3.6 billion of inflated power costs would be avoided.[3,4] EDF presents this alternately as $1.214 billion per year (p. 45) relative to an actual average annual energy cost of $6.267 billion (p. 43). In LAI's opinion, it is inconceivable an average increase in available pipeline capacity of 1.1% could result in a 19% reduction in annual electricity costs.

Additionally, as explained in section 0, operational constraints on Algonquin would almost always preclude the scheduling of any released capacity during the heating season to direct-connected generators on Algonquin. Whereas only about 340 MW is located upstream of Cromwell, CT – the contractual neighborhood of the Yankee system – roughly 7,000 MW are directly connected to Algonquin in southeast Massachusetts and Rhode Island, delivery points that are well downstream of critical bottlenecks in Connecticut and Rhode Island. Notwithstanding the absence of any economic motivation to withhold, EDF's insinuation that generation in New England could actually use such released capacity fictionalizes operational reality on Algonquin. Algonquin routinely seals daily nominations at critical chokepoints in Connecticut and Rhode Island, thereby precluding the scheduling of non-firm gas flow downstream to direct-connected generators.

EDF treats the Eversource companies as a single actor, in which a corporate-level, profit-maximizing strategy directs the operational schedulers of the Eversource LDCs to pursue pipeline capacity withholding and forgoing of potential off-system sales revenue in order to indirectly benefit PSNH by keeping its generation assets under rate-of-return regulation. This Wizard-of-Oz theory of corporate mendacity working behind an opaque curtain to drive costs up for gas and electric customers is a contrived, deceptive and irresponsible invention. In reality, gas and electric markets are subject to myriad accountability measures to safeguard against market power abuse. While the EDF paper does not assert that PSNH profits directly by obtaining higher gross margin on energy sales, EDF alleges that other vertically-integrated energy companies with merchant generators might have that direct profit motive. With respect to Eversource, the alleged profit motive is only that the Legislature will not require divestiture if its New Hampshire generating facility can be made to look more productive.

In fact, there is no evidence that the Eversource LDCs or Eversource corporate have taken actions to manipulate gas prices in order to boost the capacity factors, operating hours, gross and net margins, and other operating performance metrics of the PSNH thermal fleet. PSNH's thermal fleet operates "more" merely because there are region wide deliverability constraints

[3] 1 MDth = 1,000 MMBtu

[4] The shares are based on total New England pipeline capacity of 4.5 Bcf/d. 1 Bcf ≈ 1,000 MDth

on the pipelines serving New England, thereby limiting or precluding daily deliveries to non-firm shippers throughout the region during both cold snaps and often under more temperate conditions as well. PSNH's thermal fleet holds Capacity Supply Obligations under ISO-NE's Forward Capacity Market because ISO-NE has a call option on such capacity in case other, more efficient generation is not available for any reason, including limitations on the delivery of natural gas. In LAI's view, the capacity factors of the PSNH thermal units reflect region-wide operational dynamics and are unaffected by the Eversource LDCs' portfolio management.

The PSNH fleet is regulated under traditional cost of service regulation. The NHPUC is responsible for setting PSNH's cost of service. PSNH operates the regulated assets to benefit customers who select Standard Service from PSNH. Customers are free to shop for competitive supply from third parties doing business in New Hampshire. PSNH's Standard Service customers pay the NHPUC regulated cost of service. Hence, the market value of energy, capacity and ancillary services derived from the sale of wholesale products in markets administered by ISO-NE are credited in full to PSNH's customers, not stockholders. To the extent the value of energy is high, such as recently experienced during the "Bomb Cyclone" and associated cold weather event from December 26, 2017, through January 7, 2018, the value of such high energy prices is wholly credited to customers, not investors.

EDF acknowledged the fact that regulated utility generation assets do not directly benefit from higher electric energy prices. Instead, EDF has alleged that there is a "separate, and subtle, motive for pushing up electricity prices" under rate-of-return regulation. That alleged motive is to increase the level of operation of the generation assets so as to make them appear more beneficial to the NHPUC and the Legislature. EDF insinuates that the alleged rigging of gas prices to make the PSNH fleet appear more important perpetuates rate-base regulation, thereby avoiding divestment. This argument is baseless for three reasons.

First, right at the end of the EDF three-year study period, in July 2016, the NHPUC approved a settlement agreement in which PSNH agreed to divest its generation assets in exchange for the recovery of stranded costs regardless of the ultimate sales price received for its assets. Moreover, under the July 2016 NHPUC agreement to divest, if, for whatever reason, PSNH was not able to sell the assets, the agreement would have allowed retirement of one or more of the thermal generation assets as a *quid pro quo* for the recoupment of any stranded cost liability. Hence, the sale of the generation assets was therefore a precondition to the securitized financing of remaining stranded costs. Under the legislative and regulatory agreements, Eversource's stockholders are impervious to a good or bad outcome from the sale of the PSNH generation fleet.

Second, a general principle of utility regulation is that the value of assets resulting from a good economic outcome through divestiture is a customer benefit, not a stockholder rent.

Third, while EDF's alleged indirect, subtle motivation was to keep the PSNH thermal assets under regulation, in effect, allowing PSNH to clip coupons under cost of service regulation, EDF ignored the commercial reality that PSNH's customers have been free to shop for competitive supply rather than rely on PSNH. EDF did not analyze the dynamic consequences of increases in wholesale gas prices and energy prices on allowing renewable energy providers to be more competitive in the retail electricity market. Any effort by PSNH to recoup its cost of service over a declining customer base puts in motion a death spiral.

LAI therefore concludes that EDF's assertions about market power abuse are baseless, imaginary, and contrived.

Because the entire EDF paper's conceptual framework and empirical analysis is based on numerous basic misunderstandings of how LDC gas scheduling is performed in New England, this report has not attempted to counter or redress EDF's mistakes related to the authors' vertical market power conceptual framework and statistical analysis by performing an alternative analysis. However, to supplement our basic description and analysis of how LDCs operate in New England in the previous sections, we present a partial list of egregious errors and misrepresentations in the EDF paper.

2.2 EDF makes basic conceptual mistakes and contradictions regarding "overscheduling"

EDF defines "overschedule" as scheduling "larger deliveries in the day ahead timely cycle than are ultimately executed the next day" (p. 16). This definition ignores the key role of weather forecast uncertainty, as well as other demand forecasting uncertainties, and implies that actual volumes are known at the time that schedules are submitted.[5] Instead, over-scheduling should be defined as any excess scheduled demand in comparison with the then-forecasted demand at a high probability level. EDF's definition is overly restrictive by not allowing for demand forecast uncertainty.

EDF's definition of over-scheduling is also way too narrow. It does not matter for making gas available to generators whether a firm's scheduling procedure alternatively schedules only expected demand and later increases its schedule to cover an upward revision of the demand forecast. For either scheduling policy, the LDC will not typically release pipeline capacity rights without a recall provision attached thereto or sell firm gas until close to delivery time. LDC portfolio management requires short-term, Next Day and Same Day operational control of released capacity, which is measured in hours, not days or months. In short, EDF relies on a hindsight definition of withholding instead of a real-world operations foresight definition.

EDF only briefly considers the alternative explanation that firms A and B (Avangrid and Eversource, respectively) are risk-averse so they reserve the upper capacity that may be needed. The authors assert that is unlikely because:

- A and B are the only two firms with significant presence on AGT that also have "strong" incentives for raising electric prices.
- Their no-notice contracts make it unnecessary to overbook capacity (p. 33).

[5] Gas scheduling timelines and procedures are discussed in section 3.3.

These two counter arguments are seriously flawed. Whether the incentive to raise electric prices is strong or weak, the authors do not first demonstrate that there is any actual over-scheduling when accounting for weather and other demand uncertainties. EDF does not address the fact that whether initial scheduling of no-notice contract deliveries includes a reserve contingency component or only the expected demand, the LDCs cannot sell their rights to pipeline capacity until very close to delivery when there is little risk of not covering firm demand.

EDF alleges that aggregate withholding at the suspect nodes averaged about 50,000 MMBtu/day and the top 37 days of the three year sample period had over 100,000 MMBtu/day of capacity withheld, equal to 7% of Algonquin capacity (p. 3).[6] EDF reached this empirical conclusion about the magnitude of withholding by failing to consider the magnitude and time horizon profile of gas demand uncertainty. They did not use any weather forecast data to test whether the observed schedule adjustments were consistent with weather uncertainty and the need to reserve capacity for colder than expected weather. By omitting any analysis of the time profile of the confidence interval for weather forecasts, the timing of forecast updates, and best practices for incorporating weather information into gas demand forecasts, EDF does not have any basis for inferring purposeful withholding from the pattern of negative clean-up schedule adjustments.

EDF asserts in its introduction that Eversource and Avangrid "regularly restricted capacity to the region by scheduling deliveries without actually flowing gas" (pp. 2-3), but in the body of the paper the authors admit that there is initial uncertainty that is lessened over the course of the operational period, with LDCs obtaining better weather and other demand information, generators obtaining better electricity market information, and updated wholesale gas trading information (p. 23). Their assertion in the introduction is in opposition to this caveat in the report regarding information flows.

The introduction asserts that LDCs' over-scheduling exacerbated gas supply constraints, including the result that "significant quantities of pipeline capacity went unutilized on many of the coldest days of the year, pushing up the price of gas" (p. 3). However, in the body of the paper's analysis the authors state that the two firms reduce their schedules when it is cold and they still have excess contract capacity (p. 35), rather than on the coldest days. This behavior is consistent with the LDCs' need to use all of their contract capacity on the coldest days, regardless of weather forecast uncertainty. Hence, the claim in the introduction that overscheduling occurs on the coldest days is contradicted by the more detailed description in the body of the report. EDF's failure to reconcile the inconsistency in the introduction and the body of the report is sloppy: in EDF's public meetings and representations in the trade press they chose to ignore caveats the authors made in the body of the report.

[6] This statement is incorrect in allocating these volumes of "withheld" capacity to only particular nodes, as addressed in more detail below.

2.3 Alleged profit incentives for merchant and regulated generation assets have theoretical weaknesses and are implausible in practice

EDF makes the important concession that "by merit of its directness, the incentive pathway for merchant unregulated generation is much stronger than the derivative pathways for regulated generation" (p. 32, fn. 50). Indeed, the authors posit that the regulated firm does not keep more profit when electricity prices are higher (pp 18-19, fn. 24). Instead, the indirect pathway is that by increasing the output of units at risk of being deregulated or retired, the state regulatory commission would not force their disposal (sale or retirement), so the regulated electric utility would continue to enjoy the low-risk regulated return on its generation asset ratebase.

A major weakness in EDF's argument is that while two completely different types of profit incentive for merchant and regulated generation units were proposed, all of their conceptual equations and graphs illustrate the profit-enhancing outcome of raising electric energy prices of non-gas merchant units. Their only explication of the incentive mechanism for rate-of-return regulated generation assets is buried in a footnote (fn. 24 at pp. 18-19). The authors say that mechanism is "subtle." Their argument is that for the firm to continue to be allowed to own rate-of-return regulated generation assets, the electric utility must demonstrate to the state regulatory commission a "minimum level of operation of that generation capacity and the firm in question holds high-cost electricity generation capacity." Due to the risk of losing the at-risk rate-based assets through forced divestiture, the firm is incented to raise electricity prices in order to have the units appear to be "economically viable units" and not have the commission terminate their "revenue stream."

This is indeed a subtle mechanism, to say the least. More to the point, it is illusory. This subtle mechanism is implausible for at least five reasons.

- As previously discussed, EDF implicitly treats the firm as a single actor, in which a corporate-level profit-maximizing strategy directs the operational schedulers of the gas LDC division to pursue pipeline capacity withholding in order to benefit the electric generator division. Again, Eversource corporate is not the Wizard of Oz. The theory is far-fetched, against the law, and completely at odds with the array of gas and wholesale power safeguards long enacted to prohibit market power abuse.

- EDF is completely silent on how such alleged gas scheduling manipulation at the cost of foregone off-system sales would evade the Public Utilities Regulatory Authority's (PURA's) detection through its regular discovery process. The record shows PURA approval of Yankee's entitlements. It would not reflect well on PURA's and OCC's oversight roles if this alleged behavior had been overlooked as both PURA Staff and the OCC are authorized to leave no stone unturned when it comes to responsible management of the Yankee portfolio.

- The impact on typical operating performance metrics for electric generators, such as gross margin, capacity factor, and operating hours, is likely much smaller than in EDF's quantitative analysis as a result of several flaws in their econometric and simulation models.

- EDF did not formalize a model of the NHPUC's threshold level of operational performance that would trigger its decision to have the units be retired or divested. It may be that even for a material, noticeable higher level of performance, that some or all of the units would not be elevated to a safe level that prevents their disinvestment.

- The subjective assessment uncertainties behind the NHPUC's decision-making would eliminate any incentive to engage in this highly speculative stratagem, one where downside risk to the Eversource companies might materially weaken or destroy Eversource's market capitalization. A large economic literature of decision-making under uncertainty supports the concept that risks, especially those that cannot be easily quantified, add to "hysteresis" in decision-making. In plain English, it is insensible to embark on a high risk strategy with an ill-defined payoff, including unlimited downside. A high risk strategy means a firm could lose profit on its LDC division without achieving the outcome of retaining the regulated generation assets, or it could be at risk of severe monetary damages, loss of reputation, or even bankruptcy at the parent level if corporate mendacity were uncovered.

For merchant generation assets, the authors' analysis does not distinguish assets that operate with fixed price power purchase agreements (PPAs), such as most wind farms, from those that sell energy in the ISO-NE day-ahead (DA) and real-time (RT) spot markets. Avangrid's sole merchant generator is a wind farm, which sells its energy under a fixed-price PPA, so it would not benefit from an increase in electricity prices. When DA or RT energy prices spike, such as observed during the bomb cyclone, enhanced operating revenue from energy sales at high prices are credited to Avangrid's customers, not seller.

For energy firms with either regulated or merchant generation assets, the EDF alleged incentive mechanism for maximizing the value of the regulated assets under traditional cost of service regulation is selective, one-sided, and naive. EDF only considered the possibility that the parent company will want to retain the PSNH fleet to realize the regulated return under NH PUC jurisdiction. EDF did not consider that it may be easier for Eversource to maximize the benefits of rate base regulation by keeping gas prices as low as possible in order to incentivize still more oil-to-gas conversions in Connecticut and Massachusetts, thereby stimulating demand for capital projects at the local level. All investment by Yankee and NSTAR in expanded LDC capacity is regulated by PURA and the MA DPU, respectively, under traditional cost of service regulation. In actuality, Eversource has tried to minimize gas prices to expand upon the economic and environmental benefits attributable to increased LDC demand for residential and commercial gas conversions.

2.4 EDF wrongly suggests that FERC and PURA gas contracting policies cause the alleged vertical market power problem

EDF posits that "[t]he instance of market power discussed in this paper stems from the contracts that serve as property rights to natural gas transportation capacity" (p. 5). The authors conclude that "capacity release rules as they stand are insufficient to overcome the incentives toward inefficiency that are created by physical transportation constraints" (p. 6) in the gas pipeline network. EDF then proposes that "the firm's primary incentive to withhold capacity comes from vertical integration across the gas and electricity markets" (p. 7). The theoretical proposition is that the incentive to withhold capacity in the gas market, resulting in a foregone opportunity to sell gas (or capacity) to generators is more than offset by increased gross margin in the electric energy market by raising the price of gas and thereby the price of energy. EDF proposes that the low 1% revenue-sharing retention rule sanctioned by CT PURA on capacity release transactions and off-system sales increases the incentive to withhold capacity by greatly lessening the foregone opportunity cost (p. 15).

However, EDF makes an important concession at the start of section 5, Detecting Capacity Withholding. EDF admits that "the available data are insufficient to conclusively determine whether [raising the wholesale electricity price] is indeed the motivation of the withholding firms" (p. 21). EDF ignored this concession in its public outreach efforts with state and federal government bodies as well as the headlines reported in the media. Without hard evidence of any withholding, as we amply document, there is no basis for suggesting the need for FERC or PURA policy changes.

2.5 Limited market opportunity exists for an LDC to sell unneeded pipeline transportation capacity rights

EDF recognizes that FERC rules did not create a short-term (one year or less) transportation capacity release market with uncapped prices until 2008 (p. 9 and fn. 7). The authors observe that most secondary capacity release sales on Algonquin are for durations "of a few days to a few weeks" (p. 9). EDF does not expand on this typical multi-day contract duration characteristic of the capacity release market in the context of daily differences in alleged withholding. If the depth of the market is limited for very short duration capacity release sales, then the main opportunity for an LDC to make such sales would be when its forecasted firm demand is sufficiently below its contract capacity that the LDC can commit to sales of surplus capacity in the short-term capacity release market. This happens during the spring, summer and fall, and, to a limited extent, during more temperate conditions in the heating season, November through March, but not when there is a significant chance of occurrence that forecasted firm demand may be approximately equal to its contract entitlements.

While possible congestion rents for secondary capacity release sales or bundled gas sales may be high during the peak heating demand period, there is little or no opportunity to release capacity or sell gas more than a few hours in advance of delivery without jeopardizing reliable firm service to core customers. Simply put, the Eversource LDCs cannot be sure that they do not need their contract entitlements the day before contract delivery begins during the peak heating season as there is too much uncertainty affecting the decision.

EDF has ignored Yankee's need to maintain reliable service throughout the peak heating season, in actuality throughout the year. Yankee's retention of No Notice service is an integral part of the scheduling flexibility to maintain this assurance. While rolling the dice in the secondary market to realize net margin from layoff could conceivably lower electricity prices, it would be highly speculative to do so. Moreover, such transactions would expose Yankee's customers to adverse economic and operational impacts that are not part of the regulatory compact. Algonquin's penalties for unauthorized gas use are high, about three times the daily benchmark price. Yankee manages its portfolio to ensure reliable and economic service, including the avoidance of costly penalties on Algonquin, as well as Tennessee and Iroquois, for unauthorized gas use.

2.6 Numerous misleading and erroneous statements

EDF states that two firms "regularly restricted capacity to the region by scheduling deliveries without actually flowing gas" (pp. 2-3). This statement does not distinguish economically inefficient (or market manipulative) over-scheduling from necessary initial scheduling of reserve capacity to cover demand forecast uncertainty. It is also misleadingly presented as a behavior confined to only these two firms, although many other shippers also schedule volumes that are later reduced.

EDF falsely states that of the two firms accused of withholding capacity, "one firm is subject to rate-of-return regulation also on its electricity generation holdings" (p. 18, fn. 24). In fact, according to their Table 2, both Avangrid and Eversource have regulated generation assets. EDF's Table 2 shows that Avangrid has 155 MW of regulated generation capacity and 77 MW of unregulated capacity, while Eversource has 1,177 MW of regulated generation assets and no merchant resources.

EDF describes the two firms as owning "large portfolios of electric generation units located in the region" and having "substantial assets in both the gas distribution market and the electricity distribution market" (p. 3). These statements are highly exaggerated. The 1,177 MW they report for PSNH is only 3.5% of the 34,000 MW in ISO-NE. The 232 MW for Avangrid is less than 1%. EDF mischaracterizes the magnitude of the two firms' electric generation assets. EDF insinuates that Eversource and Avangrid have a great deal of motivation and leverage to profit in the electric sector through a small amount of foregone profits by their LDCs.

EDF asserts that there is a "large incentive" to withhold pipeline capacity on the basis of their theoretical discussion using conceptual supply-demand graphs (p. 19). One cannot conclude that an incentive is large (or small) without presenting data that quantifies the size of the incentive.

EDF states that "[u]sing a panel data regression model, we empirically demonstrate that these [withheld capacity] nodes were disproportionately served by specialized types of contracts that allow firms to call for gas on demand and to make large adjustments, without notice, in the last few hours of the day" (p. 3). The fact that the delivery nodes of the two firms were served by a large amount of no-notice contracts is a simple descriptive data conclusion that does not require use of a panel data regression model to demonstrate. This erroneous statement gives the misimpression that econometric analysis was needed to unearth this simple fact about the composition of the firms' gas supply contracts portfolios.

EDF states both that "[o]ver our three year study period, aggregate withholding at these few nodes reduced the pipeline's effective capacity by approximately 50,000 MMBtu per day, on average. On 37 days, over 100,000 MMBtu of capacity – about 7% of the pipeline's total daily capacity and about 28% of the daily capacity that is typically used to supply gas-fired generators – was withheld at these nodes" (pp 3-4). EDF later references these statistics again by stating that "[a]cross the entire system, aggregate schedule adjustments in the final three hours of the gas day averaged –48,493 MMBtu over our three-year study period and –51,152 MMBtu in the winters. On 37 days in the study period, the aggregate adjustment exceeded –100,000 MMBtu, which is roughly 7% of the pipeline's total capacity and roughly 28% of the total supply to electricity generators connected to the Algonquin pipeline" (p. 25). These two statements are referencing the same statistics, but relating them first to only an unidentified subset of meters and later to the entire Algonquin system. Conducting the referenced calculations for the six meters identified as "clear outliers" (p. 24) reveals that while the average total schedule reductions at these meters are 46,675 MMDth/d, which could perhaps reasonably be considered to equal "approximately 50,000 MMDth/d," there are in fact zero days during the three-year period on which the six meters have more than 100,000 MMBtu of total scheduled delivery reductions. The characterization of 37 days with more than 100,000 MMBtu/d of net schedule reductions is consistent with the data for the Algonquin system as a whole, as represented in the latter EDF statement. The former statement, which appears in the paper's Introduction, is inaccurate and mischaracterizes the behavior of "Firm A" and "Firm B."

2.7 Inadequate data and statistical modeling tests of alleged withholding behavior

The panel data regression analysis did not test an alternative model specification of defining the dependent variable as the fractional change in scheduled quantity, as opposed to the absolute measure (MMBtu/d) that was employed. A relative instead of absolute measure of schedule change would make the analysis more equal across LDCs and meters of greatly differing size.

The regression analysis did not include any variables to account for forecast errors resulting from weather forecast and SOLR delivery uncertainties. Hence, there was no direct test of a possible alternative explanation (demand uncertainty) for schedule revisions.

The actual weather data used was a single daily regional average HDD variable calculated as an average at locations across Connecticut, Massachusetts, and Rhode Island (p. 27, fn. 41). A more adequate actual weather dataset would use different values by location (state, LDC, or individual node), an effective heating degrees day (EHDD) measure instead of HDD in order to account for wind speed chill factor effect, and multiple measures at different times over the day.

EDF did not examine scheduling patterns on Tennessee, a pipeline that has National Grid as well as Eversource and Avangrid as prominent shippers. Besides not testing their model on a second major pipeline and another major LDC in New England, the omission of analysis of scheduling on Tennessee meant that EDF was not able to assess how Yankee and NSTAR balance their gas supply portfolios with deliveries from Tennessee (and Iroquois) in addition to Algonquin. LDCs use their entire portfolio to balance their system. Hence, the Eversource LDCs cannot be compared fairly to other LDCs without looking at how each LDC schedules across all connected pipelines and storage systems. The Eversource LDCs manage their portfolio consistent with the operational limitations and tariff provisions applicable on Algonquin, Tennessee and Iroquois. EDF has in effect put a silo on the Algonquin system, thereby ignoring crossover considerations among the pipelines serving New England.

For the subset of LDC nodes, EDF specifies five alternative regression equations that use a binary generation capacity indicator variable if the LDC parent firm owns ≥ 100 MW of generating capacity (p. 31). EDF admits they resorted to a binary instead of a continuous variable of generating capacity because the latter produced "problematic" or "erratic" results (p. 32, fn. 50). Specification and data limitation problems account for these poor results. But even a binary variable is deficient because only 4 of 11 firms have ≥ 100 MW of generating capacity and the number of firms with generation capacity was too small to test for any difference in behavior between regulated and merchant assets.

3 EDF Misunderstands and Mischaracterizes LDC Operational Practices and Priorities

Highlights

- EDF mistakenly concludes that optimizing pipeline utilization for the market as a whole should be a priority for Eversource, rather than the statutory responsibility to provide reliable and cost-effective service to firm customers.
- EDF fails to account for the reserve needed to cover weather variations and uncertainties to back stop obligations of third party suppliers, or to cover other indeterminate changes in demand so that LDC customers do not experience a loss of supply, particularly during the peak heating season.
- EDF disregards the role and responsibilities of NSTAR's Asset Manager by grouping Yankee and NSTAR scheduling behavior under one umbrella, when day-to-day control of NSTAR's portfolio is instead the purview of the Asset Manager.
- EDF fails to correctly describe how no-notice service functions on Algonquin's system and to recognize its importance to meeting Eversource's reliability and penalty avoidance objectives.
- Yankee's storage assets are a critical and finite component of its portfolio that must be carefully managed to ensure availability to support no-notice service during periods of high demand.
- Yankee uses capacity releases to recoup a portion of its transportation costs for the benefit of customers when it does not threaten system reliability to do so.
- Eversource's strategy for scheduling its no-notice service is to nominate flexible storage resources fully while targeting using approximately half of that quantity and then balance its system by adjusting the scheduled quantities, if necessary, at the end of the gas day. These schedule reductions within its no-notice contract entitlements do not change capacity availability for other Algonquin shippers.

The purpose of this section is to provide context for the operational and regulatory realities of LDC systems, in contrast to EDF's conclusion that "it has become increasingly important that already existing pipeline capacity is optimally utilized not only to protect the interests of gas and electricity ratepayers, but also to ensure that unbiased price signals lead to an efficient level of new pipeline development" (p. 47). We additionally correct specific EDF mischaracterizations regarding Eversource's operations and pipeline services.

Throughout the U.S., gas utilities are tightly regulated by state public utility commissions, with the core responsibility of providing reliable service to firm customers. In Connecticut, Yankee, is regulated by PURA. PURA is directly involved in the review and approval of Yankee's pipeline and storage portfolio, as well as its operational practices governing the use of its satellite LNG facility in Connecticut. PURA is also responsible for establishing Yankee's cost of service. NSTAR is similarly regulated by the Massachusetts Department of Public Utilities. Between Yankee and NSTAR, Eversource serves over 500,000 primarily residential customers, with annual peak day sendout of nearly 1 Bcf/d.

Regardless of temperature conditions or operational constraints on the pipelines and storage assets serving the Eversource LDCs, Yankee and NSTAR must fully serve firm customers every hour of every day. Portfolio management must be consistent with pipeline and storage nomination procedures and the confirmation process under a diverse array of planning conditions. These planning conditions include pipeline constraints and operating restrictions, operational limitations associated with the withdrawal of natural gas from conventional underground storage facilities and local satellite LNG storage facilities, as well as the potential for *force majeure* events. Yankee, like other LDCs, must plan for and proactively manage demand uncertainty.

3.1 An LDC's primary responsibility is delivering gas to customers

The Eversource LDCs provide service to multiple customer groups. Sales customers are those for whom the LDC provides both gas supply and transportation. Transportation customers are those for whom a third party delivers gas supply at the citygate and Yankee provides local transportation service from the citygate to the customer's meter. The core responsibility of LDCs is to ensure that capacity is available to meet all firm customer needs. The requirements of Yankee's firm customers support the supply, pipeline and storage entitlements that make up Yankee's resource portfolio. To meet its firm sendout requirements, Yankee does not borrow or otherwise lean on NSTAR's portfolio, and vice versa. There is no interchangeability of the Eversource LDCs' respective entitlements to serve SOLR obligations in Connecticut or Massachusetts. Management of the respective pipeline and storage portfolios is the responsibility of each Eversource LDC. Other than defined transportation contract arrangements with generators located behind the LDC citygates, Yankee and NSTAR have no obligation to serve or protect the economic interests of gas-fired generators that are directly connected to Algonquin, or, for that matter, any other generator in New England.

From a commercial standpoint, Yankee has a responsibility to follow good industry practice regarding the release of capacity or off-system sale of supply that is not needed to serve firm customer demand. Since Yankee's customers pay for the portfolio that is designed to ensure reliable service under design day conditions, the net margin recovered from capacity release or bundled off-system sales is credited to Yankee's customers. Further, LDCs are highly regulated and undergo many reviews of their portfolio, planning, and procurement practices on an on-going basis before state commissions to ensure that they are operating in accord with regulatory principles and portfolio optimization. In order to maximize portfolio benefits for its customers, Yankee systematically recoups margin from the sale of unneeded capacity, particularly during the spring, summer and fall, when Yankee's entitlements are far greater than what is needed to serve firm customers in Connecticut. Yankee is incentivized to maximize the portfolio benefits because part of the margin is earmarked toward assisting in gas expansion efforts. Yankee, like other New England LDCs, strives to keep gas costs as low as possible as it competes for load with alternate fuels and suffer increased customer complaints and billing objections when prices are high. During the heating season, November through March, Yankee often utilizes its portfolio fully or near fully, and is therefore limited in what capacity may be released from time to time in excess of firm customers' requirements. Any action taken by Yankee during the heating season must therefore strike a sensible balance between minimizing reliability risk while seeking margin recoupment to lower the cost of retail service.

Firm sales customers encompass residential customers and some commercial and industrial customers. Commercial and industrial customers also can elect to hold interruptible sales service. Yankee and NSTAR are not required to ensure service to commercial and industrial customers who elect interruptible sales service when operating conditions do not support such deliveries. The commodity needs associated with interruptible sales service do not factor into the formation of the Eversource LDC resource portfolios. Yankee customers covered under interruptible sales service are benefited under Yankee's OBAs with Algonquin, Tennessee and Iroquois, however.

3.1.1 EDF disregards scheduling uncertainties associated with transportation customers and SOLR obligations

In addition to meeting firm sales customer daily load requirements, Yankee must also be prepared to provide gas supply to its firm transportation customers served by third-party marketers in the event that a supplier fails to perform. Some of Yankee's largest individual customers are transportation-only customers, including power generators, industrial and manufacturing facilities, and military installations.

Under existing PURA regulations in Connecticut, Yankee must hold sufficient primary firm capacity to meet all firm system demands under design weather conditions absent *force majeure*. These potential supply needs can generally be anticipated on a given day based on the amount of transportation a customer has nominated on the LDC's system, but Yankee does not have visibility into the scheduling of third-party supplies on the interstate pipelines. Yankee must therefore be prepared to meet those demands on short notice.

In addition to meeting SOLR demands in the event that a third-party supplier fails to perform, Yankee is also responsible for providing balancing services for LDC transportation customers when third-party supplier deliveries to the citygate do not match what the customers take at their delivery meters. Under these circumstances, Yankee's customers benefit from the terms of Yankee's Operational Balancing Agreements (OBAs) with the interstate pipelines. OBAs are designed to give shippers the flexibility to not exactly match scheduled quantities with actual deliveries, which is effectively impossible because the last opportunity to change scheduled quantities occurs one hour prior to the end of the gas day. Yankee's goal each day is to match scheduled quantities to actual pipeline deliveries as closely as possible, which means it must also account for the difference between its transportation customers actual takes and what their third-party suppliers deliver to the citygate. This is because from the pipeline's perspective all imbalances at the citygate are netted together and applied to the point operator – in this case Yankee. In considering the data that EDF relies on, it is important to note that the available pipeline delivery data is tied to location, not to shipper – the deliveries (and changes to deliveries) to each location cannot be separated by which party scheduled them. This means that quantities scheduled by a third-party supplier to a citygate for an LDC's transportation-only customers are commingled with quantities scheduled by the LDC.

While EDF acknowledges that shippers other than Yankee can deliver gas to Yankee's citygates, the authors also state that "contracts held by Firms A and B drive the downscheduling we observe" (p. 33), disregarding any imbalances between third-party citygate supplies and the actual demands of transportation customers. This assumed alignment of supply and demand for some of Yankee's largest customers is not consistent with Yankee's experience of third-party supplier performance. In an extreme case, Yankee's SOLR obligation means that in the event of a third party marketer's default Yankee would need to balance the full demand of firm transportation customers supplied by third parties. During the three-year period in the EDF paper this third-party-supplied demand *comprised up to 25% of Yankee's firm throughput on a peak day*. EDF ignored this vital commercial obligation and potential operational constraint.

Under congested or extreme operating conditions that threaten the integrity of the pipeline system or the ability of the pipeline to provide firm service, a pipeline may issue an Operational Flow Order (OFO) requiring that customers bring receipts and deliveries into balance. Such orders generally limit takes to scheduled quantities. Failure to comply with the pipeline's directives will trigger substantial penalties or necessitate a pipeline to use flow control, if available, to restrict a customers' unauthorized use of gas in order to maintain system integrity. Algonquin's tariff stipulates a penalty of three times the daily High Common spot market gas price at Algonquin Citygates (as published in Platts' *Gas Daily*) for any gas taken in excess of the customer's hourly or daily entitlements only during OFO situations.[7] The penalty is intended to be sufficiently large to deter overruns, ensuring the operational integrity of the pipeline system and maintaining adequate pressure and flow across the system to enable pipeline deliveries for all customers.

Yankee must ensure that it has capacity available to serve firm transportation customers' needs in the event that a customer's third-party supplier fails to deliver gas to the citygate. Because Yankee does not know until supply is delivered whether third-party suppliers have successfully nominated and scheduled gas for delivery to the citygate, it must operate from the position of anticipating potential failure to deliver, particularly on days when pipeline constraints and restrictions are in effect. Yankee must therefore be prepared to serve the demand that has been nominated for transportation on its own system. Even if supply is delivered at the start of the gas day, suppliers can be subject to intraday supply cuts or shortages, which would also trigger the LDC's need to step in by providing gas supply.

[7] During the three-year period in question, the High Common price for Algonquin Citygates reached a peak of $82.98/Dth during the polar vortex in January 2014. More recently, the index reached a peak of $92.65 during the January 2018 bomb cyclone event.

3.1.2 EDF disregards NSTAR's Asset Management Arrangement by grouping Yankee and NSTAR behavior together

Whereas Yankee manages its own portfolio to meet firm customer demand in Connecticut, NSTAR relies on a third party to manage its portfolio to meet firm customer gas demand in Massachusetts. NSTAR selects an Asset Manager each year through a competitive Request for Proposal process, in which marketers submit offers to pay NSTAR for the opportunity to manage its pipeline and storage assets. NSTAR releases or assigns its portfolio assets, with the exception of local LNG storage, to the Asset Manager, and the Asset Manager in turn has a contractual obligation under the asset management arrangement (AMA) to deliver sufficient supply to NSTAR's citygates to meet its demand requirements. The AMA leverages the resources and expertise of an active, large-scale market participant to the benefit of NSTAR's customers while maintaining the high level of reliability those customers pay for and expect.

From an operational perspective, with the AMA in place, NSTAR provides the Asset Manager with its forecast of customer demand requirements, and the Asset Manager is responsible for nominating gas to the LDC's citygates to meet those demands. What remains paramount under the AMA is the provision of reliable service to NSTAR's customers. To this end, NSTAR coordinates closely with the Asset Manager to communicate changes in customer demand within the gas day via email and verbal discussions to ensure a reliable and least-cost supply for customers. While EDF groups NSTAR and Yankee behavior together under the "Firm B" umbrella, under the AMA, NSTAR's Asset Manager is the sole entity that can submit and adjust pipeline and storage nominations for the capacity that has been released or assigned to it, and the capacity is not under the day-to-day control of NSTAR or the Eversource parent. The Asset Manager can make numerous changes to nominations to optimize its own financial benefit or in response to updated demand information from NSTAR. The Asset Manager has the incentive to maximize the utilization of all of the capacity in the Company's portfolio because the manager has paid an up-front fixed fee payment to customers based on the estimated portfolio value. In fact, the Asset Manager depends entirely upon making capacity releases/sales to earn back the fee paid up front to NSTAR.

3.2 <u>Yankee's gas supply, storage and transportation portfolio is carefully developed and managed to maximize benefits to its customers</u>

Yankee and NSTAR each hold a portfolio of various resources to meet forecasted annual design day demands. The portfolios of the two LDCs are not interchangeable. Each LDC must therefore utilize its respective portfolio to meet the needs of its firm customers in Connecticut or Massachusetts. Each portfolio consists of gas supply, pipeline transportation, and storage services, including satellite LNG facilities.

3.2.1 EDF fails to correctly assess how no-notice service functions

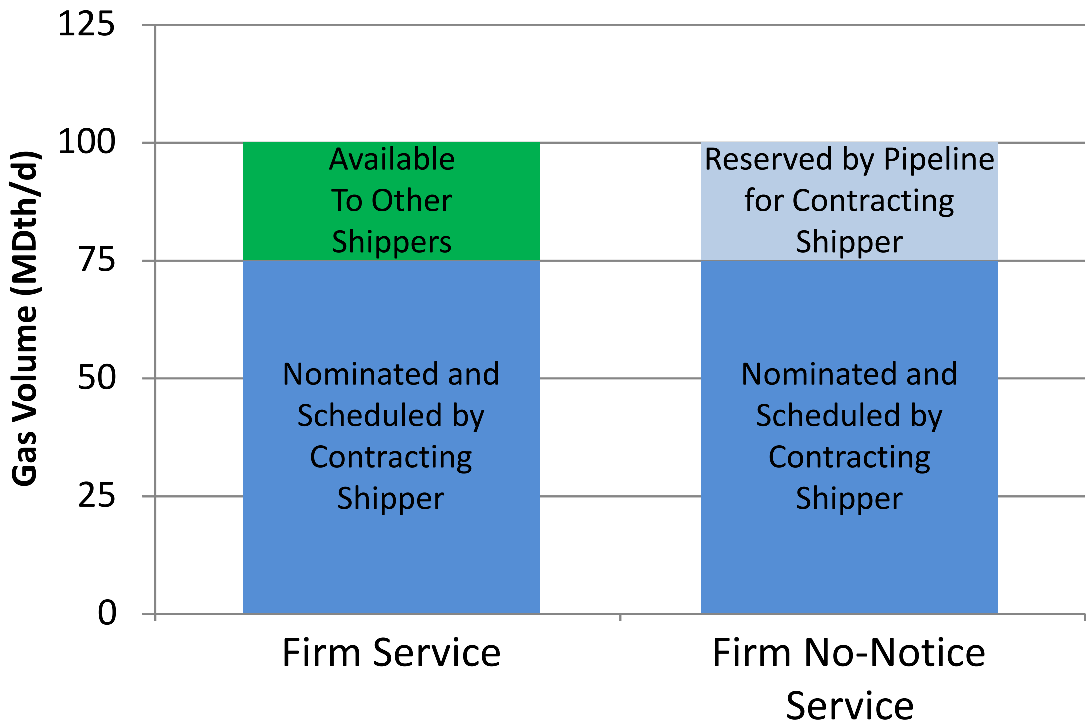
Interstate pipeline and storage companies offer two basic services: firm transportation and interruptible transportation. Pipeline infrastructure is sized to meet the demands of firm customers, with little or no excess capacity. Firm customers are those entitlement holders who pay the FERC-authorized cost-of-service rate to ensure guaranteed deliverability. Contract rights cover the transportation of gas between specific receipt and delivery points under all circumstances, except *force majeure*.[8] In exchange for this level of service reliability, firm customers pay a fixed monthly fee designed to reimburse the pipeline for the annual fixed costs and operating expenses, as well as a FERC-approved rate of return. Shippers pay these monthly fees each month irrespective of whether the entitlement is used fully, partially, or not at all. Firm shippers also pay a volumetric fee for actual usage which compensates the pipeline for variable costs. Yankee's costs for these transportation charges are passed through to its customers. Therefore, Yankee's portfolio is responsible first and foremost for meeting customer needs. In contrast, interruptible service is available only when there is sufficient capacity remaining after the needs of firm customers have been met. Unlike firm transportation, interruptible customers pay a volumetric rate for the daily quantity that the pipeline has confirmed.

Within the broad categories of firm and interruptible transportation service, pipelines can offer a range of service options. Algonquin, for example, offers no-notice service, which provides LDC and municipal customers holding this capacity with the contractual right to adjust nominations throughout the gas day with the same priority as would be reserved by Timely Cycle nominations. When the pipelines unbundled in the 1990s, Yankee received no-notice service from Algonquin as part of the separation of pipeline transportation and commodity supply when interstate pipelines transitioned from the merchant function to the transport (common carrier) function. All Algonquin no-notice contracts have receipt points at Algonquin's Lambertville and Hanover interconnections with Texas Eastern, and are supported by storage and transportation entitlements on the Texas Eastern system.

No-notice service is made possible through the pipeline's reservation of the corresponding capacity for Yankee's and other customers' use. Whereas the capacity associated with a standard firm transportation contract can be scheduled by other shippers on an interruptible basis if not nominated by the contract holder, the capacity associated with no-notice contracts can only be nominated by the contract holder. If it is not nominated, Algonquin holds this capacity in reserve in case of an incremental nomination during the gas day. The capacity earmarked for no-notice service can be made available to other shippers through capacity release by the contract holder, but it is not made available as a result of not being nominated on a given day. Figure 1 illustrates this difference in how capacity is utilized when 75 MDth/d out of a contract entitlement of 100 MDth/d is nominated by the contracting shipper during the timely cycle.

[8] *Force majeure* events are rare, and include only the most severe or unusual operating conditions when mainline segments or compression stations are not available, thereby reducing a pipeline's delivery capability such that it cannot meet its firm service obligations.

Figure 1. Comparison of Firm and Firm No-Notice Capacity Availability

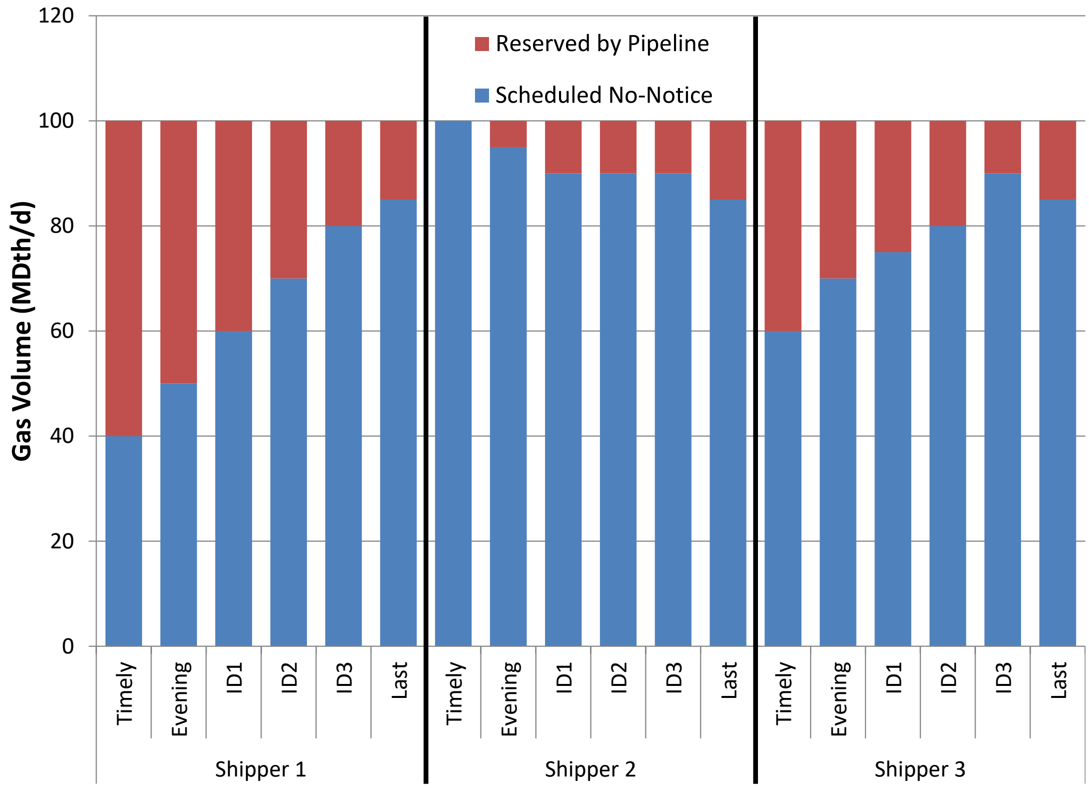


While un-nominated firm transportation capacity can be utilized on an interruptible basis by other shippers, un-nominated firm no-notice transportation capacity is reserved by the pipeline and not available to the market.

Holding this capacity gives Yankee intraday scheduling flexibility, thereby allowing the LDC to nominate contracted volumes during the Timely cycle or anytime throughout the day. This flexibility provides Yankee with a valuable operational hedge to increase or decrease nominations as needed based on variability of load. While EDF acknowledges this flexibility by stating that "[s]uch an arrangement facilitates overscheduling by ensuring that any downscheduling adjustments in the final few hours will be automatically approved by the pipeline company" (p. 29), the authors fail to recognize the obvious complement that nomination increases at the end of the gas day are also facilitated by no-notice service in arriving at the conclusion that end-of-day nomination reductions are preventing other shippers from being able to utilize the capacity. Regardless of a no-notice shipper's behavior with respect to nomination increases or decreases, the full contract quantity is reserved for the entitlement holder and therefore not liquidated as secondary firm or interruptible transportation by Algonquin. EDF has ignored the well documented history of no-notice service on Algonquin, in particular, and FERC doctrine, in general.

Figure 2 illustrates different potential scheduling patterns that could occur under a no-notice contract. The three scheduling patterns shown – representing either increasing nominations, decreasing nominations, or both increasing and decreasing nominations relative to the 100 MDth/d no notice contract quantity – each result in the same amount of the contract's capacity available to other shippers, that is, none.

Figure 2. Comparison of Firm and Firm No-Notice Capacity Availability



Under each of these scenarios, the full 100 MDth/d contract quantity is unavailable for other shippers to utilize at any point during the gas day, regardless of how much is nominated by the contracting shipper, because the remaining contract quantity is reserved by the pipeline for the contracting shipper's use.

Because Yankee relies on no-notice service to ensure reliability throughout the heating season, it does not typically release such capacity in light of the potential operational and economic consequences attributable to reducing the flexibility of its daily portfolio. Operationally, Yankee relies on no-notice service to balance its Algonquin portfolio as load uncertainty diminishes at the end of the gas day. To release its most flexible capacity while load uncertainty persists, from the timely cycle through the first few hours of the gas day and particularly during the high demand winter season, would expose Yankee to potential penalties from the pipeline, or in a worst case scenario, failure to meet its service obligations. In either case, Yankee would be failing to meet its core objective, to provide reliable and cost-effective service to its firm customers. Yankee's theoretical release of such capacity might generate a small margin allocable to its firm customers, but in so doing expose its customers to costly penalties levied by Algonquin for unauthorized gas use, threats to local system reliability, or both.

Algonquin's no notice service tariff additionally allows shippers to take up to 6% of the daily contract quantity in an hour. This contractual right to deviate significantly from a 1/24th ratable take is an integral part of Yankee's ability to meet the evening supper load and early morning ramp when residential and commercial customers' demands increase disproportionately.

3.2.2 Yankee must carefully manage its storage assets to ensure availability during high demand periods

Underground storage service consists of the storage operator accepting gas for injection into storage during the injection period – typically April through October – and then withdrawing the gas and delivering it to the customer, or customer's transporter, during the withdrawal period. The withdrawal period typically aligns with the heating season, November through March.[9] Storage entitlements are defined by the total amount of gas that can be stored and by the maximum amount of gas that can be injected or withdrawn on a daily basis. Filling storage entitlements during the summer benefits LDC customers because gas prices are usually lower and almost always less volatile than during the winter. Storage injections and withdrawals are, however, limited by contract entitlements and tariff provisions.

Storage withdrawals represent a limited resource that needs to be managed to ensure that it is available if needed in the event of extreme cold for an extended period, such as the recent bomb cyclone, or late in the storage withdrawal season. Additionally, as storage levels are drawn down and reservoir operating pressures decrease, storage operators invoke ratchet provisions in their tariffs which effectively reduce the amount of gas that can be withdrawn on a given day.[10] Yankee, like other LDCs, must manage its storage withdrawals, including those for supporting no-notice service, to safeguard storage inventory levels throughout the heating season and to ensure compliance with pipeline scheduling requirements and imbalance resolution provisions. Yankee's Gas Control determines whether storage withdrawals are needed to support sendout to its firm customers, and if so, from which storage facilities across its portfolio. Storage withdrawals are not scheduled to support capacity release transactions, bundled off-system sales, or interruptible sales service.

Yankee and NSTAR, along with other New England LDCs, hold storage-sourced transportation contracts on Tennessee, which can offer flexibility in terms of allowing decreasing nominations during the day. These contracts, however, do not come with the same flexibility in increasing scheduled volumes after the Timely Cycle. Therefore, the most likely scheduling pattern for such a contract is that shown for Shipper 2 in Figure 2 above, with storage nominated fully in the Timely Cycle and reduced over the course of the gas day.[11]

In addition to underground storage resources described above, Yankee, like other LDCs, can also utilize on-system LNG storage to meet peak day needs. These resources, however, are not designed to be regularly relied upon, due to logistical limitations in filling the tanks during the summer and replenishing the tanks during the winter. In Yankee's case, the rate of liquefaction requires steady conversion of pipeline gas to liquid throughout the summer and fall. Truck-

[9] Winter injections and summer withdrawals are usually allowed on an interruptible basis, and can also happen when more temperate conditions during the heating season allow storage customers to replenish working gas inventory, while summer withdrawals may be needed to supplement pipeline throughput or manage imbalances.

[10] Similarly, as storage levels are filled during the injection season, the ratchet provisions limit the amount of gas that can be injected on a given day.

[11] This operating paradigm is illustrated using Tennessee pipeline data in section 4.3.

transported supply from liquefied natural gas suppliers is typically only utilized during the refill off-peak season, and not during winter periods due to price, logistics, and operational considerations.

Satellite LNG tanks are designed as a peaking resource, to be used sparingly, about ten days per year during the peak heating season. Like conventional storage withdrawals, this supply must be managed in order to ensure that it is available when needed, and it is used only to serve on-system customers when contracted pipeline-delivered supplies are insufficient to meet daily demand and local operating pressures decline due to high customer sendout. They are not used to reduce Yankee's reliance on pipeline-delivered supplies below contracted levels. Also, they are not designed to furnish service to interruptible sales service customers or to bolster regional deliverability to promote electric reliability.

3.2.3 Yankee routinely releases capacity to recoup margin for its customers when doing so does not threaten service reliability

In addition to contracting directly with pipelines for service, shippers can also obtain capacity through the secondary capacity market. In the secondary capacity market, shippers holding firm capacity that they do not expect to use can release this capacity for sale to other shippers.[12] The release may be for a term as short as a partial gas day, or as long as the remaining term of the entitlement of the releasing customer. Such released capacity is posted on the pipeline's EBB, and is transferred to the highest bidder.[13] This mechanism allows shippers who do not have firm capacity on a pipeline, either because it is not available or they are not willing to pay long-term reservation charges, to contract for it for a short term. The process of releasing and re-assigning capacity helps to ensure that the available capacity is allocated according to the highest economic use.

Subject to the terms the assignor places on the released capacity, the assignee acquires entitlements that are equal in character and priority to those of the assignor. Consistent with FERC ratemaking and scheduling priorities, secondary firm capacity has a priority of service lower than primary firm transportation service (but higher than interruptible service) if the assignee uses different receipt and/or delivery points than those specified in the assignor's contract. Secondary capacity releases are differentiated by in-path release transactions versus out-of-path release transactions. In-path releases involve an assignor and assignee utilizing the receipt and delivery points located between the primary points. In other words, the assignee's path is fully within the primary firm path. Out-of-path capacity releases typically incorporate downstream delivery points, and therefore cannot necessarily be accommodated by the transporter during periods of high throughput without degrading a primary firm transportation customer's rights. For this reason, out-of-path capacity release transactions are always subordinated to primary or secondary firm in-path transactions during the scheduling process.

[12] Capacity can be released "subject-to-recall," that is, the releasing party or assignor can include a recall right that is unilaterally exercisable by the original contracting party, subject to specific terms.

[13] Under certain conditions, the capacity may be released through a pre-arranged agreement, and need not be subject to open bidding.

These scheduling priorities are important to note based on the contract paths of Yankee's capacity relative to the locations of generators on Algonquin, which will be addressed in section 0.

Yankee uses a blended approach of capacity releases, off-system sales and AMAs to manage portfolio resources and maximize the economic benefits to its customers. Longer-term monthly and seasonal capacity releases are made if capacity is determined not to be required to meet customer needs over a given period. Short-term capacity is released on a daily or intraday basis if operating conditions permit. LDCs do not typically release firm pipeline capacity into the market, especially during the coldest periods, with the exception of releases to third-party suppliers serving LDC firm transportation customers, because neither the LDC resource portfolios nor the interstate pipelines have a built-in reserve margin, and LDCs must preserve the availability of their supply and their ability to reliably deliver gas to their customers.

3.3 Eversource's daily operations and scheduling practices are more complex than the EDF paper recognizes

To ensure the systematic flow of natural gas from various producing basins and storage facilities to market centers across North America, pipelines and LDCs must utilize a standardized nomination, confirmation and scheduling process that is the product of stakeholder review and FERC approval.[14] Under the current protocol, all shippers – including primary firm transportation, secondary firm transportation, interruptible shippers, and shippers obtaining primary and secondary capacity through capacity release – must first submit a nomination to the pipeline requesting the amount of gas they want a pipeline to deliver and the receipt and delivery points. Shippers must have associated quantities of gas supply to support the requested nominations.

3.3.1 Eversource's LDCs utilize a standardized nomination, confirmation and scheduling process that is the product of stakeholder review and FERC approval

All pipelines operate on a standard 24-hour gas day beginning at 9:00 am (Central clock time, or "CCT"). The North American Energy Standards Board's (NAESB's) Wholesale Gas Quadrant (WGQ) has established five standard nomination cycles for each gas day: Timely and Evening, which occur the day before the start of the gas day, and Intra-Day 1, Intra-Day 2, and Intra-Day 3, which occur during the gas day. Each cycle consists of the following steps:

- Nomination – Shippers submit requested quantities to transporters
- Capacity Allocation – Transporters determine if there is sufficient capacity to transport the nominated quantities

[14] The NAESB WGQ develops the standards which interstate pipelines must comply with once FERC incorporates the standards into the Code of Federal Regulations.

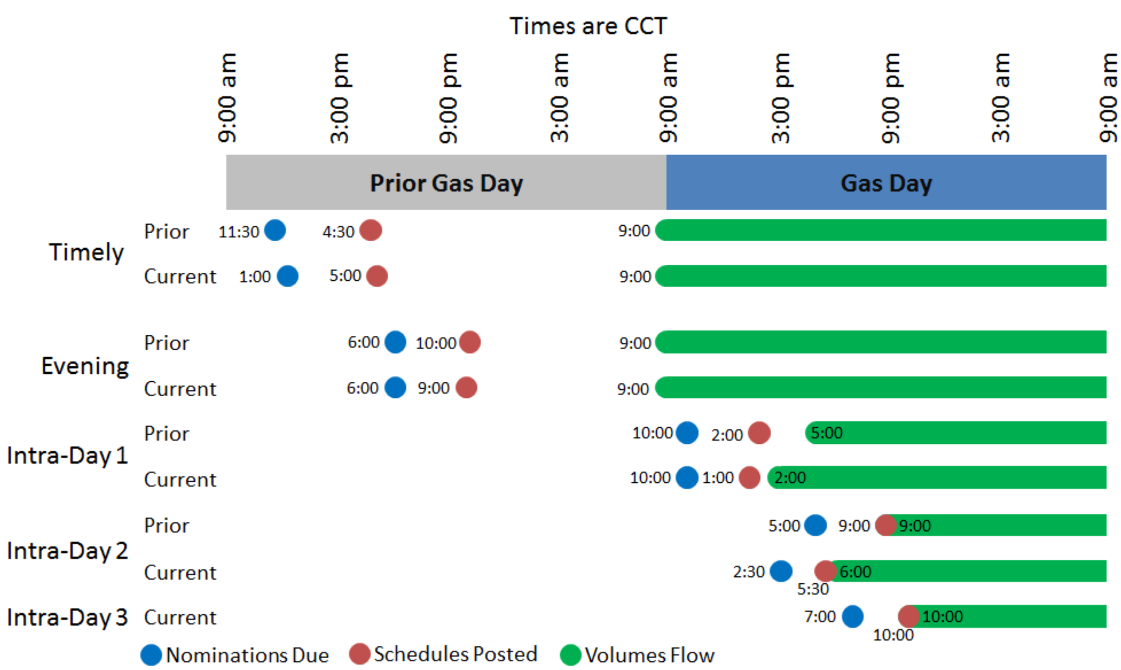
- Interconnect Confirmation – Transporters confirm quantities with upstream and downstream point operators

- Scheduling – The transportation quantity scheduled to flow is the lesser of the quantity nominated by the shipper, the capacity allocated by the transporter and the confirmed upstream and downstream quantities

The same nomination and confirmation process and schedule are used each day, including weekends and holidays. Shippers have the option to submit single-day or multi-day nominations through their interstate pipeline EBB accounts. Pipelines operate seven days a week, 24 hours a day, including holidays and weekends, with staffing schedules configured to accommodate expected shipper needs. The round-the-clock nature of pipeline nomination schedules is not necessarily reflected in gas trading markets, and obtaining gas, rather than nominating that gas to flow, can therefore become the limiting step when shippers seek to schedule gas during weekends.

Figure 3 shows a complete schedule of deadlines associated with each of the standard NAESB cycles. The gas day schedule changed on April 1, 2016, adding a third Intraday cycle and shifting the timelines for the four existing cycles. The schedules labeled "Prior" in the figure below were in place for most of the three-year period studied by EDF, including all winter days. The schedules labeled "Current" were in place for the final four months of the three-year period.

Figure 3. Standard NAESB Nomination Cycles (CCT)



Under the schedule in place during all of the winter days during the three-year period studied by EDF, nominations for the final confirmed intraday scheduling opportunity were due at 5:00 pm CCT, 16 hours prior to the end of the gas day.

Although they must offer at least the five standard nomination cycles, pipelines may elect to provide greater flexibility in their nominating procedures. Both Algonquin and Tennessee offer additional nomination and scheduling opportunities for shippers.

Following the Timely cycle scheduling process, Algonquin allows shippers to revise nominations any time prior to the end of a Gas Day, either between the Timely cycle and the start of the gas day or during the gas day, as long as the change can be implemented based on the pipeline's operating conditions, is not to the detriment of other scheduled volumes and can be confirmed with the receipt and delivery point operators. Algonquin's tariff states that notifications of schedule changes will be issued within four hours of these supplemental nominations.[15]

In addition to the five standard nomination cycles, Tennessee allows shippers to change their nominations sixty minutes in advance to be effective at the start of any hour of the day between 11:00 pm CCT and 8:00 am CCT, effectively offering hourly nomination cycles for the last ten hours of the gas day.[16,17]

3.3.2 Eversource's nomination and scheduling procedures are fully appropriate and necessary to meet reliability needs

While the authors of the EDF paper have the benefit of perfect hindsight in statistically comparing day-ahead and end-of-day delivery schedules, LDCs do not have the same privilege of making resource deployment decisions based on guaranteed information about load and the factors that affect it. The Eversource LDCs do not feign omniscience and must therefore maintain sufficient scheduling flexibility to account for demand uncertainties in the intra-day market. Timely Cycle nominations must be submitted more than 20 hours before the gas day begins, and more than 44 hours before it ends. Scheduling activities must consider what might happen in the future, because there is no relief from the obligation to deliver gas to customers based on unexpected circumstances. EDF states that "large, consistently negative adjustments just before the end of the gas day are consistent with an LDC shipper that intentionally nominates capacity in excess of its predictions of its customers' daily demand" (p. 24). EDF implies that this behavior is irresponsible. In actuality, Yankee is operating responsibly in light of demand uncertainty and its core obligation to serve.

The first step in the nomination and scheduling process for a particular gas day is to forecast load requirements based on a number of variable factors including the weather forecast, recent load observations, third-party supplier/marketer behavior, supply and storage contract limitations, distribution system operating conditions, and interstate pipeline operating conditions. Each factor incorporates a number of considerations and degrees of uncertainty based on recent and real-time experience. Figure 4 illustrates the impacts of potential load uncertainty factors.

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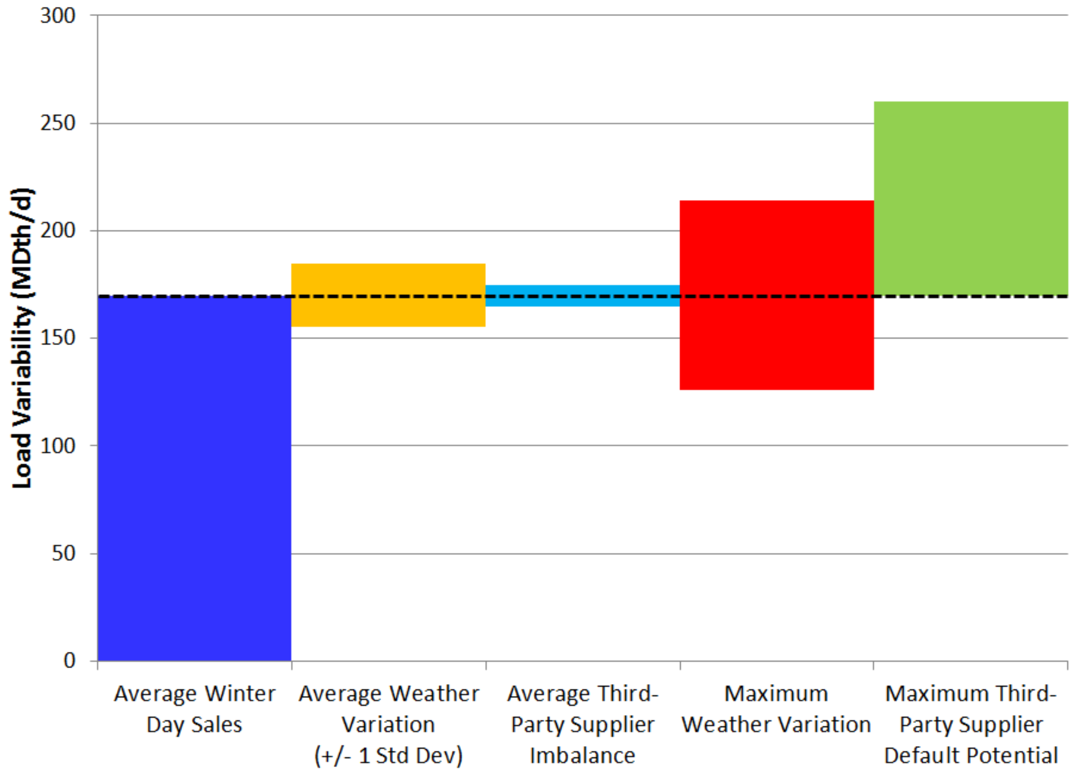
[15] Algonquin Gas Transmission LLC, FERC Gas Tariff, Sixth Revised Volume No. 1, Section 22.4.

[16] Tennessee Gas Pipeline Company LLC, FERC NGA Gas Tariff, Sixth Revised Volume No. 1, Section IV.2.(e).

[17] Nominations to be effective at 8:00 am can be submitted as late as 8:00 am.

Figure 4. Illustrative Load Uncertainty Factors[18]



This figure reflects the uncertainty factors that Yankee must consider when scheduling and balancing its system and supply portfolio.

Part of the challenge in determine Timely Cycle nomination volumes is that LDCs need to forecast three to five days ahead in some cases due to weekends and holidays. This increases the uncertainty associated with weather forecasts, operating conditions, and customer loads. While lower loads may occur on the weekend or holiday gas days, the following gas day (*e.g.* the Tuesday after a three-day holiday weekend) can have a significantly higher load. Load variations associated with third-party suppliers who have nominated and scheduled gas to citygates on behalf of LDC transportation customers are also an important consideration in the mix of factors driving resource decisions, because transportation customers are some of the largest individual LDC customers.

Forecast development begins each morning before 8:00 am CCT with the daily requirements output from the statistics-based model using the weather forecast as input. Historical information is incorporated with Gas Control's expectation of operating conditions to determine the amount of gas to nominate. This process is designed to identify the resource requirements that customers may reasonably have during any particular gas day, taking the wide range of dynamic uncertainty factors into consideration. A supply plan is then developed based on the portfolio of available transportation, storage and peaking resources, and capacity

[18] This graphic excludes uncertainties related to pipeline operations that must also be considered and managed, particularly during periods of high utilization.

that is not needed to meet customer demands and SOLR obligations is identified for release. Daily capacity releases to pre-arranged bidders can occur via pipeline EBB 24 hours prior to the gas day start. Bundled gas supply sales are also arranged on a day-ahead basis prior to the 1:00 pm CCT Timely Cycle nomination deadline, with trading typically occurring between 7:00 am and 12:00 noon CCT. Additionally, with the exception of no-notice capacity, unused pipeline capacity resources are available to the general market from the interstate pipelines on an interruptible basis or secondary basis.

On very cold winter days, Yankee's nomination process is simple. It will dispatch all firm pipeline supplies and firm pipeline storage, and plan to meet the rest of the load with on-system LNG supplies, although no-notice service may be used to balance the system if LNG is over or under-withdrawn. On winter days when peaking LNG is not expected to be needed, Yankee plans to balance the portfolio with conventional storage adjustments on an intraday basis, and therefore nominates its flexible storage contracts and the associated no-notice capacity fully while targeting the use of approximately the midpoint of storage capacity, leaving room within the storage nomination for upward or downward adjustments based on the variability of customer load and deliveries of gas supply into the LDC system. Storage assets are used to balance the system because they are more flexible on an intraday basis than supplies flowing from gas producers.

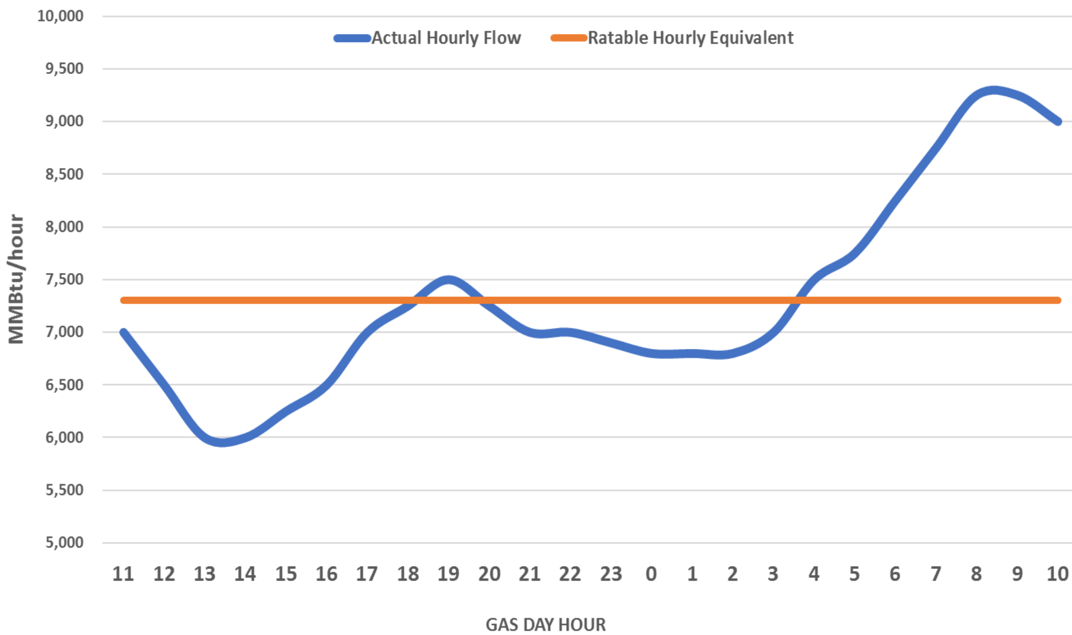
The efforts of Gas Control and the Gas Supply planning staff are closely coordinated so that adjustments can be made as necessary. Gas Control is charged with monitoring the distribution system on a 24/7 basis, and will notify the Gas Supply planning staff if actual loads are deviating from forecasts to assess what is needed and what can be done to manage those changes throughout the Gas Day. Following the Timely Cycle, Yankee is continually assessing reliability and cost considerations in order to decide whether to make nomination adjustments. Late Cycle nominations are made by 8:00 am CCT just prior to the start of the gas day based on updated information and discussions with Gas Control regarding system operations. Nominations are generally not modified unless and until there is evidence that the Timely Cycle nominations are substantially off-base, to the extent that there is no possibility that a portion of the scheduled gas will be needed for the remainder of the gas day.

For gas users in the marketplace to utilize Yankee's firm capacity on a cold day on a non-interruptible basis, or during an extended cold period, Yankee would have to release that capacity before the close of the business day in the current gas day. Incremental intraday sales can occur if updated weather and load information becomes available, but it does not happen often because there are 14 hours of potential load variation remaining after Intra-Day 3 Cycle nominations are due at 7:00 pm CCT. Intraday sales or releases cannot be undertaken unless there are no circumstances that could arise under which the LDC would need the capacity.[19] Figure 5 provides an example of the winter day variation in intraday load levels to show the timing of the evening and morning load increases, illustrating the critical point that load is

[19] This timing reflects the current gas scheduling timeline. During the scheduling timeline that was in effect for most of the three-year EDF period, there were 16 hours of potential load variation remaining after Intra-Day 2 Cycle nominations were due at 5:00 pm CCT.

highest at the end of the gas day, contributing to the extended uncertainty regarding total daily demand. When Yankee reduces its nominations at the end of the gas day to balance with its more known system demand, that capacity is then available for scheduling which at times is utilized by marketers who have nominated gas on a secondary or interruptible basis in hopes that the gas capacity becomes available.

Figure 5. Illustration of Winter Intraday Load Variation



Gas load changes significantly during the last hours of the gas day to reach its highest levels in the morning. Uncertainty associated with this morning ramp means that total daily load is not known until well after the final confirmed Intraday cycle closes.

In the afternoon of each Gas Day, Gas Control reports how the system is running in comparison to the available supplies and works with supply staff to determine whether any changes are needed to meet system requirements. If changes are made on an intraday basis, those changes would typically be made in the afternoon (2:00 pm to 3:00 pm CCT), before normal business hours are over. During what would be considered "off hours" (4:00 pm to 6:00 am CCT), Gas Control monitors the supply and demand balance in real-time and will contact the designated supply staff representative if a supply adjustment is necessary or any concerns/issues arise.

Based on Yankee's approach to utilizing its flexible storage and no-notice services, nomination adjustments on the morning at the end of the gas day are used to adjust scheduled quantities to be consistent with the amount of gas that was actually needed based on load and citygate delivery variability. If the load forecast was close to accurate, this would result in a nomination decrease of approximately half of Yankee's flexible storage capacity (13 MDth/d). If load was less than forecast, a larger nomination decrease would be needed to balance the system (13 to 23 MDth/d), and if load was greater than forecast, a smaller nomination decrease would be needed (0 to 13 MDth/d). The level of necessary balancing adjustments is not known until the highest load hours are occurring in the morning at the end of the gas day. While this approach does result in frequent downward adjustments to scheduled volumes at the end of the gas day, the adjustments involve Yankee's no-notice service entitlements, which would not have been available to other shippers even if Yankee had not nominated them. Yankee's average winter day schedule adjustment during the three-year period is 13.6 MDth/d, indicating that load forecasts were, on average, close to accurate. Looking at individual days, however, encompasses the full range of potential schedule adjustments within Yankee's no-notice contract quantity.

Yankee can make changes to its nominations until the last cycle in a gas day at 8:00 am CCT. Yankee uses this opportunity, as necessary, to adjust nominations to minimize imbalances and avoid pipeline penalties. With one hour of gas flow remaining at the time final nominations for the gas day must be submitted, it is effectively impossible to exactly match scheduled and actual deliveries, any remaining imbalances, including those associated with other shippers delivering to the Yankee citygates, are handled based on the terms of the OBAs with the respective pipelines.

4 EDF's Analysis of Pipeline Data Fails to Consider Several Key Factors in Characterizing Yankee's Scheduling Behavior Relative to Other LDCs and its Alleged Effects

Highlights

- EDF incorrectly accounts for Algonquin operating constraints by failing to consider bottlenecks in Connecticut upstream of the Burrillville compressor station and the role of reserved no-notice service in reducing available capacity.

- EDF's finding that the Eversource LDCs use their no-notice capacity to manipulate markets disregards the fact that Yankee and NSTAR utilize their no-notice capacity at a similar or higher rate as other LDCs on Algonquin, and additionally fails to consider that differences in LDC operational practices with respect to the timing of no-notice nominations do not change the net effect of each LDC's scheduling practice on availability of pipeline capacity.

- EDF's focus on days with more than 100 MDth/d of schedule changes sensationalizes its results by commingling Yankee's behavior with that of all other shippers on Algonquin's system, which EDF in one instance blatantly obfuscates. In fact Yankee's scheduling behavior on those days is within the range of its scheduling behavior on all other days in the three-year period, and on average is only 6 MDth/d different on the 37 days than on all winter days.

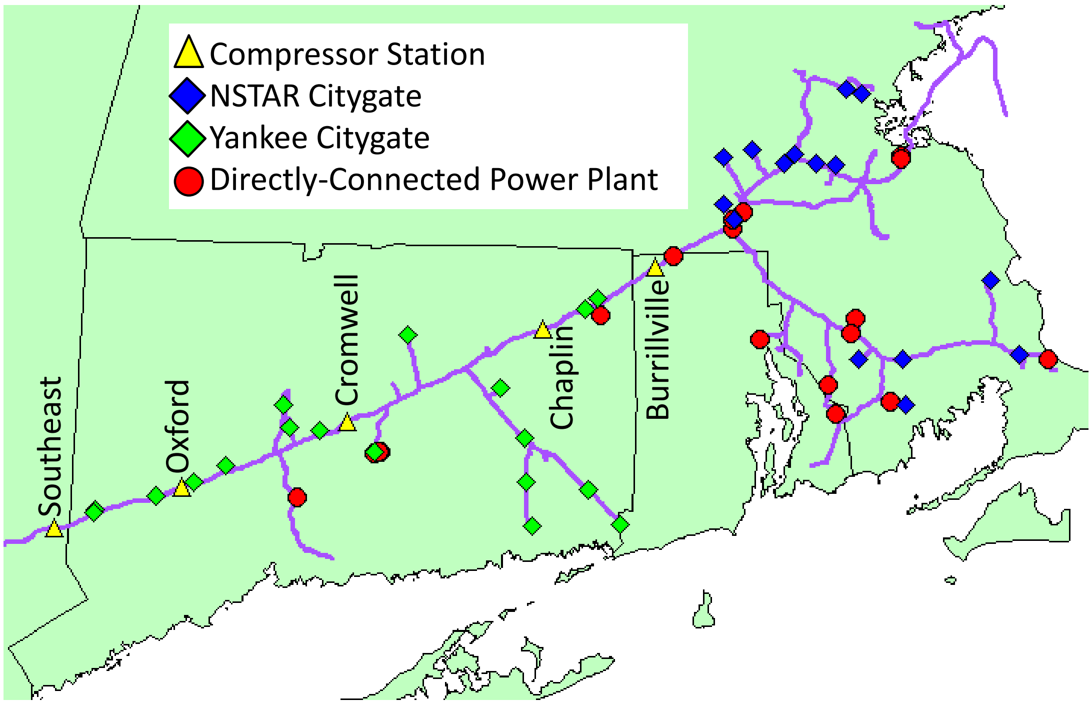
- EDF's failure to understand how LDCs utilize no-notice service is reflected in an analysis of how LDCs other than Eversource and Avangrid schedule gas on Tennessee, which does not offer no-notice service, resulting in LDCs waiting to reduce scheduled quantities until late in the gas day.

The purpose of this section is to identify flaws and inconsistencies in EDF's analysis of scheduling patterns that they have used to detect "capacity withholding." We have analyzed pipeline data from the three-year period utilized by EDF. EDF has not made their analysis database available. We have therefore attempted to replicate their analysis. This analysis has revealed that the differences in scheduling approaches between LDCs are consistent with the range of behavior allowed by no-notice capacity and are not consistent with EDCs conclusions regarding efficient capacity allocation. In addition, EDF has incorrectly accounted for capacity constraints on Algonquin, with the result that even if Yankee had scheduled less gas in such a way as to make it available to other shippers, the gas would not have been able to reach the vast majority of generators that are directly connected to Algonquin.

4.1 EDF incorrectly accounts for Algonquin operational constraints

Figure 6 shows the locations of Yankee's and NSTAR's delivery meters relative to Algonquin's compressor stations and the power plants directly connected to the pipeline.

Figure 6. Eversource Delivery Meters on Algonquin

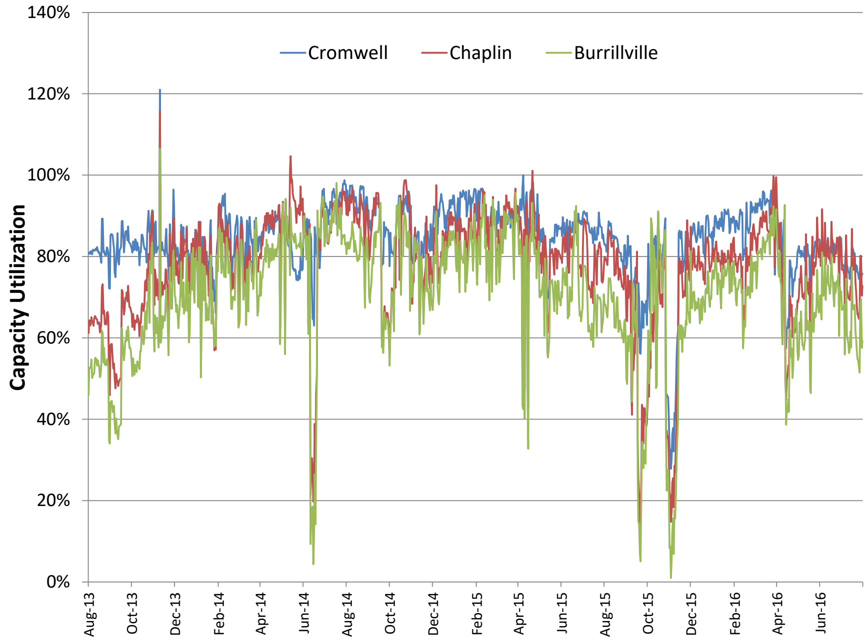


Almost all generators connected to Algonquin are located downstream of the Cromwell compressor station.

EDF states that "[t]o account for downstream capacity constraints, the daily downscheduled quantity is bounded from above by unused capacity at the compression station in Burillville, RI," which is "measured as the difference between end-of-day scheduled quantity and daily operational capacity" because "[t]he Burrillville compression station has a very high average rate of capacity utilization and is the last potential bottleneck before the Algonquin pipeline branches into a nodal network" (p. 37). While it is true that Burrillville is the easternmost compressor station on Algonquin's system, and has the smallest capacity, it is not the primary constraint point in New England due to the locations of demand. Figure 7 and Figure 8 show the utilization levels relative to available capacity at the Cromwell, Chaplin and Burrillville compressor stations for the Timely cycle and end-of-day volumes, based on the scheduled nomination and capacity data posted on Algonquin's EBB.[20] In both cases, Burrillville is often the least constrained of the three stations, with Cromwell being the highest-utilized station on 914 out of 1,096 days for the Timely cycle and 879 out of 1,096 days for the end-of-day cycle.

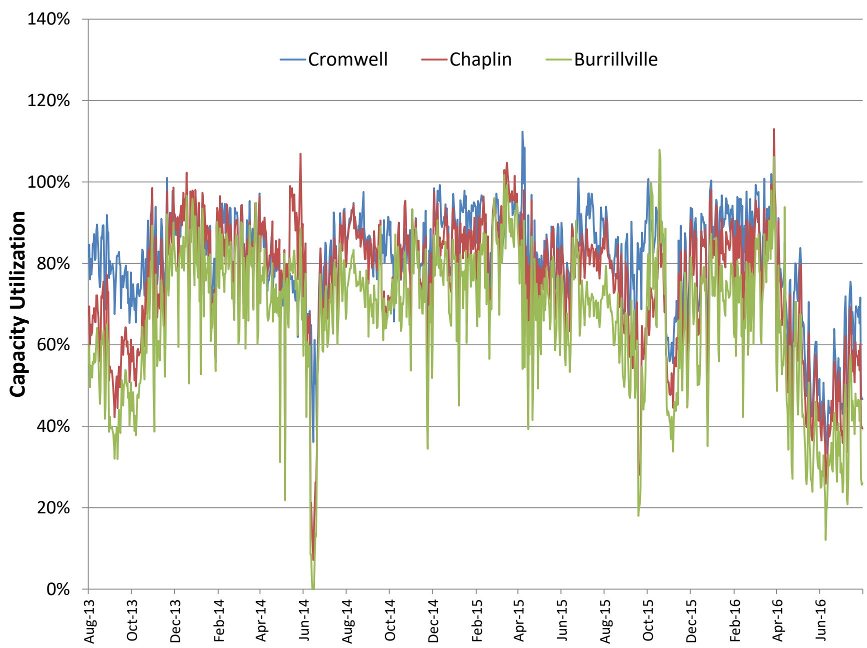
[20] Constraints also occur further upstream on Algonquin, at Stony Point, Southeast and Oxford, but these constraints do not affect the potential re-deployment of capacity not utilized by Eversource's LDCs on a given day.

Figure 7. Algonquin Compressor Station Utilization (Timely Cycle)[21]



Over this period, Cromwell's average Timely cycle winter utilization is 87.4% and Burrillville's is 76.7%. Average Timely cycle utilization over the full three-year period is 84.4% at Cromwell and 70.7% at Burrillville.

Figure 8. Algonquin Compressor Station Utilization (Last Cycle)

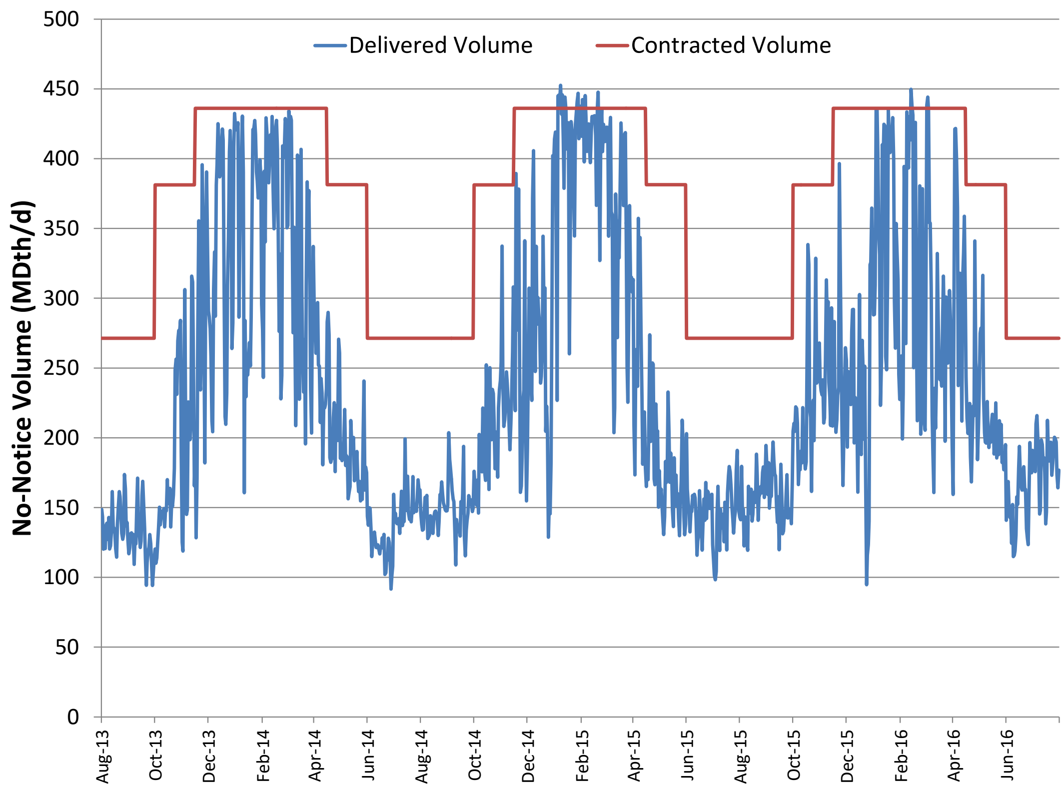


Cromwell's average Last cycle winter utilization is 87.9% and Burrillville's is 77.3%. Average Last cycle utilization over the full three-year period is 80.5% at Cromwell and 66.5% at Burrillville. Last Cycle utilization is generally less than Timely Cycle utilization, but Cromwell's utilization is still consistently higher than Burrillville's.

[21] The lower utilization volumes during summer 2016 at the right side of these figures are the result of decreased capacity at the Stony Point station while construction of the AIM facilities was underway.

While these figures indicate that utilization is less than 100% on most days, it is necessary to also consider the role of no-notice service in evaluating utilization levels. Utilization is calculated in these figures based on scheduled nominations relative to capacity, consistent with EDF's calculations, but unscheduled no-notice capacity is not included in these volumes and must therefore be accounted for separately and incrementally. Figure 9 shows the total amount of daily no-notice volumes delivered on the Algonquin system relative to the total no-notice contract volumes.[22,23]

Figure 9. No-Notice Deliveries on Algonquin



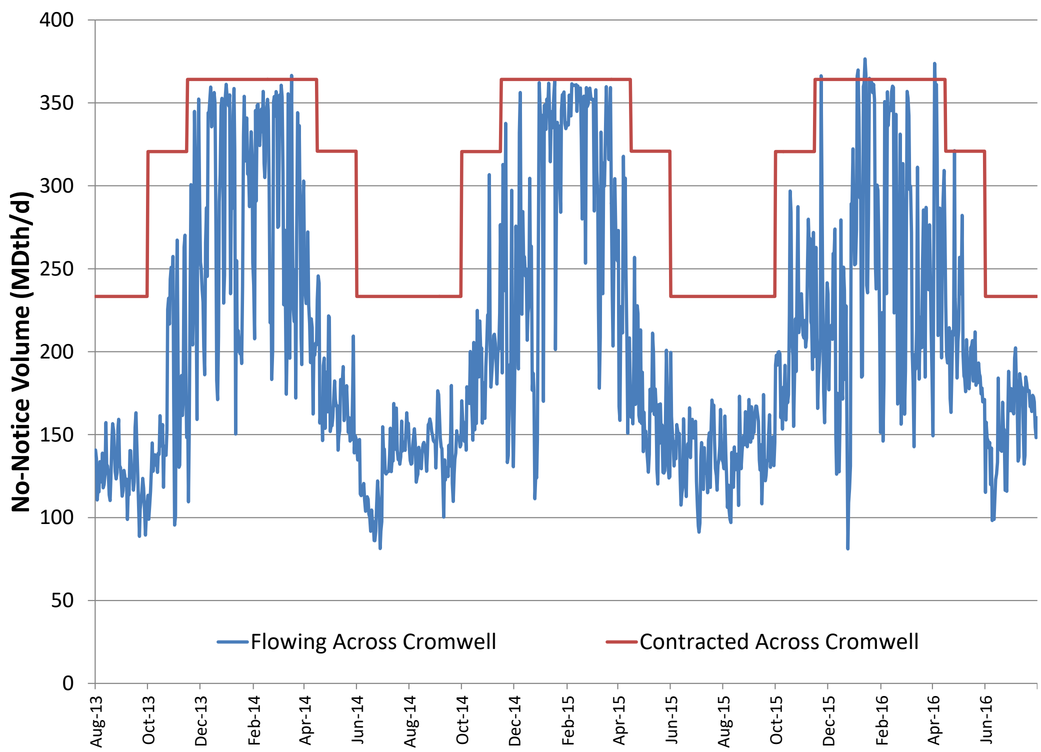
Algonquin's total no-notice capacity is utilized at a high level during peak conditions, but is often utilized at lower levels during the rest of the year. From December through March average utilization is 75.9%, and for the full period average utilization is 61.8%.

Examining the meter-level no-notice receipts and deliveries yields the no-notice volume flowing across a given compressor station, which is shown in Figure 10 and Figure 11 for Cromwell and Burrillville, respectively.

[22] On the days when delivered no-notice volumes exceeded contracted no-notice volumes, no-notice receipts at the eastern end of the pipeline offset the overage.

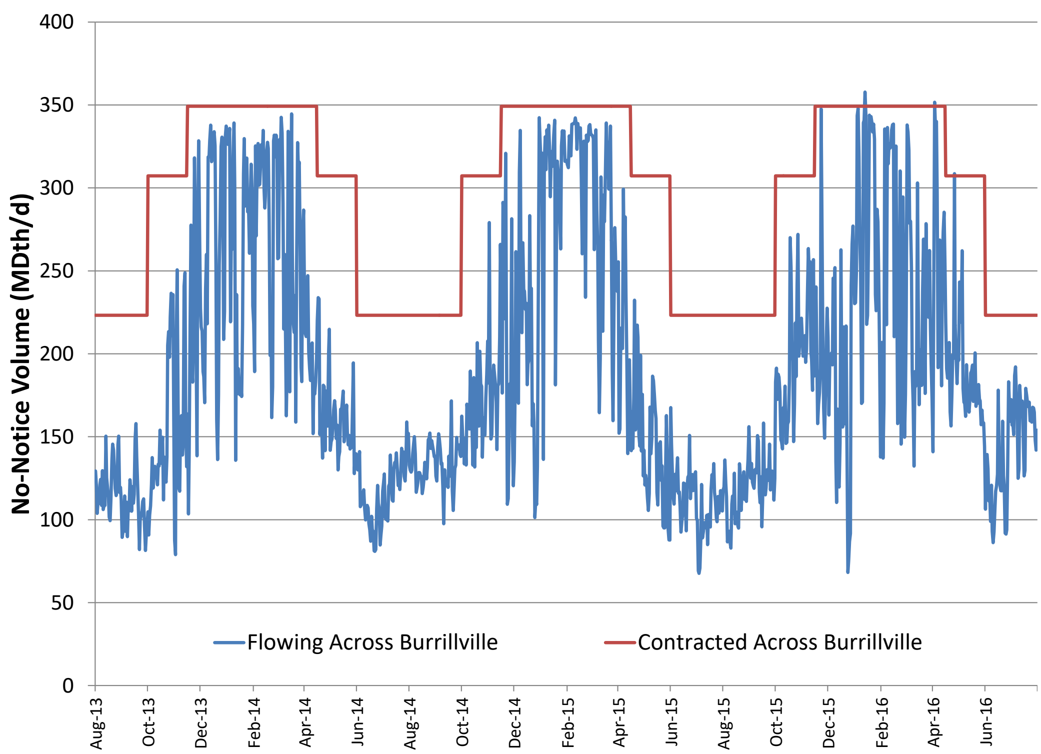
[23] Meter-level no-notice deliveries are only posted for end-of-day volumes.

Figure 10. No-Notice Volumes Flowing Through Cromwell



No-notice capacity across Cromwell is 77.0% utilized during winter months and 64.9% utilized during all months.

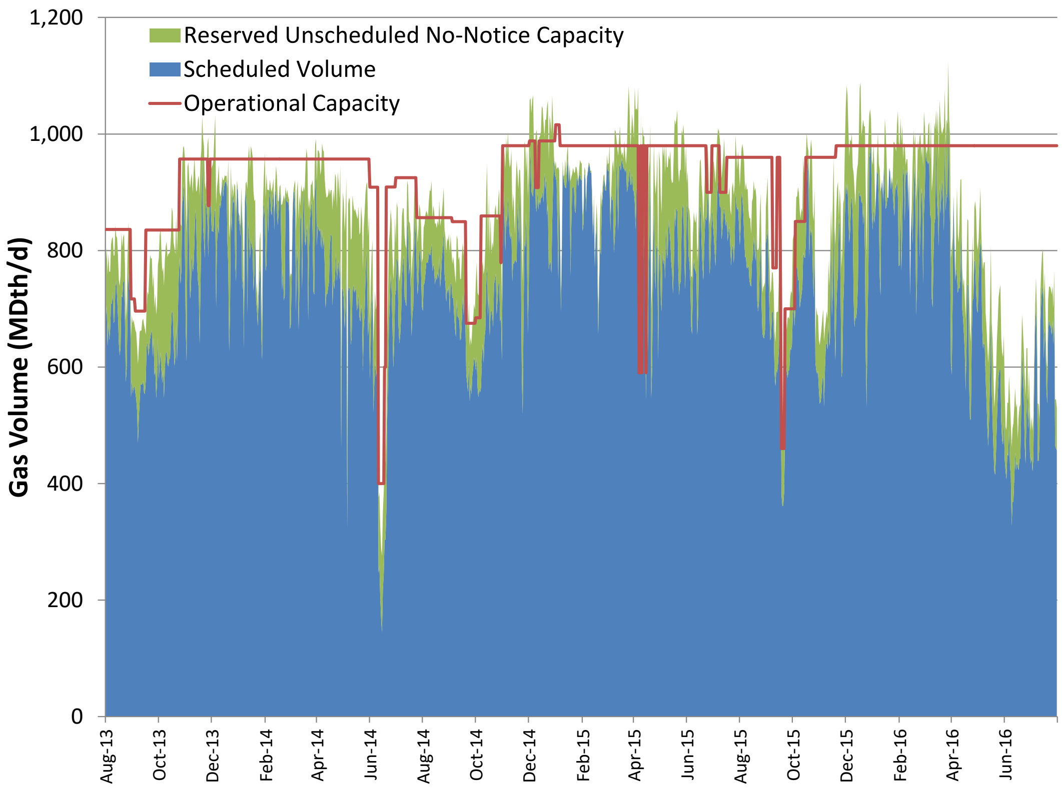
Figure 11. No-Notice Volumes Flowing Through Burrillville



No-notice capacity across Burrillville is 74.5% utilized during winter months and 62.1% utilized during all months.

The differential between flowing volumes and contracted capacity in the above figures can then be added to the scheduled volumes flowing through a compressor station to present a full picture of utilization and available capacity, because unutilized no-notice capacity is not available for other shippers to nominate. An example of this is shown in Figure 12 for Cromwell.

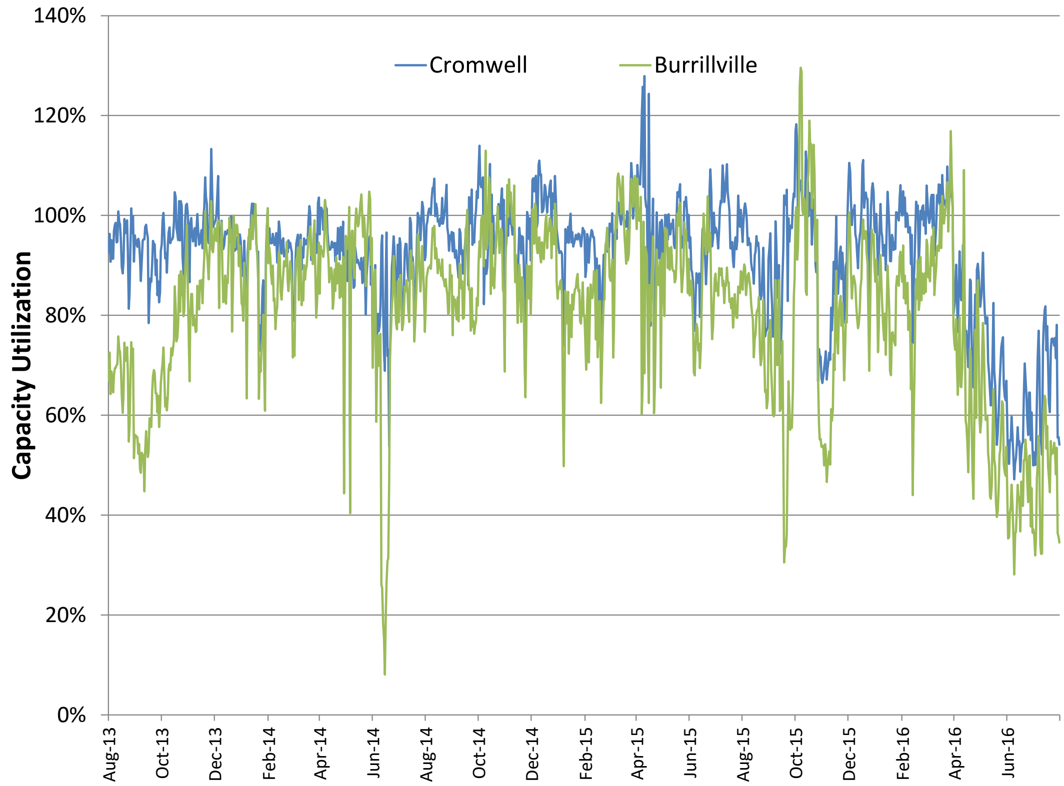
Figure 12. Scheduled and Reserved No-Notice Capacity at Cromwell



Reserved no-notice capacity fills in part of the gap between scheduled volumes and operational capacity, reducing the amount of throughput capacity available for scheduling.

Utilization at Cromwell and Burrillville during the Last scheduling cycle, when accounting for unscheduled but reserved no-notice volumes, is shown in Figure 13. Comparing this to Figure 8 reveals the increase in utilization when no-notice service is accounted for.

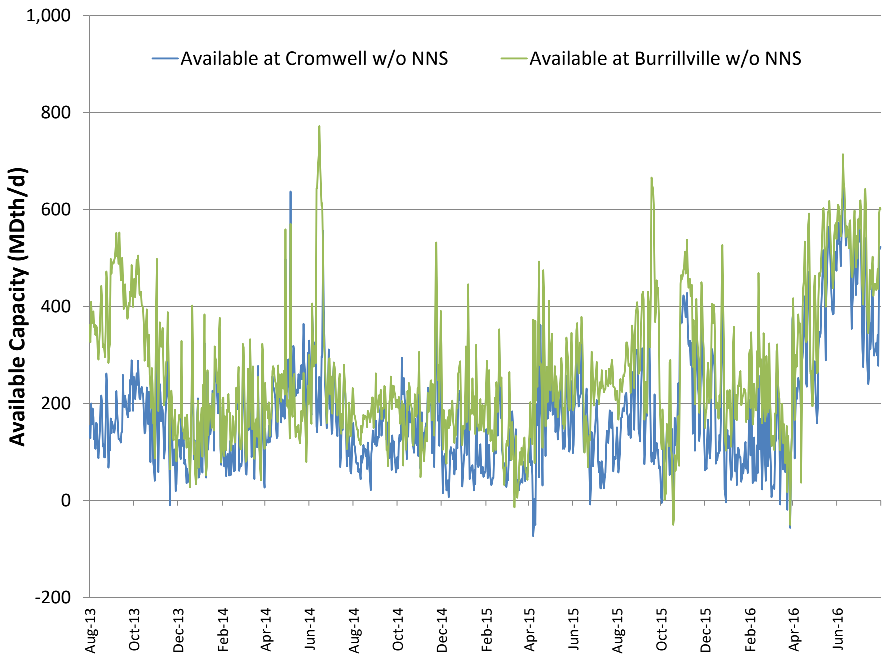
Figure 13. Algonquin Compressor Station Utilization with No-Notice Service



Accounting for no-notice capacity increases utilization at Cromwell from 87.9% during the winter months to 92.0%. At Burrillville, winter utilization increases from 77.3% to 80.6%.

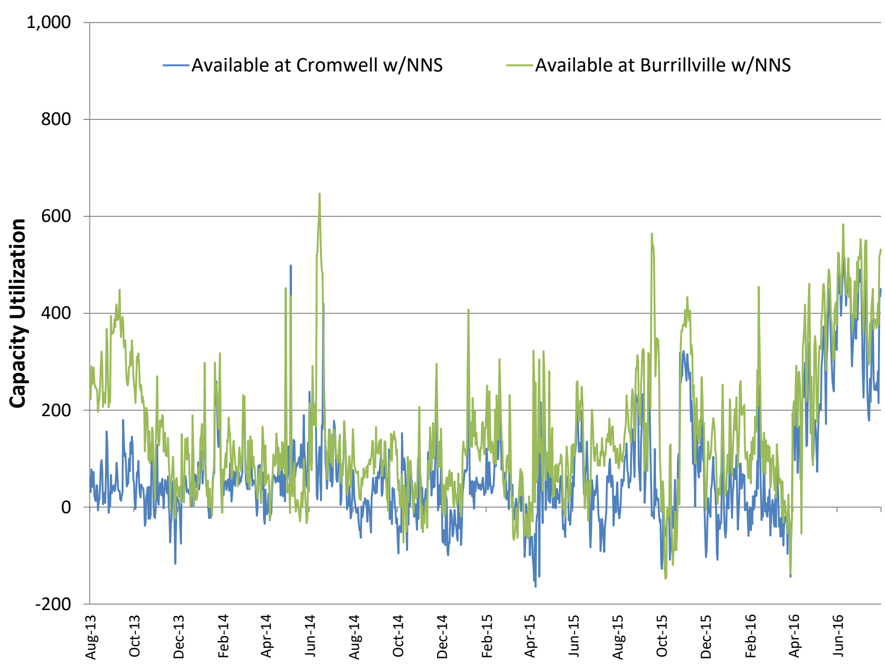
Putting these utilization values into the context of available capacity, Figure 14 and Figure 15 show the available capacity at Cromwell and Burrillville, without and with accounting for unscheduled no-notice service. Without accounting for no-notice service, average winter available capacity at Cromwell and Burrillville is 117 MDth/d and 184 MDth/d, respectively. After the correction to account for unscheduled no-notice service, average winter available capacity at Cromwell and Burrillville is reduced to 34 MDth/d and 95 MDth/d, respectively, indicative of very tight pipeline operating conditions under which secondary out-of-path nominations would not be scheduled. This is consistent with observations from a review of Algonquin's critical notices, which indicate that Algonquin regularly restricted interruptible and 80-100% of secondary out-of-path nominations through Cromwell, with the compressor station "sealed" to nomination increases after the Timely cycle other than primary firm no-notice volumes. Burrillville was also frequently sealed to increases other than primary firm no-notice service, but from the perspective of re-allocating Yankee's nomination adjustments, Cromwell is the binding constraint. EDF's analysis appears to have used the available capacity at Burrillville without accounting for reserved no-notice capacity, or an average of 184 MDth/d during the winter months, as the bound for capacity that could have flowed to downstream generators. Correcting this value to account for reserved no-notice capacity reduces the average available winter capacity at Burrillville by nearly half. Yankee's scheduled delivery reductions largely occurred at delivery points upstream of Cromwell, as addressed in the next section, further reducing the available capacity for flowing gas to downstream generators by nearly two-thirds from the corrected Burrillville available capacity.

Figure 14. Available Capacity without Accounting for No-Notice Service



Without accounting for no-notice service, average winter available capacity at Cromwell and Burrillville is 117 MDth/d and 184 MDth/d, respectively.

Figure 15. Available Capacity with Accounting for No-Notice Service



After the correction to account for unscheduled no-notice service, average winter available capacity at Cromwell and Burrillville is reduced to 34 MDth/d and 95 MDth/d, respectively.

These capacity limitations are important to acknowledge. This is because any discussion regarding whether LDCs are over-contracted must include consideration of how that capacity could alternatively be utilized if not by the LDCs holding the entitlements. For whatever reason, EDF chose not to do this, thereby disregarding or glossing over the real-world operational hydraulics along the Algonquin system. Returning to Figure 6 on page 32, nearly all power plants that are directly-connected to Algonquin are downstream of Cromwell, and most are downstream of Burrillville. If capacity contracted by LDCs were to be made available to other shippers, generators would only be able to take advantage of these secondary firm rights if they were in the path of the original contract, that is, if they were located on the same side of a constraint as the contracted delivery point.

Comparing the locations of meters with schedule adjustments to the locations of constraints and generators reveals the ability of the gas to flow to downstream shippers if, as EDF did, we ignore the mechanics of no-notice service and instead assume that such gas would have been available to other shippers if the nomination reductions had been made earlier or the gas had not been nominated in the first place. EDF's central theory is that such volumes would have had a decremental effect on market prices if made available to downstream shippers. 13.4 MDth/d of average winter end-of-day nomination reductions occurred at Yankee meters upstream of Cromwell, where only 339 MW of generation capacity is directly-connected to Algonquin. An additional 0.1 MDth/d of average nomination reductions occurred at Yankee meters between Crowell and Burrillville, where 2,039 MW of generation are located, leaving only, on average, 4.8 MDth/d managed by NSTAR's Asset Manager that could have been available to the 4,894 MW of generation downstream of Burrillville.

4.2 <u>EDF's reporting of average schedule changes does not reveal the full scope of daily LDC scheduling practices on Algonquin, including reliance on no-notice flexibility</u>

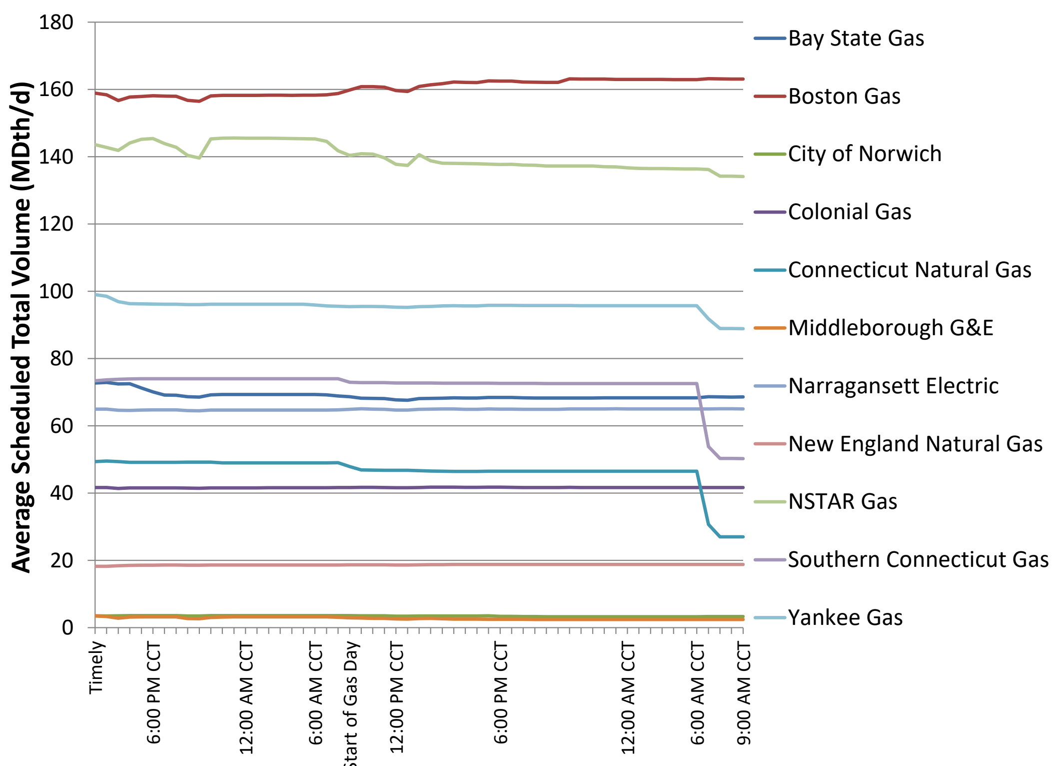
Algonquin serves eleven LDCs and municipal utilities in New England, listed in Table 1. All of these entities hold some amount of no-notice capacity except for Connecticut Natural Gas.

Table 1. New England LDCs Served by Algonquin

LDC	Parent Company	State	Winter No-Notice Capacity (Dth/d)
Bay State Gas	NiSource	MA	51,632
Boston Gas	National Grid	MA	95,594
City of Norwich	N/A	CT	5,495
Colonial Gas	National Grid	MA	23,790
Connecticut Natural Gas	Avangrid	CT	0
Middleborough Gas & Electric	N/A	MA	845
New England Natural Gas	Liberty Utilities	MA	22,812
Narragansett Electric	National Grid	RI	65,231
NSTAR Gas	Eversource	MA	89,316
Southern Connecticut Gas	Avangrid	CT	45,593
Yankee Gas	Eversource	CT	35,816

Figure 16 and Figure 17 show Algonquin's average scheduled deliveries to each LDC for each of the hourly schedule postings over the course of each gas day during the three-year period, along with normalized representations of scheduled volumes relative to end-of-day volumes.[24] Table 2 lists each LDC's average schedule change during the last three hours of the gas day. Yankee's and NSTAR's scheduling profiles, as illustrated below, do show negative schedule changes at the end of the gas day, but the average volumes are well within the utilities' no-notice contract quantities, indicative of behavior consistent with the Shipper 2 example shown in Figure 2 on page 21, with no-notice capacity fully nominated during the Timely cycle and adjusted downward later in the gas day. Boston Gas's profile, with scheduled volumes increasing over the course of the gas day, indicates that it is, on average, more like the Shipper 1 or Shipper 3 example, using no-notice capacity reserved by the pipelines to adjust nominations upward. This behavior is only possible through reliance on reserved no-notice capacity, because nomination increases after the Timely cycle other than for those using no-notice capacity are frequently prohibited by Algonquin during winter months. The Yankee and NSTAR schedule changes during the last three hours of the gas day represent less than 8% and less than 2%, respectively, of their end-of-day delivered volumes.

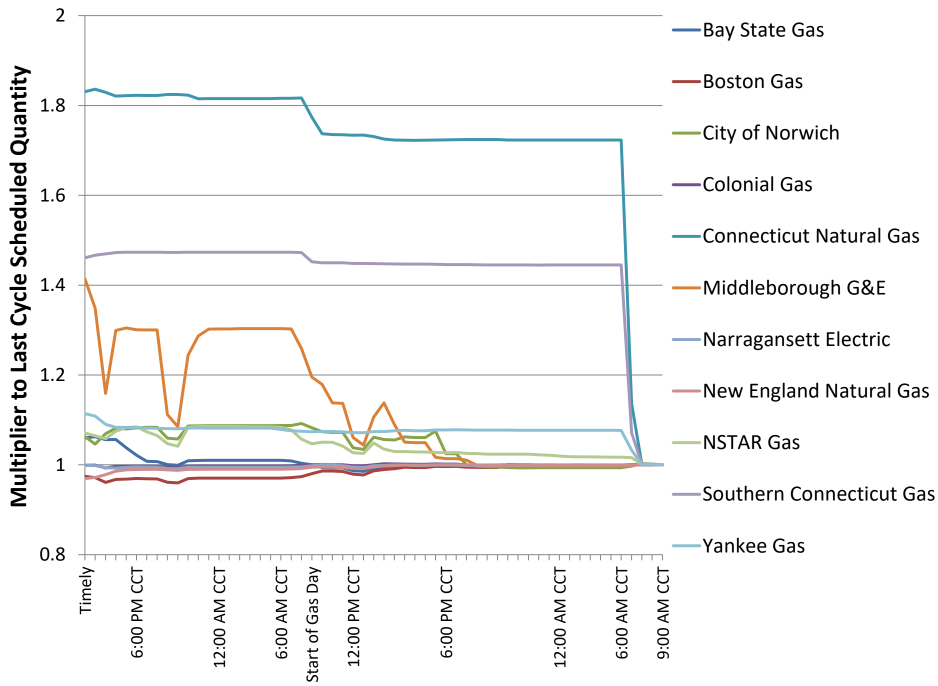
Figure 16. Average Algonquin Deliveries to New England LDCs



Adjustments to scheduled quantities occur over the course of the gas day for many LDCs.

[24] The x-axis in these figures represents the posting times for cycles over the course of the gas day. Due to the change in NAESB scheduling protocols on April 1, 2016, as discussed in section 3.3.1, the posting times of the confirmed cycles changed, and there are other occurrences when hourly cycles were not posted. In parsing the data posted to the Algonquin EBB, if a cycle was not posted for a particular gas day, the scheduled volume for the previous posted cycle was carried over to avoid discontinuities.

Figure 17. Profiles of Average Algonquin Deliveries to New England LDCs



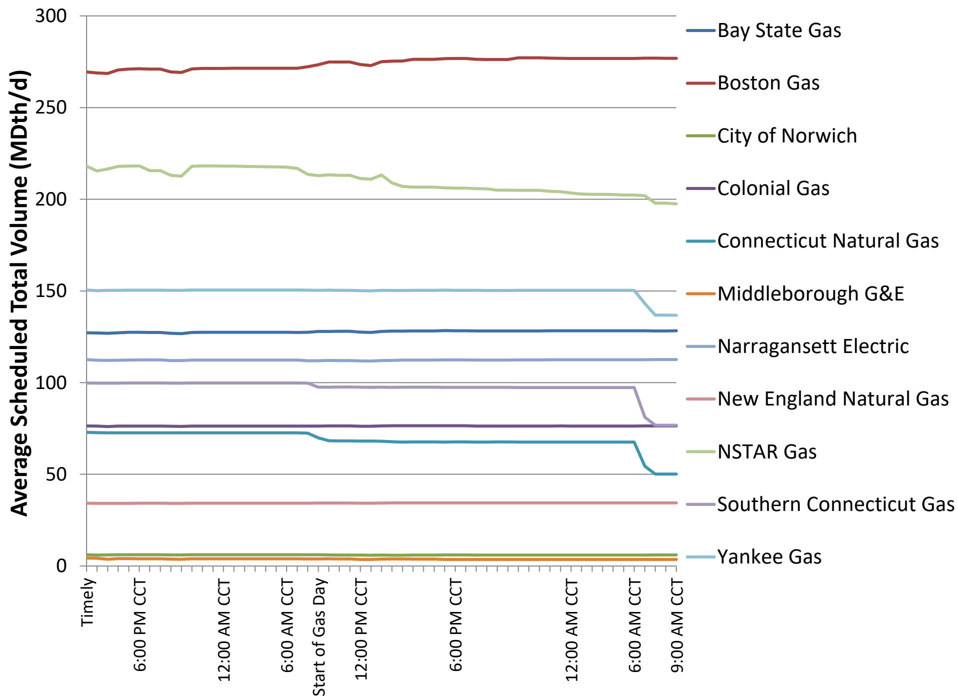
The Yankee and NSTAR schedule changes during the last three hours of the gas day represent less than 8% and less than 2%, respectively, of their end-of-day delivered volumes.

Table 2. Average Schedule Change during Last Three Hours of the Gas Day

LDC	Schedule Change (MDth/d)	Schedule Change % of End-of-Day Volume
Bay State Gas	0.29	0.4%
Boston Gas	0.13	0.1%
City of Norwich	0.02	0.7%
Colonial Gas	0.01	0.0%
Connecticut Natural Gas	-19.51	-42.0%
Middleborough G&E	0.01	0.2%
Narragansett Electric	0.01	0.0%
New England Natural Gas	0.02	0.1%
NSTAR Gas	-2.26	-1.7%
Southern Connecticut Gas	-22.35	-30.8%
Yankee Gas	-6.82	-7.1%

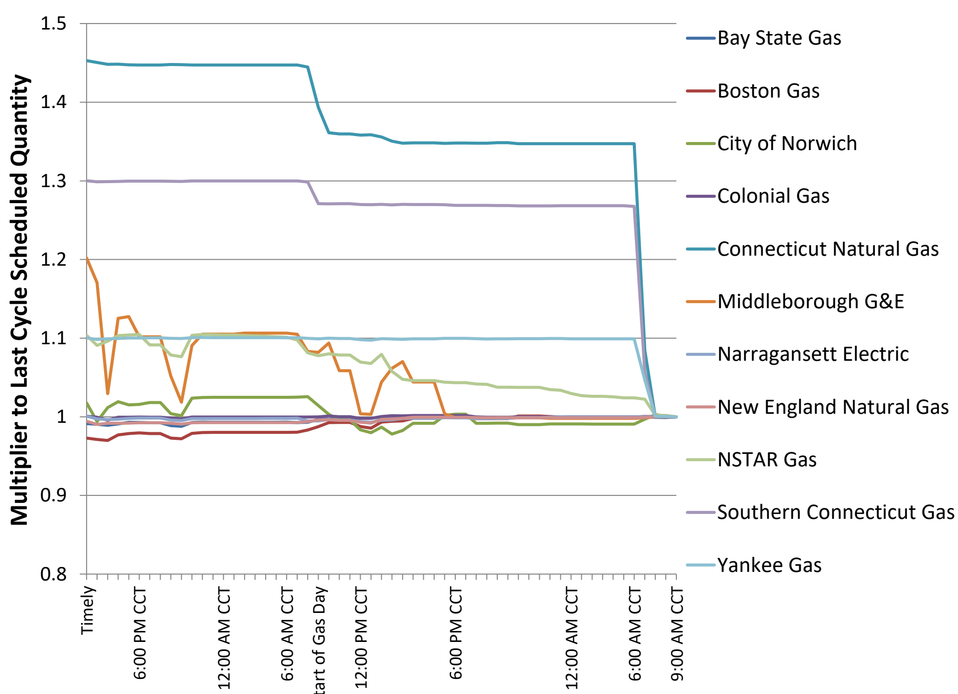
Figure 18, Figure 19 and Table 3 show the same LDC statistics for only the winter days. Yankee's and NSTAR's average schedule changes, while approximately double the volume in the previous figures, still represent less than 10% and less than 3%, respectively, of each utility's end of day volumes, and approximately 1% of Algonquin's current throughput capacity into New England. Because NSTAR's nominations and scheduling are managed by an Asset Manager, consideration of Eversource's behavior should be limited to Yankee's volumes, which on average represent less than 0.75% of Algonquin's New England capacity.

Figure 18. Average Winter Algonquin Deliveries to New England LDCs



Although the volumes are higher for winter days, LDC profiles similarly involve both upward and downward adjustments throughout the course of the gas day.

Figure 19. Profiles of Average Winter Algonquin Deliveries to New England LDCs



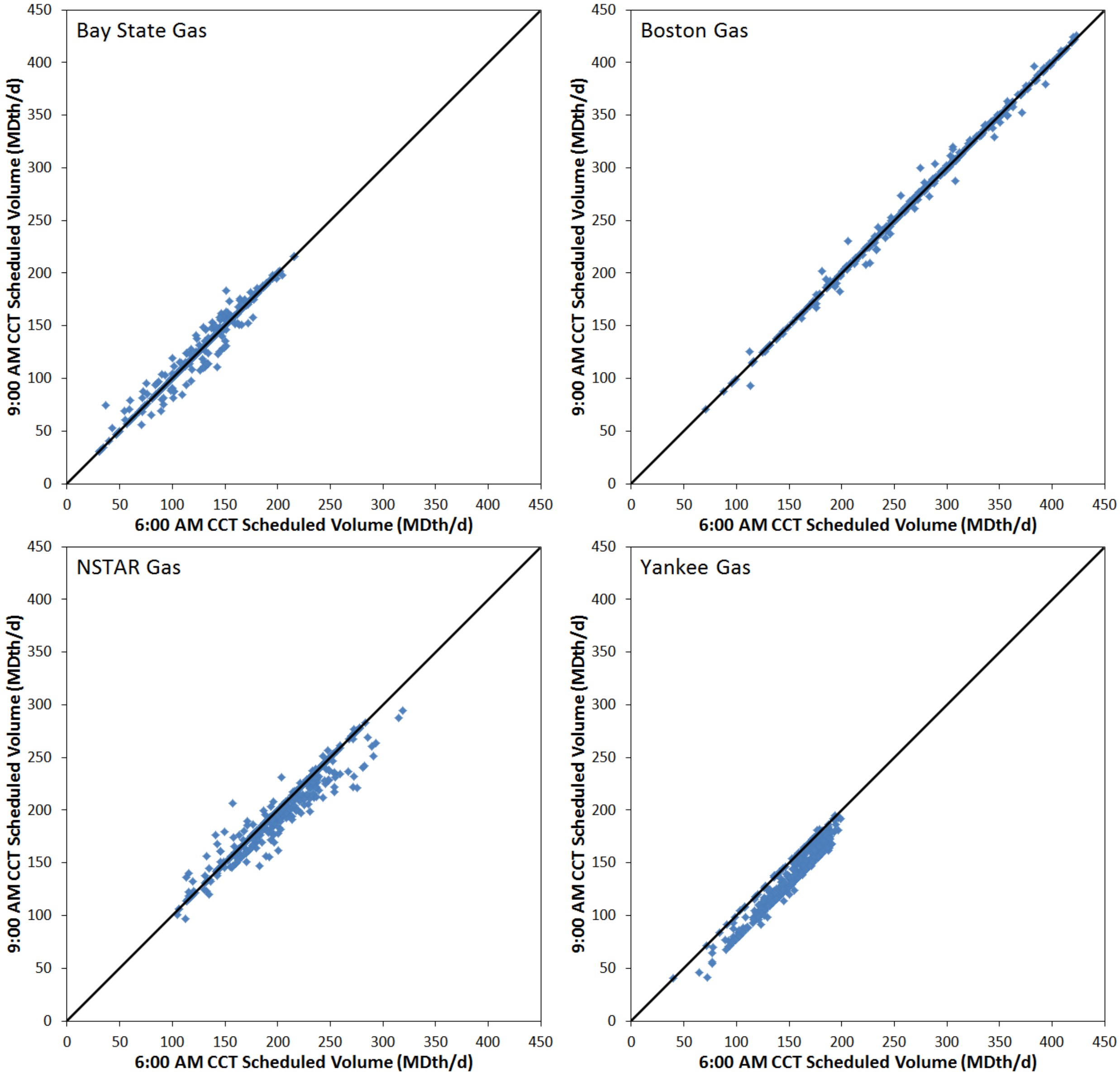
Yankee's and NSTAR's average end-of-day schedule changes represent less than 10% and less than 3%, respectively, of each utility's final volumes.

Table 3. Average Winter Schedule Change during Last Three Hours of the Gas Day

LDC	Schedule Change (MDth/d)	Schedule Change % of End-of-Day Volume
Bay State Gas	0.03	0.0%
Boston Gas	0.09	0.0%
City of Norwich	0.06	0.9%
Colonial Gas	0.01	0.0%
Connecticut Natural Gas	-17.43	-34.7%
Middleborough G&E	0.01	0.2%
New England Natural Gas	0.04	0.0%
Narragansett Electric	0.04	0.1%
NSTAR Gas	-4.77	-2.4%
Southern Connecticut Gas	-20.54	-26.8%
Yankee Gas	-13.56	-9.9%

While these average values indicate that only some LDCs consistently make schedule adjustments at the end of the gas day while other LDCs do not change their nominations, daily activity reveals that most utilities do in fact make such schedule adjustments to varying degrees, in both directions, during the winter season. Figure 20 shows NSTAR's and Yankee's last-three-hours schedule changes on the winter days of the three-year period relative to those of Bay State Gas and Boston Gas, two utilities with minimal average schedule changes that exhibit generally increasing scheduled nominations over the course of the gas day. Data points that are below the 45° line indicate a negative schedule change in the last three hours of the gas day, and above the line indicates a positive schedule change in the last three hours of the gas day. These figures are indicative of the different approaches different LDCs have to managing intraday nominations. Bay State Gas, Boston Gas, and even NSTAR show frequent nomination increases during the last three hours of the gas day, demonstrating that they are relying on no-notice service for load variability adjustments. Yankee's alternative approach to flexible storage and no-notice service, that is, to nominate capacity fully while targeting the midpoint and balancing scheduled quantities downward at the end of the day, is effectively no different than an approach that involves nominating at the midpoint and balancing scheduled quantities either upward or downward at the end of the gas day, since in either case the reserved no-notice capacity is not available to other shippers.

Figure 20. Variation Between 6:00 am and 9:00 am CCT Scheduled Winter Quantities



Yankee's data points are nearly all (350 out of 364) within the 23 MDth/d range of its flexible storage quantity, averaging a 13.6 MDth/d schedule reduction relative to a target reduction of 13 MDth/d. The Bay State Gas and Boston Gas data sets appear to reflect nominations at expected quantities, with both increases and decreases depending on variance from expected volumes. Both scheduling approaches involve reliance on storage flexibility and no-notice service. Yankee's approach only requires storage operators to reduce withdrawals, whereas the Bay State Gas / Boston Gas approach sometimes requires storage operators to increase withdrawals.

4.2.1 Eversource's LDCs utilize their contracted no-notice capacity at a similar or greater rate than other New England LDCs

Ten Algonquin shippers (all LDCs and municipals except for Connecticut Natural Gas) hold a total of 436 MDth/d of winter no-notice service, as listed above in Table 1.[25] Table 4 lists the average utilization of no-notice service over all days and all winter days during the three-year period, based on deliveries to citygates relative to no-notice contractual quantities. In addition to these deliveries, LDCs can and do release no-notice capacity, deliveries to non-LDC citygates are not included here. While the Eversource LDCs exhibit an approach to intraday scheduling that is different from some of the other Algonquin no-notice shippers, NSTAR's and Yankee's average winter no-notice capacity utilization is on par with shippers that do not reduce nomination quantities during the last three hours of the gas day with the same frequency. NSTAR's and Yankee's winter no-notice utilization rate is higher than the simple average of all LDCs and greater than or equal to the total Algonquin no-notice capacity utilization.

Table 4. LDCs' Average and Aggregate No-Notice Capacity Utilization Relative to System Total

LDC	All Days	Winter Days
Bay State Gas	60%	79%
Boston Gas	50%	71%
City of Norwich	51%	73%
Colonial Gas	54%	85%
Middleborough Gas & Electric	70%	44%
New England Natural Gas	52%	58%
Narragansett Electric	49%	70%
NSTAR Gas	63%	76%
Southern Connecticut Gas	29%	54%
Yankee Gas	49%	80%
LDC Simple Average	53%	69%
Algonquin System[26]	62%	76%

4.2.2 EDF's characterization of Yankee's locational schedule changes is inaccurate

EDF states that Yankee's nomination adjustments occurred at meters that are "disproportionately served by no-notice contracts" (p. 20). While the two meters that the EDF paper identified – Waterbury and Kensington –do have the largest amounts of delivery capacity on Yankee's no-notice contract, they are also among the highest delivery volume meters where Yankee receives gas from Algonquin.

[25] This quantity is reduced to 381 MDth/d during the shoulder periods (October 1 through November 15th and April 16th through May 31st) and to 271 during the summer months (June 1st to September 30th).

[26] The Algonquin system total includes all no-notice deliveries, including released capacity delivered to non-LDC meters.

Of additional note from a meter-level perspective is that First Light's Waterbury plant, a large transportation-only customer, is located behind the Waterbury meter. This plant does not operate as baseload, and has a large degree of variation associated with its day-to-day and intraday generation levels. During the three-year period, the plant operated between 0 and 13 hours each day, often non-consecutively.[27] The average schedule change at the Waterbury meter of 2.4 MDth/d is equivalent to approximately 3.3 hours of plant operation.

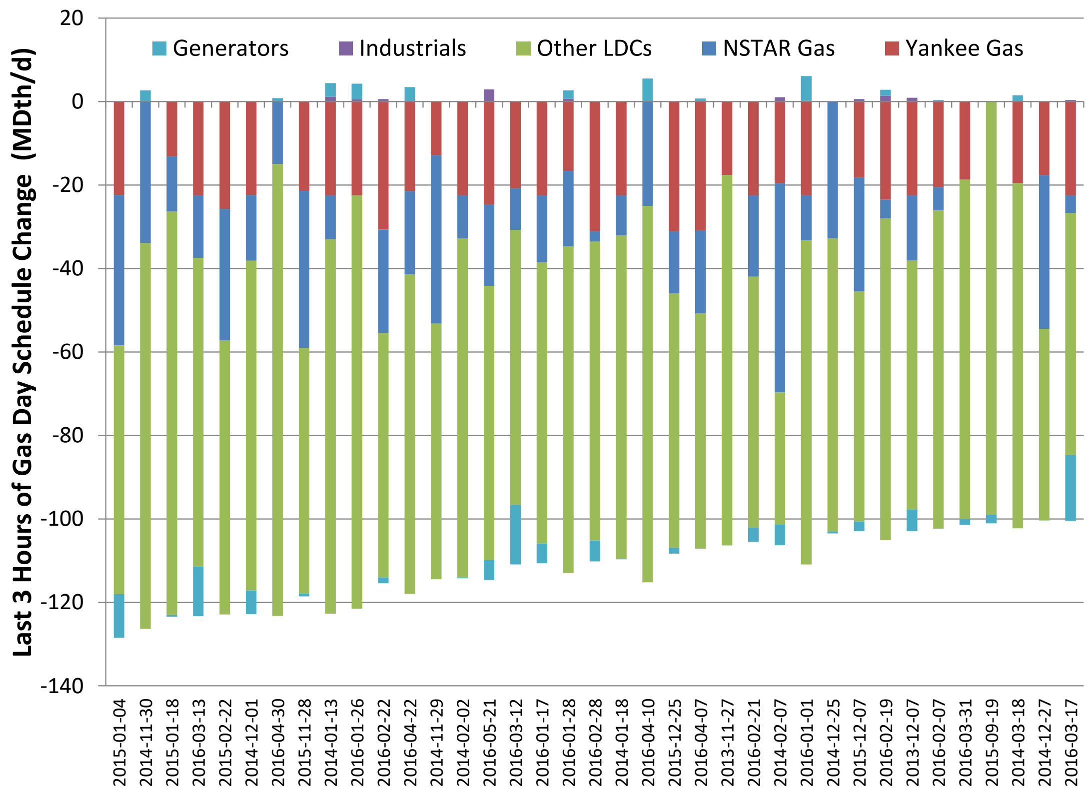
4.2.3 Eversource's LDCs' schedule changes on the 37 days with the highest total Algonquin system changes are within no-notice contract quantities

There are 37 days during the three-year period when the net decrease in scheduled volumes on Algonquin during the last three hours of the gas day was greater than 100 MDth/d. Figure 21 shows the contribution to the schedule change by Yankee, NSTAR, other LDCs, industrials, and generators.[28] While Yankee and NSTAR do contribute to the negative schedule changes to varying degrees across this set of days, each LDC's changes are less than its no-notice capacity on each of the 37 days. Yankee's average contribution to the schedule change on these days is –19 MDth/d (17%), while NSTAR's is –17 MDth/d (16%). Placed in the context of Algonquin's system, these volumes represent approximately 2% of Algonquin's current total capacity into New England. As noted previously, the scheduling changes at each meter represent the aggregate behavior of all parties delivering gas to that meter, not only the point operator.

[27] Plant operation data was retrieved from the Environmental Protection Agency's Air Markets Program Data website, https://ampd.epa.gov/ampd/.

[28] "Other LDCs" encompasses all LDCs served by Algonquin, including those outside New England.

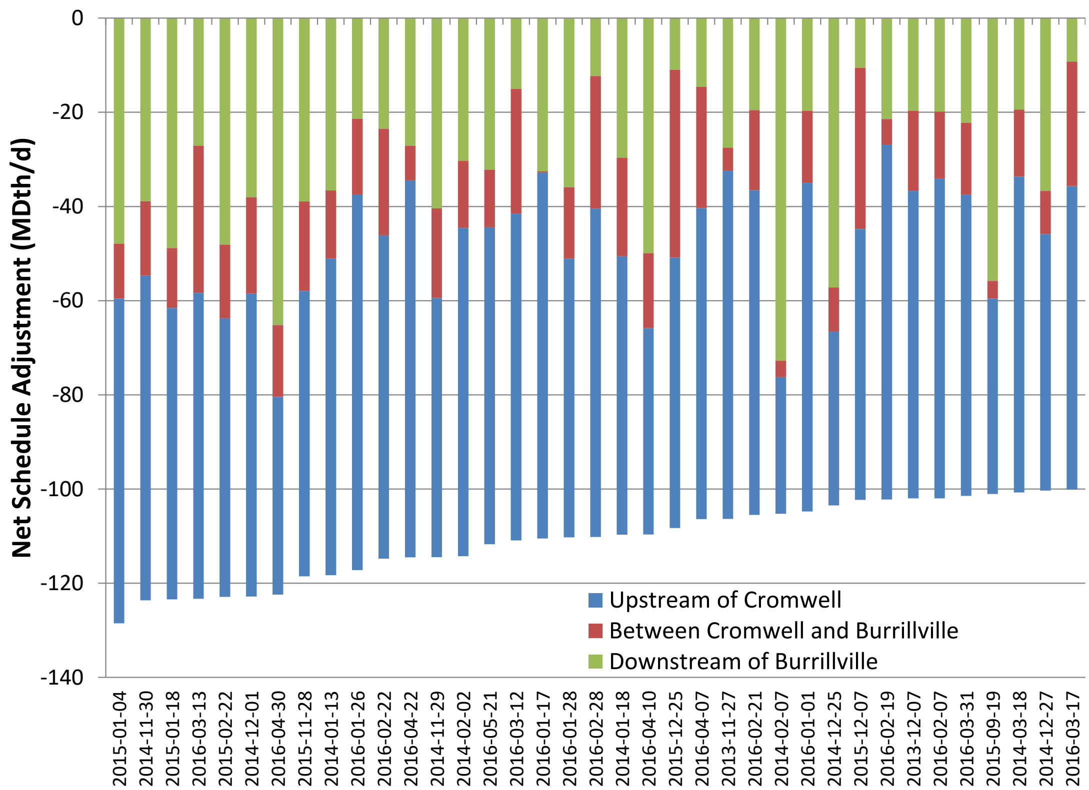
Figure 21. 37 Days with Biggest Decrease in Scheduled Volumes during Last Three Hours by Meter Operator Type



Yankee's schedule changes on these days, which are the only data series under the day-to-day control of Eversource, are in all cases within Yankee's no-notice contract volumes, and in many cases reflect circumstances where the amount of gas needed from flexible storage to balance the system is less than the target volume of 10 MDth/d, resulting in more than 13 MDth/d of schedule adjustments.

Putting the schedule adjustments on these 37 days in a locational context, Figure 22 illustrates where the adjustments occurred relative to Cromwell and Burrillville. During these days, the schedule adjustments at meters downstream of Burrillville represent an average of 28% of the total adjustments, of which 60% occurs at meters under the control of NSTAR's Asset Manager.

Figure 22. 37 Days with Biggest Decrease in Scheduled Volumes during Last Three Hours by Location

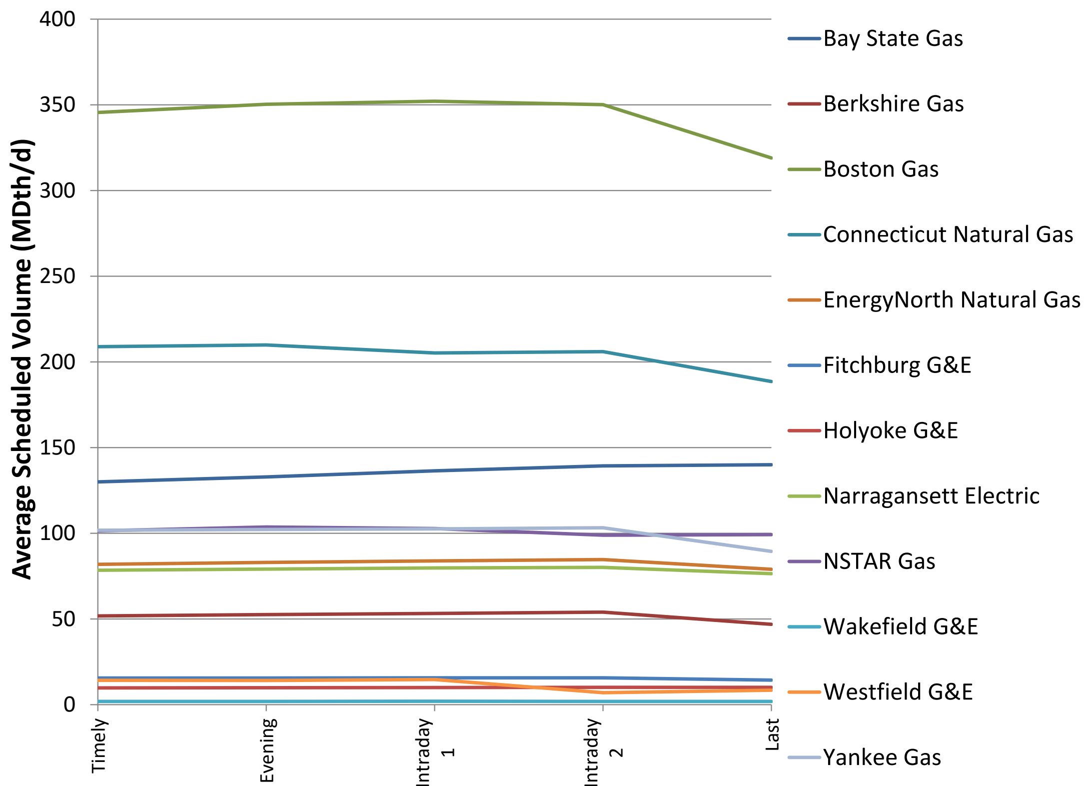


While the majority (60%) of scheduling decreases downstream of Burrillville are associated with the actions of NSTAR's Asset Manager, more than half (57%) of scheduling decreases on these days occur upstream of Cromwell and could not have flowed east to generators.

4.3 Non-Eversource or Avangrid LDCs' scheduling practices on Tennessee, which does not offer no-notice service, are similar to Yankee's scheduling practices on Algonquin

The purpose of this section is to illustrate that in the absence of reserved no-notice capacity allowing them to increase scheduled quantities during the gas day, LDCs other than those identified by EDF as exercising market power on Algonquin engage in similar end-of-day scheduling reductions on Tennessee to manage load and balancing uncertainty. Tennessee does not offer no-notice service on its system. Shippers are therefore not able to rely on the ability to increase nominations over the course of the gas day. Instead, they are more likely to more fully nominate gas flowing from storage during the Timely cycle and then make downward adjustments over the course of the day. This is similar to Yankee's scheduling approach on Algonquin, which nominates flexible storage and no-notice transportation above its target withdrawal volume as described in section 3.3.2. This behavior is illustrated in Figure 23, which shows each LDC's average scheduled nominations on Tennessee over the course of the gas day for winter days during the same three-year period studied in the EDF paper. The Tennessee data in Figure 23 shows that LDCs that have not been identified by EDF as holding generation portfolios in New England exhibit schedule reductions on winter days between the Intraday 2 Cycle and the end of the gas day.[29]

Figure 23. Average Winter Tennessee Deliveries to New England LDCs[30]



On Tennessee, Berkshire Gas, Boston Gas, EnergyNorth Natural Gas, Fitchburg Gas & Electric and Narragansett Electric have average scheduling reductions between the Intraday 2 and Last cycles. Most notably, National Grid, which is the parent company for Boston Gas and Narragansett Electric, represents 40% of the total average scheduling reductions among LDCs, even though EDF has identified it as owning only 10 MW of generation capacity in New England, none of which is unregulated (p. 52).

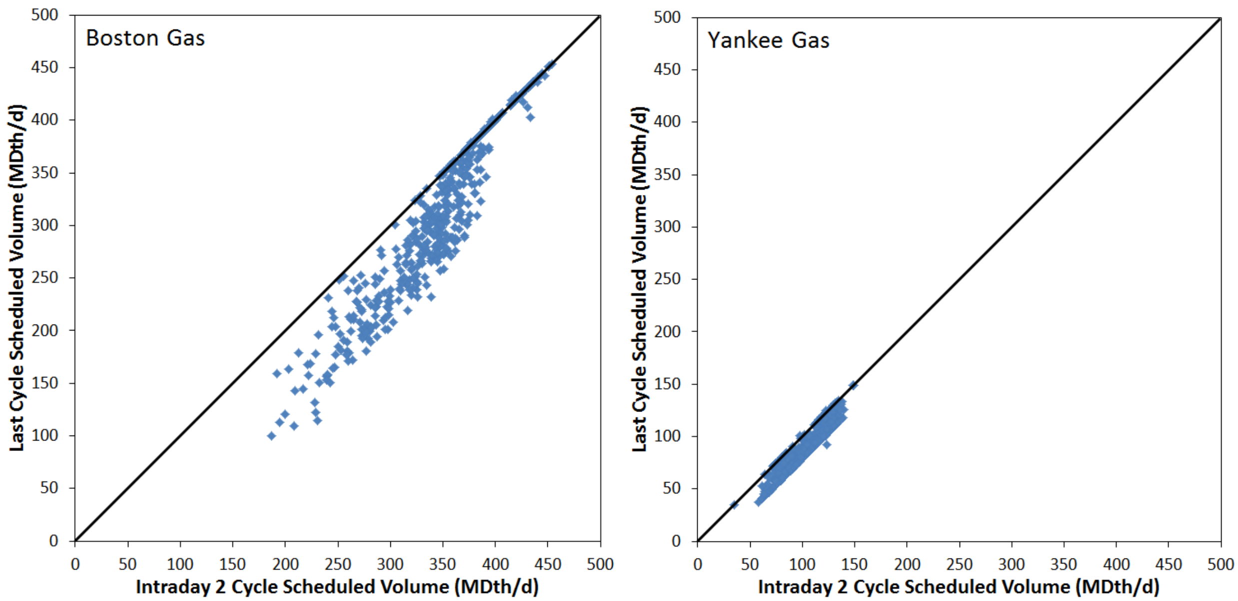
Figure 24 further compares the daily winter behavior of Boston Gas and Yankee on Tennessee. Yankee's scheduling patterns look similar to those on Algonquin, with consistent changes within a defined range. In both cases its nomination approach is to fully nominate storage and adjust nominations as necessary when load information is more accurately known at the end of the gas day. Yankee has approximately 21 MDth/d of storage withdrawal rights on Tennessee, which lines up, with one exception, with the largest daily nomination decreases, bounding the spread in scheduling uncertainty. Absent the ability to utilize no-notice capacity to increase nominations throughout the gas day, Boston Gas engages in similar behavior, consistently

[29] While Tennessee posts scheduled volumes on an hourly basis following the last confirmed intraday cycle, data for these cycles other than the last cycle (8:00 am CCT) were not available For the period prior to April 1, 2016, Intraday 3 volumes were set equal to Intraday 2 volumes for reporting consistency.

[30] The Intraday 3 cycle is not included because it had not yet been implemented as of the last winter day in the three-year period.

nominating gas at a volume higher than expected load and reducing scheduled volumes at the end of the gas day to protect its ability to serve customers reliably and cost-effectively.

Figure 24. Variation Between Intraday 2 Cycle and Last Cycle Scheduled Winter Quantities[31]



Yankee's data points exhibit a similar scheduling protocol as on Algonquin, with scheduling reductions within a fixed range consistent with its Tennessee storage contract. Whereas Boston Gas's data points show a very different pattern than on Algonquin, consistently reducing scheduled volumes, almost always within the 81 MDth/d withdrawal right associated with its storage contract on Tennessee.

[31] All winter days during the three-year period occurred prior to the addition of the Intraday 3 cycle.

5 Larger Negative Schedule Adjustments on Less Cold and Lower Demand Winter Days

Highlights

- EDF imprecisely claimed that the largest negative schedule adjustments occurred on colder or the coldest days. In fact, larger negative adjustments are correlated with milder weather.
- EDF did not analyze the important reality of weather forecast uncertainty in the paper's model of why large negative schedule adjustments occur. This may be explained by EDF's false presumption that LDCs could release reserve capacity early in the gas day and then reclaim it if forecasted and actual demand increased above earlier forecasts.
- Weather forecast uncertainty is a primary reason why Yankee frequently makes negative final schedule adjustments during the winter season.
- Larger negative schedule adjustments are correlated with larger errors in forecasted demand.
- Winter morning large ramp-ups of heating demand for gas is a large source of uncertainty that remains high until the close of the gas day.
- Physical gas spot market trading of standard Next Day products with terms longer than one day and/or with deferred start of delivery occur much more frequently on the 37 days with total AGT negative schedule adjustment greater than 100,000 MMBtu/d.

This section analyzes the influences on Yankee's final schedule adjustments of (1) cold weather, (2) weather forecast uncertainty, and (3) spot market off-system sales limitations resulting from Next Day product characteristics.

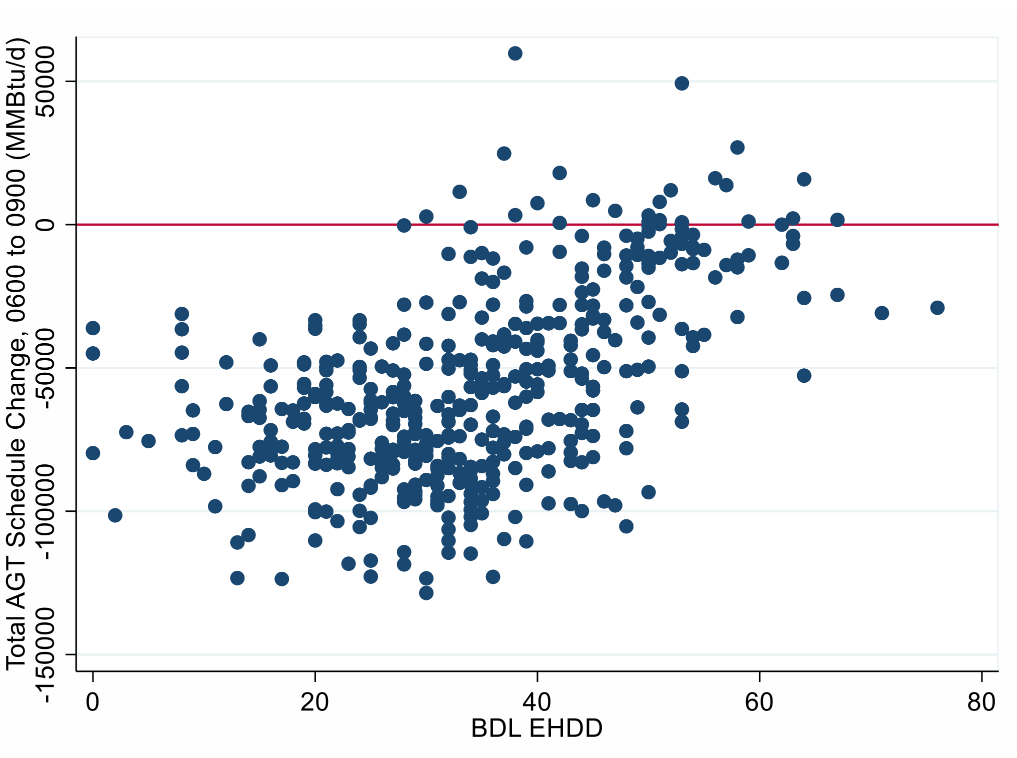
5.1 The largest negative schedule adjustments are not on the colder or coldest days, contrary to EDF's fuzzy and unfounded claims

The EDF paper claims that due to overscheduling, "significant quantities of pipeline capacity went unutilized on many of the coldest days of the year, pushing up the price of gas" (p. 3). Elsewhere, EDF asserts that "these firms primarily engage in downscheduling on colder days and during the winter months when capacity is more likely to be constrained" (p. 35). Both of these claims are expressed in an imprecise manner, resulting in different possible interpretations. Together, these two statements could be read broadly that under-utilization occurs on many cold winter days or more narrowly that the behavior was limited to the very coldest unspecified N days of the year or correlated with colder weather. Another aspect of EDF's imprecision is that the statements do not state whether coldness is with respect to actual or forecasted weather. For alleged overscheduling behavior at the Timely or Late cycles, only forecasted weather is known. The purpose of this section is to test the proposition that the magnitude of negative adjustments is correlated with cold weather, forecasted or actual.

We use Yankee's superior effective heating degree day (EHDD) measure of coldness that adjusts for wind chill, rather than EDF's simple HDD index. The weather measurement location used is the Bradley Airport. EDF's HDD index is an under-defined average of HDD "across Connecticut, Rhode Island, and Massachusetts, using data from the National Climatic Data Center" (p. 27, fn. 41). We suspect that EDF's HDD index may be a simple average of HDD at the Bradley, Providence, and Logan airports rather than a more precise LDC demand-weighted average. Regardless, we expect that the results reported here would be similar for EDF's three-state average HDD index.

For total AGT final schedule changes on days with positive EHDD, we find that colder days are associated with smaller negative or larger positive adjustments, as shown in Figure 25. A simple regression of AGT final schedule change on EHDD results in a positive, statistically significant (t = 13.9 with robust SE) coefficient. These visual and statistical results are the opposite of the weather relationship implied by EDF. All regression equation results discussed in this section and the next section are provided in the appendix.

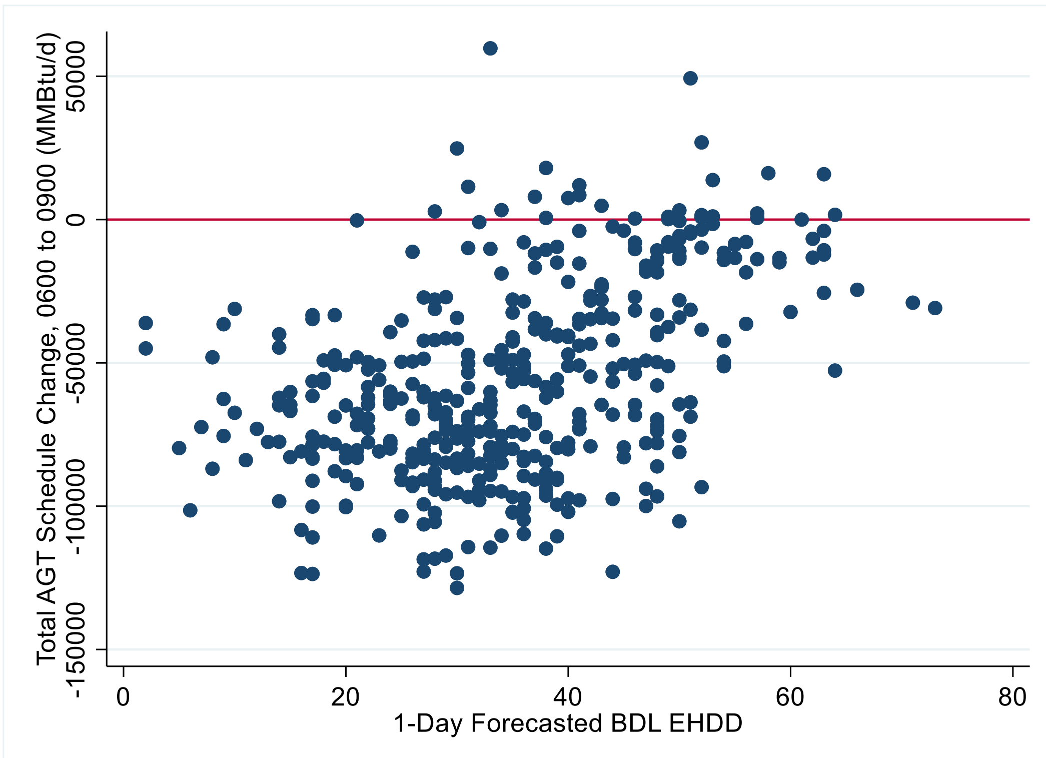
Figure 25. Total AGT Final Schedule Change versus BDL EHDD



November-March winters 2013/14 to 2015/16 (N = 454). Actual EHDD at Bradley Airport shows a positive correlation with total AGT schedule changes. Colder days are correlated with smaller reductions, or even increases, in final schedules. See equation 1 regression results in appendix table A1.

A similar positive, statistically significant, relationship with AGT final schedule adjustment is found with the 7:00 am one-day forecast of EHDD in place of actual EHDD, as shown in Figure 26. As expected, the R-squared value for the regression on forecasted EHDD is smaller (0.22) than for the regression on actual EHDD (0.29). The estimated slope coefficient still has a similar very high probability of being positive as for the regression on actual EHDD. The smaller number of observations (435 versus 454) is because forecast data are not available for November 1-19, 2014.

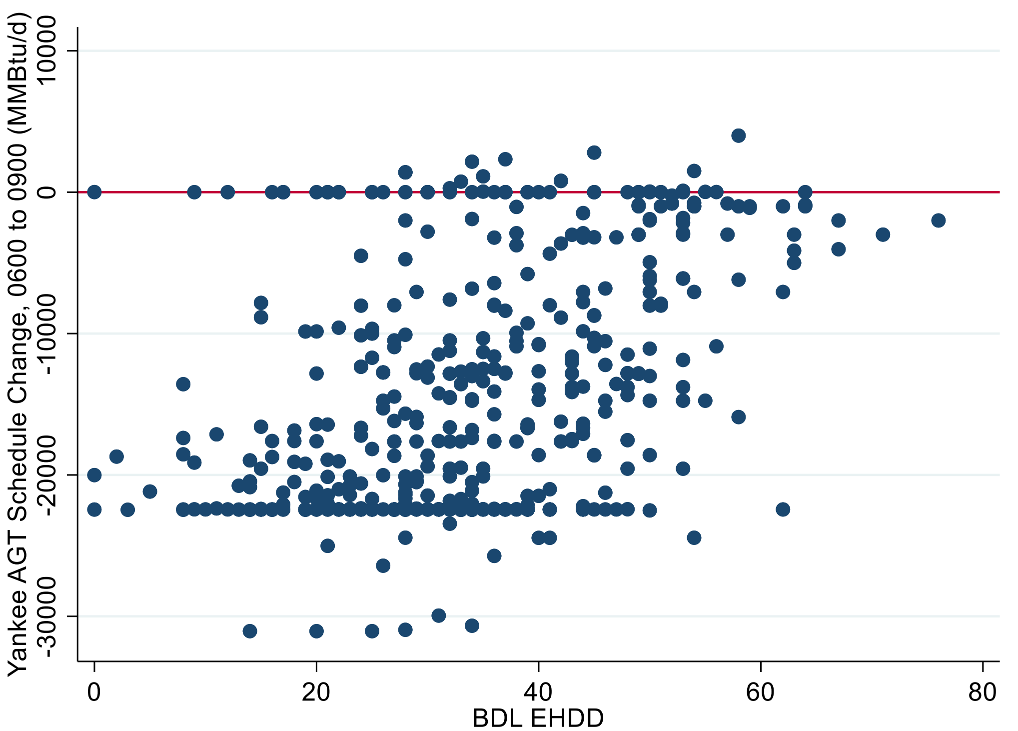
Figure 26. Total AGT Final Schedule Change versus 1-Day Forecasted BDL EHDD



November-March winters 2013/14 to 2015/16 except missing forecast data for November 1-19, 2014 (N = 435). Although the dispersion of Bradley Airport one-day forecasted EHDD is wide, a small positive correlation with resultant total AGT final schedule changes is apparent. That is, smaller (larger) forecasted EHDD are associated with larger (smaller) negative schedule adjustments, and all positive schedule changes occur on days with forecasted EHDD greater than about 28 EHDD. See equation 2 regression results in Appendix Table A1.

Examination of Yankee's final schedule adjustments reveals a similar slightly positive and statistically significant relationship to EHDD (Figure 27). The visible difference from the previous scatter plot for total AGT schedule change versus EHDD is that Yankee has many schedule changes that are either zero or around –22,400 MMBtu/d. As for total AGT final schedule changes, the positive correlation of Yankee's final schedule changes with HDD is the opposite of that asserted in the EDF paper.

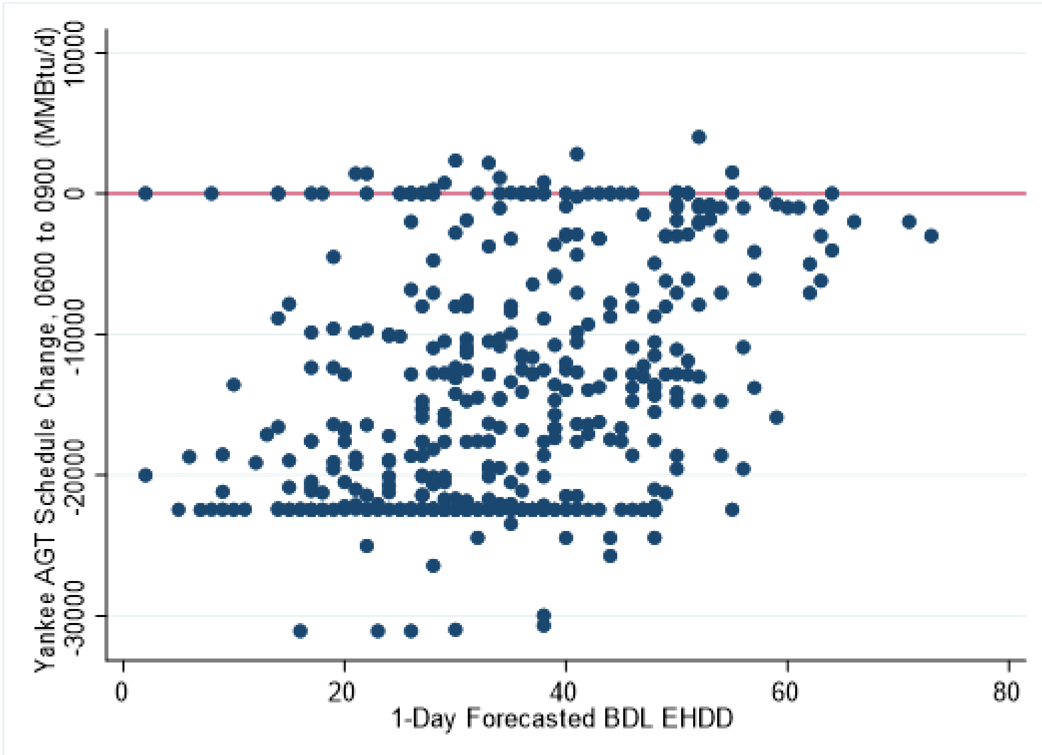
Figure 27. Yankee AGT Final Schedule Change versus BDL EHDD



November-March winters 2013/14 to 2015/16 (N = 454). Yankee has positive, or tends to have smaller negative, final schedule adjustments on days with more EHDD, opposite EDF's contention. See equation 3 regression results in appendix Table A1.

Yankee final schedule change versus 1-day-ahead forecasted EHDD also shows a slight positive correlation (Figure 28).

Figure 28. Yankee AGT Final Schedule Change versus 1-day Forecasted BDL EHDD



November-March winters 2013/14 to 2015/16 except missing forecast data for November 1-19, 2014 (N = 435). Although the dispersion of Bradley Airport one-day forecasted EHDD is wide, a small positive correlation with resultant final schedule changes is apparent. That is, smaller (larger) forecasted EHDD are associated with larger (smaller) negative schedule adjustments, and all of the positive schedule changes occur on days with forecasted EHDD greater than 20. Finally, the practice of using a rule-based negative adjustment of about 22,400 MMBtu/d ends for days with more than about 48 EHDD forecasted. See equation 4 regression results in appendix Table A1.

5.2 Weather forecast uncertainty was not analyzed by EDF

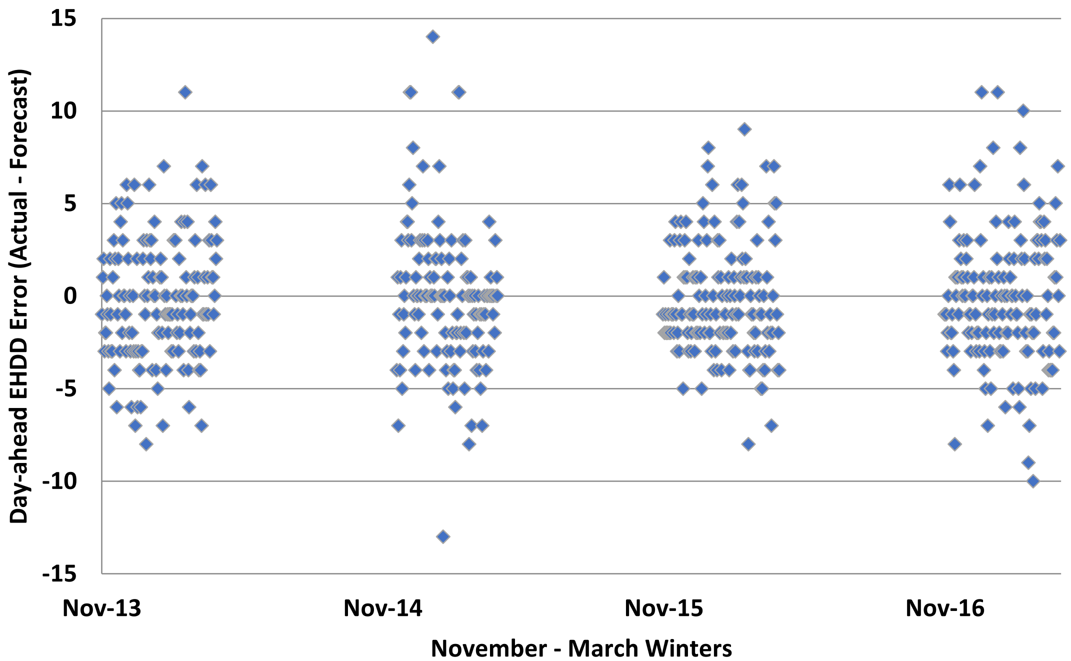
The EDF paper merely mentioned that weather forecast uncertainty narrows as new actual and forecast information arrives over the operational period for each gas day. The EDF analysis did not make use of past forecast data in its explanation of negative schedule adjustments. The purpose of this section is to provide information on the relationship between weather forecast uncertainty and final schedule adjustments. First, we show that inherent weather forecast uncertainty from each decision time after arrival of a new weather forecast through the end of the next operational gas day requires a substantial amount of pipeline gas supply reserve until the close of each gas day. In regard to weather and other sources of gas demand uncertainty, EDF presumes that timely cycle nominations for Yankee and NSTAR are too large, as evidenced by frequent negative adjustments near the end of the gas day. In Section 3.2.1 we disposed of EDF's mistaken view that LDCs should make upward as well as downward schedule adjustments as new actual usage and forecast information becomes available. In this section, we focus on the question of whether too much gas is scheduled initially than is needed to safely cover the risk of higher than expected gas demand. Second, we analyze the extent of the correlation between weather forecast errors and final schedule adjustments.

Our empirical demonstration focuses on Yankee because we have daily weather forecast data provided by Eversource for the Bradley Airport in Windsor Locks, CT. That is the principal location of two meteorological stations that Yankee uses to forecast its gas demand. Although Yankee receives seven-day hourly forecasts, neither Yankee nor its weather forecast vendor, DTN Meteorlogix, archived the hourly forecast data for the three-year EDF period. The weather forecast data provided to Yankee includes temperature, wind speed, degree-days, and effective degree-days. During cold weather, EHDDs include the wind chill effect, which is a superior measure of heating demand compared to unadjusted HDDs.

Yankee uses a regression model to forecast daily gas demand based on the weather vendor's forecast of EHDD and calendar variables. The model includes a nonlinear function of EHDD for the next gas day (for timely nomination) and a linear function of EHDD for the current (prior) gas day. Calendar effects are modeled as indicator (dummy) variables for non-peak heating months (November and March) and lower demand days (Friday, Saturday, Sunday, and holiday). Gas scheduling at Yankee also makes use of other current and forecasted weather information, such as the amount of cloud cover, and the dynamics of when a cold spell or storm is expected to pass through its franchise area in making nomination and confirmations on Algonquin each day. Nomination decisions are based on a blend of weather forecast data, gas demand model predictions, and professional judgment. Importantly, timely cycle nominations include a reserve margin in order to initially schedule the maximum probable next day demand, rather than expected demand. Until weather and other customer demand and market supplier uncertainties are resolved, Yankee needs to reserve sufficient pipeline capacity, conventional storage pull and gas supply to quickly respond to adverse weather or market conditions.

Figure 29 shows daily day-ahead EHDD forecast errors at Bradley Airport. The graph shows the available EHDD forecast error data during the last four winter seasons. The 2016-17 winter is more recent than the three winters analyzed by EDF. The scatter graph shows that the day-ahead EHDD forecast errors are fairly symmetric or unbiased. The graph also indicates that the dispersion of day-ahead EHDD errors is quite wide. Hence, Yankee must plan for the possibility of a large adverse weather change by scheduling sufficient pipeline capacity. Six of the positive errors (actual EHDD greater than forecasted) are more than 10 EHDD and the maximum error is 14 EHDD. Gas supply reserves must be available to cover at least a 14 EHDD forecast error in order to provide reliable firm service.

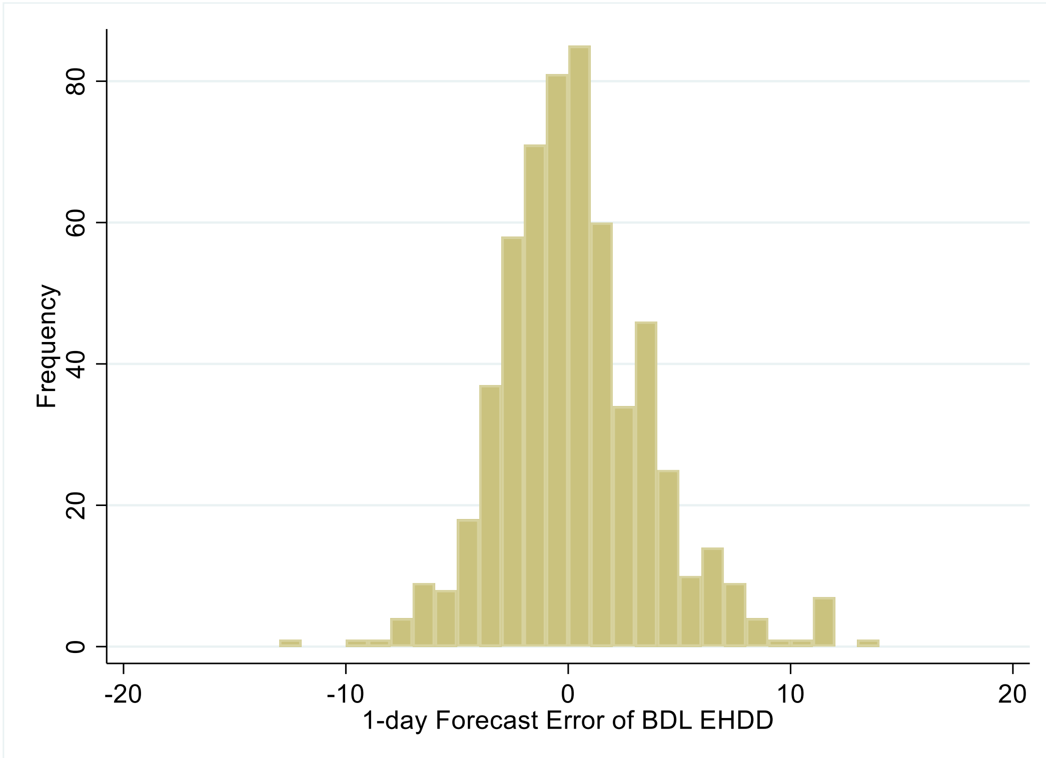
Figure 29. EHDD Day-ahead Forecast Errors for Yankee, Bradley Airport



Temperature and wind speed forecast uncertainties in the Yankee distribution area resulting in at least 14 EHDD more than forecasted must be included as a reserve margin in day-ahead gas scheduling.

Figure 30 shows the distribution of EHDD forecast errors for the same past four winters. Connecticut LDCs are required to plan for meeting a design day load that is expected to occur only one day in 30 years. If this histogram included 30 years of data, there would be more days in the tails greater than +/– 10 EHDD, and likely some days with larger absolute errors than the –13 and +14 EHDD maximum errors observed over the past four winters. For this historical sample distribution of forecast errors, based on a normal distribution of errors, the P95 level is 6 EHDD, P99 is 11 EHDD, and P99.9 is 12 EHDD. However, the empirical distribution of EHDD errors has longer, thinner tails than the normal distribution. The actual 14 EHDD error in the sample was a one in 586 observations event, putting it at the empirical P99.8 level.

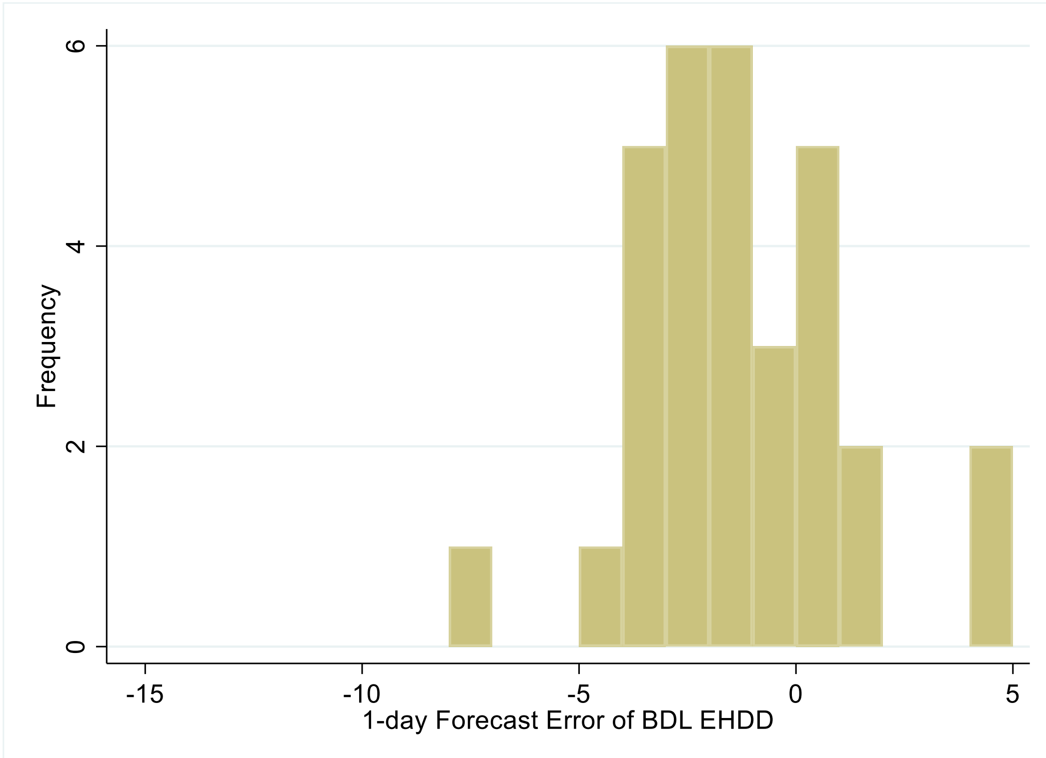
Figure 30. Distribution of EHDD Day-ahead Forecast Errors for Bradley Airport



N = 586 for 2013-14 through 2016-17 winters. The unconditional distribution of day-ahead EHDD forecast errors is quite wide and symmetric or unbiased. Positive errors must be factored into a reserve margin for gas scheduling.

Of the 37 days with the largest Algonquin-wide negative final adjustments, Yankee had negative adjustments on 32 days. Confidential actual and forecast EHDD data were provided for the 31 days within the November – March heating season. Figure 31 shows the subset of EHDD forecast errors on those 31 winter days. The majority of those forecast errors were negative. A negative error means that the day had fewer EHDD than forecasted, consistent with a negative final schedule adjustment. This evidence supports the view that the days with the largest Algonquin wide negative final adjustments were the result of common LDC weather forecast errors, rather than market manipulation to unnecessarily withhold some pipeline capacity. These data are also consistent with the perspective that resolution of weather uncertainty is a key reason for the final schedule adjustments made by Yankee. For the 29 days of the heating season with negative final adjustments, 21 days had forecasted more EHDDs than actual, 4 days had forecasted fewer EHDDs and 4 days had no forecast error. More than 70% of the days had forecast errors as expected and only 14% of the days had forecast errors in the opposite direction. Cloud cover and other weather aspects, as well as non-weather sources of demand uncertainty, may further explain the observed final adjustments.

Figure 31. Conditional Distribution of EHDD Day-ahead Forecast Errors for Bradley Airport

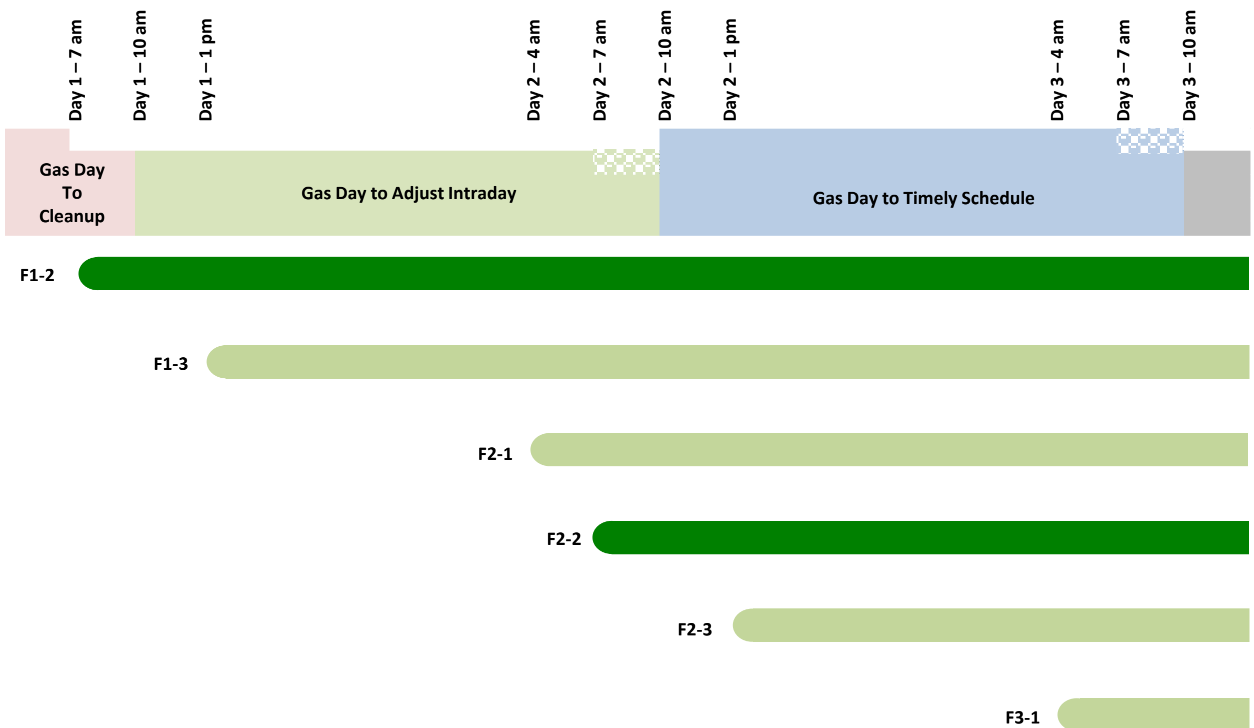


N = 31 of the 37 days of 2013-14 through 2015-16 winters with AGT final schedule negative adjustments larger than 100,000 MMBtu/d. EHDD forecast errors are skewed towards those with smaller actual EHDD than forecasted on the subset of 31 days during November-March winters over three years with total AGT final schedule negative adjustments larger than 100,000 MMBtu/d,

These historical EHDD forecast errors are only available from Yankee's weather data vendor for the 7:00 am one-clock-day-ahead forecasts of average EHDD. However, the decision period prior to timely nominations actually relies on hourly forecasts for the next 51 hours. The clock day-ahead EHDD data shown here does not fully represent the extent of the weather forecast's errors that actually occur on the basis of hourly forecasts that also consider demand for the first 10 hours of the following clock day.

The arrival of new weather information relative to operational gas days is illustrated in the timeline schematic of Figure 32. For timely nominations of the gas day beginning 10:00 am EST on day 2, the latest forecast available to Yankee is the 7:00 am forecast F1-2 of the previous day. Weather variables are forecasted up to the end of the (blue) gas day for which a timely nomination is made. While late day and intraday cycle adjustments of the previously-scheduled (green) gas day may be made on the basis of new weather forecast information available at the 1 pm F1-3 forecast as well as the 7:00 am F1-2 forecast, there is still so much weather and other demand uncertainty that the Yankee operational policy is generally to wait-and-see before making schedule adjustments. For the last three hours of the gas day when downward adjustments are often made, they are mostly based on cumulative metered volumes at that time, so the 4:00 am and 7:00 am forecasts are not of much use for end of gas day clean-up adjustment.

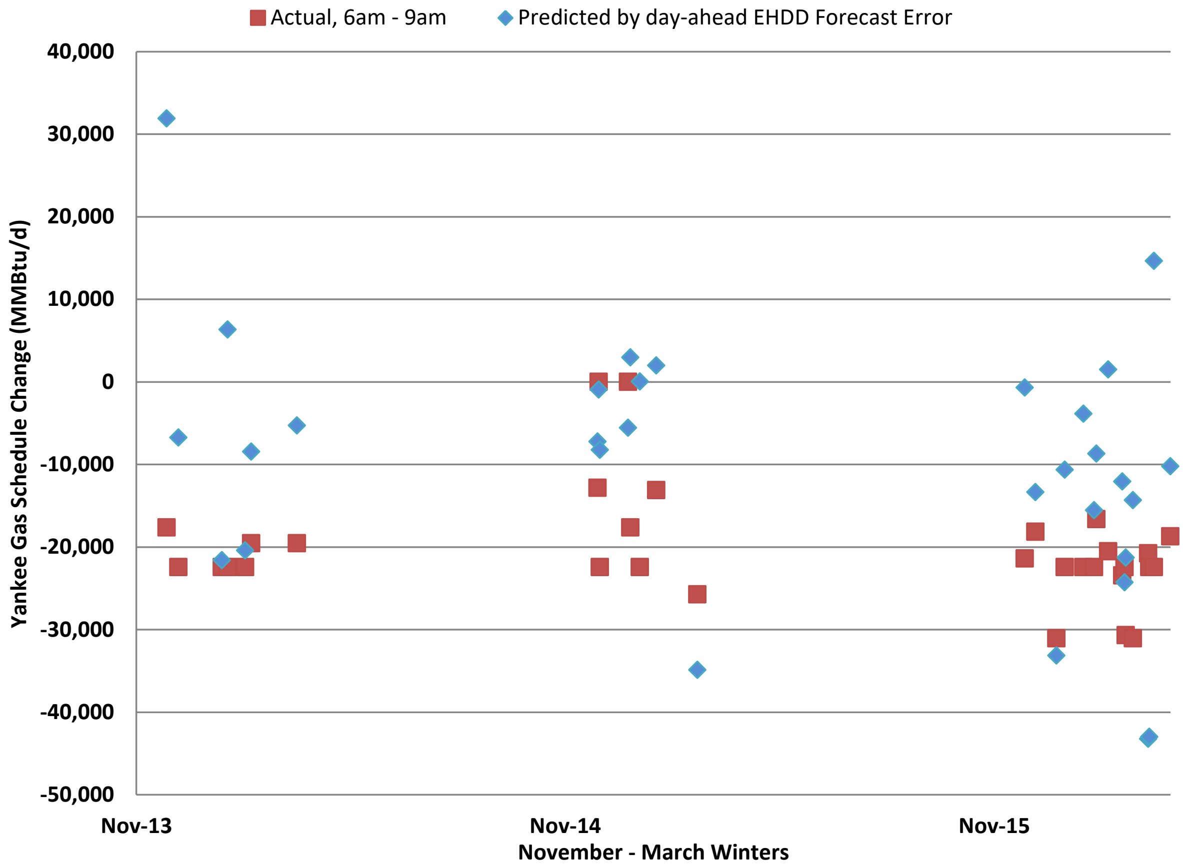
Figure 32. Timeline of Weather Forecasts and Gas Days



Of three daily weather forecasts of hourly values over seven days, the 7:00 am forecast prior to timely nominations (F1-2) is the one mainly relied on for gas scheduling. No forecasts arrive overnight, so morning cleanup adjustments at the end of the gas day are largely based on then-cumulative actual meter flows. The hashed rectangles of the current and next gas days illustrate potential negative adjustments.

LAI has analyzed the explanatory power of day-ahead EHDD forecast errors in relation to 6:00 am to 9:00 am Yankee schedule changes on the 31 of 37 days we identified as having more than 100,000 MMBtu/d negative adjustment across AGT that are within the November to March winter season used by Yankee to estimate its weather-based demand forecast model coefficients. We applied the firm gas demand regression model coefficients estimated with winter 2014-15 data that Yankee provided in Docket 13-06-02REO2 (Data Request PURA-02) to predict the change in gas demand as the difference between Yankee's predicted demand based on actual EHDD and day-ahead 7:00 am forecasted EHDD. Yankee had negative final schedule adjustments on 29 of the 31 days over three winters. Significantly, the day-ahead weather forecast errors predict negative adjustments on 24 of those 31 days. The magnitudes of actual final and EHDD forecast-based predicted changes are similar. The largest absolute actual adjustment was –31,051 MMBtu/d versus –43,271 MMBtu/d for the weather prediction error. The conditional (within the 31 days) average actual adjustment was –20,249 MMBtu/d versus –10,175 MMBtu/d based on weather prediction error. These data points are graphically compared in Figure 33.

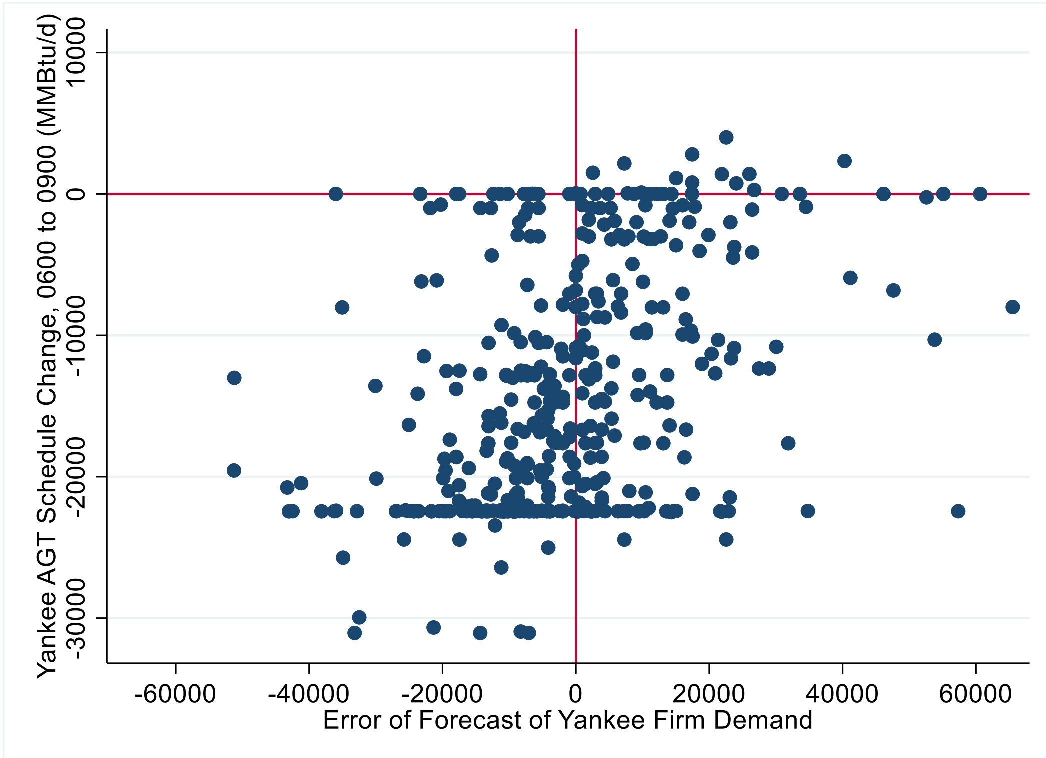
Figure 33. Conditional Actual Final Schedule Changes versus Day-ahead EHDD Forecast Error-based Schedule Changes for Yankee



EHDD forecast errors translated into model-based gas schedule changes tend to be negative on the 31 days with Yankee actual negative final schedule adjustments in the subset of 37 days with total AGT negative adjustments greater than 100,000 MMBtu/d.

Demand forecast error is positive (negative) when actual demand is larger (smaller) than forecasted demand. Yankee final schedule change versus 1-day-ahead forecasted EHDD-based demand error for all 432 days of available data over the three winters shows a slight positive correlation (Figure 34). The model for forecasting demand uses the lag of the day-ahead forecast as a proxy for the forecast of the forecast day. As a proxy, the model coefficients estimated by Yankee with 2014-15 winter data were applied to all three winters because regression results using 2013-14 winter data were not available. The regression of Yankee final schedule change on this forecast error finds a highly significant slope coefficient of about 0.2. The regression has an R-squared value of 0.16, so this very simplified data analysis "explains" about 16% of the final upward and downward schedule adjustments. This result is significant in light of the Yankee policy to hold sufficient reserve capacity in its schedules to cover any unexpected increase in demand. The R-squared value would be much greater if Yankee had a policy of making bilateral adjustments based only on meeting then-expected demand.

Figure 34. Day-ahead Yankee Demand Model Forecast Error versus Final Schedule Change



November-March winters 2013/14 to 2015/16 except missing forecast data for November 1-19, 2014 (N = 432). Although the dispersion of Yankee model-based demand forecast errors is wide, a small positive correlation with resultant final schedule changes is apparent. Days when actual demand is larger (smaller) than forecasted demand are associated with smaller (larger) schedule reductions. All of the days with positive schedule changes are when actual demand was higher than forecasted. See equation 5.1 regression results in appendix Table A2.

In order to test the robustness of this estimated coefficient, a series of other regression equations were specified that added other independent variables as controls in order to be sure that the initial positive slope coefficient was not a spurious result of omitted variables. After limited testing, the best equation found also includes one-day forecasted demand, Saturday and Sunday indicator variables, and the delivery term duration (in days) of the corresponding Next Day gas product. The results of this larger regression equation (see equation 5.2 in appendix Table A2) are:

- The R-squared value increases to 0.29 from 0.16.
- The coefficient of the EHDD-based demand forecast error is robust, only declining to 0.201 from 0.209.
- The sign of the forecasted demand coefficient is positive, opposite of what the EDF report expects. Higher forecasted demand days tend to be associated with smaller (larger) negative (positive) final adjustments. This result may be explained by the fact that on high forecasted demand days, actual demand will tend to be so high as to not allow as much ability to reduce final schedules.

- The two weekend day indicator variables result in slightly significant negative coefficients, as expected due to limited spot trading opportunities for weekend days. A holiday indicator was tested but found to have a statistically insignificant coefficient.

- The variable "term", the number of delivery days in the Next Day product of the gas day, results in a slightly significant positive coefficient. This result may be explained by a practice of scheduling a larger reserve margin for longer Next Day delivery periods.

5.3 Gas trading calendar effects on schedule adjustment not considered by EDF

Throughout North America, physical gas is traded in centralized electronic markets and bilaterally mainly as a standard Next Day product delivered over one to five gas days, beginning at 9:00 am CCT. In addition, there is infrequent trading of Same Day gas, with flows beginning at various times depending on when the trade is executed. We focus here on the sales opportunity limitations in the much larger Next Day market. The standard Next Day product is for a constant rate of delivery over its term, and the term is often longer than one day because trading is only done on non-holiday weekdays and multi-day deliveries across calendar months are split into separate sessions in order for the sum of Next Day terms within a month to be identical to its monthly product. These Next Day product definition and trading rules reduce spot market trading opportunities in any of three ways:

- Regular Friday trading is for a three-day block (Saturday, Sunday, Monday) with typically higher demand on Monday than on the weekend days.

- Before holidays, when the Next Day gas markets on NYMEX and ICE are closed, the Next Day product delivery term is extended for at least one more day. For example, trading on the day before Thanksgiving is for a five-day product (Thursday through Monday).

- Whenever a multi-day delivery term would otherwise cross a calendar month boundary, the last day(s) of the current month are traded two days before the start of delivery and the first day(s) of the next month are traded on the last trading day of the current month.

These three Next Day product definition limitations create two types of problems for LDCs and other gas market participants:

- Constant delivery across days. The longer term of constant delivery over a weekend and/or holiday period means that an LDC can only sell a block that it does not expect to need on its highest demand day over that product term. For example, if the LDC expects its demand to be lower on the weekend days than Monday, it cannot sell gas for just Saturday and/or Sunday or risk not having sufficient remaining supply to meet Monday's higher and more uncertain demand. Likewise, the lower demand on a holiday does not allow carving out separate traded volumes for the holiday.

- Greater demand uncertainty. The longer lead time of two to five days from the trading date to the start of gas day delivery for multi-day Next Day products substantially increases weather and other demand forecast uncertainties. This need to allow for a larger reserve to cover higher than expected demand reduces the opportunity to sell gas or pipeline capacity.

The importance of these product definition limitations is illustrated in Table 5 for the 37 days of negative final adjustments greater than 100,000 MMBtu on Algonquin during the EDF paper's three-year data period. We presume that the 37 largest negative adjustment days we found match those in the EDF paper's undisclosed data. The green-shaded gas days are contiguous days with large negative adjustments. The red-shaded gas days include part of a holiday. The blue-shaded values in the Trading Lead time and Delivery Term columns are special trading exceptions resulting from holiday and/or split session rules.

Table 5. Next Day Product Aspects for Delivery on AGT 37 Largest Negative Adjustment Days

(Schedule Change in MMBtu/d)

Gas Day	Day of Week	Total Schedule Change	Trading Lead (Days)	Delivery Term (Days)	Lead or Term > 1 Day (=X)	Holiday in Delivery Term	Split Session Trading	Special Next Day Trading	Special Multi-day Delivery
27-Nov-13	Wed	-106,347	1	4	X	TG (28th)	Yes	11/26/2013	11/27 - 11/30
7-Dec-13	Sat	-101,979	1	3	X				
13-Jan-14	Mon	-118,314	3	3	X				
18-Jan-14	Sat	-109,691	1	4	X	MLK (20th)		1/17/2014	1/18 - 1/21
2-Feb-14	Sun	-114,251	2	3	X				
7-Feb-14	Fri	-105,273	1	1					
18-Mar-14	Tue	-100,731	1	1					
29-Nov-14	Sat	-114,454	4	5	X	TG (27th)	Yes	11/25/2014	11/26 - 11/30
30-Nov-14	Sun	-123,637	5	5	X	TG (27th)	Yes	11/25/2014	11/26 - 11/30
1-Dec-14	Mon	-122,807	5	1	X		Yes	11/26/2014	
25-Dec-14	Thu	-103,468	1	5	X	Christmas		12/24/2014	12/25 - 12/29
27-Dec-14	Sat	-100,341	3	5	X	Christmas		12/24/2014	12/25 - 12/29
4-Jan-15	Sun	-128,513	2	3	X				
18-Jan-15	Sun	-123,423	2	4	X	MLK (19th)		1/16/2015	1/17 - 1/20
22-Feb-15	Sun	-122,893	2	3	X				
19-Sep-15	Sat	-101,054	1	3	X				
28-Nov-15	Sat	-118,552	3	5	X	TG (26th)		11/25/2015	11/26 - 11/30
7-Dec-15	Mon	-102,317	3	3	X				
25-Dec-15	Fri	-108,299	1	4	X	Christmas		12/24/2015	12/25 - 12/28
1-Jan-16	Fri	-104,788	1	4	X	New Year's		12/31/2015	1/1 - 1/4
17-Jan-16	Sun	-110,514	2	4	X	MLK (18th)		1/15/2016	1/16 - 1/19
26-Jan-16	Tue	-117,209	1	1					
28-Jan-16	Thu	-110,264	1	1					
7-Feb-16	Sun	-101,977	2	3	X				
19-Feb-16	Fri	-102,231	1	1					
21-Feb-16	Sun	-105,507	2	3	X				
22-Feb-16	Mon	-114,787	3	3	X				
28-Feb-16	Sun	-110,196	2	3	X				
12-Mar-16	Sat	-110,906	1	3	X				
13-Mar-16	Sun	-123,319	2	3	X				
17-Mar-16	Thu	-100,132	1	1					
31-Mar-16	Thu	-101,448	1	1					
7-Apr-16	Thu	-106,384	1	1					
10-Apr-16	Sun	-109,671	2	3	X				
22-Apr-16	Fri	-114,517	1	1					
30-Apr-16	Sat	-122,408	2	2	X		Yes	4/28/2016	4/29 - 4/30
21-May-16	Sat	-111,724	1	3	X				

The first aspect we note is that a disproportionate number of the large negative adjustment days occur on weekends and weekday holidays, as summarized in Table 6. Sundays occur more than twice the expected daily frequency of 14.3%, and Saturday is 10% higher than the expected daily frequency. Weekdays are all less than the expected frequency. The much greater frequencies of weekend days and holidays are related to the inability to separately trade those days. Trading for delivery on those days must also include at least one non-holiday weekday. The lower demand by generators and other market participants on weekends and holidays means that there would be little opportunity to have reduced the LDC schedules for those days.

Table 6. Day Type Frequency of the 37 Largest Negative Adjustment Gas Days

Day Type	7 Types Freq	7 Types Percent	8 Types Freq	8 Types Percent
Mon	4	10.8%	4	10.8%
Tue	2	5.4%	2	5.4%
Wed	1	2.7%	0	0.0%
Thu	5	13.5%	4	10.8%
Fri	5	13.5%	3	8.1%
Sat	9	24.3%	9	24.3%
Sun	11	29.7%	9	24.3%
Hol	N/A	N/A	6	16.2%
Weekday	17	45.9%	13	35.1%

The second key aspect related to the Next Day spot product is that the number of lead days from the trading day to the start of the instant gas day tends to be greater than if there was day-ahead trading on all days, as in the ISO-NE day-ahead market. Table 7 shows that more than half of the 37 suspect gas days have two to five lead days. Without holidays or split sessions, a single lead day would occur 71.4% and two and three lead days would each occur 14.3%. Larger reserve supply is needed to cover weather and other demand uncertainties for longer lead times. Longer lead times occur as a result of holidays and split sessions, as well as typical three-day weekend delivery terms. Weather and other demand forecasts available during Next Day trading are for nearly two days longer than the lead time for each gas day.

Table 7. Lead Days Frequency of the 37 Largest Negative Adjustment Gas Days

Days after Trade Date	Freq	Percent
1	18	48.6%
2	11	29.7%
3	5	13.5%
4	1	2.7%
5	2	5.4%

The third aspect is that 73% of the 37 gas days are for multi-day delivery terms, as described in Table 8. Almost all of the large negative adjustment gas days within a multi-day delivery period are on a holiday or weekend day. When the instant gas day occurs on part of a holiday or weekend day, scheduled demand is more likely to decline to meet typically lower actual usage.

Table 8. Delivery Term Frequency of the 37 Largest Negative Adjustment Gas Days

Delivery Term (Days)	Freq	Percent
1	10	27.0%
2	1	2.7%
3	15	40.5%
4	6	16.2%
5	5	13.5%

In Table 5, over 75% (28 of 37) of the days have either or both of the difficulties of having more than one day to the start of delivery for the instant gas day, and/or the instant gas day is in an inflexible multi-day Next Day product term. Ten of the 37 gas days are in a Next Day product term that includes a holiday, and two other gas days involve longer lead times for split trading sessions. Interestingly, the Martin Luther King, Jr. holiday and Thanksgiving are within the Next Day product delivery term each year. In 2014, three contiguous days, November 29 through December 1, each with 4 or 5 lead days, are on Thanksgiving weekend. Christmas has a high negative adjustment in two of the three years, and New Year's arises once.

Finally, we observe in Table 9 that all but two of the 37 large negative adjustment days occur during the November through April heating season, which has much more weather uncertainty driving gas demand than during the non-heating season. Their occurrence is highest in the peak heating months of January and February. April and November, which have high weather-related uncertainty due to volatile weather patterns, each have four gas days with large negative adjustments. Four of the five March days, the four April days and the sole day in May all occurred in 2016. Yankee uses the five-month November-March period for estimating the coefficients of its regression model of demand as a nonlinear function of EHDD, one day lagged EHDD, and chronological indicator variables. EDF only includes December through March as its winter season definition. Our view is that for the purpose of forecasting LDC gas demand, the heating season definition should be November through April.

Table 9. **Delivery Month Frequency of the 37 Largest Negative Adjustment Gas Days**

Month	Freq	Percent
Jan	8	21.6%
Feb	8	21.6%
Mar	5	13.5%
Apr	4	10.8%
May	1	2.7%
Jun	0	0.0%
Jul	0	0.0%
Aug	0	0.0%
Sep	1	2.7%
Oct	0	0.0%
Nov	4	10.8%
Dec	6	16.2%

Table 10 reports the negative adjustments for Yankee and NSTAR on the days with total AGT final negative adjustments greater than 100,000 MMBtu/d. The sole September 2015 day had zero final adjustments by Yankee and NSTAR. Additionally, Yankee and NSTAR each had zero final adjustments on four of the other 37 days with the largest Algonquin-wide final schedule changes. For both Yankee and NSTAR, only 32 of the 37 days had negative final adjustments.

A second observation is that many of the days with negative final adjustment for Yankee have identical or very similar values. For example, Yankee has changes of –22,448 MMBtu/d on six days, –22,441 MMBtu/d on three days, and –22,425 MMBtu/d on two days. These volumes are consistent with Yankee balancing its system by reducing nominations from flexible storage to zero.

Table 10. Yankee and NSTAR Adjustments on AGT 37 Largest Negative Adjustment Days

(Schedule Change in MMBtu/d)

Gas Day	Day of Week	Total Schedule Change	Eversource Schedule Change	Yankee Schedule Change	NSTAR Schedule Change
27-Nov-13	Wed	-106,347	-17,634	-17,634	0
7-Dec-13	Sat	-101,979	-38,034	-22,441	-15,593
13-Jan-14	Mon	-118,314	-32,999	-22,441	-10,558
18-Jan-14	Sat	-109,691	-32,139	-22,441	-9,698
2-Feb-14	Sun	-114,251	-32,841	-22,439	-10,402
7-Feb-14	Fri	-105,273	-69,648	-19,555	-50,093
18-Mar-14	Tue	-100,731	-19,555	-19,555	0
29-Nov-14	Sat	-114,454	-53,235	-12,837	-40,398
30-Nov-14	Sun	-123,637	-33,900	0	-33,900
1-Dec-14	Mon	-122,807	-38,146	-22,425	-15,721
25-Dec-14	Thu	-103,468	-32,770	0	-32,770
27-Dec-14	Sat	-100,341	-54,439	-17,616	-36,823
4-Jan-15	Sun	-128,513	-58,421	-22,425	-35,996
18-Jan-15	Sun	-123,423	-26,385	-13,116	-13,269
22-Feb-15	Sun	-122,893	-57,268	-25,726	-31,542
19-Sep-15	Sat	-101,054	0	0	0
28-Nov-15	Sat	-118,552	-59,037	-21,396	-37,641
7-Dec-15	Mon	-102,317	-45,457	-18,164	-27,293
25-Dec-15	Fri	-108,299	-46,006	-31,049	-14,957
1-Jan-16	Fri	-104,788	-33,248	-22,448	-10,800
17-Jan-16	Sun	-110,514	-38,509	-22,448	-16,061
26-Jan-16	Tue	-117,209	-22,448	-22,448	0
28-Jan-16	Thu	-110,264	-34,690	-16,629	-18,061
7-Feb-16	Sun	-101,977	-26,108	-20,508	-5,600
19-Feb-16	Fri	-102,231	-27,971	-23,448	-4,523
21-Feb-16	Sun	-105,507	-41,971	-22,448	-19,523
22-Feb-16	Mon	-114,787	-55,462	-30,664	-24,798
28-Feb-16	Sun	-110,196	-33,573	-31,051	-2,522
12-Mar-16	Sat	-110,906	-30,763	-20,763	-10,000
13-Mar-16	Sun	-123,319	-37,447	-22,448	-14,999
17-Mar-16	Thu	-100,132	-26,743	-22,448	-4,295
31-Mar-16	Thu	-101,448	-18,702	-18,702	0
7-Apr-16	Thu	-106,384	-50,804	-30,863	-19,941
10-Apr-16	Sun	-109,671	-25,000	0	-25,000
22-Apr-16	Fri	-114,517	-41,476	-21,476	-20,000
30-Apr-16	Sat	-122,408	-15,000	0	-15,000
21-May-16	Sat	-111,724	-44,146	-24,754	-19,392

6 Final Schedule Adjustments Do Not Affect Spot Gas Prices

Highlights

- EDF's analysis of the impact of negative schedule adjustments by Firms A and B is invalid. It first assumes that all the negative schedule changes could be used by electric generation units, then estimates the short-run price elasticity of gas demand by electric generators, and finally applies that elasticity coefficient to produce counterfactual changes in gas prices. It misses the mark entirely by not directly quantifying the (non-)relationship between negative schedule changes and gas prices while waving the magic wand that such available capacity could be used by generators in the market center.

- EDF misrepresented gas demand price elasticity results from a published paper (Davis & Kilian, 2011) as being comparable to EDF's estimates of short-run price elasticity of gas demand by electric generators. The Davis and Kilian results were long-term price elasticity estimates of residential customer gas demand for U.S. Census data from the years 1980, 1990, and 2000, and the larger (absolute) of the two elasticity values cited by EDF as bracketing their estimate was for the 1980 data, when federal price caps still existed.

- AGT Citygates spot prices are not as useful as the regional basis from AGT back to Tetco-M3 (TEM3) for analysis of the relationship between schedule changes and AGT prices. The AGT-TEM3 basis is more appropriate for this analysis than the longer distance basis to the national Henry Hub pricing point.

- The AGT-TEM3 basis has no statistically-significant relationship with AGT final schedule adjustments, opposite the inference in the EDF paper that negative schedule adjustments result in higher spot prices.

- The explanation for not finding any correlation between AGT basis and final schedule adjustments is most likely because random weather forecasting errors account for much of schedule adjustments and they are resolved too late to affect that day's spot price.

As LAI has demonstrated in previous sections, we find no overscheduling behavior by Yankee. Hence, there is no need to review and critique the size of the alleged increases in gas prices and electric prices modeled by EDF. But with that important disclaimer, in this section we critique EDF's data and modeling procedures on the topic of whether negative final schedule adjustments result in higher AGT Citygates spot prices than absent negative adjustments. The EDF paper's empirical analysis purports to find that the negative final schedule adjustments during winters at the ten nodes operated by Firms A and B results in significantly higher AGT spot prices than otherwise (EDF, Section 6.1, pp. 34-38). The purposes of this section are first to explain why EDF's analysis is completely wrong-headed, and then to demonstrate that no statistically-significant relationship between final schedule adjustments and spot prices exists.

6.1 EDF's analysis of the impact of negative schedule adjustments on natural gas prices entirely misses the mark

Essentially, EDF's analysis of the gas spot market impacts of alleged withholding of gas supply has three steps:

1. Most of the alleged negative schedule adjustment volumes are assumed to be available to electric generators on AGT in the counterfactual world, and would be taken at a lower price.

2. A gas demand regression model, using the instrumental variables (IV) method, was used to estimate the short-run price elasticity of demand for gas by generators.

3. The price elasticity coefficient was applied to calculate the reduction in price that would occur in order for generators to have demanded an additional quantity of gas equal to the alleged withholding.

The assumption in step 1 is critical to EDF's analysis but is not supported in reality as we have discussed in previous sections.

In step 2, EDF formulated a rather simple regression model of electric generator gas demand on AGT as a function of the Henry Hub-instrumented price of gas on AGT, linear and quadratic HDD variables, and weekend and calendar month indicator variables (p. 35). This formulation leaves a lot of econometric modeling questions unanswered:

- What would have been the impact of including an oil index price (for ULSD or RF0) as another control variable?

- What would have been the impact of including other New England gas price indexes (for TGP, especially)?

- Why wasn't the demand for electricity or the price of electric energy included?

LAI will resist the temptation here to delve into economic theory of the firm and statistical method issues. The main point is this: it is insufficient to control for just HDD and fixed chronological effects in an electric generator gas demand equation. The spatial aspects of both the gas pipeline and storage system and the electric transmission and generation system make it preferable to utilize a fundamentals production cost simulation model to estimate the gas demand response of electric generators connected to just one pipeline in New England.

Another possible shortcoming is the use of the Henry Hub gas price index as an instrument for the AGT Citygates price index, instead of the TEM3 price. The latter is more closely correlated with AGT prices, as will be shown below.

EDF states that the paper's estimates of the elasticity of electric generator gas demand, –0.24 by OLS and –0.27 by IV, are in the –0.10 to –0.34 range reported by Davis and Kilian (EDF, p.

36). However, that comparison is entirely bogus. Davis and Killian estimated implicitly long-run heating demand elasticity of natural gas prices by residential customers across U.S. states in a given year, not the short-run electric generator gas demand elasticity of gas prices. Moreover, the estimates in that article were for 1980, 1990, and 2000 U.S. Census data, not across different current data sets or model specifications as implied by EDF.[32] The –0.34 estimate was for 1980 data, which Davis and Killian used to compare then-capped (which ended in 1989) versus uncapped prices in the latter two census years, and the –0.10 estimate was for 2000 data (Davis & Killian, 2011, p. 228). EDF's reliance on obsolete and inapplicable elasticity of demand values to support its regression analysis is sloppy, suspect, and, in any event, in disaccord with quality standards for what purports to be scholarly research.

EDF claims that its IV regression analysis was restricted to days with positive HDD (p. 36), but the regression results indicate that 795 observations were used (EDF, Table 5). Over the three year sample data period, that would average 265 days/year with non-zero HDD, which is not valid. The three November-March winter seasons only have 454 days, for which Bradley Airport, for example, had 451 days of positive HDD. Because EDF has not provided the data used in their analysis, it is not clear whether the electric generator gas demand model regression equations included non-winter days or a different sample period than was stated by EDF elsewhere.

Another curiosity is that EDF appears to apply a non-standard definition of HDD. The usual definition is that HDD = max(65 – Tave, 0), where Tave is the simple average of the daily high and low Fahrenheit temperatures. In contrast, EDF states "we restrict the estimation to days with positive heating degrees (*i.e.*, days where the maximum temperature is below sixty-five degrees farenheit)[*sic*]" (p. 36). If EDF actually applied the filter of only using days with a maximum temperature below 65^{o}F, then even fewer observations should have been reported in the regression results.

6.2 No relationship exists between final schedule adjustments and AGT spot prices

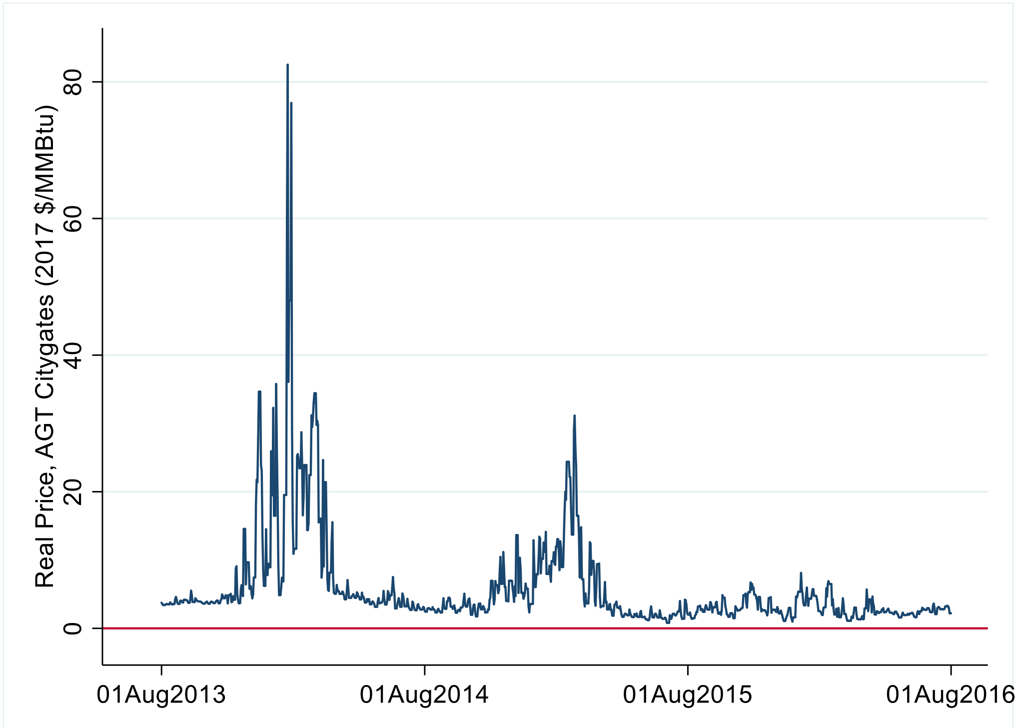
Next Day AGT Citygates real prices over the three-year period of the EDF analysis are shown in Figure 35. Real prices in 2017 dollars are calculated with the quarterly GDP implicit price deflator index. All of our price analysis uses real, constant dollar, prices because the EDF data period spans three years, which is long enough to slightly distort data analysis conducted in nominal terms, as EDF did.

The AGT price level is influenced by upstream pipeline supply-demand balances from the major producing region of Marcellus-Utica, and national level commodity price fluctuations, as typically measured by Henry Hub prices. Instead of using AGT prices directly, we analyze AGT real basis, using TEM3 as the most appropriate upstream benchmark location instead of the usual Henry Hub national pricing location. As shown in Figure 36, this AGT basis measure is generally positive, even during summer months. The few large negative basis exceptions all

[32] Lucas W. Davis and Lutz Kilian, "The Allocative Cost of Price Ceilings in the U.S. Residential Market for Natural Gas," *Journal of Political Economy*, 2011, vol. 119, no. 2.

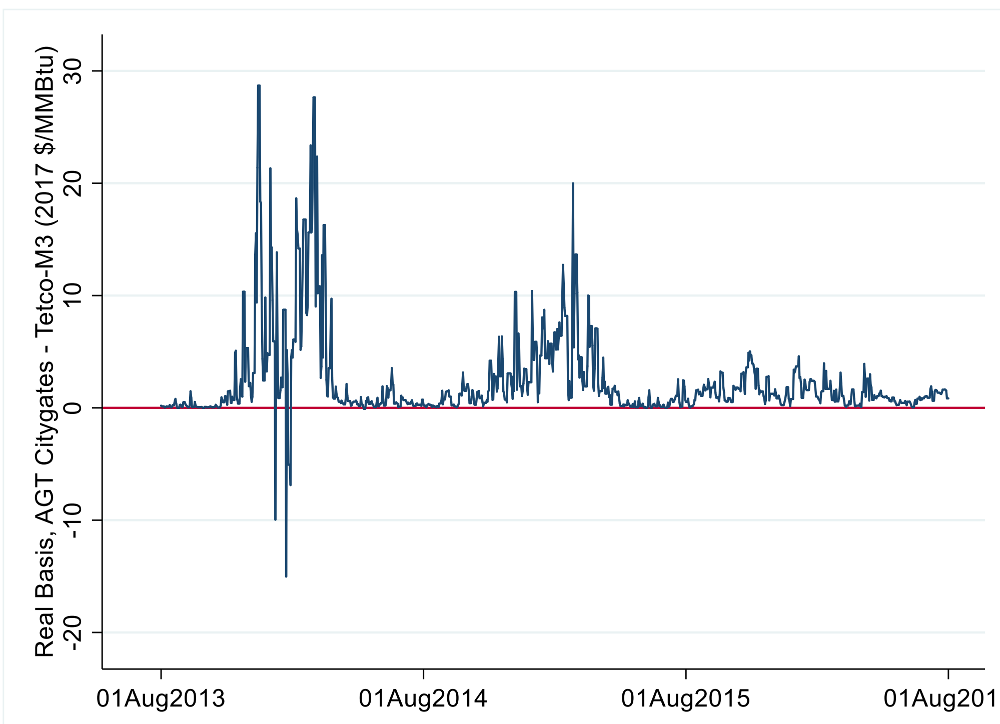
occurred during the early 2014 Polar Vortex, when TEM3 prices spiked on same days when AGT prices were more moderate. We agree with the EDF report that “[t] price of gas at TEM3, which sits at the junction of the Texas Eastern and Algonquin pipelines, captures the cost of delivering gas to – or the price paid by buyers procuring gas for takeaway at – New England's doorstep” (pp. 37-38). What is most relevant to the analysis of alleged pricing power by LDCs on AGT is the impact on this measure of local basis. This basis measure effectively isolates the impact of supply-demand forces in New England on AGT prices from the rest of the North American gas supply and pipeline system.

Figure 35. AGT Citygates Real Prices, August 1, 2013 through July 31, 2016



Modeling of spot gas prices over the three-year EDF data period is very sensitive to the treatment of the few extremely high price days during the early 2014 Polar Vortex.

Figure 36. AGT Citygates minus Tetco-M3 Real Basis, August 1, 2013 to July 31, 2016



The AGT-TEM3 basis was positive over the three-year EDF data period except for a few Polar Vortex days.

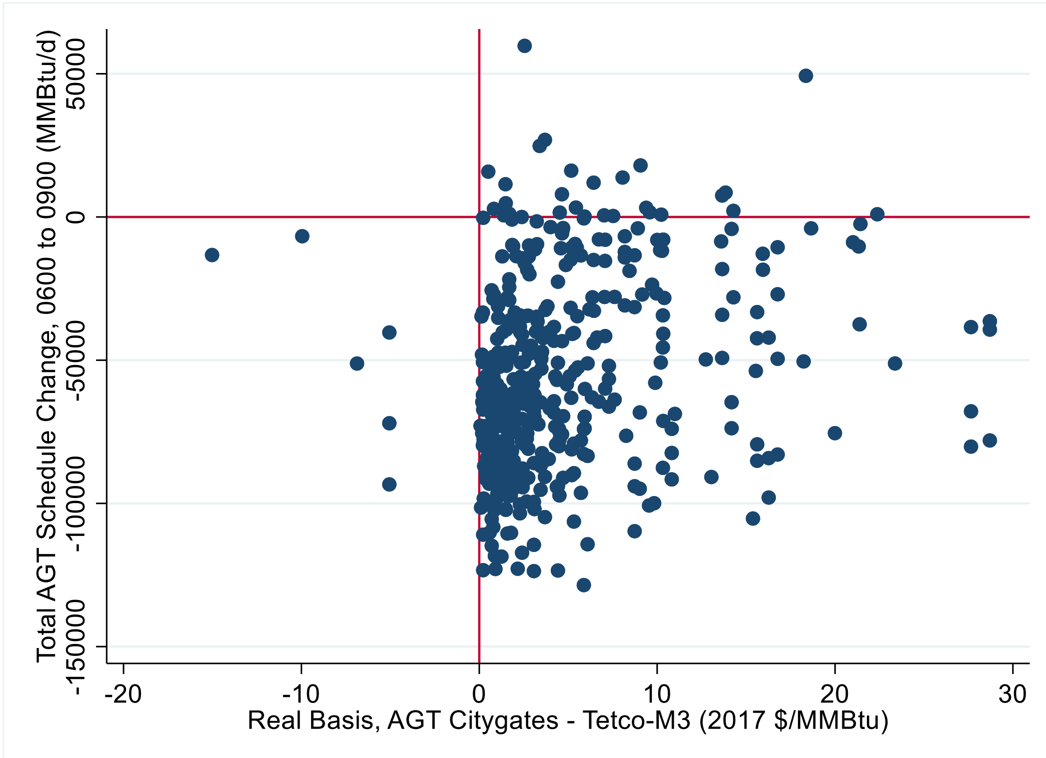
There appears to be no good conceptual reason for isolating specific final schedule adjustments at the ten meters of Firms A and B by using the average fraction of schedule adjustments at all other meters, as done by EDF (p. 37). Any relationship between spot prices and final adjustments, as in any supply-demand market-clearing behavior, is generally assumed to be with respect to aggregate net adjustments. Figure 37 shows the relationship between total final schedule adjustments across all AGT meters with AGT basis on all days in the three-year EDF analysis period with positive EHDD. Visually, it appears that larger negative schedule adjustments tend to be correlated with smaller basis. The positive-appearing slant of the scatter has a statistically-significant (t = 5.08 with robust standard errors) positive slope coefficient in a simple regression of basis on schedule change (see Table A3 in the appendix for the results of this equation and the next two alternatives discussed that include additional variables). This result is the opposite of that in the EDF paper.

However, a better approach is to control for weather and other variables that could influence both schedule changes and gas prices. By including EHDD as a control variable in regression equation, the schedule change coefficient remains positive but is not statistically significant. In other words, for that model, there is no relationship between schedule change and AGT basis. This result of no statistically-significant relationship is reinforced in a third test regression equation that also includes low demand (Saturday, Sunday, holiday) day type indicators, the number of lead days from the respective trade date to the gas day, and the duration or term of the respective Next Day product.[33]

The explanation for not finding any correlation between AGT basis and final schedule adjustments is most likely because random weather forecasting errors account for much of schedule adjustments, and they are resolved too late to affect that day's Next Day spot price.

[33] The relatively small R-squared values of these three basis regression equations are an artifact of defining the dependent variable as the basis. Alternatively, by using the AGT price as the dependent variable and including the TETM3 price as another independent variable, the R-squared values would be much larger.

Figure 37. Total AGT Final Schedule Change versus AGT Real Basis to TEM3



A positive correlation is apparent in the scatter of AGT basis with total AGT schedule changes, opposite the relationship estimated by EDF. However, statistical analysis that controls for EHDD and other independent variables results in zero statistically-significant correlation.

7 Conclusions

LAI's Critical Assessment disproves EDF's allegations about harm to the wholesale electricity market because there was no inefficient or manipulative withholding of natural gas in the first place. EDF's allegations are preposterous. EDF's findings of the exercise of vertical market power by LDCs in Connecticut and Massachusetts incorporate misleading and often mistaken assumptions about gas utility operations, scheduling protocols and contractual obligations to serve. The Eversource LDCs had no direct or indirect motivation to withhold capacity for purposes of sustaining rate-base regulation in New Hampshire. EDF's insinuation is baseless and bizarre. Technical review shows that Yankee's and NSTAR's reductions in scheduled quantities during the last three hours of the Gas Day represent a sliver of New England's peak demand. Notwithstanding the absence of any actions or motivations to withhold gas capacity and distort wholesales market prices in New England, it is incomprehensible that the postulated withholding of a comparatively trivial amount could cause wholesale power prices to be $3.6 billion higher over a three-year period.

EDF unreasonably simplified standard utility practice, where LDCs are first and foremost responsible for supplying gas to their firm customers without any interruption. EDF's empirical analysis is badly marred by failing to account for the reserve needed to cover uncertain weather and other uncertain demand fluctuations. Inexplicably, EDF failed to consider public-service reliability obligations, in particular, Yankee's SOLR obligation. EDF failed to account for the deliverability constraints along the Algonquin mainline, which would have prevented the scheduling and delivery of any released capacity in Connecticut to the lion's share of direct connected generation in Massachusetts and Rhode Island. EDF did not recognize how Yankee relies on no-notice service as an operational hedge to ensure reliability. EDF failed to recognize that Algonquin cannot release unscheduled no-notice service entitlements to third parties regardless of Yankee's scheduling and use of such entitlements. Moreover, EDF praised without foundation the scheduling practices of other LDCs in New England with no generation portfolio. Upon close inspection, LAI found that other LDCs are also relying on reserved no-notice capacity to manage demand uncertainty, with the same effect that this capacity is not available to generators. To imply that it would be safe for LDCs to run their systems with smaller margins to guard against weather-induced load variations and other uncertainty factors is to place at risk the ability of LDCs to provide reliable and cost-effective service to firm customers.

EDF's lack of transparency coupled with the array of fatal analytic flaws and lack of understanding of industry fundamentals renders both the analysis and findings useless.

Appendix: Regression Equation Results

Table A1. Total and Yankee AGT Schedule Change Function of Actual or Forecasted EHDD

	(1) Total AGT Schedule Change	(2) Total AGT Schedule Change	(3) Yankee AGT Schedule Change	(4) Yankee AGT Schedule Change
BDL EHDD	1,363.47 ***		286.42 ***	
	(98.07)		(26.41)	
F12 BDL EHDD		1,235.16 ***		242.15 ***
		(105.82)		(28.90)
Constant	-102,992 ***	-99,453 ***	-23,757 ***	-22,347 ***
	(3,519)	(3,850)	(1,001)	(1,106)
Observations	454	435	454	435
R-squared	0.294	0.216	0.192	0.128

Robust standard errors in parentheses
*** p < 0.01, ** p < 0.05, * p < 0.1

Table A2. Yankee AGT Schedule Change Function of EHDD-based Demand Forecast Error

	(5.1) Yankee AGT Schedule Change		(5.2) Yankee AGT Schedule Change	
Demand Forecast Error	0.2093	***	0.2012	***
	(0.0237)		(0.0225)	
Demand Forecast			0.0407	***
			(0.0054)	
Saturday			-3,976.9	***
			(1,323.6)	
Sunday			-3,495.1	***
			(1,173.7)	
Term			919.5	**
			(392.6)	
Constant	-13,645.0	***	-21,933.5	***
	(383.9)		(1,194.8)	
Observations	432		432	
R-squared	0.162		0.295	

Robust standard errors in parentheses
*** p < 0.01, ** p < 0.05, * p < 0.1

Table A3. AGT-TEM3 Real Basis Function of Total AGT Schedule Change

	(6.1) Real Basis, AGT - TEM3		(6.2) Real Basis, AGT - TEM3		(6.3) Real Basis, AGT - TEM3	
Total AGT Schedule Change	3.87E-05	***	1.53E-06		2.71E-06	
	(7.62E-06)		(8.26E-06)		(8.33E-06)	
BDL EHDD			0.1722	***	0.1709	***
			(0.0250)		(0.0254)	
Saturday					1.7402	**
					(0.8817)	
Sunday					2.2943	**
					(0.9327)	
Holiday					2.2180	**
					(0.9676)	
Delivery Lead					-0.6000	**
					(0.2590)	
Term					-0.3556	
					(0.2275)	
Constant	6.7396	***	-1.2439		-0.3994	
	(0.5543)		(1.0291)		(0.9713)	
Observations	454		454		454	
R-squared	0.054		0.174		0.184	

Robust standard errors in parentheses
*** p < 0.01, ** p < 0.05, * p < 0.1