Winter 2017

Keeping the Fox from Managing the Henhouse: Why Incumbent Utilities Should Not Be Allowed to Operate the Distribution System Platform

James M. Van Nostrand
West Virginia University College of Law, james.vannostrand@mail.wvu.edu

Keeping the Fox From Managing the Henhouse: Why Incumbent Utilities Should Not Be Allowed to Operate the Distribution System Platform

James M. Van Nostrand*

A transformation is underway in the electric utility industry in the United States, as local distribution utilities are faced with increased penetration of distributed generation resources, primarily solar photovoltaic ("PV") panels, thereby resulting in gradual abandonment of the traditional model featuring large, centralized generating stations. Regulators and industry observers refer to "the utility of the future," which will involve a "customer-centric" business model where the utility's role will be to manage integration of distributed energy resources ("DERs") and facilitating customer-driven energy choices such as energy efficiency and demand response programs.[1] To a large extent, these changes are driven by economics and advancing technology: the costs of distributed energy resources, particularly solar PV panels, have declined considerably in recent years, resulting in increased penetration of distributed energy resources and corresponding reductions in electricity demand being placed on the local utility, as customers "self-generat[e]" their power.[2] Improved and lower cost technology has also given utility customers an increased ability to exercise control of their energy usage, through demand-side management ("DSM") programs.[3] These measures, too, have the effect of reducing the level of electricity sales from the local utility. The collective effect of these forces is to call into question the long-term viability of the traditional electric utility business model. A number of state regulatory commissions around the country have proceedings to reformulate the utility business model—and the associated regulatory framework—in light of this industry transformation.[4]

The most prominent "Utility 2.0" proceeding is Reforming the Energy Vision ("REV"), which is underway at the New York Public Service Commission ("PSC").[5] In an order issued in February 2015, the New York PSC adopted a new utility business model that identified the foundational utility service as a "distribution system platform provider," or DSP.[6] Under this approach, the DSP would be charged with planning and designing its distribution system as a platform to facilitate uniform market access to customers and distributed energy resource providers.[7] In other words, the DSP's role would be as the platform for interface among its customers, distributed energy providers, and the distribution system, and the DSP would be expected to cease treating distributed energy providers as competitors, but rather view

* *James M. Van Nostrand is a Professor of Law and Director of Energy and Sustainable Development at West Virginia University College of Law. Professor Van Nostrand received his LL.M. from Pace University College of Law, and earned his J.D. from University of Iowa College of Law.* *The author expresses his appreciation to the WVU College of Law and the Hodges/Bloom Research Fund for their financial support for this Article.*

1. Herman K. Trabish, *How to become the "Utility of the Future?" Industry experts weigh in*, Utility Dive, Sept. 28, 2015, http://www.utilitydive.com/news/how-to-become-the-utility-of-the-future-industry-experts-weigh-in/406125/.
2. Rocky Mountain Inst. et al., The Economics of Grid Defection: When and Where Distributed Solar Generation Plus Storage Competes With Traditional Utility Service 9 (2014), http://www.rmi.org/electricity_grid_defection.
3. *See* Brandon Davito et al., *The Smart Grid and the Promise of Demand-Side Management*, in McKinsey on Smart Grid 41 (2010), www.smartgrid.gov/files/The_Smart_Grid_Promise_DemandSide_Management_201003.pdf.
4. *See* Cal. Pub. Util. Comm'n, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769, No. 14-08-013 (Aug. 20, 2014), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M103/K223/103223470.pdf; Haw. Pub. Util. Comm'n, Regarding Integrated Resource Planning, No. 2012-0036, at 2 Ex. A (Apr. 28, 2014), http://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A12C02B22338C61198; Mass. Dep't of Pub. Util., Investigation by the Dep't of Pub. Util. on its own Motion Into Modernization of the Electric Grid, Order No. 12-76-B (June 12, 2014); N.Y. Pub. Serv. Comm'n, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, No. 14-M-0101 (2014) [hereinafter Rev Motion], http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101; Energy Future Coal, *Utility 2.0: Piloting the Future for Maryland's Electric Utilities and Their Customers* (Mar. 2013), http://www.smartgridinformation.info/pdf/5230_doc_1.pdf.
5. *See* Rev Motion, *supra* note 4.
6. N.Y. Pub. Serv. Comm'n, Order Adopting Regulatory Policy Framework and Implementation Plan, No. 14-M-0101, at 40 (Feb. 26, 2015) [hereinafter Track One Order], http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={0B599D87-445B-4197-9815-24C27623A6A0}.
7. *Id.* at 40–41.

them as customers and partners. Adoption of a DSP model, however, does not end the discussion; there is the further issue of deciding whether the incumbent utility will become the DSP, and how the "market power" issues associated with that function (i.e., actions necessary to ensure that the platform is operated in a manner that promotes fair competition) can be addressed. In its February 2015 order, the New York PSC determined that the existing incumbent electric utilities would serve as DSPs.[8]

Allowing the existing distribution utility to continue to operate the distribution platform under this new utility business model, however, may present a fundamental conflict of interest. If the DSP performs its intended function by encouraging the expansion and optimization of customer-owned distributed energy resources and promoting energy efficiency and demand response programs, the result will likely be a reduction in the need for the utility to make additional investments. In other words, the utility as DSP would have strong motivation to increase its assets—the rate base upon which it earns a return—rather than promote customer-owned distributed energy resources. In many respects, this solution may be far worse than the proverbial "fox *guarding* the henhouse." Assigning the incumbent utility with the role as DSP may be more like the fox *managing* the henhouse.

In many respects, this transformation at the state level with respect to retail service in the electric industry mirrors the experience at the federal level regarding wholesale electric markets during the 1990s, when the Federal Energy Regulatory Commission ("FERC") issued a series of orders designed to introduce competition into the generation market, by requiring nondiscriminatory open access to the transmission grid.[9] FERC considered similar issues regarding the methods for addressing the market power issues associated with the incumbent utilities continuing to operate the transmission network, and its approach evolved from one allowing the incumbent utilities to continue to operate the transmission network (Order 888, issued in 1996) to a model featuring operation of the transmission network by an independent third party (Order 2000, issued in 1999).[10] This evolution of the wholesale electric markets at the federal level provides considerable guidance to state regulators as they grapple with the design of the utility business and regulatory model for retail electric service. This Article examines the lessons learned regarding the success of business structures in achieving the objective of ensuring nondiscriminatory access to electric network, based on FERC's actions to restructure the electric industry during the 1990s. To provide some context for the measures that may be necessary to address potential market power issues associated with the incumbent utility's operation of the distribution platform, the Article also examines the actual experience with respect to one particular utility, the Consolidated Edison Company of New York, Inc. ("Con Edison"). Building upon the federal experience and informed by an awareness of the local distribution utility's ability to exercise market power, this Article concludes with a recommended approach for the utility business model that mirrors the approach ultimately adopted by FERC in the wholesale transmission markets: an independent distribution system platform operator, or IDSO.

I. The Distribution System Platform Model

In its April 2014 order instituting the REV proceeding, the New York PSC indicated its intention to consider "fundamental changes in the manner in which utilities provide service" and the possibility of a "substantial transformation" of the utility business model.[11] A key question to be addressed would focus on the role of the incumbent retail electric utility in a system geared toward integration of distributed generation ("DG") resources and customer-centered load management practices, with the goal of achieving greater efficiencies in the system.[12] The PSC identified six policy objectives to guide the proceeding: providing better information and more tools to customers to manage their energy bills; stimulating the market and "leveraging" the contributions from utility ratepayers; improving the efficiency of the utility system; achieving greater diversity in energy resources; improving the reliability and resilience of the utility grid; and reducing greenhouse gas ("GHG") emissions.[13] Given the "foundational steps" that New York has previously taken to encourage the integration of DG resources into the utility grid and the presence of a single-state wholesale market administered by the New York ISO, the PSC concluded that New York was "particularly well-suited" to take the lead in the examination of possible new utility business models.[14] The *REV Order* also recognized the changes in ratemaking practices that must accompany any transformation of the utility business model.[15]

The *REV Order* established two parallel tracks for the proceeding—one to examine the utility business model, and the second to examine the regulatory framework and ratemaking issues.[16] The proceeding attracted an unprecedented number of parties—259 stakeholders have intervened in the case[17]—as well as considerable national attention.[18] One commenter

8. *Id.* at 48.
9. *Restructuring: The Effects of FERC Orders 888, 889, and 2000*, TransMissives, https://transmissives.com/the-story-of-the-grid/restructuring-the-effects-of-ferc-orders-888-889-and-2000/ (last visited Sept. 13, 2016).
10. *Id.*; *see also infra* text accompanying notes 113–35, 146–52.
11. *See* N.Y. Pub. Serv. Comm'n, Order Instituting Proceeding, No. 14-M-0101, at 4–5 (Apr. 25, 2014) [hereinafter Rev Order], http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={9CF883CB-E8F1-4887-B218-99DC329DB311}.
12. *Id.* at 2.
13. *Id.*
14. *Id.* at 4.
15. *Id.* at 4–5.
16. Rev Order, *supra* note 11, at 6.
17. N.Y. Pub. Serv. Comm'n, Developing the REV Market in New York: DPS Staff Straw Proposal on Track One Issues, No. 14-M-0101 (Aug. 22, 2014) [hereinafter Track One Proposal], http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={CA26764A-09C8-46BF-9CF6-F5215F63EF62}.
18. *See* Gargi Chakrabarty, *REV It Up in New York*, Energy Central (Aug. 25, 2014), http://www.energybiz.com/magazine/article/368385/rev-it-new-york; Stephen Lacey, *New York's Energy Czar: We Need Clean Energy Markets, Not Programs or Mandates*, Greentech Media (Nov. 24, 2014), http://www.greentechmedia.com/articles/read/new-york-energy-czar-we-need-clean-energy-markets-not-programs; Matthew Wald, *State Energy Plan Would Alter New York Utilities*, N.Y. Times, May 4, 2014, http://www.nytimes.com/2014/05/05/

referred to REV as a "landmark regulatory proceeding" the outcome of which "will reverberate across the country" as other states wrestle with the same underlying drivers.[19] In addition to the Staff Report and Proposal issued with the *REV Order*, Staff issued its proposal with respect to Track One issues on August 22, 2014.[20]

In its Report and Proposal accompanying the *REV Order*, the PSC Staff articulated a new business model for the electric distribution system that identified the foundational utility service as a "distribution system platform provider," or DSP.[21] As described in the Report and Proposal, this entity would be charged, among other things, with planning and designing its distribution system to facilitate a prominent role for DG resources in meeting system needs[22]; creating markets, tariffs and operations systems to facilitate integration of "behind-the-meter" resource providers, such as energy efficiency and DR programs, building management systems, and microgrids[23]; providing information technology and real-time pricing information among market participants, including pricing structures for DG products and services[24]; serving as the primary interface among retail customers in distribution markets and between retail customers and the wholesale markets (i.e., aggregating products for the purpose of offering them to the New York ISO)[25]; serving as the local balancing authority (i.e., balancing loads and resources to meet customer needs and maintain reliability)[26]; and developing communications networks capable of supporting a smart grid.[27] An issue to be explored in Track One of REV was the identity of the DSP: in other words, would the incumbent utilities be charged with operating the distribution platform under the new regulatory regime designed in the REV proceeding, or were there other options, such as having an independent, third-party operate the platform?

II. Who Serves as Operator of the Utility Network?

FERC explored essentially the same issue in the 1990s when it undertook to introduce competition into the generation market by requiring utilities to make the transmission grid available to others and provide "open access" to non-utilities to transmit their electricity over utility-owned transmission lines.[28] Under the historical business model, the typical vertically integrated utility served all three functions—generation, transmission, and distribution of electricity—and its transmission lines were typically used only to transmit, or "wheel," its own power from its generating plants—often located hundreds of miles away from its customer load—to its own retail customers.[29] If this transmission grid was treated more like an interstate highway system, however, and opened up for use by others to wheel electrons over long distances, then competition in the generation market would thrive, thereby resulting in lower electricity costs at the wholesale level that ultimately would translate into lower rates for consumers.[30] Sellers of electricity—the merchant power plants that were being built as a result of earlier federal initiatives—would have access to a greater number of buyers, and the retail utility "buyers" seeking wholesale power to serve their customers would have access to a greater number of sellers.[31] But the success of this strategy depended upon the transmission-owning utilities granting non-discriminatory access to the grid: what regulatory measures would be necessary to ensure that the transmission-owning utilities would not discriminate against competing electricity suppliers in the terms and conditions under which access would be granted to their transmission lines? This is the issue that FERC addressed in its *Open Access NOPR*, discussed in the next section.

Strikingly similar issues are involved at the retail level under the distribution platform model articulated by the New York PSC Staff under its DSP proposal. In a sense, the utility network—in this case the retail distribution platform rather than the wholesale transmission grid—is "opened up" for use by others—in this case, DERs and energy efficiency service providers, rather than merchant power plants and other non-transmission owners—with an objective of achieving lower energy costs, and a more efficient use of electric utility assets, for the benefit of retail customers. But the success depends upon the owners of the distribution platform granting non-discriminatory access to that platform, and not engaging in conduct that provides a competitive advantage to themselves or their affiliates. Following an examination of FERC's decision in Order 888 regarding the regulatory approach for granting access to the transmission grid, this Article will consider the approach adopted in New York with respect to operation of the distribution platform.[32]

A. *FERC's First Solution: The Incumbent Utility, With Functional Unbundling*

FERC examined similar issues in its restructuring of the electric wholesale markets when it issued its Notice of Proposed Rulemaking ("NOPR") in April 1995 in its "open access" proceeding,[33] which ultimately led to the issuance of Order 888 in 1996 opening up the electric transmission system to competition.[34] The objective of that proceeding

nyregion/state-energy-plan-would-alter-new-york-utilities.html?_r=0.

19. Ryan Katofsky & Lisa Frantzis, *Devil Is in the Details on NY's Reforming the Energy Vision*, Advanced Energy Economy (Sept. 11, 2014, 10:54 AM), http://blog.aee.net/devil-is-in-the-details-on-nys-reforming-the-energy-vision.
20. Track One Proposal, *supra* note 17.
21. *Id.* at 3.
22. *Id.* at 1, 12.
23. REV Order, *supra* note 11, at 12.
24. *Id.*
25. *Id.*
26. *Id.* at 22.
27. *Id.* at 23.
28. *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*, Order No. RM95-8-000, 60 Fed. Reg. 17,662-01 (Apr. 7, 1995) [hereinafter Open Access NOPR].
29. *Id.* at 17,668.
30. *Id.* at 17,675.
31. *Id.* at 17,676.
32. *See* discussion *infra* Sections II.B, III.A, III.C.
33. *Id.* at 17,675–76.
34. *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*, 75 FERC ¶ 61,080 (1996) [hereinafter Order 888], https://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-00w.

was removing impediments to competition in the wholesale power markets, and FERC identified "market power through the control of transmission" as the "single greatest impediment to competition."[35] According to findings in the *Open Access NOPR*, transmission service is a natural monopoly, and transmitting utilities own the transmission system necessary to facilitate bulk power transactions.[36] The owner or controller of transmission facilities has the ability to exclude generation competitors from the market, and thereby favor their own generation.[37] The exclusion can occur by denying transmission access, or providing access only on rates, terms or conditions of service that are discriminatory.[38] Specifically, FERC found that:

> [U]tilities owning or controlling transmission facilities possess substantial market power; that, as profit maximizing firms, they have and will continue to exercise that market power in order to maintain and increase market share, and will thus deny their wholesale customers access to competitively priced electric generation; and that these unduly discriminatory practices will deny customers the substantial benefits of lower electricity prices.[39]

The solution, according to FERC, was to require all public utilities owning or controlling transmission facilities to offer open, fair and non-discriminatory access to the transmission grid.[40]

Citing circumstances strikingly similar to today's situation in the retail distribution system, FERC referred to the industry as "in transition," and in the process of responding to changes in law, technology, and markets.[41] FERC acknowledged that while the move to competitive markets in generation would "fundamentally change long-standing regulatory relationships," the transition to competitive bulk power markets would ultimately fulfill the Commission's goal of encouraging lower electricity rates.[42]

In the *Open Access NOPR* and in *Order 888*, FERC identified three possible approaches to address the issue of transmission market power by public utilities. One approach would turn over management of the transmission grid to independent system operators, or ISOs.[43] Under this model, ownership would be separated from operation: While utilities may continue to *own* transmission assets, the regional transmission organizations ("RTOs") or independent system operators *operate* the grid. This would ensure that the transmission owners have no ability to leverage their monopoly power in the transportation market—by virtue of ownership of the transmission network—to advantage their positions in the commodity or power market, through anticompetitive, or discriminatory, practices regarding access to the grid.

A second approach considered by FERC was ownership unbundling (i.e., requiring separation of transmission functions through creation of a separate corporate affiliate, or selling off assets to a non-affiliate (divestiture)).[44] Under the ownership unbundling model, the operation of the electricity network would be effectively separated from generation and retail activities.[45] In other words, the previously common ownership structure between network operations and generation activities of a company are separated, including the separation of asset ownership.[46] The separate transmission company that is created not only operates, but owns, the transmission network assets.[47] Generation companies would be precluded from acquiring or maintaining transmission networks.[48]

An example of an "ownership unbundled" approach for transmission is the independent transmission system operator, or ITSO, where one legal entity both owns and operates the transmission system.[49] One such entity is National Grid in the United Kingdom, which owns and operates the national transmission network.[50] In addition to the system operator in the UK, there are three transmission operators charged with developing, operating, and maintaining the transmission grid within defined regions: National Grid Electricity Transmission plc in England and Wales, Scottish Power Transmission Limited for southern Scotland, and Scottish Hydro-Electric Transmission plc for northern Scotland and the Scottish islands.[51]

The third approach considered by FERC was functional unbundling, or requiring utilities to separate wholesale generation and transmission services without formal changes in legal ownership or corporate structure.[52] In its *Open Access NOPR* and *Order 888*, FERC determined that functional unbundling could accomplish the objective of achieving non-discriminatory open access to the transmission system.[53] FERC defined functional unbundling to have three elements. First, the public utility must take transmission services—and related ancillary services, such as scheduling and balancing—for its own needs under the same tariff under which others take such services.[54] In other words, the utility charges itself the same price for those services that it charges its wholesale transmission customers.[55] The second element was a requirement that rates for transmission and ancillary services must be unbundled, or separately stated.[56] The third

txt.
35. Open Access NOPR, *supra* note 28, at 17,664.
36. *Id.* at 17,665.
37. *Id.*
38. *Id.*
39. *Id.*
40. Open Access NOPR, *supra* note 28, at 17,665.
41. *Id.* at 17,663.
42. *Id.*
43. Order 888, *supra* note 34, at 56–61.
44. *Id.* at 60–61; *see also* Open Access NOPR, *supra* note 28, at 17,681.
45. Neelie Kroes, *Improving Competition in European Energy Markets Through Effective Unbundling*, 31 Fordham Int'l L.J. 1387, 1424–25 (2007).
46. *Id.* at 1425.
47. *Id.*
48. *Id.*
49. Michael Pollitt, *Lessons From the History of Independent System Operators in the Energy Sector*, 47 Energy Policy 32, 32–33 (2012).
50. *What We Do in the Electricity Industry*, National Grid, http://www2.nationalgrid.com/uk/our-company/electricity (last visited Sept. 12, 2016).
51. *Electricity, The GB Electricity Transmission Network*, Off. of Gas & Electricity Mkts., https://www.ofgem.gov.uk/electricity/transmission-networks/gb-electricity-transmission-network (last visited Sept. 12, 2016).
52. Order 888, *supra* note 34, at 58.
53. Open Access NOPR, *supra* note 28, at 17,681; Order 888, *supra* note 34, at 59.
54. *See* Open Access NOPR, *supra* note 28, at 17,681.
55. *See id.*
56. *See id.*

element was that the utility must rely on the same electronic network as its transmission customers when it seeks to obtain information about transmission availability for purposes of buying and selling power.[57] Apart from these three elements, FERC imposed a strong code of conduct regarding communications between a utility's merchant function of buying and selling of power and transmission operations.[58] The code of conduct proposed by FERC required that employees in transmission system functions be separated from those in wholesale marketing functions, and also defined permissible and impermissible contacts between these groups of employees.[59]

In *Order 888*, FERC determined that functional unbundling was a "reasonable and workable means" of addressing the issue of non-discriminatory access, and declined to adopt the "more intrusive and potentially more costly mechanism" of ownership or corporate unbundling.[60] While *Order 888* accommodates corporate unbundling, it does not require it.[61] FERC concluded in *Order 888* that corporate unbundling would create inefficiencies and additional costs, which was unnecessary given its conclusion that functional unbundling would be sufficient to remedy discriminatory practices.[62] *Order 888* therefore rejected corporate unbundling as a "more intrusive and potentially more costly mechanism."[63]

It also rejected "operational unbundling," which refers to the use of a third-party independent system operator, although it encouraged utilities to consider ISOs "as a tool to meet the demands of a competitive marketplace."[64] As discussed in a later section of this Article, FERC ultimately revisited this determination in Order 2000, where it extensively discussed the failures of functional unbundling to achieve the desired goals and moved toward the ISO model as the best means of ensuring nondiscriminatory access to the transmission grid.[65]

B. New York's Current Solution: The Incumbent Utility, With Functional Unbundling

In New York's REV proceeding, the DPS Staff endorsed a functional unbundling approach in its "Straw Proposal on Track One Issues."[66] As noted above, Staff defined the Distribution System Platform, or DSP, model in its April 2014 report.[67] In its *Track One Proposal*, Staff recommended that the incumbent distribution utility perform the DSP function,[68] accompanied by additional measures to address "the natural monopoly of distribution system operations" and to "prevent the unfair exercise of market power by utilities."[69] Staff concluded that there were significant advantages to this structure inasmuch as the utilities already bear the responsibility for the important function of maintaining grid reliability, and the regulatory mechanisms are already in place for the incumbent utilities, including ratemaking, audits and operational review.[70]

With respect to the issue of market power, the *Track One Proposal* cited the utility's "direct commercial market involvement" with DG resources as a source of market power, given the utility's control of (1) schedule and dispatch of these resources, (2) their ability to interconnect with the distribution platform, and (3) their access to system and customer data.[71] As a result, the utility could erect barriers to the ability of DG resources to compete, such as through burdensome interconnection requirements, inadequate tariffs, or denial of access to system or customer data.[72] The *Track One Proposal* also referred to the possibility of a "functional competitive advantage" of the platform operator, irrespective of utility behavior.[73]

To address these market power concerns, the *Track One Proposal* recommended generally that utilities not be permitted to engage directly in ownership of DG resources, unless the location of generation or storage is on utility distribution property.[74] While acknowledging that there are advantages to having utilities involved in DG resources—they know the needs and capabilities of the distribution system, and can easily identify the best sites for locating DG resources—the *Track One Proposal* concluded that allowing utility participation could have the effect of discouraging private capital and potential market participants from investing in New York, thereby stifling the possible growth of a competitive and innovative market for DG resources.[75] The *Track One Proposal* recommended that utilities be permitted to participate directly in sponsorship and management of energy efficiency programs.[76] Where an unregulated utility affiliate seeks to operate within the utility's service territory, codes of conduct would govern the interactions with the regulated utility.[77] In

57. *See id.* Order 889, issued April 24, 1996, required an Open Access Same Time Information System, or OASIS, to fulfill this third element of functional unbundling. *See Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct*, 75 FERC ¶ 61,078 (1996) (codified at 18 C.F.R. pt. 37), http://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-9-00k.txt.
58. *See* Order 888, *supra* note 34, at 59.
59. *See id.*
60. *Id.*
61. *See id.* at 60.
62. *See id.* at 54. FERC acknowledged in Order 888 that a number of commenters strongly advocated for corporate or ownership unbundling. *See* Order 888, *supra* note 34, at 56–58. One commenter noted the affiliate abuses that were occurring in the natural gas industry, and claimed that the potential was even greater in the electric industry given the domination by vertically integrated utilities. *See id.* at 55. Another commenter criticized functional unbundling as insufficient, as it would fail to address the ability of the utility to favor its marketing operations when dealing with issues related to transmission planning, capital investment, and O&M replacement costs. *See id.*
63. *Id.* at 59.
64. *Id.* at 60, 61.
65. *See* discussion *infra* Section II.C.
66. Track One Proposal, *supra* note 17.
67. *See* REV Order, *supra* note 11, at 9 attach. 1.
68. Track One Proposal, *supra* note 17, at 12.
69. *Id.* at 18–19.
70. *Id.*
71. *Id.* at 67.
72. *Id.*
73. Track One Proposal, *supra* note 17, at 67.
74. *Id.* at 72. The Track One Proposal would allow direct participation in limited circumstances, if part of a utility's Distributed System Implementation Plans, and upon a showing that the proposal addresses a substantial system need, the benefits of utility engagement outweigh the market power concerns, and a competitive solicitation is used for construction and operation of DG resources. *Id.* at 72–73.
75. *Id.* at 70.
76. *Id.* at 72.
77. Track One Proposal, *supra* note 17, at 73.

addition, regulatory scrutiny would be heightened to include monitoring of interconnection complaints and the availability of an ombudsman for DG providers.[78] If an affiliate bids into a utility's procurement for DG resource, an independent entity would select the winning bids.[79] Finally, caps on market share would be placed on the extent of affiliate participation within the service territory and within individual distribution circuits.[80]

The *Track One Proposal* in New York's REV proceeding rejected the recommendation to establish an independent DSP operator.[81] The *Proposal* acknowledged several advantages to the independent DSP operator, such as the ability to establish uniform; statewide practices, in contrast to the DSPs operated by individual utilities; and avoidance of market power concerns and issues regarding utility ownership of DG resources.[82] Moreover, an independent DSP operator was acknowledged as perhaps being more effective at stimulating technological innovation.[83] But the *Track One Proposal* also identified "numerous drawbacks" to an independent DSP operator, including the addition of significant redundant costs given that the DSP would perform many of the functions currently performed by utilities, and the addition of duplicative functions at the DSP with respect to the system planning and operations functions of the utilities.[84] The *Track One Proposal* concluded that use of an independent DSP operator approach would be an "expensive, unwieldy, and incomplete response."[85]

In its *Track One Order*,[86] the New York PSC adopted Staff's recommendation to require the incumbent utilities to serve as DSPs, finding that such an approach would be "in the best interests of New York consumers."[87] In rejecting an independent DSP approach, the PSC cited a lack of "evidence or compelling rationale" that separating the utility's planning, grid operations, and market operations functions at the distribution level would produce improved results.[88] According to the *Track One Order*, many of the services that would be performed by an independent DSP are already performed by utilities, and the investment and operating costs of an independent DSP would ultimately be flowed through to retail customers.[89] Customers would see "no value" from these increased costs, according to the *Order*.[90] To address concerns raised by the parties regarding the ability of the utilities in the role of DSP to exercise market power and suppress innovation, the PSC adopted several market structures.[91] First, it adopted Staff's recommendation to preclude the utilities from owning DERs where the market is capable of providing such services.[92] Second, the PSC indicated that its ratemaking reforms from Track Two would provide utilities with the proper financial incentives to promote the success of REV markets rather than seeking to expand their rate base investments as under the traditional utility ratemaking model.[93] Third, the PSC committed to closely monitor the performance of utilities as DSPs, using its numerous regulatory tools for monitoring and enforcing DSP requirements.[94] Fourth, the PSC proposed to address DSP activities that deter DER investments through a dispute resolution mechanism that would expedite review and action on such activities.[95] Fifth, the PSC indicated that it would continue to consider those proposals for functionally separating DSP functions from standard utility operations, so long as such separation does not interfere with efficient performance of utility functions or impose unnecessary costs.[96] Finally, the *Track One Order* held out the possibility that entities other than the utility could assume the DSP functions in the event the utilities fail to meet the performance expectations with respect to achieving REV objectives, although such a separation "is neither the preferred nor most economic approach."[97]

C. FERC's Ultimate Solution: An Independent System Operator

As noted above, FERC's *Order 888* was intended to promote competition in the wholesale electricity markets by removing impediments arising largely from the exercise of market power by transmission owners over the interstate transmission grid.[98] In addition to requiring all public utilities owning or controlling transmission facilities to offer open, fair, and non-discriminatory access to the transmission grid, *Order 888* attempted to deal with the market power issue by requiring functional unbundling.[99] The functional unbundling requirements included, among other things, the separation of transmission system functions and staffs within a public utility from wholesale generation marketing functions and staff, and abiding by codes of conduct that defined impermissible contacts between transmission and generation personnel.[100]

Within four years, however, FERC issued its Notice of Proposed Rulemaking on Regional Transmission Organizations ("RTO NOPR"), and concluded that functional unbundling had largely failed to achieve the goal of eliminating opportunities for transmission owners to unduly discriminate in the operation of their transmission systems in order to favor the power marketing activities of their affiliates.[101] As stated in the *RTO NOPR*, "there are indications that contin-

78. *Id.*
79. *Id.*
80. *Id.*
81. *Id.* at 19.
82. Track One Proposal, *supra* note 17, at 19.
83. *Id.*
84. *Id.*
85. *Id.* at 21.
86. *Id.* at 48.
87. Track One Order, *supra* note 6, at 48.
88. *Id.* at 50.
89. *Id.*
90. *Id.*
91. *Id.* at 51–53.
92. Track One Order, *supra* note 6, at 52.
93. *Id.*
94. *Id.*
95. *Id.*
96. *Id.*
97. Track One Order, *supra* note 6, at 52.
98. Order 888, *supra* note 34.
99. Open Access NOPR, *supra* note 28, at 17681; Order 888, *supra* note 34, at 60.
100. *Regional Transmission Organizations, Notice of Proposed Rulemaking*, 64 Fed. Reg. 31,390 (1999) (codified at 18 C.F.R. pt. 35) [hereinafter RTO NOPR].
101. *Id.* at 31,397.

ued discrimination in the provision of transmission services by vertically integrated utilities may . . . be impeding fully competitive electricity markets."[102] The next section of this Article describes in more detail the bases for FERC's abandonment of the functional unbundling model.[103]

In its Order 2000, issued six months later, FERC adopted a final rule that required public utilities to make various filings geared toward the formation of regional transmission organizations.[104] Because such organizations included "minimum characteristics" requiring their independence from transmission owners, FERC determined that RTOs could remove remaining opportunities for discriminatory transmission practices.[105] And, in contrast to the heavy policing required under functional unbundling, FERC expressed the view that "a properly structured RTO would reduce the need for Commission oversight and scrutiny," thereby benefitting both FERC and the industry.[106] Because the RTO would be independent of any power marketing interests, FERC would no longer be required to monitor and enforce compliance with standards of conduct to preserve the fair playing field under the functional unbundling approach.[107]

III. Lessons Learned From the Federal Experience

In its *RTO NOPR*, FERC discussed the continuing barriers to a competitive wholesale electric market associated with transmission access, notwithstanding the measures it put in place three years earlier through Order 888.[108] FERC grouped these barriers into two broad categories: (1) engineering and economic inefficiencies, and (2) continuing opportunities for transmission owners to engage in discriminatory conduct in the operation of their transmission systems in order to provide a competitive advantage to their own or affiliated merchant operations.[109] The latter category is of more relevance to this Article, and includes findings that directly bear on the design of the DSP model. These findings relate to: (1) the inherent conflicts given the economic self-interest of the owners of the utility network to provide an advantage for their own power marketing interests over competitors[110]; (2) the extensive regulatory oversight and administrative burdens associated with enforcing compliance with standards of conduct[111]; and (3) the importance of a transparent and fair framework to attract new competitors and create a robust market that will benefit consumers.[112] Many of the parties to the New York PSC's REV proceeding raised the same issues in their comments on the Track One Proposal. These findings and comments are discussed in greater detail in the sections that follow.

A. *The Inherent Conflict of Interest*

In its *RTO NOPR*, FERC acknowledged that utilities exercising monopoly power over transmission facilities—and also having power marketing interests—have "poor incentives" to provide adequate transmission services to their power marketing competitors and, in fact, utilities have an economic motivation to frustrate their competitors and provide an advantage to their own power marketing operations.[113] Fundamentally, functional unbundling did nothing to change these incentives, but attempted to minimize the ability of the transmission-owning utilities to act on those incentives.[114] FERC proceeded to identify the continued discriminatory conduct by transmission owners that represent remaining impediments to competition, which included the pattern of transmission owners to understate the available transmission capacity on paths valuable to competitors, or to divert capacity so that it is available for use by affiliated power marketing interests[115]; violations of standards of conduct, which indicate a failure of functional separation[116]; discrimination in implementing line loading relief[117]; and Open Access Same Time Information System ("OASIS") sites that are difficult to use.[118]

A number of parties in the REV proceeding in New York raised similar concerns in the context of the *Track One Proposal* to have the incumbent utilities perform the role of DSP. Jon Wellinghoff and 38 North Solutions, LLC, for example, cited the "inherent conflict" between the owners of the distribution platform and the entities seeking to interconnect with or use that platform, with the consequence that DERs will fail to realize "their full operational and market potential."[119] Walmart, for its part, claimed that allowing the incumbent utility to serve as the DSP would result in the "re-monopolization of competitive markets and opportunities" and the emergence of "monopoly-related inefficiencies."[120] The Retail Energy Supply Association stated that allowing the DSP function to be served by the incumbent utilities would tilt the marketplace heavily in favor of the utility, given its

102. *Id.* at 31,391.
103. *See* discussion *infra* Section III.A.
104. *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285, at 2 (1999) (codified at 18 C.F.R. pt. 35) [hereinafter Order 2000], http://www.ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf.
105. *Id.* at 3. Order 2000 requires that all RTOs be independent of any market participants. *Id.* at 152. Independence is satisfied by (1) the RTO, its employees, and any non-stakeholder directors not having any financial interest in any market participants; (2) the RTO having a decision-making process that is independent of control by any market participant; and (3) the RTO having exclusive and independent authority to file changes to its transmission tariff with FERC. *Id.* at 152–53.
106. Order 2000, *supra* note 104, at 96.
107. *Id.*
108. RTO NOPR, *supra* note 100, at 31,397.
109. *Id.*
110. *Id.* at 31,402.
111. *Id.* at 31,403.
112. *Id.*
113. RTO NOPR, *supra* note 100, at 31,402.
114. *Id.*
115. *Id.* at 31,403.
116. *Id.* at 31,405–06.
117. *Id.* at 31,406.
118. RTO NOPR, *supra* note 100, at 31,406.
119. N.Y. Pub. Serv. Comm'n, Jon Wellinghoff et al., Comments of Jon Wellinghoff, Stoel Rives, LLC and Katherine Hamilton and Jeffrey Cramer, 38 North Solutions, LLC, No. 14-M-0101, at 8 (Sept. 22, 2014) [hereinafter Wellinghoff Comments], http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={458FA6AD-3C38-4C70-8AAA-1ADC3EBD7C03}.
120. N.Y. Pub. Serv. Comm'n, Walmart, Comments of Walmart, No. 14-M-0101, at 3 (July 18, 2014), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={365293C6-FAD8-4C39-8370-86E6CAF5B2B7}.

monopoly power and ability to recover its costs in rates.[121] Environmental Defense Fund expressed the concern that the incumbent utilities would tend to invest in traditional transmission and distribution ("T&D") facilities to address peak demand growth rather than devote resources to stimulating DER markets through which third parties could satisfy system needs.[122] Some parties in particular took issue with the "for-profit" nature of the incumbent utilities, as compared with the non-profit status of independent system operators under the federal RTO model; according to Hudson River Sloop Clearwater, Inc., the incumbent utilities owe their "ultimate allegiance" to their shareholders, thereby resulting in a "primary motive" to maximize profit.[123] Similarly, Infinite Energy, Inc. claimed that utilities as DSPs would foster only those market activities that "ultimately benefit[] their bottom line."[124]

B. *The "Regulatory Police" and Codes of Conduct*

The *RTO NOPR* also expressed concern about the "extensive regulatory oversight and administrative burdens" associated with enforcement of the standards of conduct.[125] On this point, the *RTO NOPR* states:

> [A] system that attempts to control behavior that is motivated by economic self-interest through the use of standards of conduct will require constant and extensive policing. This kind of regulation goes beyond traditional price regulation and forces us to regulate very detailed aspects of internal company policy and communication. For functional unbundling to be successful, we have to be concerned, in some sense, about 'who spoke to whom' in the company cafeteria. Functional unbundling does not necessarily promote light-handed regulation. It also imposes a cost on those entities that have to comply with the standards of conduct who face additional training and rules that create rigidities in their internal management activities.[126]

Parties to New York's REV proceeding stressed the importance of strict enforcement of standards of conduct in order to minimize or eliminate the ability of the incumbent utilities to exercise market power. Parties advocated for "strong Commission oversight" to keep in check the "unfair exercise of market power,"[127] and the need for "strict and standardized market rules," accompanied by periodic review of the utilities' performance as DSP to "protect against anti-competitive behavior."[128] The New York Independent System Operator ("NYISO") recommended that the New York PSC mirror the provisions of FERC's Standard of Conduct for Transmission Providers into its rules that would govern operation of the DSP by incumbent utilities.[129] These include an "independent-functioning rule," that requires the separation of employees engaged in transmission and marketing functions, and thereby seeks to prevent entities from providing advantages to their competitive business through their provision of transmission service[130]; and the "no-conduit" rule, which similarly prevents marketing employees from obtaining non-public information from sources within the utility.[131] The NYISO provided an example illustrating the need for the "no-conduit" rule:

> If the [DSP's] otherwise non-public distribution system operating information was available to a DER owner/operator affiliated with the [DSP], the affiliated entity could use that information to its advantage to ensure that it was utilized at the expense of non-affiliated DER owners/operators that do not have the benefit of that information.[132]

The Independent Power Producers of New York ("IPPNY") also provided examples illustrating how utilities operating as DSPs could favor the DERs of their affiliates to the disadvantage of competitors, such as through relatively more difficult interconnection procedures for competitors, or scheduling distribution outages in a manner that favors the DERs of its affiliate over its competitors.[133] According to IPPNY:

> Each step and each decision that the T&D utility undertakes as part of that coordination role has the potential for an exercise of market power, benefitting and creating a competitive advantage for the DER owned by the T&D utility [or its affiliate] over DER that is owned by a competitor.[134]

The comments of Clean Energy Advocates also emphasized the challenges of enforcing standards of conduct:

121. Retail Energy Supply Ass'n, Comments of the Retail Energy Supply Ass'n, No. 14-M-0101, at 5–6 (July 24, 2015), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={73D991DB-D9D5-425E-9261-A2EB3D8D5DEE}.

122. N.Y. Pub. Serv. Comm'n, Envtl. Def. Fund, Initial Comments of Environmental Defense Fund Regarding Staff Proposal Distributed System Implementation Plan Guidance, No. 14-M-0101, at 8–9 (Dec. 7, 2015), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={9248D3B7-2D46-4234-81D2-CE0AD9676EA0}.

123. N.Y. Pub. Serv. Comm'n, Hudson River Sloop Clearwater, Inc., Developing the REV Market in New York: DPS Staff Straw Proposal on Track One Issue, No. 14-M-0101, at 8 (Aug. 22, 2014), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={341B225C-8019-4859-B94D-E83EA391CFBD}.

124. N.Y. Pub. Serv. Comm'n, Infinite Energy, Comments of Infinite Energy, Inc. on the DPS Staff Straw Proposal, No. 14-M-0101, at 3 (Sept. 22, 2014), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={5657024B-1EC6-4D69-B1A4-BC4D4D36D38F}.

125. RTO NOPR, *supra* note 100, at 31,406.

126. *Id.* at 31,407.

127. N.Y. Pub. Serv. Comm'n, The Clean Coalition et al., Reply Comments on New York State Department of Public Service Staff Straw Proposal on Track One Issues, No. 14-M-0101, at 5 (Oct. 24, 2014), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={E90D885F-4A84-4317-B628-47389F5CBC16}.

128. N.Y. Pub. Serv. Comm'n, Wal-Mart Stores, Inc., Reply Comments on DPS Staff Straw Proposal on Track One Issues, No. 14-M-0101, at 2, 3 (Oct. 24, 2014), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A72527F7-FB7D-4E4E-ACC7-8A4D5C8F1115}.

129. N.Y. Pub. Serv. Comm'n, N.Y. Indep. Sys. Operator, Comments of New York Independent System Operator, Inc., No. 14-M-0101, at 7, 8 (July 18, 2014), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={9858E199-C6E3-437A-B670-C60392EB7D8F}.

130. *Id.* at 7.

131. *Id.* at 8.

132. *Id.*

133. N.Y. Pub. Serv. Comm'n, Indep. Power Producers of N.Y., Comments of Independent Power Producers of New York in Response to Track 1 and Track 2 Questions, No. 14-M-0101, at 14–15 (July 18, 2014), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={5435EB30-F439-4BD5-948B-ABDC1943F049}.

134. *Id.* at 15.

Existing ISO/RTOs demonstrate that 'platforms' quickly become so complicated that almost no one—except those operating the platform—knows what is going on. Within this complexity, the opportunity for 'self-dealing' is enormous.[135]

C. *Preserving the Integrity of the System to Attract New Investment*

The *RTO NOPR* also noted the implications of continued allegations of discrimination by the transmission owners. First, there is the challenge of detecting such conduct, the inefficiency of the complaint process, and the insufficiency of any penalties in providing a deterrence.[136] More fundamentally, the *RTO NOPR* expressed the concern that such allegations represent a perception by market participants that the market is not operating fairly, given that the integrated utilities have the incentive and continued opportunity to discriminate.[137] This fear of an unfair advantage may inhibit the willingness of market participants to invest in the market, thereby jeopardizing the development of robust competition.[138] As stated in the *RTO NOPR*, this "perception that many entities that operate the transmission system cannot be trusted is not a good foundation on which to build a competitive power market" in that it "creates needless uncertainty and risk for new investments in generation."[139]

A number of parties to New York's REV proceeding similarly commented on the importance of inspiring confidence in the integrity of the regulatory framework in order to attract new investment from non-utility parties. NRG Energy, Inc., a significant participant in the competitive power markets, expressed strong support for an independent DSP, citing the broad use of an independent manager internationally.[140] According to NRG, the Staff proposal favoring incumbent utilities as the DSP fails to "appreciate[] the enormity of the challenge that faces investors trying to compete against a fully-integrated monolithic utility."[141] IPPNY, for its part, claimed that the private investment necessary for REV to succeed would be discouraged if utilities are able to exploit their "asymmetric access to information."[142] Without any confidence in the regulatory framework in New York, said IPPNY, investment will migrate to "states more friendly to competition."[143] Infinite Energy commented that the "impetus for innovative products and services" would be lost if incumbent utilities "can both design the system and then profit from its particular design."[144] Finally, Direct Energy stressed the need for "a substantial degree of structural separation" between a utility's DSP functions and its other operations before third-party participants would have any confidence that the DSP is providing services on a non-discriminatory basis.[145]

D. *The Opportunity to Learn From the Experience at the Federal Level*

In many respects, the objectives of the New York PSC in designing the new utility business model in the REV proceeding mirror the goals that FERC articulated in Orders 888 and 2000: Creation of a competitive, non-discriminatory operating platform that would attract new entrants into the market, ultimately resulting in a more efficient utility network and producing benefits to consumers in the form of lower prices and an increased ability to manage energy costs.[146] Unless the framework is designed correctly, however, these objectives will not be achieved and these benefits will not be captured. With its decision to allow the incumbent utilities to serve as DSP, the New York PSC is clearly following FERC's path from the mid-1990s, when it issued its *Open Access NOPR* and ultimately *Order 888*. But given FERC's findings regarding the deficiencies of functional unbundling, it is not clear that the New York PSC is taking full advantage of lessons learned at the federal level as the REV proceeding blazes the trail for the design of electricity markets at the retail level.

With respect to FERC's finding regarding the inherent conflict of interest, the *Track One Order* does nothing to address this fundamental issue, other than to suggest that the regulatory framework will be designed in a manner that reward utilities for "doing the right thing," and utilities can be expected to respond accordingly. Given the fiduciary obligation of utilities to maximize profits for shareholders, however, it is difficult to envision that regulatory framework being sufficiently rigorous to overcome the understandable motivation of the incumbent utilities to engage in behavior that enhances its earnings and the returns of its affiliates. While it is true that utilities will respond to the incentives provided by the regulatory framework within which they

135. N.Y. Pub. Serv. Comm'n, Columbia Univ.'s Sabin Ctr. for Climate Change Law et al., Response to New York State Department of Public Service Staff Straw Proposal on Track One Issues, No. 14-M-0101, at 17 (Sept. 22, 2014), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={8173952D-F0CE-4DE4-A469-E5A7839608AE}.

136. RTO NOPR, *supra* note 100, at 31,402–03.

137. *Id.*

138. *Id.*

139. *Id.* at 31,407.

140. N.Y. Pub. Serv. Comm'n, NRG Energy, Inc., Response of NRG Energy, Inc. to Motion of Consolidated Edison Solutions, Inc. to Reject a Portion of Comments of NRG Energy, Inc. on Proposed Rulemaking Concerning New Electric Utility Demand Response Tariffs in Accordance With "Developing the REV Market in New York: DPS Staff Straw Proposal on Track One Issues," No. 14-M-0101, at 2 (Nov. 25, 2014), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={590177DD-250E-4CEC-BCEC-8F62DDE1C6CF}.

141. *Id.*

142. N.Y. Pub. Serv. Comm'n, Indep. Power Producers of N.Y., Comments on Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, No. 14-M-0101, at 10 (Sept. 22, 2014), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={AF271B73-235D-4B4D-B415-F4A830908E7F}.

143. *Id.* at 11.

144. N.Y. Pub. Serv. Comm'n, Infinite Energy, Inc., Comments of Inifinite Energy, Inc. in Response to the Questions on Track 1 Policy Issues, No. 14-M-0101, at 18 (Sept. 22, 2014), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={949BB04B-98D3-4F1A-A8AC-C216A9969F95}.

145. N.Y. Pub. Serv. Comm'n, Direct Energy Services, LLC & Direct Energy Business, LLC, Comments of Direct Energy on Staff Straw Proposal, No. 14-M-0101, at 9 (Sept. 22, 2014), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={4D22C5EF-A140-4889-BE8A-F8AC1B8971B3}.

146. *See* Track One Order, *supra* note 6, at 11–12; Order 888, *supra* note 34, at 3–4; Order 2000, *supra* note 104, at 2–3.

operate, it is a daunting challenge to develop a framework that effectively deals with the "inherent" conflict identified by FERC in its *RTO NOPR* and by several parties in the REV proceeding.[147]

The tool available to regulators to deal with this inherent conflict, of course, is standards of conduct: enforce the functional unbundling by putting rules in place that ensure the incumbent utilities do not engage in anticompetitive behavior that unlevels the playing field. This is the path the New York PSC is pursuing, with its commitment to monitoring and enforcement, coupled with prompt dispute resolution solutions when the unavoidable disputes arise regarding anticompetitive conduct by incumbent utilities.[148] Yet compared to FERC, the New York PSC lacks the resources and the technical expertise to perform this "regulatory police" function, and seems doomed to relearn—painfully, and at the expense of those entities seeking to compete with the incumbent utilities and their affiliates—the lessons from FERC's experience between 1996 and 1999, when it attempted to enforce its functional unbundling approach in the wholesale markets. On this point, the comments of the NYISO and IPPNY are on point: it is nearly impossible to identify all the instances in which that "inherent conflict" manifests itself in the form of anticompetitive behavior by the incumbent utility.[149] Too many decisions are made behind closed doors based on claims involving complex engineering solutions, and the competitors lack the resources to challenge these abuses when they occur.[150] The next section discusses the realized potential for exercising market power at the retail level and the difficulties of challenging those abuses, as illustrated by Con Edison's performance with respect to customer-centric energy solutions. Another group of parties to the REV proceeding expressed the concern well, noting that the experience in the wholesale markets shows that operation of platforms "quickly becomes so complicated that almost no one—except those operating the platform—knows what is going on," thereby creating enormous opportunity for self-dealing.[151] Is it reasonable to think that the New York PSC will be so much wiser in its design of the regulatory framework, and so much more powerful in the resources it can devote to enforcement, that the outcome experienced in the wholesale transmission markets in the late 1990s can somehow be avoided in the design and operation of the retail distribution platform?

The answer will become apparent in the success of the New York approach in attracting new players and additional investment in the retail electricity markets. In order to get the "innovation sitting on the sidelines"[152] into the game, it is essential that the rules of the game be perceived as fair, and that existing players do not have competitive advantages by virtue of their monopoly power. If potential participants in this retail distribution market perceive that the regulatory framework is not designed in a manner that provides a level playing field, or lack confidence in the integrity of that framework because enforcement is ineffective, they simply won't make the investment, and retail customers will be denied the full benefits of the transformation that is underway in the electric utility industry.

IV. The Exercise of Market Power at the Distribution Level

As policymakers consider the options for a restructured distribution system, they should be mindful of the risks associated with the exercise of market power by the incumbent distribution utilities striving to protect their traditional business model, and the challenges of designing a regulatory framework that effectively neutralizes the "inherent conflict" posed by the incumbent utilities serving as the DSP. As noted by several parties in the REV proceeding, it is nearly impossible to monitor each and every decision by the DSP in its operation of the distribution platform, and to detect the subtle ways in which the inherent conflict manifests itself in the operation of a utility system that, by its very nature, is complex. Can the incumbent distribution utilities be expected to fairly promote deployment of DG resources, microgrids, energy efficiency and DR programs within their service territories? Can the incumbent distribution utilities be expected to act in the best interests of the end-use customers in operating the distribution platform? Or, will the market be distorted by anticompetitive behavior as the incumbent distribution utilities act to protect their traditional business model and revenue streams?

On this point, it is worth examining the track record of Con Edison's operation of its distribution system prior to the post-Superstorm Sandy rate proceeding, which ultimately led to the New York PSC initiating the REV proceeding.[153] Con Edison's performance with respect to (1) enabling DG providers to operate within its service territory, (2) facilitating microgrid development, and (3) the promotion of energy efficiency programs to customers within its service territory, provides some insights into the possible inherent conflicts associated with allowing the incumbent utilities to serve as DSPs, and the measures that may be necessary to address market power.

147. RTO NOPR, *supra* note 100 at 31,403; *see, e.g.*, Wellinghoff Comments, *supra* note 119, at 8.

148. Track One Order, *supra* note 6, at 52.

149. *Id.* at 27, 36.

150. *Id.* at 47, 133.

151. N.Y. Pub. Serv. Comm'n, Columbia Univ.'s Sabin Ctr. for Climate Change et al., Comments of Columbia University's Sabin Center for Climate Change Law, Environmental Advocates of New York, the Pace Energy and Climate Center, the Sierra Club, and the Vermont Energy Investment Corporation (collectively, "Clean Energy Advocates"), No. 14-M-0101, at 17 (Sept. 22, 2014), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={8173952D-F0CE-4DE4-A469-E5A7839608AE}.

152. Richard Kauffman, Introductory Remarks at Albany Law School Symposium, *Shaping the Future of Energy* 10 (2014), http://www3.dps.ny.gov/W/PSCWeb.nsf/All/6DB084A00222486285257CE10046E6F8?OpenDocument.

153. N.Y. Pub. Serv. Comm'n, Order Approving Electric, Gas and Steam Rate Plans in Accord With Joint Proposal, No. 13-E-0030, at 63 n.47 (Feb. 21, 2014) [hereinafter Con Edison Order], http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={1714A09D-088F-4343-BF91-8DEA3685A614}.

A. *Facilitating Integration of DG Resources: The Case Study of the Bank of America Tower*

On the issue of encouraging the development of DG resources within its service territory, the experience of one particular project in Manhattan perhaps illustrates Con Edison's strategy towards facilitating the integration of DG resources. The Durst Organization successfully developed the Bank of America Tower at One Bryant Park, a 55-story building in midtown Manhattan with 2.1 million square feet of office space that was completed in 2010.[154] At the time of its completion, it was the first skyscraper in North America to receive the designation of LEED Platinum,[155] and was described by its developers as "among the most environmentally advanced skyscrapers in the world."[156] The building includes a 4.6 MW combined heat and power, or CHP, facility that provides most of the electricity for the building.[157] The heat produced by the natural-gas-fired turbines is used to make steam, which in turn is used to heat the building and the domestic water supply, and to operate an absorption chiller for cooling.[158] According to the Durst Organization, it made a substantial investment in the CHP installation with the hopes that the facility would demonstrate the viability of DG resources.[159]

Con Edison provides both electric and natural gas service to One Bryant Park.[160] Twice over a twelve-month period, the Durst Organization had to seek relief from the New York PSC in response to efforts by Con Edison to impose increased charges for natural gas and electricity service at One Bryant Park related to the CHP facility.[161] As observed by the *New York Times*, "[i]t is not easy being green and trying to keep the electric company from raising your rates."[162]

In the case of natural gas service, the issue was the applicability of Con Edison's "Rider H," which had been developed in response to a 2003 order from the New York PSC directing utilities to develop rate schedules that would foster development of natural gas-fired DG resources, including CHP.[163] Con Edison had applied Rider H to all gas supplied to the CHP facility at One Bryant Place upon the unit being placed into service on June 9, 2010.[164] The result of the applicability of Rider H was to produce a lower rate than would otherwise apply; the New York PSC found that a discounted rate was warranted given that CHP units are less costly to serve given the higher "load factor" associated with CHP facilities.[165] Over two years later, however, in August 2012 Con Edison informed the Durst Organization that a portion of the natural gas supplied to the CHP facility was ineligible for service under Rider H, a change in position that would have increased natural gas charges to One Bryant Park by $86,129 per year.[166] Con Edison took the position that only the natural gas directly used to generate electricity was eligible for the Rider H classification, to the exclusion of gas burned in the heat recovery steam generator ("HSRG") used to provide thermal energy for One Bryant Park.[167] The Durst Organization claimed that the availability of Rider H for the entire gas load at the CHP facility "played a critical role" in its decision to incorporate the CHP installation at One Bryant Park, and still plays an "important role" in continued operation of that facility. It should be noted that New York Presbyterian Hospital, a similarly situated customer that had developed a CHP project in 2009, filed a letter in support of the Durst Organization's petition. New York Presbyterian had also received a notification from Con Edison in August 2012 that Rider H would no longer be applied to gas used in the duct burners at the hospital's CHP facility, a change that would potentially increase its natural gas charges by $100,000 to $200,000 annually, thereby denying the "efficiencies necessary to justify [its] investment in this project."[168]

The New York PSC ruled against Con Edison, finding that One Bryant Park's CHP system was entitled to Rider H rates for its entire load.[169] According to the PSC, the use of

154. *One Bryant Park*, Durst Org., http://www.durst.org/properties/one-bryant-park (last visited Sept. 10, 2016). The building is 55 stories tall, comprising fifty-one floors of tenant space and four floors of mechanical space. *Id.*; *see also* N.Y. Pub. Serv. Comm'n, Petition for Declaratory Ruling of OBP Cogen LLC, a Subsidiary of One Bryant Park LLC, No. 12-G-0389, at 1 (Sept. 5, 2012) [hereinafter Declaratory Ruling Petition].

155. Leadership in Energy and Environmental Design, or LEED, is a designation offered by the U.S. Green Building Council. U.S. Green Building Council, http://www.usgbc.org/leed (last visited Sept. 10, 2016). Projects are certified on the basis of several areas relating to sustainability and, depending upon the number of points earned, are eligible to receive one of four LEED rating levels; Certified, Silver, Gold, and Platinum. *Id.*

156. *One Bryant Park*, *supra* note 154.

157. David Sokol et al., *Learning to Live on Alternative Energy*, McGraw Hill Construction Continuing Ed. (Mar. 2008), http://construction.com/ce/articles/0803edit-5.asp.

158. *Id.* Combined heat and power, also known as CHP or cogeneration, is a form of distributed generation that captures the waste heat produced by the generation of electricity that would otherwise be wasted, and deploys it as useful thermal energy. *Combined Heat and Power (CHP) Partnership*, U.S. Envtl. Protection Agency, https://www.epa.gov/chp/what-chp (last updated Dec. 10, 2015). In the case of One Bryant Park, the waste heat is used for steam to heat the building and to drive absorption chillers for cooling. Sokol et al., *supra* note 157.

159. Declaratory Ruling Petition, *supra* note 154, at 2.

160. N.Y. Pub. Serv. Comm'n, Pace Energy & Climate Ctr., Pre-Filed Direct Testimony of Thomas G. Bourgeois, No. 13-E-0030, at 21 (May 31, 2013) [hereinafter Bourgeois 2013 Testimony], http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={EB31C202-D787-4790-8A8E-E4D94C8767C7}.

161. Patrick McGeehan, *Midtown Developer Accuses Con Ed of Overcharging*, N.Y. Times, Oct. 9, 2012, http://www.nytimes.com/2012/10/10/nyregion/con-ed-is-accused-of-overcharging-in-midtown-skyscraper.html?_r=1.

162. *Id.*

163. N.Y. Pub. Serv. Comm'n, Declaratory Ruling on the Application of Rider H Rates, No. 12-G-00389, at 2 (Mar. 18, 2013) [hereinafter Declaratory Order], http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={959D0F00-A2C8-4363-9CF3-07319E728146} (referring to N.Y. Pub. Serv. Comm'n, Order Providing for Distributed Generation Gas Service Classifications, No. 02-M-0515 (Apr. 24, 2003)).

164. Declaratory Ruling Petition, *supra* note 154, at 2.

165. Declaratory Order, *supra* note 163, at 6. CHP facilities tend to levelize the load requirements between the winter and summer seasons by using the system throughout the year, and thereby avoid the impacts costs associated with the more common winter-only peak gas usage. *Id.* at 6–7. In this manner, CHP applications produce "benefits to the entire gas system," thus justifying the preferential rates under Rider H. *Id.* at 6.

166. Declaratory Ruling Petition, *supra* note 154, at 2–3.

167. Declaratory Order, *supra* note 163, at 4.

168. *Id.*; *see* N.Y. Pub. Serv. Comm'n, N.Y. Presbyterian Hosp., Petition of OBP Cogen Partners Regarding Con Edison Gas Tariff Rider H, No. 12-G-0389 (Nov. 5, 2012), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={DE332162-C5DB-4F68-9CAF-30BEBE583B3D}.

169. Declaratory Order, *supra* note 163, at 7.

the additional natural gas by the HSRG in a CHP unit produces a higher throughput and thus improves the economics of serving such facilities, thereby justifying the lower rate.[170] The PSC ruled that the application of Rider H to CHP facilities providing both electricity and thermal energy was not only consistent with the language in Con Edison's tariff, but was also supportive of the PSC's "policy to support distributed generation technologies."[171]

The second dispute between the Durst Organization and Con Edison regarding the CHP facility involved the calculation of contract demand charges for service to One Bryant Park.[172] The issue was whether the contracted demand was to be "net" of the output of the CHP facility, or calculated according to the building's load irrespective of the generation provided by the DG resource.[173] The Durst Organization claimed that a Con Edison representative explicitly stated that contact demand charges would be calculated using the net customer load.[174] In May 2011, however, Con Edison notified the Durst Organization that it would be subject to $290,000 in contract demand penalties because the usage at One Bryant Park for that month had exceeded the contract demand established for the building.[175] In imposing those charges, Con Edison elected to disregard the generation from the CHP facility at the time of the alleged "exceedance."[176] In an order issued in November 2011, the New York PSC rejected Con Edison's tariff interpretation, and ruled that contract demand exceedances would be based on the *net* registered demand.[177] Con Edison was directed to modify its tariff to make it clear that exceedances would be measured on the *net* registered demand.[178] Upon resolution of the tariff interpretation by the PSC, Con Edison cancelled the contested overcharges and the Durst Organization withdrew its complaint.[179]

These particular disputes may not be isolated instances. The Durst Organization claimed in the natural gas billing dispute that Con Edison's decision to adopt a revised interpretation of Rider H "appears to be part of a larger, troubling pattern" by the utility to "create barriers to clean, economic distributed generation."[180] A witness in the 2013 Con Edison electric rate proceeding observed that such disputes between a utility and DG developers not only has a "chilling effect" on the development of DG resources within Con Edison's service territory, but also increases perceived risks associated with DG investments as it casts doubt upon the "longer-term projections of economic benefits and costs" associated with DG projects.[181] As stated by the witness, "[m]ost DG developers simply do not have the financial resources or 'staying power' to do battle with Con Edison over questionable tariff interpretations or disputed billing calculations."[182]

B. *Other Evidence Regarding Con Edison's Record on Facilitating Integration of DG Resources*

On the broader issue of promotion of DG resources within its service territory, Con Edison's record was disconcerting. One witness in Con Edison's 2013 rate case described the level of DG penetration in Con Edison's service territory as "unacceptably low."[183] Several practices were cited as factors contributing to Con Edison's "failure . . . to accommodate DG within its service territory."[184] First, Con Edison imposed "restrictive and unattractive terms and conditions" for DG participation in its relevant program.[185] In Con Edison's 2009 general rate proceeding, Pace presented testimony describing the "100% physical assurance" requirement that Con Edison imposed on DG providers seeking to participate in its Targeted DSM program.[186] This requirement was frequently cited by CHP developers as "a significant barrier to pursuing CHP installations within Con Edison's service territory."[187] As a result, Con Edison had no participation by DG providers in its Targeted DSM program as of 2010.[188] It was only as part of the DG Collaborative Process convened at the conclusion of the 2009 rate case that Con Edison consid-

170. *Id.* at 6–7.
171. *Id.* at 2.
172. N.Y. Pub. Serv. Comm'n, OBP Cogen LLC, Complaint of OBP Cogen LLC, a Subsidiary of One Bryant Park LLC, Regarding Overcharges by Consolidated Edison Company of New York, Inc., No. 11-E-0610, at 1 (Nov. 9, 2011) [hereinafter Durst Complaint], http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={477281A6-B5A0-4409-ACE2-26FDE513CABC}. The contract demand charge is calculated by multiplying the contract demand—which is the customer's maximum potential demand from Con Edison, as determined by the customer or by Con Edison—by the contract demand rate charged by Con Edison. *Id.* at 3.
173. *Id.* at 4.
174. N.Y. Pub. Serv. Comm'n, The Durst Org., Comments on Tariff Filing by Consolidated Edison Company of New York, Inc. to Revise Provisions of Standby Service for Retail Access, No. 11-E-0299, at 3 (Oct. 21, 2011), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={3BE8C860-8126-4810-B4F9-E23D6A6A6A03}.
175. Durst Complaint, *supra* note 172, at 4.
176. *Id.* At the time of the alleged exceedance, One Bryant Park had a contract demand of 12,000 kW, while the demand at the building reached 13,760 kW. *Id.* at 4–5. The CHP facility, however, was producing 3,237 kW at the time, and thus Con Edison was supplying only 10,539 kW, well below the contract demand. *Id.* at 5.
177. N.Y. Pub. Serv. Comm'n, Order Approving Tariff Amendments With Modifications, No. 11-E-0299, at 8–9 (Nov. 17, 2011), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={3175C595-1830-4401-83E9-1B09E95A330E}.
178. *Id.* at 9.
179. N.Y. Pub. Serv. Comm'n, OBP Cogen LLC, Complaint of OBP Cogen LLC Against Concerning Overcharges by Consolidated Edison Company of New York, Inc., No. 11-E-610, at 1 (Dec. 6, 2011), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={477281A6-B5A0-4409-ACE2-26FDE513CABC}.
180. Declaratory Ruling Petition, *supra* note 154, at 9.
181. *Id.* at 23.
182. *Id.*
183. Bourgeois 2013 Testimony, *supra* note 160, at 20.
184. *Id.*
185. N.Y. Pub. Serv. Comm'n, Pace Energy & Climate Ctr., Prefiled Direct Testimony of Thomas G. Bourgeois, No. 09-E-0428, at 11–12 (Aug. 28, 2009) [hereinafter Bourgeois 2009 Testimony], http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={C8A02A51-D2C3-4861-9839-3CFAAB10467E}.
186. *Id.* at 10–12. The effect of the 100% physical assurance requirement was either the customer load had to be isolated from Con Edison's system and served by the DG resource, or the customer had to have the capability to shed its load in the event the DG resource failed. *Id.* at 11. Con Edison's Targeted DSM program was designed to offer incentives for demand-side measures (e.g., energy efficiency or distributed generation) to be installed in those areas of its service territory with capacity issues, in order to reduce the demand on the electric system. *Targeted Demand Side Management (DSM) Program*, Con Edison, http://www.coned.com/energyefficiency/targetedDSM.asp (last visited Sept. 10, 2016).
187. Bourgeois 2009 Testimony, *supra* note 185, at 12.
188. *Id.* at 10.

ered relaxing the 100% physical assurance requirement for DG resources to participate in the program.[189]

Second, Con Edison consistently failed to invest in the necessary grid upgrades to accommodate DG resources.[190] Due to increased reliability benefits—and the ability to quickly "island" from the grid in the event of an outage—developers of DG resources prefer to have their units synchronously interconnected with the utility grid.[191] Con Edison had a policy, however, of not allowing any synchronous system to be connected to its grid, due to concerns about fault currents and system equipment damage.[192] Upon undertaking the necessary system upgrades, which are primarily circuit breaker replacements, synchronous generation can be accommodated on Con Edison's system.[193] Until such upgrades can be completed, however, DG providers are required to bear the costs of installing fault mitigation.[194] An issue in recent years was the pace at which Con Edison would undertake the necessary system upgrades to accommodate synchronous interconnection of DG resources to its system.[195] Prior to the 2013 general rate case, Con Edison had committed to a minimum of sixty circuit breaker replacements in substations, a commitment that it was proposing to terminate as part of that rate proceeding.[196] The consequences of the slow pace of these system upgrades is apparent from maps of the distribution system provided by Con Edison, which in 2005 indicated that the mitigation investments would be completed by 2014, whereas the map as of 2013 showed that the mitigation investments would not be fully in place until 2026.[197] The current map provided by Con Edison continues to show the 2026 end date for Westchester County upgrades[198] and 2024 for areas in Manhattan.[199] Testimony by Pace in the 2013 Con Edison electric rate case proposed that Con Edison be required to maintain its commitment, and in fact accelerate that commitment from a minimum of sixty per year to a minimum of ninety per year.[200] It should be noted that this issue was addressed in the *Joint Proposal* filed by the parties to settle the 2013 electric rate case: Con Edison was required to pay the cost of purchasing and installing fault current mitigation technology in those situations where an over-duty circuit breaker condition exists, or will exist with the addition of DG resources to Con Edison's system, up to a cost of $3 million annually.[201]

C. Con Edison's Record on Microgrid Development

Con Edison also had a record of discouraging development of microgrids within its service territory.[202] This issue was explored as part of the DG Collaborative process following the 2009 Con Edison electric rate case.[203] In the DG Collaborative Report, Con Edison took the position that for a "campus" type interconnection (i.e., a microgrid), customers would be required to have a minimum of two additional feeders,[204] and that generally a campus style interconnection involving DG resources "is not the preferred method for Con Edison and may be cost prohibitive for the customer."[205] In the 2013 Con Edison electric rate case, parties pressed Con Edison on measures it could take to facilitate microgrid development in its service territory, including "standardization of the process" by requiring Con Edison to develop a generic template and expand the eligibility for the "campus style" interconnection explored during the DG Collaborative process.[206] Additional recommendations involved expanding interconnection and metering options and additional service offerings by Con Edison.[207] This issue was ultimately addressed in the *Joint Proposal* agreed upon by the parties in settling the 2013 electric rate case, in which Con Edison agreed to consider elimination of the single customer limitation in its tariff to expand availability to microgrids.[208] Con Edison also agreed to file an implementation plan with respect to the development of microgrids within its service territory.[209]

D. Con Edison's Record on Promoting Energy Efficiency

On the issue of energy efficiency, testimony in the 2013 Con Edison rate case indicated that Con Edison was lagging

189. N.Y. Pub. Serv. Comm'n, Consol. Edison Co. of N.Y., 2010 Distributed Generation Collaborative Report, No. 09-E-048, at 4 (Nov. 2, 2010) [hereinafter DG Collaborative Report], http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={B731E2D5-83A9-4954-9F15-694699915503}.
190. Bourgeois 2013 Testimony, *supra* note 160, at 25–26.
191. Forester Media, *Branching Out With CHP*, Forester Daily News, Mar. 6, 2012, http://foresternetwork.com/daily/energy/branching-out-with-chp/.
192. *Id.*; *Distributed Generation, Synchronous Generation*, Con Edison, http://coned.com/dg/configurations/synchronous.asp (last visited Sept. 10, 2016).
193. Con Edison provides maps showing the availability of synchronous generation placement, by region. *See, e.g.*, *Synchronous Generation Placement Availability by Region*, Con Edison, http://www.coned.com/dg/configurations/maps.asp (last visited Sept. 10, 2016).
194. *Id.*; *Distributed Generation, Synchronous Generation*, *supra* note 192 ("The customer is responsible for tripping the generator intertie breaker and /or contactor and isolating the generator from the Company's distribution system in the event of an electric fault and/or abnormal voltage/frequency condition."). The solutions imposed on the DG providers are expensive, result in reduced efficiency in operation of the unit, and use considerable space, which is a valuable commodity in New York City. Bourgeois 2013 Testimony, *supra* note 160, at 25.
195. *Id.* at 25–26.
196. *Id.* at 25. As an incentive, Con Edison was subject to a penalty of $100,000 per breaker not achieved below the minimum target. *Id.*
197. *Id.* at 26.
198. *Synchronous Generation Placement Availability by Region, Westchester County*, Con Edison, http://coned.com/dg/images/maps/w.pdf (last updated June 1, 2016).
199. *Id.*
200. Bourgeois 2013 Testimony, *supra* note 160, at 26.
201. N.Y. Pub. Serv. Comm'n, Consol. Edison Co. of N.Y., Joint Proposal, No. 13-E-0030, at 96 (Dec. 31, 2013) [hereinafter Joint Proposal], http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={3881B193-8115-4BA0-A01A-B8D373D59726}.
202. DG Collaborative Report, *supra* note 189, at 27.
203. *Id.* at 11–14.
204. Con Edison's requirement is that each individual feeder would have to be capable of carrying the full load of the DG resource in the event the other feeders fail, hence the "minimum of two additional feeders beyond that needed for export" of the DG output. *Id.* at 12.
205. *Id.* at 13.
206. Bourgeois 2013 Testimony, *supra* note 160, at 26.
207. *Id.*
208. Joint Proposal, *supra* note 201, at 97; Con Edison Order, *supra* note 153, at 70.
209. Joint Proposal, *supra* note 201, at 97.

behind many of the other utilities in New York State with respect to implementation of energy efficiency measures.[210] For 2012, Con Edison had captured only 65% of the annual savings target under the New York PSC's Energy Efficiency Portfolio Standard ("EEPS").[211] Other utilities in the state performed substantially better: Central Hudson had 147% of the target savings, National Grid was at 93% and New York State Electric & Gas was at 87%.[212] Collectively, the utilities other than Con Edison, together with the New York State Energy and Research Development Authority, captured savings representing 74% of the annual savings target under EEPS.[213] For the preceding period under the EEPS program, October 2008 through December 2011, Con Edison acquired only 228,652 MWh of its 378,693 MWh target, which represents a shortfall of about 40%.[214]

E. Observations Regarding Con Edison's Exercise of Market Power

The experience described above with respect to Con Edison demonstrates the potential risks associated with the incumbent electric distribution utility's continued role as DSP, unless adequate measures can be put in place to minimize the opportunities for anticompetitive behavior; alternatively, the business model can be designed in a manner that eliminates the motivation for any anticompetitive behavior. Con Edison's record with respect to promoting energy efficiency and deployment of DG resources and microgrids in its service territory demonstrates the lengths to which the incumbent utility can go to defend its business model.[215] Con Edison operated its DSM programs in a way that, as a practical matter, excluded participation of DG resources, and modified those restrictions only after pressure to do so as a result of a thorough examination in a collaborative process.[216] Of more concern is Con Edison's consistent pattern of refusing to make the necessary distribution system upgrades to accommodate the seamless interconnection of DG resources and to capture the reliability benefits—to customers—of synchronous interconnection.[217] The costs of those upgrades were recoverable in rates, and the failure of Con Edison to make the necessary investment seems to be motivated by a refusal to facilitate the integration of DG resources within its service territory. Again, only after these practices were exposed in a general rate proceeding was the behavior corrected, by forcing Con Edison to make the necessary upgrades. The same holds true for microgrid development, where Con Edison's burdensome requirements for interconnection of microgrids were exposed and ultimately addressed in a settlement term requiring Con Edison to undertake necessary tariff revisions and to develop an implementation plan focused on encouraging, rather than discouraging, microgrid development within its service territory.[218]

V. Potential Solution: An Independent System Operator for the Retail Distribution Platform

As discussed above, FERC's ultimate solution in Order 2000 was to move to an independent system operator.[219] According to FERC, the independent RTO approach, by "cleanly separating the control of transmission from power market participants," would be effective in reducing opportunities for unduly discriminatory conduct.[220] Because the RTO would have no financial interest in any market participant—under the "minimum characteristic" requirement of independence—and no power market participant would be able to control an RTO, the economic incentive—as well as the ability—of the transmission provider to engage in discriminatory practices would be eliminated.[221] This approach would also eliminate the "mistrust" in current grid management, and thereby attract new participants in the generation market inasmuch as the market will be perceived as more fair and attractive for investment.[222] With the addition of more participants, the market can be expected to be deeper and more fluid.[223]

Several parties to the REV proceeding proposed to replicate the federal solution by having a third-party independent non-profit entity serve as the DSP.[224] A leading proponent of this model, sometimes referred to as the Independent Distribution System Operator in the context of retail distribution services, or IDSO, model, is Jon Wellinghoff.[225] In Wellinghoff's view, the traditional utility model is "increasingly out

210. N.Y. Pub. Serv. Comm'n, Pace Energy & Climate Ctr., Prefiled Direct Testimony of Jackson Morris, No. 13-E-0030, at 10 (May 31, 2013), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={81F2C4EB-EE3C-4921-B0F5-C5F4C6E24EF3}.
211. *Id.*
212. *Id.* at 11.
213. *Id.*
214. *Id.*
215. Track One Order, *supra* note 6.
216. *Demand Response Programs Details*, Con Edison, http://www.coned.com/energyefficiency/demand_response_program_details.asp (last visited Aug. 7, 2016).
217. Track One Order, *supra* note 6.
218. *Id.*
219. Order 2000, *supra* note 104, at 90.
220. *Id.*
221. *Id.*
222. *Id.* at 92–93.
223. *Id.* at 93.
224. According to the Track One Order, *supra* note 6, App. A, the following parties expressed support for an independent DSP: Alliance for a Green Economy, Citizens for Local Power, Clean Energy Organizations Collaborative (comprising Clean Coalition, Columbia University Sabin Center for Climate Change Law, Environmental Advocates of New York, Nature Conservancy, New York Public Interest Research Group, Pace Energy and Climate Center, and Solar Energy Industries Association), Clean Energy Advocates (comprising Columbia University Sabin Center for Climate Change Law, Environmental Advocates of New York, New York Public Interest Research Group, Pace Energy and Climate Center, Sierra Club and Vermont Energy Investment Corporation), Direct Energy Services LLC, Hudson River Sloop Clearwater, Independent Power Producers of New York, Infinite Energy, John Wellinghoff, and 38 North Solutions, Northeast Clean Heat and Power Initiative, New York Independent System Operator, NRG Energy, Retail Energy Supply Association, SolarCity, and Wal-Mart Stores, Inc.
225. Wellinghoff was Chairman of FERC from 2009 to 2013, and is currently Chief Policy Officer for SolarCity. *See* San Mateo, *SolarCity Appoints Jon Wellinghoff Chief Policy Officer*, PR Newswire (Apr. 7, 2016, 4:46 PM), http://www.prnewswire.com/news-releases/solarcity-appoints-jon-wellinghoff-chief-policy-officer-300248141.html.

of sync" with current trends in the electricity markets and the expanding penetration of DG resources.[226] Wellinghoff's approach starts with the perceived need for a fundamental reform and a re-examination of the way that utilities recover costs, based on identifying those services that are best delivered in a regulated monopoly environment versus those that can be provided under competition.[227] He concludes that the solution is to let the utility continue to *own* the grid, while an "objective and separate" IDSO would *operate* the distribution platform.[228] Under this model, the IDSO would be responsible for the reliability of the distribution system and, like the ISO at the wholesale level, would ensure open, fair, and nondiscriminatory access to the distribution platform.[229] The IDSO would also be charged with developing necessary market mechanisms and optimizing the deployment of DG resources.[230] Unlike the wholesale ISO model, where the ISO is regulated by FERC, the IDSO would be subject to the jurisdiction of state PUCs.[231]

The distribution utility would continue to be responsible for maintaining the distribution platform, subject to traditional rate-of-return regulation by state PUCs, and would thereby be permitted to earn a return on any additional investments in the distribution system.[232] The distribution utility would also continue to maintain the customer relationship with end users, including the billing function.[233] Under this model, the distribution utility would benefit from having a much simpler—and less risky—business model, more efficient cost recovery, and the ability of its unregulated affiliates to offer competitive services (e.g., investing in DG resources) in areas outside of its service territory.[234] Wellinghoff identifies the following benefits to the IDSO model: more effective and efficient integration of DG resources, increased utilization of the existing grid, more opportunities for consumer choice and participation, and stimulating the development of a "[t]ransactive Energy Framework" that would accommodate commerce in energy services.[235]

A drawback to the independent DSP, as identified by the New York PSC in its *Track One Order*, is the extra cost associated with the additional entity.[236] On this point, FERC suggested in its Order 2000 that the flexibility permitted in the *Order* would allow the creation of "streamlined" organizational structures that need not be costly.[237] Given the number of configurations possible for meeting the minimum characteristics, the admittedly high costs associated with formation of existing ISOs and power exchanges may not be relevant, according to Order 2000.[238] In contrast to formation costs, FERC claims benefits from RTO formation of $2.4 billion to $5.1 billion annually, which represents 1.1% to 2.4% of total costs in the electric power industry.[239] There is considerable evidence on the costs associated with operating some of the existing RTOs. Seven RTOs currently operate in the U.S.—ISO New England, MidContinent ISO, formerly known as Midwest ISO, PJM Interconnection, Southwest Power Pool, California ISO, New York ISO, and Electric Reliability Council of Texas.[240] The MidContinent ISO, the RTO serving all or parts of 15 states in central U.S.,[241] has 782 employees and an annual budget of $273 million.[242] PJM, which is the RTO operating in the mid-Atlantic states, has 725 employees and an annual budget of $252 million.[243] As stated by one commentator, these costs are "non-trivial."[244] Moreover, this commentator expressed the concern that ISOs are "simply bureaucracies that are not subject to any effective cost regulation."[245] He points to the sharp increases in ISO costs in the U.S. in recent years, and notes that the number of employees at the Southwest Power Pool has grown from 39 in 1998 to 131 in 2004 and 473 in 2010.[246] A former PSC Commissioner in New York complained about the absence of ratepayer participation in the process at RTOs, and noted that the cost per New York resident for services provided by the New York ISO is 41% higher than the same figure for the PJM Interconnection.[247] In its comments in the REV proceeding, NRG placed the cost of ISO operating charges at less than $1 per MW, citing the NYISO's charge of $0.956 per MWh.[248]

VI. Conclusion

The design of the business model for the "utility of the future" must achieve a number of objectives. A foundational objective is a regulatory framework geared toward the provision of

226. James Tong & Jon Wellinghoff, *Rooftop Parity: Solar for Everyone, Including Utilities*, Fort. Mag., Aug. 2014, at 4 [hereinafter Rooftop Parity], http://www.fortnightly.com/fortnightly/2014/08/rooftop-parity.
227. *Id.* at 6.
228. *Id.* at 2.
229. *Id.*; *see also* Wellinghoff Comments, *supra* note 119, at 5.
230. Tong & Wellinghoff, *supra* note 226, at 4.
231. *Id.*
232. *Id.*
233. *Id.*
234. *Id.* at 3.
235. Tong & Wellinghoff, *supra* note 226, at 3.
236. Track One Order, *supra* note 6, at 50.
237. Order 2000, *supra* note 104, at 91.
238. *Id.*
239. *Id.* at 95–96.
240. U.S. Gov't Accountability Off., GAO-08-987, Electricity Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance 3 (2008), http://www.gao.gov/assets/290/281312.pdf.
241. *Locations*, Midcontinent Indep. Sys. Operator, Inc., https://www.misoenergy.org/AboutUs/Locations/Pages/Locations.aspx (last visited July 18, 2016).
242. Michael Pollitt, *Lessons From the History of Independent System Operators in the Energy Sector*, 47 Energy Pol'y 32, 37 (2012).
243. *Id.*
244. *Id.* at 36.
245. *Id.* at 40.
246. *Id.*
247. Robert Curry, Statement at the Regular Meeting of the Public Service Commission 23 (July 15, 2010), http://www3.dps.ny.gov/pscweb/WebFileRoom.nsf/ArticlesByCategory/FAECB2BA0ACBDC4C85257767004810F4/$File/SessionTranscript_71510.pdf?. In 2010, New Yorkers paid an average of $7.16 per person for New York ISO services, as compared with $5.24 per person for ratepayers within the PJM Interconnection. Heather Haddon, *"Power" of the Purse*, N.Y. Post (Apr. 10, 2011, 4:00 AM), http://nypost.com/2011/04/10/power-of-the-purse/.
248. N.Y. Pub. Serv. Comm'n, NRG Energy, Inc., NRG Response to Track One Policy Questions and Issues Surrounding the Rethinking the Energy Vision Proceeding, No. 14-M-0101, at 8 (July 21, 2014), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={8952946A-3A4F-45A1-A39B-A4DF891A1D16}. According to NRG, the NYISO market handles energy-related transactions of about $7.5 billion annually on an annual operating budget of $160 million. *Id.*

nondiscriminatory access to the distribution platform. The current structure of the incumbent distribution utilities carries with it an "inherent conflict" and the ability of the utility to exercise market power in the operation of the platform, to the disadvantage of potential new entrants into the market. Moreover, it is exceedingly difficult to uncover the subtle self-dealing that is likely to occur, given the complexities of operating a utility network and the limitations in the resources that can be devoted to monitoring and enforcement. In the case of Con Edison, for example, actual experience demonstrates a tendency to underinvest in those upgrades to the distribution network that would facilitate competition from DG providers, to operate DSM programs in a manner that precludes participation by DG providers and fails to deliver energy efficiency programs to help customers manage their energy bills, to resist widespread deployment of microgrids within its service territory, and to employ questionable tariff interpretations in an effort to thwart the financial success of DG facilities.

While functional unbundling has the advantage of being the least disruptive to the existing utility model and potentially requiring fairly low transaction and transition costs, FERC's experience with the restructuring of the wholesale electricity markets in Order 888 and its ultimate decision in Order 2000 to reject functional unbundling in favor of independent, third-party system operators, suggests that functional unbundling may avoid short-term pain but fail to provide the long-term solution. A recurring theme in evaluating the deficiencies of functional unbundling is the failure to address the underlying conflicts of interest associated with the vertically integrated utility, and the very high compliance costs, as regulators attempt to enforce codes of conduct in a valiant effort to demonstrate to third-party providers that the system is fair. The inability to make the fundamental case that the rules of the game are fair will jeopardize the attraction of new entrants, and associated new investment, into the energy markets. Actual experience suggests that the vertically integrated model, coupled with functional unbundling, will fail to attract the necessary investment to modernize the network, as utilities will be reluctant to make any investments that enable additional competition in its affiliated lines of business. Con Edison's track record with underinvesting in distribution upgrades to accommodate synchronous interconnection is a good example of market power being used to thwart competition.

The IDSO model is more effective at addressing the inherent conflicts of interest under the vertically integrated model. Moving to this model would require a more fundamental restructuring of the business, with attendant higher transaction and transition costs, and it is understandable that the New York PSC was reluctant in its *Track One Order* to take that somewhat radical step. It is notable that the PSC held out the possibility of revisiting this issue in the event the track record of incumbent utilities serving as DSPs produces disappointing results.[249] A number of parties urged the New York PSC to continue exploring the independent DSP model, and to develop the framework for ultimately transitioning to that model.[250] This would be a prudent course of action for the New York PSC to follow, as the compelling evidence from FERC's experience with the wholesale transmission market shows that the ultimate solution will be an independent DSP approach.

---

249. Track One Order, *supra* note 6, at 53.

250. *See, e.g.*, Clean Energy Advocates, *supra* note 151, at 17 ("The Commission's final REV decision should include a fully formed plan for the implementation of an Independent Distributed System Provider (IDSP) in the event the utilities fail to provide a functioning system that is equitable to all users."); The Clean Coalition, *supra* note 127, at 5 (noting that the utility DSP planning process "should be accompanied by a parallel planning process for the implementation of an independent DSP."); *see also* N.Y. Pub. Serv. Comm'n, All. for Clean Energy N.Y., Response to Ruling Posing Questions on Selected Policy Issues and Potential Outcomes Cases 14-M-0101 and 14-M-0094, No. 14-M-0101, at 15 (July 18, 2014), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={19DB9F48-1939-4A5F-807F-283100582422} ("One proposal that may have merit and should be evaluated as the REV moves beyond its initial stages is the creation of an Independent Distribution System Operator.").