MAINTAINING SYSTEM RELIABILITY: RESPONDING TO THE RETIREMENT OF COAL-FUELED ELECTRIC GENERATION RESOURCES

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Synopsis: This article examines the procedures that Regional Transmission Organizations (RTOs) are authorized by the Federal Energy Regulatory Commission (FERC or Commission) to take to maintain system reliability[1] in response to the announced retirement or suspension of electric generation resources. The planned unavailability of electricity generators, and in particular coal-fueled generators, is increasingly related to the inability of such resources to comply with proposed environmental standards and to remain competitive in wholesale energy markets. This article analyzes the inherent differences between how RTOs and vertically integrated electric utilities not located within an RTO conduct capacity resource planning and then describes the various tariff procedures that are available to RTOs to address anticipated capacity resource issues and to maintain system reliability. The article provides a detailed examination of how one RTO's tariff procedures operate to (1) evaluate the need for an out-of-market agreement to maintain resources that plan to retire; (2) negotiate equitable compensation for a resource that commits to remain available

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1. For the purposes of this article, "system reliability" refers to the probabilistic determination that the wholesale transmission grid will reliably be able to meet peak energy demands with an outage occurring no more than once every ten years that is a result of a lack of electric generation capacity (i.e., "1-in-10" Loss of Load probability). This is similar to the North American Electricity Reliability Corporation (NERC) Reliability Standard BAL-502-RFC-02 for the Reliability*First* Corporation Region. N. AM. ELEC. RELIABILITY CORP., PLANNING RESOURCE ADEQUACY ANALYSIS, ASSESSMENT AND DOCUMENTATION, STANDARD BAL-502-RFC-02, at 1 (2011), *available at* http://www.nerc.com/files/BAL-502-RFC-02.pdf (stating that the purpose of the standard is "[t]o establish common criteria, based on 'one day in ten year' loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load"); *see also*, KEVIN CARDEN & NICK WINTERMANTEL, ASTRAPE CONSULTING, THE ECONOMIC RAMIFICATIONS OF RESOURCE ADEQUACY WHITE PAPER 1 (2013), *available at* http://www.naruc.org/grants/Documents/Economics%20of%20Resource%20Adequacy%20WhitePaper_Astrape_Final.pdf) (stating that "[t]he resource adequacy standard many regions plan to is a Loss of Load Expectation (LOLE) of one firm load shed event in 10 years ([i.e.,] 1-in-10 LOLE), suggesting the last resource added to the system is only needed approximately 0.3 hours per year"); ISO-NEW ENGLAND, ISO-NEW ENGLAND INSTALLED CAPACITY REQUIREMENT, LOCAL SOURCING REQUIREMENTS, AND MAXIMUM CAPACITY LIMIT FOR THE 2016/17 CAPABILITY YEAR 8 (2013), *available at* http://www.iso-ne.com/genrtion_resrcs/reports/nepool_oc_review/2013/icr_2016_2017_report_final.pdf) (describing ISO-NE's Installed Capacity Requirement as "the amount of capacity needed . . . such that the probability of disconnecting non-interruptible customers [(an LOLE)], on average, is no more than once in every ten years (an LOLE of 0.1 days/year)").

to maintain system reliability; and (3) obtain FERC approval for such temporary agreements, until the system reliability issue can be otherwise resolved. The article recommends that stakeholders understand and compare the varying tariff procedures available to RTOs to address planned generation retirements or suspensions in order to better ensure system reliability.

I. INTRODUCTION

Owners of many coal-fueled electric generation facilities are giving serious consideration to the economics of continued operations, in part, due to the fact that some of these facilities will be reaching the end of their useful economic lives. In addition, increasingly stringent environmental emissions requirements and competitive economic factors are making coal-fueled generation plants less economically attractive and may lead to the planned retirement of a significant percentage of the nation's coal-fueled generation facilities. There are an increased number of discussions about planned retirements of coal-fueled generation facilities based upon both regulatory and economic impacts, in part, because such retirements are projected to occur faster than the historic trend.[2]

Fossil-fueled electricity generation facilities are the largest stationary source of greenhouse gas emissions.[3] Environmental regulations, such as the Mercury and Air Toxics Standards (MATS),[4] may further encourage the owners of coal-fueled generation facilities to determine that facility retirement is more cost effective than implementing costly facility upgrades that would be required to comply with increasingly stringent environmental standards.[5]

These factors have resulted in predictions that many coal-fueled generation facilities may be approaching the end of their useful lives more rapidly than some observers had previously thought.[6] Although the impetus for coal-fueled generation retirements may be based on either environmental regulations or market economics, such facility retirements can significantly affect system reliability, particularly in regions of the nation where coal-fueled generation facilities currently make up a large percentage of the available generation capacity.[7]

Under a traditional state commission regulated structure, vertically integrated utilities[8] have been able to plan through state-approved plans, such as Integrated Resource Plans (IRP), to retire older generation facilities in a methodical manner while maintaining system reliability.[9] Under an IRP

2. *27 Gigawatts of Coal-Fired Capacity to Retire over Next Five Years*, U.S. ENERGY INFO. ADMIN. (July 27, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=7290 [hereinafter EIA, *Coal-Fired Capacity to Retire*]; *Fuel Used in Electricity Generation is Projected to Shift over the Next 25 years*, U.S. ENERGY INFO. ADMIN. (July 30, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=7310.

3. U.S. ENVTL. PROT. AGENCY, INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS: 1990-2011, at ES-5 to -7, 3-12 (2013), *available at* http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html (noting that in 2011 electric power plants were the largest stationary source of greenhouse gas emissions with 2,221 million metric tons carbon dioxide equivalent (mmtCO_2e), which equals about one-third of total U.S. emissions).

4. National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance, 77 Fed. Reg. 9304 (Feb. 16, 2012) (codified at 40 C.F.R. pts. 60, 63).

5. *See, e.g.*, EIA, *Coal-Fired Capacity to Retire*, *supra* note 2.

6. *Annual Energy Outlook 2013 Early Release Overview*, U.S. ENERGY INFO. ADMIN. (Dec. 5, 2012), http://www.eia.gov/forecasts/aeo/er/early_elecgen.cfm (noting that a combination of factors restricts the future use of coal).

7. INSTITUTE FOR ENERGY RESEARCH, IMPACT OF EPA'S REGULATORY ASSAULT ON POWER PLANTS 3-4 (2012), *available at* http://www.instituteforenergyresearch.org/epa-powerplant-closures/ (discussing concerns over reliability and highlighting the impacts of coal-fired retirements in Michigan and Ohio).

8. For the purposes of this article, a vertically integrated utility is one that (1) has a defined jurisdictional service territory in which it has the sole right to serve such customers; (2) owns generation resources to serve such customers; and (3) owns or has contractual rights to transmission facilities to deliver generation resources to its customers. The vast majority of utilities that are located outside of RTO/ISOs are vertically integrated utilities. Some RTO/ISOs, however, have a significant portion of their coincident peak demand under the control of vertically integrated utilities. *See, e.g.*, Affidavit of Richard Doying on Behalf of the Midwest Indep. Transmission Sys. Operator, Inc. at P 25, *Midwest Indep. Transmission Sys. Operator, Inc.*, FERC Docket No. ER08-394-000 (Dec. 21, 2007) (stating that "[t]he Midwest ISO Region has also experienced reduced challenges in maintaining adequate Planning Resources because the vast majority (approximately 70%) of all Loads in the Midwest ISO Region are served by traditional vertically-integrated transmission owners that have historically constructed adequate Generation Resources to serve their native Load. In contrast, the majority of LSEs in Northeast RTOs are subject to state retail choice provisions and loads may no longer be served by vertically-integrated utilities.").

9. *See infra* Section III.

structure, a vertically integrated utility can receive approval from state commissions to construct new generation facilities, or to enter into power purchase contracts and acquire power from alternate facilities, in order to maintain system reliability consistent with the vertically integrated utility's plans to retire coal generation facilities.[10]

In other states, however, the regulatory framework has been changed, and some electric utilities no longer have jurisdictional service territories where they have the sole right to provide electricity to customers.[11] In these "re-regulated" states, independently-owned generation facilities are able to more vigorously compete with a vertically integrated utility's generation facilities or with generation facilities that have been unbundled from a vertically integrated utility.[12] In these states, the economics of supply and demand in wholesale competitive markets often determines whether a particular generation resource is dispatched by a Regional Transmission Organization (RTO) or an Independent System Operator (ISO), rather than having dispatch decisions made by a vertically integrated utility.[13]

For utilities that are located within an RTO/ISO, the decision to retire a generation resource may also be subject to the RTO/ISO's FERC tariff provisions. RTO/ISO tariffs, for example, require that the system operator preserve system reliability and encourage long-term energy market solutions, as well as operate competitive wholesale energy markets.[14] As a result, many RTO/ISOs have tariff provisions that address Reliability Must Run (RMR) contracts[15] or System Support Resources (SSR) agreements[16] in order to be able to maintain system reliability within the RTO/ISO by responding to planned generation facility retirements. RMR and SSR agreements are out-of-market[17] responses to system reliability concerns resulting from the planned retirement of

10. Marty Kushler & Dan York, *Utility Initiatives: Integrated Resource Planning*, AM. COUNCIL FOR AN ENERGY-EFFICIENT ECON. (July 28, 2010), http://aceee.org/policy-brief/utility-initiatives-integrated-resource-planning.

11. *See infra* Section III.

12. REGULATORY ASSISTANCE PROJECT, ELECTRICITY REGULATION IN THE US 54 (2011), *available at* www.raponline.org/document/download/id/645.

13. WILLIAM W. HOGAN, HARVARD UNIV., RESTRUCTURING THE ELECTRICITY MARKET 9, 12-13 (1999), *available at* http://www.hks.harvard.edu/fs/whogan/hjp0499.pdf (This article discusses the concept of generation resources stacking up in a "merit order" from least cost to highest and then being dispatched according to need and cost. Therefore, the marginal cost of a generation resource determines least-cost dispatch.).

14. *See, e.g.*, Order No. 2000, *Regional Transmission Organizations*, F.E.R.C. STATS. & REGS. ¶ 31,089 (1999), 65 Fed. Reg. 810 (1999) (codified at 18 C.F.R. pt. 35.34).

15. *See, e.g.*, PJM INTERCONNECTION, L.L.C., PJM OPEN ACCESS TRANSMISSION TARIFF, pt. V (2013) [hereinafter PJM TARIFF]; *see also PJM Interconnection, L.L.C.*, 110 F.E.R.C. ¶ 61,053 at PP 123-58 (requiring compensation be paid to units that delay their retirement).

16. *E.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 142 F.E.R.C. ¶ 61,170 (2013) [hereinafter *Escanaba* Order].

17. Although various formal and informal capacity markets exist in the United States, this article describes RMR and SSR agreements as being "out-of-market" because the subject generation resources are presumed not to be economic under the prevalent capacity markets and, thus, require a special agreement outside of the capacity market to encourage continued operations under a subsidized arrangement with the RTO/ISO.

generation facilities if such resources are determined by the RTO/ISO to be required to preserve system reliability within the RTO/ISO.[18]

A significant difference exists between RMR and SSR agreements, largely because most RTOs cannot mandate that a generation resource enter into an RMR agreement.[19] In contrast, one RTO is authorized to file an SSR agreement with the FERC to compensate a generation resource that plans to retire or suspend operations for more than two months.[20]

This article begins by addressing some of the environmental and economic reasons that coal-fueled generation resources may be retiring more frequently during the next few years than they have in the past. Section III discusses the ways that vertically integrated utilities (particularly those that are not members of RTO/ISOs) respond to anticipated loss of coal-fueled generation resources and maintain system reliability. Section IV briefly outlines the different ways that RTO/ISOs ensure system reliability by encouraging the continued availability of adequate electric generation capacity to meet forecast peak demands in their region. Section V discusses the type of actions that RTO/ISOs, other than the Midcontinent Independent System Operator, Inc. (MISO),[21] are authorized to take if a planned generation resource provides notice of retirement that could adversely impact system reliability. Section VI addresses how MISO's SSR tariff provisions operate. Section VII addresses the FERC's responsibilities to review and approve RMR and SSR agreements to ensure that the contract terms and conditions are just and reasonable. Section VIII provides policy implications for stakeholders regarding consideration of different RMR and SSR tariff provisions.

II. ENVIRONMENTAL AND ECONOMIC REASONS THAT COAL GENERATION RESOURCES RETIRE

Many owners of coal-fueled electric generation resources are announcing plans to retire older coal-fueled generation, often because the economic operation and environmental upgrade costs for coal-fueled power plants render the resources unable to compete with low cost natural gas fueled generation.[22] According to the U.S. Energy Information Administration (EIA), at the end of 2012, over one-half of all generating capacity in this country was older than

18. *See, e.g.*, *Escanaba* Order, *supra* note 16, at P 1 n.2, PP 3-4; *Exelon Generating Company, LLC*, 132 F.E.R.C. ¶ 61,219 at PP 1-3 (2010).

19. *See infra* Section V.

20. *Escanaba* Order, *supra* note 16, at P 3.

21. "Effective April 26, 2013, MISO . . . amended its Certificate of Incorporation on file with the State of Delaware to reflect a change in its legal entity name from 'Midwest Independent Transmission System Operator, Inc.' to 'Midcontinent Independent System Operator, Inc.'" Motion for Extension of Time of the Midcontinent Indep. Sys. Operator at 1 n.1, *Midcontinent Indep. Sys. Operator, Inc.*, FERC Docket No. ER13-692-000 (May 23, 2013).

22. *Projected Retirements of Coal-Fired Power Plants*, U.S. ENERGY INFO. ADMIN. (July 31, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=7330 [hereinafter EIA, *Projected Retirements*] (stating that "[c]urrent trends in the electric power market put many coal-fired generators in the United States at risk for retirement. . . . Lower natural gas prices, higher coal prices, slower economic growth, and the implementation of environmental rules all play a role in the retirements."). *But see Short-Term Energy Outlook*, U.S. ENERGY INFO. ADMIN. (June 11, 2013), http://www.eia.gov/forecasts/steo/report/electricity.cfm (stating that "generators have been running their existing coal capacity at higher rates so far this year in response to the increasing cost of natural gas relative to coal").

thirty years.[23] Aging coal-fueled generation is projected to require significant capital expenditures to comply with anticipated future environmental regulations.[24] As coal-fueled generation resources approach the end of their anticipated lifespans, the resource owners face decisions, in part, over whether to make further capital expenditures for environmental compliance.[25] Owners must also consider the regulatory risks that future environmental restrictions may continue to impair a coal-fueled resource's ability to operate.[26] For many coal-fueled generation facilities, the decision to implement environmental upgrades in order to continue to operate coal-fueled facilities that are nearing the end of their useful lives does not make economic sense.

In the past, some older generation resources were "grandfathered" from having to comply with new environmental regulations in the same manner as new generation resources.[27] Recently, generation resource owners have seen a number of Environmental Protection Agency (EPA) regulatory initiatives that could adversely impact the ability of coal-fueled generation to operate.[28] These environmental regulatory initiatives could result in electric generation facilities having to upgrade air and water pollution control measures, as well as impact an owner's ability to make facility repairs without risk of losing the "grandfathered" status.

The EPA has been producing new or updated regulations under the Clean Air Act (CAA)[29] and the Clean Water Act (CWA)[30] for the past decade. For example, under the CAA, one of the EPA's responsibilities is setting National Ambient Air Quality Standards (NAAQS) that specify maximum limits of common air pollutants.[31] The EPA must determine pollution levels which allow "an adequate margin of safety [and] are requisite to protect the public health."[32] In addition, under section 112 of the CAA, the EPA determines National Emission Standards for Hazardous Air Pollutants for multiple sources, including

23. *How Old Are U.S. Power Plants?*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/energy_in_brief/article/age_of_elec_gen.cfm (last updated Mar. 5, 2013); *Most Coal-Fired Electric Capacity Was Built Before 1980*, ENERGY INFO. ADMIN. (June 28, 2011), http://www.eia.gov/todayinenergy/detail.cfm?id=1990.

24. METIN CELEBI, FRANK GRAVES & CHARLES RUSSELL, THE BRATTLE GROUP, POTENTIAL COAL PLANT RETIREMENTS: 2012 UPDATE 10 (2012), *available at* http://www.brattle.com/_documents/UploadLibrary/Upload1082.pdf.

25. *Id.* at 1.

26. *Id.*

27. *See, e.g.*, U.S. ENVTL. PROT. AGENCY, FACT SHEET: IMPLEMENTATION OF THE NEW SOURCE REVIEW (NSR) PROGRAM FOR PARTICULATE MATTER LESS THAN 2.5 MICROMETERS ($PM_{2.5}$) – FINAL RULE TO REPEAL GRANDFATHER PROVISION (2011), *available at* http://www.epa.gov/NSR/documents/20110512grandfatherfs.pdf (explaining that the EPA was repealing the "grandfather provision for any grandfathered sources that have still not received their final [Prevention of Significant Deterioration (PSD)] permit under the federal PSD program").

28. CELEBI ET AL., *supra* note 24, at 1, 4-6 (discussing EPA regulatory rules and the "acceleration of announcements to retire coal plants").

29. 42 U.S.C. §§ 7401-7671q (2012).

30. 33 U.S.C. §§ 1251-1387 (2012).

31. 42 U.S.C. § 7409(a).

32. *Id.* § 7409(b)(1).

coal- and oil-fueled electric utility steam generating units.[33] Other sources of regulation include a cooling water intake structures rule under section 316(b) of the CWA,[34] coal combustion residuals (i.e., "coal ash") regulations under the Resource Conservation and Recovery Act,[35] Regional Haze Program Requirements,[36] and the recently vacated Cross-State Air Pollution Rule (CSAPR) that set up a NO_x and SO_2 allowance trading program.[37] Additionally, there is the ever-present concern that greenhouse gas emissions will come under additional regulatory control in the future.[38]

In *EME Homer City Generation, L.P. v. EPA*, the U.S. Court of Appeals for the D.C. Circuit vacated and remanded back to the EPA the CSAPR and associated Federal Implementation Plans (FIPs).[39] The court held, in part, that CSAPR violated the CAA because it exceeded the EPA's scope of authority granted under section 110(a)(2)(D) by requiring upwind states "to reduce emissions by more than their own significant contribution to a downwind state's nonattainment."[40] Additionally, the court held that the EPA promulgated FIPs without first giving states the opportunity to address their contributions to downwind emissions under the CAA's so-called "good neighbor" provision.[41] The court left the EPA's previously remanded 2005 Clean Air Interstate Rule[42] in place until the EPA promulgates a replacement.[43]

As generation resource owners attempt to forecast anticipated costs of environmental compliance, they must consider the dates that new environmental

33. National Emission Standards for Hazardous Air Pollutants from Electric Utility Steam Generating Units and Standards of Performance, 77 Fed. Reg. 9304 (Feb. 16, 2012) (to be codified at 40 C.F.R. pts. 60, 63).

34. National Pollutant Discharge Elimination System–Cooling Water Intake Structures, 76 Fed. Reg. 22,174 (Apr. 20, 2011) (to be codified at 40 C.F.R. pts. 122, 125).

35. Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities, 75 Fed. Reg. 35,128 (proposed June 21, 2010) (to be codified at 40 C.F.R. pts. 257, 261, 264-65, 268, 271, 302). On August 2, 2013, the EPA solicited additional comments on the Coal Combustion Residuals Rules. Hazardous and Solid Waste Management System, 78 Fed. Reg. 46,940, 46,940 (Aug. 2, 2013). However, the comment period ended on Sept. 3, 2013. *Coal Combustion Residuals – Proposed Rule*, EPA, http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/ccr-rule/index.htm (last updated Sept. 3, 2013).

36. Regional Haze Regulations, 64 Fed. Reg. 35,714 (July 1, 1999) (to be codified at 40 C.F.R. pt. 51).

37. Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, 76 Fed. Reg. 48,208, 48,271 (Aug. 8, 2011) (to be codified at 40 C.F.R. pts. 51-52, 72, 78, 97). This rule was vacated on August 21, 2012, by the United States Court of Appeals for the District of Columbia Circuit. EME Homer City Generation, L.P. v. EPA, 696 F.3d 7, 11-12 (D.C. Cir. 2012), *cert. granted in part*, 133 S. Ct. 2857 (2013).

38. On June 25, 2013, President Obama announced that the EPA would be issuing new air emission regulations specifically targeting new coal-fueled generation facilities, which he stated was the source for one-third of all domestic greenhouse gas emissions. President Barack Obama, Remarks by the President on Climate Change (June 25, 2013), *available at* http://www.whitehouse.gov/the-press-office/2013/06/25/remarks-president-climate-change.

39. *EME Homer City Generation*, 696 F.3d 7.

40. *Id.* at 11.

41. *Id.* at 11-12.

42. North Carolina v. EPA, 531 F.3d 896 (D.C. Cir. 2008) (considering a challenge to the EPA's 2005 Clean Air Interstate Rule, or CAIR. CAIR built on the 1998 NO_x Rule and defined twenty-eight states' good neighbor obligations with respect to the 1997 ozone NAAQS and the 1997 NAAQS for annual levels of fine particulate matter, or annual $PM_{2.5}$).

43. *EME Homer City Generation*, 696 F.3d at 38.

regulations are anticipated to take effect. The initial MATS compliance deadline of April 16, 2015, is three years after the rule's effective date.[44] In its November 2011 report *Potential Impacts of Future Environmental Regulations*, North American Electric Reliability Corporation (NERC) analyzed the multiple anticipated regulations from the EPA that were identified as potentially accelerating the retirement of fossil-fuel units.[45] As resource owners contemplate whether to continue operation or to retire a generation resource, the compliance deadline for MATS may have a "bunching" effect on announced retirements of coal-fueled generation facilities.[46]

The relatively low cost of natural gas, in comparison with the costs for coal, also has at times allowed natural gas-fueled electric generation resources to have a competitive advantage, compared with coal-fueled generation, in the wholesale energy marketplace.[47] The competitive status of older coal-fueled baseload generation is being challenged, in part, due to the decrease in Henry Hub natural gas spot prices over the past three years.[48] Natural gas prices are predicted by many to only rise modestly during the next several years, in part, due to the increased production of natural gas through "fracking" and other modern production techniques that allow producers to develop formations that had previously been deemed to be non-economically productive.[49]

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44. National Emission Standards for Hazardous Air Pollutants from Electric Utility Steam Generating Units and Standards of Performance, 77 Fed. Reg. 9304, 9465 (Feb. 16, 2012) (to be codified at 40 C.F.R. pts. 60, 63).

45. N. AM. ELEC. RELIABILITY CORP., POTENTIAL IMPACTS OF FUTURE ENVIRONMENTAL REGULATIONS 116, 143 (2011), *available at* http://www.nerc.com/files/EPA%20Section.pdf (stating that "[p]ower industry unit retirement decisions will not be based upon any single factor, but the combined effect from all the EPA regulations, economic conditions, and potential future requirements (e.g., from stricter national ambient air quality standards for SO_2, ozone and fine particulate, carbon control, national clean energy standards, effluent guidelines, etc.) that may be proposed over the remaining lifetime of the power plant facility").

46. In May 2013, PJM conducted a resource adequacy capacity auction for the 2016-2017 planning years, which includes the time frame when many coal-fueled generation facilities in the PJM region were anticipated to retire and thus raise capacity prices. PJM INTERCONNECTION, L.L.C., 2016/2017 RPM BASE RESIDUAL AUCTION RESULTS (2013) [hereinafter PJM INTERCONNECTION, 2016/2017 AUCTION], *available at* http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx. To the surprise of some observers, the capacity prices in all of the PJM zones (except one) were significantly lower than for the 2015-2016 planning year. *Id.* at 1. These auction results have led some to speculate that fewer coal-fired generation facilities than had previously been expected will actually retire from the PJM capacity market. *Id.* at 25, 29; *see, e.g.*, News Release, PJM Interconnection, L.L.C., PJM Capacity Auction Secures Record Amounts of New Generation, Demand Response, Energy Efficiency (May 18, 2012), *available at* http://www.pjm.com/~/media/about-pjm/newsroom/2012-releases/20120518-pjm-capacity-auction-secures-record-amounts-of-new-generation-demand-response-energy-efficiency.ashx.

47. *See, e.g.*, EIA, *Projected Retirements*, *supra* note 22.

48. *Henry Hub Gulf Coast Natural Gas Spot Price*, U.S. ENERGY INFO. ADMIN. (Sept. 5, 2013), http://www.eia.gov/dnav/ng/hist/rngwhhdd.htm (tracking the Henry Hub price of natural gas); *Competition Among Fuels for Power Generation Driven by Changes in Fuel Prices*, U.S. ENERGY INFO. ADMIN. (July 13, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=7090.

49. *Annual Energy Outlook 2013: Market Trends—Natural Gas*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/forecasts/aeo/MT_naturalgas.cfm (last visited Sept. 18, 2013) (noting that "[s]hale gas production, which grows by 113 percent from 2011 to 2040, is the greatest contributor to natural gas production growth").

Another factor that is challenging coal generation facilities is that the costs to transport coal from coal fields to the coal generation facilities have also increased over the past ten years.[50] These coal transportation increases have further increased the costs that some coal-fueled generation facilities must incur, at the same time that competing natural gas facilities have been able to reduce their historic fuel costs.

In addition, the recently-extended production tax credits for electricity generated by wind[51] have made wind power more competitive and, thus, have further adversely impacted the competitive status of coal generation facilities.[52] Finally, demand for electricity from coal-fueled generation facilities may be influenced by energy efficiency standards, which are predicted to level off or even to temporarily reduce the nation's demand for electricity as building codes and appliance efficiency standards increasingly take effect.[53]

III. RELIABILITY APPROACHES THAT VERTICALLY INTEGRATED UTILITIES USE TO MAINTAIN SYSTEM RELIABILITY

Before addressing the available authority that RTO/ISOs have to respond to the retirement of coal-fueled generation facilities, it is useful to compare how vertically integrated utilities respond to regulatory and economic conditions affecting such facilities. Under a traditional regulatory framework, a state has the authority to regulate the utilities that operate in that state.[54] Utilities generally submit data to the state commissions, including, but not limited to,

50. *Cost of Transporting Coal to Power Plants Rose Almost 50% in Decade*, U.S. ENERGY INFO. ADMIN. (Nov. 19, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=8830.

51. *See, e.g.*, K. Kaufmann, *Wind Energy Tax-Credit Extension Part of 'Cliff' Deal*, USA TODAY (Jan. 2, 2013, 2:46 PM), http://www.usatoday.com/story/news/nation/2013/01/02/fiscal-cliff-wind-energy-extension/1804447/ (noting that a one year extension of the tax credit was included in the budget negotiations).

52. *See, e.g.*, PHILLIP BROWN, CONG. RESEARCH SERV., U.S. RENEWABLE ELECTRICITY: HOW DOES THE PRODUCTION TAX CREDIT (PTC) IMPACT WIND MARKETS? (2012), *available at* http://thornberry.house.gov/uploadedfiles/r42576.pdf; *see also* Jeff Deyette & Steven Frenkel, *Ripe for Retirement*, *Catalyst: Spring 2013*, UNION OF CONCERNED SCIENTISTS, http://www.ucsusa.org/publications/catalyst/sp13-ripe-for-retirement.html (last visited Sept. 26, 2013) (analyzing the cost to modernize existing coal generation by installing pollution controls and comparing the operating cost of the coal-fired generator to a natural gas combined-cycle generator or a wind power facility).

53. INNOVATION ELEC. EFFICIENCY (IEE), FACTORS AFFECTING ELECTRICITY CONSUMPTION IN THE U.S. (2010-2035) at 1, 4, 9-28 (2013), *available at* http://www.edisonfoundation.net/iee/Documents/IEE_FactorsAffectingUSElecConsumption_Final.pdf. IEE concluded that total electricity usage in the United States is expected to dip to 3,590 Terawatt-hours (TWh) in 2025 from the 3,730 TWh in 2010 under the moderate case from IEE. *Id.* at 1, 44. The IEE is funded by the Edison Foundation and is affiliated with the Edison Electric Institute; "IEE members are investor owned utilities that represent about 70% of the [industry]." The Edison Foundation, About *IEE*, INNOVATION ELEC. EFFICIENCY, http://www.edisonfoundation.net/iee/about/Pages/default.aspx (last visited Sept. 19, 2013).

54. *E.g.*, Consolidated Edison Co. v. Public Serv. Comm'n, 447 U.S. 530, 549-550 (1980) (Blackmun, J., dissenting) (stating on dissent that "[a] public utility is a state-created monopoly. . . . Although monopolies generally are against the public policies of the United States and of the State of New York . . . utilities are permitted to operate as monopolies because of a determination by the State that the public interest is better served by protecting them from competition. . . . This exceptional grant of power to private enterprises justifies extensive oversight on the part of the State to protect the ratepayers from exploitation of the monopoly power through excessive rates and other forms of overreaching" (citations omitted)); *see generally* Evans B. Brasfield, *Regulation of Electric Utilities by the State Corporation Commission*, 14 WM. & MARY L. REV. 589 (1973) (discussing the rationale for regulation and to what extent the State Corporation Commission regulates utilities within the Commonwealth of Virginia).

load forecasts, electric generation supply plans, and a requested return on investment.[55] The state commissions review such information and approve the utilities' rates.[56] State regulatory oversight has evolved from a monopolistic focus on approval of supply side generation to include a comprehensive blend of options under an IRP.[57] While the terminology differs from state to state and among regulators, the goal of an IRP is improving long-term planning so that the utility can reliably meet anticipated electricity demands at the least cost.[58]

There is no universal definition for an IRP. Under the Energy Policy Act of 1992, the term "integrated resource planning" was defined to include the entire spectrum of alternatives for new energy resources; demand and supply resources, for example, were to be treated "on a consistent and integrated basis."[59] State regulatory bodies have specific requirements for IRPs that vary in terms of planning horizon, the frequency with which plans must be updated, the resources required to be considered, and the requirements for potential generating unit retirement.[60] The framework provided by an IRP process allows regulators to balance both supply and demand side options with a goal of selecting the least cost overall mix of options to achieve utility planning goals.[61] Under this framework, a utility is able to meet its demand forecast through traditional electric generation development, power purchase agreements, allowing merchant or independent generation, demand response, and/or energy efficiency.[62] As an example of how the IRP process works, in a recent Virginia State Corporation Commission docket, the Electric Power Supply Association challenged the incumbent utility's plans to self-supply new generation and instead urged competitive market solutions.[63] In another recent docket, the Minnesota Public Utilities Commission rejected a proposed IRP, in part, because regulators sought

55. *See, e.g.*, Kushler & York, *supra* note 10.

56. *See generally Utility Regulation and Policy*, AM. COUNCIL FOR AN ENERGY-EFFICIENT ECON., http://www.aceee.org/topics/utility-regulation-and-policy (last visited Sept. 26, 2013) (noting that states are often "responsible for overseeing and authorizing [utilities'] investment decisions, operations and customer rates").

57. Kushler & York, *supra* note 10.

58. *Id.*

59. Energy Policy Act of 1992 § 111(d)(19), 16 U.S.C. § 2602(19) (2012).

60. *See, e.g.*, GA. COMP. R. & REGS. 515-3-4.06 (2013); 170 IND. ADMIN. CODE 4-7-4 (2013); MO. CODE REGS. ANN. tit. 4, § 240-22.060 (2013); NEB. REV. STAT. § 66-1060 (2012); VA. CODE. ANN §§ 56-597 to -599 (2013); WASH. ADMIN. CODE § 480-100-238 (2013).

61. Kushler & York, *supra* note 10; STATE & LOCAL ENERGY EFFICIENCY ACTION NETWORK, USING INTEGRATED RESOURCE PLANNING TO ENCOURAGE INVESTMENT IN COST-EFFECTIVE ENERGY EFFICIENCY MEASURES 14 (2011), *available at* http://www1.eere.energy.gov/seeaction/pdfs/ratepayer_efficiency_irpportfoliomanagement.pdf (stating that "[t]he best IRP processes consider a range of possible values for the future cost and availability of all types of resources, as well as a range of possible future scenarios for demographic, economic, and regulatory changes").

62. STATE & LOCAL ENERGY EFFICIENCY ACTION NETWORK, *supra* note 61, at iv.

63. Direct Testimony of Michael M. Schnitzer on Behalf of Electric Power Supply Association (EPSA) at 5-6, Va. Elec. & Power Co.'s Integrated Res. Plan Filing, Va. Corp. Comm'n Case No. PUE-2011-00092 (Mar. 15, 2012) (challenging Dominion Virginia Electric and Power Company's 2011 Integrated Resource Plan before the Virginia State Corporation Commission for unfairly dismissing competitive market alternatives in order to favor Dominion's preference for wholly self-built plants).

additional details on environmental compliance related to coal-fired generation.[64] State regulators use different approaches to seek an optimal mix of solutions to ensure reliable least cost electric service; an IRP framework assists the regulators in determining the best solution for that state.

Under the traditional state regulatory oversight structure, a vertically integrated utility has an incentive to identify planned retirements of generation resources in order to include replacement energy resources (e.g., energy efficiency, demand response, or new generation) as part of its IRP.[65] Resource retirement is inextricably linked with seeking regulatory approval to add new energy resources so that regulators and the utility may preserve system reliability.[66] In organized wholesale markets operated by RTO/ISOs, where a utility is located in a re-regulated state, there may be no analogous binding IRP process.[67] RTO/ISOs must operate organized wholesale markets that preserve system reliability while remaining responsive to the concerns of both state and federal regulators.

State regulators are often in the best position to address the levels of prescribed system reliability within their jurisdiction. State regulators, however, may not be as well prepared to analyze multi-state wholesale electric markets to assist in addressing the system reliability needs that may result from unplanned events outside of their jurisdiction. Although it is difficult to predict whether large-scale retirement of coal-fired generation will occur, the possible retirement of coal-fueled generation may leave some state regulators facing a transition within their jurisdiction due to the unavailability of coal-fueled generation outside of their jurisdiction. While each state may respond differently, states that take advantage of least-cost capacity resources through wholesale markets may minimize the impacts of unforeseen coal plant retirements on retail ratepayers (who will ultimately bear the brunt of cost impacts from generation retirements).

IV. DIFFERENT RESOURCE CAPACITY SYSTEM RELIABILITY APPROACHES USED BY RTOS/ISOS

In contrast with utilities that are not located in RTO/ISOs, load serving entities within an RTO/ISO are often subject both to state regulatory requirements, as well as to RTO/ISO resource adequacy requirements that are

64. David Shaffer, *Regulators Reject Great River Energy's Business Plan*, STAR TRIBUNE, http://www.startribune.com/business/215928901.html (last updated July 17, 2013); Staff Briefing Papers at 8, Great River Energy's 2012 Integrated Resource Plan, Minn. Pub. Util. Comm'n Docket No. ET2/RP-12-1114 (July 17, 2013) (noting a concern with the calculation of environmental externality values); *see also*, Notice of Information In Future Filings, Minn. Pub. Util. Comm'n (Aug. 5, 2013) (noting that Minnesota law requires that an Integrated Resource Plan "must include whether the resource plan helps the utility achieve the [state's] greenhouse gas reduction goals . . . , the [state's] renewable energy standard . . . , or the [state's] solar energy standard").

65. Kushler and York, *supra* note 10.

66. CELEBI ET AL., *supra* note 24, at 1.

67. *See, e.g.*, APS Initial Response to Commission Inquiry Regarding Electric Restructuring at 2, 7, Commission's Inquiry into Retail Elec. Competition, Ariz. Corp. Comm'n Docket No. E-00000W-13-0135 (July 15, 2013), *available at* http://azenergyfuture.com/wp-content/uploads/2013/07/APSDeregCommentsFiledwithACC_130715.pdf.

authorized by the FERC.[68] These dual-jurisdictional obligations may include meeting dual resource adequacy requirements both through IRP requirements and through FERC capacity market requirements.

RTO/ISOs are responsible for maintaining system reliability, including developing and implementing appropriate resource adequacy provisions to enhance the operation of competitive, wholesale energy markets, in part, by encouraging adequate generation capacity.[69] Although Order No. 2000 specified eight standardized functions for RTOs,[70] RTO/ISOs have evolved differently, and they have developed alternate approaches to comply with Order No. 2000.[71] One example of these tariff differences is the type of approaches that RTO/ISOs have taken to ensure adequacy of supply of electric generation capability (i.e., resource adequacy).[72] One element of assuring resource adequacy is for RTO/ISOs to have the tariff authority to be able to respond to system reliability challenges by entering into out-of-market contracts with the owners of electric generation resources that announce plans to retire a facility (i.e., RMR or SSR contracts).[73] The different resource adequacy approaches that RTO/ISOs have developed are complemented by their different types of tariff provisions to ensure system reliability through such out-of-market contracts.

A. Differing Resource Adequacy Methodologies

Some regions of the country, such as the Electric Reliability Council of Texas (ERCOT), implemented what has been described as an "energy only market," in which the wholesale price of energy also reflects the costs that generation resources incur in acquiring adequacy capacity to meet peak forecast

68. Order No. 2000, *Regional Transmission Organizations*, F.E.R.C. STATS. & REGS. ¶ 31,089, at pp. 30,993-94, 31,210-11, 31,213 (1999), 65 Fed. Reg. 810 (1999) (codified at 18 C.F.R. pt. 35) [hereinafter Order No. 2000], *order on reh'g*, Order No. 2000-A, F.E.R.C. STATS. & REGS. ¶ 31,092 (2000), *aff'd sub nom.* Public Util. Dist. No. 1 v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

69. *Id.* at pp. 31,092, 31,103, 31,106.

70. *Id.* at p. 31,106. The listed functions include tariff administration and design, congestion management, parallel path flow, ancillary services, Open Access Same-Time Information System (OASIS), market monitoring, planning and expansion, and interregional coordination. *Id.*

71. *E.g.*, *infra* note 72. In approving Order No. 2000, the Commission adopted the principle of open architecture to allow an RTO to have the flexibility to grow in structure, geographic scope, market support, and operations to meet market needs. Order No. 2000, *supra* note 68, at p. 30,994.

72. It is beyond the scope of this article to do more than to briefly summarize the various resource adequacy provisions that RTO/ISOs have adopted to provide context to an RTO/ISO's need to enter into out-of-market RMR or SSR contracts. For further resource adequacy information, see, for example, JOHANNES P. PFEIFENBERGER, KATHLEEN SPEES, & SAMUEL A. NEWELL, THE BRATTLE GROUP, RESOURCE ADEQUACY IN CALIFORNIA: OPTIONS FOR IMPROVING EFFICIENCY AND EFFECTIVENESS (2012) [hereinafter PFEIFENBERGER ET AL., RESOURCE ADEQUACY IN CAL.], *available at* http://www.brattle.com/_documents/UploadLibrary/Upload1088.pdf (discussing California's resource adequacy framework and analyzing potential market reforms); KEVIN CARDEN & NICK WINTERMANTEL, ASTRAPE CONSULTING, THE ECONOMIC RAMIFICATIONS OF RESOURCE ADEQUACY WHITE PAPER (2013), *available at* http://www.naruc.org/grants/Documents/Economics%20of%20Resource%20Adequacy%20WhitePaper_Astrape_Final.pdf (discussing the history of resource adequacy and analyzing the market structures located in the Eastern Interconnection).

73. PFEIFENBERGER ET AL., RESOURCE ADEQUACY IN CAL., *supra* note 72, at 6-7, 10.

demands.[74] Advocates of such resource adequacy constructs contend that system reliability can be ensured at a lower cost when the costs associated with resource adequacy are incorporated into wholesale energy prices.[75] Critics contend that an energy only market may not provide sufficient capacity to maintain system reliability, in part, because of a vertical demand curve for energy.[76] Although the terms "supply" and "demand" are often used to describe capacity markets, the application of economic principles is different in a capacity market than, for example, a pure energy market where sellers and buyers jointly establish prices.[77] This is, in part, because the buyers in a capacity market cannot choose to procure less capacity than necessary to preserve system reliability.[78] Regulators and utilities determine the necessary amount of capacity that is needed to preserve system reliability in a region, and if buyers in a capacity market were able to decline to purchase sufficient capacity to meet their needs, then system reliability could suffer.[79]

If the demand curve that is established by an RTO/ISO for capacity resources is not downward sloping, then resource adequacy capacity arguably may have very little value, as long as there is at least a small amount of surplus capacity.[80] The price for capacity, however, tends to increase dramatically when capacity scarcity occurs or is threatened due to a virtually vertical capacity demand curve.[81] Some critics of an energy only market believe that this resource adequacy mechanism may not send sufficient price signals to encourage the development of required generation capacity without first experiencing unacceptable capacity shortage conditions.[82]

In other regions, RTO/ISOs have established specified resource adequacy requirements through the mandates of state commissions (e.g., the California Independent System Operator, Inc. [83] (CAISO) and the Southwest Power Pool[84] (SPP)). In these regions, the relevant state commissions, which have extensive jurisdiction over utility operations in a state, mandate that load serving entities (LSEs) periodically demonstrate to the state commission that the LSE has adequate contractual generation commitments to meet anticipated peak demands,

74. *E.g.*, 16 TEX. ADMIN. CODE § 25.501 (2013) (discussing the "Wholesale Market Design for the Electric Reliability Council of Texas" including the energy and ancillary capacity services markets); *see also* ERIC S. SCHUBERT ET AL., THE TEXAS ENERGY-ONLY RESOURCE ADEQUACY MECHANISM 6-12, *available at* http://www.ucei.berkeley.edu/POWER-07/Files/6.pdf.

75. SCHUBERT ET AL., *supra* note 74, at 2.

76. *Id.* at 6, 10-11 (describing the energy-only market mechanism in ERCOT, noting that "offer curves for balancing energy and ancillary services . . . raise the greatest concerns about the possibility of market power abuse and other market manipulation," and proposing to disclose the name of the price-setting supplier along with the price of the offer to deter gaming).

77. *Id.* at 2.

78. *Id.*

79. *Id.* at 2, 4.

80. *PJM Interconnection, L.L.C.*, 117 F.E.R.C. ¶ 61,331 at PP 75-76 (2006).

81. *Id.* at P 76.

82. SCHUBERT ET AL., *supra* note 74, at 4 (arguing that "[c]apacity payment mechanisms distort price signals").

83. *Resource Adequacy*, CAL. PUB. UTIL. COMMISSION, http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ (last updated Feb. 5, 2013) (describing the program's two goals as providing grid reliability and incentivizing new resources).

84. *Southwest Power Pool, Inc.*, 141 F.E.R.C. ¶ 61,048 (2012).

with a specified reserve margin to take into account unusual load peaks and/or the loss of planned generation assets and/or transmission facilities.[85] LSEs in such RTO/ISOs are able to meet such statutory obligations without participating in a mandatory capacity market construct operated by an RTO/ISO.

In the midwestern portion of the nation, MISO has developed an annual capacity construct which mandates that LSEs demonstrate on an annual basis that they have sufficient planning reserve margin requirements on a locational basis to reliably meet forecast peak demands plus a specified planning reserve margin.[86] MISO's resource adequacy construct includes an annual auction clearing mechanism to enable LSEs that lack sufficient capacity to acquire zonal resource credits from entities that have an excess of such resources, as well as the ability of LSEs to self-supply capacity resources or to demonstrate adequacy through a fixed resource adequacy plan.[87] This mechanism overlays state IRP programs with which the majority of MISO utilities must also comply.[88]

In the mid-Atlantic and northeast portions of the nation, RTO/ISOs have developed mandatory, centralized forward capacity markets (e.g., PJM Interconnection, L.L.C.[89] (PJM), New York Independent System Operator, Inc.[90] (NYISO), and ISO-New England[91] (ISO-NE)). Although each of these resource adequacy programs are different, LSEs are generally required to pay for capacity for each megawatt (MW) of load that the LSE serves based upon locational capacity prices established through a forward capacity auction process conducted by the RTO/ISO.[92] These auctions use a downward sloping demand curve.[93] Proponents of such forward capacity market mechanisms contend that an auction that is held a year or more prior to the commitment date creates valuable capacity price discovery.[94] Publishing the results of such auctions can provide potential new generation resources with a valuable tool to justify investment in new capacity resources, which can increase system reliability in an efficient manner.[95] Critics of such market mechanisms contend that such auctions

85. *See, e.g.*, CAL. PUB. UTIL. COMMISSION, *supra* note 83.

86. *Midwest Indep. Transmission Sys. Operator, Inc.*, 139 F.E.R.C. ¶ 61,199 at PP 2, 6, 238 (2012).

87. *Id.* at PP 3, 18.

88. *Id.* at PP 28-31, 41.

89. *PJM Interconnection, L.L.C.*, 119 F.E.R.C. ¶ 61,144 (2007), *order on reh'g*, 121 F.E.R.C. ¶ 61,073 (2007).

90. N.Y. INDEP. SYS. OPERATOR, INSTALLED CAPACITY MANUAL: MANUAL 4 at 1-1 (2013), *available at* http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf (containing "the procedures that will be followed by the NYISO and its Customers with regard to the Installed Capacity markets and auctions administered by the NYISO pursuant to the *NYISO Market Administration and Control Area Services Tariff* . . . . The Installed Capacity Market provisions are discussed generally at Sections 5.9 through 5.16 of the *NYISO Services Tariff* . . . .").

91. ISO-NEW ENGLAND, INC., INTERNAL MARKET MONITORING UNIT REVIEW OF THE FORWARD CAPACITY MARKET AUCTION RESULTS AND DESIGN ELEMENTS (2009), *available at* http://www.iso-ne.com/markets/mktmonmit/rpts/other/fcm_report_final.pdf.

92. *Id.* at 20.

93. *E.g.*, *PJM Interconnection, L.L.C.*, 117 F.E.R.C. ¶ 61,331 at P 75 (2006).

94. ERIC HILDEBRANDT, CAL. INDEP. SYS. OPERATOR, POTENTIAL EFFECTIVENESS OF THE DEMAND CURVE APPROACH FOR MITIGATION OF LOCAL MARKET POWER IN CAPACITY MARKETS 2, 7 (2009), *available at* http://www.caiso.com/2747/2747edae27b70.pdf.

95. JOHANNES PFEIFENBERGER, KATHLEEN SPEES & ADAM SCHUMACHER, THE BRATTLE GROUP, A COMPARISON OF PJM'S RPM WITH ALTERNATIVE ENERGY AND CAPACITY MARKET DESIGNS 66 (2009)

artificially inflate capacity costs and may result in windfalls for existing generation facilities, which arguably already receive adequate compensation based upon energy and ancillary service revenues.[96]

B. Consequences from Different Resource Adequacy Constructs

One characteristic of all forward capacity market auctions is that the RTO/ISO will obtain contractual commitments from generation resources that offer capacity into the auction to be available during the applicable forward contract year.[97] A coal-fueled generation facility that plans to retire within the next three years, for example, would not be expected to bid capacity from the facility into a forward capacity auction because the facility would not expect to be able to deliver capacity during the future contract period if it retired.[98] Thus, the results of bidding in a forward capacity auction may provide an RTO/ISO with valuable advance notice of the anticipated availability of generation resources.[99]

In contrast, an RTO/ISO with a shorter forward capacity construct could experience challenges in conducting resource adequacy planning to maintain system reliability if the generation resources are able to announce planned retirements with relatively little advance notice and also are not shackled by forward capacity construct commitments.[100]

Most RTO/ISOs are able to utilize out-of-market contract procedures in their tariffs to achieve system reliability—rather than just allow prices for energy to balloon and/or to allow "planned" shedding of load—when system reliability is threatened based upon the announced retirement of specific generation facilities.[101] Out-of-market mechanisms (i.e., RMR contracts) may provide a stop-gap tool for organized wholesale electric markets to preserve system reliability when generation resources seek to retire.[102] RMR contracts, however, are not a panacea because ultimately market participants in the region determine the optimal generation supply mix to meet their system reliability obligations.[103] This article will next focus on how different RTO/ISO tariffs operate to preserve wholesale competitive energy markets while encouraging adequate supplies of generation resources to maintain system reliability and also while maintaining competitive wholesale markets for capacity.

[hereinafter PFEIFENBERGER ET AL., COMPARISON OF PJM], *available at* http://www.hks.harvard.edu/hepg/Papers/2009/Brattle%20RPM%20Comparison%20Whitepaper_Sept09.pdf.

96. Joint Comments of the Pub. Power Ass'n of N.J. & the Am. Pub. Power Ass'n at 7, Board's Investigation of Capacity Procurement & Transmission Planning, N.J. Bd. Pub. Util. Docket No. EO11050309 (Oct. 19, 2011), *available at* http://www.nj.gov/bpu/pdf/energy/APPA%20comments.pdf (referring to centralized capacity markets as fundamentally broken and noting an "inverse relationship between prices and resource development [where there is a] perverse financial incentive to keep higher priced zones constrained in order to maximize the revenues paid to existing [generation resources]"); *id.* app. A at 18-19.

97. ISO-NEW ENGLAND, *supra* note 91, at 1.

98. *See, e.g.*, PJM INTERCONNECTION, 2016/2017 AUCTION, *supra* note 46, at 17.

99. ISO-NEW ENGLAND, *supra* note 91, at 49-50.

100. PFEIFENBERGER ET AL., RESOURCE ADEQUACY IN CAL., *supra* note 72, at 17, 29-30.

101. *Id.* at 10.

102. *Id.*

103. *Id.* at 18.

V. ACTIONS THAT RTO/ISOS, OTHER THAN MISO, ARE AUTHORIZED TO TAKE TO RESPOND TO NOTICE OF A PLANNED RETIREMENT OR SUSPENSION

RTO/ISOs do not have uniform tariff provisions that require generation resources in a region to provide identical advance notice prior to permanently retiring a generation resource or prior to suspending operations for a significant period of time.[104] Such advance notice tariff provisions are important, however, because they permit RTO/ISOs to analyze the potential adverse effects of system reliability due to the unavailability of specific generation resources as capacity resources.[105] More importantly, some RTO/ISO tariffs authorize the RTO/ISO to take steps in such situations to maintain system reliability by entering into out-of-market contracts with the capacity resource in exchange for remaining in operation.[106]

Once an RTO/ISO receives notice from a generation resource of a planned retirement or a long-term suspension (other than a normal planned maintenance or repair outage), tariffs generally require that the RTO/ISO study the available data to determine if the proposed retirement or suspension will result in a system reliability issue in the RTO/ISO's region.[107] If the study reveals no increase in planned 1-in-10 Loss of Load probability,[108] then the RTO/ISO would most likely notify the generation resource that retirement or suspension is permissible without any need for an out-of-market contract.[109] If, however, a study reveals that planned retirement or suspension will increase the planned 1-in-10 Loss of Load probability, then most RTO/ISOs have tariff authority to take further steps to try to maintain system reliability.[110] MISO has unique tariff authority under its SSR provisions,[111] which will be discussed in Section VI herein.

As described in more detail below, an RTO/ISO will generally contact the generation resource and request a delay in retirement or suspension until network upgrades and/or planned new generation resource and/or demand response can be implemented to preserve the reliability metric of a planned 1-in-10 Loss of

104. RTO/ISOs also have tariff procedures that require generation resources to provide advance notification of planned outages due to routine planned maintenance, refueling, or other outages where the generation resource will be unavailable for period of time, but will later return to service. *E.g.*, PJM TARIFF, *supra* note 15, § 113. The subject retirement or suspension notices in this article involve situations where a generation resource will either be unavailable for a reason other than planned maintenance or plans a long-term retirement of the resource.

105. *E.g.*, Joint Comments of the ERCOT, MISO, NYISO, PJM, and SPP at 4, National Emission Standards of Hazardous Air Pollutants from Coal and Oil-Fired Electric Utility Units, EPA-HQ-OAR-2009-0234, EPA-HQ-OAR-2011-0044, FRL-9286-1 (2011).

106. PFEIFENBERGER ET AL., RESOURCE ADEQUACY IN CAL., *supra* note 72, at 10; PFEIFENBERGER ET AL., COMPARISON OF PJM, *supra* note 95, at 58, 66-67.

107. *E.g.*, PJM TARIFF, *supra* note 15, § 113.2; N. AM. ELEC. RELIABILITY CORP., *supra* note 1, at 1-3.

108. Sources cited *supra* note 1 (discussing the 1-in-10 Loss of Load probability).

109. *See, e.g.*, PJM TARIFF, *supra* note 15, § 113.2.

110. *See, e.g.*, PFEIFENBERGER ET AL., RESOURCE ADEQUACY IN CAL., *supra* note 72, at 10; PFEIFENBERGER ET AL., COMPARISON OF PJM, *supra* note 95, at 58, 66-67.

111. MIDCONTINENT INDEP. SYS. OPERATOR, FERC ELECTRIC TARIFF (2013) [hereinafter MISO TARIFF]. Because of a pending compliance filing, it should be noted that references herein to MISO's tariff section 38.2.7, System Support Resources, are to version 3.0.0 as filed on compliance. Compliance Filing & Proposed Tariff Revisions, *Midwest Indep. Transmission Sys. Operator, Inc.*, FERC Docket No. ER12-2302-001 (Dec. 18, 2012).

Load probability. RTO/ISOs are entitled to use their out-of-market tariff authorities to encourage the generation resource to delay retirement or suspension, as briefly outlined below.

A. PJM

Electricity generators that are subject to the PJM tariff are required to provide that RTO with ninety days advance notice of their intent to retire a generation resource.[112] "PJM will then study the transmission system to determine if the proposed deactivation could adversely affect system reliability."[113] PJM will notify the relevant generation owner within thirty days of any "specific system reliability concerns," and PJM will provide the owner of the generation resource with "an estimate of the period of time needed to construct needed transmission upgrades" to maintain system reliability in the absence of the specific generation resource.[114]

An owner of a generation resource that is located within the PJM region, however, "has a right to deactivate a generation resource, following timely notification to PJM, even if PJM determines that there are [system] reliability concerns" associated with the absence of the generation resource.[115] The generation resource owner, however, "may elect to continue to operate the [facility] past its planned deactivation date to maintain system reliability pending the completion of necessary transmission system upgrades. If the generation owner chooses to continue to operate the unit," then the owner or operator of a unit would be "entitled to file [an RMR contract] with the Commission in order to recover the entire cost of operating the unit beyond its proposed deactivation date."[116]

Under PJM's RMR tariff procedures, generation resources may elect to either accept a "going forward" compensation system or, in the alternative, to file a "rate case" cost recovery mechanism.[117] By moving the determination of costs and compensation before the FERC, PJM is able to allow the adversarial regulatory process to resolve any outstanding questions regarding equitable out-

112. PJM TARIFF, *supra* note 15, § 113.1; *PJM Interconnection, L.L.C.*, 110 F.E.R.C. ¶ 61,053 at PP 123-24 (2005) (requiring compensation be paid to units that delay their retirement).

113. *Exelon Generating Company, LLC*, 132 F.E.R.C. ¶ 61,219 at P 3 (2010); PJM TARIFF, *supra* note 15, § 113.2

114. *Exelon*, 132 F.E.R.C. ¶ 61,219 at P 3; *see also* PJM TARIFF, *supra* note 15, § 113.2.

115. *Exelon*, 132 F.E.R.C. ¶ 61,219 at P 3; *see also* PJM TARIFF, *supra* note 15, § 113.2 (stating that "[r]egardless of whether the Deactivation of the generating unit would adversely affect the reliability of the Transmission System, the Generation Owner or its Designated Agent may deactivate its generating unit, subject to the notice requirements in section 113.1 of this Tariff").

116. *Exelon*, 132 F.E.R.C. ¶ 61,219 at P 3; *see also* PJM Tariff, *supra* note 15, § 113.2 (providing that "[u]pon receipt of notification from the Transmission Provider that Deactivation of the generating unit would cause reliability concerns, the Generation Owner shall immediately be entitled to file with the Commission a cost of service rate to recover the entire cost of operating the generating unit until such time as the generating unit is deactivated"); *id.* §§ 115, 119.

117. PJM TARIFF, *supra* note 15, §§ 113.2, 115, 119. For an example of a generation resource opting for the cost of service recovery rate (i.e. "rate case") option under the PJM tariff, see *Exelon*, 132 F.E.R.C. ¶ 61,219 (accepting and suspending a tariff filing that requested Reliability Must Run status and establishing settlement judge proceedings on the same); *Exelon Generating Co., LLC*, 135 F.E.R.C. ¶ 61,190 (2011) (order approving settlement).

of-market payments to maintain the generation resource until system changes make the generation resource no longer necessary for system reliability.[118]

B. ISO-NE

In a series of orders beginning in 2003, the Commission rejected the widespread use of RMR agreements to allow generating facilities to recover, outside of the energy market, its costs under a cost of service contract in order to ensure system reliability.[119] Instead, the FERC directed ISO-NE to establish new mechanisms to allow generators an opportunity to recover such costs through a forward capacity market.[120] In response to the Commission (and after various market iterations that were intended to allow cost recovery for facilities through the market), ISO-NE developed and the Commission approved a Forward Capacity Market (FCM) tariff mechanism.[121]

ISO-NE, through the FCM mechanism, provides "capacity payments to resources that provide capacity to the New England region, and capacity resources compete, through an annual [Forward Capacity Auction], to be selected to provide capacity on a three-year forward basis."[122] The FCM allows "an existing resource to opt out of the market by submitting" either a static or "a dynamic de-list bid."[123] Additionally, a resource may request non-price retirement, and, even if ISO-NE determines that the resource is needed for system reliability, the resource has the option to retire.[124]

On August 6, 2012, the Commission issued a letter order in Docket No. ER12-2041-000 and accepted modifications to ISO-NE's Appendix I, Form of Cost-Of-Service Agreement under the FCM construct.[125] Pursuant to section 2.1 of the pro forma agreement, if ISO-NE has not notified a resource owner that the resource is no longer required for system reliability prior to "the [c]apacity

118. *See, e.g.*, Comments of the Indep. Mkt. Monitor for PJM, *AmerenEnergy Res. Generating Co. v. Midcontinent Indep. Sys. Operator, Inc.*, FERC Docket Nos. EL13-76-000, ER13-1962-00 (July 31, 2013). The filings by the PJM Independent Market Monitor and by other intervenors document a dispute over whether section 119 of part V of the PJM Tariff allows for a full cost of service rate recovery (e.g., including depreciation expenses) under an RMR agreement. *Id.*

119. *E.g.*, *Devon Power LLC*, 102 F.E.R.C. ¶ 61,314 (2003); *Devon Power LLC*, 103 F.E.R.C. ¶ 61,082 (2003); *PPL Wallingford Energy LLC*, 103 F.E.R.C. ¶ 61,185 (2003); *Devon Power Co.*, 104 F.E.R.C. ¶ 61,123 (2003); *PPL Wallingford Energy LLC*, 105 F.E.R.C. ¶ 61,324 (2003).

120. *E.g.*, 105 F.E.R.C. ¶ 61,324 at PP 1-6; 104 F.E.R.C. ¶ 61,123 at PP 2, 33; 103 F.E.R.C. ¶ 61,185 at PP 1, 13; 103 F.E.R.C. ¶ 61,082 at P 1.

121. *See, e.g.*, *Devon Power LLC*, 107 F.E.R.C. ¶ 61,240 (2004) (deferring implementation of and establishing hearing procedures for a plan that proposed locational installed capacity (LICAP), which was a predecessor proposal to the FCM); *Devon Power LLC*, 115 F.E.R.C. ¶ 61,340 (2006) (approving Forward Capacity Market settlement agreement), *order on reh'g*, 117 F.E.R.C. ¶ 61,133, *aff'd in relevant part sub nom.* Maine Pub. Utils. Comm'n v. FERC, 520 F.3d 464 (2008), *order on remand*, *Devon Power LLC*, 126 F.E.R.C. ¶ 61,027 (2009).

122. *ISO New England Inc.*, 137 F.E.R.C. ¶ 61,056 at P 2 (2011) (discussing the background of the FCM and accepting the results of the fifth Forward Capacity Auction).

123. *Id.* at P 7 & n.3.

124. *Id.* at P 8 & n.6 (citing ISO NEW ENGLAND INC., TRANSMISSION, MARKETS & SERVICES TARIFF § III.13.2.5.2.5.3(a)(iii) (2013) [hereinafter ISO-NE TARIFF]); *cf.* ISO-NE TARIFF, *supra*, § III.13.2.5.2.5.1 (specifying the compensation terms for a resource that has a de-list bid rejected).

125. Order Accepting Filing Revisions, Docket Nos. ER12-2041-000, ER12-2041-001 (FERC Aug. 6, 2012) (letter order).

[c]ommitment [p]eriod for which [either] the [p]ermanent [d]e-[l]ist [b]id was rejected [or] the [n]on-price [r]etirement [r]equest was not accepted," then the term of the cost-of-service agreement is set to a minimum of twelve months, subject to a 120-day termination notice provision that is used if the resource is no longer needed for system reliability.[126] If a resource owner has submitted a permanent de-list bid or non-price retirement request, then the provisions of Market Rule 1, section III.13.2.5.2.5 apply after the cost of service agreement terminates or expires.[127] ISO-NE reviews whether the capacity associated with non-price retirement requests or de-list bids are required for system reliability during the capacity commitment period for the forward capacity auction.[128]

On June 14, 2013, the FERC issued an order in Docket No. ER13-1291-000, finding that section III.A.15 of Appendix A of the ISO-NE tariff needed to be modified so that it provides resources with an adequate opportunity to recover costs incurred to comply with ISO-NE dispatch directives during periods when resources were required.[129] ISO-NE was directed to submit a compliance filing within forty-five days of the order.[130]

C. CAISO

CAISO and the Public Utility Commission of the State of California (CPUC) have interrelated responsibility for resource adequacy in California, and the FERC has recognized California's "established resource adequacy programs as the primary means of ensuring that there are sufficient resources in California to maintain reliable grid operations."[131] CAISO does not possess final review authority regarding the potential retirement of a unit and instead must react to the system reliability impacts of such decisions when notified by the owner or operator of a planned retirement of such unit.[132] Utilities that purchase power from independent power producers have a degree of uncertainty related to the potential retirement decisions of the owner of such a facility.[133] For example, the CPUC has stated that "[m]ost of the state's fleet of aging plants are owned by unregulated entities, and the factors that inform an owner's decision to retire the plant are not within the knowledge or control of the [investor-owned utilities (IOUs)] or the Commission."[134] The CPUC also imposes a Resource Adequacy Requirement (RAR)[135] obligation on retail suppliers and implements a Long Term Procurement Plan (LTPP)[136] process to oversee the development of new

126. ISO-NE TARIFF, *supra* note 124, § III app. § 2.1-2.2.1.

127. *Id.* § III app. § 2.2.4.

128. *Id.* § III app. § 2.1-.2.

129. *Dominion Energy Mktg., Inc.*, 143 F.E.R.C. ¶ 61,233 at PP 25-26 (2013).

130. *Id.* at PP 26, 30.

131. *California Indep. Sys. Operator Corp.*, 142 F.E.R.C. ¶ 61,248 at P 4 (2013).

132. *Id.* at PP 7, 45.

133. *See, e.g.*, Decision 07-12-052, Order Instituting Rulemaking to Integrate Procurement Policies and Consider Long-Term Procurement Plans, Rulemaking 06-02-013, at 84 (Cal. PUC Comm'n Dec. 20, 2007), *available at* http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/76979.doc.

134. *Id.* at 84.

135. CAL. PUB. UTIL. CODE § 380 (West 2013); *see also* CAL. PUB. UTIL. COMMISSION, *supra* note 83.

136. CAL. PUB. UTIL. CODE § 454.5; *see also Long-Term Procurement Plan History*, CAL. PUB. UTIL. COMMISSION, http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm (last modified July 22, 2013).

generation resources.[137] Similarly, the CAISO tariff provides for an out-of-market backstop to ensure resource adequacy through the use of tools such as the Capacity Procurement Mechanism (CPM)[138] and RMR contracts.[139]

In 2013, the FERC analyzed CAISO's authority to deal with premature resource retirements and determined that "CAISO currently has at its disposal a number of options for addressing any imminent resource retirements that may result in reliability threats, including its existing CPM risk-of-retirement provisions."[140] The FERC recognized that circumstances may arise when insufficient capacity is procured under the CPUC programs to meet operational and/or system reliability needs.[141] In such an instance, CAISO may utilize "the backstop procurement authority in the [CPM] . . . provisions of its tariff."[142] A CPM designation may be offered by CAISO "to a resource that notifies CAISO that it is at risk of retirement and satisfies a number of requirements, including a finding by CAISO that the resource will be needed for reliability purposes, either for its locational or operational characteristics, by the end of the next calendar year."[143]

RMR agreements in CAISO are the by-product of negotiations between CAISO and the owner or operator of the impacted generation facility.[144] CAISO may, at any time, designate a generating unit as an RMR unit based upon CAISO's technical analysis; however, the unit remains subject to any existing power purchase contracts that the generating unit may have.[145] CAISO performs a local capacity technical study to ensure compliance with system reliability criteria,[146] and once the need for an RMR agreement is determined, CAISO and the counterparty use a pro forma RMR agreement that incorporates the rates, terms, and operating parameters specific to the facility.[147] CAISO's designation of a specific generating unit as an RMR unit may not, in and of itself, resolve the system reliability concern because the parties must agree on the proposed contract terms.[148] Thus, although the pro forma agreement resolves many of the

137. *E.g.*, *California Indep. Sys. Operator Corp.*, 142 F.E.R.C. ¶ 61,248 at P 4 (stating that "in addition to the resource adequacy program, CPUC conducts a biennial long-term procurement planning process that determines the California investor-owned utilities' procurement needs for the next ten years, including contracting for energy and constructing new generation").

138. CAL. INDEP. SYS. OPERATOR CORP., FIFTH REPLACEMENT FERC ELECTRIC TARIFF § 43 (2013) [hereinafter CAISO TARIFF].

139. *Id.* § 41.

140. 142 F.E.R.C. ¶ 61,248 at P 68.

141. *California Indep. Sys. Operator Corp.*, 134 F.E.R.C. ¶ 61,211 at P 4 (2011).

142. *Id.*

143. 142 F.E.R.C. ¶ 61,248 at P 5; CAISO TARIFF, *supra* note 138, § 43.2.6.

144. *E.g.*, *AES Huntington Beach, L.L.C.*, 142 F.E.R.C. ¶ 61,017 at PP 2-3, 5-6, 16 (2012).

145. CAISO TARIFF, *supra* note 138, § 41.2.

146. *Id.* § 40.3.1.

147. *Id.* § 41.3-.4 & sched. G; *see also*, *California Indep. Sys. Operator Corp.*, 87 F.E.R.C. ¶ 61,250 (1999) (approving a settlement that resulted in the pro forma RMR agreement).

148. CAISO TARIFF, *supra* note 138, § 41.3; *see also* CAL. INDEP. SYS. OPERATOR CORP., BUSINESS PRACTICE MANUAL FOR RELIABILITY REQUIREMENTS § 7.3.2 (version 15 2012), *available at* http://bpmcm.caiso.com/BPM%20Document%20Library/Reliability%20Requirements/BPM_for_Reliability_Requirements_V15_redline.pdf.

outstanding issues associated with entering into such contracts, the parties must still tailor the agreements to the individual circumstances.[149]

An example of CAISO's process for addressing an RMR may be found in *CalPeak Power, LLC*, where CalPeak Power (CalPeak) filed an unexecuted RMR agreement between CalPeak and CAISO with the FERC.[150] CAISO had identified CalPeak's generation facility, consisting of simple cycle natural gas-fueled combustion turbines totaling a nominal electric capacity of forty-nine MW, during its annual Local Area Reliability Services process as a resource that was required to meet system reliability.[151] The FERC determined that "CAISO conducts the Local Area Reliability Service analysis on an annual basis to determine which resources CAISO requires to ensure that local areas meet their reliability criteria."[152] CalPeak bid during CAISO's 2004 Local Area Reliability Service process to provide RMR services for the year 2004.[153] The Commission accepted the RMR agreement, in part, based upon determining that under the terms of the RMR agreement, CAISO could not dispatch the RMR units if doing so would breach an existing contract, which in this instance included an obligation under a power purchase agreement to provide 2500 hours of service to a third-party.[154]

In another instance, CAISO filed a waiver request with the Commission in January of 2012

> as a last resort, to protect against the retirement of Sutter Energy Center (Sutter), a flexible resource that CAISO determined would be needed in the 2017-2018 timeframe because of the [anticipated] retirement of once-through-cooling [generating] resources. . . . [U]nder the direction of the CPUC, [California's] investor-owned utilities were able to reach a resource adequacy agreement with Sutter for the remainder of 2012, and the waiver request was withdrawn.[155]

The RMR process in CAISO does not guarantee that the resource that is needed for system reliability will enter into an RMR agreement. CAISO attempted to address the need to have certain units available for system reliability by creating a new mechanism for financial support.[156] On December 12, 2012, CAISO filed tariff revisions "to implement an interim flexible capacity and local reliability resource retention (FLRR) mechanism to offer financial support to resources that are uneconomic or at risk of retirement but are determined to be needed for flexible capacity and local reliability in the next two-to-five year forward period."[157] In rejecting the proposed FLRR mechanism, the FERC noted that it believed "that the most effective course of

149. *E.g.*, *AES Huntington Beach*, 142 F.E.R.C. ¶ 61,017 at PP 1, 7-10 (approving an RMR agreement to operate AES Huntington Beach Units 3 and 4).

150. *CalPeak Power, LLC*, 107 F.E.R.C. ¶ 61,026 (2004).

151. Motion to Intervene & Comments of the Cal. Indep. Sys. Operator Corp. at 1-2, 107 F.E.R.C. ¶ 61,026 (FERC Docket ER04-517-000) (filed Feb. 20, 2004).

152. 107 F.E.R.C. ¶ 61,026 at P 3 n.3 (2004).

153. *Id.* at P 3.

154. *Id.* at PP 5, 9-10.

155. *California Indep. Sys. Operator Corp.*, 142 F.E.R.C. ¶ 61,248 at P 6 (2013); Petition for Waiver of Tariff Provisions & Request for Confidential Treatment at 1-2, *California Indep. Sys. Operator Corp.*, 139 F.E.R.C. ¶ 61,072 (FERC Docket No. ER12-897-000) (filed Jan. 25, 2012).

156. 142 F.E.R.C. ¶ 61,248.

157. *Id.* at P 1; Flexible Capacity & Local Reliability Res. Retention Proposal, 142 F.E.R.C. ¶ 61,248 (FERC Docket No. ER13-550-000) (filed Dec. 12, 2012).

action would be for CAISO and its stakeholders to focus on the development of a durable, market-based mechanism to provide incentives to ensure that the reliability needs are met."[158]

The CPUC has engaged with stakeholders to review an initiative to adopt a flexible capacity procurement obligation for jurisdictional load serving entities in an effort to ensure that sufficient flexible capacity is maintained on the system and operationally available for system reliability.[159] In response, CAISO commenced a stakeholder initiative to establish flexible resource adequacy criteria and must-offer obligations.[160] Both efforts are focused on assisting in the development of flexible capacity resources in California to quickly respond to variable renewable resources in the state.[161]

D. ERCOT

In ERCOT, a generation resource must provide ERCOT with at least ninety days advance notice of an intent to suspend operations, as follows:

> Except for the occurrence of a Forced Outage, a Resource Entity must notify ERCOT in writing no less than [ninety] days prior to the date on which the Resource Entity intends to cease or suspend operation of a Generation Resource for a period of greater than 180 days . . . [by submitting] a completed Part I and Part II of the Notification of Suspension of Operations (found in Section 22, Attachment E, Notification of Suspension of Operations). The Resource Entity may also complete Part III of the Notification and submit it along with Parts I and II, or may wait to submit Part III until ERCOT makes an initial determination of the need for the Generation Resource as an RMR Unit. The Part I Notification must include the attestation of an officer of the Resource Entity that the Generation Resource is uneconomic to remain in service . . . and will be unavailable for Dispatch by ERCOT for a period specified in the Notification.[162]

If after ninety calendar days following ERCOT's receipt of the generation entity's notice "either ERCOT has not informed the [generation entity] that the [g]eneration [r]esource is not needed for ERCOT [s]ystem reliability or both parties have not signed an RMR [a]greement for the [g]eneration [r]esource, then the [generation entity] may file a complaint" with the commission against ERCOT, pursuant to section 25.502 of the Texas Administrative Code.[163]

ERCOT deploys RMR units to (1) solve local reliability constraints, (2) provide voltage support, and (3) acquire additional system capacity under special conditions (such as possibly using a currently undefined type of Load

158. 142 F.E.R.C. ¶ 61,248 at P 2.

159. Cal. Pub. Utils. Comm'n, Presentation at CPUC Public Agenda 3316 (June 27, 2013), *available at* http://www.cpuc.ca.gov/NR/rdonlyres/388AA4D6-DAA6-4945-AB44-88BB2F97833D/0/130627_pptagenda.pdf (proposing to adopt local procurement obligations for 2014 and a flexible capacity framework and to further refine the resource adequacy program in Rulemaking 11-10-023).

160. CAL. ISO, 2012 STAKEHOLDER INITIATIVES CATALOG § 8.1 (2012), *available at* http://www.caiso.com/Documents/2012_StakeholderInitiativesCatalog.pdf (updated as of Dec. 4, 2012).

161. *Id.* § 8.

162. ELEC. RELIABILITY COUNCIL OF TEX., ERCOT NODAL PROTOCOLS § 3.14.1.1(1)-(2) (2013) [hereinafter ERCOT NODAL PROTOCOLS], *available at* http://www.ercot.com/mktrules/nprotocols/current (current version as of Sept. 27, 2013).

163. *Id.* § 3.14.1.2(7) (referencing 16 TEX. ADMIN. CODE § 25.502(e)(1) (2013)).

Resource).[164] ERCOT's Protocols specify that RMR agreements are contracts with the resource entities for both capacity and energy from generation resources "that otherwise would not operate and that are necessary to provide voltage support, stability, or management of localized transmission constraints under applicable reliability criteria, where market solutions do not exist."[165] The ERCOT protocols specify the type of costs that are recoverable under an RMR agreement and also specify what costs are not recoverable.[166] In exchange for entering into an RMR agreement, a generation resource is reimbursed for the actual eligible costs of operation plus a ten percent incentive factor; however, the incentive factor excludes fuel costs.[167]

Two possible paths lead to the designation of an RMR unit in ERCOT. Either ERCOT performs an analysis of the needs for system capacity or the resource submits a Notice of Suspension Form.[168] In response to either event, ERCOT may request the owner of a potential RMR unit to submit estimated costs to run the units.[169] ERCOT then evaluates the costs and system reliability needs and makes a final procurement assessment.[170]

ERCOT's tariff allows the recovery of specific RMR unit costs, such as labor and services, materials and supplies, maintenance, fuel, property taxes, and all variable costs.[171] However, not all costs incurred by a generation resource are eligible for recovery, and those include depreciation expenses, return on equity, fixed property taxes, income taxes of the property owner, labor costs that are not associated with the operation of the RMR unit, and any costs the RMR owner "would have incurred even if the unit had been mothballed or shutdown."[172]

> ERCOT may execute RMR [a]greements for no less than one month and no more than one year, with one exception. ERCOT may execute an RMR [a]greement for a term longer than [twelve] months if [in ERCOT's opinion] the Resource Entity must make a significant capital expenditure to meet environmental regulations or to ensure availability to continue operating the RMR Unit[, to justify] an RMR agreement in excess of [twelve] months . . . . The term of a multi-year RMR [a]greement must take into account the appropriate RMR exit strategy discussed in section 3.14.1.4, Exit Strategy from an RMR agreement. In the event ERCOT chooses to contract for an RMR Unit for longer than one year, ERCOT shall annually re-evaluate the need for the RMR Unit . . . .[173]

ERCOT will enter into settlement true-ups with an RMR Unit. "Actual Eligible Costs incurred by the RMR Unit will be used for subsequent Final, Resettlement, or True-Up Settlements as agreed upon in [s]ection 6.6.6, Reliability Must-Run Settlement."[174]

164. *Id.* § 3.14.1.
165. *Id.* § 3.14.1(1); *see also id.* § 22 attachment B (providing the ERCOT pro forma RMR agreement).
166. *Id.* § 3.14.1.10 (listing examples of eligible costs).
167. *Id.* § 3.14.1.13.
168. *Id.* § 3.14.1(a), (f).
169. *Id.* § 3.14.1.11(1).
170. *Id.*
171. *Id.* § 3.14.1.10.
172. *Id.*
173. *Id.* § 3.14.1(1)(e).
174. *Id.* § 3.14.1.11.

E. NYISO

The New York Public Service Commission (NYPSC) asserts jurisdiction over generation retirements within NYISO.[175] The NYPSC requires owners of wholesale generators equal to or greater than eighty MW to provide the NYPSC, NYISO, and affected transmission owners with 180 days' notice before the generator can be retired or mothballed.[176] The NYPSC defined "retirements" to collectively include, among other things, "mothballing, and other circumstances where a generating unit is taken out of service for a substantial period of time, excluding scheduled maintenance and forced outages."[177]

Although the NYPSC requires generators to provide notice prior to retirement and may request that NYISO and the generator perform a system reliability study, the generators bear the burden of filing both before the FERC and before the NYPSC.[178] The generator may file a term sheet for a Reliability Support Services agreement of all reasonably incurred costs and may request a reasonable return on its investment.[179] For example, in the matter of the Cayuga generating station, Cayuga notified the NYPSC of its intent to mothball the generating facility.[180] In response, the NYPSC ordered NYISO and the New York State Electric & Gas Corporation (NYSEG) to conduct a study of the system reliability impacts.[181] The facility was determined to be necessary to maintain system reliability as a result of that study.[182] The NYPSC was asked by NYSEG to review an unexecuted term sheet for Cayuga, and Cayuga filed an RMR tariff with the FERC.[183] Cayuga requested a two-part cost of service rate consisting of a monthly fixed charge and a variable mechanism to recover "fuel, emissions, and other variable expenses."[184] Interestingly, Cayuga stated in its section 205 filing that if the NYPSC accepts the term sheet for a Reliability Support Services agreement between NYSEG and Cayuga, then Cayuga would withdraw the FERC filing.[185]

175. *E.g.*, Order Instituting Proceeding & Notice Soliciting Comments at 4, Proceeding on Motion of the Comm'n to Establish Policies and Procedures Regarding Generation Unit Rets., Case No. 05-E-0889 (N.Y. Pub. Serv. Comm'n July 27, 2005) (wherein the NYPSC asserted jurisdiction over wholesale generation retirements by drawing parallels to the traditional state jurisdictional issues of abandonment of service and the transfer of utility property).

176. Order Adopting Notice Requirements for Generation Unit Rets. at 15-16, Case No. 05-E-0889 (N.Y. Pub. Serv. Comm'n Dec. 20, 2005).

177. *Id.* at 1 n.1.

178. *Id.* at 7-8.

179. Cost-of-Service Agreement at 4, *Cayuga Operating Co.*, FERC Docket No. ER13-405-000 (Nov. 16, 2012).

180. *Id.* at 2-3.

181. *Id.* at 3.

182. *Id.*

183. *Id.* at 3-4.

184. *Id.* at 8.

185. *Id*. at 4.

VI. HOW MISO'S SSR PROVISIONS OPERATE

Unlike the other RTO/ISOs discussed in Section V herein, MISO has tariff authority to file an out-of-market contract with a generation resource[186] or Synchronous Condenser Unit (SCU) at the FERC for approval if MISO determines that that generation resource or SCU is required for system reliability.[187] It is worth noting that the Commission determined that such contracts (SSR agreements) are to be used only in exceptional situations as a "last resort" to preserve system reliability.[188]

A. Overview of MISO's SSR Process

A recent FERC order succinctly described how the SSR provisions in section 38.2.7 of the MISO tariff operate:

> [M]arket participants that have decided to retire or suspend a generation resource or SCU must submit a notice (Attachment Y [n]otice), pursuant to Attachment Y (Notification of Potential Resource/SCU Change of Status) of the MISO Tariff at least [twenty-six] weeks prior to the resource's retirement or suspension effective date. During this [twenty-six]-week notice period, MISO will conduct a study (Attachment Y Study) to determine whether all or a portion of the resource's capacity is necessary to maintain system reliability, such that SSR status is justified. If so, MISO and the market participant shall enter into an SSR agreement, as provided in Attachment Y-1 (Standard Form SSR agreement) of the MISO Tariff, to ensure that the resource continues to operate, as needed.[189]

The order required MISO to "(1) submit all SSR [a]greements for Commission review; (2) provide a description of alternatives that were evaluated; (3) discuss the estimated earliest termination date for the SSR [a]greement; and (4) explain how MISO would ensure grid reliability once the resource retires."[190]

As of the publication of this article, MISO has only filed six[191] SSR agreements with the FERC; although, over 100 market participants have submitted Attachment Y notices to MISO during the prior eight years.[192] These statistics demonstrate that the retirement of most generation resources in the MISO region normally does not involve SSR contracts. The statistics also confirm that "SSR agreements are used only as a limited, last-resort measure" where MISO's system reliability is threatened.[193] Even though the retirement or suspension of a generation resource might have contributed to increased

186. Capitalized terms not otherwise defined in Section VI have the meanings ascribed thereto in section 1 of the MISO Tariff. MISO TARIFF, *supra* note 111, § 1.

187. *Escanaba* Order, *supra* note 16, at PP 3, 7.

188. *Id.* at P 6.

189. *Id.* at P 3.

190. *Id*.

191. *Midwest Indep. Transmission Sys. Operator, Inc.*, FERC Docket Nos. ER13-37, ER13-38 (Escanaba agreements); *Midwest Indep. Transmission Sys. Operator, Inc.*, FERC Docket Nos. ER13-1225, ER13-1226 (Harbor Beach SSR agreements); *Midcontinent Indep. Sys. Operator, Inc.*, FERC Docket Nos. ER13-1962, ER13-1963 (Edwards agreements); *Midwest Indep. Transmission Sys. Operator, Inc.*, FERC Docket Nos. ER14-109, ER14-111 (Gaylord agreements); *Midwest Indep. Transmission Sys. Operator, Inc.*, FERC Docket Nos. ER14-112, ER14-113 (Straits agreements); *Midwest Indep. Transmission Sys. Operator, Inc.*, FERC Docket Nos. ER14-292, ER14-294 (Coleman agreements).

192. Filing to Enhance Sys. Support Res. Provisions at 2, *Midwest Indep. Transmission Sys. Operator, Inc.*, FERC Docket No. ER12-2302-000 (July 25, 2012).

193. *Escanaba* Order, *supra* note 16, at P 6.

congestion costs or led to higher prices for energy and ancillary services, almost all market participants historically have been able to retire or suspend generation resource operations without further actions by MISO.[194]

To date, the Commission has not been requested to determine whether MISO has the required tariff authority to mandate that a generation resource or SCU (that has notified MISO of its intent to retire or suspend operations for more than two months) remain in operation if the generation resource or SCU does not believe that the compensation in the SSR agreement that MISO files at the FERC is just and reasonable to compensate the resource for remaining available to support system reliability. The Commission, however, has approved tariff language stating, in part, that "[MISO] will file an SSR [a]greement with the Commission for approval if the Transmission Provider's analysis determines that the [g]eneration [r]esource or SCU is required for reliability of the Transmission System."[195] Therefore, MISO appears to have the requisite tariff authority to require a generation resource or SCU to remain in operation to preserve system reliability, subject to FERC approval of a submitted SSR agreement.

The unique authority in MISO's tariff appears to partly reflect the history of the MISO energy markets. The Commission order approving MISO's original SSR tariff provisions emphasized that the prescriptive tariff language was a just and reasonable "backstop measure to assure reliability in the markets to be operated by [MISO]" as part of MISO's initial implementation of an energy market.[196] Moreover, the Commission stated in the initial order that the SSR tariff provisions "will be used primarily for reactive power."[197]

B. Submission of Attachment Y Notice to MISO

MISO's tariff requires that a generation resource provide at least twenty-six weeks of advance notice of retirement or suspension to MISO by submitting an Attachment Y [n]otice,[198] the longest advance notice tariff provision of any RTO/ISO.[199] This requirement only applies, however, to generation resources that have been designated to serve load within the MISO region.[200] If a generation resource within the MISO region serves load outside of the region, then section 38.2.7 of the MISO tariff does not require that the generation resource provide MISO with notice prior to retirement of such facility.[201] However, if a generation resource that is located inside or outside of the MISO region is serving load that is located within the MISO region, then section 38.2.7 of the MISO tariff requires that the owner or operator of such facility provide

194. *Midwest Indep. Transmission Sys. Operator, Inc*., 140 F.E.R.C. ¶ 61,237 at P 5 (2012) (final SSR order pending rehearing).

195. MISO TARIFF, *supra* note 111, § 38.2.7.e.

196. *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,163 at P 370 (2004).

197. *Id.* at P 368.

198. MISO TARIFF, *supra* note 111, § 38.2.7.a.

199. *See, e.g., supra* notes 112, 162, 176 and accompanying text.

200. MISO TARIFF, *supra* note 111, § 38.2.7.

201. *Id.*

MISO with twenty-six weeks of advance notice of intent to retire or to suspend operations.[202]

The Commission has affirmed that an Attachment Y notice should only be made after careful consideration.[203] Attachment Y is a binding contract and, therefore, is only made after a market participant has made a definitive decision to retire or suspend a generation resource or SCU, as attested to by a corporate officer.[204] The rationale for requiring the sworn oath of the officer of a market participant is to distinguish such "definitive decisions" from mere inquiries by market participants as to whether a particular generation resource would be required for system reliability.[205] Section 38.2.7.a also provides that an Attachment Y notice is confidential information that MISO is not permitted to disclose to third parties without the consent of the owner or operator that submitted the notice.[206]

The formality of Attachment Y notices provides MISO with a degree of certainty that a study which it conducts regarding potential impacts to system reliability from the loss of a specific generation resource will be a worthwhile endeavor.[207] Because such studies are conducted as part of MISO's Schedule 10 cost recovery mechanism, all LSEs within MISO participate in sharing the costs of such SSR studies.[208]

C. Analysis of System Reliability Impacts

In situations where a market participant submits an Attachment Y notice of intent to retire or suspend a generation resource, MISO will conduct a technical review to determine whether the specified generation resource is required for system reliability.[209] This analysis looks at the probabilistic effects on system reliability if the specified generation resource is not available to provide energy and/or ancillary services, particularly during peak load conditions, in order to

202. *Id.* MISO's tariff also requires all generation resources to provide notice to MISO of planned outages of generation facilities due to maintenance or fuel supply issues. *Id.* § 38.2.5.g.

203. Section 38.2.7.a of the MISO tariff provides, in part, that

> [a] [m]arket [p]articipant certifies by submitting an Attachment Y [n]otice that such [m]arket [p]articipant has made a definitive decision to [r]etire or [s]uspend a [g]eneration [r]esource or SCU and the Attachment Y [n]otice shall be executed by an officer of the owner or operator of the [g]eneration [r]esource or SCU attesting to the facts supporting that claim, who has the legal authority to bind such [m]arket [p]articipant. The decision to [r]etire must be definitive at the time of submittal of the Attachment Y [n]otice, and remain so, unless modified by a rescission prior to receiving Attachment Y [r]eliability [s]tudy results from [MISO], except as otherwise provided herein.

Id. § 38.2.7.a.

A definitive decision to retire must remain so unless modified by a rescission meeting certain conditions prior to receiving Attachment Y Reliability Study results from the Transmission Provider. *Id.*

204. *Id.*

205. *Midwest Indep. Transmission Sys. Operator, Inc.*, 140 F.E.R.C. ¶ 61,237 at P 53 (2012).

206. MISO TARIFF, *supra* note 111, § 38.2.7.a.

207. 140 F.E.R.C. ¶ 61,237 at P 53.

208. Compliance Filing at 25, *Midwest Indep. Transmission Sys. Operator, Inc.*, FERC Docket No. ER12-2302-000 (Dec. 18, 2012); *see also* MISO TARIFF, *supra* note 111, sched. 10.

209. MISO TARIFF, *supra* note 111, § 38.2.7.c.

evaluate whether MISO's system reliability might be violated.[210] The system reliability study is not an analysis of how the absence of the generation resource might impact MISO's energy or ancillary services prices.[211] An Attachment Y notice will remain confidential information if MISO determines that the generation resource is not required for system reliability.[212]

MISO's tariff provides procedures for releasing the results of an Attachment Y analysis if MISO determines that the generation resource is required for system reliability.[213] MISO is required to "notify the [m]arket [p]articipant prior to publicizing the Attachment Y [n]otice and Attachment Y [r]eliability [s]tudy results that the Attachment Y [r]eliability [s]tudy is complete."[214] MISO, however, is prohibited from providing any information related to the Attachment Y reliability study results to the market participant at that time.[215]

If the owner or operator of a generation resource does not exercise its right of rescission, then MISO identifies the generation resource and posts on MISO's Open Access Same-Time Information System (OASIS) the fact that the generation resource is required for system reliability.[216] MISO then initiates negotiations with the market participant to develop an SSR agreement to compensate the SSR Unit for remaining in operation after the proposed date of retirement or suspension.[217] Additionally, and as discussed *infra* in Section VI.F, in some instances, an owner or operator of a generation resource that MISO has determined is required for system reliability may wish to rescind its Attachment Y notice and continue to operate.[218]

D. Negotiation of the Terms of an SSR Agreement

The FERC has concluded that the terms and conditions of an SSR agreement are to be negotiated between MISO and the owner or operator of a generation resource that submits an Attachment Y; such terms and conditions are not necessarily strictly limited to recovery of the generation resource's operating costs.[219] Instead, the FERC has held that MISO can use a "negotiated approach" to determining SSR Unit compensation.[220] In order to conduct such negotiations, MISO begins by obtaining relevant cost data from the owner or operator of a generation resource.[221] MISO requests, for example, information to enable MISO to determine the monthly operations and maintenance (O&M) payments

210. MIDCONTINENT INDEP. SYS. OPERATOR, INC., MANUAL NO. 020, BUSINESS PRACTICES MANUAL: TRANSMISSION PLANNING § 6.2 (Jan. 17, 2013).

211. MISO TARIFF, *supra* note 111, § 38.2.7.c.

212. *Id.* § 38.2.7.a.

213. *Id.*

214. *Id.*

215. *Id.*

216. *Id.*

217. *Id.* § 38.2.7.h(i).

218. *Id.* § 38.2.7.a.

219. *Midwest Indep. Transmission Sys. Operator, Inc.*, 140 F.E.R.C. ¶ 61,237 at PP 3-4 (2012).

220. *Id.* at PP 139-40.

221. MISO TARIFF, *supra* note 111, § 38.2.7.

that are required to make the generation resource "break even."[222] This information enables MISO to determine the $/MWh at which the generation resource will be dispatched, so that if locational marginal prices are higher than that value, the difference will be "credited" to the LSEs that must pay the monthly O&M payment under an SSR agreement.[223]

MISO also negotiates with the market participant to address various SSR agreement issues, including, but not limited to the term of agreement (no more than one year, but it can be re-filed) and compensation for going-forward costs.[224] Compensation (including a "true-up" mechanism based upon actual energy, regulation, and capacity payments received by an SSR Unit) is specified in Exhibit 2 to an SSR agreement.[225] Section 38.2.7.i.ii of the MISO tariff limits the compensation that MISO may include in the SSR agreement, as follows:

> The SSR [a]greement will provide compensation only for going forward costs (i.e., the costs that will be incurred by an SSR Unit owner or operator to remain in-service that are in excess of the costs the SSR Unit would have incurred had it been retired or suspended). The Transmission Provider will evaluate, at a minimum, the following factors in negotiating compensation for an SSR Unit: (a) fixed and variable operating and maintenance costs to existing equipment; (b) applicable state, federal, local or property taxes; (c) non-capital costs of any environmental waivers, allowances, and/or exemptions that are obtained by the SSR Unit and not otherwise recoverable by the SSR Unit owner or operator; and (d) capital costs associated with continued operation, including reasonable and prudent costs to comply with environmental regulations or local operating permit requirements, subject to the provisions of [s]ection 38.2.7.d.iii.(3). Any compensation to the SSR Unit will be reduced by payments under Schedule 2 of this Tariff, payments under resource adequacy programs, infra-marginal rents from Energy and Operating Reserve Market transactions, and any other compensation paid under the market or via other contractual arrangements.[226]

One issue that MISO has negotiated with market participants concerns appropriate compensation for unanticipated repairs to an SSR Unit.[227] In paragraph 50 of the *Escanaba* Order, the FERC reviewed proposed SSR agreement language regarding compensation for unanticipated repairs.[228] The provision contained a mechanism for the SSR Unit to receive cost recovery for unanticipated repairs that were required to maintain the SSR Unit.[229] Section 9.G of the proposed SSR agreement would have "provide[d] MISO with the ability to terminate the SSR [a]greement rather than fund the unanticipated repairs, and [would have required] MISO to make [a Federal Power Act] section 205 filing before any such costs could be incurred, except in the case of emergency repairs."[230]

The FERC agreed with the protestors:

> [S]ection 9.G of the SSR [a]greement, which would give MISO sole discretion to determine whether it will fund unanticipated repairs to the SSR Units or that it will

222. *E.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 144 F.E.R.C. ¶ 61,151 at P 21 (2013).

223. *E.g.*, *id.*

224. *Id.* Attachment Y-1 §§ 3, 7.

225. *Id.* Attachment Y-1 § 9.D; *id.* Attachment Y-1 exhibit 2; *id.* sched. 10 § III.

226. *Id.* § 38.2.7.i(ii).

227. *E.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 142 F.E.R.C. ¶ 61,170 at P 50 (2013).

228. *Id.*

229. *Id.*

230. *Id.*

> not fund such upgrades and will terminate the agreement, is inconsistent with the need to have the SSR Units available for reliability purposes. In both the TEMT II Orders and the SSR Order, the Commission found that the owner of SSR Units must be fully compensated for reasonably and prudently incurred costs that are necessary to ensure continued availability. We anticipate that these repairs would usually be routine and ordinary; however, this does not preclude unanticipated repairs or significant repairs from being reasonable and prudent in certain cases in order to maintain availability. Therefore, we direct MISO to revise section 9.G, within [sixty] days of this order, to eliminate the language allowing MISO to unilaterally determine whether or not it will fund unanticipated repairs to the SSR Units or to terminate the SSR [a]greement if the unanticipated repairs are of such a scope that they would preclude the SSR Units from fulfilling their contractual obligations.[231]

Although MISO sought rehearing regarding this issue on April 3, 2013, MISO submitted a compliance filing on May 3, 2013 which "eliminate[d] the language allowing MISO to unilaterally determine whether or not it will fund unanticipated repairs to the SSR Units or to terminate the SSR agreement if the unanticipated repairs are of such a scope that they would preclude the SSR Units from fulfilling their contractual obligations."[232]

E. Consideration of Alternatives to SSR Agreements

Simultaneously with the process of negotiating an SSR agreement, MISO commences discussions with its stakeholders regarding available alternates to entering into an SSR agreement.[233] These discussions include bringing issues regarding the planned retirement or suspension into MISO's regional transmission expansion planning process under Attachment FF of the MISO tariff.[234] Stakeholders have the opportunity to discuss and propose alternatives to MISO entering into an initial one-year SSR agreement with the owner or operator of the generation resource.[235] MISO considers stakeholder suggestions in determining the continued need for an SSR agreement with the generation resource, as well as the planned duration of an SSR agreement.[236]

Proposed alternatives to an SSR agreement could include (1) planned or proposed network upgrades to bring energy from other locations to the Commercial Pricing Node (CPNode) where the generation resource is located; (2) planned alternate generation (frequently natural gas-fueled facilities due to the shorter construction lead time); and/or (3) planned demand response alternatives to reduce demand at the CPNode so that the generation resource is not required.

In an order approving MISO's revised SSR tariff provisions, the Commission determined that SSR Units should seek to comply with

231. *Id.* at P 55 (citations omitted).

232. *Midwest Indep. Transmission Sys. Operator, Inc.*, 144 F.E.R.C. ¶ 61,128 at PP 1-2, 19-20 (2013) (granting rehearing and conditionally accepting the amended compliance filing).

233. MISO TARIFF, *supra* note 111, attachment FF.

234. *Id.* attachment FF §§ I.A.1.a.vi, I.A.1.b, I.A.2.

235. MISO TARIFF, *supra* note 111, § 38.2.7.c.

236. *Id.* § 38.2.7.c, .l.

environmental regulations in a manner that minimizes the costs that would be allocated to LSEs.[237] The Commission required MISO to include

> [t]ariff revisions to ensure that: (1) all potential SSR alternatives have been examined and the SSR is the last-resort measure to address the underlying reliability issue(s); (2) SSRs are able to fully recover the capital costs associated with their continued operation, including reasonable and prudent costs to comply with environmental regulations or local operating permit requirements; and (3) address the treatment of SSRs that later return to service, including to implement a refund provision that requires SSRs that later return to service to refund with interest all costs, less depreciation, of repairs or capital expenditures needed to meet the applicable environmental regulations."[238]

MISO was also required to "include revisions . . . to ensure that SSRs can recover fixed and variable operating and maintenance costs to both new and existing equipment."[239]

The MISO tariff provides that SSR costs will only include "non-capital" costs "of any environmental waivers, allowances, and/or exemptions that are obtained by the SSR Unit and not otherwise recoverable by the SSR Unit owner or operator."[240]

In addition, MISO clarified in its compliance filing with the SSR order that the SSR process is not intended to "upgrade" a generation resource so that it will be economic to operate and comply with MATS standards.[241] "The market participant that owns or operates the generation resource or SCU subject to review under this section" shall make good faith efforts to minimize the costs to be incurred by seeking any available waivers or exemptions from environmental regulatory requirements that would necessitate improvements to the potential SSR Unit.[242] "[MISO] will reasonably assist the owner or operator of a potential SSR Unit in working with regulatory agencies to obtain environmental waivers or exemptions to the extent necessary to maintain the reliability of the Transmission System."[243]

F. Revocation of Attachment Y Notices of Retirement or Suspension

The foundation principle of the SSR process is that a generation resource has made a definitive decision to retire or suspend operation of a specific electricity generation resource.[244] This decision is fundamentally different from a generation resource request for MISO to conduct a "study" to determine whether a facility is required for system reliability.[245]

237. *Midwest Indep. Transmission Sys. Operator, Inc.*, 140 F.E.R.C. ¶ 61,237 at P 138 (2012).

238. *Id.* (citations omitted).

239. *Id.* at P 138 n.198.

240. MISO TARIFF, *supra* note 111, § 38.2.7.i.ii.

241. Compliance Filing & Proposed Tariff Revisions at 15, *Midwest Indep. Transmission Sys. Operator, Inc. System Support Resources*, FERC Docket No. ER12-2302-000 (Dec. 18, 2012).

242. MISO TARIFF, *supra* note 111, § 38.2.7.c.

243. *Id*.

244. *E.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 140 F.E.R.C. ¶ 61,237 at P 33.

245. *Id.* at PP 65-66. See also section 38.2.7.n of MISO's tariff, which expressly provides an opportunity for an owner or operator of a generation resource to request the MISO conduct a "study" of the system reliability need for the generation resource. MISO TARIFF, *supra* note 111, § 38.2.7.n. This study would not be binding unless the market participant elected to submit a formal Attachment Y notice, *id.* § 38.2.7.a, .n; however, the study would provide the market participant with a good indication of whether a particular

Because an Attachment Y notice is considered definitive, the tariff establishes specific provisions to address situations where the owner or operator of a facility "changes its mind" with regard to retirement or suspension.[246] Section 38.2.7.d clarifies the processes and timelines associated with modification of an Attachment Y notice, allowing rescission either (1) before receiving the results of the Attachment Y reliability study; (2) after receiving the results, but prior to commencing suspension, retirement, or starting operation under an SSR agreement; and (3) after commencing suspension, retirement, or starting operation pursuant to an SSR agreement.[247]

Section 38.2.7.d.i addresses situations where a generation resource rescinds its Attachment Y notice prior to MISO publicizing the Attachment Y notice.[248] This section requires that MISO notify the generation resource that the Attachment Y reliability study is complete; however, MISO "shall not provide any information related to the Attachment Y [r]eliability [s]tudy results to the [generation resource] at that time."[249] The generation resource

> may rescind its Attachment Y [n]otice by notifying [MISO] of such rescission via electronic communication and certified mail not more than five (5) [b]usiness [d]ays after receiving notice from [MISO] that the Attachment Y [r]eliability [s]tudy is complete, in which case the confidentiality of the Attachment Y [n]otice shall be preserved. If a [generation resource] rescinds an Attachment Y [n]otice, then such [generation resource] shall not receive the results of the Attachment Y [r]eliability [s]tudy, and such [generation resource] shall pay [MISO] 100% of the costs that [MISO] has incurred in conducting an Attachment Y [r]eliability [s]tudy up until the date of such rescission.[250]

Section 38.2.7.d.ii also addresses situations where a generation resource rescinds its Attachment Y notice after MISO has posted on OASIS that a generation resource or SCU is required for the reliability of the transmission system but before MISO has entered into an SSR agreement with the resource.[251] In such situations,

> the owner or operator of such facility may modify the effective date of a definitive decision to [r]etire or [s]uspend if: (1) [MISO] has determined that demand response, generation, or transmission expansion alternatives are required; and (2) the owner or operator of the [g]eneration [r]esource or SCU agrees in writing with [MISO] to continue to operate the facility without entering into an SSR [a]greement until the alternative(s) have been implemented to maintain the reliability of the Transmission System by either submitting an amended Attachment Y [n]otice with a modified effective date, or by submitting a written rescission of its Attachment Y [n]otice.[252]

generation resource would be required for system reliability, *id.* § 38.2.7.n. In such instances, the costs of the system study are borne solely by the owner or operator of a generation resource that requested such a study, and the Attachment Y-2 is treated as confidential information. *Id.* MISO is required to "use reasonable efforts to submit the results of such study to the [m]arket [p]articipant upon its completion within [seventy-five] days of receipt of the deposit and completed Attachment Y-2, unless an alternative period is mutually agreed to." *Id.*

246. *Id.* § 38.2.7.d.

247. *Id.* § 38.2.7.d.

248. *Id.* § 38.2.7.d.i.

249. *Id.*

250. *Id.*

251. *Id.* § 38.2.7.d.ii.

252. *Id.*

Finally, section 38.2.7.d.iii addresses situations where a generation resource rescinds its Attachment Y notice after commencing a retirement, suspension, or entering into an SSR agreement.[253]

> An owner or operator of a [g]eneration [r]esource or SCU that notifies [MISO] in writing of a definitive decision to [s]uspend, and for which the resource has not been designated an SSR Unit, may modify its decision to [s]uspend by notifying [MISO] of the intention to do so. [However, an] owner or operator of a [g]eneration [r]esource or SCU that notifies [MISO] in writing of a definitive decision to [r]etire, and for which the [r]esource has not been designated an SSR Unit, may modify its decision to [r]etire by re-entering the generator interconnection queue. Cost responsibility for any [n]etwork [u]pgrades to enable the new interconnection shall be determined as provided in Attachment X of the tariff.[254]

As discussed above, the tariff allows an owner or operator of an SSR Unit to rescind its decision to suspend or to retire.[255] MISO has proposed a provision requiring that to the extent that repairs or capital expenditures were needed in order to satisfy environmental regulations, the owner or operator must refund to MISO with interest all such costs, less depreciation, when the SSR agreement is terminated and the SSR Unit returns to service.[256] However, as of this printing, the FERC has not issued a response to these proposed changes.

Further, where network upgrades were necessitated solely by the Attachment Y notice to retire, the owner or operator of the SSR Unit that rescinded its decision to retire may bear responsibility for the incurred and committed costs of such network upgrades.[257] The estimated costs of such network upgrades are included in MISO's Transmission Expansion Plan (MTEP) when the network upgrade is approved by the MISO Board of Directors.[258] However, if the network upgrades are "to address [t]ransmission issues other than the [r]etirement of the SSR Unit," then the owner or operator of the SSR Unit may not bear cost responsibility.[259] Similarly, where multiple parties bear a share of the cost responsibility, MISO's submitted Tariff proposes a pro rata allocation of the incurred or committed network upgrade costs based on the relative Generation Verification Test Capacity of each resource.[260] Thus, the SSR process is based on the premise that a generation resource has made a definitive decision to retire or suspend operation, and when such definitive decision is rescinded, the owner or operator of such generation resource may bear the cost responsibility for actions taken in an effort to preserve the reliability of the transmission system, based upon the decision to retire or suspend operation.

253. *Id.* § 38.2.7.d.iii.

254. *Id.* § 38.2.7.d.iii(1)-(2).

255. *Id.* § 38.2.7.d.

256. *Id.*; Compliance Filing & Proposed Tariff Revisions, *Midwest Indep. Transmission Sys. Operator, Inc.*, FERC Docket No. ER12-2302-000 (Dec. 18, 2012); *but see* Motion to Hold Compliance Filing in Abeyance, FERC Docket No. ER12-2302-000 (July 5, 2013).

257. MISO TARIFF, *supra* note 111, § 38.2.7.d.iii(3).

258. *Id.* attachment FF §§ II.A(1), III.A(2).

260. *Id.* § 38.2.7.d.iii(3).

260. *Id.*

VII. FILING RMR OR SSR AGREEMENTS AND RELATED INFORMATION WITH THE FERC

A. Obtaining FERC Approval for RMR/SSR Agreements

Both RMR and SSR contracts are "rates, terms and conditions of service" that an RTO/ISO must file with the Commission for its approval under section 205 of the Federal Power Act.[261] In addition, if the agreement does not address cost recovery, then the RTO/ISO must make a separate FERC filing to obtain approval to collect the out-of-market payments to the generation resource from the entities that benefit from the continued operation of the RMR or SSR Unit.[262]

MISO, for example, submits to the FERC the following information to obtain FERC approval of an SSR agreement: (1) the proposed SSR agreement with the SSR Unit,[263] which addresses all requested modifications from the approved pro forma Attachment Y-1 agreement;[264] (2) the supporting cost information affidavit;[265] and (3) the supporting SSR study report, which describes the key elements, such as an adequate evaluation of alternatives to the SSR agreement, of the report.[266]

In addition, MISO concurrently files a proposed Cost Recovery Schedule to address the cost recovery of costs associated with an SSR agreement.[267] Section 38.2.7.j of the MISO tariff provides that SSR costs will be allocated "to [the] LSE(s) which require(s) the operation of the SSR Unit for reliability purposes, and shall be specified in the SSR [a]greement," except costs of operating an SSR Unit "allocated to the footprint of the American Transmission Company shall be allocated to all [LSEs] within the footprint of the American Transmission Company on a pro rata basis."[268]

The FERC issues notices of all RMR or SSR filings so that interested parties may intervene, comment, or protest, and, as appropriate, file an answer to pleadings to assist the Commission in its decision-making.[269] Interested parties have the opportunity to contest any issue, including, but not limited to, proposed compensation for such generation resources.[270]

261. 16 U.S.C. § 824d (2012); *see, e.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 140 F.E.R.C. ¶ 61,237 at PP 10, 51 (2013).

262. 140 F.E.R.C. ¶ 61,237 at P 140 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,163 at P 372 (2004)).

263. An SSR agreement can be filed "unexecuted" if the owner or operator of an SSR Unit fails to execute, just like an unexecuted Generation Interconnection Agreement. *E.g.*, SSR Agreement, *Midcontinent Indep. Sys. Operator, Inc.*, FERC Docket No. ER13-1962-000 (July 11, 2013).

264. *E.g.*, *id.* at 1.

265. *E.g.*, Allocation of SSR Costs Associated with the Escanaba SSR Units at 2-3, *Midwest Indep. Transmission Sys. Operator, Inc.*, FERC Docket No. ER13-37-000 (Oct. 5, 2012).

266. *E.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 F.E.R.C. ¶ 61,157 at P 288 (2004).

267. MISO TARIFF, *supra* note 111, sched. 10.

268. *Id.* § 38.2.7.j.

269. *E.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 144 F.E.R.C. ¶ 61,151 at P 11 (2013); Combined Notice of Filings #1, 78 Fed. Reg. 21,353 (FERC Apr. 10, 2013).

270. *See, e.g.*, Motion for Leave to Answer & Answer of the Midcontinent Indep. Sys. Operator, Inc. at 2, *Midcontinent Independent Sys. Operator, Inc.*, FERC Docket Nos. ER13-1962-000, ER13-1963-000 (July 25, 2013); Docket Sheet: Docket ER13-1962, FED. ENERGY REGULATION COMM'N, http://elibrary.ferc.gov/idmws/docket_sheet.asp (last visited Oct. 11, 2013).

The FERC may request additional information through deficiency letters, or the FERC may issue an order regarding the RMR or SSR agreement based upon the paper record in the proceeding.[271] In addition, the Commission may set issues for settlement or litigated hearing to ensure that the RMR or SSR agreement terms are just and reasonable.[272]

VIII. RECOMMENDATIONS AND FINAL THOUGHTS

To address the concerns of generation resource retirements, RTO/ISOs have developed tools to ensure that adequate reserves of capacity remain available in order to preserve system reliability. RMR and SSR contracts are exceptions—created by system reliability concerns—to the basic principle that energy and capacity markets should be competitive and, wherever possible, should not be based upon out-of-market contracts. By their very nature, such contracts can potentially disrupt competitive market signals and, thus, can adversely impact financial planning for generation resources in a region. Accordingly, RTO/ISOs need to be mindful not to overuse RMR or SSR agreements because over-reliance on such out-of-market contracts could cause lasting harm to competitive wholesale markets by providing inequitable subsidies to certain generation resources. Contract term limits in such agreements properly allow stakeholders and regulators to review and plan for the eventual generation resource retirement while encouraging market solutions to be developed in response to an identified system reliability need.

RTO/ISOs have different tariff authority to respond to situations where generation resources that are required for system reliability provide notice that they plan to retire or suspend operations for a significant period of time. The tariff provisions contain some similar provisions, particularly with regard to the RTO/ISO's obligation to conduct a study to determine whether such generation resources will impact system reliability. Both SSR provisions and RMR provisions are also "out-of-market" solutions which the FERC has concluded are a "last resort" to preserve system reliability.[273] In both instances the terms and conditions of continued service must be submitted to and approved by the Commission as being "just and reasonable."[274]

There are also considerable differences in RTO/ISO tariff authorities. For example, under an SSR agreement provision, MISO is able to file an SSR agreement with the FERC for a generation resource to remain available until a viable alternative to the SSR agreement can be implemented.[275] In contrast, the RMR provisions that PJM and other RTO/ISOs are able to implement do not contain similar authorities to enable an RTO/ISO to file an RMR agreement with the FERC.[276]

271. *E.g.*, Deficiency Letter, *Niagara Mohawk Power Corporation*, Docket No. ER13-1182-000 (FERC June 26, 2013).

272. *E.g.*, *GenOn Power Midwest, LP*, 140 F.E.R.C. ¶ 61,080 (2012) (accepting RMR agreement subject to the parties establishing procedures for a hearing and settlement).

273. *E.g.*, *Escanaba* Order, *supra* note 16, at P 3; *California Indep. Sys. Operator Corp.*, 142 F.E.R.C. ¶ 61,248 at PP 6, 53 (2013).

274. Federal Power Act § 205, 16 U.S.C. 824d(a) (2012).

275. MISO TARIFF, *supra* note 111, § 38.2.7.d.

276. PJM TARIFF, *supra* note 15, §§ 113.2, 116-17, 119.

The Commission has stated that the type of out-of-market contract approach that the FERC will approve for an RTO/ISO should be based, in part, upon the type of resource adequacy program that the RTO/ISO has implemented. As discussed above, CAISO requested FERC approval of a set of FLRR provisions in 2012 that would permit CAISO to use out-of-market contracts to ensure the availability of generation resources that had plans to retire.[277] CAISO specifically noted in its FERC filing "that both PJM Interconnection, LLC and [MISO] have [analogous] Commission-approved retirement deferral mechanisms that permit recovery of capital investment costs."[278] Nonetheless, the Commission rejected the CAISO FLRR proposal.[279]

One of the primary reasons the FERC rejected the FLRR proposal appeared to be based upon the differences between the CAISO and the PJM and MISO resource adequacy programs.[280] The Commission emphasized, for example, that the FLRR mechanism was unjust and unreasonable for CAISO, in part, because "[t]he FLRR mechanism fails to generate transparent price signals to reach its intended outcome."[281] In the FLRR order, the Commission emphasized that "[t]he Commission has previously affirmed the need to employ market-based tools to provide transparent and effective locational price signals to ensure reliability."[282] The FERC also emphasized in the order rejecting the FLRR that CAISO should continue to work with its stakeholders to improve its resource adequacy program before the FERC would consider the out-of-market contract proposal.[283]

As coal-fueled generation resources grapple with ever tightening environmental regulations, coupled with an influx of affordable natural gas fuel, regulators should evaluate whether alternative procedures (such as those found in the RMR or SSR protocols) are appropriate to address generation retirement in order to maintain system reliability. Regulators that are inclined toward seeking the benefits of competitive wholesale markets may be encouraged by the very limited use and the limited terms of RMR and SSR contracts to avoid unnecessary interference with competitive wholesale markets. Regulators might also benefit from evaluating what is the "right" generation fuel mix for their jurisdiction, as well as the characteristics of the generation response (such as flexible capacity with the ability to quickly ramp upwards and downwards) in order to maintain system reliability.

277. *California Indep. Sys. Operator, Inc.*, 142 F.E.R.C. ¶ 61,248 (2013). The Commission's order described this concept as follows: "an interim flexible capacity and local reliability resource retention (FLRR) mechanism to offer financial support to resources that are uneconomic or at risk of retirement, but are determined to be needed for flexible capacity and local reliability in the next two-to-five year forward period." *Id.* at P 1.

278. *Id.* at P 17 n.22.

279. *Id.* at P 1.

280. *Id.* at P 64.

281. *Id.*

282. *Id.* (citing *PJM Interconnection, L.L.C.*, 115 F.E.R.C. ¶ 61,079 at P 29 (2006)).

283. 142 F.E.R.C. ¶ 61,248 at P 2 (explaining that "we believe that the most effective course of action would be for CAISO and its stakeholders to focus on the development of a durable, market-based mechanism to provide incentives to ensure that the reliability needs are met."). As was noted in Section V.C, the CPUC has been working with stakeholders to address resource adequacy. *See supra* notes 159-61 and accompanying text.

RTO/ISOs may also benefit by evaluating the different out-of-market tariff procedures used by other RTO/ISOs and how such authorities interact with the RTO/ISOs' resource adequacy provisions. Although there is no perfect model for such out-of-market contracts, RTO/ISOs may wish to consider improvements to their tariff provisions to make the out-of-market contract process more transparent and uniform. Such tariff improvements would provide better competitive pricing signals to market participants, consistent with the resource adequacy provisions in the RTO/ISOs' individual tariffs.