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# Natural Gas & Electricity

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# Using Natural Gas Price Indices

*Thomas N. Russo*

In today's $3.00-per-million-Btu natural gas price environment, it's difficult to envision the Edison Electric Institute, Electric Power Supply Association, American Gas Association, American Public Power Association, and independent power producers complaining about natural gas indices.

However, back in early 2006, when Federal Energy Regulatory Commission (FERC) staff held discussions with gas market participants regarding natural gas index use, those same groups were very upset with high natural gas price indices and wanted FERC to do something about it. In 2005, spot prices at the Henry Hub averaged $8.63 per million Btu's and ranged between $5.53 per million Btu's and $15.39. Certainly, the natural gas price spikes caused by the Polar Vortex got market participants' attention in New England, New York, the Midwest, and the Mid-Atlantic states.

Regardless, the growing popularity of natural gas indices to price physical natural gas sales and purchases has remained high since FERC began collecting the information in its Form 552 Annual Report of Natural Gas Transactions in 2008. In fact, the Form 552 reports through calendar year 2013 consistently show that almost 75 percent of the physical gas transactions collected in the Form

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## Columns



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552 are priced with monthly and daily price indices. In fact, the use of daily and monthly natural gas indices to price gas made up 79 percent of the volumes collected in the 2016 Form 552 report.

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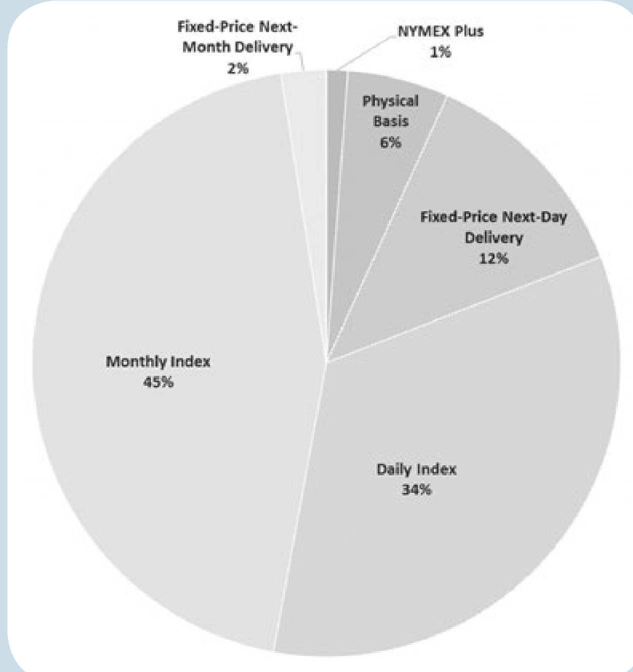
As shown in **Exhibit 1,** the index forming volumes (Fixed-Price Next-Day, Next-Month Delivery, Physical Basis, and NYMEX Plus) are much lower (21 percent of total reported transactions); they made up 28 percent of total volumes in 2013. FERC staff has been concerned about this trend, because natural gas indices can be moved by large trades or by manipulation, especially at trading sites with poor liquidity. In fact, FERC convened a Technical Conference on natural gas index liquidity and transparency on June 29 in Washington, DC.

The liquidity of many physical natural gas trading sites pales in comparison to financial futures and swaps done on the Intercontinental Exchange (ICE). See **Exhibit 2**. Over the years, the overall volume of financial gas derivatives and physical gas has declined. In 2015, the ratio of ICE financial to physical trading volumes was 38 to 1, a decline from 43 to 1 seen in 2014. This multiple is why most index publishers, such as ICE, Platts, and Natural Gas Intelligence (NGI), provide information regarding volumes traded, number of deals, and number of counterparties, which prospective buyers and sellers should consider before using any specific natural gas index.

In 2015, the ratio of ICE financial to physical trading volumes was 38 to 1, a decline from 43 to 1 seen in 2014.

Marketers as a group have historically transacted more than 50 percent of the total sales and purchase volumes in physical gas collected in the Form 552 reports in earlier years. The firms below make up the top-eight reporting purchase volumes in the 2016 Form 552 report. Because of their size, most of the firms are probably routinely surveilled by FERC Enforcement because they hold offsetting positions in futures and swaps to hedge their physical natural gas assets.

**Exhibit 1**. Breakdown of Purchase Transactions Used to Price Physical Natural Gas in 2016




Obviously, if natural gas indices are manipulated, market participants that use them could be adversely affected. The eight firms are the following:

1. BP Energy Company
2. Tenaska Marketing Ventures
3. Southern Company Gas (formerly AGL Resources)
4. Shell Energy North America (US), L.P.
5. Macquarie Energy LLC
6. ConocoPhillips Company
7. CenterPoint Energy Inc.
8. J. Aron & Company

## USE OF NATURAL GAS INDICES IN JURISDICTIONAL TARIFFS

Sellers and buyers of physical natural gas are free to use any natural gas index in commercial transactions. However, FERC's Policy


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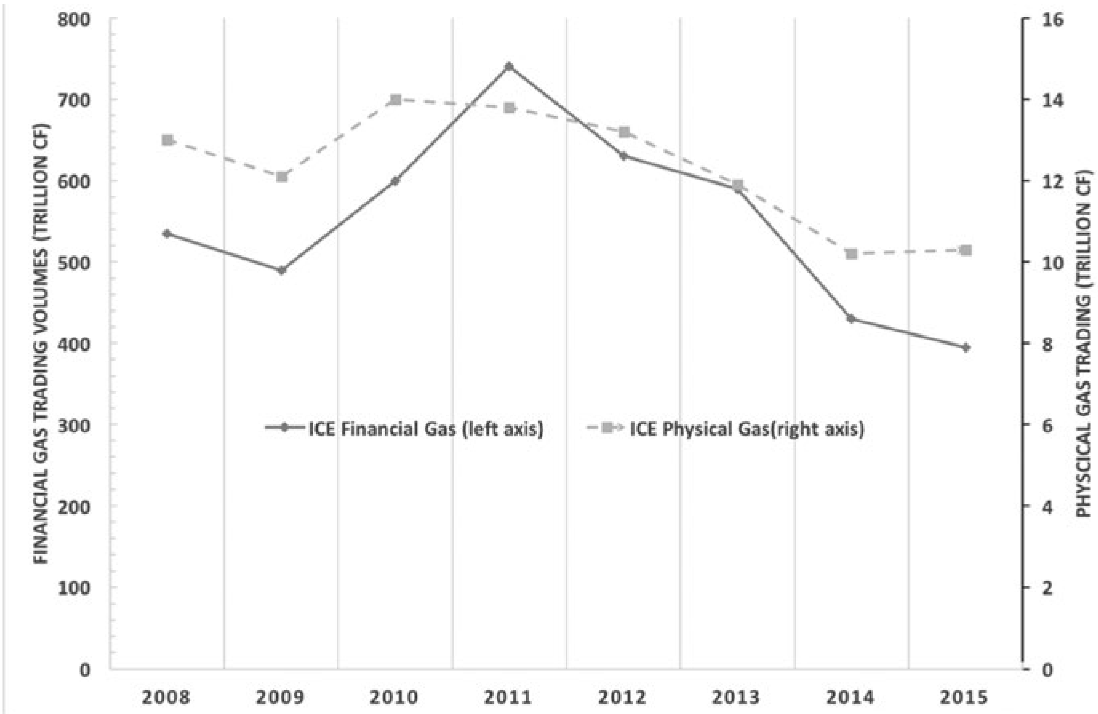
**Exhibit 2.** Liquidity of Natural Gas Physical and Financial Traded on ICE




*Source*: Form 552 reports and Intercontinental Exchange.

Statement on Natural Gas and Electric Price Indices requires that jurisdictional natural gas pipelines and facilities use only gas price indices that meet minimum liquidity requirements in computing cash-out transactions, and other charges (**Exhibit 3**).

Despite the popularity of natural gas indices, many energy analysts take a dim view of them. They argue that sellers and buyers should be analyzing the fundamentals of supply and demand at specific hubs to determine a fair price and not following the crowd. They believe that using indices is a bad idea and that overreliance can exact a toll.

Despite the popularity of natural gas indices, many energy analysts take a dim view of them.

In the low-price environment we are now in, most sellers and buyers are not concerned, except in regions like New England and New York that experience natural gas price hikes due to extreme cold or where pipeline or storage constraints exist.

Most sellers and buyers are not concerned, except in regions like New England and New York that experience natural gas price hikes.

## INDEX USE IS HERE TO STAY, BUT THERE IS A COST

Those companies that voluntarily report their transactions to index publishers per FERC's Policy Statement are bearing the cost, because they have to report all transactions. Some companies indicate that it costs them $100,000 per year to voluntarily report their transactions to index publishers. Companies that do a large number of index deals may not see the benefit of reporting just a small percentage of fixed-

**Exhibit 3.** FERC Liquidity Requirements for Using Natural Gas Indices in Jurisdictional Tariffs

| Type of Natural Gas Index | Average Volume Traded | Average Number of Transactions | Average Number of Counterparties |
|---|---|---|---|
| **Daily Indices** must meet one condition within nonholiday weekdays within a 90-day review period | At least 25,000 MMBtu's/day | 5 or more | 5 or more |
| **Monthly Indices** should meet at least one of the following conditions within a 12-month review period | At least 25,000 MMBtu's/day | 10 or more per month | 10 or more per month |

*Source*: FERC's Policy Statement on Natural Gas and Electric Price Indices.

price next-day and next-month deals that are used to calculate daily and monthly gas indices, respectively.

ICE has been providing natural gas trade data to NGI since 2008 to improve the liquidity of natural gas trading hubs and trading sites and strengthen the indices. Because only 70–80 percent of the physical deals are done on the ICE platform, most index publishers are advising companies to continue to report transactions to them. ICE has also agreed to provide natural gas trade data to Platts, and any differences between indices on NGI and Platts should be negligible in the next few months.

Some natural gas purchasers have complained that some index publishers are charging very high fees for the privilege of using the data. This may be the case.

At first blush, it may seem that those companies that don't voluntarily report their transactions but use natural index prices are getting a "free ride" at the expense of companies that report. However, index publishers view information and data differently. For example, I may be able to glean daily and monthly natural gas price indices from Platts, NGI, or ICE. However, if I want to use the data to price my natural gas contract, I'll probably have to pay the index publisher a fee for that privilege.

This only seems fair, because the index publisher is performing a service of screening the data and bearing the costs along with companies that report. Some natural gas purchasers have complained that some index publishers are charging very high fees for the privilege of using the data. This may be the case.

The only alternative may be to call other index publishers and compare fees and the liquidity of those trading sites.

## IT'S JUST PHYSICAL NATURAL GAS, RIGHT?

Congress has defined the federal regulatory landscape for natural gas between FERC and the Commodity Futures Trading Commission (CFTC).

FERC regulates wholesale physical natural gas transactions common between suppliers and commercial end-users. The CFTC deals with natural gas futures and swaps. While this may seem very clear, the reality is that physical natural daily and monthly gas indices are a part of the definition of natural gas index swaps and basis swaps. Index swaps use the daily and monthly natural gas indices at a trading site or hub, while popular basis swaps use the monthly gas index and the NYMEX Natural Gas Futures Contract settlement.

Some energy traders would even argue that the settlement of the NYMEX Natural Gas contract on the third day of bid week at 2:30 p.m. EST is a physical transaction because it has no future value. In fact, physical basis deals for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next-month delivery done during bid week rely on the NYMEX Natural Gas Futures settlement price and a negotiated basis to price the transactions. Physical basis deals also contribute to monthly index formation.

Hence, any manipulation of physical natural gas indices can have far-reaching effects concerning commercial hedging in the financial markets, which is a common activity using natural futures and gas swaps.

## IS THE REGULATORY RISK OF REPORTING JUST A MYTH?

Many market participants state that the greatest obstacle of voluntarily reporting transactions is the perception of regulatory risk.

Many companies just can't get past their risk officers and to "yes" when it comes to reporting, although many believe that reporting would strengthen natural gas indices and be good for the market. Those with reservations fear that reporting puts them more in the crosshairs of FERC's Office of Enforcement auditors or market manipulation investigators. The audits are the lesser of two evils; they take time and resources, but usually don't result in fines or penalties. Most investigations do not result in fines or penalties. However, if investigative staff finds a problem, it can be time-consuming, result in bad public relations, and be costly.

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Those with reservations fear that reporting puts them more in the crosshairs of FERC's Office of Enforcement auditors and market manipulation investigators. While some of these concerns were valid years ago, they are not strong arguments today. There are several reasons why. First, FERC does not base its investigations and audits on the fact that a company reports transactions to an index publisher.

Second, FERC enforcement staff already knows the companies who are trading physical natural gas, courtesy of the CFTC and ICE. The CFTC provides a daily feed of "unmasked" data to FERC on physical natural gas trading. Together with the unmasked data and Form 552 filing, FERC enforcement staff probably has a good understanding of a company's trading profile. In fact, a company that does a large volume of index forming trades but doesn't report to an index publisher is probably sending a subliminal message to FERC that the company has something to hide. In the end, tips from FERC's Enforcement Hotline and FERC's growing arsenal of sophisticated trading screens are more likely to initiate an investigation or audit than whether a company reports transactions on its Form 552.

A company that does a large volume of index-forming trades but doesn't report to an index publisher is probably sending a subliminal message to FERC that the company has something to hide.

Some energy professionals believe FERC has the authority to require mandatory reporting of a company's physical natural gas transactions and to even calculate indices. FERC has not done so, and there's no reason why FERC should. The only thing that would precipitate mandatory reporting would be if a very large natural gas marketer that reports today decides to no longer report its transactions.

FERC has the authority to require mandatory reporting of a company's physical natural gas transactions and to even calculate indices. FERC has not done so.

There are several ways of incenting companies to report their natural gas transactions to index publishers and make the indices more robust. One approach would be for FERC to give positive recognition to a company that wants to start voluntarily reporting in the form of a compliance credit. This disclosure would be an important factor in the event that the company self-reports a problem or in assessing a fine or penalty. This same approach would be used to reward those companies that have been reporting their transactions and recognizing their contribution to more robust physical natural gas markets.

Another approach that could be used in settlement discussions in lieu of fines and penalties would be to get a company to begin to voluntarily report its transactions.

## MARKET'S RELIANCE ON FERC ENFORCEMENT

Market participants that use natural gas indices to price gas are not always cognizant of the relatively low liquidity of physical natural gas indices compared to natural gas futures and swaps. These participants are relying on index publishers and companies that report their transactions to comply with FERC's Policy Statement on Natural Gas and Electric Price Indices and on FERC Enforcement to actively conduct routine audits, market oversight, and surveillance to ensure the indices are not being manipulated. The latter includes investigations of alleged market manipulation reported to FERC's Enforcement Hotline or directly divined by FERC staff.

Since Congress expanded FERC's civil penalty authority in the Energy Policy Act of 2005, FERC's investigatory record over the last 10 years demonstrates its commitment to competitive markets free of manipulation. While alleged market manipulators may criticize FERC Enforcement for its zeal, FERC is not apologetic and has no appetite for a return to the large-scale manipulation of the natural gas and electricity markets that was common in the 2000–01 Western Energy Crisis. Those familiar with those days can remember the ensuing crisis, large-scale manipulation, and lack of confidence in natural gas and electricity indices that plagued energy markets then and are still being litigated today.

## WILL MARKET MANIPULATION BE MORE COMMON IN FUTURE YEARS?

Both the Federal Power Act (FPA) and Natural Gas Act (NGA) allow companies accused of market manipulation to seek hearings before a FERC administrative law judge. Most companies have settled with FERC and relied on the agency's hearing record. However, several companies—notably, Barclays Bank and Total Gas and Power—have litigated their cases in the courts.

FERC has argued that companies that are accused of market manipulation should only rely on FERC's hearing record. However, the courts in the case of manipulation of electricity markets believe that the companies are entitled to a "de novo" review in court. The FPA allows companies to opt for de novo review of their cases in federal court. However, there is no such provision for this under the NGA, which may mean that in the future, Congress may change the NGA to also allow a de novo review.

The recent court decisions are a setback for FERC, because they can tie up staff resources in litigation and can reduce FERC's ability to conduct new investigations. Of course, this assumes that new staff cannot be hired to fill the gap. Even a de novo review in federal court could result in a decision favorable to FERC.

Recent court decisions are a setback for FERC, because they can tie up staff resources in litigation and can reduce FERC's ability to conduct new investigations.

Assuming that both FPA and NGA market manipulation investigations may undergo de novo reviews in the courts, FERC may up the stakes by imposing higher fines and penalties to incent alleged manipulators to settle rather than pursue litigation. However, a series of FERC wins and losses in the courts would probably clarify a number of issues regarding market manipulation once and for all. Only time will tell whether litigation was a good idea or not.

Assuming that both FPA and NGA market manipulation investigations may undergo de novo reviews in the courts, FERC may up the stakes by imposing higher fines and penalties to incent alleged manipulators to settle.

In the interim, users of natural gas price indices should be vigilant and not equate index use with low prices.


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# Telephone Consumer Protection Act: Key Challenges and Protection for Utilities

*Mark W. Brennan and Cara O. Schenkel*

An electric company calls or texts the cell phone number on file for a customer to notify her or him of an upcoming payment deadline. Months later, the company receives a class action complaint stating that by making the call, the company violated the Telephone Consumer Protection Act (TCPA).

What happened?

Violations can be incredibly costly.

The TCPA, passed in 1991, restricts how utilities and companies in other sectors can use modern technologies to communicate with customers. It imposes consent requirements for certain phone calls, and violations can be incredibly costly—the minimum statutory damages are $500 per call or text, increased to $1,500 per call or text for knowing or willful violations.

There have been plenty of six-, seven-, and eight-figure TCPA settlements.

The TCPA also allows for class actions, and there have been plenty of six-, seven-, and eight-figure TCPA settlements hitting the news in recent years. Our firm's TCPA Working Group has handled dozens of TCPA class actions, where we have secured dismissals and nominal settlements for clients. **Exhibit 1** shows the enormous growth over the last few years in the number of TCPA cases filed.

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The TCPA now poses additional compliance obstacles and class action litigation risks for organizations of all sizes.

Due to recent legal developments, the TCPA now poses additional compliance obstacles and class action litigation risks for organizations of all sizes. In what follows, we walk through some of the key TCPA requirements and challenges, as well as steps you can take to help protect your organization against TCPA liability.

## TCPA ENACTED TO CURB AGGRESSIVE TELEMARKETERS

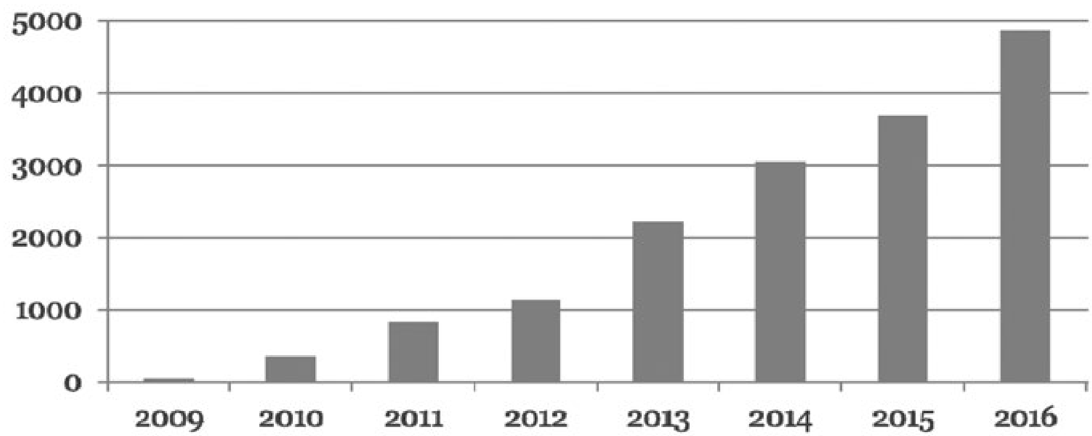
Congress enacted the TCPA in 1991 to curb aggressive telemarketing practices and address concerns about public safety and telemarketers shifting marketing costs to wireless consumers.

The TCPA is implemented by the Federal Communications Commission (FCC). The TCPA and the implementing rules impose a number of restrictions on telemarketing calls, faxes, and other outbound communications. Some other restrictions, specifically those applicable to wireless telephone numbers, apply to nontelemarketing calls. The requirements under the TCPA are separate from those under the Do Not Call Registry.

The TCPA contains two provisions that have become particularly problematic for companies. First, the TCPA prohibits autodialed or prere-

  / DOI 10.1002/gas.21995 

**Exhibit 1.** Rapid Growth in TCPA Cases Filed




*Source*: WebRecon LLC.

corded or artificial voice calls to wireless numbers unless there is an emergency, the call is to collect a federal debt, or the caller has "prior express consent." This prohibition applies regardless of content and includes collection and servicing calls. The FCC and some courts have determined that this prohibition currently applies to texts or short message service messages, in addition to voice calls.

The prohibition currently applies to texts or short message service messages, in addition to voice calls.

Second, the TCPA prohibits prerecorded or artificial voice marketing calls to residential telephone numbers without "prior express *written* consent." The statute includes several exceptions to this rule, including calls that are not a solicitation or telemarketing call, calls not made for a commercial purpose, emergency calls, calls by or on behalf of a tax-exempt nonprofit organization, health care calls subject to the Health Insurance Portability and Accountability Act, and calls to collect federal debts.

## WHAT DETERMINES "CONSENT"?

Generally speaking, unless it is an emergency or a call to collect a federal debt, a caller must obtain "prior express consent" from the called party to use an "automatic telephone dialing system" (an "autodialer") or a prerecorded or artificial voice (the robots) to call a wireless telephone number. As stated earlier, this requirement applies even to nonmarketing, informational calls. **Exhibit 2** demonstrates the increasing importance of calls to wireless numbers as more and more households go wireless only.

Obtaining the telephone number from third-party sources may not suffice for "prior express consent."

How do you get consent? Even though the TCPA does not define "prior express consent," the FCC has stated that the provision of a telephone number within the context of a transaction—such as the provision of a phone number as contact information when signing up for electricity service—confers "prior express consent" for *some* prerecorded or autodialed nonmarketing calls, assuming the individual does not instruct you otherwise. But the full scope of the consent depends on the facts. To compare, obtaining the telephone number from third-party sources may not suffice for "prior express consent."

The FCC's rules also state that "prior express *written* consent" is normally required for any


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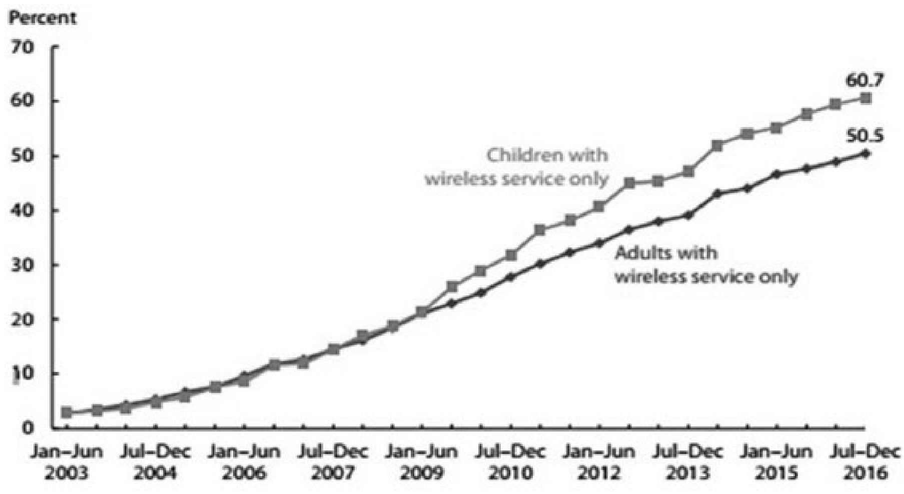
**Exhibit 2.** Wireless Versus Conventional Service




*Note*: Adults are age 18 and over; children are under age 18.
*Source*: CDC/NCHS, National Health Interview Survey.

autodialed or prerecorded voice call to a wireless number that "includes or introduces an advertisement or constitutes telemarketing." The same applies to prerecorded voice calls to landline numbers.

To obtain "prior express written consent," an organization must acquire a signed written agreement from *each* party it seeks to call. This agreement must include "clear and conspicuous" disclosures that the consumer consents to receive autodialed calls or texts at a specific number and that the provision of consent is not a condition to purchasing any goods or services. The phone number to be called must be included in the agreement.

In comparison to obtaining "prior express consent," obtaining "prior express written consent" is a heavier burden, essentially requiring organizations to carefully craft written agreements with stand-alone opt-in "checkboxes."

## JULY 2015 TCPA OMNIBUS DECLARATORY RULING

In July 2015, the FCC released an Omnibus Declaratory Ruling that aimed to clarify aspects of the TCPA around what constitutes an autodialer, who constitutes the maker of a call, and consent of the called party. Unfortunately, the declaratory ruling introduced additional uncertainty for companies around these issues.

### Autodialers

The TCPA defines an autodialer as "equipment which has the capacity 1) to store or produce telephone numbers to be called, using a random or sequential number generator; and 2) to dial such numbers." Prior to the 2015 Omnibus Declaratory Ruling, the general consensus was that any dialing system requiring human intervention to place a call to would not fall within the definition of an autodialer.

A core function of an autodialer is the system's ability to dial thousands of numbers without human intervention in a short period of time.

In the July 2015 Omnibus Declaratory Ruling, however, the FCC emphasized that the "capacity of an autodialer is not limited to its current configuration but also includes its potential functionalities." The FCC has also stated that a core function of an autodialer is the system's ability to dial thousands of numbers without human intervention in a short period.

The FCC refused to exempt equipment that lacks the "present ability" to dial randomly or sequentially. The FCC said equipment would be covered "even if it is not presently used for such purposes." The FCC said the important question is whether the equipment has the *capacity* to dial randomly or sequentially. It also stated that predictive dialers satisfy the TCPA definition of "autodialer."

The FCC did explain that there must be more than a "theoretical potential that the equipment could be modified," offering a rotary phone as the sole example of a telephone that is categorically not an autodialer. All other equipment is subject to a case-by-case determination.

The FCC also explained that callers cannot avoid obtaining consent for autodialed calls by dividing ownership of dialing equipment among multiple entities. For example, two entities with separate storage and dialing equipment effectuate a call using an autodialer "if the net result of such voluntary combination enables the equipment to have the capacity to store or produce telephone numbers to be called, using a random or sequential number generator, and to dial such calls."

The FCC's interpretation creates significant ambiguity and has been appealed to the US Court of Appeals for the District of Columbia Circuit.

### Who Is "Maker" of a Call Required FCC Analysis

In the 2015 Omnibus Declaratory Ruling, the FCC also analyzed who constitutes the "maker" of a call or text and said it would look at the totality of circumstances to determine who took necessary steps to physically place the call or was so involved in placing the call as to be deemed to have initiated it. Based on this analysis, for example, when an individual sends a message through a messaging app, he or she may be the "maker" of the call, but the app developer could have liability depending on the amount of involvement the developer had in suggesting, drafting, or submitting the message.

### Consent of Called Party—Revoking Consent

The FCC explained that a called party may validly revoke consent to receive calls at any time through any reasonable means, either orally or in writing. The FCC provided examples of reasonable opt-out methods, including a consumer-initiated call or opt-out in person at an in-store bill payment location.

### Consent of Called Party—Reassigned Numbers

Under the 2015 Omnibus Declaratory Ruling, if a customer changes his or her telephone number, callers may be liable for autodialed or prerecorded calls to the new subscriber at the old number, even if the caller had previously obtained consent from the prior subscriber. The FCC clarified in the 2015 Omnibus Declaratory Ruling that the current subscriber or customary user of the phone constitutes the "called party" and may give prior express consent. The FCC rejected proposals to instead interpret "called party" to mean the "intended recipient" of the call. Callers have a one-call grace period after the reassignment of the number, after which the callers are considered to have constructive knowledge of the reassignment and are liable for possible violations of the TCPA.

The caller bears the burden of showing he or she had a reasonable belief and no knowledge of reassignment of a phone number. Recipients have no obligation to notify callers that a number has been reassigned, to answer calls, or to opt out. The FCC recommended that companies use the following methods to learn about reassigned numbers, though it did not adopt a safe harbor:

- Accessing databases with consumer numbers
- Contracting with consumers to inform them about reassignment
- Putting an interactive opt-out mechanism in all artificial/prerecorded calls
- Recording and tracking wrong-number reports from outbound calls and new phone numbers from incoming calls
- Sending emails asking for updated contact information
- Recognizing "triple-tones" that identify disconnected numbers
- Establishing policies to determine if a number has been reassigned when there is no response to a "two-way" call

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- Enabling consumers to update contact information in response to texts

## EEI AND AGA PETITION FOR EXPEDITED DECLARATORY RULING

A recent FCC declaratory ruling offers some relief from TCPA liability for utility companies.

A recent FCC declaratory ruling offers some relief from TCPA liability for utility companies.

On February 12, 2015, the Edison Electric Institute (EEI) and American Gas Association (AGA) asked the FCC to declare that a "utility customer's provision of a telephone number, including a cellphone number, to an energy utility satisfies the TCPA consent requirements for such [a] customer to receive nontelemarketing, informational calls at that number related to the customer's utility service." The petition stated that utilities need the ability to contact customers about important service updates (such as outages or repair work). However, under the TCPA, because of the issues outlined above, such communications are associated with significant litigation risks.

In an FCC filing on June 9, 2015, the EEI narrowed its requested relief and asked the FCC to declare that the provision of a customer's phone number to a utility allows the utility to place calls for the following purposes:

- To warn customers about service outages (planned and unplanned)
- To update consumers about service outages or service restoration
- To confirm lack of service, or service restoration
- To alert customers of field work (such as tree trimming)
- To alert customers of payment or other issues that may lead to service curtailment (post–service termination debt calls are not allowed)
- To notify consumers of eligibility for low-cost/subsidized service due to disability, age, or income

The FCC released a decision on August 4, 2016, confirming that utilities may place calls or send texts regarding matters "closely related" to utility service. The FCC's decision specifically allows calls and texts regarding the following:

- Outage notifications
- Work that directly affects a customer's service (such as tree trimming or meter repair)
- Potential brownouts
- Notification of subsidized or low-cost programs for which the customer may qualify
- Calls warning about the likelihood that failure to make a payment will result in service disruption

These calls apply to current customers of the utility. Once utility service has been terminated, routine debt-collection calls will be governed by existing TCPA precedent.

## WHAT YOU CAN DO

These are just a few examples of the many recent TCPA developments and challenges for the utilities ecosystem.

Companies should take a fresh look at their TCPA compliance strategies, including reviewing intake and account forms, calling scripts, and other consent channels for adequate disclosures—and make sure that the telephone number "type" (mobile or home) is specified. Privacy policies may also need to be supplemented.

Privacy policies may also need to be supplemented.

Callers should also review their calling policies and manuals and prepare training modules for employees. In addition, companies will want to evaluate how they manage telephone number changes and identify ways to keep the calling database as accurate and up-to-date as possible.

It is increasingly critical to monitor for TCPA developments in courts and at the FCC, as a single decision can have a significant impact on day-to-day compliance efforts.

Finally, it is increasingly critical to monitor for TCPA developments in courts and at the FCC, as a single decision can have a significant impact on day-to-day compliance efforts.

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# It's All (Mainly) Good: FERC Shows Plentiful Gas Reserves, Low Prices

*FERC Staff*

Overall in 2016 there were record-low natural gas prices and near-record-low electricity prices. Although natural gas production fell for the first time since 2005, flat demand due to above-average winter temperatures at the start of the year and high natural gas storage inventories contributed to the low prices. The low natural gas prices further incentivized gas-fired generation in 2016, and for the first time in history, natural gas's share of total electricity generation output overtook coal's on an annual basis.

In the West, California, in coordination with the Federal Energy Regulatory Commission (FERC), continued to work on ensuring adequate natural gas supplies were available to the region given the loss of storage capacity at Aliso Canyon. On the electricity side, the Energy Imbalance Market expanded. In the Northeast, an increase in natural gas pipeline capacity helped move low-cost supplies from Appalachia to demand centers along the East Coast and into the Midwest. Adequate natural gas supplies and mild weather had a moderating impact on electricity prices in the East, which fell from last year's levels. Meanwhile, the Gulf Coast and Southwest saw increases in natural gas exports via pipeline and liquefied natural gas (LNG) cargoes.

**The Federal Energy Regulatory Commission** (ferc.gov) is an independent agency that regulates the interstate transmission of natural gas, electricity, and oil. This article is a US government work and, as such, is in the public domain in the United States of America.

## NATURAL GAS PRICES FELL TO RECORD LOWS IN 2016

Natural gas prices fell across the country (**Exhibit 1**), with the Henry Hub averaging $2.48 per million Btu's, the lowest level in 20 years. Above-average temperatures in the 2015–16 winter limited natural gas demand during the first three months of the year, leading to robust storage inventories at the start of the 2016 injection season in April, and reduced demand for storage injections through the summer. Prices fell to record lows in the first half of 2016, before climbing through the second half of the year, driven by steady domestic demand, rising exports, and a drop in production. By December 31, the Henry Hub price had risen to $3.68 per million Btu's.

Although prices in Boston were the highest in the country in 2016, they were 33 percent below 2015 levels. New York City prices experienced the largest year-on-year decrease, falling 42 percent, and in the fall, prices fell to record lows, with Transco Zone 6-NY averaging 32 cents per million Btu's on September 30, as new pipeline infrastructure transporting lower-priced Marcellus Shale gas into New England, New York, and the Mid-Atlantic states became operational.

New York City prices experienced the largest year-on-year decrease, falling 42 percent.

Despite the logistical challenges posed by the loss of storage capacity in California's Aliso Canyon, natural gas prices at the SoCal Border averaged $2.41 per million Btu's throughout the year.

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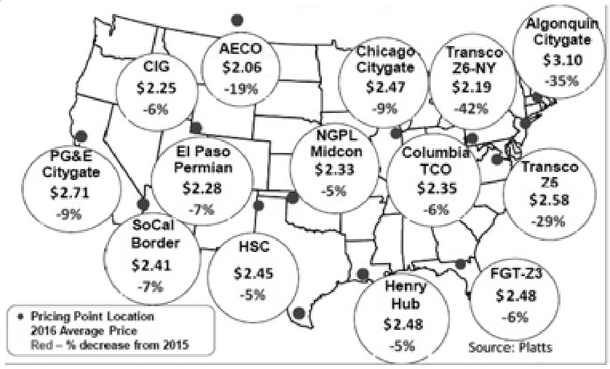
**Exhibit 1.** Spot Natural Gas Prices 2016 Average ($/MMBtu)




*Source:* Derived from Platts Daily Price Survey data.
*Note:* Average of Platts 2016 daily midpoint prices.

## NATURAL GAS PRODUCTION DECLINES IN 2016 BUT COULD REBOUND IN 2017

During 2016, US natural gas production fell 2.5 percent, averaging 72.3 billion cubic feet per day, the first year-over-year drop since large-scale shale production began in 2005. However, as oil prices recovered beginning in the first quarter of 2016, natural gas production rose 11 percent in the oil and natural gas liquids-rich Bakken Shale in North Dakota; Marcellus and Utica Shales in Pennsylvania, West Virginia, and Ohio; and Permian Basin in Texas and New Mexico. These gains were offset by an estimated 14 percent drop in conventional production, and by production declines in the Eagle Ford Shale in Texas, the Haynesville Shale in Texas and Louisiana, and the Niobrara Shale in Colorado and Wyoming.

Natural gas production from the Marcellus and Utica Shales accounted for 30 percent of the US total in 2016, due to the prolific nature of these formations, relatively low production costs, and proximity to the large Northeast markets. In addition, new pipeline infrastructure reduced bottlenecks, allowing additional gas to reach the demand centers. Total US production is poised to rebound slightly in 2017, driven by a projected 26 percent increase in oil and gas exploration and production investment in North America from 2016 levels.

Helping support the increased production are drilled but uncompleted (DUC) wells. The Energy Information Administration (EIA) estimates that as of December 2016, there were 803 DUC wells in Marcellus and Utica, which accounts for 13 percent of the total US backlog. Other areas with large numbers of DUC wells are the Eagle Ford with nearly 1,300 and the Permian Basin with over 1,700. The number of these wells is significant, as they can allow production to recover quickly if prices rise. Additional pipeline infrastructure, including gathering lines and other midstream facilities, may be needed before natural gas from DUC wells can be accessed by demand centers.

The number of these wells is significant, as they can allow production to recover quickly if prices rise.

Increased production and high levels of demand for natural gas transportation have led to one of the largest increases in natural gas pipeline capacity in US history. In 2016, 7.1 billion cubic feet of FERC jurisdictional pipeline capacity went into service, with 43 percent designed to move natural gas from Appalachia to markets in the Northeast and Midwest. Staff expects the new natural gas pipeline capacity to continue contributing toward shrinking price differentials between regions throughout the United States, and help keep natural gas prices relatively low.

## POWER BURN AND INDUSTRIAL CUSTOMERS DRIVE DOMESTIC DEMAND GROWTH

Following a 17 percent increase in 2015, natural gas demand from power generators rose 4 percent in 2016, averaging 27.5 billion cubic feet per day. According to EIA data, for the first time ever natural gas was the primary source of electric generation output on a national level, outpacing coal generation almost every month of the year. States in the Midcontinent, Southeast, and Mid-Atlantic experienced the highest increases in natural gas power burn in 2016. In the Southeast, natural gas demand for power generation rose 2 percent in 2016, after experiencing a 21 percent increase between 2014 and 2015. Power burn averaged a combined 7.9 billion cubic feet per day in the SERC Reliability

Corporation and the Florida Reliability Coordinating Council regions.

For the first time ever, natural gas was the primary source of electric generation output on a national level, outpacing coal generation.

Demand from the US industrial sector continued a steady increase as new plants built to consume natural gas entered service (**Exhibit 2**). Demand from this sector rose 1.3 percent from 2015, to 21 billion cubic feet per day, 17 percent higher than in 2005, before the growth in shale gas production. US residential and commercial demand fell 5.1 percent in 2016, to 24.5 billion cubic feet per day, as above-average temperatures in January and February contributed to lower space heating needs.

Overall domestic demand rose almost 1 percent, to 75.6 billion cubic feet per day.

## NATURAL GAS EXPORTS CONTINUE TO GROW

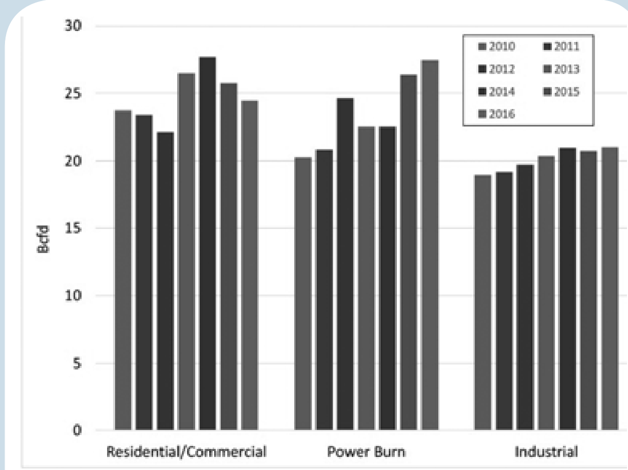
Pipeline exports to Mexico continued to grow in 2016, averaging 3.6 billion cubic feet per day, up 0.7 billion cubic feet per day from 2015.

This is the sixth year in a row exports to Mexico have increased (**Exhibit 3**). Growing demand from power generators and industrial customers in Northern Mexico, along with increased pipeline transportation capacity on both sides of the border, are driving the growth in exports. Pipeline capacity into Mexico on the US side totaled 7.3 billion cubic feet per day by the end of 2016 and will increase by 3.5 billion cubic feet per day in 2017, as three new pipelines are scheduled to go into service.

This is the sixth year in a row exports to Mexico have increased.

LNG exports became a source of demand growth in 2016, after the first liquefaction train at Cheniere's Sabine Pass in Louisiana entered service in February, and a second train entered service in the fall. US LNG exports jumped from virtually zero in 2015 to an average of 635 million cubic feet per day in 2016. At this time, construction is underway at five US LNG export terminals, with expected in-service dates ranging from August 2017 to 2021. When completed, these facilities will have a combined liquefaction capacity of over 8 billion cubic feet per day.

**Exhibit 2.** Demand Growth by Sector

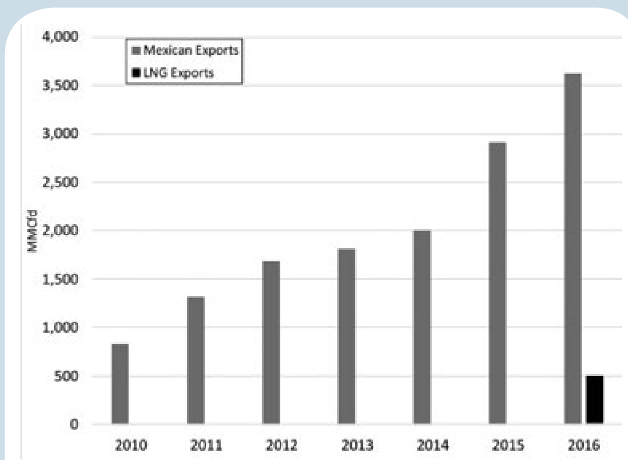



*Source:* Derived from Bentek Energy data.

## SECOND CONSECUTIVE RECORD YEAR FOR NATURAL GAS STORAGE

The 2015–16 winter was the warmest on record (since 1880), reducing natural gas demand.

**Exhibit 3.** Exports to Mexico




*Source:* Derived from Bentek Energy and DOE LNG exports data.


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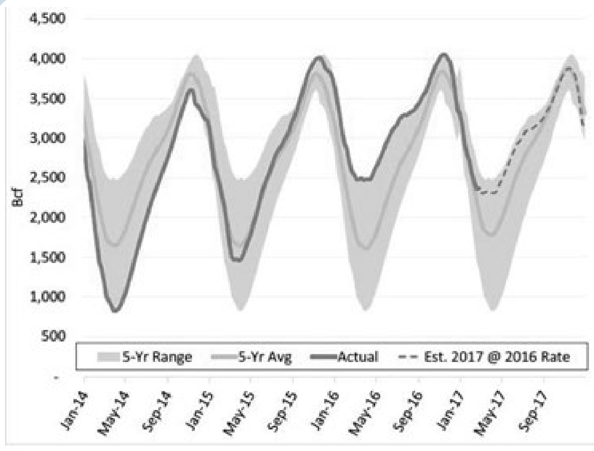
**Exhibit 4.** Gas Storage




*Source:* Derived from EIA data.

As a result, storage withdrawals during that season totaled 1.8 trillion cubic feet, the lowest in four years (**Exhibit 4**). By April, storage inventories stood at 2.5 trillion cubic feet, the highest level at the start of the traditional injection season. Operators injected gas at a moderate rate throughout the summer and fall, and by November 11, 2016, storage reached a record of 4.047 trillion cubic feet, edging the previous record of 4.009 trillion cubic feet set in 2015.

The 2015–16 winter was the warmest on record (since 1880), reducing natural gas demand.

December 2016 recorded 38 percent more heating degree days (HDDs) than December 2015, resulting in a 12 percent increase in demand from commercial and residential customers. Operators withdrew 684 billion cubic feet of natural gas from storage, more than triple the 200 billion cubic feet withdrawn in December 2015, leaving inventories below both the 2015 and the five-year average. While inventories ended 2016 9 percent below the inventory levels in 2015, January and February 2017 experienced 18 percent fewer HDDs than the same period in 2016.

In addition, the week ending February 24 of this year recorded the first-ever February injection.

## REGIONAL DEVELOPMENTS

### California Works to Ensure Reliability After the Aliso Canyon Incident

California continues to address the natural gas leak at the 86-billion-cubic-feet Aliso Canyon natural gas storage facility (**Exhibit 5**) detected on October 23, 2015, causing SoCalGas, the facility's operator, to withdraw all but 15 billion cubic feet of working gas and to discontinue injections.

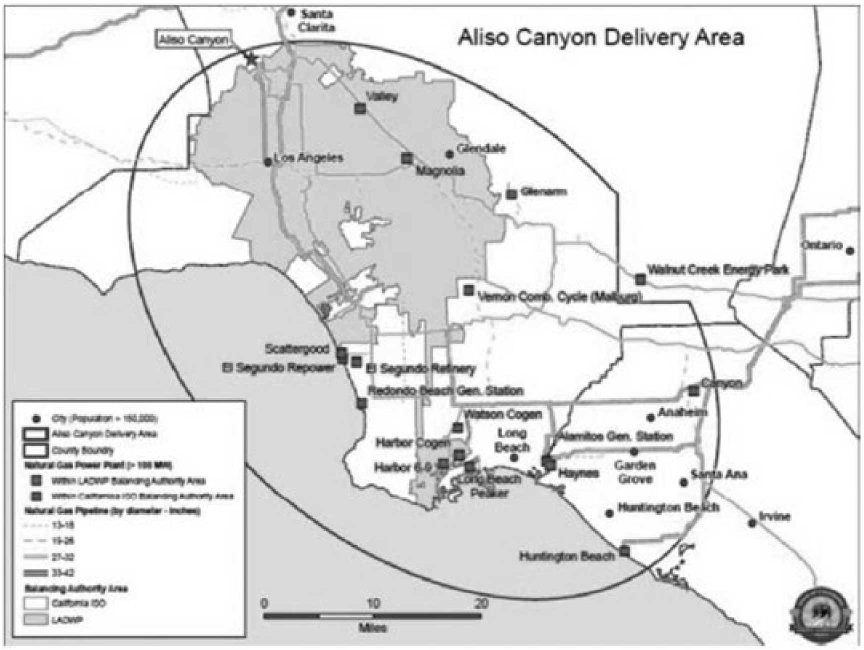
California put in place several measures to mitigate the impact of the loss of Aliso Canyon on natural gas and electric operations. These included a new Operational Flow Order authority granted by the California Public Utilities Commission (CPUC), which SoCalGas used to help ensure adequate pressure and supply flows into its system. CAISO, with approval from FERC, implemented a natural gas constraint to factor the loss of storage capacity in its market-clearing processes and to help manage dispatch of affected natural gas generators and their associated natural gas use. The constraint was used during two cold-weather events this past winter.

These and other initiatives helped CAISO maintain reliability throughout several periods of high demand for electricity and natural gas during extreme weather, both in summer and winter, with no major impact to the system or to natural gas and electricity prices. Further, the CPUC approved protocols for the withdrawal of natural gas from Aliso Canyon, and natural gas was withdrawn to help meet demand during a cold-weather event in late January of this year. The various stakeholders continue to prepare for challenges that may arise this coming summer.

These and other initiatives helped CAISO maintain reliability throughout several periods of high demand for electricity and natural gas during extreme weather.

At this time, it is unclear whether or at what level Aliso Canyon may resume natural gas injections, decisions that involve the CPUC and California's Division of Oil, Gas, and Geothermal Resources (DOGGR). On January 17, 2017, DOGGR completed its safety review and will make a decision about whether injections at Aliso

**Exhibit 5.** Aliso Canyon




Canyon can resume once they review public comments. The CPUC, at its public Voting Meeting on February 9, 2017, initiated a proceeding to determine the feasibility of reducing or eliminating the use of Aliso Canyon while maintaining electric and natural gas reliability in the region. If the CPUC's analysis determines it is feasible to eliminate or reduce the usage of Aliso Canyon, a following study will determine the conditions and time frame for implementing this action.

FERC considered and approved on an expedited basis CAISO's request for market rules that would allow it to address limitations that could adversely impact the reliability of CAISO's electric grid and market operations resulting from the Aliso Canyon outage in the natural gas delivery system in Southern California. Staff conducted outreach with industry and state agencies, participated in state workshops, and hosted FERC technical conferences discussing the effect of the outage on 2016 summer market operations in California.

Staff also participated on the White House–established interagency task force on natural gas storage safety established after the leak at Aliso Canyon.

### Southern California Natural Gas and Power Prices Generally Remained Low Relative to Past Five Years

As shown in **Exhibit 6**, 2016 natural gas and power prices in Southern California generally fell within or at the low end of the 2012–16 five-year range of prices.

SoCalGas's use of its operational flow order authority helped ensure natural gas was available in Southern California, which helped maintain power plant availability. Other factors, such as greater hydro generation in the spring and increased levels of renewable generation, reduced the need for natural gas use by generators, helping to ease natural gas and power prices. When CAISO triggered the natural gas constraint or manually dispatched generation during summer heat or winter cold events, prices still generally remained below those of recent peak-day events.

Persistently low wholesale electricity prices can place downward pressure on energy costs; however, such prices may also create challenging market conditions for certain market participants, such as merchant generators.


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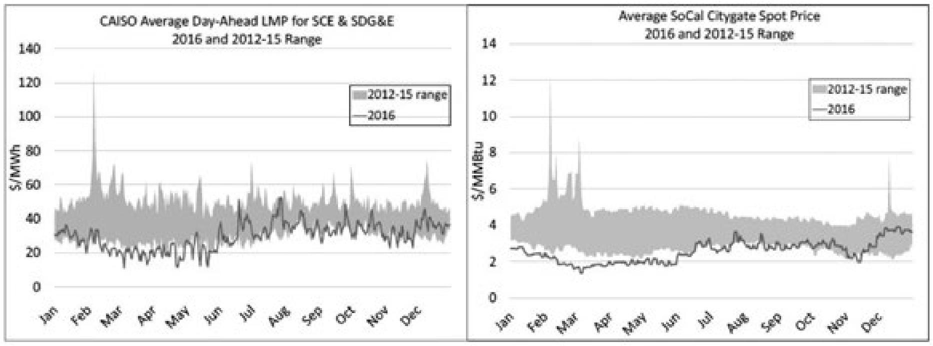
**Exhibit 6.** California Prices




*Source*: Derived from ICE and ABB data.
*Note*: Lower figure reflects simple average of day-ahead hourly LMPs at load zones for Southern California Edison and San Diego Gas & Electric.

**Exhibit 7.** New Pipelines to New England


*Source*: Spectra Energy.

## Other Notable Regional Natural Gas Developments

In the Northeast, approximately 1.0 billion cubic feet per day of new FERC jurisdictional pipeline infrastructure capacity went into service in 2016 (**Exhibit** 7), allowing more low-cost natural gas from the Appalachian region to move to markets in New England and the Mid-Atlantic.

For example, Spectra's Algonquin Incremental Market Project (AIM) began operation in the fall of 2016 and became fully operational in January 2017. AIM increases the capacity on the Algonquin pipeline by 342 million cubic feet per day. Other notable pipeline projects in the region include the 192-million-cubic-feet-per-day Transco Rock Springs Expansion Project and 152-million-cubic-feet-per-day First ECA Midstream Existing Pipeline Project, both of which transport Marcellus Shale gas to electric generators and other customers.

# Electricity Prices Have Dropped, Natural Gas and Renewable Generation Make Gains

*FERC Staff*

Current market measures show generally good news for end-users in prices, increases in natural gas and renewables, and decreases in coal and nuclear.

## DAY-AHEAD ON-PEAK ELECTRIC PRICES REACH NEAR-RECORD LOWS IN 2016

Wholesale electricity physical prices were down at most major trading hubs across the nation in 2016 compared to 2015 (**Exhibit 1**), driven primarily by low prices for natural gas. Monthly average wholesale electricity prices were highest in the Northeast, PJM, and MISO, while SPP and the West had slightly lower prices. In 2016, PJM prices were near the lowest they have been since the regional transmission organization (RTO) was formed in 1999.

Wholesale electricity physical prices were down at most major trading hubs across the nation in 2016 compared to 2015, driven primarily by low prices for natural gas.

Wholesale electricity prices also remained low with the mild winter weather in 2016, which both reduced electricity consumption for heating and simultaneously reduced demand for natural gas.

This effect was especially prominent in New England, where prices in the first quarter of 2016 were significantly lower relative to the first quarter of 2015.

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## CAPACITY PRICE TRENDS VARY ACROSS REGIONS

In 2016, capacity auction prices declined in many parts of the country, with some notable exceptions. See **Exhibit 2**.

Capacity auction prices declined in many parts of the country, with some notable exceptions.

### ISO-NE and PJM

In ISO-NE, the Forward Capacity Auction Price fell by 26 percent compared to the prior year. In PJM, the Base Residual Auction Clearing Price for Capacity Performance fell by 39 percent between 2015 and 2016.

While drivers of lower capacity clearing prices in the latest auctions include lower systemwide target requirements, increased supply, and fewer major retirements, staff notes that comparisons must be made with a degree of caution due to changing market rules. In particular, both PJM and ISO-NE have in recent years instituted various changes to their capacity markets.

### MISO

In MISO, the capacity auction clearing prices saw sharp changes compared to the previous year. Zone 4, which saw a large increase in price during the 2015–16 Planning Resource

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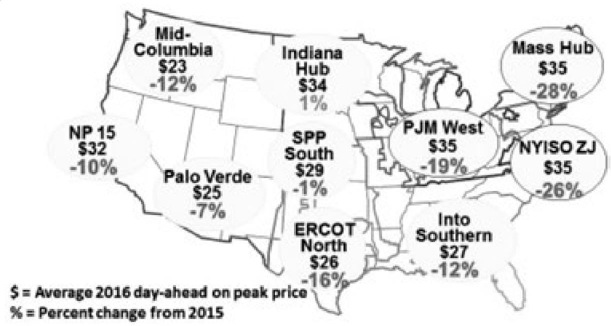
**Exhibit 1.** Electric Prices




*Source*: Derived from SNL data.
*Note*: Prices are a simple average of day-ahead on-peak physical prices.

Auction, fell by 52 percent for the 2016–17 auction (from $150.00 per megawatt-day to $72.00 per megawatt-day). Meanwhile, prices in Zones 2–7, with the exception of Zone 4, increased sharply, from $3.48 per megawatt-day to $72.00 per megawatt-day. Rule changes resulted in more sharing of capacity between zones in 2016–17, causing prices not to separate as they had in the prior auction. In addition, the market tightened, causing Zones 2–7 to move on to a steeper portion of the supply curve and clear at a higher price.

Elsewhere in MISO, capacity auction clearing prices in Zone 1 increased from $3.42 per megawatt-day to $19.72 per megawatt-day, while capacity auction clearing prices in Zones 8 and 9 decreased by 9 percent.

## NYISO

New York also had mixed capacity results but less volatility than other markets. Average monthly prices for NYISO's Zone J, representing New York City, fell by 18 percent in 2016 compared to 2015. The prices for the NYCA region, representing upstate New York, rose moderately, by 6 percent, during the same time period.

## ELECTRICITY DEMAND GROWTH REMAINS LOW

Nationwide electricity demand as measured by sales fell by 13 percent from 2015 to 2016. This continues a trend of relatively flat demand growth dating back more than a decade. As the US Energy Information Administration has reported, long-term trends indicate that US electricity demand growth is slower than the overall economic growth. See **Exhibit 3**.

The flat growth in electricity demand can be explained by a number of factors, including

**Exhibit 2.** Capacity Price Trends

| ISO/RTO | Capacity Auction Price | Zone or Region | Period of Comparison | Percent Change |
|---|---|---|---|---|
| ISO-NE | Forward Capacity Auction Clearing Price | Systemwide | 2019–20 vs. 2018–19 | –26 |
| PJM | Base Residual Auction Clearing Price for *Base Capacity* | Rest-of-RTO | 2019–20 vs. 2018–19 | –47 |
| | Base Residual Auction Clearing Price for *Capacity Performance* | Rest-of-RTO | 2019–20 vs. 2018–19 | –39 |
| MISO | Planning Resource Auction Clearing Price | Zone 4 | 2016–17 vs. 2015–16 | –52 |
| | Planning Resource Auction Clearing Price | Zones 2, 3, 5, 6, and 7 | 2016–17 vs. 2015–16 | +1,969 |
| NYISO | Average ICAP Spot Market Auction Price | Zone J, NYC | 2016 vs. 2015 | –17 |

*Source*: Derived from PJM, ISO New England, MISO, and NYISO data via SNL.
*Note*: Comparisons shown for selected zones/regions to illustrate variation

greater utilization of energy-efficient technologies and reduced demand for heating and cooling from the residential and commercial sectors because of mild weather in 2016. Also, the increase of behind-the-meter generation contributes to lower growth in wholesale electricity sales, as it reduces the need for energy from utility-scale plants.

Long-term trends indicate that US electricity demand growth is slower than the overall economic growth.

## SHARE OF NATURAL GAS–FIRED GENERATION CONTINUES TO INCREASE

The annual share of electricity produced from natural gas exceeded coal-fired generation for the first time in 2016, with natural gas–fired plants producing 34 percent of total generation compared to 30 percent for coal. This milestone was the product of many years of relative gains by natural gas plants relative to coal plants. Economic conditions have proved favorable to natural gas–fired generation, while the viability of coal plants has declined in most markets (**Exhibit 4**).

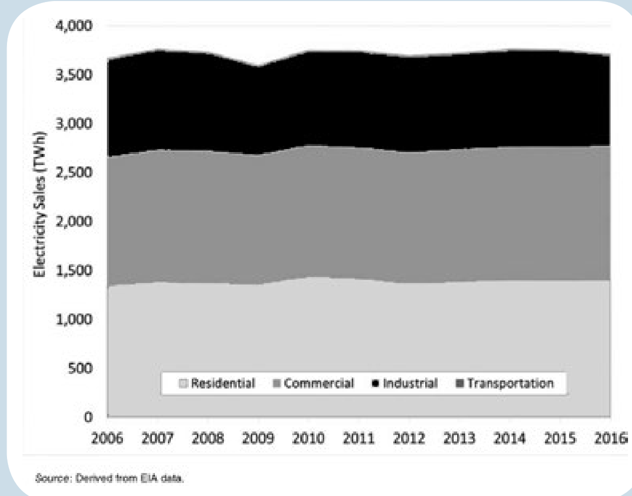
Renewables also continued to grow in the share of total generation capacity.

Renewables also continued to grow in the share of total generation capacity.

## RENEWABLES ACCOUNT FOR THE MAJORITY OF CAPACITY ADDITIONS IN 2016

In 2016, the markets saw continued growth in utility-scale renewable generation capacity, and renewables represented the majority of generating capacity additions (**Exhibit 5**). Renewable capacity was buoyed by the extension of both the production tax credit (PTC) for wind resources and the solar investment tax credit (ITC) for photovoltaic resources in December 2015. Both tax credit systems are slated to decline, with the PTC expiring completely in 2020 and the ITC reducing to 10 percent for commercial projects and expiring for residential projects.

**Exhibit 3.** Slow Electric Demand Growth




At the same time, state-level policies such as renewable portfolio standards (RPSs) drive renewable capacity additions and affect markets. The specifics of state RPS rules vary substantially state to state but encourage the procurement of either energy or capacity from renewable sources. Currently, 29 states and the District of Columbia have some form of RPS. Some states, including Massachusetts, New Jersey, and others, have instituted RPS

**Exhibit 4.** Decreasing Coal Share of Electric Generation

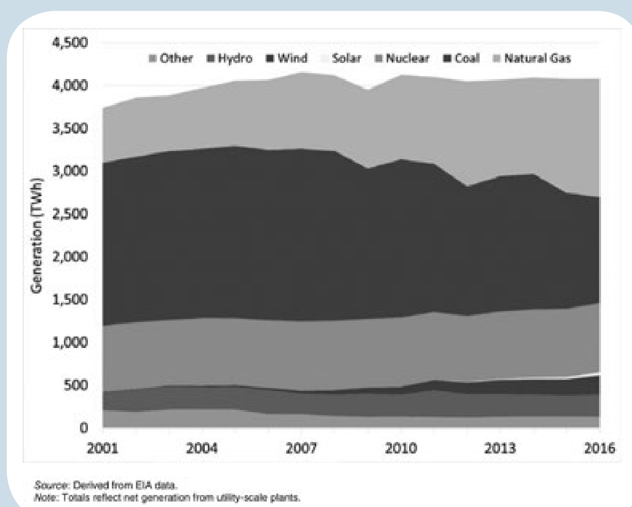




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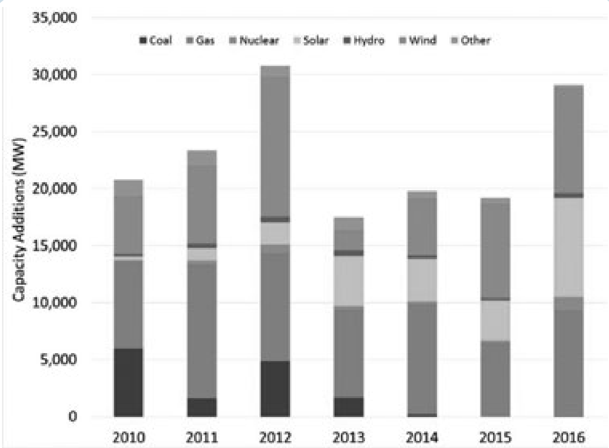
**Exhibit 5.** Renewables Continue to Increase



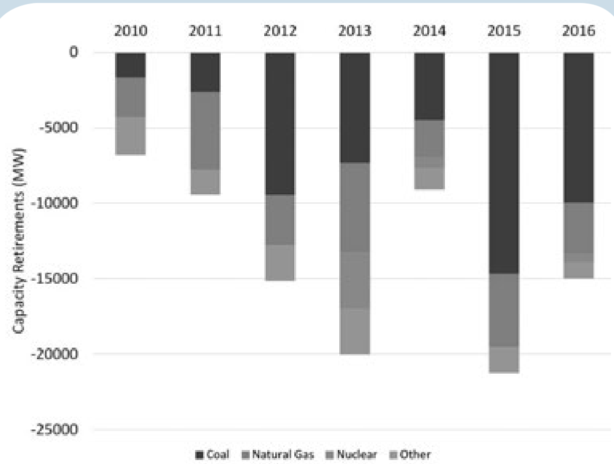

*Source:* Derived from Velocity Suite ABB Enterprise Software data.
*Note:* Capacity additions include new capacity, uprates, repowering, and return to service of plants out for more than five years.

solar carve-outs to encourage the use of distributed solar.

In 2016, several RPS goals expanded. New York adopted a new clean energy standard requiring utilities to purchase 50 percent of electricity from eligible clean sources by 2040. Oregon increased its requirement to 50 percent by 2040 for large investor-owned utilities, and the District of Columbia increased its requirement to 50 percent by 2032.

In 2016, there were some notable developments related to offshore wind capacity. The 30-megawatt Block Island facility in Rhode Island, which began production in December 2016, became the first operational offshore wind farm in the United States. Also, a Massachusetts law signed in August 2016 requires utilities in that state to procure up to 1,600 megawatts of offshore wind by 2027.

**Exhibit 6.** Continued Shutdowns of Coal and Nuclear




*Source:* Derived from ABB data.

Renewable capacity was buoyed by the extension of both the production tax credit for wind resources and the solar investment tax credit for photovoltaic resources in December 2015. Both tax credit systems are slated to decline.

After renewable resources, the next-largest share of new capacity in 2016 came from natural gas–fired resources, with about 9 gigawatts added, according to ABB. In addition, 2016 saw its first new US nuclear unit in 20 years, as the Tennessee Valley Authority's Watts Bar Unit 2 commenced commercial operation in October.

2016 saw its first new US nuclear unit in 20 years.

## BASELOAD RETIREMENTS CONTINUE IN 2016

The continued low cost of natural gas, among other factors, contributed to the reduced competitiveness of coal-fired power plants. Approximately 10 gigawatts of coal-fired capacity were retired in 2016 (**Exhibit 6**).

Low wholesale electricity prices have also contributed to nuclear plant retirements in recent years. In October 2016, the 478-megawatt Fort Calhoun plant in Eastern Nebraska shut down. Despite this retirement, the completion of the Watts Bar Unit 2, mentioned previously, resulted in a net gain in nuclear generating capacity in 2016. Since 2013, however, nuclear generating capacity has declined, with retirements of 5 gigawatts of nuclear capacity in total. Similarly, a number of retirements have also been announced for future years.

These trends have led some states to pursue policy support for certain baseload resources. In August 2016, for example, New York state initiatives led to the creation of zero-emissions credits, which provide selected nuclear plants with payments of up to $17.5394 per megawatt-hour for the first year, and similar payments for the next 10 years. Similarly, the Illinois state legislature approved a plan that would provide up to $16.50 per megawatt-hour in the first year to support the continued operation of nuclear plants at risk of retirement for the next 10 years.

These trends have led some states to pursue policy support for certain baseload resources.

Both of these plans are currently being challenged in the courts and at the Federal Energy Regulatory Commission.

## NET METERING CAPACITY CONTINUES TO GROW NATIONWIDE

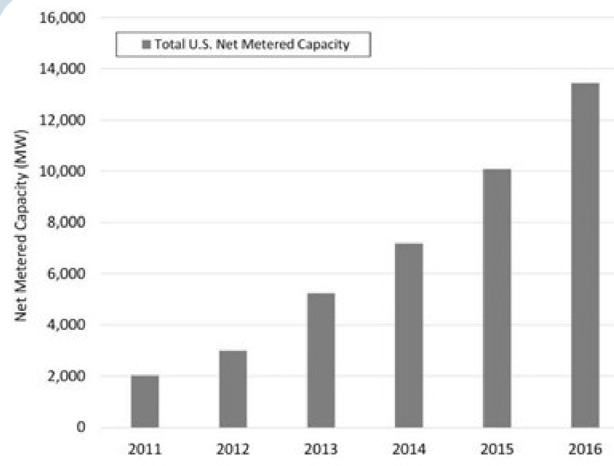
Net metering capacity has seen high growth in recent years (**Exhibit** 7), driven in part by wide-scale adoption of small-scale photovoltaic generators.

In recent years, cost reductions in solar photovoltaic systems drove substantial installation of both utility-scale and distributed solar energy projects across the country. Solar currently accounts for 99 percent of net-metered capacity. Although net-metered projects largely participate in retail markets, their aggregate impact has begun to affect wholesale markets with large penetration of distributed solar projects. These impacts can largely be seen as a functional reduction on demand from the RTO/independent system operator (ISO) perspective, with subsequent shifting of system load curves.

Solar currently accounts for 99 percent of net-metered capacity.

Some states and regions are seeking to integrate distributed energy resources into the market through alternative mechanisms. CAISO has introduced market rules to allow for aggregating distributed resources into a "virtual power plant," which would sell into the wholesale markets.

**Exhibit 7.** Net Metering, 2011–16




*Source:* Derived from EIA Form 826.

In November, FERC issued a Notice of Proposed Rulemaking (NOPR) that would require each RTO/ISO to create rules to accommodate the participation of electric storage and distributed energy resource aggregators in the organized wholesale markets.

## EIM EXPANSION CONTINUES

Since its launch in 2014, the electricity imbalance market (EIM) has steadily expanded its geographic footprint in the West. In October 2016, Puget Sound Energy and Arizona Public Service expanded the EIM to portions of eight Western states. Three entities also announced their intention to join the EIM: Idaho Power in 2018 and both Seattle City Light and the Balancing Authority of Northern California in 2019.

The Los Angeles Department of Water and Power, the Mexican operator El Centro Nacional de Control de Energía Baja, the Salt River Project, and Northwestern Energy are exploring membership in the EIM.

## PJM CONTINUED TO LEAD FINANCIAL TRADING OF ELECTRIC PRODUCTS IN 2016

**Exhibit 8** shows all cleared futures traded on the Intercontinental Exchange (ICE) for electric products outside ERCOT in 2016. PJM's financial products continue to be the most traded on ICE, with 65 percent of the total volume of


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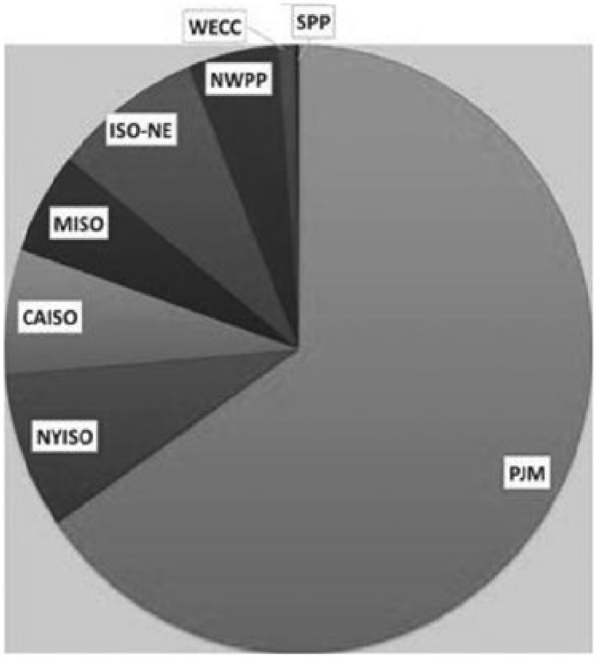
**Exhibit 8.** PJM Central to Financial Trading




*Source*: Derived from Intercontinental Exchange data.

financial trades involving a PJM product, up from 64 percent in 2015.

Last year, 94 percent of the financial trading of US electricity products outside ERCOT took place at an RTO hub, same as in 2015. All regions of the country outside of ERCOT experienced an increase in financial trading volumes compared to 2015, with the highest proportional increase happening in SPP.

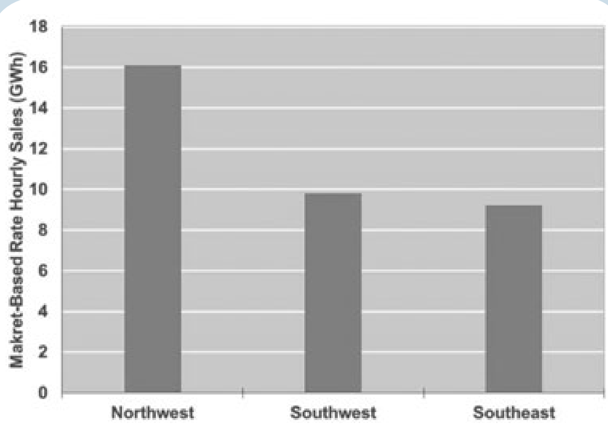
Last year, 94 percent of the financial trading of US electricity products outside ERCOT took place at an RTO hub.

## NORTHWEST REGION HAD LARGEST SHARE OF HOURLY MARKET-BASED RATE SALES OUTSIDE OF RTOS/ISOS

The Electric Quarterly Reports (EQRs) summarize data on electric power contracts and wholesale power sales by utilities with rates on file, as required by Section 205(c) of the Federal Power Act. The EQR provides data to the public and market participants, which increases transparency in wholesale energy markets.

As shown in **Exhibit 9**, the Northwest region reported the largest volume of hourly sales of energy and booked out power at market-based rates in the first three quarters of 2016 among bilateral (non-RTO/ISO) markets. The large volume of hourly market-based rate sales in the Northwest continues a trend seen in past years and reflects the structure of the bilateral markets in that region. The Northwest has a robust trade in short-term products, which is reflected in the larger number of sellers reporting trades in the region.

**Exhibit 9.** Share of Market-Based Rates




*Source*: Derived from Electric Quarterly Reports.

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The volume-weighted price for hourly market-based rate sales reported to the EQR for the first three quarters of 2016 closely tracked the annual reported price at nearby trading hubs. Among the regions shown in Exhibit 9, the volume-weighted price for hourly market-based rate sales was highest in the Southwest (approximately $26 per megawatt-hour), followed by the Southeast (approximately $23 per megawatt-hour) and the Northwest (approximately $20 per megawatt-hour).

# Increased Investment Needed in Integrated Resource Planning

*Paul A. DeCotis*

Integrated resource planning (IRP) by electric utilities in the United States is getting increasingly complex.

Before many states restructured the industry, requiring vertically integrated utilities to sell off their generation, utilities focused predominantly on developing least-cost supply portfolios to ensure sufficient generation was available to meet demand across several different scenarios. Such scenarios included planning for high and low fuel prices, high and low peak and energy demand, planned generation additions and retirements, planned transmission and distribution system investments, and environmental emissions considerations. Demand for electricity in the form of megawatts and kilowatt-hours was taken as a given, with planned demand reductions and energy efficiency reductions being modeled as load or demand modifiers.

## MANY FACTORS TO BE CONSIDERED

Because utilities are the "provider of last resort" and have the "obligation to serve," planning for uncertainties to ensure the utilities could meet these requirements was the primary driver for robust resource planning. Policy directives by states and regulators to consider the impact on the cost of electricity, local job creation, and the environment in the form of pollutant emission reductions and land-use planning added a layer of complexity to IRP development, as did higher expectations for stakeholder engagement. In some instances, increased stakeholder engagement morphed into utilities being required to consider alternative planning scenarios, including least-cost environmental emissions dispatch, more aggressive energy efficiency and renewable energy goals, and other factors.

In jurisdictions, like among others, New York, California, Massachusetts, the Northwest, and Vermont, such investment strategies and planning scenarios were considered in rate cases and generic statewide policy proceedings. These considerations also led to mandated or aspirational energy policy goals in the form of clean energy and renewable energy standards and carbon reduction goals in states. But by and large, IRP focus remained on optimizing and planning for sufficient generation supply resources to meet demand.

By their very nature, IRP processes involve planning to meet customers' needs for electricity and peak demand in a way that satisfies multiple and often competing objectives. Generally, among others, IRP goals and objectives include the following:

- Showing a path and plans to meet state and regulatory energy, economic, and environmental policy objectives

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- Maintaining system reliability and planning for multiple contingencies, e.g., plant and transmission and distribution (T&D) service disruptions
- Reducing or slowing the increase in electricity costs compared to a "next-best" alternative
- Improving the environment or reducing land-use, water, and pollutant emissions of electricity supply and use
- Enhancing energy system resiliency
- Preserving or creating jobs and tax base in at-risk communities hosting power projects

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## IRP TODAY REQUIRES MORE INVESTMENT, BETTER TOOLS

In the last five to seven years, utility planning has been getting increasingly more complex, and utility planners and the models they use are being challenged. As customers become more engaged in deciding where and how they receive electric service, and alternatives to utility-provided power abound, with energy service providers competing directly with utilities for customers, IRP needs and processes need to become more robust and flexible.

IRP needs and processes need to become more robust and flexible.

As growing amounts of distributed energy resources (DERs), including demand response, are added by customers, the responsibility for and management of utility-owned distribution systems needs to adopt new software tools and models to plan effectively and realistically for meeting IRP goals and objectives listed earlier. The goals and objectives have not changed. If anything, utilities are being required by regulators to report more frequently on their progress in implementing their plans and meeting IRP objectives and to plan more aggressively to ensure continued customer engagement and to support competitive alternatives to utility-provided service.

Planning models and processes need to respond quickly to anticipated and planned changes in supply and now also demand. With more intermittent and distributed energy resources being added to the system, real-time imbalances in supply and demand and voltage regulation become more critical. Utility planners (and system operators) need visibility into demand-side resources to reliably forecast their availability and, if possible, exert some limited control over the resource. Of course, this is the utility's role, unless the utility is relieved of its obligation to be the provider of last resort, or of having the obligation to serve.

With more intermittent and distributed energy resources being added to the system, real-time imbalances in supply and demand and voltage regulation become more critical.

Real-time operation of the grid with more DERs requires investment in distribution system infrastructure and necessary information and operations technology to help dynamically manage the grid. Traditional radial topologies will transform into more complex networked systems requiring two-way communications, new controls and sensors, and new data management systems. These new tools will aim to balance available supplies with real-time demands—in effect cooptimizing supply and demand. Traditional supply planning now needs to account for demand planning rather than simply accepting demand as a given and planning to meet it. Uncertainty in planning has also increased, requiring more probabilistic analysis and Monte Carlo methods, where repeated random sampling or randomness is used to solve demand and supply optimization in cases where utilities do not control DERs.

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Such investment in systems and models is necessary for utilities to continue providing reliable and

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resilient electric service. Planners can model DERs as a load modifier, much like energy efficiency or demand response (clipping peak) or as a generation source, giving DERs the characteristics of a power plant, in which case they could be dispatched and somewhat predicable. Of course, this requirement requires utilities and system planners to have some visibility to DER performance and forecasting and/or control over the DER operation.

Such investment in systems and models is necessary for utilities to continue providing reliable and resilient electric service.

By and large, utility planning models for IRP development forecast out 10 to 20 years, or even more. These models are dependent on input data and assumptions, and predictions of many possible future states, including planned regulated and merchant investment in T&D infrastructure, estimates of private investment in new central-station and baseload or variable or intermittent generation resources, all or most outside of the utilities' direct control or influence. Yet utilities need to be the backup in the event sufficient private investment is not forthcoming or market-based plans do not materialize. This risk puts utilities at a potential competitive disadvantage by waiting for markets to address electric system and resource needs first, and purportedly puts the utilities in a situation of having to backstop markets in the event such private investments are not made.

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This posture is rather defensive and reactionary, and then places utilities at the mercy of regulators for recovering utility investments deemed necessary to meet its obligations to customers. Some jurisdictions and regulators are being proactive, and rightly so, requiring utilities to determine the need for new resource additions, including supply- and demand-side resources, and requiring utilities to look at various competitive alternatives to traditional utility investment. This requirement puts utilities in an active role, while providing competitors the ability to respond to meet defined needs. If no competitive market-based solutions are offered, utilities have a basis and record for advancing their own alternative to meet demand. While this provides a means for utilities to meet immediate and planned needs, it does little to improve IRP.

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## REGULATORY AND UTILITY PLANNING NEEDS

Just as DERs can include supply-side and demand-side resources, *distributed energy resource management systems* are beginning to emerge. For the utilities, this new development means that the line between supply and demand as resources available to help operate the system begins to blur. For customers, it begins to unlock the full value of any DERs they own, as well as the value of behavioral changes when electricity is used. For example, an intelligent thermostat receiving real-time pricing signals can become a source of information to drive more energy-efficient behavior on the part of customers.

Another example is the potential to use electric vehicles as both a demand resource, through the control of the EV charging cycle, and a supply resource, by using the EV battery for energy storage and later use. Utilities and regulators alike need to recognize the potential conflict inherent in resource planning and encourage utilities and planners, as well as stakeholders, to improve their IRP capabilities and modeling and not jeopardize sustained grid system reliability. Giving utilities more visibility and control over supply and demand resources, regardless of ownership, and enhancing IRP modeling capabilities to account for greater uncertainty will provide the framework and ability for optimizing supply-and-demand planning consistent with IRP objectives.


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# Electricity Deregulation Under Siege

*Jeff D. Makholm*

It has not been a good few years for the advance of competition in electricity supply in a number of places in the world.

One of the planks in the Tory platform involved capping retail electricity prices, widely seen as a broad-based move to use Brexit as the means to reregulate the power sector in a way not permitted in the European Union.

In the United States, the competitive electricity markets that began so hopefully in the 1990s and then froze in the wake of the 2000–2001 electricity crisis in California face problems in various states—from the inability of the market to get enough gas during a Polar Vortex in New England to an effort to reregulate competitive electricity suppliers in New York.[1] In the recent election in the United Kingdom, one of the planks in the Tory platform involved capping retail electricity prices, widely seen as a broad-based move to use Brexit as the means to reregulate the power sector in a way not permitted in the European Union.[2]

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Then again, there are places in the world where electricity competition seems to be working well.

There are places in the world where electricity competition seems to be working well.

Nord Pool, the largest electricity market in Europe, serving Norway, Sweden, Finland, Denmark, the Baltic countries, and others, appears to have developed the kind of electricity market that a number of far-sighted economists envisaged, where bilateral contracts between competitive generators and energy retailers handle most of the money and the spot market works mainly, and merely, as a clearinghouse for the funds and a source of "balancing" for the unexpected.[3] The Texas electricity market seems to be working reasonably well for consumers and is well-regarded by analysts—a fact that may well be due to it being the only US electricity market free from the jurisdiction of the Federal Energy Regulatory Commission (FERC), and also the implementation of "full retail access" for electricity (meaning that the local wires utilities do not provide regulated "default" service).[4]

To be sure, deregulation—in any industry—is a hugely complicated subject representing the intersection of regulatory institutions, industrial history, technology, the role of investor-owned companies (where they appear), and the demands of those who buy the services. But electricity deregulation is especially complicated because of various unique aspects of the service. Electricity consumers still mostly connect physically to natural monopoly distributors.[5] Even the most

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competitive electricity markets rely on regulated transmission grids and the cooperative power pools operating over those grids. There is great complexity inherent in those transmission grids (related to pricing and the governance of capacity expansions) and power pools (regarding both the spot price and means to purchase long-term "reliability")—the details of which are off-putting to any but the experts involved.

The successful efforts in electricity deregulation—Nord Pool and the Texas market—seem to have overcome the complexity; others have not. There seem to be a few reasons why not, all on display in the current problems that seem to beset those power markets where competitive supply is under some form of assault.

## ELECTRICITY COMPETITION IN NORTH AMERICA AND ELSEWHERE

**Exhibit 1** shows the states and provinces with some sort of competitive retail electricity markets and also those states that suspended such markets after the California energy crisis.[6]

The push for electricity competition had economic elements but was mostly about a disgruntled industrial sector during a period of steeply rising retail electricity prices—shown in **Exhibit 2**, where the share of electricity in household expenditures grew rapidly between the late 1960s and early 1980s, as inflation, the OPEC oil embargo, and the practical end of the period of scale economies with larger central station power plants upset the long decline in US electricity prices.[7]

**Exhibit 1.** Residential Electricity Choice


*Sources:* Map data: Morey, M., & Laurence, K. (2016, February 2). *Retail choice in electricity: What have we learned in 20 years?* Washington, DC: Electric Markets Research Foundation. Retrieved from https://www.hks.harvard.edu/hepg/Papers/2016/Retail%20Choice%20in%20Electricity%20for%20EMRF%20Final.pdf; Direct Energy. (n.d.). *Energy deregulation in the United States and Canada.* Retrieved from https://business.directenergy.com/what-is-deregulation#deregmarket; *Guide to understanding Alberta's electricity market.* (2016). Calgary, Alberta: Alberta Electric System Operator. Retrieved from https://www.aeso.ca/aeso/training/guide-to-understanding-albertas-electricity-market/.

Other countries faced some of the same pressures as the US electricity market in the 1980s and pushed for competition. New Zealand became the first country to implement full retail competition access for consumers in 1994.[8] Australia followed in 1998 with the splitting of traditional utilities into generators, transmission, and distribution companies and the provision of competitive retail service.[9] Great Britain (England, Wales, and Scotland) implemented a full retail electricity competition program in 1999 for all customers.[10] Norway began its move to competitive electricity markets in 1990. Sweden moved toward competitive electricity markets in 1996. Norway, Sweden, Finland, and Denmark created a common electricity market—Nord Pool—that came on line in 1996.[11]

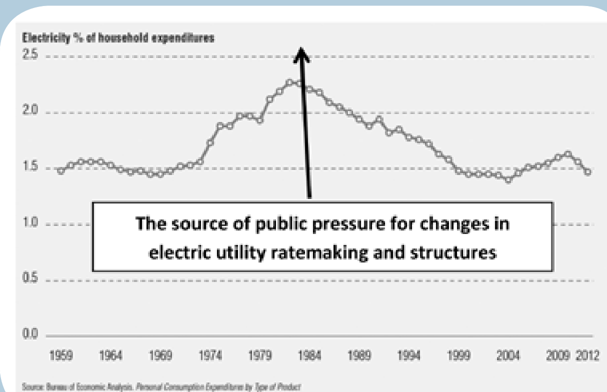
What we see in 2017 is a period of backsliding in the movement, away from competitive electricity markets. I suggest—looking only at the United States and the United Kingdom simply to keep this column short—that there are three principal reasons why.

### Default Service and the "Heisenberg Principle"

The Heisenberg Principle in particle physics holds that the observer biases the experiment.

In electricity deregulation, an analogous sort of bias comes through the lens of "default retail service" provided by incumbent regulated utilities. Different types of agencies see different things through the default service lens. The people in public service regulatory agencies, who normally

**Exhibit 2.** Electricity's Share Consistently Small in GDP

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set allowable prices in industries presumed to be monopolies, have a long-standing tendency to look to intervene in markets. Antitrust authorities (such as the US Justice Department staff) analyze market structures and conditions of competitive entry to decide whether to intervene in markets—and look for reasons not to.

The people in public service regulatory agencies, who normally set allowable prices in industries presumed to be monopolies, have a long-standing tendency to look to intervene in markets.

A case study of the differences in perspective is at hand in a current initiative in New York to reexamine whether competitive electricity retailers should fall under some sort of price regulation. In that case, the staff of the regulator, with an idealized vision for competitive markets, appears to consider any revenues gained by competitive retailers above default revenues a problem in the electricity market potentially worthy of regulation.[12] Antitrust agencies, seeing no worrisome barriers to entry and a reasonably informed market, would probably leave that pricing alone (as they generally do in insurance and telecommunications markets).

Another case study exists in a 2016 report by the UK Competition and Markets Authority into the state of electricity competition. The report said that "since electricity [is an] entirely homogenous product . . . most customers . . . could have made considerable savings from switching a combination of suppliers, tariffs, and payment methods."[13] The report takes the fact that many UK consumers do not automatically switch to the lowest retail price offers as a problem in the market worthy of a remedy—for which the proposed Tory price cap proposal on retailers is a direct consequence.

But electricity is not a homogenous product—a point coming from some of the earliest scholarly inquiries into deregulated power markets.[14] Electricity is better described as a *service* with various attributes (including green power and smoothed prices) and various ancillary services and discounts like those accompanying other products and services provided in competitive markets (like reward points, loyalty programs, and cash back). Such a competitive service market should be expected to display the kind of pricing diversity seen in auto/home insurance markets or in the market for telecommunications services.[15]

Electricity is better described as a *service* with various attributes (including green power and smoothed prices) and various ancillary services and discounts.

Regulators and politicians seem to not expect this price diversity and have few tools by which to evaluate the fact that consumers in competitive markets do not automatically switch to the lowest pricing option when it appears (as in insurance or telecommunications markets).

### "Two-Sided Platform" Markets

A persistent tendency in evaluating electricity markets, particularly in the United States, is to consider success in wholesale markets as separate from the success in retail markets.

It is as if the locational spot market for wholesale power supplies is what competition is all about at that stage of the industry. From that perspective, electricity retailers are all about "retail choice," with little to do with the operating of wholesale markets. This "separable" perspective of electricity competition pervades the recent popular literature.[16]

A more cogent economic theory of what drives electricity markets treats retailers (and providers of other smart electricity services) as operating in "platform" markets. A platform market exists when one or more groups is linked by an intermediary—the platform provider—that coordinates their interactions.[17] Electricity markets provide choices for both power producers and consumers.

Retailers in electricity markets exist between generating stations and consumers—they have the ability to offer services to both. In electricity markets like those governed by Nord Pool, retailers offer contracts that permit generators to count on a multiyear stream of payments. Such large-scale bilateral trading of electricity uses the relevant independent system operator power pool operations simply as a physical/financial clearinghouse and as a means for "balancing" actual with anticipated sales and purchases under those bilateral contracts.

In contrast, various US power markets (such as in New York) direct default service to draw from

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the local pool spot price. Such arrangements, called "virtual direct access" to the spot market, tend to remove electricity retailers as financial intermediaries for producers, as in Nord Pool. As my late colleague Sally Hunt said, such virtual direct access "makes too much electricity pass through the spot markets" and as a result undermines the price stability that default consumers would appear to want.[18] The power market cannot help but exhibit more volatile pricing as a result of such a large virtual direct access component for default service—exactly the conditions that beset, and destroyed, the California wholesale electricity market around 2000 with its "near-total access of forward contracting."[19]

Much of the US literature on the success or failure of the retail electricity markets tends to focus solely on consumers (i.e., "consumer choice") and insufficiently on how retailers provide a means for dealing with the credit risk of power plants through bilateral contracting. This oversight is not surprising given the dominance of default service—either through virtual direct access or through regulated default service.

### Problems With "Letting Go"

My long-time NERA colleague Alfred Kahn wrote at length about the difficulties of regulatory restraint in pursuing deregulation.[20] My economic perspective on this question is shaped by my long association with Kahn. Many of his later writings—long after his role in deregulating airlines and as chair of the New York Public Service Commission—were devoted to pressing regulators to recognize the benefit of "letting go" in markets where competition, even if sometimes with unpredictable results, was a better avenue to pursue than regulation.

US industry has benefitted greatly from the tendency of regulators to pursue competitive options even when the result of "letting go" was somewhat unclear. The US gas market displays a triumph of regulatory restraint where FERC regulates very little—only the licensing of new gas pipelines and the cost-based tariffs of those already in place. The benefits to US consumers and markets are immense: since 2009, US consumers have paid hundreds of billions of dollars less for the gas flowing through US pipelines than their European counterparts have.[21] In airlines, lifting price regulation and abolishing the regulatory agency was a triumph of economics over the protectionist forces that had used regulation to support the cartelization of a structurally competitive airline transport industry.[22] In rail, an industry decline turned around with the 1980 Staggers Act, where Interstate Commerce Commission Chairman Darius Gaskins pursued close to full deregulation by deferring to market outcomes whenever possible—and freight rail costs fell from 4.2 cents in the 1970s to 2.6 cents in 1988, while the industry as a whole became more profitable. In trucking, the 1980 Motor Carrier Act—again, under Gaskins—has saved the trucking industry an estimated roughly $10 billion annually.[23]

Benefits to US consumers and markets are immense: since 2009, US consumers have paid hundreds of billions of dollars less for the gas flowing through US pipelines than their European counterparts have.

All of these cases involved the systematic targeting of entry barriers and the promotion of pricing or contract-based rivalry among competing modes of transport—with no regulated default service by which only seemingly to judge the efficacy of competitive spot or contract rates. The pursuit of competition in electricity was a deliberate act in many states and countries in the broader worldwide trend to promote competition in energy markets. Where default service tends to attract reregulation, I believe that Kahn would counsel electricity regulators everywhere to dispense with it and "let go."

## CONCLUSION

Electricity retailers around the world perform a widely recognized function in serving both sides of power markets. They act as intermediaries to reduce market power problems, stabilize electricity prices, and provide wider competitive options for consumers. Progress in local grid efficiencies tied to climate change (e.g., microgrids, smart service contracts, peer-to-peer power exchanges) would appear to depend on the innovation of competitive participants, particularly competitive retailers of power, in the market to provide services to all electricity consumers.

All of that notwithstanding, further progress in pursuing competitive power markets is going

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to be difficult. It is easy not to appreciate the way that competitive retailers serve the markets in places like Texas and Scandinavia. It is also easy to make inapt billing comparisons—essentially comparing average revenues for essentially noncomparable services—between retailers and regulated default service providers. And the most effective pressure groups of an earlier era—the industrial firms that looked at the rising price of power in the 1970s and 1980s and pressed for changes—have enjoyed both the most responsive retail access and power market effects of the deregulated US gas markets.

How future electricity markets square with the desire for more efficient and green initiatives in electricity service delivery will probably involve many battles in many diverse jurisdictions.

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