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Energy Market Outlook: What to Expect in 2020 and Beyond

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Contents

Introduction

Energy markets emerged in 2019 as laboratories for climate policy while policymakers aimed to reduce greenhouse gas emissions. The impact has been deep and wide.

Nearly 25 state and provincial governments across North America enacted climate programs last year—introducing carbon-pricing mechanisms, financing a wave of new offshore wind and battery storage technology, and indefinitely postponing PJM's capacity auctions.

As a result, the strategies that helped energy managers control expenses during the period of low, stable prices over the past five years have become considerably less effective:

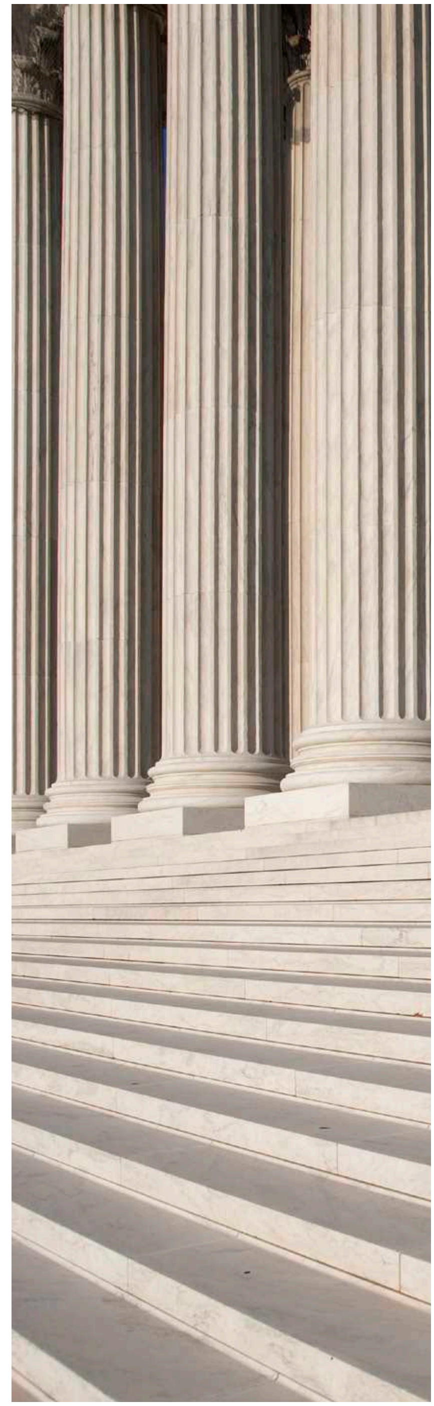
> Fixed-price agreements may now carry more risk than flexible contracts in many markets

> Energy costs are a shrinking portion of overall energy expense in most regions

> State-sponsored incentive programs are creating winners (that earn incentives) and losers (that pay for them)

Ultimately, overreliance on traditional retail purchasing strategies leaves more money on the table every year.

As experts supporting more than $11 billion in annual energy spend for our customers, Enel X prepared the following report to help energy managers understand the markets, policies and regulations driving costs in their region and identify ways to adjust their strategy.



New England
(MA, CT, RI, NH and ME)

Electricity prices in New England are the highest in the Continental US and are poised to remain elevated for years to come. As state-sponsored clean energy resources represent a growing portion of the region's resource mix, ISO-NE will face significant challenges accommodating the environmental goals of its member states while maintaining a reliable and competitive market.

Retail third-party supply costs should soften slightly in the early 2020s, though we expect those declines to be offset by higher distribution tariff rates. Persisting pipeline constraints, potential delays in federal/state permitting for large-scale renewable generation projects, and/or a rebound in natural gas prices could lend upward pressure on wholesale energy prices. Ultimately, we expect the 2020s to bring more complexity and risk to the region.

Continued Natural Gas Constraints Keep Winter Prices Elevated

Between 2000 and 2019, natural gas-fired generation grew from 15% to 49% of ISO-NE's electricity mix due to the availability of relatively inexpensive gas supplies and regulations that restrict the use of oil and coal.

The buildout of supporting pipeline infrastructure, however, has not kept pace. When heating demand is at its highest on cold winter days, insufficient natural gas supplies have led to extreme price spikes—most notably during the Polar Vortex in 2013/14 when extreme cold conditions led real-time wholesale electricity and gas spot prices to average $132/MWh and $18.5/MMBtu, respectively, over a four-month period.

With New England States' sights on a low carbon-emission future, there is neither the political appetite nor private capital available to build new pipelines. Thus, with no significant additional pipeline capacity on the horizon, the region will continue to be seasonally gas-constrained for the foreseeable future.

SEMA ATC Real Time Monthly Averages ($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
2009	$67.98	$49.98	$40.47	$34.59	$37.17	$34.51	$33.62	$38.25	$30.89	$39.91	$36.41	$60.63	$42.03
2010	$62.73	$53.35	$39.12	$36.26	$48.06	$50.66	$59.27	$54.96	$47.05	$34.74	$41.79	$63.09	$49.26
2011	$71.29	$57.32	$44.44	$43.72	$43.74	$43.15	$58.06	$43.89	$42.62	$39.49	$37.82	$33.88	$46.62
2012	$37.12	$30.12	$25.45	$25.42	$28.08	$33.87	$41.93	$42.82	$33.48	$34.54	$56.61	$43.97	$36.12
2013	$85.07	$110.06	$54.32	$42.59	$38.53	$39.53	$57.43	$35.03	$36.13	$35.70	$46.28	$99.72	$56.70
2014	$163.44	$152.88	$117.15	$41.16	$35.31	$37.89	$34.82	$30.11	$35.99	$30.42	$44.93	$42.93	$63.92
2015	$66.07	$127.52	$58.02	$25.97	$26.07	$19.53	$25.30	$35.43	$36.44	$32.75	$26.34	$21.60	$41.75
2016	$34.15	$27.87	$17.34	$28.06	$21.10	$21.13	$29.27	$40.25	$27.25	$22.83	$24.35	$53.98	$28.96
2017	$36.57	$28.08	$34.69	$31.42	$29.90	$23.85	$26.56	$23.65	$26.03	$31.77	$33.53	$80.44	$33.88
2018	$108.17	$36.86	$33.17	$43.74	$23.85	$25.69	$33.58	$39.36	$41.22	$39.84	$55.72	$42.02	$43.60
2019	$51.60	$36.99	$36.80	$26.79	$22.89	$22.60	$29.38	$23.67	$20.60	$20.49	$34.51	$43.20	$30.79
Avg.	$71.29	$64.64	$45.54	$34.52	$32.25	$32.04	$39.02	$37.04	$34.34	$32.95	$39.84	$53.22	

Algonquin Settlements $/MMBtu (NYMEX + Basis)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
2012	$5.43	$5.09	$3.03	$2.45	$2.32	$2.76	$3.39	$3.55	$3.03	$3.50	$4.43	$9.26	$4.02
2013	$9.22	$9.69	$3.47	$4.84	$4.82	$4.66	$4.25	$3.85	$3.60	$3.67	$5.10	$14.82	$6.00
2014	$22.01	$32.21	$15.36	$6.27	$4.65	$5.65	$4.24	$2.95	$2.64	$3.28	$5.67	$14.00	$9.91
2015	$10.89	$10.11	$9.62	$3.29	$2.33	$2.25	$2.02	$1.99	$2.62	$3.45	$4.76	$5.15	$4.87
2016	$6.77	$4.73	$2.97	$2.55	$2.53	$2.11	$3.12	$2.68	$2.68	$2.36	$2.52	$4.77	$3.32
2017	$11.23	$7.27	$3.19	$3.26	$3.36	$3.17	$2.73	$2.45	$2.30	$2.56	$2.70	$5.85	$4.17
2018	$12.50	$13.29	$3.52	$4.09	$2.63	$2.48	$2.77	$2.88	$2.93	$3.47	$3.68	$10.59	$5.40
2019	$9.33	$7.86	$4.62	$2.95	$2.38	$2.34	$2.17	$2.10	$1.84	$1.84	$3.54	$5.21	$3.85
Avg.	$10.92	$11.28	$5.72	$3.71	$3.13	$3.18	$3.09	$2.81	$2.70	$3.02	$4.05	$8.71	

Capacity Prices Set to Decline Through 2023

While New England continues to struggle with fuel supplies during the winter, the region is expected to have more than enough electricity generation to meet Peak Summer Demand. Capacity rates are set to decline over the next three years after reaching all-time highs in 2017/18 in Northeastern Massachusetts (NEMA) and in 2018/19 in all other New England zones.

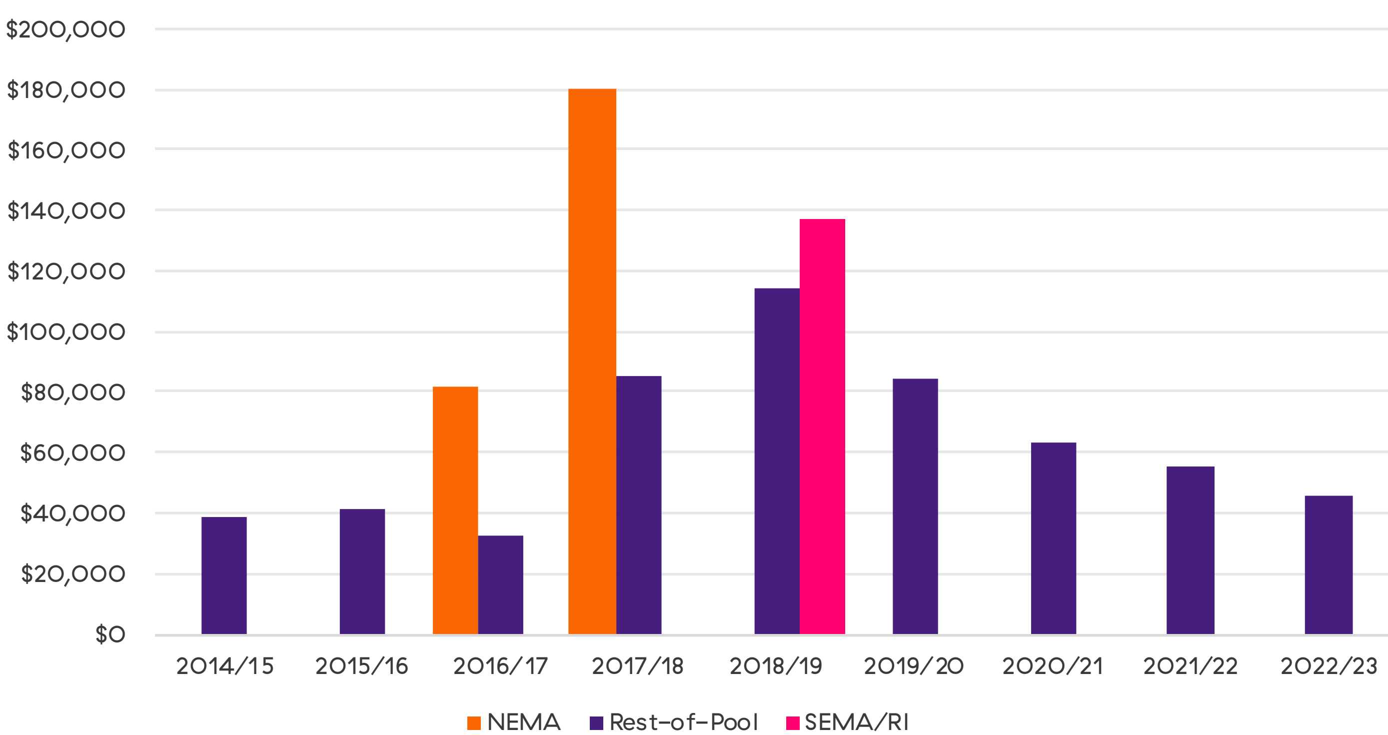
Since 2010, the ISO-NE grid operator has held an annual Forward Capacity Auction (FCA) to secure the power generation needed to meet energy demand forecasts three years in the future. The auction sets the price that generators receive for commitments to produce power when needed. In turn, these costs are recouped from ratepayers based on their demand contribution to the ISO-NE system peak hour each summer.

Due to increased behind-the-meter resources, energy efficiency, and demand response, ISO-NE FCA prices cleared at a five-year low ($45,600/MW-Year) for the June 2022 — May 2023 delivery period. These prices offer significant relief to energy buyers that recently saw prices as high as $180,000/MW-Year in NEMA and $137,000/MW-Year in Southeastern Massachusetts (SEMA) and Rhode Island.

When considering the influence that capacity charges have on a customer's total energy spend, it is important to note that the above prices do not account for reserve margins. All-in capacity charges including reserve margins exceeded $245,000/MW-Year in the NEMA 2017/18 delivery year and nearly $215,000/MW-Year in SEMA 2018/19. While customers will benefit from declining capacity rates in the early 2020s, peak demand strategies will still save New England customers more than $95,000/MW in 2020/21 and $75,000/MW in 2021/22.

ISO-NE Forward Capacity Auction Prices

($/MW-Year)



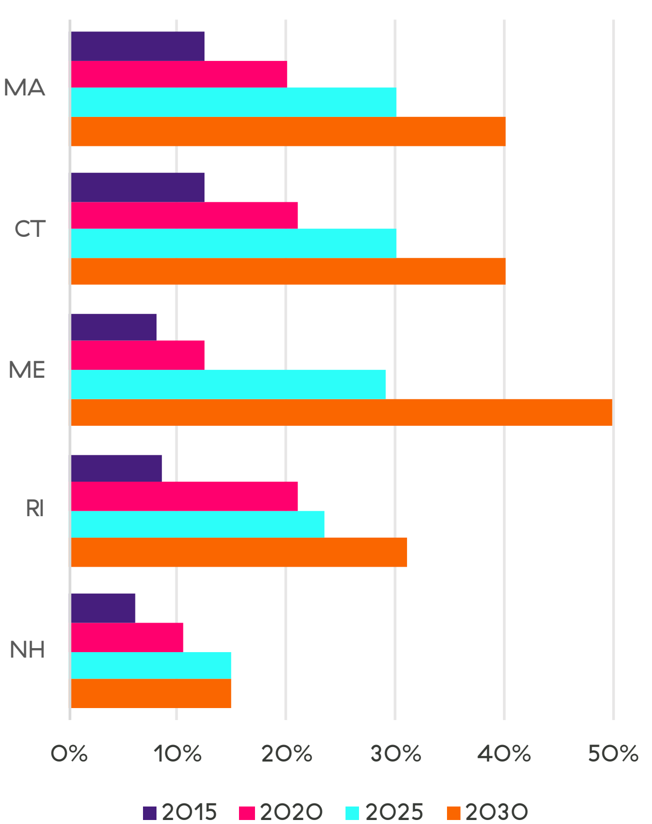
Non-Bypassable Surcharges Support Renewable Energy Development

Since 2008, most New England States have passed legislation requiring an 80% or greater reduction in GHG emissions economy-wide below 1990 levels by 2050 with interim targets of 35-40% by 2030. To achieve those targets, New England states are leveraging out-of-market mechanisms to expand renewable energy generation.

Renewable Portfolio Standards (RPS) to Double

Massachusetts, Connecticut and Maine account for roughly 85% of the electric load in ISO-NE and have each passed legislation requiring electric suppliers to purchase twice as much power from Class I or equivalent resources (such as new wind/solar/hydro) in 2030 compared to 2020. Depending on the region, the costs associated with increasing RPS targets will show up on either supply or utility distribution bills. Either way, the increased targets carry non-bypassable charges.

RPS Class I or Equivalent Requirement by State



Budgetary Impact of Massachusetts' Clean Peak Standard (CPS) to be Modest in 2020, Greater in Out-Years

Massachusetts will roll out the CPS program in 2020, the country's first standard aimed at increasing the use of clean energy during peak demand periods. Under the CPS, retail electric suppliers will be required to purchase a percentage of their power from clean peak energy resources such as battery storage, demand response, and Class I renewable resources. Compliance will start at 1.5% in 2020 and grow 1.5% annually to reach 16.5% by 2030. Based on a proposed Alternative Compliance Payment (ACP) rate of $30/MWh per Clean Peak Energy Certificate (CPEC), the maximum cost to retail end-users will be $0.50/MWh in 2020 and $5/MWh in 2030.

Massachusetts Solar Incentive Programs Cost 3x More in 2020

Massachusetts introduced the Solar Massachusetts Renewable Target (SMART) in November 2018, which replaced the nearly nine-year-old Solar Renewable Energy Credit (SREC) incentive program. SMART aims to double installed solar capacity from 1,600 MW to 3,200 MW in the Commonwealth. While Massachusetts previously supported solar development through SRECs, the SMART program now offers solar developers fixed 20-year incentive payments. Thus, solar incentive costs that were once billed via RPS/SREC on the supply bill will now be recovered from ratepayers via a non-bypassable "Distribution Solar Charge" on the utility distribution bill. Costs to Massachusetts ratepayers are poised to jump from an average of $0.50/MWh in 2019 to $1.50/MWh in 2020.

Massachusetts Energy Storage Incentivized to Grow 5x by 2025

Under comprehensive clean energy legislation passed in July 2018, Massachusetts increased its energy storage target from 200 MWh by 2020 to 1,100 MWh by 2025. While both the CPS and SMART programs are designed to incentivize storage, the Massachusetts Department of Energy Resources (DOER) is permitted to explore a variety of other polices, such as the inclusion in RPS, to achieve the 2025 target.

State-Sponsored Offshore Wind and Hydropower Transfers Risk to Ratepayers

New England States have cumulatively authorized the procurement of 5,600 MW of offshore wind by 2030 and 1,200 MW of imported Canadian hydropower—equivalent to 20% of the grid's current generation capacity. In the absence of additional gas pipelines, these resources should add much-needed fuel diversity during periods of extreme cold; however, they also transfer significant price risks to New England ratepayers.

Offshore wind and hydropower commitments are backed by three states: 3,200 MW of offshore wind authorized by Massachusetts, 2,000 MW by Connecticut, and 400 MW by Rhode Island. To put these targets in perspective, there is currently only one operational offshore wind farm in the entire US: a 30 MW farm off the coast of Block Island, Rhode Island.

To date, 2,300 MW has been awarded to three offshore wind projects: Vineyard Wind 800 MW (est. 2022), Revolution Wind 704 MW (est. 2023), and Mayflower Wind 804 MW (est. 2025). In addition, the full 1,200 MW of hydropower has been awarded to the New England Clean Energy Connect (est. 2022).

To support these projects, New England utilities entered into 20-year fixed power purchase agreements (PPAs). The PPAs are structured as contracts-for-differences, such that utilities (and subsequently ratepayers) guarantee a fixed MWh rate of return for each project. Any difference in costs between the proceeds from the sale of energy and RECs and the PPAs' contracted rates will be either charged or credited back to ratepayers. Thus, if revenues from the projects fall short of the PPA price, those costs will be recovered from consumers on their utility distribution bill. Vice versa, if the projects generate net revenue above the PPA price, ratepayers will see a credit applied to their distribution bill.

Connecticut Nuclear Support Transfers Risk to Ratepayers

Following three years where Exelon appealed to Connecticut lawmakers that the 2,200 MW Millstone nuclear facility was at risk of closing due to rising expenses and competition from low natural gas prices, Connecticut lawmakers awarded the plant a 10-year PPA in late 2018. The negotiated Millstone contract rate is not yet public, but it is structured as a contract for differences where Connecticut ratepayers will assume the risk, similar to offshore wind procurements.

Non-Bypassable Charges Support Grid Reliability Initiatives

ISO-NE received approval from federal regulators in late 2018 to support the 2,000 MW Mystic Generating Station in Everett, Massachusetts, which was at risk of retirement. The Mystic plant uses LNG from the nearby Distrigas facility instead of relying on constrained interstate pipeline capacity, and therefore offers fuel security and reliability during the winter. While the costs are not defined, Mystic will receive a cost-of-service rate intended to cover the plant's operating expenses, including a return on investment estimated at $200 million per year. Those costs will be recovered from ratepayers through an estimated $1.6/MWh line item on their supply bill from 2022-24.

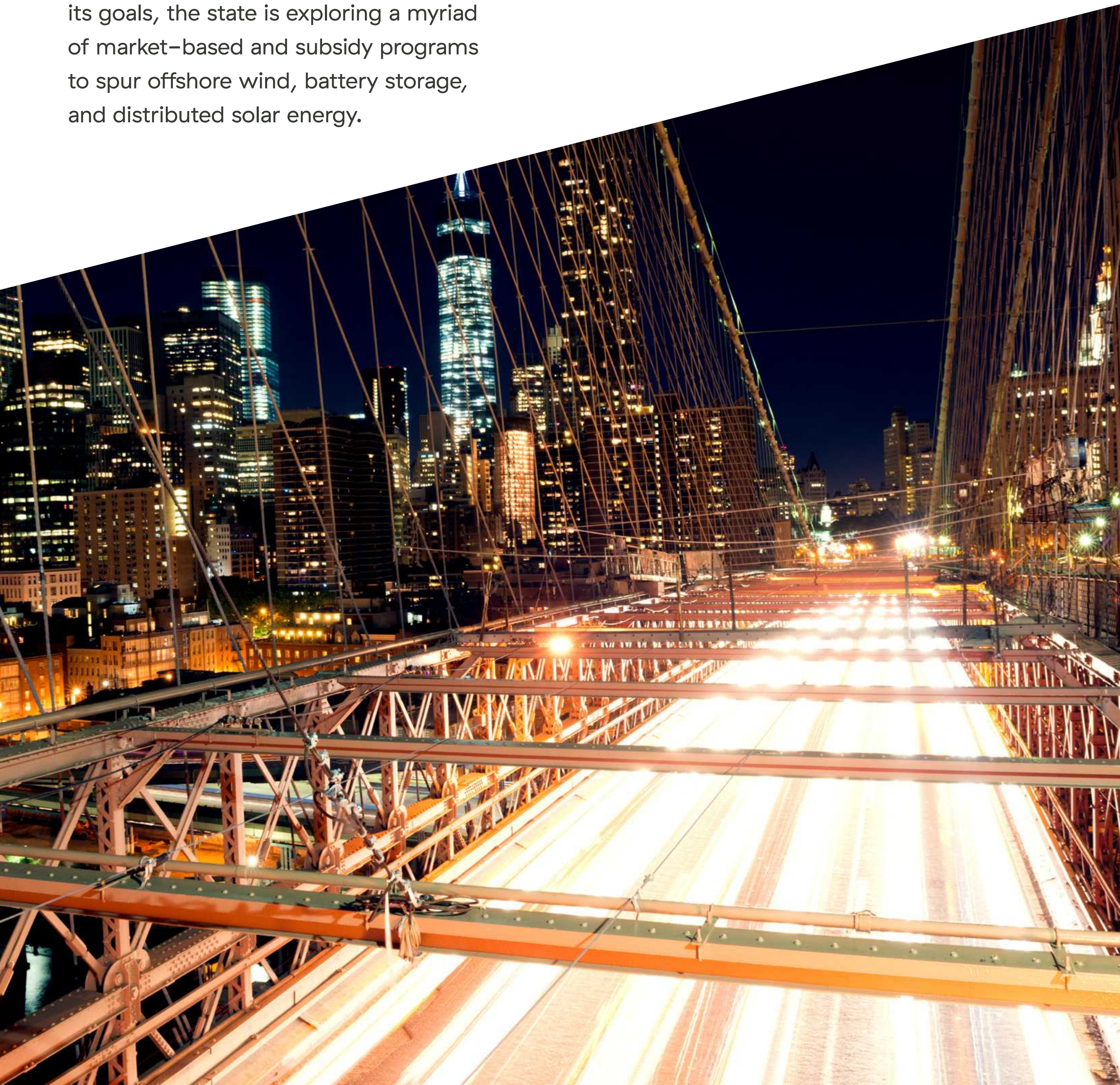
ISO-NE is actively preparing longer-term solutions for fuel reliability after May 2024, when the cost-of-service agreement with the Mystic power plant expires. While still early in its development, ISO-NE is considering other changes to the wholesale market, including a "multi-day ahead market," additional ancillary services, and a seasonal forward capacity market.

Resource Name	Fuel Type	State	Contracted Capacity	Contract Start	PPA Term	Contract Includes	Term Price (Nominal $)
Millstone Nuclear Plant	Nuclear (existing)	CT	1,100 MW	2019	10 yrs	Energy-only	*Not yet announced*
Seabrook Nuclear Plant	Nuclear (existing)	CT	235 MW	2022	8 yrs	Energy-only	$39/MWh
New England Clean Energy Connect	Hydro	MA	1,200 MW	2022	20 yrs	Energy + Hydro RECs	$59/MWh
Vineyard Wind Phase 1	Offshore Wind	MA	400 MW	2022	20 yrs	Energy + Class I RECs	$84.23/MWh
Vineyard Wind Phase 2	Offshore Wind	MA	400 MW	2023	20 yrs	Energy + Class I RECs	$84.23/MWh
Revolution Wind	Offshore Wind	RI	400 MW	2023	20 yrs	Energy + Class I RECs	$98.4/MWh
Revolution Wind	Offshore Wind	CT	300 MW	2023	20 yrs	Energy + Class I RECs	*Not yet announced*
Mayflower Wind	Offshore Wind	MA	800 MW	2025	20 yrs	Energy + Class I RECs	*Not yet announced*

New York

New York is pursuing one of the most ambitious climate policies in the United States, targeting 100% carbon-free electricity by 2040 and economy-wide carbon neutrality by 2050. To achieve its goals, the state is exploring a myriad of market-based and subsidy programs to spur offshore wind, battery storage, and distributed solar energy.

In the short-term, customers can expect continued price volatility during cold winter months, higher capacity and RPS charges, and elevated futures pricing.



Seasonal Price Volatility Continues Amid Natural Gas Constraints

Natural gas-fired generation grew from 26%[1] to 46%[2] of New York's power supply in the ten years from 2009 to 2019, helping lower electric commodity prices significantly.

While the low-cost resource has had an overall positive effect on supply rates, NY ratepayers continue to grapple with periods of extreme price volatility when pipeline capacity dries up during winter cold snaps.

This is a trend that is likely to continue. In an effort to curb reliance on fossil-fuel-based resources, New York halted the construction of several gas pipelines by denying the projects' water quality permits under the Clean Water Act. Three of the most notable pipelines, the Northern Access Project, Constitution Pipeline, and Northeast Supply Enhancement would have brought an additional 1.547 Bcf/d of pipeline capacity to New York.

Zone J ATC Real Time Monthly Averages ($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
2009	$71.57	$57.13	$49.98	$42.22	$37.02	$40.43	$40.21	$47.76	$33.17	$41.60	$38.58	$61.19	$46.74
2010	$65.38	$56.82	$41.73	$44.39	$50.31	$68.14	$78.73	$57.90	$54.34	$35.88	$44.68	$70.48	$55.73
2011	$78.83	$55.22	$49.30	$50.74	$45.89	$54.03	$68.01	$52.60	$48.69	$39.62	$39.45	$35.03	$51.45
2012	$40.81	$32.11	$30.71	$29.03	$36.77	$35.69	$49.26	$42.83	$36.96	$36.84	$50.58	$41.35	$38.58
2013	$91.21	$73.12	$47.70	$45.86	$40.34	$43.81	$74.37	$39.24	$39.65	$37.24	$38.42	$55.29	$52.19
2014	$156.31	$124.02	$98.07	$44.53	$33.88	$38.09	$36.16	$32.04	$33.19	$29.61	$37.85	$35.52	$58.27
2015	$52.84	$112.16	$47.49	$26.60	$29.99	$25.30	$28.60	$32.93	$36.95	$25.34	$21.53	$22.25	$38.50
2016	$33.96	$28.62	$19.44	$28.50	$21.88	$26.99	$35.76	$41.22	$24.87	$21.46	$25.65	$45.14	$29.46
2017	$37.49	$26.93	$35.47	$34.54	$30.08	$28.68	$30.79	$25.29	$27.17	$26.66	$29.28	$53.48	$32.15
2018	$102.05	$32.88	$31.24	$35.84	$27.63	$29.36	$35.71	$41.34	$41.21	$37.30	$38.88	$36.07	$40.79
2019	$43.80	$32.45	$33.72	$26.92	$23.22	$24.74	$31.88	$23.97	$21.17	$20.30	$27.35		$28.14
Avg.	$70.38	$57.41	$44.08	$37.20	$34.27	$37.75	$46.32	$39.74	$36.12	$31.99	$35.66	$45.58	$42.91

New York Gas Demand During the Five Highest Priced Months Since 2009

Month	Average LMP ($/MWh)	Delivered Bcf/d
January 2014	$156.31	5.53
February 2014	$124.02	5.23
February 2015	$112.16	5.83
January 2018	$102.05	5.74
March 2014	$98.07	5.11

Source: www.eia.gov/dnav/ng/ng_cons_sum_dcu_SNY_m.htm

To put that additional pipeline capacity in perspective, NY currently consumes roughly 5.5 Bcf/d when temperatures are lowest and prices are highest.

In September 2019, FERC found that the New York Department of Environmental Conservation waived its authority under the Clean Water Act when it failed to "issue or deny a water quality certification" to the 650 MMcf/d Constitution pipeline according to federal statutes. FERC's decision represents an important legal milestone, but it remains unlikely that the project will proceed unchallenged. We expect New York to continue to face volatile pricing due to natural gas shortages for several years.

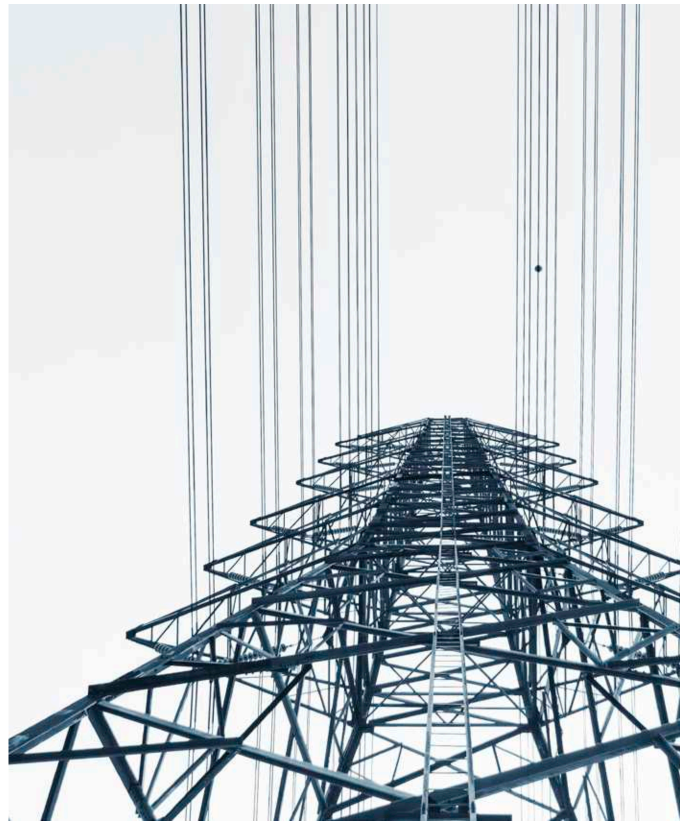
Capacity Costs to Increase in Early 2020s

Capacity prices are expected to reach five-year highs in New York City (Zone J) and may rebound in the Lower Hudson Valley (Zones G, H, and I) and Rest-of-State.

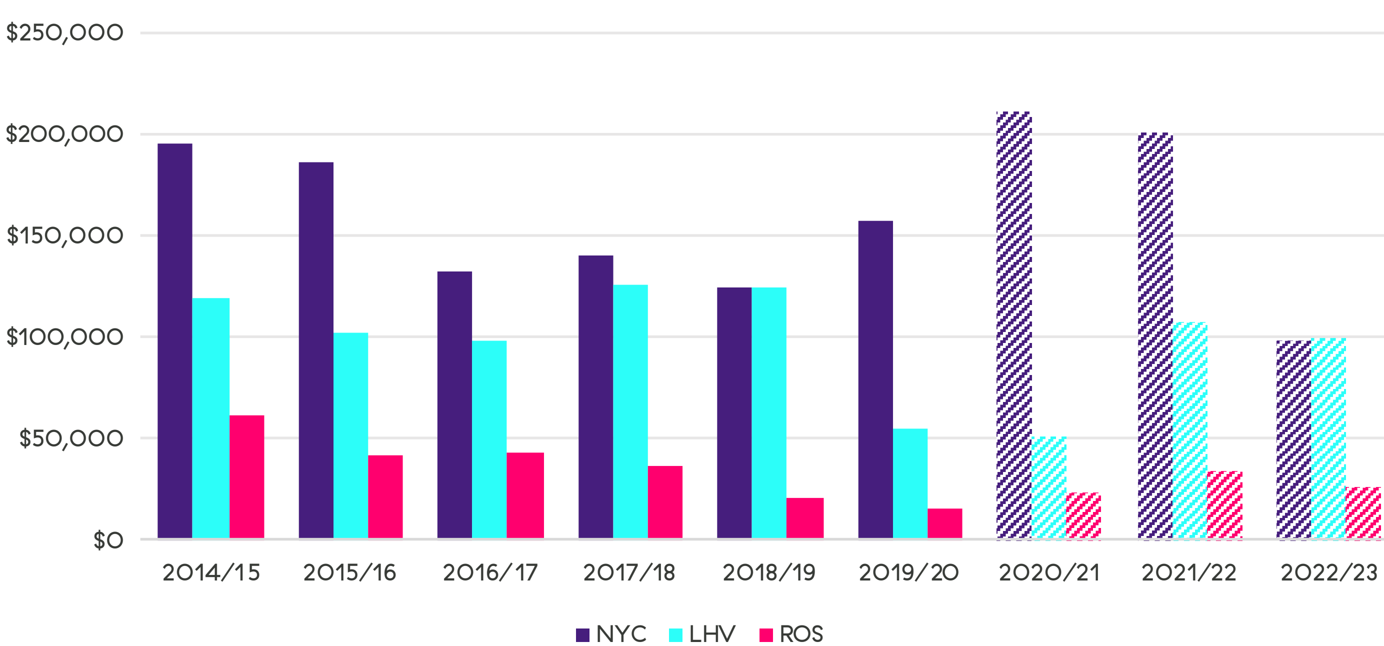
New York will lose the first of two reactors at the Indian Point Nuclear Facility in May 2020, which together provide roughly 25% of the electric retail load for New York City and Westchester.[3] While two new natural gas plants (Valley Energy Center and Cricket Valley Energy Center) will replace the majority of lost generation, the shift in resource mix is lending upward pressure on capacity prices.

Compounding the retirement of Indian Point, the New York State Reliability Council (NYSRC) announced a substantial increase in Installed Reserve Margin (IRM) requirements for the New York Control Area (NYCA) for the May 2020 to April 2021 period.

The new IRM is the highest NYCA reserve margin over the past 15 years and will require utilities and retail suppliers to purchase additional capacity. Customers that pass-through capacity charges or that have not yet signed a fixed-price contract for the 2020-22 period should expect higher capacity rates effective May 2020.



Summer Capacity Strips & Forward Prices by Zone ($/MW-Year)



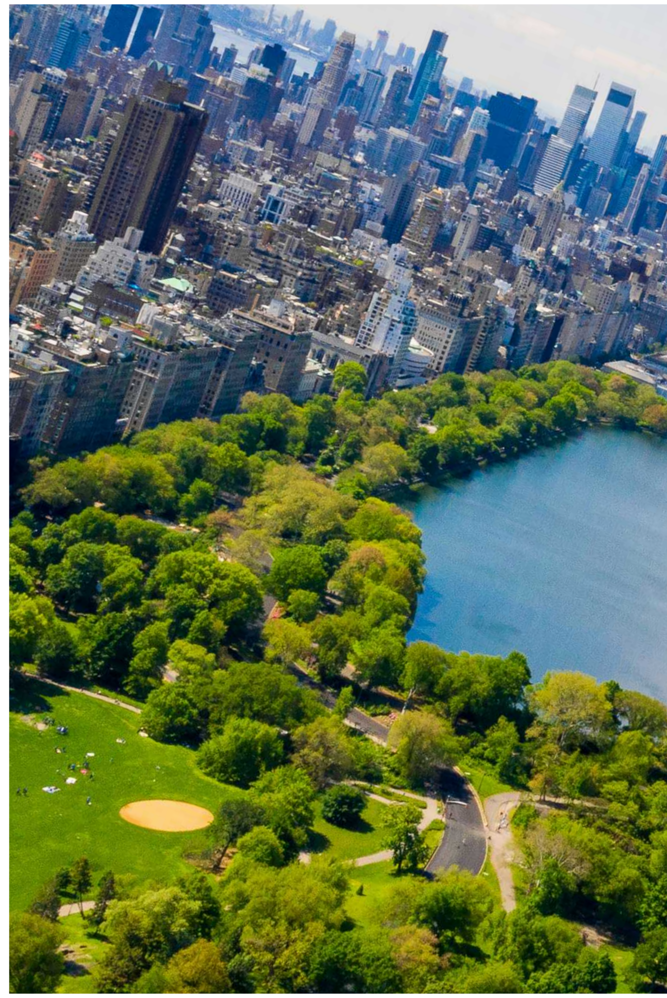
<< Contents

Ambitious NY Climate Policy Will Reshape Energy Market in the Near-Term

When Governor Andrew Cuomo signed the Climate Leadership and Community Protection Act (CLCPA) in July 2019, New York officially joined a growing list of states to mandate a transition to a carbon-free electricity sector and emission-neutral economy. The bill is one of the most aggressive in the nation based on both the target and timeline, committing the state to a 40% reduction in emissions by 2030 and 85% by 2050 from 1990 levels, with all remaining emissions to either be reduced further or offset through investments in carbon sinks.[4]

As part of the overall emissions reductions plan, utilities received a specific interim goal to supply 70% of electricity sales through renewable generation by 2030, revised up from the 50% target set in 2016.[5] By 2040, electric utilities in New York will be required to supply 100% of generation from emission-free resources.

To meet its ambitious goals, New York is launching a multi-pronged approach. The multitude of strategies New York will employ include an expansion of its existing Clean Energy Standard, a carbon-tax and stringent building efficiency standards. These also include several state-sponsored procurements of renewable resources, such as large-scale offshore wind, as well as new mechanisms to incentivize distributed solar and energy storage. The result will undoubtedly reshape the New York energy market over the coming decade with much of the groundwork laid in the near-term.



2025	2030	2035	2040	2050
6 GW Distributed Solar	70% Carbon-free Generation	9 GW Offshore Wind	100% Emission-free Generation	Carbon Neutral Economy

Cost of Renewable and Zero-Emission Credits Likely to Top $5.60/MWh by 2022

To support the development of new renewable energy and keep nuclear generation online, the Clean Energy Standard (CES) requires NY utilities and retail suppliers to purchase Tier I renewable energy credits (RECs) and zero-emission credits (ZECs). These charges are passed directly onto consumers and should cost roughly $4/MWh in 2020 and climb above $5.60/MWh by 2022, based on current Tier I REC and ZEC prices.

To ensure the market retains existing renewable generators, several states in the Northeast have proposed measures that would compensate existing renewable energy producers—typically either through an expansion in Clean Energy Standards or through long-term PPAs. In late 2019, Governor Cuomo vetoed a bill that would have required retail suppliers to purchase power from existing generation at 75% of the rate paid to new projects. In its place, the Governor directed the Department of Public Service to develop a competitive program to support the ongoing operation of existing renewable energy projects. The proceeding is expected to start in early 2020. While details around the program are not yet known, costs may be recovered through customers' utility distribution bills.

Expectations of Carbon Pricing System Buoying Forward Contracts

In June 2018, NYISO and the Public Service Commission proposed a carbon pricing scheme for NY State.[6] If the NYISO Board of Directors and FERC approve the framework, the program may be implemented before 2023 with initial pricing at $50/ton CO_2e.

The Role and Economic Impacts of a Carbon Price in NYISO's Wholesale Electricity Markets, an independent analysis commissioned by NYISO and performed by the Analysis Group, finds that the carbon-pricing scheme should deliver $1.72–$3.25 billion in net benefits between 2022 and 2036.[7] Susan Tierney and Paul Hibbard, authors of the analysis, list 14 key benefits of the market-based pricing system, most notably that the scheme will:

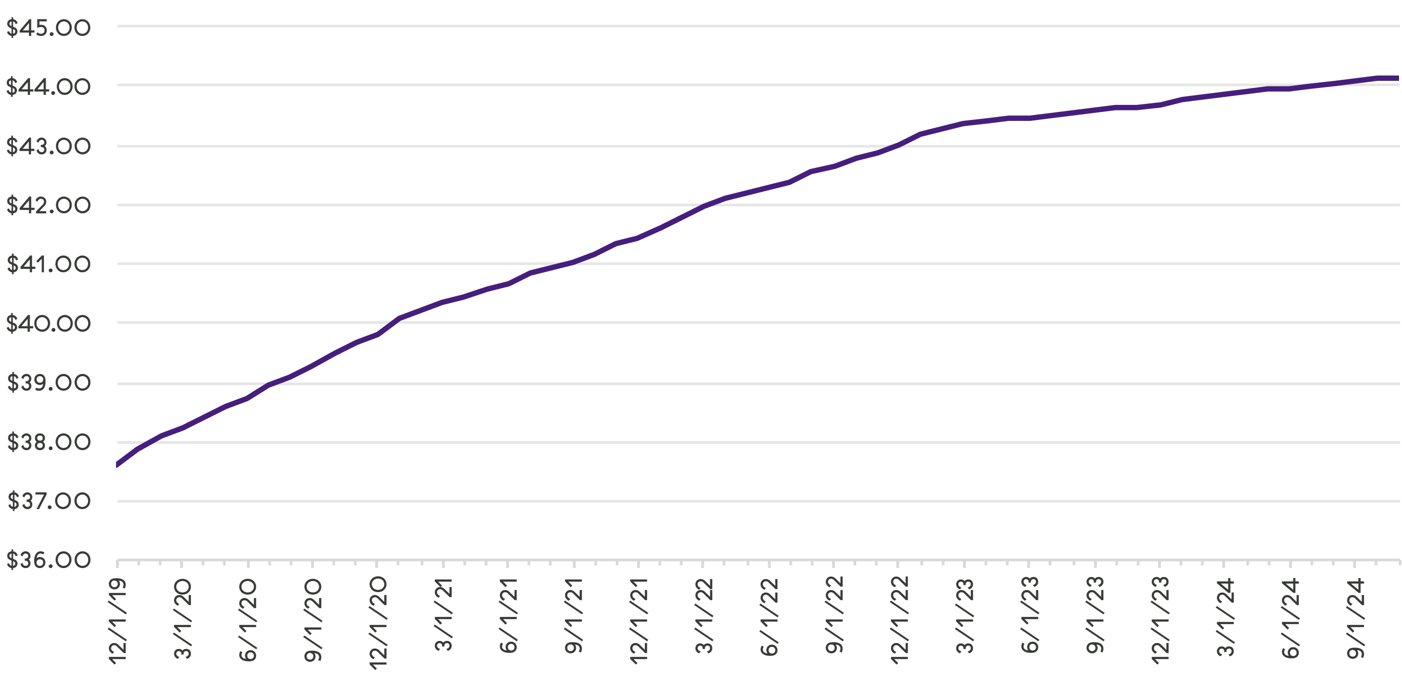
- Provide a lower-cost means to achieve New York's climate targets by leveraging market efficiencies in the power sector
- Lower risks for energy consumers by shifting risk to market participants and providing a market-based price signal
- Accelerate the adoption of clean energy projects by introducing new financing mechanisms
- Incentivize new transmission infrastructure to provide better down-state access to the valuable low-carbon and renewable energy resources in upstate regions
- Protect against potential interference by federal regulators by leveraging a wholesale energy market economic model rather than a statutory model.[8]

While the pricing scheme is expected to deliver significant social benefits to New Yorkers and financial benefits to the NY economy, it is pushing the electricity futures market higher. Forward pricing for Zone J jumped nearly $10/MWh when the program was first introduced. Prices have subsided in recent months, but 2023 forwards are still trading at a $6/MWh premium to 2021 levels.

We encourage customers to consider block and index contracts until the market settles, rather than locking into contracts that pull forward these elevated futures.

NYISO Zone J 12-Month Forward Contracts

($/MWh)



Texas

ERCOT is an "energy-only" market. With no forward capacity market available to ensure grid reliability, ERCOT relies solely on energy prices to incentivize generation. Real-time energy prices jump to $9,000/MWh when reserve margins drop below 2,000 MW, which they did for 90 minutes this past August. During a heat wave from August 10 — 17, real-time prices hovered above $1,000/MWh for more than 10 hours.

While the region is expected to add significant new generation through 2023, much of that will come from intermittent renewable energy resources. Moreover, Texas total demand is growing in line with increasing population and manufacturing growth, as well as warmer temperatures.

We expect many energy buyers in the region to hedge exposure to summer price spikes and take advantage of long-term price trends, as 3-year contracts are currently trading at an 11% discount compared to 12-month terms.

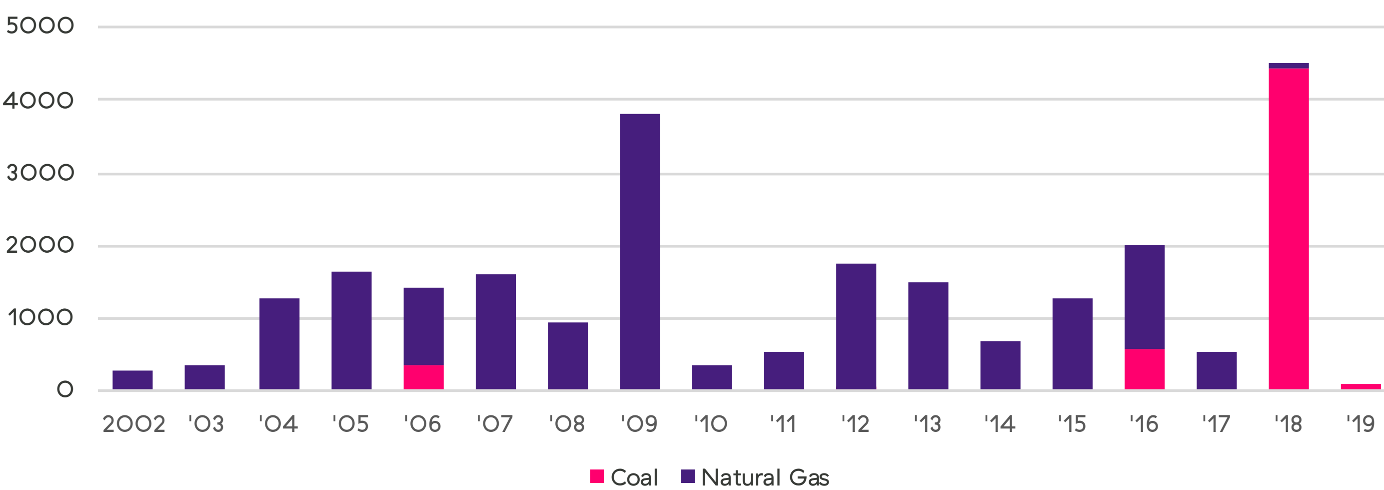
Shrinking Reserve Margins Create Significant Price Volatility

On the back of significant coal power plant retirements in 2018, reserve margins (the delta between forecast demand and expected capacity) shrank considerably. ERCOT entered summer 2019 with a reserve margin of just 7.4%, an all-time low.

That margin was stressed as summer heat set in and generation supplies struggled to match the record-setting 74,666 MW peak hourly demand. Real-time prices soared and led to the highest average prices over the past decade.

Energy buyers should see some relief during the 2020 summer, as the grid plans to add more than 10,000 MW of solar, wind, and natural gas resources. In its December Capacity, Demand and Reserves (CDR) Report, ERCOT predicted that reserve margins will reach 10.6% in 2020—a significant improvement over 2019 but still shy of the state's 13.75% target.

ERCOT Power Plant Retirements (MW)



North Hub ATC Real Time Monthly Averages ($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
2011	$34.35	$56.71	$28.34	$30.39	$32.42	$41.75	$45.11	$126.42	$33.21	$27.28	$28.24	$25.62	$42.49
2012	$22.40	$19.68	$28.06	$24.05	$21.05	$27.95	$26.60	$28.48	$24.91	$26.79	$27.34	$24.46	$25.15
2013	$24.89	$24.41	$29.86	$35.05	$28.33	$30.04	$31.23	$31.56	$34.48	$33.27	$29.95	$32.56	$30.47
2014	$42.30	$46.82	$48.80	$38.15	$36.03	$35.20	$33.14	$34.96	$32.98	$32.60	$31.76	$25.36	$36.51
2015	$23.32	$25.69	$27.61	$23.29	$25.04	$22.76	$26.94	$32.94	$23.34	$20.03	$18.87	$15.47	$23.78
2016	$18.08	$14.83	$17.69	$17.93	$16.91	$21.69	$25.51	$28.06	$26.05	$22.66	$19.70	$23.69	$21.07
2017	$24.86	$19.17	$19.33	$21.83	$25.46	$24.82	$28.72	$26.58	$23.40	$21.61	$21.05	$21.78	$23.22
2018	$33.38	$23.76	$18.89	$22.89	$29.97	$30.35	$41.44	$34.67	$27.69	$33.93	$34.25	$27.54	$29.90
2019	$22.85	$23.05	$27.19	$25.34	$24.81	$25.14	$30.20	$131.48	$51.04	$27.40	$24.31	$16.57	$35.78
Avg.	$27.38	$28.23	$27.31	$26.55	$26.67	$28.86	$32.10	$52.79	$30.79	$27.28	$26.16	$23.67	

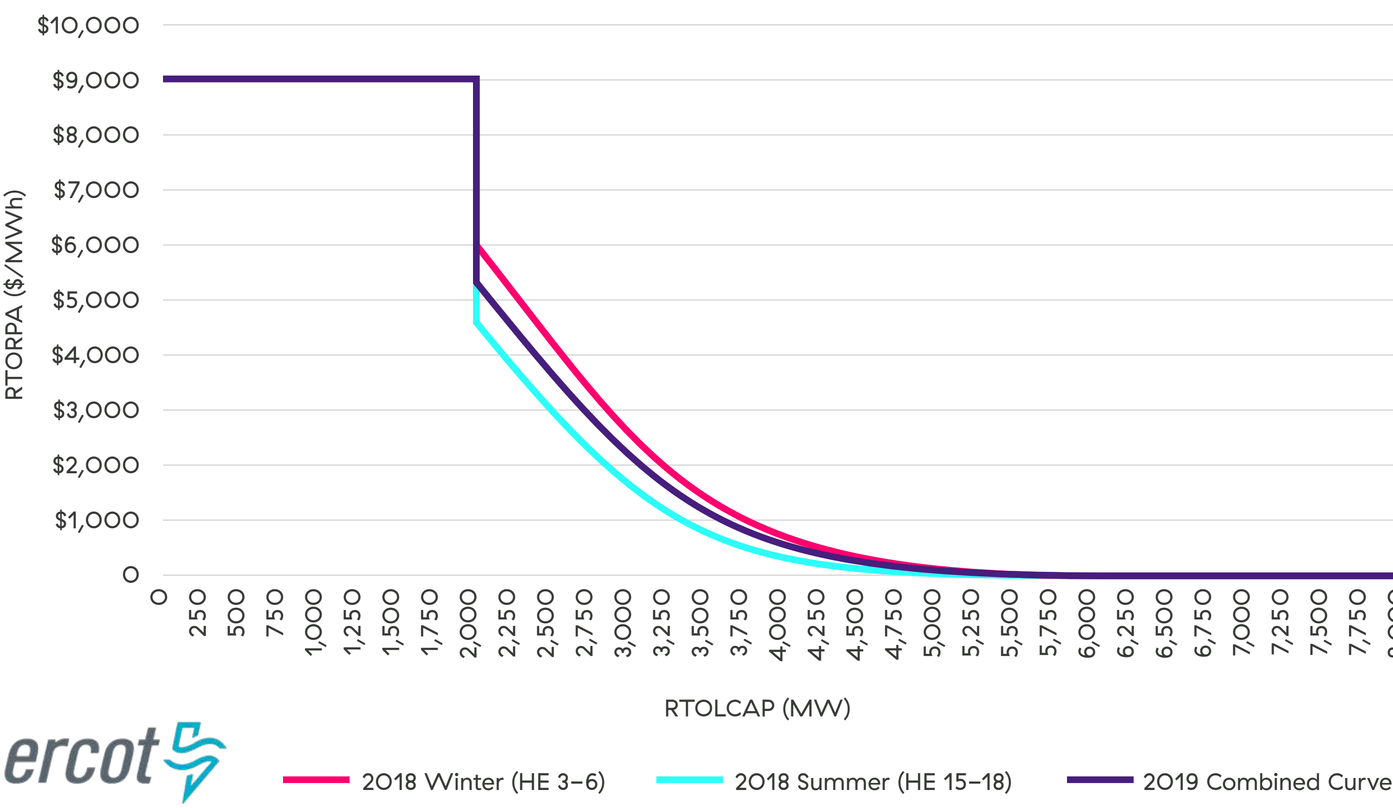
Operating Reserve Demand Curve (ORDC) Revisions Signal Higher Summer Prices

ERCOT instituted the ORDC in June 2014, creating a price adder to reflect the value of available resources during times of scarcity. The adder can ultimately reach $9,000/MWh (known as the system-wide offer cap) when reserve margins dip below 2,000 MW. However, prices escalate significantly well before that 2,000 MW threshold.

ERCOT based the real-time price adder on the probability of load loss and its value.[9] Until 2019, the ORDC used seasonal curves to evaluate the value and probability of load loss, one for winter and one for summer. In March, however, the Public Utilities Commission of Texas directed ERCOT to implement a 0.25 standard deviation shift in the loss of load probability using a single blended curve. As a result, the single blended curve is priced higher than the previous summer curve and lower than the previous winter curve.

The trend toward higher summer prices will continue in 2020. ERCOT will implement an additional 0.25 standard deviation, causing the curve to become even steeper than the 2019 blended curve.

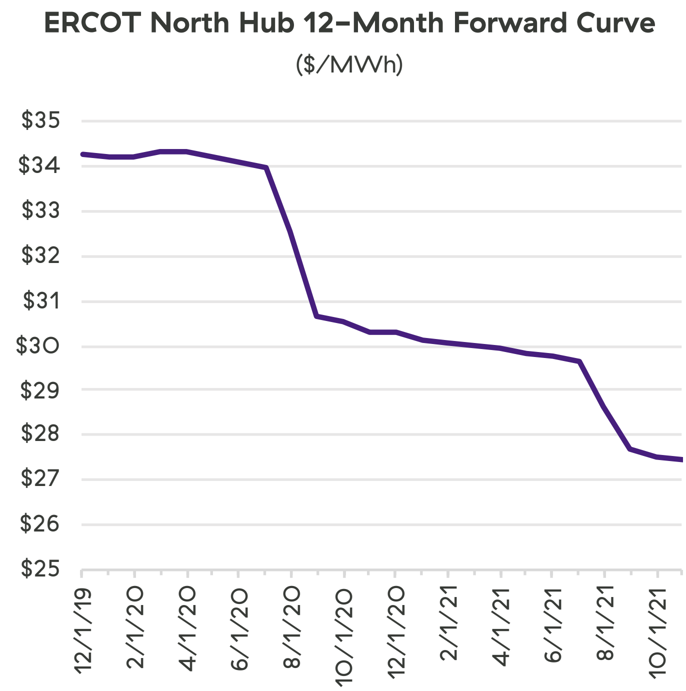
With reserve margins still below 11%, we expect the net effects to increase average summer prices. For example, energy prices will now reach $3,500/MWh when reserve margins drop to 2,500 MW as compared to $2,600/MWh under the previous ORDC.

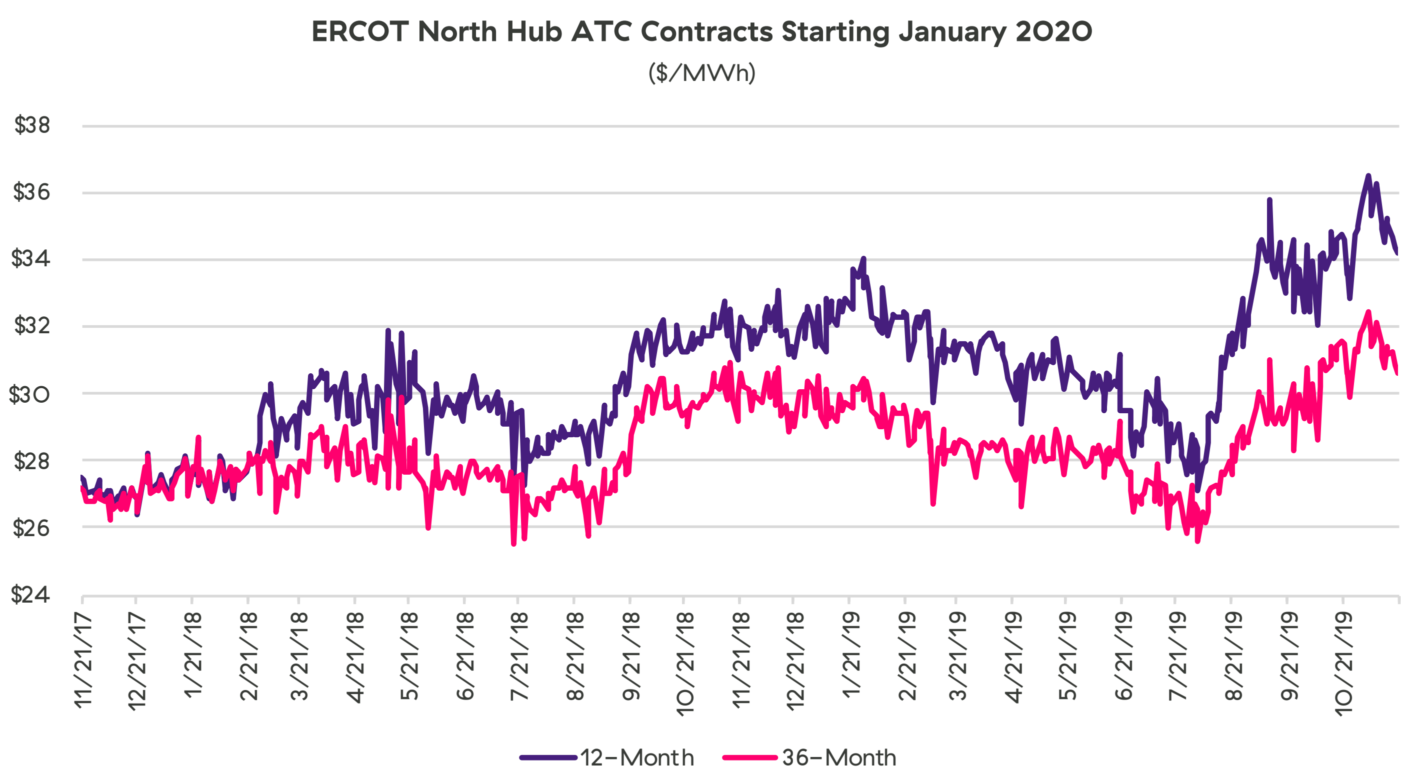


Energy Market Backwardation Discounts Longer-Term Contracts

Looking further ahead, ERCOT expects to add more than 17,000 MW of additional capacity to the grid through 2023. For context, that 17,000 MW of additional capacity represents roughly 23% of the grid's record Peak Demand set this past summer. The expected generation is currently depressing futures prices, as seen in the 12-month forward curve.

Twelve-month contracts starting in January 2020 are currently trading above $34/MWh at ERCOT North Hub, 30% higher than they were during the summer of 2017. In contrast, 12-month contracts starting in January 2021 are trading at $30.11/MWh. And contracts starting in January 2022 are trading at $27.5. As a result, the three-year contracts that pull forward those low-priced futures currently offer an 11% discount as compared to those with 12-month terms.





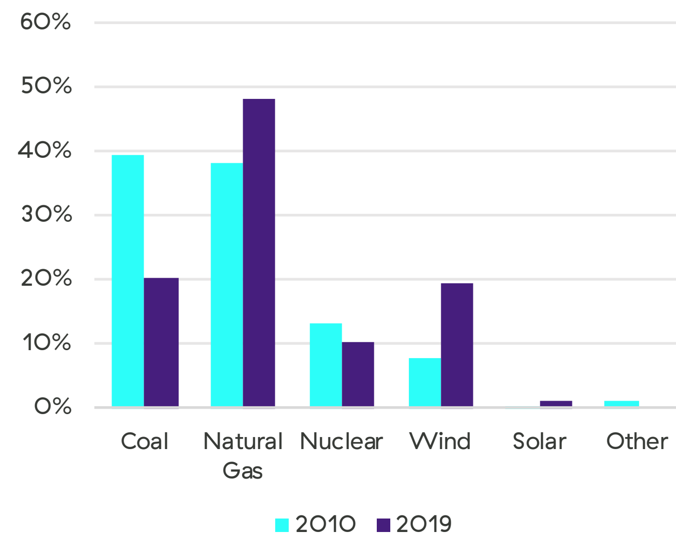
Solar Better than Wind in Hedging Summer LMP Volatility

As the cost of utility-scale renewable energy tumbled over the past few years, organizations across the country began evaluating renewable power purchase agreements (PPAs) as risk management instruments. In Texas, large wind PPAs in particular have been touted as a means to hedge summer scarcity pricing.

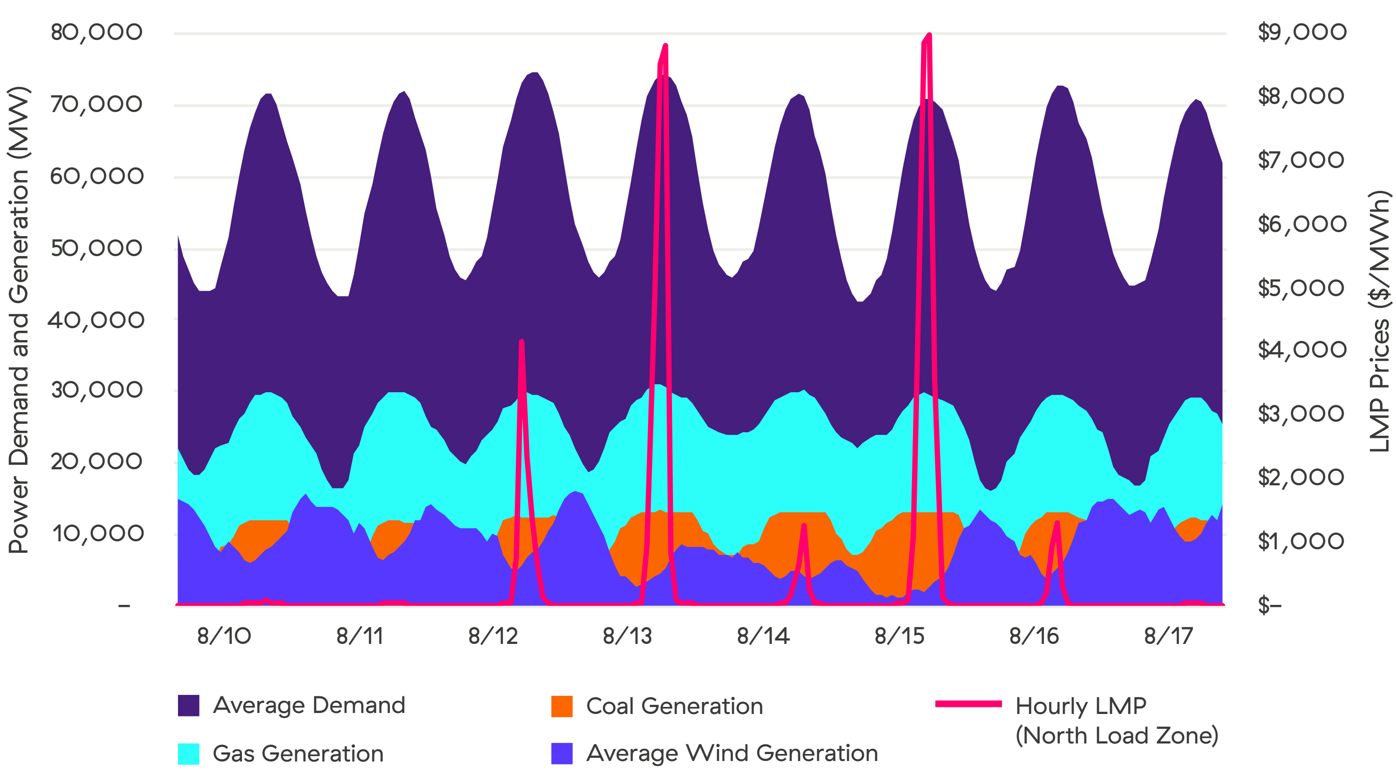
Yet as wind power represents a growing share of ERCOT's power generation mix, ERCOT LMP pricing has become increasingly correlated with wind production.

During the August 2019 heat wave, for example, real-time prices traded as low as $21/MWh when hourly wind production was high. As wind production fell, however, hourly LMP pricing shot up to the $9,000/MWh limit.

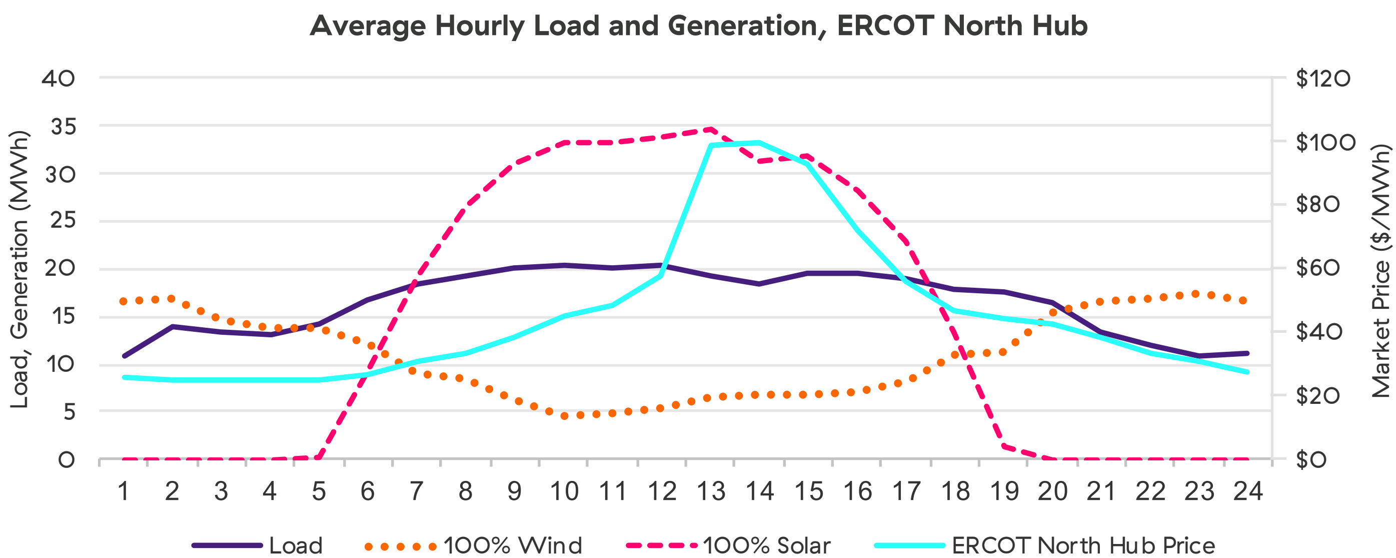
ERCOT Power Generation Mix



Correlation of Hourly LMP Prices, Demand, Wind Production, Coal and Gas Generation



While solar PPA prices often carry a 50% premium to wind PPAs in ERCOT, their correlation with peak demand can often make them a better investment. Unlike wind, solar still represents a relatively small portion of the ERCOT's power generation mix—making it less correlated with real-time LMP prices. Also unlike wind, solar production typically peaks during business hours. As a result, solar PPAs are a better hedge against ERCOT scarcity pricing and can often offer better long-term value despite higher strike prices.



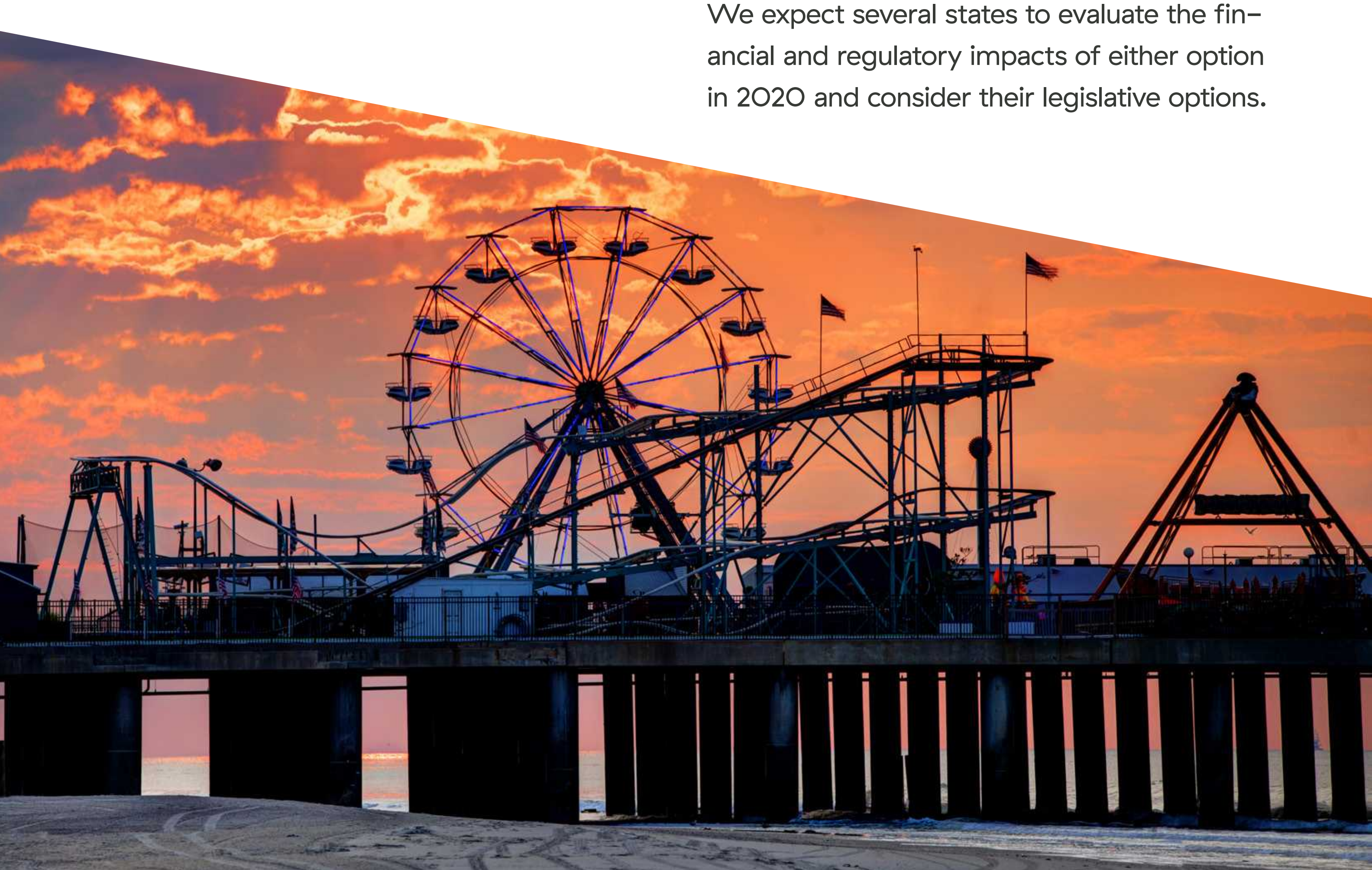
Mid–Atlantic
(NJ, MD, PA, VA, DE and WV)

The Federal Energy Regulatory Commission's (FERC) December 19 decision to expand PJM's Minimum Offer Price Rule (MOPR) introduced a significant amount of energy market risk and uncertainty at the year's end.

FERC's ruling has the potential to add billions of dollars in extra costs, which we anticipate will be distributed unevenly across Mid–Atlantic States and utility zones. By enforcing an administratively set minimum offer price, the decision may bar new renewable energy resources from earning revenues in PJM's capacity market.

We expect the decision to increase both wholesale commodity prices and capacity costs, but the degree of increase is still unclear at the time of this writing. If nuclear generators are similarly priced out of capacity markets and PJM does not revise down its reserve margins, however, rate increases may be significant.

The biggest outstanding question entering 2020 is whether the decision will encourage states to leave the PJM capacity market and conduct resource adequacy planning under the Fixed Resource Requirement Alternative. As another option, states may opt to leave the Independent System Operator (ISO) altogether. We expect several states to evaluate the financial and regulatory impacts of either option in 2020 and consider their legislative options.



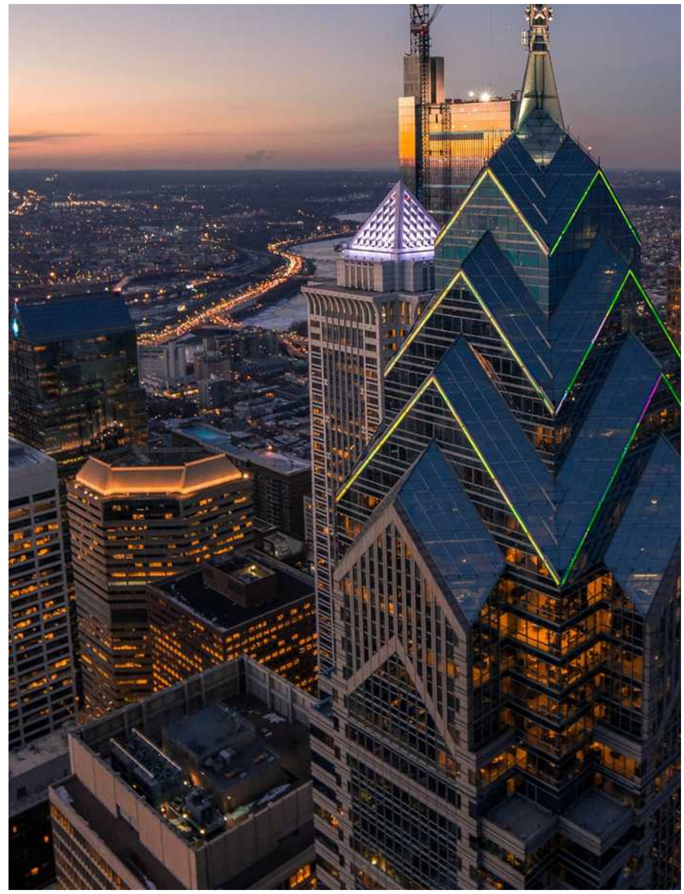
Significant Risk Premiums in Forward Capacity Market

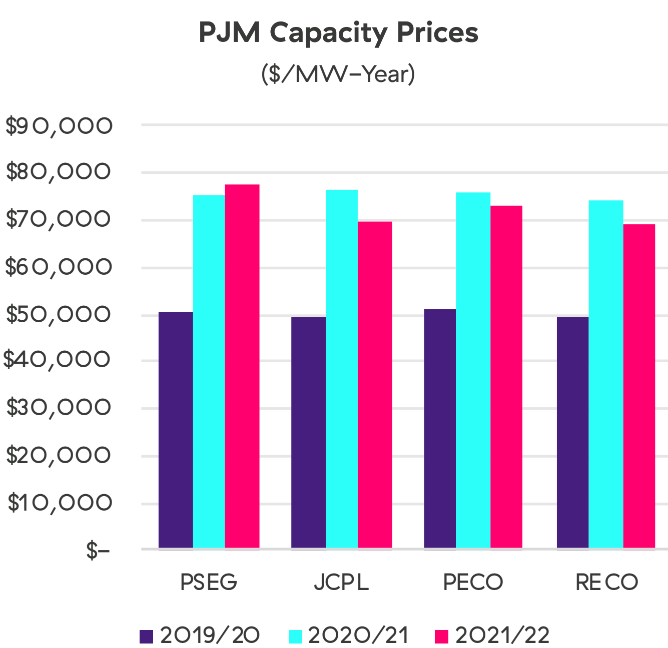
The Base Residual Auction (BRA) is the market mechanism that PJM uses to procure adequate electric capacity to meet peak demand and maintain long-term grid reliability. In September 2019, PJM posted notice that BRA activities and deadlines would remain suspended "until further notice."[10]

At question is whether states have the right to support nuclear and renewable generation through Zero Emission Credits or RPS programs. In 2018, FERC acknowledged that subsidized generation caused suppressive impacts to both the Reliability Pricing Model (RPM) and the Minimum Offer Price Rule (MOPR) used to establish pricing.

On December 19, FERC directed PJM to expand the MOPR to address state subsidies for renewable generators. According to Wood Mackenzie Senior Analyst Daniel Muñoz-Álvarez, this will likely drive up renewable energy costs as utility-scale solar and wind projects tend to rely on capacity payments for 10-15% of revenues.[11]

As of this publishing, it is still unclear whether the nuclear generators receiving out-of-market support in New Jersey and Illinois will be affected by the ruling. If these plants are priced out of PJM's capacity markets and PJM does not revise down its reserve margins, capacity prices will face upward pressure.





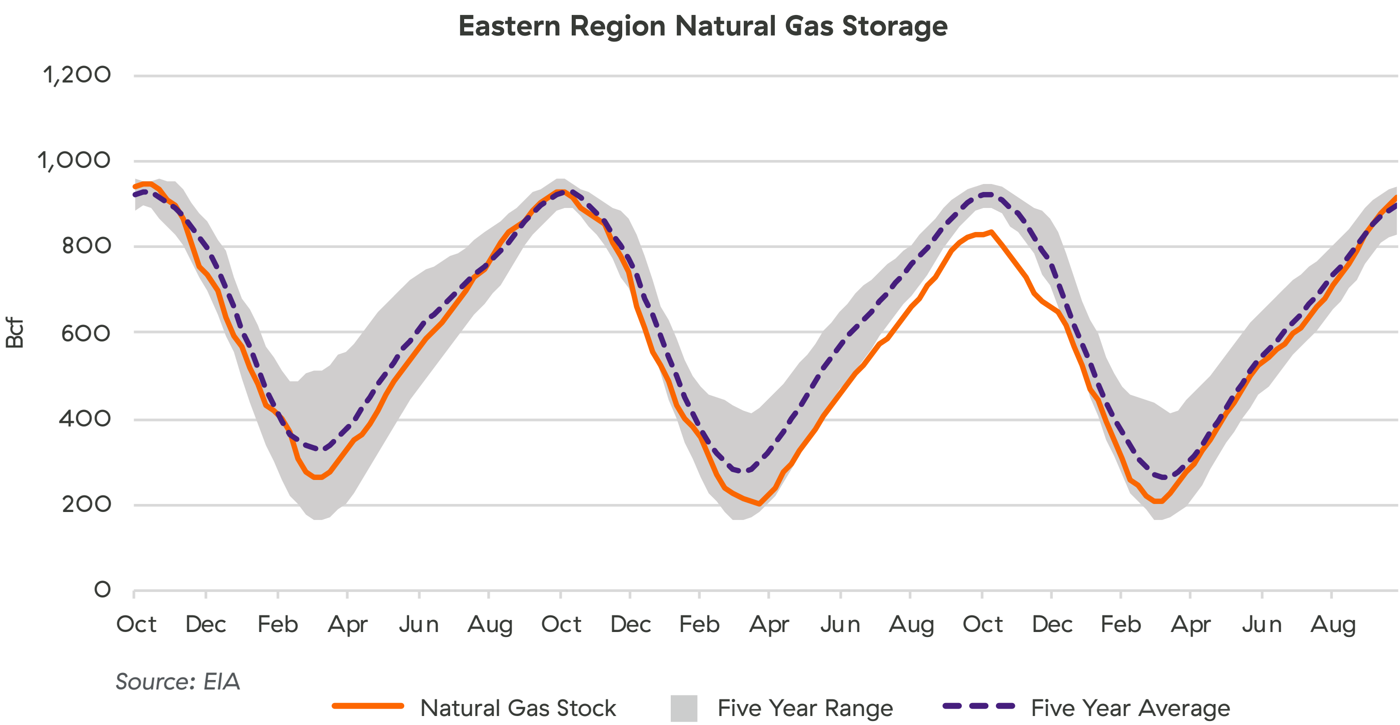
Because capacity is the second-largest cost component in PJM, this uncertainty is a source of material risk—particularly in congested utility zones like PSEG, JCPL, PECO, and RECO, where capacity prices have already climbed more than 50% from 2019/20 to 2020/21.

Contrary to conventional wisdom, energy buyers that enter into fixed-price contracts for the 2022-23 period will wear the risk associated with this uncertainty. Fixed-price offers that extend into 2023 will carry significant risk premiums. If capacity prices rise higher than expected, suppliers will invoke the "material change" clause in the retail contract to pass those higher rates onto customers. If capacity prices settle lower than forecast, however, buyers will likely continue to pay those premiums. We recommend that buyers in these and other high-priced capacity zones evaluate capacity pass-through contracts in their next retail agreements.

Natural Gas Prices to Remain Relatively Low and Stable

Natural gas pricing fell considerably in 2019. Basis at the Transco Z6 xNY pipeline, which supplies most of the region, came down nearly 75% from January–November 2019 versus 2018. Including NYMEX, buyers enjoyed prices 22% below 2018 averages.

We expect natural gas prices to remain relatively low and stable throughout 2020, as natural gas storage levels in the Eastern Region remain higher than the five-year average and within 3% of 5-year highs.[12]



Transco Z6 xNY Natural Gas Forward Basis Prompt Month ($/MMBtu)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
2012	$1.11	$1.01	$0.29	$0.15	$0.17	$0.22	$0.29	$0.22	$0.12	$0.10	$0.19	$0.72	$0.38
2013	$0.88	$0.76	$0.30	$0.20	$0.15	$0.11	$0.04	-$0.10	$0.01	$0.13	$0.03	$0.90	$0.28
2014	$1.45	$11.26	$1.35	$0.00	-$0.42	-$1.46	-$1.11	-$1.27	-$1.61	-$1.71	-$0.92	$1.84	$0.62
2015	$2.85	$3.22	$1.76	-$0.15	-$0.15	-$0.17	-$0.71	-$0.86	-$0.48	-$0.27	$0.16	$0.65	$0.49
2016	$0.94	$0.87	-$0.14	-$0.54	-$0.51	-$0.39	-$0.46	-$0.74	-$1.36	-$1.72	-$0.90	$0.45	-$0.37
2017	$2.06	$1.01	-$0.12	-$0.32	-$0.26	-$0.27	-$0.62	-$0.66	-$0.38	-$0.49	-$0.18	$0.59	$0.03
2018	$2.61	$5.99	$0.27	-$0.11	-$0.26	-$0.18	-$0.10	-$0.04	-$0.18	-$0.33	-$0.04	$1.02	$0.72
2019	$3.32	$1.67	$0.06	-$0.20	-$0.36	-$0.37	-$0.24	-$0.21	-$0.58	-$0.93	-$0.15	$0.84	
Avg.	$1.90	$3.22	$0.47	-$0.12	-$0.21	-$0.31	-$0.36	-$0.46	-$0.56	-$0.65	-$0.23	$0.87	

Transco Z6 xNY Natural Gas Full Prompt Month ($/MMBtu)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
2012	$4.19	$3.68	$2.73	$2.34	$2.20	$2.64	$3.06	$3.23	$2.75	$3.12	$3.66	$4.41	$3.17
2013	$4.23	$3.98	$3.72	$4.17	$4.30	$4.26	$3.75	$3.36	$3.57	$3.63	$3.53	$4.71	$3.93
2014	$5.86	$16.82	$6.20	$4.58	$4.38	$3.16	$3.29	$2.54	$2.34	$2.28	$2.81	$6.13	$5.03
2015	$6.04	$6.08	$4.66	$2.44	$2.37	$2.64	$2.07	$2.02	$2.15	$2.30	$2.19	$2.85	$3.15
2016	$3.32	$3.06	$1.57	$1.37	$1.48	$1.57	$2.46	$1.94	$1.49	$1.23	$1.86	$3.68	$2.09
2017	$5.99	$4.40	$2.51	$2.86	$2.88	$2.96	$2.45	$2.31	$2.54	$2.48	$2.57	$3.66	$3.13
2018	$5.35	$9.62	$2.91	$2.58	$2.56	$2.70	$2.90	$2.78	$2.72	$2.69	$3.15	$5.73	$3.81
2019	$6.96	$4.62	$2.91	$2.52	$2.20	$2.27	$2.06	$1.93	$1.67	$1.49	$2.45	$3.31	
Avg.	$5.24	$6.53	$3.40	$2.86	$2.80	$2.78	$2.75	$2.51	$2.41	$2.40	$2.78	$4.31	

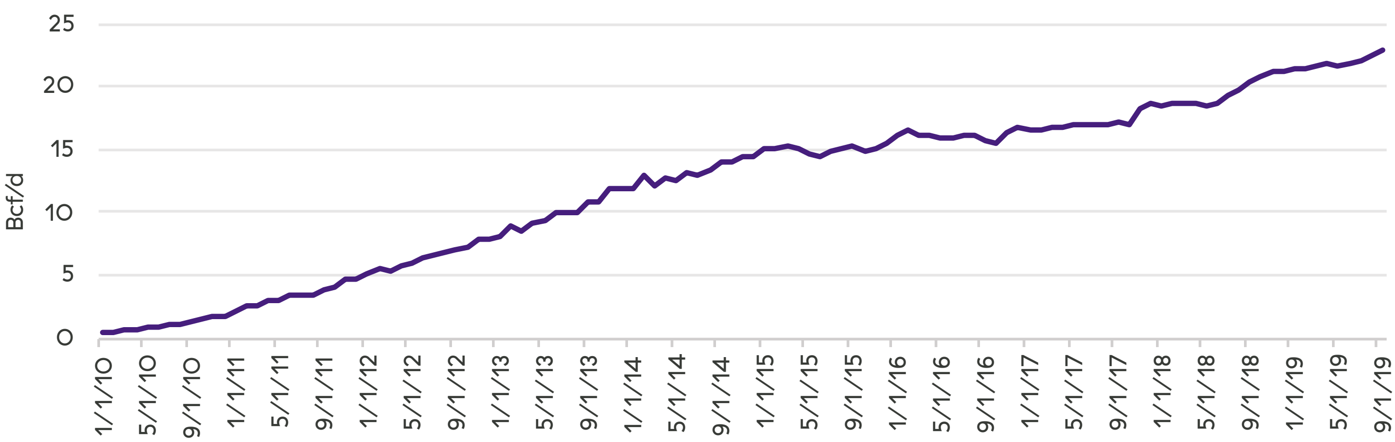
Power Prices to Remain Relatively Low and Stable

We expect wholesale electricity prices to remain relatively low and stable throughout 2020, but do anticipate significant retail variation across regions.

The Mid-Atlantic States will see net-positive additions to the generation stack in 2020, with 3,800 MW of new capacity expected to come online compared to 630 MW of capacity expected to retire.[13] Moreover, Summer Peak and Winter Peak Load in the region are both expected to decrease from 2019 to 2020, 0.3% and 0.4%, respectively.[14]

While high levels of natural gas storage and record levels of natural gas production out of the Marcellus Shale should insulate buyers from sustained high prices, we still recommend winter hedging strategies as cold winter snaps can skyrocket prices as they did during the bomb cyclone in January 2018, when West Hub real time LMPs reached nearly $80/MWh.

Monthly Dry Shale Gas Production, Marcellus Shale (PA, WV, OH & NY)



Sources: EIA derived from state administrative data collected by DrillingInfo Inc. Data are through September 2019 and represent EIA's official tight gas estimates, but are not survey data. State abbreviations indicate primary state(s).

West Hub ATC Real Time Monthly Averages ($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
2009	$59.32	$46.31	$41.63	$34.48	$33.40	$33.25	$32.42	$36.70	$30.38	$35.65	$33.03	$43.12	$38.31
2010	$51.92	$44.36	$37.31	$38.31	$42.33	$49.00	$60.43	$51.84	$44.27	$35.79	$37.98	$57.00	$45.88
2011	$52.78	$44.40	$40.12	$43.69	$48.20	$49.90	$54.64	$43.34	$40.33	$36.74	$34.73	$33.71	$43.55
2012	$33.19	$30.11	$29.92	$29.24	$34.26	$27.55	$44.43	$35.61	$34.22	$37.03	$40.23	$30.55	$33.86
2013	$36.46	$34.94	$39.95	$38.32	$38.67	$35.87	$47.02	$33.84	$35.40	$34.18	$34.00	$38.86	$37.29
2014	$123.88	$70.16	$73.99	$38.65	$42.13	$40.93	$36.25	$33.52	$35.26	$36.06	$36.44	$32.61	$49.99
2015	$38.12	$71.44	$43.21	$33.38	$32.45	$31.12	$34.29	$28.93	$32.16	$29.00	$26.79	$24.89	$35.48
2016	$29.69	$27.01	$23.65	$30.94	$24.13	$26.79	$30.14	$33.31	$30.28	$29.67	$26.11	$31.29	$28.59
2017	$31.80	$25.67	$31.70	$27.84	$29.27	$25.88	$29.52	$26.63	$30.37	$28.53	$29.76	$40.26	$29.77
2018	$79.95	$25.54	$34.42	$35.71	$35.69	$29.63	$31.01	$32.05	$32.94	$31.83	$35.96	$32.45	$36.43
2019	$30.47	$27.84	$29.22	$25.40	$24.62	$22.18	$27.62	$23.49	$28.34	$26.14	$28.40	$22.93	$26.39
Avg.	$51.60	$40.71	$38.65	$34.18	$35.01	$33.83	$38.89	$34.48	$34.00	$32.78	$33.04	$35.24	$36.87

<< Contents

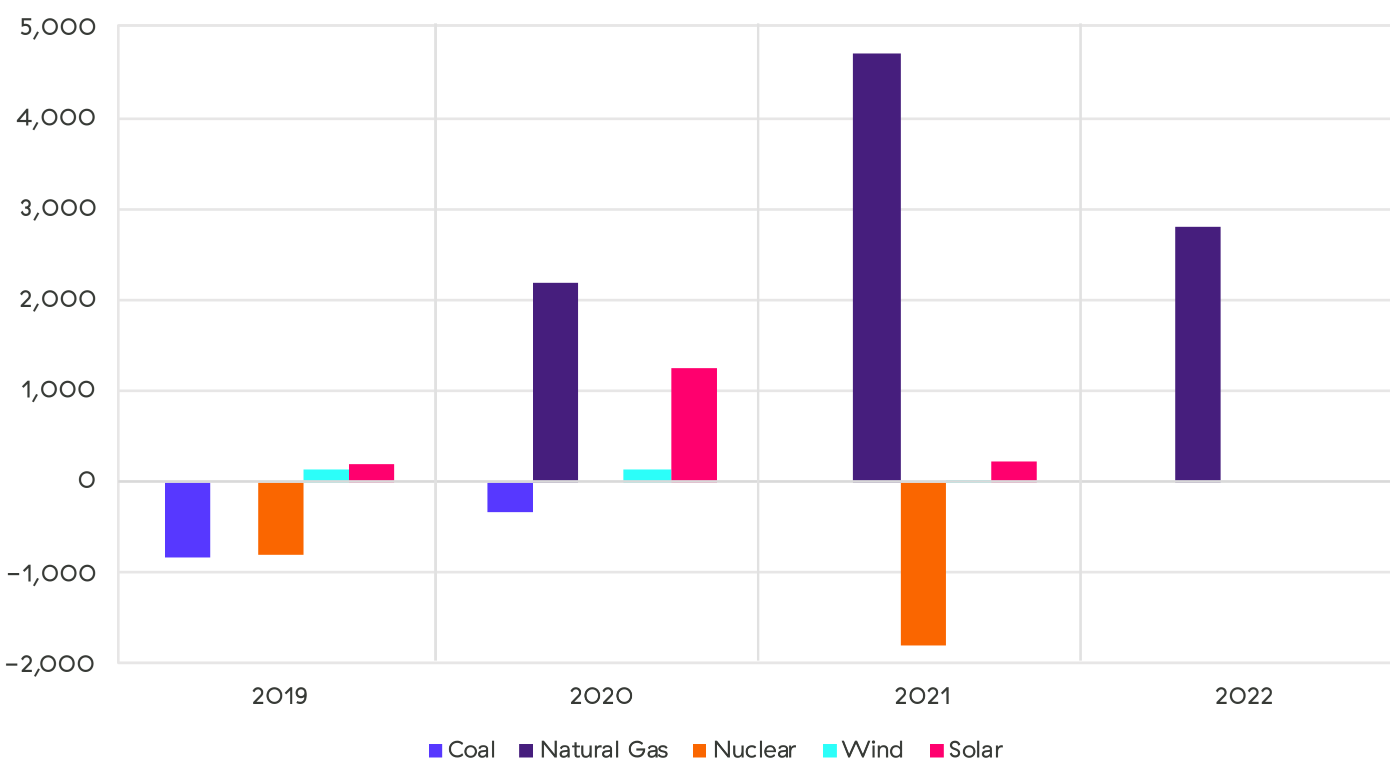
Coal and Nuclear Retirements Increasing Weather/Price Correlation

As renewable energy and natural gas generators continue to displace baseload coal and nuclear generation, we expect weather, gas and power prices to remain tightly correlated.

Pennsylvania is currently experiencing the most pronounced displacement of coal and nuclear generation by natural gas in the region. In 2019, the state retired over 1,600 MW of coal and nuclear generation and is slated to retire another 1,800 of nuclear power in 2021—while it plans to complete 2,400 MW of new natural gas generation in 2020.[15]

Though Virginia is not displacing coal or nuclear generation at the rate Pennsylvania is, the Commonwealth is similarly planning significant renewable and natural gas generation additions with more than 1,500 of renewable energy and 1,000 MW of new natural gas-fired generation expected before 2022.

Mid-Atlantic Planned Net Generation (MW)



Renewable Energy Providing Upward Price Support

State regulations and customer demand across the Mid-Atlantic is supporting new renewable developments. While it is yet to be seen how state regulators and legislators will react to FERC's MOPR ruling, we can expect additional upward price pressure.

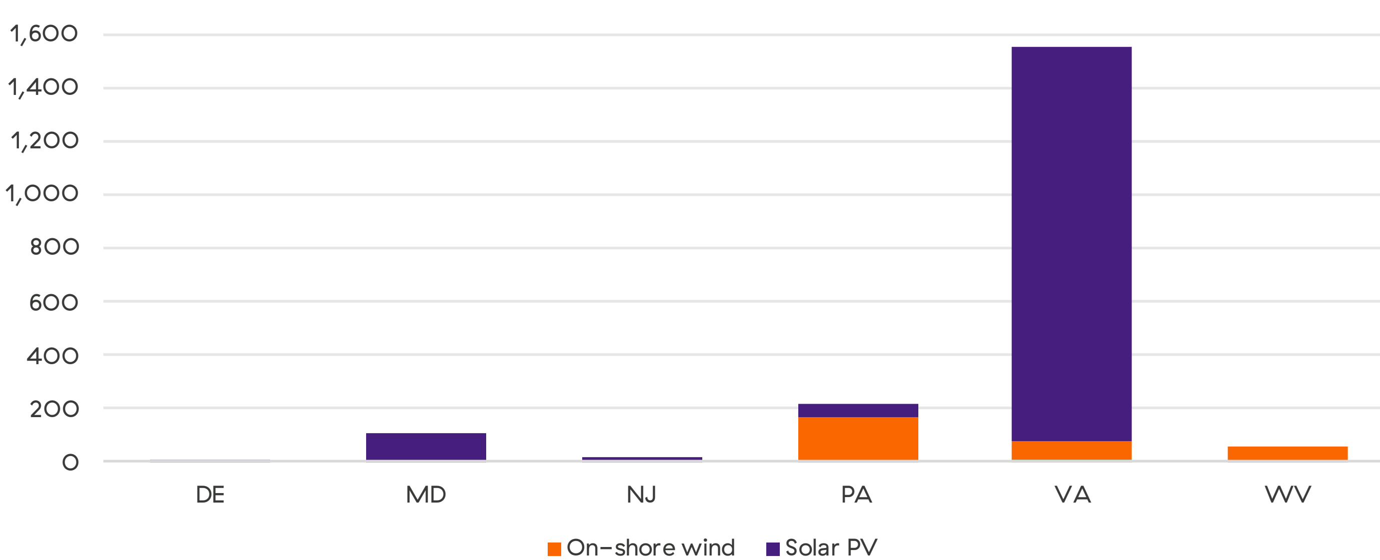
Maryland lawmakers passed the Clean Energy Jobs Act in May 2019, doubling the state's Renewable Portfolio Standard (RPS) and setting a 50% target by 2030.[16] The law caused a rally in MD-Tier 1 and MD-Solar renewable energy credits (RECs). MD-Solar RECs, for example, rallied from $12.88 in early January 2019 to $77.42/MWh in November, according to S&P Global. The law also requires at least 1,200 MW of offshore wind generation by 2030. To date, Maryland has authorized two offshore wind projects totaling 368 MW. Those two projects, US Wind and Skipjack Offshore Energy, are authorized to sell RECs at $132/MWh—a figure that should increase commercial and industrial electricity bills roughly 1.4% in 2020.[17]

New Jersey is making similar renewable energy strides in the region. In July 2019, NJ legislators released a draft of the 2019 Energy Master Plan (EMP), which outlines the steps needed to achieve 50% renewable energy by 2030 and 100% carbon-neutral electricity generation by 2050.[18] Like Maryland, the push to expand renewable generation in New Jersey is putting upward pressure on REC values and RPS charges. According to S&P Global, 2020 NJ Class-1 REC prices climbed from $6.11/MWh in February 2019 to $8.58 in November, a 40% increase. Also important to note, New Jersey's offshore wind goals more than doubled in November, scaling from a 3,500 MW by 2030 target to 7,500 by 2035.[19]

While neither Pennsylvania nor Virginia have passed the sweeping renewable targets that Maryland and New Jersey has, there are signals that both will significantly expand renewable generation in the near-term. If passed, Pennsylvania Senate Bill 630 will require the Commonwealth to achieve 100% renewable generation by 2035.[20]

Though Virginia's energy market remains largely regulated, the Commonwealth is showing the fastest adoption of renewable energy in the region. Pressured by large tech firms with significant data-center load and legislation that allows C&I buyers to access the retail markets by purchasing 100% green energy, Virginia is expected to add over 1,400 MW of solar power before the close of 2020.[21] Governor Ralph Northam's executive order in September will further accelerate this trend, as it sets a goal for the state to transition to 30% carbon-free electricity by 2030 and 100% carbon-free by 2050.[22]

Mid-Atlantic Planned Renewable Developments 2019-2021 (MW)



System Peak Demand Charges Eclipse $230,000/MW-Year in PSEG

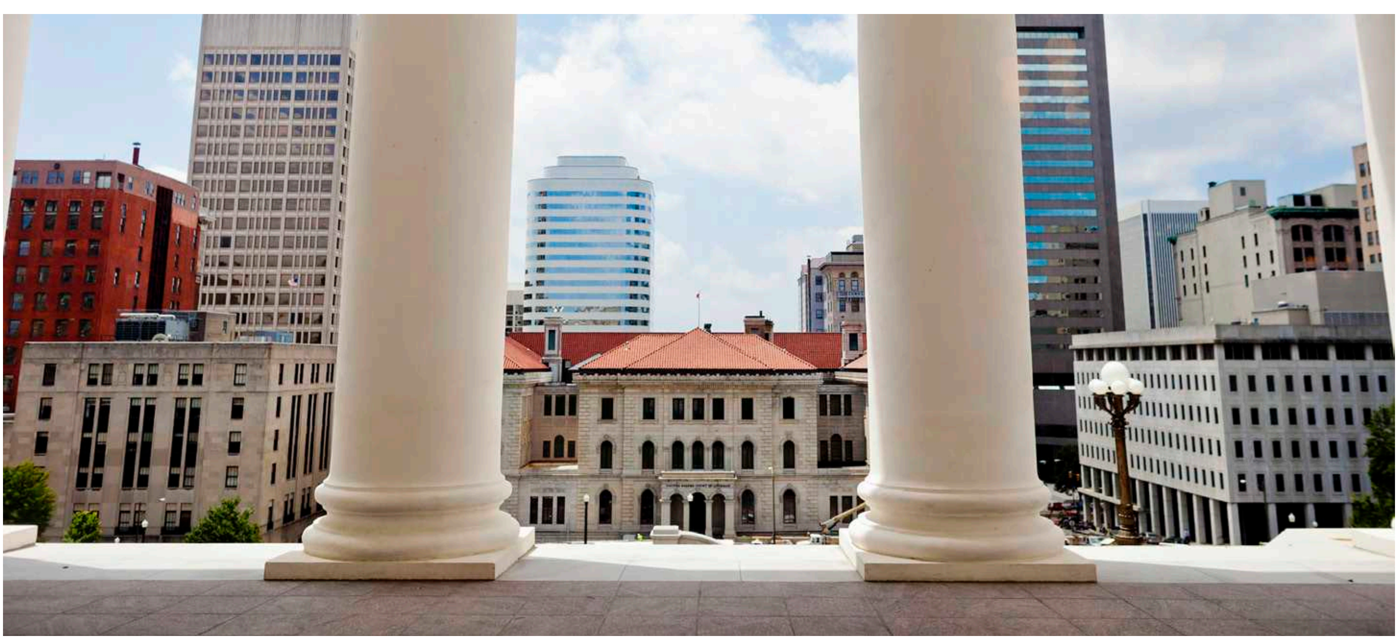
PJM transmission rates (NITS) are calculated and updated on an annual basis and are unique to each utility zone. PSEG in New Jersey already carried the most expensive NITS rates in PJM (by a far margin) in 2019, and NITS prices are slated to increase further in 2020, jumping more than 30% from $119,735/MW-Year to $156,503/MW-Year.

NITS charges are determined by system peak demands, and correlation between transmission and capacity system peaks has been strong over the past eight years. With PSEG capacity prices at roughly $75,000/MW-Year and NITS above $156,000, we strongly recommend that organizations with the flexibility to either shift or curtail load consider capacity and transmission pass-through products in PSEG, as they stand to benefit roughly $230,000 for every MW of load they can shift or curtail.

Increasing Competitive Pressure in Virginia

Virginia is currently working its way through a significant energy market reform. The State Corporation Commission (SCC) Code § 56-577 allows C&I customers with 5 MW+ in site-level demand or 5 MW+ in aggregated load to enter competitive third-party markets. In many cases, third-party retail options offer significant cost-saving opportunities versus both Dominion Power and Appalachian Power tariff rates. Accessing third-party markets, however, has proven to be a challenge for many organizations, as Dominion and Appalachian Power maintain significant political influence.

In the wake of 2019 elections, however, new Democratic legislators took control over the state legislature, and in September, the Democratic Party of Virginia[23] joined dozens of prominent Virginia politicians[24] by pledging to forego future political contributions from the state's biggest utility. The shift in power may accelerate the opening of Virginia's competitive third-party electricity market.



Mid-West
(IL, MI, OH, IN, WI and MN)

Like the rest of the country, states across the Mid-West will face significant changes in energy policy and market mechanics in 2020 and throughout the decade. Unlike the rest of the country, however, energy markets in the Mid-West are managed by two Independent System Operators (ISOs), as well as several smaller regional grids that span multiple states in various stages of deregulation. Recent changes in PJM's capacity market will significantly affect the COMED region in Illinois and Ohio. We encourage Illinois and Ohio ratepayers to consider the risks mounting in their supply decisions and actively manage their exposure to wholesale power and capacity prices.

This said, many of the policies currently being advanced by Mid-Western States and utilities will carry a bigger impact on customer distribution charges in the early part of the decade. Monthly peak demand management will remain a critical component of supply and risk management strategies.

Five States Accelerating Renewable Energy Penetration

Coal production in the Mid-West and surrounding states accounts for more than 90% of domestic supply,[25] and so readers may not be surprised to learn that coal accounts for 36% of the power produced across the six largest energy-consuming states in the region: Illinois, Michigan, Ohio, Indiana, Wisconsin, and Minnesota.[26]

What may be more surprising, however, is the wave of support for renewable energy that is sweeping the region.

In March, Minnesota Governor Tim Walz issued a proposal to transition to 100% emission-free resources by 2050.[27] Governor Walz's proposal was preceded by a similar proposal in the state legislature in February.[28]

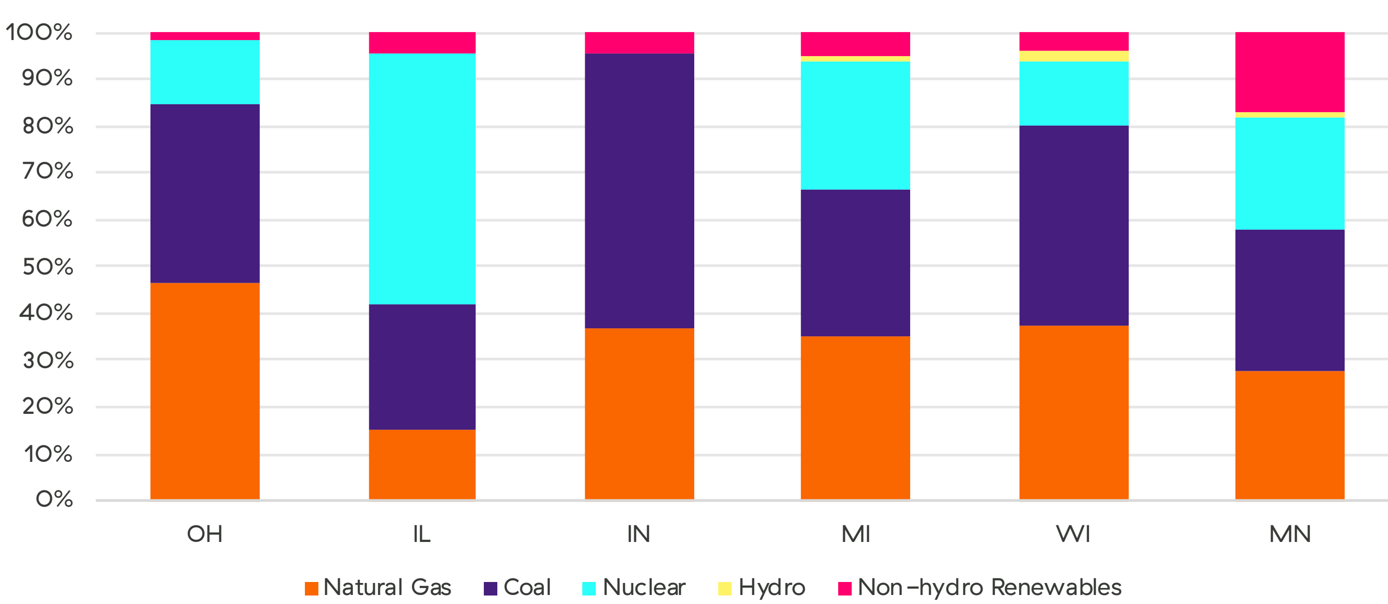
Also in March, Illinois legislators introduced the Clean Energy Jobs Act (SB 2132 / HB 3624) in the House and Senate, aiming to make Illinois the first state in the Continental US to be powered entirely by renewable energy (not including nuclear), and setting a 100% renewable target by 2050 with a 100% carbon-free target (including nuclear) by 2030.[29] FERC's recent direction to expand PJM's Minimum Offer Price Rule (MOPR), discussed more thoroughly in the Mid-Atlantic section of this report, threatens Illinois' ability to achieve these goals. As a result, we can expect Illinois to seriously consider legislation in 2020 that would have the state leave the PJM capacity market.

In June, the Michigan Public Service Commission (MPSC) approved Consumers Energy Co.'s integrated resource plan (IRP) that calls for the rapid retirement of its coal fleet, including 515 MW of coal-fired generation by 2023. To offset the coal retirements, Consumers will look to add an additional 1,200 MW of new solar power before 2021, invest in energy efficiency to eliminate 718 MW of energy waste by 2022, and increase demand response (DR) programs to shave peak consumption by an additional 607 MW.

In August, Wisconsin Governor Tony Evers signed an executive order calling for the state to transition to 100% renewable power.[30] Without legislative support, Evers and renewable energy advocates will face challenges accom-plishing that goal, but advocates see a path forward after Evers appointed Rebecca Cameron Valcq to the state's Public Service Commission, who appears to support the direction.

And in September, Northern Indiana Service Company (NIPSCO) announced that it would retire its coal fleet and transition to renewable resources. NIPSCO Senior Vice President Mike Hooper predicts 65% of NIPSCO's electricity generation will come from solar, wind and battery storage by 2028 and that the transition will save ratepayers more than $4 billion.[31]

Mid-West Power Generation by Resource



Ohio Decelerating Renewable Energy Transition

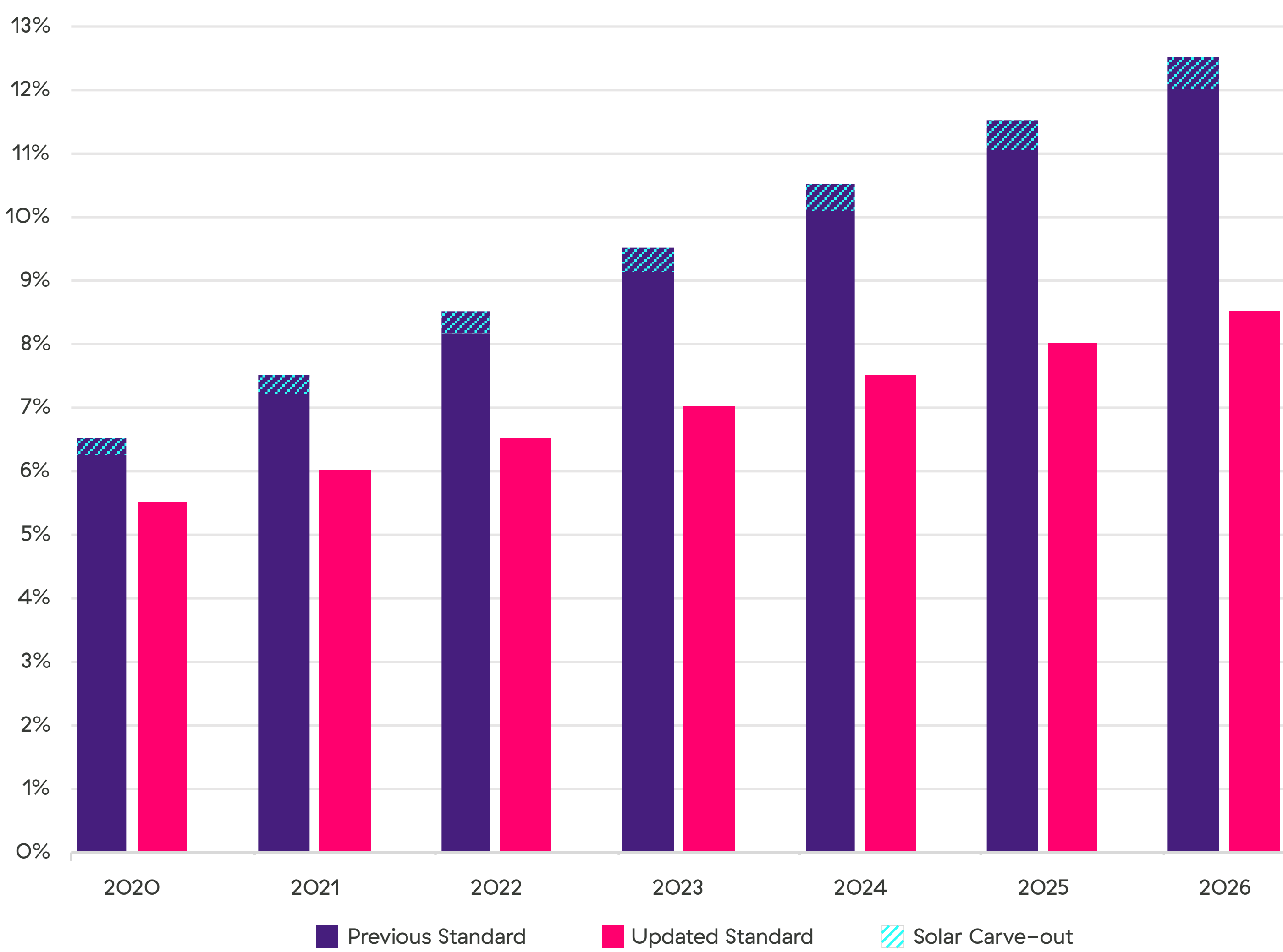
While the rest of the region aims to accelerate renewable energy and retire inefficient coal-fired generators to achieve environmental objectives, Ohio's House Bill 6 (HB 6)[32] moves the state in the opposite direction. The new legislation will provide economic support for First Energy's struggling nuclear fleet, and it will subsidize Ohio Valley Electric Corp.'s coal-fired plants in Ohio and Indiana.

Together, the subsidies for coal and nuclear generation are expected to cost Ohio's commercial and industrial customers roughly $18,000 per year in new charges.[33]

The bill also restructures Ohio's renewable portfolio standards, lowering renewable penetration targets 15% in 2020 and 32% by 2026, while eliminating the solar carve-out.

Ultimately, we do not expect the new legislation to significantly impact customer overall spend in the short-term. The additional $18,000 in subsidies will appear on customer distribution bills this year, but subsidies should dampen the volatility that would have accompanied reductions to Ohio's coal and nuclear baseload generation. If Ohio's nuclear generators are priced out of PJM's capacity markets, however, ratepayers may see substantial price increases.

Updates to Ohio Renewable Portfolio Standard

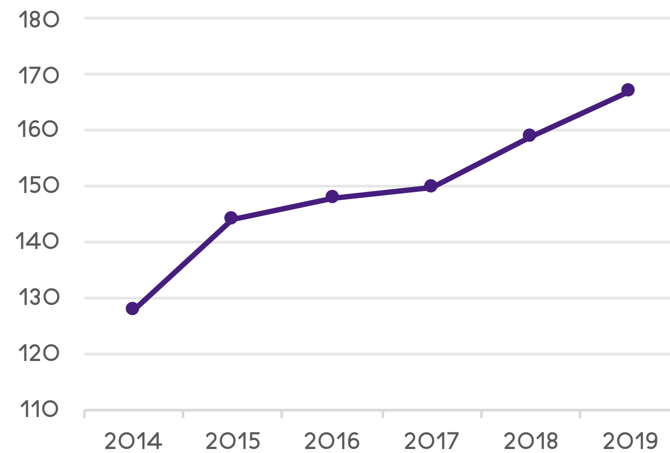


Ohio Demand Charges May Rise as First Energy Looks to Decouple Revenues from Customer Use

Decoupling revenues from consumption allows utilities to offset the loss of revenues that result from customer efficiency programs, irregular temperature patterns, and/or economic conditions. We expect First Energy in Ohio to join the growing list of utilities decoupling revenues from customer use, as they intend to submit a decoupling proposal to the Public Utilities Commission of Ohio (PUCO).

If passed, shifting the utility's revenues from a consumption basis to a more fixed overall return should lead to tariff changes in 2020 that would either increase fixed customer fees or distribution demand charges. Increased demand charges is a trend intensifying across both the region and the country, stressing the importance of a coordinated supply and demand-side energy management strategy.

Utilities with Decoupling Mechanisms in Place



Demand Charge Management Increasingly Important in Michigan

Many of Consumer Energy's commercial and industrial customers experienced a significant increase in demand-related charges in 2019 as the utility adjusted demand rates 30-60% upward for several rate classes.

As seen in Ohio, utilities across the country are leveraging demand charges and riders to recoup revenues lost to energy efficiency, distributed generation, and cheap natural gas. What is unique to Consumers is the overall expense.

Sites under Consumers territory that consistently experience their monthly Maximum Demand during the On Peak Window (11am — 7pm) will face charges up to $412,000/MW-Year. These charges are among (if not the) most expensive demand-related charges in North America.

Published Demand Rates

Tariff/Rate Code Short Name (and Long Name)	**Date Effective**	**Annualized On Pk Dmd Rate** ($/MW-Yr)	**Annualized Max Dmd Rate** ($/MW-Yr)	**Total Annualized Dmd Rate** ($/MW-Yr)
GSD Commercial (General Service Secondary Demand Rate, with or without 100 kW guarantee)	Aug 1, 2018	$131,600	$13,800	**$145,400**
	Jan 10, 2019	$221,680	$13,800	**$235,480**
GPD, Commercial/Industrial CVL1 (Large General Service Primary Demand Rate, Customer Voltage Level 1)	Aug 1, 2018	$234,880	$11,520	**$246,400**
	Jan 10, 2019	$340,880	$10,920	**$351,800**
GPD, Commercial/Industrial CVL2 (Large General Service Primary Demand Rate, Customer Voltage Level 2)	Aug 1, 2018	$246,880	$22,200	**$269,080**
	Jan 10, 2019	$354,440	$22,320	**$376,760**
GPD, Commercial/Industrial CVL3 (Large General Service Primary Demand Rate, Customer Voltage Level 3)	Aug 1, 2018	$258,880	$50,400	**$309,280**
	Jan 10, 2019	$369,680	$43,200	**$412,880**

Source: www.consumersenergy.com/-/media/CE/Documents/rates/electric-rate-book.ashx

California

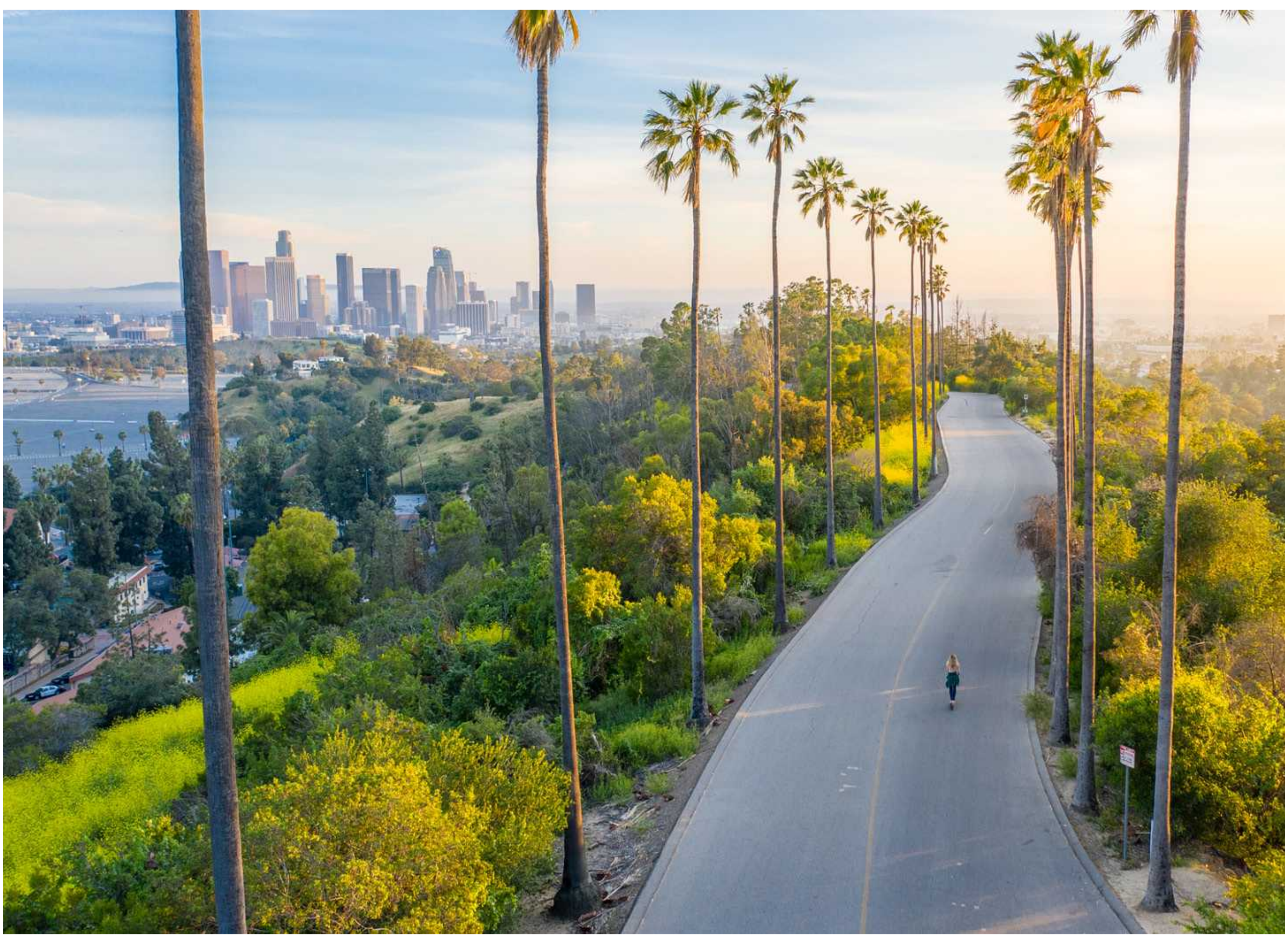
California is in the midst of profound energy-sector transformation as the state seeks to achieve ambitious renewable energy goals while simultaneously addressing unprecedented power outages for millions of PG&E ratepayers.

The challenges inherent in this transition manifest in extremely volatile energy prices. For example, winter power prices reached 10-year highs in February 2019, while summer prices reached 10-year lows later in June.

Between PG&E's bankruptcy filing, expansion of the Direct Access program and Community Choice Aggregation, and the changing role of Investor Owned Utilities in the state, California presents one of the most challenging and risk-laden energy markets in the United States.

SP15 Day Ahead Monthly Averages ($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
2010	$44.63	$43.43	$40.20	$34.21	$29.58	$27.17	$35.10	$33.50	$34.77	$33.32	$33.49	$33.25	$35.22
2011	$32.58	$32.23	$26.02	$27.63	$23.84	$27.54	$34.45	$36.25	$35.89	$31.33	$30.40	$29.61	$30.65
2012	$27.52	$25.58	$22.59	$25.16	$26.64	$26.07	$29.67	$36.61	$35.90	$37.76	$35.55	$34.30	$30.28
2013	$42.88	$42.75	$46.44	$49.05	$43.69	$42.14	$43.85	$41.25	$43.42	$39.97	$40.64	$48.58	$43.72
2014	$46.47	$61.70	$47.60	$44.71	$45.85	$45.25	$47.75	$45.89	$46.66	$45.17	$44.98	$37.87	$46.66
2015	$33.51	$30.05	$29.00	$27.93	$27.21	$33.94	$36.02	$35.69	$34.76	$32.62	$28.86	$28.09	$31.47
2016	$28.18	$22.99	$18.05	$18.44	$21.01	$29.95	$34.29	$34.93	$32.89	$33.06	$27.79	$33.95	$27.96
2017	$33.55	$26.39	$21.75	$24.80	$28.83	$32.80	$36.70	$45.34	$38.43	$41.09	$39.51	$39.12	$34.03
2018	$34.37	$33.83	$30.53	$24.88	$21.65	$28.17	$75.42	$69.73	$35.33	$38.88	$51.59	$52.93	$41.44
2019	$39.96	$70.89	$36.02	$23.52	$18.43	$23.07	$31.52	$32.84	$36.08	$34.36	$42.03	$40.24	$35.75
Avg.	$36.36	$38.99	$31.82	$30.03	$28.67	$31.61	$40.48	$41.20	$37.41	$36.75	$37.48	$37.80	



Moderated Winter Price Volatility for SoCal Gas

In September, the California Public Utilities Commission (CPUC) instructed Southern California Gas Co (SoCalGas) to take immediate steps to improve reliability service by increasing injections "at all available storage facilities."[34] That direction is welcome for ratepayers who, as of September, were looking at gas storage levels 10% lower than last year and 15% lower than the 5-year average.

SoCalGas ratepayers will see additional relief from winter price volatility as the CPUC also loosened restrictions on Aliso Canyon's withdrawal protocol in July. Previously, Aliso Canyon was an asset of last resort and only available when regulators deemed that withdrawals were necessary to maintain reliability. The relaxed withdrawal protocols allow gas removal if storage levels at Aliso Canyon are greater than 70% of its capacity in February and March, or if the two largest gas storage facilities in the region (Honor Rancho and La Goleta) are within 10% of their month-end minimum capacity.[35]

In addition to ramped injections and Aliso Canyon's looser withdrawal protocols, SoCalGas recently completed maintenance on Line 235 and Line 4000 pipelines. Both lines are running at partial capacity since returning to service, yet still have increased capacity by roughly 15%.[36] SoCalGas expects pipeline capacity to reach 3.805 Bcf/d (up from 2.35 Bcf/d) when the pipelines return to full service, which will temper price spikes if the lines can return to full service this winter.

SoCal Settlements $/MMBtu (NYMEX + Basis)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
2012	$3.37	$2.93	$2.54	$2.34	$2.12	$2.54	$2.85	$3.03	$2.70	$3.13	$3.65	$3.86	$2.92
2013	$3.48	$3.40	$3.51	$4.18	$4.09	$4.18	$3.80	$3.54	$3.70	$3.54	$3.68	$3.87	$3.75
2014	$4.56	$5.47	$5.14	$4.74	$4.84	$4.67	$4.61	$4.10	$4.26	$4.05	$3.77	$4.62	$4.57
2015	$3.35	$2.79	$2.76	$2.45	$2.42	$2.79	$2.87	$3.01	$2.69	$2.62	$2.15	$2.42	$2.69
2016	$2.63	$2.30	$1.58	$1.70	$1.88	$1.91	$2.97	$2.92	$2.81	$2.85	$2.71	$3.59	$2.49
2017	$3.82	$3.33	$2.47	$2.85	$2.81	$3.02	$2.85	$2.87	$2.81	$2.67	$2.76	$3.50	$2.98
2018	$3.06	$3.09	$2.51	$2.07	$2.06	$2.31	$2.75	$5.22	$2.73	$2.47	$3.03	$6.40	$3.14
2019	$4.31	$3.13	$3.25	$2.33	$1.95	$2.10	$2.67	$2.71	$2.41	$2.46	$2.64	$4.00	$2.83
Avg.	$3.57	$3.31	$2.97	$2.83	$2.77	$2.94	$3.17	$3.43	$3.01	$2.97	$3.05	$4.03	

Changing Roles of Investor Owned Utilities (IOUs)

In 2018, Governor Jerry Brown signed Senate bill 237[37] and expanded California's Direct Access program, opening up an additional 4,000 GWh to third-party electric supply. The bill also required the California Public Utilities Commission (CPUC) to recommend by July 2020 whether all remaining IOU commercial and industrial customers should be eligible to procure through third-party markets.

With roughly 15.5% of C&I customers in the state now participating in the Direct Access program and an exploding Community Choice Aggregation (CCA) program that saw 14 new CCAs launch since 2017, the role of California's IOUs may look very different by mid-decade.

In a July 8, 2019 interview with Utility Dive, for example, Colin Cushnie, Southern California Edison (SCE) Vice President for Power Supply, estimated that SCE, SDG&E, and PG&E might serve "less than half the retail load in California and potentially a much smaller share" by 2020.[38] Similar projections show that PG&E will only sell power to roughly 60% of its load by the end of 2020.[39]

As more customers procure through Direct Access or CCA programs, California's IOUs will increasingly become "wires only" utilities—responsible only for transmission and distribution.

Increasing Resource Adequacy Charges

The California Independent System Operator (CAISO) does not have a centralized capacity market like PJM or ISO-NE. Instead, load-serving entities (LSEs) enter into bilateral contracts directly with generators to ensure that they have the power generation needed to meet forecast energy demands. Those capacity requirements are governed by the Resource Adequacy (RA) framework and are subject to market dynamics.

Bilateral contracts between LSEs and generators are not publicly available, but we have seen indications in recent months that RA prices for end-users may increase significantly, as much as 15% in PG&E (to $7.50/MWh) and more than 50% in SCE (to $5.75/MWh).

California's Department of Water Resources Board (DPWR) CWA 316 policy[40] is one of the factors driving RA price increases. CWA 316 requires power plants that use ocean water to produce steam to reduce water intake by 93% from 2010 levels. As a result, nearly 4,800 MW of generating resources face closure by the end of 2020. CPUC and CAISO voted to extend the timeline for these resources to maintain grid reliability, and DPWR approval is pending. Without knowing whether these resources will be available in 2021, LSEs may be procuring capacity with less efficient generators.

To compensate for impending gas-fired plant retirements, CPUC and CAISO have authorized the procurement of 3,300 MW of new clean energy resources to be added to the grid by 2023.[41] Unless these resources are paired with dispatchable storage capacity, the extent to which they displace quick-start gas generators will only exacerbate RA rate increases.

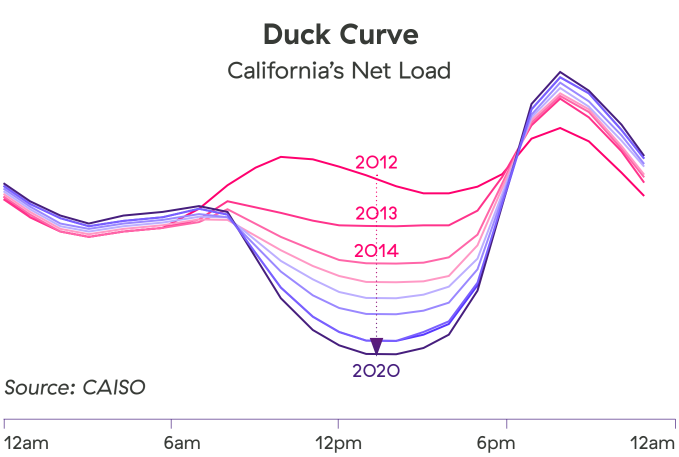
Increasing Market Volatility Related to Renewable Penetration

California's renewable portfolio standards (RPS) required 31% of the state's power generation to come from renewable resources in 2019, a target that climbs to 50% by 2026. While the increase in renewable generation is ambitious, California IOUs are on track to achieve those targets. In August 2019, the CPUC reported the state's IOUs are expected "to exceed their 2020 RPS compliance period requirements and to have procured 40% RPS by 2020."[42]

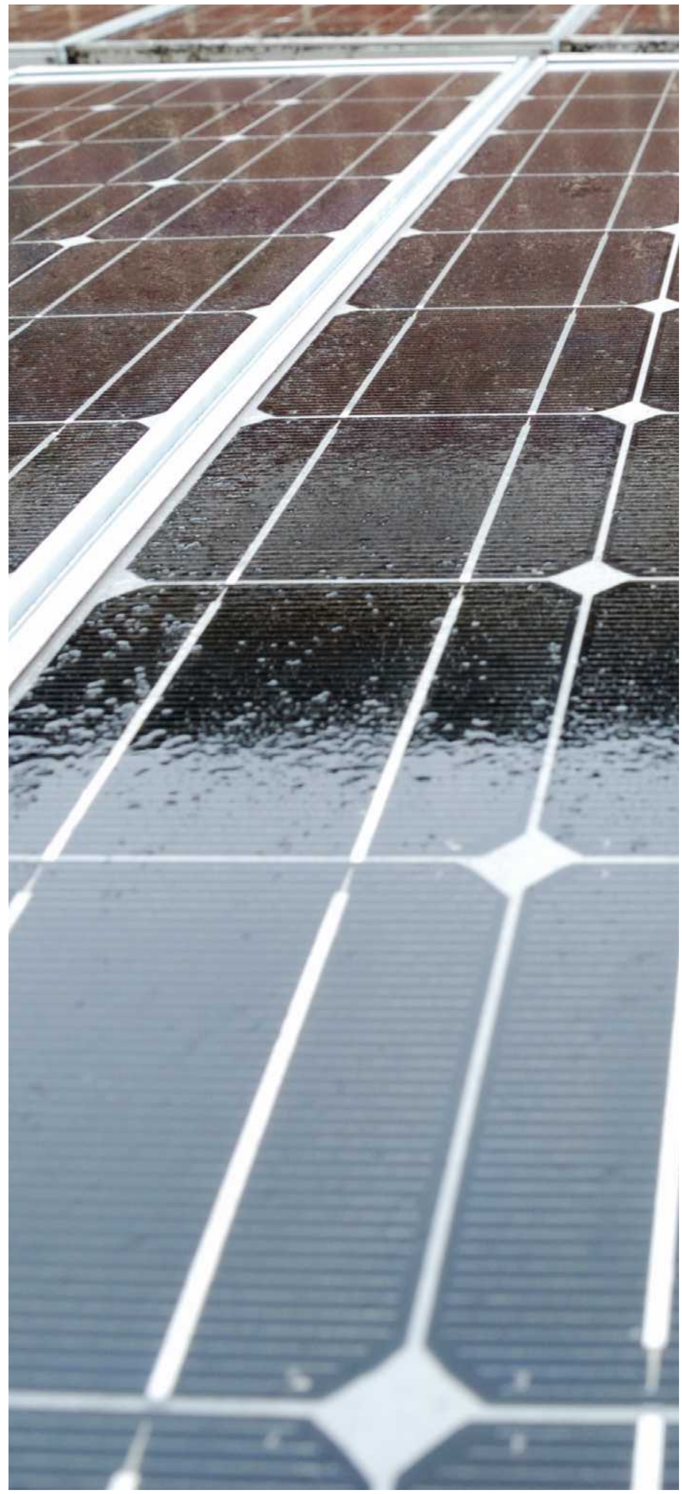
Actual 2018 Large Investor-Owned Utilities' RPS Procurement Percentages	
Pacific Gas and Electric	39%
Southern California Edison	36%
San Diego Gas & Electric	44%

Source: IOUs' Annual RPS Compliance Reports, August 2019

The rapid increase in California's renewable production has not come without challenges. Intermittent resources like solar and wind now contribute up to 25% of California's hourly peak load. These levels of intermittent generation add significant pressure to short-term energy and ancillary markets, and they have fundamentally changed the shape of California's electric load curve—a phenomenon commonly referred to as the duck curve.



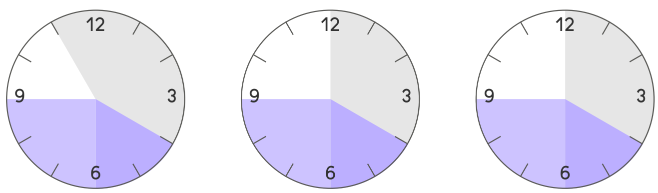
Source: CAISO



To meet evening demand when solar production drops off, California has had to rely on expensive quick-start resources. As a result, California's IOUs pushed back summer peak hours, and the spread between on-peak and off-peak pricing has grown (in both wholesale markets and utility tariff rates).

California's Changing Time-Of-Use Rates

SDG&E effective Dec 2017	**SCE** effective Feb 2019	**PG&E** effective Oct 2019



PREVIOUS	PREVIOUS	PREVIOUS
11am—6pm, May—Oct	12pm—6pm, Jun—Sep	12pm—6pm, May—Oct
NEW	NEW	NEW
4pm—9pm, Jun—Oct	4pm—9pm, Jun—Sep	4pm—9pm, Jun—Sep

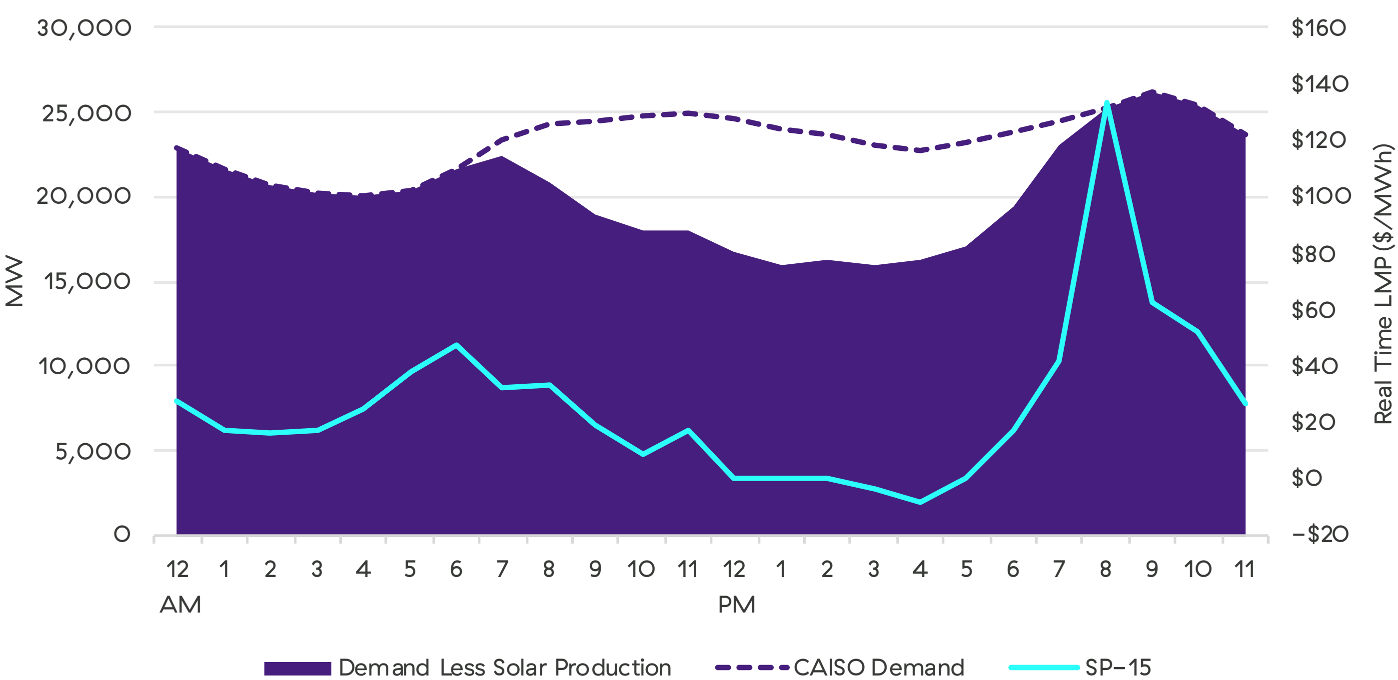
On-peak prices for July and August contracts at SCE, for example, were 35% higher than off-peak prices in 2016. By 2018, on-peak prices were 72% higher than off-peak prices.

The impact of this trend is unmistakable in hourly LMP prices. As seen in the May 16, 2019 example below, real-time LMP prices at Southern California's SP-15 Zone jumped from $0.39/MWh at 5:00 PM to $133.75 at 8:00 PM as solar production dropped off and the grid replaced more than 6,000 MW of solar capacity with non-renewable, peak-load resources.

Overproduction has become another consequence of such significant levels of renewable capacity, particularly when there is little heating/cooling demand during spring and fall months. In April 2018, renewable generators curtailed nearly 95,000 MWh[43] to avoid damaging the grid, a figure considerably higher than the previous record of 88,000 MWh in April 2016. Along with the duck curve, curtailments and negative pricing related to intermittent resources add significant risk to California's wholesale markets.

Correlation of CAISO Demand, Solar Production, LMP Prices

May 16, 2019



Relief from Seasonal Market Volatility May Be In Sight

As mentioned earlier, 2018 July and August on-peak contracts were 72% higher than off-peak contracts at SCE. By 2019, however, on-peak prices were just 44% higher than off-peak prices. That reduction may not prove to be an anomaly. California added roughly 260 MW of storage capacity by August 2019 and is on track to add another 1,300 MW by 2023.[44] As the price of utility-scale battery storage continues to fall lower than gas-fired peaker plants, California's seasonal volatility may begin to subside.

Similarly, we expect CAISO to continue to expand the Western Energy Imbalance Market (EIM), a real-time bulk power trading market[45] that allows balancing authorities outside of CAISO to participate in a western wholesale energy market. As the EIM grows, California will be able to decrease negative pricing scenarios and curtailments by selling excess renewable capacity to neighboring states.

Yet it is important to note increasing intermittent generation requires higher levels of operating reserves. While expanding battery storage capacity and the EIM may slow or, even to some degree, subdue the volatility related to renewable generation in the out-years, we expect ratepayers to face climbing ancillary service charges in the shorter-term.

CA Wildfire Fund Extends DWR Bond Charge to 2035

PG&E, California's largest utility, filed for Chapter 11 bankruptcy in January 2019 as it faced billions of dollars in civil liabilities for its role in the California wildfires in 2017–18. In response, the California State Assembly passed Assembly Bill (AB) 1054 in an effort to provide financial stability to the state's largest Investor Owned Utilities (IOUs) as potential wildfire liabilities put their solvency at risk.

AB 1054 extends the DWR Bond Charge that was set up in 2001 to support PG&E in its last bankruptcy filing during the California Electricity Crisis. The DWR Bond Charge, which costs ratepayers of California's Investor-Owned Utilities (SDGE, SCE, and PG&E) $5.25/MWh, will now extend until at least 2035.

PG&E, specifically, will not be allowed to participate in the fund unless it exits Chapter 11 by June 30, 2020. Added scrutiny over the company's power shutoffs in October 2019 has created additional obstacles, and the California Public Utilities Commission is currently considering splitting the utility into separate companies.

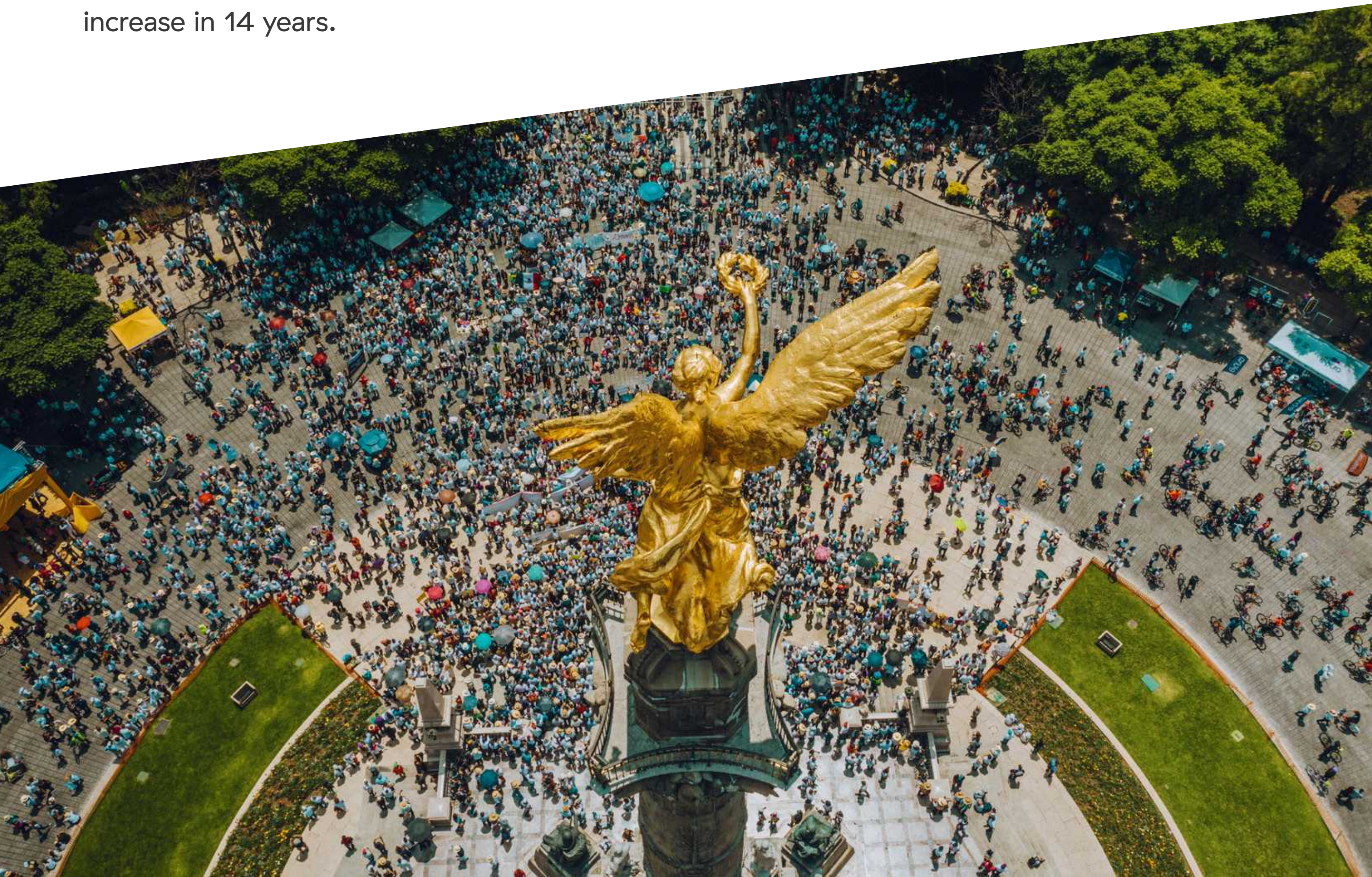
Mexico

More than in any other market in North America, energy buyers in Mexico face tremendous risks entering 2020.

Since his election, President Andrés Manuel López Obrador (AMLO) has shown ambivalence toward both foreign investment and competitive markets while providing significant financial and regulatory support to Mexico's state-sponsored energy companies. As a result, tariff rates under the Comisión Federal de Electricidad (CFE) have stabilized and the CFE posted its first profitable quarter in two years.[46] Similarly, according to S&P Global, Petróleos Mexicanos (PEMEX) announced its first quarterly production increase in 14 years.

These developments have not slowed the expansion of Mexico's retail energy markets, however, and ratepayers under the CFE and PEMEX are not in the clear. The significant financial burdens that the CFE and PEMEX carry, along with Mexico's economic slowdown and recent credit rating downgrades, all point to escalating prices.

We see little chance that PEMEX and the CFE will be able to keep prices depressed in the long term and encourage energy buyers to pursue retail options that provide immediate savings while hedging long-term volatility.



Low-Cost Natural Gas Pipeline Imports Stabilizing Energy Prices in North and Central Regions

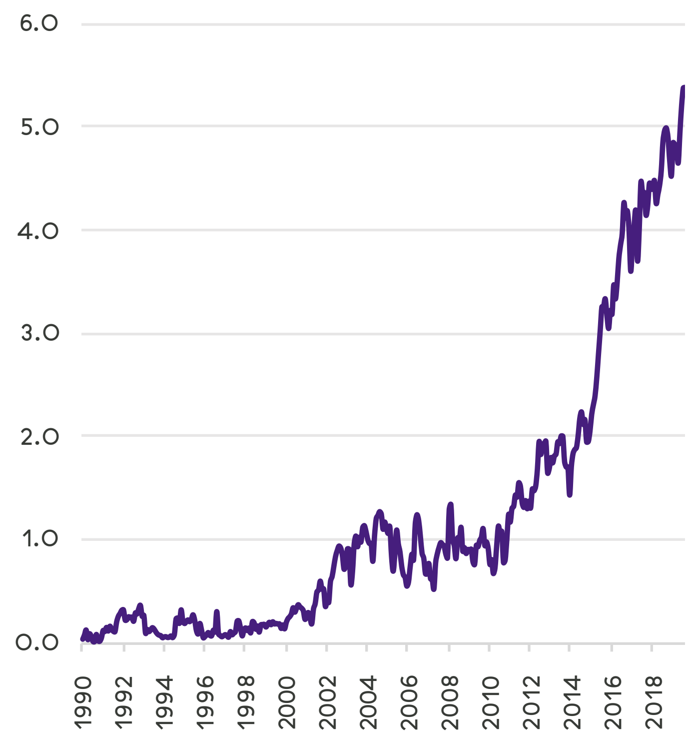
Increasing natural gas supplies will continue to provide regional gas and power price relief in 2020, as natural gas fuels more than 48% of Mexico's power generation.[47] Pipeline imports from the US have increased 150% over the past five-years, currently topping 5.4 Bcf/d.

As roughly 90% of the natural gas used to fuel Mexico's power generation comes from US imports, Mexico's electricity prices are tightly correlated with Texas natural gas markets. Record dry gas production across the Texas shales depressed gas prices in 2019. Last year, prices at the Waha Hub were down 50% from 2018 and more than 60% from the previous three-year average.

The August agreement between the AMLO administration and gas pipeline companies to renegotiate the terms of seven US-Mexico pipelines provides additional short-term relief to both ratepayers and power generators, though it does introduce longer-term risks. The AMLO administration estimates that restructuring the pipeline contracts will save taxpayers $4.5 billion over the next 30 years.[48] Private analysts, however, appear skeptical of the valuations those claims imply and worry that the sudden renegotiation of terms may deter future private investment.

Natural Gas Pipeline Imports from the US

Bcf/d



Waha Hub Settlements $/MMBtu (NYMEX + Basis)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
2012	$3.03	$2.63	$2.37	$2.07	$1.95	$2.43	$2.71	$2.94	$2.55	$2.96	$3.43	$3.64	$2.73
2013	$3.27	$3.21	$3.35	$3.90	$4.08	$4.14	$3.66	$3.44	$3.46	$3.43	$3.44	$3.66	$3.59
2014	$4.35	$5.45	$4.86	$4.47	$4.69	$4.42	$4.28	$3.77	$3.88	$3.82	$3.54	$4.29	$4.32
2015	$3.12	$2.63	$2.76	$2.47	$2.39	$2.68	$2.61	$2.81	$2.49	$2.43	$1.95	$2.11	$2.54
2016	$2.19	$2.05	$1.55	$1.69	$1.83	$1.83	$2.80	$2.58	$2.68	$2.79	$2.57	$3.10	$2.31
2017	$3.71	$3.17	$2.35	$2.76	$2.72	$2.88	$2.72	$2.65	$2.58	$2.51	$2.30	$2.61	$2.75
2018	$2.38	$2.97	$1.96	$1.33	$1.38	$2.01	$1.84	$1.86	$1.35	$1.22	$1.51	$0.62	$1.70
2019	$1.78	$1.67	$1.21	-$0.01	$0.15	-$0.17	$0.14	$0.85	$1.22	$1.62	$0.90	$1.34	$0.89
Avg.	$2.98	$2.97	$2.55	$2.34	$2.40	$2.53	$2.60	$2.61	$2.53	$2.60	$2.46	$2.67	

Increased PEMEX Production May Provide Short-Term Price Relief

Mexico will need to increase natural gas supplies to ensure price stability and reliable service for both power and gas customers. PEMEX's 2019–23 business plan, announced in July 2019, intends to do just that, aiming to increase gas production to 6.5 Bcf/d by 2024.[49]

In Q3 2019, according to S&P Global, PEMEX was able to increase natural gas production to 4.6 Bcf/d, a 2% increase over the previous quarter. While that production increase appears positive on its surface, it did not come without cost. According to the same sources, PEMEX net losses doubled, growing from roughly ($2.3 billion) in Q2 to ($4.6 billion) in the third quarter.

Increasing Demand May Maintain Short-Term Price Support

We expect increased energy demand to balance additional natural gas fuel supplies in the short-term. The number of electric service customers in Mexico is expected to grow 1.6% annually from 2019–33. Mexico will need to add upwards of 70,000 MW of new supply to meet growing demand over the next 10–15 years.[50] The majority of that generation, however, is not yet in planning stages.

The CFE's surprise decision to cancel the fourth long-term electricity auction further complicates matters. In a series of telling statements, both President AMLO and CFE Director General Manuel Bartlett signaled plans to curb the development of private generation.[51]

In a January press conference, President AMLO lamented the current state where "the CFE generates now only half of what is consumed, while private companies are supplying the market with very high costs."[52] Although the president was correct that the CFE currently generates roughly half of the power consumed in Mexico, his claims regarding the relative cost of public and private generation are at odds with clearing prices during previous power auctions. Mexico's second power auction in 2016 rendered record-low prices for Latin America.[53] Mexico's third auction in November 2017 produced some of the lowest power prices in the world.[54]

Director Bartlett offered similar concerns during a televised interview in March, questioning why the CFE would "buy power if we can produce it," adding "the CFE does not require third-party support."[55] Director Bartlett's claim of self-sufficiency is similarly misleading, as it does not acknowledge that the CFE relies on billions of dollars in subsidies each year.

Without private investment in additional power generation, the CFE should be forced either to increase production from existing inefficient resources or assume more debt to finance new plants. Either way, tariff rates will face upward pressure.

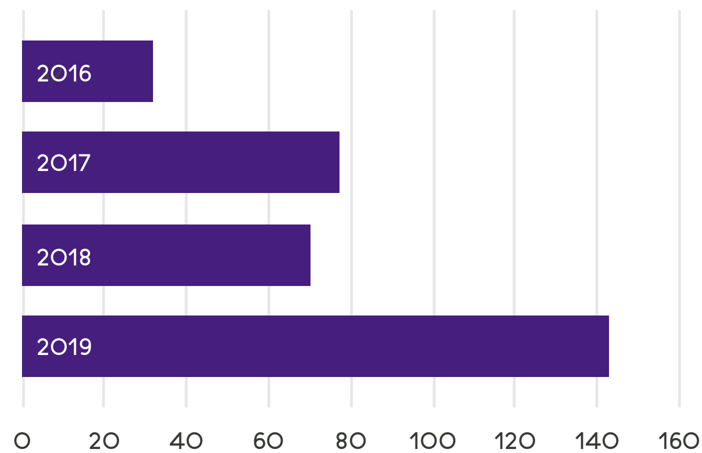
Growing Retail Market Participation Pressures CFE Tariff Rates

More than 300 of the biggest power consumers across Mexico have already left the CFE tariff, and the rate at which the CFE's largest customers are migrating to the retail supply market is accelerating.

With 143 Qualified User registrations and an additional 39 applications pending as of the CFE's last update in November, it is likely that more than 150 large power users will leave the CFE in 2019 alone.

The shrinking pool of CFE customers leaves fewer accounts and kWh to distribute fixed costs. Given that the CFE's third quarter labor, financing, maintenance and depreciation costs increased 40% year-over-year,[56] customers that remain on the tariff should expect to absorb a larger share of the CFE's financial burden.

Qualified User Registrations

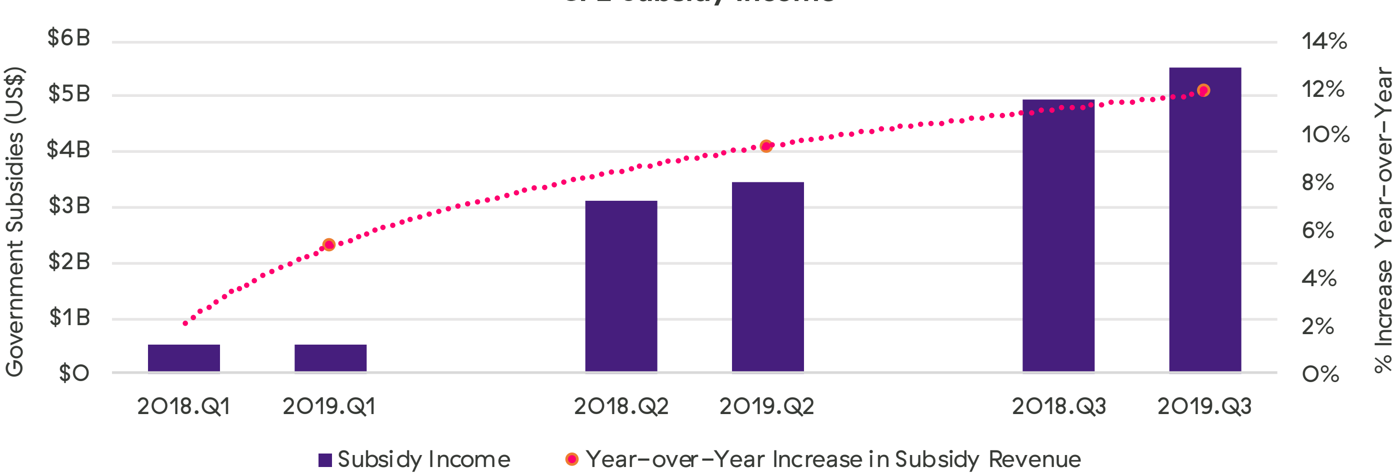


Mounting Risk in CFE and PEMEX Business Models

We expect significant tariff rate increases related to CFE and PEMEX business models and financial burdens over the long term. Faced with growing dependence on government subsidies, optimistic revenue assumptions baked into PEMEX's 2019–23 business plan and maturing third-party markets, the financial stability of these state-supported enterprises is questionable.

The government has increased CFE subsidies in every quarter of 2019, as compared to 2018. Taxpayers provided 5% more subsidies in the first quarter of 2019 than they had in 2018.[57] By the third quarter, taxpayers were providing 12% more subsidies than 2018. This is a concerning trend, given that Mexico's GDP decreased 0.4% in Q3.2019 and is currently in recession.[58] Government subsidies should be harder to come by if the overall economy continues to slow.

CFE Subsidy Income

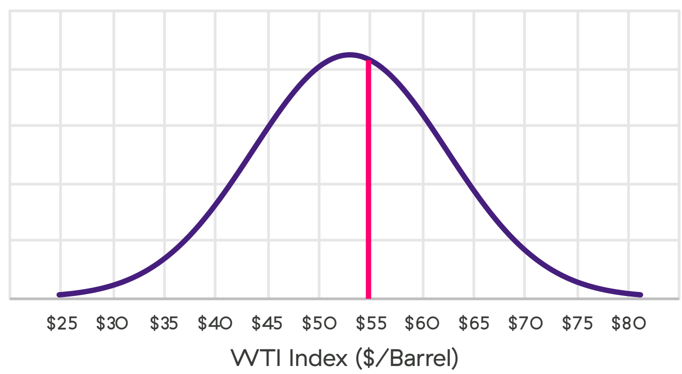


Similarly, PEMEX investments are contingent upon government support and hinge on optimistic revenue projections. PEMEX's 2019–23 business plan relies on oil prices that remain above US$ 55/barrel, according to S&P Global. The ratings agency cautioned that PEMEX "could get trapped in a negative circle" if either oil prices and/or production fail to meet expectations. For context, oil prices have averaged US$ 53/barrel over the past five years, trading below $55 in 62% of months.

Adding further risk to the situation, S&P Global downgraded PEMEX's credit rating from B– to BB– and cut PEMEX's outlook from stable to negative in March 2019.[59] PEMEX, one of the world's most indebted oil companies, suffered another credit downgrade in June when Fitch Ratings reduced its rating from investment grade to "junk." According to Reuters reporter Abraham Gonzalez, "a second downgrade to junk from another major rating agency would likely trigger billions of dollars in forced selling of the company's bonds from funds whose mandates prohibit holding such assets."[60]

While PEMEX and the CFE compete for more taxpayer subsidies in a shrinking national economy, they face stiffening competition from the retail sector. For example, there are now roughly 60 qualified electric suppliers in Mexico[61] all looking to steal CFE market share. To do so, most are currently offering rates 7–15% below the CFE tariff with steadily improving customer terms.

Frequency Distribution of 1-Month Oil Futures 2014—2019



Tariff Customers Advised to Closely Monitor Energy Markets and Government Policy

We recommend that all CFE customers closely monitor government policies and energy market developments in 2020.

Ongoing policy debates regarding the definition of clean energy certificates (CELs), the cancelling of forward energy auctions and emergence of private energy auctions, application of the Grid Code, the restructuring of CFE generation subsidiaries, Mexico's anemic economic growth, and the sustainability of state-sponsored energy companies all foster uncertainty in the regulated energy market. We see significant price volatility on the horizon.

Canada

2020 will be a year marked by regulatory transition amidst political strife in Alberta and Ontario, Canada's two deregulated electricity markets.

Despite a flat demand outlook and relatively stable generation fleet in Ontario, the recent federal election sets the stage for struggle between left-leaning Ottawa and conservative provincial leadership.

As Alberta transitions off coal-fired generation, political uncertainty and the future of both provincial and federal carbon legislation create a difficult environment for investment in new fossil plants.

Ontario Premier Ford's Climate Policies Won't Abate Carbon Taxes in 2020

Four consecutive terms of Liberal rule in Ontario came to an end during the June 2018 elections. In a resounding victory, the right-leaning Progressive Conservative (PC) party formed a majority government under Doug Ford, who made electricity costs central to his campaign and promised to reduce consumer Hydro bills 12%.

In his first few months as Premier, Ford cancelled over 750 early-stage renewable energy contracts[62] and repealed the Green Energy Act of 2009[63] before pulling Ontario out of the cap & trade program it shared with Quebec and California.

On June 21, 2018, however, the Greenhouse Gas Pollution Pricing Act received Royal Assent, allowing the federal government to establish a carbon-pricing program in any province that chooses not to impose one themselves. Under the direction of Premier Ford, Ontario is challenging the legality of a federal carbon-pricing scheme and has brought its grievance to the Supreme Court after losing in a lower court challenge.[64]

Following its withdrawal from cap & trade, however, Ontario became subject to the federal carbon pricing system. Companies that emit 50 kilotons or more of CO_2e will be subject to the "output-based pricing system" (OBPS), which establishes industry-specific emission limits. Prices will be set at $30/ton in 2020 and escalate $10/ton annually until 2022.

Federal Output-Based Pricing System (OBPS) to Have Marginal Impact on Ontario Power Market

Ontario's fossil fuel-based power generators will be charged for their carbon emissions under OBPS. In 2018, however, 94% of Ontario's electricity supply came from nuclear, hydro, wind and solar resources.[65] Since less than 6% of Ontario's fuel supply is carbon-based, the effects of the OBPS will be limited.

Fixing the Hydro Mess Act Does Not Fundamentally Change GA Structure

As the Progressive Conservative government moved to redesign the Liberal party's Hydro plan, many customers wondered what affects its Fixing the Hydro Mess Act might have on the future of the Global Adjustment program.

Under the legislation,[66] the Ford government expects to generate significant savings by eliminating several energy efficiency incentive and rebate programs and by moving conservation programs away from individual utilities and placing them under IESO administration.

Under the Fair Hydro Act of 2017, the Liberals achieved an immediate 25% decrease in Hydro rates by refinancing a portion of the Global Adjustment (GA) to be paid by electric ratepayers at a later date. Under the new plan, the Ontario government takes on the debt, maintaining the near-term price relief for consumers, but also largely leaving the situation unchanged.

Importantly, the GA cost-recovery mechanism for Ontario's largest electricity consumers, or Class A customers, appears to remain intact for the foreseeable future. Those customers, who can be charged upwards of CA$ 500,000/MW-year (US$ 375,000/MW-year) based on their contribution to the system's peak, will continue to benefit from opportunities to control those costs through demand management, on-site generation, and battery storage.

Low-Priced Forward Contracts Offer Risk Management Opportunity in Ontario

Aside from Global Adjustment, which can represent over 70% of a customer's electric supply costs when left un-managed, ratepayers in Ontario enjoy some of the lowest commodity charges in North America.

Due to its inverse correlation to monthly GA costs, prevailing wisdom has been to maintain exposure to real-time energy prices through the Hourly Ontario Energy Price (HOEP). Entering 2020, however, customers that manage the GA can find value in forward contract purchases to stabilize future costs.

Forward contracts are currently trading just above historic lows, and nuclear refurbishments beginning in 2022 may inject future volatility into HOEP prices. As a result, large energy users may benefit by hedging that exposure to price risks by fixing a portion of their electric spend.

Alberta to Remain Energy-Only Market

Jason Kenney and the right-leaning United Conservative Party (UCP) of Alberta won control of the provincial legislature in May 2019 with a commitment to repeal the provincial carbon tax. Shortly thereafter, on July 24, the Government of Alberta cancelled plans for the forward capacity market that had been in development since 2016 and expected to be in place by 2021.[67]

By cancelling plans for the forward capacity market, the Government needed another means to address concerns over grid reliability and price volatility. So, the following day, the UCP Government directed the Alberta Electric System Operator (AESO) to advise by July 31, 2020 whether changes might be needed to the existing energy-only market, considering price floor/ceilings and shortage pricing in particular.[68]

Alberta Technology Innovation and Emissions Reduction (TIER) Provides Temporary Relief to Heavy Emitters

The first piece of legislation introduced by Premier Kenney and the UCP was a repeal of Alberta's consumer carbon tax.[69] Despite repealing the consumer tax, Kenney and the UCP quietly left Alberta's Carbon Competitiveness Incentive Regulation (CCIR) intact for 2019, which at least temporarily exempts the province from the federal OBPS program.

In 2020, the Government will replace CCIR with the TIER program—a new pricing scheme that maintains the $30/ton price on carbon for heavy emitters but provides more flexibility in compliance.

Unlike the previous CCIR policy, TIER will not evaluate facility emissions against an industry standard. Instead, each facility will measure itself "against its own average emissions intensity from 2013 to 2015. Its target will then be set at 10 percent below that level for 2020."[70] And by establishing a "high performance target, the new policy aims to avoid punishing facilities that have already made significant carbon emission reductions. These facilities will be able to select whichever target is "less stringent."[71]

While it is estimated that the new TIER framework will save Alberta's oil-sands refineries, natural gas producers, chemical manufacturers and fertilizer plants (which account for 55-60% of Alberta's GHG emissions) more than CA$ 330 million in avoided compliance cost in 2020,[72] it is not clear whether Ottawa will accept the new framework.

Alberta Energy Prices to Remain Elevated

The 2019 year-over-year increase in Alberta's average off-peak pool prices was roughly $12-14/MWh, likely reflecting the $30/ton carbon tax implemented under CCIR as roughly 89% of generation in the province comes from either coal or natural gas.[73] It is unlikely that Alberta will see a significant change in costs related to carbon regulation in 2020, but the general decrease in reserves and retirement of large baseload coal will keep forward prices elevated relative to the low levels seen from 2015 to 2017.

Natural Gas

As domestic production of natural gas has climbed over the past 10 years—more than 50%—so has demand: power burn, international pipeline and LNG exports have all reached record highs. For buyers, the net effect has been relatively low NYMEX prices since 2015 as gas production ramped.

However, growing pressure from international exports and increasing power burn is driving natural gas price volatility and more strongly correlating pricing with unpredictable short-term weather.

The lack of pipeline infrastructure connecting the Marcellus production region to the Northeast and Mid-West will likely remain an issue in 2020, particularly in the demand-heavy months of January and February.

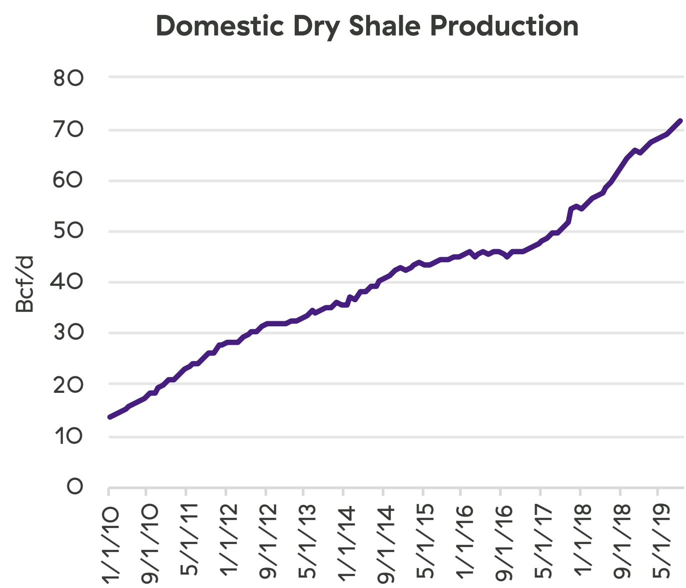
NYMEX Settlements ($/MMBtu)

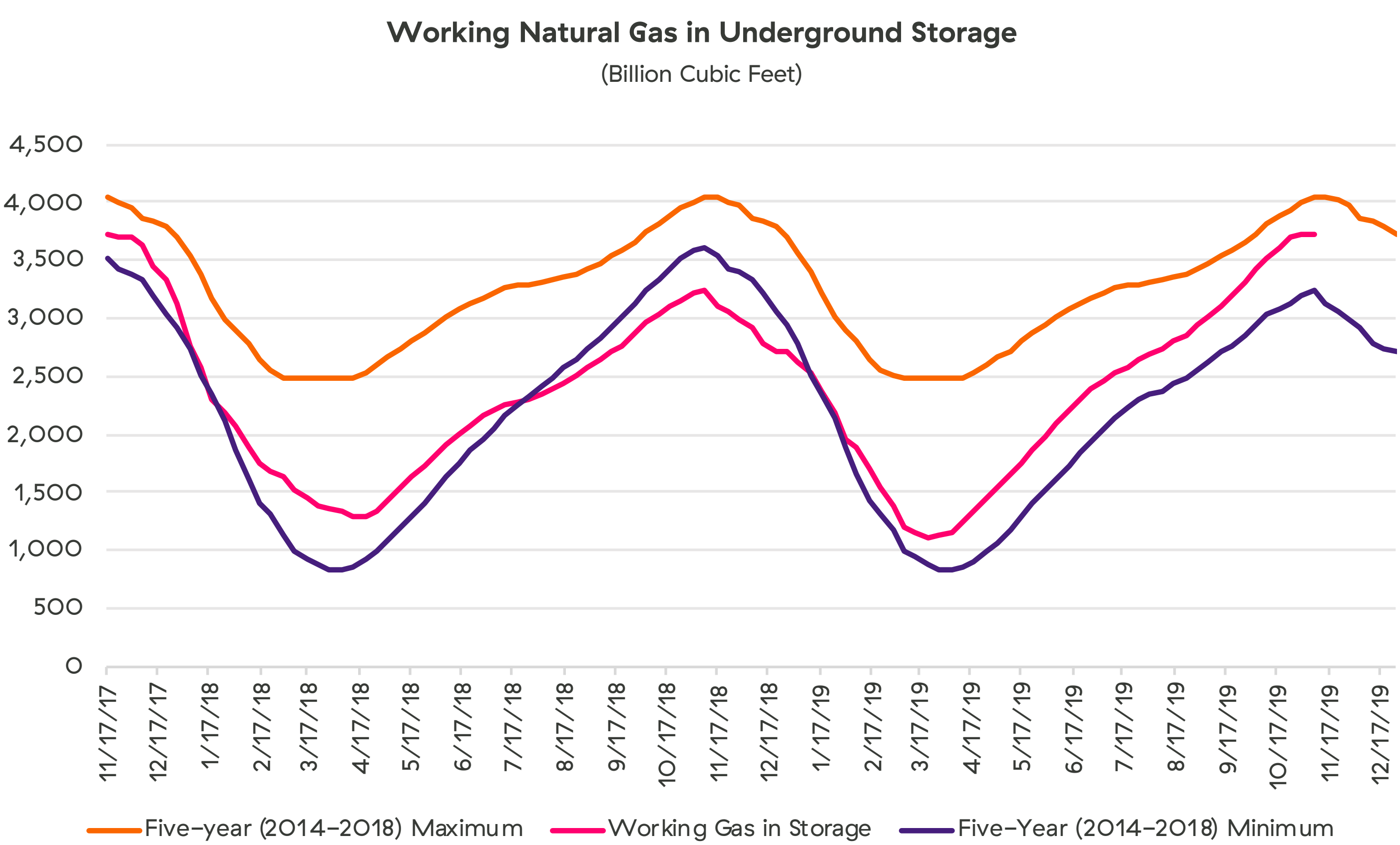
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
2012	$3.08	$2.67	$2.44	$2.19	$2.03	$2.42	$2.77	$3.01	$2.63	$3.02	$3.47	$3.69	$2.79
2013	$3.35	$3.22	$3.42	$3.97	$4.15	$4.15	$3.71	$3.46	$3.57	$3.50	$3.50	$3.82	$3.65
2014	$4.41	$5.56	$4.86	$4.58	$4.80	$4.62	$4.40	$3.81	$3.96	$3.98	$3.73	$4.28	$4.41
2015	$3.19	$2.87	$2.89	$2.59	$2.52	$2.82	$2.77	$2.89	$2.64	$2.56	$2.03	$2.21	$2.66
2016	$2.37	$2.19	$1.71	$1.90	$2.00	$1.96	$2.92	$2.68	$2.85	$2.95	$2.76	$3.23	$2.46
2017	$3.93	$3.39	$2.63	$3.18	$3.14	$3.24	$3.07	$2.97	$2.93	$2.97	$2.75	$3.07	$3.11
2018	$2.74	$3.63	$2.64	$2.69	$2.82	$2.88	$3.00	$2.82	$2.90	$3.02	$3.19	$4.72	$3.09
2019	$3.64	$2.95	$2.86	$2.71	$2.57	$2.63	$2.29	$2.14	$2.25	$2.43	$2.60	$2.47	$2.63
Avg.	$3.34	$3.31	$2.93	$2.98	$3.00	$3.09	$3.12	$2.97	$2.96	$3.06	$3.00	$3.44	

Increased Gas Supplies Will Soften Annual Price Increases

Natural gas supplies are favorable entering 2020. Despite prices that averaged 10% lower than 2018, shale production still reached record highs in 2019.[74] The number of drilled but uncompleted wells in gas-dominated regions fell from 1,230 in March 2016 to just 713 in March 2019,[75] increasing available production as pipeline takeaway capacity increased during the period.

Moreover, increased production has largely closed the national storage-level deficit, a key supply metric monitored by market participants.[76] According to the EIA, storage inventories began the 2019 injection season at a 28% deficit relative to the five-year average. By the end of October, however, gas storage levels hit 3,762 Bcf, 16% higher than 2018 levels and 1% higher than the five-year average. The EIA is currently forecasting inventories roughly 9% above the five-year average at the end of the storage withdrawal season.[77]





Source: EIA www.eia.gov/naturalgas/weekly/#tabs-storage-1

Increasing Natural Gas Demand to Cause Price Spikes

We expect natural gas buyers to face price spikes resulting from a combination of fundamental and technical factors in 2020. Significant power burn, domestic pipeline delays, and increased international exports will continue to provide upward price support, and there is a good chance that NYMEX prices will return to 2018 levels.

Increasing Power Burn

Power burn continues to drive natural gas demand. Gas-fired power generation is up 42% since 2008.[78] With coal becoming increasingly uneconomical and the country's nuclear plants getting older, the EIA forecasts gas demand for power generation to grow by 1% annually through 2035. EIA analysts expect "60 percent of new electric generation capacity built by 2035 will be natural gas combined-cycle or combustion turbine generation."[79]

California is the only state in the country facing significant retirement of natural gas-fired generation in 2020, and only five states plan to retire any significant gas-fired power plants over the next five years.

Delays in Domestic Pipelines

Unlike 2018, there will be very little pipeline capacity added to the Northeast this 2019-20 winter season. Compared to the 4.5 Bcf/d of capacity added during the fourth quarter of 2018, S&P Global expects just 0.19 Bcf/d of new capacity to go into service in the Northeast this winter.[80]

Pipeline build-out activity has slowed down significantly, and the current slate of projects on the docket will offer little relief. The current projects that are underway, such as Mountain Valley, PennEast, and Atlantic Coast pipelines, are plagued with various legal battles that have resulted in additional expense and delays.[81]

Additions and Retirement of 250 MW+ Gas-Fired Power Plants Through 2025

State	Additions (MW)	Retirements (MW)
PA	5,875	
OH	4,965	
CA		4,788
TX	2,130	412
IL	2,476	
MI	2,439	
FL	1947	
LA	1,250	428
WV	1,213	
VA	1,060	
MD	1,008	
CT	814	
NY	790	
NM	680	
NJ	570	
MS		530
AR		522
AZ	390	
NC	310	
WI	260	
IN	260	
SD	260	
Total	**28,699**	**6,679**

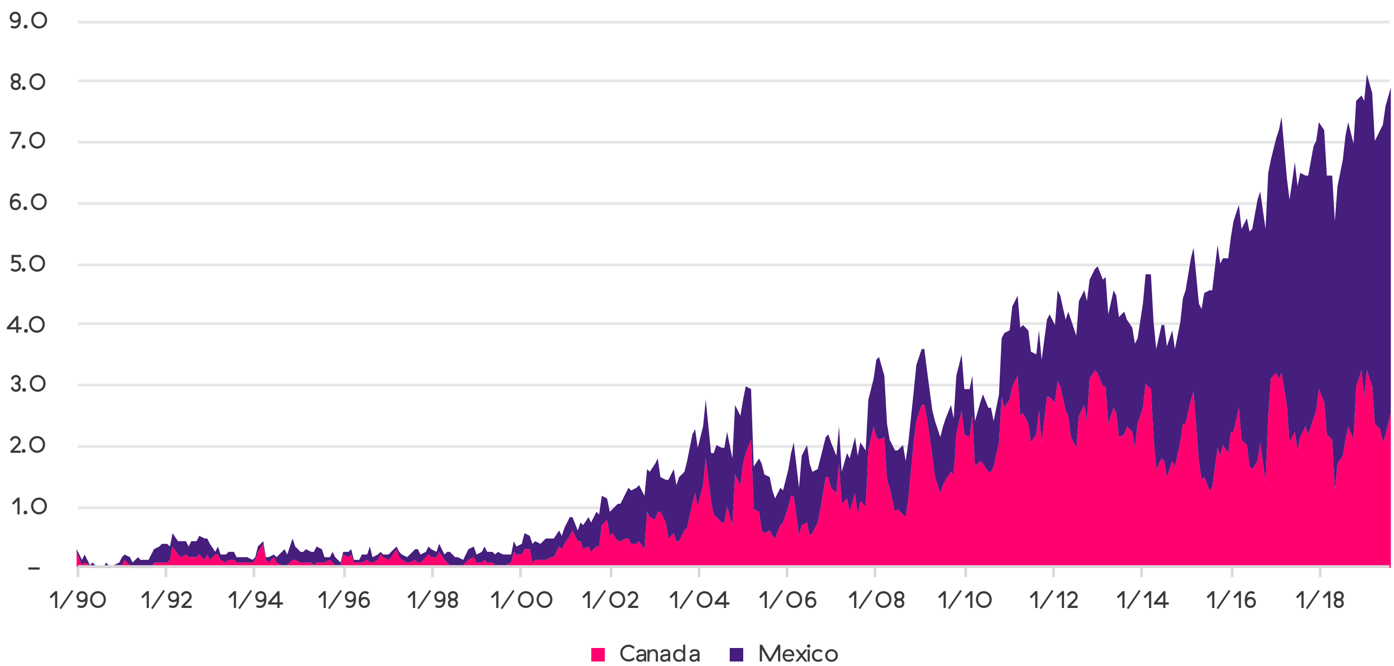
Growing International Pipeline Exports

Net exports to Canada underwent substantial increases in 2018 with the completion of the NEXUS and Rover pipeline projects, which connected shale production regions in Appalachia with Canadian demand markets. Additionally, net pipeline exports to Mexico increased by 5% over the first six months of 2019, hitting a July 2019 high of 5.3 Billion Cubic Feet/Day (Bcf/d).[82]

For perspective, the 7.92 Bcf/d of natural gas currently exported to US and Canada totals more than 11% of the 71.41 Bcf/d of total US dry shale production.

Natural Gas Pipeline Exports

Bcf/d



Source for Mexico: www.eia.gov/dnav/ng/hist/n9132mx2m.htm
Source for Canada: www.eia.gov/dnav/ng/hist/n9132cn2m.htm

International LNG Exports

Demand for US LNG export facilities represents the fastest-growing natural gas demand sector, growing from 1.4 Bcf/d in December 2018 to set a new record of 6.6 Bcf/day in October 2019 due to two new LNG trains ramping up in the Gulf.[83]

Record-setting LNG export volumes appear to have no end in sight. Market expert Charles Riedl from the Center for Liquefied Natural Gas, for example, suggests that five more export projects may be sanctioned in 2020. While likely not operational for several years if they are approved, the prospect of five additional export projects signals continued LNG export growth for years to come.[84] The EIA projects the LNG daily export average for 2020 to be 6.4 Bcf/d.[85]

What this All Means for You

Energy managers will continue to feel the effects of an evolving power generation mix in 2020. Short-term price volatility will continue—and may yet increase—as renewable energy and natural gas assume larger roles in the power supply mix.

Demand management strategies will play an increasingly important role in supply decisions, as utilities and grid operators transfer the majority of ratepayers' financial burdens from volumetric to demand-related cost components.

Regulators, investors, customers, and employees alike will continue to advance the renewable energy market. As more intermittent resources come online, purchasing decisions will carry more risk.

Energy is not an expense that should be passively managed in the 2020s. It will be critically important to follow market and policy decisions at the state and local levels as RPS targets, carbon pricing schemes and deregulation will carry outsized influence in the early years of the new decade.

Enel X's team of experts is here to help you make sense of the market and identify opportunities to lower costs and/or manage long-term risks. If you'd like to speak with one of our experts to get a better sense of how these trends may impact your business, contact us today at www.enelx.com/n-a/en/forms/get-demo.

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