# ISO/RTO Carbon Pricing Initiatives

Energy 159 (2018) 579–587

Contents lists available at ScienceDirect

Energy

journal homepage: www.elsevier.com/locate/energy

# Carbon trading's impact on California's real-time electricity market prices

C.K. Woo [a, *], Y. Chen [b], J. Zarnikau [c], A. Olson [d], J. Moore [d], T. Ho [e]

[a] Department of Asian and Policy Studies, Education University of Hong Kong, 10 Lo Ping Road, Tai Po, New Territories, Hong Kong
[b] Department of Technology Management, Jack Baskin School of Engineering, UC Santa Cruz, CA 95064, USA
[c] Department of Economics, University of Texas at Austin, TX 78713, USA
[d] Energy and Environmental Economics, Inc. (E3), 101 Montgomery Street, Suite 1600, San Francisco, CA 94104, USA
[e] Independent SAS Analyst, Flat H, 16/F, Block 3, Wing Fai Centre, Fanling, New Territories, Hong Kong

ARTICLE INFO

*Article history:*
Received 16 October 2017
Accepted 26 June 2018
Available online 27 June 2018

*Keywords:*
Carbon trading
Real-time electricity market prices
$CO_2$ emissions cost pass-through
California

ABSTRACT

What is the extent of a real-time electricity market's pass-through of the marginal cost of $CO_2$ emissions due to a cap-and-trade (C&T) program? This is an important policy question, as an incomplete pass-through would suggest the program's limited effectiveness in achieving efficient pricing of electricity. To answer the question, we perform a regression analysis of California's electricity market data for a 65-month period of 01/01/2011–05/31/2016. Based on this newly constructed large sample, we find that the California Independent System Operator's real-time market prices contain a $CO_2$ premium that closely tracks the marginal cost of $CO_2$ emissions of California's natural-gas-fired generation units, which are often at margin that determines the power prices. While the $CO_2$ premium provides much needed incentives for renewable energy development, it does little to improve the incentive for natural-gas-fired generation investment in California. Hence, procurement of dispatchable generation capacity via long-term contracts continues to be useful for the state to meet the mandatory criteria for resource adequacy and system reliability.



## 1. Introduction

Restructuring the electricity sectors in Europe, North America, South America, Australia, New Zealand, and Asia has fostered wholesale trading of electricity [1]. Wholesale electricity prices are inherently volatile with sharp spikes and dives,[1] prompting extensive research in price behavior [2,3], risk management [4,5], product differentiation [6], system operation [7], and integrated resource planning [8].

Along with competitive electricity trading, there have been efforts to decarbonize, or reduce $CO_2$ emissions of electricity generation. Despite the Trump administration's withdrawal of the U.S. commitment made in the 2015 Paris Climate Change Summit and unwillingness to implement the Clean Power Plan, California and other states have reaffirmed their efforts to combat global warming.[2] In particular, California will continue to pursue its legislated program for cap-and-trade (C&T) of $CO_2$ allowances.[3] Carbon trading is a market-based mechanism for effective and efficient decarbonization [9]. The extent of the $CO_2$ cost pass-through in electricity prices is an important policy question because it aids efficient pricing of electricity and encourages investment in clean energy and energy efficiency [10].

Extant regression analyses of market data have not reached a

* Corresponding author.
*E-mail addresses:* chiwoo@eduhk.hk (C.K. Woo), yihsuchen@ucsc.edu (Y. Chen), jayz@utexas.edu (J. Zarnikau), arne@ethree.com (A. Olson), jack@ethree.com (J. Moore), hstony1@outlook.com (T. Ho).

[1] Wholesale electricity prices are inherently volatile due to: (a) daily fuel-cost variations, especially for the natural gas that is widely used by combustion turbines and combined-cycle gas turbines; (b) hourly weather-sensitive demands and wind and solar resources with intra-day and inter-day fluctuations, which must be balanced in real time by dispatchable generation and transmission already in place; (c) planned and forced outages of electrical facilities; (d) hydro conditions for systems with significant hydro resources; (e) carbon-price fluctuations affecting thermal generation that uses fossil fuels; (f) transmission constraints that cause transmission congestion and generation re-dispatch; and (g) lumpy capacity additions that can only occur with long lead times.

[2] https://insideclimatenews.org/news/21092017/states-paris-trump-climate-change-alliance-leadership-jerry-brown-cuomo-inslee-nrdc-2050.

[3] https://www.arb.ca.gov/cc/pillars/pillars.htm.

https://doi.org/10.1016/j.energy.2018.06.188
0360-5442/

consensus on the $CO_2$ cost pass-through in electricity market prices. Notable examples include: (a) an almost 100% pass-through in the Spanish electricity prices [11]; (b) a pass-through of 84%–104% in the German electricity prices [12]; (c) a statistically insignificant pass-through for the second phase of the European Union Emission Trading System (EU ETS) [13]; (d) rising $CO_2$ prices of EU ETS permits having a stronger impact on wholesale electricity prices than falling $CO_2$ prices [14]; (e) an approximately 0.32% increase in the European electricity prices due to a 1% increase in the $CO_2$ price [15]; and (f) a 100% pass-through of California's $CO_2$ price in the day-ahead market (DAM) prices of the Pacific Northwest [16] and California [17].

This paper is a regression analysis of real-time market (RTM) data available from the California Independent System Operator (CAISO) for the period of 01/01/2011 to 05/31/2016. Based on this newly constructed large sample, the analysis aims to answer three interrelated questions of substantive policy relevance:

(1) Do the CAISO's RTM prices contain a $CO_2$ premium that measures the RTM price increase in response to carbon trading? If the RTM prices' estimated $CO_2$ premium tracks marginal cost (*MC*) of $CO_2$ emissions from electricity generation, California's C&T program is deemed effective in internalizing the formerly unpriced $CO_2$ emissions.
(2) How big is the $CO_2$ premium for natural-gas-fired generation? An engineering estimate of *MC* is the product of the $CO_2$ price, the $CO_2$ emissions per MMBtu of natural gas usage, and the marginal generation unit's heat rate (*HR*). When the marginal unit in a given hour is an aging combustion turbine (CT) with a relatively high *HR*, an owner of infra-marginal units, such as a relatively new CT or a combined cycle combustion turbine (CCGT) with a lower emission rate, can profit from that hour's relatively high $CO_2$ premium.[4]
(3) Does the $CO_2$ premium vary by time-of-day (TOD) period? This question is related to an electricity grid's marginal *HR*. For example, an aging CT (ACT) may be the marginal unit during the peak hours when the system experiences very high system loads, though not in the remaining non-peak hours when a relatively new CT or CCGT is the marginal unit. If the $CO_2$ premium's time pattern is found to match the marginal *HR*'s, it lends further support to the effectiveness of carbon trading in internalizing the formerly unpriced $CO_2$ emissions.

We summarize our findings to answer the aforementioned three questions. First, the CAISO's RTM prices are found to contain a non-trivial and time-varying $CO_2$ premium that closely tracks the daily $CO_2$ permit price. It corroborates the prior findings for Spain [11] and Germany [12], as well as the Pacific Northwest [16] and California [17]. Along with results in Refs. [11,12,16,17], this finding affirms the efficiency of wholesale electricity markets in those countries or regions to fully pass through the marginal cost of $CO_2$ emissions of generation plants, notwithstanding that these markets have different demand profiles and resource mixes (e.g., European countries vs. regions in the U.S.A.), trading platforms (e.g., bilateral trading in the Pacific Northwest vs. centralized markets in California and Texas), and trading time frames (e.g., California's DAM vs. RTM). Hence, it affirms the use of a C&T program to achieve an economy's deep decarbonization goal.

Second, the CAISO's RTM prices move with their fundamental drivers. Specifically, they tend to decline with renewable generation and available nuclear capacity but increase with the natural gas price and market demands. While intuitively appealing, this finding corroborates the documented price-dependence on fundamental drivers for California [18], the Pacific Northwest [19], Texas [20], and other regions (e.g., the 13 states served by the PJM grid and the European countries referenced in Ref. [18]).

Our paper makes two main contributions, especially to the current policy debates of using C&T in pursuit of sustainability in the power sector while minimizing interference with wholesale electricity market operations. First, it reports a comprehensive set of estimates of the $CO_2$ cost pass-through in California's RTM prices. To the best of our knowledge, these estimates are new, chiefly because they are based on a database that has not been considered in the extant literature. Together with the recently developed DAM estimates in Ref. [17], they confirm the California C&T program's effectiveness in pricing $CO_2$ emissions in the CAISO's electricity markets so that producers can effectively internalize emission costs in their bids. Second, it documents the fundamental drivers' estimated RTM price effects by TOD period. In particular, they show that the estimated merit-order effects of renewable energy such as wind and solar are time-dependent, sharply contrasting the time-invariant estimates previously reported for California [18], the Pacific Northwest [19], Texas [20], and other regions like PJM, Germany, Denmark and Spain noted in Ref. [18].

The rest of this paper proceeds as follows. Section 2 describes the CAISO markets, explains the RTM prices' pass-through of natural-gas-fired generation's marginal cost of $CO_2$ emissions, specifies our RTM price regressions, and describes our data sample. Section 3 reports our regression results. Section 4 concludes.

## 2. Materials and methods

### 2.1. The CAISO electricity markets

With a gross domestic product of US$2.45 trillion in 2015, California is the sixth largest economy of the world.[5] Its vast electric system has an in-state generation capacity of roughly 80,000 MW in 2015,[6] diversely fueled by natural gas (~59%), large hydro (~16%), renewables (~22%), and nuclear (~3%).[7] The CAISO operates the DAM and RTM for energy, as well as co-optimizing procurement of ancillary services (AS) for regulation and contingency reserves.[8] The DAM accounts for 90+% of the CAISO's energy transactions, while the remainder is transacted through the RTM. Though accounting for less than 10%, the RTM's trading volume is substantial because the state's total generation in 2015 was 196,819 GWh,[9] the fourth largest in the U.S.A.[10]

The CAISO's DAM and RTM are distinctly different. To see this point, consider that the DAM opens for bidding seven days before and closes at 1:00 p.m. the day prior to the trade date. The CAISO

[4] To see this point, consider the case of a 100% pass-through of *MC*. When an aging CT is the marginal unit, the $CO_2$ premium is based on this CT's heat rate $HR_{ACT}$. A CCGT owner benefits from carbon trading because $HR_{CCGT} < HR_{ACT}$, resulting in a per MWh benefit equal to the product of the $CO_2$ price, the per-MMBtu $CO_2$ emissions, and the heat rate difference of $(HR_{ACT} - HR_{CCGT}) > 0$.

[5] http://fortune.com/2016/06/17/california-france-6th-largest-economy/.

[6] http://energyalmanac.ca.gov/electricity/electric_generation_capacity.html.

[7] The ~22% renewable capacity is the sum of biomass (1.6%), geothermal (3.4%), small hydro (2.1%), solar PV (5.9%), solar thermal (1.6%), and wind (7.5%).

[8] To maintain the state's grid stability and reliability, the CAISO uses four types of AS products: regulation up, regulation down, spinning reserve and non-spinning reserve. As these products' primary goal is to provide frequency stability and standby and quick-start capacity, an analysis of the AS market prices is well beyond the scope of this paper.

[9] http://www.energy.ca.gov/almanac/electricity_data/electric_generation_capacity.html.

[10] https://www.eia.gov/electricity/state/california/.

determines the **hourly** DAM prices as follows. First, it daily runs a market power mitigation test to exclude generation supply bids with price quotes exceeding its preset benchmarks. Second, it determines the day-ahead forecast of the state's hourly locational loads. Finally, it uses a full network model to analyze the active transmission and generation resources to find the least-cost resource mix to serve the forecast loads. The model's results are the hourly day-ahead schedules for generation resources and loads, as well as the DAM prices for settling the day-ahead transactions.

Now consider the RTM, a spot market that opens after the DAM and closes 75 min before the start of the trading hour. Further detailed in Section 2.2 below, the CAISO's real-time economic dispatch automatically runs every 5 min to obtain imbalance energy and energy from ancillary services. As real-time energy imbalances are the result of unanticipated deviations from the day-ahead schedules of loads and resources, their resolution leads to **5-min** RTM prices that tend to fluctuate significantly more than the DAM prices.[11]

Both the hourly DAM and 5-min RTM prices are highly volatile, have sharp spikes and dips, occasionally have negative values,[12] move with their fundamental drivers, and can regionally diverge due to intra-state transmission congestion [18]. Further, the hourly DAM prices have been found to move with the $CO_2$ price resulting from the state's C&T program established under Assembly Bill 32 (AB32), the Global Warming Solutions Act of 2006 [17]. However, little is known about the effects of C&T on the RTM. A higher than 100% pass-through of the carbon price indicate that producers tend to over-estimate their emissions costs, or deliberately markup their bids to take advantage of the RTM. A lower than 100% pass-through, however, suggests that producers tend to under-estimate their emissions costs, causing an unnecessary financial risk exposure. Hence, deviations from a 100% pass-through distort the price signal of carbon trading, thereby affecting incentives of long-run investment in the power market.

Fig. 1 shows the state's two major wholesale electricity trading hubs: (1) North of Path 15 (NP15) in northern California, whose major local distribution company (LDC) is Pacific Gas and Electric (PG and E); and (2) South of Path 15 (SP15) in southern California, whose largest LDC is Southern California Edison (SCE).[13] Along with the Mid-Columbia hub in the Pacific Northwest and the Palo Verde hub in the Desert Southwest, the NP15 and SP15 hubs are major delivery points in the Western Interconnection, a vast electricity grid encompassing the western portion of North America. Our primary research goal is to determine the impact of carbon trading on the NP15 and SP15 RTM prices.

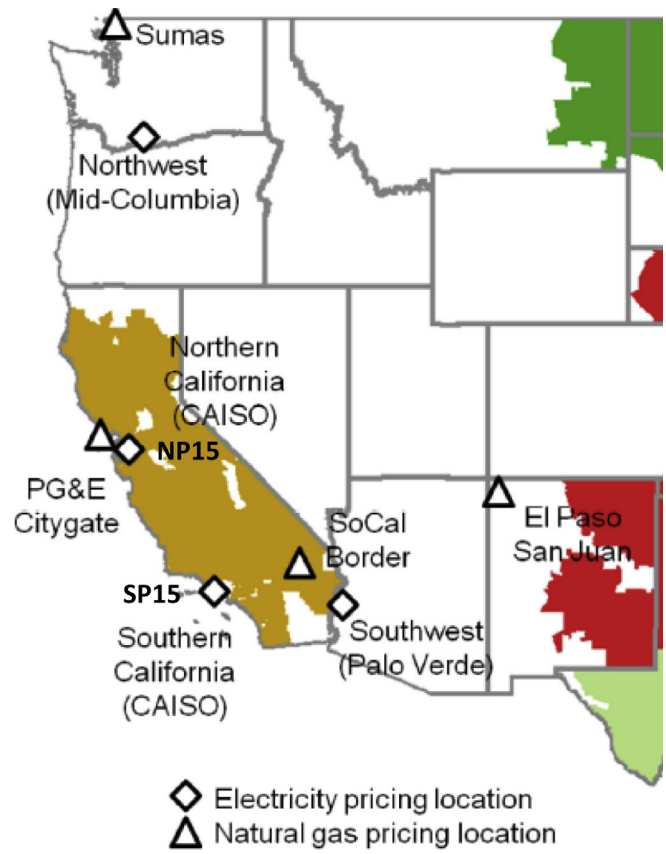



**Fig. 1.** Major pricing locations in the Western Interconnection (Source: https://www.eia.gov/electricity/monthly/update/wholesale_markets.cfm#tabs_wh_price-3).

### 2.2. Competitive bidding and the RTM price's $CO_2$ cost pass-through

To establish the theoretical underpinning of our empirical results, consider a natural-gas-fired generation unit's competitive supply bid into the CAISO's RTM. In addition to the unit's hours of availability, dispatchability, delivery rate, and points of injection and withdrawal, the bid specifies the 5-min MW quantity at a price that the unit's operator is willing to accept.

After receiving the supply bids from all generation participants in the RTM, the CAISO performs a security-constrained, least-cost dispatch of the online units under its control, so as to maintain real-time load-resource balance and determine the 5-mintue market-clearing price at each electrical node. Absent transmission congestion, these nodal RTM prices tends to converge, reflecting the least-cost condition of equal line-loss-adjusted marginal costs across electrical nodes. As the volume of 5-min price data are huge and the intra-hour prices tend to be similar, our empirical analysis uses hourly price data, with a given hour's RTM price ($/MWh) being the equally-weighted average of the 12 intra-hour RTM prices in that hour.

All dispatched generation units receive market-clearing prices not less than their bid prices. In the absence of market power, each generator has the incentive to truthfully submit a bid price equal to the sum of its short-run marginal costs for fuel, variable O&M, and $CO_2$ emissions [21]. Under C&T, a natural-gas-fired generation unit's marginal cost for $CO_2$ emissions is given by[14]

[11] In November 2014, the CAISO launched the western energy imbalance market (EIM), a real-time bulk power trading market in the Western U.S.A. (https://www.westerneim.com/Pages/About/default.aspx). This EIM is evolving, with planned entries by electric utilities likely to cover 65% Western Interconnection load by 2020, spanning 7 states and one Canadian province. The EIM essentially extends the CAISO RTM to balancing authority areas (BAAs) beyond CAISO's boundaries, creating pricing nodes for a much broader range of locations. Our paper does not consider the EIM prices nodes outside of CAISO for the following reasons. Including the EIM prices in our regression analysis would greatly reduce our 65-month sample period by 36 months. Also, all currently participating EIM zones (excluding CAISO) are located outside of the state of California, and therefore their generation is not subject to the California C&T regulations.

[12] Negative prices occur when the grid's demands cannot fully absorb the output from non-dispatchable generation units like nuclear, wind, and solar. The CAISO uses negative prices to induce generators to curtail their output for maintaining California's real-time load-resource balance.

[13] "Path 15 connects the transmission grids between northern and southern California and plays an important role in maintaining regional electric system reliability and market efficiency" (http://www.datcllc.com/projects/path-15/).

[14] The U.S. EIA reports that the $CO_2$ content of burning natural gas is 117 pounds/MMBtu = 53 kg/MMBtu (https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11).

$$MC = CO_2\text{price}(\$/\text{metric ton}) \times CO_2\text{emissions from burning natural gas}(= 0.053\text{metric ton/MMBtu})^{14} \times \text{Generator's } HR(\text{MMBtu/MWh}). \quad (1)$$

If the RTM price's $CO_2$ premium when a natural gas-fired unit is at margin equals $MC$ defined in (1), the RTM's $CO_2$ cost pass-through is said to be 100%. When this premium is above (below) $MC$, we infer that the pass-through is more (less) than 100%. For a competitive electricity market with price-insensitive demands, the extent of $CO_2$ cost pass-through is expected to be close to 100% [3].

### 2.3. Real-time price regressions

Regression analysis is used to quantify the impact of the $CO_2$ price on the RTM electricity price. The left-hand-side (LHS) variable of each TOD-specific price regression is $P_{jkt}$, the average price (\$/MWh) of RTM $j$ (= 1 for NP15 and 2 for SP15) in TOD period $k$ (= 1 for 00:00–06:00, 2 for 06:00–10:00, 3 for 10:00–14:00, 4 for 14:00–18:00, 5 for 18:00–22:00, 6 for 22:00–24:00) on day $t$ (= 01/01/2011–05/31/2016).[15] Guided by a clustering analysis of hourly RTM price data, these TOD periods are defined to match the time-of-use pricing periods used by PG&E and SCE, as well as those used in bilateral trading in the Western Interconnection. Omitted here for brevity, the details for deriving these TOD periods are available in Ref. [17].

Using the NP15 and SP15 average RTM price data for six TOD periods, we estimate a total of 12 price regressions. Each price regression's specification is as follows:

$$P_{jkt} = \alpha_{jkt} + \beta_{jk}C_t + \gamma_{jk}G_t + \theta_{1jk}X_{1kt} + \ldots + \theta_{10k}X_{10t} + \varepsilon_{jkt}. \quad (2)$$

As equation (2) is a linear regression, each coefficient measures the marginal price effect of a right-hand-side (RHS) variable. Admittedly simple and therefore easy to understand, it is chosen herein due to its empirical usefulness in our prior studies of electricity market price behavior in the Pacific Northwest, California and Texas [16–20]. As reported below, it yields sharp findings *sans* a complicated formulation, an important consideration in the public debate on an economy's decarbonization policy.[16] It is unrestrictive, readily allowing the use of different RHS variables to explain the TOD price movements observed in other jurisdictions. We decide not to use the log-linear or double-log specification that causes undefined values for the regressand because of the presence of negative and zero RTM prices in our sample.

In equation (2), $\alpha_{jkt}$ is assumed to be a linear function of a constant, six binary indicators for the RTM price's day of week (= Monday, …, Saturday), and 11 binary indicators for the RTM price's month of year (= January, …, November). Inclusion of those fixed-effect specifications serves to capture the residual price variations not explained by the other RHS variables, which are the fundamental drivers of electricity market prices identified by the price regression analyses reported in Refs. [16–20].

The variable $C_t$ is the daily $CO_2$ price, whose expected marginal effect on $P_{jkt}$ is $\beta_{jk} > 0$, reflecting how the C&T program tends to raise a natural gas generator's bid price. Based on Eq. [1], $\beta_{jk}$ for a competitive RTM with price-insensitive demands should approximately equal the product of (a) 0.053 metric ton of CO2 emissions from burning one MMBtu of natural gas (see equation (1)); and (b) RTM $j$'s marginal $HR$ in period $k$. Hence, we can use the $\beta_{jk}$ estimates to gauge the extent of $CO_2$ cost pass-through.

The variable $G_t$ is the daily natural gas price (\$/MMBtu) at the Henry Hub, the spot market for the U.S. natural gas futures.[17] Highly correlated ($r > 0.9$) with the California natural gas price at the PG&E Citygate or SoCal Border hub in Fig. 1, it is used here to circumvent the potential bias caused by the bidirectional causal relationship between California's wholesale electricity and natural gas prices [22].

The marginal effect of $G_t$ on $P_{jkt}$ is $\gamma_{jk}$, the market-based marginal heat rate for RTM $j$ in TOD period $k$ [18]. For most daytime hours, the $\gamma_{jk}$ estimate is likely between 7 MMBtu/MWh and 11MMBtu/MWh, the range of the marginal engineering-based heat rates of natural-gas-fired generation in California.[18] For the nighttime hours or midday hours with high solar output, however, the $\gamma_{jk}$ estimate can be less than 7 MMBtu/MWh because these hours' marginal unit may sometimes be hydro, nuclear, or renewable generation.

The next two variables are $X_{1kt}$ and $X_{2kt}$, PG&E's and SCE's average hourly demands (MWh) in TOD period $k$ of day $t$, respectively. Expected to be positive, their corresponding marginal price effects are $\theta_{1jk}$ and $\theta_{2jk}$.

The variables $X_{3kt}$ and $X_{4kt}$ are California's average wind and solar generation (MWh) in TOD period $j$ on day $t$. Their expected marginal price effects are $\theta_{3jk} < 0$ and $\theta_{4jk} < 0$, mirroring renewable energy's merit-order effect of reducing RTM prices [18].

During the sample period, California's nuclear energy came from: (1) the Diablo Canyon plant in Northern California, (2) the San Onofre plant in Southern California, which was shut down since 01/31/2012, and (3) the Palo-Verde plant in Arizona. We include $X_{5t}$, $X_{6t}$ and $X_{7t}$, these plants' capacities (MW) available on day $t$, as the RHS variables in the RTM price regressions. Because nuclear generation is baseload that displaces the state's natural-gas-fired generation, we expect the marginal price effects of $X_{5t}$, $X_{6t}$ and $X_{7t}$ measured by $\theta_{5jk}$, $\theta_{6jk}$ and $\theta_{7jk}$ to be all negative.

Our sample period contains the prolonged drought that hampered the state's hydro generation in Northern California.[19] To account for the hydro conditions' marginal price effects, we use $X_{8kt}$ and $X_{9kt}$ to denote the daily average discharge (1000 $ft^3$/sec) in period $k$ on day $t$ of Sacramento River and Klamath River, the two watersheds with main hydro facilities. We also use $X_{10t}$ to denote the state's daily hydro index (1 = driest, …, 7 = wettest) as our last RHS variable in order to capture the impacts by other hydro facilities with a smaller size. The marginal price effects of $X_{8kt}$, $X_{9kt}$ and $X_{10t}$ are $\theta_{8jk}$, $\theta_{9jk}$ and $\theta_{10jk}$ are all expected to be negative.

The random error of the RTM price regression is $\varepsilon_{jkt}$, assumed to be contemporaneously correlated. Hence, we use the method of iterative seemingly unrelated regressions (ITSUR) in PROC MODEL of SAS/ETS [23] to jointly estimate the system of 12 RTM price regressions. To gauge the coefficient estimates' precision and statistical significance, we use robust standard errors that are autocorrelation- and heteroscedasticity-consistent [24], thereby circumventing the empirical challenge of suitably identifying the random error's stochastic specification.

[15] While $P_{jkt}$ is a daily TOD-specific value, it is an equally-weighted average based on the 5-min RTM prices. The averaging is done for the following reasons. First, the 5-min prices exhibit little intra-hour variations. Second, estimating 24 hourly RTM price regressions would generate voluminous regression results and would not materially aid our understanding of the RTM's $CO_2$ cost pass-through.

[16] While engineering simulation can demonstrate the price effect of carbon trading, its results are hard to verify by stakeholders who lack deep knowledge and experience in power engineering and economics.

[17] https://www.cmegroup.com/confluence/display/EPICSANDBOX/Natural+Gas.

[18] The engineering-based heat rate data come from the California Energy Commission available at http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF.

[19] https://ca.water.usgs.gov/data/drought/.

### 2.4. Data description

Table 1 presents the descriptive statistics of the RTM prices and their fundamental drivers, showing that the data series are volatile. Table 2 reports the price correlation coefficients, indicating that a TOD period's RTM price on day $t$ at a given hub (e.g., NP15) is positively correlated with the other TOD period's on the same day at the same hub (i.e., NP15). Further, the NP15 and SP15 RTM prices on day $t$ for a given TOD period are modestly correlated, reflecting moderate real-time transmission congestion between the NP15 and

**Table 1**
Descriptive statics for the real-time market prices and their fundamental drivers for the sample period of 01/01/2011–05/31/2016.

| Variable | Time of day period | Mean | Standard deviation | Minimum | Maximum |
|---|---|---|---|---|---|
| NP15 real-time price ($/MWh) | 00:00–06:00 | 25.38 | 13.48 | −57.75 | 123.42 |
| | 06:00–10:00 | 32.06 | 23.47 | −56.78 | 315.45 |
| | 10:00–14:00 | 33.90 | 24.95 | −36.09 | 422.26 |
| | 14:00–18:00 | 39.57 | 40.70 | −38.45 | 771.83 |
| | 18:00–22:00 | 42.62 | 27.02 | −8.87 | 256.94 |
| | 22:00–24:00 | 32.27 | 18.21 | −24.58 | 311.35 |
| SP15 real-time price ($/MWh) | 00:00–06:00 | 26.28 | 19.11 | −82.50 | 364.26 |
| | 06:00–10:00 | 31.31 | 27.52 | −105.48 | 357.40 |
| | 10:00–14:00 | 33.23 | 29.36 | −141.36 | 390.88 |
| | 14:00–18:00 | 41.71 | 44.31 | −181.55 | 554.28 |
| | 18:00–22:00 | 44.55 | 29.02 | −21.65 | 434.39 |
| | 22:00–24:00 | 33.20 | 21.36 | −69.08 | 316.99 |
| California's $CO_2$ price ($/metric ton) | 00:00–24:00 | 8.07 | 6.22 | 0.00 | 16.45 |
| Henry Hub natural gas price ($/MMBtu) | 00:00–24:00 | 3.38 | 0.91 | 1.49 | 8.15 |
| PG&E's daily average load (MWh) | 00:00–06:00 | 10203.04 | 805.30 | 8475.67 | 13401.67 |
| | 06:00–10:00 | 11798.02 | 966.61 | 9216.25 | 15432.25 |
| | 10:00–14:00 | 12595.53 | 1500.68 | 9660.25 | 19162.50 |
| | 14:00–18:00 | 13189.69 | 2129.89 | 9593.75 | 20725.25 |
| | 18:00–22:00 | 13595.79 | 1628.37 | 10469.25 | 19635.75 |
| | 22:00–24:00 | 11679.78 | 1216.69 | 9602.00 | 16520.50 |
| SCE's average load (MWh) | 00:00–06:00 | 9823.28 | 894.41 | 7909.50 | 13370.33 |
| | 06:00–10:00 | 11316.49 | 1250.83 | 8094.50 | 15647.00 |
| | 10:00–14:00 | 12803.63 | 2167.54 | 8420.25 | 20806.50 |
| | 14:00–18:00 | 13556.75 | 2838.48 | 9223.25 | 22898.50 |
| | 18:00–22:00 | 13516.14 | 1966.66 | 10214.00 | 21447.50 |
| | 22:00–24:00 | 11516.27 | 1420.30 | 9196.00 | 16743.50 |
| California's average wind energy (MWh) | 00:00–06:00 | 1398.78 | 996.35 | 0.00 | 4259.17 |
| | 06:00–10:00 | 1032.68 | 833.52 | 0.00 | 4181.75 |
| | 10:00–14:00 | 921.09 | 854.35 | 0.00 | 4020.50 |
| | 14:00–18:00 | 1245.09 | 1003.16 | 0.00 | 4473.00 |
| | 18:00–22:00 | 1527.88 | 1086.17 | 0.00 | 4548.25 |
| | 22:00–24:00 | 1561.92 | 1102.38 | 0.00 | 4393.00 |
| California's average solar energy (MWh) | 00:00–06:00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | 06:00–10:00 | 1016.47 | 928.95 | 0.00 | 4123.75 |
| | 10:00–14:00 | 2364.18 | 1925.12 | 0.00 | 7266.25 |
| | 14:00–18:00 | 1556.53 | 1493.18 | 0.00 | 6187.75 |
| | 18:00–22:00 | 108.29 | 148.02 | 0.00 | 755.75 |
| | 22:00–24:00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Diablo Canyon's available capacity (MW) | 00:00–24:00 | 1956.80 | 416.28 | 0.00 | 2160.00 |
| San Onofre's available capacity (MW) | 00:00–24:00 | 383.20 | 791.27 | 0.00 | 2150.00 |
| Palo Verde's available capacity (MW) | 00:00–24:00 | 3674.51 | 587.40 | 1335.00 | 4005.00 |
| Sacramento River's average discharge (000ft$^3$/sec) | 00:00–06:00 | 16.91 | 13.96 | 2.04 | 85.91 |
| | 06:00–10:00 | 16.92 | 13.89 | 1.02 | 86.08 |
| | 10:00–14:00 | 17.93 | 13.61 | 0.67 | 85.99 |
| | 14:00–18:00 | 17.28 | 13.87 | 1.06 | 85.98 |
| | 18:00–22:00 | 16.90 | 13.98 | 0.98 | 86.72 |
| | 22:00–24:00 | 17.33 | 13.91 | 0.21 | 85.46 |
| Klamath River's average discharge (000ft$^3$/sec) | 00:00–06:00 | 14.15 | 17.18 | 2.01 | 170.88 |
| | 06:00–10:00 | 14.14 | 17.21 | 2.00 | 196.06 |
| | 10:00–14:00 | 14.17 | 17.20 | 2.01 | 185.13 |
| | 14:00–18:00 | 14.18 | 17.16 | 2.01 | 170.25 |
| | 18:00–22:00 | 14.17 | 17.13 | 2.01 | 165.88 |
| | 22:00–24:00 | 14.16 | 17.15 | 2.02 | 157.25 |
| California's hydro index (1 = driest, …, 7 = wettest) | 00:00–24:00 | 3.60 | 0.72 | 1.00 | 5.65 |

Notes: (1) The RTM prices can be negative during low-load hours (e.g., 00:00–06:00) when the grid's demands cannot fully absorb the output from non-dispatchable generation units like nuclear and wind. The CAISO uses these negative prices to induce dispatchable generators to curtail their output for maintaining California's real-time load-resource balance. These negative RTM prices discourage us from using a double-log regression specification because their natural log values are undefined. Finally, solar energy for the 00:00–06:00 and 22:00–24:00 periods is zero.
(2) Our data sources are as follows. The CAISO provides the data for the RTM price, $CO_2$ price, system loads, and solar and wind output (http://oasis.caiso.com/mrioasis/logon.do;jsessionid=5D9A2B355EF0330B4D1D9631157487E5). The natural gas price data come from SNL (www.snl.com). The nuclear capacity data are from the U.S. Nuclear Regulatory Commission (http://www.nrc.gov/reading-rm/doc-collections/event-status/reactor-status/index.html). Finally, the U.S. Geological Survey (USGS) supplies the California hydro index (http://waterwatch.usgs.gov/index.php?r=ca&id=pa01d&sid=w__table2) and river discharge data http://waterdata.usgs.gov/ca/nwis/rt). The Klamath River's station is USGS 11530500 and the Sacramento River's station USGS 11447650.
(3) The California $CO_2$ price is zero prior to the C&T program's 01/01/2013 commencement. Further, the California $CO_2$ price data since the C&T program's first trading date of 01/01/2013 have been stable, with an average of about $13/metric ton and a standard deviation of about $2/metric ton. The San Onofre available capacity is zero after the plant's 01/31/2012 shutdown.

**Table 2**
Real-time price correlations for the sample period of 01/01/2011–05/31/2016.

| Time of day period | NP15 price | | | | | | SP15 price | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 00:00–06:00 | 06:00–10:00 | 10:00–14:00 | 14:00–18:00 | 18:00–22:00 | 22:00–24:00 | 00:00–06:00 | 06:00–10:00 | 10:00–14:00 | 14:00–18:00 | 18:00–22:00 | 22:00–24:00 |
| Panel A: NP15 price | | | | | | | | | | | | |
| 00:00–06:00 | 1.0000 | 0.3547 | 0.2301 | 0.1621 | 0.2476 | 0.3123 | 0.6549 | 0.2570 | 0.1353 | 0.1367 | 0.2478 | 0.2618 |
| 06:00–10:00 | 0.3547 | 1.0000 | 0.3847 | 0.1557 | 0.1797 | 0.1885 | 0.2145 | 0.7448 | 0.2025 | 0.0801 | 0.1932 | 0.1870 |
| 10:00–14:00 | 0.2301 | 0.3847 | 1.0000 | 0.3155 | 0.1876 | 0.1748 | 0.1492 | 0.2385 | 0.5610 | 0.2337 | 0.1507 | 0.1818 |
| 14:00–18:00 | 0.1621 | 0.1557 | 0.3155 | 1.0000 | 0.3127 | 0.1598 | 0.1005 | 0.1255 | 0.2039 | 0.6320 | 0.1798 | 0.1053 |
| 18:00–22:00 | 0.2476 | 0.1797 | 0.1876 | 0.3127 | 1.0000 | 0.3599 | 0.1746 | 0.1872 | 0.1098 | 0.2140 | 0.7541 | 0.2838 |
| 22:00–24:00 | 0.3123 | 0.1885 | 0.1748 | 0.1598 | 0.3599 | 1.0000 | 0.2598 | 0.2402 | 0.0893 | 0.1215 | 0.3391 | 0.7536 |
| Panel B: SP15 price | | | | | | | | | | | | |
| 00:00–06:00 | 0.6549 | 0.2145 | 0.1492 | 0.1005 | 0.1746 | 0.2598 | 1.0000 | 0.3273 | 0.1747 | 0.1262 | 0.1879 | 0.2638 |
| 06:00–10:00 | 0.2570 | 0.7448 | 0.2385 | 0.1255 | 0.1872 | 0.2402 | 0.3273 | 1.0000 | 0.3048 | 0.1356 | 0.1951 | 0.2144 |
| 10:00–14:00 | 0.1353 | 0.2025 | 0.5610 | 0.2039 | 0.1098 | 0.0893 | 0.1747 | 0.3048 | 1.0000 | 0.3875 | 0.1194 | 0.1191 |
| 14:00–18:00 | 0.1367 | 0.0801 | 0.2337 | 0.6320 | 0.2140 | 0.1215 | 0.1262 | 0.1356 | 0.3875 | 1.0000 | 0.2534 | 0.1071 |
| 18:00–22:00 | 0.2478 | 0.1932 | 0.1507 | 0.1798 | 0.7541 | 0.3391 | 0.1879 | 0.1951 | 0.1194 | 0.2534 | 1.0000 | 0.3213 |
| 22:00–24:00 | 0.2618 | 0.1870 | 0.1818 | 0.1053 | 0.2838 | 0.7536 | 0.2638 | 0.2144 | 0.1191 | 0.1071 | 0.3213 | 1.0000 |

SP15 electricity zones.

Table 3 reports the correlations between a TOD period's RTM price and its fundamental drivers. Though not used as the basis for our key findings reported in Section 3 below, these correlations presage whether our regression-based approach is likely fruitful for quantifying California's RTM price behavior. While largely consistent with the fundamental drivers' expected price effects, they do not delineate the marginal effects of the daily $CO_2$ price on the RTM prices or those of the remaining drivers, an empirical issue to be settled by the regression results reported in the next section.

## 3. Results

### 3.1. Empirical evidence

Table 4 reports the ITSUR results for the 12 RTM price regressions, whose relatively low adjusted $R^2$ values of 0.14–0.40 echo our parsimonious regression setup to explain the highly volatile RTM price data. We use the Phillips-Perron test [25] to reject the null hypothesis of the regressions' residuals following a random walk, thus obviating concerns of spurious regressions [26]. Finally, while 26 of the 140 coefficient estimates for the fundamental drivers have the wrong sign, only two of those are statistically significant at the 5% level. Thus, Table 4 portrays an empirically plausible data generating process underlying the volatile RTM prices.

Using the estimates of the $CO_2$ price's coefficient $\beta_{jk}$ and their standard errors, we construct the 95% confidence intervals reported in Table 5. Based on these intervals, eight of the 12 regressions have $\beta_{jk}$ estimates ***not*** statistically different from a CCGT's *MC*-benchmark of \$0.371/MWh (= \$1/metric ton increase in the $CO_2$ price × 0.053 metric ton/MMBtu × CCGT's *HR* of 7 MMBtu per

**Table 3**
Real-time price's correlation with their fundamental drivers for the sample period of 01/01/2011–05/31/2016.

| Fundamental driver | Time of day period | | | | | |
|---|---|---|---|---|---|---|
| | 00:00–06:00 | 06:00–10:00 | 10:00–14:00 | 14:00–18:00 | 18:00–22:00 | 22:00–24:00 |
| Panel A: NP15 price | | | | | | |
| California's $CO_2$ price (\$/metric ton) | 0.3764 | 0.1255 | 0.0792 | 0.0385 | 0.1283 | 0.1396 |
| Henry Hub price (\$/MMBtu) | 0.3197 | 0.2452 | 0.2254 | 0.1549 | 0.2536 | 0.3494 |
| PG&E's average load (MWh) | 0.0020 | 0.1093 | 0.1478 | 0.3214 | 0.1574 | 0.0088 |
| SCE's average load (MWh) | 0.0627 | 0.1002 | 0.1300 | 0.2764 | 0.1400 | 0.0040 |
| California's average wind energy (MWh) | −0.1350 | −0.1482 | −0.1097 | −0.1381 | −0.0748 | −0.1331 |
| California's average solar energy (MWh) | 0.0000 | −0.0889 | −0.0997 | −0.0160 | 0.0093 | 0.0000 |
| Diablo Canyon's available capacity (MW) | 0.0070 | *0.0164* | −0.0003 | −0.0200 | −0.0277 | −0.0111 |
| San Onofre's available capacity (MW) | −0.2751 | −0.1181 | −0.0404 | −0.0600 | −0.0856 | −0.0356 |
| Palo Verde's available capacity (MW) | −0.0151 | −0.0607 | −0.0275 | 0.0418 | 0.0185 | −0.0287 |
| Sacramento River's average discharge (000ft$^3$/sec) | −0.3077 | −0.0746 | −0.1029 | −0.1307 | −0.1065 | −0.1021 |
| Klamath River's average discharge (000ft$^3$/sec) | −0.2720 | −0.0457 | −0.1295 | −0.1676 | −0.1295 | −0.1075 |
| California's hydro index (1 = driest, …, 7 = wettest) | −0.3725 | −0.1393 | −0.0866 | −0.0867 | −0.1409 | −0.1555 |
| Panel B: SP15 price | | | | | | |
| California's $CO_2$ price (\$/metric ton) | 0.2491 | 0.0773 | −0.0426 | 0.0043 | 0.1658 | 0.1022 |
| Henry Hub price (\$/MMBtu) | 0.2074 | 0.2120 | 0.2146 | 0.1565 | 0.2511 | 0.2911 |
| PG&E's average load (MWh) | *−0.0294* | 0.1169 | 0.2175 | 0.3025 | 0.0506 | −0.0057 |
| SCE's average load (MWh) | 0.0429 | 0.1150 | 0.2620 | 0.3632 | 0.0890 | 0.0101 |
| California's average wind energy (MWh) | −0.1351 | −0.2073 | −0.2269 | −0.1723 | −0.0877 | −0.1615 |
| California's average solar energy (MWh) | 0.0000 | −0.1383 | −0.2165 | −0.0644 | −0.0110 | 0.0000 |
| Diablo Canyon's available capacity (MW) | −0.0417 | −0.0368 | −0.0397 | −0.0278 | −0.0409 | −0.0052 |
| San Onofre's available capacity (MW) | −0.2234 | −0.0937 | *0.0194* | −0.0413 | −0.0962 | −0.0498 |
| Palo Verde's available capacity (MW) | −0.0410 | −0.0192 | *0.0205* | *0.0581* | *0.0010* | −0.0357 |
| Sacramento River's average discharge (000ft$^3$/sec) | −0.1982 | −0.0312 | −0.0297 | −0.1125 | −0.1061 | −0.0510 |
| Klamath River's average discharge (000ft$^3$/sec) | −0.1534 | −0.0090 | −0.1219 | −0.1718 | −0.1039 | −0.0897 |
| California's hydro index (1 = driest, …, 7 = wettest) | −0.2385 | −0.0776 | 0.0257 | −0.0252 | −0.1413 | −0.0988 |

Note: Solar energy for the 00:00–06:00 and 22:00–24:00 periods is zero. Correlation coefficients in *italic* are at odds with our expectations.

**Table 4**
ITSUR results for the CAISO's daily real-time market price ($/MWh) regressions for the sample period of 01/01/2011–05/31/2016 by time-of-day period; autocorrelation-heteroscedasticity-consistent standard errors in ( ); "*" = "significant at the 5% level".

| Variable | NP15 | | | | | | SP15 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 00:00 −06:00 | 06:00 −10:00 | 10:00 −14:00 | 14:00 −18:00 | 18:00 −22:00 | 22:00 −24:00 | 00:00 −06:00 | 06:00 −10:00 | 10:00 −14:00 | 14:00 −18:00 | 18:00 −22:00 | 22:00 −24:00 |
| Adjusted $R^2$ | 0.3952 | 0.2187 | 0.1241 | 0.1846 | 0.1500 | 0.1981 | 0.2032 | 0.1906 | 0.1970 | 0.2162 | 0.1409 | 0.1557 |
| California's $CO_2$ price ($/metric ton) | 0.5443* | 0.4116* | 1.0719* | 0.5613* | 0.3737* | 0.3032* | 0.4606* | 0.5401* | 1.1052* | 0.7777* | 0.7228* | 0.2760* |
| | (0.0495) | (0.1460) | (0.1901) | (0.2325) | (0.1330) | (0.0748) | (0.1219) | (0.1809) | (0.2214) | (0.2654) | (0.1330) | (0.1203) |
| Henry Hub price ($/MMBtu) | 5.6811* | 7.5397* | 4.3312* | 6.0246* | 9.0108* | 7.7186* | 5.8213* | 7.2641* | 3.7377* | 6.0356* | 9.7248* | 7.9175* |
| | (0.3649) | (0.8217) | (0.8627) | (1.1309) | (0.7178) | (0.5407) | (0.4597) | (0.9629) | (0.8491) | (1.0628) | (0.8311) | (0.5675) |
| PG&E's average load (MWh) | 0.0024* | 0.0076* | 0.0041* | 0.0097* | 0.0052* | 0.0039* | *−0.0014* | 0.0061* | *−0.0014* | *−0.0010* | *−0.0005* | 0.0021* |
| | (0.0008) | (0.0014) | (0.0009) | (0.0020) | (0.0013) | (0.0009) | (0.0013) | (0.0019) | (0.0011) | (0.0019) | (0.0009) | (0.0011) |
| SCE's average load (MWh) | 0.0006 | 0.0001 | 0.0008 | 0.0004 | 0.0004 | *−0.0005* | 0.0034* | 0.0018 | 0.0056* | 0.0095* | 0.0035* | 0.0014* |
| | (0.0006) | (0.0009) | (0.0006) | (0.0010) | (0.0009) | (0.0006) | (0.0009) | (0.0013) | (0.0009) | (0.0016) | (0.0008) | (0.0007) |
| California's average wind energy (MWh) | −0.0042* | −0.0038* | −0.0050* | −0.0085* | −0.0050* | −0.0042* | −0.0058* | −0.0075* | −0.0086* | −0.0095* | −0.0066* | −0.0054* |
| | (0.0003) | (0.0006) | (0.0007) | (0.0010) | (0.0007) | (0.0005) | (0.0005) | (0.0008) | (0.0008) | (0.0010) | (0.0008) | (0.0005) |
| California's average solar energy (MWh) | | −0.0032* | −0.0036* | −0.0033* | *0.0107* | | | −0.0046* | −0.0052* | −0.0042* | *0.0173** | |
| | | (0.0008) | (0.0005) | (0.0007) | (0.0058) | | | (0.0010) | (0.0005) | (0.0009) | (0.0060) | |
| Diablo Canyon's available capacity (MW) | −0.0002 | *0.0008* | −0.0001 | −0.0034 | −0.0023 | −0.0004 | −0.0017 | −0.0028 | −0.0029 | −0.0038 | −0.0015 | *0.0002* |
| | (0.0007) | (0.0011) | (0.0014) | (0.0028) | (0.0015) | (0.0012) | (0.0013) | (0.0018) | (0.0017) | (0.0029) | (0.0015) | (0.0012) |
| San Onofre's available capacity (MW) | −0.0031* | −0.0052* | −0.0017 | −0.0040* | −0.0037* | −0.0006 | −0.0055* | −0.0066* | −0.0036* | −0.0059* | −0.0043* | −0.0033* |
| | (0.0005) | (0.0010) | (0.0012) | (0.0016) | (0.0013) | (0.0008) | (0.0007) | (0.0009) | (0.0013) | (0.0018) | (0.0012) | (0.0011) |
| Palo Verde's available capacity (MW) | −0.0017* | −0.0039* | −0.0024 | −0.0011 | −0.0019 | −0.0001 | −0.0027* | −0.0038* | −0.0023 | *0.0004* | −0.0010 | −0.0005 |
| | (0.0006) | (0.0013) | (0.0019) | (0.0015) | (0.0011) | (0.0008) | (0.0008) | (0.0015) | (0.0017) | (0.0018) | (0.0013) | (0.0010) |
| Sacramento River's average discharge (000ft$^3$/sec) | −0.0957* | *0.0098* | −0.1464 | −0.1979* | −0.0224 | −0.0446 | −0.1100* | −0.0249 | −0.0673 | −0.2494* | −0.1439* | *0.0153* |
| | (0.0288) | (0.0675) | (0.0800) | (0.0881) | (0.0580) | (0.0481) | (0.0345) | (0.0740) | (0.1018) | (0.0828) | (0.0674) | (0.0642) |
| Klamath River's average discharge (000ft$^3$/sec) | −0.0155 | *0.0474* | *0.0211* | *0.0901** | *0.0457* | *0.0695* | *0.0030* | *0.1031* | *0.0628* | *0.0595* | *0.0339* | *0.0028* |
| | (0.0324) | (0.0557) | (0.0501) | (0.0435) | (0.0415) | (0.0369) | (0.0589) | (0.0696) | (0.0621) | (0.0466) | (0.0482) | (0.0365) |
| California's hydro index (1 = driest, …, 7 = wettest) | −2.0867* | −2.6379* | −0.9027 | −2.9180 | −1.8822 | −3.2678* | −0.3952 | −0.9924 | *0.6746* | *3.2474* | *1.2834* | −1.2139 |
| | (0.7496) | (1.3300) | (2.1876) | (1.8771) | (1.1170) | (0.7647) | (0.9922) | (1.3665) | (2.1366) | (2.1192) | (1.1689) | (0.9197) |

Note: For brevity, this table does not report the estimates for the intercepts and effects of day-of-week and month-of-year, which are mostly significant at the 5% level. 26 of the 140 coefficient estimates for the fundamental drivers in *italic* have the wrong sign. Of these 26 coefficient estimates, only two are statistically significant.

**Table 5**
95% confidence intervals (CI) of the coefficient estimates in Table 4 for the $CO_2$ price.

| Variable | NP15 | | | | | | SP15 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 00:00 −06:00 | 06:00 −10:00 | 10:00 −14:00 | 14:00 −18:00 | 18:00 −22:00 | 22:00 −24:00 | 00:00 −06:00 | 06:00 −10:00 | 10:00 −14:00 | 14:00 −18:00 | 18:00 −22:00 | 22:00 −24:00 |
| Estimate | 0.544 | 0.412 | 1.072 | 0.561 | 0.374 | 0.303 | 0.461 | 0.540 | 1.105 | 0.778 | 0.723 | 0.276 |
| Lower bound = Estimate − 1.965 × standard error | 0.447 | 0.125 | 0.698 | 0.104 | 0.112 | 0.156 | 0.221 | 0.185 | 0.670 | 0.256 | 0.461 | 0.040 |
| Upper bound = Estimate + 1.965 × standard error | 0.642 | 0.699 | 1.445 | 1.018 | 0.635 | 0.450 | 0.700 | 0.896 | 1.540 | 1.299 | 0.984 | 0.512 |

MWH). Further, nine regressions have $\beta_{jk}$ estimates ***not*** statistically different from a CT's *MC*-benchmark of $0.477/MWh at $HR = 9$ MMBtu/MWh and an ACT's *MC*-benchmark of $0.583/MWh at $HR = 11$ MMBtu/MWh. Taken together, the $\beta_{jk}$ estimates suggest that the RTM prices contain a $CO_2$ premium that approximately equals the marginal cost of $CO_2$ emissions attributable to the California's C&T program.

We construct the 95% confidence intervals of the market-based marginal heat rate estimates, which are given by the Henry Hub price's coefficient estimates. Table 6 shows that eight of these 12 intervals contain natural-gas-fired generation's engineering-based heat rates of 7 MMBtu/MWh to 11 MMBtu/MWh. Thus, Table 6 indicates that natural gas is California's marginal fuel for most hours of the day.

**Table 6**
95% confidence intervals (CI) of the coefficient estimates in Table 4 for the Henry Hub's natural gas price.

| Variable | NP15 | | | | | | SP15 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 00:00 −06:00 | 06:00 −10:00 | 10:00 −14:00 | 14:00 −18:00 | 18:00 −22:00 | 22:00 −24:00 | 00:00 −06:00 | 06:00 −10:00 | 10:00 −14:00 | 14:00 −18:00 | 18:00 −22:00 | 22:00 −24:00 |
| Estimate | 5.681 | 7.540 | 4.331 | 6.025 | 9.011 | 7.719 | 5.821 | 7.264 | 3.738 | 6.036 | 9.725 | 7.917 |
| Lower bound = Estimate − 1.965 × standard error | 4.964 | 5.925 | 2.636 | 3.802 | 7.600 | 6.656 | 4.918 | 5.372 | 2.069 | 3.947 | 8.092 | 6.802 |
| Upper bound = Estimate + 1.965 × standard error | 6.398 | 9.154 | 6.026 | 8.247 | 10.421 | 8.781 | 6.725 | 9.156 | 5.406 | 8.124 | 11.358 | 9.033 |

**Table 7**
*P*-values of the Wald statistic for testing the 100% pass-through of the marginal cost of $CO_2$ at natural-gas-fired generation's engineering heat rate of a CCGT, a CT, or an aging CT.

| Null hypothesis: 100% pass through of the marginal cost of $CO_2$ emissions at natural-gas-fired generation's engineering heat rate | NP15 | | | | | | SP15 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 00:00 −06:00 | 06:00 −10:00 | 10:00 −14:00 | 14:00 −18:00 | 18:00 −22:00 | 22:00 −24:00 | 00:00 −06:00 | 06:00 −10:00 | 10:00 −14:00 | 14:00 −18:00 | 18:00 −22:00 | 22:00 −24:00 |
| **H1**: $\beta_{jk}$ = \$0.371/MWh and $\gamma_{jk}$ = 7 MMBtu/MWh | *<.0001* | 0.5096 | *0.0006* | 0.5071 | *0.0193* | 0.2841 | *0.0133* | 0.4980 | *0.0002* | 0.2633 | *<.0001* | 0.2433 |
| **H2**: $\beta_{jk}$ = \$0.477/MWh and $\gamma_{jk}$ = 9 MMBtu/MWh | *<.0001* | *0.0191* | *<.0001* | *0.0304* | 0.7389 | *0.0034* | *<.0001* | 0.1796 | *<.0001* | *0.0181* | 0.1105 | *0.0173* |
| **H3**: $\beta_{jk}$ = \$0.583/MWh and $\gamma_{jk}$ = 11 MMBtu/MWh | *<.0001* | *<.0001* | *<.0001* | *<.0001* | *0.0045* | *<.0001* | *<.0001* | *<.0001* | *<.0001* | *<.0001* | 0.1958 | *<.0001* |

Note: A *p*-value in *italic* indicates that the null hypothesis in question is rejected at the 5% level. If **H1** to **H3** are ***all*** rejected for a TOD period's RTM price regression, we infer that the 100% pass-through of the marginal $CO_2$ cost of natural-gas-fired generation is inconsistent with California's marginal generation fuel being natural gas for that TOD period.

As a final check that was not done in Ref. [17], we consider whether the estimates for the marginal $CO_2$ cost's pass-through in Table 5 are consistent with those for the market-based heat rates in Table 6. Hence, we use the Wald test to statistically test the following null hypotheses for each of the twelve RTM price regressions:

- H1: $\beta_{jk}$ = \$0.371/MWh and $\gamma_{jk}$ = 7 MMBtu/MWh, implying that the pass-through is 100% and the marginal generation unit's market-based heat rate equals a CCGT's engineering heat rate.
- H2: $\beta_{jk}$ = \$0.477/MWh and $\gamma_{jk}$ = 9 MMBtu/MWh, implying that the pass-through is 100% and the marginal generation unit's market-based heat rate equals a CT's engineering heat rate.
- H3: $\beta_{jk}$ = \$0.583/MWh and $\gamma_{jk}$ = 11 MMBtu/MWh, implying that the pass-through is 100% and the marginal generation unit's market-based heat rate equals an aging CT's engineering heat rate.

If H1 to H3 are ***all*** rejected for a TOD-specific RTM price regression, we infer that the 100% pass-through of the marginal $CO_2$ cost of natural-gas-fired generation is inconsistent with the view that California's marginal generation fuel is natural gas for that TOD period, an important assumption upon which we base our analyses.

Table 7 reports the *p*-values of the Wald statistic, showing that **H1** − **H3** are rejected for only four of the twelve cases. These test results reinforce our inferences based on Tables 5 and 6: (1) the RTM prices generally contain a carbon premium equal to natural-gas fired generation's marginal cost of $CO_2$ emissions; and (2) California's marginal generation fuel is mostly natural gas.

The remaining coefficient estimates in Table 4 suggest the following findings. First, an increase in the system loads likely raises the RTM prices, and its estimated price effects vary by TOD period and location. Second, an increase in the renewable energy tends to lower the RTM prices by amounts that change in commensurate with TOD period and location. Third, an increase in nuclear capacities available tends to reduce the RTM prices, with estimated price effects that also vary by TOD period and location. Finally, the coefficient estimates for the hydro conditions suggest that a prolonged drought tends to raise market prices.

## 4. Conclusion

This paper presents a comprehensive regression analysis of the daily market data for a 65-month period of 01/01/2011–05/31/2016, documenting that the CAISO's NP15 and SP15 RTM prices by TOD period contain natural-gas-fired generation's marginal costs of $CO_2$ emissions. Further, these prices are found to decline with renewable generation and nuclear capacities available but increase with the natural gas price and RTM demands.

These estimated price effects are good and bad news. The good news is that the California C&T program is deemed effective in internalizing the in-state $CO_2$ emissions. The bad news is that it is unlikely to improve natural-gas-fired generation's investment incentive because California's marginal fuel is mainly natural gas rather than coal, whose higher $CO_2$ emissions cost could have further increased the state's market price. At the engineering-based *HR* of ~11 MMBtu/MWh, a CT investor is unlikely to see an increase in the unit's per-MWh profit, chiefly because the $CO_2$-related price increase is offset by the $CO_2$-related cost increase. While a CCGT investor may benefit from carbon trading due to the small increase in the unit's per MWh profit,[20] this profit increase cannot overcome the problem of insufficient investment incentive, which will likely worsen over time due to California's large-scale renewable energy deployment [27].[21] Hence, the policy implication of our findings' is that California should continue its use of long-term contacts to procure dispatchable generation capacity to meet the Western Interconnection's criteria for system reliability and the state's resource adequacy targets.

## Acknowledgement

We thank the subject editor and two reviewers for their very helpful comments that have greatly improved our analysis and exposition. This paper is partially funded by a consultancy contract between Bonneville Power Administration and Energy and Environmental Economics Inc. (www.ethree.com) and the first author's research grant R3698 from Education University of Hong Kong. Without implication, all errors are ours.

## References

[1] Sioshansi FP. Evolution of global electricity markets: new paradigms, new challenges, new approaches. San Diego, California: Elsevier; 2013.
[2] Weron R. Modeling and forecasting electricity loads and prices. New York, New York: John Wiley; 2006.
[3] Gal N, Milstein I, Tishler A, Woo CK. Fuel cost uncertainty, capacity investment and price in a competitive electricity market. Energy Econ 2017;61:233–40.
[4] Eydeland A, Wolyniec K. Energy and power risk management: new development in modeling, pricing and hedging. Hoboken, New Jersey: John Wiley & Sons; 2003.
[5] Deng SJ, Oren SS. Electricity derivatives and risk management. Energy 2006;31:940–53.
[6] Woo CK, Sreedharan P, Hargreaves J, Kahrl F, Wang J, Horowitz I. A review of electricity product differentiation. Appl Energy 2014;114:262–72.

[20] The profit increase is the product of the heat rate difference, the average $CO_2$ price, and the $CO_2$ emissions from burning natural gas. It is equal to \$0.212/MWh (= 2 MMBtu/MWh × \$13/metric ton × 0.053 metric ton/MMBtu).

[21] The estimated price increases due to California's load growth and nuclear plant retirement can only partially offset the merit-order effects of renewable energy on market prices [18]. This is because the state's projected scale of renewable energy development far exceeds the combined size of load growth and retired nuclear capacity.

[7] Thompson M. Optimal economic dispatch and risk management of thermal power plants in deregulated markets. Oper Res 2013;61:791–809.
[8] Sreedharan P, Miller D, Price S, Woo CK. Avoided cost estimation and cost-effectiveness of permanent load shifting in California. Appl Energy 2012;96:115–21.
[9] Palmer KL, Paul A. A primer on comprehensive policy options for states to comply with the Clean Power Plan. 2015. http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2622697. [Accessed 6 September 2016].
[10] Paul A, Palmer KL, Woerman M. Incentives, margins, and cost effectiveness in comprehensive climate policy for the power sector. Climate Change Economics 2015;6(4). http://www.worldscientific.com/doi/abs/10.1142/S2010007815500165. [Accessed 6 September 2016].
[11] Fabra N, Reguant R. Pass-through of emissions costs in electricity markets. Am Econ Rev 2014;104(9):2872–99.
[12] Hintermann B. Pass-through of $CO_2$ emission costs to hourly electricity prices in Germany. J Associa Environ Resource Econo 2016;3(4):857–91.
[13] Lo Prete CL, Norman CS. Rockets and feathers in power futures markets? Evidence from the second phase of the EU ETS. Energy Econ 2013;36:312–21.
[14] Zachmann G, Von Hirschhausen C. First evidence of asymmetric cost pass-through of EU emissions allowances: examining wholesale electricity prices in Germany. Econ Lett 2008;99(3):465–9.
[15] Fezzi C, Bunn DW. Structural interactions of European carbon trading and energy prices. Journal of Energy Markets 2009;2(4):53–69.
[16] Woo CK, Olson A, Chen Y, Moore J, Schlag N, Ong A, Ho T. Does California's $CO_2$ price affect wholesale electricity prices in the Western U.S.A. Energy Pol 2017;110:9–19.
[17] Woo CK, Chen Y, Olson A, Moore J, Schlag N, Ong A, Ho T. Electricity price behavior and carbon trading: new evidence from California. Appl Energy 2017;204:531–43.
[18] Woo CK, Moore J, Schneiderman B, Ho T, Olson A, Alagappan L, Chawla K, Toyama N, Zarnikau J. Merit-order effects of renewable energy and price divergence in California's day-ahead and real-time electricity markets. Energy Pol 2016;92:299–312.
[19] Woo CK, Zarnikau J, Kadish J, Horowitz I, Wang J, Olson A. The impact of wind generation on wholesale electricity prices in the hydro-rich Pacific Northwest. IEEE Trans Power Syst 2013;28(4):4245–53.
[20] Woo CK, Horowitz I, Moore J, Pacheco A. The impact of wind generation on the electricity spot-market price level and variance: the Texas experience. Energy Pol 2011;39:3939–44.
[21] Laffont JJ, Tirole JA. Theory of incentives in procurement and regulation. Cambridge, Massachusetts: MIT Press; 1993.
[22] Woo CK, Olson A, Horowitz I, Luk S. Bi-directional causality in California's electricity and natural-gas markets. Energy Pol 2006;34:2060–70.
[23] SAS/ETS 9.1 User's guide. Cary, North Carolina: SAS Institute; 2004.
[24] Wooldridge JM. Econometric analysis of cross section and panel data. Cambridge, Massachusetts: MIT Press; 2010. 2010.
[25] Phillips PCB, Perron P. Testing for a unit root in time series regression. Biometrika 1988;75:335–46.
[26] Davidson R, Mackinnon JG. Estimation and inference in econometrics. New York: Oxford University Press; 1993.
[27] Woo CK, Horowitz I, Zarnikau J, Moore J, Schneiderman B, Ho T, Leung E. What moves the ex post variable profit of natural-gas-fired generation in California? Energy J 2016;37(3):29–57.

The Electricity Journal 30 (2017) 22–30

Contents lists available at ScienceDirect

The Electricity Journal

journal homepage: www.elsevier.com/locate/tej

# Do coal and nuclear generation deserve above-market prices?

Amory B. Lovins

*Rocky Mountain Institute, Basalt, CO, United States*

ARTICLE INFO

*Keywords:*
Coal
Nuclear
Carbon
Competition
Efficiency
Renewables

ABSTRACT

All 14 current rationales for mandating or subsidizing uncompetitive coal and nuclear plants lack technical merit or would favor competitors instead. Subsidizing distressed nuclear plants typically saves less carbon than closing them and reinvesting their saved operating cost into severalfold-cheaper efficiency. Carbon prices, not plant subsidies, best recognize decarbonizing attributes. Grid reliability needs careful integration of diverse, distributed demand-side and renewable resources, using competitive market processes and resilient architectures, but does not require 'baseload' plants.

## 1. Introduction

The new federal administration faces an unusual dilemma in forming a coherent electricity strategy. Its Secretary of Energy, Rick Perry,[1] has said that coal and nuclear power plants too costly to clear in competitive markets must be kept running anyhow for "national security," even if doing so requires overruling state regulation and (by implication) ISO/RTO practices.[2] The Secretary ordered a quick staff study to seek an analytic basis for his policy, but finding credible support won't be easy. Without clear statutory authority to execute his policy, his evidence—and the transparency, objectivity, and stakeholder participation of his study's process—would need to persuade judges to set aside the conclusive, consistent, and empirically validated findings of virtually all prior expert studies by his own Department[3] and its National Laboratories,[4] the grid reliability regulator,[5] grid operators like PJM,[6] MISO,[7] WECC,[8] SPP,[9] ERCOT,[10] and CAISO,[11,12] trade associations,[13] the International Energy Agency,[14] many foreign and academic experts, and leading global electricity-industry firms.

This evidentiary challenge is compounded by the policy's internal contradictions. Efficient end use is steadily shrinking the electricity

*E-mail address:* ablovins@rmi.org.

[1] Bade, G. Updated: Perry orders DOE review of clean energy impacts on baseload generation. 17 Apr 2017. http://www.utilitydive.com/news/updated-perry-orders-doe-review-of-clean-energy-impacts-on-baseload-genera/440578/.

[2] Pyper, J. How the Trump Administration could pre-empt state policeis to shore up baseload power. May 4, 2017. https://www.greentechmedia.com/articles/read/how-the-trump-administration-could-preempt-state-policies-to-shore-up-basel. Sec. Perry's quoted video is at https://about.bnef.com/summit/event/new-york/.

[3] Department of Energy. *Quadrennial Energy Review: Second Installment*. Jan. 6, 2017. https://energy.gov/epsa/quadrennial-energy-review-second-installment.

[4] National Renewable Energy Laboratory. *Renewable Electricity Futures Study*. 2012. http://www.nrel.gov/analysis/re_futures/.

[5] North American Electric Reliability Corporation. *2016 Long-Term Reliability Assessment*. Dec. 2016. http://www.nerc.com/pa/rapa/ra/reliability%20assessments%20dl/2016%20long-term%20reliability%20assessment.pdf.

[6] PJM Interconnection. *PJM's Evolving Resource Mix and System Reliability*. Mar 30, 2017. http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

[7] Schuerger, M. Grid integration of wind & solar. U. Minn. Workshop, Apr 16, 2016. http://cusp.umn.edu/assets/Mpls_2016_RWorkshop/Matt_Schuerger.pdf.

[8] NREL. Western wind and solar integration study. https://www.nrel.gov/grid/wwsis.html.

[9] Southwest Power Pool, *2016 Wind Integration Study*, Jan. 2016, https://www.spp.org/documents/34200/2016%20wind%20integration%20study%20(wis)%20final.pdf.

[10] The Brattle Group. Integrating renewable energy into the electricity grid. Advanced Energy Economy. 2015. http://info.aee.net/integrating-renewable-energy-into-the-electricity-grid.

[11] Loutan, C. & Gevorgian, V. Using renewables to operate a low-carbon grid. 2017. http://www.caiso.com/Documents/UsingRenewablesToOperateLow-CarbonGrid.pdf.

[12] California ISO. What are we doing to green the grid? Accessed May 6, 2017. http://www.caiso.com/informed/Pages/CleanGrid/default.aspx.

[13] American Wind Energy Association. Wind energy helps build a more reliable and balanced electricity portfolio. 2015. http://awea.files.cms-plus.com/AWEA%20Reliability%20White%20Paper%20-%202-12-15.pdf.

[14] International Energy Agency (Paris). The Power of Transformation. 2014. https://www.iea.org/publications/freepublications/publication/The_power_of_Transformation.pdf.

http://dx.doi.org/10.1016/j.tej.2017.06.002

Available online 04 August 2017
1040-6190/ 

sales for which all generators compete,[15] and that shrinkage will intensify.[16] Coal and nuclear plants have both done poorly in capacity auctions meant to favor them,[17] losing mainly to gas and casting doubt on their reliability claims. Coal and nuclear are also uneasy yokemates: they compete toe to toe. Illinois's new long-term nuclear subsidy drove down regional capacity prices 98% in a year, making Dynegy move to close most or all of its Illinois coal capacity.[18] Its Vice President Rob Hardman called[19] nuclear operating subsidies the "new front in the War on Coal," while his colleague David Onufer said state-by-state policies "have turned markets from a competition to produce the lowest-cost electricity to a competition for [nuclear] subsidies".[20] Claiming, as EPA Administrator Scott Pruitt did,[21] that coal plants' avoidance of vulnerabilities in the natural-gas pipeline network confers a national-security advantage also undermines the case for fracking—the main actual market threat to coal and nuclear plants,[22] but another strong administration favorite.

Pricing $CO_2$ emissions as Republican elder statesmen urge[23] would hurt both coal and gas, help nuclear against gas, but not help nuclear beat renewables, which increasingly beat coal, gas, and nuclear wherever allowed to compete. Renewables also enjoy strong bipartisan political support; California rooftop solar adoption was found to be five times greater in Republican- than in Democratic-leaning areas,[24] over four-fifths of U.S. windfarms are in Republican congressional districts, and the top six windpowered states voted for Donald Trump. Red-state sentiment is bolstered by outstanding commercial successes like Texas windpower, whose 25,000 jobs, 15% of electricity, and record-low 2016 wholesale electricity prices culminated under Energy Secretary Perry's leadership as governor. In Iowa, the first state to become more than one-third windpowered (now 37%), Senator Chuck Grassley said[25] the tax credits he authored could be attacked "over my dead body," and trenchantly added[26] that many in favor of "all of the above" energy policies are "really for none of the above and all of the below"—i.e., not for renewables but for dug-up fuels.

Across the country and across party lines, state regulators and states' rights advocates will fiercely guard their prerogatives. ISO/RTOs will defend the competitive markets that Congress and many states told them to build to provide adequate and reliable electricity at the lowest efficient price. Customers and merchant generators will fight for those markets' benefits. Financiers will shun added risks. The military will continue to lead renewable deployment for its own operational success and mission continuity: it was then-General James Mattis who famously appealed from Iraq in 2003 to "unleash us from the tether of fuel".[27] Over 3 million renewable workers—California has more solar workers than America has coal miners—will defend their jobs. And judges will restrict the executive to reasoned administrative decisions and legally authorized powers.

Amidst the debate trigged by Secretary Perry's statements, the Federal Energy Regulatory Commission convened a lively Technical Conference on May 1–2, 2017, to examine whether the Eastern Interconnect's wholesale energy and capacity markets are properly pricing electrical resources to ensure reliable, resilient, and affordable electricity supply, and how state actions to advantage specific resources may affect those technology-neutral markets. This article adapts, expands, and updates my written comments[28] to FERC for that event.

## 2. Around-market nuclear subsidies' climate protection rationale

FERC's focus on some state policymakers' efforts to select or advantage specific resources that can't compete in technology-neutral wholesale markets arose mainly from new long-term state subsidies to specific distressed nuclear plants, as recently adopted by Illinois legislators and New York regulators, and together totaling at least $10 billion. There is no competition to obtain the targeted payments, and renewables can't get them. Those bailouts are being litigated[29,30] amidst uncertainties in federal law.[31] Similar bailouts are being considered in Connecticut, New Jersey, Ohio,[32] and Pennsylvania. A Bloomberg study estimated customer costs up to $3.9 billion a year if the 28 GW of Northeast and Mid-Atlantic nuclear plants won New York-level subsidies, so the losers would be customers and competitors. Such subsidies are influenced by local political considerations like jobs and tax revenues, and are sometimes extorted from states under threat of abrupt nuclear shutdowns that would disrupt grid operations. But their main rationale is the climate benefit of prolonging a carbon-free (in operation) resource for as long as safely possible.

I believe this argument is fundamentally mistaken and the claimed climate benefits are illusory, because of climate opportunity cost: avoiding and properly reinvesting nuclear operating cost (opex) could save even more carbon. Using 2013 $ throughout, the argument is:

1. Distressed nuclear plants' high opex makes them uncompetitive in wholesale markets. Estimates of the number of such plants vary widely but seem to trend upward, because their economic challenges are rising, and so are proposals for subsidies that would

[15] Chediak, M. U.S. power demand flatlined years ago, and it's hurting utilities. Apr 24, 2017. https://www.bloomberg.com/news/articles/2017-04-25/u-s-power-demand-flatlined-years-ago-and-it-s-hurting-utilities.

[16] Lovins, A. "Why Are We Saving Electricity Only Half As Fast As Fuels?," Forbes blog, Apr 25, 2017, https://www.forbes.com/sites/amorylovins/2017/04/25/why-are-we-saving-electricity-only-half-as-fast-as-fuels/.

[17] Gilbert, A. Addressing the plight of existing nuclear retirements, Part 1. Jul. 14, 2016. https://sparklibrary.com/addressing-plight-existing-nuclear-part-1/.

[18] Maloney, P. Pressed by nuke subsidies, Dynegy to decide by year-end whether to leave Illinois market. May 5, 2017. http://www.utilitydive.com/news/pressed-by-nuke-subsidies-dynegy-to-decide-by-year-end-whether-to-leave-il/441994/.

[19] @taykuy tweet at https://twitter.com/taykuy. May 4, 2017.

[20] Kuykendall, T. Trump environmental order does little to change coal retirement plans. Mar 30, 2017. https://www.snl.com/web/client?auth=inherit#news/article?id=40042063&KeyProductLinkType=4&cdid=A-40042063-13113.

[21] Walton, R. EPA chief Pruitt: Coal plants necessary to ensure grid reliability. May 5, 2017. http://www.utilitydive.com/news/epa-chief-pruitt-coal-plants-necessary-to-ensure-grid-reliability/442049/.

[22] Goggin, M. Low natural gas prices, not wind energy, primarily responsible for coal's troubles. Apr 5, 2017. http://www.aweablog.org/low-natural-gas-prices-not-wind-energy-primarily-responsible-coals-troubles/.

[23] Schwartz, J. Republican group calls for carbon tax. *N.Y. Times*, Feb 7, 2017. https://www.nytimes.com/2017/02/07/science/a-conservative-climate-solution-republican-group-calls-for-carbon-tax.html. Pricing carbon was the only consensus at the 1–2 May 2017 FERC Technical Conference: Bade, G. The carbon consensus: Generators, analysts back CO2 price at FERC technical conference. May 3, 2017. http://www.utilitydive.com/news/the-carbon-consensus-generators-analysts-back-co2-price-at-ferc-technical/441862/.

[24] Fragoso, A. California Republicans have more solar panels than Democrats. Sep 30, 2016. https://thinkprogress.org/california-republicans-buy-more-solar-panels-than-democrats-81ff9ceb28d.

[25] Henry, D. Grassley: Trump will attack wind energy 'over my dead body." *The Hill*. Aug 31, 2016. http://thehill.com/policy/energy-environment/293924-grassley-trump-will-attack-wind-energy-over-my-dead-body.

[26] Little, A. Will conservatives finally embrace clean energy? *The New Yorker*. Oct 29, 2015. http://www.newyorker.com/tech/elements/will-conservatives-finally-embrace-clean-energy.

[27] Douquet, G. "Unleash Us From the Tether of Fuel." Jan 11, 2017. http://www.atlanticcouncil.org/blogs/defense-industrialist/unleash-us-from-the-tether-of-fuel.

[28] Lovins, A. Letter to Acting Chairman C. LaFleur, FERC, 23 Apr 2017 for FERC Technical Conference, May 1–2, 2017, Docket AD17-11-000, accession #20170428-4001, https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14575878.

[29] PJM *amicus* brief, Apr 24, 2017, http://www.pjm.com/Media/documents/other-fed-state/20170424-1-17-cv-01164.pdf.

[30] Knauss, T. NY nuclear subsidies kick in Saturday, but high-stakes legal challenge looms. Mar 27, 2017. http://www.syracuse.com/news/index.ssf/2017/03/ny_nuclear_subsidies_kick_in_saturday_but_high-stakes_legal_challenge_looms.html.

[31] Bullock, J. With energy law federalism under construction, state policymaking may be delayed. *NYU Envtl. Law J.*, Nov 2016, http://www.nyuelj.org/2016/11/with-energy-law-federalism-under-construction-state-policymaking-may-be-delayed/.

[32] Knox, T. FirstEnergy asking for 'zero-emission' subsidies for its Ohio nuclear plants. Feb 22, 2017. http://www.bizjournals.com/columbus/news/2017/02/22/firstenergy-asking-for-zero-emission-subsidies-for.html.

reward exaggerating those challenges.

2. Individual nuclear plants' and units' opex (and financial performance) are generally secret, but aggregated data from the Electric Utility Cost Group, published by the Nuclear Energy Institute, show that the latest available nuclear opex, for 2010–12, averaged 6.2¢ per busbar kWh for the highest-cost quartile and ~4¢ for the third-highest-cost quartile.[33] Opex for the average 2014–15 nuclear plant was ~3.5¢/kWh,[34] exceeding many modern renewables bids.
3. Closing a distressed nuclear plant would avoid its opex, with immaterial effect on present-valued decommissioning cost (which must be paid anyway somewhat later).
4. Utilities pay an average of 2–3¢/kWh to buy end-use efficiency for customers.[35]
5. Closing an average top-opex-quartile nuclear plant *and* buying equivalent efficiency instead, as state regulators could require, would therefore procure (at the average price) 2–3 kWh of efficiency for each nuclear kWh not generated. One of those kWh could serve the nuclear output's function while the other 1–2 kWh could displace fossil-fueled generation.
6. This swap of nuclear operations for a greater quantity of efficiency could save at least as much carbon, plausibly twice as much, as if a fossil-fueled plant had been closed instead. Both are desirable.
7. This ability to close a nuclear plant *and* cut $CO_2$ underlies PG & E's multi-stakeholder agreement to close the Diablo Canyon two-unit nuclear plant—well-running but redundant and with a forward levelized operating cost ~7¢/kWh—and buy cheaper efficiency, renewables, or other carbon-free resources instead.[36] The mix will be determined by California's Integrated Resource Planning process so that market competition can find the cheapest carbon abatements, subject to reliability and other constraints. PG & E agreed that this orderly substitution for Diablo Canyon—cheaper to close than to run (by ≥$1 billion NPV, says NRDC)—will make the grid more flexible, emit no more carbon, and deliver other societal benefits. Allowing enough time for graceful carbon-free substitutions will avoid the interim rise in gas-fired generation ascribed to past abrupt nuclear shutdowns like San Onofre. (Vermont Yankee is often so cited, too, based on first-year data, but ISO-NE's 2014-16 nuclear output loss was 91% offset by renewables and hydro-dominated imports, and another 69% by reduced sales.[37])
8. Thus, the argument that reducing $CO_2$ emissions requires new subsidies for uncompetitive-to-run nuclear plants is generally wrong. (Even for lower-opex plants, around < 2–4¢/kWh, it may not be true if cheaper-than-average efficiency is substituted.)
9. These comparisons are conservative because efficiency is already delivered to the retail meter, so it defers or avoids any marginal components (operating costs and losses, modernization, upgrades, expansions) of the embedded average ~4.1¢/kWh cost[38] of delivery.

In summary, closing a nuclear unit in at least the top quartile of operating costs (> 6¢/kWh) does not directly save $CO_2$, but can indirectly save *more* $CO_2$ than closing a coal-fired power plant *if the nuclear plant's larger saved operating costs are reinvested in efficiency* that in turn displaces more fossil output. Exact values will depend on specific details, but the logic is unavoidable if one tracks both carbon *and* money. New York and Illinois policymakers apparently thought only about carbon, not also about avoidable opex and how its reinvestment could save more carbon.

Broadly, such reinvestment enables closing either an average coal plant *or* a high-operating-cost nuclear plant to avoid similar releases of fossil carbon—and the latter plausibly even twice as large. Thus neither kind of closure should be discouraged. But buying a carbon abatement that does not save the most carbon per dollar results in emitting more carbon than necessary. Nuclear *new*-build is clearly many times costlier than almost any alternative,[39] so it makes climate change worse than if the best buys, saving far more carbon per dollar, were procured instead.

Additional nuclear subsidies are claimed to be justified by market failure. On the contrary, they create it. Around-market subsidies like those just adopted in New York and Illinois distort pool-wide prices, crowd out competitors, discourage new entrants, destroy competitive price discovery, reduce transparency, reward undue influence, introduce bias, pick winners, and invite corruption. As the former chairs of the New York and Texas Commissions—one a former Nuclear Regulatory Commissioner and NARUC president, the other a recent FERC chairman—agreed,[40] such targeted subsidies may "unravel U.S. power markets altogether." Before approving such radical arrangements, FERC, ISO/RTOs, the states, and the courts should require a high standard of proof that the market is unable to provide a cost-effective solution to a real problem, for reasons that cannot be fixed within market principles. The burden of proof should be on proponents of around-market subsidies. Absent definitive proof, the market should be allowed to work.

States have many tools for valuing specific attributes like carbon-free operations. For example, states wanting to buy carbon-free resources without harming existing market mechanisms could run a laddered series of auctions open to all such demand- and supply-side options. This free-market approach would value the carbon-free attribute without substituting policymakers' prophecies for evolving prices discovered in the market.[41] Historically, such guesses have almost always been wrong, and that risk is rising because prices are

[33] Fertel, M. Nuclear energy 2014: status and outlook, http://www.nei.org/Issues-Policy/Economics/Financial-Analyst-Briefings/Nuclear-Energy-in-2014-Status-and-Outlook (2014)

[34] Fertel, M. Nuclear energy 2014–2015: recognizing the value (data set excludes five units), http://www.nei.org/CorporateSite/media/filefolder/Policy/Wall%20Street/WallStreetBriefing2015slides.pdf (2015). His Feb 11, 2016 update (http://www.nei.org/CorporateSite/media/filefolder/Policy/Wall%20Street/WallStreetBriefing2016Slides.pdf?ext=.pdf) gives 2014 averages as 3.63¢/kWh for all U.S. nuclear plants (possibly excluding some troubled ones), comprising 3.38¢ for multi- and 4.41¢ for single-unit stations, with 2.92¢ for the lowest quartile and unstated for the highest. Fertel's Nov. 2016 data for 2015, again lacking transparency about the completeness of the data set, are similar to the 2014 data: https://www.nei.org/CorporateSite/media/filefolder/Policy/Papers/statusandoutlook.pdf?ext=.pdf.

[35] Billingsley, M., Hoffman, I., Stuart, E., Schiller, S., Goldman, C. The program administrator Cost of Saved Energy for utility customer-funded energy efficiency programs, Lawrence Berkeley National Laboratory, https://emp.lbl.gov/sites/all/files/lbnl-6595e.pdf (2014); Molina, M. The best value for America's energy dollar: a national review of the cost of utility energy efficiency programs, http://aceee.org/research-report/u1402 (2014); Wemple, M. DSM Achievements and Expenditures 2013, http://www.esource.com/members/DSM-INDBMK-Achievements-2013/DSM-Achievements-and-Expenditures-Study (2013).

[36] Lovins, A. Closing Diablo Canyon Nuclear Plant Will Save Money and Carbon, Jun 22, 2016, http://www.forbes.com/forbes/welcome/?toURL=http://www.forbes.com/sites/amorylovins/2016/06/22/close-a-nuclear-plant-save-money-and-carbon-improve-the-grid-says-pge.

[37] ISO New England. Net Energy and Peak Load Reports 2000–2015 and 2016. Accessed May 7, 2017. https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/net-ener-peak-load.

[38] Energy Information Administration, *Annual Energy Outlook 2014* (3.9¢/kWh adjusted for 5.5% grid loss), conservatively below the 2015-39 undiscounted mean of 4.27¢/kWh in EIA's 2017 AEO Reference Case (table "Electricity Supply, Disposition, Prices, and Emissions) because a least-cost portfolio of resources will probably avoid significant grid investments.

[39] Rowe, J.W., Chairman & CEO, Exelon Corporation, "Energy Policy: Above All, Do No Harm," American Enterprise Institute, Washington, DC, Mar 8, 2011, at PJM slide 13 in Koplow, D., Cost-Efficient Greenhouse Gas Reductions: Nuclear Is No Silver Bullet, Capitol Hill Club, Washington DC, Feb 29, 2016, https://earthtrack.net/sites/default/files/uploaded_files/Nuclear%20and%20ghg%20Abatement_Koplow_final_29Feb2016_web.pdf; Lazard, Levelized Cost of Energy Analysis—Version 10.0, Dec. 2016, https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf.

[40] Knauss, T. NY nuclear subsidies kick in Saturday, but high-stakes legal challenge looms. Mar 27, 2017. http://www.syracuse.com/news/index.ssf/2017/03/ny_nuclear_subsidies_kick_in_saturday_but_high-stakes_legal_challenge_looms.html.

[41] Bradford, P. Wasting time: Subsidies, operating reactors, and melting ice. *Bull. atom. Scient.* 73(1), 13–16 (2016).

in rapid flux. During 2008-16, a period shorter than the duration of the New York and Illinois nuclear subsidies just added, average U.S. real PPA prices fell 83% for PV power and 71% for windpower.[42] In 2016 alone, global prices fell by 17% for solar PV, 18% for onshore windpower, and ≥16% for lithium-battery storage, and their fall is accelerating. Regional prices can be even more volatile, falling in about eight months of 2016 by 37% for Mexican solar PV and 43% for European offshore windpower. In this maelstrom, no policymaker, however wise, can be confident of guessing 2027-29 relative prices. It's foolish to substitute long guesses for market outcomes constantly calibrated to reality. Illinois' new nuclear subsidies, rejecting such competition, were rationalized on the grounds that renewables could not compete without the deal-sweetening RPS increase, but some local renewable developers dispute that and deny they were given a fair chance to disprove it in the market.

Continued nuclear operations might win such a carbon-abatement auction initially, until cheaper new efficiency and renewables ramped up and won on cost per unit of time-integrated carbon avoided; but markets, not regulators or legislators, should determine that outcome. Nuclear operators' insistence on locking in decade-plus subsidies is especially harmful to market flexibility, innovation, and competition. It rejects and defeats the whole purpose of having wholesale power markets. In my view, operators that insisted on restructuring so they could benefit from wholesale markets should live with the consequences. After all, they've been compensated first for building their assets (with subsidies around 0.8–4.6¢/kWh for shareholder-owned and 1.7–6.3¢/kWh for public utilities, excluding ~8.3¢/kWh of historic subsidies that originally launched the nuclear enterprise[43]), then for transition costs of the restructuring they later demanded (notably "stranded-asset" allowances), sometimes yet again by some ISO/RTOs' additional capacity payments favoring large thermal units, and now (they hope) for a fourth time via new state payments and competitive boosts for alleged unrecognized virtues. Once is enough.

## 3. Carbon and other pollution pricing

Coal and nuclear power plants have a growing number of real or imagined attributes for which their owners would like to be paid more so they can keep milking often-amortized assets despite ever more competitive markets. The suite of properties said to merit added payments, whether via higher wholesale prices or other subventions, keeps expanding, and currently comprises at least the 14 elements analyzed here. The first of those, the claimed climate benefits just discussed, is often expressed in a different form: that U.S. reactors aren't rewarded at a national level for not directly emitting $CO_2$, conferring unfair advantage on fossil-fueled plants that do. (The Regional Greenhouse Gas Initiative,[44] however, is designed to cap, trade, and cut power-sector $CO_2$ emissions in nine states—including New York, which just added nuclear subsidies for the same purpose, and Connecticut, which is being asked to.)

I agree with the Nuclear Energy Institute that pricing $CO_2$ emissions—and for that matter other air pollutants, as California has done for $NO_x$ since 1994—is desirable and would help nuclear plants compete with gas-fired plants. However, it would equally advantage carbon-free renewables—a cheaper, nonvolatile-and-declining-price, more resilient, more popular, and more potent and ubiquitous competitor than gas. If avoided carbon or other emissions are valued, they should be valued equally for all resources, and in principle should recognize all material externalities.[45]

Rather than acknowledging that carbon pricing wouldn't help nuclear power beat renewables—and should replace, not augment, nuclear subsidies—nuclear advocates argue that (1) renewable energy has an inherently limited role, especially in providing reliable supply, while (2) nuclear power has *other* important attributes not recognized in its wholesale-market power price. These are claimed to cause "market failures" and "inefficient pricing" that regulators or ISO/RTOs should change market structure to correct. We turn next to those attributes.

## 4. Subsidies

Secretary Perry's view that "federal subsidies that boost one form of energy at the expense of others" can distort markets and may weaken the grid is a compelling objection to New York's and Illinois' new nuclear subsidies. However, even as such state policies' contagion spreads, their logical basis is collapsing, for two reasons. First, as noted above, their climate (or other environmental) rationale is mistaken. Second, the subsidies relevant to current power-market prices, some current and others long in force but still affecting today's prices, appear to be generally larger and more durable for fossil-fueled and nuclear plants than for modern renewables.[46,47] As a small example, new U.S. nuclear plants get slightly higher operating subsidies per kWh than new U.S. windfarms,[48] plus far larger capital subsidies, around 5–12¢/kWh, rivaling their construction cost—and even existing nuclear plants' capital subsidies often exceed the wholesale price they receive.[49]

The whole energy system is riddled with opaque subsidies—federal, state,[50] and local. I earnestly hope the Secretary will seek a comprehensive and unbiased assessment of *all* energy subsidies (unlike slanted EIA studies that Congressional sponsors carefully structured to produce biased conclusions[51]). The last thorough federal-subsidy assessment I know of, for FY1984,[52] found 1-2-order-of-magnitude distortions favoring incumbents. Bringing such work up to date, as Doug Koplow has valiantly attempted without official help,[53] would be a vital tool for crafting fair policies to desubsidize the entire energy sector.[54] Honest analysis of *all* energy subsidies, current (which PJM and FERC consider) *and* relevantly previous, for both capital and operating costs, will probably find that nuclear and coal

[42] Leibreich, M. Keynote to Apr 25, 2017 New York BNEF summit. https://about.bnef.com/summit/event/new-york/.

[43] Koplow, D. Nuclear Power: Still Not Viable Without Subsidies, UCS, 2011, http://www.ucsusa.org/nuclear-power/cost-nuclear-power/nuclear-power-subsidies-report.

[44] See http://www.rggi.org/design.

[45] Many would argue that pricing externalities is a risky argument for nuclear advocates to make, because the societal cost of their technology's safety, terrorism, waste, and perhaps other unpriced risks, though fiercely contested, could be very high. Japan offers a sobering example of costs that far exceeded plausible benefits.

[46] Pfund, N. & Healey, B. What Would Jefferson Do? The Historical Role of Federal Subsidies in Shaping America's Energy Future, DBL Investors, 2011, http://i.bnet.com/blogs/dbl_energy_subsidies_paper.pdf, and extensive anal-yses and citations at Koplow, D., www.earthtrack.net/publications.

[47] Oil Change International. Fossil Fuel Subsidies: Overview, 2017, http://priceofoil.org/fossil-fuel-subsidies/.

[48] Lovins, A. The economics of a US civilian nuclear phase-out. *Bull. atom. Scient.* 69, 44–65 (2013). http://connection.ebscohost.com/c/articles/85849091/economics-us-civilian-nuclear-phase-out, notes 2–3. Under current conditions, uncompetitive pricing of tax-equity capital reduces the wind PTC from ~$23/MWh book value (consistent with 10% IRR and 35% capacity factor) to ~$15/MWh market value.

[49] Ref. 44.

[50] Koplow, D. State subsidies to fossil fuels: A review of Colorado, Kentucky, Louisiana, Oklahoma, and Wyoming. Earthtrack. 2012. https://earthtrack.net/blog/state-subsidies-to-fossil-fuels-a-review-of-colorado-kentucky-louisiana-oklahoma-and-wyoming.

[51] Koplow, D. EIA Energy Subsidy Estimates: A Review of Assumptions and Omissions, Earthtrack, 2010, https://earthtrack.net/documents/eia-energy-subsidy-estimates-review-assumptions-and-omissions.

[52] Heede, H.R. A Preliminary Assessment of Federal Energy Subsidies in FY1984, RMI Publ. #CS85-27, summarized in Heede, H.R. & Lovins, A.B., Hiding the true costs of energy sources, *Wall St. J.*, p. 28, Sep 17, 1985.

[53] Koplow, D. Fossil Fuel Subsidy Reform in the United States: Impediments and Opportunities, Earthtrack, Sep 2016, https://earthtrack.net/document/fossil-fuel-subsidy-reform-united-states-impediments-and-opportunities, and see generally https://earthtrack.net for numerous analyses.

[54] Lovins, A., Nuclear socialism, *Weekly Standard*, Oct 25, 2010, www.weeklystandard.com/nuclear-socialism/article/508830.

electricity are already more heavily subsidized than solar and wind-power. If so, then leveling the playing field, as the Secretary and I both advocate, would not help but harm the coal and nuclear resources he aims to advance; but I'm glad we agree on the principle even before we know the up-to-date numbers.[55]

History, though, suggests energy subsidies are a triumph of political muscle over principle. That's why the 1986 Tax Reform Act cut the hydrocarbon industries' taxes *and* kept their specific tax subsidies. But unbalanced energy subsidies are rising. Broadly speaking, all renewable subsidies are declining, fossil-fuel subsidies aren't, and already-large nuclear subsidies are rising sharply. The Secretary seems inclined to intensify the resulting market distortions. As someone who takes market economics seriously (though not literally), I think that's a bad idea and rejects conservative free-market principles.

## 5. 'Large-scale' electricity generation

A traditional giant power station produces far more power than practically any application needs except uranium enrichment plants and giant metal smelters. A gigawatt exceeds the typical electricity draw of a typical office building by several orders of magnitude, of a home by about five, of a home air conditioner by five or six, and of a laptop computer by about eight. Those power stations are built so big simply because their construction cost per kilowatt becomes even more prohibitive if they're smaller. Economies of unit scale in construction are real, and can apply also to solar and wind facilities that are typically one to three orders of magnitude smaller. However, more than 200 *dis*economies of scale are even more important to the *customer's* economics. Better matching scale of supply to scale of use generally reduces total cost and risk.[56]

Every kind of electricity generator sometimes breaks, but some fail more gracefully than others. Big, lumpy units make failure (in generation or its transmission pathways) more consequential, requiring larger reserve margin, spinning reserve, and often cycling costs than with a diversified and distributed portfolio of small, granular units. The latter also improves resilience, as we'll see.

## 6. 'Baseload' generation

Secretary Perry asserts[57] that "baseload" plants are "critical" resources "necessary to a well-functioning electric grid," so national security may require their continued operation and hence preemption of state policies exposing them to full and fair competition. This traditional view reflects a common misperception about what "baseload" means; the word has at least five meanings.[58] It simply encapsulates how an inflexible big thermal generator functions and the role such plants have historically played on the grid. It is not a grid need today. This has been clearly stated by, among others, former FERC Chairman Jon Wellinghoff,[59] National Grid CEO Steve Holliday,[60] and General Electric (which says[61] inverters can provide frequency response and other ancillary services even better than synchronous generators). Indeed, inflexible baseload generators are becoming an impediment to further grid integration.[62] The weight of expert opinion clearly concurs.[63,64,65,66,67] As Bloomberg New Energy Finance's founder wrote[68]:

> Super-low-cost renewable power—what we are now calling "base-cost renewables"—is going to force a revolution in the way power grids are designed, and the way they are regulated.
>
> The old rules were all about locking in cheap base-load power, generally from coal or hydro plants, then supplementing it with more expensive capacity, generally gas, to meet the peaks. The new way of doing things will be about locking in as much locally available base-cost renewable power as possible, and then supplementing it with more expensive flexible capacity from demand response, storage and gas, and then importing the remaining needs from neighbouring grids.
>
> New nuclear plants will remain the political bauble they currently are, unless next-generation nuclear can prove it can deliver fail-safe designs at affordable cost. Demand will be suppressed by energy efficiency and self-generation, and augmented by electrified transport and heat.
>
> Putting super-cheap, "base-cost" renewable power at the heart of the world's grids in this way will require a revolution in the way the electricity system is regulated. Renewable power's progress to date has been achieved mainly by subsidizing or mandating its installation, while forcing the rest of the system to provide flexibility, within otherwise unchanged regulatory environments and power market rules. The additional system costs have been material but generally affordable….[But we] are reaching the point…where power system regulation will have to be fundamentally rethought. Simply layering on a capacity market is the wrong response: creating guaranteed demand for obsolete technologies has never ended well.

Confirming the feasibility of reliable, largely renewable supply without a "storage miracle," four EU countries with modest or no hydropower met 46–64% of their 2014 electricity needs with renewables (Spain 46%, Scotland 50%, Denmark 59%, Portugal 64%), with no

[55] Broadly speaking, nuclear and fossil-fuel subsidies are much older (most decades, some a century) than renewable subsidies, are collectively larger, and are generally permanent, unlike the solar and wind subsidies that are phasing out. "Zero emissions credits" are simply the latest way to pile new nuclear subsidies onto huge old ones in the name of fictitious equity. (See https://earthtrack.net for the best scholarship on U.S. energy subsidies.) Renewable Portfolio Standards, though no longer important in most markets, should continue to be just for renewables because they have different positive and negative externalities than, say, nuclear, and many of those are not about $CO_2$.

[56] Lovins, A. *et al. Small Is Profitable: The Economic Benefits of Making Electrical Resources the Right Size*. Rocky Mountain Institute. 2002. http://www.smallisprofitable.org.

[57] Perry, R., Study Examining Electricity Markets and Reliability. Memorandum to the Chief of Staff, DOE. Apr 14, 2017.

[58] "Baseload" may mean: to utility load analysts, the apparently steady-in-aggregate portion of demand below the shoulder of the load-duration curve; to utility resource buyers, the resource of least levelized long-run marginal cost; to grid dispatchers, the resource of least short-run marginal (dispatch) cost; to laypeople, the big thermal power plants that traditionally satisfied the second and third roles (but no longer can because renewables undercut their dispatch costs); and to nuclear advocates, a mythical 24/7/365 power plant. It's important to know which is meant.

[59] Straub, S., Behr, P. Energy regulatory chief says new coal, nuclear plants may be unnecessary. *N Y Times*. Apr 22, 2009. http://www.nytimes.com/gwire/2009/04/22/22greenwire-no-need-to-build-new-us-coal-or-nuclear-plants-10630.html?pagewanted=all (2009).

[60] Beckman, K. Steve Holliday, CEO National Grid. "The idea of large power stations for baseload is outdated." Sep 11, 2015. http://www.energypost/eu/interview-steve-holliday-ceo-national-grid-idea-large-power-stations-baseload-power-outdated/.

[61] Parkinson, G., GE. Why grids don't need to rely on "synchronous" generation, Dec 16, 2016, http://reneweconomy.com.au/ge-grids-dont-need-rely-synchronous-generation-89161/.

[62] Diesendorf, M. Do We Need Base-Load Power Stations? EnergyScience Coalition, Dec 2015, http://www.energyscience.org.au/BP16%20BaseLoad.pdf.

[63] Trabish, H. How renewables are changing the way we operate the grid. http://www.utilitydive.com/news/how-renewables-are-changing-the-way-we-operate-the-grid/364541/ (2015).

[64] *Renewable Global Futures Report: Great Debates Towards 100% Renewable Energy*, REN21.net, Paris, 2017.

[65] Trabish, H. Why utilities are more confident than ever about renewable energy growth. Apr 25, 2017. www.utilitydive.com/news/why-utilities-are-more-confident-than-ever-about-renewable-energy-growth/440492/.

[66] Energy Transitions Commission. *Better Energy, Greater Prosperity*, Apr 25, 2017. http://www.energy-transitions.org/better-energy-greater-prosperity.

[67] Milligan, M. et al. Wind power myths debunked. *IEEE Power and Energy Magazine*, Nov/Dec 2009, pp 89–99, doi:10.1109/MPE.2009.934268, file:///Users/amory/Downloads/Wind%20Power%20Myths%20Debunked.pdf.

[68] Liebreich, M. & McCrone, A. The shift to 'base-cost' renewables: 10 predictions for 2017. 18 Jan, 2017. https://about.bnef.com/blog/10-renewable-energy-predictions-2017/.

added bulk storage yet superior reliability. In 2015, the ultrareliable former East German utility 50Hertz was 49% powered by renewables, three-fourths of which were wind and PV—~9X what was thought possible 10–15 years ago, says its CEO—yet its last high-voltage outage was many decades ago, and he says 60–70% variable renewables would not require more bulk storage.[69] What has changed, he explains, is the evolution of mindset and of adaptive market mechanisms. The modern view is that supposed storage and backup needs are less a need of variable renewables than a consequence of central thermal plants' relative *in*flexibility. That's not the renewables' fault.

## 7. Dispatchability

ISO/RTO bidders must satisfy uniform, pool-wide reliability criteria. Sustaining those standards as variable renewable fractions increase requires careful, non-trivial, but well-proven and well-understood technical and institutional improvements.[70] These tend to become more burdensome if inflexible and uncompetitive resources are retained. Grid balancing costs may be paid by the system or by new resources. Most current U.S. practice does this asymmetrically, favoring incumbents over new entrants. Specifically, variable renewables' grid balancing costs are generally borne by their developers or owners, and are usually < $5/MWh, nearly always < $10.[71] Yet coal and nuclear plants impose analogous costs on the system without being charged for them, at least outside ERCOT. Instead, the grid balancing costs of managing the intermittence (forced outages) of central thermal plants—reserve margin, spinning reserve, cycling costs, part-load penalties—are traditionally socialized, treated as "inevitable system costs," and hardly ever analyzed.

This asymmetry appears to favor fossil-fueled and nuclear plants, because their balancing costs, emerging evidence suggests, may be severalfold *greater* than those of a well-designed and −run portfolio of PV and wind resources. Conversely, variable renewables may need *less* backup (or storage) than utilities *have already bought* to manage the intermittence of their big thermal plants. (For example: utilities have found that high wind fractions can be firmed by fueled generators ≤5% of wind capacity[72]—severalfold below classical ~15–20% reserve margins for thermal-dominated systems. Unbundled ERCOT ancillary-services market price data confirm that wind's reserve costs per MWh are about half those of thermal generation.[73,74] NREL's models confirm for the western U.S. that central thermal plants cost more to integrate than variable renewables.[75]) FERC should investigate these grid balancing costs, and ensure they are analyzed and applied symmetrically for *all* resources—big and small, renewable and nonrenewable, supply- and demand-side—or are treated as system costs not charged to a specific resource type.

## 8. Loadshape value

ISO/RTOs should and do consider match to load, and most compete load flexibility resources against supply. PVs' often-strong correlation with midday peak loads can be valuable, but big thermal plants' relatively steady output (in between outages) is of no special value to modern grids, which require energy, capacity, flexibility, and ancillary services rather than steady generation. The faster ramp rates required to integrate high fractions of variable renewables can be gracefully managed without bulk storage, and not only by the latest fast-ramping gas plants, because many other resources are also flexible but cheaper. For example, preliminary research at Rocky Mountain Institute recently found that demand response alone could more than eliminate California's "duck curve" and halve daily load variation with a roughly five-month payback. Other important grid-balancing resources include efficient end use, precise forecasting of variable renewables, their diversification by size and location, their integration with dispatchable renewables and with cogeneration, thermal storage, hydrogen storage, and distributed electricity storage including electric vehicles.

## 9. 'Fuel on hand'

"Fuel on hand" is a new label for coal and probably for nuclear plants—what's left after excluding gas-fired generators (whose fuel is delivered just-in-time by pipelines) and renewables (which burn no fuel). EPA Administrator Pruitt refers specifically to "solid hydrocarbon fuels on hand"—meaning coal, not also uranium—but apparently with Secretary Perry, let's assume both.

The notion that "fuel on hand" enhances grid resilience by reducing dependence on fuel logistics seems intuitively plausible. But an initial review[76] of historic experience suggests it's incorrect even in its own narrow terms (fuel logistics is an important but far from exclusive or dominant part of the spectrum of threats to electric resilience). Renewables need no fuel but aren't mentioned in the Secretary's memo. Moreover, coal and gas delivery both exhibit worrisome weaknesses that concern NERC, the grid-reliability regulator. Coal plants have proven vulnerable to fuel-logistics problems—rail and bridge failures, frozen barges and onsite coal piles, etc. Gas infrastructure suffers freezeups and the inherent physical[77] and cybervulnerabilities of pipeline systems. Nuclear plants have suffered mass shutdowns caused by accidents, safety concerns, heat waves, and grid failures, and some failures can persist. For example, in the Northeast blackout of Aug. 14, 2003, nine U.S. nuclear plants SCRAMmed from 100% to 0% output as designed, but then took nearly two weeks to restore (< 3% in three days, 41% in seven days), due largely to xenon and samarium poisoning and core-flux inhomogeneities.[78] This inherent physics attribute makes power reactors an "anti-peaker" resource, guaranteed unavailable when most needed.

Photovoltaics and windpower are variable, with average respective 2016 U.S. utility-scale capacity factors of 27.2% and (net of several points' curtailment) 34.7%.[79] Yet their variations are generally more predictable than are variations of electricity demand. PV and

[69] Parkinson, G. German grid operator sees 70% wind + solar before storage needed, Dec 7, 2015, http://www.energypost.eu/german-grid-operator-can-handle-70-wind-solar-storage-needed/.

[70] Bird, L., Milligan, M. & Lew, D. Integrating variable renewable energy: challenges and opportunities. NREL/TP-6A20-60451, Sep 2013. http://www.nrel.gov/docs/fy13osti/60451.pdf.

[71] Wiser, R., Bolinger, M., *2013 Wind Technologies Market Report*. Lawrence Berkeley National Laboratory. LBNL-6809E, http://emp.lbl.gov/publications/2013-wind-technologies-report (2014), p. 70, Fig. 52 .

[72] *Id.*

[73] American Wind Energy Association. Wind energy helps build a more reliable and balanced electricity portfolio. http://awea.files.cms-plus.com/AWEA%20Reliability%20White%20Paper%20-202-12-15.pdf (2015).

[74] Trabish, H. How renewables are changing the way we operate the grid. http://www.utilitydive.com/news/how-renewables-are-changing-the-way-we-operate-the-grid/364541/ (2015).

[75] Stark, G. A Systematic Approach to Better Understanding Integration Costs. National Renewable Energy Laborato-ry. NREL/CP-5D00-64930. http://www.nrel.gov/docs/fy15osti/64930.pdf. Sep 2015.

[76] Lovins, A. Does 'fuel on hand' make coal and nuclear power plants more valuable? *Forbes* blog, May 1, 2017. https://www.forbes.com/sites/amorylovins/2017/05/01/does-fuel-on-hand-make-coal-and-nuclear-power-plants-more-valuable/.

[77] Lovins, A. & L.H., *Brittle Power: Energy Strategy for National Security*, 1981 report to DoD, Brick House (1982), http://www.rmi.org/Knowledge-Center/Library/S82-03_BrittlePowerEnergyStrategy. This study remains the definitive unclassified work on energy-infrastructure resilience (though it predates cyberthreats), and its Chapter 13 presents a comprehensive approach to resilience that far transcends reliable fuel logistics.

[78] www.nrc.gov/reading-rm/doc-collections/event-status/reactor-status/2003/index.html, www.nrc.gov/info-finder/reactor/. Canada's CANDU reactors, having less reactivity margin, were even harder-hit.

[79] Energy Information Administration. Table 6.7.B, Capacity Factors for Utility Scale Generators Not Primarily Using Fossil Fuels, https://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_97_b.

windpower also have far lower forced outage rates than big thermal stations, typically < 1% and 1–2% respectively (for a leading brand of utility-scale PV inverter, nearly the only failure source in such projects, the guaranteed maximum is 0.15%). These renewables have repeatedly sustained reliable grid service when fueled stations' failures endangered it. Other kinds of renewables are dispatchable and also have very high technical availability.

Just comparing different generating plants misses the most important point: distributed resources can largely or wholly bypass *grid* failures, which trigger ~98–99% of U.S. power outages.[80] Distributed generators can thus be especially resilient, especially if architected as islandable microgrids that normally exchange power freely with the larger grid but can isolate and stand alone at need, serving at least the critical loads from local resources until grid service is restored. That's how my house works. It's how the Department of Defense aims to power military bases, because they need their stuff to work. So do the rest of us citizens whom they're defending. Liberalized policies for distributed renewables, like the plug-and-play rule pioneered in Texas by PUCT Chair Pat Wood under Gov. George W. Bush, should make resilient hookups (which protect lineworkers by standards like IEEE1547) the legal and normal default design, so America's renewable adoption can build a resilient grid from the bottom up.

## 10. Price deflation

The supposed inevitability of renewables' "eating their own lunch"—because high renewable fractions depress wholesale prices, making it progressively harder to elicit further investment—is an artifact of models that artificially constrain or exclude ways to mitigate this problem (if lower prices are a problem rather than a societal benefit).[81] Though featured in a major MIT study,[82] such "price deflation" has not withstood analysis—and identical modeling of nonrenewables, especially nuclear power, would show "price deflation" affects them worse than renewables.

Such issues are described differently from different perspectives. For example, renewables' and gas-fired electricity's reductions in wholesale prices are called "price suppression"[83] by the nuclear industry when they beat its plants in "merchant markets," wrongly implying that the price verdict is somehow wrong and needs fixing. Carbon should indeed be priced as discussed above, but other nuclear attributes do not appear to merit higher payments for real value delivered.

## 11. Accounting vs. economics

The prior employer of the head of Secretary Perry's new grid study claimed[84] (along with exorbitant supposed storage needs) that revenues lost by incumbent thermal plants are an "imposed cost" of the renewables that outcompeted them. This novel theory would have had Netflix compensate cable-TV providers and Henry Ford compensate horse-stable owners. Such a proposed barrier to competition and innovation confuses economics (sunk costs) with accountancy (unamortized assets). Under the rubric of "utilization effect," it was soundly rejected by two EU workshops advised by the theory's originator. Those workshops found that society bears transformation costs and needn't ascribe them to particular technologies, new or old, nor to particular parts of the power system.[85] Of course, renewables with virtually zero dispatch cost do push higher-opex thermal plants up the load-duration curve so they run less. Customers then benefit from lower market-clearing prices. Owners suffer from correspondingly lower revenues for which they would love to be made whole. But they were already compensated for all the risks of their investments, including competition and innovation, and should not be paid twice.

## 12. Financial economics of volatile fuel prices

A major distortion in wholesale power markets is their typical failure to risk-adjust different resources. To compare volatile-price resources, notably gas-fired power plants, fairly against fixed-price resources, like efficiency and renewables, requires risk-equalization by adding to volatile cost streams the market value of their price volatility (which can be approximated by the straddle in the options market—the spread between the prices of simultaneous put and call options). For natural gas, that volatility value approximates recent natural-gas prices, so plant and grid operators that don't count the gas-price risk are imposing on customers all the burdens of acting as if gas cost only about half as much as it actually does on a risk-adjusted basis. A sophisticated recent analysis using a different method found that properly counting gas-price volatility makes modern renewables robustly cheaper than efficient combined-cycle gas plants.[86] Coal has also recently exhibited considerable price volatility meriting analysis and risk-adjustment.

FERC and ISO/RTOs that don't risk-equalize for the volatile prices of gas and other fuels are creating a market failure. Nearly all market players routinely do the same. That violation of the basic principles of financial economics should not become customers' problem. The next time someone says, as the chairman of a large utility told a *Wall Street Journal* conference a few years ago, "Windpower can't compete in my area because I have two-cent[-opex] gas power," please reply: "Just a minute. You're being offered windpower at a fixed nominal price, hence a declining real price, for at least 20 years. How much two-cent gas power do you want to sell me on those terms?" The answer, of course, was zero—the gas was a spot price—but then the conversation about "cheap gas" continued as if nothing had happened. Policymakers should know better.

## 13. Local expenditures and jobs

Big thermal plants employ people and pay taxes. State and local governments will properly consider this, but such production costs are hardly a basis for raising the prices ISO/RTOs pay for the resource. All reasonable costs of generation are costs, not benefits; are reimbursed by ratepayers; and should not be paid again via added subsidies. At least for employment, such local benefits are also empirically inferior to those of equivalent efficiency and renewables.[87]

## 14. Nuclear power's support for the U.S. nuclear weapons program

Secretary Perry's novel assertion[88] that maintaining civilian nuclear

[80] Lovins, A. *et al. Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*, Rocky Mountain Institute, 2002, www.smallisprofitable.org, at p. 241.

[81] Dyson, M., Mandel, J., & Lovins, A. 3 Ways Wind and Solar Can Continue To Grow In a 21st-Century Grid. Rocky Mountain Institute. Nov 30, 2015. http://blog.rmi.org/blog_2015_11_30_3_ways_wind_and_solar_can_continue_to_grow_in_a_21st_century_grid.

[82] MIT, *The Future of Solar Energy*, 2015, energy.mit.edu/research/future-solar-energy/.

[83] Nuclear Energy Institute. Policy brief: Electricity markets undervalue nuclear power plants. Feb 2015. https://www.nei.org/Master-Document-Folder/Backgrounders/Policy-Briefs/Electricity-Markets-Undervalue-Nuclear-Power-Plant.

[84] Stacy, T. & Taylor, G. The Levelized Cost of Electricity from Existing Generation Resources, Institute for Energy Research, 2015, http://instituteforenergyresearch.org/wp-content/uploads/2015/06/ier_lcoe_2015.pdf.

[85] Agora Energiewende. *The Integration Costs of Wind and Solar Power*. 2015. https://www.agora-energiewende.de/fileadmin/Projekte/2014/integrationskosten-wind-pv/Agora_Integration_Cost_Wind_PV_web.pdf.

[86] Bolinger, M. Using Probability of Exceedance to Compare the Resource Risk of Renewable and Gas-Fired Generation. LBNL-1007269, Mar 2017, https://emp.lbl.gov/publications/using-probability-exceedance-compare/.

[87] Department of Energy. *2017 U.S. Energy and Employment Report*, https://energy.gov/downloads/2017-us-energy-and-employment-report.

[88] Perry, R. Video of interview at Bloomberg New Energy Finance New York summit, Apr 25, 2017, https://about.bnef.com/summit/event/new-york/, at 30:28–32:17.

power because its technical expertise and manufacturing capabilities are vital to the U.S. nuclear weapons capability (partly via links that cannot be discussed because they're highly classified) will doubtless be rebutted by nuclear weapons experts. It could also embarrass the nuclear industry, whose brand is built on the longstanding (if dubious[89,90]) claim that nuclear power and nuclear weapons are wholly unrelated. In the United States, actual civilian/military nuclear links are too tenuous to violate the Non-Proliferation Treaty's obligation on non-weapons states to use nuclear energy for *exclusively* peaceful purposes; unlike major nuclear-weapons states (France, UK...) where the two sectors are intimately linked, U.S. materials-production links are minor and readily transferable to existing military facilities. But the Secretary's suggestion that uneconomic civilian nuclear energy must be sustained because its intellectual and manufacturing support of the nuclear weapons establishment is vital to national security will astonish all three of those expert communities. And if the claimed linkages were real, defense budgets, not electric bills, should pay for them.

## 15. Diversifying power supplies

As U.S. electricity supply rapidly diversifies away from incumbents' coal and nuclear assets and toward insurgents' gas and renewable assets plus efficient and timely use, the supply portfolio is getting more diverse, not less. Incumbents naturally want their own legacy assets retained on grounds of still greater diversity. However, "The commendable impulse to diversify power sources does not require substituting one particularly brittle and costly source for another, any more than diversifying a financial portfolio will make it perform better if you unwisely choose costly and risky investments".[91] It's therefore fortunate that efficient market outcomes—choosing demand-side and renewable resources over gas-fired generation, and all of these over coal and nuclear generation—can also enhance reliability, resilience, choice, competition, national and community security, climate protection, and Creation care.

## 16. Fourteen magical properties claimed for coal and nuclear power stations

The electricity debate sparked by the 2017 change of federal administration is just beginning. Perhaps my taxonomy of 14 novel virtues claimed for prolonging the operation of coal and nuclear plants (if not building more), and arguments that customers should pay more and competitive markets should give way to obtain those virtues, will help inform a discussion that needs clear thinking, rigorous logic, and sound evidence. So far, the proposed case for compensating coal and nuclear plants more than wholesale power markets now do is not convincing. This article, reinforced by other recent analyses,[92,93,94,95] has explained and documented why:

1. Prolonging the operation of distressed nuclear plants reduces and retards climate protection, because high operating costs avoided by those plants' retirement could buy more carbon savings.
2. Pricing carbon and other pollutants, instead of adding targeted subsidies, would properly recognize zero-emission resources, advantage nuclear against gas and coal, and not distort nuclear power's competition with renewables. (Broader internalization to reflect other attributes may not favor nuclear power.) In contrast, targeted nuclear subsidies harm power markets vital to competitive renewable deployment, block new entrants, and stifle innovation; they protect the old energy system rather than enabling the new one.
3. Thorough and independent analysis of subsidy streams would probably find that nuclear and fossil-fueled generation are more subsidized than renewables.
4. "Large-scale" generation is not needed, and decreases net economic value and resilience.
5. "Baseload" (large, thermal, relatively steady) generation is not a needed attribute, but often brings inflexibility that complicates grid management and inhibits adoption of cheaper, cleaner, and more-resilient renewables.
6. The rich menu of grid flexibility resources, of which bulk storage is the costliest and least necessary, makes dispatchability no longer a vital attribute. Maintaining reliability despite high fractions of variable renewables requires well-known improvements to operations, grids, and markets. Renewables are generally charged for these, but big thermal plants are not charged for their corresponding balancing costs, which emerging evidence suggests are probably larger.
7. Coal and nuclear plants merit no special rewards for their relatively steady output shape—quite the contrary, as their inflexibility complicates grid integration.
8. Coal and nuclear plants' "fuel on hand" has not historically shielded them from widespread coincident failures arising onsite or in upstream infrastructure, and hence does not improve grid resilience. Rather, their large unit scale reduces resilience, increases exposure to grid failures (overwhelmingly the main cause of blackouts), and increases backup costs.
9. Resisting "value deflation" is a greater problem for nonrenewable than for renewable generators, and for renewables, has been greatly exaggerated by modeling artifacts.
10. Charging renewables for "imposing" coal and nuclear plants' competitive losses is improper and contrary to accepted market principles whereby competitors win or lose.
11. Financial economics requires, but many buyers neglect, counting the market value of fuels' price volatility. Doing so would recognize renewables' and efficiency's valuable fixed-price attribute and reduce societal risk.
12. Coal and nuclear plants' outlays for payrolls and taxes are reimbursed by customers, are costs rather than benefits, should not be specially rewarded in power markets, and support fewer jobs per MWh than do equivalent efficiency and modern renewables.
13. Nuclear power's claimed support for U.S. nuclear weapons programs seems illusory (and contradicts the industry's branding), but it were real, should be paid for via defense budgets, not electric bills.
14. Modern renewables and demand-side resources are rapidly diversifying U.S. electricity from vulnerability toward resilience. Retaining obsolete and less resilient technologies for the sake of diversification would advance this goal in name but contradict it in practical effect.

These conclusions suggest that if the lively and worthwhile national debate Secretary Perry has launched is well-informed and transparent, its conclusions should support wider use and faster deployment not of coal and nuclear energy but of efficiency, flexible loads, and modern renewables. Elucidating the complex and important issues the Secretary has

[89] Lovins, A. & L., & Ross, L. Nuclear power and nuclear bombs. *Foreign Affairs* 58:1137–1177 (Summer 1980), www.rmi.org/rmi/Library/S80-02_NuclearPowerNuclearBombs.

[90] Cooke, S. *In Mortal Hands*. Bloombury USA, 2010.

[91] Ref. 77.

[92] Goggin, M. Renewable Energy Builds a More Reliable and Resilient Electricity Mix. American Wind Energy Association, May 2017, http://awea.files.cms-plus.com/FileDownloads/pdfs/AWEA%20Renewable%20Energy%20Builds%20a%20More%20Reliable%20and%20Resilient%20Electricity%20Mix.pdf.

[93] Solar Energy Industries Association, "Solar & Renewables Benefits the Grid and the U.S. Economy," May 16, 2017, http://www.seia.org/sites/default/files/resources/Grid-Econ-Benefits-Briefing-Paper_5-16-17.pdf.

[94] Advanced Energy Economy Institute, "Changing the Power Grid for the Better," May 2017, http://info.aee.net/changing-the-power-grid-for-the-better.

[95] American Council On Renewable Energy, "Energy Fact Check: The Impact of Renewables on Electricity Markets and Reliability," May 16, 2017, http://www.acore.org/energyfactcheck-gridstudy.

raised should build understanding, advance the national interest, and enhance global prosperity and security. Experts who understand these issues have a special responsibility for promptly contributing to the debate.

## Acknowledgements

The author thanks Peter Bradford, Mark Dyson, Virginia Lacy, Ryan Laemel, Chris Nelder, and several anonymous reviewers for research and editorial help.

**Physicist Amory B. Lovins** has advised major firms (including utilities) and governments worldwide for over 40 years; written 31 books and over 600 papers; and received the Blue Planet, Volvo, Zayed, Onassis, Nissan, Shingo, and Mitchell Prizes, MacArthur and Ashoka Fellowships, 12 honorary doctorates, the Heinz, Lindbergh, Right Livelihood, National Design, and World Technology Awards, and Germany's Officer's Cross of the Order of Merit. An honorary architect, Swedish engineering academician, and former Oxford don, he has taught at 10 universities. *Time* named him one of the world's 100 most influential people, and *Foreign Policy*, one of the 100 top global thinkers.

# ARTICLE

# Carbon Pricing in New York ISO Markets: Federal and State Issues

JUSTIN GUNDLACH & ROMANY WEBB*

## EXECUTIVE SUMMARY

*New York's Clean Energy Standard ("CES"), adopted in August 2016, aims to steer the state's electricity sector away from carbon-intensive generation sources. It supports low-carbon alternatives by requiring retail electricity suppliers to purchase credits, the proceeds from which are paid to renewable and nuclear generators. Recognizing that this will affect the operation of wholesale electricity markets, New York's electric transmission grid operator (the "New York Independent System Operator" or "NYISO") has commenced a review to assess possible means of incorporating the cost of carbon emissions into market prices.*

*This Article explores two approaches to carbon pricing in NYISO markets: the first would involve NYISO adopting a carbon price of its own initiative with a view to improving the operation of wholesale electricity markets ("Approach 1"), while the second would involve adoption of a carbon price designed to reflect and harmonize state-level policies aimed at reducing electricity sector emissions ("Approach 2"). Under either approach, NYISO would adopt a per megawatt hour carbon price and use it to establish a fee for each generating unit, consistent with its emissions profile. This fee would be added to the prices generators bid into the wholesale*

* Associate Research Scholars at Columbia Law School and Climate Law Fellows at the Sabin Center for Climate Change Law. The authors would like to thank Michael Gerrard, the Andrew Sabin Professor of Professional Practice at Columbia Law School and Faculty Director of the Sabin Center for Climate Change Law, for his helpful advice and guidance in the drafting of this paper. We also thank Michael Burger, Executive Director of the Sabin Center for Climate Change Law, and Ari Peskoe, Senior Fellow in Electricity Law at the Harvard Law School Environmental Law Program Policy Initiative, for their insightful comments on an early draft of this paper.

*electricity market and those adjusted prices used by NYISO to determine the dispatch order. The result would likely be a re-ordering of dispatch, with high-emitting generators dispatched (and paid) less frequently, and cleaner alternatives more frequently.*

*Our proposal, while conceptually simple, is likely to be difficult to implement. Key issues that must be addressed before its adoption and implementation include:*

- ***Design**: NYISO could derive a carbon price from the social cost of carbon ("SCC"), though this basis would likely be contentious.*
- ***Ensuring fairness for generators**: Whether NYISO derives its carbon price from the SCC or another touchstone, care must be taken to ensure that it does not duplicate other carbon pricing schemes. Some generators bidding into NYISO markets are already subject to carbon pricing through the Regional Greenhouse Gas Initiative ("RGGI"), a cap-and-trade program. The carbon fee may also need to be adjusted to account for the value of zero-emission credits paid to nuclear generators under tier 3 of the CES.*
- ***Mitigating consumer impacts**: Adoption of a carbon pricing scheme by NYISO would likely lead to an increase in wholesale electricity prices, at least in the short term. To offset this increase, revenues generated through carbon pricing should be refunded to retail electricity suppliers in an equitable manner, not tied to their specific purchases.*
- ***Providing legal justification:** Any NYISO carbon pricing scheme would be subject to review by FERC. The Federal Power Act confers broad authority on FERC to shape wholesale electricity markets to ensure that they produce just and reasonable rates. This paper argues that incorporating a carbon price into wholesale electricity rates—under either Approach 1 or Approach 2—would be just and reasonable. We acknowledge, however, that Approach 1 would push the boundaries of past market regulation, though in ways that are consistent with the law and with FERC practice. Approach 2 would fit more comfortably within the existing boundaries of FERC's authority to strike a balance between respecting state-level public policy and ensuring the smooth operation of wholesale markets.*

- ***Arguments supporting Approach 1:***
  - ***Enhancing competition in wholesale energy markets****: The current failure to price carbon undermines the competitiveness of wholesale markets and, more specifically, low-carbon generators' participation in those markets. Adopting a carbon price, based on the SCC, would level the playing field for all market participants and would be wholly consistent with FERC's past efforts to improve the functioning of markets.*
  - ***Ensuring proper wholesale price formation****: FERC has emphasized that, to provide the correct incentives for investment, wholesale electricity rates must reflect the full cost of generation. Currently, however, market-based rates do not reflect the cost of carbon dioxide emissions and associated climate change. As the SCC would exceed costs to market participants, its use could not be justified solely by this argument. Considered in isolation, this argument would justify a lower carbon price, based on costs to market participants.*
- ***Arguments supporting Approach 2:***
  - ***Align wholesale markets with state-level public policy for the short and long term:*** *New York has adopted several policies in service to its goal of decarbonizing the electricity sector, including three that impose disparate prices on a patchwork of generators. It has also articulated long-term targets for emissions reductions that will not be achieved without the adoption of further specific policy measures. A carbon pricing scheme that rationalizes existing public policy and anticipates foreseeable changes to that policy would respect state authority while also ensuring that wholesale markets operate efficiently and send accurate signals to market participants and investors.*

**TABLE OF CONTENTS**

## LIST OF ACRONYMS

| | |
|---|---|
| CAISO | California Independent System Operator |
| CARIS | Congestion Assessment and Resource Integration Study |
| CES | Clean Energy Standard |
| CRP | Comprehensive Reliability Plan |
| dCC | Dormant Commerce Clause |
| DEC | Department of Environmental Conservation |
| EIA | Energy Information Administration |
| EPA | Environmental Protection Agency |
| ERCOT | Electric Reliability Council of Texas |
| FERC | Federal Energy Regulatory Commission |
| FPA | Federal Power Act |
| GHG | Greenhouse gas |
| ICAP | Installed capacity market |
| IMAPP | Integrating Markets and Public Policy |
| ISO | Independent System Operator |
| ISO-NE | New England Independent System Operator |
| LCOE | Levelized cost of electricity |
| LMP | Locational marginal pricing |
| LSE | Load serving entity |
| LTP | Local Transmission Plans |
| LTPP | Local Transmission Planning Process |
| MST | Market Services Tariff |
| MISO | Midcontinent Independent System Operator |
| MW | Megawatt |
| MWh | Megawatt hour |
| NEPOOL | New England Power Pool |
| NYCA | New York Control Area |
| NYGATS | New York Generator Attribute Tracking System |
| NYISO | New York Independent System Operator |
| NYPSC | New York Public Service Commission |

| | |
|---|---|
| NYSERDA | New York Energy Research and Development Authority |
| OATT | Open Access Transmission Tariff |
| PURPA | Public Utilities Regulatory Policies Act |
| PPTPP | Public Policy Transmission Planning Process |
| REC | Renewable Energy Credit |
| RGGI | Regional Greenhouse Gas Initiative |
| RNA | Reliability Needs Assessment |
| RPP | Reliability Planning Process |
| RTO | Regional Transmission Operator |
| SCC | Social Cost of Carbon |
| SPP | Southwest Power Pool |
| ZEC | Zero Emission Credit |

## I. INTRODUCTION

As part of its ongoing efforts to combat climate change, New York has committed to reduce statewide greenhouse gas ("GHG") emissions by forty percent below 1990 levels by 2030 (the "40 by 30 goal").[1] The bulk of emissions reductions are expected to come from the electricity sector, with the state aiming to secure fifty percent of its electricity needs from zero-emitting renewable generators.[2] Consistent with this goal, the state's Clean Energy Standard ("CES") requires retail electricity suppliers ("Load Serving Entities" or "LSEs") to purchase Renewable Energy Credits ("RECs"), the proceeds from which will be paid to renewable generators.[3] The CES also requires LSEs to obtain Zero-Emission Credits ("ZECs"), which compensate nuclear generators for their zero-emission attributes.[4]

Prompted in part by the adoption of the CES, the New York Independent System Operator ("NYISO"), a non-profit corporation which oversees electricity transmission and wholesale sales in New York, commenced a review in the fall of 2016 to assess whether and

1. N.Y. STATE ENERGY PLANNING BD., THE ENERGY TO LEAD: 2015 NEW YORK STATE ENERGY PLAN 112 (2015), https://perma.cc/F2B9-LTF9.
2. *Id.*
3. Order Adopting a Clean Energy Standard, Case No. 15-E-0302 at 14–16 (N.Y. Pub. Serv. Comm'n Aug. 1, 2016), https://perma.cc/ZJZ8-WX4S [hereinafter NYPSC Clean Energy Standard Order].
4. *Id.* at 19–20.

how generators' GHG emissions should be priced in wholesale electricity markets.[5] The Brattle Group was engaged by NYISO to analyze various emissions pricing schemes and published a report summarizing their likely effects in August 2017.[6] Building on that report, this Article explores two approaches to emissions pricing in wholesale markets and discusses the legal implications of each.

Wholesale electricity markets have generally treated GHG emissions as a wholly exogenous externality of generation, to be addressed—if at all—through environmental policy tools such as pollution control laws or temporary emerging-market subsidies for the nascent renewables industry.[7] In our view, however, the Federal Energy Regulatory Commission ("FERC") has authority to approve a NYISO tariff that prices-in emissions insofar as it (a) merely makes way for or harmonizes public policy at the state level or (b) can be shown to improve the functioning of wholesale markets to ensure just and reasonable rates. These two legal paths to emissions pricing are not mutually exclusive, but they are distinct and would have implications for the approach taken by NYISO.

Both paths are rooted in the authority conferred by the Federal Power Act ("FPA"), which empowers FERC to shape wholesale electricity markets and steer transmission planning to ensure that the bulk power system delivers reliable electricity services for just and reasonable rates.[8] Although FERC has not previously relied on this authority to price GHG emissions, neither the FPA's capacious language nor the judicial decisions that have interpreted it prevent such a step. Indeed, as explained below, we read existing authority as all but commanding that wholesale markets be reconfigured to better account for the costs of emissions.

---

5. *See generally* Shawn Whites, *Pricing Carbon in Wholesale Electricity Markets: RTOs/ISOs Looking at a Carbon Price to Integrate Regional Public Policy Goals*, AG SPEAKING ENERGY (Oct. 21, 2016), https://perma.cc/TF6B-SB78 (discussing the NYISO review).
6. SAMUEL A. NEWELL ET AL., THE BRATTLE GRP., PRICING CARBON INTO NYISO'S WHOLESALE ENERGY MARKET TO SUPPORT NEW YORK'S DECARBONIZATION GOALS (2017), https://perma.cc/QH8S-6X9R.
7. *See* Grand Council of the Crees v. FERC, 198 F.3d 950, 957 (D.C. Cir. 2000) ("[Potential] siting, health, safety, environmental [or] archeological problems . . . [are] beyond the Commission's authority to consider under sections 205 and 206 of the Federal Power Act.").
8. 16 U.S.C. § 824d(a) (requiring wholesale electricity rates to be just and reasonable).

The authors recognize that one of our proposed paths to pricing emissions—which would see NYISO adopting an emissions price of its own initiative with a view to improving the operation of wholesale electricity markets—would push the boundaries of what has to date been considered the limit of FERC's authority. Many view climate change as an environmental externality whose attendant costs lay beyond the scope of what ought to inform FERC's assessment of wholesale rates' justness and reasonableness.[9] We argue, however, that climate change and the GHG emissions that cause it materially affect the wholesale energy market. The carbon pricing scheme we propose would ensure that those effects are properly accounted for in market prices. The proposal would, like several other recent orders, enhance competition and improve price formation. It would also support effective planning.

The fact that the FPA does not expressly authorize emissions pricing in wholesale markets is not fatal. FERC has, in the past, taken steps not contemplated in the FPA. The establishment of wholesale markets is a good example. At the time the FPA was enacted, electricity services were provided by vertically integrated utilities.[10] Markets evolved gradually over time, as a result of various FERC actions, beginning with the adoption of Order 888 in 1996.[11] That order laid the groundwork for competitive energy markets by requiring utilities to provide "open access" transmission services to unaffiliated generators.[12] The order is widely considered a response to the Energy Policy Act of 1992, which authorized FERC to order individual utilities to provide transmission

9. *See* Todd S. Aagard, *Energy-Environment Policy Alignments*, 90 WASH. L. REV. 1517, 1546 (2015) ("Broadening FERC's authority to encompass externalities and other market failures . . . would fundamentally re-orient the agency in ways that would likely generate significant opposition from both inside and outside the agency—and perhaps from courts as well."); John S. Moot, *Subsidies, Climate Change, Electric Markets and the FERC*, 35 ENERGY L.J. 345, 348 (2014) (stating without explanation that ignoring generators' GHG emissions is "fuel-neutral"); ERIC FILIPINK, NAT'L REGULATORY RESEARCH INST., SERVING THE "PUBLIC INTEREST" — TRADITIONAL VS EXPANSIVE UTILITY REGULATION NO. 10-02 (2009), https://perma.cc/UMU7-WKXN (discussing aspects of issue in retail market context).
10. *See generally* New York v. FERC, 535 U.S. 1, 6 (2002).
11. Order No. 888, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 Fed. Reg. 21,540 (Apr. 24, 1996) (codified at 18 C.F.R. pts. 35, 38).
12. *Id.* at 4.

services on a case-by-case basis.[13] Crucially, however, it is the FPA and not the 1992 Act that provides the legal basis for FERC's creation of wholesale markets.[14] Indeed, FERC went beyond what the 1992 Act required after recognizing that the process it prescribed would be too costly and time-consuming to ensure just and reasonable rates.[15]

This paper proceeds as follows: Parts 2, 3, and 4 provide background on electricity infrastructure, wholesale markets, and carbon pricing respectively—topics that are likely familiar for some readers. Part 5 briefly discusses New York State's current carbon pricing programs, which are designed to operate outside the wholesale electricity market. Part 6 explores mechanisms NYISO could employ to implement a carbon price in the wholesale market. And Part 7 offers arguments that could be presented in support of a NYISO carbon price proposal to FERC.

## II. ELECTRICITY MARKETS 101

Electricity services were historically provided by vertically integrated utilities, which owned generating units as well as transmission and distribution infrastructure.[16] Each utility operated as a regulated monopoly, selling electricity within an exclusive service territory.[17] Regulation of electricity sales was—and still is—shared between the federal government and the states.[18] At the federal level, FERC is authorized to regulate the transmission and wholesale sale of electricity in interstate commerce under the FPA.[19] The FPA defines wholesale sales as sales of electricity "to

13. *See, e.g.*, Marcel A. Lamoureux, *FERC's Impact on Electric Utilities*, 8 IEEE POWER ENG'G REV. 8 (2001) ("As a direct result of the Energy Policy Act of 1992, FERC issued Orders 888 and 889 in 1996.").
14. New York v. FERC, 535 U.S. 1, 11 (2002) ("Rather than grounding its legal authority [to issue Order 888] in Congress' more recent electricity legislation, FERC cited §§ 205–206 of the 1935 FPA—the provisions concerning FERC's power to remedy unduly discriminatory practices—as providing the authority for its rulemaking. *See* 16 U.S.C. §§ 824d–824e.").
15. *Id.* at 11–14.
16. *See generally* New York v. FERC, 535 U.S. 1, 6 (2002).
17. *Id.*
18. 16 U.S.C. § 824 (2012). *See also* Fed. Power Comm'n v. S. Cal. Edison Co., 376 U.S. 205 (1964).
19. 16 U.S.C. § 824(a)–(b) (2012) (providing for federal regulation of the "transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce").

any person for resale."[20] Those sales are considered to occur in "interstate commerce" whenever electricity is transmitted via an *interstate* grid.[21] Where transmission occurs via an *intrastate* grid, the sale is not subject to regulation by FERC, but may be regulated by the state in which it occurs.[22] The states also regulate retail electricity sales.[23]

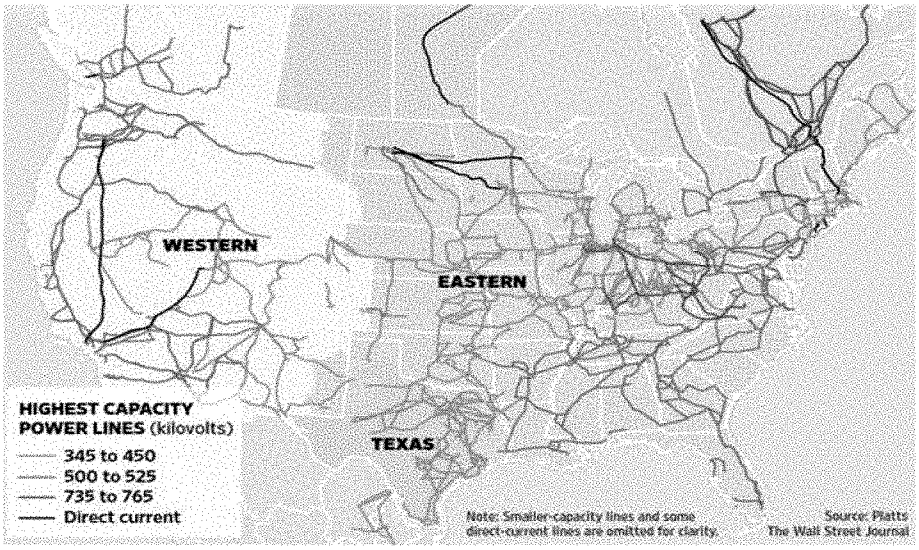
In the contiguous U.S., electricity is transmitted via three main synchronous grids, namely:

1. the Eastern Interconnection, which extends from central Canada south to Florida and includes all U.S. territory east of the Great Plains, except parts of Texas and Maine;
2. the Western Interconnection, which extends from western Canada south to Mexico and includes all U.S. territory west of the Great Plains; and
3. the Texas Interconnection, which covers most of Texas.[24]

As the Eastern and Western Interconnections cross state borders, electricity transmission thereon is considered to occur in interstate commerce, subjecting it to regulation by FERC.[25] FERC's regulatory duties include ensuring that wholesale electricity rates are just and reasonable and not unduly discriminatory or preferential, and that the bulk power system operates reliably.[26]

20. *Id.* § 824(d).
21. Fed. Power Comm'n v. Fla. Power & Light Co., 404 U.S. 453, 461 (1972).
22. 16 U.S.C. § 824(b)(1). *See also S. Cal. Edison Co.*, 376 U.S. 205.
23. *S. Cal. Edison Co.*, 376 U.S. 205.
24. *Learn More About Interconnections*, U.S. DEP'T OF ENERGY, https://perma.cc/S688-5L7T.
25. New York v. FERC, 535 U.S. 1, 7–8 (2002).
26. 16 U.S.C. § 824d(a) (requiring that "[a]ll rates and charges made, demanded, or received by any public utility for . . . [the] sale of electric energy subject to the jurisdiction of the Commission . . . shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful"); § 824d(b) (providing that "[n]o public utility shall, with respect to any . . . sale subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage"); § 824d(e) (authorizing FERC to conduct "a hearing concerning the lawfulness of" any rate or charge); § 824e(a) (requiring FERC, when it determines that a rate or change "is unjust, unreasonable, unduly discriminatory or preferential . . . [to] determine the just and reasonable rate" or charge); § 824o (providing FERC with authority to enforce "reliability standards" via "Electric Reliability Organizations" certified by FERC).

**Figure 1: Transmission Interconnections in the Continental U.S.**[27]




For most of the 20th century, FERC regulated wholesale electricity rates exclusively on a cost-of-service basis, under which utilities were permitted to recover the prudent expenses they incurred in providing services, plus a reasonable return on capital.[28] Recently, however, FERC has increasingly relied on markets to set rates. This shift began in the late 1980s, with FERC issuing a series of market-based rate authorizations which exempt utilities and other suppliers from cost-of-service regulation, allowing them to sell electricity at market-based rates.

### A. The Evolution of Wholesale Electricity Markets

Historically, vertically-integrated utilities produced electricity through self-supply (i.e., by constructing their own generating units).[29] Utilities also entered into long-term bilateral contracts to

27. Matt Kasper, *How to Secure the Grid and Save Ratepayers Money*, ENERGY & POLICY INSTITUTE, https://perma.cc/C3PP-FY77.
28. JAMES H. MCGREW, FERC: FEDERAL ENERGY REGULATORY COMMISSION 179 (2d ed. 2009).
29. FRED BOSSELMAN ET AL., ENERGY, ECONOMICS AND THE ENVIRONMENT: CASES AND MATERIALS 659 (2000).

purchase electricity from independently owned generating units.[30] Such bilateral contracts are still widely used to procure electricity today; procurement also occurs through wholesale spot markets in some areas.[31]

The origins of wholesale markets can be traced back to the energy crisis of the 1970s. In response to the crisis, Congress enacted the Public Utilities Regulatory Policies Act of 1978 ("PURPA")[32] to incentivize alternative means of electricity generation, among other things. PURPA led to the construction of hundreds of merchant generating facilities, the owners of which demanded access to the utility-owned transmission grid to transport their electricity to retailers and/or consumers.[33] In response to those demands, Congress enacted the Energy Policy Act of 1992,[34] which authorized FERC to order individual utilities to provide transmission services to merchant generators.[35] After issuing twelve such orders in twelve separate proceedings, FERC determined that this case-by-case approach was too costly and time-consuming to provide an adequate remedy for undue discrimination.[36] Thus, in 1996, it issued Orders 888[37] and 889 requiring all utilities to provide "open access" transmission services.[38]

Orders 888 and 889 aimed to, among other things, enhance merchant generators' access to electric utilities' transmission infrastructure.[39] Utilities were required to unbundle electricity transmission from sales[40] and act as common carriers, providing

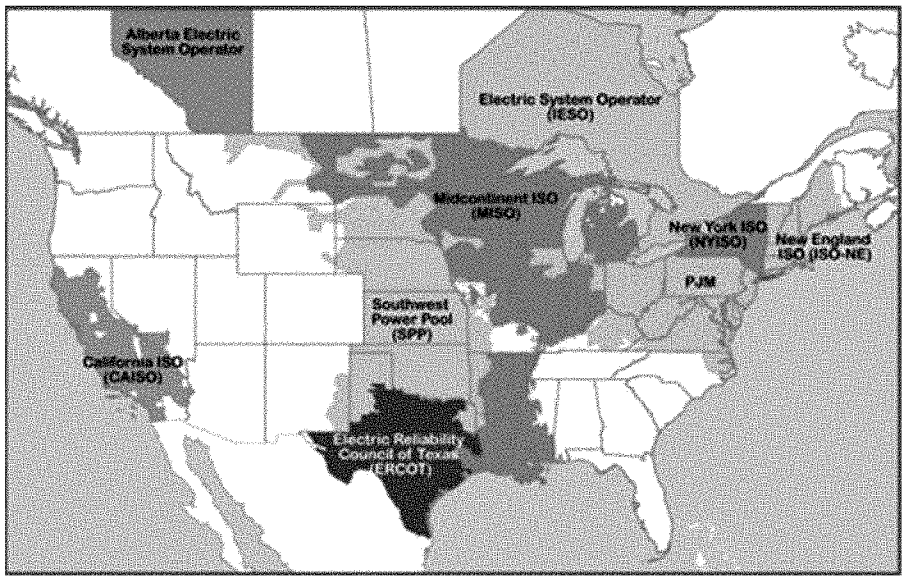
30. *Id.* at 671.
31. *Id.* at 671, 787.
32. Public Utilities Regulatory Policies Act, Pub. L. No. 95-617, 92 Stat. 3117 (1978) (codified as amended at 16 U.S.C. §§ 2601–2645 (2012)).
33. BOSSELMAN ET AL., *supra* note 29, at 718–19.
34. Energy Policy Act of 1993, Pub. L. 102-486; 106 Stat. 2776 (1992).
35. 16 U.S.C. § 824j.
36. For a discussion of this issue, see New York v. FERC, 535 U.S. 9–14 (2002).
37. Order No. 888, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 Fed. Reg. 21,540 (Apr. 24, 1996) (codified at 18 C.F.R. pts. 35, 385).
38. Order No. 889, Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct, 61 Fed. Reg. 21,736 (Apr. 24, 1996) (codified at 18 C.F.R. pt. 37).
39. Order No. 888, 61 Fed. Reg. at 21,540.
40. *Id.* at 21,525–29.

transmission services to both affiliated and non-affiliated companies on a non-discriminatory basis.[41] FERC suggested that utilities could "ensure fair and non-discriminatory access to transmission services" by forming independent system operators ("ISOs") to manage the transmission grid.[42] Subsequently, in Order 2000, FERC encouraged utilities to place their transmission facilities under the management of an ISO or Regional Transmission Operator ("RTO").[43]

ISO/RTOs are independent bodies which operate the transmission system in one or more states. Figure 2 below shows the ISO/RTOs currently operating in the U.S. Six of those ISO/RTOs—the California IOS ("CAISO"), Midcontinent ISO ("MISO"), New England ISO ("ISO-NE"), NYISO, PJM Interconnection ("PJM"), and Southwest Power Pool ("SPP")—are regulated by FERC.[44] FERC does not have regulatory authority over the Electric Reliability Council of Texas ("ERCOT"), as its transmission system "is located solely within the state of Texas and is not synchronously interconnected to the rest of the United States."[45]

41. *Id.*
42. *Id.* at 21,596.
43. Order No. 2000, Regional Transmission Organizations, 65 Fed. Reg. 45,854 (July 20, 2000) (codified at 18 C.F.R. pt. 35).
44. CAISO, ISO-NE, MISO, NYISO, PJM, and SPP operate interstate transmission facilities subject to FERC jurisdiction. 16 U.S.C. § 834(b)(1) (providing that FERC has jurisdiction over all facilities used in the interstate transmission of electricity). *See also Compliance*, PJM, https://perma.cc/67VZ-D4R2; *Diligent Oversight Ensures a Competitive Market*, CAISO, https://perma.cc/3L9K-ZGB6; *History: 75 Years of Reliability Through Relationships*, SPP, https://perma.cc/5YCZ-APEF; *Industry Standards, Structure, and Relationships*, ISO NEW ENGLAND, https://perma.cc/GX8N-WDK5; *Leadership and Governance*, MISO, https://perma.cc/9EBT-WZKK; *Regulatory Accountability*, NYISO, https://perma.cc/AJY3-5HGP .
45. *ERCOT*, FERC, https://perma.cc/UE82-FFE3 (last updated Nov. 17, 2015). ERCOT's operations are overseen by the Public Utility Commission of Texas and the state legislature. *See Electric Power Markets: Texas (ERCOT)*, FERC, https://perma.cc/GB6D-6SGV (last updated Mar. 10, 2016).

**Figure 2: ISO/RTOs Operating in the U.S.**[46]




Each ISO/RTO is a non-profit or profit-neutral corporation that contracts with transmission facility owners ("Transmission Owners") regarding transmission and wholesale market governance.[47] In addition to those basic contracts, each ISO/RTO also adopts two types of tariffs, subject to FERC review (ERCOT's excepted), that specify how the ISO/RTO is to oversee regional transmission facilities and markets; the Open Access Transmission Tariff ("OATT") governs to the former, the RTO tariff, sometimes called the Market Services Tariff, the latter.[48]

46. *Regional Transmission Organizations (RTO) / Independent System Operators (ISO)*, FERC, https://perma.cc/NBP4-837E (last updated Oct. 19, 2017).
47. CAISO, AMENDED AND RESTATED TRANSMISSION CONTROL AGREEMENT AMONG THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION AND TRANSMISSION OWNERS (2017), https://perma.cc/JRQ6-2EJ5; PJM INTERCONNECTION, AMENDED AND RESTATED OPERATING AGREEMENT OF PJM INTERCONNECTION, LLC (2011), https://perma.cc/KX2K-2T8Y; *Transmission Operating Agreements*, ISO NEW ENGLAND, https://perma.cc/UVB4-HWFL (providing links to Transmission Operating Agreement, Rate Design and Funds Disbursement Agreement, Phase I/II Transmission Operating Agreement, and Phase I/II HVDC transmission facility).
48. FERC, ENERGY PRIMER: A HANDBOOK OF ENERGY MARKET BASICS 53, 57 (2015), https://perma.cc/KT2H-QQ3Q.

### B. Wholesale Electricity Market Operation

Each ISO/RTO operates two wholesale electricity or "energy" markets, namely:

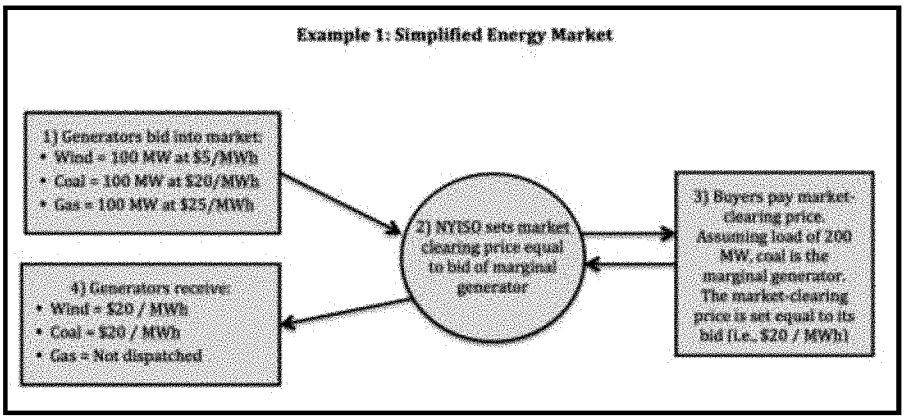
1. a day-ahead market, in which participants commit to buy or sell electricity at various times over the next twenty-four hours, based on forecast demand ("load"); and
2. a real-time market, in which participants buy and sell electricity to balance differences between the day ahead commitments and actual load and generation.[49]

Wholesale energy markets are open to any entity that, after securing the necessary approvals, can generate electricity and deliver it to the grid. The principal suppliers in most markets are utilities with excess generating capacity, utility-affiliated competitive generators, and independent power producers.[50] The principal buyers in most markets are LSEs, which provide retail electricity services to residential, commercial, and industrial customers. LSEs participating in wholesale energy markets currently serve consumers accounting for two-thirds of national electricity load.[51]

While the specific design of energy markets varies between ISO/RTOs, all use bid-based auctions to set prices. During the auction, generators submit bids indicating the price at which they are willing to supply electricity, based on their marginal costs.[52] Generators are dispatched based on their bids, from lowest to highest, until load is satisfied.[53] The bid of the last supplier dispatched (the

49. FERC, SECURITY CONSTRAINED ECONOMIC DISPATCH: DEFINITION, PRACTICES, ISSUES, AND RECOMMENDATIONS 5–6 (2006), https://perma.cc/8HW6-KKHC.
50. Another category of suppliers is demand-response aggregators—entities that enlist end-users to participate in demand-response programs, whereby the end-users agree to curtail their electricity use at certain times and sell the combined load reduction in wholesale energy markets.
51. *Electric Power Markets: National Overview*, FERC, https://perma.cc/2X7R-S2RH (last updated Feb. 9, 2016).
52. Generators' bids typically reflect their variable costs of operation, including operations and maintenance costs, fuel costs, and emissions costs (e.g., the cost of acquiring emissions permits) (if any). SUSAN F. TIERNEY & PAUL J. HIBBARD, ANALYSIS GRP., CARBON CONTROL AND COMPETITIVE WHOLESALE ELECTRICITY MARKETS: COMPLIANCE PATHS FOR EFFICIENT MARKET OUTCOMES 35 (2015), https://perma.cc/F2Q7-WUFK.
53. An ISO/RTO may elect not to dispatch generators on the basis of cost if doing so would threaten the security of the electricity system. Thus, for example, an ISO/RTO may choose not to dispatch the least-cost generator if doing so would result in transmission congestion or other operational problems. This

"marginal generator") determines the market-clearing price which is paid to all suppliers regardless of their bids (see Example 1).[54]




Several ISO/RTOs also administer auctions for procuring capacity. In Order 2000, FERC determined that ISO/RTOs should be responsible for maintaining electric system reliability,[55] which, in practice, means ensuring sufficient generating capacity is available to satisfy load.[56] To that end, ISO/RTOs may operate capacity markets in which owners of generating facilities are paid to have

approach is known as "security constrained least-cost" dispatch. For a discussion of security constrained least cost dispatch, see FERC, *supra* note 49, at 5–9.

54. AM. PUB. POWER ASS'N, WHOLESALE ELECTRICITY MARKETS AND REGIONAL TRANSMISSION ORGANIZATIONS 2 (2017), https://perma.cc/V74X-WH99.

55. Order No. 2000, Regional Transmission Organizations, 65 Fed. Reg. 45,854, 45,854 (July 20, 2000) (codified at 18 C.F.R. pt. 35).

56. *See* N. AM. ELEC. RELIABILITY CORP. (NERC), 2016 LONG-TERM RELIABILITY ASSESSMENT 1 (2016) (explaining that, over the long term, reliability is primarily a function of resource adequacy).

reserves[57] available in case they are needed in the future.[58] Capacity markets operate in a similar way to energy markets, with participants submitting bids that reflect the price at which they are willing to buy and sell capacity.[59] The ISO/RTO then matches the bids to determine a clearing price, which is typically expressed per unit of capacity and paid to suppliers monthly.[60] Whereas capacity prices are recovered through fixed monthly payments, electricity prices fluctuate hourly.

If there were no logistical impediments to the flow of electricity, a single price would apply throughout an ISO/RTO region for a given interval.[61] However, because transmission congestion and/or other operational problems regularly impede electricity flows, some areas must rely on electricity priced above the region's lowest price.[62] To account for differences in the cost of electricity used in different areas, ISO/RTOs price electricity using the locational marginal price ("LMP") at each of various nodes (i.e., locations) on the transmission system.[63]

57. The term "reserves" refers to generating capacity that is currently unused but which is available to serve load. *See generally* ZHI ZHOU ET AL., CTR. FOR ENERGY, ENVTL., AND ECON. SYS. ANALYSIS, SURVEY OF U.S. ANCILLARY SERVICES MARKETS (2016), https://perma.cc/HQ8N-4NBM ("[R]eserves are typically segmented into two categories, 1) Spinning or Synchronized Reserves that are provided by generation units that are actively generating and have the ability to increase or decrease their output, 2) Non-spinning or Non-synchronized Reserves that are provided by generation resources that are not actively generating, but are able to start up and provide generation within a specified timeframe. Operating reserves typically have response times on the order of ten to 30 minutes and can similarly be provided by supply-side resources that are capable of reducing their load.").
58. Alternatively, an ISO/RTO may impose "resource adequacy" obligations on load-serving entities, requiring them to self-supply capacity, either through construction of new capacity resources or by entering into bilateral arrangements to purchase capacity. *See* TIERNEY & HIBBARD, *supra* note 52, at 36.
59. Adam James, *Explainer: How Capacity Markets Work*, MIDWEST ENERGY NEWS (Jun. 17, 2013), https://perma.cc/8VTY-U9X4.
60. *Id. See also What You Need to Know About Capacity Payments*, ENERGYWATCH, https://perma.cc/KJ8B-V6P5.
61. PJM INTERCONNECTION, LOCATIONAL MARGINAL PRICING (2016), https://perma.cc/T9VQ-KD4K.
62. *Id.*
63. For a discussion of locational marginal pricing, see *Frequently Asked Questions, Locational Marginal Pricing*, ISO-NE, https://perma.cc/2FCU-ULAT; NYISO, "Locational Based Marginal Pricing: The Cornerstone of the NYISO Market Operation," https://perma.cc/FXR3-VJWL; and *Buying & Selling*

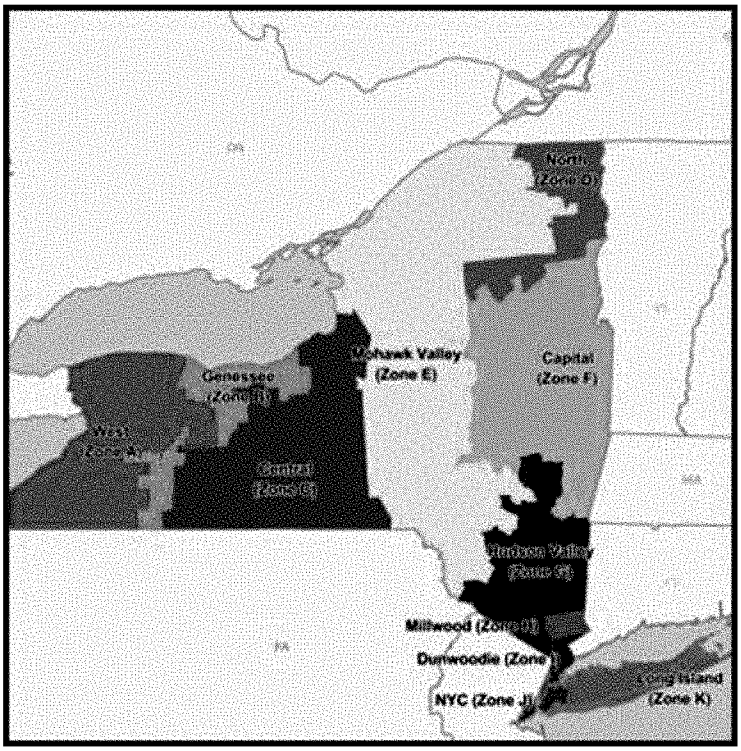
## III. ELECTRICITY MARKETS IN NEW YORK

Electricity transmission and wholesale electricity sales in New York are managed by NYISO. NYISO's responsibilities include balancing electricity generation and load in the New York Control Area ("NYCA"), which is coterminous with New York's borders.[64] NYISO divides the NYCA into 11 Zones (see Figure 3 below). Of those, the five "downstate" Zones (Long Island, New York City, Dunwoodie, Millwood, and the Lower Hudson Valley) account for about fifty-eight percent of the state's load and sixty-five percent of its peak load, but generate only forty percent of its electricity.[65] This mismatch has made congestion between downstate and upstate zones[66]—and downstate transmission adequacy more generally—a high-priority issue.[67] The addition of over 2,700 MW of transmission capacity since 2000 has not resolved the issue, not least because peak load continues to grow even as NYISO-wide load has flattened out.[68]

*Energy, Locational Marginal Pricing*, PJM INTERCONNECTION, https://perma.cc/6BED-UX4C.

64. NYISO, "Power System Fundamentals," Slide 11 (Oct. 17, 2017), https://perma.cc/T2JR-RQHJ.
65. NYISO, POWER TRENDS 2016: THE CHANGING ENERGY LANDSCAPE 2, 29 (2016), https://perma.cc/W3QB-9DZH [hereinafter NYISO, POWER TRENDS 2016].
66. B. Howard et al., *Current and Near-Term GHG Emissions Factors from Electricity Production for New York State and New York City*, 187 APPLIED ENERGY 255, 258 (2017).
67. *See* DAVID B. PATTON ET AL., POTOMAC ECONOMICS, 2015 STATE OF THE MARKET REPORT FOR THE NEW YORK ISO MARKETS 10 (2016), https://perma.cc/DRW2-GSFJ (charting levels of inter-zone congestion and noting that the value of congestion—meaning costs resulting from it—were $539 and $700 for the day-ahead and real-time energy markets respectively).
68. NYISO, POWER TRENDS 2016, *supra* note 65, at 9–10 fig.6.

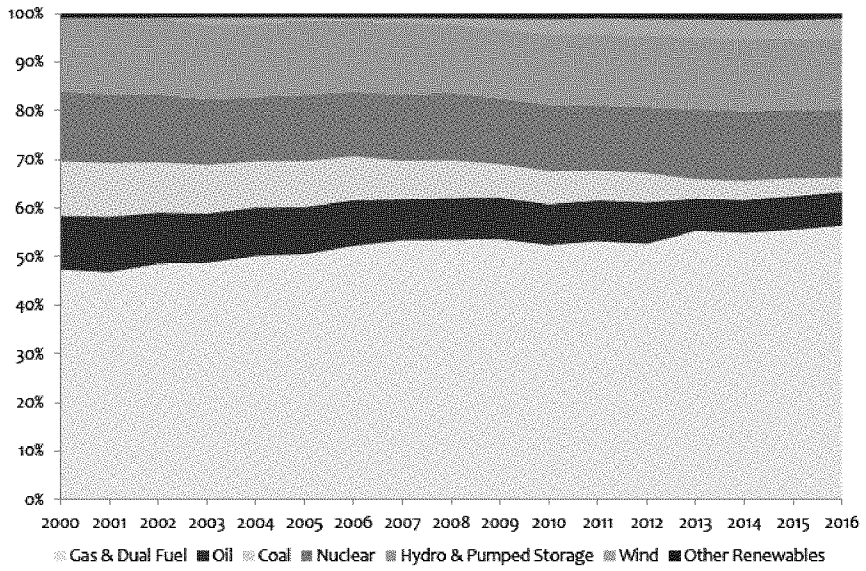
**Figure 3: NYISO Zones A through K**[69]




The generation mix in NYISO has changed substantially over the last decade.[70] Since 2000, coal and oil have declined, natural gas and renewables have made up the difference, and nuclear and hydro have held steady (see Figure 4).[71] These changes have contributed to substantial reductions in regional emissions: annual sulfur dioxide emissions have dropped ninety-seven percent and carbon dioxide emissions forty-two percent.[72]

69. *Electric Power Markets: New York (NYISO)*, FERC, https://perma.cc/WQ7X-DVR8 (last updated Aug. 3, 2017).
70. *See* NYISO, 2016 LOAD & CAPACITY DATA, GOLD BOOK (2016), https://perma.cc/W45L-JLDR.
71. NYISO, POWER TRENDS 2016, *supra* note 65, at 26 fig.20.
72. *Id.* at 36.

**Figure 4: NYISO Generation Mix 2000 - 2016**[73]




### A. NYISO Markets for Energy, Capacity, and Ancillary Services

Like other ISO/RTOs, NYISO manages markets that allocate energy, ancillary services, and capacity. The energy and ancillary services markets establish prices reflective of the value of energy at each locational node on the NYISO transmission network.[74] The capacity markets establish prices reflective of expectations for how much existing and new capacity will be required to meet demand generally and at peak times.[75]

NYISO's markets for energy assign location-specific prices in five-minute increments based on day-ahead and real-time auctions, as well as bilateral contracts between wholesalers and retailers.[76] The day-ahead market schedules about ninety-six percent of

73. *Id.* at 26.
74. NYISO, NYISO MARKETS: NEW YORK'S MARKETPLACE FOR WHOLESALE ELECTRICITY 4, https://perma.cc/48C2-Q7JP [hereinafter NYISO, NYISO MARKETS].
75. *Id.*
76. *Id.* at 11.

the energy that is delivered in NYISO; the real-time market schedules the remainder and thereby serves as a corrective for day-ahead arrangements that over- or under-estimate load.[77] Auctions account for about sixty percent of NYISO's energy transactions; bilateral contracts account for the remaining forty percent.[78]

NYISO's ancillary services markets assign prices to a group of operations that underpin reliability by filling in gaps left by the energy markets. NYISO provides some of those operations, some are provided by transmission customers and suppliers, and others are self-provided by NYISO market participants.[79] These operations, which draw on both physical equipment and human resources, include:

- voltage support, meaning maintenance of a voltage level that falls within both power quality requirements and transmission facilities' heat tolerances;[80]
- regulation and frequency response, which involves minute-to-minute adjustments that balance out unexpected small changes in generation and load;[81]
- energy imbalance, which is the term of art for allocations and settlements arrived at through the real-time market that correct for over- or under-estimates by day-ahead market participants and managers;[82]
- operating reserves, which stand ready to provide backup electricity or demand response for ten- and thirty-minute intervals in case of a sudden large change in generation or load at a given nodal location;[83] and
- black start capability, which is the ability of a generating unit to, after shutting down due to a general blackout and without assistance from the grid, begin operating and delivering power to the grid.[84]

Whereas NYISO's energy and ancillary services markets provide for electricity services in the short term, its installed capacity

77. PATTON ET AL., *supra* note 67, at 36.
78. NYISO, NYISO MARKETS, *supra* note 74, at 4.
79. NYISO, ANCILLARY SERVICES MANUAL 1-1 (2016), https://perma.cc/ENW4-ED26.
80. *Id.* at 3-1.
81. *Id.* at 4-1.
82. *Id.* at 5-1.
83. *Id.* at 6-1 to 6-2.
84. *Id.* at 7-1.

market ("ICAP") trades in options to access transmission, generation, and demand response resources at some date up to six months in the future.[85] NYISO's ICAP operates through a series of auctions.[86] In the Capability Period Auction or "strip auction," which occurs twice each year,[87] buyers and sellers trade for one or more months of capacity. Subsequent Monthly Auctions, held at least 15 days before the next calendar month (called an "Obligation Procurement Period"), allocate capacity for any gaps left by the Capability Period Auction.[88] Finally, Spot Market Auctions, held at least two days before each Obligation Procurement Period, resolve any remaining gaps.[89] By assigning auction-derived prices to options to access particular resources, the ICAP signals when additional resources—whether located within the NYCA or other balancing areas—are foreseeably necessary to ensure reliability over the subsequent months.[90]

### B. NYISO's Approach to Planning and Tariff Revision

Although NYISO's geographic boundaries align with those of New York, NYISO's physical integration in the Eastern Intercon-

85. NYISO, NYISO MARKETS, *supra* note 74, at 11; *see also* EMILIE NELSON, NYISO, WRITTEN STATEMENT, DOCKET NO. AD14-18-000, JOINT TECHNICAL CONFERENCE ON NEW YORK MARKETS & INFRASTRUCTURE 2–5 (2014), https://perma.cc/SH7V-5BEV (summarizing recent history of ICAP).

86. NYISO, INSTALLED CAPACITY MANUAL §§ 5-1 to 5-5 (2016), https://perma.cc/L9LH-HAGE [hereinafter NYISO, INSTALLED CAPACITY MANUAL]. The parameters for "reliability," which include reserve margins and other elements, are specified by the New York State Reliability Council. *See generally* N.Y. STATE RELIABILITY COUNCIL, RELIABILITY RULES & COMPLIANCE MANUAL FOR PLANNING AND OPERATING THE NEW YORK STATE POWER SYSTEM, VERSION 38 (2016), https://perma.cc/8YVT-5MSG.

87. Auctions must be held at least thirty days before each capability period. The summer capability period runs from May through October, while the winter period runs from November through April.

88. NYISO, INSTALLED CAPACITY MANUAL, *supra* note 86, at 5-3 (2016).

89. *Id.* at 5-4.

90. NYISO, INSTALLED CAPACITY MANUAL, *supra* note 86, at 2-1 to 2-2. The parameters for "reliability," which include reserve margins and other elements, are specified by the New York State Reliability Council. *See generally* N.Y. STATE RELIABILITY COUNCIL, *supra* note 86.

nection means that it trades energy and services in interstate commerce, subjecting it to FERC's authority pursuant to the FPA.[91] As noted in Part II above, under the FPA, FERC is authorized to regulate interstate electricity transmission and wholesale sales.[92] FERC's regulatory authority extends to "any person who owns or operates facilities" used in those activities (defined as a "public utility").[93] As the operator of New York's transmission facilities, NYISO is a public utility for the purposes of the FPA.

NYISO codifies nearly all its decision-making protocols in the OATT and MST it files with FERC. These tariffs provide comprehensive prescriptions for parameters to be achieved, parties to involve, procedures to follow, and valid bases for issuing directions and allocating resources.[94] This subsection summarizes key features of planning and tariff amendment in NYISO, both of which give prominent roles to stakeholders.[95]

1. Planning

NYISO's Comprehensive System Planning Process updates an operational model of facilities in NYISO and yields plans for maintaining reliability over the coming ten-year period.[96] It consists of the following four subsidiary processes:

1. Local Transmission Planning Process ("LTPP");

91. 16 U.S.C. § 824(b). Disputes still sometimes arise over previously unexplored instances of jurisdictional line-drawing between NYISO and state entities like the New York PSC. *See, e.g.*, Competitive Transmission Developers v. N.Y. Indep. Sys. Operator, Inc., 156 FERC ¶ 61,164, 61,718 (Sept. 8, 2016) ("CTD contends that NYISO improperly surrenders its responsibilities to the New York Commission."); N.Y. Indep. Sys. Operator, Inc., 153 FERC ¶ 61,010, 61,040 (Oct. 2, 2015) (resolving that NYISO rather than the PSC had jurisdiction to "establish[] compensation for a generator's return to service to resolve a reliability need").
92. 16 U.S.C. § 824(b)(1)–(2).
93. *Id.* § 824(e).
94. The November 2016 combined version of these tariffs weighed in at almost 2,800 pages. *See* NYISO, NYISO TARIFFS (2016), https://perma.cc/4W5K-WQK2.
95. References to "stakeholders" in NYISO tariffs and manuals indicate merchant transmission developers, generation plant owners, generation developers, demand response providers, and other participants. NYISO, RELIABILITY PLANNING PROCESS MANUAL 2-2 (2016), https://perma.cc/8PE7-LWLG [hereinafter NYISO, RELIABILITY PLANNING PROCESS MANUAL].
96. *See* NYISO, OATT, ATTACHMENT Y § 3(a) (2008), https://perma.cc/8FPL-5YT2 (codifying approach to Comprehensive System Planning Process).

2. Reliability Planning Process ("RPP");
3. Congestion Assessment and Resource Integration Study ("CARIS"); and
4. Public Policy Transmission Planning Process ("PPTPP").[97]

NYISO coordinates the timing of these subsidiary processes so that the LTPP is followed by the RPP, which is followed by the CARIS; the PPTPP begins midway through LTPP.

The LTPP gathers NYISO Transmission Owners' studies of their respective areas ("Local Transmission Plans," or "LTPs") for review by stakeholders and NYISO's Electric System Planning Working Group and Transmission Planning Advisory Subcommittee.[98] LTPs can be thought of as schematic maps of existing and planned transmission facilities, complete with descriptions of those facilities' operational features.[99]

The biennial RPP builds on the LTPs drafted by each of NYISO's eight Transmission Owners.[100] The RPP consists of the development, review by stakeholders, and approval by NYISO's Board of Directors of two studies. The first, known as the Reliability Needs Assessment ("RNA"), memorializes NYISO staff's assessment of whether existing and planned Bulk Power Transmission Facilities are expected to meet Reliability Criteria for resource adequacy, security, and stability over a ten-year time horizon.[101] The RNA identifies Reliability Needs—i.e., deficiencies vis-à-vis Reliability Criteria that signal where transmission and other projects might be necessary—and specifies a Responsible Transmission Owner for each need.[102] Once NYISO's Board of Directors approves

97. NYISO, RELIABILITY PLANNING PROCESS MANUAL, *supra* note 95, at 1-1.
98. *See* NYISO, MARKETS & OPERATIONS: LOCAL TRANSMISSION OWNER PLANNING PROCESS, https://perma.cc/5T6Z-9GUA ("Customers, Market Participants and other interested parties may review and comment on the planning criteria and assumptions used by each Transmission Owner, as well as other data and models used by each Transmission Owner in its LTPP.").
99. *See, e.g.*, Long Island Power Authority (LIPA), "Local Transmission Owner Plan (LTP), Presentation to NYISO Interested Parties" (Oct. 24, 2013), https://perma.cc/824X-S67U.
100. NYISO, 2016 RELIABILITY NEEDS ASSESSMENT (2016), https://perma.cc/7JGP-6VUS.
101. *See id.* at 26–41.
102. NYISO, RELIABILITY PLANNING PROCESS MANUAL, *supra* note 97, at 1-4.

the RNA, NYISO requests proposals to address each identified Reliability Need[103] and, at the same time, seeks a "regulated backstop solution" from the Responsible Transmission Owner.[104] For the purpose of the RPP, a backstop solution serves both as a benchmark against which to assess market-based solutions' viability and—of course—as a backstop in case no satisfactory market-based solution materializes.

The second report prepared as part of the RPP, known as the Comprehensive Reliability Plan ("CRP"), lists all viable solutions proposed to address Reliability Needs and contains NYISO's evaluation of those solutions.[105] NYISO selects from among viable solutions based on their relative cost-effectiveness.

Completion of the CRP prompts the start of the third subsidiary planning process: CARIS. Like the RPP, CARIS identifies possible needs, seeks proposed solutions, and then evaluates and selects from among those solutions.[106] The chief difference is that congestion, unlike Reliability Needs, is chiefly an issue of cost-effectiveness rather than system stability, security, or reliability. Thus, both the identification and evaluation phases of CARIS involve cost-benefit analyses that can result in a decision to simply tolerate—rather than address—a given instance of congestion.[107]

The PPTPP addresses "public policy requirements," which NYISO defines as a:

> federal or New York State statute or regulation, including a New York Public Service Commission ("NYPSC") order adopting a rule or regulation . . . , or any duly enacted law or regulation passed by a local governmental entity in New York State, that may relate to

103. *Id.* Proposals can include all resource types: transmission, generation, demand response, or non-transmission alternatives.
104. *Id.* Whereas market-based solutions receive compensation through NYISO-administered markets or bilateral agreements, backstop solutions receive compensation directly from NYISO pursuant to provisions of NYISO's tariff.
105. *Id.* at 1-5.
106. NYISO, ECONOMIC PLANNING PROCESS MANUAL – CONGESTION ASSESSMENT AND RESOURCE INTEGRATION STUDIES 1-4 to 1-5 (2014), https://perma.cc/Z3QC-2C6L.
107. This is why NYISO categorizes the CARIS as part of its economic planning process rather than the RPP or public-policy-oriented process. *See* NYISO, PUBLIC POLICY TRANSMISSION PLANNING MANUAL 1-2 to 1-3 (2015), https://perma.cc/ACT6-VVP3 [hereinafter NYISO, PUBLIC POLICY TRANSMISSION PLANNING MANUAL].

> transmission planning on the [Bulk Power Transmission Facilities].[108]

The PPTPP was developed to identify transmission needs rooted in public policy in compliance with FERC's Order 1000, and it looks to the NYPSC to help identify and specify public policy requirements.[109] The subjects of public policy requirements in New York include reducing congestion (on its own or as a means of reducing electricity rates) and reducing the carbon intensity of generation in the NYCA, among others.[110]

NYISO initiates the PPTPP upon the release of a draft version of the RNA, at which point the PPTPP follows the same basic steps as the RPP and CARIS: identify needs, seek viable solutions, evaluate solutions (in the PPTPP context, make a Viability and Sufficiency Assessment), and select from among solutions based on efficiency and cost-effectiveness.[111] A recent example of the PPTPP at work relates to plans to "unbottle" the transmission linkage connecting western New York to the hydroelectric generation and pumped storage facilities located near Niagara Falls.[112] The NYPSC designated unbottling as a Public Policy Transmission Need after concluding that it would result in "significant environmental, economic, and reliability benefits."[113] Whatever project or projects address a transmission need will qualify as a Public Policy Transmission Project, eligible to recover costs under NYISO's

108. NYISO, OPEN ACCESS TRANSMISSION TARIFF, ATTACHMENT Y § 31.1.1 (2016), https://perma.cc/3QHZ-FNU6.
109. Order Addressing Public Policy Transmission Need for Western New York, Case No. 14-E-0454 at 2–3 (N.Y. Pub .Serv. Comm'n Oct. 13, 2016), https://perma.cc/3WK5-NP97 [hereinafter Case No. 14-E-0454] (describing origin and purpose of PPTPP).
110. Order Finding Transmission Needs Driven by Public Policy Requirements, Case No. 12-T-0502 et al. at 8–12 (N.Y. Pub. Serv. Comm'n Dec. 17, 2015), https://perma.cc/5RZU-4565 [hereinafter Case No. 12-T-0502].
111. NYISO, PUBLIC POLICY TRANSMISSION PLANNING MANUAL, *supra* note 107, at 1-3.
112. Case No. 14-E-0454, *supra* note 109, at 5–7 (describing need); NYISO, WESTERN NEW YORK PUBLIC POLICY TRANSMISSION NEED PROJECT SOLICITATION (2016), https://perma.cc/ULS5-HCTJ (requesting Solicitations to address need).
113. Oct. 13, 2016 Order, Case 14-E-0454, *supra* note 109, at 4–5.

OATT.[114] In its comments in an ongoing NYPSC proceeding dealing with transmission needs, NYISO observed that "[a]ll of the Submittals point to the [New York Clean Energy Standard], which requires 50 percent of the state's electric energy to come from renewable resources by 2030 ('50% by 30'), as a primary driver of the need for new transmission facilities in New York."[115] Thus, it appears that many, if not all, transmission proposals currently before NYISO could qualify as a Public Policy Transmission Project.

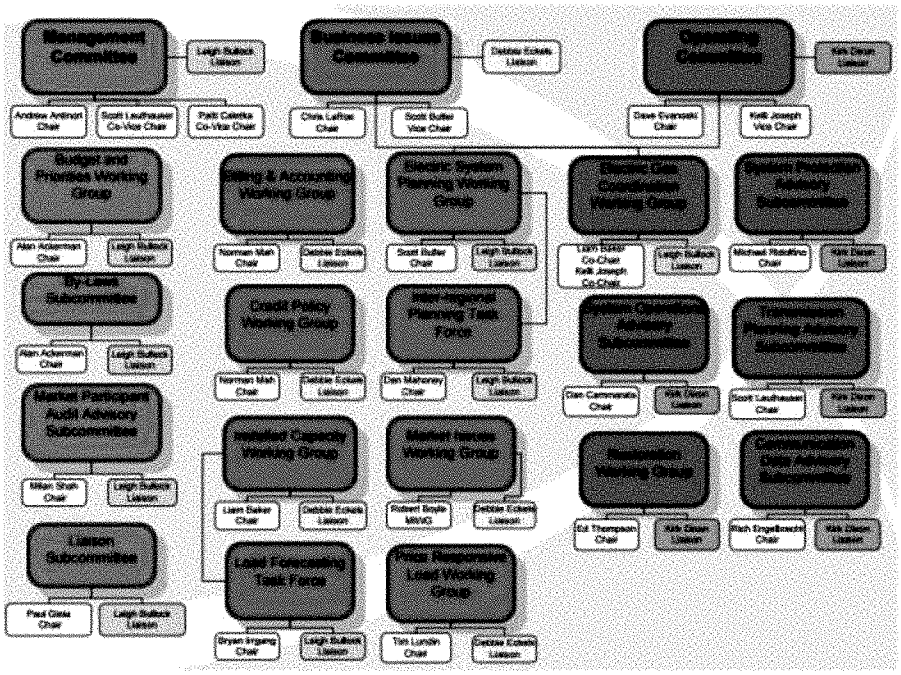
2. Tariff Revisions and Stakeholder Involvement

NYISO uses a multi-committee review process to make decisions, including about whether to propose a tariff revision for FERC's approval. NYISO's basic contract provides for three committees: Management, Operations, and Business Issues.[116] Each is further governed by By-Laws.[117] Formally, NYISO may propose revisions to its MST or OATT to FERC if majorities of the ten-member NYISO Board of Directors and the Management Committee concur.[118] But this formal step is just the last in a more elaborate process, sometimes called the "shared governance process" or "stakeholder review process."[119] Figure 5 depicts the structure of committees and subsidiary subcommittees and working groups whose members review, mark up, and revise proposals before the Management, Operations, or Business Issues Committee finalizes

114. NYISO, PUBLIC POLICY TRANSMISSION PLANNING MANUAL, *supra* note 107, at 3-3.
115. In the Matter of New York Independent System Operator, Inc.'s Proposed Public Policy Transmission Needs for Consideration for 2016, Case No. 16-E-0558 at 7 (N.Y. Pub. Serv. Comm'n Dec. 5, 2016), https://perma.cc/GA4F-XZEF.
116. NYISO, NYISO AGREEMENTS art. 7–9 (2013), https://perma.cc/4NN2-6MAM.
117. NYISO, BY-LAWS OF THE BUSINESS ISSUES COMMITTEE (2015), https://perma.cc/CP59-5Y9Z; NYISO, BY-LAWS OF THE MANAGEMENT COMMITTEE (2015), https://perma.cc/5CNB-NXWS [hereinafter NYISO, BY-LAWS OF THE BUSINESS ISSUES COMMITTEE]; NYISO, BY-LAWS OF THE OPERATING COMMITTEE (2015), https://perma.cc/59CZ-H9J6 [hereinafter NYISO, BY-LAWS OF THE OPERATING COMMITTEE].
118. NYISO, BY-LAWS OF THE NYISO, INC. art. II § 6(b) (2016), https://perma.cc/WFR8-U7WL; NYISO, NYISO AGREEMENTS art. 19 (2013), https://perma.cc/4NN2-6MAM [hereinafter NYISO, BY-LAWS OF THE NYISO, INC.].
119. *See generally* NYISO, NYISO SHARED GOVERNANCE (2017), https://perma.cc/Z4LM-3ZVH.

them for consideration by the Board.[120]

**Figure 5: NYISO Committee Structure**




Percolation up through this committee structure ensures that committee members receive notice and an opportunity to be heard on matters relevant to their client or constituents. NYISO's basic contract allocates votes on the Management Committee among generators, other suppliers, transmission owners, end-use consumers, and public power and environmental groups;[121] the other committees follow the same rubric.[122]

120. For a short description of what each component contributes to the whole, see NYISO, COMMITTEE STRUCTURE: SCOPE OF RESPONSIBILITIES 2–5 (2014), https://perma.cc/WE8Q-DUZY.

121. NYISO, BY-LAWS OF THE NYISO, INC., *supra* note 118, at art. 7, § 7.06.

122. NYISO, BY-LAWS OF THE BUSINESS ISSUES COMMITTEE, *supra* note 117, at § 12.01; NYISO, BY-LAWS OF THE OPERATING COMMITTEE, *supra* note 117, at § 12.01.

### C. FERC Oversight of NYISO

The FPA requires public utilities to notify FERC before making changes to rates or "rules and regulations affecting or pertaining to" rates.[123] Such notice must be given by filing, with FERC, new rate schedules showing the change(s) to be made to the schedules in force.[124] The new schedules will take effect after sixty days unless FERC, on its own initiative or following a complaint, commences a review thereof.[125] Where a review is undertaken, FERC may suspend operation of the schedules for up to five months while it assesses their lawfulness.[126] Based on that assessment, FERC may accept or reject the schedule, in whole or in part.[127]

FERC's review is intended to ensure that the rates and practices set out in the schedule are just and reasonable[128] and not unduly preferential or discriminatory.[129] These terms are not defined in the FPA or other legislation. Guidance on their meaning has, however, been provided in numerous administrative and court decisions. The U.S. Supreme Court has acknowledged that the just and reasonable standard is "incapable of precise judicial definition."[130] FERC is, therefore, "afford[ed] great deference . . . in its

123. 16 U.S.C. § 824d(a), (d) (stating that "no change shall be made by any public utility in any . . . rate, charge, classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days' notice to the Commission").
124. *Id.* § 824d(a). FERC may allow changes to take effect without requiring sixty days' notice.
125. *Id.* § 824d(e).
126. *Id.* The schedules will go into effect after five months, regardless of whether FERC has completed its review.
127. *Id.* (indicating that, after completing its assessment, FERC "may make such orders with reference [to the rates] as would be proper in a proceeding initiated after it had become effective"). *See also id.* § 824e (authorizing FERC to determine just and reasonable rates).
128. *Id.* § 824d(a) (requiring that "all rates . . . made, demanded, or received by any public utility for or in connection with the transmission or sale of electricity energy . . . and all rules and regulations affecting or pertaining to such rates . . . be just and reasonable").
129. *Id.* § 824d(b) (providing that public utilities must not "(1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect").
130. Morgan Stanley Capital Group Inc. v. Pub. Util. Dist. No. 1, 554 U.S. 527, 532 (2008).

rate decisions."[131] FERC is not required to set rates at any particular level[132] or use any particular methodology.[133] The only requirement is that the methodology used appropriately balance the interests of suppliers and customers,[134] such that rates fall "within a 'zone of reasonableness,' where [they] are neither 'less than compensatory' nor 'excessive.'"[135] Rates must be high enough to enable suppliers to recover their costs and earn a return on investment,[136] but not so high as to result in customer exploitation, abuse, or gouging or unjust discrimination between customer groups.[137]

The same just and reasonable standard applies to both cost- and market-based rates. With respect to the latter, FERC has taken the view that rates set in competitive markets will fall within the "zone of reasonableness," provided that no participant can exercise market power.[138] This approach has been upheld by the courts. In *Tejas Power Corp. v. FERC*, the D.C. Circuit observed that, "[i]n a competitive market, where neither buyer nor seller has significant market power, it is rational to assume that the terms of their voluntary exchange are reasonable."[139] In this context, market power has been defined as the ability of a seller to "significantly influence price in the market by withholding service and excluding competitors for a significant period of time."[140] Prior to approving a market-based tariff, FERC requires the seller to demonstrate that it lacks or has adequately mitigated market power and is unable to erect barriers to entry.[141] FERC monitors sellers' activities in the market to ensure that they do not re-attain

131. *Id.*
132. Permian Basin Area Rate Cases, 390 U.S. 747, 767 (1968).
133. Fed. Power Comm'n v. Hope Nat. Gas Co., 320 U.S. 591, 603 (1944).
134. *Id.*
135. Farmer's Union Cent. Exch., Inc. v. FERC, 734 F.2d 1486, 1502 (D.C. Cir. 1984).
136. *Hope Nat. Gas Co.*, 320 U.S. at 603.
137. *Farmer's Union Cent. Exch., Inc.*, 734 F.2d at 1502.
138. Order No. 697, Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, 72 Fed. Reg. 39,903, 39,906 (July 20, 2017) (to be codified at 18 C.F.R. pt. 35).
139. Tejas Power Corp. v. FERC, 908 F.2d 998, 1004 (D.C. Cir. 1990).
140. This definition was adopted in FERC's first market-based rate authorization. *See* Citizens Power & Light Corp., 48 FERC ¶ 61,210, 61,777 (Aug. 8, 1989).
141. Order No. 697, 72 Fed. Reg. at 39,908.

market power.[142]

FERC has also taken steps to enhance the functioning of markets and improve their competitiveness. For example, beginning in 2008, FERC adopted several orders aimed at removing barriers to the participation of demand-side resources in markets.[143] More recently, in 2014, FERC initiated a broad-ranging review of market design and operational practices that may impair competition.[144] Based on that review's findings, FERC has required various design changes aimed at improving how markets run.[145] Thus, as the Supreme Court has observed, FERC "ensure[s] 'just and reasonable' wholesale [electricity] rates by enhancing competition—attempting . . . to break down regulatory and economic barriers that hinder a free market in wholesale."[146]

## IV. PRICING CARBON IN ELECTRICITY MARKETS

There is growing interest among ISO/RTOs in incorporating carbon pricing into wholesale energy and/or capacity markets. In August 2016, NYISO launched the Integrating Public Policy Project ("IPPP") to assess whether introduction of a carbon price "would improve the overall efficiency of . . . energy and capacity markets," among other things.[147] Proposals for how to better respond to state and federal policies aimed at reducing carbon dioxide emissions from electricity generation have also been considered by CAISO, ISO-NE, and PJM.

142. *Id.*
143. Order No. 745, Demand Response Compensation in Organized Wholesale Energy Markets, 76 Fed. Reg. 16,657 (Mar. 24, 2011) (codified at 18 C.F.R. pt. 35) [hereinafter Order No. 745]; Order No. 719, Wholesale Competition in Regions with Organized Electric Markets, 74 Fed. Reg. 37,775 (July 29, 2009) (codified at 18 C.F.R. pt. 35).
144. FERC, Notice: Price Formation in Energy and Ancillary Services Markets Docket Operated by Regional Transmission Organizations and Independent System Operators, Docket No. AD14-14-000 (June 19, 2014), https://perma.cc/W2ZL-BZEB.
145. *See, e.g.*, Order No. 825, Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, 81 Fed. Reg. 42,881 (June 30, 2016) (codified at 18 C.F.R. pt. 35) [hereinafter Order No. 825].
146. *EPSA*, 136 S. Ct. 760, 768 (quoting Morgan Stanley Capital Group Inc. v. Pub. Util. Dist. No. 1, 554 U.S. 527, 536 (2008)).
147. Mike DeSocio, "NYISO, 2017 Integrating Public Policy: Detailed Scope," Slide 3 (2016), https://perma.cc/MQ3P-LYTD.

### A. Electricity Generation and Carbon Dioxide Emissions

Electricity generation is a leading source of carbon dioxide emissions in the U.S. According to the U.S. Environmental Protection Agency ("EPA"), electricity generation emitted over two billion metric tons of carbon dioxide in 2014, equivalent to 36.7 percent of national carbon dioxide emissions.[148] The level of emissions from a particular generating unit varies depending on the fuel used and its carbon intensity.[149] Coal is the most carbon-intensive generating fuel, followed by oil (which contains twenty-five percent less carbon than coal per unit of energy) and gas (which contains forty-five percent less carbon than coal).[150] Other generating fuels, such as nuclear and renewables, contain little or no carbon.

When coal and other fossil fuels are combusted during electricity generation, the carbon stored in the fuel is oxidized, producing carbon dioxide and small amounts of other gases.[151] The Energy Information Administration ("EIA") estimates that coal-fired generating units emit, on average, 2.1 pounds of carbon dioxide per kilowatt hour ("KWh") of electricity generated.[152] Carbon dioxide emissions from oil- and gas-fired units average 1.7[153] and 1.2[154] pounds per KWh of electricity generated respectively.

Carbon dioxide traps heat in the earth's atmosphere, causing surface temperatures to rise. According to the 2014 National Climate Assessment, average annual temperatures in the U.S. have risen by 1 to 2°F since 1895, and may rise a further 2 to 4°F "over

148. EPA, INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS: 1990–2014 ES-5, tbl.ES-2 (2016), https://perma.cc/T3LT-5AMU.
149. *Id.* at 3-6, tbl.3-6.
150. *Id.*
151. *Id.* at 3-8.
152. *Frequently Asked Questions: How Much Carbon Dioxide is Produced per Kilowatt Hour when Generating Electricity with Fossil Fuels?*, ENERGY INFO. ADMIN. ("EIA") (Feb. 29, 2016), https://perma.cc/VHF4-8EDV (estimating emissions from generating units using bituminous coal, subbituminous coal, and lignite coal at 2.07, 2.16, and 2.17 pounds per kilowatt hour ("KWh") respectively).
153. *Id.* (estimating emissions from generating units using distillate oil (no. 2) and residual oil (no. 6) at 1.64 and 1.76 pounds per KWh respectively).
154. *Id.* (estimating emissions from generating units using natural gas at 1.22 pounds per KWh).

the next few decades."[155] Temperatures have risen far faster in Alaska—since 1949, average annual temperatures have risen by 3.73°F and average winter temperatures by 6.71°F.[156] Rising temperatures lead to more variable precipitation patterns and increase the frequency and severity of extreme weather events. Impacts expected in the New York region include more frequent and intense heat waves, more intense precipitation events, storm surges incident to sea level rise, and more powerful coastal storms.[157] These impacts are already being felt in many areas and "have affected and will continue to affect human health, water supply, agriculture, transportation, energy . . . and many other sectors of society" over coming decades.[158]

### B. Regulation of Carbon Dioxide Emissions from Electricity Generation

Recognizing that climate change endangers public health and welfare, in December 2009, the EPA listed carbon dioxide as an air pollutant under the Clean Air Act.[159] EPA regulations, adopted in August 2015 and known as the Clean Power Plan, aim to reduce emissions from existing electric generating units by thirty-two percent below 2005 levels by 2025.[160] The regulations establish emissions limits for each state's electricity sector but do not specify how those limits are to be achieved.[161] This is left to the discretion of

155. U.S. GLOB. CHANGE RESEARCH PROGRAM, CLIMATE CHANGE IMPACTS IN THE UNITED STATES: THE THIRD NATIONAL CLIMATE ASSESSMENT 8 (Jerry M. Melillo, Terese (T.C.) Richmond, and Gary W. Yohe eds., 2014), https://perma.cc/6S2L-66DV.
156. *Temperature Changes in Alaska*, UNIV. OF ALASKA-FAIRBANKS: ALASKA CLIMATE RESEARCH CTR., https://perma.cc/M6T7-XND2.
157. *New York City Panel on Climate Change 2015 Report Executive Summary*, 1336 ANNALS N.Y. ACAD. SCI. 9, 9–11 (2015), https://perma.cc/3LCU-58YM.
158. U.S. GLOB. CHANGE RESEARCH PROGRAM, supra note 155, at 9.
159. Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 75 Fed. Reg. 66,496, 66,496 (Dec. 15, 2009) (codified at 40 C.F.R. pt. 1).
160. Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,662 (Oct. 23, 2015) (codified at 40 C.F.R. pt. 60). On February 9, 2016, the Supreme Court stayed implementation of the regulations, pending judicial review. *See* West Virginia v. EPA, 136 S. Ct. 1000 (2016).
161. *See Clean Power Plan State-Specific Fact Sheets*, EPA, https://perma.cc/8872-AXVM (last updated Sept. 16, 2016).

the states, which have wide latitude in deciding how to comply. A number of states were considering carbon pricing as a means of complying with the Clean Power Plan.[162] Notably, however, many states suspended their compliance work following the February 2016 Supreme Court decision to stay implementation of the Clean Power Plan pending resolution of legal challenges thereto.[163] Even if the Clean Power Plan is upheld by the courts, and not successfully repealed by the Trump Administration's EPA,[164] it is unlikely to be implemented for the duration of the Trump Administration, having been strongly opposed by President Trump during his campaign.[165]

### C. Why Put a Price on Carbon Dioxide Emissions?

The costs associated with carbon dioxide emissions are generally not reflected in electricity market prices.[166] Those costs take the form of "externalities"—impacts felt by third parties or the public at large—but have no price attributed to them by market participants.[167] This results in a market failure, whereby prices are lower than costs, leading to higher levels of production and consumption than are socially optimal.[168] Government intervention is therefore needed to ensure that social costs are fully considered in production and consumption decisions.[169] Such intervention could

162. *See, e.g.*, MELINDA E. TAYLOR & ROMANY M. WEBB, UNIV. OF TEX. SCH. OF LAW, EPA'S CLEAN POWER PLAN: IMPLEMENTATION OPTIONS 15 (2015), https://perma.cc/99DR-CM5L.
163. *E&E's Power Plan Hub: Supreme Court Stay Response*, E&E NEWS (2016), https://perma.cc/3RW5-VDGX.
164. Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 82 Fed. Reg. 48035 (proposed Oct. 16, 2017) (to be codified at 40 C.F.R. pt. 52).
165. Annie Sneed, *Trump's First 100 Days: Climate and Energy*, SCIENTIFIC AMERICAN (Nov. 29, 2016), https://perma.cc/RKF8-D7U7.
166. For a discussion of this issue, see NOAH KAUFMAN ET AL., WORLD RESOURCES INST., PUTTING A PRICE ON CARBON: REDUCING EMISSIONS 6 (2016), https://perma.cc/4NFQ-K3AD.
167. *Id.*
168. *Id.*
169. NAT'L RESEARCH COUNCIL, HIDDEN COSTS OF ENERGY: UNPRICED CONSEQUENCES OF ENERGY PRODUCTION AND USE 3 (2010), https://perma.cc/2AHP-VD5W (stating that, when prices do not reflect external costs, they "are 'hidden' in the sense that government and other decision makers, such as electric utility managers, may not recognize the full costs of their actions. When market failures like this occur, there may be a case for government interventions in the form of regulations, taxes, fees,

take a number of forms, including command-and-control regulations that limit the use of fossil fuels in electricity generation, or market-based instruments, such as carbon pricing.

A carbon price internalizes the external costs of carbon dioxide emissions from electricity generation and thus increases the cost of generation using fossil fuels, leading to lower demand from consumers and encouraging generators to switch to cleaner alternatives. Generators will make the switch and/or take other steps to reduce emissions wherever the costs of doing so are less than the carbon price. In this way, carbon pricing affords generators flexibility to find and exploit the most cost-effective emissions reductions. It tends to be more efficient than command-and-control regulation, which may force generators to pursue higher-cost emissions reductions.

Despite these benefits, to date, Congress has failed to enact legislation establishing a national carbon pricing scheme. In the absence of federal action, some states have adopted their own, more limited pricing schemes. One example is California, which has established a cap-and-trade program requiring in-state electricity generators and importers[170] emitting 25,000 metric tons or more of carbon dioxide equivalent per year to purchase allowances, at prices set through quarterly auctions.[171] Another even more limited example is the Regional Greenhouse Gas Initiative ("RGGI"), in which New York and eight other northeastern states participate.[172] As part of RGGI, fossil fuel generators with at least twenty-five megawatts ("MW") of capacity in New York and other participating states are required to purchase carbon dioxide emissions allowances through quarterly auctions.[173] RGGI thus assigns a price to approximately eight percent of state-wide emissions from all sectors; it ignores emissions from smaller electricity generators

tradable permits, or other instruments that will motivate such recognition.").

170. An electricity importer's emissions are calculated based on the annual emissions from each of its sources. *See* CAL. CODE REGS. tit. 17 § 95812(c)(2)(B) (2014).

171. *Id.* § 95852(b).

172. *RGGI, Inc.*, RGGI, https://perma.cc/H3H4-MD2N.

173. *Regulated Sources*, RGGI, https://perma.cc/9TGG-9R2D [hereinafter RGGI, *Regulated Sources*]. For a list of covered facilities in New York, see *New York: Facility Information*, RGGI, https://perma.cc/BQ7F-KL4S [hereinafter RGGI, *New York: Facility Information*].

and electricity imports, as well as direct emissions from the industrial, transportation, or agricultural sectors.[174]

### D. Proposals for Carbon Pricing in ISO/RTOs

Several ISO/RTOs have recently explored mechanisms that would support the direct or indirect pricing of generation sources' carbon intensity. The mechanisms and the reasons why they are being considered are summarized in this part. One notable impetus for this exploration in NYISO, PJM, CAISO, and ISO-NE was EPA's adoption of the Clean Power Plan, which aimed at reducing carbon dioxide emissions from existing fossil fuel power plants. The Trump Administration's proposal to withdraw the Clean Power Plan has raised questions about the direction each ISO/RTO will take. While rescission of the Clean Power Plan would remove a key driver for action nationwide and in New York, it would not, from a legal perspective, directly affect ISO/RTOs' authority to adopt a carbon pricing scheme, which does not rely on EPA regulations. (This might change, should the Trump Administration and Congress undo EPA's 2009 Endangerment Finding and the various regulatory authorities built upon it.[175]) For many ISO/RTOs, including NYISO, state-level policies (e.g., New York's CES) will continue to drive interest in carbon pricing.

#### 1. New York ISO

NYISO's IPPP will assess "[w]hether a redesign is needed in the wholesale market" and, in particular, whether and how to "internalize the cost of carbon" to improve market efficiency.[176] The IPPP was launched to "investigate potential market impacts from

174. LUCAS BIFERA, CTR. FOR CLIMATE AND ENERGY SOLUTIONS, REGIONAL GREENHOUSE GAS INITIATIVE 2 fig.1 (2013), https://perma.cc/9HCE-K6QB; *see also* NYSERDA, NEW YORK STATE GREENHOUSE GAS INVENTORY AND FORECAST: INVENTORY 1990-2011 AND FORECAST 2012-2030, UPDATED FINAL REPORT S-2 (2015), https://perma.cc/Q76D-AQW8.

175. *See* Christopher J. Bateman & James T. B. Tripp, *Toward Greener FERC Regulation of the Power Industry*, 38 HARV. ENVTL. L. REV. 275, 305 (2014) ("*In today's dominant regulatory and policy paradigm*, the environmental consequences of electricity generation are 'matters directly related to the economic aspects' of such transactions.") (emphasis added).

176. DeSocio, *supra* note 147, at Slides 3, 5.

the implementation of the [CES]"[177] adopted by the NYPSC in August 2016.[178] As part of the IPPP, NYISO will consider "[a]lternative market friendly approaches" to achieving the goals of the CES, including carbon pricing.[179]

2. PJM Interconnection

An August 2016 PJM white paper put forward a mechanism for reconciling two competing priorities in the PJM region:

1. states' subsidies and price supports for renewable generation, which depress energy market prices; and
2. timely investments in new generation capacity, which rely on signals sent by market price rises.[180]

That mechanism would involve a two-stage auction. In Stage 1, subsidized resources and the demand they would serve ("related demand") would both be removed from the auction for the purpose of determining capacity requirements for the relevant time period.[181] The resources that clear the auction *and* the subsidized resources would both take on capacity commitments, all with identical performance requirements.[182] Compensation for the subsidized resources' capacity commitments would be entirely the responsibility of their sponsoring state government; the related demand would not have to pay.[183] In Stage 2, subsidized resources would be included in the auction, but at a reference price that approximates the unsubsidized cost for that resource type at the relevant locational node.[184] Any resource that fails to clear in Stage 1 would not be eligible to receive compensation through the auction, even if it bids into Stage 2 at a price below the second stage clearing price.[185]

177. *Id.* at Slide 2.
178. Press Release, Governor of New York's Press Office, Governor Cuomo Announces Establishment of Clean Energy Standard that Mandates 50 Percent Renewables by 2030 (Aug. 1, 2016), https://perma.cc/8TLM-LQ64.
179. DeSocio, *supra* note 147, at Slide 5.
180. STU BRESLER, PJM INTERCONNECTION, POTENTIAL ALTERNATIVE APPROACH TO EXPANDING THE MINIMUM OFFER PRICE RULE TO EXISTING RESOURCES 1 (2016), https://perma.cc/M7YG-7BWW.
181. *Id.* at 2.
182. *Id.*
183. *Id.*
184. *Id.*
185. *Id.*

This two-stage process would not assign a price to carbon, but would make it easier for states located in the PJM balancing area to do so without disrupting the operation of the wholesale energy or capacity markets.

3. California ISO

California's legislature and governor have called for expansion of CAISO to encompass other western states on the grounds that such expansion will serve several goals, including lowering costs, improving reliability, and supporting renewable energy development.[186] That expansion would, however, mean departing from a situation where the California Public Utility Commission and CAISO largely share a geographic footprint that does not extend beyond California's borders. The new, expanded CAISO would have to devise and manage a wholesale marketplace that spans multiple states, only one of which assigns a price to GHG emissions. CAISO devised three possible mechanisms ("Options") for navigating this circumstance:

Compare the actual dispatch of electricity from particular sources that serve load in California to weeks- or months-long baselines, and thereby attribute estimated GHG emissions to particular sources based on the differences between actual and baseline dispatch;

1. Conduct quick (at five-minute intervals) two-step analyses that first determine the most cost-effective regional dispatch of electricity and then attribute GHG emissions to sources; or
2. Conduct a two-step analysis similar to Option 2, but rather than mapping dispatch and attributing emissions with

186. California Clean Energy and Pollution Reduction Act of 2015, c. 547 § 13 (2015) (amending Pub. Util. Code § 359.5 (a) to read: "It is the intent of the Legislature to provide for the transformation of the Independent System Operator into a regional organization . . . , and that the transformation should only occur where it is in the best interests of California and its ratepayers."); Letter from Edmund G. Brown, Jr., Governor of Cal., to Cal. State Legislature (Aug. 8, 2016), https://perma.cc/68RM-KPDV; *see also* THE BRATTLE GROUP ET AL., SENATE BILL 350 STUDY: THE IMPACTS OF A REGIONAL ISO-OPERATED POWER MARKET ON CALIFORNIA, EXECUTIVE SUMMARY I-xiv (2016), https://perma.cc/TVD8-8NVT (noting that demand for integration of more renewables prompts need to expand).

complete specificity (a computationally difficult task), impose either an averaged emissions factor or a residual emissions rate (sometimes called a "hurdle rate") on imported generation, making exceptions for generators party to bilateral contracts with California LSEs.[187]

Of these, CAISO and the California Air Resources Board ("CARB") are now considering only Option 3.[188] CAISO and CARB raised concerns about Option 1 because CARB's regulations would not permit the crediting of emissions reductions involved.[189] And CAISO indicated that performing the quick calculations required for Option 2 would exceed its computational capacity.[190]

4. ISO New England

The New England Power Pool ("NEPOOL") initiated the Integrating Markets and Public Policy ("IMAPP") stakeholder process in August 2016 to explore options for decarbonizing the electric grid without sacrificing reliability or market-based electricity price formation.[191] In addition to anticipating Clean Power Plan compliance measures, two other factors motivated IMAPP: first, natural gas has dominated regional capacity additions to such an extent since the late 1990s that ISO-NE is now susceptible to significant adverse effects should there be a natural gas supply shock or price

187. G. ANGELIDIS & D. TRETHEWAY, CAL. ISO, REGIONAL INTEGRATION CALIFORNIA GREENHOUSE GAS COMPLIANCE AND EIM GREENHOUSE GAS ENHANCEMENT STRAW PROPOSAL 9–10 (2016), https://perma.cc/8EE6-8MEU; *see also* Northern California Power Agency, Comments on Regional GHG Compliance October 13 Technical Workshop 2–3 (Oct. 27, 2016), https://perma.cc/2YCH-MNJD (describing rate applied to out-of-state entities as a "hurdle rate").

188. Don Tretheway, "Regional Integration-California Greenhouse Gas Compliance Initiative–Second Update," Slide 42 (Oct. 13, 2016), https://perma.cc/4X4F-2YU2.

189. *Id.* at Slide 16.

190. *Id.* at Slide 18 ("[c]urrent computational power would require simplifying (less accurate) first pass to ensure [real-time dispatch] successfully completes").

191. NEW ENGLAND POWER POOL ("NEPOOL"), CHAIRMAN'S OPENING REMARKS, NEPOOL IMAPP INITIATIVE 2 (2016), https://perma.cc/3PU4-8X5T ("Our goal is to achieve and maintain our high standards for reliability that our constituents demand, and to do so using the discipline of competition, *while incorporating the states' goals of decarbonizing our industry over time.*") (emphasis added). IMAPP agendas, presentations, and white papers are all posted online. *See Integrating Markets and Public Policy*, NEPOOL (2017), https://perma.cc/8BX8-WLY7.

jump;[192] and second, wholesale market prices are artificially reduced by the inclusion of subsidized resources in capacity auctions, which in turn distorts incentives for investment in new capacity.[193] (All six states within ISO-NE's territory provide for some form of support for renewables.[194])

Participants put forward fifteen different proposals, which fall into four broad categories as follows:

1. introduction of a carbon pricing scheme, whereby a carbon adder would be imposed on generators' bids, reflecting their carbon intensity;
2. changes to the forward capacity market such that certain generators would receive payments for both their capacity and their zero emission attributes;
3. introduction of a two-stage auction, similar to that proposed by PJM, which insulates wholesale market price formation from state policies; and
4. establishment of a Forward Clean Energy Market, in which LSEs could procure long-term commitments (up to ten years) for zero-emitting energy (not capacity) resources.

## V. NEW YORK'S EXISTING CARBON PRICING POLICIES

New York has introduced not one but two partial carbon prices, first by participating in RGGI, a cap-and-trade scheme, and more recently with the NYPSC's adoption of the CES. Both programs focus on the electricity sector but take different approaches to price formation and leakage, i.e., out-of-state emissions that are (i) not subject to restrictions or pricing and (ii) caused by in-state

192. ISO NEW ENGLAND, 2016 REGIONAL ELECTRICITY OUTLOOK 14 (2016), https://perma.cc/K2TM-VS5A.

193. ISO NEW ENGLAND, THE IMPORTANCE OF PERFORMANCE-BASED CAPACITY MARKET TO ENSURE RELIABILITY AS THE GRID ADAPTS TO A RENEWABLE ENERGY FUTURE 5 (2015), https://perma.cc/Z5PQ-KJE7.

194. Gordon van Welie, ISO New England, "State of the Grid: ISO on Background," Slide 30 (Jan. 26, 2016), https://perma.cc/E4SQ-SPH5 (noting that all six states impose RPSs); *see also, e.g.*, Mass. H.B. 4568 (2016) (authorizing state agency to draft and execute PPAs for renewable generation); Conn. Pub. Act No. 15-107 (same).

electricity consumption.[195] As described in this part, their approaches to prices and leakage have important legal implications.

### A. RGGI

RGGI, the older of New York's two carbon pricing programs, requires New York's seventy-six largest in-state fossil-fuel-fired generators to purchase carbon dioxide emissions allowances.[196] The legal basis for New York's participation in RGGI is a set of regulations adopted by the state Department of Environmental Conservation ("DEC") and Energy Research and Development Authority ("NYSERDA").[197] State regulations require covered generators to purchase carbon dioxide emissions allowances through quarterly auctions.[198] Auctions are conducted using a sealed bid

195. *See* JONATHAN L. RAMSEUR, CONG. RESEARCH SERV., R41836, THE REGIONAL GREENHOUSE GAS INITIATIVE: LESSONS LEARNED AND ISSUES FOR CONGRESS 14 (2016), https://perma.cc/ML6H-CFZL. A more general definition of leakage is: an "increase in emissions by entities not subject to a regulation, due to increases in costs for generators subject to the regulation." Daniel Shawhan, "Emission Reductions and 'Leakage' from US State Cap-and-Trade Programs," Slide 5 (Sept. 19, 2013), https://perma.cc/PEJ7-F9FL.

196. Generators with a capacity of 25MW or more are required to purchase allowances through RGGI. *See* RGGI, *Regulated Sources*, *supra* note 173. For a list of covered facilities in New York, see RGGI, *New York: Facility Information*, *supra* note 173.

197. N.Y. COMP. CODES R. & REGS. tit. 6, § 242 (2017) (DEC: CO2 Budget Trading Program; requiring covered facilities to purchase allowances); N.Y. COMP. CODES R. & REGS. tit. 21, § 507 (2017) (NYSERDA: CO2 Allowance Auction Program; authorizing NYSERDA to coordinate New York facilities' participation in auctions). Governor Pataki, along with the governors of other RGGI states, signed a Memorandum of Understanding in 2005. RGGI, MEMORANDUM OF UNDERSTANDING (2005), https://perma.cc/G6YQ-443U. That document has no legal force and merely memorialized the governors' commitments to pursue whatever was necessary for their respective states to participate. *See* Thrun v. Cuomo, 976 N.Y.S.2d 320, 324 (App. Div. 3d Dep't 2013). The only legal challenge brought against New York's participation in RGGI argued that (i) because it is effectively a tax, legislative approval is required; (ii) the Memorandum of Understanding is an unconstitutional interstate compact; and (3) the regulations themselves were arbitrary and capricious and promulgated pursuant to an "error of law." *Id.* at 323. The court rejected all these arguments, which were raised well after the four-month statute of limitations had run. *Id.* at 324.

198. N.Y. COMP. CODES R. & REGS. tit. 6, §§ 242-1.4, 242-1.5(c).

format in which each generator may submit multiple bids to purchase a specified number of allowances at different prices.[199] Bids are ranked by price, from high to low, and allowances issued until cumulative demand equals supply.[200] A region-wide declining cap limits the number of allowances available for purchase.[201] The cap was set at 86.5 million allowances in 2016[202] and will decline to 76 million allowances by 2020.[203] Each allowance permits the holder to emit one ton of carbon dioxide.

Because RGGI states impose a price on carbon dioxide emissions, in the form of an allowance cost, and the states around them do not, the program is vulnerable to leakage. Like other RGGI states, New York's RGGI-implementing regulations do not currently seek to prevent leakage. Recent analyses of whether this leakage tolerance has undermined RGGI's carbon price conclude that, to date, RGGI's emissions pricing has increased imports,[204] but that access to imports from relatively cheap natural gas-fired generation in Pennsylvania and Ohio and hydropower in Québec have meant a decrease in emissions nonetheless.[205] Regardless of

199. RGGI, FACT SHEET: RGGI CO2 ALLOWANCE AUCTIONS (2017), https://perma.cc/AKD6-V6B8.
200. RGGI, $CO_2$ ALLOWANCE AUCTIONS: FREQUENTLY ASKED QUESTIONS 10 (2016), https://perma.cc/MP8D-R33N.
201. *See generally* RAMSEUR, *supra* note 195.
202. *2016 Allowance Allocation,* RGGI (2016), https://perma.cc/6HM3-ZUFL.
203. For a discussion of the cap, see ELIZABETH A. STANTON ET AL., SYNAPSE ENERGY ECONOMICS, THE RGGI OPPORTUNITY: RGGI AS THE ELECTRIC SECTOR COMPLIANCE TOOL TO ACHIEVE 2030 STATE CLIMATE TARGETS 1–2 (2016), https://perma.cc/D6T2-7UK7.
204. Harrison Fell & Peter Maniloff, *Beneficial Leakage: The Effect of the Regional Greenhouse Gas Initiative on Aggregate Emissions* 23–24 (Colo. Sch. of Mines Div. of Econ. & Bus., Working Paper No. 2015-06, 2015), https://perma.cc/543W-8V6X (identifying a 2451.95 gigawatt-hours per month increase in imports into New York from PJM during RGGI's implementation). *But see* ANDREW G. KINDLE ET AL., RENSSELAER POLYTECHNIC INST. & NYISO, AN EMPIRICAL TEST FOR INTER-STATE CARBON-DIOXIDE EMISSIONS LEAKAGE RESULTING FROM THE REGIONAL GREENHOUSE GAS INITIATIVE 19 (2011), https://perma.cc/MD2R-CYBS (finding no empirical evidence of leakage in Pennsylvania-New York electricity transmission data from first year of RGGI's operation).
205. Fell & Maniloff, *supra* note 204. Fell and Maniloff find that in regions that export electricity to New York, RGGI's carbon price seems to have prompted capacity factor increases of ten to eleven percent by gas-fired generation sources—but no increases by coal-fired sources. These have offset capacity factor reductions of seven to ten percent by New York-based coal-fired generators. *Id.* at 17–18. *See also* RGGI, CO2 EMISSIONS FROM ELECTRICITY

whether this fortuitous circumstance is likely to last, RGGI participants have committed to examining options for improving the tracking of imports from outside RGGI and potentially adjusting the prices assigned to those imports to prevent leakage.[206]

### B. CES

New York's CES, adopted by the NYPSC in August 2016, aims by 2030 to reduce state-wide GHG emissions by forty percent from a 1990 baseline.[207] While this 40 by 30 goal applies economy-wide, the bulk of emissions reductions are expected to come from the electricity sector, with New York aiming to generate half of its electricity using renewable energy sources.[208]

The CES consists of three "tiers" of requirements for New York LSEs[209] but is more usefully understood as a combination of two programs, one oriented to renewables (Tiers 1 and 2) and the other (Tier 3) to three of the state's four nuclear power plants. As explained below, neither program assigns a price directly to carbon, but each assigns a price to "attributes" that include the non-emission of carbon.

CES Tiers 1 and 2 extend and modify the state's existing RPS, which required LSEs to collect a surcharge, payable to NYSERDA, and authorized NYSERDA to acquire "RPS attributes," embodied in RECs, from renewable generators.[210] This approach kept the REC market separate from the market for electricity and also allowed NYSERDA to steer investments in utility-scale and smaller renewable generation developments. Under the new CES Order, LSEs can comply with the RPS by acquiring RECs from

GENERATION AND IMPORTS IN THE REGIONAL GREENHOUSE GAS INITIATIVE: 2013 MONITORING REPORT 6–7 (2016), https://perma.cc/8KVD-QDGW (reporting net imports from PJM and Quebec).

206. *See* RGGI, RGGI 2012 PROGRAM REVIEW: SUMMARY OF RECOMMENDATIONS TO ACCOMPANY MODEL RULE AMENDMENTS 3 (2013), https://perma.cc/6DKK-KQYX.

207. Case No. 15-E-0302, *supra* note 3.

208. N.Y. STATE ENERGY PLANNING BD., *supra* note 1, at 112.

209. NYPSC Clean Energy Standard Order, *supra* note 3, at 14–19.

210. For a description of the RPS first adopted in 2004, see *03-E-0188: Renewable Portfolio Standard*, N.Y. STATE DEP'T OF PUB. SERV. (June 3, 2016), https://perma.cc/6YTE-EPMV.

NYSERDA, from renewable generators directly or by making "Alternative Compliance Payments" to NYSERDA.[211] One qualifying REC is "produced" alongside each MWh of electricity produced by a renewable facility that began commercial operation after January 1, 2015.[212] LSEs must acquire RECs in proportion to the annual load they supply—0.6 percent of load supplied in 2017, 1.1 percent in 2018, and up to 4.8 percent in 2021.[213]

CES Tier 3 requires LSEs to purchase ZECs "produced" by three of the state's four nuclear generating stations.[214] As with the RECs required to be purchased under Tiers 1 and 2, the Tier 3 ZECs place a value on a zero-emitting attribute and so are separate from the electric energy sold by the nuclear generators. However, three key alleged differences have led diverse parties to challenge Tier 3 on the grounds that it violates the dormant Commerce Clause ("dCC") and is pre-empted by the FPA, namely:[215]

1. out-of-state generators cannot actually qualify to sell ZECs, even if there is no formal mechanism preventing them from doing so;
2. ZEC prices will be set by the NYPSC and limited by wholesale market prices; and
3. ZECs will soak up ratepayer spending in a way that is likely to suppress wholesale capacity market prices.[216]

It appears that the Supreme Court's recent *Armstrong* decision, which held that "[t]he Supremacy Clause . . . does not create a cause of action,"[217] may well rescue the CES from challenges argu-

211. NYPSC Clean Energy Standard Order, *supra* note 3, at 14–18, 94, 106–10.
212. *Id.* at 103.
213. *Id.* at 14.
214. *Id.* at 43.
215. Plaintiffs' Memorandum in Opposition to Motion to Dismiss at 35, Coalition for Competitive Elec. v. Zibelman, No. 16-CV-8164, 2017 WL 3172866 (S.D.N.Y. July 5, 2017).
216. *See* NYPSC Clean Energy Standard Order, *supra* note 3, at 108 ("For the Year 2017 compliance period . . . [t]he REC price offered will equal the weighted average cost per MWh NYSERDA paid to acquire the RECs to be offered," i.e., they will reflect the cost of developing and operating renewable generation, "plus a reasonable Commission-approved adder to cover the administrative costs and fees incurred by NYSERDA to administer Tier 1.").
217. Armstrong v. Exceptional Child Ctr., Inc., 135 S. Ct. 1378, 1383 (2015); *see also* Mont.-Dakota Utils. Co. v. Nw. Pub. Serv. Co., 341 U.S. 246, 251 (1951) (holding that FPA does not provide for any private right of action); *cf.* Allco Fin. Ltd. v. Klee, 861 F.3d 82 (2d Cir. 2017) (petitioner brought case via

ing that it is pre-empted by the FPA. Thus, Tier 3's chief legal danger relates to challenges rooted in the dCC.

## VI. MECHANISMS OF A NYISO CARBON PRICING SCHEME

Partly in response to adoption of the CES, NYISO launched the IPPP to evaluate options to "achieve New York's . . . decarbonisation goals at least cost," consistent with the operation of wholesale markets.[218] The focus is on "approaches that would internalize the cost of carbon emissions" in markets.[219] To that end, NYISO could set a dollar value for each ton of carbon dioxide emitted during electricity generation (the "carbon price"), which would then be used to calculate a carbon fee for each generating unit reflecting its emissions profile. Ideally, this calculation would be based on the generating unit's actual emissions[220] as follows:

*Carbon fee ($ / MWh) = carbon price ($ / ton) × unit emissions (tons / MWh)*

A carbon fee would be calculated for all in- and out-of-state generators bidding into energy markets administered by NYISO. While the same carbon price would be applied to all units, regardless of technology, the resulting carbon fee would vary depending on the fuel used. Coal-fired generating units would face the highest carbon fee, followed by oil and then natural gas.

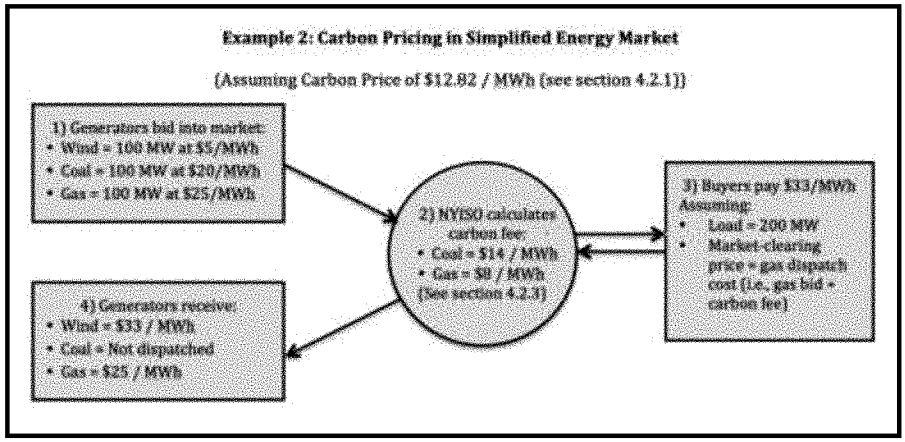
Each generating unit's carbon fee would be added to its energy market bid to produce a dispatch cost which NYISO would use to determine the dispatch order. The likely effect would be a re-ordering of dispatch, with coal- and oil-fired generating units dispatched less frequently and natural gas and renewable generators more frequently, compared to the situation without a carbon fee (compare examples 1 and 2). The dispatch cost of the marginal generator would determine the market-clearing price. Generators would receive that price less their carbon fee.

cause of action expressly granted by Congress for claims arising under PURPA but not the FPA more generally).

218. DeSocio, *supra* note 147, at Slide 5.

219. *Id.*

220. In the alternative, the calculation could be based on the carbon intensity of the fuel used by the generating facility and its heat rate. That is: carbon fee = carbon price × fuel carbon intensity × heat rate.




### A. Setting the Carbon Price

Various technical issues will need to be considered in designing a carbon pricing scheme. Key among these is the level at which to set the carbon price. As discussed in Part C above, carbon pricing generally aims to internalize the external costs of carbon dioxide emissions.[221] While the New York public policy triad of RGGI, RECs, and ZECs is based on multiple aims, at the root of all of them is the reflection in market prices of the cost of GHG emissions, whether directly or in the form of a non-emitting attribute. To estimate the costs imposed by GHG emissions, the Obama Administration developed the social cost of carbon ("SCC"), which reflects:

> the economic damages associated with a small increase in carbon dioxide . . . emissions, conventionally one metric ton, in a given year . . . . [It] is meant to be a comprehensive estimate of the climate change damages and includes, among other things, changes in agricultural productivity, human health, property damages from increased flood risk and changes in energy system costs, such

221. INTERAGENCY WORKING GRP. ON SOC. COST OF CARBON, TECHNICAL SUPPORT DOCUMENT: TECHNICAL UPDATE OF THE SOCIAL COST OF CARBON FOR REGULATORY IMPACT ANALYSIS UNDER EXECUTIVE ORDER 12866 (2013, revised 2015), https://perma.cc/3NCG-6ZQT.

as reduced costs for heating and increased costs for air conditioning.[222]

The SCC was calculated by an interagency working group, including representatives of EPA and other federal government agencies, convened by the Obama Administration.[223] In March 2017, the Trump Administration disbanded the interagency working group and rescinded the SCC, indicating that it should no longer be used in federal policy making.[224] However, it continues to be used in many states, including New York, where the ZEC price is based in part on the SCC.[225]

The SCC was calculated by quantifying the current and future damage expected to result from one metric ton of carbon dioxide.[226] That figure was then discounted back to present value to arrive at the SCC.[227] The interagency working group used three different discount rates to calculate three SCCs shown in Table 1 below.[228] Each SCC increases over time as the incremental impact of emissions rises in line with the atmospheric concentration of carbon dioxide.[229]

222. EPA, FACT SHEET: SOCIAL COST OF CARBON 1 (2015), https://perma.cc/ZQC7-DB43.
223. INTERAGENCY WORKING GRP. ON SOC. COST OF CARBON, TECHNICAL SUPPORT DOCUMENT: SOCIAL COST OF CARBON FOR REGULATORY IMPACT ANALYSIS – UNDER EXECUTIVE ORDER 12866 4 (2010), https://perma.cc/Z655-ZQE8.
224. Exec. Order No. 13,783, Promoting Energy Independent and Economic Growth, 82 Fed. Reg. 16,093 (Mar. 28, 2017).
225. NYPSC Clean Energy Standard Order, *supra* note 3, at 131.
226. EPA, *supra* note 222, at 1.
227. *Id.*
228. *Id.* at 3 (indicating that the "values are based on the average [SCC] from three integrated assessment models, at discount rates of 5, 3, and 2.5 percent . . . [A] fourth value [was estimated based on] the 95th percentile of the [SCC] from all three models at a 3 percent discount rate, and is intended to represent the potential for higher-than-average damages").
229. *Id.* at 1 (stating that the SCC "should increase over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater levels of climate change").

**Table 1: SCC Calculated by the Federal Government[230]**

| Year in which carbon dioxide emissions occur | SCC (2007 $ / metric ton) | | |
|---|---|---|---|
| | 5% discount rate | 3% discount rate | 2.5% discount rate |
| 2015 | $11 | $36 | $56 |
| 2020 | $12 | $42 | $62 |
| 2025 | $14 | $46 | $68 |
| 2030 | $16 | $50 | $73 |
| 2035 | $18 | $55 | $78 |
| 2040 | $21 | $60 | $84 |
| 2045 | $23 | $64 | $89 |
| 2050 | $26 | $69 | $95 |

The SCC was developed to assist federal agencies in performing cost-benefit analyses during rulemaking.[231] There is, however, support for its use in other contexts.[232] It could be used by NYISO to set the carbon price to be incorporated into bids in the wholesale

230. INTERAGENCY WORKING GRP. ON SOC. COST OF CARBON, *supra* note 221, at 13.

231. EPA, *supra* note 222, at 1; *see also* Zero Zone Inc. v. U.S. Dep't of Energy, 832 F.3d 654 (7th Cir. 2016) (upholding agency's use of SCC in cost-benefit analysis); Ctr. for Biological Diversity v. Nat'l Hwy. Transp. Safety Bd., 538 F.3d 1172 (9th Cir. 2008) (remanding environmental review and requiring agency to estimate cost imposed by GHG emissions).

232. *See, e.g.*, High Country Conservation Advocates v. U.S. Forest Serv., 52 F. Supp. 3d 1174 (D. Colo. 2014) (suggesting that the SCC could be used to estimate the costs of increased carbon dioxide emissions in environmental reviews under the National Environmental Policy Act). *See also* Michael Burger & Jessica Wentz, *Downstream and Upstream Greenhouse Gas Emissions: The Proper Scope of NEPA Review*, 41 HARV. ENVTL. L. REV. 109 (2017) (discussing the possibility of using the SCC in environmental reviews); Sarah E. Light, *NEPA's Footprint: Information Disclosure as a Quasi-Carbon Tax on Agencies*, 87 TUL. L. REV. 511, 545–46 (2013) (noting that the EPA has encouraged federal agencies to use the SCC in environmental reviews under the National Environmental Policy Act).

energy market. This would provide certainty for market participants, as the SCC is a robust metric, developed using technical models, with input from multiple government departments and the public. Recognizing this, in the context of ISO-NE's IMAPP stakeholder process, electric utility Exelon Corporation has recommended using the SCC as the touchstone for pricing carbon in energy markets.[233]

Despite this support, it is worth noting that the SCC is not universally accepted.[234] Use of the SCC to price carbon in wholesale energy markets is likely to be opposed by some industry and other groups on the basis that it does not merely reflect the costs climate change imposes on electric grid operations but also includes various other costs (e.g., to the agricultural sector). Those costs are, however, an externality of electricity generation. As we explain in Part VII below, internalizing those external costs is necessary to enhance competition in wholesale electricity markets and ensure that they operate effectively to produce just and reasonable rates.

The SCC arguably provides the best metric for pricing the external costs of electricity generation's carbon dioxide emissions. The lowest SCC, calculated using a five-percent discount rate, is consistent with the carbon prices currently used elsewhere in the electricity sector. For example:

- It is below the implicit carbon price used by the EIA in calculating the levelized cost of electricity ("LCOE"). The LCOE reflects the per-KWh cost of building and operating an electric generating plant over an assumed financial life and duty cycle, taking into account capital, operation, maintenance, and financing costs.[235] When calculating the LCOE, the EIA includes a three-percent cost of capital ad-

233. Exelon Corporation, "Using Carbon Pricing in Dispatch to Meet the IMAPP Process Goals," Slide 1 (Aug. 30, 2016), https://perma.cc/6RJQ-Q9K3.

234. For a discussion of opposition to the SCC, see Bruce Lieberman, *Social Cost of Carbon: A Continuing Little-Told Story*, YALE CLIMATE CONNECTIONS (Sept. 12, 2013), https://perma.cc/C49E-8Z47. *See also* David Malakoff et al., *Trump Team Targets Changes to Key Metric that Calculates Social Cost of Carbon*, SCI. INSIDER (Dec. 16, 2016), https://perma.cc/PKM5-6BVM.

235. EIA, LEVELIZED COST & LEVELIZED AVOIDED COST OF NEW GENERATION RESOURCES IN THE ANNUAL ENERGY OUTLOOK 1 (2016), https://perma.cc/CS5S-83MA.

der for carbon-intensive generating units, such as those using coal.[236] The impact of this, according to the EIA, is "similar to that of an emissions fee of $15 per metric ton of carbon dioxide."[237]

- It is in line with the carbon price implicit in California's cap-and-trade program.[238] As part of the cap-and-trade program, California has adopted an allowance auction system, with a minimum or "reserve" price which functions as a minimum carbon fee.[239] That fee was $12.73 in 2016[240] and will rise to $13.57 in 2017.[241]
- It is in line with, and in some cases less than, the carbon prices used internally by electric utilities. A number of utilities use a carbon price, for example, in their integrated resource planning processes. These include Xcel Energy Inc., which uses prices in the range of $9 to $34 per ton, Sempra Energy, which uses a price of about $13 per ton, NiSource Inc., which uses a price of $20 per ton, and Ameren Corporation, which uses prices in the range of $23 to $54 per ton.[242]

236. The EIA asserts that the adder is necessary as, "[b]ecause regulators and the investment community have continued to push energy companies to invest in technologies that are less greenhouse gas-intensive, there is considerable financial risk associated with major investments in long-lived power plants with a relatively higher rate of carbon dioxide emissions." *Id.* at 3.
237. EIA, LEVELIZED COST & LEVELIZED AVOIDED COST OF NEW GENERATION RESOURCES IN THE ANNUAL ENERGY OUTLOOK 3 (2014), https://perma.cc/L8SK-CKEQ.
238. *See supra* Part 3.
239. *Auction Information*, CAL. AIR RES. BD., https://perma.cc/27HD-2CTG (discussing the auction reserve price which establishes the minimum at which allowances will be sold).
240. CAL. AIR RES. BD., CALIFORNIA CAP-AND-TRADE PROGRAM AND QUÉBEC CAP-AND-TRADE SYSTEM: 2016 ANNUAL AUCTION RESERVE PRICE NOTICE 1 (2015), https://perma.cc/NC69-2SQW.
241. CAL. AIR RES. BD., CALIFORNIA CAP-AND-TRADE PROGRAM AND QUÉBEC CAP-AND-TRADE SYSTEM: 2017 ANNUAL AUCTION RESERVE PRICE NOTICE 1 (2016), https://perma.cc/7TG7-A57V.
242. CARBON DISCLOSURE PROJECT ("CBD"), PUTTING A PRICE ON RISK: CARBON PRICING IN THE CORPORATE WORLD 62 (2015), https://perma.cc/B4R2-7ZDP.

Given the above, NYISO may elect to use the lowest SCC, calculated using a discount rate of five percent, to mitigate cost impacts. That would result in an initial carbon price of $12.82.[243]

### B. Carbon Price Adjustment

Economists generally agree that carbon prices should rise over time to reflect the fact that, as more carbon accumulates in the atmosphere, the incremental damage caused by one additional ton increases.[244] Consistent with this view, the SCC rises steadily from $11 in 2015 to $21 in 2040 and to $26 in 2050 (see Table 1 above).

At the time of establishing a carbon pricing scheme, NYISO should adopt procedures specifying when and how price adjustments will be made. Ideally, to maximize certainty and predictability for the private sector, adjustments should be made at predefined intervals. NYISO could, for example, adjust prices every five years in line with the SCC. Assuming NYISO elects to use the lowest SCC (i.e., calculated using a five-percent discount rate), this would result in a modest increase in carbon prices over the next two decades, mitigating the impact on costs.

### C. Interaction with Other Carbon Prices

#### 1. Interaction with RGGI

Some electric generators bidding into NYISO markets are already subject to carbon pricing through RGGI. It is important that any NYISO carbon pricing scheme avoid requiring generators—directly or indirectly—to pay twice for the same emissions (i.e., once to comply with the NYISO MST and once to comply with RGGI). The RGGI price should, therefore, be deducted from whatever carbon price NYISO adds to covered generators' bids. The CES, which confronts the same problem when deriving a ZEC price, solves it by subtracting two values from the SCC. The first is a fixed projection of the RGGI price, borrowed from NYISO's CARIS model, which anticipates patterns of and costs arising from transmission

243. The 2015 SCC value, calculated using a five-percent discount rate, is $11 in 2007. After adjusting for inflation, that is equivalent to $12.82 in 2016 dollars.

244. *See, e.g.*, Joseph E. Aldy & Robert N. Stavins, *The Promise and Problems of Pricing Carbon: Theory and Experience*, 21 J. ENV'T & DEV. 152, 155 (2012).

grid congestion.[245] The second value is a hybrid of independent forecasts of NYISO's energy and capacity markets whose projections capture anticipated changes to RGGI's carbon price.[246]

2. Interaction with New York's CES

FERC has determined that it does not have jurisdiction over markets for RECs unbundled from markets for energy or capacity.[247] Thus, Tiers 1 and 2 of New York's CES can operate in parallel with a wholesale market carbon price without legal consequence. Tier 3, however, establishes a ZEC price that is both derived from the SCC and constrained by NYISO energy market prices.[248] Some of the litigants in the current dispute over New York's CES argue that these features make the ZEC price potentially subject to FERC's jurisdiction (see Part 5.2 above), as well as logically duplicative of any carbon price based on the SCC. Consequently, if NYISO's carbon price were to derive from the SCC, then NYISO and the NYPSC would have to decide which price would accommodate or displace the other. Otherwise, given their common goal (correcting electricity prices to better reflect the value of avoiding the adverse effects of climate change), both would impose costs that, combined, exceed the value they aim to approximate, namely a version of the SCC. This logical failing would be legally problematic as well because it would belie the argument that the carbon pricing scheme improves wholesale price formation by more accurately incorporating costs that are relevant but were heretofore ignored.[249]

Ultimately, either accommodating or displacing Tier 3 of the CES would mean applying a carbon price more or less uniformly to all the generation sources subject to NYISO's tariff. The key differences between the two approaches would relate to implementation. Accommodation would mean crafting a new mechanism that alters

245. NYPSC Clean Energy Standard Order, *supra* note 3, at 57, 131, 135–36.
246. Those forecasts pertain to Zone A, where no nuclear facilities are located. This lowers ZEC prices at times when electricity prices are expected to increase.
247. WSPP, Inc., 139 FERC ¶ 61,061, 61,425 (Apr. 20, 2012) (clarifying that FERC has jurisdiction over bundled REC and energy transactions, but not over unbundled REC-only transactions).
248. NYPSC Clean Energy Standard Order, *supra* note 3, at 131 & 150.
249. *See infra* Part VII.

non-nuclear generator bid prices, operates alongside the CES, and leaves the ZEC prices paid to three nuclear generators undisturbed. Displacement would mean eliminating Tier 3 and simply modifying the bid prices of all generators based on the carbon content of their fuel. Practically, displacement would be far simpler; politically, both are fraught.

### D. Likely Effect on Wholesale Electricity Prices

Adoption of a carbon pricing scheme by NYISO will, in the short run, likely lead to an increase in the market-clearing price of electricity. The amount of that increase will depend on the carbon dioxide emissions profile of the marginal generator, since, as described above, prices will be set equal to that generator's bid plus a carbon fee based on its emissions. Average emissions from various classes of generating units are shown in Table 2. Based on those averages and assuming a carbon price of $12.82,[250] the table shows the carbon fee for each class of generator.

**Table 2: Estimated Carbon Fee for Fossil Fuel Generators**

| Generating Resource | Average Emissions Rate[251] (per MWh) | Carbon Fee[252] (per MWh) |
|---|---|---|
| Coal – Lignite | 1.09 tons | $13.97 |
| Coal – Subbituminous | 1.08 tons | $13.85 |
| Coal – Bituminous | 1.04 tons | $13.33 |
| Oil – Residual (No. 6) | 0.88 tons | $11.28 |
| Oil – Residual (No. 2) | 0.82 tons | $10.51 |
| Natural Gas | 0.61 tons | $7.82 |

250. *See supra* Part A.
251. EIA, *supra* note 152 (estimating the number of pounds of carbon dioxide produced per KWh of electricity generated, based on the average heat rates for steam electric generators in 2014).
252. Calculated assuming a carbon price of $12.82 per ton.

Currently, in NYISO markets, natural-gas-fired resources are the marginal source of supply in most intervals.[253] It is unclear whether that will remain the case after introduction of a carbon pricing scheme. We anticipate some reordering of resources but cannot determine exactly how the supply mix will change and/or whether gas will remain at the margin. This will depend on a number of factors, including each generator's cost and emissions profile, as shown in simplified example 2 above. Further complicating matters, there will likely also be a demand response, which affects dispatch. For example, if higher prices reduce electricity demand, fewer generating units may need to be dispatched, leading to a change in the marginal unit.[254]

In intervals when natural gas is at the margin, the market-clearing price would increase by around $8 (per MWh), depending on the marginal generator's actual emissions. Should coal be at the margin, the market clearing price increase would be around $14 (per MWh). Each generator would receive the market-clearing price less their carbon fee. Thus, as the carbon fee is highest for fossil fuel generators, there would be an incentive to increase investment in renewable and other low-carbon generation. In the long run, the market-clearing price may decrease as the generating fleet becomes less carbon intensive and low- and zero-emitting generators are increasingly on the margin. Such a decrease could be partially or wholly offset by increases in the carbon price. Such increases could cause the market-clearing price to rise over time.

### E. Options for Re-distributing Revenues

To offset increased wholesale electricity prices, revenues generated through the carbon pricing scheme should be reimbursed to LSEs and other buyers in an equitable manner. This could be achieved in several ways. One option is to require LSEs to pay the full market-clearing price, including the amount of any carbon fee. Each generator would receive that price, less their unit specific carbon fee, which would be retained by NYISO. The retained funds could then be equitably refunded to LSEs. States could direct LSEs

253. PATTON ET AL., *supra* note 67, at 7 (indicating that natural gas-fired resources were the marginal source of supply in 67 percent of intervals in 2013 and 2015).

254. For a discussion of this issue, see Jos Sijm et al., *$CO_2$ Cost Pass-Through and Windfall Profits in the Power Sector*, 6 CLIMATE POL'Y 49 (2006).

to use the refunded amount to mitigate end-customer bill impacts or fund state policy goals (e.g., energy efficiency investments). Studies suggest that, where the refunds are passed through to customers, any increase in retail bills is likely to be minimal. By way of example, Exelon estimated an increase in retail bills of just one to two percent, assuming a carbon price of $20 per ton.[255] Another study for the Clean Air Task Force estimated that, with a carbon price of $34 per ton, retail rates would increase by 4.1 percent.[256]

Ideally, refunds to LSEs should not be tied to their specific purchases in energy markets to avoid dampening any demand response.[257] NYISO could, for example, provide periodic refunds based on each LSE's share of total load during the period. Refunds would not be tied to LSEs' actual share of carbon fees, meaning that all LSEs would receive the same amount per MWh of electricity purchased, regardless of whether purchases are made during times of low or high fees.

Similar refund schemes have been adopted by ISO/RTOs in other circumstances. For instance, since 2007, PJM has included the marginal cost of transmission line losses in energy market prices.[258] As marginal losses rise exponentially with transmission system flows, they exceed average losses, resulting in PJM overcollecting revenues relative to costs.[259] PJM refunds the excess to buyers on a monthly basis, in proportion to each buyer's MW usage

255. Assuming that the revenues from the carbon price were applied to retail bill relief programs. *See* Exelon Corporation, Comments of Exelon Corporation on U.S. Environmental Protection Agency's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources 19, 33 (Dec. 1, 2014), https://perma.cc/EK3C-3DPP.

256. BRUCE PHILLIPS, THE NORTHBRIDGE GRP., ALTERNATIVE APPROACHES FOR REGULATING GREENHOUSE GAS EMISSIONS FROM EXISTING POWER PLANTS UNDER THE CLEAN AIR ACT: PRACTICAL PATHWAYS TO MEANINGFUL REDUCTIONS 2 (2014), https://perma.cc/2QXX-MP33.

257. *See supra* Part D.

258. Atlantic City Electric Co. v. PJM Interconnection, 115 FERC ¶ 61,132, 61,474 (May 1, 2006). For a discussion of this decision and its relevance to carbon pricing in wholesale electricity markets, see STEVEN WEISSMAN & ROMANY WEBB, UNIV. OF CAL., BERKELEY, SCHOOL OF LAW, ADDRESSING CLIMATE CHANGE WITHOUT LEGISLATION: HOW THE FEDERAL ENERGY REGULATORY COMMISSION CAN USE ITS EXISTING LEGAL AUTHORITY TO REDUCE GREENHOUSE GAS EMISSIONS AND INCREASE CLEAN ENERGY USE 10–11 (2014), https://perma.cc/LFV6-DZ3K.

259. *Atlantic City Electric Co.*, 115 FERC at ¶ 61,478.

rather than its actual contribution to the surplus funds.[260] A similar marginal loss collection and refund scheme is used by CAISO.[261] FERC has approved both the CAISO and PJM schemes; the U.S. Court of Appeals for the District of Columbia Circuit has upheld FERC's approval of the PJM scheme.[262]

As an alternative to collecting and then refunding carbon fees, ISO/RTOs could adjust the electricity prices paid by LSEs and other buyers to reflect the market-clearing price less the average carbon fee for all dispatched generators (see example 3 below). This approach would dampen the demand response to the carbon pricing scheme, as LSEs would face a lower price compared to when the adder is collected by NYISO. It is, however, likely to be simpler to administer than the refund schemes described above.

### F. Monitoring and Reporting

To successfully implement a carbon pricing scheme, data will be required on each generator's carbon dioxide emissions to calculate the carbon fee to be added to its bids. The required data is already recorded in the New York Generator Attribute Tracking System ("NYGATS"). Maintained by NYSERDA, NYGATS tracks the environmental attributes of electricity generated within New York as well as that imported to the state.[263] For each MWh of electricity, NYGATS records the generation source (whether in or out of state) and key characteristics of that source, including its carbon dioxide emissions rate.[264] The emissions data is entered by NYISO, based on reports filed by generators participating in its market.

260. Atlantic City Electric Co., v. PJM Interconnection, 117 FERC ¶ 61,169 (2006).

261. California Independent System Operator, 116 FERC ¶ 61,274 (Sept. 21, 2006), *order on reh'g*, 119 FERC ¶ 61,076 (Apr. 20, 2007).

262. Black Oak Energy, LLC v. FERC, 725 F.3d 230 (D.C. Cir. 2013). FERC's approval of the CAISO scheme was not appealed to the courts.

263. *New York Generation Attribute Tracking System (NYGATS)*, NYSERDA, https://perma.cc/V5KH-79WW. *See also* NYSERDA, "New York Generation Attribute Tracking System (NYGATS) Stakeholder Meeting," Slide 8 (Apr. 13, 2017), https://perma.cc/G9BR-WA4E.

264. *Id.* at Slide 14.

## VII. DOES THE LAW PERMIT NYISO TO PRICE CARBON?

Any NYISO carbon pricing scheme would be subject to FERC review. As explained in Part C above, under the FPA, FERC is responsible for overseeing wholesale electricity rates to ensure that they are just, reasonable, and not unduly discriminatory or preferential. The FPA requires public utilities, including ISO/RTOs, to submit to FERC proposed changes to their rates or practices affecting rates.[265]

FERC has traditionally shown great deference to ISO/RTOs to formulate market rules as they see fit.[266] FERC may approve an amended NYISO tariff establishing new market rules, without finding that the existing tariff is deficient or that the amended tariff is somehow superior.[267] The applicable standard requires only that the amended tariff be just, reasonable, and not unduly discriminatory or preferential.

### A. Including a Carbon Price in Wholesale Electricity Rates is Just and Reasonable

This sub-part presents two distinct lines of argument supporting the conclusion that carbon pricing in NYISO markets is just and reasonable. The first is the bolder of the two and builds on the premise that FERC has wide latitude to authorize a NYISO proposal aimed at improving the functioning of its wholesale markets. The second resembles arguments made elsewhere for adopting a wholesale carbon price: it reflects and rationalizes state public policy. As noted in the introduction, though these arguments are distinct from one another, they are not mutually exclusive. Importantly, these arguments are intended to justify inclusion of a carbon price of some sort in NYISO's tariff and do not address the level at which any such price should be set. That issue is discussed in Part 3 below.

265. 16 U.S.C. § 824d(d).

266. Michael H. Dworkin & Rachel Aslin Goldwasser, *Ensuring Consideration of the Public Interest in the Governance and Accountability of Regional Transmission Organizations*, 28 ENERGY L.J. 543, 555 (2007).

267. 16 U.S.C. § 824d(d).

1. Argument 1: Improving the Functioning of Wholesale Markets Administered by NYISO

***Argument 1(a): A carbon price would enhance competition in NYISO markets.*** As discussed in Part C above, FERC considers rates to be just and reasonable if they are set in well-functioning, competitive wholesale energy markets. FERC regulates markets to mitigate the exercise of market power and otherwise enhance competition, viewing such regulatory intervention as "integral to . . . fulfilling its statutory mandate under the FPA to ensure supplies of electric energy at just [and] reasonable" prices.[268] FERC put this premise to the test in 2011 when, in Order 745,[269] it required ISO/RTOs to pay the full LMP to qualifying demand-response resources on the grounds that promoting "meaningful demand-side participation" in wholesale markets would increase competition in those markets with salutary effects on prices.[270] The Supreme Court ultimately endorsed FERC's logic in *FERC v. Electric Power Supply Association* ("*EPSA*").[271]

In upholding Order 745, the Court in *EPSA* noted that FERC "undertakes to ensure just and reasonable wholesale rates by enhancing competition—attempting . . . to break down regulatory and economic barriers that hinder a free market in wholesale electricity."[272] The Court emphasized that Order 745 is intended "to improve how [the wholesale energy] market runs."[273] According to the Court, FERC's "justifications for regulating demand response are all about, and only about, improving the wholesale market. . . . FERC explained that demand response participation could help create a 'well-functioning competitive'" market with reduced rates and enhanced reliability.[274]

The decision in *EPSA* suggests that FERC has broad authority to promote competition in wholesale markets as a means to ensure just and reasonable rates. Based on *EPSA*, at least two commentators have suggested that FERC could approve an ISO/RTO-

268. Order No. 745, Fed. Reg. 16,657, 16,659–60, 16,676 (Mar. 24, 2011) (codified at 18 C.F.R. pt. 35).
269. *Id.* at 16,659.
270. *Id.*
271. *EPSA*, 136 S. Ct. 760 (2015).
272. *Id.* at 768.
273. *Id.* at 776.
274. *Id.* at 776–77.

proposed carbon price as just and reasonable, so long as evidence demonstrates that the adder would enhance competition.[275] Peskoe, who makes this argument in relation to ISO-NE, emphasizes that FERC's approval "may be on more solid legal ground" if the adder is designed to achieve specific competitive outcomes independent of the environmental harm caused by carbon dioxide emissions.[276] Thus, Peskoe stops short of endorsing what has been called "social-cost dispatch"—the adjustment of market-based rates so that they reflect social costs rather than private ones.[277]

Weissman and Webb, writing before the *EPSA* decision, argued that including the social cost of carbon dioxide emissions in rates is *necessary* to enhance competition in wholesale markets:

> [L]ess-polluting generators are placed at a competitive disadvantage when more-polluting generators can mask the true cost of power by ignoring externalities . . . The existence of environmental externalities represents [a] kind of market failure to which FERC could . . . respond by adjusting the bid price . . . [In doing so, FERC's] objective would be to stimulate the development of generating units that will impose the lowest cost on society and remove [a] market distortion—the ability of some generators to undercut their competitors by escaping responsibility for their environmental costs.[278]

This reasoning takes the characterization of environmental externalities as being outside of FERC's remit and stands it on its head. By Weissman and Webb's logic, ignoring environmental externalities means giving some market participants an unfair competitive

275. *See, e.g.*, Joel B. Eisen, *FERC's Expansive Authority to Transform the Electric Grid*, 49 U. CAL. DAVIS L. REV. 1783, 1788 (2016) ("[FERC] can even take an 'environmental' action—such as addressing climate change through a carbon adder—if it has a direct relationship to wholesale rates."); Ari Peskoe, Integrating Markets and Public Policy in New England 9 (Oct, 27, 2016) (discussion draft), https://perma.cc/MWY8-FQDK (stating that FERC could approve a carbon adder if it "can conclude that there is adequate support in the record that [the] proposal furthers that goal" of enhancing competition).

276. Peskoe, *supra* note 275, at 28.

277. Bateman & Tripp, *supra* note 175, at 330.

278. WEISSMAN & WEBB, *supra* note 258, at 4, 6.

advantage over others and thereby impairing market competitiveness.[279] This view sees an analogy between compensating emitting and non-emitting generators at the *same* rate and compensating generation and demand response at *different* rates. FERC Order 745 eliminated the latter distinction on the grounds that inadequate compensation inhibited wholesale market participation by demand response resources, which, in turn, kept average rates higher than necessary and, more generally, reduced competition in wholesale energy markets. In the case of a carbon price, FERC would be acting to facilitate the participation of low-carbon generators that, like demand response resources, are inadequately compensated for the services they provide because rates do not reflect their zero-emission attributes. Adopting a carbon price would ensure that rates more accurately reflect the value that low- and high-carbon electricity sources deliver and, thus, level the competitive playing field.

Another, more recent example of FERC action to enhance competition in wholesale markets is its draft order on electric storage resources' participation in wholesale markets.[280] That draft order pertains to a wide array of storage technologies (fly wheels, batteries, compressed air, and others) capable of charging and discharging electricity.[281] According to FERC, this capability "provides [storage] resources with significant operational flexibility," enabling them to deliver various grid services.[282] Currently, however, storage resources' participation in wholesale markets is limited by the fact that they "often must use existing participation models designed for traditional generation or load resources."[283] FERC's draft order seeks to adjust the parameters that wholesale markets use to determine resource participation and valuation to better capture evident but unrealized benefits to market participants:

279. *See* Bateman & Tripp, *supra* note 175, at 304 ("[B]y not incorporating GHG externalities into its rate regulation, FERC influences decisions about what generation should be built just as much as it would by incorporating these externalities. The effect of its exclusion of the externalities is simply to give GHG-intensive generation, such as coal, an advantage vis-à-vis cleaner energy, such as wind.").

280. *See* Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 81 Fed. Reg. 86,522 (Nov. 17, 2016) (codified at 18 C.F.R. pt. 35).

281. *Id.* at 86,525.

282. *Id.*

283. *Id.*

> We take action in this NOPR so that electric storage resources will be able to participate in the organized wholesale electric markets to the extent they are technically capable of doing so based on rules that take into account their unique characteristics and not based on market rules designed for the unique characteristics of other types of resources . . . Current tariffs that do not recognize the operational characteristics of electric storage resources serve to limit the participation of electric storage resources in the organized wholesale electric markets and result in inefficient use of these resources.[284]

FERC's instructions to ISO/RTOs to revise their participation models are technology-neutral and recognize the indispensable role of aggregators in integrating storage technologies meaningfully into grid operations.[285] Their objective is straightforward: level the competitive playing field for technologies with a particular capability—i.e., "receiving electric energy from the grid and storing it for later injection of electricity back to the grid regardless of where the resource is located on the electrical system"—that has to date been undervalued.[286] The approach to NYISO carbon pricing proposed here would also improve wholesale markets' valuation of a particular capability or attribute, namely low- or non-emitting electricity generation.

The playing field is particularly skewed in NYISO markets, which are affected not only by the current failure to internalize carbon externalities at the wholesale level but also by state policies adopted in more or less direct response to that failure. The policies, described in Part V above, effectively attach a value to generators' carbon-related attributes. They do not, however, apply equally to all generators with the same attributes. Just 76 of New York's roughly 170 fossil fuel generators have their carbon dioxide emissions priced through RGGI.[287] Some low-carbon generators that operate renewable energy sources are compensated for their zero-

284. *Id.*
285. *Id.* at 86,523–24.
286. *Id.* at 86,525.
287. Generators with a capacity of 25MW or more are required to purchase allowances through RGGI. *See* RGGI, *Regulated Sources, supra* note 173. For a list of covered facilities in New York, see RGGI, *New York: Facility Information*, *supra* note 173.

emission attributes through REC sales.[288] Such compensation is not, however, consistently available to non-renewable low-carbon generators.[289] Finally, three, but not all four, of the state's nuclear generators receive compensation from ZEC sales which is not available to renewable generators.[290]

Due to their partial application, state policies provide only incomplete and inchoate remedies for the market failure described above and arguably further distort the market, thereby impairing effective competition among wholesale buyers and sellers. The policies give some market participants a competitive advantage over others with the same attributes. RGGI, for example, increases the costs faced by large fossil fuel generators due to the need to purchase emission allowances. Those generators are, therefore, forced to bid into the market at higher prices. Smaller fossil fuel generators (i.e., that are not subject to RGGI) can, however, continue making bids that exclude the cost of emissions and, thus, undercut their competitors.[291] Similarly, as a result of the CES, nuclear power plants can undercut fossil fuel and other generators. The CES increases the return nuclear power plants receive for electricity sold in wholesale markets, creating an incentive for them to reduce their bids (i.e., to ensure they are dispatched), thereby putting downward pressure on market prices. This is likely to affect the financial viability of other generators, both low- and high-carbon, impeding their ongoing participation in wholesale markets.

We note that some commentators have disputed FERC's authority to adjust wholesale market prices to internalize the external costs of carbon dioxide emissions.[292] Moot, for example, has argued that such costs are fundamentally extrinsic to wholesale markets and, thus, beyond FERC's legal domain.[293] He states:

288. NYPSC Clean Energy Standard Order, *supra* note 3, at 16, Appendix A (indicating that RECs may be produced and sold by resources that came into operation after January 1, 2015 and use certain renewable resources to generate electricity).

289. *Id.*

290. *Id.* at 128 (indicating that the FitzPatrick, Ginna, and Nine Mile Point nuclear generators will be eligible to receive ZEC payments).

291. This is because smaller generators, with a capacity less than 25MW, are not required to purchase allowances through RGGI. *See* RGGI, *Regulated Sources*, *supra* note 173.

292. *See, e.g.*, Moot, *supra* note 9.

293. *Id.* at 358–61.

> FERC can remove barriers to participation by renewable resources in wholesale power markets . . . if those barriers constitute an undue preference. That preference must relate to a matter within FERC's jurisdiction, however, not a matter committed to the jurisdiction of other governmental bodies. Just as the FERC cannot remedy perceived inequities in the tax code by withholding wholesale market revenues from firms allegedly taking advantage of tax loopholes, it cannot counteract Congress' failure to enact cap-and-trade or carbon tax legislation by creating its own program through a wholesale market design change.[294]

In our view, however, FERC approval of a NYISO carbon price would not amount to an extension of environmental policy by other means. Rather, it would be a logical application of the principles that have long guided FERC's management of wholesale markets. While we agree with Moot that neither the FPA nor other federal legislation expressly authorizes FERC to address emissions, that would not be FERC's primary purpose in approving a carbon price. FERC's purpose would be to enhance wholesale market operations and promote competition, much as it has done in other instances where it has lacked express legislative sanction but has proceeded anyway.[295]

***Argument 1(b): A carbon pricing scheme would ensure proper wholesale price formation.*** In considering FERC's authority to approve a carbon pricing scheme following *EPSA,* it is important to bear in mind the features of Order 745. Most notably, as the Supreme Court observed, the order "is all about" reducing wholesale electricity prices.[296] In contrast, a carbon pricing scheme is likely to increase *wholesale electricity prices,* at least in the short run.[297] In the long run, however, prices should fall as the generating fleet becomes less carbon intensive.[298] In contrast, from the start, the *costs* of generation will likely fall. While electricity prices

294. *Id.* at 361.
295. *See supra* Part A.
296. *EPSA*, 136 S. Ct. 760, 774 (2015). As noted above, Order 745 aims to promote the participation of demand-response resources in wholesale markets by compensating them at the full LMP. Such compensation is, however, only required where resources pass a net benefits test indicating that their dispatch will result in lower wholesale prices (i.e., compared to if all load was met with generation).
297. *See supra* Part D.
298. *Id.*

and costs are often assumed to be equivalent,[299] in fact, costs currently exceed prices due to the presence of externalities. These externalities reflect a cost to society—one that, in our view, must be incorporated into prices if they are to provide clear signals to market participants and investors.

FERC has recently emphasized the importance of proper price formation to, among other things, maximize market surplus and incentivize investment.[300] According to FERC Commissioner Cheryl LaFleur, to achieve these objectives, prices must "reflect the true cost of reliable operations."[301] The near-term effects of climate change—warmer ambient temperatures, heat waves, less reliable access to water, and more frequent and intense storms—have clear import for system reliability. These effects will impair generation and transmission facility efficiency,[302] undermining reliability and creating costs, which must be reflected in prices to provide correct

299. In *EPSA*, the court uses the terms "price" and "cost" interchangeably. *Compare EPSA*, 136 S. Ct. at 778 (indicating that "wholesale market operators accept demand response bids only if those offers lower the wholesale *price*" (emphasis added)), *with id.* at 782 (stating operators will accept a bid "so long as that bid can satisfy a 'net benefits test'—meaning that it is sure to bring down *costs*" (emphasis added)).

300. Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators; Notice Inviting Post-Technical Workshop Comments, 80 Fed. Reg. 3,580 (Jan. 23, 2015).

301. FERC, TRANSCRIPT OF HEARING: PRICE FORMATION IN ENERGY AND AUXILIARY SERVICES MARKETS OPERATED BY REGIONAL TRANSMISSION ORGANIZATIONS AND INDEPENDENT SYSTEM OPERATORS 6 (2014), https://perma.cc/YAM8-L6FE.

302. *See* U.S. DEP'T OF ENERGY, U.S. ENERGY SECTOR VULNERABILITIES TO CLIMATE CHANGE AND EXTREME WEATHER 10 (2013), https://perma.cc/62TQ-VUCN (indicating that, in natural gas and coal units, "heat is used to produce high-pressure steam, which is expanded over a turbine to produce electricity. The driving force for the process is the phase change of the steam to a liquid following the turbine . . . A vacuum is created in the condensation process that draws the steam over the turbine. This low pressure is critical to the thermodynamic efficiency of the process. Increased backpressure will lower the efficiency of the generation process. Increases in ambient air temperatures and cooling water temperatures will increase steam condensate temperatures and turbine backpressure, reducing power generation efficiency."); *see also* Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, Case No. 13-E-0030 (N.Y. Pub. Serv. Comm'n Feb. 21, 2014), https://perma.cc/RCU5-ZKQS; SOFIA AIVALIOTI, SABIN CTR. FOR CLIMATE CHANGE LAW, ELECTRICITY SECTOR ADAPTATION TO HEAT WAVES (2015), https://perma.cc/93FG-8NHF.

incentives for investment in new facilities. Put another way: climate change is imposing costs on the electric grid and its end users that wholesale markets currently interpret as noise rather than signal; carbon pricing would serve to translate that signal into price effects and thereby more accurately reflect the value that high- and low-carbon sources of electricity deliver.

FERC has recently taken steps to ensure that market prices more fully account for the cost of generation. In Order 825, for example, FERC directed market operators to implement various reforms aimed at ensuring that prices more accurately reflect energy and reserve shortages[303] so that generators "are compensated for the value of the service that they provide" and, thus, face the correct incentives to invest in enhancing reliability.[304] While Order 825 relates to the pricing of features endogenous to wholesale markets, FERC has also dealt with exogenous features in the past. FERC has previously adjusted wholesale market prices to achieve public policy objectives such as reduced transmission line losses.[305] In 2006, FERC ordered PJM to include an uplift charge—equal to the marginal cost of line losses—in wholesale prices to cover the cost of energy lost during transmission. According to Weissman and Webb:

> FERC's decision to require marginal loss pricing was made on policy grounds and aimed to ensure that prices provide the strongest signal possible to encourage more efficient use of the transmission system . . . FERC emphasized that use of this methodology would reduce electricity supply costs and thereby increase electricity market efficiency [stating]: "by changing to the marginal losses method, PJM would change the way that it dispatches generators

303. FERC noted that "some RTOs/ISOs currently restrict the use of shortage pricing to certain causes of shortages, or some RTOs/ISOs require a shortage to exist for a minimum amount of time before triggering shortage pricing." *See* Order No. 825, 81 Fed. Reg. 42,881, 42,894 (June 30, 2016) (codified at 18 C.F.R. pt. 35). FERC determined that "existing shortage pricing triggers that do not invoke shortage pricing when there is a shortage (regardless of duration or cause) are unjust and unreasonable." *Id.* FERC therefore required "each RTO/ISO to trigger shortage pricing for any interval in which a shortage of energy or operating reserves is indicated." *Id.* at 42,900.

304. *Id.* at 42,884.

305. For a discussion of this issue, *see* WEISSMAN & WEBB, *supra* note 258, at 10–11.

> by considering the effects of [transmission line] losses. As a result . . . the total cost of meeting load would be reduced."[306]

Just as line losses create a burden for buyers and sellers of electricity, justifying market rule adjustments, so too do carbon dioxide emissions and associated climate change. Both lead to reduced system reliability and, thus, increased costs for market participants. Adopting a carbon price would internalize the external costs of emissions, ensuring that they are taken into account by market operators when dispatching generators, and thereby causing electricity demand to be served by the lowest *cost* resources.

2. Argument 2: Ensuring orderly development of the electric system

***Argument 2(a): Wholesale carbon pricing reflective of diverse state policies would, in the short run, harmonize those policies.*** As discussed in Part C, in exercising its authority to set just and reasonable rates, FERC must balance the interests of suppliers and customers.[307] FERC must also ensure protection of the public interest.[308] This does not, however, give FERC "a broad license to promote the general public welfare."[309] Rather, as the Supreme Court has observed, it "is a charge to promote the orderly production of plentiful supplies of electric energy" at reasonable prices.[310] Achieving this goal in the age of climate change means ensuring that prices provide appropriate signals for investment in low-carbon generation consistent with state policy.[311] In the short run, this means rationalizing the current patchwork of carbon-related electricity pricing policies in New York. In the long run, it means ensuring that market participants align their plans

306. *Id.* (internal citations omitted).
307. Fed. Power Comm'n v. Hope Nat. Gas Co., 320 U.S. 591, 603 (1944).
308. *See, e.g.*, Fed. Power Comm'n v. Sierra Pacific Power Co., 350 U.S. 348, 355 (1956) (declaring that "the purpose of the power given the Commission by § 206(a) [i.e., to set just and reasonable rates] is the protection of the public interest").
309. NAACP v. Fed. Power Comm'n, 425 U.S. 662, 669 (1972).
310. *Id.* at 670.
311. *See generally* TASK FORCE ON CLIMATE-RELATED FIN. DISCLOSURES, RECOMMENDATIONS OF THE TASK FORCE ON CLIMATE-RELATED FINANCIAL DISCLOSURES (2016), https://perma.cc/W45A-NH47 (characterizing categories of investment risk arising from climate change).

with existing and *foreseeable* future legal requirements.[312]

Some but not all NYISO market participants are subject to state policies aimed at supporting the transition to low-carbon electricity generation. As discussed in Part 1 above, the patchwork of state policies provides partial coverage of New York generators with respect to carbon emissions. It also imposes diverse price levels on those emissions or their absence: REC values derive from an independent market whose participants must comply with the state's RPS; ZEC values derive from a formula derived from the SCC; and RGGI allowance prices derive from an interstate allowance-trading market. As of January 2017, REC purchasers paid $21.16 per MWh,[313] ZEC purchasers $17.54 per MWh,[314] and RGGI participants $3.55 per short ton of carbon dioxide,[315] which translates to about $2.17/MWh for natural-gas-fired generators and $3.67 for bituminous-coal-fired ones.[316]

Partial coverage and diverse pricing complicates and distorts the values transmitted via wholesale electricity markets to participants, thereby impairing efficient planning and investment. This situation is ripe for improvement via the sort of rationalization that a more uniformly applicable wholesale carbon price would provide.

***Argument 2(b): Wholesale carbon pricing reflective of state-level public policy would improve long-run planning.*** A harmonizing wholesale carbon price would also help ensure orderly electric system development over the long term. New York policymakers responsible for the electric grid have long recognized the need to mitigate climate change and have embodied that goal in a variety of policies. Achieving the state's climate change mitigation goals, such as the 40 by 30 goal, will require replacing a

312. *See* Peskoe, *supra* note 275, at 16–17, 24 (discussing FERC's authority to ground decisions in expectations about expected future policy choices).

313. *Clean Energy Standard: REC and ZEC Purchases from NYSERDA*, NYSERDA, https://perma.cc/QVC9-89VC.

314. *Id.*

315. *Auction Results: Allowance Prices and Volumes (by Auction)*, RGGI, https://perma.cc/V4R8-VVTE (indicating that, in Auction 34, held on December 7, 2016, carbon dioxide allowances sold for $3.55).

316. The EIA estimates that natural-gas-fired generation emits, on average, 1.22 pounds of carbon dioxide per kWh and bituminous-coal-fired generation emits 2.07 pounds of carbon dioxide per kWh. *See* EIA, *supra* note 152. We multiplied these figures by the RGGI auction clearing price to determine the carbon price faced by generators.

significant volume of fossil-fueled generation with energy efficiency and zero-emitting resources, which will, in turn, require expanding transmission capacity and making changes to bulk power system operations. Planning must begin now if New York and NYISO are to minimize the impact of these changes on electric system reliability while ensuring continued availability of plentiful supplies of electricity at reasonable rates.

FERC has previously taken steps to improve electric system planning, including adopting Order 1000, which requires Transmission Owners "to develop a regional transmission plan that reflects the evaluation of whether alternative regional solutions may be more efficient or cost-effective" than local solutions.[317] Specifically, Order 1000 requires Transmission Owners seeking to develop new transmission facilities to participate in a regional planning process which:

1. considers "transmission needs driven by public policy requirements established by" enacted statutes or regulations,[318] and allows for consideration of transmission needs driven by public policy objectives not codified in existing laws;[319] and
2. gives "comparable consideration" to transmission and non-transmission alternatives—a category that includes storage, energy efficiency, distributed energy resources, and demand response.[320]

Adoption of a NYISO carbon price reflective of state-level public policies would promote the same goals as Order 1000, albeit on different legal grounds. Specifically, it would embody New York's policies with respect to climate change mitigation and adaptation, including those not yet codified, in a way that directly informs bulk power system planning—a potentially important corrective, given

317. Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 76 Fed. Reg. 49,842, 49,845 (Aug. 11, 2011) (codified at 18 C.F.R. pt. 35) [hereinafter Order No. 1000].

318. *Id.*

319. *Id.* at 49,878; *see also* Shelly Welton, *Non-Transmission Alternatives*, 39 HARV. ENVTL. L. REV. 457, 481–86 (2015) (describing examples of planning pursuant to Order 1000 that fail to realize that Order's stated aims).

320. Order No. 1000, 76 Fed. Reg. at 49,868.

the ambition of New York's 40 by 30 goal[321] and the fact that uncodified policies are often ignored by transmission operators in their planning processes.[322]

Similarly, a wholesale carbon price would also push in the same direction as Order 1000's "comparable consideration" requirement. This requirement was intended to ensure that investments in transmission—which are always costly and long-lived—are not made before due consideration is given to potentially more efficient and cost-effective alternative approaches.[323] Despite this, however, regional transmission planning efforts still typically focus on how to develop transmission and largely or completely ignore the question of whether non-transmission alternatives might contribute to a more optimal solution, either by supplanting transmission facilities or enabling more cost-effective routes or combinations of transmission and alternatives.[324] The state's "Reforming the Energy Vision" initiative, adopted to further progress towards the 40 by 30 goal, includes support for energy efficiency, distributed generation, and other non-transmission alternatives.[325] The NYPSC is working to ensure that retail electricity

321. N.Y. STATE ENERGY PLANNING BD., *supra* note 1, at 111 (stating that goal of energy efficiency reductions of 600 trillion BTU in buildings would mean a twenty-three percent reduction by 2030 from a 2012 baseline).

322. *See, e.g.*, WEISSMAN & WEBB, *supra* note 258, at 36 (finding that "[w]hile some transmission operators have voluntarily elected to consider additional policy objectives not codified in existing laws and regulations, most have not"). *But see* CDP, *supra* note 242, at 40 (indicating that some electric utilities have begun considering "the potential future policy and regulatory risk associated with carbon [dioxide] emissions" in their planning processes).

323. Order No. 1000, 76 Fed. Reg. at 49,851–53; *see also* Scott Hempling, *'Non-Transmission Alternatives': FERC's 'Comparable Consideration' Needs Correction*, ELEC. POL'Y 9 (2013), https://perma.cc/SKR5-TY8S ("It is not prudent for a public utility not to consider all feasible alternatives. The costs that emerge from an imprudent process—one that ignores alternatives—cannot be reasonable costs.").

324. Welton, *supra* note 319, at 481–86 (illustrating with examples how Order 1000 has failed to realize its stated aims); Interview by Marta Monti with Allen Gleckner, Humphrey Sch. of Pub. Affairs, Univ. of Minn. 10–11 (June 16, 2015), https://perma.cc/LRT5-HPCB ("[A] problem with transmission planning nation-wide is how non-transmission alternatives are looked at . . . . Right now there are a few different wonky reasons why it's not being fully looked at on a level playing field with the transmission proposals.").

325. Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision: Order Adopting Regulatory Policy Framework and Implementation Plan, Case No. 14-M-0101 at 10–11 (N.Y. Pub. Serv. Comm'n Feb. 26, 2015).

markets operate in a way that is consistent with and furthers investment in these alternatives.[326] A wholesale carbon price would reflect this purpose by pushing stakeholders to more thoroughly examine non-transmission alternatives.[327]

3. Carbon Prices Aligned to Arguments 1 and 2

Parts 1 and 2 above present various arguments in support of carbon pricing in NYISO. Design of the pricing scheme and the pricing level depends heavily on which of those arguments NYISO relies upon:

- *Argument 1(a)*, which emphasizes the need to internalize carbon externalities to improve wholesale market competitiveness, logically corresponds to a carbon price based on the SCC. As explained in Part A, the SCC is an approximation of the damage to social welfare resulting from carbon dioxide emissions. Its use would, therefore, ensure that the external costs of emissions from fossil fuel generation are reflected in electricity prices, which, in our view, is necessary to level the playing field for non-fossil generators and thus improve the functioning of wholesale markets.
- *Argument 1(b)*, which focuses on the costs fossil fuel generation imposes on the electric system, e.g., in terms of reduced reliability, would not justify adoption of a carbon price based on the SCC. As the SCC is a measure of the economy-wide cost of carbon dioxide emissions, its use would overstate the reliability and other electric system costs of such emissions. We are not aware of an analysis that traces cost causation from generators to end-users, but we are confident that it could be done by examining carefully the effects on reliability and resiliency of particular fuel and facility types.[328]

326. *Id.*
327. *Cf.* NYISO, DISTRIBUTED ENERGY RESOURCES ROADMAP FOR NEW YORK'S WHOLESALE ELECTRICITY MARKETS (DRAFT) (2016), https://perma.cc/Y87U-UVBG.
328. For a discussion of service reliability studies, see MICHAEL J. SULLIVAN ET AL., ERNEST ORLANDO LAWRENCE BERKELEY NAT'L LAB., UPDATED VALUE OF SERVICE RELIABILITY ESTIMATES FOR ELECTRIC UTILITY CUSTOMERS IN THE U.S. (2015), https://perma.cc/6M6Y-6KDA.

- *Argument 2*, which emphasizes the need to improve short- and long-run electric system planning, would arguably justify use of a price derived from the SCC as the basis for a scheme that harmonizes various state-level public policies. Underlying this argument is a concern that current and future state policies aimed at addressing climate change will necessitate a shift away from carbon-intensive generation. NYISO's adoption of a carbon pricing scheme derived from the SCC, which is already a touchstone for New York public policy, would help ensure that market participants plan for that shift now.

### B. A NYISO Carbon Price Would Not Be Unduly Discriminatory

FERC cannot approve a utility tariff that it finds to be unduly discriminatory in the sense of "grant[ing] any undue preference or advantage to any person or subject[ing] any person to any undue prejudice or disadvantage or . . . maintain[ing] any unreasonable difference in rates."[329] This was historically assessed on a customer-specific basis, with FERC requiring utilities to offer like rates, calculated on a cost-of-service basis, to all similarly situated customers.[330] More recently, with the shift to market-based rates, FERC has undertaken a broader inquiry, focusing on whether market conditions are discriminatory. As Eisen has observed, "[i]nstead of judging whether an individual firm's action is . . . discriminatory, [FERC] decides whether features of the wholesale markets' operation contribute to [this] effect."[331]

Some commentators have suggested that a carbon pricing scheme could be viewed as discriminatory.[332] Peskoe, for example, has noted that opponents of carbon pricing may argue that it favors some generators over others.[333] We recognize, as Peskoe does, that carbon pricing will necessarily treat generators differently based

329. 16 U.S.C. § 824d(b).
330. Eisen, *supra* note 275, at 1812.
331. *Id.*
332. *See, e.g.*, Peskoe, *supra* note 275, at 26.
333. *Id.* (stating that "opponents of carbon adder may argue that an adder would be contrary to FERC's long-standing policy of not favoring particular types of electric generation").

on their emissions profiles.[334] This is because, while the same carbon price would be applied to all generating units, regardless of technology, the resulting carbon fee would differ based on each unit's emissions.[335] Some may, therefore, view carbon pricing as supporting renewable generating units at the expense of fossil fuel power plants. That is not necessarily the case, however. Some renewable generators (e.g., using biofuels) produce emissions which would be subject to carbon pricing. Those generators would face a higher carbon fee than fossil fuel plants with low or zero emissions (e.g., clean coal facilities).

Even though it applies different fees to each generator, in our view, carbon pricing does not violate the prohibition on undue discrimination in the FPA. Differential treatment is permitted under the FPA if FERC "offer[s] a valid reason for the disparity . . . [which is related] to the achievement of permissible policy goals."[336] With respect to a carbon price, NYISO may argue that disparate treatment of low- and high-carbon generators is necessary to improve the functioning of wholesale electricity markets, a long-accepted policy goal. A similar argument, albeit in a different context, was upheld by the Court of Appeals for the District of Columbia Circuit in *Wisconsin Public Power, Inc. v. FERC* ("*WPP*").[337] That case involved a FERC decision exempting certain transmission providers from compliance with MISO's OATT on the basis that they provided services under contracts predating MISO's formation.[338] The court noted that FERC's decision "was in some loose sense discriminatory," as the exempt providers were not subject to certain fees levied on others and could schedule services on short notice with greater flexibility.[339] The court concluded, however, that the discrimination was not undue, as it was necessary to solve a specific problem in the market, stating:

334. *Id.* (noting that "[a] carbon adder . . . is essentially a payment from owners of emitting resources to owners of emission-free resources. By definition, such a fee discriminates. Whether that discrimination is 'undue' is a separate matter.").
335. *See supra* Part VI.
336. Black Oak Energy, LLC v. FERC, 725 F.3d 230, 239 (D.C. Cir. 2013)
337. Wis. Pub. Power, Inc. v. FERC, 493 F.3d 239 (D.C. Cir. 2007).
338. *Id.* at 249.
339. *Id.* at 274.

> MISO's development was complicated by the existence of several hundred pre-existing bilateral contracts between its transmission owners and other utilities. These long-term contracts, known as grandfathered agreements (GFAs), obligated the transmission owners to provide transmission service under terms and rates that were inconsistent with the OATT. . . . The tension between GFA terms and practices on the one hand and the MISO Tariff on the other hand was from the very beginning a "fundamental problem in the proposed design and operation" of MISO. . . . [The] discrimination [complained of] was inherent in the solution to [that] problem.[340]

A carbon price would also address a fundamental problem in the design and operation of wholesale electricity markets. As explained above, the problem arises from the failure of markets to accurately value low- and high-carbon sources of electricity, which impairs competition. This problem is particularly acute in NYISO markets, which have been further distorted by state laws that impose diverse carbon prices on some but not all market participants. Extending carbon pricing to all participants would remedy this distortion. To the extent that this results in differential treatment of participants, it is "inherent in the solution" to the problem at hand and, thus, not undue under the test articulated in *WPP*.

This conclusion is further supported by the fact that those benefiting from the extension of carbon pricing account for a relatively small share of generation. The key beneficiaries of carbon pricing are, of course, zero-carbon generating units. Most of those units already have their zero-carbon attributes valued through New York's CES. The remaining zero-carbon generators serve a relatively small share of electricity load. This is significant as, in *WPP*, the court emphasized that the limited extent of discrimination suggested it was not undue.[341] In that case, those benefiting from the discriminatory practices accounted for approximately ten percent of peak load.[342]

340. *Id.* at 249, 270, 274.
341. *Id.* at 274 (noting that "the extent of discrimination was relatively small and not 'undue'").
342. *Id.* at 270.

## VIII. CONCLUSION

In response to federal and state policies aimed at limiting the electricity sector's carbon dioxide emissions, several ISO/RTOs have commenced reviews into whether and how to price carbon in wholesale energy markets. With some notable exceptions, emissions are not currently priced in wholesale markets but rather treated as externalities. This results in a mismatch between the price and cost of fossil fuel generation, which leads to higher levels of such generation than are socially optimal. To correct this market failure and equalize prices with costs, an ISO/RTO could include a carbon fee reflecting each generator's emissions profile in its bids into the wholesale market. By causing high-emitting generators, such as coal- and oil-fired units, to be dispatched less frequently, this would provide an incentive for investment in cleaner generating options and in non-transmission alternatives like energy efficiency or demand response.

Although the carbon pricing scheme we propose is conceptually simple, its implementation would raise numerous and complex issues. In the New York context, for example, any carbon pricing scheme proposed by NYISO would have to be integrated with RGGI. Thus, after determining a carbon fee for each generator—a difficult task in itself—NYISO would need to adjust that fee to exclude the cost of RGGI allowances. NYISO would also need to resolve whether the fee should accommodate or displace Tier 3 of the CES.

NYISO's proposed carbon pricing scheme would be subject to review by FERC. This Article argued that a carbon price could be justified as a means of improving the functioning of wholesale markets to ensure just and reasonable rates. While we view this as fully consistent with the law and with long-standing FERC practice, we note that it would push the boundaries of what has been done in the past. A more modest approach would see carbon pricing used solely to reflect and harmonize state-level policies aimed at reducing electricity sector emissions.