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Our File No. 173011

August 16, 2017

VIA EMAIL, RESS AND COURIER

Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, ON
M4P 1E4

Attention: Kristen Walli, Board Secretary

Dear Ms. Walli:

Re: EB-2017-0150: IESO, 2017 Expenditure and Revenue Requirement Application - BOMA's Written Submissions on Issues List

Pursuant to Procedural Order No. 2, please find enclosed BOMA's Interrogatories.

Yours truly,

FOGLER, RUBINOFF LLP

Thomas Brett
TB/dd
Encls.
cc: All Parties *(via email)*

EB-2017-0150

ONTARIO ENERGY BOARD

Independent Electricity System Operator

Application for approval of 2017 revenue requirement, expenditures and fees

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Interrogatories of

Building Owners and Managers Association, Greater Toronto ("BOMA")

August 16, 2017

Tom Brett
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Toronto, ON M5K 1G8

Counsel for BOMA

Interrogatories of BOMA

1. ***Ref: Issues 1.0, 5.1; Exhibit A, Tab 2, Schedule 2, Appendix 1, p21; Corporate Performance Measures***

(a) Please provide a copy of the 2016-2020 Strategic Plan.

(b) Please provide the input received from the IESO's Stakeholder Advisory Committee as it relates to each of the ten CPMs described on pp21-24.

(c) "Ontario's electricity service is reliable". To what extent is the IESO compliant with the NERC's other (medium or low level risk factor) reliability standard requirements? Please provide a quantitative assessment.

(d) For each of the forty-four key recommendations from the fifteen regional plans, please provide a brief status report, noting achieved targets and milestones for each project.

(e) Please list the five priority and key transmission projects in Northwest Ontario that are referred to here, and provide a brief status report for each, noting milestones, achieved or not, and targets.

(f) What are the target dates for sharing operating data and two-way communication with Ontario LDCs? For how many and which LDCs has this link/structure been put in place, and now operating? What is the target date, and milestones for having this data sharing in place for the remaining LDCs? What are the objectives for establishing this coordination? For example, how will such information sharing increase the likelihood of reaching DSM targets (2015-2020 program)? Please discuss fully.

(g) What is the operational data being shared and for what purpose(s)? Please provide a detailed answer.

(h) Cybersecurity, p22 - Has the advanced malware detection technology been installed by the end of First Quarter, 2017, as promised at p20? If not, what is the target date for completion and milestones?

(i) What are the objectives contained in the 2016-2017 cybersecurity work plan? When is each objective going to be achieved?

2. ***Ref: Issues 1.0, 5.1; Conservation First Framework; Industrial Accelerator Program***

(a) What percentage of the 1.7 Twh of targeted savings to be achieved by the Industrial Accelerator Program by the end of 2020 is currently (i) has been achieved and measured to date; (ii) under construction pursuant to implementation contracts; (iii) under study pursuant to engineering/audit contracts; (iv) not yet the subject of a site specific study? Please provide this information as of June 30, 2017. When was the program established?

(b) Please explain the management structure and reporting structure for this program. How many FTEs are dedicated to this program? What are their functions? Are outside contractors used to administer, manage, or promote the program?

(c) The program has been very slow to produce results in the form of projects in operation. Please describe the plan to increase contracted investments to 0.78 Twh (half of the six year target) by December 2017 (our emphasis), or explain fully why that acceleration is not possible. When will these projects come into operation? Please provide a rough timetable for project completion and commencement of measured savings.

(d) What are the milestones between now and December 31, 2020 to measure progress of the program?

(e) Please provide copies of any internal or third party studies that have been done to assess the reasons for the slow start and which suggest solutions. Should this program be transferred to another party, such as Hydro One Transmission? Please discuss.

3. ***Ref: Issues 1.0, 5.1; #7, Business Plan, p23; Conservation First Framework***

(a) Please provide more detail on the mid-term renewal of the Conservation First Framework. Who is directing the review within the IESO? What groups in the IESO are on the team? What resources are dedicated to the team?

(b) Who are the members of the external working group? Have any outside contractors been utilized? On what topics? Please provide a copy of the Technical Potential Study, and of the Terms of Reference of the midterm review.

(c) What is the timetable for the completion of the midterm review of the Conservation First Framework? Has the midterm review of the Conservation

First Framework been commenced, and has the midterm review of the Industrial Accelerator Program been commenced? Please provide a status report on each review, along with the terms of reference of each review. When will these reviews be filed with intervenors?

(d) How does the IESO propose to collaborate with the gas utilities' midterm reviews which are being done over the same timeframe? How is it collaborating at this time?

(e) Please provide a status report on residential demand response initiative. Please provide an update on the Demand Response program in general, the cost of MW saved since the program commenced, number and type of participants (aggregators, industrial, commercial, institutional, etc.), and average cost per MW.

(f) Please provide the target dates and nature of the utility innovation programs that will make up the $50 million share of the Conservation First Framework. What grants have been given to date; to whom; for what projects?

(g) Please provide the membership of the demand response working group. What is the target date for an auction for residential demand response in 2017?

(h) What access do consumers currently have to SME data received by IESO systems? When will they have such access?

(i) What level of access will consumers have to the data?

(j) What are the milestones for achieving this access, and when will the access be put in place for all Ontario smart-meter customers? How exactly will such access help customers conserve energy, do demand response, or install distributed generation? Please discuss.

4. ***Ref: Conservation First Framework***

(a) The credibility of CDM programs depends, in good part, on the ability to measure the results of such programs. Please provide the steps the IESO is taking beyond what is addressed in evidence to ensure that energy and demand savings are measured to the greatest extent possible. Please confirm that the midterm review is addressing that issue.

(b) (i) Where, in the IESO's view, does the accountability for achieving the Conservation First Framework, 2015-2022 reside? Is it with the IESO, the LDCs, or shared responsibility between the IESO and the seventy-six LDCs, and if shared, how is the accountability for program results determined?

(ii) Please confirm that the IESO manages directly at least one aspect of the Conservation First Framework, the industrial accelerator program.

(c) How does the IESO plan to steer the implementation of the Conservation First to ensure that its interim and final targets are met on time? What steps will the IESO take to make its fullest possible contribution to the realization of the program? Please discuss fully.

(d) What is the total FTE, full-time staff, dedicated to guiding the Conservation First Framework?

(e) What impact does the OEB's recent residential rate design change to uniform customer rates for residential customers, unrelated to either demand or consumption, have on the IESO's efforts to implement CDM in the residential sector? How would your response differ if the questions were about the OEB's proposed commercial/industrial rate changes?

5. ***Ref: Ibid, p17; Conservation First Framework***

(a) Please explain the status of the implementation of the Conservation First Framework, its target date for completing implementation, and milestones.

(b) Please list the projects (and dollar amounts of the grants/loans for each) with description of each project (including the role of the LDC) that the IESO has funded through the LDC Innovation Fund. Please describe the purpose and background for this project, its funding targets and milestones.

(c) Please provide copies of the 2015 and 2016 quarterly conservation reports and the annual verified or draft conservation results posted to date by the IESO, both with respect to the Conservation First Framework.

(d) Please provide an organizational chart of the IESO, which shows all managerial positions, including Vice-Presidents, and the next level of management below the Vice-Presidents, and the size (FTEs, dollars) of the units for which each of the Vice-Presidents and next level managers are responsible.

(e) How does the IESO propose to integrate its market renewal efforts with the OEB/utility driven initiative to introduce fixed rates in place of volumetric rates for various rate cases, especially residential ratepayers? How will this integration impact the growth of distributed generation, demand response, energy storage, and other demand side contributions? How will it impact net metering?

6. ***Ref: Issue 5.1; #8, p23; Customer/Stakeholder Engagement***

(a) Please advise which stakeholders and communities were consulted in 2016; have been consulted in 2017; will be consulted in 2018.

(b) The 2016 sixty-five percent satisfaction rating seems low, as does the two percent targeted increase. Why is the percentage so low? What steps would IESO need to take to increase customer satisfaction from 65% (2016) to 80% in three years? Please discuss fully.

(c) Please provide the survey/study(ies) that establish the sixty-five percent approval rate in 2016, and any other recent customer satisfaction studies.

(d) What steps will IESO take to more quickly increase the percentage of satisfied customers?

(e) How will the proposed two percent increase in satisfaction with the customer engagement process be measured?

(f) How has a stakeholder consultation to date on the Market Renewal Project been reflected in the key Market Renewal Project documents, for example, in the Brattle Group's "Benefits Study"?

7. ***Ref: Issues 1.6, 5.1; #9, p23; Employee Engagement***

(a) Please provide a copy of the employee engagement survey referred to in this section, or if another method has been used, please provide details.

(b) Both the 2016 baseline 71% and the 2% target increase for 2017 seems low. How does the IESO measure employee engagement?

(c) Why is the employee engagement so low? How does that number compare with other entities in the electricity sector, such as Ontario LDCs and Ontario generators, in the IESO's view?

(d) What steps will the IESO take to increase employee engagement from 71% to 85%? Over what period of time could this be done?

(e) If the IESO believe 85% level of employee engagement is an unattainable goal, please explain why. Please discuss fully.

8. ***Ref: CPM, Business Plan #10***

What are the "priority change initiatives"? Please describe each one in reasonable detail. When will each one of these initiatives be achieved and at what costs? What are the milestones?

9. ***Ref: Application Letter/Business Plan***

Please provide:

(a) The original IESO letter to the Minister of Energy, requesting approval of the Business Plan.

(b) The initial response of the Minister to the letter, including any requests to modify the Business Plan. A copy of the Minister's letter to the IESO of December 8, 2016.

(c) Any revisions to the Business Plan made as a result of feedback from the Minister in his letter of December 8, 2016.

(d) What does IESO plan to do to establish a sensible schedule for timely review of its Business Plans by the Minister and the OEB review of its expenditure and revenue requirement? Please discuss fully.

10. ***Ref: Issue 5.3; Assistance to GHG Policy Implementation***

(a) The Ontario Climate Change Solution Deployment Corporation (the "OCCSDC") has been established with a Board of Directors. What steps is the IESO taking, and what step does it plan to take in 2017, and 2018, to collaborate and support the Corporation, in its mandate to ensure low carbon energy choices?

(b) Preamble - The Brattle Report states (p23) that:

> *"The Working Group and Stakeholders have voiced consistent strong concerns about governance and interactions with environmental policy objectives, neither of which will be directly addressed by Market Renewal. Though Market Renewal would prepare the Ontario market to more*

efficiently accommodate and operate under changing policy objectives, Market Renewal does not currently include all elements necessary to achieve the new policy objectives."

(i) Does the IESO agree with Brattle's assessment? If not, please explain in which respects it disagrees.

(ii) Please provide an assessment of how each of IESO's strategic objectives, and how its proposed Market Renewal Project will contribute to the achievement of the government's low carbon energy initiative.

(c) More particularly, please explain for each of the principal work stream how the Market Renewal Project will include features that support and reinforce the government's carbon policy, as articulated in the Government's Greenhouse Gas Policy, and the recently enacted GHG legislation and regulation.

11. ***Ref: Ibid***

Where will the additional 25 FTEs for 2017 be deployed throughout the organization? How many in market renewal? How many in CDM?

12. ***Ref: Ibid, p13***

(a) Please describe the current allocation of FTEs and compensation for those FTEs, and budgets, both existing FTEs, and (separately) new FTEs projected in this submission (25 in 2017, 75 in 2018) across the various functional parts of the organization, as outlined in the Business Plan's breakdown of the IESO functions, including:

(i) planning;

(ii) market renewal;

(iii) generation procurement;

(iv) CDM;

(v) Cap and Trade;

(vi) Market System Operations;

(vii) Finance;

(viii) Internal Audit, IT;

(ix) Enforcement and Support;

(x) Regulatory and Legal;

(xi) Office of the President;

(xii) First Nations.

(b) Please provide the allocation of consulting fees 17.8 (2016) and 17.7 (2018) across the organization's functions, listed in the previous question.

(c) Please provide the allocation of any other OM&A categories in the same manner.

13. ***Ref: Ibid, p16***

Do you expect the new responsibilities assigned to the IESO for Procurement of transmission will become operational in 2017 or 2018, given that last July, the Ontario government designated a transmission company to construct the line to Pickle Lake in Northwestern Ontario, in what had been, to that point, a competition between two transmitters to build the line. The designated transmitter is set to apply to the OEB for a Leave to Construct later this year. Did the IESO play any role in the designation, or provide some guidance after the designation was made?

14. ***Ref: Issues 1.1, 1.2, 1.3; Ibid; Appendix 2, p25; Key Risks/Mitigation Plans***

Please provide the mitigation plans to address each of the nine key risks to the Business Plan, listed on p26.

15. ***Ref: Issue 1.5; Ibid, Appendix 4, p29; 2017 Capital Projects***

(a) Please provide more detail on the Infrastructure Refresh project for 2017, 2018, and 2019.

(b) Please explain the IESO's fiduciary and contract management responsibilities for the Conservation First Framework.

(c) Why is the IESO proposing to spend $5 million over three years (2017, 2018, 2019) to replace its CRS with a standard software application? Please provide the benefits/cost study for so doing.

(d) Please explain the "MACD Enforcement Support Tool and related projects". What is the MACD, its purpose, and its impact on market efficiency?

(e) Please explain in what ways each of the above noted software projects contribute to increasing the efficiency of the Ontario market, or, if they do not, provide the purpose of each and its relative importance compared to other projects in Appendix 4.

16. ***Ref: Issue 5.1; Exhibit C, Tab 1, Schedule 1, Attachment 1; Elenchus Report***

(a) (i) In the Scorecard, attached to the Elenchus Report, and attached to this IR (Appendix 1), and entitled "Proposed and Illustrative IESO Regulatory Scorecard" (and found at p7 of the Elenchus Report, being proposed by the IESO as the regulatory scorecard for 2017, and 2018); does the IESO support and endorse this Scorecard for use in this case?

(ii) Is the IESO asking that the Board approve this Scorecard in this proceeding?

(iii) The Scorecard shown on p7 of the Elenchus Report does not have 2017, 2018 targets for many of the metrics. Does the IESO intend to set targets for these measures? If so, when?

(b) Please provide a copy of the 2017 IESO Internal Scorecard, unless the Internal Scorecard is the 10 key performance metrics addressed in the 2017-2019 Business Plan, at pp19-22.

(c) (i) Please explain the difference between the purposes of a corporate scorecard and the purposes of a regulatory scorecard. Is it not the case that a regulated utility (whether an LDC or IESO) that does not score well on its internal "corporate" scorecard, that is, that it is not properly managed, or insufficiently or excessively resourced, will not perform well on its regulatory scorecard.

(ii) Do you agree that a manager's and the corporation's performance on its corporate scorecard is an important driver of executive/manager compensation, which is of interest to the OEB, and an important part of the revenue requirement?

(iii) Put another way, does the OEB not have the responsibility to assess the effectiveness and efficiency of the IESO, much of which was determined by the quality of its management, which is reflected in the extent to which it has met its own key performance targets and metrics, in judging whether its expenditure and revenue requirement submission is reasonable? Please discuss fully.

(d) Does the IESO consider safety of its employees important to their level of engagement? Please discuss.

(e) Does the IESO consider itself a stakeholder in its stakeholding process, or is it the sponsor of its submission, seeking the input of stakeholders?

(f) Should not the scorecard also apply to some outcomes which the IESO can substantially influence, though not completely control? Please discuss with reference to the proposed scorecard in this case.

(g) Please confirm that in evaluating the cost-effectiveness of the IESO's activities, the fact that the OEB does and should look to the success, or failure of the programs, the output of which the IESO substantially influences, as well as those it controls.

17. ***Ref: Business Plan, p22***

(a) Please provide the basis, using 2016 as an example, for the calculation of the CDM portfolio costs target of under four cents per kwh. Where does the target originate, and what is the rationale for that number? Please show the actual calculation to determine whether the four cents per kwh is met. Please provide the three-year target for the average costs of the CDM portfolio.

(b) Please provide a copy of the Elenchus Proposal to the IESO, and the IESO Terms of Reference.

18. ***Ref: Transmission Lines***

Given the recent changes to the Ontario Energy Board Act and the Electricity Act, please confirm that in some circumstances, the IESO may be directed to procure transmission services, and in other cases, the government itself will delegate transmitters to build a particular project.

19. ***Ref: Issue 1.0; Exhibit A, Tab 2, Schedule 2, p22; Preamble; EB-2010-0279***

In Procedural Order in EB-2010-0279, the Board, in determining the issues list, stated:

> *"The Board finds that its mandate in this case is limited to approval of the OPA's administrative fees, which comprise approximately 3% of the OPA's total annual spending. However, the Board is of the view that an assessment of the OPA's administrative fees must require an examination and evaluation of the management, implementation, and performance of the OPA's charge-funded activities. <u>This is necessary because the OPA's administrative and non-</u>*

> *administrative activities that are funded by fees and charges, respectively, are unavoidably linked. It is the Board-approved fees that give the OPA the means to acquire and allocate the resources (e.g., staff) that are required to undertake its various responsibilities, resulting in charge-funded activities. The Board finds that an assessment of the performance of the OPA's charge-funded activities is a necessary, legitimate and reasonable tool for determining the effectiveness of the OPA's utilization of its Board approved fees."* (our emphasis)

Further, in its findings in that case, it stated:

> *"For the purposes of considering the fiscal 2011 proposed expenditure and revenue requirement and fees application by the OPA, the Board expanded the scope of the issues that had traditionally been considered, the purpose of which was to recognize, as set out above, that the OPA's administrative and non-administrative activities that are funded by fees and charges, respectively, are unavoidably linked. While the Board's mandate in this case is limited to approval of the OPA's administrative fees, which comprise approximately 3% of the OPA's total annual spending, an assessment of the performance of the OPA's charge-funded activities is a necessary, legitimate and reasonable tool for determining the effectiveness of the OPA's utilization of its Board approved fees."* (p10) (our emphasis)

Given the importance of IESO's collaboration between IESO and the LDCs to achieve CDM objectives, distributed generation, broader (residential) demand response implementation, why would it not be important to track the achievement and activation of the necessary two-way communication protocols with the LDCs, and to ensure that the protocols, and links, were in place across the province with all LDCs as soon as possible? Please discuss.

20. ***Ref: Preamble***

In its Business Plan, p14, IESO states that:

> *"A need has been identified for up to 300 megawatts (MW) of flexible resources by the end of 2017 and up to an additional 700 MW by the end of 2018."*

(a) Please define what the IESO means by flexible resources, and specify what types of resources are included in the "flexible resources" category, eg. gas peakers, combined cycle, hydro, pumped storage, Demand Response, various types of reserves, regulation, others, and provide examples of how such resources are being used now, and how they would be used to achieve the desired results. Also, please provide an explanation of why these "flexible resources" are needed in such quantities by the end of 2017 and 2018, respectively.

(b) Will the scorecard contain a measure to reflect the IESO's progress in procuring these required resources?

(c) Has the IESO provided further comments to Elenchus and/or the taskforce in response to Elenchus' June report.

21. ***Ref: Elenchus, Appendix D, p4***

(a) Please provide pertinent details on both the settlement auditor who performs the audit, at what frequency. What is the substance of CSAE3416? Please provide copies of both the most recent auditor's reports, and the Terms of Reference for the reports.

(b) Please provide information on D80 review, and a copy of CICA8600, and the most recent Review Report, and its Terms of Reference.

22. ***Ref: Ibid, p34***

Please provide a breakdown of the number of IESO personnel spending 100% of their time; between 50% and 100% of their time; between 25% to 50% of their time, and less than 25% of their time - creating, negotiating, renegotiating, or managing, procurement contracts with generators.

23. ***Ref: Ibid, p36***

(a) Please confirm that the IESO has substantial influence over the reduction of transmission losses (Hydro One Transmission, in its recent rates case, said it was IESO, not Hydro One, that has the most responsibility over losses), and that it would need a directive for the IESO to take steps to reduce transmission losses. How, in IESO's view, is accountability for loss reduction control shared by IESO and Hydro One?

(b) Do any of the AESO, or the US RTO/ISOs have programs, either alone, or in conjunction with the transmitters which they supervise, to reduce system losses? Please provide details and results achieved.

(c) Please provide copies of any studies that IESO has made of transmission losses or that AESO or the IESO's US counterparts have made of such losses in the last few years. What is best practice among the IESO's US counterparts and AESO with respect to taking steps to reduce transmission losses on those transmission facilities that they oversee?

(d) Please provide IESO's definition of transmission losses, and how they are traditionally measured, and what figure is currently used by the IESO in making calculations that require an assumption about the amount of transmission losses. Which are the major IESO functions that require such calculations?

(e) Please provide a copy of the "Operating Agreement" between the IESO and Hydro One Transmission. Does the Agreement deal with the issue of responsibility for reducing transmission losses?

(f) Which amounts for losses are included in the AQEW and SQEW, is calculating domestic and export usage fees, respectively?

(g) Please confirm that end use customers ultimately pay for the losses in their rates. What is the forecast amount and dollar value (show calculation of dollar value) of losses for 2017, 2018? What step is the IESO taking, or plans to take, to try to lower the transmission losses?

24. ***Ref:*** ***Ibid, p38***

(a) Has the IESO provided an MD&A from 2016, or any earlier year? Where is this found? Is it a part of the IESO's Annual Reports?

(b) What is the purpose of the $10 million cash reserve (ratepayer loan)? Why is it necessary for the IESO, when it is not necessary for other regulated entities/LDCs? Please discuss fully.

25. ***Ref: Ibid, p41***

Is the IESO prepared to undertake the development of performance measurement for its contract negotiation and management functions? What efforts have been made to date to do this?

26. ***Ref: Ibid, p44***

Please provide a copy of the Norton/Kaplan HBIL HBR article on performance scorecards.

27. ***Ref: Ibid, p48 (Elenchus)***

(a) Please discuss each of the metrics which address Bulk Power System Reliability on p48. Please describe each of the criteria, and its purpose, and whether it would be appropriate for use as a metric for the IESO.

(b) Please do the same for metrics in the boxes on p49, addressing Coordinated Wholesale Power Markets, and Organizational Effectiveness.

28. ***Ref: Ibid, p52***

Has the IESO ever incurred any notifications and/or penalties from NERC or the NPCC over the last five years for violation of Violation Risk Factors ("VRF") assigned High, Medium, or Lower? If so, what were the incidents, and what remedial action was taken?

29. ***Ref: Ibid, p56***

Please provide copies of both surveys and the description of the "melding process" to achieve the reported satisfaction level.

30. ***Ref: Issue 3.1***

(a) Please explain the conservation and load management procurements that attract the $10,000 registration and application fees. Please list the proposals submitted in each of the last three years ending in 2016, for which the fee was required. Do you define CDM and Demand Response initiatives at the program, or individual customer level; how?

(b) Does each individual (commercial or residential) Demand Response proposed require a $10,000 fee? How does that fee compare to the fee requested of aggregators (eg. Enernoc, Rodan) that aggregate Demand Response proposals on behalf of a group of end users? How will the fee for residential Demand Response be determined?

(c) Please list the new or changing requirements for the IESO as a result of the passage of Bill 135. Has the IESO developed application fees for these jobs?

31. ***Ref: Exhibit B, Tab 1***

Why is the full domestic usage fee levied on embedded generators, regardless of the amount of time that they operate?

32. ***Ref: Exhibit B, Tab 1, Schedule 1, p9***

(a) Please explain the extent of the redeployment of consulting support. What does the phrase mean? What is the dollar value of the consulting support that will be redeployed, and for what purpose?

(b) How many key internal IESO resources (FTEs or partial FTEs) will be seconded to the Market Renewal Project team? How will positions be backfilled; on a temporary basis; for how long? Please explain which of the positions are management positions.

(c) Of the contracted suppliers of consulting services for the development of Market Renewal Project to date (IESO has stated that the Market Renewal Project work started in April 2016), how many have been selected after competitive RFP? Was Brattle selected in this manner? Please provide reasons why any contracts were awarded without an RFP process.

(d) What steps will the IESO take to enhance cost control and mitigate risk for the duration of the Market Renewal Project?

33. ***Ref: Issue 5.3; Ibid, p10***

(a) Has the IESO completed an agreement with the OCCSDC pursuant to which it will be reimbursed for the tasks that it will do for it, both listed on p10, or otherwise that may arise? If there is an agreement, please provide it.

(b) How many FTEs in the IESO are dedicated to that work, in whole or in part, in 2017 and 2018?

34. ***Ref: Ibid***

(a) What staff (dollar value) will be redeployed, and where, as a result of the termination of Market Renewal Project?

(b) Other than to reduce proposed 2018 usage fees, does the IESO have other reasons to retain excess revenue in 2017, assuming there are any? Why should the Market Renewal Project be treated differently from any other IESO program, with respect to the manner in which it is funded as part of the IESO's revenue requirement?

(c) When will the IESO be able to estimate with accuracy any 2017 underspend or overrecovery? What is the forecast as of July 31, 2017? How fair is that forecast (±?%)?

35. ***Ref: Exhibit B, Tab 2, Schedule 1***

(a) Please provide an estimate of IESO capital expenditures for 2018 and 2019, including capex for the Market Renewal Project.

(b) Please explain what is meant by a "superior reliability performance". Superior to what or whom?

36. ***Ref: Ibid, p6***

Please provide a reference in the 2016 Annual Report to each of the accounting policy changes shown on this page, and any other accounting changes that have been made. Please provide an explanation, if necessary, for each referenced item.

37. ***Ref: Exhibit B, Tab 3, Schedule 1, p2***

(a) Please explain what is meant by embedded demand. Please show the calculations which underpin the statements made on p2. Please provide a breakdown of revenues from domestic, deemed export demand, and embedded demand.

(b) Please explain the variation in operating costs relative to budget and amortization relative to budget. In both cases, what items were it responsible for?

38. ***Ref: Ibid***

(a) Please provide:

(i) the number of full-time positions available from the government directive to terminate certain renewable energy procurements;

(ii) the number of positions currently vacant;

(iii) when will these vacant positions be filled through the Market Renewal Project or otherwise;

(iv) what has been the average number of FTEs vacant in the IESO in each of the last three years.

(b) What is the proposed compensation (salary and benefits) budget for 2017, 2018?

39. ***Ref: Exhibit C, Tab 2, Schedule 1, Attachment 2, p1, Appendix 2-JB***

(a) Please explain the difference between the proposed increase in Operating Costs of about $9 million, and the "$12 million in forecast 2017 costs", referred to in the text.

(b) Where does the IESO get the $3 million it proposes to allocate from its "core business operations"? What expenditures are reduced or eliminated to generate the $3 million?

40. ***Ref: Ibid, Attachment 3***

(a) Please explain the composition of the "Corporate Adjustments" item on Appendix 2-JC. What accounts for the reduction of $7.5 million in the item in 2017 budget versus 2016 actual?

(b) Please provide a breakdown of the $7.2 million amount of Office of the CEO in the 2017 budget.

(c) Please confirm that the Draft Scorecard is not a document which benchmarks IESO costs against costs of AESO, or the six major US RTO/ISOs.

41. ***Ref: Issue 5.4***

(a) Please confirm that there are certain metrics that can be used to compare activities under the control of the IESO, AESO, and the US RTO/ISOs, such as actual administrative spending per MW/h versus budget forecasts, customer satisfaction indices, billing/audits.

(b) Is it not the case that, while the IESO, AESO, and the US RTO/ISOs each may have unique responsibilities, such as, in the case of IESO, responsibility for CDM, there is a common set of activities, performed by all or most of the above agencies, including operation of energy and capacity markets, oversight of transmission systems, transmission planning, oversight of conduct of market participants and enforcement of standards (rules), and monitoring of reliability. Please discuss fully.

(c) Please provide a table which shows the functions provided by each of the IESO, AESO, and the six US RTO/ISOs, which are the subject of the ongoing FERC review, in particular, ISO NE, NYSO, PJM, MISO, and CAISO, and ERCOT. ERCOT is not FERC-jurisdictional, but studies have been made of the ERCOT's operations.

42. ***Ref: Brattle, p9***

<u>Preamble</u>:

> *"The costs of the Market Renewal will mostly be incurred during the lead-up to the operationalization of the project, as the planning and implementation of new systems and new markets take place. The majority of these costs will be capitalized, however, and will not be recouped from consumers until the project is implemented and its benefits are starting to be realized".*

(a) Does the IESO agree with this description of the recovery of Market Renewal Project design and implementation capital costs? Please explain your answer whether you agree, disagree, or agree in part. Will any of the OM&A costs shown for 2017, 2018, and 2019, be capitalized? Are all costs beyond 2019 capitalized? Please discuss.

(b) Further to (a) above, please confirm that the capital costs of market renewal, forecast at $20 million in 2018, and $40 million in 2019, will not be recovered in IESO's revenue requirement submission until the new systems are in place (used and useful) in 2021. Put another way, is it the intent to recover depreciation in 2019 for 2018 Market Renewal Project capital expenditures or not? If that is not the plan, please describe how these costs will be recovered, if at all, in each of 2018, 2019, 2020, in revenue requirements or otherwise. What will be the approximate amortization period be for these capital expenditures, and the approximate impact on the revenue requirement application in those years?

(c) How will the IESO provide implementation financing for those expenditures, prior to commencement of recovery from ratepayers? Will it increase its debt, and by how much?

43. ***Ref: Recent FERC Reports; Benchmarking; Issue 5.4, Exhibit C, Tab 1***

(a) In particular, has the IESO studied, in depth, the effort by FERC to develop metrics for comparing the performance of the US RTO/ISOs, the initial report, entitled "Performance Metrics for Independent System Operators and Regional Transmission Organizations", April 2011 (Appendix 2), together with the follow-up FERC Staff Report, "Common Metrics Report, October 2016, Docket AD14-15-000" ("Common Metrics Report") (Appendix 3)? Copies of both reports are attached to these Interrogatories.

(b) The Common Metrics Report provides, at pp66-70, a comparison of administrative costs, both operating costs and capital costs, for the five major FERC jurisdictional ISO/RTOs that were the subject of FERC's studies, CAISO, ISO, NE, NYISO, and PJM. Please confirm that it would be possible to compare IESO's administrative costs, appropriate operating and capital to those numbers with adjustment for the IESO's CDM function. Please discuss fully.

(c) Appendix A of the Common Metrics Report shows the List of Common Metrics developed by the FERC Staff, based on information submitted by the five major ISO/RTOs. Please indicate which common metrics would not be appropriate metrics to apply to the IESO's performance, and why, and which would be appropriate, or appropriate with modifications.

(d) Please confirm that the IESO and the AESO, and the five RTO/ISOs conduct similar activities and operations, including:

(i) administration and management;

(ii) billing;

(iii) meet customer satisfaction;

(iv) transmission planning;

(v) supervision of open access transmission;

(vi) maintain system reliability as established by NERC, and its regional designates;

(vii) economic dispatch subject to system constraints;

(viii) acquire generation capacity;

(ix) balance the market, both internally and externally, and supervise activities;

(x) forecast system demand;

(xi) operate wholesale markets to ensure maximum efficiency given constraints;

(xii) encourage growth of new and diversified power sources, eg. demand response, renewables;

(xiii) operate energy and reserve and ancillary markets.

Please note which functions any of the RTO/ISOs, including AESO, perform which the IESO does not perform, and which functions the IESO performs that are not performed by one or more of the other RTO/ISOs. Please discuss each of the functions (i) through (xiii) separately.

(e) Please confirm that most of the items on which IESO will provide information for the purposes of constructing a scorecard, as shown at Exhibit C, Tab 1, Schedule 1, Attachment 1, p7 of 56, would also be useful for a benchmarking study with the five major US ISO/RTOs and AESO.

44. ***Ref: Exhibit B, Tab 4, Schedule 1, p2; Issue 6.0***

(a) Please confirm that if it followed the Board decision in EB-2015-0040, it would clear each year, in favour of ratepayers, any surplus in the account plus interest accruing at the Board-approved rate.

(b) Please provide a copy of the text of the variance account that the IESO has established to comply with EB-2015-0040 – Report of the Ontario Energy Board, Regulatory Treatment of Pension and Other Employment Benefits (OPEB) Costs (the "Report").

(c) Please confirm that if IESO were to follow the Board's default option in its Report, the IESO would clear, on an annual basis, any balance in the variance account as at December 31st of the previous year, in favour of ratepayers, that is, any excess of forecast pension and OPEB payments on an accrued basis, over actual IESO's cash contributions in that year for pension and OPEBs, and it would credit any balance in favour of shareholders against its next year's revenue requirement submission.

(d) Having established the deferral account on June 1, 2017:

(i) What is the current balance in the account, and how does that balance arise?

(ii) If the balance is a credit to ratepayers at year end, does the IESO propose to credit the balance to ratepayers, as part of its 2018 revenue requirement application? If not, what treatment does it propose for the principal in the variance account?

(iii) Does IESO propose different treatment for interest accruing on the balance of the variance account? What is that treatment? If so, why should the treatment accorded interest be different than the treatment accorded the amount of the variance itself? The IESO proposes to use any surplus, both principal and interest, in the Pension/Benefits deferral account to reduce its debt. What debt is the IESO referring to? Notes, 7(a) and (b) of the 2016 Financial Statement (Exhibit A, Tab 3, Schedule 1, p44) shows a term loan of $90 million from the Ontario Energy Finance Corporation ("OEFC"), which was repayable in full April 30, 2017. Was that repaid, renewed or refinanced in some other manner? It also shows a credit facility from OEFC of $95 million, also terminated on April 30, 2017. What are the current debts to OEFC or others, and which "debt" do they propose to reduce?

(iv) What is the current interest rate on the IESO's debt? Who now holds the IESO's debt? What is the amount, and what are the repayment arrangements? What has been the average amount of debt outstanding over the last five years?

(v) Does the IESO agree that establishing a variance account, as suggested by the Board, with any surplus paid to ratepayers, provides for greater transparency of the impact of pension and OPEB to benefit of the Board and ratepayers? Please discuss.

(vi) Please provide the variance between the forecast pension and OPEB accruals and each actual cash contributions in each of the last five years, ending in the year 2016, and show, by reference to previous financial statements, the actual debt reduction that occurred.

(vii) What would have been the impact on the IESO's operating expenses for each of the last three years had the IESO followed the Board's proposed approach in EB-2015-0040?

(viii) What is the relevance of the fact that the IESO is a not-for-profit corporation to whether it should have a different method than that proposed by the Board for the operation of the variance account and disposition of interest charges? Please discuss fully.

(ix) What percentage, and how, does the IESO propose to capitalize any of its pension and OEB costs in 2017? Did it do so in 2016? If so, where does it show the arrangement on its financial statements?

45. ***Ref: Market Renewal***

Preamble: Overall costs of the Market Renewal Project have been estimated in the IESO Business Plan (Exhibit A, Tab 2, Schedule 2, p8) to be in the range of $150-$200 million. It does not say over what period of time. The application shows Market Renewal Project operating costs of $12 million in 2016, $14 million in 2017, and $6 million in 2019, and capital costs at $0 in 2017, $20 million in 2018, and $40 million in 2019. Over eighty percent of the costs will be incurred in the start-up phase, 2017-2021. The Brattle Group, in its "Benefits Study" (The Future of Ontario's Electricity Market – A Benefits Case Assessment of the Market Renewal Project, p86), a study commissioned by the IESO (Exhibit B, Tab 1, Schedule 5, p5), the total cost to implement, and test, the Market Renewal Project system estimates implementation costs of $190 million, including a twenty percent contingency factor, with an upper limit of $300 million, over the period 2017 to 2025 (p86) (Appendix 4). A footnote on p86 of the Brattle study says that the $310 million is the present value of the total costs in 2021, using a five percent discount rate. The table does not differentiate between capital and operating costs, nor does it outline an annual revenue requirement for the project over the eight year period. The IESO's 2016 Annual Report estimates a range of $200 million to $300 million.

(a) Does the IESO accept the implementation costs as proposed by its consultant, Brattle? If not, what changes does it propose for the:

    (i) schedule of proposed expenditures over the years 2017-2025 (at pp87-88);

    (ii) the sequencing of the design, implementation and testing the outputs of the three work streams, energy, operability, and capacity.

    (iii) breakdown of capital and operating costs in each year of the Market Renewal Project from 2017 to 2025.

(b) (i) Please break down the estimated operating costs among the three work streams for each year from 2017 to 2025, of the design, implement, and test phases, for each work stream, in each year.

(ii) Please break down the estimated capital costs among the three work streams for each year from 2017 to 2025, and each of the design, implement, and test phases, for each work stream, in each year.

(iii) Will the proposed changes to the energy market result in the adoption of nodal pricing based pricing (LMP)? If not, please explain what form of pricing would replace the uniform Ontario energy price.

(iv) Does the IESO consider that it has policy approval and stakeholder buy-in for LMP pricing and the termination of the Ontario uniform energy price?

(v) Would the proposed energy or capacity market changes result in a departure from the Ontario uniform transmission rate? Please explain.

(c) Please provide the Market Renewal Project milestones which will allow the Board and intervenors to understand key go/no go points in the design and implementation of the project, and each of its component work streams, points where project could be terminated or altered if actual forecast costs to complete the work escalate beyond a reasonable amount, or for any other reason.

(d) Please provide a table which will show the cost of the work completed at each milestone versus budgeted cost to complete the overall project versus the amount of work necessary to reach completion. The schedule (and milestones) should cover the entire project, in effect the IESO version of the table on p86 of Brattle report.

(e) Please describe:

(i) the financial and other impacts of any delays or acceleration in the proposed schedules set out in question (c) above;

(ii) the prospective major implementation hardware and software contracts, once they are known, with details on the nature of the procurement process, eg. competitive bid versus sole source, fixed price, or time and materials, or target price, or hybrid;

(iii) scope of each contract, and how it relates/dovetails with other contracts;

(iv) whether there will be one vendor for all core systems, and if not, how many, and how will the IESO ensure that their outputs are coordinated and the systems operate in unison;

(v) a risk analysis for each stage of the project.

(f) Please provide costs (capital and OM&A), broken down into the types of cost itemized by Brattle at p86, for each year of the project:

(i) technology costs, i.e. "development of the core systems including the combined hardware and external resourcing costs of licensing, customization and implementation;

(ii) designing the market including use of outside consultants;

(iii) costs of implementation and testing.

(g) Does the IESO intend to update this cost and implementation data on each annual revenue requirement filing? If not, please explain.

(h) Please provide the degree to which the expected new long-term energy plan and the IESO's current proposed market renewal rationale are linked. The IESO, earlier this year, completed a 2016 Ontario Planning Outlook to assist the government with the preparation of its new Long-Term Energy Plan. When does it expect the government to publish its new Long-Term Energy Plan? In the IESO's view, will the new Long-Term Energy Plan determine or influence the scope of the Market Renewal Project? Please discuss.

APPENDIX 1

PROPOSED IESO REGULATORY SCORECARD (ILLUSTRATIVE)

Performance Outcomes	Performance Categories	Measure	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	20xx Target	Target met unmet (3)	5-year trend (4)
Stakeholder Responsiveness	Stakeholder Satisfaction	Satisfaction with the engagement process		65%				xx%		
Operational Effectiveness	Reliability	Compliance with NERC high risk reliability standards	Yes	Yes				Yes		
	Planning	Timely implementation of key IRRP recommendations	NA	xx/30	xx/44			xx/yy (or %)		
		Timely implementation of key LTEP project milestones	NA	xx/yy				xx/yy (or %)		
	Cost Control	Variance from the OEB-approved revenue requirement	+/-%	+/-%				0.0%		
		Total Expenses/TWh (3-yr rolling average) (1)	$/TWh	$/TWh				$/TWh		
	Contract Management	Resources Required for Capacity Contracts (2)	#/FTE	#/FTE				#/FTE		
		Resources Required for Capacity Contract GW (2)	GW/FTE	GW/FTE				GW/FTE		
	IESO Administered Markets									
	Settlements Operations	Unqualified biennual Settlements Operations CSAE 3416 audit	Yes	--				Yes		
	Market Dispatch	Number of high or medium risk observations in the biennual Dispatch Scheduling Optimizer review	--	0				0		
	Projects	Market Renewal Initiative proceeding according to the schedule and budget						Yes		
Public Policy Responsiveness	Conservation	Annual reporting of portfolio cost ($/kWh)	$/kWh	$/kWh				$/kWh		
		Achievement of 2020 energy savings target milestones (TWh)	TWh	TWh				TWh		

Notes:
1. IESO to begin 3-year rolling average reporting with 2018, 3 years after IESO-OPA merged on January 1, 2015.
2. IESO to develop a process for identifying the resources required for contract management functions. Reporting to commencing with the 2018 fiscal year.
3. Target met/unmet could be colour coded, similar to the OEB Distributor Scorecard.
4. The five-year trend could be shown graphical, similar to the OEB Distributor Scorecard.

APPENDIX 2

PERFORMANCE METRICS

For Independent System Operators And Regional Transmission Organizations

A Report to Congress In Response to Recommendations of the United States Government Accountability Office

Office of the Chairman Federal Energy Regulatory Commission April 2011 www.FERC.gov

Performance Metrics
For Independent System Operators And Regional Transmission Organizations

A Report to Congress
In Response to Recommendations of the United States Government Accountability Office

April 2011

Federal Energy Regulatory Commission
Office of the Chairman

888 First Street NE, Washington DC 20426

TABLE OF CONTENTS

Federal Energy Regulatory Commission
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Message from the Chairman

To the Chairman and Ranking Member of the Senate Committee on Homeland Security and Governmental Affairs, and the Chairman and Ranking Member of the House Committee on Oversight and Government Reform:

I am pleased to submit a report on Performance Metrics for Independent System Operators and Regional Transmission Organizations. This report is being submitted in response to recommendations of the Government Accountability Office (GAO). As outlined in its report, *FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance*, GAO recommended that the Federal Energy Regulatory Commission (FERC) develop standardized measures or metrics to track the performance of Independent System Operator (ISO) and Regional Transmission Organization (RTO) operations and markets.

Under my direction, Commission Staff has led an 18-month voluntary and collaborative process with ISOs, RTOs, transmission customers, market participants and other stakeholders and interested experts to develop metrics that track the performance of ISO/RTO operations and markets in delivering benefits to consumers for those ISO/RTOs under the jurisdiction of the FERC. This information provides the framework for an ongoing analysis of ISO/RTO performance; as well as a starting point for further evolution of these measures into industry best practices by ISO/RTOs.

The culmination of these efforts to date has been the submittal of performance metrics reports by each of the ISOs and RTOs which are attached in the Appendices to this report.. These reports, that represent the first step in a multi-year evaluation of performance for utilities under the jurisdiction of the FERC, provide a wealth of information on the ISO/RTO markets and operations over a five-year period (2005 – 2009) for 57 performance measures. As outlined in FERC's FY 2009-2014 Strategic Plan, next steps in this evaluation include development of performance metrics in non-RTO regions in fiscal year 2011 followed by development of common metrics for both ISOs/RTOs and non-RTO regions – thereby allowing for comparisons across all electric regions and markets – and further evaluation of the performance results in subsequent fiscal years.

Jon Wellinghoff
Chairman
Federal Energy Regulatory Commission

Commission Staff Analysis

This Commission Staff analysis[1] provides a high level overview of some of the more significant aspects of the performance metrics submitted by the ISOs and RTOs[2] in Appendices D through I. Commission Staff plans to continue to evaluate this large body of information and analysis that has been compiled for the first time. However, we believe the full value of this effort will take several years to materialize. In the longer term the metrics will assist the utility industry, stakeholders and the Commission in evaluating industry trends and best practices.

Before discussing our overview of the performance results, the basic characteristics of the ISOs and RTOs under the Commission's jurisdiction must be understood. Each ISO/RTO is responsible for managing the high-voltage electric transmission assets of its member utilities and the wholesale electricity market(s) for the region it serves. As can be seen on the ISO/RTO Map, however, there are significant differences in the geographic scale of the ISOs and RTOs. NYISO and CAISO operate within a single state, while others operate in a multi-state environment, such as the Midwest ISO which operates in all or parts of 13 U.S. states and the Canadian province of Manitoba. There are also differences in the scope of their respective operations. For example, in addition to providing open-access transmission services, SPP operates a single real-time balancing market for its members whereas other ISO/RTOs operate a number of markets, including longer-term energy markets, ancillary services markets and capacity markets.

These differences must be kept in mind when evaluating performance results across the ISOs and RTOs. Recognizing these differences, ISO/RTO performance can be compared in the following ways:

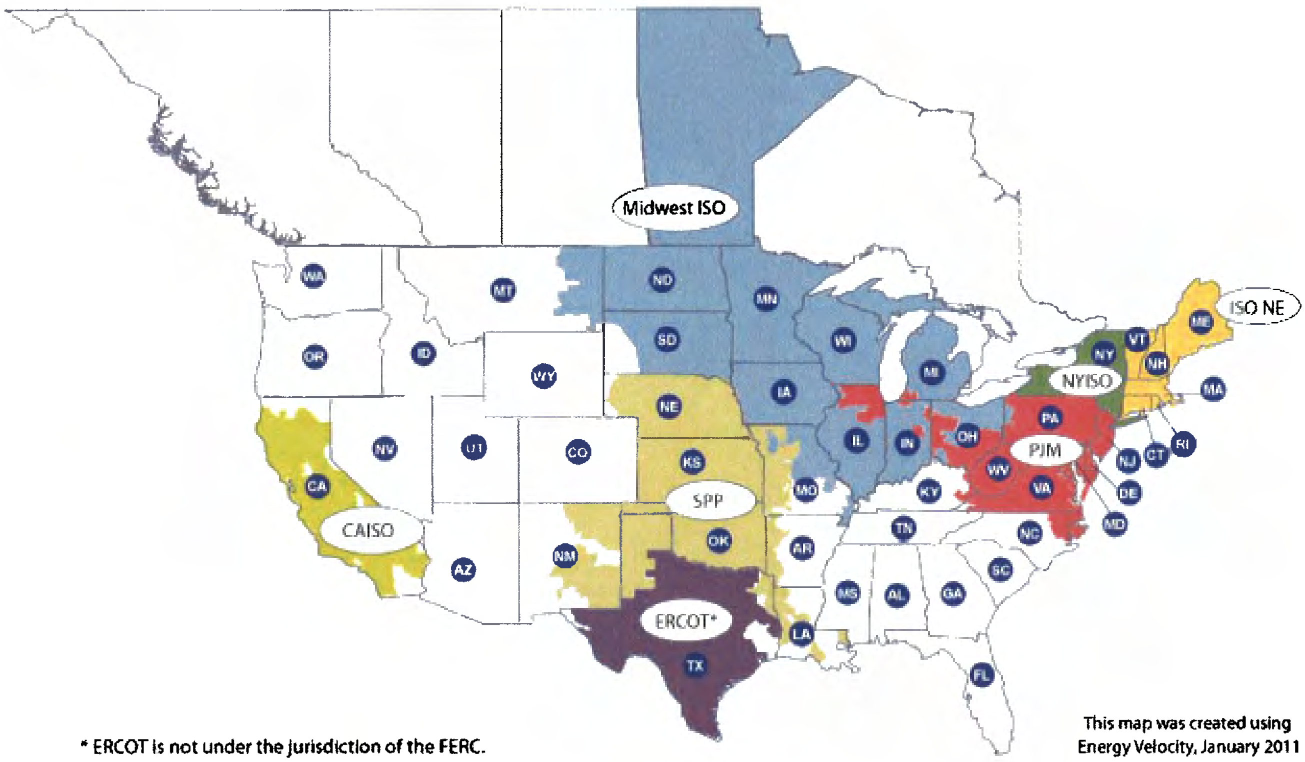
- Direct comparisons can be made of performance for certain metrics that reflect activities under the control of ISOs/RTOs and that are not a function of the scale and scope of the ISOs/RTOs. Metrics in this category include a metric that compares ISO/RTO actual administrative spending with budget forecasts, as well as metrics on billing audits and customer satisfaction indices.

- Other metrics are best compared in terms of their performance trends over the 2005-2009 review period. Clearly, some of the performance results reflect the impact of a wide range of factors beyond simply performance. Differences in market prices between the ISOs and RTOs, for example, reflect

1 The opinions and views expressed in this staff analysis do not neccessarily represent those of the Federal Energy Regulatory Commission, its Chairman, or individual Commissioners, and are not binding on the Commission.

2 The ISOs and RTOs providing information for this report are ISO New England (ISO-NE), New York Independent System Operator, Inc. (NYISO), PJM Interconnection, L.L.C. (PJM), Midwest Independent Transmission System Operator, Inc. (Midwest ISO), Southwest Power Pool, Inc. (SPP), and the California Independent System Operator Corporation (CAISO).

ISO/RTO Map



* ERCOT is not under the jurisdiction of the FERC.

This map was created using Energy Velocity, January 2011

different resource profiles in the various ISO/RTO regions. Since entities other than ISOs and RTOs develop and operate resources, ISOs and RTOs must work within the parameters of their given resource profiles to improve efficiency in the markets within their regions. While market prices within ISOs/RTOs differ, the five year trend for each ISO/RTO will provide a better basis to compare the relative performance among ISOs/RTOs, particularly with respect to market metrics that more directly measure costs that can be influenced by ISO/RTO programs designed to make markets operate efficiently, as discussed more fully below.

- As explained in the narratives provided in the ISO/RTO performance reports, all metrics must be evaluated in the context of all of the factors that influence performance, to determine the extent to which the metrics are measuring ISO/RTO performance and the extent to which they reflect the impact of other factors.

Review of Performance Results

ISO/RTO metrics were designed to measure performance on three dimensions: (1) market benefits; (2) organizational effectiveness; and (3) reliability. The following provides highlights of the performance results in each of these categories.

Market Benefits

ISO and RTO markets provide benefits to energy producers and consumers to the extent their markets are competitive and their programs for making their markets operate more efficiently are successful in lowering customer costs. ISO/RTO security-constrained economic dispatch[3] is intended to facilitate maximum participation by all resources and maximum utilization of the least-cost resources, thereby enhancing competition and ensuring a reasonable cost of energy for customers. ISO/RTO efficiency programs, such as incentives to induce resources to be available, are intended to ensure the full benefits of competition are realized.

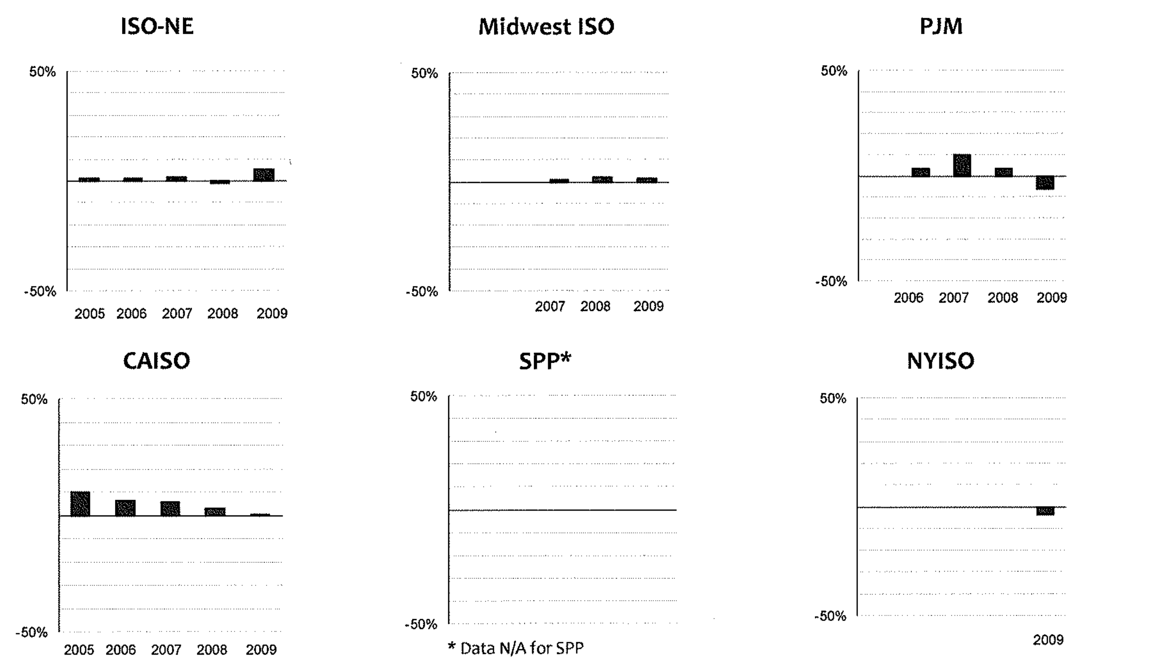
Of the 16 metrics developed to measure the performance of ISOs and RTOs in delivering market benefits, and that are detailed in the reports in Appendices D through I, we focus below on one of the competition metrics, several efficiency metrics, such as generator availability, and the market price measures.

The price-cost metric (Chart 1) compares the marginal price to the marginal cost of energy production. The closer the marginal price is to the marginal cost, the more competitive the market. Performance against this metric supports the proposition that all ISOs/RTOs have competitive markets, as reflected in the close parity of marginal prices and marginal costs.[4] However, there are some differences in data reported by the ISOs and RTOs that result from historical differences during the reporting period. CAISO's report for this metric relies on estimates based on bilateral price indices and cost estimates for the earlier years. Only the 2009 data represents actual market data, because CAISO did not have a forward energy market prior to that time. As a result, while the CAISO trend appears to show marginal prices and marginal costs converging, indicating more competitive conditions, such a conclusion may not be accurate. We also note that while it appears that the PJM price-cost markup in 2007 reflects less competitive conditions, a substantial portion of the 2007 markup occurred on high-load days. Therefore, it is likely that the higher prices were the result of administratively-determined scarcity pricing rather than the exercise of market power.

3 Security-constrained economic dispatch is the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limit of generation and transmission facilities. See Energy Policy Act of 2005, section 1234.

4 SPP does not report a price-cost mark-up. Its Independent Market Monitor assesses its market to be competitive based on an evaluation of threshold tests for market-based rate applications.

Chart 1: Price-Cost Mark Up 2005-2009*



* Price-Cost Mark Up Definition: Load-weighted average mark up on cost-based offer divided by load-weighted price offer, expressed as a percentage. Positive percentage indicates that the marginal price is higher than the marginal cost. Negative percentage indicates the marginal cost is higher than the marginal price.

Source: Derived from content presented in Appendices D through I

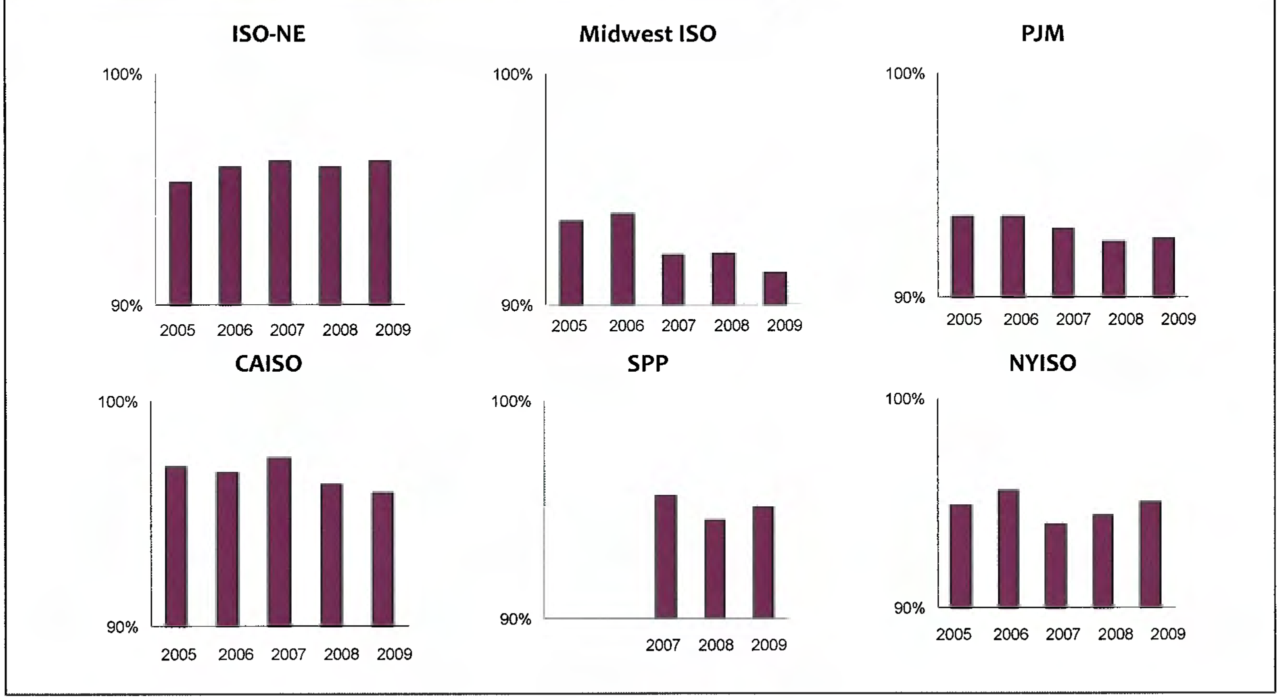
Commission Staff plans to continue to monitor this metric in future reports as additional actual market data is generated and included in the metric.

Additional indicators that support the conclusion that ISO/RTO markets are competitive are low market concentration indices, as discussed in more detail in the individual ISO/RTO performance reports,[5] and energy market prices are closely tracking fuel costs, discussed further below. Also, demand response entering markets as new resources have provided additional competition.

The market benefits of ISO/RTO programs for making their markets operate more efficiently can be measured by the generator availability, demand response availability and congestion management metrics. While resource availability and congestion management are influenced by market factors, incentive programs for resource participation and effective transmission planning by ISOs/RTOs to manage congestion can also improve efficiency.

5 See, for example, Appendix F at p. 106.

Chart 2: Generator Availability Range 2005-2009*



*Generator Availability Definition: The capacity of a generator adjusted for planned outages, expressed as a percentage of hours available over a year.
Source: Derived from content presented in Appendices D through I.

Generator availability (Chart 2) was in the range of 91 to 98 percent over the 2005 – 2009 period. It is noteworthy that the five-year trend in ISO-NE generator availability reflects improvements in the availability of generators using all fuels except coal generation that declined slightly. The trend in decreasing availability in PJM reflects the impact of decreased availability of older coal-fired generation units that outweighed reduced outage rates system-wide over this period.[6] It is not possible to assess the causes of the decreasing generator availability reflected in the Midwest ISO generator availability metric because the Midwest ISO based the data reported for the years prior to 2009, in part, on North American Electric Reliability Corporation (NERC) industry-wide class average estimates[7] rather than on actual data provided by generators in the Midwest ISO.

ISOs and RTOs have evaluated demand response availability during emergency events, such as the August 2006 heat wave, as discussed in their reports. It is not possible to show this information on a chart due to the lack of comparable information across all ISOs and RTOs. ISO-NE estimated the availability of

6 See Appendix H at p. 300 for a complete discussion.

7 NERC estimates class average capacity factors for the various types of generation based on historical data.

all demand response resources, passive and active, to be 84 percent based on events from August 1, 2006 through August 25, 2009. In NYISO, demand response provided 865 MW on August 2, 2006 and 345 MW on July 27, 2006 during emergency conditions. In PJM, demand response availability was 121 percent in 2006 and 118 percent during testing in 2009/2010.

Congestion costs[8] vary between the ISOs and RTOs, reflecting differences in system topologies and shifts in loads over the evaluation period, as detailed in the discussion in the Appendices. Nonetheless, ISO/RTO programs can have an impact on congestion, for example through transmission planning initiatives. As an example, PJM's Regional Transmission Expansion Plan includes increases in transmission system capacity that are expected to alleviate 90 percent of the current congestion costs in the region.

Finally, with respect to the bottom line for consumers – their costs – security constrained economic dispatch and ISO/RTO efficiency programs have yielded benefits. For example, PJM was able to reduce annual generation production costs by $122 million due to improved generation dispatch in 2009. Security constrained economic dispatch also reduced reliance by ISOs and RTOs on less efficient and less reliable physical and manual procedures, such as transmission loading relief, to resolve system constraint problems. Midwest ISO was particularly successful in reducing transmission loading relief,[9] from 842 in 2006 to 371 in 2009.

Market price trends in Chart 3 (on next page) reflect the impact on market prices of market factors such as fuel costs as well as ISO/RTO efficiency programs. The top two lines in Chart 3, the energy cost and total power cost metrics, illustrate the impact of fuel price trends. As detailed in the ISO/RTO performance reports, the nation-wide increase in fuel costs in 2008 and the decrease in 2009 were closely tracked in wholesale energy prices. More relevant to an assessment of ISO/RTO performance is the bottom line in Chart 3, the market price adjusted for fuel costs. This metric, when compared to unadjusted market prices, shows the impact of security constrained economic dispatch, incentives for improved generator availability, investment in more efficient generating units and other factors on prices. Therefore, this metric provides a measure of the efficiency of the ISO/RTO markets, and how that efficiency provides a benefit to consumers in their cost of energy. It should be noted that each of the ISOs/RTOs uses a different base year for their fuel adjustments and different fuel mixes and therefore direct comparisons among the ISOs/RTOs are not meaningful. The meaning and significance of the trends in this metric for each ISO/RTO are of particular interest to Commission Staff and will be evaluated further in future reports.

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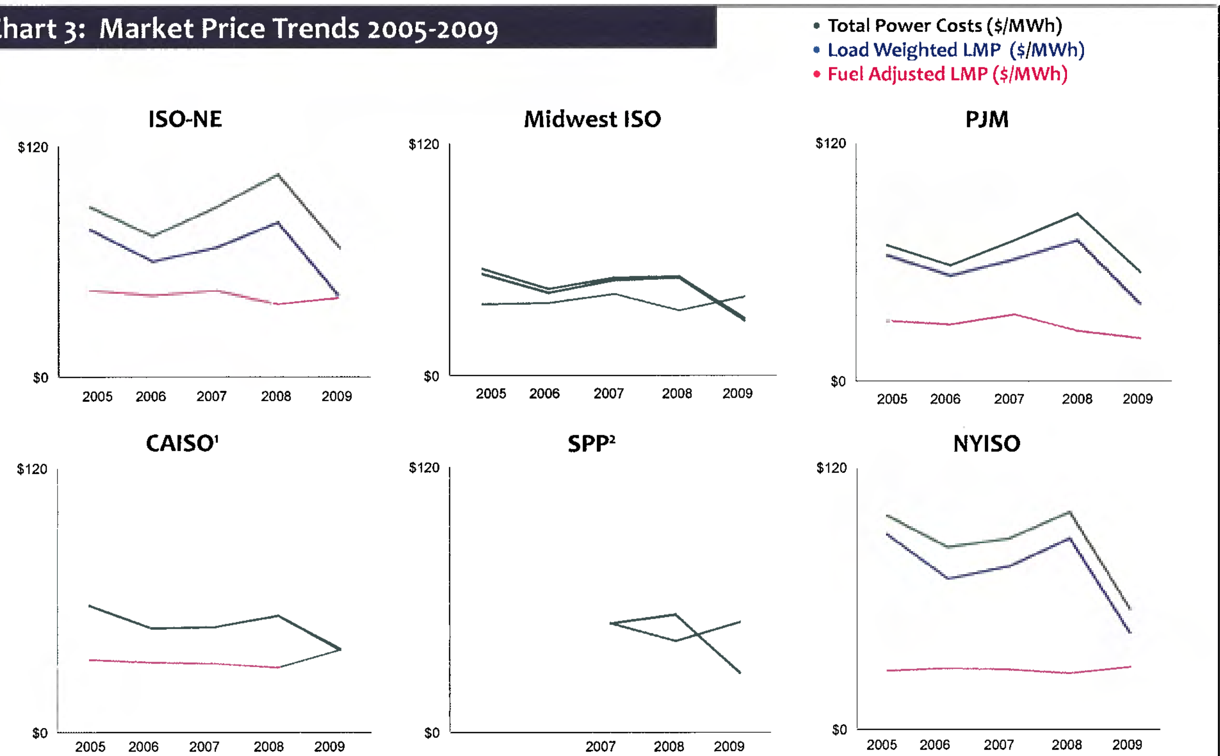
8 Congestion occurs when the physical limits of a line prevent load from being served with the least cost energy. Congestion costs measure the difference between the actual cost of energy and least cost energy.

9 Transmission loading relief is an action taken by a Reliability Coordinator to ensure that reliability is maintained within the operating limits of a transmission system. Such actions include curtailment of transmission transactions and load shedding.

Chart 3: Market Price Trends 2005-2009

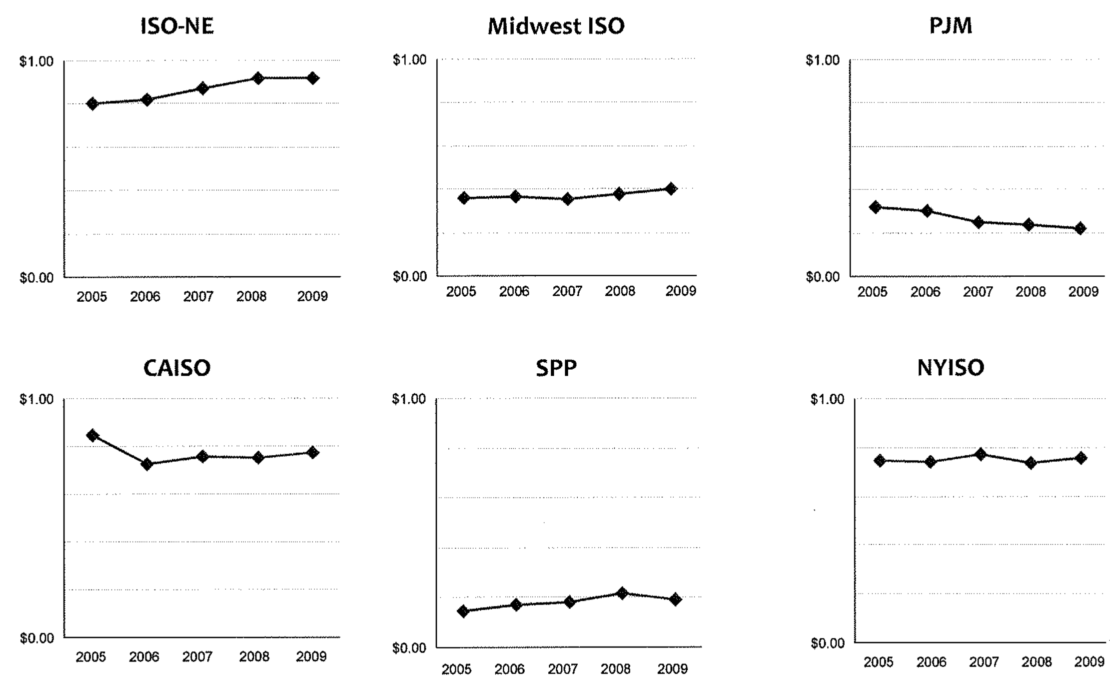


1. The CAISO Load Weighted LMP and Total Power Cost is the same for years 2005-2008.
2. Data for SPP is only available since 2007. The SPP Load Weighted LMP and Total Power Cost is the same for years 2007-2009.

Note: Total power costs include the cost of energy, transmission, capacity, ancillary services and administative costs. Load-weighted LMP represents the average load-weighted wholesale electricity energy spot prices in ISOs/RTOs. Fuel Adjusted LMP is derived by holding the fuel cost constant over the five-year period and represents the average load-weighted wholesale electricity energy spot prices that result from this adjustment.
Source: Derived from content presented in Appendices D through I

Demand response participation reduced market prices, as discussed in the ISO/RTO reports. It is not possible to show this information on a chart due to the lack of comparable information across all ISOs and RTOs. ISO-NE estimates that demand response participation reduced real-time prices from $0.04 to $1.43/MWh over the 2008 – 2009 period. Demand response in NYISO provided an average price reduction of $0.27 per MWh during 2005 – 2009 resulting in a total savings of $44 million over this period. PJM estimates that demand response saved $650 million during the August 2006 event and that wholesale energy prices were reduced by more than $300 per MWh during the highest usage hours. Demand response in Midwest ISO provided approximately 3000 MW during the August 2006 emergency event, reducing clearing prices by $100 - $200 per MWh for savings of over $3 million.

Chart 4: Administrative Costs 2005-2009 (in $/Mwh of Load)



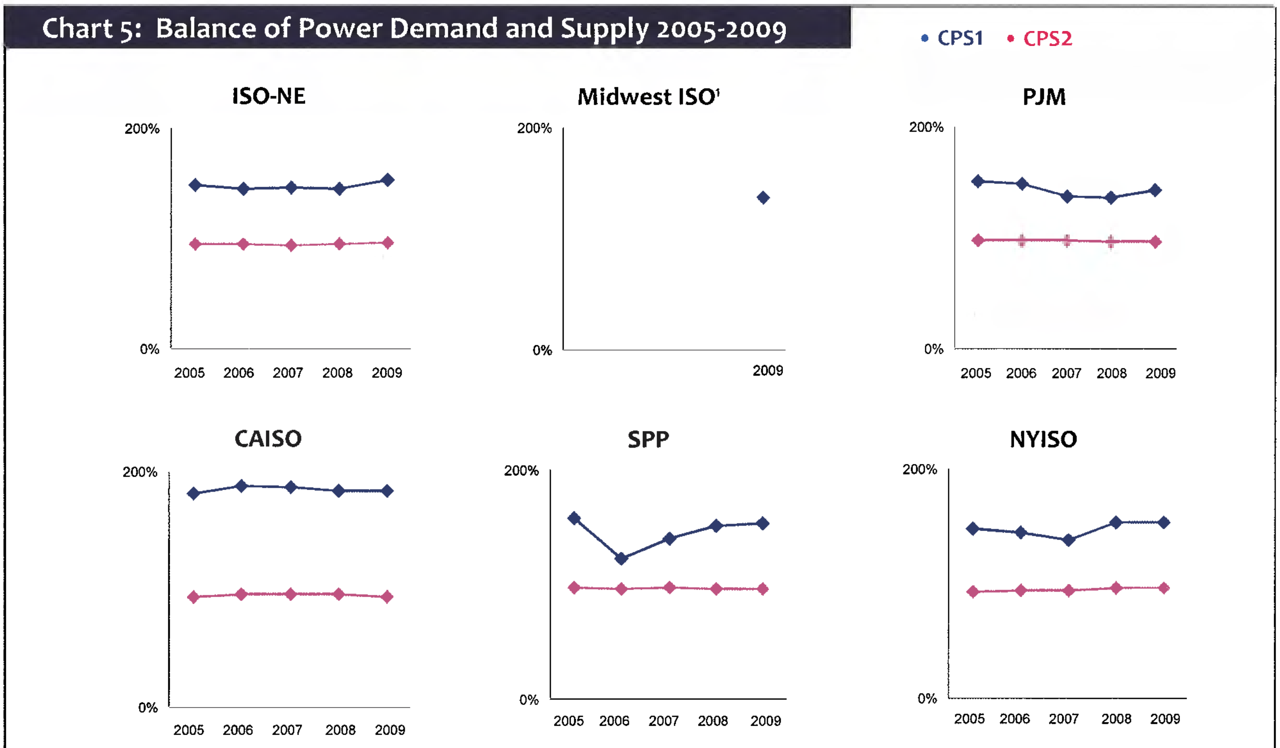
Source: Derived from content presented in Appendices D through I

Organizational Efficiency

The five organizational effectiveness metrics are designed to measure ISO/RTO performance in accomplishing their objectives in a cost-effective manner that provides value to market participants.

Of particular interest in this regard is the administrative cost metric. Between 2005 – 2009, CAISO and PJM reduced administrative costs per MWh of load, NYISO costs per unit of load held steady and Midwest ISO's, SPP's and ISO-NE's costs per unit of load increased, as illustrated in Chart 4.

Chart 5: Balance of Power Demand and Supply 2005-2009



1. No CPS1 data available for 2005-2008. No CPS2 data available for 2005-2009. Midwest ISO was participating in Balance Authority Ace Limit (BAAL) Field Test.

Source: Derived from content presented in Appendices D through I

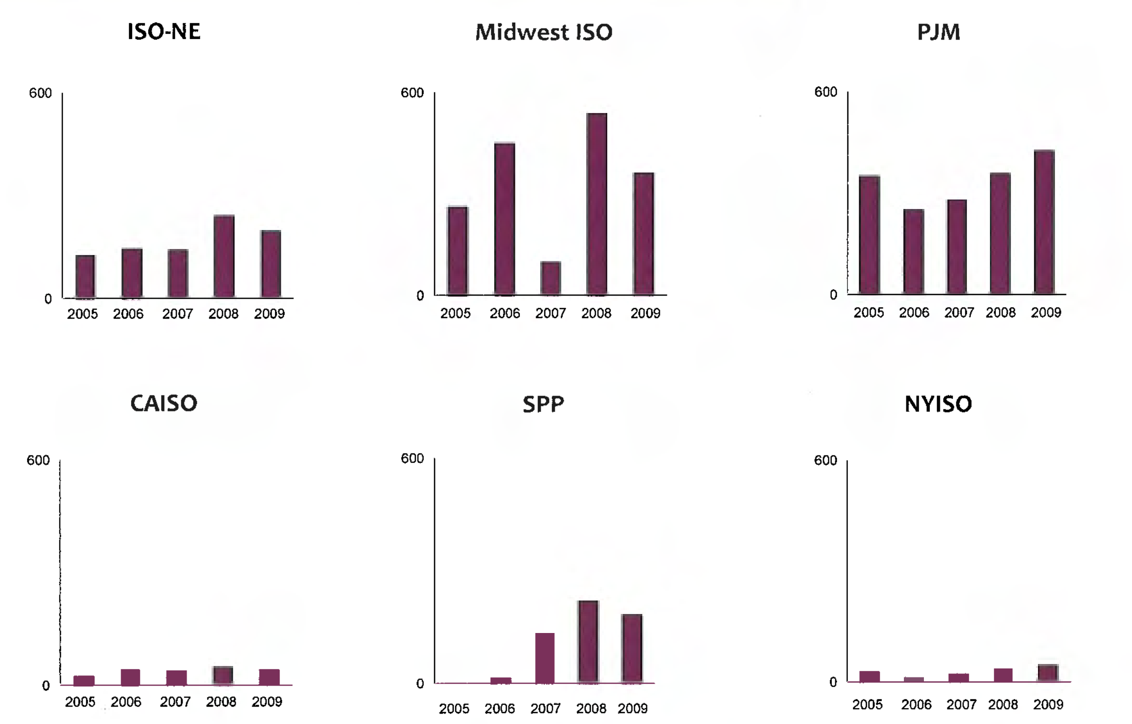
Reliability

The 36 reliability performance metrics were designed to measure both the reliability of day-to-day operations and long-term reliability. We focus on one of the day-to-day operational performance metrics and one of the long-term reliability metrics.

Real-time dispatch reliability in ISOs and RTOs, a short-term reliability measure (shown in Chart 5), was maintained at levels that exceeded national and regional reliability required standards, based on Control Performance Standard 1 and 2 metrics that measure the ability of Balancing Authorities to balance power demand and supply in real-time.[10] Control Performance Standard 1 results were in the 188 to 123 percent range, significantly above the minimum required standard of 100 percent and Control Perfor-

10 Control Performance Standard 1 is a statistical measure of Area Control Error (or ACE, defined as the difference between actual and scheduled net interchange) in combination with the interconnection's frequency error. Control Performance Standard 2 is a measure of the magnitude of ACE. Some RTOs use Balancing Authority ACE Limit (BAAL) as an alternative metric. This metric requires the Balancing Authority to balance its resources and demands so that ACE does not exceed the BAAL limit for a time greater than 30 minutes and limits the recovery period to no more than 30 minutes for a single event.

Chart 6: Approved Reliability Transmission Projects 2005-2009



Source: Derived from content presented in Appendices D through I

mance Standard 2 results were in the 98 to 94 percent range, above the minimum required standard of 90 percent. These results indicate a strong level of compliance in this area of load-generation balancing under the current Reliability Standards.

ISOs and RTOs also play a role in ensuring long-term reliability through their long-term transmission planning programs that evaluate and prioritize regional reliability transmission projects. ISO/RTO long-term reliability transmission planning resulted in the approval of hundreds of reliability transmission projects over the 2005 – 2009 period as illustrated in Chart 6.

The transmission planning process is a comprehensive assessment that evaluates the impacts of a wide range of resource and load trends and technology innovations on the transmission system to ensure that the regional plans incorporate those transmission projects with the greatest reliability and economic benefit. Regional transmission plans include the consideration of demand response solutions to system requirements. Demand response accounts for 3 to 7 percent of installed capacity in a number of the ISO/RTO markets.

Next Steps

In closing, the foregoing summary is intended to be a high level introduction to the performance metrics discussed in greater detail in the performance report appendices that follow. Commission Staff will be evaluating these reports further. In assessing these initial reports, the ISOs and RTOs have identified several challenges that we will evaluate in the next report.

- The need for new transmission capacity to ensure reliability and to reduce congestion.
- The need for improved wind and solar forecasts to address an increase in variable energy resources.
- The need to address the control, communication and reliability challenges associated with intergrating demand response resources into energy and ancillary services markets.
- The need for more accurate transmission project cost estimates, thereby ensuring that the growing number of transmission expansion projects stay on schedule and obtain the support of stakeholders.

Further detail on these performance results as well as a complete assessment of the 57 performance metrics are provided in the Performance Metrics Summary in Appendix C and the individual ISO/RTO reports in Appendices D through I. Also, the ISO/RTO Performance Metrics Development Process in Appendix A describes the voluntary and collaborative process undertaken by Commission Staff to develop ISO/RTO performance metrics with input from the ISOs and RTOs, transmission customers, market participants and other stakeholders and interested experts. This voluntary and collaborative approach will be used to develop performance metrics for non-ISO/RTO regions during fiscal year 2011. The Commission Staff Report in Appendix B provides a summary of comments from stakeholders and other interested parties and Commission Staff's recommendations that resulted in the final list of metrics.

Appendix A

ISO/RTO Performance Metrics Development Process

- Commission Staff, at the Chairman's direction, initiated the development of ISO/RTO Performance Metrics in May 2009.
- Through the summer and fall of 2009 Commission Staff developed a list of proposed performance metrics and discussed them with a team of ISO and RTO staff representing the ISOs and RTOs under the jurisdiction of the Federal Energy Regulatory Commission.[1]
- In January 2011 Commission Staff held focused outreach meetings with a variety of industry, consumer and state regulatory associations.[2]
- On February 2, 2010 Commission Staff issued the proposed performance metrics for comment and reply comment.
- On March 5 and March 19, 2010 comments and reply comments were filed by 59 parties.[3]
- Commission Staff reviewed the comments and issued a Commission Staff Report on October 21, 2010 (Appendix B). In the report, Commission Staff revised the proposed metrics based on the comments received and addressed issues raised by commenters. Commission Staff also requested that ISOs and RTOs submit reports with three to five years of data for the recommended metrics.[4]
- On December 6, 2010 the ISOs and RTOs submitted their reports.
- On April 7, 2011 the Chairman submitted this report to Congress.

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1 These ISOs and RTOs are ISO New England, Inc. (ISO-NE), New York Independent System Operator, Inc. (NYISO), PJM Interconnection, L.L.C. (PJM), Midwest Independent Transmission System Operator, Inc. (Midwest ISO), Southwest Power Pool, Inc. (SPP), and the California Independent System Operator Corporation (CAISO).

2 American Public Power Association, Electricity Consumers Resource Council, National Rural Electric Cooperative Association, National Association of Regulatory Utility Commissioners, National Association of State Utility Consumer Advocates, Edison Electric Institute, American Wind Energy Association, New England Public Utilities Commissioners and the Electric Power Supply Association.

3 The parties are listed in the Commission Staff Report in Appendix B.

4 These reports are attached as Appendices D through I.

APPENDIX 3

STAFF REPORT

Common Metrics Report

Docket No: AD14-15-000

Performance Metrics for Regional Transmission Organizations, Independent Systems Operators, and Individual Utilities for the 2010-2014 Reporting Period

Federal Energy Regulatory Commission • August 2016
(Revised August 2017)

2016

Common Metrics Report: Performance Metrics for Regional Transmission Organizations, Independent System Operators, and Individual Utilities for the 2010-2014 Reporting Period

Staff Report

Federal Energy Regulatory Commission
August 2016 (Revised August 2017)

This report is a product of the staff of the Federal Energy Regulatory Commission. The opinions and views expressed in this paper represent the preliminary analysis of the Commission staff. This report does not necessarily reflect the views of the Commission.

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Table of Contents

List of Tables

List of Figures

Preface and Caveats

This report is the latest activity in an initiative originally designed to examine the performance and benefits of Regional Transmission Organizations (RTO) and Independent System Operators (ISO). The initiative arose in response to a 2008 Government Accountability Office (GAO) report recommending that the Federal Energy Regulatory Commission (FERC) do more to track the performance and benefits of RTO and ISO markets.[1] The previous report in this initiative, issued in August 2014, established a set of common performance metrics for evaluating the performance of RTOs and ISOs and individual utilities in regions outside of RTOs and ISOs (referred to hereinafter as "non-RTOs and ISOs," "non-RTO and ISO respondents," or "non RTO and ISO utilities") in areas where these entities perform identical functions. These performance metrics cover both reliability and system operations activities.

The source of data for this report is primarily information collected from RTOs and ISOs and non-RTOs and ISOs under Information Collection FERC-922, "Performance Metrics for ISOs, RTOs and Regions Outside ISOs and RTOs" (Office of Management and Budget Control No. 1902-0262). Other market-specific data were voluntarily submitted by the six Commission-jurisdictional RTOs and ISOs. Consistent with past practice in this initiative, respondents submitted information on a voluntary basis. Six RTOs and ISOs responded,[2] along with seven non-RTO and ISO utilities. Commission staff greatly appreciates the efforts of those who contributed information to this initiative.

The report contains analyses, presentations, and conclusions that, unless otherwise noted, are based on or derived from the data provided by respondents, but do not necessarily reflect the positions or conclusions of the respondents themselves. Furthermore, the opinions and views expressed in this report do not necessarily represent those of the Commission, its Chairman, or individual Commissioners, and are not binding on the Commission. Any errors are those of Commission staff.

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[1] U.S. Gov't Accountability Off., GAO #08-987, Gov't Accountability Off. Report to the Committee on Homeland Security and Government Affairs, U.S. Senate; Electricity Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance (2008) (2008 GAO Report).

[2] The six Commission-jurisdictional RTOs and ISOs responded. These are as follows: California Independent System Operator Corporation (CAISO); ISO New England Inc. (ISO-NE); Midcontinent Independent System Operator, Inc. (MISO); New York Independent System Operator, Inc. (NYISO); PJM Interconnection, L.L.C. (PJM); and Southwest Power Pool, Inc (SPP).

The metrics used in this report pertain to both RTOs and ISOs and non-RTOs and ISOs. However, several limitations preclude all but the most basic observations about the metrics submitted by RTOs and ISOs relative to those submitted by non-RTOs and ISOs. While the intent behind these metrics is to compare areas in which RTOs and ISOs and non-RTOs and ISOs perform identical functions, Commission staff notes that there are significant differences in the scale of operations performed by the largest RTOs and ISOs as compared to non-RTO and ISO respondents with relatively smaller service territories (e.g., PJM's footprint covers territory in 13 states and the District of Columbia,[3] whereas Arizona Public Service Company's territory covers 11 counties in Arizona).[4] These data limitations and differences must be carefully considered when comparing metrics-related information submitted by RTOs and ISOs and non-RTOs and ISOs. As such, Commission staff has largely avoided drawing these types of comparisons.

In addition, these metrics do not capture some of the potential benefits that are difficult to isolate and measure, e.g., benefits created by providing opportunities for input by a broad range of stakeholders.

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[3] California Independent System Operator Corporation; ISO New England Inc.; Midcontinent Independent System Operator, Inc.; New York Independent System Operator; PJM Interconnection, L.L.C.; and Southwest Power Pool, Inc. October 30, 2015 Filing, at 279 (October 2015 RTO and ISO Metrics Report).

[4] Arizona Public Service Company November 5, 2015 Filing, at 1 (November 2015 APS Metrics Report).

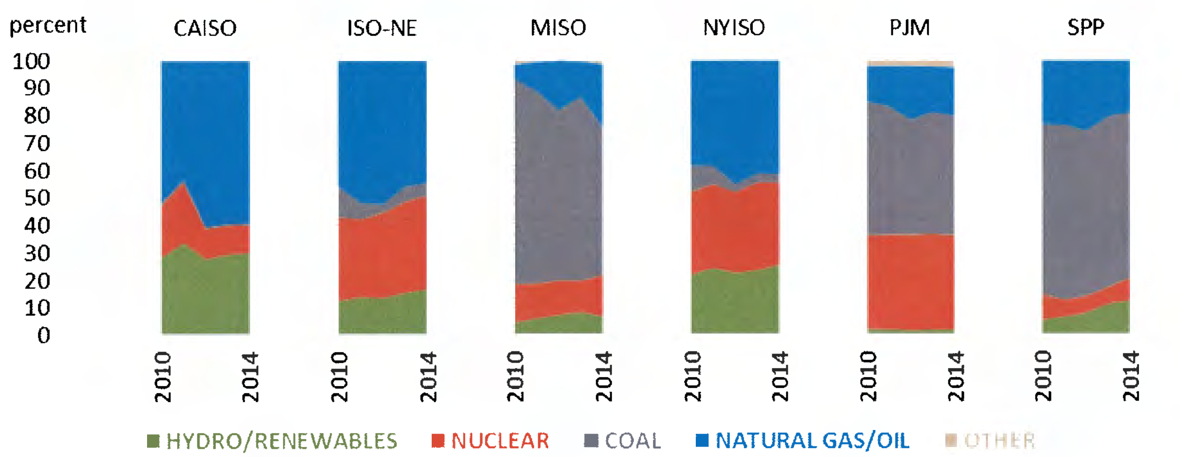
Executive Summary

This report contains a review of performance metrics for RTOs and ISOs as well as non-RTO and ISO utilities for the period from 2010-2014.

Key Insights Regarding RTOs and ISOs

RTOs and ISOs managed the dispatch of energy from a diverse set of generating fuel-types from 2010-2014. RTOs and ISOs manage the scheduling and deployment of different resource types through day-ahead and real-time energy markets, which operate as market clearing auctions that establish commitment and dispatch schedules subject to system constraints. RTOs and ISOs report managing the dispatch of energy from varying fuel sources from 2010-2014; as seen in Figure 1, most RTOs and ISOs report managing an increasing share of energy from renewable generation and fluctuations in the relative amounts of energy provided by natural gas-fired generation and coal-fired generation.

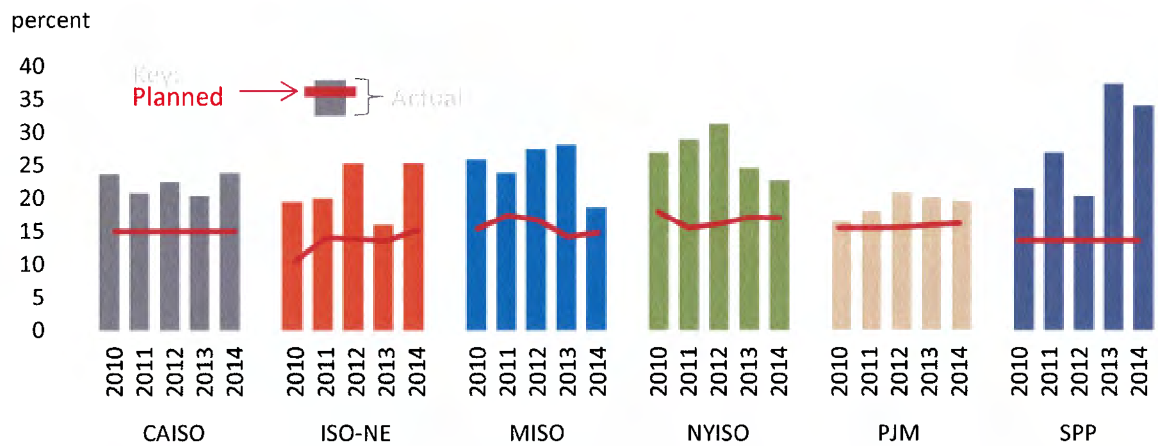
Figure 1: Share of total generation by fuel type, 2010-2014.



Source: Commission staff based on information collection FERC-922.

RTO and ISO regions maintained adequate power supplies, in accordance with planned reserve margins from 2010-2014. Planning reserves ensure that there is a low probability of loss-of-load due to inadequate supply. As shown in Figure 2, RTOs and ISOs report capacity in excess of planned reserve levels in each year from 2010-2014.

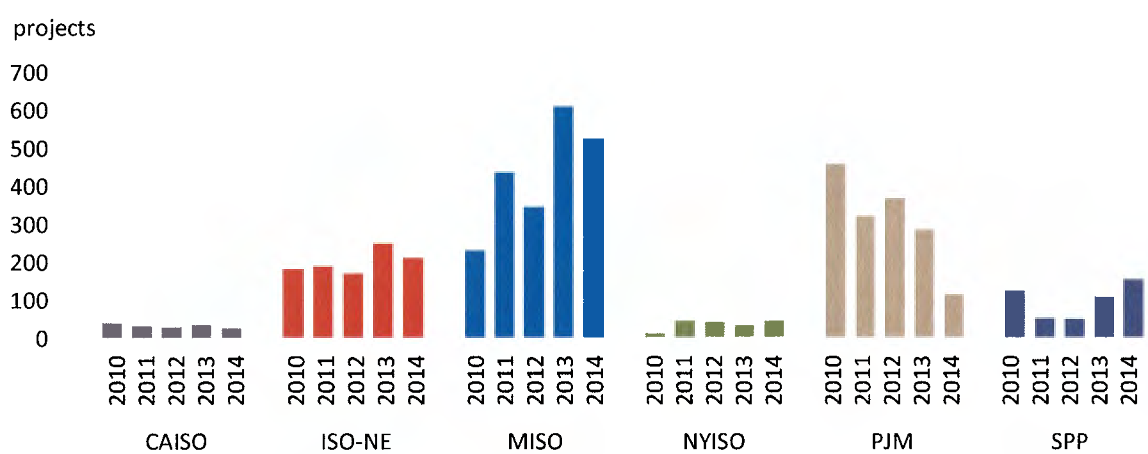
Figure 2: RTOs and ISOs planned and actual reserve margins, 2010-2014.



Source: Commission staff based on information collection FERC-922.

RTOs and ISOs report the approval of a large number of transmission projects for reliability purposes from 2010-2014. Adequate transmission is an essential element of a reliable power system. RTOs and ISOs evaluate transmission projects for reliability purposes in their planning processes. As shown in Figure 3, all RTOs and ISOs report the construction of transmission projects for reliability purposes between 2010 and 2014, helping to ensure a reliable grid.

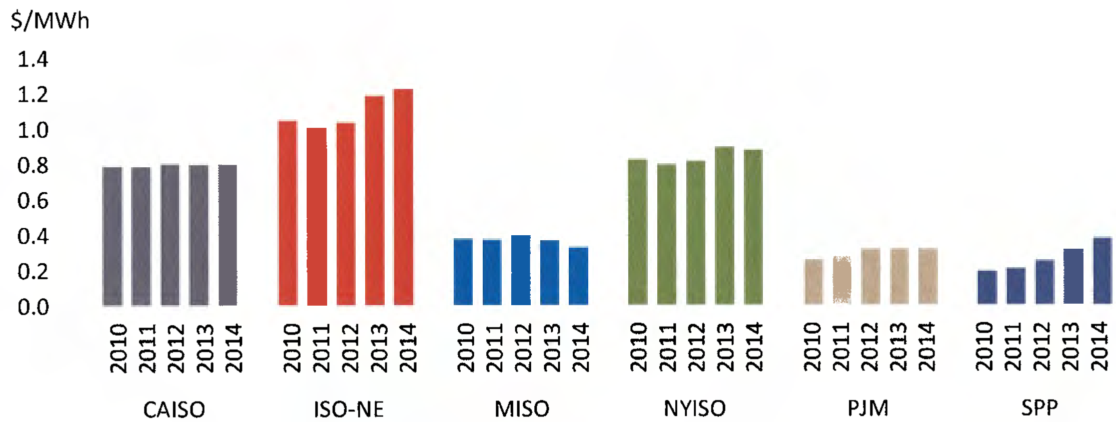
Figure 3: Number of transmission projects approved for construction for reliability purposes, 2010-2014.



Source: Commission staff based on information collection FERC-922.

Administrative costs per megawatt-hour varied across RTOs and ISOs from 2010-2014. Administrative charges (including both capital and non-capital costs) measured as per megawatt-hour of load allows for comparison across markets of different sizes. As shown in Figure 4, RTOs and ISOs report a range of administrative charges per megawatt-hour of load. In some cases, these charges were relatively flat between 2010 and 2014, while in other cases the charges increased, in nominal terms. PJM and MISO, two of the largest RTOs, report relatively low administrative charges per megawatt-hour. Administrative costs typically represent a small percentage of the total cost of wholesale power.[5]

Figure 4: Annual per-megawatt-hour administrative costs, 2010-2014.



Source: Commission staff based on 2015 RTO and ISO Metrics Report.
Note: Values are expressed in nominal dollars per megawatt-hour.

[5] *See infra* pp. 51-52.

I. Introduction and Overview

This report presents Commission staff's review of data relating to performance metrics that measure activities in which RTOs and ISOs and non-RTO and ISO utilities performed identical functions during the 2010-2014 reporting period. Additionally, the report presents Commission staff's review of certain metrics data submitted by RTOs and ISOs that are specific to RTO and ISO market and administrative functions.

During 2015, six RTOs and ISOs submitted performance metrics data in a joint report in Docket No. AD14-15-000. Additionally, seven utilities in non-RTO and ISO regions submitted performance metrics data on a voluntary basis.

Commission staff collected the 30 common metrics from RTOs and ISOs and non-RTO and ISO utilities under information collection FERC-922, "Performance Metrics for ISOs, RTOs and Regions Outside ISOs and RTOs" (OMB Control No. 1902-0262). Information Collection FERC-922 includes 30 common metrics used to measure the performance of certain reliability and system operations in areas where RTOs and ISOs and non-RTO and ISO respondents perform identical functions. The reliability performance metrics measure both day-to-day operations and long-term reliability. The system operations metrics measure certain aspects of operational efficiency. Table 13 in Appendix A lists the 30 common metrics.

Table 1 lists the entities who submitted the metrics data reflected in this report and the acronyms used to refer to these entities in the remainder of this report.

Table 1: Respondents submitting performance metrics reports for 2010-2014.

RTOs and ISOs	non-RTOs and ISOs
California Independent System Operator Corporation (CAISO)	Arizona Public Service Company (APS)
ISO New England Inc. (ISO-NE)	Duke Energy Carolinas, LLC (DEC)
Midcontinent Independent System Operator, Inc. (MISO)	Duke Energy Progress, LLC (DEP)
New York Independent System Operator, Inc. (NYISO)	Duke Energy Florida, LLC (DEF)
PJM Interconnection, L.L.C. (PJM)	Louisville Gas and Electric Company and Kentucky Utilities Corporation (LG&E/KU)
Southwest Power Pool, Inc. (SPP)	PacifiCorp (PAC) (note that some metrics are reported separately for PacifiCorp – East (PACE) and PacifiCorp – West (PACW))
	Southern Company (SOU)

This report contains the following sections:

- Background, which briefly summarizes the history of the common metrics initiative;
- Common Metrics Review, which reviews the metrics data submitted by RTOs and ISOs and non-RTO and ISO respondents;
- Other Metrics, which reviews data responsive to metrics specific to RTO and ISO markets;
- Appendix A, which contains detailed descriptions of the 30 common metrics; and
- Appendix B, which summarizes recent studies that have quantified certain RTO and ISO benefits that the metrics do not cover.

II. Background

In May 2007, Senators Joseph I. Lieberman and Susan M. Collins of the U.S. Senate Committee on Homeland Security and Governmental Affairs requested that the GAO investigate RTO and ISO costs, structure, processes, and operations.[6] In a September 2008 Report to the U.S. Senate Committee on Homeland Security and Governmental Affairs, the GAO recommended that FERC work with RTOs, ISOs, stakeholders and other interested parties to develop standardized measures to track the performance of RTO and ISO operations and markets; report on those measures; and interpret how the measures communicate evidence of RTO and ISO benefits or performance concerns.[7]

Commission staff developed the common metrics initiative in response to the 2008 GAO Report. The evolution of the initiative included Commission staff taking steps to meet five objectives. These objectives, as described in FERC's Fiscal Year 2009-2014 Strategic Plan, include: (1) developing appropriate operational and financial metrics for RTOs and ISOs; (2) exploring and developing appropriate operational and financial metrics for non-RTO and ISO utilities; (3) establishing appropriate common metrics

[6] The Senators made this request in a May 21, 2007 letter to the GAO. The letter expressed the Senators' concern that RTOs and ISOs may not be living up to their full potential with respect to improving efficiencies and reducing costs, and that RTOs and ISOs might not have adequate incentives to minimize costs.

[7] *See* 2008 GAO Report at 56, 59-61.

between RTOs and ISOs and non RTO and ISO utilities; (4) monitoring implementation and performance; and (5) evaluating performance and seeking changes, as necessary.[8]

In April 2011, after establishing metrics for RTOs and ISOs under the first objective, the then-Chairman's Office submitted a Report to Congress summarizing RTO and ISO performance for the years 2005-2009.[9] To meet the second objective, Commission staff issued a report on performance in regions outside RTOs and ISOs in October 2012.[10] An August 2014 Commission Staff report[11] satisfied the third, fourth, and fifth objectives by establishing, implementing, and evaluating a set of common metrics. This report represents a continuation of the fifth objective.

III. Common Metrics Review

A. Reliability Metrics

1. NERC Reliability Standards Compliance

a. References to Applicable NERC Standards

This metric provides an overview of the North American Electric Reliability Corporation (NERC) standards that are applicable to each respondent. Each respondent submitted a table identifying applicable NERC functional model registrations.[12] As shown in Tables 2 and 3, there are several areas in which the respondents perform similar functions. For example, most respondents are registered balancing authorities and transmission operators. In other areas, the RTO and ISO respondents are dissimilar from the non-RTO

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[8] FERC, *The Strategic Plan: FY 2009-2014 (Revised 2013)*, at 13, http://www.ferc.gov/about/strat-docs/FY-09-14-strat-plan-print.pdf.

[9] FERC, *Performance Metrics For Independent System Operators and Regional Transmission Organizations*, Docket No. AD10-5-000, at 5 (2011); *see also* FERC, *2010 ISO/RTO Performance Metrics Commission Report*, Docket No. AD10-5-000 (2010).

[10] FERC, *Performance Metrics In Regions Outside ISOs and RTOs Commission Staff Report*, Docket No. AD12-8-000 (2012).

[11] FERC, *Common Metrics Commission Staff Report*, Docket No. AD14-15-000 (2014), http://www.ferc.gov/legal/staff-reports/2014/ad14-15-performance-metrics.pdf.

[12] The timing of snapshots of each respondent's functional model registrations did not coincide, e.g., ISO-NE's submittal represents registrations as of the end of 2013; NYISO's submittal represents registrations as of the end of 2014, and APS' submittal represents registrations as of August 2015.

and ISO respondents. For instance, most of the RTOs and ISOs perform reliability coordinator functions while most of the non-RTO and ISO respondents do not.

Table 2: Selected NERC functional model registrations identified by RTO and ISO respondents.

	Balancing Authority	Interchange Authority	Planning Authority	Reliability Coordinator	Resource Planner	Transmission Operator	Transmission Planner	Transmission Service Provider
CAISO	●		●			●		●
ISO-NE	●	●	●	●	●	●	●	●
MISO	●	●	●	●	●	●		●
NYISO	●	●	●	●	●	●	●	●
PJM	●	●	●	●	●	●	●	●
SPP	●		●	●			●	●

Source: Commission staff based on information collection FERC-922.

Note: Cells marked with "●" denote that the respondent identified the functional model registration in its data submittal.

Table 3: Selected NERC functional model registrations identified by non-RTO and ISO respondents.

	Balancing Authority	Interchange Authority	Planning Authority	Reliability Coordinator	Resource Planner	Transmission Operator	Transmission Planner	Transmission Service Provider
APS	●		●		●	●	●	●
DEC	●	●	●		●	●	●	●
DEF	●	●	●		●	●	●	●
DEP	●	●	●		●	●	●	●
LG&E/KU	●	●	●		●	●	●	●
PAC	●		●		●	●	●	●
SOU	●	●	●	●	●	●	●	●

Source: Commission staff based on information collection FERC-922.

Notes: (1) Cells marked with "●" denote that the respondent identified the functional model registration in its data submittal. (2) PACE and PACW are each an individual balancing authority.

b. Violations Made Public by FERC or NERC[13]

These metrics measure the number of violations of NERC reliability standards, provide information on how these violations were reported (e.g., self-reported or reported in audits), and indicate the severity of violations, when such information is provided. These metrics also detail compliance with operating reserve standards and unserved energy (or load shedding) caused by violations.

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[13] In addition to the violations data discussed in this section, certain respondents provided information regarding (1) the severity level of violations and (2) compliance with operating reserves standards. Reporting formats for the severity level of violations were not uniform, as some respondents reported that severity levels did not apply or that severity classifications changed during the reporting period. *See, e.g.*, October 2015 RTO and ISO Metrics Report at 32 (CAISO stating that "[the Western Electricity Coordinating Council] has stopped identifying severity levels of violations, and they are not included for violations identified as a result of a NERC/FERC investigation.") Additionally, all respondents who discussed operating reserve standards indicated compliance for each year in the reporting period.

i. Number of violations

The number of violations metric measures both the number of violations and how these violations were reported (e.g., self-reported or reported in audits). Mandatory reliability standards only apply based on the NERC functional model categories for which each entity is registered. As a result of the variety of categories, different reliability standards apply to different RTOs and ISOs and to different non-RTO and ISO respondents.

As shown in Figure 5,[14] PJM reports the highest total number of violations for the 2010-2014 reporting period. Most of PJM's violations were self-reported, as is generally the case across both RTO and ISO and non-RTO and ISO respondents. Because PJM is the registered Transmission Operator for the PJM region, PJM executive management has the ultimate decision-making authority to determine whether a potential violation has occurred and whether PJM must submit a self-report to NERC the relevant Regional Entity.[15]

When comparing across entities, it is important to note that it is difficult to draw conclusions based on the relative magnitude of self-reported violations. Differences in self-reported violations may or may not correspond to underlying differences in performance.

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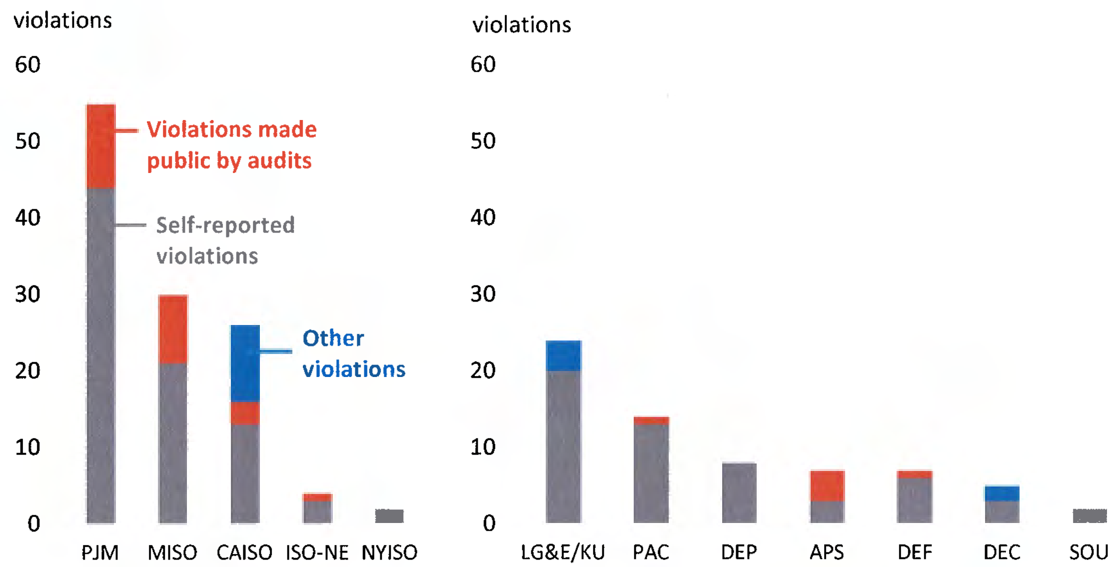
[14] Figure 5 shows total violations reported by each respondent for the 2010-2014 period. Responses are not shown by year, as the year in which a violation is made public may not correspond to the year in which a respondent self-reported a violation or was subject to an audit or spot-check.

[15] *Id.*

Figure 5: Number of violations made public by FERC/NERC as submitted by respondents, 2010-2014.



Source: Commission staff based on information collection FERC-922.
Notes: (1) "Other violations" shown in the figure reflects the difference between the reported total number of violations and the sum of (a) the reported number of self-reported violations and (b) the reported number of violations made public by audits. (2) SPP does not report any violations associated with this metric. (3) The violation totals shown for CAISO derive from values in Tables A, B, and C on pp 30-31 of the October 2015 RTO and ISO Metrics Report. (4) ISO-NE and NYISO totals reflect a supplemental response received by email on January 5, 2016.

ii. Unserved energy (load shedding) caused by violations

Among RTOs and ISOs, CAISO and PJM report instances of load shedding caused by violations during the 2010-2014 reporting period.[16] CAISO reports that in April 2010, an operator believed that load shedding was necessary to maintain an import limit; CAISO also indicates a load shedding event from September 2011, associated with the Pacific Southwest outage.[17] PJM reports that it shed a total of 154.1 MW of load on two days in 2013 in order to protect system reliability.[18] No other RTOs or ISOs report load shedding during the 2010-2014 reporting period.

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[16] Additionally, CAISO discusses a load shedding event from November 2008, which is outside of the reporting period. *See* October 2015 RTO and ISO Metrics Report at 33.

[17] *Id.*

[18] *Id.* at 282.

Among non-RTO and ISO respondents, APS reports load shedding associated with the September 2011 Pacific Southwest outage.[19] No other non-RTO and ISO respondents report load shedding during the 2010-2014 reporting period.

2. Dispatch Reliability

Dispatch reliability metrics measure the performance of dispatch operations in maintaining steady-state frequency within defined limits by balancing power demand and supply in real time, as well as the availability of systems that perform real-time monitoring and security analysis functions.

a. Control Performance Standard 1 (CPS1)

CPS1 is a statistical measure of Area Control Error[20] variability. This standard measures Area Control Error in combination with the interconnection's frequency error.[21] Balancing authorities must achieve a minimum CPS1 compliance of 100 percent over a 12 month period.[22] As shown in Figure 6, each RTO and ISO respondent achieved CPS1 compliance for calendar years 2010-2014.

Among the non-RTO and ISO respondents, only LG&E/KU and PAC submitted annual CPS1 values, demonstrating compliance with CPS1 requirements for calendar years

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[19] November 2015 APS Metrics Report at 6.

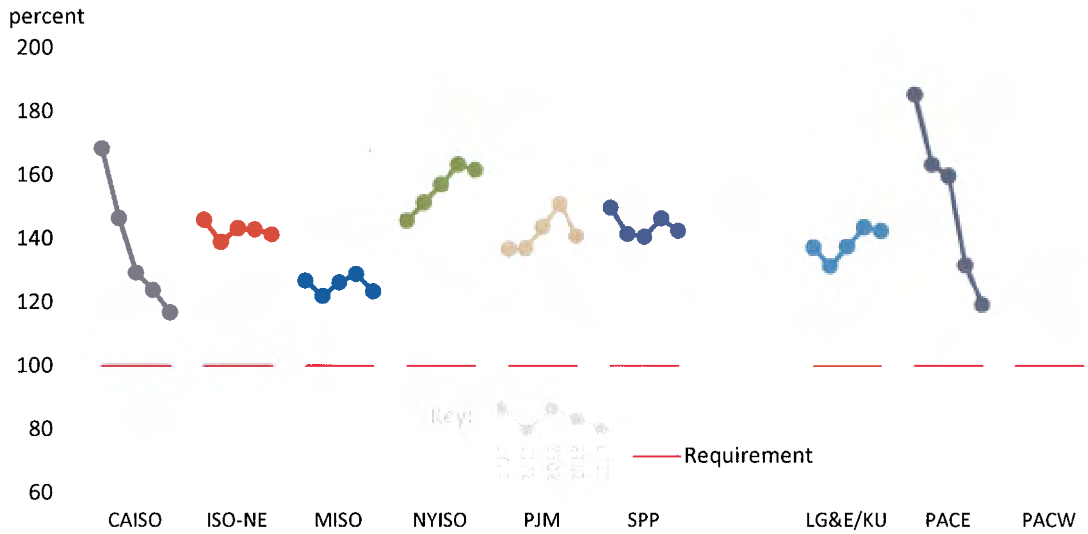
[20] NERC defines Area Control Error as the instantaneous difference between a balancing authority's net actual and scheduled interchange, taking account of frequency bias and meter error. *See* NERC, *Glossary of Terms Used in NERC Reliability Standards* 7 (Apr. 2016).

[21] NERC defines frequency error as the difference between actual and scheduled frequency. *See* NERC, *Glossary of Terms Used in NERC Reliability Standards* 44 (Feb. 2016), http://www.nerc.com/files/glossary_of_terms.pdf.

[22] When a balancing authority's frequency is exactly on schedule or Area Control Error is zero, CPS1 equals 200 percent. The CPS1 calculation is structured such that, if a balancing authority's Area Control Error is proportionally as "noisy" as a benchmark frequency noise, that balancing authority's CPS1 would equal 100 percent. *See* NERC, Balancing and Frequency Control 33-34 (Jan. 2011), http://www.nerc.com/docs/oc/rs/NERC%20Balancing%20and%20Frequency%20Control%20040520111.pdf.

2010-2014. APS;[23] the Duke Energy respondents (DEC, DEF, and DEP);[24] and SOU[25] report compliance with CPS1 for the 2010-2014 period, although they do not report annual values.

Figure 6: CPS1, 2010-2014.



Source: Commission staff based on information collection FERC-922.
Note: PACE and PACW are separate balancing authority areas.

b. Control Performance Standard 2 (CPS2)

CPS2 is a statistical measure of Area Control Error magnitude. The intent of the standard is to limit a control area's unscheduled power flows. APS and two Duke Energy respondents (DEF and DEP) report compliance with CPS2 over the reporting period, but do not provide annual values.[26] CAISO, MISO, PJM, SOU, DEC, and PAC do not report

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[23] November 2015 APS Metrics Report at 6.

[24] Duke Energy Corporation October 27, 2015 Filing at 5 (October 2015 Duke Metrics Report).

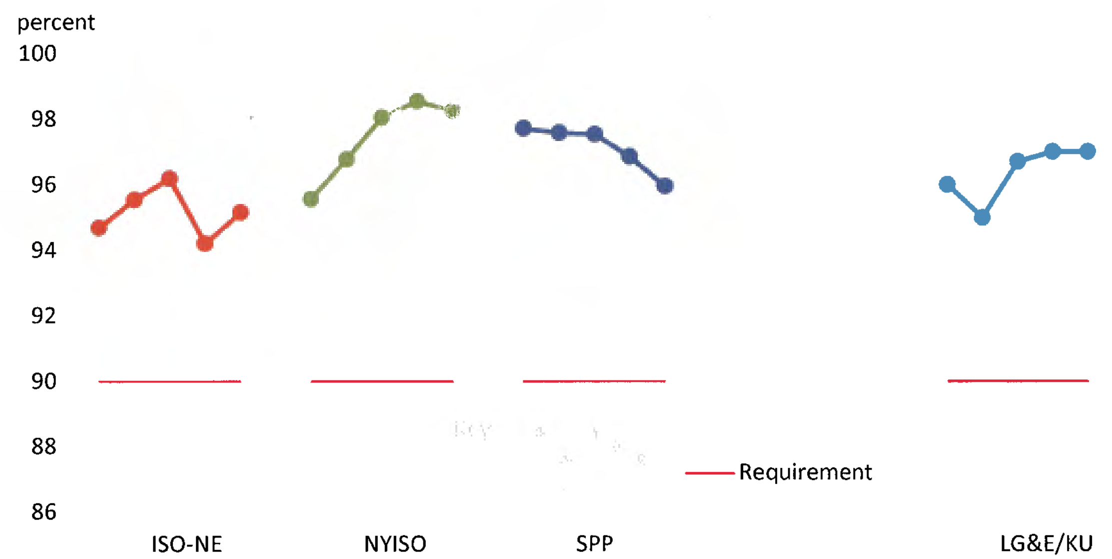
[25] Southern Company October 30, 2015 Filing at 16 (October 2015 SOU Metrics Report).

[26] *See* November 2015 APS Metrics Report at 6, October 2015 Duke Metrics Report at 5.

CPS2 data, explaining that during 2010-2014 they participated in a proof-of-concept field trial that included a waiver from CPS2 requirements.[27]

Figure 7 displays the CPS2 metrics from ISO-NE, NYISO, SPP, and LG&E/KU.

Figure 7: CPS2, 2010-2014.



Source: Commission staff based on information collection FERC-922.

c. Energy Management System availability

The Energy Management System availability metric measures the availability of the systems used for real-time monitoring and security analysis functions, reported as a percentage of minutes of operational availability each year. Figure 8 shows the five-year average and range of annual Energy Management System availability for respondents providing data. Lower values indicate that a respondent's Energy Management System was unavailable more often relative to those of respondents reporting higher values. Among RTOs and ISOs, only PJM reports a five-year average availability of less than 99.90 percent, with annual values ranging from 99.54 percent in 2010 to 99.99 percent in 2011 and 2013.[28] All other RTOs and ISOs report annual Energy Management System availability above 99.90 percent in every year from 2010-2014.

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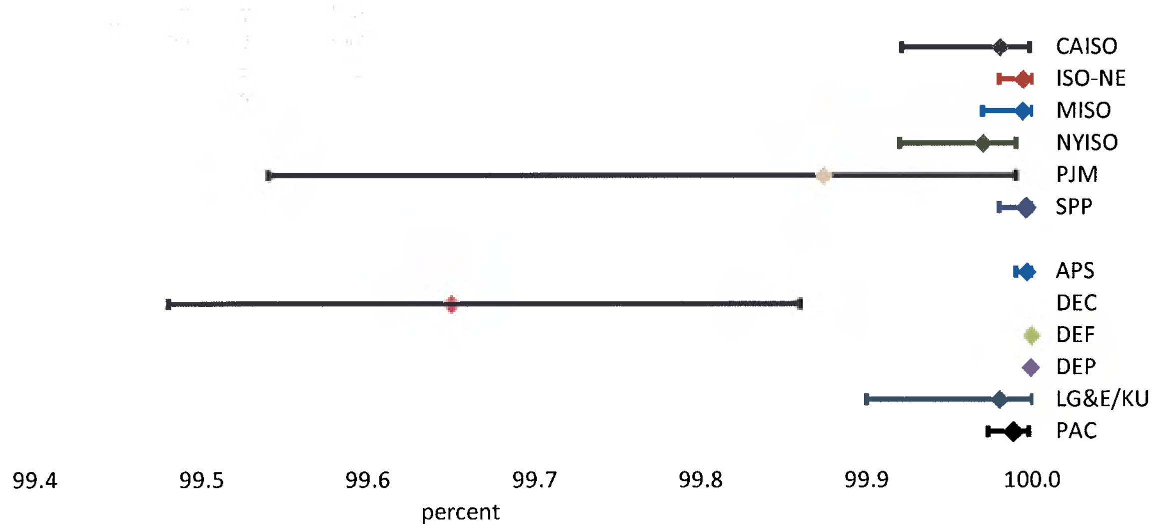
[27] *See* October 2015 RTO and ISO Metrics Report at 34, 159, 284; October 2015 SOU Metrics Report at 16; October 2015 Duke Metrics Report at 5; PacifiCorp February 10, 2016 Filing at 11 (February 2016 PAC Metrics Report).

[28] PJM reports that in November 2011 it implemented a second control center with dual independent data communication links to the Energy Management Systems at each

Among non-RTO/ISO respondents that report Energy Management System availability, only DEC reports a five-year average availability of less than 99.90 percent, with annual values ranging from 99.86 percent in 2012 to 99.48 percent in 2013.

Figure 8: Energy Management System availability (average and range), 2010-2014.



Source: Commission staff based on information collection FERC-922.
Notes: (1) SOU reports that it transitioned to a new Energy Management System during the 2010-2014 time period and therefore it does not provide specific annual availability values. (2) SOU reports that it had zero "Loss of [Energy Management System] capability" events pursuant to Reliability Standard EOP-004-2 during 2010-2014.[29] (3) PAC does not report this metric in percentage terms, but instead reported annual outage minutes for its Ranger EMS system,[30] and in the above chart, PAC's Energy Management System availability reflects annual outage minutes reported divided by 525,600 minutes per year.

3. Load and Wind Forecast Accuracy

The load forecast accuracy metric measures the accuracy of the day-ahead load forecast, based on the absolute percentage deviation between actual peak load and forecasted peak load.[31] As load forecasting affects resource commitment, load forecast accuracy impacts

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control center, and that these enhancements helped to increase availability. *See* October 2015 RTO and ISO Report at 283.

[29] *See* October 2015 SOU Metrics Report at 16.

[30] *See* February 2016 PAC Metrics Report at 11-12.

[31] RTOs and ISOs generally calculate this metric based on the mean absolute percentage error of the forecast at a reference point on the prior day. The reference point varies across RTOs and ISOs, from 5:00 a.m. on the prior day in NYISO to 3:30 p.m. on

the incurrence of commitment costs. The more accurate a respondent is in forecasting load, the greater the likelihood that it can commit sufficient resources in a cost-effective manner that avoids over-commitment of resources, inefficient commitment of short lead time resources, and under-utilization of available resources.

The wind forecast accuracy metric measures the percentage accuracy of actual wind availability compared to day-ahead forecasted wind availability. Accurate wind forecasting facilitates the timely commitment and dispatch of sufficient supplemental, non-wind resources.

Figure 9 summarizes the load forecast accuracy and wind forecast accuracy metrics data submitted by each respondent. The wind forecast metric is not applicable for certain utilities that do not perform wind forecasting functions because they have little to no wind generation interconnected with their systems.

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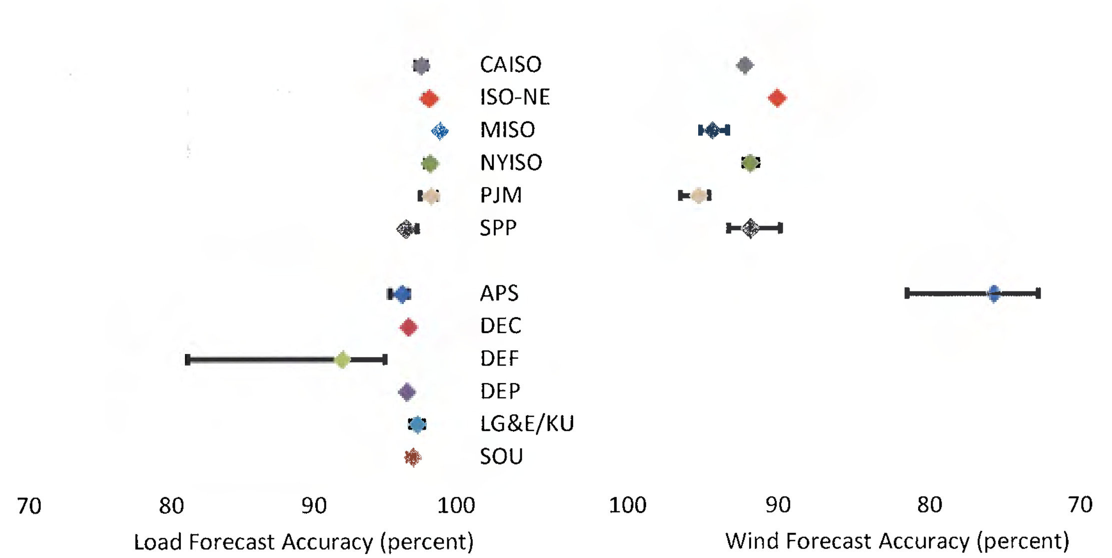
the prior day in MISO. For additional details, *see* October 2015 RTO and ISO Metrics Report at 36, 81, 161, 218, 284, 346.

Figure 9: Average and range of load forecast accuracy and wind forecast accuracy, 2010-2014.



Source: Commission staff based on information collection FERC-922.
Notes: (1) For wind forecast accuracy, ISO-NE reports values for 2014; SPP reports values for 2011-2014; and APS reports values for 2012-2014. (2) LG&E/KU report that their load forecast data are not based entirely on day-ahead information, as it contains some intra-day adjustments.[32] (3) PAC (not shown) does not report the load forecast metric as day-ahead forecasted load compared to actual load; rather, PAC reports annual load forecast values compared to actuals.[33] (4) Wind forecast error reflects mean absolute error for CAISO, ISO-NE, MISO, NYISO, and APS. SPP calculates wind forecast error based on the absolute difference between actual and forecast output divided by capacity. PJM does not explain its wind forecast error methodology in detail. PAC (not shown) reports aggregate annual forecast and actual MWh.[34]

4. Unscheduled Flows

The unscheduled flows metric measures the difference between net actual interchange (actual measured power flow in real time) and the net scheduled interchange in megawatt-hours, as reported in FERC Form No. 714, "Annual Electric Balancing Authority Area and Planning Area Report." In other words, it is a measure of what actually occurred in real time as compared to what was scheduled.[35] As such,

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[32] Louisville Gas & Electric and Kentucky Utilities Corporation October 30, 2015 Filing at 5 (October 2015 LG&E/KU Metrics Report).

[33] February 2016 PAC Metrics Report at 12.

[34] *Id.* at 13.

[35] Unscheduled flows reflect the difference between scheduled flows and actual

unscheduled flows provide information relevant to operational planning that is part of a comprehensive reliability assessment for an RTO and ISO or utility.[36] When unscheduled flows exceed system operating limits, curtailments could occur, hindering efficient scheduling of the grid.

Unscheduled flows vary among the reporting entities. Table 4 reviews the unscheduled flows data submitted by each respondent. The data are not normalized across respondents and therefore do not take account of differences in the size of each system.

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flows on a particular interconnection between two balancing authorities. Unscheduled flows may also reflect the difference between scheduled and actual flows on a contract path, either between or within balancing authorities.

[36] The two components of unscheduled flows are (1) inadvertent energy, defined as the difference between actual and scheduled interchange for all interties; and (2) parallel flow (or loop flow), defined as the difference between scheduled and actual flows on a contract path. Parallel flows are a function of grid conditions and the physical characteristics of the transmission system.

Table 4: Summary of unscheduled flows in 2010 and 2014.

Respondent	2010 unscheduled flows (million megawatt-hours)	2014 unscheduled flows (million megawatt-hours)	percent change from 2010-2014
	RTOs and ISOs		
CAISO	22.5	5.8	-74.1
MISO	31.0	43.0	38.7
NYISO	8.0	1.7	-78.8
PJM	29.3	28.4	-3.1
	non-RTOs and ISOs		
APS	0.0	0.7	5,344.9
DEC	10.2	10.7	5.0
DEF	14.3	17.1	19.2
DEP	13.7	11.7	-15.1
LG&E/KU	0.0	0.0	-67.6
SOU	46.7	28.3	-39.3

Source: Commission staff based on information collection FERC-922.
Notes: (1) ISO-NE, SPP, and PAC do not report data for this metric.[37] (2) PAC reports total hours of transmission curtailment in WECC, along with total hours of coordinated operation of phase shifters in WECC.[38]

5. Transmission Outage Coordination

The transmission outage coordination metrics include (1) a measure of advance notice of planned outages and (2) a measure of cancellations of outages due to factors such as conflicting planned outages or forced outages that could cause reliability issues and additional congestion costs.

a. Early Notification Metric

This metric measures the percentage of planned transmission outages of five days or longer submitted at least one month in advance of the outage commencement date. The metric only applies to transmission facilities at voltages of 200 kilovolts and above. Figure 10 displays this metric for RTOs and ISOs and non-RTO and ISO respondents from 2010-2014. A higher percentage could reflect more effective outage coordination.

Among RTOs and ISOs, ISO-NE and NYISO report the highest levels of early notification, while SPP reported the lowest five-year average. In SPP, the early notification of planned outages ranged from a low of 19.3 percent in 2011 to a high of 24.9 percent in 2014. SPP reports that its tariff does not outline specific timeframes and guidelines for transmission outage coordination, but contains a general requirement that, "consistent with the SPP Membership Agreement, Transmission Owners are required

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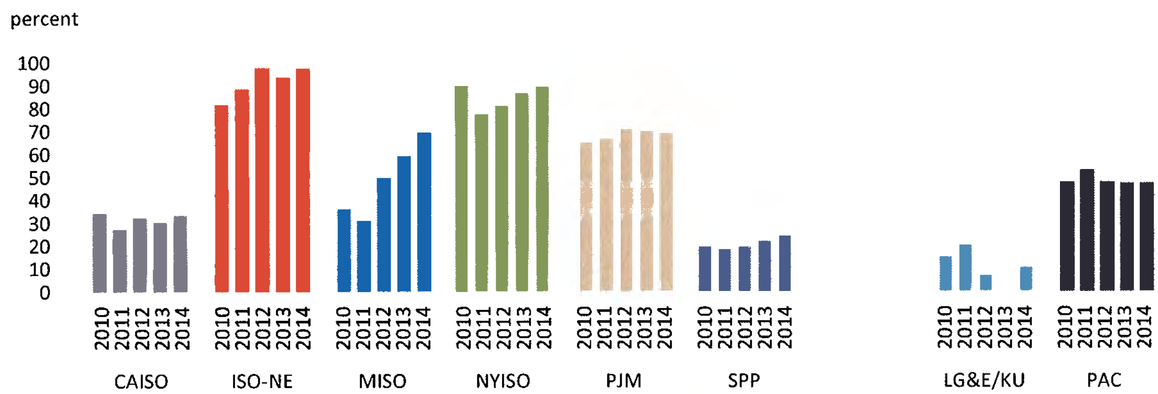
[37] October 2015 RTO and ISO Metrics Report at 85, 347; February 2016 PAC Metrics Report at 14-15.

[38] *Id.* at 14-15.

to coordinate with the Transmission Provider for all planned maintenance of Tariff Facilities."[39] By contrast, ISO-NE reports steps it has taken to improve the lead time for outage request submissions, including efforts to focus on the issue collaboratively with transmission owners and local control centers.[40]

This metric does not measure advance notification that occurs less than 30 days before an outage. For instance, in 2012, CAISO modified its tariff to require entities to submit outages seven calendar days prior to the outage;[41] however, the metric does not reflect the percentage of seven-day notifications. With regard to non-RTO and ISO respondents, LG&E/KU coordinates outage notifications with the Tennessee Valley Authority, which uses a seven-day notice requirement for planned outage requests.[42]

Figure 10: Percentage of planned transmission outages with at least one month notification, 2010-2014.



Source: Commission staff based on information collection FERC-922.
Note: APS, DEC, DEF, DEP, and SOU do not provide data for this metric. Commission staff notes that APS, DEC, DEF, DEP, and SOU report that they post planned outages on their respective Open Access Same Time Information Systems (OASIS).[43]

b. Cancelation Metric

This metric reflects cancelations of outages due to conflicting planned outages as well as forced outages. The metric measures the percentage of previously-approved transmission

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[39] October 2015 RTO and ISO Metrics Report at 348.

[40] *Id.* at 86-87.

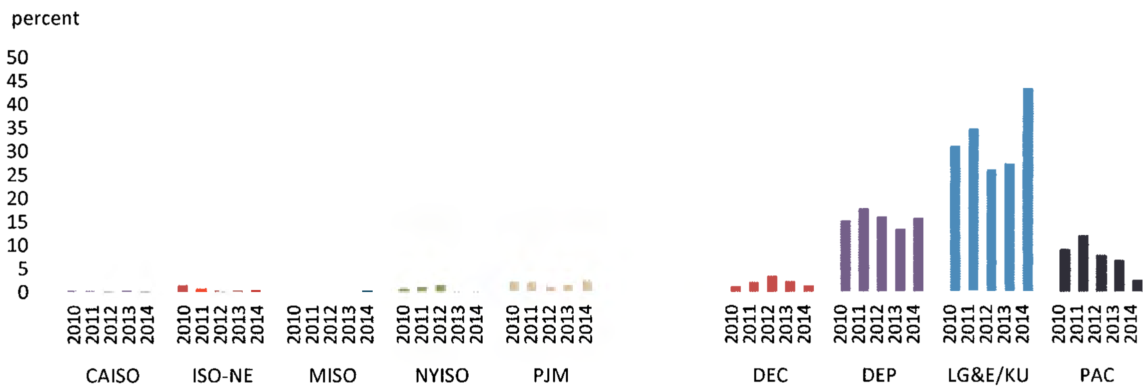
[41] *Id.* at 41.

[42] October 2015 LG&E/KU Metrics Report at 7.

[43] November 2015 APS Metrics Report at 9; October 2015 Duke Metrics Report at 13; and October 2015 SOU Metrics Report at 20.

outages that are later canceled for transmission facilities with voltages of 200 kilovolts and above. Lower values represent fewer canceled outages and may indicate better outage coordination. Figure 11 shows the percentage of canceled outages from 2010-2014 for RTOs and ISOs and non-RTOs and ISOs submitting data. The RTOs and ISOs submitting data for this metric generally report significantly lower cancelation percentages than the non-RTO and ISO respondents, with the exception of DEC.

Figure 11: Average percentage of previously-approved transmission outages canceled by the transmission provider, 2010-2014.



Source: Commission staff based on information collection FERC-922.
Notes: (1) APS, DEF, and SOU did not provide data for this metric. (2) SPP (not shown) provided only two years of data. SPP's reports cancelation percentages of 0.5 percent in 2013 and 0.3 percent in 2014.

6. Long-Term Reliability Planning – Transmission

a. Transmission Projects Approved for Construction

This metric measures the number of transmission facilities approved for construction for reliability purposes. Each of the respondents has a role in approving transmission projects through their respective local and regional reliability planning processes. In reviewing this metric, it is important to consider that the size of the transmission system varies across respondents.

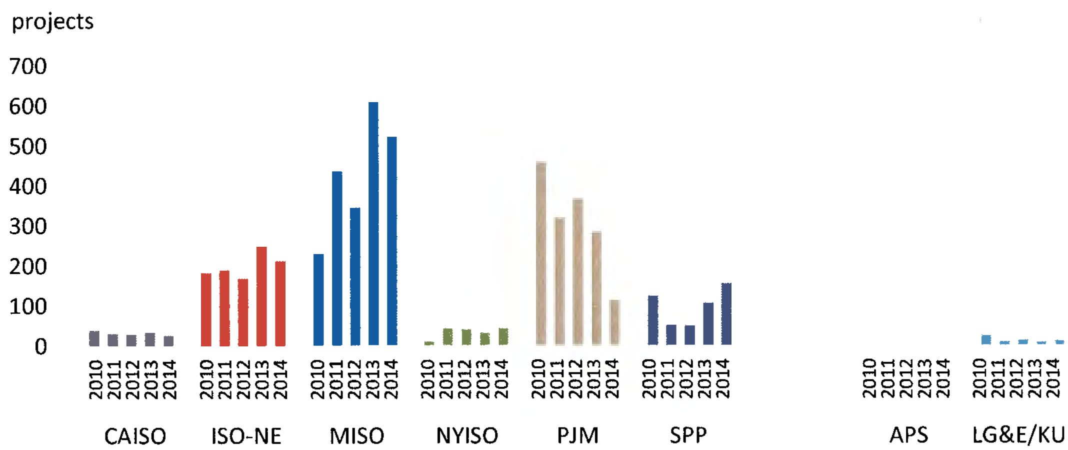
As shown in Figure 12, MISO reports more approved transmission projects than any other respondent. Over the reporting period, MISO approved 2,153 transmission projects for reliability purposes.[44] As part of the local transmission planning process, transmission owners in MISO are responsible for submitting their transmission construction plans to MISO for evaluation and possible inclusion in the MISO Transmission Expansion Plan. After evaluation, projects identified as the best solution

[44] October 2015 RTO and ISO Metrics Report at 170.

for a particular issue or opportunity are included in the report and recommended for approval by the MISO Board of Directors.[45]

Among the non-RTOs and ISOs, only APS and LG&E/KU provide data on the approval of transmission projects. LG&E/KU reports approval of 85 transmission projects from 2010-2014.[46]

Figure 12: Number of transmission projects approved for construction for reliability purposes, 2010-2014.



Source: Commission staff based on information collection FERC-922.
Notes: (1) PAC (not shown) provides data summarizing the total number of projects for all five years, but does not provide separate data describing project approvals. PAC reports projects initiated, ongoing, or completed during the 2010-2014 time frame, based on transmission reliability capital investment. PAC either initiated or completed 85 projects, 51 of which were completed during the 2010-2014 time frame.[47] (2) DEC, DEF, and DEP provide data summarizing projects completed in each year, but these non-RTO and ISO utilities do not provide separate data describing project approvals.

b. Transmission Projects Completed

This metric is a measure of transmission planning performance and represents the percentage of approved construction projects completed and on schedule.

RTOs and ISOs report the percentage of projects approved in each year that were completed by the end of the reporting period. Figure 13 shows the percent of approved projects completed for RTOs and ISOs from 2010-2014. Across RTOs and ISOs, ISO-

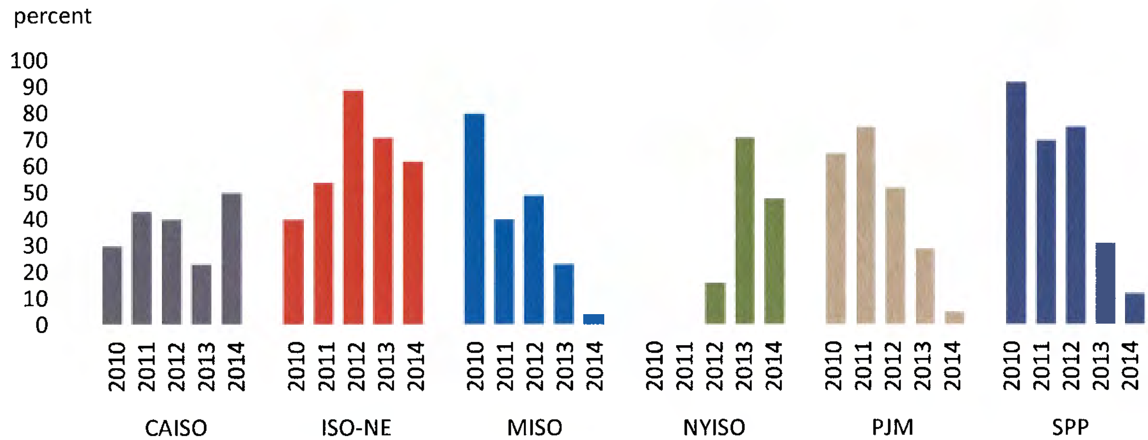
[45] *Id.* at 170.

[46] *Id.* at 8.

[47] February 2016 PAC Metrics Report at 17-18.

NE reports the highest annual average percentage of approved projects completed over this time period.

Figure 13: Percentage of approved transmission projects completed, 2010-2014.



Source: Commission staff based on information collection FERC-922.
Notes: (1) CAISO does not specify whether projects were complete before December 31, 2014. (2) CAISO reports the percentage of approved construction projects completed and projects on-schedule per the original in-service date.[48] (3) ISO-NE reports the ratio of under-construction and in-service projects to completed projects.[49] (4) MISO reports the percentage of completed reliability projects only.[50] (5) NYISO reports "N/A" for 2010 and 2011.

Non-RTO and ISO respondents report the percentage of projects that were on schedule each year. Using this measure, the Duke Energy respondents (DEC, DEF, and DEP), and SOU report 100 percent of transmission projects on schedule, as shown in Figure 14.[51] APS reports 100 percent of projects on schedule with the exception of years 2012 and 2013.[52]

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[48] *Id.*

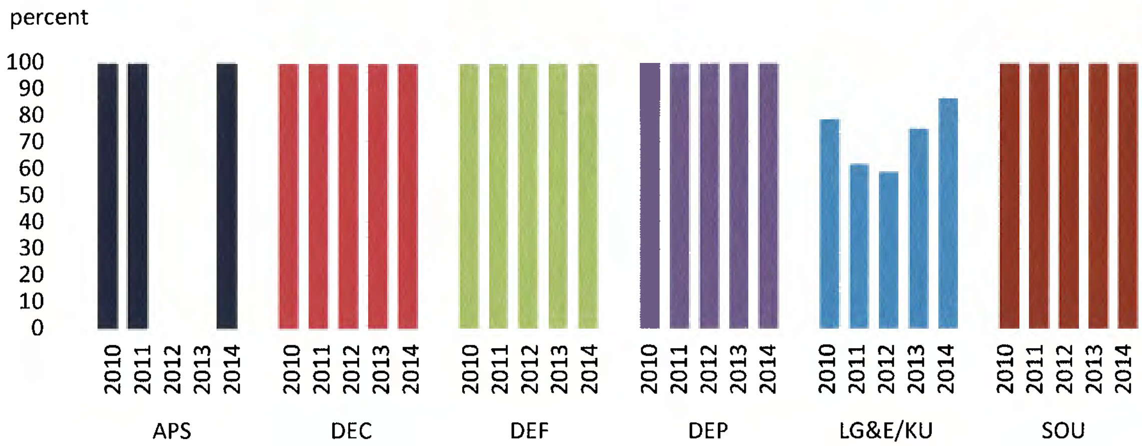
[49] *Id.* at 89-90.

[50] *Id.* at 171.

[51] October 2015 Duke Metrics Report at 14-15; and October 2015 SOU Metrics Report at 21.

[52] November 2015 APS Metrics Report at 9.

Figure 14: Percentage of transmission projects on schedule, 2010-2014.



Source: Commission staff based on information collection FERC-922.
Note: PAC (not shown) does not report a percentage, but reports 51 completed projects out of 85 initiated projects during the 2010-2014 period, and notes that one of those projects was behind schedule.[53]

7. Long-Term Reliability Planning – Resources

a. Generator Interconnection Processing Time

The time it takes to process generation interconnection requests is one measure of the effectiveness of processes in achieving timely interconnection of new resources. Each respondent interconnects generators under different operating conditions. Some entities, such as ISO-NE, report challenges in initiating and performing wind interconnection studies because of complex control interactions that increase the potential for more detailed modeling.[54]

As shown in Figure 15, among RTOs and ISOs, NYISO, MISO, and ISO-NE report the longest interconnection processing times.[55] NYISO reports that its average process time was high in 2013 for two reasons: (1) a previously-rejected project was re-studied and retained its queue position; and (2) a project presented the unique circumstance of proposing to interconnect to a 345 kilovolt tie-line between NYISO and a neighboring ISO. As a result of these projects, the necessary analysis required significant additional

[53] February 2016 PAC Metrics Report at 18.

[54] October 2015 RTO and ISO Metrics Report at 107.

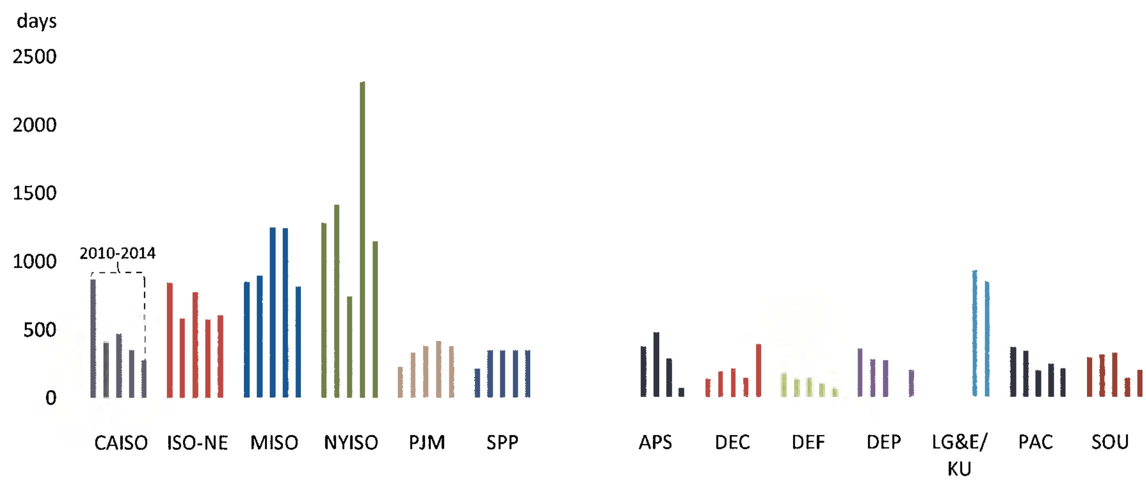
[55] *Id.* at 94-95, 174, 231.

time.[56] NYISO's average generation interconnection request processing time ranged from a low of 750 days in 2012 to a high of 2,318 days in 2013.

MISO reports that projects that completed the interconnection process prior to 2012, and then subsequently withdrew, caused several restudies that affected interconnection queue times.[57]

Among the non-RTO and ISO respondents, LG&E/KU reports the longest average generator interconnection processing time. However, LG&E/KU does not report values for 2010-2012, and their average processing time reflects a two-year average.[58] Others, such as APS, SOU, and the Duke Energy respondents (DEC, DEF, and DEP) report, on average, less than 400 days to process their respective generator interconnection requests.[59]

Figure 15: Annual average generator interconnection processing time, 2010-2014.



Source: Commission staff based on information collection FERC-922.
Note: (1) APS reports values for 2011-2014. (2) DEP reports values for 2010-2012 and 2014. (3) LG&E/KU reports values for 2013-2014.

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[56] *Id.* at 231-233.

[57] *Id.* at 174.

[58] October 2015 LG&E/KU Metrics Report at 9.

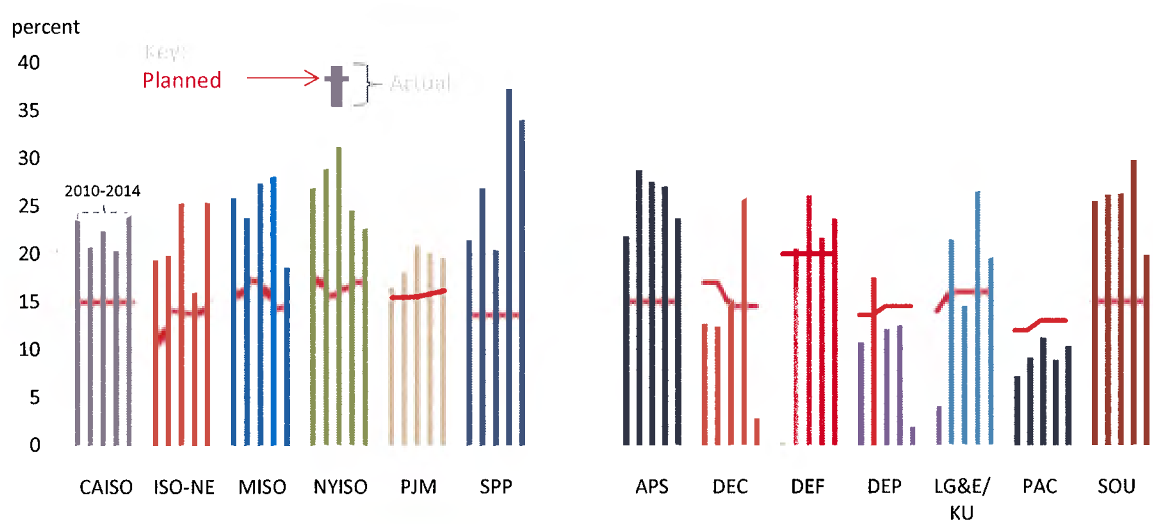
[59] October 2015 SOU Metrics Report at 24; October 2015 Duke Metrics Report at 17; November 2015 APS Metrics Report at 10.

b. Actual and Planned Reserve Margins

The comparison of the actual reserve margin to the planned reserve margin measures the extent to which generation resource planning processes are ensuring long-term resource adequacy and reliability. Actual reserve margins in excess of planned levels represent a low probability of loss-of-load due to inadequate supply.

As shown in Figure 16, RTOs and ISOs report actual reserve margins in excess of planned levels between 2010 and 2014. SPP reports the largest difference between actual and planned reserve margins from 2010-2014, with an average planned reserve margin of approximately 13 percent and an average actual reserve margin of approximately 28 percent.[60] Among non-RTO and ISO respondents, APS and SOU report actual reserve margins that were substantially higher than the planned levels. Some entities report actual reserve margins below planned levels. For example, in 2014 DEP reports that its planned reserve margin was 14.5 percent in 2014 and its actual reserve margin was 1.9 percent.[61]

Figure 16: Planned and actual reserve margins, 2010-2014.



Source: Commission staff based on information collection FERC-922.

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[60] October 2015 RTO and ISO Metrics Report at 355.

[61] *See* October 2015 Duke Metrics Report at 18. DEC, DEF, and DEP report actual reserve margin based on balancing authority reserves at the time of the actual balancing authority hourly integrated peak demand in each year. DEP reports that its peak load occurred during the winter in 2014.

8. Interconnection and Transmission Processes

a. Interconnection and Transmission Service Request Process

The number of study requests and completed studies illustrates the progress that respondents have made in completing their reliability reviews (feasibility, system impact and facility studies) of interconnection and transmission service requests in a timely and efficient manner.

With respect to the number of study requests and completed studies, PJM reports the most study requests and completions while DEP reports the fewest.[62] As shown in Table 5, MISO reports nearly four times as many studies completed as requested. MISO reports that each interconnection request may have several studies performed.[63]

Table 5: Interconnection and transmission service requests: number of study requests, number of completed studies, and ratio of completed to requested studies, 2010-2014.

Respondent	2010-2014 Total		
	Requested	Completed	Ratio
	RTOs and ISOs		
CAISO	529	635	1.2
ISO-NE	174	94	0.5
MISO	354	1366	3.9
NYISO	121	123	1.0
PJM	1689	2185	1.3
SPP	289	446	1.5
RTO and ISO average	526	808	1.5
	non-RTOs and ISOs		
APS	160	70	0.4
DEC	34	48	1.4
DEF	61	61	1.0
DEP	27	23	0.9
LG&E/KU	120	97	0.8
PAC	825	222	0.3
SOU	354	267	0.8

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[62] *Id.* at 19-21; October 2015 RTO and ISO Metrics Report at 300-302.

[63] *Id.* at 180.

Table 5: Interconnection and transmission service requests: number of study requests, number of completed studies, and ratio of completed to requested studies, 2010-2014.

Respondent	2010-2014 Total		
	Requested	Completed	Ratio
Non-RTO and ISO average	226	113	0.8

Source: Commission staff based on information collection FERC-922.
Note: The studies completed in any particular year may correspond to requests from a prior year and an interconnection request may have several studies performed; the number of completed studies can be higher than the number of requested studies.

b. Average Age of Incomplete Studies

The average age of incomplete studies metric assesses the progress that RTOs and ISOs and non-RTO and ISO utilities have made in completing their reliability reviews (feasibility, system impact and facility studies) of interconnection and transmission service requests in a timely and efficient manner.

As shown in Figure 17, relative to other RTOs and ISOs, SPP reports a consistently low average age of incomplete studies over the five-year reporting period, while MISO reports the largest decline in average age of studies between 2010 and 2014. ISO-NE reports a relatively high average age of incomplete studies from 2010-2014. ISO-NE conducts studies in the order in which projects enter the interconnection queue.[64] MISO points to its 2012 queue reform as leading to a reduction in the volume of interconnection requests in the active queue, and states that these tariff revisions and ongoing process improvements led to the downward trend in study completion time. MISO also reports that the lower average time to complete studies resulted in lower average study costs.[65]

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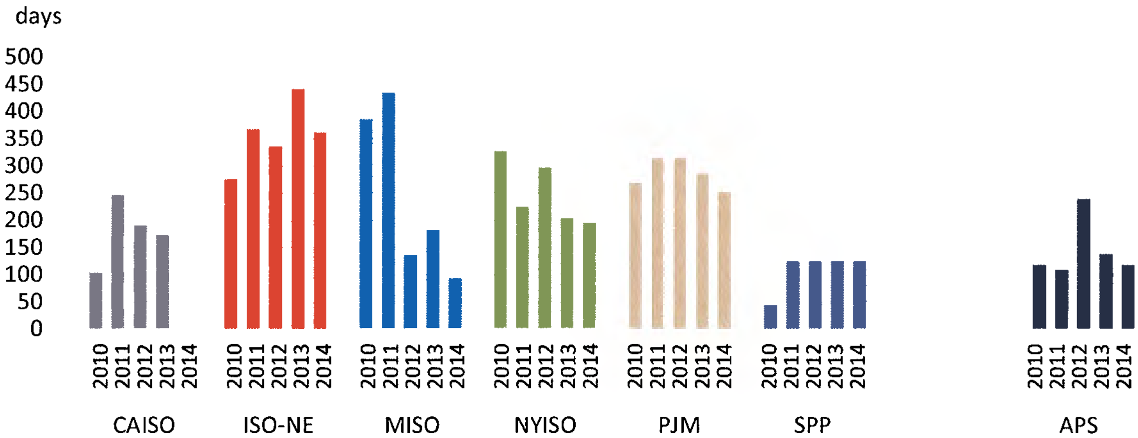
[64] October 2015 RTO and ISO Metrics Report at 104-105.

[65] *Id.* at 180.

Figure 17: Average age of incomplete studies, 2010-2014.



Source: Commission staff based on information collection FERC-922.
Notes: (1) DEC, DEF, DEP, and LG&E/KU report zero days. (2) SOU does not report annual values for 2010-2014; instead, SOU reports that as of January 1, 2015, the average age of incomplete generator interconnection studies was 48 days and the average age of incomplete transmission service studies was 28 days. (3) The CAISO value shown in the figure reflects a four-year average.

c. Average Cost of Studies

The average cost of studies metric measures the cost of completing reliability reviews (feasibility, system impact, and facility impact studies)[66] of interconnection and transmission service requests. Tables 6, 7, and 8 compare the average cost for each of these studies over the 2010-2014 period.

Among RTOs and ISOs, ISO-NE reports the highest feasibility study costs, with an average of $98,626 per study from 2010-2014.[67] In ISO-NE, some issues that affect the average feasibility study costs include the following: (1) costs incurred by the respective

[66] As explained by PJM in its report: "Feasibility studies assess the practicality and cost of transmission system additions or upgrades required to accommodate the interconnection of the generating unit or increased generating capacity with the transmission system. System impact studies provide refined and comprehensive estimates of cost responsibility and construction lead times for new transmission facilities and system upgrades that would be required to allow the new or increased generating capacity to be connected to the transmission system . . . . Facility studies develop the transmission facilities designs for any required transmission system additions or upgrades due to the interconnection of the generating unit or increased generating capacity." *Id.* at 301-302.

[67] *Id.* at 106.

transmission owners performing the requested and necessary studies; and (2) the fact that the interconnection feasibility study may be conducted as part of the interconnection system impact study or as a separate study.[68] Additionally, ISO-NE reports that wind interconnection studies are becoming more involved and detailed in New England, especially where the largest interest in development is occurring.[69]

Across all respondents, NYISO reports the highest facility impact study costs (approximately $319,000 per study for 2013 and 2014). NYISO reports that the higher average cost of facility impact studies in 2013 and 2014 was largely due to the unique circumstances of one proposed project to interconnect to a 345 kilovolt tie-line between NYISO and ISO-NE, resulting in complications and increased study costs.[70]

As MISO does not separate feasibility, system impact, and facility impact studies, MISO is not included in the tables below. MISO reports annual average values for total study costs from 2010-2014, with a high of $216,597 in 2011 and a low of $78,450 in 2013.[71] The details of MISO's response to this metric are accessible in Docket No. AD14-15-000.[72]

Table 6: Average annual feasibility study costs.

Respondent	2010	2011	2012	2013	2014
RTOs and ISOs					
CAISO	15,383	6,819	6,789	7,001	0
ISO-NE	94,960	88,237	98,582	148,307	63,044
NYISO	31,820	50,280	58,600	43,540	33,800
PJM	3,700	5,000	6,700	7,600	5,000
SPP	2,976	6,667	11,039	7,563	6,456
non-RTOs and ISOs					
APS	16,428	103,552	0	0	0

[68] *Id.* 105-108.

[69] *Id.* at 107.

[70] *Id.* at 239-240.

[71] *Id.* at 182.

[72] *Id.*

Table 6: Average annual feasibility study costs. (cont'd.)

Respondent	2010	2011	2012	2013	2014
DEC	5,464	2,292	8,020	3,068	
DEP					753
PAC					
SOU		17,906	14,769	10,068	12,964

Source: Commission staff based on information collection FERC-922.
Notes: (1) The values in the table are expressed in nominal dollars. (2) DEF does not submit data for this metric and LG&E/KU do not submit data for this metric; (3) MISO submits average costs across all study types and does not separate feasibility study costs. (4) PAC reports only the five-year average. (5) The table reflects responses of $0 as reported.

Table 7: Average annual system impact study costs, 2010-2014.

Respondent	2010	2011	2012	2013	2014
			RTOs and ISOs		
CAISO	33,199	15,516	14,992	16,268	0
ISO-NE	121,363	102,468	131,287	135,500	175,409
NYISO	43,650	53,410	66,513	45,940	118,430
PJM	10,800	7,100	13,100	16,600	11,300
SPP	15,655	20,623	18,428	25,232	20,009
			non-RTOs and ISOs		
APS	37,127	27,646	152,195	384,097	411,226
DEC	27,414	109,783	25,701	62,276	5,010
DEP					297
PAC					
SOU		11,490	20,830	12,550	18,229

Source: Commission staff based on information collection FERC-922.
Notes: (1) The values in the table are expressed in nominal dollars. (2) DEF does not submit data for this metric and LG&E/KU does not submit comparable data for this metric. (3) MISO submits average costs across all study types and does not separate system impact study costs. (4) PAC reports only the five-year average. (5) The table reflects responses of $0 as reported.

Table 8: Average annual facility impact study costs, 2010-2014.

Respondent	2010	2011	2012	2013	2014
			RTOs and ISOs		
CAISO	48,537	21,571	21,142	53,749	26,758
ISO-NE	131,692	0	20,404	0	18,973
NYISO		200,000	52,630	318,805	319,530
PJM	44,800	36,200	30,300	22,900	22,800
SPP	14,998	4,255	1,953	2,853	2,596
			non-RTOs and ISOs		

Table 8: Average annual facility impact study costs, 2010-2014. (cont'd.)

Respondent	2010	2011	2012	2013	2014
APS	29,890	0	32,840	44,080	25,237
DEC	7,422	14,710	17,825	3,940	34,250
PAC					
SOU		37,766	15,014	6,414	12,870

Source: Commission staff based on information collection FERC-922.
Notes: (1) The values in the table are expressed in nominal dollars. (2) DEF and DEP do not submit data for this metric and LG&E/KU does not submit comparable data for this metric. (3) MISO submits average costs across all study types and does not separate facility impact study costs. (4) PAC reports only the five-year average. (5) The table reflects responses of $0 as reported.

9. Special Protection Systems

This metric measures both the frequency with which the region relies on Special Protection Systems[73] and their effectiveness, as measured by successful activations and the number of unintended activations. Special Protection Systems are designed to detect abnormal or predetermined system conditions and take corrective actions, such as changing demand, generation, or system configurations in order to maintain system stability, acceptable voltage levels, or power flows.

Table 9 lists the number of Special Protection Systems reported by respondents.

[73] Other terms used to describe Special Protection Systems include Special Protection Schemes, Remedial Action Schemes, and System Integrity Protection Schemes.

Table 9: Total number of Special Protection Systems reported.

Respondent	Special Protection Systems
RTOs and ISOs	
CAISO	5
ISO-NE	27
NYISO	14
MISO	35
PJM	44
SPP	4
non-RTOs and ISOs	
APS	5
DEF	1
DEC	1
PAC	13
SOU	< 5

Source: Commission staff based on information collection FERC-922.
Notes: (1) Totals are for 2014 only. (2) DEP had no such devices. DEF had two such devices in 2010 – 2014; one of which was retired in 2011. DEC had one such device in 2010-2014. (3) SOU reports that it had less than five special protection systems as of 2014.

Respondents also provide information on Special Protection System activations. PJM reports a total of nine intentional Special Protection System activations, eight of which were on the Warren-Falconer 115 kilovolt tie line with NYISO. ISO-NE reports the successful activation of one Special Protection System in 2014, separating the Bangor Hydro and the Maritimes from the interconnected system in a controlled manner.[74] MISO and NYISO report no activations of Special Protection Systems from 2010-2014.[75] No RTOs or ISOs report unintended activations of Special Protection Systems.

B. System Operations Performance Metrics

1. Resource Availability

Resource availability is a measure of efficiency and cost management. Higher generator availability can result in the commitment of fewer higher cost peak generators (or fewer high-cost imports), thereby resulting in reduced costs.

[74] October 2015 RTO and ISO Metrics Report at 108-110.

[75] *Id.* at 183, 241; October 2015 SOU Metrics Report at 26.

The intended calculation methodology for this common metric is one minus the system forced outage rate over 12 months.[76] However, respondents' submissions reveal the use of a variety of calculation methodologies, including effective forced outage rate-demand (EFORd), forced outage rate, and dividing megawatts of unavailable capacity by maximum capacity, among others. Due to concerns about the comparability of the responses received, Commission staff does not include a graphical comparison of the availability metric. Individual responses for this metric are accessible in the submittals from respondents in Docket No. AD14-15-000.

2. Fuel Diversity

a. Generating Capacity by Fuel Type

This metric measures the fuel-type mix of installed generating capacity. This metric provides insight into the different types of generating capacity installed in different regions. Generating capacity mix of certain regions reflects increasing percentages of renewable and natural gas-fired capacity and flat or declining percentages of coal-fired capacity.[77] Figure 18 illustrates the percentage capacity shares by fuel type in RTOs and ISOs and non-RTOs and ISOs, respectively. For purposes of comparison across respondents, Figure 18 aggregates hydroelectric and renewable capacity into a single category, and similarly groups natural gas and oil-fired capacity into a single category.[78] When evaluating these figures, it is important to consider that individual non-RTO and ISO respondents tend to have fewer resources in their footprints compared with the largest RTOs and ISOs.

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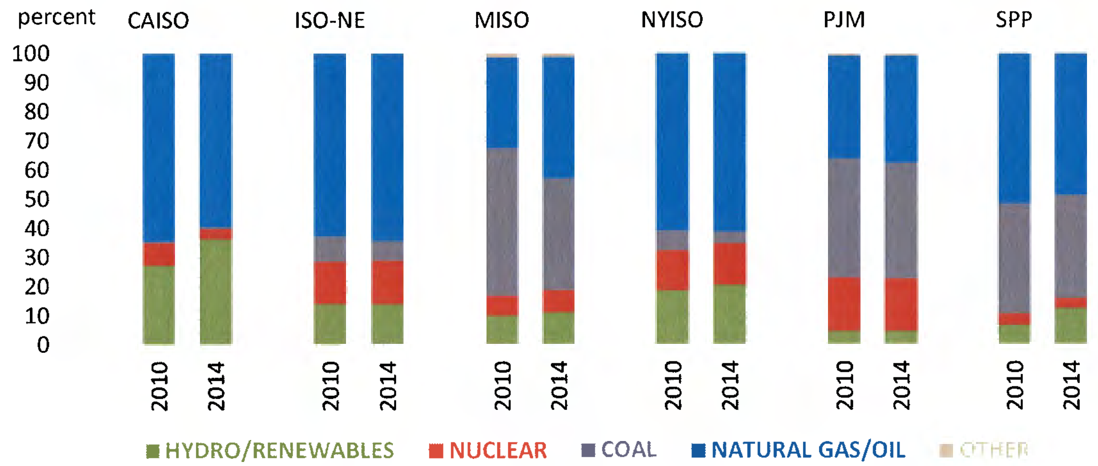
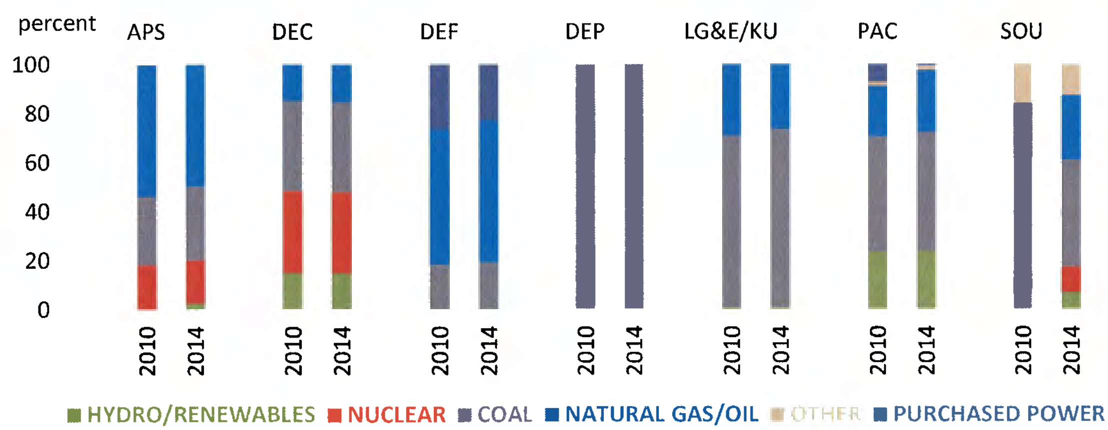
[76] *See* Comment Request, Docket No. AD14-15-000 at 17 (May 20, 2015).

[77] The specific trends differ across regions.

[78] Some respondents aggregated multiple fuel types into single categories, while others provided more disaggregated data.

Figure 18: Generating capacity mix by fuel type, 2010 and 2014.





Source: Commission staff based on information collection FERC-922.
Notes: (1) ISO-NE 2014 nuclear capacity values do not reflect the retirement of Vermont Yankee. (2) Per email correspondence on January 5, 2015, SPP revised its 2010 capacity percentage for nuclear to 3.9 percent. (3) Per email correspondence on January 11, 2016, LG&E/KU corrected its 2014 capacity percentages for coal and natural gas-fired capacity to 72.6 percent and 26.4 percent, respectively. (4) APS reports APS-owned capacity. (5) PAC includes contracted capacity. (6) DEP includes jointly-owned capacity.

i. Renewables and hydroelectric generating capacity

Among RTOs and ISOs, CAISO and NYISO report the largest shares of renewables and hydroelectric generating capacity. As of 2014, renewable and hydroelectric generators represented 36.5 percent of capacity in CAISO and 20.2 percent of capacity in NYISO. The largest relative increase occurred in SPP, where the share of renewable and hydroelectric capacity increased from 6.9 percent in 2010 to 12.6 percent in 2014.

Among non-RTO and ISO respondents, PAC reports the highest total percentage of renewable and hydroelectric generating capacity. Commission staff also notes that a number of non-RTO and ISO respondents report significant shares of capacity associated with purchased power, which could include renewables and other unidentified sources of generation. For PAC, the purchased power category represents non-renewable net purchases, but PAC's "other" category includes capacity related to certain renewable fuel types.

ii. Natural gas/oil-fired generating capacity

Among RTOs and ISOs, CAISO, ISO-NE, and SPP each report more natural gas-fired capacity than other fuel types from 2010-2014. MISO reports natural gas-fired capacity in combination with oil-fired capacity. The share of natural gas and oil-fired capacity in MISO increased significantly, from 31.3 percent in 2010 to 41.7 percent in 2014, as a number of utilities in the Gulf Coast region joined MISO in December, 2013. In the process, MISO transitioned from a majority coal-fired capacity mix in 2010 to a majority natural gas and oil-fired capacity mix in 2014. NYISO also reports that the New York Control Area has become increasingly dependent on natural gas and dual-fuel generating units,[79] although the share of natural gas and oil-fired generation increased modestly in NYISO, from 60.7 percent in 2010 to 61.2 percent in 2014.

Among non-RTO and ISO respondents, DEF reports the largest share of natural gas/oil-fired capacity during the reporting period. DEP, SOU, and PAC all report significant increases in the percentage of natural gas/oil-fired capacity.[80]

iii. Coal-fired generating capacity

PJM, MISO, and SPP report the highest shares of coal-fired generating capacity among RTOs and ISOs. Coal-fired generators accounted for the largest share of installed capacity in PJM from 2010-2014, ranging from a high of 42 percent in 2011 to a low of 39.7 percent in 2014. MISO reports that coal-fired generating capacity represented the largest share of generating capacity from 2010-2012, prior to the integration of MISO-South.

Across all RTO and ISO and non-RTO and ISO respondents, LG&E/KU report the largest share of coal-fired generating capacity (coal-fired generating capacity represented

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[79] October 2015 RTO and ISO Metrics Report at 260.

[80] For SOU and PAC, this category represents natural gas-fired generating capacity.

more than 70 percent of the total capacity mix in LG&E/KU in each year from 2010-2014).

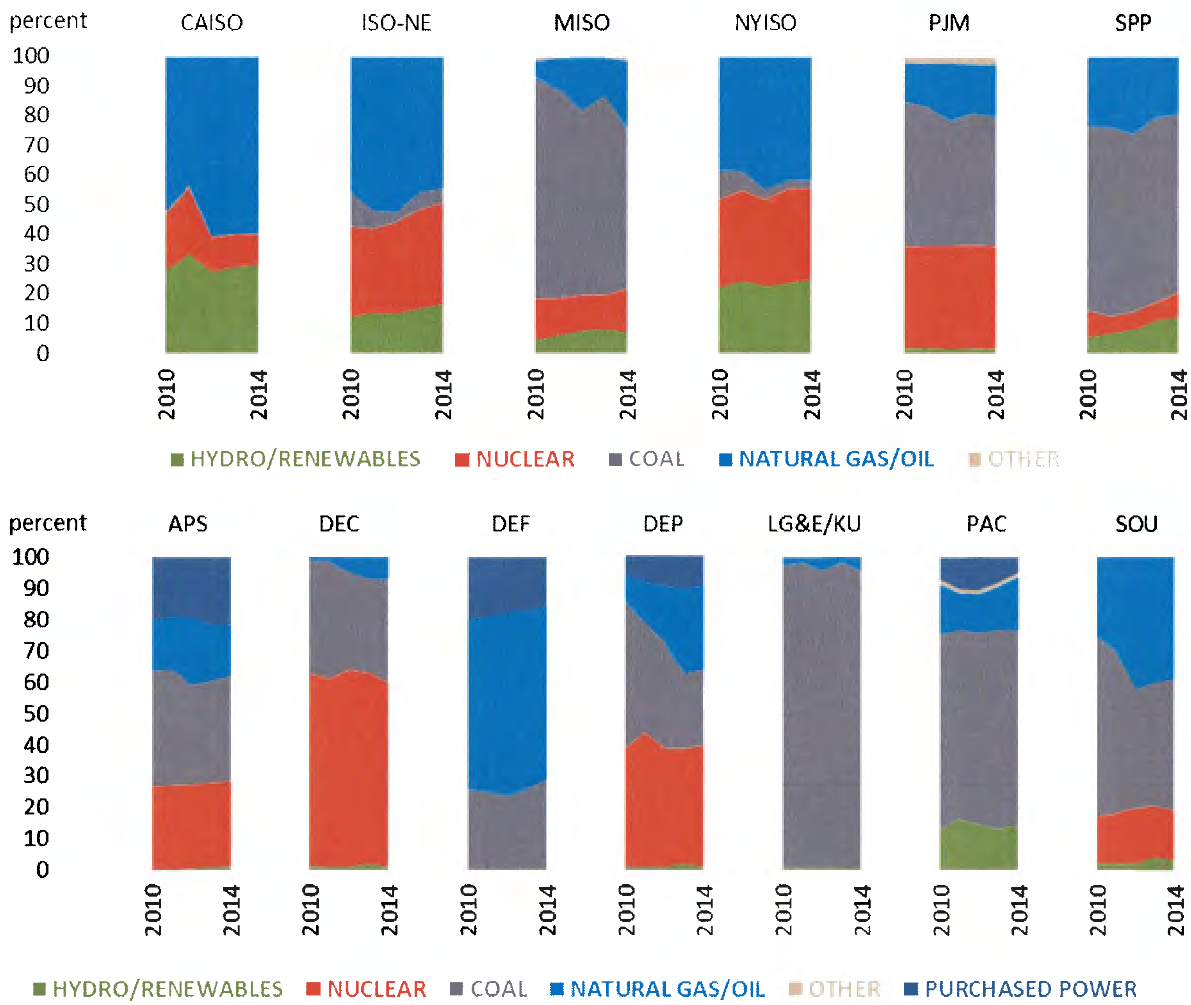
iv. Nuclear generating capacity

Across all respondents, CAISO reports the largest change in the share of nuclear generating capacity, declining from 7.8 percent in 2010 to 3.5 percent in 2014, which is attributable to the retirement of the San Onofre Nuclear Generating Station (SONGS).

b. Generation by Fuel Type

This metric measures the percentage mix of fuel types used to generate electricity (generation fuel diversity). The metric provides an indication of the level of integration of fuels with different characteristics, such as fuels with lower costs or lower environmental impacts. The mix of fuels used to generate electricity in a given time period follows from, among other factors, the types of generating capacity in service and conditions in fuel markets. Figure 19 shows the share of generation by fuel type from 2010-2014 as reported by respondents.

Figure 19: Share of total generation by fuel type .



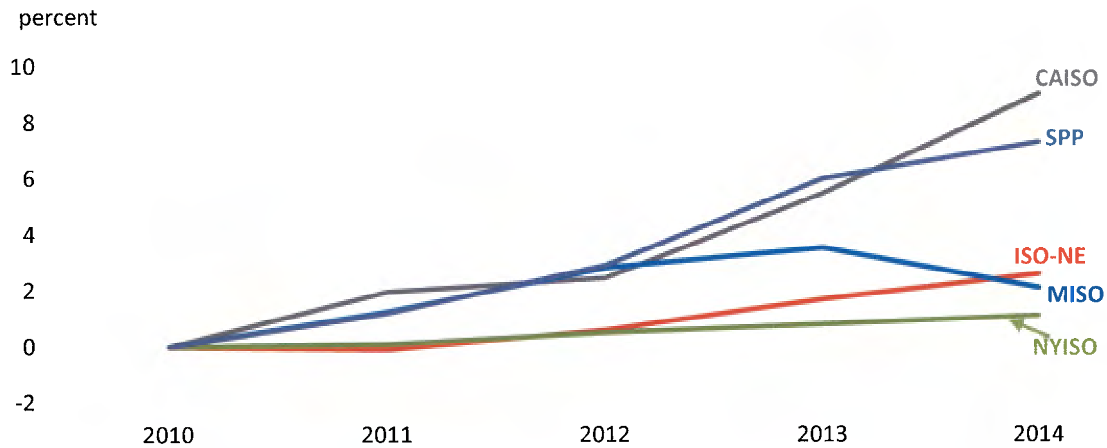
Source: Commission staff based on information collection FERC-922.
Notes: (1) SPP provided minor corrections to rounding errors in its original submittal via email correspondence on January 5, 2016. These include revising the 2014 share of natural gas-fired generation from 19.03 percent to 19.04 percent, and revising the 2010 share of hydro and renewables generation from 5.5 percent to 5.4 percent. The figure reflects the revised values. (2) Several non-RTO/ISO utilities report generation from purchased power, which may include a variety of fuel types. (3) PAC's "Other" category reflects waste heat and other sources which include biomass, biogas, geothermal, and solar.[81] PAC's "Purchased Power" category represents non-renewable net purchases.

[81] February 2016 PAC Metrics Report at 31.

i. Renewables generation

Most RTOs and ISOs generally report increases in the proportion of energy generated from renewable and hydroelectric sources between 2010 and 2014. In addition, the RTOs and ISOs separately report renewable generation as a percentage of total energy, separate from hydroelectric generation as a percentage of total energy. Figure 20 shows the increase in the share of total energy from non-hydro renewable sources relative to 2010 for five RTOs and ISOs. From 2010-2014, CAISO and SPP reported the largest gains in the share of energy provided from non-hydro renewable sources among RTOs and ISOs.

Figure 20: Gain/loss in non-hydro renewables share of total energy relative to 2010.



Source: Commission staff based on information submitted in the October 2015 RTO and ISO Metrics Report.
Note: PJM is not included in this figure. PJM reports renewables as a percentage of total energy increasing from 4.1 percent to 4.3 percent between 2010 and 2014. However, in comparing these totals to other values reported by PJM, it is not clear whether PJM included or excluded hydroelectric generation from the total.

ii. Coal, natural gas, and oil-fired generation

Among RTOs and ISOs, MISO, PJM, and SPP relied most heavily upon coal-fired generation to meet energy requirements from 2010-2014. However, in some RTOs and ISOs, the share of coal-fired generation declined as generation from natural gas-fired and renewable resources increased. PJM reports that generation produced from coal declined from 48.7 percent in 2010 to 43.5 percent in 2014.[82] In MISO, which integrated the

[82] October 2015 RTO and ISO Metrics Report at 324-325.

MISO South region in late 2013, the share of generation from coal-fired generators declined from 74.6 percent in 2010 to 54.2 percent in 2014.[83]

Trends in the total amount of generation provided by natural gas and coal-fired generation followed underlying fuel market trends. Several RTO and ISO regions report that the share of natural gas-fired generation increased between 2010 and 2012, as average natural gas prices declined, and then receded as natural gas prices increased between 2012 and 2014.

Among utilities in non-RTO and ISO regions, coal-fired generation provided nearly all the energy generated for LG&E/KU load. SOU and DEP report substantial declines in the proportion of energy produced by coal-fired generation from 2010- 2014.

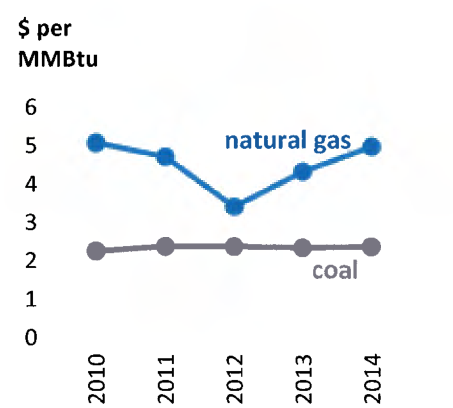
iii. Nuclear Generation

Across respondents, the most notable change in the proportion of energy provided by nuclear generation between 2010 and 2014 occurred in CAISO following the retirement of SONGS.

3. System Lambda

System lambda measures the incremental cost of energy derived from the economic dispatch function performed by a balancing authority area's control center. System lambda represents the incremental cost of energy of the marginal generating unit, assuming no system constraints, and generally tracks trends in marginal fuel costs for a given balancing authority area. The basis for the system lambda metric is information submitted in FERC Form No. 714.

Figure 21: Average cost of natural gas and coal delivered to U.S. electric power plants, 2010-2014.



Source: U.S. Energy Information Administration.
Note: Values are expressed in nominal dollars per MMBtu.

System lambda correlates with fuel prices and demand, among other factors, and reflects regional differences in the mix of generating resources. For instance, in areas where natural gas is the primary fuel used by generators on the margin, system lambda correlates with the price of natural gas. In areas with very large amounts of coal-fired generation, coal may be more likely to be the marginal fuel in a given hour. Figure 21 shows the average cost of natural gas and coal

[83] *Id.* at 203.

delivered to U.S. electric power plants from 2010-2014, expressed in nominal dollars per million British thermal units (MMBtu).[84] The average price of natural gas declined on an annual basis from 2010-2012, then increased from 2012-2014. As shown in Figure 22, the system lambda for most respondents also followed the trend of decreasing prices from 2010-2012, and increasing prices from 2012-2014. The responses from DEC and LG&E/KU do not follow this trend. As seen previously (Figure 19), the shares of natural-gas fired generation were lowest in DEC and LG&E/KU among respondents; thus, the incremental cost of energy in these regions is more likely to reflect the cost of other resource types (such as coal-fired generators).

Regional variation in system lambda levels could reflect local fuel market conditions, electricity demand, and changing resource mixes, among other conditions. For example, ISO-NE reported the highest system lambda values among respondents, explaining that its system marginal cost values reflect movements in underlying fuel prices, especially during 2013 and 2014.[85] In 2013 and 2014, the northeast United States experienced extreme cold weather, operational challenges due to pipeline constraints, and fuel availability and delivery issues for both gas and oil-fired resources.[86]

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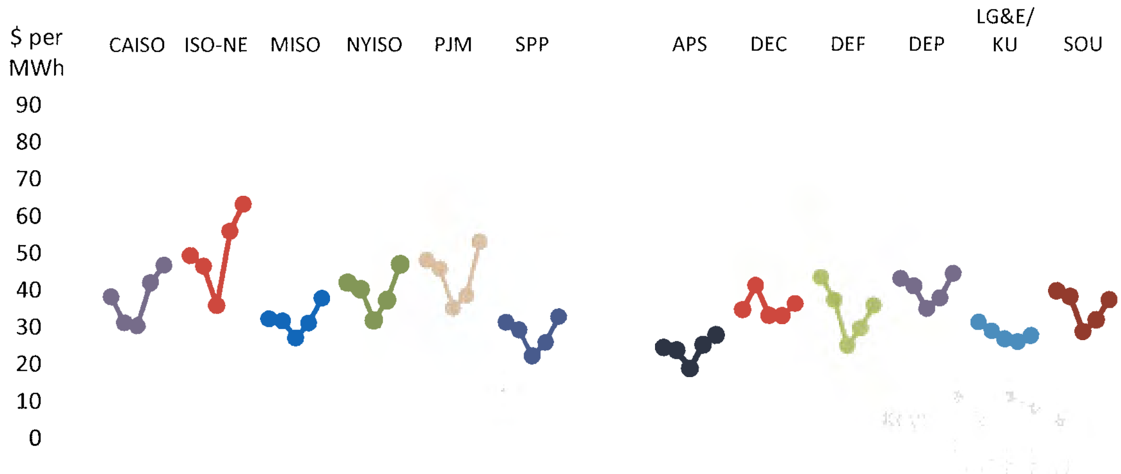
[84] U.S. Energy Information Administration, *Short-Term Energy Outloo*k, (Jan. 2016) http://www.eia.gov/forecasts/steo/query/.

[85] October 2015 RTO and ISO Metrics Report at 123.

[86] *Id.* at 121-124.

Figure 22: System lambda by respondent, 2010-2014.



Source: Commission staff based on information collection FERC-922 and FERC Form No. 714.
Notes: (1) Values expressed in nominal dollars. (2) RTOs and ISOs report the marginal energy component of LMP; SOU does not provide system lambda values in this docket; values shown are based on Southern's submittals in FERC Form No. 714 (values shown for each year represent unweighted hourly averages). (3) PAC reports that it does not calculate system lambda because the PACW Balancing Authority Area carries a significant amount of hydroelectric generation on the regulating margin, and such resources do not have a fuel price component; PAC reports that the same hydroelectric resources are used as incremental regulating resources by the PACE Balancing Authority Area, through dynamic transfers.[87]

IV. Selected Other Metrics Specific to RTO and ISO Performance

A. Metrics Related to Coordinated Wholesale Power Markets

RTO and ISO respondents report a number of additional metrics that are not part of Information Collection FERC-922, because they are not common metrics that are applicable to the entire industry. For example, the RTOs and ISOs provide data that measure the performance of RTO and ISO day-ahead and real-time markets. The following sections contain an evaluation of selected RTO and ISO-specific metrics.

1. Proportionate Market Transaction Charges in 2014

RTOs and ISOs offer largely the same services. The cost of these services are charged to customers according to specified charge types. This metric should be considered in the context of differences in the scale and scope of market operations across RTOs and ISOs. The relative size of any category of cost to total cost is a function of many variables including whether there were major market design changes.

[87] February 2016 PAC Metrics Report at 30.

Table 10 summarizes the dollars billed across charge categories for RTOs and ISOs in 2014. For 2014, MISO reports billing the highest percentage of dollars for energy market transactions, at 82.7 percent.[88] Among RTOs and ISOs with capacity markets, NYISO reports the highest percentage capacity market charges relative to total dollars billed, at 30.0 percent.

It should be noted that SPP's Energy Imbalance Market was in operation through February 28, 2014, and was replaced with the Integrated Marketplace on March 1, 2014. The percentage of dollars billed in SPP reflects this transition.[89] It should also be noted that CAISO does not report the percentage of dollars billed.

Table 10: Summary of dollars billed by charge type, 2014.

RTO or ISO Category	Dollars Billed (billions)	Percentage of Total Dollars Billed
ISO-NE		
Energy Markets	9.079	72.3
Capacity	1.056	8.4
Transmission Tariff	1.819	14.5
Financial Transmission Rights Auction Revenues	0.032	0.3
Reserve Markets	0.207	1.7
Regulation Market	0.029	0.2
ISO-NE Administrative Expenses	0.171	1.3
Net Commitment-Period Compensation (NCPC)	0.167	1.3
Total	12.560	100.0
MISO		
Energy Markets	31.958	82.7
Resource Adequacy	0.145	0.4
Transmission Service	2.004	5.2
Financial Transmission Rights	4.115	10.6
Contingency Reserves	0.093	0.2
Regulation Market	0.087	0.2
Administrative Costs	0.247	0.6
Other	0.033	0.1
Total	38.680	100.0
NYISO		
Energy Markets	5.023	46.7

(cont'd.)

[88] October 2015 RTO and ISO Metrics Report at 184.

[89] *Id.* at 360.

Table 10: Summary of dollars billed by charge type, 2014.

RTO or ISO Category	Dollars Billed (billions)	Percentage of Total Dollars Billed
Installed Capacity	3.222	30.0
Transmission Service	0.105	1.0
Transmission Congestion	1.198	11.1
Transmission Losses	0.478	4.4
Transmission Congestion Contracts - Billed Fiscal Year	0.391	3.6
Ancillary Services	0.171	1.6
Administrative Costs	0.161	1.5
Market-wide charges	-0.004	0.0
Other	0.004	0.0
Total	10.749	100.0
PJM		
Energy Markets	30.573	61.1
Capacity	7.735	15.5
Transmission Service	3.241	6.5
Transmission Congestion	2.572	5.1
Transmission Losses	1.677	3.4
Transmission Enhancement	0.961	1.9
Financial Transmission Rights Auction Revenues	0.960	1.9
Operating Reserves	0.918	1.8
Reactive Supply	0.280	0.6
Regulation Market	0.258	0.5
PJM Administrative Expenses	0.274	0.5
Other	0.581	1.2
Total	50.030	100.0
SPP		
Energy Imbalance Market	0.295	2.8
Integrated Marketplace	7.458	70.5
Transmission	1.506	14.2
Transmission Congestion Rights	1.165	11.0
SPP Administrative Fee	0.149	1.4
Total	10.573	100.0

Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Notes: (1) Billing amounts are expressed in nominal dollars. (2) In ISO-NE, NCPC represents make-whole payment (uplift) costs, and may relate to energy or reserves markets. (3) SPP transitioned from the Energy Imbalance Market to the Integrated Marketplace in March 2014.

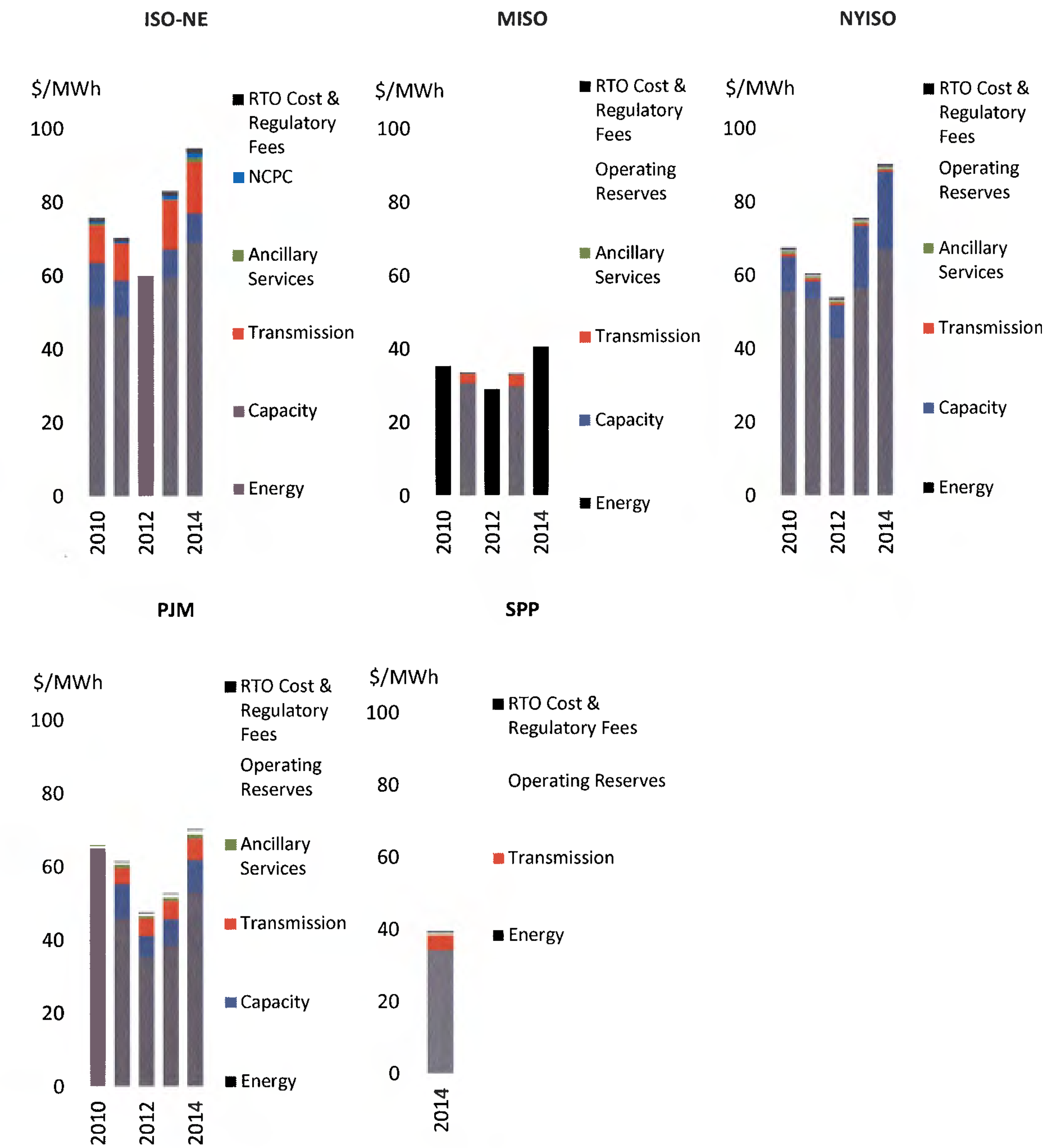
2. Wholesale Power Cost Breakdown

The wholesale power cost breakdown metric disaggregates costs paid by load, thereby providing a comprehensive assessment of all RTO and ISO market costs.[90] This metric should be considered within the context of different fuel mixes and market designs in each RTO and ISO region. As shown in Figure 23, ISO-NE and NYISO report the highest total wholesale power costs, with energy costs representing the largest component. The three eastern RTOs and ISOs (ISO-NE, NYISO, and PJM) each operate centralized capacity markets and report varying levels for the capacity-related component of wholesale power costs (with NYISO reporting the highest capacity-related costs). MISO also operates a voluntary capacity market to help ensure resource adequacy in its region. MISO reports a relatively low capacity-related component of wholesale prices as of 2014. It should be noted that SPP reports that data for this metric is only available beginning with the implementation of the Integrated Marketplace on March 1, 2014.[91]

[90] The cost breakdown includes the following cost categories: RTO or ISO costs and regulatory fees, operating reserve costs, ancillary services costs, transmission costs, capacity costs and energy costs.

[91] October 2015 RTO and ISO Metrics Report at 367.

Figure 23: Wholesale power cost breakdown, 2010-2014.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Notes: (1) Values expressed in nominal dollars. (2) CAISO (not shown) does not report the numeric values corresponding to its wholesale power cost breakdown for 2014 and uses unique category names that are specific to CAISO. CAISO's response can be found on p. 59 of the October 2015 RTO and ISO Metrics Report.

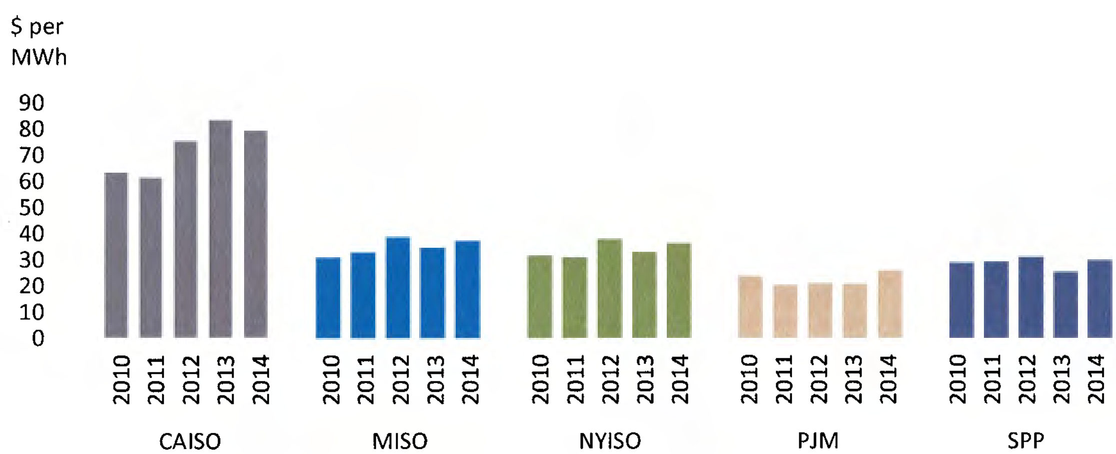
3. Fuel-Adjusted Wholesale Price

The load-weighted, fuel-adjusted locational marginal price is derived by holding fuel costs constant over a defined time period. This metric reflects the impact of load growth, new capacity, and the retirement of facilities, among other factors. As shown in Figure 24, CAISO reports the highest fuel-adjusted costs with an average of $73.20 per megawatt-hour and PJM the lowest with an average cost of $22.48 per megawatt-hour from 2010-2014.[92] PJM reports that its load-weighted fuel-adjusted wholesale spot energy prices increased 24 percent from 2013 to 2014, primarily driven by high demand and generator forced outages in PJM during periods of severe weather in 2014.[93]

Each RTO and ISO uses a different base year for its fuel adjustments. For instance, PJM uses a fuel cost reference year of 1999 because this is the first year that PJM administered both spot and day-ahead energy prices, whereas CAISO uses a base fuel cost reference year of 2008 gas prices and NYISO uses a base day for fuel-cost references year of 2000.

It should be noted that ISO-NE did not report a load-weighted, fuel adjusted locational marginal price.[94]

Figure 24: Load-weighted, fuel-adjusted locational marginal prices, 2010-2014.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Note: Values are expressed in nominal dollars per megawatt-hour.

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[92] *Id.* at 59 and 314.

[93] *Id.* at 314.

[94] *Id.* at 120.

4. Price-Cost Mark-up

The price-cost mark-up metric is based on a comparison between the price-based offer and cost-based offer of marginal units.[95] Low mark-ups suggest competitive market performance. This metric reflects the percentage mark-up for each year. Figure 25 shows the price-cost markup from 2010-2014 as reported by RTOs and ISOs.

CAISO's wholesale markets had a negative price-cost mark-up in all years. In 2012, the mark-up was very close to zero percent. In 2014, the price-cost mark-up was negative 4.8 percent. CAISO states that negative mark-ups can occur because default energy bids include a 10 percent mark-up, and that many resources choose to bid below their default levels by small amounts in order to remain competitive in the market, especially as more renewable generation has come online over the past several years.

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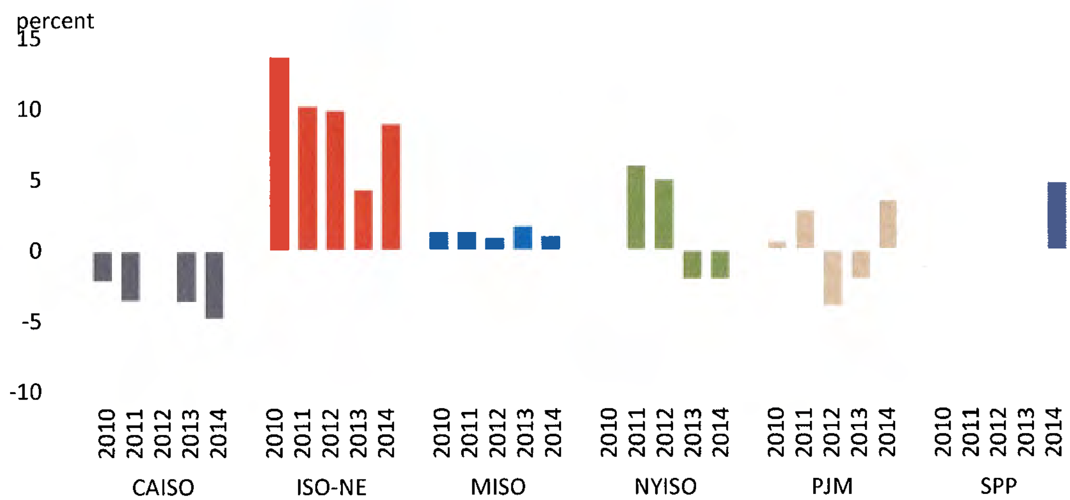
[95] *See id.* at 19 (RTOs and ISOs stating that price-cost mark-ups represent "the load weighted average markup component of dispatched generation divided by the load-weighted average price of dispatched generation.").

Figure 25: Price-cost mark-up, 2010-2014.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Notes: (1) CAISO compares total estimated wholesale energy costs to costs that would result under competitive baseline prices by re-simulating the market after replacing market bids for gas-fired generation with bids reflective of the unit's actual marginal costs.[96] (2) ISO-NE provides Lerner Index values as LI = (P-MC)/P, and states that beginning in 2012 it revised its methodology to calculate this index based on the day-ahead market, whereas before 2012 it was calculated based on the real-time market.[97] (3) MISO computes price-cost mark-up by comparing system marginal price based on actual offers to a simulated system marginal price based on assuming suppliers had all submitted offers at their estimated marginal costs.[98] (4) NYISO's 2010 data do not appear on this figure because NYISO's Cost Price Mark-Up that year was zero percent. (5) PJM reports that the mark-up component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units.[99] (6) SPP only reports data for 2014.

5. Percent of Unit-Hours Mitigated

This metric provides an indication of the magnitude of mitigation occurring in RTO and ISO markets, as measured by the percentage of unit hours that prices were set at the mitigated price on an annual basis. As shown in Figure 26, RTOs and ISOs report low percentages of mitigated hours from 2010-2014. Across RTOs and ISOs, CAISO reports the highest percentage of unit-hours mitigated from 2011-2014, with a downward trend

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[96] *Id.* at 54.

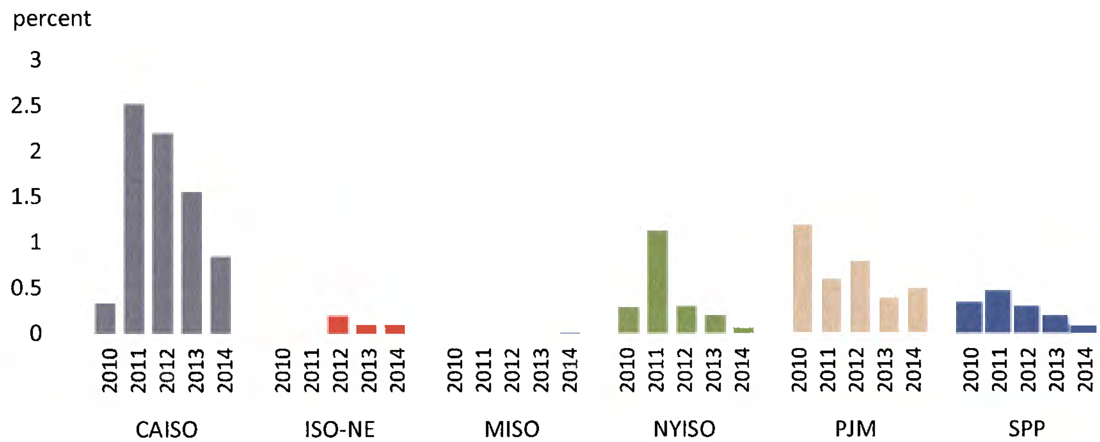
[97] *Id.* at 113-114.

[98] *Id.* at 186.

[99] *Id.* at 307.

over those four years.[100] MISO reports the lowest percentage of unit-hours mitigated among the RTOs and ISOs.

Figure 26: Percentage of unit-hours mitigated, 2010-2014.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Notes: (1) CAISO reports Real-Time Energy Market Percentage of Unit Hour Bids Mitigated due to Mitigation. (2) ISO-NE reports data only from April 18, 2012 onward. ISO-NE reports ISO-NE Percentage of Mitigated Hours in the Real-time Market Imposed under Market Rule 1, Appendix A, Section 5. (3) MISO reports Real-Time Energy Market Percentage of Unit Hours Offer Capped due to Mitigation. (4) NYISO reports Real-Time Energy Market Percentage of Unit Hours Offer Capped due to Mitigation. (5) PJM reports Real-Time Energy Market Percentage of Unit Hours Offer Capped due to Mitigation. (6) SPP reports Percentage of Unit Hours Offer Capped due to Mitigation.

6. Energy Market Price Convergence

Convergence of day-ahead and real-time energy prices provides an indication of the efficiency of RTO and ISO markets. Since the majority of energy settlements and generator commitments occur in the day-ahead market, day-ahead price convergence with the real-time market ensures efficient day-ahead commitments that reflect real-time operating needs.

Figure 27 shows the trend in convergence of day-ahead and real-time energy prices over 2010–2014 for each RTO or ISO calculated as the percentage of the annual difference between real-time energy market prices and day-ahead market prices. PJM reports less than two percent divergence between day-ahead and real-time prices in each year during the reporting period. Among all RTOs and ISOs and across all years, CAISO reports the least day-ahead to real-time price convergence, at 91.2 percent in 2010. However,

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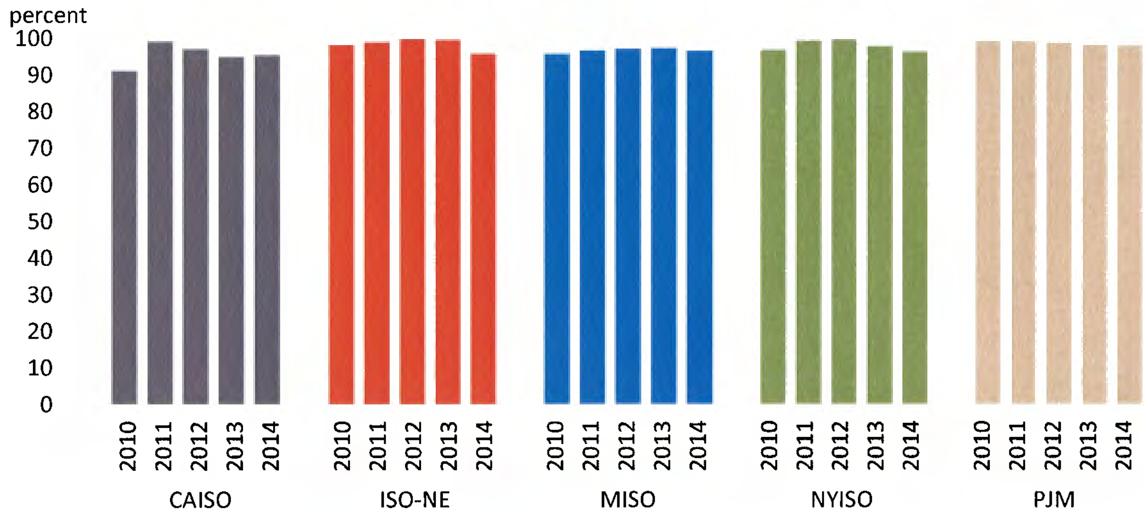
[100] In 2012, CAISO adopted a new approach that uses actual market conditions to produce a more accurate assessment of transmission competitiveness. *See id.* at 57.

CAISO also reports substantially greater price convergence in each year from 2011-2014.[101]

Figure 27: Percentage day-ahead to real-time energy market price convergence, 2010–2014.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Notes: (1) NYISO explains that this metric is the annual index based on the deviation of the annual average load weighted Real-Time Dispatch (RTD) price from the annual average of the absolute divergence of the RTD prices from the day-ahead prices, over annual average load weighted RTD price.[102] (2) SPP only reports price convergence information for 2014 because the day-ahead market in SPP began with the implementation of the Integrated Marketplace on March 1, 2014. SPP reports 97.0 percent day-ahead to real-time price convergence for 2014.

7. New Entrant Net Revenue

Generator net revenue measures the difference between a new[103] generator's variable production costs and the energy price received. This metric can be an indicator of whether generator net revenues are sufficient to ensure new investment, if needed, and are consistent with competitive markets. This metric reflects analysis conducted by each entity's market monitor.

Table 11 illustrates the new entrant net revenues for combustion turbines. ISO-NE, MISO, and SPP had little to relatively small growth over the five-year period, while

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[101] CAISO has taken steps to improve price convergence such as improving load forecast accuracy and implementing flexible ramping constraints. *See id.* at 61.

[102] *Id.* at 254.

[103] ISO-NE reports net revenues for proxy resources, while CAISO, ISO-NE, MISO, NYISO, PJM, and SPP specify that the net revenues are for new entrants.

NYISO, which reports values for the Hudson Valley Zone, reports an increase of more than 2.5 times from 2010-2014.

Table 11: New entrant natural gas-fired combustion turbine net generation revenues.
(dollars per installed MW-year)

Respondent	2010	2011	2012	2013	2014
CAISO	53,430	44,550	49,290	31,520	28,820
ISO-NE	30,502	23,398	22,162	30,710	33,225
MISO	26,626	26,957	21,902	20,864	26,308
NYISO	25,906	12,606	35,675	88,498	92,088
PJM	32,781	36,103	23,240	19,004	51,753
SPP	26,430	10,739	3,119	2,820	31,516

Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Note: Values are expressed in nominal dollars. NYISO values reflect the Hudson Valley Zone.

Table 12 shows new entrant net revenues for combined cycle plants. Several RTOs and ISOs, including ISO-NE, MISO, and SPP report reductions in combined cycle net revenues, while CAISO, NYISO, and PJM report increases.

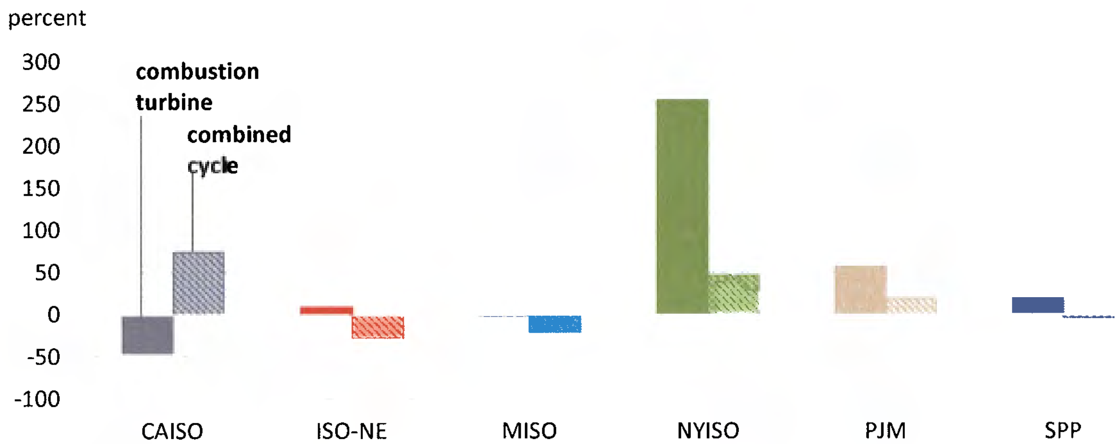
Table 12: New entrant natural gas-fired combined cycle net generation revenues, 2010-2014.
(dollars per installed MW-year)

Respondent	2010	2011	2012	2013	2014
CAISO	33,060	23,145	32,830	49,675	57,625
ISO-NE	61,246	53,026	42,458	40,146	44,380
MISO	43,899	35,561	36,847	25,627	34,714
NYISO	92,746	68,891	82,119	129,175	136,302
PJM	89,027	106,616	97,259	81,012	106,370
SPP	60,748	44,374	30,948	28,868	58,636

Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Note: Values are expressed in on nominal dollars. NYISO values reflect the Hudson Valley Zone.

Figure 28 details the percentage change in net revenues from 2010-2014 for new entrant combustion turbines and combined cycles for each region.

Figure 28: Percentage change in nominal net revenues for new entrant natural gas-fired combustion turbine and combined cycle generators, 2010-2014.



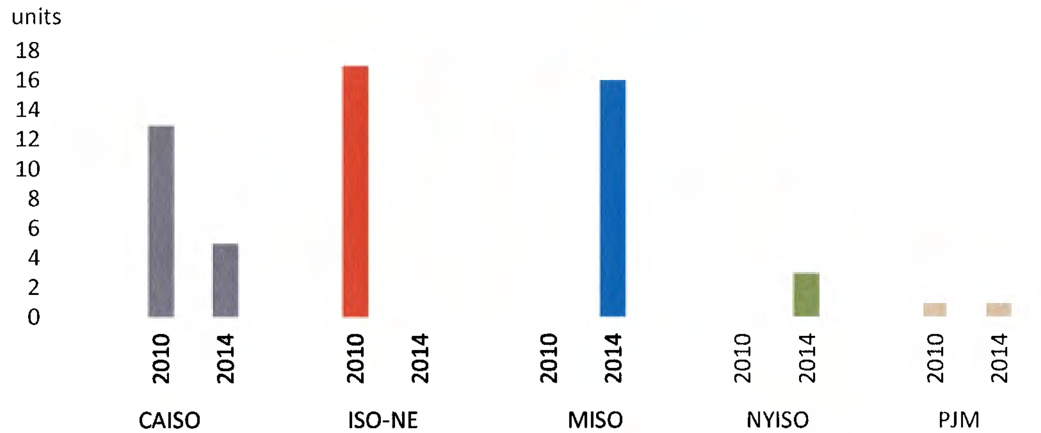
Source: Commission staff based on October 2015 RTO and ISO Metrics Report.

8. Reliability Must-Run Units

The reliability must-run (RMR) metric provides a measure of the degree to which an RTO or ISO must depend on critical facilities to maintain reliability and the flexibility of an RTO or ISO system to respond to emergencies and other contingencies. A RMR unit is typically a unit that continues to operate under a temporary contract after a planned retirement decision in order to resolve a reliability need.[104] As shown in Figure 29, CAISO and ISO-NE reported significant drops in RMR units from 2010-2014. MISO reported an increase from zero to 16 units under RMR-type arrangements.

[104] RTOs and ISOs use various terms to refer to such arrangements, e.g., "System Support Resources" in MISO. For the purposes of this report, such arrangements are collectively referred to as RMR.

Figure 29: Number of units under RMR contracts, 2010 and 2014.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Notes: (1) NYISO reports that it did not have any RMR contracts under its tariff between 2010 and 2014; however, NYISO states that in 2013 and 2014 it had three units totaling 406 MW operating under Reliability Support Service Agreements established under state procedures. Reliability Support Service Agreements are contracts to keep resources operating while local transmission is under construction to resolve the associated reliability need.[105] (2) Beginning June 1, 2010, existing generating resources submit delist bids in ISO-NE's Forward Capacity Market indicating a price at which the resource wishes to opt out of capacity market obligations. If ISO-NE denies a delist bid for reliability reasons, the resource may be compensated at the denied delist bid price or through a cost-of-service agreement.[106] At the end of 2014, ISO-NE had zero units receiving such delist bid reliability payments.[107]

Figure 30 illustrates the change in capacity under RMR agreements or similar arrangements in RTOs and ISOs from 2010-2014. In MISO, capacity under such agreements increased from zero to 1,024 MW from 2010-2014. By contrast, CAISO[108] and ISO-NE reported sharp declines in the amount of capacity under RMR agreements or similar arrangements over the same period.

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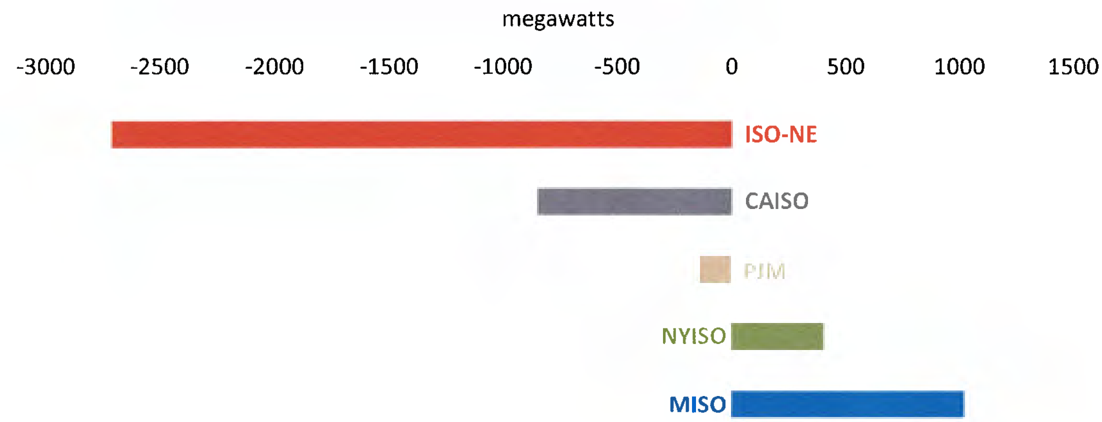
[105] October 2015 RTO and ISO Metrics Report at 235.

[106] *Id.* at 101.

[107] *Id.*

[108] CAISO explains that much of the capacity needed for local reliability is provided through the capacity procured under resource adequacy. CAISO also notes that the amount of RMR capacity declines as existing RMR units retire. *See id.* at 48.

Figure 30: Change in capacity under RMR or similar agreements between 2010 and 2014.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Note: SPP does not report any RMR capacity between 2010 and 2014.

9. Demand Response

The demand response metrics provide an indication of the role played by demand response resources in maintaining short-term and long-term reliability in RTOs and ISOs. Demand response can lead to deferred investment in generation capacity by reducing load during peak periods.

In Order No. 745, the Commission established rules for compensating demand response in organized wholesale electricity markets,[109] which were upheld by the Supreme Court in January 2016.[110]

Figure 31 shows demand response as a percent of total installed capacity in six RTOs and ISOs from 2010-2014. Every RTO and ISO reports a decline in demand response's share of total installed capacity in 2014 relative to 2010.

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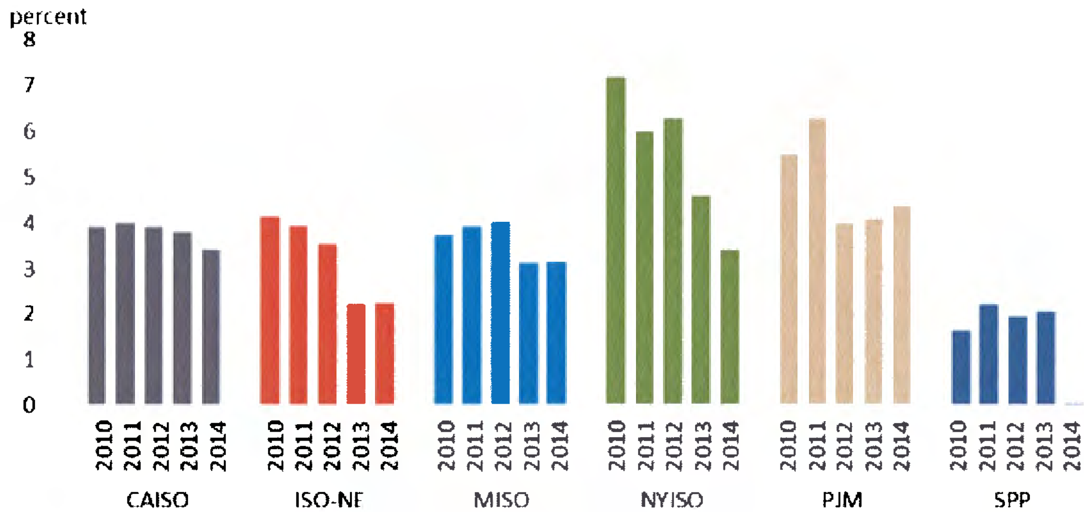
[109] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322 (2011), *order on reh'g*, Order No. 745-A, 137 FERC ¶ 61,215 (2011), *reh'g denied*, Order No. 745-B, 138 FERC ¶ 61,148 (2012), *rev'd and remanded sub nom. Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *rev'd and remanded*, 136 S. Ct. 760 (2016).

[110] *See FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760, 774 (2016).

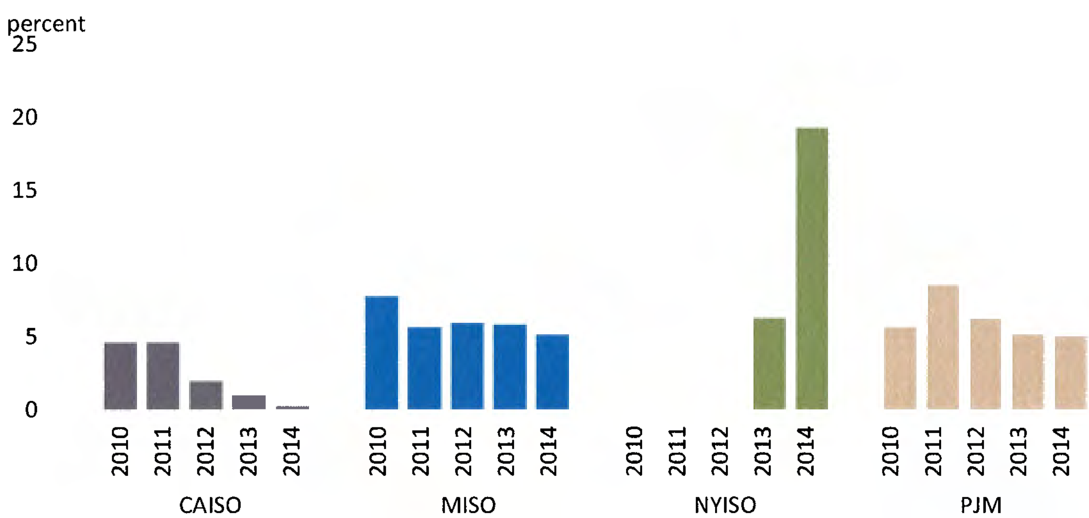
Figure 32 shows demand response as a percentage of reserves in four RTOs and ISOs from 2010-2014. During this period, CAISO reports a decrease in demand response as a percentage of reserves, while NYISO reports an increase from 2013 to 2014.

Figure 31: Demand response as a percentage of total installed capacity.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.

Figure 32: Demand response as a percentage of operating reserves, 2010-2014.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Notes: (1) SPP does not provide data in response to this metric. ISO-NE reported only a Demand Response Reserves Pilot program ending after the first six months of 2010, with no additional activity; (2) CAISO and PJM data indicate the shares of demand response in their respective synchronized reserve markets.

10. Congestion Management

Congestion represents the cost to customers of paying for more expensive energy because physical transmission line limits do not allow full delivery of least-cost energy. This metric can be measured in two ways. First, annual congestion costs divided by the megawatt-hours of load served, tracks congestion cost trends relative to load growth, providing an indication of the efficiency of the overall RTO and ISO system, as well as the effectiveness of RTO and ISO efforts to manage congestion costs through transmission expansion planning and other efficiency measures. This measurement is not entirely within the control of the RTO and ISO because other factors, such as load trends, also influence this metric. Second, congestion can be expressed in terms of congestion revenues as a percent of congestion costs. In general, RTOs and ISOs use day-ahead congestion revenues to fund the financial entitlements of congestion rights holders. Figure 33 shows these metrics and provides details on RTO and ISO-specific calculation methods.

RTOs and ISOs report varying methods for calculating the percentage of congestion dollars hedged under this metric. CAISO divides the amount of net revenue the market receives by total congestion costs.[111] ISO-NE reports the extent to which day-ahead and real-time congestion revenue and negative target allocations were sufficient to fund the transmission-hedge instruments each year.[112] MISO reports the relationship between congestion revenues and congestion payments to financial transmission rights holders.[113] NYISO reports the "total annual revenue collected from the hedging contracts purchased through the Transmission Congestion Contracts auctions divided by the total annual congestion cost."[114] PJM reports that financial transmission rights revenue adequacy declined from 2010-2014 due to reasons such as increased transmission outages, flows from external RTOs onto the PJM system, market-to-market constraints, and uncontrollable circumstances, such as forced outages, voltage and thermal constraints, real-time switching, and reliability-related de-rates.[115]

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[111] October 2015 RTO and ISO Metrics Report at 63.

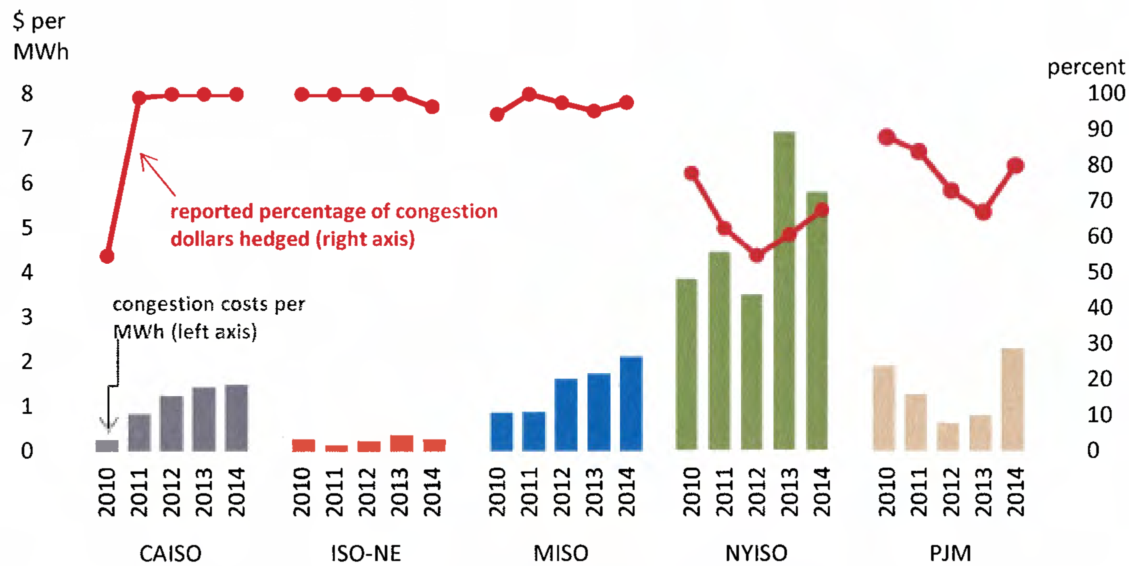
[112] *See id.* at 127-128. ISO-NE explains that negative target allocations are associated with counter-flow congestion in which a contract holder is required to contribute to the congestion revenue fund.

[113] *Id.* at 197.

[114] *Id.* at 257. NYISO also reports that there is an active market in over-the-counter contracts for differences which provide an additional hedging instrument.

[115] *Id.* at 322.

Figure 33: Annual congestion costs per megawatt-hour of load served and percentage of annual congestion costs hedged.



Source: Commission staff based on October 2015 RTO and ISO metrics report.
Notes: (1) Congestion costs are expressed in nominal dollars per MWh. (2) SPP (not shown) reports data for 2014 only. For 2014, SPP reports $2.11 of congestion costs per megawatt-hour of load served, and 85.9 percent of congestion costs hedged through congestion management markets.

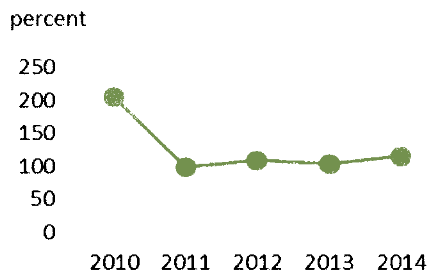
B. Metrics Related to Organizational Effectiveness

1. Administrative Costs

Administrative cost metrics measure the ability of RTOs and ISOs to manage the growth rate of administrative costs commensurate with the growth rate of system load (administrative charges per megawatt-hour of load served metric) and to keep costs within budgeted levels (actual versus budgeted administrative charges metric). The components of RTO and ISO administrative costs are capital costs – capital charges, debt service, interest expense and depreciation expense – and operating and maintenance costs net of miscellaneous income. By managing administrative costs, RTOs and ISOs can reduce customer costs.

For this metric, values below 100 percent reflect actual costs below budgeted costs.

Figure 34: NYISO capital costs as a percentage of budgeted costs, 2010-2014.

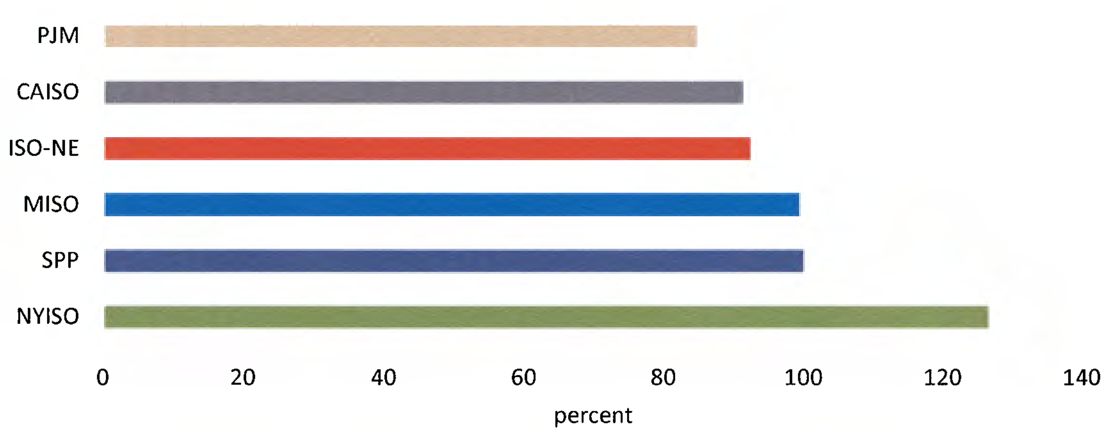


Source: Commission staff based on October 2015 RTO and ISO Metrics Report.

NYISO measured especially higher capital costs as a percentage of budgeted costs in 2010 (see Figure 34). NYISO explains that its capital recovery costs exceeded budget because anticipated long-term financing to proceed with infrastructure modifications did not receive approval during calendar year 2010. NYISO funded the cost of these capital improvements with spending under-runs on the non-capital costs portion of its annual budget recoveries. NYISO states that in a given year, it could overspend capital while underspending non-capital (or underspend capital while overspending non-capital); however, budget total spend is ultimately managed within the total overall NYISO budget.

Figure 35 shows the 2010-2014 five-year average capital costs as a percentage of budgeted costs for each RTO and ISO.

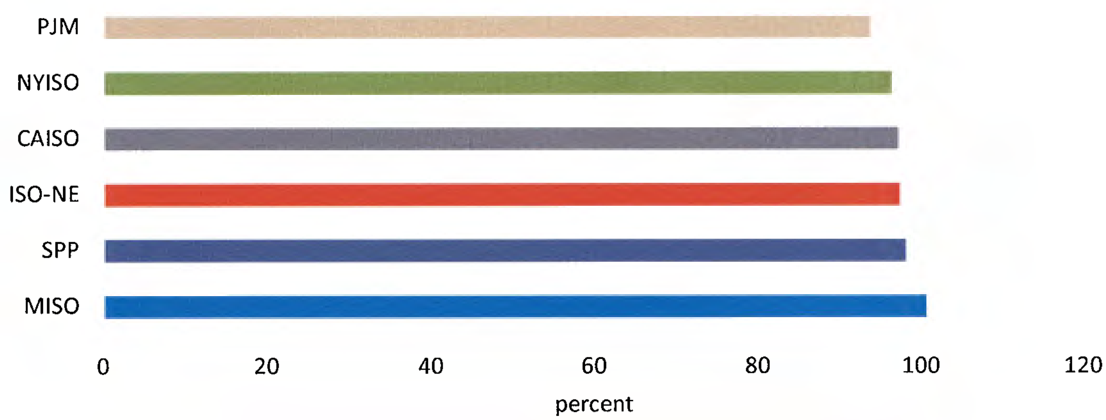
Figure 35: Five year average capital costs as a percentage of budgeted costs.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Notes: (1) Unweighted five-year average. (2) NYISO's 2010-2014 average reflects large capital expenditures in 2010.

The metric for noncapital (or administrative) costs, shown in Figure 36, shows each RTO's or ISO's administrative cost budget performance. The main categories of costs included in the non-capital costs metric are salaries and benefits, external professional fees, and computer services.

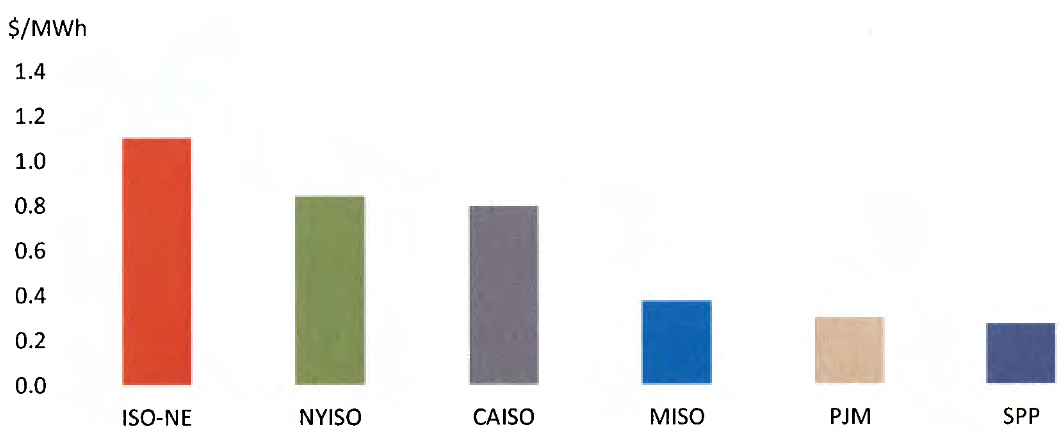
Figure 36: Non-capital costs as a percentage of budgeted costs, 2010-2014 average.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Note: Unweighted five-year average.

Figure 37 shows the 2010-2014 five-year average administrative cost per megawatt-hour in each RTO and ISO. Administrative costs vary widely across the RTOs and ISOs, with the five-year average administrative costs ranging from $0.27 per megawatt-hour for SPP to $1.10 per megawatt-hour for ISO-NE. While SPP has the lowest administrative costs on average over the reporting period, its annual rate of increase was the fastest rate among RTOs and ISOs (approximately 18 percent per year), and SPP reports higher per-megawatt-hour administrative costs ($0.38/MWh) than either PJM ($0.32/MWh) or MISO ($0.33/MWh) for calendar year 2014. The rate of increase seen in administrative costs in SPP may be attributable to the fact that SPP was in the process of launching its Integrated Marketplace during the reporting period.

Figure 37: Per-megawatt-hour administrative costs, 2010-2014 average.



Source: Commission staff based on 2015 RTO and ISO Metrics Report.
Notes: (1) Unweighted five-year average. (2) Average calculated using nominal dollars per megawatt-hour.

2. Billing Control Audits and Billing Accuracy

This metric indicates the accuracy and integrity of the RTO and ISO billing processes, based on audits conducted according to the Statement on Auditing Standards No. 70 (SAS 70) guidelines set by the American Institute of Certified Public Accountants. There are two types of SAS 70 audits: Type 1 audits, which assess the adequacy of the control design, and Type 2 audits, which review both the adequacy of the control design and whether the controls are being followed. An unqualified opinion indicates that the independent auditor found the control objects for each of the areas covered by the audit to be adequately designed and operated for the audit period. A qualified opinion means the independent auditor found the design and/or the operation of one or more of the control objectives inadequate. Each RTO and ISO reports unqualified audit opinions, with the exception of MISO in 2014. MISO reports that in 2014 one control objective was deemed qualified in the area of configuring and monitoring information systems.[116]

PJM, MISO and NYISO report a billing accuracy of over 95 percent.[117] MISO reports a billing accuracy of 95.4 percent and both NYISO and PJM report a billing accuracy of 99.9 percent. It should be noted that CAISO, ISO-NE and SPP did not report on billing accuracy.[118]

3. Customer Satisfaction

The customer satisfaction metric provides an indication of the extent to which RTOs and ISOs provide value to their customers. This metric is based on independent assessments of customer satisfaction surveys undertaken by independent, third-party entities. These surveys analyze customer perspectives on a wide range of RTO and ISO activities. RTOs and ISOs achieved relatively high levels of customer satisfaction between 2010 and 2014. The average customer satisfaction rating for CAISO, ISO-NE, PJM, and SPP was 90 percent.[119] Beginning in 2011, PJM began taking customer surveys bi-annually, and CAISO did not conduct a survey in 2013.[120] ISO-NE used qualitative measures of overall performance (extremely satisfied to extremely dissatisfied) and report card data

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[116] *Id.* at 209.

[117] *Id.* at 209, 269-270 and 334.

[118] *Id.* at 72, 148 and 380.

[119] *See id.* at 72, 145-148, 333, 379.

[120] *See id.* at 72, 333.

(on a scale of zero to 100) to measure its customer satisfaction metric.[121] MISO and NYISO report average customer satisfaction ratings of 78 percent and 76 percent, respectively.[122]

[121] *Id.* at 145-148.

[122] *See id.* at 208, 268-269, 333, 379.

Appendix A: List of Common Metrics

Table 13. Common metrics included in information collection FERC-922.

Reliability Metrics Metric No.	Category	Description
1	NERC Reliability Standards Compliance	References to applicable NERC standards
2		Number of violations self-reported and made public by NERC/FERC
3		Number of violations identified and made public as NERC audit findings
4		Total number of violations made public by NERC/FERC
5		Severity level of each violation made public by NERC/FERC
6		Compliance with operating reserve standards
7		Unserved energy (or load shedding) caused by violations
8	Dispatch Reliability	Balancing Authority ACE Limit (BAAL) or Control Performance Standards 1 and 2 (CPS1 and CPS2)
9		Energy Management System (EMS) Availability
10	Load Forecast Accuracy	Actual peak load as a percentage variance from forecasted peak load
11	Wind Forecast Accuracy	Actual wind availability compared to forecasted wind availability
12	Unscheduled Flows	Difference between net actual interchange and the net scheduled interchange (in megawatt-hours)
13	Transmission Outage Coordination	Percentage of planned outages (200 kilovolt and above) of at least 5 days for which the RTO and ISO or utility notified customers at least one month prior to the outage date
14		Percentage of outages (200 kilovolt and above) canceled by RTO and ISO or utility after being approved previously
15	Long-Term Reliability Planning – Transmission	Number of facilities approved to be constructed for reliability purposes
16		Percentage of approved construction projects on schedule and completed
17		Performance of planning process related to completion of (1) reliability studies and (2) economic studies
18	Long-Term Reliability Planning – Resources	Processing time for generation interconnection requests
19		Actual reserve margins compared with planned reserve margins
20	Interconnection and Transmission Process Metrics	Number of study requests
21		Number of studies completed
22		Average age of incomplete studies
23		Average time for completed studies
24		Total cost and types of studies completed
25	Special Protection Systems	Number of special protection systems
26		Percentage of special protection systems that responded as designed when activated
27		Number of unintended activations
28	System Lambda	System Lambda (on marginal unit), based on FERC Form No. 714 information
29	Availability	(1 – system forced outage rate) as measured over 12 months
30	Fuel Diversity	Fuel diversity in terms of energy produced and installed capacity

Source: Commission staff based on May 20, 2015 Comment Request in Docket No. AD14-15-000.
Note: For purposes of this report, Commission staff considers metrics 1-27 to be reliability metrics; Commission staff considers metrics 28-30 to be system operations metrics.

Appendix B: Recent RTO and ISO Expansion Activity

Since the release of the GAO Report in 2008, SPP, CAISO, MISO and PJM have expanded their footprints. The utilities that voluntarily joined RTOs and ISOs and/or imbalance markets attribute their decision to the more efficient commitment and dispatch of generation plants and enhanced reliability, coordination, competition and economies of scale provided by RTOs and ISOs. In some cases, the expanding RTO or ISO or the joining member estimated the monetized benefits from RTO and ISO expansion (usually in the form of estimated production cost savings); the accompanying sidebar discusses notable highlights from these analyses.[123]

SPP

SPP estimates that the net Integrated Marketplace savings were $131 million in its first 12 months of performance as of the third quarter of 2015.

CAISO

A report for the fourth quarter of 2015 estimated the gross benefit of CAISO's energy imbalance market that began in November 2014 to be $45.7 million.

MISO

MISO estimates that the integration of the MISO South Region yielded net benefits between $730 and $954 million.

PJM

East Kentucky Power Cooperative estimates that its 16 member-owned cooperatives will realize $131.9 million in net benefits over its first decade of PJM membership.

In 2014, CAISO expanded the use of the imbalance energy portion of its real-time market to other balancing authority areas in the Western Interconnection.[124] Several utilities outside of RTOs and ISOs in the West are participating in CAISO's Energy Imbalance Market (EIM) to share reserves and integrate renewable resources across a larger geographic region reliably and efficiently.

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[123] *See* SPP, *Results 2014 Annual Report,* 8 http://www.spp.org/documents/28682/ar-2014%2004302015.pdf; CAISO, *2015 Q4 Report: Quantifying EIM Benefits* (Feb. 2016) https://www.caiso.com/Documents/ISO_EIMBenefitsReportQ4_2015.pdf: MISO, *MISO 2014-2015 Winter Assessment Report Information Delivery and Market Analysis* 29 (May 2015), https://www.misoenergy.org/Library/Repository/Report/Seasonal%20Market%20Assessments/2015%20Winter%20Assessment%20Report.pdf; and Compete, *Public Power Utilities Flock to PJM, MISO for Benefits of Wholesale Power Market Competition* (June 2013), http://competecoalition.com/blog/tag/competitive-electricity-market.

[124] *Cal. Indep. Sys. Operator Corp.*, 149 FERC ¶ 61,058 (2014).

In 2011, American Transmission Systems, Inc. and Cleveland Public Power joined PJM;[125] in 2013, East Kentucky Power Cooperative, Inc. joined PJM.[126] In December 2013, Entergy's utility operating companies – Entergy Arkansas, Inc., Entergy Mississippi, Inc., Entergy Texas, Inc., Entergy Louisiana, LLC, Entergy Gulf States Louisiana, L.L.C., and Entergy New Orleans, Inc. – completed the integration of their transmission systems into MISO.[127] The Entergy utility operating companies, among other industry participants, comprise the MISO South Region.

On November 1, 2014, CAISO and PAC participated in the launch of the EIM.[128] In April 2015, PAC and CAISO signed a Memorandum of Understanding (MOU) to examine the potential benefits of creating a regional ISO.[129] The parties have extended the MOU to further explore costs and requirements needed to achieve the benefits of integration outlined in a study conducted by Energy Environmental Economics,[130] as well as to develop a transition agreement to outline the terms and conditions for the potential integration of PAC into a regional market.

Additionally, Puget Sound Energy and APS are scheduled to begin financially binding participation in CAISO's EIM in October 2016. NV Energy, Inc. began participating in

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[125] PJM, *PJM History,* (Feb. 2015), http://www.pjm.com/about-pjm/who-we-are/pjm-history.aspx?p=1.

[126] On May 22, 2013 in Docket Nos. ER13-1177-000, ER13-1178-000, and ER13-1179-000, the Commission accepted tariff revisions filed in connection with East Kentucky Power Cooperative, Inc.'s integration into PJM under delegated authority. *See also East Kentucky Power Cooperative, Inc.*, 147 FERC ¶ 61,028 (2013) and *East Kentucky Power Cooperative, Inc.* 147 FERC ¶ 61,097 (2014).

[127] *Midwest Indep. Trans. Sys. Op., Inc.*, 139 FERC ¶ 61,056, *on reh'g*, 141 FERC ¶ 61,128 (2012).

[128] *Cal. Indep. Sys. Op. Corp.*, 147 FERC ¶ 61,231 (2014).

[129] CAISO, *News Release: Western grid integration could produce significant cost savings, environmental benefits,* (Oct. 2015), http://www.caiso.com/Documents/WesternGridIntegrationCouldProduceSignificantCostSavings-EnvironmentalBenefits.pdf.

[130] Utility Dive, *Study: Integrating PacifiCorp and CAISO grids could create up to $9.1B in savings,* (Oct. 2015), http://www.utilitydive.com/news/study-integrating-pacificorp-and-caiso-grids-could-create-up-to-91b-in-s/407203/.

CAISO's EIM on December 1, 2015.[131] Portland General Electric Company filed an agreement with FERC to participate in CAISO's EIM starting in 2017.[132] Idaho Power signed an agreement with CAISO to participate in CAISO's EIM starting in 2018.[133] As a result, CAISO's EIM will encompass seven western states – California, Oregon, Washington, Nevada, Utah, Idaho, and Wyoming.

On October 1, 2015, the Integrated System and its three primary entities became full members of SPP. The Integrated System is comprised of Western Area Power Administration-Upper Great Plains, Basin Electric Power Cooperative, and Heartland Consumers Power District.[134] This expands SPP's footprint to 14 states, adding the Dakotas and parts of Iowa, Minnesota, Montana, and Wyoming. Western Area Power Administration-Upper Great Plains is the first federal power marketing administration to join an RTO or ISO.

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[131] CAISO, *News Release*: *NV Energy enters the western Energy Imbalance Market*, (Dec. 2015), https://www.caiso.com/Documents/NVEnergyEntersTheWesternEnergyImbalanceMarket.pdf

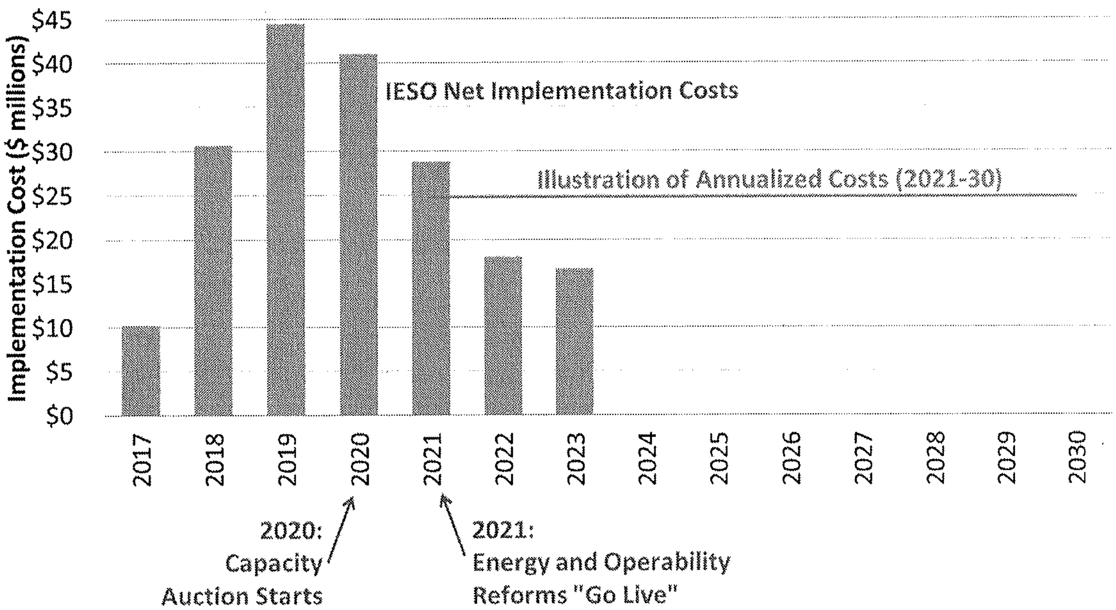
[132] CAISO, *News Release*: *Portland General Electric formalizes agreement to join EIM*, (Nov. 2015), http://www.caiso.com/Documents/PortlandGeneralElectricFormalizesAgreementToJoinEIM.pdf, see also CAISO, Implementation Agreement Filing, Docket No. ER16-366-000.

[133] Idaho Power Company, *News Release: Company Agrees to Join Western EIM,* (Apr. 2016), https://www.idahopower.com/NewsCommunity/News/NewsReleases/showPR.cfm?prID=3796.

[134] *Southwest Power Pool, Inc.*, 149 FERC ¶ 61,113 (2014) *reh'g Southwest Power Pool, Inc.*, 153 FERC ¶ 61,051 (2015).

There is substantial uncertainty in this estimate given the early indicative stage of the initiative, with a bigger uncertainty on the high end than on the low end. We therefore provide an upper-end estimate of $300 million.[141] This upper-end estimate incorporates higher-end assumptions regarding technology costs and project schedule.

Figure 21
IESO Implementation Costs



Notes:
The baseline estimate is based on the best current information on expected costs and parameters. We use a 5% discount rate to annualize the costs.

B. Experience from Other Markets

We interviewed staff at other ISOs and reviewed public documentation to identify lessons learned, implementation risks, and successful strategies that the IESO might adopt in Market Renewal. Each of these markets faced different challenges and drew different lessons from their experience. We first provide a discussion of the experiences in ERCOT and SPP, which are the markets we believe offer the IESO the most relevant and actionable information based on the detailed documentation on the challenges they faced during implementation. We then report the primary pieces of advice from staff at other ISOs offered to the IESO while pursuing Market Renewal.

141 These are a simple sum of the net implementation costs reported in nominal dollars. The present value of the cost in 2021 using a 5% discount rate is $310 million.