White Paper

Indian Point: Filling a Nuclear Void

By Dan Jerke, Aaron Geschiere, Kevin Petak, Ken Collison, and Chris MacCracken, ICF

Executive Summary

Following years of discussion and conjecture, New York and Entergy reached an agreement in January to shut down the Indian Point nuclear plant. As New York's single largest source of generation, the Indian Point retirement will have widespread implications for wholesale energy and capacity markets, Northeast carbon and gas markets, and transmission and grid reliability. Challenges and opportunities abound for a number of market participants.

Shareables

- Capacity prices could soar to $135/kW-year or higher in 2021, absent additional builds.
- Energy prices may increase in the Lower Hudson Valley and NYC by as much as 5%.
- Transmission upgrades are now more compelling, namely the Order 1000 projects for Central/East and UPNY/SENY interfaces.
- Northeast gas markets will likely tighten with up to 200-300 mmcf/d incremental demand from CPV Valley and Cricket Valley.
- RGGI prices have begun to creep higher, but continued clean energy development could mitigate large price increases.

Capacity Markets: Prices May Soar Absent Additional Builds

The announced retirement of Indian Point has the potential to jolt the New York capacity market. Absent additional builds, apart from CPV Valley and Cricket Valley, capacity prices in the Lower Hudson Valley region could increase to $135/kW-year or more ($15/kW-month summer), a sharp increase from the 2016 calendar year spot value of $75/kW-year. While certain factors appear known, such as the additions of the two combined cycle plants, much uncertainty remains. The key questions for the capacity market are:

1. Will there be additional builds by 2021 to avert the higher prices when the second Indian Point unit (IPEC 3) retires?
2. How will the demand curves evolve in upcoming years and into 2021/2022 with the next quadrennial demand curve reset?
3. How will the Locational Capacity Requirements (LCRs) be adjusted for changes in supply and transmission, or if the current methodology is overhauled?

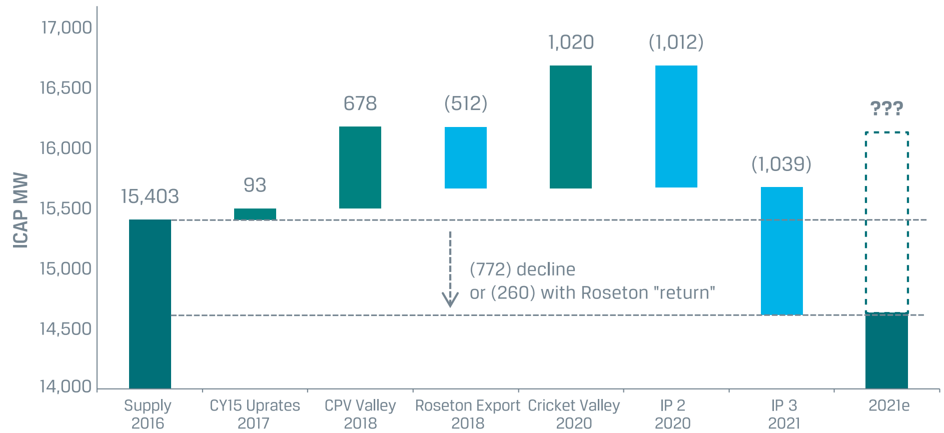
Replacement Capacity – An Opening in 2021?

The Indian Point nuclear facility is comprised of Unit 2 (1,020 MW) and Unit 3 (1,040 MW) in NYISO Zone H within the Lower Hudson Valley (LHV) capacity region. The January announcement states that Unit 2 will retire by April 30, 2020, and that Unit 3 will retire by April 30, 2021. However, the units may stay online until 2024 and 2025, respectively, if needed for reliability.

At present, the anticipated replacements are two combined cycle plants: the CPV Valley Energy Center (680 MW, Zone G) with an estimated online date in early 2018, and Cricket Valley Energy (1,020 MW, Zone G), which is expected online in early 2020. There are also a handful of uprates to existing units that recently completed in Class Year 2015. Potential new entrants include:

- The 1,000 MW HVDC line from Quebec to Astoria, under development by TDI;
- Various projects from NYC suppliers such as NRG Berrians repowering (up to 1,000 MW), Eastern Generation's Astoria Unit 40 return-to-service, the Luyster Creek CCGT, and South Pier peaker; and
- Several projects in New Jersey proposing to interconnect into NYC, including Bayonne Energy Center II (121 MW peaker), Linden Cogen uprate (230 MW), and Liberty Generation CCGT (1,000 MW).
- LHV candidates include NRG Bowline 3 (775 MW, Zone G), the possible "return" of Roseton exports, and potentially a repowering of Danskammer.

EXHIBIT 1. LHV SUPPLY OUTLOOK: WHAT MIGHT REPLACE IPEC3 IN 2021?



Source: NYISO 2016 Gold Book, NYISO Class Year 2015 materials, ICF calculations

Demand Curve – Bullish as Well

By 2021, the LHV demand curve is projected to be 34% higher and steeper than 2016, due to the outcome of the latest demand curve reset, projected increases in the net cost of new entry (net CONE), and modest load growth. However, if proxy unit energy margins increase, net CONE could decline.[1] This is unlikely given that the current winter of warm temperatures and moderate prices that will replace the Polar Vortex winter of high energy margins.[2] Thus, an increase in net CONE is expected going into the 2018/19 Capability Year.

The anticipated price support from the higher net CONE may be lessened by NYISO's low demand growth outlook. The NYISO projects a mere 0.1% CAGR over the next four years for the LHV Locality net peak.[3] Future projections could be lower, and the growth rate could turn negative as various Reforming the Energy Vision (REV) initiatives pick up speed.

Another potentially-moderating factor is that the next demand curve reset will develop new curves for 2021 to 2024, when the most price uncertainty is expected. If key assumptions change such as the proxy unit technology, a drop to the reference point could erase projected gains.

[1] The demand curve reference price is set using the net cost of new entry of a proxy peaking unit in each capacity region. The MW requirement is equal to the load forecast multiplied by the LCR and converted to UCAP with the applicable derating factor.

[2] In its quadrennial Demand Curve Reset process, the NYISO calculates the proxy peaking unit's energy margin using net energy and ancillary services revenues over a historic three-year period. For 2018, this period will span September 2014 to August 2017. As such, the energy margin (and net cost of new entry) calculations will exclude the high energy prices of the January 2014 Polar Vortex.

[3] New York ISO (April 2016), "2016 Load and Capacity Data ("Gold Book")," at p. 14, available online here.

Locational Capacity Requirements – The Big Wild Card

The setting of the Locational Capacity Requirements (LCRs) may be the biggest wild card for pricing. The LCRs represent the amount of capacity that must be procured from resources located within each locality. Currently, the LCR for LHV is very sensitive to changes in supply – nearly one-to-one. This means that a given change in supply will result in a nearly-offsetting shift in the demand curve, such that the price moves much less than the amount suggested by multiplying the quantity change times the demand curve slope. To illustrate, in its recent mitigation analysis, the NYISO assumed a 95.5% LCR for the LHV to reflect the addition of CPV Valley in 2018.[4] The 95.5% value is 4.0% higher than the recently-approved 91.5% value for 2017. The increase in the LCR would be expected to raise prices by $5/kW-month (62%) in 2018 when CPV Valley enters and more capacity is procured within LHV to satisfy the 95.5% LCR.

The LCR swings could be exacerbated by the unprecedented supply changes surrounding the retirement of Indian Point. The NYISO is currently evaluating alternate LCR methodologies in its stakeholder process. ICF expects the entry of CPV Valley to serve as a catalyst for finalizing a new methodology in 2017, lest prices would have a muted response or not change at all following its entry.

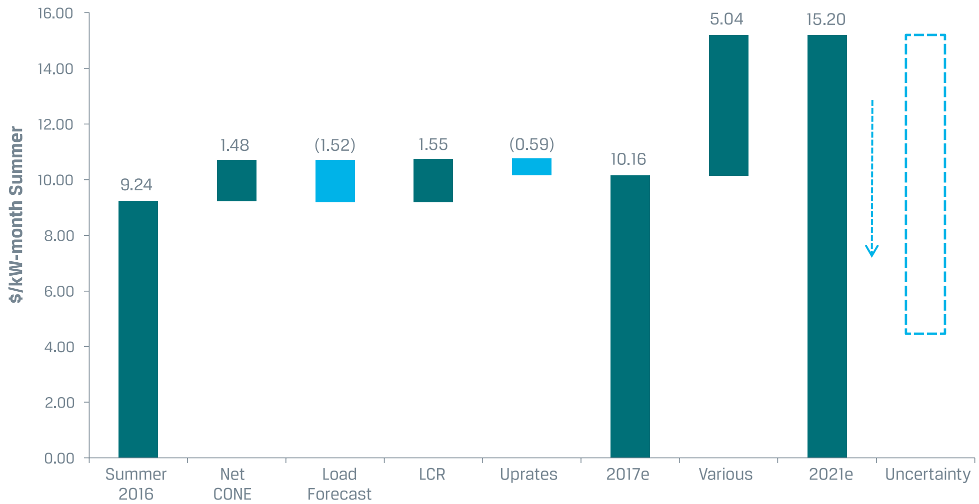
Price Outlook – Summing It Up

The salient price drivers are shown in Exhibit 2 and are summarized here.

- Summer 2016 LHV prices averaged $9.24/kW-month.
- Summer 2017 is expected to increase about $1.00 (10%) to $10.16/kW-month. Key drivers are the higher reference point ($2.16 higher or 17%) and final 2017 LCR (1.5% higher, from 90.0% to 91.5%). Offsetting factors are the 248 MW (1.5%) peak load decline and the 93 MW of uprates in Class Year 2015.
- 2018 sees addition of CPV Valley (early 2018) and 512 MW Roseton exports to ISO-NE (beginning June). The application of the Locality Exchange Factor will cause a demand curve shift in June that will reduce the impact of the exports by 47.8%. On net, a $2.00/kW-mo price reduction is expected, but prices stay flat or go higher if the LCR is increased.
- 2019 positive with higher net CONE and modest load growth.
- 2020 IPEC2 retirement offset by addition of Cricket Valley.
- 2021 IPEC 3 retirement. Prices could jump to $15/kW-month or higher, absent additional builds, a lower LCR, and the possible "return" of Roseton. Significant uncertainty remains with worse-case plausible downside at $5.00/kW-month in the summer.

[4] Potomac Economics (Feb. 2, 2017), "Assessment of the Buyer-side Mitigation Exemption Tests for the Class Year 2015 Projects," at p. 49, available online here.

EXHIBIT 2. PRICES LOOKING UP, BUT UNCERTAINTY REMAINS



Source: NYISO ICAP AMS for 2016; ICF forecasts thereafter

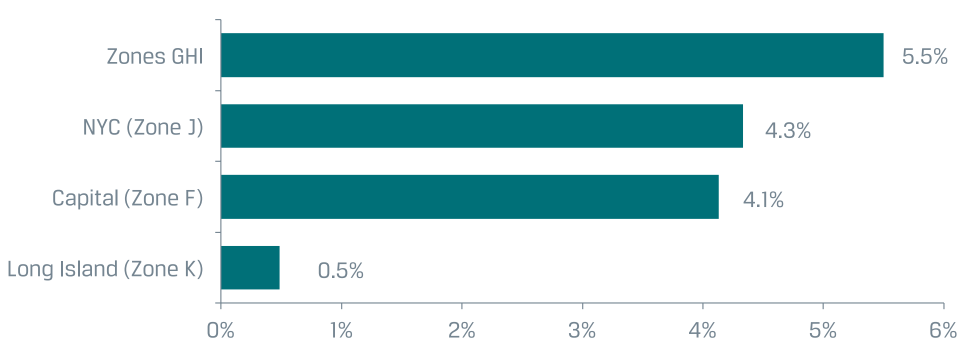
Energy Market: Uplift in the Range of 5%

ICF modeled the impact of the Indian Point retirement on New York's energy prices using its Integrated Planning Model, under the following assumptions:

- The initial case included the entry of CPV Valley (678 MW, Zone G) in 2018.
- The revised case retired Indian Point Unit 2 (1,020 MW, Zone H) and Unit 3 (1,040 MW, Zone H) in 2020 and 2021, respectively, and added the Cricket Valley Energy Center (1,020 MW, Zone G) in 2020.

Over the 2020-2024 period, the highest price increases were in Zones G, H, and I – in the vicinity of Indian Point – which saw average all-hours prices increasing by over 5%. NYC (Zone J) prices rose over 4% as flows from upstate were reduced. Prices in the Capital region (Zone F) also increased by just over 4% as more expensive generation further upstate dispatched to fill the supply gap. Impacts to Zones A to E were fairly minimal. Significant mid-term sources of uncertainty include new transmission, gas basis, and generation build.

EXHIBIT 3. PROJECTED ENERGY PRICE IMPACT



Source: ICF

Transmission & Grid Reliability: Improvements Underway, Uncertainty Remains

ConEdison is the most affected transmission owner by the IPEC retirement, however, the utility has been preparing for this retirement for several years, with contingency planning to alleviate reliability concerns. The utility's contingency projects include:

- Local demand response, energy efficiency, and combined heat and power projects. ConEdison's original contingency plan included a total of 125 MW of these projects, but the latest progress report shows that nearly 150 MW of projects have been completed or approved.[5]
- Three "transmission owner transmission solution" (TOTS) projects providing more than 600 MW of additional transfer capability:[6]
  - A second transmission line between the Ramapo to Rock Tavern substations, developed by Con Edison,
  - The Staten Island Unbottling project, which increases the deliverability of generation on Staten Island to the Gowanus and Farragut substations, and
  - The Marcy/Fraser re-conductoring project, developed by NYPA and NYSEG.

Despite these transmission upgrades, reliability issues resulting from the Indian

Point retirement may persist. NYISO's Reliability Needs Assessment (RNA) assesses both the transmission and resource adequacy, and the transmission security of the New York Control Area (NYCA) bulk power transmission system over the next ten years. The most recent iteration, the 2016 RNA, describes the location of Indian Point in Zone H in southeastern New York as "an area of the State that is subject to transmission constraints that limit transfers in that area."

The study adds that even with Indian Point in service, southeastern New York relies on power transfers to augment existing capacity, and therefore loss of generation capacity in that area would aggravate those constraints.[7]

Indeed, the 2016 RNA did not explicitly include an analysis to assess the impact of the Indian Point retirement on transmission security. Instead, the assessment referenced results from earlier studies that are somewhat dated. For example, the studies in the 2014 RNA showed that shutting down Indian Point would result in overloads on the 345 kV Leeds-Pleasant Valley and Athens-Pleasant Valley transmission lines, which are some of the key backbone transmission lines required to transfer power to southeastern New York.[8]

---

[5] NYS DPS (Nov. 29, 2016), "DMP 3rd Qtr 2016 Status Report Final," available online here.

[6] NYS DPS (Feb. 24, 2016), "Order Accepting IPEC Reliability Contingency Plans, Establishing Cost Allocation and Recovery, and Denying Requests for Rehearing" available online here.

[7] New York Independent System Operator (Oct. 18, 2016), "2016 Reliability Needs Assessment," at p. 45.

[8] Potential solutions to the AC Transmission Public Policy Transmission Need could alleviate some of these problems.

Additional details in the 2012 RNA indicate that the retirement of Indian Point will also reduce the ability to import power into New York City and Long Island; presumably, the TOTS projects alleviated some of these concerns.

The next RNA will be in 2018. Reliability needs will likely be assessed earlier under the NYISO's generator deactivation process, which is expected in mid-2017, upon Entergy's filing of a deactivation notice.

In addition to incremental transmission upgrades, grid operations and reliability in southeastern New York will be affected by a number of uncertain proposed supply resources. These include CPV Valley, Cricket Valley, and the Champlain Hudson Power Express. Unexpected obstacles with these projects and other required system upgrades are possible, and could adversely impact grid reliability.

Gas Markets: New York Increases its Exposure

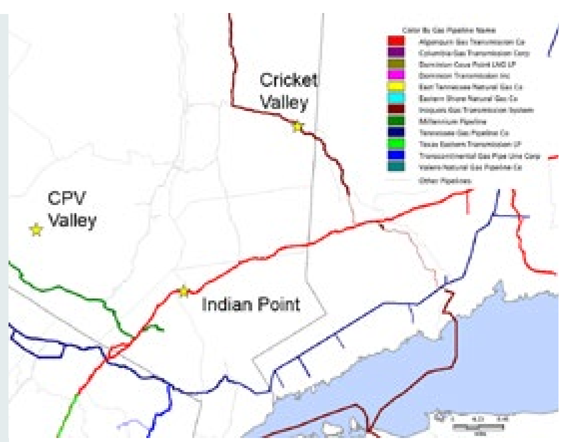
The CPV Valley Energy Center is expected to be interconnected to the Millennium pipeline, while Cricket Valley will be interconnected to the Iroquois pipeline. At full utilization, the CPV Valley and Cricket Valley facilities would consume between 200 and 300 million cubic feet per day of natural gas, a level of consumption equal to 5% to 8% percent of New York's total gas consumption. This increase would have a fairly negligible effect on Henry Hub gas prices. However, due to regional natural gas availability and siting constraints, there is still some potential for challenges for these facilities.

The CPV Valley facility will receive firm gas supply from a new 7.8 mile lateral to the existing Millennium mainline, which receives gas in the Marcellus region and delivers gas to both upstate New York markets and eastward towards New York and New Jersey. In its current form, the Millennium pipeline is fully subscribed and fully utilized; however, Millennium has proposed an upgrade to the eastern portion of the pipeline (appropriately referred to as the "Eastern System Upgrade").

EXHIBIT 4. INTERSTATE GAS PIPELINES IN-PLAY

In spite of the facility's plans for firm fuel supply, the new lateral project still faces a number of challenges. Despite a target in-service date of April 2017, the project has not yet begun construction due to permitting delays. In December, Millennium filed a lawsuit against the New York Department of Environmental Conservation, alleging that the delays are improper.[9]

In addition, the developers have not reached eminent domain agreements with all property owners and one is attempting to intervene in the Millennium lawsuit.[10]



Source: SNL

[9] Times Herald-Record "CPV wants to join Millennium lawsuit"

[10] Times Herald-Record "Residents seek to intervene in federal appeal over pipeline case"

For Cricket Valley, the Draft Environmental Impact Statement indicates that the facility will receive a combination of firm and interruptible gas supply from a 500 foot lateral to the existing Iroquois Pipeline.[11] The Iroquois Pipeline has a much more seasonal utilization than Millennium, peaking in winter months with very little spare capacity on peak days, which could affect Cricket Valley's availability due to the nature of their proposed contract.

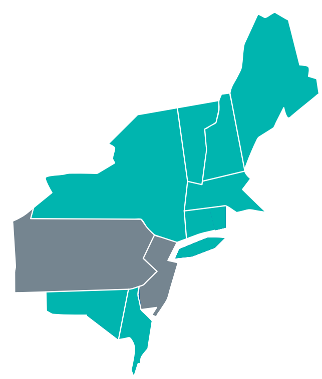
Finally, it is important to note that the transition from nuclear to additional natural gas capacity will leave the New York market more exposed to natural gas prices. Gas markets are complex and driven by many factors including weather, producers' balance sheets, economic activity, and unforeseen regulatory changes, and despite some belief that gas prices would remain near $2/MMBtu following the warm winter of 2015-2016, gas prices at Henry Hub have risen from about $2/MMBtu to over $3/MMBtu over the past year. We note that while the retirement of Indian Point provides an opportunity for natural gas in New York, there remain a number of issues and challenges surrounding the availability and affordability of gas-fired power generation in the state.

Northeast Carbon Markets: RGGI Prices Creep Higher, but Mitigating Factors Exist

New York Governor Andrew Cuomo has pledged New York to an aggressive path of greenhouse gas emission reductions, with targets to reduce GHG 40 percent by 2030 and 80 percent by 2050.[12]

The plan to achieve these goals includes participation in the Regional Greenhouse Gas Initiative (RGGI), a nine-state regional cap and trade program to control carbon dioxide (CO2) emissions from power plants, and the state's new Clean Energy Standard (CES), among other efforts.

The Indian Point units have served as a significant source of carbon-free generation in New York, with average annual generation between 2011 and 2015 of 16,900 GWh per year, and replacement for their generation must be done in the context of achieving these environmental goals and requirements. If fully replaced by generation from gas-fired combined cycle units within the RGGI footprint, emitting at roughly 0.4 tons per MWh, CO2 emissions in New York would increase by 6.8 million tons, or just under nine percent of the 2020 RGGI emissions cap. These added emissions would put upward pressure on RGGI allowance prices. The market is already beginning to show signs of this with spot allowance prices increasing from about $3.50/ton to almost $4.00/ton in January 2017.[13]



[11] Draft Environmental Impact Statement Cricket Valley Energy Project

[12] Governor of New York Website "Governor Cuomo, Joined By Vice President Gore, Announces New Actions to Reduce Greenhouse Gas Emissions and Lead Nation on Climate Change"

[13] SNL Energy

However, there are other drivers in play for RGGI prices.

- Renewable capacity and generation will continue to come online in New York over the next several years, including a number of projects already under contract with the New York State Research and Development Authority (NYSERDA) and the recently-approved South Fork offshore wind farm. Together, these facilities could replace about 10% of Indian Point's annual generation.
- In addition, NYSERDA has committed to annual renewable procurements under the CES, with the first procurement scheduled for April 2017. The magnitude and timing of other zero-carbon projects, such as TDI's Champlain Hudson Power Express (if built), will also impact RGGI prices.
- RGGI member states continue to work through the 2016 Program Review. As part of that effort, the states are "considering potential cap reductions," including annual cap reductions of 2.5% or 3.5% after 2020. A reduction in the cap would magnify the impact of any emissions associated with replacement power for Indian Point.

About ICF

ICF (NASDAQ:ICFI) is a global consulting and technology services provider with more than 5,000 professionals focused on making big things possible for our clients. We are business analysts, policy specialists, technologists, researchers, digital strategists, social scientists, and creatives. Since 1969, government and commercial clients have worked with ICF to overcome their toughest challenges on issues that matter profoundly to their success. Come engage with us at **icf.com**.

For more information, contact:

Dan Jerke
dan.jerke@icf.com +1.703.272.0609

Kevin Petak
kevin.petak@icf.com +1.703.218.2753

Ken Collison
ken.collison@icf.com +1.703.934.3806

Chris MacCracken
chris.maccracken@icf.com +1.703.934.3277

About the Authors

Dan Jerke joined ICF in 2016 and has over five years of experience at the New York Independent System Operator, where he was responsible for the development and implementation of market power mitigation measures for the capacity market. His areas of expertise include market power analysis and mitigation, capacity market design, power plant investment due diligence, and litigation strategy. Mr. Jerke has a B.S. degree with dual majors in Applied Economics and Natural Resources from Cornell University and an M.S. degree in Financial Engineering and Risk Analytics from Rensselaer Polytechnic Institute.

Aaron Geschiere is an Associate at ICF, where he has five years of experience providing project and modeling leadership and support for the Commercial Energy Division. Mr. Geschiere's work at ICF focuses on renewable energy fundamentals and project evaluation. Mr. Geschiere has B.S. degrees in Economics and Environmental Science from the University of Michigan.

Kevin Petak is a Vice President of Gas Market Modeling in ICF International has over 30 years of experience in the energy industry. He has directed numerous energy market analyses to support strategic planning needs at energy companies. Mr. Petak has a M.S. in Business from the University of Texas at Dallas and a B.S. in Petroleum and Natural Gas Engineering from the Pennsylvania State University.

Ken Collison is a Vice President at ICF, and currently leads the Transmission and Ancillary Services Group within Energy Advisory Solutions. Mr. Collison is an expert on is an expert on power system planning, economic analysis, and reliability assessments. He also serves as expert witness in T&D cases. Mr. Collison also testifies as an expert witness on electric transmission and distribution cases.

Chris MacCracken is a Principal with ICF. He assists clients in assessing the impacts of environmental regulation on their portfolios to support the development of compliance, regulatory, and operational strategies. Chris' clients include electric utilities, IPPs, and NGOs. He has directed ICF's support in a number of regulatory analysis engagements, including for RGGI Inc. in support of the 2016 RGGI Program Review and several related to state plan design strategy under the Clean Power Plan.