NORTHEAST POWER MARKETS

ENERGY WATCH

Authors: Paul Flemming, Scott Niemann, Julia Criscuolo, and José Rotger

3rd Quarter 2018

EXECUTIVE SUMMARY

In this issue of *Energy Watch*™, ESAI Power discusses the energy margin outlook for gas-fired generation in the northeast markets. The issue begins with an overview of the factors affecting gas-fired generation, focusing on prospects for new additions and on simple-cycle versus combined-cycle plants

In the New England section ESAI provides a discussion of tariff provisions for winter fuel security. The fuel security (or more broadly energy security) rules under development for New England will have a significant impact of the financial performance of some assets and are likely to affect the mix of capacity retired over the next ten years.

In the New York section, ESAI provides the current outlook for energy prices and spark spreads throughout the New York State, along with projected energy margins for generators in New York City and the Lower Hudson Valley. The energy market impacts of proposed carbon pricing for New York are also evaluated.

The PJM section focuses on the outlook for gas and coal-fired generation in various locations and highlights the impact of differences between the ESAI gas forecast and the current forward curve.

The gas outlook section compares the ESAI outlook with the EIA gas forecast.

In This Issue

ESAI POWER LLC

401 Edgewater Place
Suite 640
Wakefield, MA 01880
Tel: 781.245.2036
Fax: 781.245.8706
www.esai.com

Gas-Fired Generation Economics

In this issue of *Energy Watch*™, ESAI's analysis focuses on the financial performance of new gas-fired generation in each market. Entry of new gas-fired generation in each of the northeast markets has been significant over the past five years and development projects continue to move forward, despite surplus conditions in each market compared to required reserve margin levels. A few key questions arise about the future of new entry in PJM, New England, and New York.

- In a low demand growth environment, will new entry opportunities persist or emerge?
- To what extent can uneconomic existing generation be displaced by new gas-fired units?
- Will the markets support CCGT or Simple Cycle capacity additions?
- How will policy decisions and market rule changes affect the economic performance of new capacity additions?

WILL ADDITIONAL NEW ENTRY BE SUPPORTED AND EXISTING CAPACITY RETIRED?

ISO-New England

In New England, retirements left the ISO facing a capacity shortfall against LCR in 2017/18 Forward Capacity Auction (FCA). New capacity cleared in the next two FCAs, which combined with declines in the load forecast, have left the region with a surplus for the next several years. New entry of gas-fired generation has largely stalled for New England, given this existing surplus and an expected wave of new renewable capacity additions. ESAI expects retirements of capacity in New England, but additional new entry in future FCAs is not expected to be economic over at least the next five years. However, given the relatively small size of the New England market, a combination of retirements and faster-than-expected demand growth could result in the market recovering more quickly. Given the prevalence of gas-fired capacity in New England, however, energy margins are for new CCGT capacity will be moderated and the potential for new entry to force displacement of existing resources is limited.

New York

In New York, new CCGT capacity is being added in the Lower Hudson Valley in advance of the retirement of the Indian Point nuclear units. Given the retirement of baseload capacity in the region, new entry has consisted of CCGT units. Although no additional new entry is expected over the next few years, increasing capacity requirements along with expected retirement of older peaking units is expected to support new entry for New York City. Unlike the Lower Hudson Valley additions, the New York City new builds are expected to come from new simple-cycle units. Just over 100 MW of simple cycle capacity has already been added for New York City at the existing Bayonne site (located in New Jersey and connected to New York City via an underwater radial transmission line).

Like New England, new entry in New York is bnot likely to displace enough existing resources to allow capacity market recovery. However, to the extent that new transmission additions or changes in market rules put downward pressure on the market, existing capacity resources are likely to be retired, helping to limit the downside risk for efficient new units in good locations.

PJM

In PJM, over 20 GW of new CCGT capacity has been added recently or is currently under construction. The PJM capacity has been built on the expectation of continued low natural gas prices and declining profitability for coal-fired generation. The PJM market is also facing a surplus of capacity, with approximately 20 GW of existing capacity remaining unsold in the RPM capacity market Base Residual Auction (BRA) conducted for 2021/22, carrying over surpluses from prior BRAs. However, unlike ISO-NE where development of new gas-fired capacity has largely stalled, new development continues for PJM. The hopes of developers of PJM capacity are built on the potential for additional retirements of coal and nuclear capacity in the region. As shown in the figure below and in more detail in the regional discussions in this issue, power and gas prices in some PJM locations over the past five years would have supported substantial energy margins for new CCGT units. For example, ESAI estimates that based on historical pricing, a new CCGT unit (6,500 Btu/kWh heat rate) in the PENELEC zone with access to Dominion South natural gas pricing would have earned $13.65/kW-month on average over the past five years. With energy margins at that level, ESAI estimates that the all-in costs of new entry could be recovered with capacity payments as low as $60-75/MW-day – below the level needed to cover the costs of much of the coal and nuclear fleet in PJM. However, ESAI's forecast for the PJM market (discussed in the PJM regional section), shows that these historical energy gross margin levels will not be sustainable due to changing gas prices, renewable additions, and the substantial amount of gas-fired additions already underway.

New England

SUMMARY

A few key factors will determine the energy market outlook for New England over the next ten years. Under ESAI's currently base case assumptions, winter natural gas prices are expected to remain high with no significant pipeline upgrades expected. In the longer-term, increased LNG imports along with additional wind generation and imported hydro power will help to moderate tight gas supply in the winter months. However, without additional infrastructure, the region will remain dependent on dual-fuel generating capacity and LNG-fueled generation for winter supply. This section begins with a discussion of the tariff changes developed by ISO-NE for winter fuel security. With the provision in place for the near-to-mid-term and rules under development for the longer-term, ESAI has assumed the Mystic Units 8 and 9 will continue to operate.

Along with the forecast for energy prices and spark spreads, this issue of *Energy Watch*™ includes estimated energy gross margins for gas-fired and nuclear capacity in New England. With flat-to-negative demand growth forecasted and substantial renewable additions expected for New England, spark spreads and energy gross margins for generators in New England are expected to remain flat, at levels below recent history. Retirements of capacity, beyond those already announced, are expected as a result of surplus supply in the capacity market and flat energy margin outlook. However, most of the generating units are risk for retirement run at low capacity factors and the deactivations are not expected to significantly affect energy margins.

ISO-NE FILES TARIFF CHANGES FOR WINTER FUEL SECURITY UNIT RETENTION AND RELIABILITY AGREEMENTS

On August 31 and in compliance with FERC's July 2 order rejecting ISO-NE's request for a tariff waiver, ISO-NE filed tariff changes to implement an "interim" mechanism to retain resources seeking to retire but needed to maintain regional fuel security. The proposed tariff changes rely on a very similar framework to that proposed by ISO-NE in its tariff waiver request to retain the LNG-fueled Mystic Units 8 and 9 and the associated Distrigas LNG terminal.

The proposed fuel security reliability agreement criteria and review method is based on a 90-day winter energy analysis to quantify operational "stress" on the system by measuring hours of reserve depletion and load shedding. Notably, the trigger for retaining a unit for fuel security is effectively based on the winter energy analysis showing any hour of ten-minute reserve depletion below 700 MW in more than one of the LNG supply scenarios studied (i.e., with LNG injections varying from 0.8 to 1.2 Bcf/day). Note that 700 MW is the minimum amount of reserves assumed in the FCM installed capacity requirement (ICR) calculation. Note that this operational analysis does not consider fuel costs or prices, market responses to fuel and power prices, or potential increases to gas pipeline capacity.

From a market perspective, this trigger means that 30-minute reserves are beyond a binding constraint, with the 30-minute reserve constraint penalty factor (RCPF) violated (which would also trigger an FCM scarcity event). ISO-NE's position is that any one-hour depletion beyond 700 MW of 10-minute reserves (likely a binding constraint but well before a 10-minute RCPF violation) in more than one of the LNG supply scenarios modeled is an unacceptable condition that crosses the fuel security "line in the sand." Not allowing the triggering of 10-minute RCPFs before a unit is retained for fuel security ignores the market design for reserve constraints and FCM pay-for-performance (PFP), both of which assume (and provide prices for) the depletion of 10-minute reserves.

The interim fuel security tariff provisions would be in place for FCA13 (2022/23), FCA14 (2023/24) and FCA15 (2024/25). To comply with FERC's directive to file permanent tariff changes by July 1, 2019, ISO-NE intends to replace the interim tariff provisions with a market-based winter energy security solution to be developed and implemented for FCA16 (2025/26).

Notably, NEPOOL approved a competing version of the interim tariff changes with several key changes to ISO-NE's proposal, including:

1) ***Revised trigger for retaining resources*** – NEPOOL approved a fuel security retention trigger at load shedding in any one scenario of ISO-NE's winter energy analysis equal to or greater than the MWh of expected energy not served at the Net ICR value under the MRI demand curve for the most recent FCA – for the recently concluded FCA12 for 2021/22, 683 MWh. This revised trigger is much more stringent than ISO-NE's reserve depletion trigger, resulting in a much lower probability that units would be retained for fuel security. The revised trigger is also more consistent with the design of ISO-NE's resource adequacy (capacity) and reserve markets.
2) ***Higher assumed renewables in the winter energy analysis*** – NEPOOL approved a New England state proposal to revise ISO-NE's winter energy analysis to assume that all New England states will achieve their renewable portfolio standards (RPS) mandates by the dates specified in the mandates (ISO-NE had assumed a much more conservative approach in achieving the mandates). NEPOOL also approved a change to the model to update wind capacity factor and output data to reflect future technology improvements. Both these changes significantly increase the amount of fuel-secure, non-pipeline-gas-fired energy in the winter energy analysis, thus further reducing the likelihood of unit retentions.
3) ***Limit fuel security retention interim tariff provisions to two years*** – NEPOOL approved provisions to limit the fuel security interim tariff changes to FCA13 (2022/23) and FCA14 (2023/24), effectively seeking to force ISO-NE to develop a market-based fuel security solution for FCA15 (2024/25), one year earlier than proposed by ISO-NE. The approved provisions further limit any fuel security cost of service agreement to no more than 2023/24 (FCA14); in other words, an FCA14 agreement could not be renewed to 2024/25 (FCA15).

A FERC order on the interim tariff changes is due by October 31. We believe there is a reasonable chance that FERC may adopt one or more of the NEPOOL-approved alternatives to ISO-NE's proposal.

Designing a Market-Based Winter Energy Security Mechanism

In the meantime, ISO-NE has begun discussions on a winter energy security market mechanism, with an initial focus on defining the fuel security "problem" to be addressed by the market mechanism. Notably, ISO-NE has shifted its characterization of the issue from the broader "fuel security" term to the phrase "winter energy security," a narrowing of the issue to a seasonal perspective as well as to energy markets and not capacity. ISO-NE defined the problem as the need to assure a reliable supply of energy during the winter, regardless of fuel or technology. Thus, we are confident that the proposed solution will be an energy market mechanism and not an adder or "bolt-on" to the ISO-NE capacity market.

Although still in early stages, discussions are centering on a conceptual energy and reserve market construct with the following elements:

- ***Multi-day-ahead energy market*** **–** ISO-NE would run the day-ahead energy market using a rolling seven-day (or more) ahead horizon, optimizing all energy (including energy inventory reserve, as described below) over that timeframe.
- ***New reserve product/ancillary service market*** **–** ISO-NE would procure a new ancillary service product in the real-time and multi-day ahead markets for "Energy Inventory Reserve," defined as energy inventory (MWh) available to be used on-demand over the next seven (or more) days. The new Energy Inventory Reserve constraint would be integrated into the multi-day-ahead market optimization, re-dispatching the system to preserve energy inventories and shifting production as needed to higher-cost, energy-inflexible ("use or lose it") resources.
- ***Seasonal forward procurement of energy inventory*** **–** ISO-NE would conduct a voluntary, seasonal auction for "Forward Energy Inventory Reserve" obligations that settle against the corresponding price for the new energy inventory reserve ancillary service product (real-time and day-ahead).

The design of the winter energy security market mechanism will be finalized next spring with stakeholder votes in May/June in order to meet FERC's July 1, 2019 filing deadline. As indicated above, ISO-NE wants to delay implementation of this mechanism to 2025 at the earliest (the FCA16 2025/26 commitment period); however, several stakeholders are pushing for an earlier implementation date of the FCA15 commitment period (June 2024).

NEW ENGLAND ENERGY MARKET OUTLOOK

Forecast Assumptions

ESAI's base case market forecast assumptions for New England are consistent with recent outlooks but with some changes to reflect recent RFP activity described below. Demand assumptions are based on the 2018 CELT Report forecast and include declining peak load and annual energy demand over the next ten years due to increasing energy efficiency and distributed solar generation. Peak load is forecasted to decline at an average rate of 0.4 percent annually, while annual energy demand is forecasted to decline by 0.9 percent annually.

ESAI's current forecast for New England delivered natural gas prices reflects forward pricing values for the winters of 2018/19 and 2019/2020 to reflect forward values that have reasonably liquid trading in the first two years. Beyond the winter of 2019/2020, ESAI expects Algonquin winter basis to decline moderately due to the gas substitution effects of the 1,000 MW Canadian hydro import via the Northeast Clean Energy Connect (NECEC) as well as increased renewable penetration and the addition of offshore wind (see Figure 4).

Figure 4: Algonquin City Gate Natural Gas Price Forecast

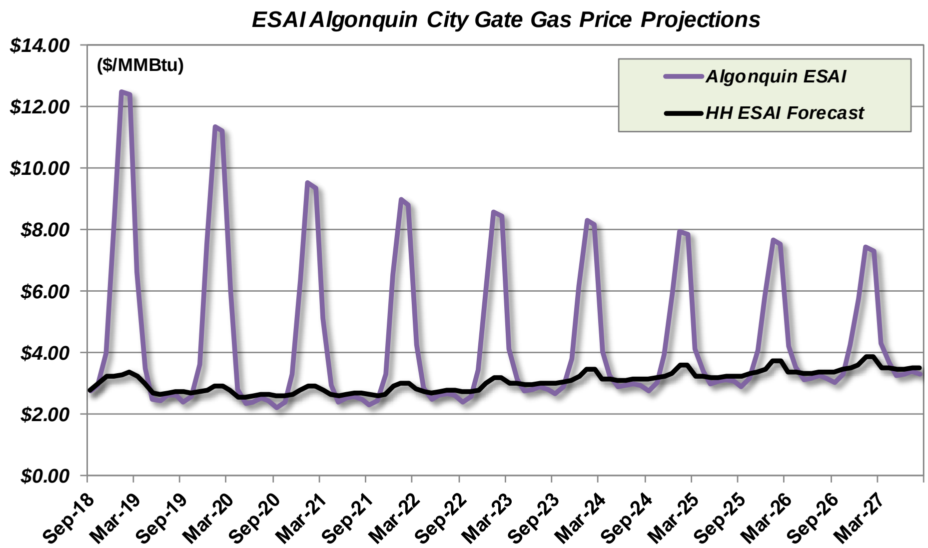


Table 2 and Table 3 provide assumptions for retirements and new generation additions in New England. One change to the new additions table is the removal of the 485 MW Clear River project. Due to ongoing permitting issues, Clear River has consistently failed to meet its milestone objectives and as a result, ISO-NE has terminated Clear River's capacity supply obligation (CSO) for 2021/22 (subject to FERC approval). Replacement capacity had already been secured to cover the project's CSOs for 2019/20 and 2020/21. Clear River will no longer receive capacity payments and also loses its seven-year price lock. The financial assurance posted for the project for the 2021/22 Capacity Commitment Year will also be forfeited. Clear River will not be qualified for the Forward Capacity Auction (FCA) for 2022/23 and would need to re-enter the qualification process in order to bid into future auctions. Given the surplus expected to be available in upcoming FCAs, ESAI believes it is unlikely that a future iteration of Clear River could clear. ESAI assumes that all other generation cleared in the forward capacity auctions will proceed to completion.

As a result of the Massachusetts 83D solicitation for clean energy, 1,000 MW of Canadian hydro will be imported via the NECEC line as noted above. This energy will be

NYISO

SUMMARY

The outlook for energy prices in New York is highly dependent upon delivered gas prices and the generator supply stack in each region. Due to the cascading transmission constraints within New York, LMP outlooks for Zone A in the west, Zone G (Lower Hudson Valley), Zone J (NYC), and Zone K (LI) have significant variation. The following sections provide:

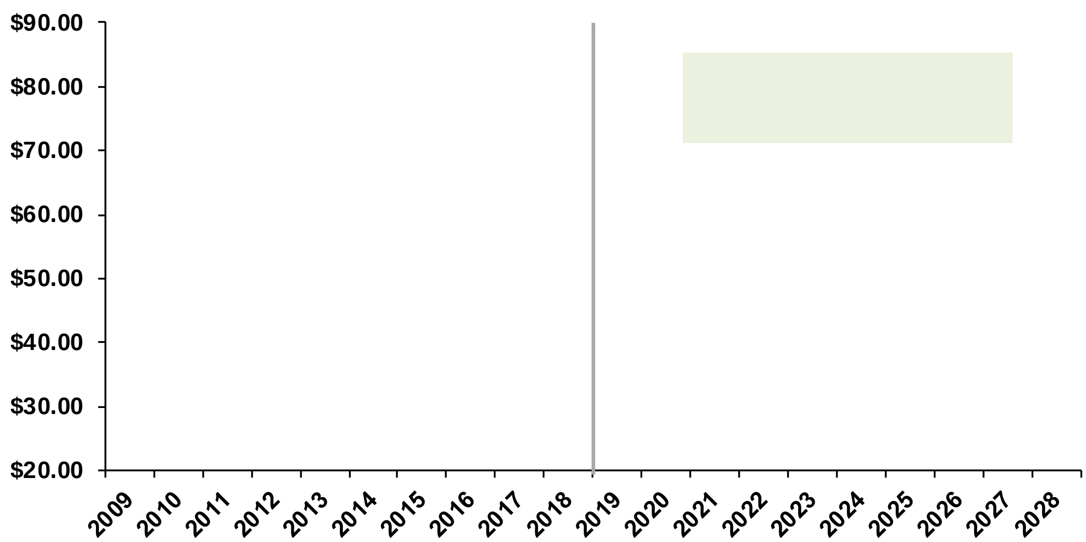
1) An overview of LMPs, implied market heat rates and spark spreads over the ten-year forecast period
2) An assessment of energy gross margins for simple cycle and combined cycle gas-fired units in each of the major load zones, and
3) An evaluation of the impact of proposed CO2 pricing on New York LMPs and energy gross margins for gas-fired units.

NEW YORK TEN-YEAR OUTLOOK

Forecast Summary

ESAI's forecasts for the New York power market, summarized in Figure 11, reflect shifts in gas price expectations and moderate escalation in energy prices due to rising natural gas prices and RGGI allowance costs. Moderate growth in spark spreads is being driven by retirements and increasing CO_2 emissions allowance costs, overcoming near-term negative demand growth. For 2021 and beyond, forward market prices continue to reflect the potential implementation of for a carbon adder in NYISO. As a result, implied market heat rates remain above the ESAI base case outlook as ESAI's base case does not assume any CO2 costs beyond RGGI. ESAI's projected heat rates are much lower therefore than those implied by forward market prices which are pricing in carbon adders starting in 2021. In 2019 and 2020, ESAI's Zone G on-peak outlooks are very close to the forward curve.

Figure 11: NYISO LBMP Forecast ($/MWh, On-Peak)



New York City Outlook

2019 New York City LMPs are expected to clear higher than 2018 levels due to the shift higher in non-winter TZ6-NY delivered gas prices, although winter premiums will remain strong. In 2020 and 2021, TZ6-NY prices drift lower and Zone J LMPs trend lower in line with gas prices. Lower winter TZ6-NY premiums are expected in early 2021 due to the expected addition of the Northeast Supply Enhancement project that will bring an additional 400 MMscf/d of gas into New York City. After 2021 a slow rise in gas prices contributes to an escalating trend in LMPs.

Also contributing to the escalating trend in LMPs (and higher spark spreads and heat rates) is the retirement of the Indian Point nuclear units in 2020 and 2021. Although not located within Zone J, their proximity provides low cost imports. Although CPV Valley and Cricket Valley will make up a large portion of the capacity lost by Indian Point, neither of these plants are close to Zone J and therefore do not have the same impact on energy prices that the Indian Point units have.

Additional 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. ESAI expects significant retirements of older peaking facilities as the result of pending NOx regulations that will require the addition of SCRs that will not be economic for the large majority of peaking units. ESAI assumes that some of these peaking units will be replaced by new peaking capacity, the most likely candidate being the Berrien's project which has already cleared the buyer-side mitigation process, receiving an exemption from mitigation.

The Northeast Supply Enhancement pipeline upgrade will increase gas delivery capacity into New York City, resulting in lower gas costs relative to gas plants in upstate New York that will continue to contend with higher gas costs, particularly in the winter. Since New York City power prices are frequently set by imports from the Lower Hudson Valley and Upstate New York, lower delivered gas prices for New York City will make gas-fired units in Zone J more competitive, resulting in market heat rate and spark spread growth over the longer-term.

As shown in Figure 20, market heat rates increase significantly from 11,500 Btu/kWh in 2018 (lower due to high winter gas prices) to near 15,000 by 2022. The rise in heat rates is the result of a combination of retirements (noted above and outlined in Table 8 and Table 7) and the decline in delivered gas prices.

Similar to Zone A and Zone G, forward market prices for Zone J result in a very different pattern of implied market heat rates after 2019, as ESAI's forecast does not include the proposed pricing of carbon emissions which are built into forward prices starting in 2021.

PJM

SUMMARY

PJM energy prices, implied market heat rates and spark spreads continue to be dependent upon natural gas prices, regional transmission constraints and coal plant economics. Low natural gas prices have shifted the patterns of congestion pricing, such that prices in the eastern zones have converged to prices in the west as represented by the AEP-Dayton Hub. The following sections provide:

1) An overview of the PJM energy market outlook
2) An assessment of projected energy gross margins for CCGTs in various key locations within PJM with sensitivities that compare results using ESAI's gas forecast and forward curve gas prices.
   - ESAI provides gross margins for gas plants and coal plants at AD Hub, NI Hub and PENELEC
3) Detailed energy price, implied market heat rate and spark spread projections for PJM Western Hub, PJM Eastern Hub, AEP-Dayton Hub and Northern Illinois Hub.

PJM ENERGY MARKET OUTLOOK

Overview

ESAI's forecast of power prices for the PJM regional hubs is shown in

Figure 33 and Figure 34. The corresponding spark spreads are shown in Figure 35 and Figure 36. The forecast is shown for four hubs spanning PJM: 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 assumed gas pricing as follows:

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

Similar to the forecast presented in Q2 2018 issues of *Energy Watch*™, the current ESAI outlook shows the differences in prices and spark spreads between these locations continuing to converge over the next ten years. The convergence is the result of reduced regional spreads in natural gas prices due to pipeline build out, along with new capacity additions and retirement of existing resources.

DETAILED REGIONAL FORECASTS

The following sections provide additional detail about forecasted prices, implied market heat rates, and spark spreads for each of these four PJM pricing hubs.

Outlook for PJM Western Hub

ESAI's outlook for PJM Western Hub prices is provided in Figure 44 and Table 21 below. LMP projections for 2019-2021 are relatively flat and slightly higher than historicals seen in 2016 and 2017. 2018 LMPs were higher due to high gas prices during the winter and a warmer than normal summer. Under normal conditions, on-peak LMPs in 2019 are expected to average $36.00/MWh which is a $4.00 drop from 2018 levels. PJMWH LMPs are expected to remain flat through 2023 on stable gas pricing but starting in 2024, moderate gas price escalation is a key driver in increasing LMPs from 2024 to 2028. In 2028, on-peak LMPs are forecast to reach $45.00/MWh assuming that gas prices shift slightly higher.

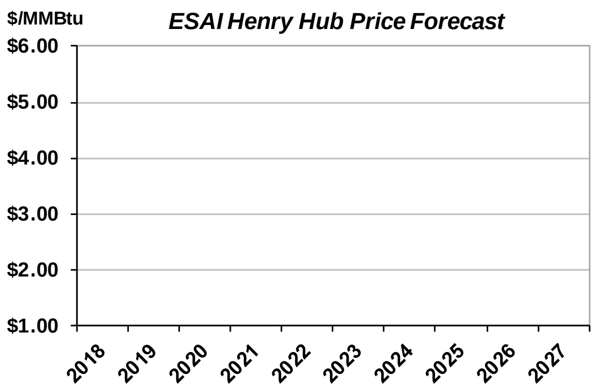
ESAI's outlook for implied market heat rates are shown in Figure 45. Market heat rates for PJMWH are using the TETCO M3 natural gas price index. Due to high winter gas prices in 2018, the annual 2018 on-peak implied market heat rate should average close to 11,300 Btu/kWh. Despite lower forecast LMPs in 2019, the 2019 heat rate projection is slightly higher at 11,700 Btu/kWh. This is a result of lower gas prices in 2019 than in 2018 and in particular, lower projections for Tetco M3 winter gas prices. In January 2018 Tetco M3 prices averaged almost $14.00/MMBtu compared to a projection of $5.70/MMBtu for January 2019 (in line with forwards). Beyond 2019, a significant drop in Tetco M3 prices is expected that will drive implied market heat rates (and spark spreads) higher. The drop in Tetco M3 prices is a function of lower prices in both winter and non-winter periods as Marcellus/Utica production increases as the result of major pipeline expansions from 2018 to 2020 (see Natural Gas section for more discussion on the impact of regional pipelines). For Tetco M3 specifically, the addition of the PennEast pipeline will reduce winter premiums and promote convergence of Tetco M3 non-winter prices to Dominion South and Leidy. PennEast will bring gas supply from Leidy to the Tetco mainline in Lambertville, providing gas to the demand-centric end of the line. ESAI assumes that PennEast will be delayed by one year and will commence operations in late 2020.

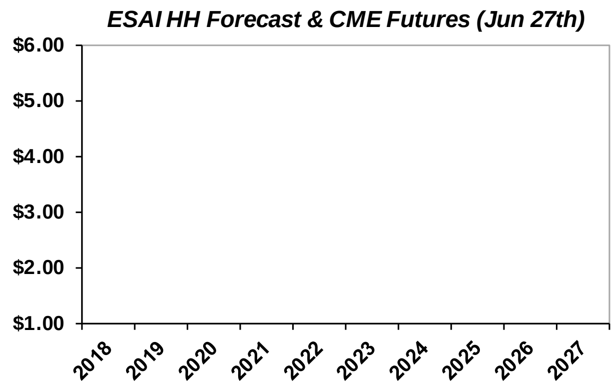
ESAI's spark spread outlook is provided in Figure 46. As noted above, the drop in gas prices results in an upward shift in spark spreads in 2020, largely as a result of increasing competitiveness of gas-fired plants against coal in the lower gas price environment. The shift in higher spark spreads and heat rates due to gas prices is offset by the addition of 9 GW of new combined cycle entry in 2018 (includes units expected in 2017), 3 GW in 2019 and a further 7 GW from 2020 to 2022 (see Table 30).

A full list of generation retirements and additions is provided for all of PJM in Table 30 and Table 31 at the end of this section.

Natural Gas 10-Year Henry Hub Forecast

ESAI Long-Term Henry Hub Forecast ($/MMBtu) - Nominal Dollars										
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027





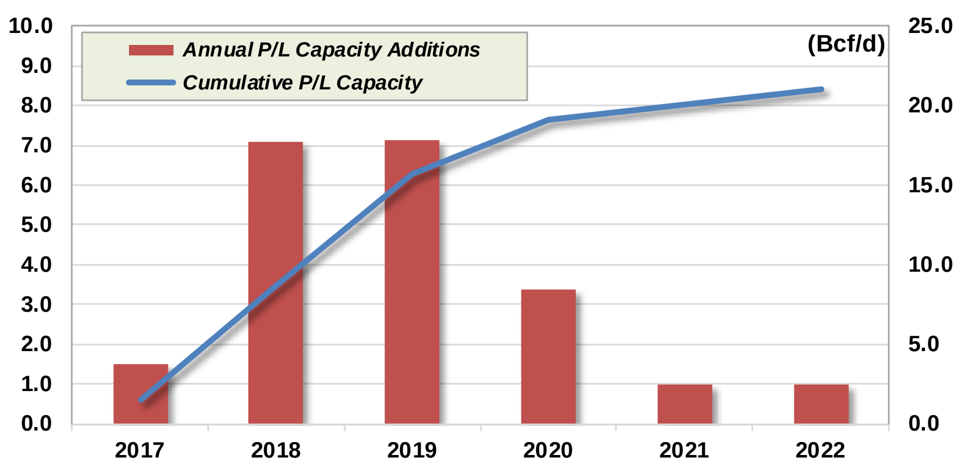
In this issue of *Energy Watch*[TM], ESAI presents two topics. The first is an overview of pipeline capacity build-out in the Northeast relative to expected increases in Marcellus/Utica production. In particular, the analysis focuses on potential headroom available through 2022.

The second topic is a discussion that compares the ESAI Henry Hub forecast with the EIA and forward market outlooks. ESAI presents a comparison of the key supply and demand assumptions that drive the ESAI and EIA forecasts and also presents a discussion of price expectations embedded in the Henry Hub forward curve.

NORTHEAST PIPELINE CAPACITY & HEADROOM TRENDS

Northeast pipeline additions are expected to be robust over the next five years with 7.0 Bcf/d of new pipeline capacity entering service in 2018 and 2019 (see Figure 56 below).

Figure 56: Annual Northeast Pipeline Additions

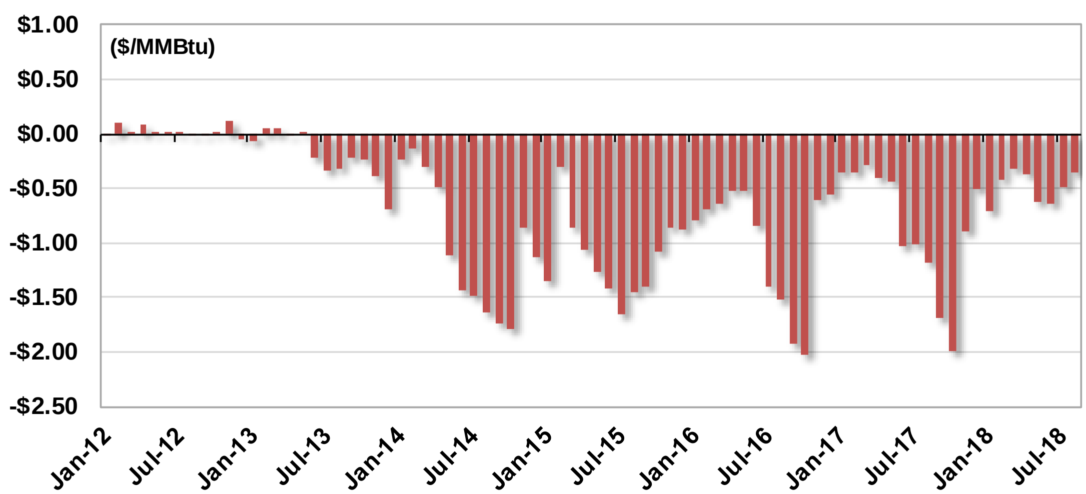


By 2022, cumulative 'take-away' capacity will reach 21 Bcf/d with 14 Bcf/d of that capacity entering operations in 2018 and 2019. Details of the pipelines included as take-away capacity can be found in Figure 60 and Table 32 at the end of this section.

Prior to this year, Marcellus and Utica production has often been constrained by limited pipeline capacity, resulting in steep discounts at regional pricing points such as Leidy and Dominion South. As shown in Figure 57 below, Dominion South priced at close to parity with Henry Hub until late 2013. As Marcellus production ramped up, Dominion South prices were discounted to Henry Hub by $1.50 or more. During the winter periods, local demand helped ease Dominion South pricing pressures, but discounts in the non-winter months have averaged $1.00 or more. At the end of 2017, Rover Phase I entered commercial operations and in January of this year, Leach Express entered service. These two projects added 3.2 Bcf/d of pipeline capacity (1.7 Bcf/d for Rover and 1.5 Bcf/d for Leach Express). Rover Phase II and most of the supporting laterals are also now in service, bringing Rover to its full capacity of 3.2 Bcf/d.

As a result of these additions, Dominion South pricing discounts have narrowed from $1.00-$2.00 over the last few years to $0.30-$0.60/MMBtu this past summer. Continued additions of pipeline capacity as shown in Figure 56 will keep Dominion South pricing relatively narrow to Henry Hub for the next few years. Forward market pricing shows Dominion South discounts of about $0.55/MMBtu through 2021 but then widening to about $0.75/MMBtu in 2023 and $0.80/MMBtu in 2024.

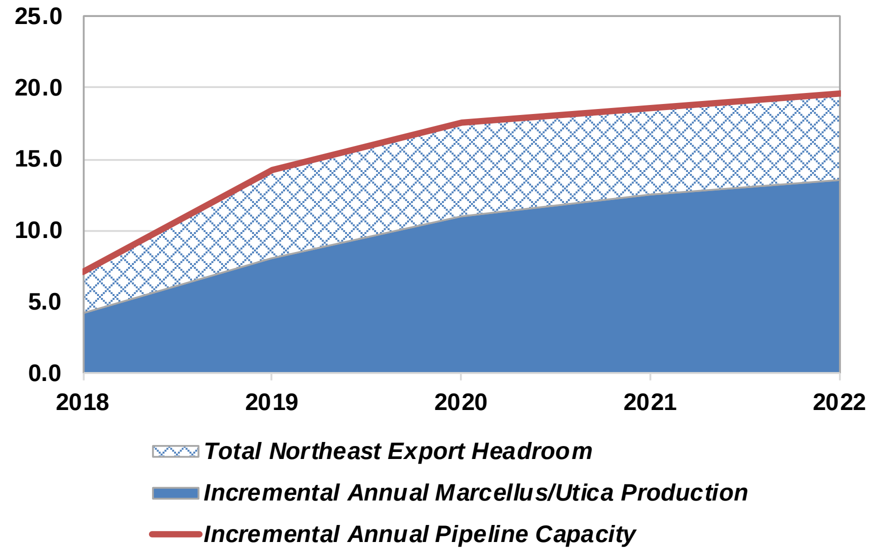
Figure 57: Dominion South Basis Pricing History



ESAI projects that Dominion South discounts will remain in the $0.50/MMBtu range through at least 2022 and likely for one or two years after that depending on Marcellus/Utica production increases and further pipeline development. One metric to assess is the overall pipeline headroom which measures production against potential takeaway capacity. If there is headroom on the pipeline system to take production out of the region, then flows should be relatively unconstrained and Dominion South prices will remain only moderately discounted to Henry Hub.

Figure 58 provides a comparison of annual increases in Marcellus/Utica production with annual increases in pipeline takeaway capacity. The pipeline headroom in 2018 is about 3 Bcf/d and increases to 6 Bcf/d in 2019. After 2019, increases in pipeline capacity slow down, but projections for Marcellus/Utica production slow down also. The main drivers of slower production increases for Marcellus/Utica are increases in associated gas production and a slowdown in LNG export growth after 2020.

Figure 58: Northeast Pipeline Capacity & Headroom vs. Production



The projected headroom for pipeline capacity in the Northeast suggests that Dominion South pricing discounts should be moderate in the coming years. If associated gas production does not increase as expected (28 Bcf/d in 2018 to 38 Bcf/d in 2022) or demand is stronger than expected, Marcellus/Utica production can ramp up and still have room to expand before hitting constraints that will expand Dominion South discounts.

ESAI, EIA & FORWARD MARKET GAS PRICE PROJECTIONS

As natural gas is a major price driver for Northeast power markets, LMP forecasts are dependent on the choice of the underlying natural gas forecast. When selecting a natural gas forecast, power market analysts face several choices. The EIA forecast is updated annually in the Annual Energy Outlook (AEO) and is widely known and respected. Independent forecasts from market consultants are available but often show significant variation in their projections. Lastly, the forward market quotations are also utilized as a transparent option to assess future gas prices.

Varying the choice of the gas forecast underlying energy market assessments will not only provide different outlooks for LMPs but varying the gas price can greatly influence regional spark spreads and energy gross margins for individual plants. In PJM for example, a