UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

State Policies and Wholesale Markets
Operated by ISO New England, New York ISO Docket No. AD17-11-000
And PJM Interconnection

INITIAL POST-TECHNICAL COMMENTS OF
ALLIANCE FOR A GREEN ECONOMY AND
NUCLEAR INFORMATION AND RESOURCE SERVICE

Nuclear Information and Resource Service (NIRS) and Alliance for a Green Economy (AGREE) offer the following comments on the topics discussed at the technical conference held on May 1 and 2, 2017.

We appreciate the Commission's intent in opening up this docket to address various actions being taken by state governments. These actions are both driving and responding to widespread changes occurring in the energy markets and the electricity system, and we believe FERC can and must play a constructive role. We start by noting concerns about the timing and circumstances of the docket, and the options FERC staff have presented. We then provide observations on trends affecting the nuclear power industry, and make constructive recommendations on how FERC should address state-level policy interventions in a consistent and productive fashion.

In short, we believe that existing procedures provide a strong and established basis for handling incumbent generator retirements and, with minor modifications, could support state environmental goals, bolster the competitive market, and facilitate needed upgrades to the transmission system.

Timing and Circumstances of this Docket

We are concerned about the timing and circumstances of this proceeding and how it might frustrate or derail a productive outcome. The decision to start a docket to collect input and inform the commission's approach to evolutions in state energy policies is valuable. But the commission that started the docket has had no way to set substantive policy or issue decisions, for lack of a quorum. In addition, once a quorum has been re-established following confirmation of President Trump's appointments, the entire direction the Commission takes may change due to the drastically different energy policies of the current administration from those of the Obama administration and the previous Commission.

For instance, there was a significant level of agreement about wholesale market-based carbon pricing among presenters at the May 1-2 technical conference. While we do not necessarily believe that carbon pricing is either the best policy approach to reducing carbon dioxide emissions in the electricity sector, nor that the wholesale markets are the best venue for regulating carbon, the notion is consistent with Obama administration policy and most of the state policies and programs that precipitated this docket. However, the very concept of regulating carbon and promoting renewable energy appear to be anathema to the direction for energy policy in the Trump administration. Several actions and statements in the administration's first five months suggest that regulation of carbon emissions is to be rolled back, and fossil fuel generation to be expanded: the president's decision to exit the Paris climate agreement; his expressed intent to roll back the EPA's Clean Power Plan rule; the opening up of public lands to fossil fuel extraction; the commissioning of a Department of Energy report on the need to promote baseload coal and nuclear generation for the purposes of national security; and DOE Secretary Perry's suggestion that the administration may exercise preemption authority to block state renewable energy policies.

Based on this record, the significant expenditures of time and effort parties have provided on this docket could be found largely irrelevant by the new commission, or the docket closed altogether. Rather than accommodate or facilitate state renewable energy and emissions programs, the new commission could decide to overrule or undermine them. Similarly, rather than authorize carbon pricing to support nuclear and renewable energy programs, the commission could decide to enhance capacity market prices to support coal and nuclear generation. It should be noted that, while Illinois and New York have decided to offer subsidies to some nuclear reactors, others have not followed suit, with legislation failing in Connecticut and Ohio this year, and other states with announced or potential reactor closures not registering significant interest (Massachusetts, Michigan, Nebraska, New Jersey and Pennsylvania). Most of these states share a goal of advancing renewable energy and reducing carbon emissions and reliance on coal generation. Yet the report ordered by Secretary Perry may urge FERC to impose measures not only to prevent closures of nuclear reactors, but to increase coal generation and the carbon intensity of electricity generation, and block the expansion of renewable energy sources.

Staff-Proposed Options

We believe that the policy approaches presented do not adequately address the underlying issues. In short, the options FERC staff has presented, as well as some of the state policies in question, focus too much on the symptoms of change in the energy markets and not the underlying causes driving them.

These forces are not just economic or market-based in nature, but they are also technological and generational. That is to say, they arise from a confluence of circumstances, in which the generation mix is fundamentally changing and the energy system is undergoing a fundamental, long-term transformation. On the one hand, older power plants – primarily coal and nuclear – are increasingly unable to compete on a price basis as they reach the end of their technological lives: their costs of operation are higher than those of competing generation sources, and their owners are unable either to reduce those costs or to justify investments to extend their operation.

On the other hand, new, more efficient and/or more environmentally sustainable technologies are becoming more prevalent and changing the way the electricity system is operated and market prices are formed. One-way grid management and control of baseload, load-following, peaking, and standby reserve generation is gradually yielding to the integration of variable renewable generation with flexible generation, demand-side management, and energy storage, along with aggregation of distributed energy resources.

At the same time, major players in the market are being affected differently, based on how their asset portfolios and business strategies intersect with these changes. That is to say, generators with large shares of nuclear and/or coal generation are seeking to preserve the value of those assets for as long as possible, rather than write them down and pursue new business strategies. Other established market participants are embracing the transition and seeking market rules and energy policies that are in alignment. Still other, new market participants are emerging and pursuing business strategies that would accelerate the deployment of renewables, distributed energy, and demand-side management, and the pace of grid and market transformation.

As detailed in comments submitted by Public Citizen, Public Utility Law Project, and Pennsylvania Utility Law Project, the stakeholder processes at FERC and Regional Transmission Organizations are dominated by private sector market participants, with little or no input from public sector entities, non-profit consumer advocates, and other public interest organizations, and with none of the transparency and democratic controls necessary to ensure that FERC's public interest mandates are well-served. The May 1-2 technical conference reflected the tendency to exclude the views of public interest organizations while privileging the views of merchant generators. Out of nine panels with fifty-nine (59) scheduled presenters in the two-day technical conference, there were only three presenters representing public interest organizations, and no non-profit consumer advocates.

Nuclear Operating Costs and Retirement Trends

In addition, there were no independent experts on nuclear power and nuclear industry economics, who could have provided valuable insight into the trend of reactor closures and state subsidy proposals, which are only partially driven by market price trends. FERC and state regulators must understand the nature of the economic trends facing the nuclear industry in order to address the situation effectively. First, reactor operating costs are a significant factor driving plant retirements; the industry's challenge is not simply one of insufficient "valuation" of nuclear-generated electricity in the markets, and reasonable carbon prices and/or capacity market adjustments may not provide sufficient revenue to guarantee long-term operation of aging reactors. Second, as the reactors that are most at risk of closure are the smallest and oldest, with the most uneconomic cost profiles, the market seems to be performing as intended, with old, uneconomic generation yielding to new investment in modern, more cost-effective technologies. Third, these reactors represent a disproportionately smaller share of total nuclear generation. For instance, while the Ginna and FitzPatrick reactors represent 50% of New York's nuclear power plants, they are only 26% of the state's nuclear generation capacity. Fourth, the majority of nuclear generation is not subject to as much financial pressure and not so much at risk of closure in the short term:

- 60% of nuclear generation capacity is comprised of reactors that are larger than the average size. For instance, in Pennsylvania, the Three Mile Island 1 reactor (829 MW) has a far different cost profile than the two-reactor Peach Bottom plant (2,710 MW).
- 75% of reactors are part of multi-unit nuclear sites.
- More than 50% of reactors (51 of 99) are operated by regulated utilities under cost-of-service ratemaking, and not directly subject to wholesale market pressures.

The nuclear power industry is undergoing a significant reduction in capacity, through the retirement of the oldest and most uneconomical generating units, but it is not significant or widespread enough to have unmanageable impacts on the electricity system or carbon dioxide emissions as a whole.

Conversely, however, the measures that may be required to prevent the closures of uneconomic reactors could carry a very high cost and have widespread impacts on both energy system investment and the viability of wholesale energy markets. New York's Zero Emissions Credit (ZEC) program is a key example. The policy adopted by the state Public Service Commission has thus far succeeded in preventing the closure of the FitzPatrick and Ginna reactors, in part by inducing Exelon to purchase FitzPatrick from Entergy, which was determined to close the reactor as part of its strategy to exit the merchant generation business. The pricing of ZECs in New York is extremely expensive, though, estimated to cost up to $7.6 billion over the course of twelve years (2017-2029), unless market prices rise dramatically in NYISO during that period. That cost is on top of the carbon price built into NYISO wholesale prices through the Regional Greenhouse Gas Initiative (RGGI), for which the ZEC price incorporates an adjustment. In effect, through ZECs and RGGI, New York's four upstate nuclear reactors stand to receive over $9 billion in above-market revenues from 2017-2029. NIRS published a report in November 2016 evaluating the cost of subsidies to nuclear reactors if a national subsidy program were implemented based on the New York model. We found that, adjusting for regional carbon prices, such a program could cost $160 billion to $280 billion by 2030, depending on whether all reactors were eligible for the subsidy or just those reactors deemed to be at risk of economic retirement.[1] We urge FERC to develop a more flexible and cost-effective approach to nuclear reactor closures, and to encourage states to do the same.

Declining market prices have decreased the available revenue for nuclear generators, but even at today's record-low levels, the purported widespread unprofitability of operating reactors would not be so prevalent if not for significant, industry-wide increases in operating costs as reactors have aged. Through biennial industry surveys, the Nuclear Energy Institute documented a 58% increase in average operating costs from 2002-2012 from $27.91/MWh to $44.17/MWh (2012 dollars).[2] Adjusted to 2017, nuclear operating costs averaged $29.75/MWh in 2002, within the range of current average market prices in the major competitive RTOs.

It is also important to recognize that reactor operating costs vary significantly, depending on the basic characteristics of the nuclear power plant, which determine the fundamental economies of scale:

- **Size or Generating Capacity:** The average reactor in the U.S. is 1,084 MW, but there is wide variation. Reactors in operation now range from 550 MW (Prairie Island 1 and 2) to 1,478 MW (Grand Gulf). The recently closed Fort Calhoun reactor was only 476 MW.
- **Single- or Multi-Unit Site:** single-unit reactors bear many of the same fixed costs as multi-unit sites, and have correspondingly higher cost profiles. Dual-reactor merchant plants have staffing levels 20%-33% lower than single-unit merchant plants. For instance, Exelon's single-reactor Ginna plant (581 MW) employs 600 full-time staff, and the dual-reactor Nine Mile Point plant (1,932 MW) 40 miles away employs 800 -- 33% fewer on a per reactor basis and 60% fewer on a capacity basis.
- **Reactor Age:** The average age of the U.S. reactor fleet is over 36 years, older than the global average. Nearly half of the reactors currently operating (forty-six of ninety-nine) have been in-service for longer than their originally-licensed forty years. Due to the

[1] Judson, Tim. "Too Big to Bail Out: The Economic Costs of a National Nuclear Power Subsidy." Nuclear Information and Resource Service. November 2016. https://www.nirs.org/big-bailout-economic-costs-national-nuclear-power-subsidy/#more-8718
[2] Nuclear Energy Institute. "Nuclear Energy 2014: Status and Outlook. Annual Briefing for the Financial Community." February 13, 2014.

specialized equipment, quality assurance standards, custom design-build, and old vintage of U.S. reactors, maintenance needs are driving up the costs of operation.

Most of the reactors that have closed since 2013 or that are cited as at risk of closure fall on the higher-cost side of these factors:

Recent Merchant Reactor Closures and Closure Announcements
(red = three negative cost factors; orange = two negative factors; yellow = one negative factor).

Reactor	Closure Year	Size	Reactors On-Site	Age
Kewaunee	2013	556 MW	1	39
Crystal River 3	2013	860 MW	1	37
San Onofre 2 & 3	2013	2,350 MW	2	30 and 29
Vermont Yankee	2014	620 MW	1	42
Fort Calhoun	2016	476 MW	1	43
Palisades	2018	811 MW	1	46 (current)
Pilgrim	2019	688 MW	1	45 (current)
Oyster Creek	2019	637 MW	1	48 (current)
Indian Point 2 & 3	2020 and 2021	2,069 MW	2	44 and 42 (current)
Diablo Canyon 1 & 2	2024 and 2025	2,240 MW	2	32 and 31 (current)
Clinton	n/a	1,065 MW	1	30 (current)
Quad Cities 1 & 2	n/a	1,824MW	2	44 (current)
Ginna	n/a	581 MW	1	47 (current)
FitzPatrick	n/a	838 MW	1	42 (current)

The vast majority of reactors (thirteen of eighteen) that have closed, or for which closure dates have been announced, have two or more negative operating cost characteristics:

- Smaller than average size (< 1,080 MW)

- Stand-alone reactor (single-unit plant)
- Older than average (currently or at time of closure)

Decisions to close five of those reactors have since been rescinded as a result of state-authorized subsidies to improve their profitability (Ginna, FitzPatrick, Clinton, and Quad Cities 1 and 2), but the underlying economic characteristics that led to the initial decision are relevant.

Poor economic characteristics alone are not the only factors driving the retirement of reactors. The San Onofre units 2 and 3 and Crystal River 3 reactors all closed due to botched replacements of major components, and state utility commissions' refusal to grant the utilities full cost-recovery. The complexity and high cost of major maintenance requirements has been a consistent factor in reactor closures historically: Yankee Rowe, Zion 1 and 2, Millstone 1, Connecticut Yankee, and Maine Yankee all closed in the 1990s due to large maintenance expenses for which the utilities could not justify regulatory cost recovery. While the immediate cause for closures in these circumstances is a large maintenance cost, in many cases the underlying or root cause has been systemic mismanagement and non-compliance with nuclear safety regulations.

Environmental protection standards also contribute to reactor closures. Oyster Creek, Indian Point 2 and 3, and Diablo Canyon 1 and 2 are all closing as a result of legal settlements in licensing and permit disputes, including impacts on water resources and/or wildlife habitats. However, forward-looking profitability concerns were also cited by the owners of Indian Point and Diablo Canyon in announcing the closure agreements; and Oyster Creek failed to clear the PJM capacity market auctions in 2015 and 2016, a sign of the high operating cost profile of the reactor, which is the oldest and one of the smallest still operating in the U.S.

The rate of cost increases may slow down for a time. As a result of the increased scrutiny of the industry's economics, utility-owned reactors may have begun exercising greater cost discipline. In addition, fewer reactors are expected to go through the expensive process of Nuclear Regulatory Commission relicensing. Over 75% of reactors have already received a first license extension (except for Oyster Creek and Indian Point, all for the standard twenty years).[3] Only

[3] U.S. Nuclear Regulatory Commission. "Status of License Renewal Applications and Industry Activities." https://www.nrc.gov/reactors/operating/licensing/renewal/applications.html

four reactors are currently undergoing relicensing (relicensing of Indian Point 2 and 3 is now in settlement; and Diablo Canyon 1 and 2 relicensing requests will be withdrawn), and only five more reactors are listed as having plans to pursue relicensing (plans for some of which may yet be rescinded in favor of closure, such as Exelon's Clinton and First Energy's Perry reactors).

These near-term factors notwithstanding, there is not much hope of reversing the high operating cost trend among aging reactors. Recent predictions of industry-wide cost-reductions by NEI should be regarded with skepticism. In 2016, NEI announced a new initiative called "Delivering the Nuclear Promise," through which average operating costs would come down by 30% by 2018.[4] This followed the issuance of NEI's most recent biennial operating cost study, covering the period 2012-2014. The report claimed a reversal of the decade-long (2002-2012) trend of operating cost escalation had dramatically reversed, and that average costs had decreased by 9% by 2014. While the report itself is proprietary and only summary data are available, there are notable inconsistencies between this report and the previous one (published in 2014).

For instance, a table listing the average annual cost for each year from 2002-2014 in the 2016 report, broken down by expense category (fuel, capital, operating), reports significantly lower costs than those in the 2014 report. The same table in the 2014 report shows the total average operating cost in 2012 as $44.17/MWh in 2012 dollars; but the 2012 cost in the 2016 report is only $39.70 in 2014 dollars. Adjusted for inflation based on the Consumer Price Index, the value reported in 2014 would have been $38.82/MWh in 2012 -- over 12% less than the actual reported value. This inconsistency is repeated throughout the figures in the reports, and raise serious questions about the credibility of NEI's assessments and the assurances that operating costs are being brought quickly under control.

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[4] Nuclear Energy Institute. "Delivering the Nuclear Promise: Advancing Safety, Reliability and Economic Performance." February 2016. https://www.nei.org/Master-Document-Folder/Backgrounders/White-Papers/Delivering-the-Nuclear-Promise-Strategic-Plan

Table from 2014 NEI Report

10-Year Trend of U.S. Nuclear Plant Costs
(2012 $ per MWh)

Year	Fuel	Capital	Operating	Total
2002	5.57	3.76	18.58	27.91
2003	5.47	5.02	20.27	30.75
2004	5.10	6.12	19.56	30.78
2005	4.89	6.56	20.27	31.73
2006	4.81	6.42	20.71	31.94
2007	4.98	6.34	20.31	31.62
2008	5.24	7.27	20.78	33.29
2009	5.89	10.58	22.46	38.92
2010	6.67	10.53	22.49	39.69
2011	7.01	11.50	23.34	41.85
2012	7.35	12.96	23.86	44.17

Table from 2016 NEI report

12-Year Trend of Nuclear Plant Costs
2014 $ per Megawatt-hour

YEAR	FUEL	CAPITAL	OPERATING	TOTAL
2002	5.72	3.92	18.59	28.23
2003	5.59	4.93	18.84	29.37
2004	5.28	5.65	18.54	29.47
2005	5.02	5.80	18.95	29.77
2006	5.04	5.56	19.21	29.81
2007	5.13	6.12	19.07	30.31
2008	5.35	6.76	19.51	31.62
2009	5.93	8.91	20.49	35.33
2010	6.76	9.16	20.63	36.55
2011	7.10	10.06	21.88	39.04
2012	7.46	10.76	21.47	39.70
2013	7.73	8.20	20.93	36.86
2014	7.17	8.18	20.92	36.27
2002-14 INCREASE	25%	109%	13%	28%

Incumbent Generators vs. New Investment

FERC staff's proposals promote a false equivalence between different types of state-level interventions: subsidies and bailouts for incumbent nuclear generation, on the one hand; and competitive procurements for new renewable energy sources, through RPS targets or bilateral contracts. These measures are sometimes justified on similar grounds, such as meeting state emissions targets, but they are, in fact, fundamentally different in structure, impact, and often in purpose; they also have significantly different implications for wholesale markets and energy system investments. All nuclear subsidy programs proposed to date are uncompetitive, unlike the vast majority of the renewable energy programs discussed at the May 1-2 technical conference. Reactors in New York and Illinois are determined to be eligible for subsidies through an administrative process, based on their projected unprofitability in the wholesale markets, not through a competitive procurement process. Salient features of these programs include:

- Nuclear generators do not have to compete against one another for access to the credits.
- The programs do not set targets or caps in a way that might lead to competition for access to credits. For instance, New York sets a cap on the total amount of ZECs that eligible reactors may sell, but at an aggregate amount equivalent to the highest level of output of all eligible reactors.
- The prices of nuclear energy credits are established administratively.
- At no point are any other generation sources that might contribute comparable benefits permitted to compete for nuclear energy credits.

In most cases, these programs are providing or would provide subsidies to only one corporation (or set of owners). For instance, Exelon has a controlling ownership interest in all of the reactors being subsidized in New York and Illinois. Similarly, in Ohio and Connecticut, FirstEnergy and Dominion would, respectively, be the sole beneficiaries; and in New Jersey, PSEG has the controlling share of all three reactors being discussed for subsidies, and Exelon is the minority partner in two of them.

Whether the rationale for these programs is carbon emissions (Illinois and New York) or some other attribute (such as reliability), their practical effect is to prevent the retirement -- and preserve the asset value -- of specific aging generators owned by market participants which have historically controlled a substantial share of the wholesale electricity markets. At the May 1-2 technical conference, some presenters indicated that the Illinois and New York nuclear subsidy programs have already had a chilling effect on capital formation in those markets. Had those states followed a competitive process like the one we have outlined above, investors would be able to have confidence that a significant amount of market share would be open to investment in new technologies. Instead, these programs have effectively locked over 50 million MWh/year of market share out of competition in the PJM and NYISO markets.

By contrast, RPS and other renewable energy procurement programs are driving new investment in the electricity markets, through competitive, market-based processes. RPS programs typically provide financial rewards to renewable generation sources through competitive auctions for RECs. REC prices can decline, both through the competitive bidding process, and as more cost-effective technologies enter the market. Similarly, renewable energy procurements may target particular generation sources (such as offshore wind and hydro), but there is still typically an open, proposal-based procurement process, through which companies can submit competitive bids and states can secure the best prices. For instance, offshore wind procurements in Maryland, Massachusetts, New York, and Rhode Island are already resulting in new entrants and investments in the PJM, NYISO, and ISO-NE markets: Deepwater Wind, DONG Energy, Renexia S.p.A.(U.S. Wind), and Copenhagen Infrastructure Partners (Vineyard Wind). By contrast, the subsidies to nuclear generators in New York have had the net effect of actually expanding Exelon's market share to an unprecedented level in NYISO; and in both Illinois and New York, of decreasing opportunities for new investment.

Competitive Proposal for Nuclear Retirements

We urge the Commission to keep a clear eye on the core reason for competitive wholesale markets -- to drive down costs to consumers through competition and innovation. That underlying goal must be central to this proceeding. This is especially important to reiterate and highlight because many generators participating in this docket are suggesting policies that would protect their market share, preserve their income in the face of market share loss due to uncompetitive subsidization of their competitors, or otherwise compromise affordability for consumers and subvert a competitive market where the highest cost resources exit and lower cost resources thrive.

In the past, the main considerations for interfering in the outcomes of the competitive market were largely around reliability. If a large generator was planning to retire due to lack of sufficient revenues in the market, and if the closure of that generator would compromise electricity reliability, regulators would intervene through a Reliability Must Run (RMR) process. But this intervention is meant to be temporary, and it includes a requirement for a competitive solicitation for alternatives so that consumers are guaranteed to receive the reliability attributes at the lowest cost possible.

The existence of the RMR process indicates that regulators value reliability to such a degree that it is worth market distortions in order to keep the lights on, but regulators have sought to limit the length and the cost of these distortions. A similar approach could be used to accommodate states that similarly have determined that they highly value greenhouse gas reductions. The critical need to respond to climate change by decarbonizing our energy system is rightly driving some states to create policies to support renewable energy and other low-carbon or no-carbon resources. To the extent that these policies drive innovation and competition to provide these environmental attributes at the lowest cost to consumers, FERC should accommodate these state goals, even when out of market subsidies threaten legacy generation or raise costs to consumers compared to having no environmental values incorporated into the market.

Where we do think FERC should consider interceding is in cases where states enact policies that interfere with the competitive market in order to support specific wholesale generators or a class of generators, without creating opportunities for market actors to compete to provide the environmental attributes sought.

States must have the right to set greenhouse gas reduction goals and when states set aggressive goals, this is going to necessarily have a collateral impact on wholesale markets, which are still largely dominated by fossil fuel generation sources. FERC should seek to support and accommodate these state goals by creating clear guidelines to remove uncertainty, leaving room for policy flexibility and innovation, and by discouraging uncompetitive subsidies that benefit one company or one technology, when a competitive solicitation or market mechanism could drive a lower cost outcome for consumers.

By way of illustration, we offer an example from our experience in New York with the Ginna nuclear reactor, which is an uneconomic generator that has received an RMR contract followed by Zero Emissions Credits (ZEC) through New York's newly minted Clean Energy Standard (CES).

In 2014, Ginna's owner informed the New York Independent System Operator (NYISO) and the New York PSC that without subsidization, the plant would likely close.[5] NYISO assessed reliability needs in light of Ginna's planned closure and determined that a need existed. Thus followed a process to seek economical alternatives to an RMR contract. This search turned up a utility transmission upgrade that could eliminate the reliability need and would cost consumers less money over time than an open-ended RMR contract. Ginna was awarded an RMR contract for two years while the utility built the transmission upgrade, at which point, the RMR expired. Through this process, the reliability needs were met, the RMR was a short-term stop-gap measure, and a permanent upgrade saved consumers millions of dollars.

On the heels of the Ginna RMR case, the New York Public Service Commission instituted a Clean Energy Standard (CES) proceeding with the express purpose of ensuring that the state will

[5] FERC Docket ER15-1047-000 (R.E. Ginna Nuclear Power Plant, LLC submits tariff filing per 35.12: Initial Rates).

achieve its goal of 50% renewable energy and 40% greenhouse gas reductions by 2030.[6] The CES mandates that utilities buy ever increasing numbers of Renewable Energy Credits (RECs) such that by 2030, half of the electricity served to customers in New York will come from renewable energy resources. Renewable energy providers will compete to sell RECs to utilities, ensuring the innovation and competition at the heart of functional markets.

The CES also mandates that utilities purchase Zero Emission Credits (ZECs) from three existing nuclear plants, one of which is the Ginna reactor and all of which happen to be owned by the same corporation, Exelon. The ZEC price is set administratively through a formula based on the Social Cost of Carbon (supposedly coincidentally, the administratively set price happens to approximate what the nuclear owner announced was necessary to remain in business), and no other resources or companies are allowed to compete to provide the same emissions attributes that the ZEC policy seeks to preserve. This is an example of a state greenhouse gas reduction policy run amok, and one that FERC should disallow.

In the case of the Ginna RMR process, through an effort to preserve competition and limit the term of uncompetitive out of market payments, a lower cost alternative was found and the generator was subsidized through an RMR contract only to preserve reliability in the interim. In the case of the ZEC subsidies that Ginna is now receiving, no effort was made to solicit lower cost alternatives or allow other resources or companies compete to provide the low-carbon attributes that Ginna is compensated for. The policy was established with the singular intent to prevent Ginna and three other reactors from closing, on the presumption that no other resource could provide the same attributes.

In an ideal scenario, the state should set its greenhouse gas reductions goals, determine how many megawatt-hours of zero carbon generation are needed to meet that goal, and then run competitive solicitations or a competitive REC market so that resources compete on a level playing field to sell their clean energy attributes. In the case that the closure of a large generating unit such as an uneconomical nuclear plant would clearly jeopardize a state's climate goals, a

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[6] NY Public Service Commission: Case 15-E-0302- In the Matter of the Implementation of a Large-Scale Renewable Program and a Clean Energy Standard.

similar process to the RMR *could* be undertaken.[7] But like RMRs, the duration should be limited only to the length of time necessary to put into place less costly alternatives, chosen through a competitive solicitation process.

Such a process would strike the right balance to respect state policy priorities and climate strategies while protecting the goals of competition and innovation that are necessary for functioning wholesale markets.

Respectfully submitted,

Jessica Azulay
Program Director
Alliance for a Green Economy
2013 E. Genesee St.
Syracuse, NY 13210
Jessica@allianceforagreeneconomy.org

Timothy Judson
Executive Director
Nuclear Information and Resource Service
6930 Carroll Ave., Suite 340
Takoma Park, MD 20912
TimJ@nirs.org

[7] We deliberately use the word "could" here in recognition that for some states, the environmental and safety threats posed by nuclear power and the need to invest in the flexible technologies of the future will outweigh any value provided by nuclear plants. FERC should not force states to preserve nuclear reactors to meet their greenhouse gas reduction goals.