NORTHEAST POWER MARKETS

ENERGY WATCH

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In light of recent growth in natural gas production growth and expected costs of future supply, ESAI has revised its long-term natural gas price forecast down compared to previous recent quarterly projections. This issue of *Energy Watch*™ discusses in detail the natural gas supply and demand trends underlying this updated price outlook and the corresponding impact on power prices and spark spreads for each of the Northeast regions.

The latest power price outlook is discussed in the regional sections. In addition to ESAI's updated long-term gas price outlook, a few supply and demand changes will affect power prices in all three Northeast markets. On the demand side, all three ISOs have revised long-term demand forecasts down. The lower expected demand growth in PJM was reflected in ESAI's Q4 2017 outlook, but both NYISO and ISO New England have since published lower demand forecasts. On the supply side, several capacity retirements have been announced, which if completed, could have significant market impacts. However, the potential for reliability-based agreements with non-market payments could prevent the retirements from occurring. As a result, the outlook for energy prices includes increased uncertainty.

ESAI's Q1 2018 forecast for the PJM energy market includes projections for additional regional hubs. The PJM section discusses the outlook for each of these locations and the key drivers of regional differences in power prices and spark spreads within PJM.

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ESAI 10-Year Natural Gas Forecast Shifts Lower

SUMMARY

With natural gas-fired generation on the margin in most hours in New York and New England and in a significant portion of hours in PJM, the price of natural gas is a major driver of energy prices in the Northeast. Gas prices are critical to the economics of coal and nuclear plants, and any recovery in gas prices provides hope of improved economics for these facilities. In addition, higher gas prices would brighten the economics for renewable energy. Given the importance of gas prices in the Northeast, this issue of *Energy Watch*™ leads with a discussion of ESAI's natural gas pricing outlook.

Northeast gas prices have decoupled from Henry Hub prices and are now dictated by Marcellus and Utica shale gas production and pipeline transportation dynamics within the region. Northeast gas prices are defined by regional production and pipeline constraints, with low priced regions (Leidy, Dominion South) characterized by a lack of pipeline takeaway capacity in the supply basins. Higher prices (mostly in winter) are defined by constraints in delivering gas to high demand regions such as New England and southeastern New York, where supplies to generators are rationed by high prices. Regional basis spreads are discussed more in depth in the natural gas section at the end of this report.

ESAI has held its natural gas forecast steady for the past 18-24 months, but a number of recent developments have lowered our outlook for long-term gas prices. Figure 3 below compares ESAI's updated Henry Hub outlook with the forecast presented in the December issue of *Energy Watch*™. Our current Dominion South forecast is included as it is a key driver for the Henry Hub outlook.

The key drivers of ESAI's natural gas outlook are summarized below, with more detail provided in the following sections:

SUPPLY SIDE

Production costs are influenced by changes in technology that can lower unit production costs and potentially change production profiles (slower production decline rates). ESAI's recent forecasts assumed that future demand (post 2021) would be met by supply from higher cost basins than Marcellus/Utica, driving prices higher in the long term than what would be expected by marginal supplies from Marcellus/Utica.

ESAI's current forecast incorporates three changes that lower future price expectations:

- Higher production expectations from lower cost Marcellus/Utica
- Higher production expectations from very low cost associated gas in West Texas (Permian) and Oklahoma (SCOOP/STACK)
- Some shale basins previously considered to have higher cost structures are now seeing lower production costs as technological advances from Marcellus/Utica are being applied to these regions. An example is the increase in production in the Louisiana Haynesville shale, the result of advanced techniques that are reducing costs in areas previously considered uneconomic.

DEMAND SIDE

In the near to medium term, demand is driven by exports from LNG facilities that are currently under construction. LNG exports will reach 9 Bcf/d by 2020 assuming a 90% capacity factor. Due to a global oversupply of LNG, it is possible, but less likely, that additional LNG export facilities will move forward beyond the 10 Bcf/d of capacity already completed or under construction. Thus, no further demand increases from LNG are expected after 2020. Other demand sources show relatively flat growth (residential, commercial, and power sector demand) as price elasticity is relatively low. Industrial demand growth is expected to increase by 2.0-2.5 Bcf/d by 2023, consistent with prior projections as low gas prices incentivize the construction of new petrochemical facilities, primarily in the Gulf Coast.

OUTLOOK

Near and medium-term growth in LNG and industrial demand can be met by increases in low-cost producing areas (Marcellus/Utica, associated gas, Haynesville) that are being actively drilled. The cost of these resources is expected to drift higher starting in 2022.

In the longer term, the need for gas from higher cost basins lessens as a result of lower demand growth expectations after 2020 and significant improvements in Marcellus/Utica pipeline takeaway capacity. Additionally, the expected production costs in these higher cost basins have been lowered based on experience with efficiency improvements gained in actively producing basins.

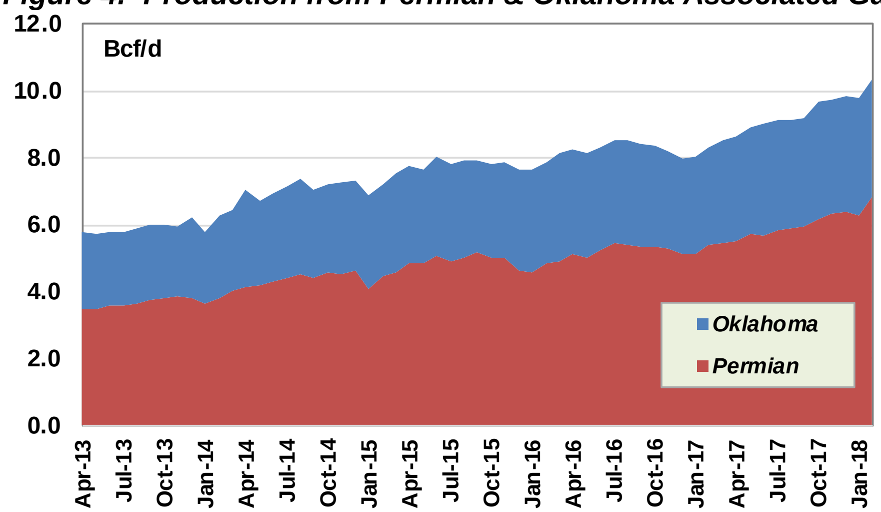
The net result is that more low-cost supply should be available to meet the transparent, near-term demand increases from LNG and industrial sources. Longer term, demand increases will moderate after the completion of the first wave of LNG export construction and new petrochemical facilities that will also increase demand for natural gas and ethane into 2020/21. The need for drilling will continue, however, as decline rates for existing shale gas production necessitate ongoing drilling to maintain production levels. Overall, the stability of demand and improved economics of shale basins outside of Marcellus/Utica provide the basis for lowering the long-term outlook for gas prices after 2021. Any unexpected incremental demand increases should be readily met by production increases in currently producing basins.

SUPPLY SIDE DRIVERS

While in the near term production is fixed and prices are driven by demand-side interests, in the longer term there is an abundance of natural gas that can be recovered and delivered to markets. Long-run production costs should dictate longer term pricing trends, as there will certainly be enough supply to meet rising demand. The outlook for long-run breakeven costs has changed as technological advances successfully deployed in Marcellus/Utica are being applied to other basins that had been largely abandoned due to higher cost structures.

Associated gas is a byproduct of drilling for oil in shale formations. As a result, associated gas production is highly dependent upon the production levels of crude oil from shale and therefore on the price of oil. With oil prices well above $50/barrel (currently $65), crude oil production from shale is attractive to most producers and highly profitable for top-tier producers. Increases in crude oil production will naturally bring higher volumes of associated gas. Likewise, if oil prices were to fall well below $50, oil drilling would decline and associated gas production would level off or decline (for example, existing production in the Permian basin alone currently declines by 0.25 Bcf/d each month).

Figure 4: Production from Permian & Oklahoma Associated Gas



Current associated gas production is near 10.0 Bcf/d and represents approximately 20 percent of total shale gas production.

CHANGES TO WATCH FOR

There are a number of supply-side factors that could shift production expectations relative to our base case assumptions. Although the demand-side outlook is relatively stable, shifts in expectations for imports and exports could alter supply and demand fundamentals. Potential changes to watch for are described below:

- **Crude oil prices –** lower crude oil prices would result in lower crude oil drilling and lower associated gas. At prices above $50/barrel, oil drilling will continue in earnest, however, at lower prices, oil drilling and associated gas production will be reduced.
- **Technological advances –** longer laterals reduce unit production costs for gas. Further, by limiting flows at the wellhead, production decline rates can be improved. Many companies will continue to push the limits of lateral lengths and experiment with fracking proppants to improve economics. Another improvement that has not been fully exploited to date is using the same well pad to tap into two shale formations. For example, there are many areas where both Marcellus and Utica shale formations (at different depths) could be tapped from the same well pad location, providing access to additional shale gas with much lower costs from land leases and wellhead infrastructure.
- **Sweet spot exhaustion –** Over time, the most productive locations with a specific shale formation will have been exploited. The next tiers of lower shale productivity will be exploited at higher costs.
- **LNG exports –** The potential for a significant 'second wave' of LNG export terminals is diminished given the current global surplus in LNG supplies. As LNG contracts and prices become less linked to oil prices, a sharp rise in oil prices would have limited influence on encouraging increased development and construction of LNG liquefaction capacity.
- **Imports/Exports –** ESAI's current view of increased exports to Mexico is modest, as power generation and pipeline infrastructure within Mexico will take time to build out. Actual pipeline capacity from the US to Mexico is being built well ahead of demand and is unlikely to be filled in the near to medium term. Also, Canadian exports appear to be stabilizing relative to previous projections for significant annual declines. Changes in net exports could swing the supply/demand outlook by as much as 2-3 Bcf/d if exports to Mexico were to increase more rapidly and Canadian imports were to decline.

CONCLUSIONS

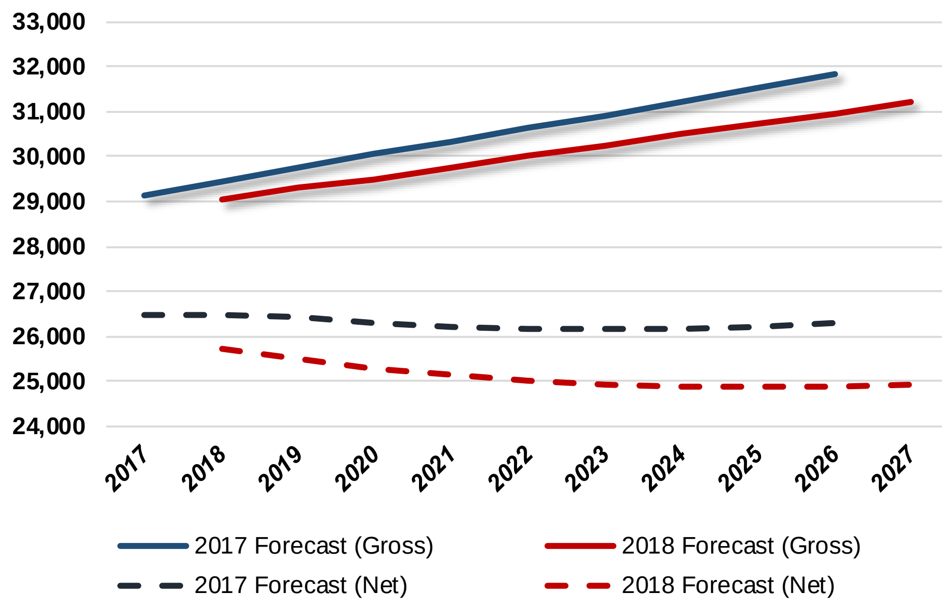
Over the past 18 months, the gas market has adjusted to lower demand resulting from mild weather (2016 and 2017) by reducing rig counts, as seen in the rig count lows seen in January 2017. Through the course of 2017, rig counts have increased and dry gas production has increased from 72 Bcf/d to over 78 Bcf/d. Meanwhile, prices have remained relatively stable in the $2.75-$3.00/MMBtu range.

New England

ISO-NE DEMAND FORECAST REVISED DOWN; NEGATIVE GROWTH PROJECTED

ISO-NE issued a draft final demand forecast for the 2018 Capacity, Energy, Load, and Transmission (CELT) report in late March. As shown in Figure 14 and Figure 15, the updated forecast includes a significant downward revision compared to the demand forecast published in the 2017 CELT report. The gross peak load before reduction for Passive Demand Response (PDR) and distributed photovoltaic solar (PV) is forecast to grow at a rate of 0.8 percent, slightly lower that the 1 percent growth rate in the 2017 forecast. After accounting for PV and PDR, the peak load is expected to drop at a compound average rate of 0.4 percent over the next ten years, compared to the 0.1 percent decline forecasted last year.

Figure 14: Draft 2018 Peak Load Forecast vs. 2017 CELT (MW)



The forecast for gross annual energy demand is almost unchanged from the 2017 CELT report. However, after accounting for the PV and PDR reductions, the forecast for net demand is lower, resulting in a drop in forecasted net demand for 2026 of 5 TWh and an increase in the 10-year average rate of decline from 0.6 percent to 0.9 percent. As shown in Figure 16 and Figure 17, PDR accounts for the largest portion of the difference between gross and net demand.

As shown in Figure 18, ESAI has estimated that the lower demand will lower the Mass Hub clearing price by approximately \$0.50/MWh to \$1.00/MWh during peak hours and by approximately \$0.20/MWh during off-peak periods.

Figure 15: Draft 2018 Annual Energy Demand Forecast vs 2017 CELT (GWh)

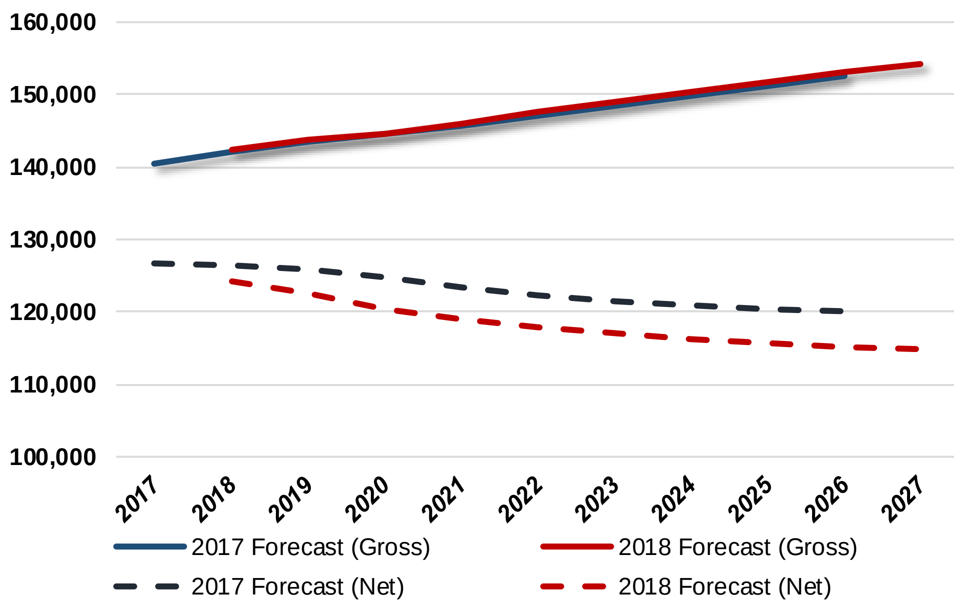


Figure 16: Demand Reductions Due to Distributed Solar (GWh)

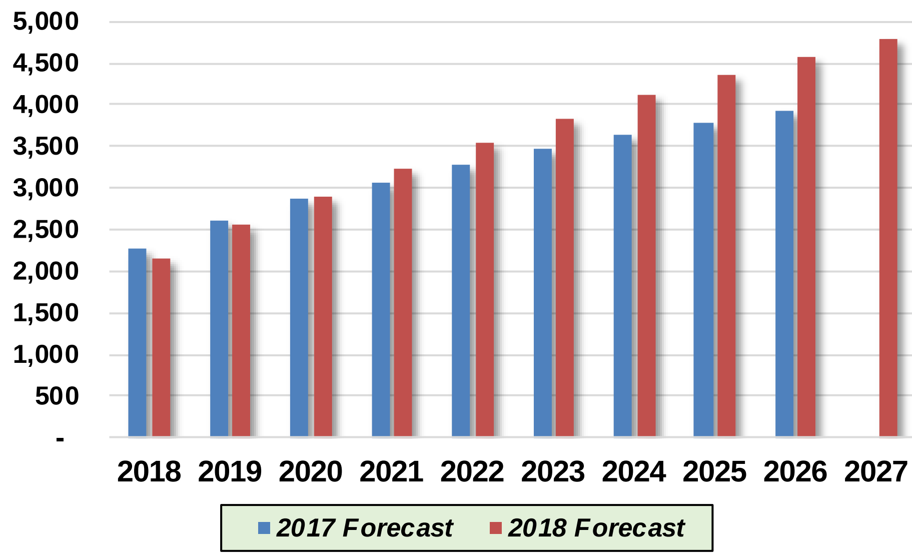
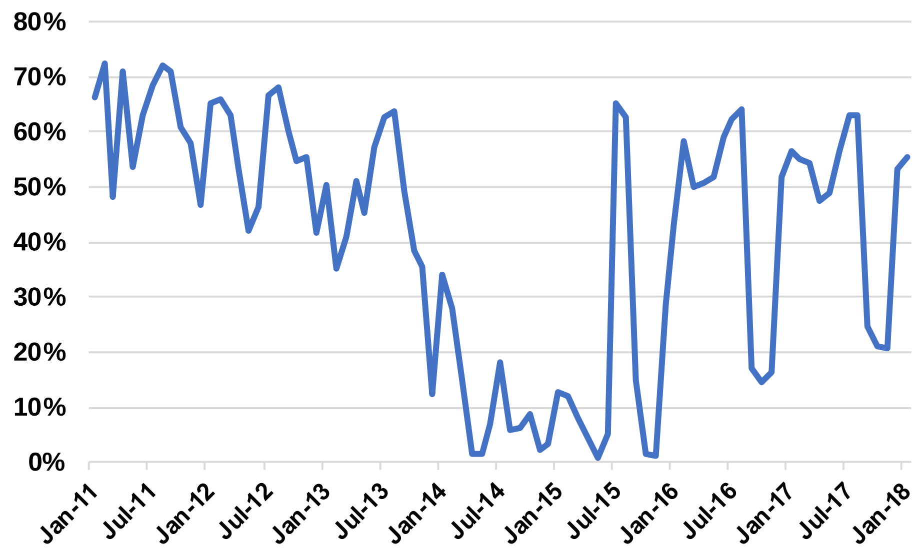


Figure 19: Mystic CCGTs (Units 8 & 9) Capacity Factors



NEW ENGLAND ENERGY MARKET OUTLOOK

ESAI's long-term outlook for delivered natural gas prices in New England has been updated to included sustained winter basis. Some reduction in the winter price premiums over other parts of the Northeast with more direct access to supply from the Marcellus region is still expected in the longer-term. However, ESAI now expects the infrastructure additions and demand impacts needed to facilitate lower basis to be delayed. As discussed in the gas forecast section, continued growth in gas demand and cancellation of major pipeline infrastructure additions will result in continued periods of high pricing in the winter months.

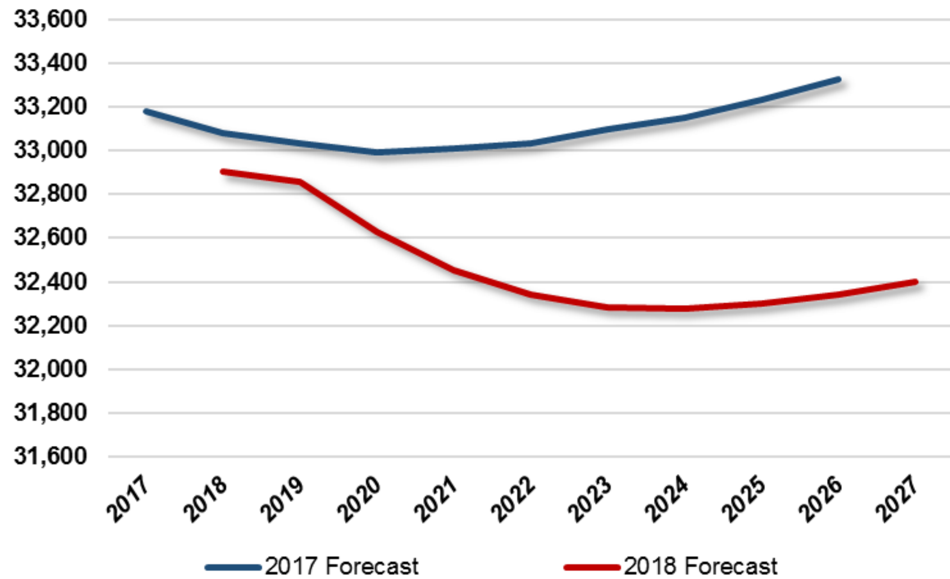
Figure 20 and Figure 21 show ESAI's forecast for the ISO-NE Internal Hub (Mass Hub) LMPs and implied market heat rates. The Mass Hub LMP is project to increase moderately over time, with escalation in gas prices and RGGI allowance prices being partially offset by declining demand. The implied market heat rates are expected drop between 2018 and 2019 with the addition of new CCGT capacity and a decline in winter gas prices (due to normal weather). After 2019, the implied market heat rate is expected to increase slightly, due to higher CO2 costs under the RGGI program and Massachusetts Clean Energy Standard. The increases in the market heat rate, along with gas price escalation over the longer-term, result in higher spark spreads over time.

New York

INCREASED ENERGY EFFICIENCY GROWTH EXPECTATIONS RESULT IN LOWER DEMAND FORECAST

Similar to ISO-NE, the NYISO has recently revised its long-term demand forecast down significantly. The current and prior year forecasts for the state-wide (NYCA) peak load and annual energy demand, as well as the forecasts for New York City (Zone J) are shown in the figures below. Over the next 10 years, negative growth is expected for both annual energy demand and peak load, both statewide and for Zone J. The 2017 forecast had called for slightly positive peak load growth, but declining annual energy demand.

Figure 23: Peak Load Forecast, NYCA (MW)



and changes in relative natural gas prices. The most substantial retirements planned for NYISO are Indian Point 2 (2020) and Indian Point 3 (2021). These nuclear units will be replaced, almost MW-for-MW, by new gas-fired CCGT capacity. Because the new CCGT units will be very efficient and are expected to run as baseload units, the energy price impact of the nuclear capacity being retired will be limited to mostly very low load hours. This outcome results in relatively flat expected market heat rates for Zone G, as shown in Figure 28. ESAI's projected heat rates are very close to those implied by the forward price curves.

For New York City some escalation in implied market heat rates is expected over the next five years, as shown in Figure 31. This escalation is driven by two principal factors. First, retirement of capacity resources in Zone J is expected in response to low capacity market prices, surplus capacity conditions, and the age of the New York City fleet. Second, pipeline upgrades will increase the gas delivery capacity into New York City and result in lower gas costs relative upstate New York and New Jersey. New York City power prices are frequently set by imports for the Lower Hudson Valley and Upstate New York. The lower delivered gas prices for New York City will make gas-fired units in Zone J more competitive, resulting in spark spread growth over the longer-term.

Figure 27: ESAI Power Price Outlook – Zone G LBMPs

PJM

PJM ENERGY MARKET OUTLOOK

ESAI's forecast for sparks spreads for PJM power pricing hubs is summarized in Figure 32 and Figure 33, which show historical and projected spark spreads for four PJM pricing points: Eastern Hub, Western Hub (PJMWH), AEP-Dayton Hub (AD Hub), and the Northern Illinois Hub (NI Hub). The spark spreads for each location are based on a proxy heat rate of 7,500 Btu/kWh and assume gas pricing as follows:

- Eastern Hub: Transco Zone 6 Non-NY
- Western Hub: TETCO M3
- AD Hub: Dominion South Point
- NI Hub: Chicago Citygate.

Compared to the last ten years, the differences in prices and spark spreads between these locations have narrow substantially and additional convergence is expected over the next ten years. The convergence is the result of reduced regional spreads in natural gas prices due to pipeline buildout (as discussed in the natural gas outlook section of this issue of *Energy Watch*™) along with new capacity additions and retirement of existing resources. In particular, the addition of the Atlantic Sunrise and Penn East pipeline projects will result in a substantial increase in gas delivery capacity to eastern PJM from receipt points in the Marcellus region. The lower resulting delivered gas prices in eastern PJM, along with moderately higher prices in the Marcellus region, will result in fewer periods with high LMP premiums in the eastern zones, particularly during the non-winter months. In the winter months, scarcity-driven pricing for natural gas is expected during fewer periods, also lowering (but not eliminating) winter gas price premiums in the eastern PJM zones.

New generation coming online over the next three years will temper spark spreads in the Mid-Atlantic region (MAAC), while retirement of coal-fired capacity and decreased capacity factors for remaining coal-fired units will maintain prices in western PJM at levels closer to the historically-constrained eastern zones. Spark spreads for PJM Eastern Hub have historically have been higher than the other PJM hubs, however, consistent with the more recent trend, eastern spark spreads are expected to be at a level similar to the AD Hub going forward. Higher LMPs and spark spreads are likely within some electrical load pockets in eastern PJM, however.

Under ESAI's base case, the Western Hub spark spread is expected to increase over time and trend above other hubs. However, this outcome is a result, in part, of the approach used to calculate the Western Hub spark spread. The electrical locations included in the LMP nodes that make up the Western Hub are geographically spread over Southwestern MAAC (predominantly PEPCO) and central MAAC (Predominantly PENELEC). The generating units setting the prices at these various locations burn a variety of fuels, including coal (mostly in Southwest MAAC, where delivered coal prices are very high), and natural gas that are indexed to various pricing points, including TETCO M3, Transco Zone 6 Non-NY, and Dominion South (among others). The Western Hub spark spreads shown below were calculated the using TETCO M3 gas prices, which under ESAI's base case assumptions declines in price relative to other fuels burned by some of the generators that set prices at the nodes included in the Western Hub price. In particular, prices in the PEPCO and BGE zones are expected to be set by higher cost fuels in many hours. Additionally, the Western Hub price is affected by RGGI allowance prices, which are expected to increase over the forecast horizon. Generators in Maryland must pay for RGGI allowances, while under ESAI's base case assumptions, generators in Pennsylvania (which is not currently a part of the RGGI program) do not face any cost for CO_2 emissions.

Figure 32: Historical and Forecast On-Peak Spark Spreads: PJM Hubs

Figure 33: Historical and Forecast Off-Peak Spark Spreads: PJM Hubs

Additional detail about forecasted prices, implied market heat rates, and spark spreads for each of these four PJM pricing hubs are provided below. Note that the forecasts shown for each hub assume continued operation of the Davis-Besse, Perry, and Beaver Valley nuclear units, for which First Energy has recently announced retirement plans and files deactivation notices with PJM. Despite these actions by First Energy, the future of the plants remains uncertain, as First Energy has also requested emergency action by the DOE to secure financial support to keep the units open. Additional discussion of the future of these plants and the potential market impacts will be provided in the next issue of *Capacity Watch*™.

Outlook for PJM Western Hub

Figure 34 shows ESAI's base case projections for PJM Western Hub prices. Figure 35 shows the corresponding implied market heat rates, which were calculated using the TETCO M3 natural gas price index. For 2018, annual average power prices are expected to increase relative to 2017, largely as a result of higher gas prices. The relatively mild winter of 2017 resulted in relatively low gas prices, while gas prices in 2018 year-to-date have been much higher. Beyond 2018, PJMWH power prices are expected trend closely with natural gas prices, as indicated by the relatively flat implied market heat rates shown in Figure 35. An exception to this flat trend in heat rates is projected for 2021, when the forecasted implied heat rate increases from the expected 2020 level. The 2021 increase is driven primarily by an expected drop in the TETCO M3 price following completion of the Penn East pipeline project. This forecasted increase in the implied heat rate does not appear to be reflected in forward market prices, which are very similar to ESAI's forecast over the next three years, but do not include

Natural Gas 10-Year Henry Hub Forecast

As detailed in the front section of this issue of *Energy Watch*, ESAI has lowered its long term forecast for Henry Hub and Dominion South gas prices. The forecast has come down slightly for 2018-2020, but prices beyond 2021 have come down by $0.70 to $0.80/MMBtu. The drivers for ESAI's gas forecast are provided in the front section of this report. Figure 47 compares ESAI's current outlook with the recently released EIA projections from the 2018 Annual Energy Outlook and with Henry Hub futures as of March 29.

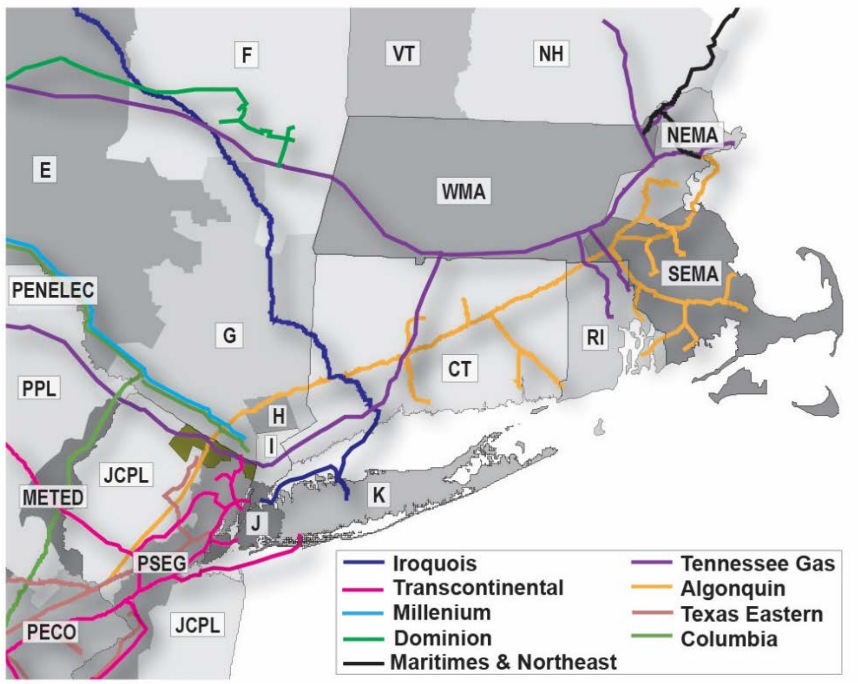
Figure 47: Henry Hub Price Outlooks; ESAI, EIA & Futures

In the following sections, ESAI provides a more detailed outlook for delivered gas prices in the Northeast region. New pipeline capacity is the main driver for shifts in delivered pricing over time. Expectations for new pipeline capacity additions are included in the discussions below.

NEW ENGLAND AND NEW YORK

In this section, ESAI provides an outlook for delivered prices for key pricing points in New England and New York. Algonquin City Gate is the key price index for New England while Transco Zone 6-NY is the main index for New York City and Long Island. Iroquois Zone 2 is the price marker for generators in upstate New York (Zone F).

Figure 48: Pipelines Serving New England & SE New York



ESAI utilizes forward delivered prices through December 2019, as forward prices are transparent and liquid over the near term. Starting in January 2020, ESAI takes into account fundamental factors that are likely to change delivered prices, largely increases in pipeline capacity that can lower winter premiums typically seen in New England and New York. ESAI adjusts the outlook for delivered prices based on incremental changes to supply in each area and an assessment of the potential effects on scarcity pricing for winter deliveries.

Table 27: Pipeline Projects in New England & New York

Project Name	Pipeline	Capacity (MMcf/d)	Miles	Compression (HP)	Online Date	ESAI Online Date	Status
Salem Lateral	Algonquin	115	1		Nov-16	Nov-16	Online
Algonquin Incremental Market (AIM) Project	Algonquin	342	37	81,620	Dec-16	Dec-16	Online
New York Bay Expansion Project	Transco	115			Oct-17	Oct-17	Online
Atlantic Bridge (Phase I)	Maritimes and Algonquin	39	2	15,500	Nov-17	Nov-17	Online
Connecticut Expansion Project	TGP	72	13		Nov-17	Nov-17	Online
Bayway Lateral Project	Texas Eastern	300	0.44		Jan-18	Jan-18	Online
Garden State Expansion Project (Phase 2)	Transco	160		50,500	Mar-18	Mar-18	Online
Atlantic Sunrise	Transco	1,700	197	132,000	Jun-18	Jun-18	Under Construction
Eastern System Upgrade	Millennium / Algonquin	223	8	44,800	Sep-18	Sep-18	Under Construction
Atlantic Bridge (Phase II)	Maritimes and Algonquin	93	4	11,000	Nov-18	Nov-18	Under Construction
Rivervale South to Market Project	Transco	190	1		Nov-19	Nov-19	Permitting
Northeast Supply Enhancement	Transco	400	36	51,000	Dec-19	Dec-19	Permitting
Constitution Pipeline (w/ Wright Compressor project)	Iroquois and TGP	650	124	22,000			On Hold
Northern Access	National Fuel / Empire	350	97	22,000	Nov-20	Nov-20	Approved / Delayed

Source: FERC's Approved and Major Pending Pipeline Projects, EIA, SNL and ESAI.

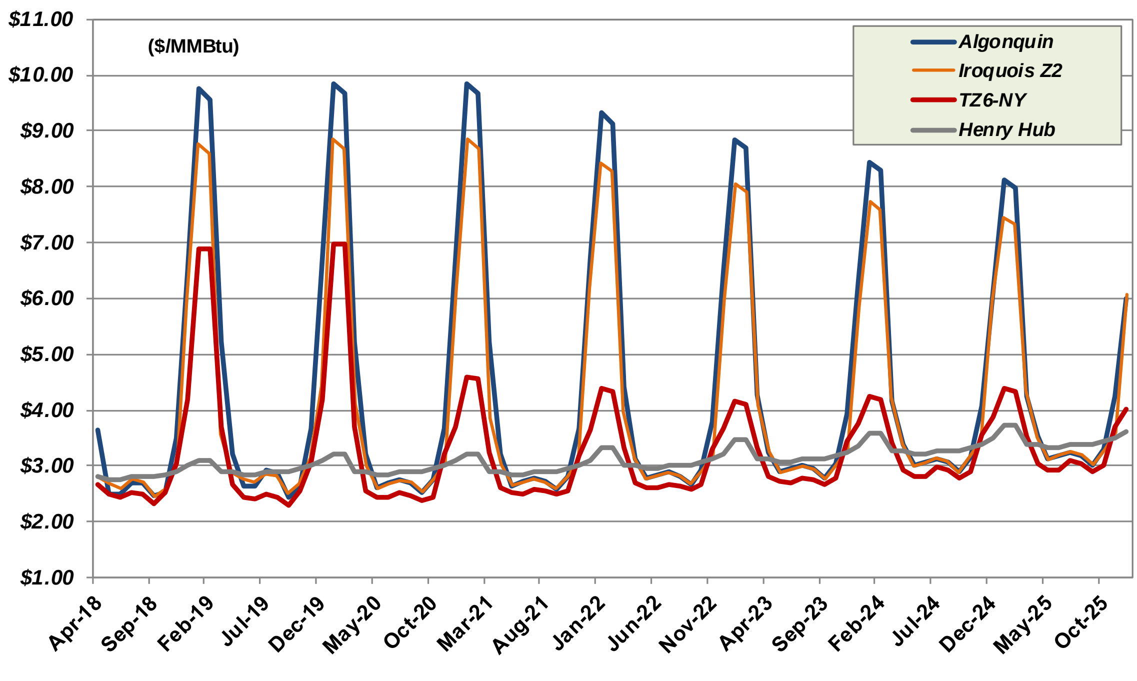
New England

Table 27 shows recently completed pipeline projects in New England and New York and provides an overview of projects that are under construction or advanced development.

In New England, the Algonquin Incremental Market (AIM) project was completed last fall and added 342 MMscf/d of incremental capacity on the Algonquin system into New England. Given that there is significant competition for volumes on Algonquin during cold weather, the AIM project was relatively small in comparison to the capacity that would be needed to radically reduce winter premiums. This can be seen in prices this past winter when Algonquin prices averaged almost $16.00/MMBtu during the cold weather in January.

With the cancellation of two earlier proposed pipeline projects (Northeast Energy Direct sponsored by Kinder Morgan & Access Northeast sponsored by Spectra), there are no other major pipeline projects in the queue for New England. ESAI expects Algonquin winter prices to remain stable at high levels (highly dependent on weather outcomes) until 2022. Starting in 2022, ESAI has a very modest decline in winter prices to account for increased renewable penetration, greater imports of Canadian hydro and eventually offshore wind. Figure 49 provides the outlook for Algonquin prices on a monthly basis through the end of 2025.

Figure 49: Delivered Gas Prices – Algonquin, Iroquois Z2, & TZ6-NY



New York

Supplies into the TZ6-NY pricing area are largely unconstrained during the non-winter months. TZ6-NY prices at a slight premium to Tetco M3 and Dominion South during these unconstrained periods (note that extensive maintenance on the Transco system resulted in higher TZ6-NY prices last fall). During the winter months, supply constraints into TZ6-NY result in high prices during cold weather periods.

There are several factors that will influence TZ6-NY prices going forward. First, new pipelines are under development that should alleviate winter constraints and relax high winter premiums. Second, some generators in New Jersey have been assessing the viability of switching their gas source from Transco to Texas Eastern (Tetco). As generators in New Jersey make the switch, (or add in the optionality to source from both systems), demand will be reduced for supplies in the TZ6-NY pricing area and this will help alleviate supply constraints and reduce upward pressure on pricing. While new pipelines and generator switching will help reduce winter basis premiums, New York City's elimination of the use of heavy residual fuel oil (#6 oil) by 2020 will put upward pressure on prices. Oil substitution for gas in New York City steam units will become more expensive as generators will be forced to purchase more expensive #4 oil instead of #6 oil.

A number of Marcellus pipeline projects are targeting New Jersey and New York that should relieve supply constraints and pricing for TZ6-NY (see Table 27). Recently completed projects include Transco's New York Bay Expansion Project and Tetco's Bayway Lateral Project. The New York Bay Expansion Project was completed in October 2017 and adds compressor capacity that increases flows by 115 MMscf/d to National Grid's system in New York City. The Bayway Lateral Project was completed in January and provides 0.3 Bcf/d of capacity from the Tetco system to industrial users such as the Phillips Bayway refinery and Linden Cogen. This project provides lower cost supply and lowers demand from the more constrained Transco system, potentially dampening TZ6-NY winter pricing premiums.

By June 2018, ESAI expects that the 1.7 Bcf/d Atlantic Sunrise project will be in service and will move additional supply from the bottlenecked Leidy region of Marcellus (Northeast Pennsylvania) southeast to the Transco system in Southeast Pennsylvania and Maryland (impacting TZ6-non-NY prices). While this project connects to the Transco system south of the TZ6-NY pricing area, the additional supply should support more competitive pricing in the non-winter months for TZ6-NY relative to Tetco M3 and Dominion South. The additional supplies from Atlantic Sunrise should increase the incentives to further reduce bottlenecks into northern New Jersey and New York City.

The 1.1 Bcf/d PennEast Project is currently targeted for Spring 2019 completion and will connect supply in the constrained Leidy region in Northeast Pennsylvania to the Tetco system at Lambertville, New Jersey and on to the Transco system in Mercer County, New Jersey near Trenton. PennEast will not directly impact supplies in New York City, but should relieve supply pressures for buyers in northern New Jersey and thus reduce winter pricing pressure for the TZ6-NY pricing area as a whole. The PennEast project has most of its permits but was recently denied a key water permit by the NJ Department of Environmental Protection. PennEast is confident of its ability to obtain this permit but the project is likely to be delayed to 2020.

