Final Report

Connecticut and New England Natural Gas and Power Infrastructure Supply Changes, 1999 – Present

Prepared for
Milford Power Company, LLC

July 28, 2010

R·W·BECK
An SAIC Company

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DISCLAIMER

Certain statements included in this Report constitute forward-looking statements. The achievement of certain results or other expectations contained in such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause actual results, performance or achievements described in the Report to be materially different from any future results, performance or achievements expressed or implied by such forward looking statements. We do not plan to issue any updates or revisions to the forward-looking statements if or when our expectations, or events, conditions or circumstances on which such statements are based, occur.

In preparing the Report, we have made certain assumptions with respect to conditions that may exist or events that may occur in the future. While we believe the use of these assumptions to be reasonable for the purposes of this Report, we offer no other assurances with respect thereto, and it should be anticipated that some future conditions might vary significantly from those assumed due to unanticipated events and circumstances. To the extent that future conditions differ from those assumed in the analysis, actual results and outcomes may vary from those projected. This Report summarizes our work up to the date of the Report; thus, changed conditions occurring or becoming known after such date could affect the material presented to the extent of such changes.

Section 1
EXECUTIVE SUMMARY

At the request of Milford Power. LLC ("Milford Power"), RW Beck has evaluated changes in the natural gas and electric markets and infrastructure since 1999, the year that Milford Power received its authorization from the Connecticut Siting Council.

Since 1999, the supply, delivery, and subsequently the reliability of natural gas as a fuel for power generation in Connecticut have all improved significantly.

Improving the supply availability, abundant new supplies of shale gas and a four-fold increase in LNG maximum available sendout capacity from three additional new regasification terminals have more than compensated for decreases in western Canadian, Canadian Atlantic, and offshore Gulf of Mexico gas supplies.

Furthermore, the locations of these new shale gas and LNG supplies near the New England market areas and at the eastern end of the west-to-east and south-to north major delivery paths for natural gas in North America, have relieved pipeline constraints, improving conditions for reliable delivery to New England.

Similarly, significant improvements have occurred in delivery infrastructure – gas storage and pipelines – in the northeast U.S., increasing the reliability and cost-effectiveness of transporting gas to Connecticut for power generation.

The Iroquois Pipeline, to which Milford Power is connected and upon which the facility is dependent, has undergone four expansions since 1999 that have added more than 500 MMcf/d to produce a current peak deliverability of 1.6 Bcf/d.

Even more significant is Iroquois' restructuring to provide for a long-term stable diversity of gas supplies. In the past, Iroquois was dependent upon Canadian supplies delivered by TransCanada Pipeline at Waddington, but since 2000, when Alliance Pipeline went in-service with 1.3 Bcf/d of capacity, contracted volumes on TransCanada to eastern Canada have been dropping. Iroquois is changing (through expansions and proposed extensions) from a unidirectional pipeline sourced primarily from Canadian supplies, to a regional bidirectional header system with significant supply attachment at both its north and south ends. This strategy has and will continue to make Iroquois a more reliable and flexible gas delivery source into Connecticut and for Milford Power.

On summer peak days, Milford Power should expect ample capacity on Iroquois and minimal probability for curtailment either of firm or interruptible capacity. Iroquois also has an excellent record of reliability of both interruptible and firm capacity under winter peak conditions. Even during the January, 2005 cold snap, Iroquois did not curtail either its firm or interruptible gas deliveries, although it did request hourly balancing at contract demand volumes. As a result, during that winter peak event, Milford Power's operations were not negatively impacted. Since 2005, the Iroquois system has been further improved for winter peaking events as the result of two expansions in 2008 and one in 2009 (see Table 2-5), including the addition of two compressor stations, reducing the probability of curtailment during the winter as well.

In the late 1990s, Southwest Connecticut (SWCT) bulk transmission system faced reliability problems due to transmission constraints within the geographic area and in the transmission ties to the rest of New England and New York. The reliability to the SWCT area was vulnerable because of inadequate local generation and transmission and failed to meet mandated transmission reliability standards. Also, SWCT was an inefficient and vulnerable portion of the New England transmission system that was isolated from the 345-kV transmission system and much of the available lower cost power generated from within the state and the surrounding region.

The effect of the increased transmission capacity placed in-service in 2006 and 2008 has dramatically changed the transmission and generation landscape in Southwest Connecticut, providing the area with a robust and reliable transmission system. The completion of the 345kV loop transmission has significantly reduced the impact of the loss of local generation or transmission on grid reliability. Southwest Connecticut is now an integrated part of the New England bulk electric transmission system and is capable of providing continued service to Connecticut electric customers following major outages of generation or transmission facilities in Connecticut.

Continued development of local generation in Connecticut has also resulted in additional reliability and grid stability for the bulk electric system. The SWCT area is no longer vulnerable to loss of supply because of the loss of local generation or transmission resources and is now in compliance with mandated NPCC and ISO-NE transmission reliability standards.

Section 2
NATURAL GAS SUPPLY AND INFRASTRUCTURE CHANGES

Overview

Since 1999, the supply, delivery, and subsequently the reliability of natural gas as a fuel for power generation in Connecticut have all improved significantly.

Improving the supply availability, abundant new supplies of shale gas and a four-fold increase in LNG maximum available sendout capacity from three additional new regasification terminals have offset the decreases in western Canadian, Canadian Atlantic, and offshore Gulf of Mexico gas supplies.

Furthermore, the locations of these new shale gas and LNG supplies near the New England market areas and at the eastern end of the west-to-east and south-to north major delivery paths for natural gas in North America, have improved pipeline constraints on a seasonal basis (monthly), generally improving conditions for reliable delivery to New England, on a monthly basis.

Similarly, significant improvements have occurred in delivery infrastructure – gas storage and pipelines – in the northeast U.S., increasing the reliability and cost-effectiveness of transporting gas to Connecticut for power generation.

The strategic location of new market-area storage tied to multiple interstate pipelines is highly significant for long-term reliable and cost-effective gas delivery to New England. Such storage provides a means of optimizing future liquids-rich shale gas production. It also optimizes LNG, which requires storage to accommodate spot cargoes.

The availability of pipeline capacity accessing a diversity of supply basins has also improved markedly. Between 1999 and 2009, approximately 40 gas pipeline projects that service the Northeast and New England markets have been completed. These include seven new pipelines (including Millennium and Rockies Express or REX), three extensions, and approximately 30 capacity expansions. Supplies are now so abundant that some pipelines are offering new backhaul services to Mid-Atlantic and southern delivery points, while others (Iroquois and Empire) are planning bi-directional deliveries to Canada.

Iroquois Pipeline, to which Milford is connected and upon which the facility is dependent, has undergone four expansions since 1999 that have added more than 500 MMcf/d to produce a current peak deliverability of 1.6 Bcf/d.

Even more significant is Iroquois' restructuring to provide for a long-term stable diversity of gas supplies. In the past, Iroquois was dependent upon Canadian supplies delivered by TransCanada Pipeline at Waddington, but since 2000, when Alliance

Pipeline went in-service with 1.3 Bcf/d of capacity, contracted volumes on TransCanada to eastern Canada have been dropping. Iroquois is changing (through expansions and proposed extensions) from a unidirectional pipeline sourced primarily from Canadian supplies, to a regional bidirectional header system with significant supply attachment at both its north and south ends. This strategy is making Iroquois a more reliable and flexible route for gas delivery into Connecticut. Attachment of incremental gas supplies at Iroquois' south end (Rockies, Appalachian, Mid-Atlantic Cove Point LNG) will promote efficient use of the pipeline through capacity displacements, multiple basis swaps and supply exchanges, all of which increase delivery reliability and potentially reduce rate stacking.

R. W. Beck evaluated the historical daily flow data on Iroquois pipeline and its interconnections with Algonquin, Tennessee, and Dominion pipelines and their flows with reported operating capacity (see Appendices A and B). On a few days, delivery point capacity at Brookfield and the estimated receipt point capacity at Wright were reached prior to 2005. Since 2005, only the daily receipt point flow at Brookfield reached its operating capacity (approximately 400 MMcf/d) during 2010.

Daily flows upstream of Algonquin at Lambertville (TETCO) and Centerville (Transco) and Mahwah (Tennessee) have not reached their operating capacity since 2004. After 2004, daily flows at the Mendon (Tennessee) interconnects have not reached its operating capacity after 2007.

R. W. Beck has also provided our forecast of flows along zones relevant to serving projected demand in Connecticut on Iroquois, Algonquin and Tennessee pipelines. GPCM's (a natural gas price forecasting model owned by RBAC, Inc and utilized by R. W. Beck for modeling/forecasting purposes) forecast of planned pipeline expansions indicate that all flow volumes needed to serve Connecticut demand do not exceed operational capacity over the next 10 years. However, Algonquin, Connecticut, and Tennessee Zone 6 Connecticut projected capacity is within 200 MMcf/d and 25 MMcf/d of operational capacity, respectively. After approximately 2020, Tennessee Zone 6 Connecticut reaches operational capacity. However, with shippers' requests, Tennessee would expand capacity on this pipeline segment. Shippers would also have alternatives to bring incremental gas supply that would utilize the surplus capacity on Iroquois Zone 2.

The historical daily flow data show that gas demand in Connecticut was generally served without reaching operating capacity along relevant pipeline zones and at supply and delivery points. On approximately 10 days over the 1999 to 2010 period, daily flows reached operating capacity for delivering gas to Connecticut. The level of any daily or hourly curtailment, including the number of consecutive hours, during those 10 days would require information from the transporters. Iroquois has stated that its system has experienced only two instances of force majeure since 2000, the most recent on January 29, 2010. On that day, an outage at the Brookfield Transfer Compressor Station necessitated a cut in firm deliveries of 117,000 Dth out of a 1,500,000 Dth design receipt capacity (8%). Historical daily pipeline delivery capacity to Connecticut has generally accommodated changes in attachment of incremental supply and in demand growth.

Based on planned pipeline expansions that serve Connecticut, and the results of R. W. Beck's North America gas market modeling, pipeline capacity should satisfy projected gas demand for the forecast period through 2032.

Natural Gas Supply and Infrastructure

This section discusses the adequacy of natural gas supplies and delivery infrastructure to New England in general and to Connecticut specifically. It will focus on changes in these factors as well as in gas demand since 1999. The objective of the gas delivery assessment is to evaluate the comparative availability and reliability of current natural gas supply and delivery compared to 1999.

The gas supply discussion will include the development of unconventional new gas resources from shales, tight sands, and coal beds that have been drilled using specialized drilling and completion technology and brought to market in far larger volumes than most industry analysts expected in 1999. The result of these abundant new sources, including significant volumes favorably situated with respect to major markets such as the Northeast U.S., Middle Atlantic states, and Texas-Louisiana, has significantly reduced the long-run marginal cost for incremental production and made natural gas relatively inexpensive compared to oil products.. The discussion of new supply will include the history of major changes since 1999, specifically:

- Unconventional gas supply
- New LNG facilities
- The relative prices of oil and gas

Similarly, gas delivery infrastructure has been developed and is expected to continue to be developed to bring the mass of new gas supply to market. These changes in gas infrastructure were not envisioned in 1999. The discussion of natural gas infrastructure will include the history of major changes since 1999, specifically:

- New pipelines;
- New capacity on existing pipelines (expansions);
- Extensions of existing pipelines;
- New storage fields; and
- New LNG facilities.

Then, using R. W Beck's 2nd Q 2010 Base Case Natural Gas Forecast (using the GPCM® model), we will forecast changes in natural gas supply and gas infrastructure in the future (2010 – 2032).

Finally, focusing on the primary interstate pipeline delivering gas to Milford and adjacent power plants, we will address the likelihood of widespread natural gas delivery interruptions on the Iroquois pipeline, and the potential for curtailment of gas delivery to Milford due to gas supply or delivery constraints.

Natural Gas Supply

Between 1999 and 2008, there has been a significant change in the types, sourcing and attachment of gas supply for existing and incremental gas-fired capacity. The indigenous U.S. gas supply mix for the domestic market changed as shown below in Table 2-1 and on Figure 2-1.

Table 2-1. Percentage Change in Supplies Between 1999 and 2008

Supply Category	Percentage Change
Offshore	-50
Onshore	17
CBM	43
Shale gas	367

Source: EIA. CBM means Coal Bed Methane

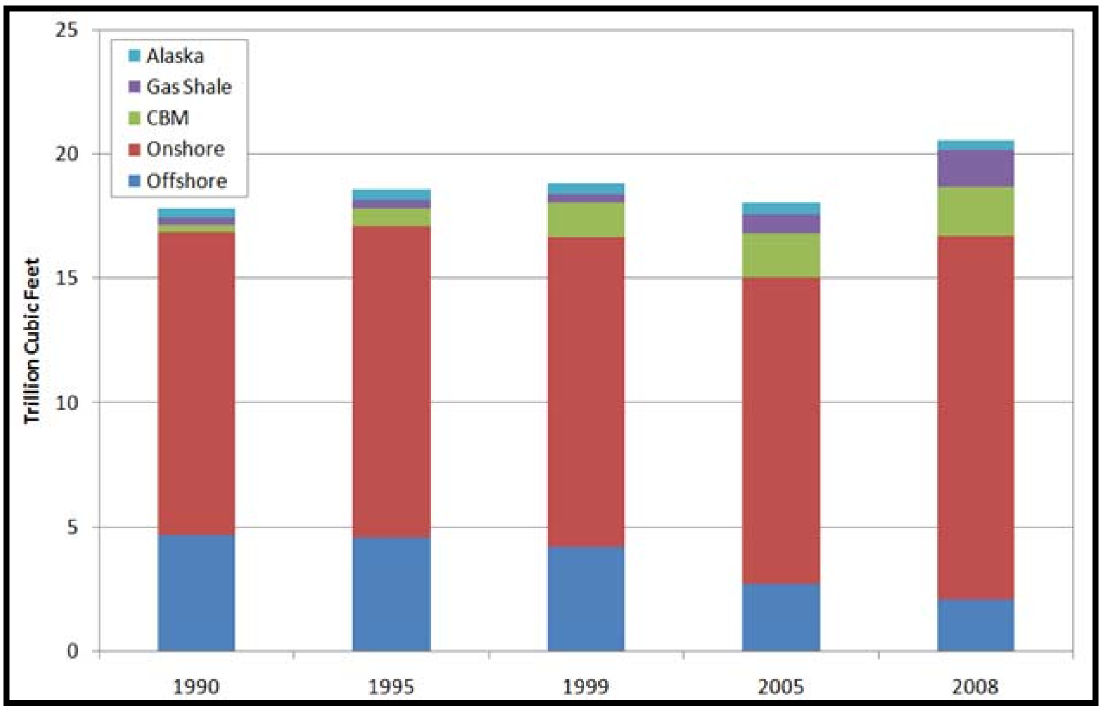

Figure 2-1. U.S. Historical Supplies from 1990 to 2008
(Source: EIA)

In 1999, the industry regarded imported LNG as the key factor in filling in the supply shortages from declining conventional production in the Gulf of Mexico and from recent and expected declines in Canadian conventional gas supplies exported to the U.S. The expectation was that in the coming decades (2000 and beyond), the U.S. would become more dependent upon international sources of natural gas beyond North America.

Indeed, Canadian exports have declined, by approximately 15% from 2007 to 2009. They represented approximately 18% of U.S. demand in 1999 and 14% of total U.S. demand in 2009. These imports are projected to decrease by 80% from 2009 (9,000 MMcf/d) to 2025 (1,750 MMcf/d). They are projected to be replaced by indigenous unconventional gas and by LNG imports.

Between 1999 and 2010, total U.S. LNG imports increased by approximately 200%, with supplies largely from Trinidad and Egypt. Total LNG imports are projected to increase approximately 50% by 2020 with approximately 9 to 10 Bcf/d of incremental liquefaction capacity. LNG is an infra-marginal supply, a price taker, and generally a market of last resort for U.S. deliveries. (LNG in New England and North America generally is discussed in a separate section of this report.)

The high Henry Hub prices for natural gas during 2000 – 2005, and 2008 sent a strong signal to the gas production industry to find more indigenous gas supplies as close as possible to major markets since 2008. The high prices for crude oil reinforced the economics of developing liquids- and Btu-rich shale gas within the condensate and oil maturation window (e.g., Barnett, Marcellus, Hainesville, Eagleford, and Bakken reservoirs).

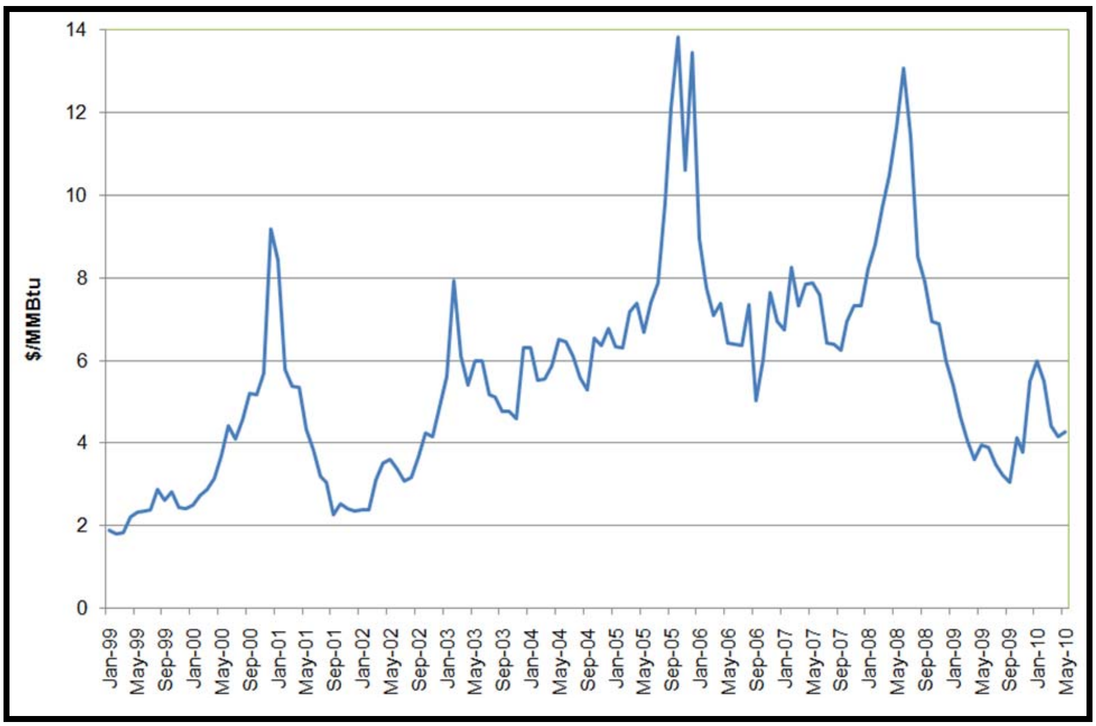

Figure 2-2. Henry Hub Prices 1999-2010 (Nominal $/MMBtu)
(Source: EIA)

These price signals (see Figure 2-2) for both natural gas and oil throughout the decade (1999 through mid-2009) and the resulting development of new drilling technology for unconventional gas reversed the previous expectations that it would be LNG that would provide the replacement supplies for declines in other supply sources. The resulting increase in unconventional gas production in the U.S. has now spearheaded similar exploration for natural gas in shales world-wide. U.S. 2009 production, chiefly incremental unconventional gas, allowed the U.S. to record the world's largest increase in production for the third consecutive year, surpassing Russia as the world's largest gas producer.

Figure 2-3 shows the projection of natural gas supplies in the 2010 EIA Annual Energy Outlook Figure 2-4 shows the projection of major gas supply sources to North America in R. W. Beck's 2nd Quarter 2010 long-term forecast.

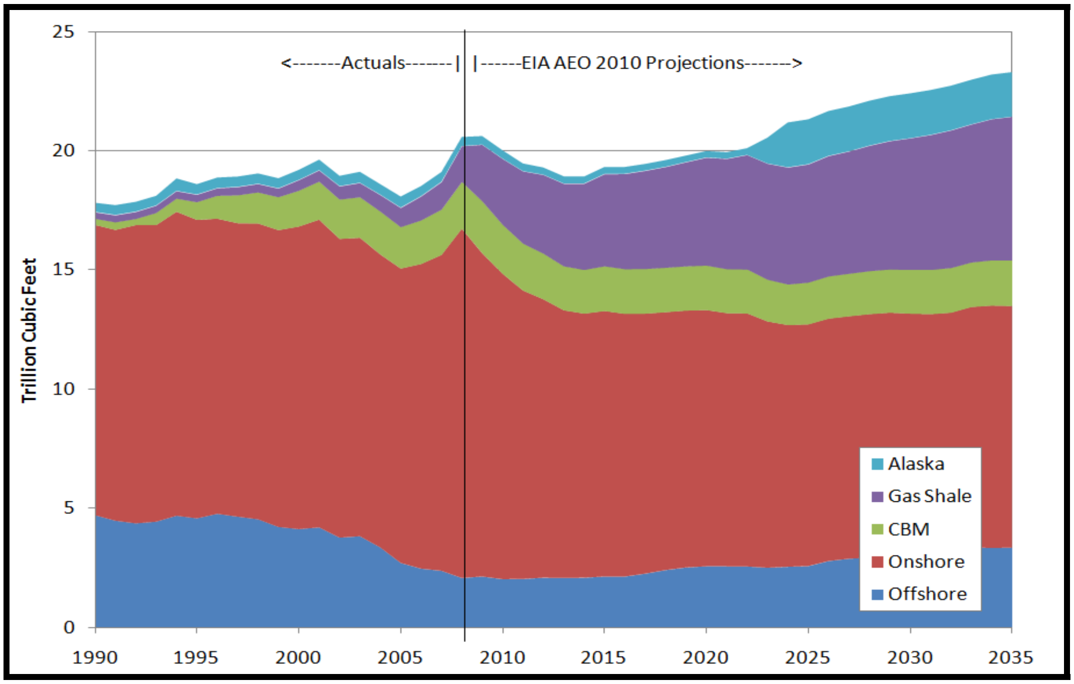

Figure 2-3. Gas Supply Forecast, EIA Annual Energy Outlook, 2010

Unconventional gas has three main sources, all having low permeability: tight sandstone, shale, and coal. Tight sandstone contains gas in porosity while shale and coal typically absorb gas on fractures. All three rock types contain source gas that has not migrated to a host reservoir. They therefore need artificial fracturing to develop commercial flow rates. Tight sandstone currently provides approximately 65% of total unconventional production, with shale and coal providing approximately 20% and 15%, respectively.

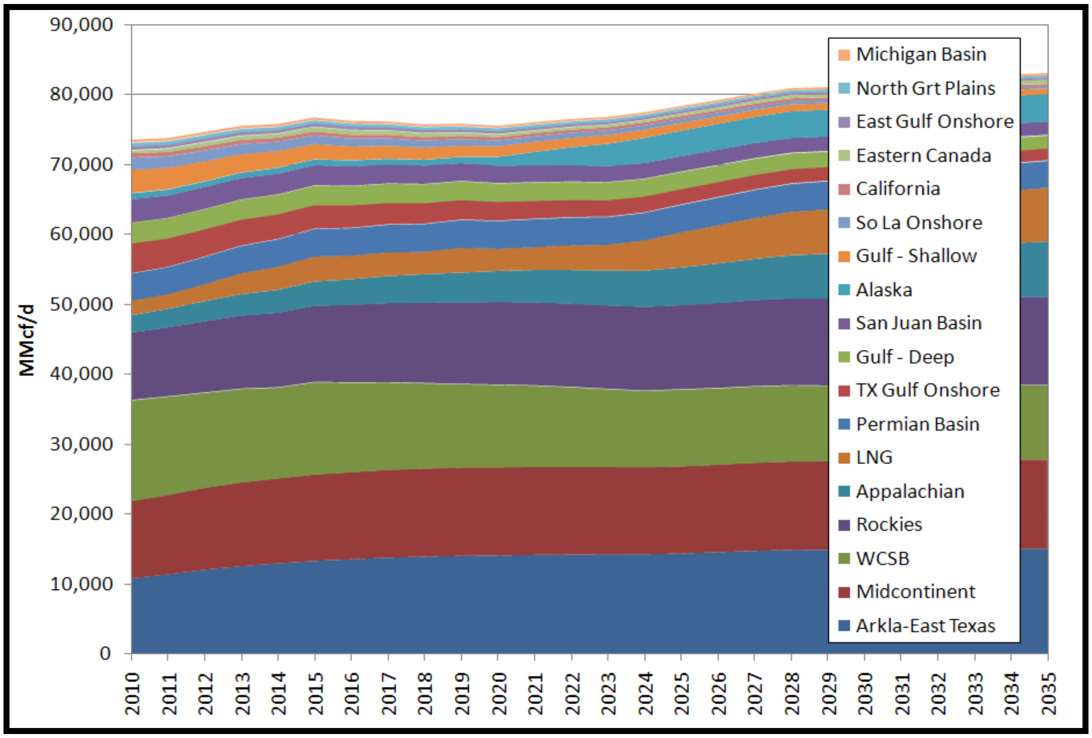

Figure 2-4. Natural Gas Supply Sources for U.S. and Canada
(R. W. Beck Q2 2010 Forecast)

Shale gas is projected to displace incremental tight sandstone production, increasing 2.0x (from 12,000 MMcf/d to 25,000 MMcf/d) by 2020 and 2.5x by 2030 (see Figure 2-5). Shale gas is projected to provide 30 percent to 50 percent of total unconventional gas production by 2020, equivalent to 40 percent to 60 percent of the total U.S. gas demand. Its proved reserve to annual production (R/P) ratio has increased from 7 to 8 in 2006 to 14 to 15 in 2010.

Shale gas will influence the Henry Hub gas prices and will therefore influence the level of gas displacement of coal. This displacement will be greatest in all Appalachian coal regions that are near liquids-rich shale resource plays:

- Southern Appalachian (SAPP) (vs. Haynesville, Barnett and Eagleford)
- Central Appalachian (CAPP) (vs. Chattanooga, Ohio-Rhinestreet and New Albany)
- Northern Appalachian (NAPP) (Marcellus, Huron and Utica)

These liquid-rich shale resources have going-forward costs (drilling and development only) of \$1.50-\$3.00/MMBtu. They have all-in long-run marginal costs (LRMC) of \$3.50 to \$6.00/MMBtu (\$ 2009). These prices generally allow gas to displace coal in the Appalachian power markets. They also allow displacement in the Southeast markets when the Henry Hub price is lower than \$5.00/MMBtu (2009\$), and the FOB Appalachian coal price to Henry Hub price ratio is less than 5:1.

The projection of LRMC, annual production and R/P ratio all indicate that shale gas should be the marginal supply of indigenous pipeline gas in U.S. and in Canada, with sufficient investment in gas infrastructure, especially processing and storage. Shale gas should have the marginal costs that establish the level of coal displacement in the Appalachian and Southeast power markets. It will also put downward price pressure on and reduce volatility of Henry Hub gas. It will also then set the price for spot and contract LNG imports linked to Henry Hub gas index as a price taker for its infra-marginal supply. Figure 2-6 shows the sources of the growing supplies of North American shale gas.

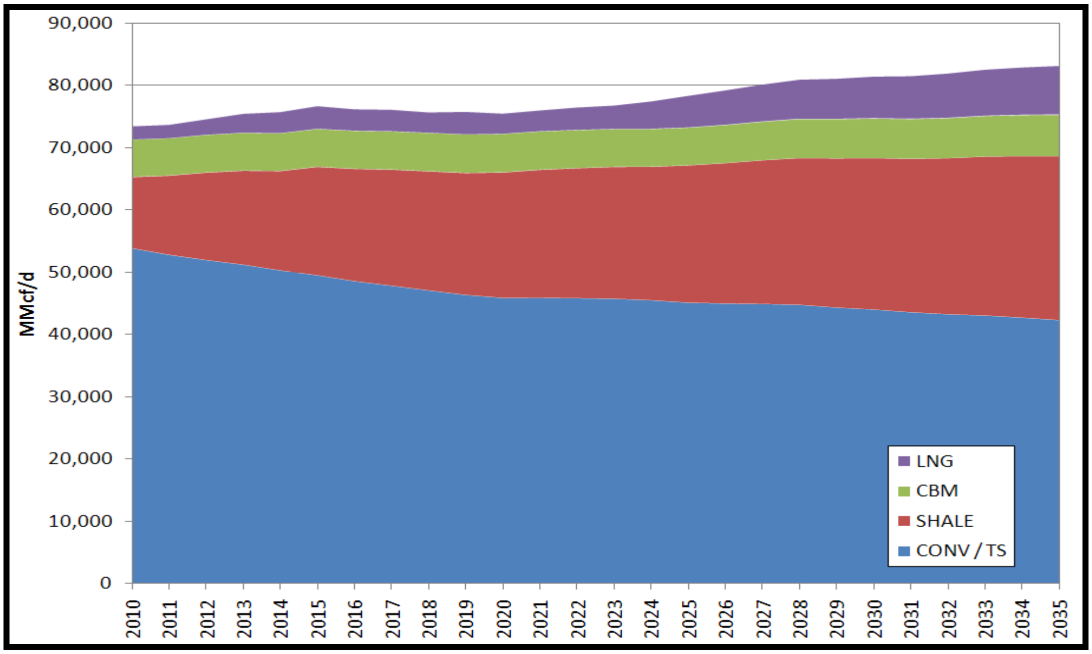

Figure 2-5. North America Natural Gas Supply Types
(R. W. Beck Q2 2010 Forecast)
(LNG=Liquefied Natural Gas; CBM=coal bed methane; Conv/TS = conventional/tight sands)

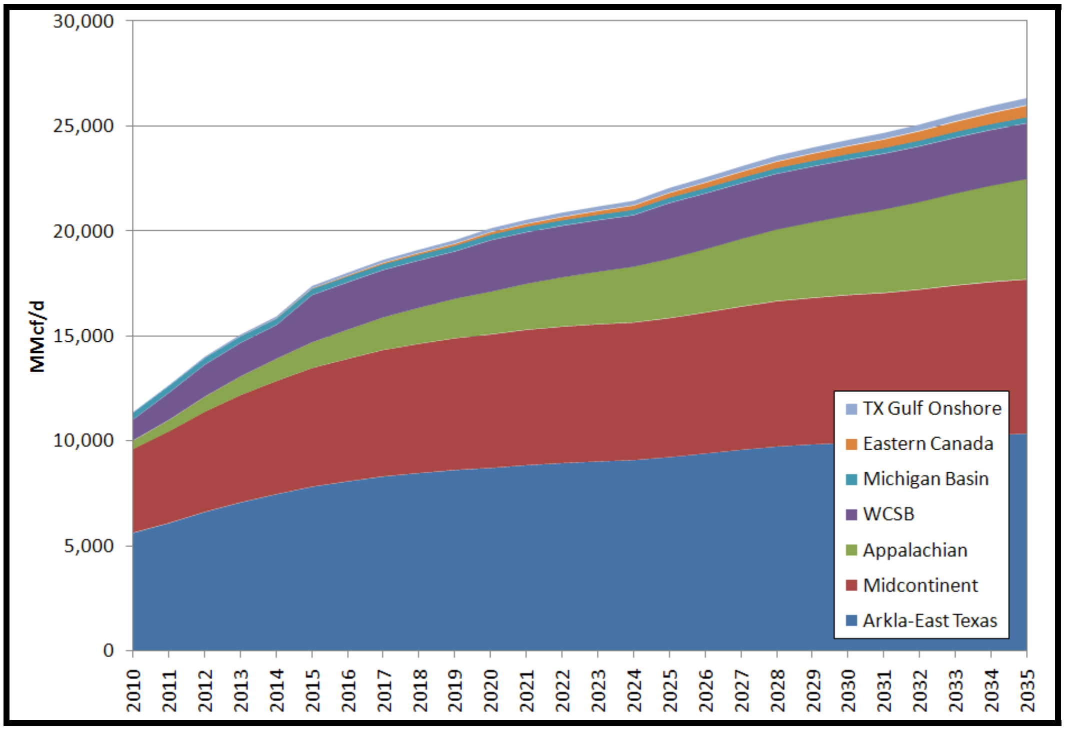

Figure 2-6. Major North America Shale Gas Production
(R. W. Beck Q2 2010 Forecast)

The growth rate of incremental production (unconventional and conventional) is largely controlled by the value of associated petroleum liquids (oil, condensate, NGLs), in other words by the price of crude oil. It is also controlled by their gathering, processing, and storage capacity, as well as distance to market trading hubs.

Most (50-100 percent) of this new North American incremental production is hedged in advance to cover the large-scale statistically-driven investment, at prices approximately 125 percent to 165 percent of Long Run Marginal Costs.

Hedge prices reported during 2009 for shale gas development:

- For 2009: $8.00-$9.50/MMBtu
- For 2010: $7.00-$7.50/MMBtu
- For 2011: $6.00-$6.50/MMBtu

Serious challenges to the development of shale gas production include:

- Water supply and water disposal for advanced fracturing completion technology; fast developing environmental requirements for permitting will slow development, restrict land access and add costs for all shale gas production[1] as well as increase the tax burden.
- Steep topography in the Appalachians including steep valleys and ridges in the region, requiring equipment customized to local road condition.

[1] The primary concerns include: risk of shallow freshwater aquifer contamination, with fracture fluids; risk of surface water contamination; risk of excessive demand on local water supply (The Future of Natural Gas: An Interim MIT Study, Interim Report, June, 2010.)

- Scarcity of pipeline takeaway capacity including gas gathering and laterals to interstate pipelines
- Legal barriers relating to overlapping significant coal reserves and to water development interests

While all the new supplies of natural gas in North America ultimately benefit the Northeast U.S. Region (by displacement, exchange, or direct delivery), the Marcellus Shale (New York, Pennsylvania and West Virginia) is of particular importance to New England and Connecticut (Figures 2-7 and 2-8). Its specific significance for supply abundance and reliability derives from its geographic position directly upstream of that region, and its planned connection to new pipeline capacity to be built specifically to service the Northeast U.S. market. It is also significant as an eastern replacement supply for declining Canadian supplies needed in Canada, to replace coal-fired capacity in Ontario with natural gas fired resources and to provide thermal recovery of tar sands in Alberta.

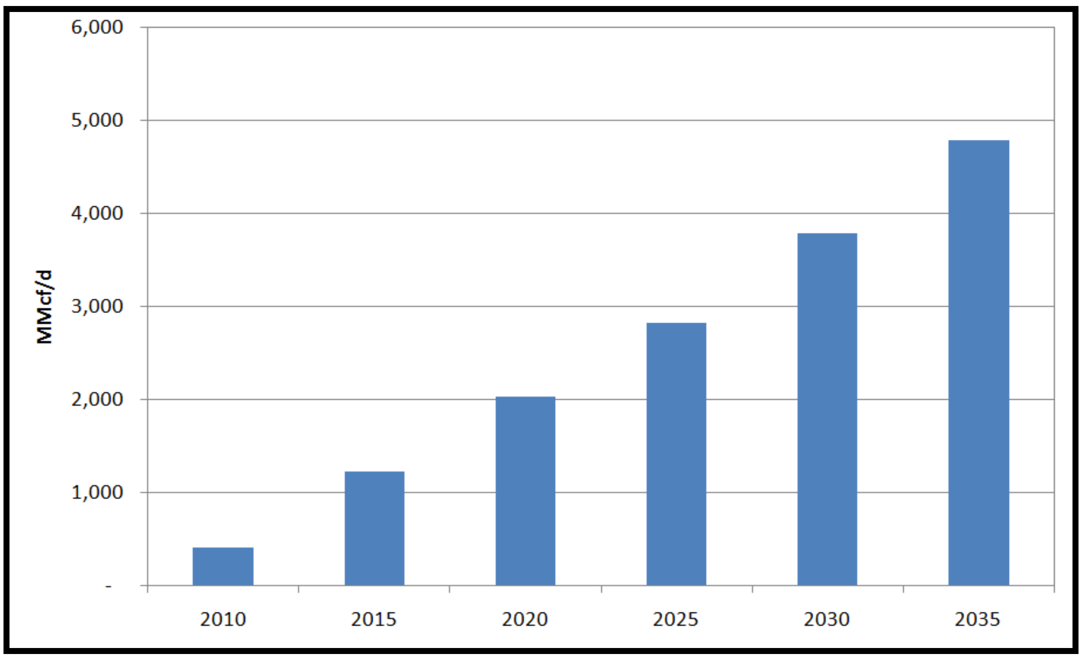

Figure 2-7. Forecasted Marcellus Shale Gas
(Source: R. W. Beck Q2 2010)

Figure 2-8. Marcellus Shale Map
(Source: Unconventional Gas Hart Publications)

Modern exploration of the Marcellus Shale dates from 2003 when Range Resources, a leading player in the Barnett Shale in the Fort Worth Basin in Texas, drilled its first Marcellus well in Washington County, Pennsylvania, applying completion techniques developed in Texas.

Five years later, in 2008, preliminary reserve estimates for the Marcellus Shale were published by Engelder and Lash (2008) and discussed in Wells and Gognat (2009)[2.]. Gas in place is estimated at 168 Probable and 516 Tcf Possible assuming 10% recovery, giving rise to an estimate of 50 Tcf of technically recoverable natural gas. If so, Marcellus is a giant field.

Such preliminary estimates early in the development of Marcellus are valuable primary as a benchmark for improved estimates as drilling and production results become public. At this stage, reserve estimates in the Marcellus Shale are hampered by challenges to estimating and extending gas in place, recovery factors, and other characteristics that are highly variable in the Marcellus reservoirs. The highly competitive and confidential nature of the play increases the difficulty of obtaining reliable estimates.

2 Richard B. Wells and Timothy A. Gognat, The Marcellus Marches Out, July 2009, Marcellus Play Book, Hart Publications

Nonetheless, there is no doubt that the Marcellus is a highly significant development in the history of North American gas industry. Evidence of its international significance is the entrance of Norwegian national oil company StatoilHydro in November 2008. Statoil signed a major agreement for Marcellus drilling and development with Chesapeake Energy, including in the Otten #2H well targeting the Marcellus at 7,500 feet in northern Pennsylvania, which spudded in February 2009.

Additional evidence is the trend in lease prices for landowners, which have risen from a reported $100/acre before the rush, doubling by 2007, and rising to a reported $2,000/acre in 2009 (Wells and Gognat, 2009). In 2007, with Henry Hub prices averaging $6.95/MMBtu due to the nearness to lucrative Eastern markets for gas, the average realized price for Marcellus production was $9.30, resulting in an estimated internal rate of return of 86%. Comparisons at that time estimated for exploration in other shale gas plays include:

- Marcellus: 86%
- Barnett core area: 69%
- Haynesville/Bossier: 69%
- Fayetteville: 47%
- Woodford (Arkoma basin): 33%
- Huron (Appalachian basin): 45%

Marcellus participant XTO has reported that, at $5.00/MMBtu gas price, the Marcellus returned 70%, Barnett core 47%, Haynesville and Fayetteville 36%, and Woodford shale 32%. Such a favorable comparison for Marcellus at this stage provides a level of confidence that its development will be among the leaders in the industry for the foreseeable future.

LNG in New England

Another significant factor in improving the diversity and abundance of natural gas supplies to Connecticut since 1999 is the much improved regional access to imported LNG. LNG (including non-imported LNG derived from pipeline gas) supplies nearly 30% of daily peak winter supply for New England gas utilities and in 2007 provided 20% of the region’s total gas supply (Northeast Gas Association).

Since 1999, the maximum available sendout per day of imported LNG at New England region terminals has quadrupled with the addition of three new facilities (Table 2-2, Figure 2-9, and Figure 2-10). These supplies, situated at the northeastern margin of the North American natural gas system, are well positioned to optimize the available conventional pipeline capacity, which primarily delivers gas from southern and western sources (Western Canada, the Gulf Coast, and the Rockies). They thus alleviate pipeline constraints while also adding diversity and robustness to the supply mix.

Table 2-2. LNG Capacity, Northeast U.S Region

Facility	Owner/Operator	Sendout (Bcf/d)	In-Service	Location
Everett	GDF-Suez Distrigas	0.715[3]	1971	Everett, Massachusetts
Northeast Gateway	Excelerate Energy	0.4	2008	Massachusetts Bay
Canaport	Repsol, Irving Oil	1.0	2009	St. John, New Brunswick
Neptune	GDF Suez	0.750	2010	SE of Gloucester, Massachusetts
Total		2.865		

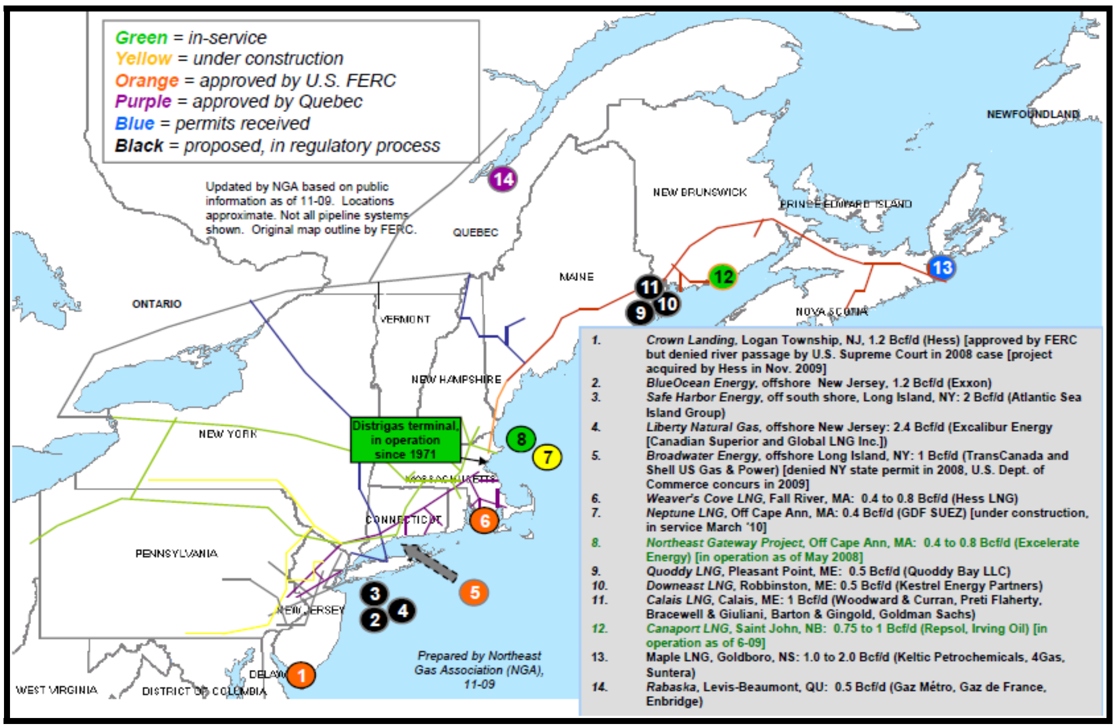

Figure 2-9. Existing and Proposed LNG Import Facilities, Northeast
(Source: Northeast Gas Association)

[3] Sustainable daily throughput

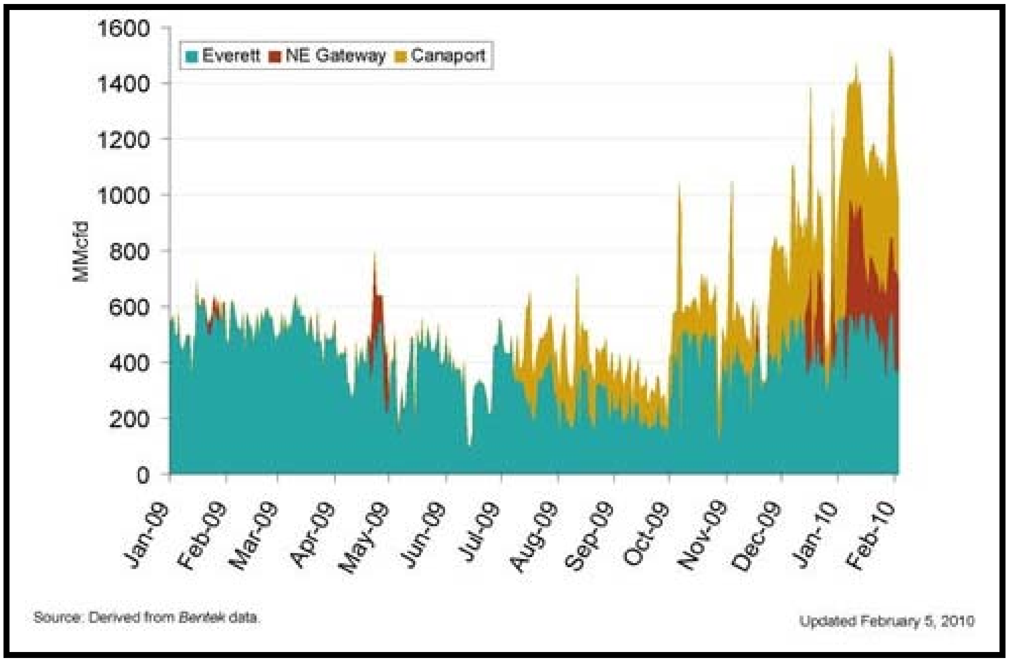

Figure 2-10. Sendout from New England LNG Terminals
(Source: Northeast Gas Association)

LNG – North America

Historical Imports

Since 2000, the level of LNG imports has ranged from approximately 620 to 2,110 MMcf/d. The 2009 level was approximately 1,240 MMcf/d; or 2.0% of total U.S. demand (see Figure 2-11).

Forecasted Imports

In R. W. Beck’s 2nd Q Base Case forecast, the level of imports projected for 2010 are equivalent to the average level over the last five years (approximately 1.5 Bcf/d). Over the next eight to ten years, the volume of imported LNG is projected to increase from 1.2 Bcf/d to 3 Bcf/d, equivalent to 3% to 5% of total domestic demand. Between 2010 and 2025, the level of LNG imports doubles to approximately 4 Bcf/d or approximately 6.5% of total demand, and then gradually increases to approximately 7 Bcf/d or 11% of total demand (see Figure 2-12).

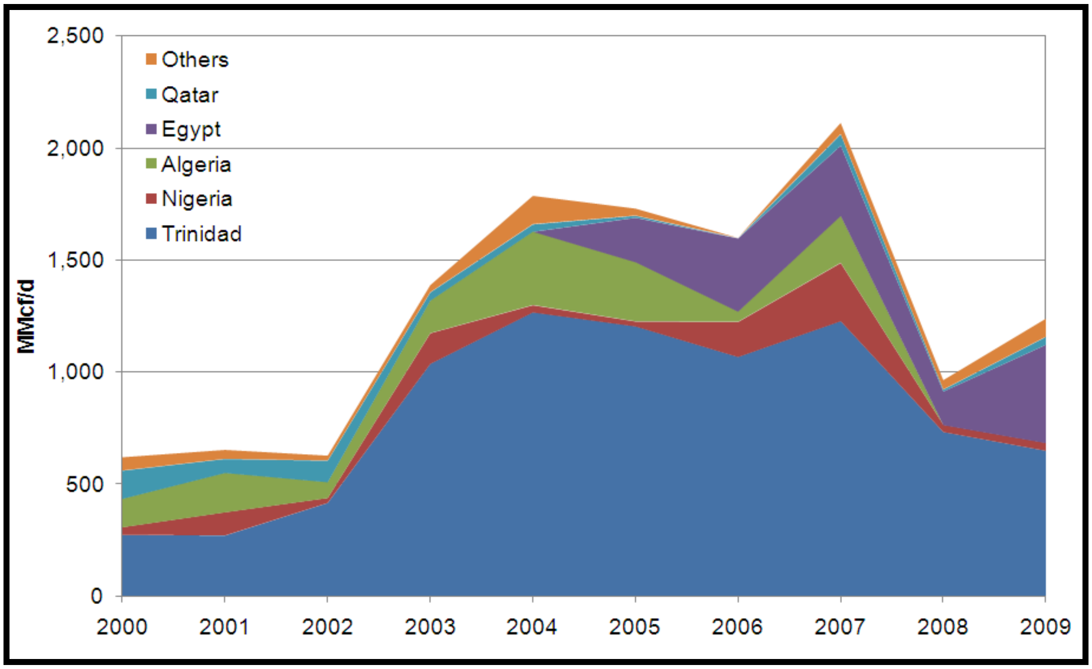

Figure 2-11. Historical LNG Imports
(Source: R. W. Beck Q2 2010)

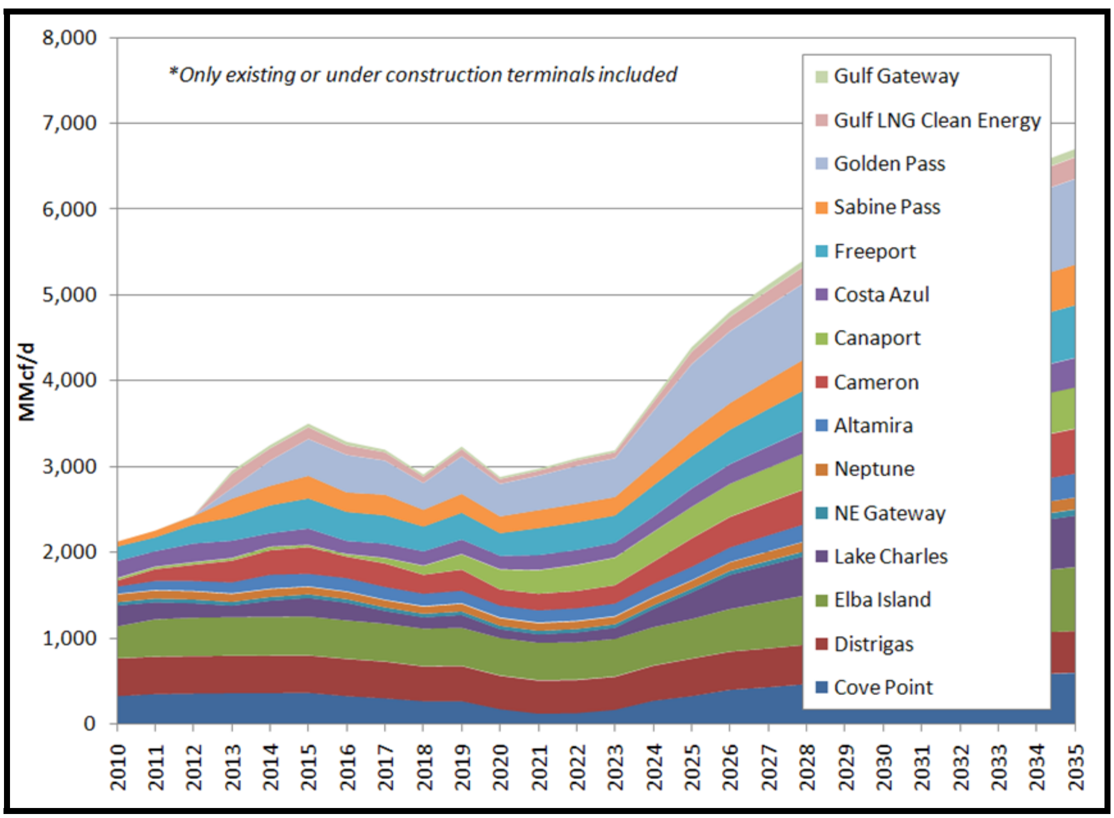

Figure 2-12. Projected LNG Imports by Terminal
(R. W. Beck Q2 2010 Base Case Forecast)

LNG imports provide for the decline in Canadian pipeline imports and for incremental demand not satisfied by relatively steady production of pipeline gas from indigenous sources. These consist largely of incremental production from unconventional shale reservoirs.

Undedicated liquefaction capacity from Qatar, Yemen, Russia, Timor, Indonesia and other export countries will be available over the next five years. In addition, more pipeline gas will flow into Europe, reducing their need to LNG supply diversity. The U.S. could increase its level of the "last-resort market" and its discounted price relative to Henry Hub gas for "dumped" LNG cargoes, especially with conventional gas storage.

LNG is therefore an infra-marginal supply and is projected to take the price established by indigenous pipeline gas. In addition, spot cargoes "dumped" into the U.S. market over the last two years have suffered an average discount of approximately $0.70/MMBtu or 15% to a basis-adjusted Henry Hub price. This discount is equivalent to the cost for conventional low-cycle gas storage.

Supply Sources to Connecticut

Figures 2-13 and 2-14 show R. W. Beck's forecast of supply sources to Connecticut and New England, showing the projected growing importance of Appalachian (shale gas) supplies and of LNG.

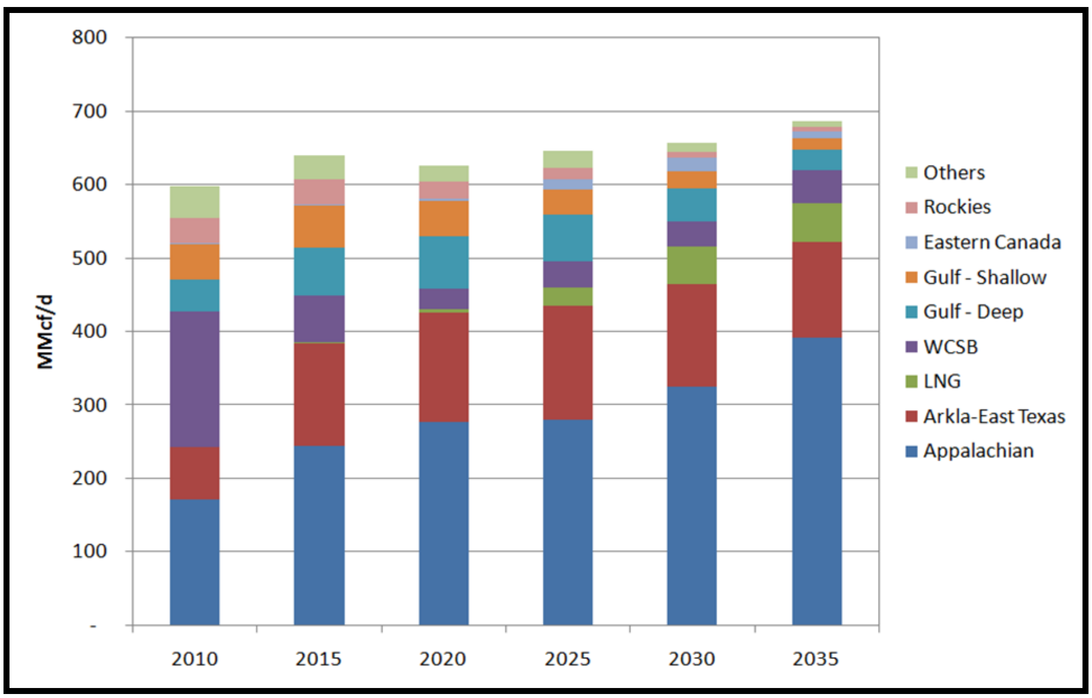

Figure 2-13. Supply Sources to Connecticut
(Source: R. W. Beck Q2 2010)

Appalachian and Arkla-East Texas supply delivered to Connecticut is forecast to increase by approximately 75% between 2010 and 2020, largely due to shale gas production, including Marcellus, Fayetteville, and Woodford. Shale gas production in the Southeast region, including Barnett, Haynesville and liquids-rich shales such as Granite Wash and Eagleford are responsible in part for the approximate 30% increase to Connecticut in GOM supply. These new sources of unconventional gas largely offset the 85% decline by Western Canadian sedimentary basin and the 30% decline in Rockies gas between 2010 and 2020.

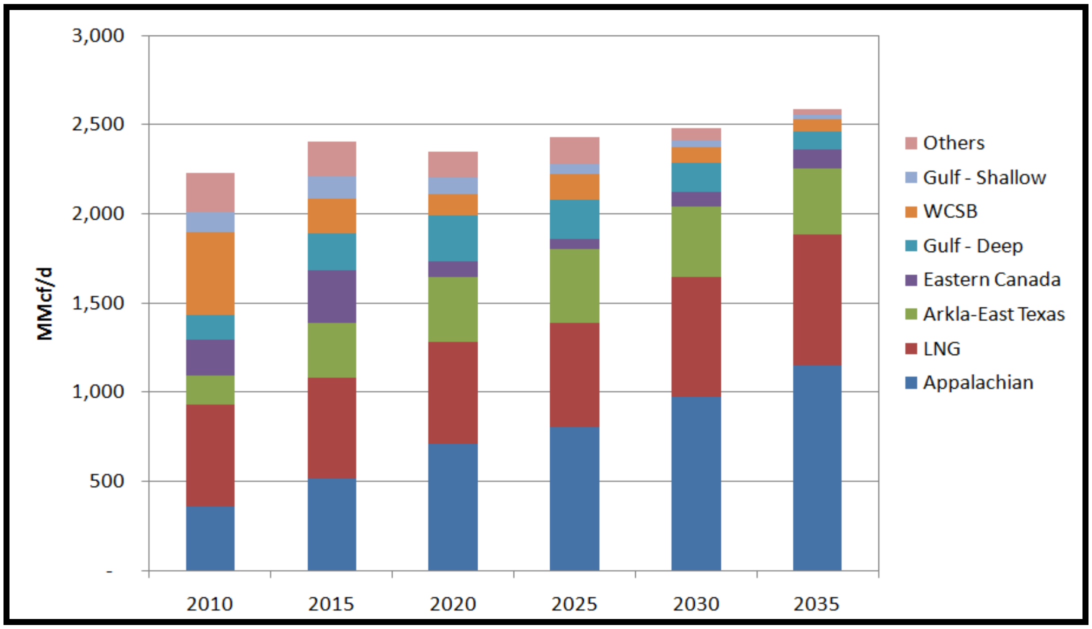

Figure 2-14. Supply Sources to New England
(Source: R. W. Beck Q2 2010)

Fuel Demand

Incremental gas demand in the Northeast U.S. (includes Mid-Atlantic and New England) is projected to be satisfied by incremental supply. However, the source of this additional supply is changing.

Figures 2-15 and 2-16 below show that the fuel mix for Connecticut power generation has changed significantly from 1999 to 2008 (the last year for which these data are available).

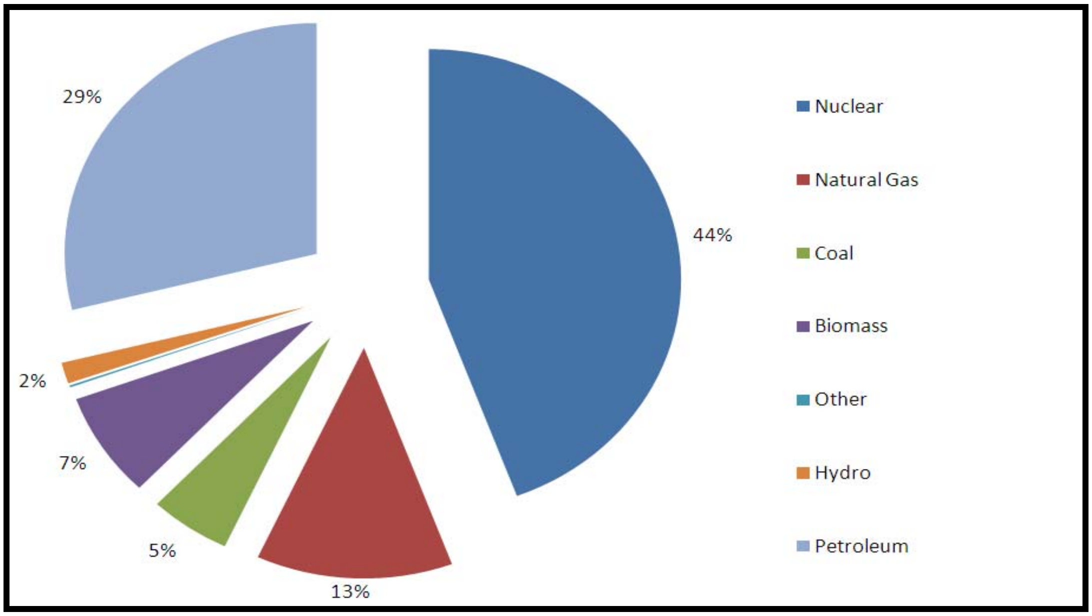

Figure 2-15. Connecticut Net Generation by Fuel (MWh): 1999
(Source: EIA)

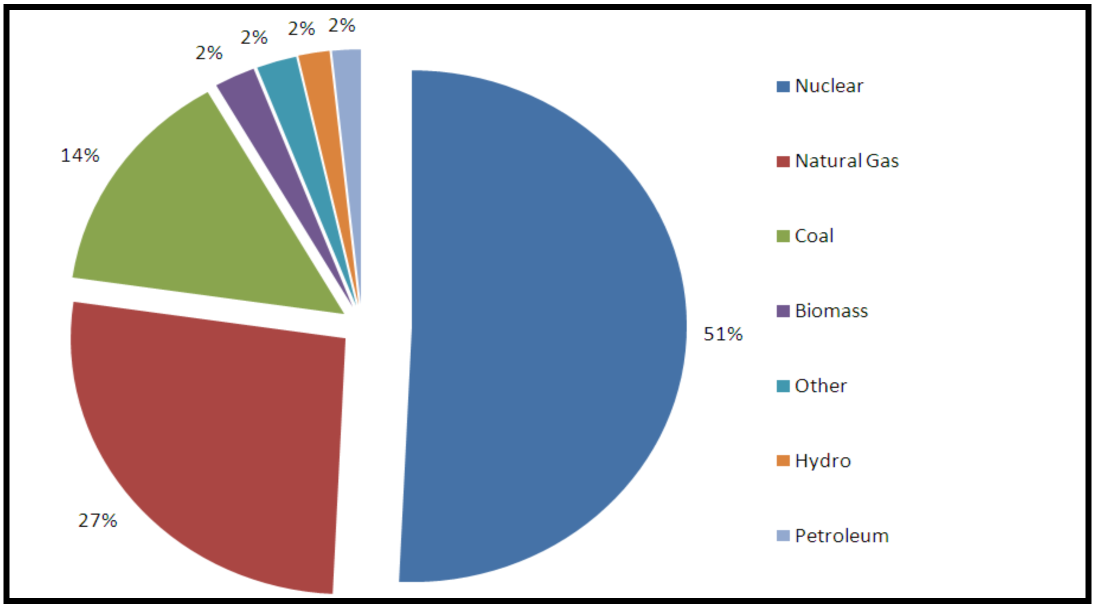

Figure 2-16. Connecticut Net Generation by Fuel (MWh): 2008
(Source: EIA)

Table 2-3. Change in Fuel Demand for Power Generation in Connecticut

Fuel Category	1999 %	2008 %	% Change
Nuclear	44	51	7
Petroleum	29	2	-27
Natural Gas	13	27	14
Coal	5	14	9
Biomass	7	2	-5
Hydro	2	2	0
Other	0	2	2
Total	100	100	0

(Source: EIA)

Demand for petroleum fuels has decreased significantly (27%) and for natural gas has increased significantly (14%) (see Table 2-3). (As has been explained in the Supply section, increased gas supplies, primarily from unconventional gas and LNG, during the same time frame more than accommodated the increase in demand). During 2009, Connecticut used approximately 1% of total U.S. demand (see Figures 2-17 and 2-18). Note that monthly gas demand has a greater seasonal swing (approximately 2.0x) than for the total U.S. demand (approximately 1.7x). Connecticut's maximum monthly swing volume since 2001 has been approximately 3,500-6,000 MMcf/mo (117 to 200 MMcf/d). Demand increase generally occurred between November and December (five years out of last nine years), but less often between December and January (three years out of last nine years). The same range (117 to 200 MMcf/d) load decrease generally occurred between March and April (six years out of the last nine years) and less often between April and May (two years out of the last nine years).

Incremental pipeline capacity and supply attachment since 2001, and especially since 2008, accommodated the increase in average monthly demand during the peak months (Nov-Dec-Jan). This fuel usage pattern is the result of both market price and emission reductions.

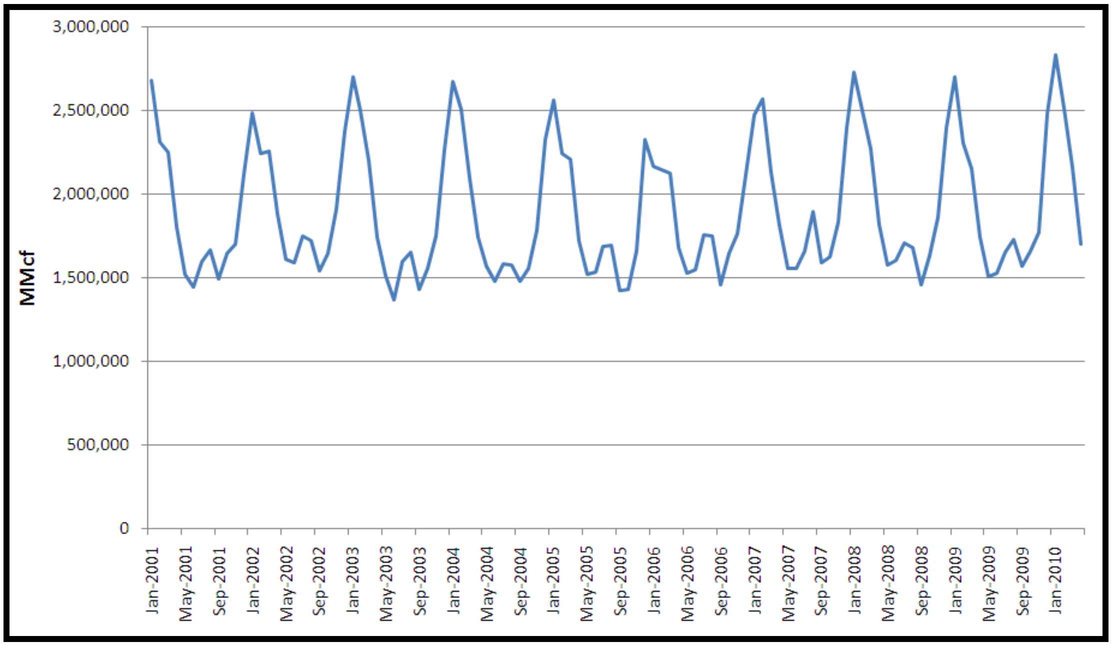

Figure 2-17. U.S. Natural Gas Total Consumption
(Source: EIA)

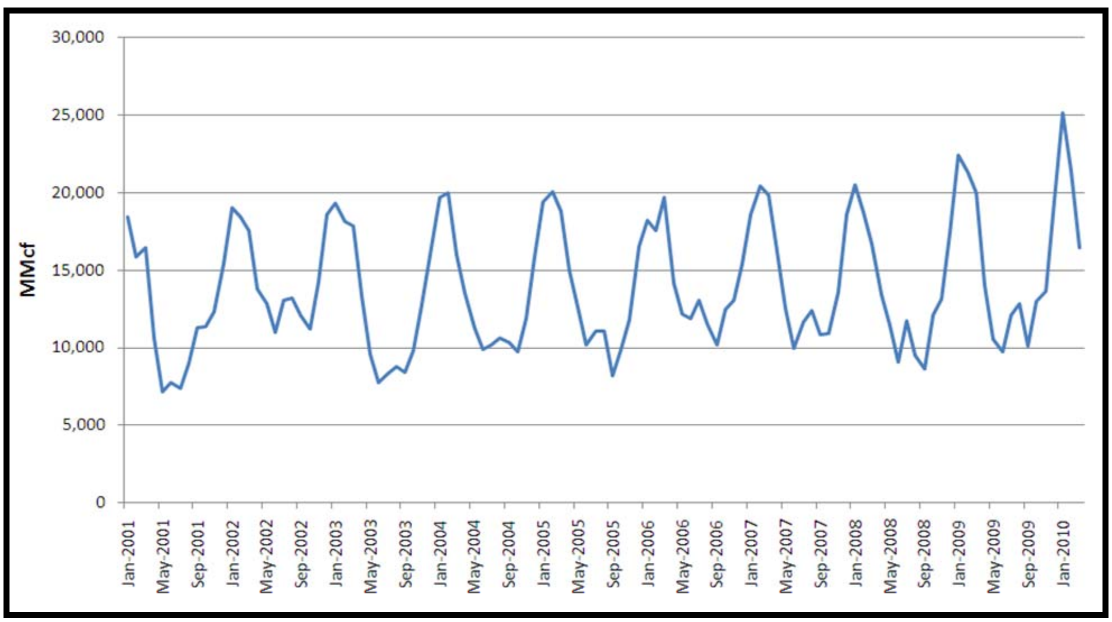

Figure 2-18. Natural Gas Delivered to Consumers in Connecticut (Including Vehicle Fuel) (Approximately 98% of Total CT Natural Gas Consumption)
(Source: EIA)

Fuel Switching

Historically, approximately 25% of New England power generation had dual capacity to switch to fuel oil (No. 6 residual and No. 2 distillate). New England fuel oil prices generally follow N.Y. Harbor fuel oil prices (+/-$1.00/MMBtu).

Since 2006, the relatively high price of No.2 oil has generally precluded economic switching between it and natural gas. Since 2007, the relatively high price of No.6 oil has similarly precluded economic switching with gas. In the case of future gas supply shortage or pipeline capacity curtailment, approximately 2418 MW of existing New England plants (with fuel oil as their primary fuel) would have the capability of oil-fired generation if they had been using natural gas (see Table 2-4) (approximately 10 MW of No. 2 fuel from Gas/Oil Internal Combustion and 2408 MW from No. 6 fuel oil from Gas/Oil Steam generation).

Table 2-4.New England Oil-Fired Capacity (from 2010 CELT Report)

New England Oil-Fired Capacity
(With Fuel Oil as Primary Fuel)
Source: 2010 CELT Report

Fuel Type	No. of Assets	Gen Type	Total MW As of 2009/2010 Winter Peak Winter	Summer
No. 2				
- Gas Alternative Fuel	1	Gas/Oil Internal Combustion	9.495	10.24
- Oil Combustion Terminal	25	Oil Combustion (Gas) Turbine	626.146	510.454
- Oil Internal Combustion	41	Oil Internal Combustion	170.865	167.626
- Subtotal	67		806.506	688.32
No. 6				
- Gas Alternative Fuel	8	Gas/Oil Steam	2407.781	2356.495
- Oil Steam	13	Oil Steam	3163.583	3101.722
- Subtotal	21		5571.364	5458.217
Total	88		6377.9	6146.5

Connecticut Oil-Fired Capacity

Source: 2010 CELT Report

Fuel Type	No. of Assets	Gen Type	Total MW As of 2009/2010 Winter Peak Winter	Summer
No. 2				
- Oil Combustion Terminal	2	Oil Combustion (Gas) Turbine	92.731	87.646
- Oil Internal Combustion	12	Oil Internal Combustion	26.98	26.911
- Subtotal	14		119.711	114.557
No. 6				
- Gas Alternative Fuel	4	Gas/Oil Steam	899.974	881.894
- Oil Steam	6	Oil Steam	1294.059	1267.896
- Subtotal	10		2194.033	2149.79
Total	24		2313.744	2264.347

Vermont Oil-Fired Capacity

Source: 2010 CELT Report

Fuel Type	No. of Assets	Gen Type	Total MW As of 2009/2010 Winter Peak Winter	Summer
No. 2	8	Oil Combustion (Gas) Turbine	56.082	83.890
	3	Oil Internal Combustion	12.874	12.196
No. 6	0		0	0
Total	11		68.956	96.086

Maine Oil-Fired Capacity

Source: 2010 CELT Report

Fuel Type	No. of Assets	Gen Type	Total MW As of 2009/2010 Winter Peak Winter	Summer
No. 2				
- Oil Combustion Terminal	2	Oil Combustion (Gas) Turbine	40.283	31.753
- Oil Internal Combustion	4	Oil Internal Combustion	18.29	16.04
- Subtotal	6		58.573	47.793
No. 6	4	Oil Steam	833.171	820.79
Total	10		891.7	868.6

Rhode Island Oil-Fired Capacity

Source: 2010 CELT Report

			Total MW As of 2009/2010 Winter Peak	
Fuel Type	No. of Assets	Gen Type	Winter	Summer
No. 2				
- Oil Combustion Terminal	1	Oil Combustion (Gas) Turbine	55.841	35.441
- Oil Internal Combustion	1	Oil Internal Combustion	9.988	9.912
- Subtotal	2		65.829	45.353
No. 6	1	Gas/Oil Steam	445.52	435
Total	3		511.349	480.353

New Hampshire Oil-Fired Capacity

Source: 2010 CELT Report

			Total MW As of 2009/2010 Winter Peak	
Fuel Type	No. of Assets	Gen Type	Winter	Summer
No. 2				
- Oil Combustion Terminal	1	Oil Combustion (Gas) Turbine	18.082	14.069
- Oil Internal Combustion	1	Oil Internal Combustion	0.691	0.691
- Subtotal	2		18.773	14.76
No. 6	1	Gas/Oil Steam	400.2	400.2
Total	3		418.973	414.96

Massachusetts Oil-Fired Capacity

Source: 2010 CELT Report

			Total MW As of 2009/2010 Winter Peak	
Fuel Type	No. of Assets	Gen Type	Winter	Summer
No. 2				
- Gas Alternative Fuel	1	Gas/Oil Internal Combustion	9.495	10.24
- Oil Internal Combustion	20	Oil Internal Combustion	102.042	101.876
- Oil Combustion Terminal	11	Oil Combustion (Gas) Turbine	363.127	257.655
- Subtotal	32		474.664	369.771
No. 6				
- Gas Alternative Fuel	2	Gas/Oil Steam	662.087	639.401
- Oil Steam	3	Oil Steam	1036.353	1013.036
- Subtotal	5		1698.44	1652.437
Total	37		2173.1	2022.2

Residual Fuel Oil No. 6

Prior to mid-2007, the price of residual No.6 fuel oil was generally less ($2 – $6/MMBtu) than natural gas and could serve as a soft floor for gas prices (see Figure 2-19). This price differential allowed economic fuel switching to residual fuel oil if permitted by operational and regulatory constraints.

After mid-2007, the price of N.Y. Harbor No. 6 residual fuel (and New England) has been greater ($2-$8/MMBtu) than for natural gas at the Algonquin Citygate and could serve as a soft ceiling for gas prices. This price differential does not facilitate economic fuel switching.

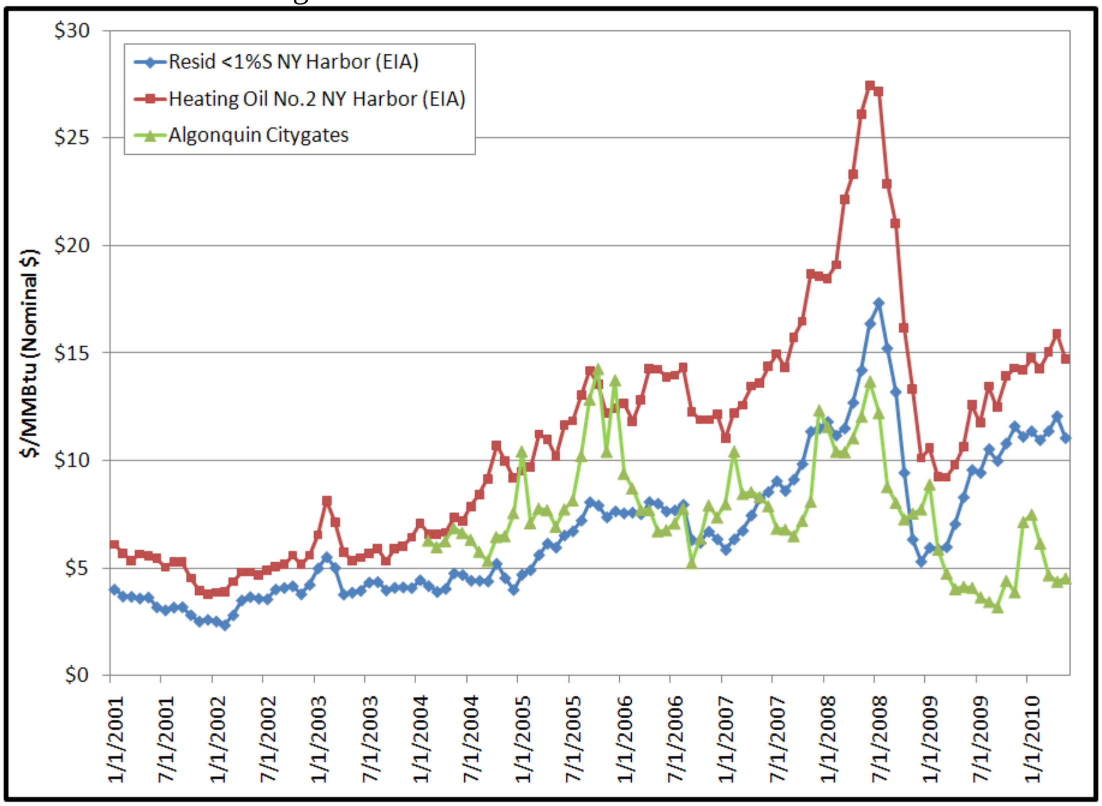

Figure 2-19. Historical Comparison of NY Harbor Residual Fuel Oil and Algonquin Citygate Gas Prices, showing Higher Price for Residual Fuel Oil Since 2007

Distillate Fuel Oil No. 2

Prior to 2006, only in three periods, one in 2004 and two in 2005, was the price of New York Harbor and New England No. 2 fuel oil low enough to be displaced by the price of Algonquin Citygate natural gas. During these three periods, No 2 oil was priced at approximately $40/bbl (2004), $60/bbl and $85/bbl (2005). The 2004 price of approximately $6.75/Mcfe lasted five consecutive months (largely due to Hurricane Ivan), and the two 2005 prices at approximately $10/Mcfe and $14/Mcfe, respectively, were for one to three consecutive months (largely due to Hurricanes Katrina and Rita).

After 2006, the price of New York Harbor and New England No. 2 fuel oil has been greater ($6-$8-$10/MMBtu) than natural gas at the Algonquin Citygate. However when WTI prices reached approximately $150/bbl in 2008, the price spread was approximately $14/MMBtu. Also, during the early 2009 price collapse of WTI ($35-$40/bbl), the price for No. 2 oil was only $2 to $4/MMBtu greater than Algonquin Citygate gas for three consecutive months. No. 2 fuel oil switching during this time was economically possible if allowed by operational and regulatory constraints. The price differential quickly increased to $6-$12/MMBtu.

New England Fuel Oil and Gas Price Forecast

Residual fuel oil has historically had an approximate 25%-30% price discount to WTI. Distillate fuel oil No. 2 has historically had a 15%-20% premium over WTI. The higher prices of crude oil and oil products are forecasted to be maintained into the future based upon R. W. Beck's fundamental analyses of spot prices (Figure 2-20).

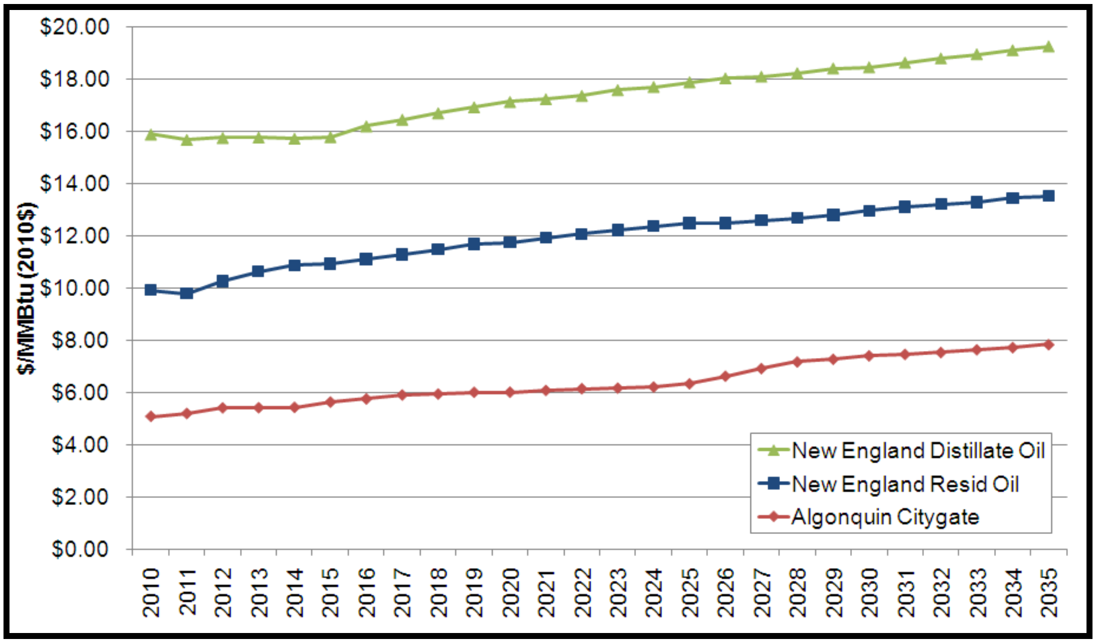

Figure 2-20. R. W. Beck Q2 2010 Forecast New England Residual Oil and Natural Gas, Algonquin Citygate
(Source: R. W. Beck)

The price of New England residual oil is projected to be approximately $5.00 to $6.00/MMBtu greater than the Algonquin Citygate natural gas price. The price of New England No. 2 fuel oil is projected to be approximately $6.00/MMBtu greater than New England residual fuel oil, and approximately $11.00 to $12.00/MMBtu greater than Algonquin Citygate gas. Economic displacement of natural gas in New England over the forecast period is unlikely based on the R. W. Beck's WTI, oil products, and natural gas price forecasts. The use of fuel oil, however, due to daily and/or hourly curtailment of transit pipeline flows to New England cannot be forecasted without modification to our North America gas price model. These projections are also supported by the heat-equivalent price ratio of WTI to Henry Hub (Figure 2-21).

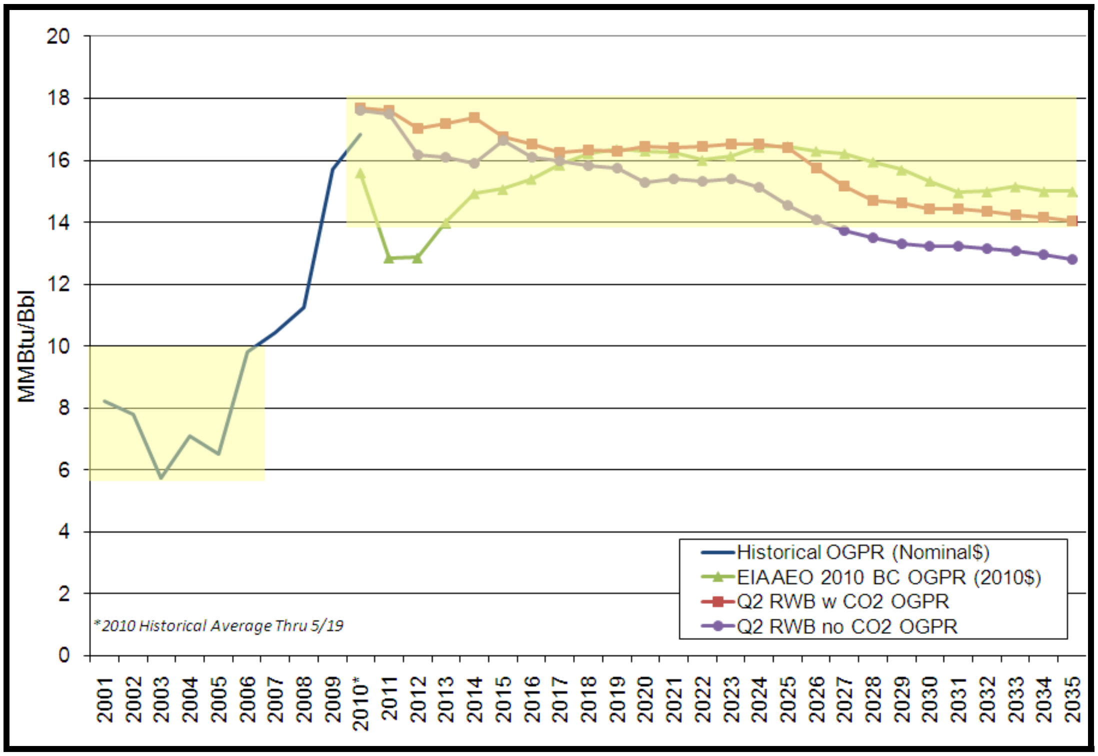

Figure 2-21. Heat-Equivalent Price Ratio – WTI to Henry Hub
(Source: EIA and R. W. Beck)

Regional Gas Supply and Prices

Historical and forecasted capacity to provide regional gas supply, pipeline transportation capacity storage capacity and LNG regasification capacity in North America (including for Connecticut) is driven by the follow elements:

1. Incremental demand is always satisfied by marginal supply
2. The long-run marginal cost of incremental supply and its location always control the:
   a. Location of regional infrastructural capacity expansion
   b. Regional pipeline flow volumes and directions
   c. Capacity utilization rates, including backhaul and storage cycling capacity
3. A interconnected gas pipeline grid with liquid market hubs that convert marginal supply and transportation capacity costs to market-clearing regional prices by:
   a. Use of supply availability/price curves with annual elasticity functions,
   b. Selection of least-cost regional gas (gas-on-gas competition), and
   c. Application of a transportation capacity scarcity function

Regional gas prices are the result of satisfying regional demand.

Natural Gas Infrastructure (Storage and Pipelines)

Since 1999, substantial improvements have been made in the availability of natural gas storage as well as pipeline capacity upstream from Connecticut.

Storage

In July 2005, Inergy L.P., a fast-growing master limited partnership focusing on mid-stream assets, announced an agreement to purchase the membership interests of the entities that own the Stagecoach natural gas storage facility located in Tioga County, N.Y. By October, Inergy could announce that its affiliate Central New York Oil and Gas Company, LLC had sold 100% of existing Phase I storage capacity. In 2006 – 2007, Central New York Oil and Gas Company, LLC also sold out of available capacity on its Stagecoach Phase II expansion.

Table 2-5 shows Stagecoach's customers for FSS (Firm Storage Service), including gas marketers and gas utilities.

Table 2-5. Stagecoach Natural Gas Storage, Firm Storage Service Customers

Shipper	Effective Date	End Date	Maximum Millennium Withdrawal (MMBtu)	Maximum Tennessee Withdrawal (MMBtu)
BG Energy Merchants	11/1/2009	10/31/2010	47,500	47,500
BP Energy	4/1/2010	10/31/2010	16,667	50,000
Consolidated Edison of NY	9/1/2007	3/31/2018	35,000	105,000
Consolidated Edison of NY	6/1/2008	12/31/2011		25,337
Consolidated Edison of NY	9/1/2008	12/31/2011		15,203
Consolidated Edison of NY	8/1/2007	12/31/2011		25,337
D Inergy Gas Marketing LLC	4/1/2002	3/31/2021		287,779
Keyspan	4/1/2008	3/31/2014	47,500	47,500
Louis Dreyfus	6/25/2008	8/31/2011		20,000
Merrill Lynch	4/1/2007	3/31/2017		17,000
Merrill Lynch	6/1/2007	10/31/2017		100,000
New Jersey Natural Gas	4/1/2008	3/31/2011		21,728
New Jersey Natural Gas	4/1/2008	3/31/2011		25,337
Nexen Marketing USA	9/1/2007	3/31/2013		22,500
NJR Energy Services	9/1/2009	3/31/2011		11,667
NJR Energy Services	1/1/2010	3/31/2011		21,728
Pivotal Utility Holdings	9/1/2008	3/31/2011		3,040
Tenaska Gas Storage	4/1/2010	3/31/2012	10,000	10,000
Valley Energy Inc.	4/1/2008	3/31/2013		2,838
Macquarie Cook Energy	3/1/2009	3/31/2011	20,390	20,390

Source:www.stagecoachstorage.com

Stagecoach has 13.6 Bcf of working gas capacity, maximum withdrawal capability of 500 MMcf/day, and maximum injection capability of 250 MMcf/day. At the time of

Inergy's acquisition, Stagecoach was a facility of limited utility, connected only to Tennessee Gas Pipeline Company's 300 Line. The involvement of a forward-thinking investment group contributed strategic concepts of multiple pipeline interconnections and optionality into the planning process. In 2008, Inergy announced completion of its Stagecoach North Lateral, a ten-mile lateral to Millennium Pipeline with supply generally restricted to Canadian sources at Niagara. In July 2009, Inergy announced a non-binding open season to build the MARC I Hub Line Project and the North-South Project. Together these projects will permit shippers to wheel gas bidirectionally on a firm basis to and from the Millennium Pipeline, to and from Transcontinental Gas Pipeline (Transco) at Leidy and to and from points in-between.

The strategic location of Stagecoach (with its interconnections to these three major interstate pipelines) upstream of Connecticut is shown on Figure 2-22.

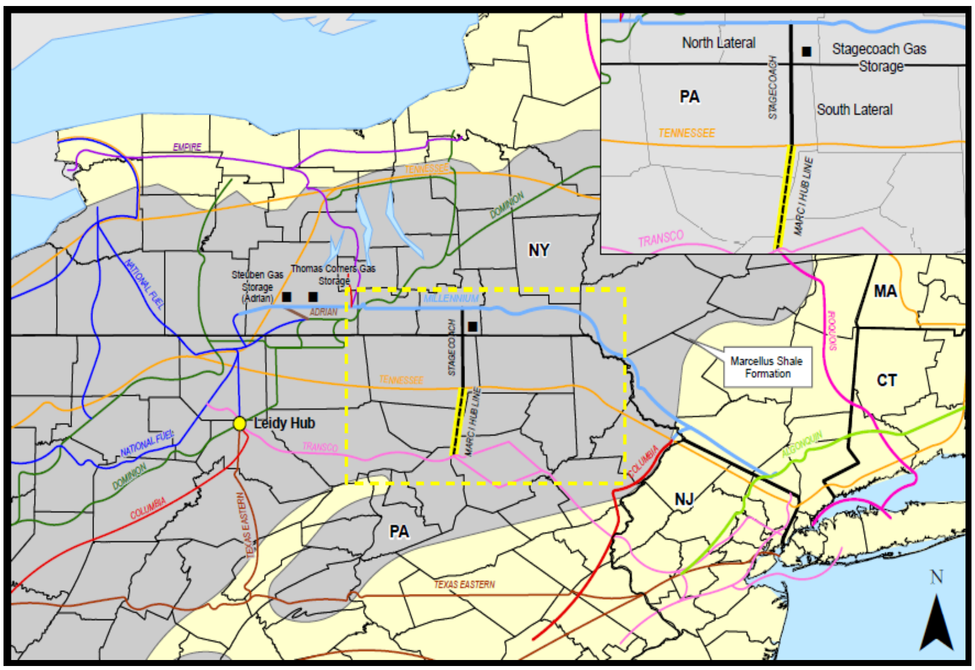

Figure 2-22. Central New York Oil and Gas Company LLC, Marc I Hub – Stagecoach
(Source: www.stagecoachstorage.com)

In January 2010, Inergy initiated purchase of Seneca Lake natural gas storage facility in Schuyler County, New York and related pipelines. Seneca Lake is an approximately 2.0 Bcf underground salt cavern storage facility (and thus capable of high rate of withdrawal). Maximum withdrawal capacity is 145 MMcf/d and injection capability is 75 MMCf/d. It is connected to Dominion Transmission (largely an Appalachian supply transporter), and indirectly to Millennium via the Seneca East Pipeline (part of the acquisition assets).

This new market-area storage is highly significant for long-term reliable and economic gas delivery to New England. Such storage provides a means of optimizing abundant liquids-rich and basis-adjusted shale gas that is largely hedged and geologically difficult to curtail due to problems of water incursion. It also optimizes LNG, which requires storage to accommodate opportunistic spot cargoes delivered to the likely summer market of last resort.

Natural Gas Pipeline Capacity

Historical Capacity

Between 1999 and 2009, approximately 40 gas pipeline projects that service the Northeast and New England markets have been completed. These include seven new pipelines (including Millennium and Rockies Express or REX), three extensions, and approximately 30 capacity expansions. Approximately half of these projects occurred between 2007 and 2009 (see Table 2-6 and Figure 2-23).

Table 2-6. Significant Completed Natural Gas Pipeline Construction Projects With Impact on Northeast U.S. Gas Supply

In Service Year	Pipeline	Project Name	Project Type	Additional Capacity (MMcf/d)	Comments
1999	Portland Natural Gas Transmission System (PNGTS)		New	178	
1999	Maritimes & Northeast	M&NE Phase II	New	400	
1999	PNGTS/Maritimes & Northeast	PNGTS/M&NE Phase I	New	632	
1999	National Fuel	Elllisburg to Leidy Line	Expansion	59	
1999	Columbia Gas Transmission	CGT Market Project III	Expansion	118	
2000	Alliance		New	1,325	BC to Joliet, IL. capacity to Joliet now approximately 1,600 MMcf/d
2000	Vector		New	720	Joliet, IL to Dawn, Ontario (including Canadian portion of pipeline)
2001	Transco	MarketLink Phase I	Expansion	162	
2002	Vector		Expansion	280	
2002	Texas Eastern Transmission (TETCO)	TIME	Expansion	100	
2002	Transco	Leidy East	Expansion	126	
2002	Transco	MarketLink Phase II	Expansion	127	
2003	Algonquin	HubLine	Extension	295	
2003	Maritimes & Northeast	M&NE Phase III	Extension	230	
2003	Niagara Mohawk		Expansion	200	
2003	Columbia Gas Transmission	Rock Springs	Expansion	263	
2003	Dominion Transmission (DTI)	Ellisburg-Leidy Line	Expansion	127	
2003	Tennessee Gas Pipeline (TGP)	Can-East/Leidy	Expansion	150	
2004	Iroquois	Eastchester Marine	Expansion	230	
2004	TETCO	Dominion Expansion	Expansion	217	
2005	Transco	Central New Jersey	Expansion	105	
2007	Vector		Expansion	250	
2007	Algonquin	Northeast Gateway LNG	Lateral	800	
2007	TGP	Northeast ConneXion	Expansion	136	

Table 2-6. Significant Completed Natural Gas Pipeline Construction Projects With Impact on Northeast U.S. Gas Supply

In Service Year	Pipeline	Project Name	Project Type	Additional Capacity (MMcf/d)	Comments
2007	Transco	Leidy to Long Island	Expansion	100	
2007	TETCO	TIME II (Phase 1)	Expansion	150	
2008	Algonquin	Ramapo	Expansion	325	
2008	Iroquois	08/09 (Phase 1)	Expansion	95	
2008	Neptune	LNG Lateral	Lateral	750	
2008	Maritimes & Northeast	M&NE Phase IV LNG	Expansion	420	
2008	DTI	Pennsylvania Exp	Expansion	700	
2008	TETCO	TIME II (Phase 2)	Expansion	150	
2008	Transco	Sentinel (Phase 1)	Expansion	100	
2008	Iroquois	MarketAccess	Expansion	100	
2008	Millennium		New	525	
2008	Empire/Millennium		Extension	250	
2009	Rockies Express	Rex-East Phase	New	1,800	To Clarington, Ohio
2009	Iroquois	08/09 (Phases 2 &3)	Expansion	105	
2009	TETCO	Northern Bridge	Expansion	105	Clarington, Ohio to Oakford, PA

(Sources: EIA and Pipeline Websites)

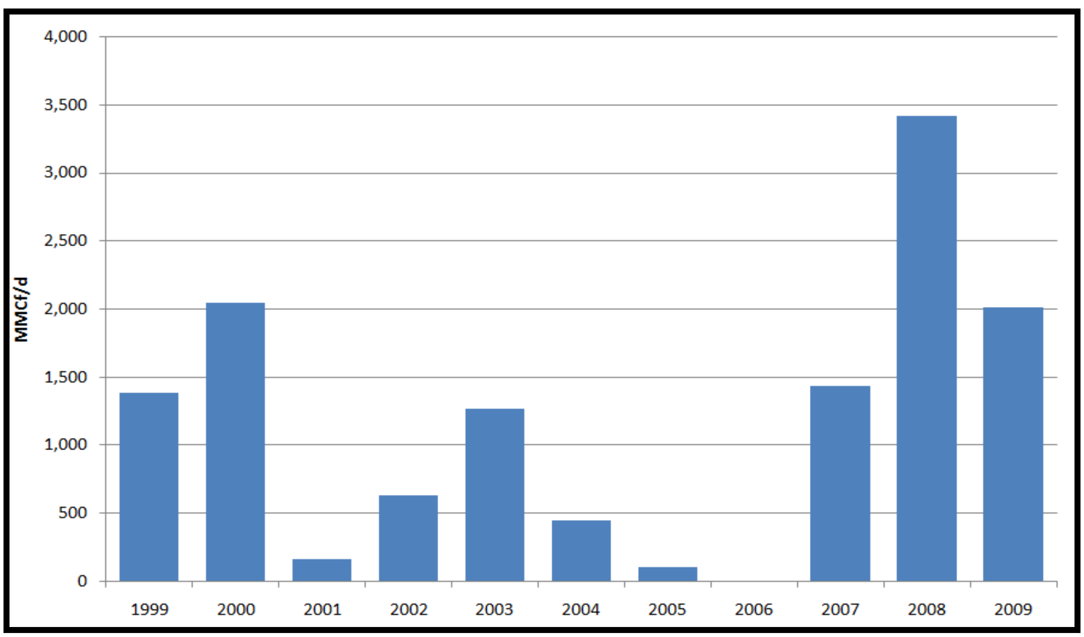

Figure 2-23. Additional Northeast Gas Pipeline Capacity 1999-2010
(Sources: EIA and Pipeline websites)

The sharp increase in gas volumes produced from the Marcellus Shale has caused gas flows in the northeastern U.S. to change radically. Gas demand in the region, though growing, is not growing as fast as is the volume of unconventional gas, especially Marcellus production. The excess gas volumes are increasingly utilizing backhauls from the northeast to the Mid-Atlantic and even farther South. As reported by McGraw Hill Platts (6/20/2010), Marcellus producers such as Chesapeake Energy consider backhauls their cheapest way to reach southern markets. Tennessee and Transco (including its Leidy Line) are both offering backhaul services to permit Marcellus production to flow south and westward to Tennessee Zone 4 and Transco Zone 5.

These interstate pipeline proposals involve the following realignments of pipeline capacity:

1. Forward haul of Rockies and Appalachian supplies.
2. Backhaul of Northern Appalachian gas, especially Marcellus shale to upstream markets:
   a. Westward to Leidy and Ellisburg storage hubs
   b. Westward to REX at Clarington (e.g. Columbia and Tennessee pipelines)
   c. Northwestward to Niagara for Ontario demand (e.g. Iroquois and Empire pipelines)
   d. Southward to Mid-Atlantic markets (e.g. Transco pipeline)
   e. Northeastward to eastern Canada markets (e.g. Tennessee, Algonquin, Portland Natural Gas and Maritime and Northeast pipelines).
3. Backhaul of coastal LNG (e.g. Tennessee and Algonquin pipelines. Iroquois can access Algonquin’s 1.0 Bcf/d of LNG at their Brookfield, CT interconnect.)
4. Bidirectional capacity to flow to Rockies and Appalachian gas northward to Canada (e.g., Iroquois and Empire pipelines).
5. Flow reversal of natural gas liquids (NGL) pipelines for delivery to the west and northwest from Btu-rich Appalachian shale gas (e.g. Marcellus and Huron shale gas to Chicago and Ontario markets). The residue natural gas remains at the processing plant to be dumped on the market.

Concurrently, Iroquois management is developing strategies to allow Marcellus production to reach markets in Ontario, also through backhauls. As of 2010, Empire Pipeline in New York is studying a plan to become bidirectional, to allow Marcellus production to flow from New York into Canada, to fuel the replacement of Ontario coal plants with gas-fired generation.

These trends - displacement of east-and north-bound gas with market-area gas (shale gas and LNG), new storage and bidirectional capacity – significantly improve the current and future reliability and cost effectiveness of gas delivery to Connecticut when compared to 1999.

GPCM Capacity Expansion

The Historical Capacity section above summarizes historical Northeast U.S. natural gas pipeline capacity additions, based on EIA data and pipeline website information. Table 2-7 summarizes how historical capacity additions and projected additions are organized in GPCM for the three interstate gas pipelines which serve Connecticut. For each of these three pipelines, the total pipeline operating capacity is for each listed year by the respective pipeline zones. Listed capacity levels begin with year 1999 and jump to 2007. Significant expansions which occurred during that time period on these pipelines are noted in the far right column. Starting in 2007, each year with significant capacity additions, historical or projected, are shown. Once again, specific significant additions are listed in the far right column. For these three pipelines, GPCM's assumed capacity additions occur in years 2012, 2014 and 2020. Algonquin's Hub Line West to East Expansion (400 MMcf/d) and TGPs 300 Line Expansion (350 MMcf/d) are projected to occur in 2012 in GPCM. Year 2014 contains Algonquin's New Jersey New York expansion (800 MMcf/d), TGP's Northeast Expansion (636 MMcf/d) and part of Iroquois' NY Marc extension (500 MMcf/d). GPCM includes a second phase (an additional 500 MMcf/d) of NY Marc extension capacity will be available in year 2020. The GPCM Algonquin and TGP expansion assumptions mentioned above do generally match those stated in their respective public company documents. Note however, GPCM's assumed NY Marc timing and capacity volumes do not match exactly those currently put forth by Iroquois itself (see Table 2-8).

Table 2-7. GPCM Gas Pipeline Capacity As Of The Listed Year (MMcf/d)

GPCM Pipeline Zones	1999	2007	2008	2009	2012	2014	2020	Major Sources of Capacity Additions
Algonquin Boston	650	1,450						Northeast Gateway LNG Lateral (2007) (800 MMcf/d)
Algonquin CT	1,060	1,060	1,385					Ramapo Expansion (2008) (325 MMcf/d)
Algonquin Hubline		1,100						HubLine (2003) (300 MMcf/d)
								Northeast Gateway LNG Lateral (2007) (800 MMcf/d)
Algonquin J (RI, SE MA)	600	600			1,000			Hub Line East to West Expansion
Algonquin Mendon	750	750						
Algonquin NJ NY	1,300	1,300	1,625			2,425		Ramapo Expansion (2008) (325 MMcf/d)
								New Jersey New York Expansion (2014) (800 MMcf//d)
Iroquois Z1	900	1,160						Eastchester Extension/Expansion (2004) (230 MMcf/d)
Iroquois Z2	900	1,160						Eastchester Extension/Expansion (2004) (230 MMcf/d)
Iroquois 08/09 Expansions	- - - -	- - - -	95	375				Includes MarketAccess Expansion
Iroquois NY Marc Extensions						500	1,000	Extensions for Accessing Marcellus Shale
TGP Z5 NJ	506	580			930	1,566		Portion of Can-East Leidy Expansion (2003) (150 MMcf/d)
								TGP 300 Line Expansion (2012) (350 MMcf/d)
								TGP Northeast Expansion (2014) (636 MMcf/d)
TGP Z5 NY	1,053	1,189			1,539	2,175		Northeast ConneXion Expansion (2007) (136 MMcf/d)
								TGP 300 Line Expansion (2012) (350 MMcf/d)
								TGP Northeast Expansion (2014) (636 MMcf/d)
TGP Z6 CT	179							
TGP Z6 East MA	1,079	1,215						Northeast ConneXion Expansion f(2007) (136 MMcf/d)
TGP Z6 West MA	1,058	1,194						Northeast ConneXion Expansion (2007) (136 MMcf/d)

Natural Gas Price Forecasting Model Assumptions - Historical and Projected By Pipeline Zone Algonquin Gas Transmission, Iroquois Gas Transmission, and Tennessee Gas Pipeline (TGP)

Iroquois Pipeline Capacity

As shown on Table 2-8, Iroquois Pipeline (the interstate pipeline delivering gas to Milford, see Figure 2-24) has undergone four expansions since 1999 that have added more than 500 MMcf/d to produce a current peak deliverability of 1.6 Bcf/d. As currently constituted, Iroquois offers a variety of upstream paths from producing basins, through direct receipt or indirect interconnections with:

- TransCanada Pipeline (Canadian supply)
- Tennessee Gas Pipeline (Gulf Coast supply and Everett LNG)
- Algonquin Pipeline (Gulf Coast and Everett LNG)
- Dominion Gas Transmission (Appalachian supply)

In the past five years, Iroquois expansion projects (completed and planned) have aimed at restructuring the pipeline to accommodate the new conditions. Plans are to change it from a unidirectional pipeline sourced primarily from Canadian supplies, to a regional header system with significant supply attachment at both its north and south ends. This strategy, as it is realized, will make Iroquois a more reliable and flexible route for gas delivery into Connecticut. Attachment of incremental gas supplies at Iroquois' south end (Rockies, Appalachian, Mid-Atlantic Cove Point LNG) will promote efficient use of the pipeline through capacity displacements, multiple basis swaps and supply exchanges, all of which increase delivery reliability and reduce rate stacking and thus cost.

Iroquois' current projects focus on accessing new Marcellus supplies in New York and Pennsylvania and building pipe to new generation markets in Queens, New York. Proposed in-service dates are subject to market acceptance and market conditions.

Table 2-8. Current Iroquois Expansion Projects

Proposed New Capacity	Volume (MMcf/d)	Location	Proposed In-service Date
NYMarc/-Penn Option	900	Tennessee in PA to Pleasant Valley NY	11/1/15
NYMarc Project	700	Tennessee in NW New Jersey to Pleasant Valley NY	11/1/15
Astoria Lateral	300	Extend main line to Astoria, NY power generation facilities	6/1/13

(Source: Scott Rupff Presentation, Iroquois Pipeline, 2010 Northeast LDC Forum).

Historical Utilization Rates on Iroquois Pipeline

To address the potential for curtailment on Iroquois, Figures 2-25, 2-26 and 2-27 show the sums of scheduled quantities at Waddington (interconnect with TransCanada Pipeline near the international border) and at Brookfield (Iroquois Zone 2) from the Iroquois website. As seen in Figure 2-25, since mid-2008 the Canadian gas supply received at Waddington has declined from its operating capacity by approximately 65% (1.2 Bcf/d to 0.40 Bcf/d).

Figure 2-26 shows that delivery of Canadian gas from Zone 1 at Wright into Tennessee has declined approximately 0.60x since the start of 2009 (200 MMcf/d to 75 Mcf/d). The delivery of Zone 1 gas into Tennessee has been relatively stable (0-50 MMcf/d).

Figure 2-27 shows that since mid-2008 gas received into Iroquois at the Brookfield interconnect with Algonquin has increased approximately 8.0x (50 Mmcf/d to 400 Mmcf/d) approaching receipt point capacity at 500 Mcf/d. Likewise gas delivered into Algonquin from Zone 2 Iroquois has decreased approximately 0.50-0.65x (100-150 Mmcf/d to 50 Mmcf/d or less).

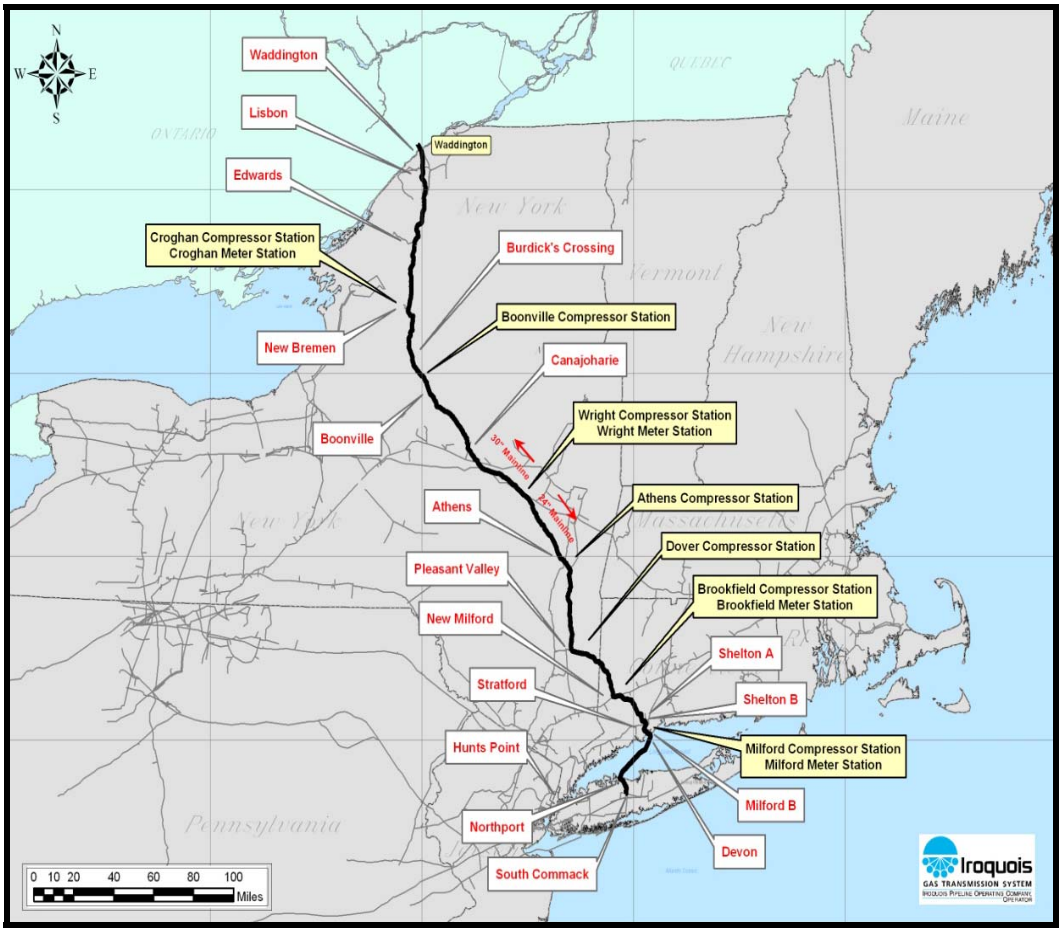

Figure 2-24. Iroquois Gas Transmission System
(Source: www.iroquois.com)

These three figures indicate significant decreases in Canadian gas flowing southward on Iroquois, and significant decrease in delivery of Canadian gas into Tennessee (Zone 1) and Algonquin (Zone 2). These decreases are offset in part by deliveries of non-Canadian gas into Zone 2 Iroquois by Algonquin (Rockies and Appalachian gas as well as LNG).

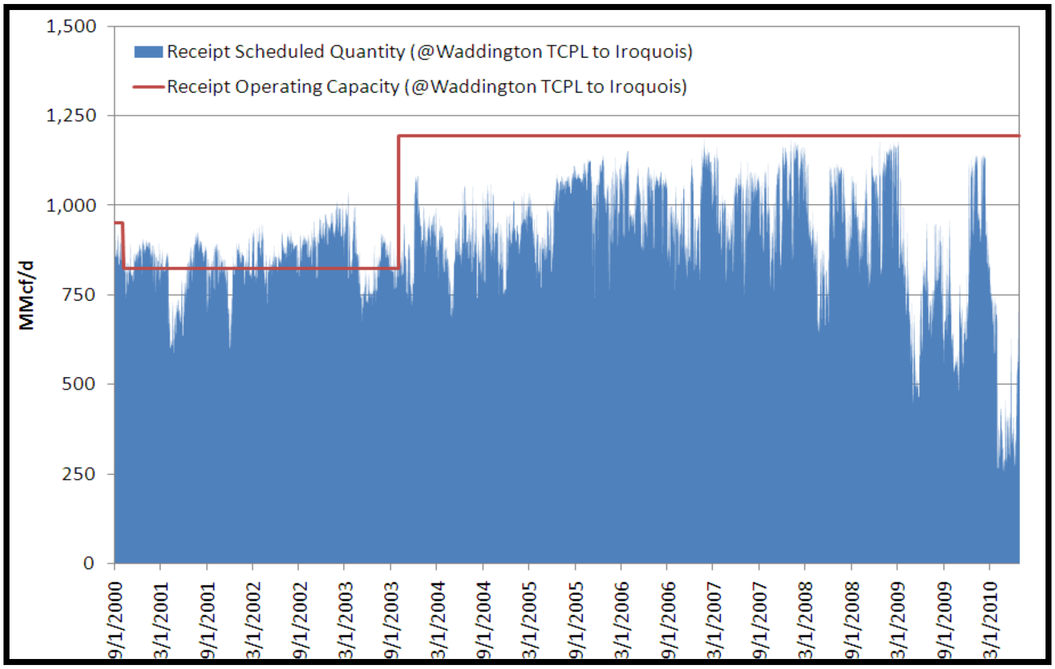

Figure 2-25. Waddington Historical Flow Data

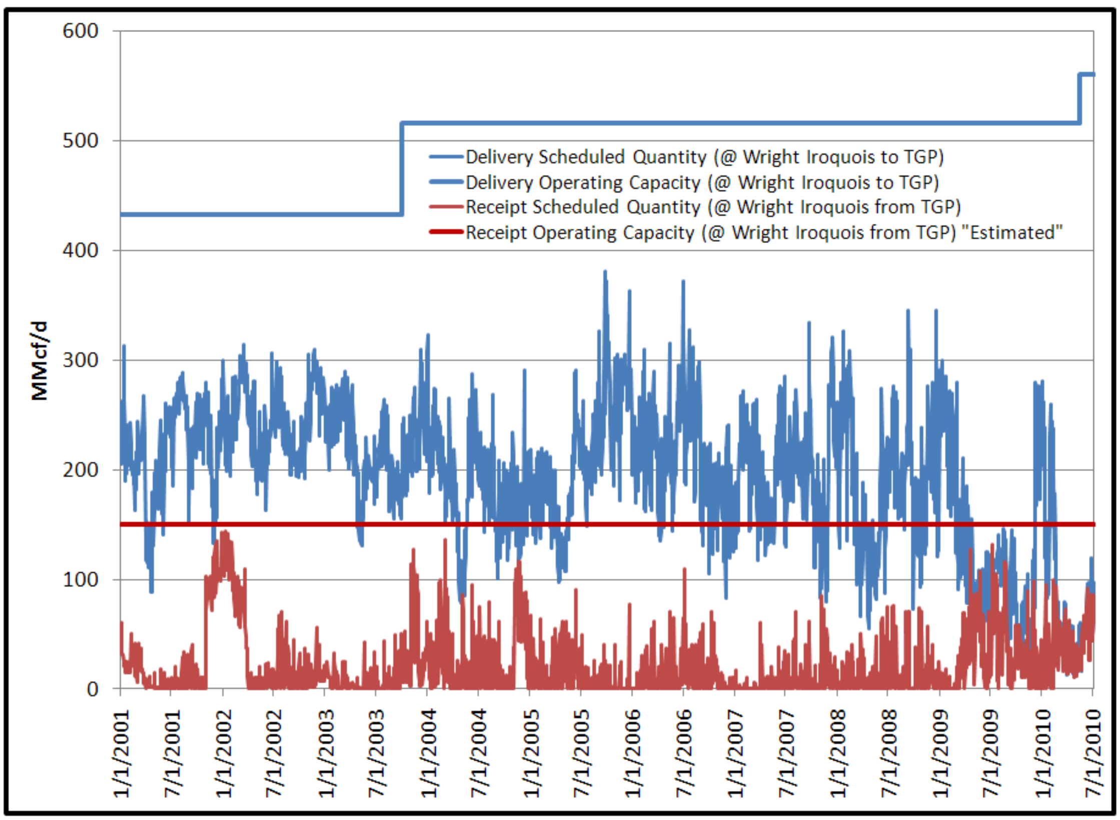

Figure 2-26. Wright Historical Flow Data at Interconnect with Tennessee

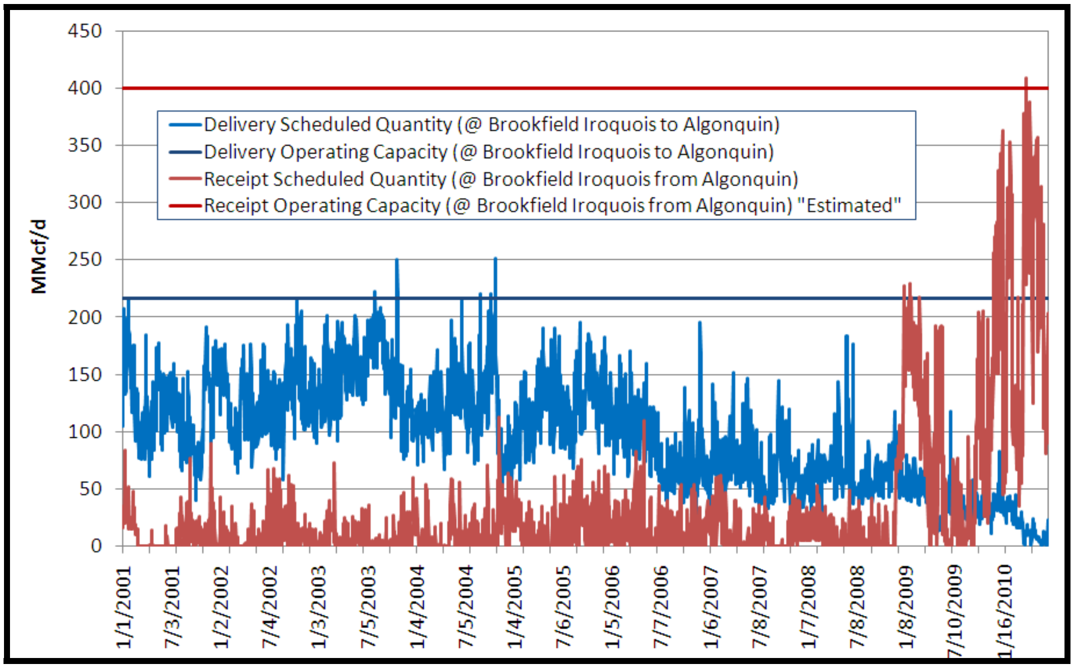

Figure 2-27. Brookfield Historical Flow Data at Interconnect with Algonquin

Figure 2-28 shows the total historical and forecasted annual capacity utilization rate at Waddington into Zone 1 Iroquois. The rate decreases since mid-2008 from 80% to 30% for 2010 and generally less than 10% after 2013. Also shown is the forecasted utilization for Zone 2 which is generally flat at approximately 20% for the forecast period. Winter usage can be as great as 80% to 90%.

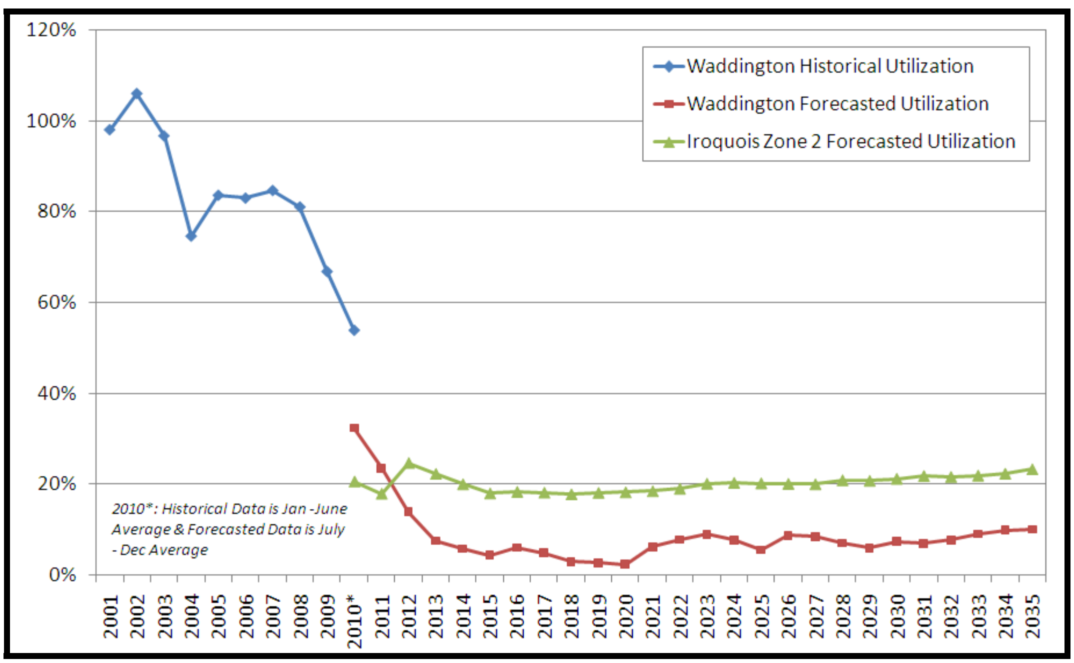

Figure 2-28. Iroquois Utilization
(Source: R. W. Beck Q2 2010

These capacity utilization data indicate a very low probability for curtailment of Zone 1 capacity and a similarly very low probability on Zone 2. Such a conclusion is supported by empirical experience. In the January, 2005 cold snap, Iroquois did not cut gas flows of either firm or interruptible supply, but did request hourly balancing at contract demand. Since 2005, the Iroquois system has been further improved for winter peaking events as the result of two expansions in 2008 and one in 2009 (see Table 2-6), including the addition of two compressor stations.

Iroquois has an excellent record of reliability. Since 2000, Iroquois has only declared a force majeure on two separate occasions, the most recent of which occurred on January 29, 2010 due to an outage at the Brookfield Transfer Compressor Station. In that case, the force majeure was declared for one day resulting in a cut in firm delivery of 117,000 Dth out of 1,500,000 Dth design receipt capacity (8%). (Scott Rupff, Iroquois Pipeline, email communication, July 26, 2010).

Summer peak days for electricity generation should experience ample capacity on Iroquois and minimal probability for curtailment for firm capacity and likely interruptible capacity also. Based on the improvements to the Iroquois pipeline, Milford Power's risk of natural gas delivery curtailment in winter is also significantly reduced from historical levels existing as of 1999.

Forecasted Pipeline Capacity

R. W. Beck has also provided our forecasted flows along zones relevant to serving projected demand in Connecticut on Iroquois, Algonquin, and Tennessee pipelines (see Appendices C and D).

Iroquois south-bound flows on Zone 2 (between Wright, N.Y. and Chesire, CT do not approach the zone's operating capacity (400 MMcf/d maximum flow versus approximately 1,200 MMcf/d capacity.

Algonquin north-bound flows across Connecticut (between Brookfield and CT/MA border just south of Mendon, MA) are close to the operational capacity, with approximately 200 MMcf/d surplus capacity.

Tennessee flow on the 16-inch bidirectional pipeline that is across Connecticut and connects line 200 (at Thompsonville) and line 300 (at CT/NJ corridor) have approximately 25 MMcf/d surplus capacity over the operating capacity (approximately 180 MMcf/d). By approximately 2020, the flows generally exceed operating capacity. At that point, Tennessee would increase its capacity if shippers so requested. Shippers could also utilize two alternative receipt points from Tennessee into the surplus capacity of Iroquois Zone 2:

1. Any available capacity at Wright from Tennessee Line 200
2. Any available capacity at Pleasant Valley from Tennessee Line 300, if Iroquois' proposed New York NY Marc extension to bring 700-900 MMCf/d is completed.

Projected flows on Tennessee pipeline upstream of Connecticut in New York (line 200, upstream of Wright) and New Jersey (line 300, between Wagoner and Ramapo) generally do not exceed operating capacity. Flows (approximately 1,200-1,500 MMcf/d) reach the N.Y. zone capacity between 2010 and 2014, but the Northeast Expansion provides approximately 635 MMcf/d of additional capacity after 2014. Flows on Tennessee line 300 do not reach N.J. zone capacity, with approximately 100 to 300 MMcf/d surplus capacity.

Project flows on Algonquin upstream and downstream of Connecticut and New Jersey (between Lambertville, NJ and Brookfield, CT), and Massachusetts (between Brookfield, CT and Mendon, MA) approach but do not exceed operational capacity. New Jersey capacity provides approximately 300 surplus capacity between 2010-2014, and after 2014 approximately 1,100 MMcf/d surplus capacity to Mendon has approximately 200 MMcf/d surplus capacity.

Conclusions for New England Gas Supply and Delivery

Since 1999, as described in the previous sections, natural gas supply and delivery conditions to New England have experienced significant improvements that greatly reduce the risk of interruption. We regard the following trends as most important to the enhanced and consistent reliability of the natural gas delivery system going forward:

- Development of Appalachian and southeast U.S. region unconventional gas and the associated pipeline capacity to deliver new supplies of gas to New England; thus offsetting production declines in Western Canadian Sedimentary basin and in the offshore Canadian Atlantic.
- The availability of new LNG import capacity into terminals in Massachusetts and New Brunswick, thus providing for enhanced winter peaking capacity, including displacement and supply exchanges
- Resulting, freed-up west-to-east pipeline capacity on TransCanada Pipeline and potentially north to south pipeline capacity on Portland Pipeline and Maritimes and Northeast (MNE), thus further alleviating the previously constrained delivery system into New England.
- Expansions of capacity on Iroquois, Tennessee and Algonquin, to improve the reliability and winter peaking capacity of that interstate pipeline system and to diversify its supply base
- New planned pipeline capacity to bring abundant gas supplies from the Rockies into the eastern U.S. and New England, which increases backhaul (east to west) and bidirectional (south to north) capacity; this enhances reliability of gas delivery to New England.
- Increase in New York market-area storage directly upstream from Connecticut to optimize unconventional gas, both shale and LNG.
- Change in the price relationship between natural gas and petroleum fuels delivered to New England in the last five years; Since 2006, the relatively high price of No.2 oil has generally precluded economic switching between it and natural gas. Since 2007, the relatively high price of No.6 oil has similarly precluded economic switching with gas. In the case of future gas supply shortage or pipeline capacity curtailment, approximately 2418 MW of existing New England plants (with fuel

oil as their primary fuel) would have the capability of oil-fired generation if they had been using natural gas.

Section 3
POWER INFRASTRUCTURE CHANGES

Introduction

Milford Power has engaged R. W Beck to conduct a review of the changes to the bulk electric transmission infrastructure in Southwest Connecticut (SWCT) and their impact on reliability since 1999, the year Milford Power received approval from the CSC to construct its generation facility in Milford, Connecticut. Since that time significant improvements have been made to increase the capacity of the bulk transmission infrastructure in Connecticut and to promote the development of electric generation in the region, both of which address operational deficiencies in the bulk electric transmission system in Connecticut.

Background

The Connecticut Siting Council (CSC) issued a Certificate of environmental Compatibility and Public Need (Certificate) to Milford Power on January 8, 1999. At that time, SWCT faced electric transmission reliability problems due to transmission constraints into the region and due to the need for new generation to be built there. As a measure of additional reliability, the CSC required that Milford install the capability to run on a back up low sulfur distillate oil should natural gas not be available. The added value and need for a backup fuel as an added measure of reliability has been substantially reduced due to the substantial improvements in the regional transmission system and the more than 2,000 MW of new power generating facilities which have been added since 1999.

In the late 1990s, Southwest Connecticut (SWCT) faced reliability problems due to transmission constraints into and within that geographic area. In July 2000, the Connecticut Department of Public Utility Control (DPUC) investigation into Electric Capacity and Distribution identified SWCT as having operational difficulties and a near term need to reinforce the bulk transmission system. During that time several electric system events threatened transmission system reliability. Therefore, in March of 2002, the Connecticut legislative committee on Energy and Technology directed the DPUC to conduct an investigation into possible shortages of electricity in SWCT during summer periods of peak demand. The DPUC determined that the reliability to the SWCT area was vulnerable because of inadequate local generation and transmission capability. In fact, the SWCT region failed to meet critical NPCC transmission reliability standards.

As a result, stakeholders, including ISO-NE, FERC, local utilities and the DPUC instituted a number of policies and mechanisms to improve system reliability in the region. These included:

1. Construction of a massive $1.5 Billion 345Kv loop to lower costs and enhance reliability;
2. Granting of RMR contracts to ensure that existing generation plants would not retire; and
3. Granting of long-term Purchase Power Agreements and incentives for new generation to be built.

Southwest Connecticut Transmission System Conditions (1999-2009)

The effect of the increased transmission capacity placed in-service in 2006 and 2008 has significantly increased the capacity and reliability of the bulk transmission system in SWCT. Figure 3-1 provides an illustration of the SWCT region and transmission system.

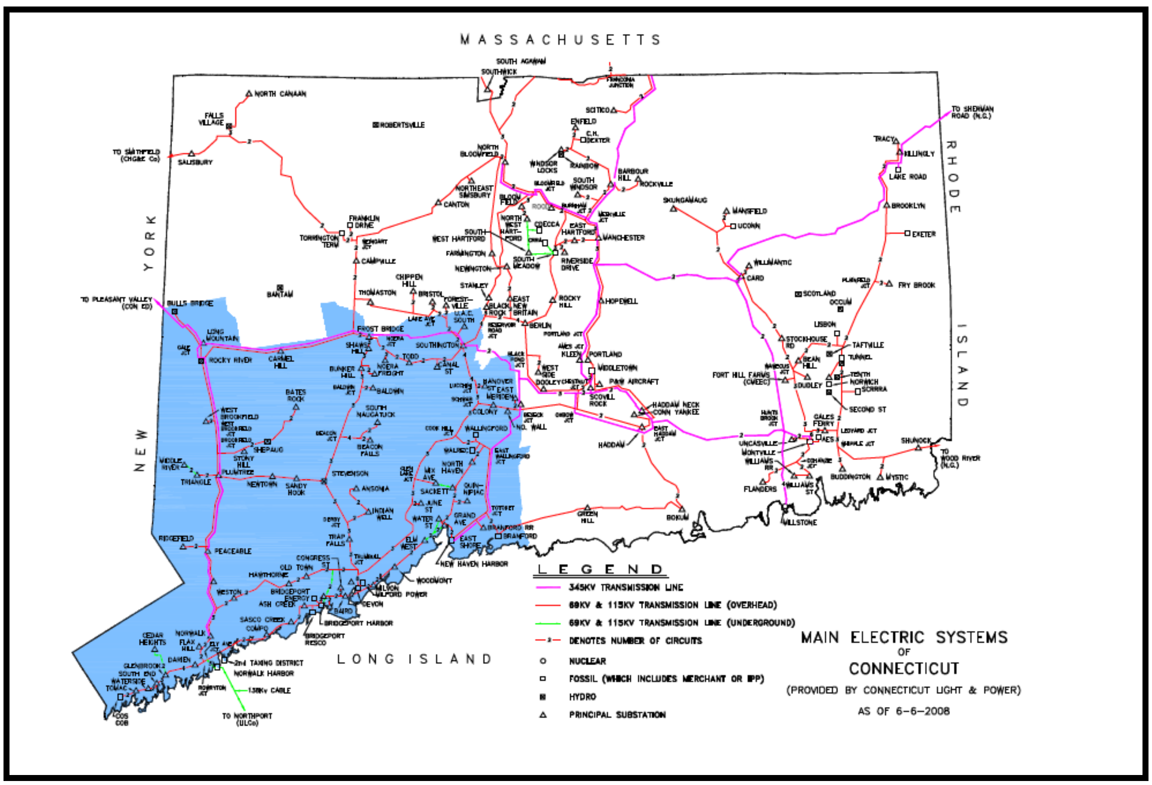

Figure 3-1. Connecticut Transmission Systems

An area, such as southwest Connecticut, that has high load demand and that also lacks sufficient generation and transmission to serve this load, is referred to as a "load pocket". The State of Connecticut, ISO-NE, and the Connecticut electric utilities recognized that SWCT was an inefficient and vulnerable portion of transmission infrastructure that was isolated from the 345-kV transmission system and much of the available lower cost power generated from within the state and the surrounding region. Figure 3-2 shows the congested transmission paths in SWCT.

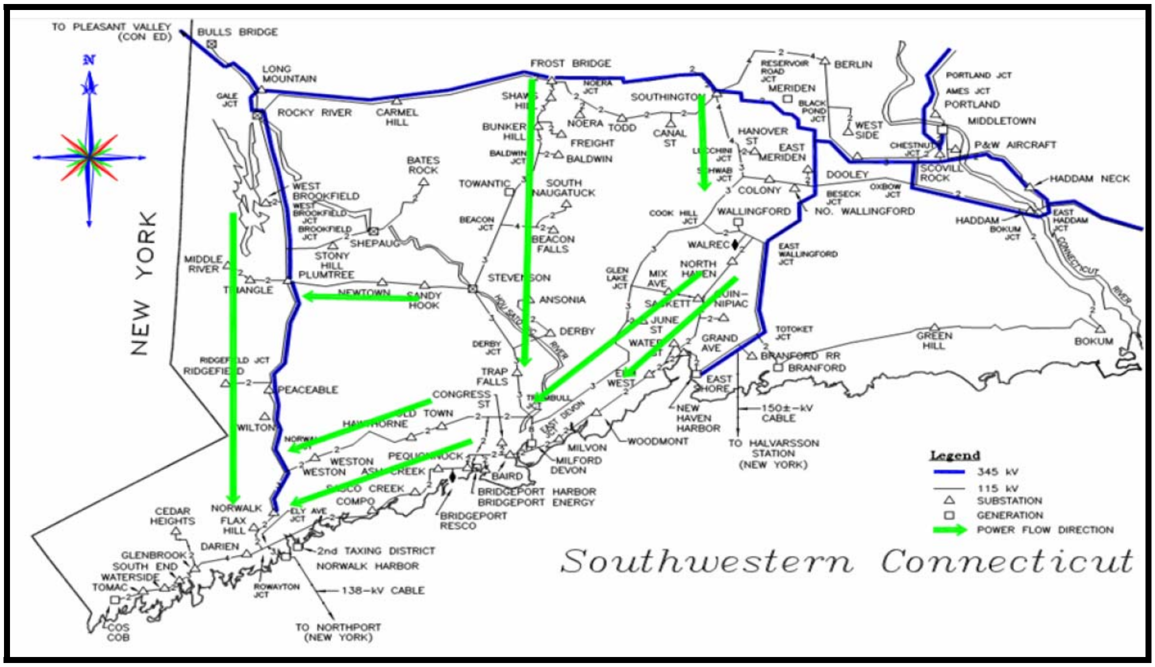

Figure 3-2. Transmission Overloads under contingency
(Pre Bethel –Norwalk and Middletown-Norwalk transmission reinforcements)

Southwest Connecticut Transmission Reinforcement Plan

United Illuminating and Northeast Utilities developed a plan to address the concerns expressed at both the regional and federal levels surrounding SWCT electric transmission infrastructure. In 2003, the companies submitted a joint filing of an application with the Connecticut Siting Council with respect to the Middletown to Norwalk (M-N) project, which completed the 345-kV loop in southwestern Connecticut. As outlined in the joint Connecticut Siting Council filing, some of the factors contributing to the need for the transmission system improvements included:

- Limited transmission capability to reliably serve increased loads;
- Transmission constraints impeding implementation of a competitive generation marketplace, resulting to exposure to congestion costs; and
- Uncertainty surrounding the long-term viability of generation currently operating in southwest Connecticut.

The M-N project was completed in two phases:

The first phase of this proposed upgrade, Phase I, involved the construction of a 345-kV transmission line from Plumtree Substation in Bethel to the Norwalk Substation in Norwalk. Construction was completed in 2006.

The second phase involved the construction of a 345-kV transmission line from Middletown to Norwalk Substation which was completed in December 2008.

Figures 3-3 and 3-4 show the location of the two upgrade projects in SWCT.

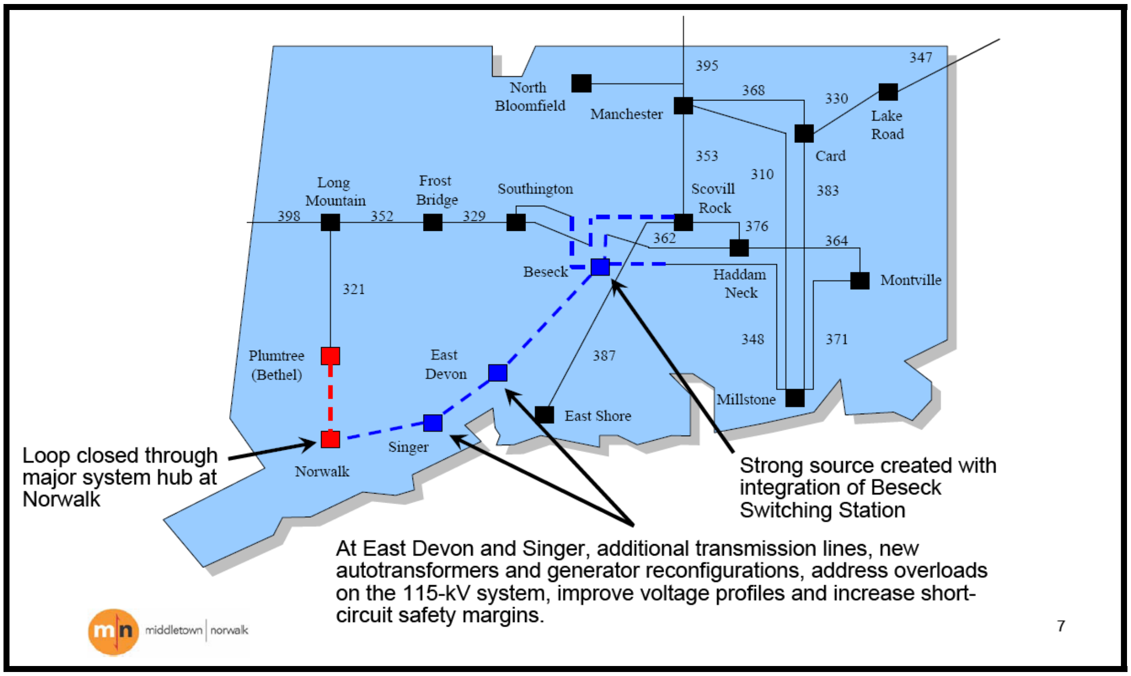

Figure 3-3. Bethel – Norwalk and Middletown – Norwalk Transmission Reinforcements

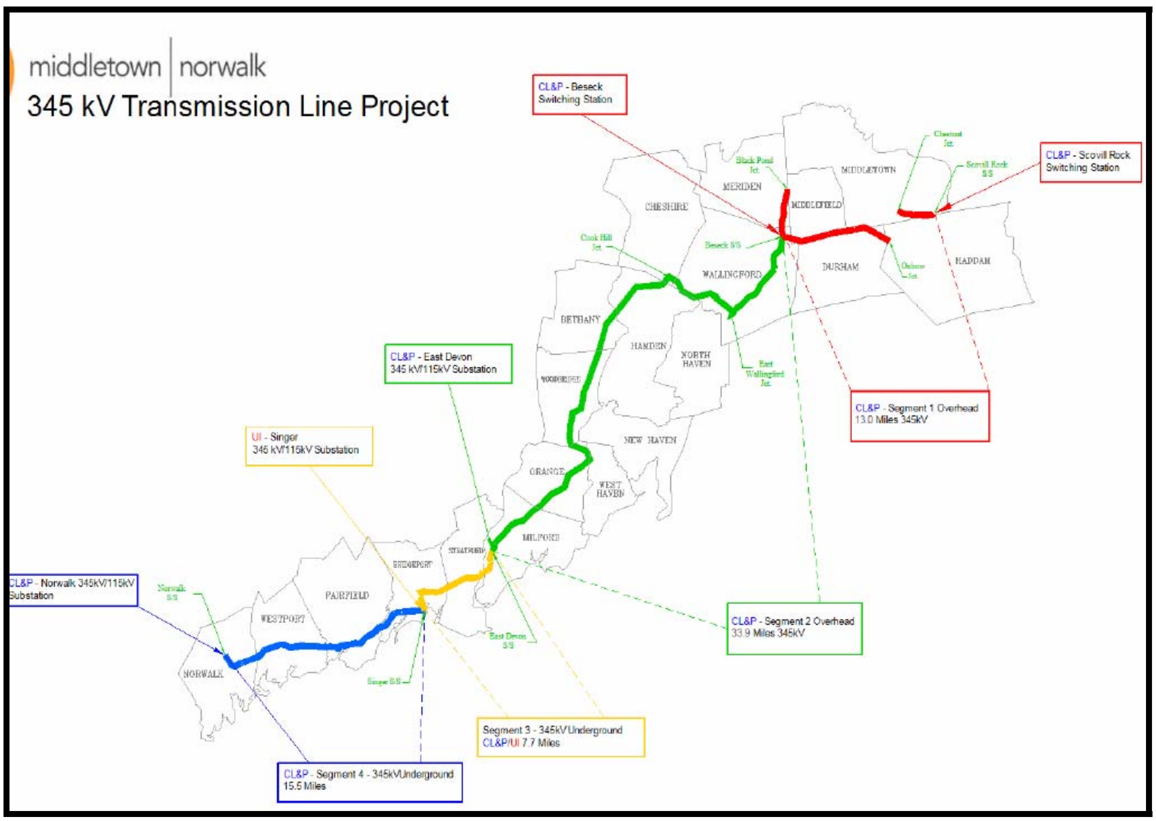

Figure 3-4. Middletown-Norwalk Transmission Reinforcements

Benefits of the Bethel – Norwalk and Middletown – Norwalk Transmission Line

In the Connecticut Siting Council 2005-14 Ten-Year forecast, the Council anticipated that the state's power supply resources would be adequate to meet demand in the near term under normal weather conditions assuming the availability of all units and no loss of existing generation due to retirement. However, taking the most conservative forecast (ISO-NE's 09/10 estimate), Connecticut faced a significant generation capacity shortage throughout the forecast period. In addition, some sub-regions such as SWCT, to a lesser extent, eastern Connecticut were threatened with supply deficiencies and operating problems due to insufficient transmission and inadequate resources within the region.

Completion of the two major transmission projects greatly improved electricity reliability in SWCT by allowing some 1,300 MW of generation located in the north and central part of the state to be imported into the SWCT region. Evidence of the improved reliability brought about by the completion of these projects is the reduced transmission congestion charges and the elimination of the need for reliability must run agreements with generators located in the area.

Transmission Congestion Relief as a result of the Bethel – Norwalk and Middletown – Norwalk Transmission Lines

The construction of the 345kV transmission loop in SWCT has connected the area to the New England 345kV network which has resulted in reduced transmission congestion and the associated congestion charges.

Historically, constraints on the SWCT interface have resulted in congestion and higher Locational Marginal Prices (LMPs) in the region. As discussed above, the Bethel-Norwalk 345 kV and Middletown-Norwalk 345 kV projects were constructed to increase the capacity of the transmission interface and reduce congestion in SWCT These transmission upgrade projects increased the ability to import power into SWCT by approximately 1,300 MW.

Figure 3-5 provides a summary of the congestion component of the LMPs for the Connecticut Zone (an aggregate of loads and generation LMP nodes within Connecticut) and for the Milford generating node from January 2005 to June 2010. When the transmission system is constrained, congestion differentials between different nodes within the system will arise due to the cost to alleviate the congestion and the impact of generation on the constraint(s). If there is no congestion on the transmission grid, the congestion component of all of the nodal prices will be zero.

Figure 3-5 shows that congestion is decreasing with the implementation of the SWCT upgrades particularly, with the Middletown-Norwalk 345 kV project in December 2008. In the summer of 2009, the congestion converges to near zero demonstrating that there is minimal congestion for the Connecticut Zone and for the Milford generating node. This trend is direct evidence of the improved strength of the transmission grid in SWCT and its ability to bring lower cost energy reliably into the region.

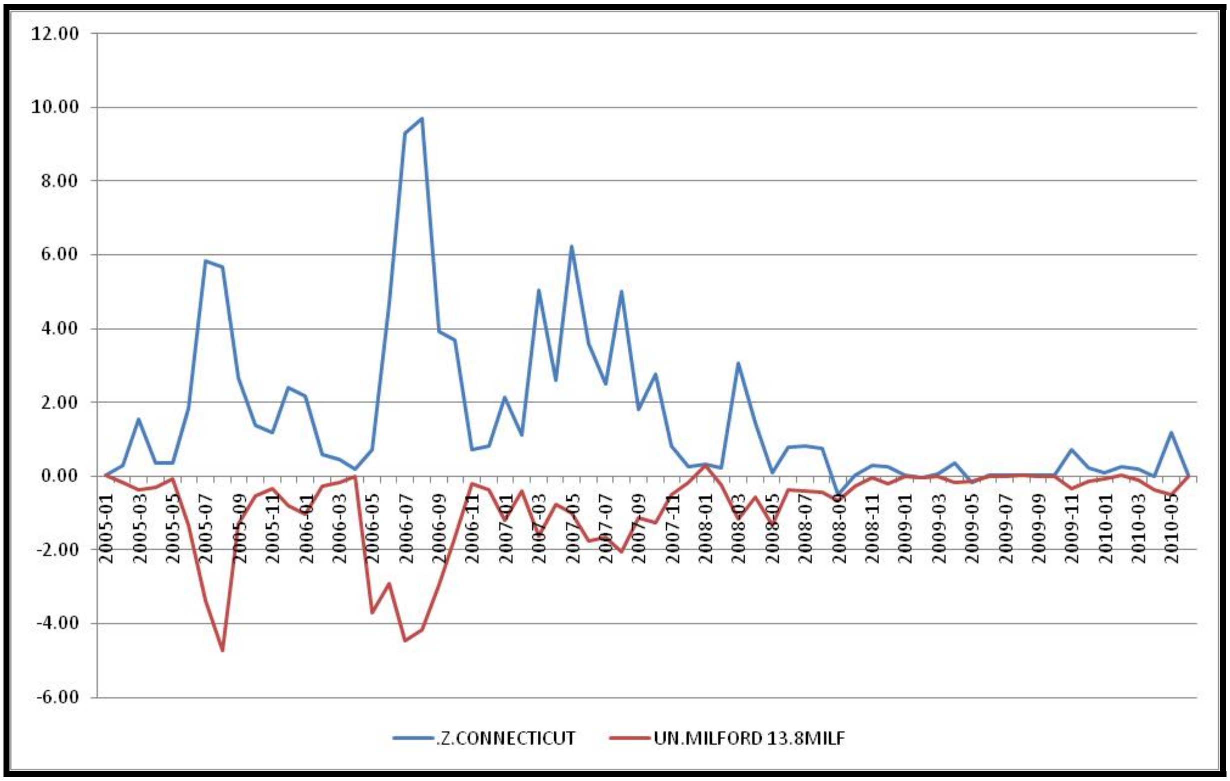

Figure 3-5. LMP Congestion in Connecticut

Impact on Reliability Must-Run Generation as a result of the Bethel-Norwalk and the Middletown – Norwalk Transmission Lines

Subject to FERC approval, RMR contractual arrangements provide financial support to facilities that are uneconomic to operate, but essential to maintain reliability. The agreements reflect a determination by the ISO-NE that the system requires the operation of certain generating units to maintain reliability because of transmission constraints or for voltage support, operational reserves, or other reliability reasons. The vast majority of RMRs are in load pocket areas because transmission constraints prevent less expensive generation from being imported to meet local demand. These RMR contract agreements were increasing in the import constrained areas of Connecticut and Boston (NEMA). As of December 2006, 41% (3,082 MW) of the total generating plant capacity in Connecticut was under RMR agreements. However, since completion of the 345 KV loop as well as the development and construction of new generation in the region and the demand response program all RMR contracts have expired and have not been replaced or extended. The capacity of the SWCT transmission system is now adequate to provide reliable service during peak load periods or transmission constraints and meet all regional reliability requirements without the support of local generation.

Construction of New Generation

Connecticut policy makers have taken the lead in providing incentives for new capacity resources to be built in the state. Since 2005, long-term power purchase agreements have incentivized nearly 1,200 MW of new generation to be built in the state. While the primary driver may have been to reduce costs to Connecticut ratepayers, the additional generation has the significant ancillary benefit of improving transmission reliability in the region.

In June 2005, Connecticut policy makers enacted Public Act 05-01, An Act Concerning Energy Independence (EIA), which authorized the Connecticut DPUC to launch a competitive procurement process geared toward motivating new supply-side and demand-side resources in order to reduce the impact of Federally Mandated Congestion Charges (FMCCs) on Connecticut ratepayers. The DPUC's primary objective with this procurement process is to reduce the impact of FMCCs and other costs on Connecticut ratepayers by facilitating the development of new or incremental capacity. Development of a regional demand response program in New England has added 3000 MW of additional "resources" that can be dispatched to reduce load during peak load periods or a times of transmission system constraint.

The Department of Public Utility Control (DPUC) selected four projects, totaling an aggregate 787 MW, as winning bidders in its RFP process for new capacity. According to the DPUC this portfolio of projects is expected to reduce costs to CT ratepayers, improve system reliability, and provide important environmental benefits. The selected portfolio consists of: a 620 MW gas-fired combined cycle baseload plant in Middletown; a 66 MW oil-fired peaking facility located in the heart of congested Southwestern CT (Stamford); a 96 MW gas-fired peaking facility also located in Southwestern CT (Waterbury); and a 5 MW state-wide energy efficiency project offered by Ameresco.

In addition, in 2007 the State of Connecticut's General Assembly passed Public Act 07-242, Section 50, which sought a long-term solution to Connecticut's need for more peaking power generation, or power that is required during times of highest demand, such as periods of extreme weather conditions or unexpected transmission or generation outages. A joint venture between United Illuminating and NRG, known as GenConn, was awarded long term contracts to construct 400 MW of new peaking capacity – 200 MW at NRG's existing Devon plant in Milford, Connecticut which is expected to be commercial this year and 200 MW at a Middletown location.

This new generation, when completely on line, will greatly improve electricity reliability in the region as it provides additional generation sources within the SWCT load pocket. This new generation development, when combined with the new bulk transmission system reinforcements within the region, have brought the bulk transmission system in SWCT in compliance with all regional reliability requirements.

Conclusion

The electric generation and transmission infrastructure in SWCT is vastly different today from what it was in 1999, the year Milford Power was granted its CSC Certificate. Since that time, some 2000 MW of new generation has been built or is under construction in SWCT and 69 miles of new 345Kv transmission lines have been constructed at a cost of $1.5 Billion to vastly improve regional transmission capacity and supply reliability while at the same time reducing congestion costs to consumers.

The capacity of the SWCT transmission system is now adequate to provide reliable service during transmission constraints or outages and meet all regional reliability requirements without the support of local generation. The local and regional generation currently in service or under development only add a level of reliability above what is required to further provide reliable service the Connecticut electric customers.

ECONOMIC ANALYSIS

This task is comprised of an analysis of the economic impact of a natural gas supply interruption at the Milford Station. R. W. Beck has utilized its 2010-Q2 Base Case data assumptions to structure an economic analysis of the ISO-NE system as well as neighboring power markets which trade power with ISO-NE, and thus impact both the reliability and cost structure for the ISO-NE customer demand.

R. W. Beck has prepared this economic impact for a representative year, specifically 2013, to forecast the cost impact of natural gas interruption at the Milford Plant, if the plant has no oil backup system. Thus, if Milford Power has no oil backup and if its natural gas supply is interrupted, then other generation must be dispatched to replace the Milford power output. This replacement power may be supplied from generators located in Connecticut, or in other parts of the ISO-NE, or it may be purchased from external markets.

The decision of how to dispatch to meet an interruption in Milford generation will be based on the Security-constrained Unit Commitment ("SCUC") and Security-constrained Economic Dispatch ("SCED") of the ISO-NE system, optimizing generation and use of the transmission grid, which will change each hour. Similarly, if Milford has an oil backup system, and if its natural gas supply is suspended, the SCED may dispatch Milford on oil, either at full output or partial output, or dispatch other generation. The cost impact of an interruption of Milford production has been measured as the change in replacement power cost between having oil backup and not having oil backup, i.e. Milford unavailable for dispatch.

To date, natural gas interruption at Milford Power for either firm or interruptible transportation has occurred only once, on January 29, 2010, when an outage at a compressor station necessitated curtailment of 23% of firm capacity. During the January, 2005 cold snap, neither firm nor interruptible deliveries occurred, though the pipeline requested shippers to balance hourly at contract demand. This economic cost impact analysis has been based on a worst case scenario of a 5-day interruption in natural gas supply. The largest impact to power prices would probably result from a natural gas interruption during the peak summer months. To address the seasonality and interruption period issues, this economic analysis has determined the impact of gas interruption of a 5-day period for each month, based on the highest 5-day load period of each month.

The economic analysis shows that the cost impact of having no oil backup system at the Milford Plant ranges between $20,500 and $300,000 per month for a 5-day interruption. The highest cost impact occurs during the summer months, as expected. The lowest cost impact occurs in May when demand is low and hydro-electric water supply is high. The average monthly cost impact during the December through

February winter season is $19,767. The daily average cost impact ranges between $4,100 and $60,000. Table 4-1 illustrates the monthly cost impacts.

Table 4-1. Seasonal Cost Impact of 5-day Gas Interruption with No Oil Backup

	Impact of No Oil Backup at Milford ($)	Daily Average Impact ($)
Jan	97,439	19,488
Feb	38,782	7,756
Mar	68,989	13,798
Apr	45,735	9,147
May	20,504	4,101
Jun	120,367	24,073
Jul	154,256	30,851
Aug	299,904	59,981
Sep	156,500	31,300
Oct	87,674	17,535
Nov	64,142	12,828
Dec	31,741	6,348