U.S. Energy Information Administration

Survey Forms

> 2014 Electricity Form Proposals

Comments received in response to 60-day Federal Register Notice published March 6, 2013

Organization	Organization
Alaska Electric Light and Power	IEEE Working Group on Distribution Reliability
American Public Power Assn	Integrys Business Support, LLC
Anchorage Municipal Light and Power	ISO/RTO Council
Big Sky Dairy Digester Plant Contact	Lawrence Berkeley National Lab(EIA-861)
Bonneville Power Administration	Lawrence Berkeley National Lab(EIA-930)
Bureau of Economic Analysis	Louisville Gas & Electric and Kentucky Utilities
Center for Energy, Sustainability, & the Environment at The Ohio State University	Midcontinent Independent System Operator, Inc. (EIA-930)
Center for Resource Solutions	National Mining Assn
Chugach Electric Association	National Renewable Energy Laboratory
Commissioner, FERC	National Rural Electric Cooperative Assn
Commonwealth Edison Company in Illinois	North American Electric Reliability Corp
Consortium for Energy Efficiency	Northwest Balancing Authorities
DOE, Assistant Secretary, Office of Electricity Delivery and Energy Reliability	Omaha Public Power District
DOE, Smart Grid Investment Program, Office of Electricity Delivery and Energy Reliability	PowerSouth Energy Cooperative
DOE, Wind and Water Power Technologies Office, Energy Efficiency and Renewable Energy	Renewable Energy Markets Assn
Edison Electric Institute	Southwest Power Pool
Electricity Consumers Resource Council	Tennessee Valley Authority
FERC Commissioner	The Balancing Authority of Northern California
First Energy Corp Utilities Business Services	Ventyx
First Energy Corp.	Volunteer Members of the Large Public Power Council Efficiency Working Group Benchmarking Subcommittee
Golden Valley Electric (Alaska)	Western Area Power Administration
Homer Electric Assn (Alaska)	Wood Mackenzie

AEL&P
ALASKA ELECTRIC LIGHT AND POWER COMPANY
(907) 780-2222 FAX (907) 463-3304
5601 Tonsgard Court, Juneau, AK 99801-7201

May 6, 2013

Rebecca Peterson
U.S. Department of Energy
U.S. Energy Information Administration
Mail Stop EI-23, Forrestal Building
1000 Independence Avenue SW
Washington, D.C. 20585

VIA U.S. Mail and E-mail:
ERS2014@eia.gov
Rebecca.Patterson@eia.doe.gov

Re: Comments on Form EIA-930

Dear Ms. Peterson:

Alaska Electric Light and Power (AEL&P), the electric utility serving Juneau, Alaska, offers these comments on the proposed implementation of Form EIA-930 "Balancing Authority Operations Report."

(a) whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility.

AEL&P is a small, electrically isolated utility. AEL&P generates, transmits and distributes power to all firm customers in the City and Borough of Juneau. There are no interconnections or power sales to customers outside of the AEL&P service territory.

There is no interchange of power between AEL&P and any outside utility. Therefore, AEL&P believes that the reporting requirement is not necessary and will not have any practical utility.

(b) the accuracy of the agency's estimate of the burden of proposed collection of information, including the validity of the methodology and assumptions used

The implementation of Form EIA-930 would require internet posting of:

- same day demand, hourly
- prior day demand, net generation and actual interchange
- prior day's day-ahead demand forecast

AEL&P is a small utility with approximately 65 full-time personnel, including linemen, metering, generation, billing, engineering, management, customer service and operations.

The AEL&P operations department has a single system operator on duty at any given time who takes manual hourly readings of instantaneous power generated. At the present time, there are no automated readings taken for hourly demand or net generation. Implementation of reporting hourly demand is estimated to take a minimum of 80 hours for the initial programming and at least 2 hours weekly to ensure that the data collection and distribution is correct and functioning per the requirements. This additional burden could not be met with existing staff on straight-time hours.

AEL&P utilizes hydro-electric generation to meet customer load; however, AEL&P maintains diesel standby plants which can be used if necessary for planned or unplanned maintenance events. The hydro-electric facilities in the system consist of four smaller facilities and one larger facility. The larger facility is in operation at all times and provides substantial spinning reserve.

The hourly demand of the AEL&P system can vary from 69MW in the peak winter season to as low as 20MW in the summer. However; these variations are temperature related and track closely year to year and season to season and are therefore very predictable. Therefore, AEL&P does not currently do daily hourly demand forecasts for the system. Adding this requirement to our operations would take an additional 1 hour daily. Again, this could not be done with AEL&P staff on straight-time hours.

Reporting of the information required in Form EIA-930 would require additional technical and personnel resources which are not currently in place. AEL&P believes that the burden required to implement Form EIA-930 is too high for a small utility with no interchange, particularly given the lack of any apparent benefit to EIA or anyone else from this reporting requirement.

(c) ways to enhance the quality, utility, and clarity of the information to be collected

AEL&P has no comments on this.

(d) *ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology.*

AEL&P has no comments on this.

For the reasons outlined above, AEL&P believes that Form EIA-930 does not provide any value to AEL&P or any other organization. Implementation of this requirement will require additional resources that a small company, such as AEL&P does not currently have in place. AEL&P would therefore request an exemption from reporting Form EIA-930.

Sincerely,

K. Scott Willis
V.P. Generation

cc: Senator Mark Begich
Senator Lisa Murkowski
Representative Don Young

CRS center for resource solutions

May 6, 2013

U.S. Department of Energy
U.S. Energy Information Administration
Mail Stop EI–23, Forrestal Building
1000 Independence Avenue SW
Washington, DC 20585
Attention: Rebecca Peterson

Dear Ms. Peterson,

Center for Resource Solutions (CRS) appreciates the opportunity to provide these comments on the proposed revisions to the Energy Information Administration's (EIA) data collection practices. CRS administers the Green-e programs, which encourage the use of high-quality renewable electricity and carbon offsets as one means to combat and mitigate climate change. Through these programs, more than 600,000 individuals and companies in the US voluntarily purchased renewable electricity or carbon offsets in 2011.

The efforts of electric utilities in supporting and providing voluntary green electricity options for their customers is integral to our work and to the ability of individual Americans to take personal action against climate change. The EIA data collected on utility green electricity programs and renewable electricity is one of the few sources of hard information that can be used to demonstrate the growth and availability of such programs for American consumers. As such, CRS strongly encourages the EIA to continue to collect this data without interruption.

The EIA's data on renewable electricity is unique and far-reaching. By requiring reporting, data that is not widely available anywhere else will be maintained continuously, even if the data were only collected annually. An unbroken record is extremely important for showing trends over time and for providing a sound basis for decisions by technology producers, facility developers, corporate and individual purchasers, and electric utilities themselves. CRS and other entities, such as the National Renewable Energy Laboratory, rely on this data for annual reporting, projections, planning and communications in order to make the case for continued support and growth of renewable electricity in the US.

There is strong and broad interest in renewable electricity among consumers in the US, based on periodic surveys by the Natural Marketing Institute; their most recent data shows that 80% of respondents care about the use renewable energy, while only about one in six are aware that they can buy renewables from their electricity supplier despite half of consumers are able to. To bridge this gap in awareness, more data is needed, not less. In order for practical and effective communication of the availability of renewable energy, the EIA data must be maintained.

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Announcements by high-profile companies such as Google, Apple and Facebook about their growing efforts to use renewable energy also show that there is increasing interest by corporates, who are also responding to demand from their customers. While there are multiple mechanisms to purchase renewable energy, the most straightforward for the average customer and most businesses is through their electricity provider. Again, we feel that this supports the need for continued data collection and the continued relevance of the data, to further support the efforts and interests of US companies and individuals.

If you have any questions or thoughts in response to our comments, please do not hesitate to contact me at 415-561-2100 or alex@resource-solutions.org.

Best regards,

Alex Pennock
Manager, Green-e Energy
Center for Resource Solutions

Peterson, Rebecca

From: Allen J. Gray <AJGray@gvea.com>
Sent: Tuesday, May 14, 2013 12:35 PM
To: ERS2014
Cc: Peterson, Rebecca; McArdle, Paul; McGrath, Glenn; 'Paul Jones'; Lynn N. Thompson; Donna L. Rose
Subject: Comments on Form EIA-930

Golden Valley Electric Association
758 Illinois Street
PO Box 71249
Fairbanks, AK 99707-1249

Via Email to ERS2014@eia.gov

RE: Comments on Form EIA-930

Rebecca Peterson
U.S. Department of Energy
U.S. Energy Information Administration
Mail Stop EI-23, Forrestal Building
1000 Independence Avenue SW
Washington, D.C. 20585

Ms. Peterson:

Golden Valley Electric Association (GVEA) is the electric utility which serves Fairbanks and nearby communities on the road system of interior Alaska. We submit the following comments on the proposed Form EIA-930 Balancing Authority Operations Report.

Without any clear indication as to the purpose given to collect this information it is our belief that GVEA should not be required to furnish it per The Paperwork Reduction Act of 1980.

I seems more reasonable to provide hourly data a month at a time with a month delay or annually.

GVEA's SCADA system does not finish its top of the hour processing until 8 to 9 minutes after the hour. A system operator then reviews and accepts the hourly data within the next 10 minutes if system operation permits. It is unlikely that we would be able to meet the proposed 10 minute after the hour reporting timeframe.

The cost of reporting the data will not be "extremely low" for GVEA and will be borne by our members.

Sincerely,

Allen Gray
Power Systems Manager
Golden Valley Electric Association

May 6, 2013

To: Rebecca Peterson, ERS2014@eia.gov
Re: Public Comments on Form EIA–861, ''Annual Electric Power Industry Report''

From:
Volunteer members of the Large Public Power Council Energy Efficiency Working Group (LPPC EEWG) Benchmarking Subcommittee, led by:

- Subcommittee Chair Norman Muraya (Austin Energy) norman.muraya@austinenergy.com,
- Member Tom Gross (Orlando Utilities Commission) tgross@ouc.com, and
- Facilitated by Annika Brink (Alliance to Save Energy/Clean and Efficient Energy Program for Public Power) abrink@ase.org.

Over the course of the past year, the LPPC EEWG's Benchmarking Subcommittee has leveraged data from Form EIA-861, Schedule 6 to benchmark the energy efficiency activities and performance of LPPC member utilities. This work has included ongoing discussions among Subcommittee members and with the Energy Information Administration regarding the quality and consistency of data collected via Form EIA-861. Questions and comments on the public comments submitted below can be directed toward the three working group participants listed above.

Comments on Form EIA-861: Excel Version of Form
Incorrect terminology in Tab "ENERGY EFFICIENCY 6a"

1. Tab "ENERGY EFFICIENCY 6a"
   a. In the title of the last section, the word "Weighed" in "Weighed Average Life for Portfolio (Years) - Use Spreadsheet to Calculate" should be replaced with "Weighted."
   b. In line 10, the word "Weighed" in "Weighed Average Life" should be replaced with "Weighted."
2. Tab "Weighed average life calculator"
   a. In the name of the tab, the word "Weighed" should be replaced with "Weighted."
3. To verify that the term "Weighed average life" is not widely used, try an internet for this term, which retrieves zero results. A search for "Weigh<u>t</u>ed average life" on the other hand, returns over 3 million results. To take things a step further: we prefer "Weighted average <u>measure</u> life," which is widely used in utility energy efficiency and returns over 7,000 results, most of which seem to relate directly back to energy efficiency.

© used instead of (c)

- In Tabs "ENERGY EFFICIENCY 6a," "DEMAND RESPONSE 6b," and "DYNAMIC PRICING PROGRAMS 6c," Excel autocorrect has mistakenly replaced (c) with © for the "Industrial" columns.

Inconsistency between "whom" and "that"

- In Tab "ADVANCED METERING AND CUSTOM 6d," Line 6 asks for the "Number of Customers for whom…" while Line 9 asks for the "Number of customers that can…"

In the tab labeled “Weighed average life calculator,” the title “Residential Customers” links back to the “ENERGY EFFICIENCY 6a” Tab, while the titles for “Commercial Customers,” “Industrial Customers,” and “Transportation Customers” do not link back to anything. This is confusing.

In the tab labeled “Weighed average life calculator,” the terminology “Average mean life program” is unclear. This should read “Average measure life,” or “Average life of program or measure,” or “Average life of measure or measures in program” (Columns D, I, N, and S).

Comments on Form EIA-861: Pdf Version of Instructions

On Page 2, Point 9, where the instructions state “See the Glossary for terms used in this survey,” please provide a link to the Glossary.

On Page 2, Point 9 where the instructions state “The financial and accounting terms are consistent as outlined in the Uniform System of Accounts for Public Utilities and Licensees (U.S. of A.) (18 CFR Part 101),” please provide a link to this source.

On Page 9-10, under “SCHEDULE 6. DEMAND-SIDE MANAGEMENT AND SMART GRID INFORMATION,” additional guidance is needed on the reporting responsibilities of wholesale utilities and joint action agencies, etc. that conduct demand-side management activities on behalf of distribution utilities. The instructions note that “Power supply cooperatives, municipal joint action agencies, and Federal Power Marketing Administrations should coordinate the reporting of DSM information with their power purchasing utilities to avoid double counting the effects and costs of DSM programs.” In this section, EIA should also state its preference for which entity should report this information.

Typo on Page 10: Where the instructions state “An energy efficiency resource must achieve a long term continuous reduction in demand for electricity and <u>are</u> available…” the word “are” should read “be.”

On Page 10 where the instructions state “Examples are replacing light bulbs with more efficient technology or replacing older HVAC systems with high efficiency systems,” we recommend replacing this with better examples: “Examples are adding additional insulation in older homes or replacing an HVAC system with a higher efficiency system that exceeds current codes and standards.”

On Page 11, under “1. Incremental Annual Savings—Reporting Year,” the two bullets are confusing and could be eliminated to simply read: “Participants in DSM programs.” If EIA insists on keeping both bullets, then we recommend replacing “DSM programs that operated in the previous reporting year” with “Existing DSM programs.”

On Page 11, under “Incremental Savings—Life Cycle, we recommend striking “DSM programs have a useful life, and the net effects of these programs will diminish over time. To the extent possible consider the useful life of efficiency by accounting for building demolition, equipment degradation, and program attrition.” This guidance is directly in conflict with EIA guidance on Page 10 to report Gross Savings. As a reminder: EIA has decided to switch from Net Savings to Gross Savings in order to achieve better consistency of reporting across different utilities. This guidance would introduce a new opportunity for inconsistency by asking utilities to self-define a type of Net Savings. We recommend replacing the phrase quoted above with, "Gross savings do not consider free ridership, spillover effects, building demolition, equipment degradation, and program attrition."

Page 11: It might be better if the terminology did not vary slightly between the form and the instructions:

- "Reporting Year Incremental Annual Savings" vs. "Incremental Annual Savings—Reporting Year"
- "Incremental Life Cycle Savings" vs. "Incremental Savings—Life Cycle"

Page 11: In general, the proposed instructions use the word "program" where "measure" or "project" would be more appropriate.

- Here, and throughout the instructions, it would be more accurate to refer to "DSM program measures" rather than "DSM programs" when discussing the useful life of savings.
- The instructions also state that a "Life cycle" <u>mean</u> the number of years the program is planned to exist…" First, there is a typo: it should read "means" rather than "mean." Second, this is inaccurate: a program may exist for 2 years, but install measures that last 30 years. Clearly, EIA wants to collect information on savings from the installed measures over the course of 30 years rather than from the two years the program is in existence, actively implementing new measures.
- Building off the example outlined above, we recommend replacing "the number of years the program is planned to exist" with "the number of years the effects of the program measures are planned to exist."
- For "Incremental Savings—Life Cycle," instead of "the life cycle of the incremental programs and participants," it would be better to say, "the life cycle of the program measures implemented in the reporting year."

Page 12: Point 3, Costs

- We recommend that this section offer guidance on what "all other costs" should include, e.g. utility DSM staff time, administration, marketing, contractual obligations, EM&V costs, etc.
- We recommend that this section offer guidance on whether or not costs should be "loaded"/"fully burdened" i.e. include fringe, overhead, etc.
- We think EIA should consider pulling out marketing costs into their own, third, separate category. Marketing often composes a large percentage of DSM budgets, making this data useful for benchmarking purposes. (If EIA makes this change, it should provide guidance on whether or not to include marketing staff labor costs as part of marketing DSM costs.)
- The instructions designate "in-kind services (e.g. design work)" as part of customer incentives. However, the inclusion here of "in-kind services" could be misconstrued to include many types of activities traditionally undertaken by utility energy efficiency staff and not generally counted as "customer incentives." Additional clarification is required.

- We recommend not switching back and forth between "reporting year" and "incremental year" if these terms are meant to be used interchangeably. It would be clearer to choose one term and use it consistently: we prefer "reporting year."
- The proposed instructions state that, "Reporting Year Incremental costs should include all costs for the programs for years prior to the incremental year if these costs were incurred at part of the start up of the program."
  - "costs" should be capitalized to read "Costs."
  - "at" should read "as"
  - As the proposed instructions currently read, it is not clear whether or not start up costs are meant to be re-reported each year that the program is in existence. Should the utility report the entire start up cost again each year? Should it only re-report a certain portion that it considers attributable to program activities that occurred in the reporting year?
  - Please include an example that shows how to count start up costs incurred in previous years, while avoiding double-counting across years.

Page 12: SCHEDULE 6. PART B. DEMAND RESPONSE PROGRAMS

- For "Demand Response Programs" we recommend that EIA replace "dimming of lights" with "cycling HVAC" (because it's a more common DR program).
- Instead of "shutting down industrial processes" we recommend "shifting industrial processes."
- For "Potential peak demand savings" we are not in agreement as to whether or not EIA should be collecting information on energy savings in MWh from demand response programs. It is not clear that there are significant energy savings from demand response, because energy use is generally shifted to non-peak hours. (Industrial/production processes are shifted, generators are less efficient, HVAC is deferred momentarily, etc.)
- For "Potential peak demand savings" EIA requests information on grid interactive water heaters. Please add a link to the DOE definition or provide a definition. Why just Water Heaters and not HVAC, pool pumps, or thermostats?

Page 12: Point 4, Weighted Average Life for Portfolio (Years)

- Here, the instructions correctly use the word "weighted" rather than "weighed." However, we still recommend use of the term "Weighted Average Measure Life" rather than "Weighted Average Life." This should be standardized across the instructions and the form itself.

From: Cheryl LaFleur [mailto:cheryl.lafleur@ferc.gov]
Sent: Tuesday, March 19, 2013 6:27 PM
To: Sieminski, Adam
Subject: Power system metrics

Dear Adam,

I enjoyed sitting next to you last month at the National Press Foundation dinner. I hope you are doing well.

I am just writing to say I was very pleased to read in Megawatt Daily that EIA will start collecting additional data on electric grid reliability. This has been a priority area for me, and it would be very useful to have well-accepted national statistics so that we can measure the performance of the grid over time, and the impact of reliability standards on grid performance. . I think the data you will be collecting on power plant construction costs and emission controls will also be very valuable.

As I told you at the dinner, few if any other sources of energy data have the credibility that EIA does. Please let me know if I or anyone at FERC can ever help you on data development, particularly on reliability.

Best,

Cheryl LaFleur

Commissioner Cheryl A. LaFleur

Federal Energy Regulatory Commission

888 First St., N.E.

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Christina Bigelow
Compliance Counsel
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November 6, 2013

Mr. Stan Kaplan
Mr. William Booth
U.S. Energy Information Administration
1000 Independence Ave., SW
Washington, DC 20585

VIA EMAIL

RE: Form EIA-930 Hourly and Daily Balancing Authority Operations Report Revisions

Dear Mssrs. Booth and Kaplan:

On behalf of the Midcontinent Independent System Operator, Inc[1]. ("MISO"), I want to extend our appreciation for your time and consideration of the input of the Independent System Operators and Regional Transmission Organizations ("ISOs/RTOs") regarding the proposal to collect additional Balancing Authority ("BA") operations information from all "Balancing Authorities in the contiguous United States and from selected electric utilities in Alaska and Hawaii" ("Form EIA-930")[2] Please also know that MISO greatly appreciates the opportunity to provide additional information and clarification regarding how the MISO Balancing Authority Area ("BAA") and associated responsibilities are structured and function within the Eastern Interconnection. MISO looks forward to working with the U.S. Energy Information Administration ("EIA") to ensure successful, timely implementation of revisions to Form EIA-930. To further facilitate your review, MISO is also providing the regulatory history regarding the development and implementation of the MISO BAA.

BACKGROUND

When MISO proposed its Ancillary Services Market ("ASM") in 2007, the Federal Energy Regulatory Commission ("FERC" or "the Commission") "expressed concern with regard to short-term reliability and how the Midwest ISO would retain independent control of the system despite the ability of the 24 Balancing Authorities to re-dispatch their generation or to reconfigure transmission to resolve constraints."[3] To address these concerns, "the Commission required the Midwest ISO to establish a dialogue with stakeholders … for the express purpose of achieving … **the eventual consolidation of most Balancing Authority functions into the Midwest ISO**."[4] On May 23, 2008, in Docket No. ER07-1372-008, MISO submitted its

[1] Formerly the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"), until its name changed effective April 26, 2013.
[2] *See* 78 Fed. Reg. 14526.
[3] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,172 (2008).
[4] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 107 FERC ¶ 61,191, at P 124 (2004) (Emphasis Added.).

amended Balancing Authority Agreement, which transferred key responsibilities from the existing Balancing Authorities to the Midwest ISO, enabling MISO to operate as the sole Balancing Authority in the ASM. The Commission accepted MISO's Balancing Authority Agreement effective September 9, 2008, subject to required compliance filings that were timely submitted and accepted by the Commission. Accordingly, the initiation of the current MISO BAA structure and function are a direct result of directives by the Commission to address potential reliability concerns associated with MISO's ASM.

In satisfaction of the Commission's directives as described above, as a part of the development of the MISO ASM, MISO worked with its members to consolidate the BA responsibility in the MISO region. On April 13, 2007, MISO requested certification as a Joint-Registered Balancing Authority pursuant to the Co-Registrant (Type 2) Joint Registration Organization ("JRO") process detailed in the North American Electric Reliability Corporation ("NERC") Rules of Procedure. Under the JRO (hereinafter "JRO00001"), MISO and its members co-registered for individual BA requirements and sub-requirements with each member being held accountable for the requirements for which it registered. MISO's Balancing Authority ("BA") certification under JRO00001 was granted on April 16, 2008, and operation of the MISO BAA under JRO00001 began with the start of the ASM on January 6, 2009. The Co-Registrant, Type 2 JRO process, was replaced with the Coordinated Functional Registration ("CFR") process approved by FERC on June 10, 2010, which is set forth in Section 508 of the NERC Rules of Procedure. Under both the former Type 2 JRO and the CFR, the MISO BA and Local Balancing Authorities ("LBAs") divided responsibility for the specific BA requirements and sub-requirements applicable to the MISO BAA. This division of responsibility was assumed by the MISO and the LBAs in the Amended Balancing Authority Agreement,[5] which was approved by FERC as Rate Schedule 03 to the Midwest ISO ASM Tariff on July 21, 2008.[6]

Through JRO00001 and the Midwest ISO Amended Balancing Authority Agreement, one BAA was created for the Midwest ISO ASM footprint – namely the MISO BAA.[7] Even more specifically, however, JRO00001 eliminated the multiple local BAAs within the MISO footprint. Accordingly, because the only BAA created in JRO00001 was the MISO BAA, the registration of LBAs for specific requirements and sub-requirements occurred solely to facilitate the overall BA function as it pertains to the MISO BAA and did not create multiple BAs. It is notable that the term "LBA" or "Local Balancing Authority Areas" are not defined or contemplated by NERC within either its Glossary of Terms Used in in NERC Reliability Standards or its Visual

[5] *See* "Agreement between Midwest ISO and Midwest ISO Balancing Authorities Relating to Implementation of TEMT," as amended on March 14, 2008, filed as "First Revised Rate Schedule FERC No. 3" to the Midwest ISO ASM Tariff.
[6] *Order Conditionally Accepting Amended Balancing Authority Agreement and Requiring Compliance Filing*, 124 FERC ¶61,074 (2008); with acceptance of amendments to the Amended Balancing Authority Agreement in accordance with the Compliance Filing on December 4, 2008.
[7] *See* ASM Order, 122 FERC ¶ 61,172; Order Approving ASM Start Up, 125 FERC ¶ 61,318; Midwest Independent Transmission System Operator, Inc., 125 FERC ¶ 61,322 (2008) ("Order on Compliance Filing").

Representations of BAs and BAAs.[8] Accordingly, while Section 1.364 of the Midwest ISO ASM Tariff defines LBAs as:

> "An operational entity or a Joint Registration Organization which is (i) responsible for compliance to NERC for the subset of NERC Balancing Authority Reliability Standards defined in the Balancing Authority Agreement ***for their local area within the Midwest ISO Balancing Authority Area***, (ii) a Party to Balancing Authority Agreement, excluding the Midwest ISO, and (iii) shown in Appendix A to the Balancing Authority Agreement."[9]

That term exists solely within the MISO Tariff and was not intended to imply that these entities are BAs in a broader context.

In summary, prior to registration under JRO00001, the MISO region was composed of several localized BAAs. However, pursuant to the Balancing Authority Agreement and JRO00001, the current BA registration for MISO creates one MISO BAA for the entire MISO ASM footprint. The limited subset of requirements assigned to LBAs within the Balancing Authority Agreement and JRO00001 are solely to facilitate the structure and operation of the MISO BAA by MISO as the BA. Both the Commission and NERC have previously recognized the MISO BAA as the sole BAA for the MISO region as described above and within other dockets.[10]

DISCUSSION

As set forth in the Federal Register notice regarding EIA Form-930, the purpose of the survey is to provide basic operating statistics for the nation's electric power systems on a current basis.[11] Specifically, the "EIA would make available a comprehensive set of the current day's system demand data on an hourly basis and the prior day's basic hourly electric system operating data on a daily basis."[12] Further, the Federal Register notice indicates that:

> " [t]he burden of providing these data is extremely low relative to their value, particularly since the information requested is already collected by or known to the proposed respondents in the course of their normal operations…"

and

[8] See NERC Glossary of Terms Used in in NERC Reliability Standards, Updated October 30, 2013 and NERC Regions and Balancing Authorities Diagram dated July 25, 2012. The Diagram is attached hereto as Attachment A. MISO respectfully notes that Attachment A identifies on MISO as a BA and does not identify any of the entities that participate in JRO00001 as BAs.
[9] *See* MISO ASM Tariff at Section 1.364.
[10] *See* filings and issuances of NERC and the Commission, respectively, in Docket No. RD10-4-000.
[11] *See* 78 Fed. Reg. 14526.
[12] *Id*.

> "[t]he proposed survey is specifically designed to minimize burden on electric system operators. The surveyed data is typically produced in the normal course of business by Balancing Authority energy management systems."

Finally, the Federal Register notice describes that this data will be collected from "Balancing Authorities in the contiguous United States and from selected electric utilities in Alaska and Hawaii."[13]

MISO respectfully notes that a Balancing Authority is currently defined in the NERC Glossary of Terms Used in in NERC Reliability Standards as:

> "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time."

In accordance with JRO00001, MISO is assigned responsibility for compliance with all applicable requirements of NERC Reliability Standards BAL-001, BAL-002, and BAL-003 and is further wholly responsible for the majority of applicable requirements set forth in NERC Reliability Standard BAL-005 (with the exception of those associated with metering), which Reliability Standards comprise the majority of real-time balancing activities performed for and within the MISO BAA. MISO is further wholly responsible for the majority of NERC Reliability Standards obligations governing Emergency Operations, Interconnection-wide Operations, Transmission Operations, and Interchange Scheduling Operations. MISO performs these obligations for its BAA, which is defined by NERC as:

> "The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area."

Because JRO00001 creates only one BAA for the entire MISO footprint (MISO BAA) and assigns responsibility for the MISO BAA to MISO as the Balancing Authority, data associated with the aforementioned NERC Reliability Standards is routinely produced in the normal course of business by MISO systems for the MISO BAA as a whole. This data is then used by MISO Real-Time Operating Personnel in ensuring the balancing and reliable operation of the entire MISO BAA. Data routinely produced in the normal course of business by MISO systems for use by MISO as the BA for the reliable operation of the MISO BAA as a whole includes Net Actual Interchange, Hourly Demand, Next Day Demand Forecasts, and Net Generation. Hence, as MISO is the BA for the sole BAA in the MISO footprint (MISO BAA) and entities identified as LBAs for the purposes of MISO's Tariff have no associated, NERC-recognized LBA Areas for which to produce and provide data, it is appropriate that:

1. MISO be recognized as the sole respondent to Form EIA-930 for the MISO BAA;

[13] *See* 78 Fed. Reg. 14526.

2. The MISO BAA be recognized as the only BAA within the MISO footprint; and
3. Data is provided as it is produced and utilized in the real-time operating environment for the MISO BAA.

MISO acknowledges the EIA's concerns with the size of the MISO BAA and the potential that important trends could be obscured if data is reported at the MISO BAA level. However, as described above, reporting of data at the MISO BAA level is the only method of reporting that would respect the currently-approved structure and function of the MISO BAA, which structure and function does not differ from other large BAAs. Further, MISO notes that, although it has chosen an alternate registration strategy from other ISO/RTOs, it is similarly situated to other ISOs/ RTOs that are currently anticipated to respond to EIA Form-930 at the BAA level. More specifically, the NERC Balancing Authorities Diagram provided as Attachment A to this letter depicts MISO (whole) as a Balancing Authority. In the same way, other ISOs/RTOs are depicted as Balancing Authorities at the ISO/RTO footprint level. As an example, MISO refers the EIA to the depiction of New York ISO ("NYISO"), PJM Interconnection, L.L.C. ("PJM"), ISO-New England ("ISONE"), etc. within the NERC Balancing Authorities Diagram (Attachment A to this letter). To ensure that the data being provided in response to the Form EIA-930 is uniform across all respondent BAs, the MISO BAA should report data at the same level as similarly situated large BAAs such as the ISOs/RTOs provided above.

Further, MISO notes that it has investigated the potential to report data on a zonal level within the MISO BAA in response to EIA Form-930 and has identified significant data and systems concerns that would prohibit it from timely providing its data at a zonal granularity in response to EIA Form-930. First, MISO identified that, at present, only a limited amount of the data required for response to Form EIA-930 is calculated at a zonal level and that such calculation occurs after-the fact. In particular, data that is provided for the MISO BAA on a zonal level is currently completed only for select next-day data, requires significant recalculation, and would not be feasible to produce during the real-time operating day. MISO respectfully notes that the "zonal" data that is currently produced is produced utilizing: (1) the data initially produced and utilized to operate the MISO BAA and (2) loosely defined regions within the MISO BAA that have no direct correlation or significance to MISO's real-time operations. Because EIA Form-930 is specifically requiring real-time operating data and characteristics, data that has been re-calculated and re-characterized, such as would be the case with any zonal data provided by MISO may obscure rather than facilitate the identification of operating trends.

While it would be *possible* for MISO to provide zonal data for certain next-day data, it is not feasible for current operating day data nor is it feasible utilizing MISO's current processes and systems, which primarily produce and utilize data for the entire MISO BAA. MISO notes that significant resources would be required to revise its systems, processes, and data reporting mechanisms to routinely, reliably produce accurate zonal data. This type of resource commitment is contradictory to the descriptions provided in the Federal Register notice describing EIA Form-930, which description clearly indicates that intent to " … to minimize burden on electric system operators" and use "information … already collected by or known to the proposed respondents in the course of their normal operations…"[14]

Finally, MISO respectfully submits that, because there are regular changes in the population and configuration of BAs, all stakeholders, including the EIA, would expend significantly less costs and resources in implementation and maintenance of data collection efforts if such efforts leveraged tools and data streams already in place within each BAA. Leveraging existing tools and data streams in the provision of data in response to Form EIA-930 would facilitate EIA's implementation of Form EIA-930 while ensuring that data provided in response to Form EIA-930 maintains integrity as BA footprints change. Accordingly, MISO respectfully suggests that Form EIA-930 should utilize data that is readily available from BAs for their associated BAAs (regardless of whether that data is provided at the BAA level) in this initial implementation and, after experience is gained with such data, consider revisions to the provision of such data as necessary to enhance the value of such data to the wider audience referenced in the Federal Register notice.[15] Nonetheless, should MISO be required to provide re-engineered zonal data, all process and system enhancements necessary to produce and provide such data could not be achieved by the identified March 1, 2014 deadline due to resource constraints associated with the integration of the MISO Southern region as well as other key MISO initiatives.

CONCLUSION

In conclusion, MISO respectfully requests that the EIA join the Commission and NERC in recognizing that the MISO BAA is the only BAA within the MISO footprint and that MISO is the recognized BA for the MISO BAA. Such recognition would:

1. Appropriately assign responsibility for responding to EIA Form-930 to MISO as the BA for the MISO BAA.
2. Result in the data provided in response to EIA Form-930 to be the operating data actually utilized to "integrate[s] resource plans ahead of time, maintain[s] load-interchange-generation balance within [the MISO] Balancing Authority Area, and support[s] Interconnection frequency in real time."
3. Align data provided in response to EIA Form-930 with that also provided by MISO to NERC and its Regional Entities to ensure continuity of data across all data submissions as well as efficiency and minimal administrative burden.

MISO respectfully suggests that this recognition could occur through a variety of methods including retaining the exemption for LBA entities or through clarification of the applicability such as:

"For the contiguous United States: all entities that are listed in NERC's

[14] *See* 78 Fed. Reg. 14526.
[15] *See* 78 Fed. Reg. 14526.

> Compliance Registry as a Balancing Authority with primary responsibility for an associated Balancing Authority Area must post operating information associated with its Balancing Authority Area required by this survey"

MISO hopes that the analysis set forth above facilitates the EIA's understanding of the structure and function of the MISO BAA. We welcome any comments or questions that you might have on this letter and look forward to the successful implementation of EIA Form-930.

Warm Regards,

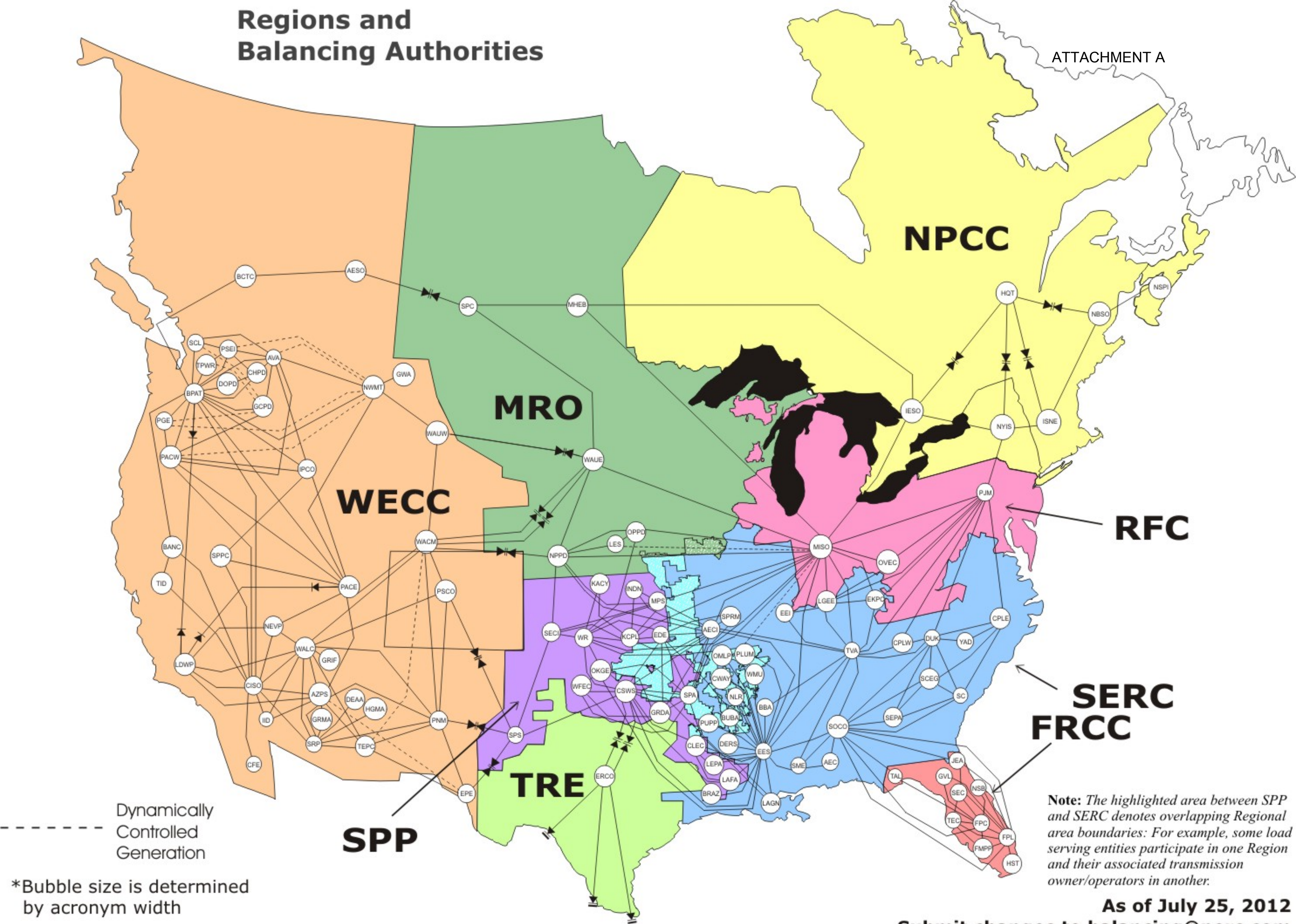
Christina V. Bigelow

ATTACHMENT A

NERC BALANCING AUTHORITIES DIAGRAM

Regions and Balancing Authorities

ATTACHMENT A



*Bubble size is determined by acronym width

Note: *The highlighted area between SPP and SERC denotes overlapping Regional area boundaries: For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.*

As of July 25, 2012

Submit changes to balancing@nerc.com

April 30, 2013

Ms. Rebecca Peterson
U.S. Department of Energy
Energy Information Administration, Mail Stop EI-23
Forrestal Building
1000 Independence Avenue, SW
Washington, DC 20585

RE: *Federal Register* notice of March 6, 2013, for the Energy Information Administration's Electric Power Surveys (Forms EIA–63B, EIA–411, EIA–826, EIA–860, EIA–860M, EIA–861, EIA–861S, EIA–923, EIA–930) (OMB Number: 1905-0129)

Dear Ms. Peterson:

The Bureau of Economic Analysis (BEA) strongly supports the continued collection of data by the Energy Information Administration (EIA) for the Electric Power Surveys. The data collected on these forms are crucial to key components of BEA's economic statistics.

BEA uses data from several Electric Power Survey forms to prepare the gross domestic product (GDP), the industry accounts, and the GDP by state estimates. Data from the following surveys are used:

- EIA-826 forms are used to prepare estimates of electricity services in the personal consumption expenditures component of GDP and to estimate quarterly and annual industry gross output.

- EIA-826 and EIA-861 are used to prepare quarterly, annual, and benchmark industry estimates of gross output, intermediate inputs, revenue growth, and final demand.

- EIA-923 data are used to prepare estimates of the inventories of utilities in the change in private inventories component of GDP and to estimate the dollar value of purchased fuels for electric utilities.

- EIA-860 and EIA-860M are used to prepare annual estimates of capital charges in the gross operating component of GDP by state.

A list of specific items used is described in the attachment below.

BEA has reviewed the proposed changes for the EIA surveys and has determined that they will not impact our use of the data. Specifically, changes to the form EIA-860M "Monthly Update to the Annual Electric Generator Report" will allow BEA to better quantify utility water usage. BEA also supports the new Schedule 9 "Smart Grid Transmission System Devices and Applications" for form EIA-411, "Coordinated Bulk Power Supply Program Report." BEA may use the smart grid technology and outage data collection to develop improved industry statistics.

Please keep BEA informed concerning any further modifications to these forms. We are particularly interested in any modifications proposed during the forms' approval process that would substantially affect our use of these data. For additional information, please contact Ruth Bramblett, Source Data Coordinator, on 202-606-9653 or by e-mail at Ruth.Bramblett@bea.gov. Should you need assistance in justifying these forms to the Office of Management and Budget, please do not hesitate to contact BEA.

Sincerely,

Dennis Fixler

Dennis J. Fixler
Chief Statistician

Attachment

Attachment

Direct Use of EIA Forms 923 and 826 in Preparation of BEA's National Income and Product Accounts (NIPA)

Items	Uses	NIPA Estimate
Data balance and stocks at the end of the reporting period	Used to estimate the inventories of utilities	Change in private inventories
Residential kilowatt hours (Price and Usage), U.S. total	Used to estimate electricity consumed by households	Personal consumption expenditures for electricity

Direct Use of EIA Forms 860 and 860M in Preparation of BEA's Regional Accounts

Items	Uses	Regional Account Estimate
Generating capacity by company and state	Used to apportion the capital charges data that are reported by company to the states where each company operates. Capital charges is a large portion of gross operating surplus	Capital charges component of gross operating surplus

Direct Use of EIA Forms 826 and 861 in Preparation of BEA's Industry Accounts

Industry	Uses	Industry Account Estimate
NAICS 2211 "Electric power transmission, generation, and distribution"	Primary measure of electric utility growth. Used to create company level database and time series for electric utilities by ownership and revenue type; final electricity demand in the Input/ Output table	Benchmark, quarterly, and annual estimate: gross output, intermediate inputs, revenue growth and final demand

Direct Use of EIA Forms 923 in Preparation of BEA's Industry Accounts

Industry	Uses	Industry Account Estimate
NAICS 2211 "Electric power transmission, generation, and distribution"	Used to estimate dollar value of purchased fuels for electricity generation utilities	Benchmark intermediate input estimates, "Purchased fuels"

Peterson, Rebecca

From: Diane.Tedore@ComEd.com
Sent: Thursday, April 25, 2013 2:04 PM
To: ERS2014
Cc: courtney.erickson@ComEd.com; michael.kanosky@ComEd.com
Subject: Comments regarding EIA: Federal Register Notification Regarding 2014 Survey Changes

Rebecca,

I am the survey contact for Utility ID 4110 – Commonwealth Edison Company in Illinois (ComEd). I have reviewed the proposed changes to EIA reporting beginning in 2014, and I have the following comments.

Form EIA-826 "Monthly Electric Sales and Revenue with State Distributions Report"

- Schedule 3, part A, "Green Pricing" removal: ComEd does not have a green pricing program, so we agree with removing this section from the report.
- Schedule 3, part B, "Net Metering" modifications: ComEd's net metering program is limited to applications less than 2 MW in Illinois, so we are already reporting all applications. ComEd will continue to report Commercial and Industrial as a combined number on this schedule, as we do not track these customers separately. ComEd will continue to be unable to provide energy sold back to the utility. ComEd cannot provide any information regarding CHP/Cogen category of net metering applications.
- Schedule 3, part C, "Advanced Metering" modifications: ComEd should be able to provide information regarding AMI meters operating as AMR versus AMI meters operating as AMI, but we would have to request support from our IT department in order to aggregate the data as requested.

Form EIA-861 "Annual Electric Power Industry Report"

- Schedule 2, part C, "Green Pricing" removal: ComEd does not have a green pricing program, so we agree with removing this section from the report.
- Schedule 2, part D, "Net Metering" modifications: ComEd's net metering program is limited to applications less than 2 MW in Illinois, so we are already reporting all applications. ComEd will continue to report Commercial and Industrial as a combined number on this schedule, as we do not track these customers separately. ComEd will continue to be unable to provide energy sold back to the utility.
- Schedule 4, part A, "Sales to Ultimate Customers – Full Service" modification: ComEd's rates are not currently decoupled, but we should be able to provide this information if it would apply in the future.
- Schedule 6, part A, "Energy Efficiency Programs" modifications: ComEd currently tracks energy efficiency programs based on net savings, but we should be able to develop a way to track gross savings if this is required. ComEd will continue to report Commercial and Industrial as a combined number on this schedule, as we do not track these customers separately. Instead of "average mean life of program," ComEd uses "expected useful life" for energy efficiency programs. We believe this would be an appropriate proxy for average mean life, but it would be helpful if the EIA could define this concept further.
- Schedule 6, part B, "Demand Response Programs" modifications: ComEd should be able to provide this information on an annual basis.
- Schedule 6, part C, "Dynamic Pricing Programs" new schedule: ComEd should be able to provide this information on an annual basis.
- Schedule 6, part D, "Advanced Metering and Customer Communications" modifications: ComEd should be able to provide information regarding AMI meters operating as AMR versus AMI meters operating as AMI, but we would have to request support from our IT department in order to aggregate the data as requested. For the new questions regarding electronic communications, direct load control, and daily access, we would also have to request support from our IT department in order to aggregate the data as requested.

- Schedule 6, part E, “Distribution System Information” new schedule: ComEd should be able to provide this information on an annual basis.
- Schedule 6, part F, “Distribution System Reliability Information” new schedule: ComEd should be able to provide this information on an annual basis.

Thanks,

Diane Tedore
Senior Accountant
Revenue Accounting
ComEd
630-437-2321

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202.508.5615 | Fax: 202.508.5673 | Mobile: 202.258.2909 | ecomer@eei.org

Power by Association℠

Edison Electric Institute

Edward H. Comer
Vice President, General Counsel & Corporate Secretary

May 6, 2013

Ms. Rebecca Peterson
U. S. Energy Information Administration
U. S. Department of Energy
Forrestal Building, Mail Stop EI-23
1000 Independence Avenue SW
Washington, DC 20585

Submitted by e-mail to ERS2014@eia.gov

Re: EIA electricity survey forms – 2014 triennial review –
Comments requested at 78 Fed. Reg. 14521 (Mar. 6, 2013)

Dear Ms. Peterson:

The Edison Electric Institute (EEI) is filing these comments in response to the above-referenced *Federal Register* notice. In the notice, the Energy Information Administration (EIA) has proposed to renew its existing electricity survey forms EIA-63B, 411, 826, 860, 860M, 861, and 923 with changes, and EIA has proposed the three-year authorization of a new form EIA-930.

EEI Has a Direct Interest in This Proceeding

EEI is the association of U.S. shareholder-owned electric companies, international affiliates, and industry associates. Our members represent approximately 70% of the U.S. electric power industry. They are among the primary respondents to the EIA electricity survey forms, which request large volumes of information about company facilities, operations, staffing, fuels, and finances. Therefore, EEI and our members have a direct interest in this proceeding.

The information requested in the EIA electricity survey forms and changes to the forms is quite burdensome for companies and other entities to collect, compile, verify, and submit. Furthermore, some of the information is commercially sensitive, and some can raise security concerns. EEI's goal in submitting these comments is to assist EIA in undertaking a careful review of the forms and proposed changes to them in order to minimize the reporting burden and to ensure confidential handling of information that is commercially sensitive or raises security concerns.

EEI Encourages EIA to Modify its Proposal Before Submitting it to OMB

EIA's proposed renewals, changes, and new form are being evaluated in this proceeding under the Paperwork Reduction Act (PRA), 44 USC 3501 et seq. The PRA requires EIA to avoid unnecessary data collection, to minimize the burden of collecting data, and to handle confidential information with appropriate care. The PRA also requires data collections to be approved by the Office of Management and Budget (OMB) as meeting these requirements. The PRA review process occurs every three years in two steps, this first step with a 60-day public comment period for input to EIA, and a second later step with a 30-day minimum public comment period for input to OMB.

EEI and our members have provided substantial input to EIA about the existing electricity survey forms and the proposed new form EIA-930 over the course of the past year. EEI submitted comments to EIA on February 17, 2012, encouraging EIA to adopt a number of improvements to the existing forms and form submission process. In addition, EEI and our members participated in eight EIA public listening sessions last summer to hear EIA's initial plans for revising the forms and collecting new information, and we provided substantial feedback to EIA on the agency's proposals during those sessions.

EEI appreciates that EIA has taken some of our suggestions to heart and is proposing some improvements along the lines we recommended last year. For example, EIA is proposing to delete a number of questions eliciting data that are of limited value or not readily available. Also, EIA is proposing to make certain questions easier to answer by conforming to current industry terminology and classifications. We support these changes.

On the other hand, despite strong, united industry opposition, EIA is forging ahead with its proposal to create the new form EIA-930, and EIA has not adopted changes to make that form more workable. Furthermore, EIA has not addressed various other industry suggestions for changes in the forms and filing process to clarify the forms and to reduce the burden that will be imposed upon respondents. In these comments, we are reiterating and adding to those points, and we encourage EIA to revise its proposal to address our suggestions more fully before submitting the proposal to OMB for review.

EEI is Particularly Concerned About the Proposed New Form EIA-930

Several times during and after the public meetings held last summer, EEI, EEI members, and others participating in the meetings raised numerous concerns about EIA's proposal to collect new hourly balancing-authority (BA) information in close-to-real time in the Form EIA-930, the "Balancing Authority Operations Report." We noted that:

- the volume and frequency of information EIA was proposing to collect is unprecedented in the EIA survey forms
- the information will be extremely burdensome for reporting entities to provide

- the information cannot be provided accurately in the time frames EIA is proposing
- the information duplicates other information collections
- the information raises confidentiality and commercial concerns
- EIA has not substantiated the need for the information especially given these problems

Yet to our dismay, EIA has proceeded to propose the new form essentially as originally envisioned, and EIA has effectively ignored the industry input. We strongly object. EIA's approach to introducing the form fails the test of meaningful review under the PRA and meaningful dialogue with the regulated community under the Administrative Procedure Act, 5 USC 551 et seq. To propose the form over such industry objections without seriously addressing those objections is arbitrary and capricious.

First, EIA is proposing to collect hourly demand information within ten minutes after the end of each, and to collect hourly demand, demand forecast, net generation, and interchange data by 7 a.m. Eastern time the next day, without explaining why EIA needs the information, and if it needs the information why quarterly, monthly, or at most daily values with more lag time would not suffice instead. By contrast, the FERC-714 collects hourly integrated demand data on an annual basis, with a minimum 5-month lag. If that suffices for FERC as the regulatory commission charged with overseeing markets and rates, we question EIA's need for more detailed information.

Second, EIA is proposing to collect large volumes of information that is already available in more accurate form and on more reasonable reporting time-frames elsewhere. Transmission providers are already required by FERC Order No. 890 et seq. to post their load forecast assumptions and actual peak loads to their OASIS websites daily. And companies send demand forecast data to their local reliability coordinators. If EIA does need the information it proposes to collect, it would be far less burdensome to the reporting entities for EIA to obtain such information from these other sources than for EIA to create the proposed new, expansive EIA-930.

Third, utilities do not have the type of data EIA is proposing to collect by the proposed deadlines with any level of accuracy. Some data, such as dynamic schedules from remote generation facilities, must be updated from estimated to actual values within 60 minutes after the end of the flow hour. And it often takes utility energy accounting and billing staff a week or more after the month ends to finalize net integrated load data. Staff has to coordinate the calculation of hourly inadvertent interchange with their counterparts in the adjoining balancing authority areas through the local reliability coordinating council.

So reporting by EIA's proposed deadlines is simply not practical. At worst, reporting entities would regularly have to chase after data already reported as corrected information became available, creating an ongoing additional burden. Furthermore, the discrepancies between preliminary information reported to EIA and more accurate information reported elsewhere would create confusion and lead to complaints by market participants.

Fourth, even if EIA's proposal were achievable, it would come at a substantial cost that would end up having to be borne by utilities' retail customers. To meet the proposed reporting deadlines would involve significant, additional automation of data transfer. Increasing security procedures around these processes already make them difficult to build and maintain. The proposed EIA-930 forms would exacerbate these challenges. EIA does not appear to have accounted for such costs in estimating the burden of the proposed new form. Such costs should not be lightly imposed, especially absent a demonstrated need for the information and when more reasonable counterpart information is already available elsewhere.

Fifth, EIA's proposal raises a number of practical concerns. The proposal still does not recognize the difference between net instantaneous and net integrated loads. The latter is more meaningful, and that is what is already collected on an annual basis in the FERC-714, as discussed previously. These are important technical details that, if new data are to be collected, should be worked out in dialogue with the industry before a new form is initiated.

Sixth, EEI is concerned about public disclosure of the data EIA proposes to collect. Data at this level of detail are often going to be competitively sensitive. Any party with access to the EIA website would have a picture of a BA's proprietary short or long resource position. Over time, the BA's historical load and generation data would provide seasonal and annual historical trends that could be used in an inappropriate manner in the electric markets.

Moreover, if a BA consists of a single load-serving entity (LSE), this information will expose commercial details about the LSE that will harm its ability to participate on even footing in electricity markets. Likewise, if a BA encompasses just two LSEs, each can know important operating details of the other. EEI and others raised these concerns during the public sessions last year and in our previous comments.

Though EIA acknowledges that there may be competitive concerns for single-unit BAs with this proposal's information collection and publication, EIA still does not accept that this concern also can arise for utilities that operate larger BAs. When even a larger BA loses a big unit and/or fuel supply, that loss could become apparent from the interchange information posted on a next-day basis. From that, it would be clear that the utility operating the BA has to purchase significantly-more than normal on an hourly basis. In turn, suppliers that are not constrained by FERC to offer cost-based rates could potentially exert market power in their pricing to the BA, causing higher prices to the BA utility and its customers.

Seventh, EEI also is concerned about disclosure of the data from a security perspective. There clearly may be risks in disclosing at a BA level the range of information EIA is proposing to collect, if for example that information helps miscreants identify key areas of demand and supply and transmission paths to serve them. The public dissemination of these types of information raises significant cyber-security concerns for the industry.

Eighth, EEI is concerned about a single BA being required to report data for other entities within the BA. Consent would be needed from these other entities before their data can be provided to EIA, and many BAs have non-disclosure agreements with parties that may not consent to release of the data.

For these reasons, EEI requests that EIA withdraw its proposal to launch the new form EIA-930. At a minimum, EIA should modify the form to address industry concerns in dialogue with the industry, and should provide another 60-day comment period on the modified form, before asking OMB to review and approve the revised form.

<u>EEI Recommends Improvements to the Existing EIA Forms and Filing Process</u>

In Attachment A to these comments, EEI is proposing a number of clarifications and improvements to the existing EIA electricity survey forms and filing processes and EIA's communications with reporting entities. We made a number of these suggestions in preliminary comments that we submitted to EIA on February 12, 2012, and during the EIA listening sessions last summer. But we cannot tell from the March 2013 *Federal Register* notice whether EIA is planning to adopt the changes. Others of these suggestions have arisen in response to the March 2013 notice.

<u>EIA Needs to Provide Adequate Time to Implement Any OMB-Approved Changes</u>

EEI has summarized EIA's proposed changes to the existing electric survey forms and the proposed new form EIA-930 in Attachment B to these comments. As Attachment B visibly demonstrates, EIA is proposing a large number of changes to its current data collection. Again, some of the changes involve deleting questions from existing forms. But most involve collecting new information, or information broken down into new categories, on the existing forms and the proposed new form.

The large number of changes being proposed during this triennial cycle heightens EEI's concern about EIA's proposal. Such changes impact the entire process that reporting entities must undergo to collect, compile, analyze, and file the information, including related software, staffing, and employee training. Thus, the changes clearly will impose a substantial new burden on reporting entities.

To minimize this burden, EIA should keep changes in its data collection to a reasonable minimum. And EIA needs to provide companies adequate time to adopt the changes. Reporting entities need six months to a year to modify their information collection and reporting procedures, software, staffing, and employee training. The longer time-frame is especially important for financial data governed by the Sarbanes-Oxley Act and other financial control requirements.

In this regard, we are very concerned that EIA appears to be heading toward OMB review of the EIA proposal during the last half of this year, less than six months before any changes OMB approves – potentially including an entirely new form – would take effect at the end of the year. As mentioned above, OMB is required to provide a 30-day comment period on the proposal once EIA submits it to OMB. Moreover, OMB typically takes 60 to 90 days or more to review agency proposals under the PRA.

As a result, unless EIA delays the effective date of the approved changes, there is a good chance that any changes OMB does approve in the EIA electric survey form package will take effect with little if any transition time for reporting entities to adapt to the changes. This actually happened one or two review cycles ago, when OMB approved changes literally at the end of the year, effectively immediately, leaving EIA and reporting entities in a bind that persisted well into the following year.

We encourage EIA to make sure that any changes to the existing forms and any new form take effect no sooner than six months to one year following OMB approval. Specifically, reporting entities should not be required to begin collecting or reporting the proposed new information any sooner than six months to one year after the date OMB approves the changes.

<u>EEI Encourages EIA to Maintain Confidentiality of Sensitive Information</u>

EEI is concerned that EIA is proposing to remove the protection of individual responses to the forms EIA-63-B, 411, 826, 860, and 923. Specifically, EIA is proposing to discontinue applying disclosure limitation rules that test aggregate statistics for the risk of disclosing identifiable information in the forms. Furthermore, EIA acknowledges that as a result, knowledgeable persons may be able to estimate the information reported by particular respondents.

In addition, EIA is not yet assuring confidentiality of individual responses for the proposed form EIA-930, though EIA asks for input on this issue. Industry has raised serious concerns that information provided for BAs that consist of either a single utility or small number of utilities will contain information that is sensitive from a commercial and security perspective and must be protected from disclosure.

At a minimum, EEI requests that EIA clarify that data currently treated as confidential will continue to be treated as confidential, and treat the proposed new EIA-930 data if collected as confidential. We also encourage EIA to continue applying aggregation techniques to avoid disclosure of individual utility responses to the forms, including the six mentioned above.

EEI appreciates that, according to EIA's proposal, EIA plans to treat new generator construction and financing cost data on Form 860 as confidential. We agree that such information is commercially sensitive.

Contact Information

If you have any questions about these comments or need additional information, please contact either Henri Bartholomot (hbartholomot@eei.org, 202.508.5622) or Steve Frauenheim (sfrauenheim@eei.org, 202.508.5580) here at EEI. Thank you.

Respectfully submitted,

Edward H. Comer

cc: Administrator Adam Sieminski, adam.sieminski@eia.gov
Deputy Administrator Howard K. Gruenspecht, howard.gruenspecht@eia.gov

Attachment A –
Additional EEI Recommendations for Improving the EIA Forms, Filing Process, and Communications[1]

General

- Duplicative data – Avoid collecting duplicative data in multiple EIA forms and in EIA and other agency forms. For example, the data required on EIA Form EIA-860, "Annual Electric Generator Report" and EIA Form EIA-923, "Electric Power Generation and Fuel Consumption, Stocks, and Receipts," overlap to a significant degree. A simpler, more effective approach would be to require data common to Forms EIA-860 and EIA-923 to be submitted only once through a single form.

- Materiality thresholds – Set a materiality threshold for EIA reporting requirements, to avoid the reporting of immaterial levels of information.

- Name of filer – Ask for the name of the person submitting each report, and reference this name when EIA contacts the filing company with questions about the data. Large organizations that file reports with EIA may have multiple personnel submit such reports. In such cases, including the name of the person who submitted the report on the report itself would assist if EIA later contacts the company about a given report.

- Data uploads – Modify EIA's secure e-file system to permit users to upload data. Reporting entities have developed systems to automate the production of certain EIA reports, with the data formatted according to EIA's requirements. But EIA's secure e-file system does not permit a user to upload data files, and EIA has informed reporting entities that data must be manually entered into the e-file system. Such manual entry not only is more burdensome than uploading reports – particularly in the case of the monthly Form EIA-923 reports – but it also increases the probability of data entry error. We encourage EIA to modify the e-file system to allow for the upload of reports, without sacrificing the system's security features.

- EIA notices – Post notices on the EIA website whenever the functionality of the EIA web-based reporting systems has changed. For example, EIA should post a notice in advance of any time when the web-based reporting system will be unavailable because of website maintenance or other technical issues. Further, EIA should post a notice whenever the process for electronic filing of certain reports has changed. Such notices would reduce the administrative burden on filers and help filers plan ahead to meet the various filing deadlines.

[1] This Attachment A together with the EEI's May 6, 2013 cover letter to Rebecca Peterson at EIA and separate Attachment B comprise EEI's comments on the EIA electric survey forms in response to EIA's request for comments at 78 Fed. Reg. 14521 (Mar. 6, 2013).

EIA-411

- Duplicative data – EEI members already provide NERC with the same information at the level of granularity being proposed in the revised EIA-411.

- Schedule 7A, Annual Data on Transmission Line Outages for AC Lines – Refine the proposed new reporting of transmission lines 100-199kV and less than 100 kV to be consistent with the current industry Bulk Electric System definition. Note that these additional data elements will impose a large new burden and will require a large increase in respondent resources to supply the information.

- Schedule 7A, Annual Data on Transmission Line Outages for AC Lines – Adopt the definitions in the TADS instruction manual found on the NERC web site for the proposed three new outage classifications, namely::

    - Single Mode – "An Automatic Outage of a single Element which occurred independent of any other Automatic Outages (if any)"

    - Dependent Mode – "An Automatic Outage of an Element which occurred as a result of an initiating outage, whether the initiating outage was an Element outage or a non-Element outage. (Note: to re-emphasize, a Dependent Mode Outage must be a result of another outage.)"

    - Common Mode – "One of two or more Automatic Outages with the same Initiating Cause Code and where the outages are not consequences of each other and occur nearly simultaneously (i.e. within cycles or seconds of one another)"

- Schedule 8, Generating Unit Outages, Deratings, and Performance Indexes – Keep these data confidential. They are labeled as confidential when provided to NERC and in discussions with public utility commissions, and they need to be kept confidential when provided to EIA.

EIA-826

- Schedule 3B, Net Metering – Establish monthly dollar and MWH materiality thresholds. Companies are reporting amounts for as few as one customer and as small as 1.5MW in a month for a given customer class, which is unnecessary.

EIA-860 and EIA-860M

- Schedule 2, Ash Impoundments – Delete this proposed new data collection. The U.S. Environmental Protection Agency already has collected this information, as part of an extensive information collection request (ICR) in 2010 for the agency's steam-electric effluent limitation guideline rulemaking. EIA has no need to collect the information a second time.

- Schedule 2, Net metering – Explain why EIA needs to know whether a plant whose primary purpose is other than electricity generation for sale is net metered.

- Schedule 2, Blackstart Units – Delete this proposed new data collection. This information is part of each utility's system restoration plan and is directly related to system reliability. Accordingly, a listing of a utility's blackstart units is highly confidential, should be treated as CEII, and should be heavily guarded. EEI strongly recommends that the EIA reconsider this request and not require utilities to provide a listing of blackstart units in the EIA-860, as such reporting could compromise the bulk electric system. In addition, this information is already reported to the NERC regional entities. If necessary, the EIA should coordinate with NERC to obtain access to the blackstart information in a manner that will ensure the confidential treatment of this highly sensitive information.

- Schedule 3, Uprates and Derates – Collect this information just for nuclear facilities, which appear to be the reason EIA is posing the question.

- Schedule 3, Generator Minimum Load and Time to Full Load – Do not add this question. It will be difficult to answer and could lead to inconsistent results. Many utilities do not track this information for all of their units.

- Schedule 3, Solar Energy Systems – Add a materiality threshold.

- Schedule 3, Proposed Generators – Clarify that "planned" generation means generation that has reached the permitting stage, as EIA explained during an August 11, 2009 briefing for EEI and its members. The current form instructions do not include this helpful clarification.

- Schedule 3, Proposed Generators – Clarify that utilities have to complete the data fields only if the information requested is available. Ten years out from construction, many details of a project may not yet be available, and utilities should not be required to complete the form based on speculation.

- Schedule 5, Generator Construction and Financing Costs – Do not add this question, especially as to annual estimates of long-lead-time coal and nuclear units, because it will impose a significant new burden with limited benefit.

- Schedule 6, Boiler NOx – Consider not adding this question, which will be burdensome to answer. At a minimum, do not require information unless readily available (e.g. do not require historic information that has not already been compiled), and treat any information collected as confidential because of its commercial sensitivity.

- Filing software – Change navigation in the EIA-860 and EIA-860M reporting database so a plant can be selected from within Schedule 6. Currently, utilities must change back to Schedule 3 every time, change the plant, and then go back to Schedule 6 when entering or verifying data. This change would cut down on the amount of time needed to report the data and make it less burdensome.

- Filing process – Expand availability to any interested reporting entity of last year's pilot program in which EIA put company data into spreadsheets and sent the spreadsheets to the company instead of requiring the company to do on-line entry. Improve the program by: (1) including the instruction line number with the field description; and (2) providing reporting entities the ability to download their data at any time from the EIA website in a spreadsheet format so they can also have a final copy of the entire report when it is completed.

<u>EIA-861</u>

- Schedule 6, Energy Efficiency – Explain proposed new concepts, such as: (1) net versus gross energy savings, (2) annual, annualized, and life cycle incremental costs, savings, and effects, and (3) weighted average life. Explain how these changes will improve the information reported.

- Schedule 6, Energy Efficiency – Note that the proposal to collect the Weighed Average Life of a portfolio of Energy Efficiency programs would require additional resources to gather historical data in order to generate a reliable lifespan of all of EEI member energy efficiency programs. Provide this automated spreadsheet in advance for testing purposes prior to the formal request for data required to complete the EIA survey.

- Schedule 6, Advanced Metering – Explain what type of communications EIA wants from service providers. As written, the requirement is very broad and would be costly and difficult to implement.

- Schedule 7 – Explain what is distributed versus dispersed generation. We understand that standby and emergency generators can be classified as dispersed. What else falls under the two terms?

- Filing software – Allow filers to update the pre-populated Schedule 8, Distribution Information by City field when necessary.

<u>EIA-861S</u>

- Schedule 6, Advanced Metering – Do not change the capacity limit from 2 MW to unlimited. This would require reporting on every customer source of generation from the smallest PV unit to the largest windmill. Clarify that the reporting period is annual.

<u>EIA-923</u>

- Schedule 2, Fuel Quality – Specify that information should be reported only if already available. For example, a number of utilities do not test coal shipments for mercury or chloride. The proposed additional reporting requirements would require additional testing currently not being performed. Costs could be on the order of $50,000 to $250,000 per year per respondent, plus the cost of inputting the data into company systems and records and reporting it to EIA. These costs would not provide operational benefits.

- Schedule 6, Coal Terminal-Plant Link – Do not add this question because the information is not accurately available. The tons and gallons of coal and fuel oil delivered to a terminal, respectively, do not necessarily align to what the terminal delivers to a station, especially when multiple destinations are served. Providing more detail in most cases will only be an assumption of what actually occurs given the time variant and blending variant that are present with fuel terminals.

- Schedule 6, Nonutility Electricity – Do not add the proposed question on "energy provided under tolling arrangements," as it already is available in the FERC Electric Quarterly Reports. At a minimum, explain more fully what EIA has in mind with the change, as companies still report fuel information on the tolling agreements even though not purchasing the fuel.

- Schedule 7, Annual Revenues – Clarify in the proposed question that retail sales by power plants that normally sell power at wholesale applies only to non-utilities.

- Schedule 8, Environmental Information – Specify that information should be reported only if already available. Otherwise, the proposed additional reporting requirements would require additional testing not currently being performed. Adding such testing would require significant capital investment with no operational benefits. Also, clarify: (1) what is meant by "no Hg control" or what is considered Hg control; and (2) what is meant by "cooling water."

- Schedule 8, Annual Environmental Information, Parts C, E and F – Clarify the changes EIA is planning to make, so EEI and its members can more thoroughly evaluate them.

- Filing process – Allow utilities to submit data in XML or other easily up-loadable format. The EIA-923 involves reporting of large amounts of information. But the current filing process uses an online form that requires respondents to enter numerous lines of data by hand and has limited ability to print a clean copy of the submittal for Q/A review and internal record-keeping purposes. EIA should adopt other filing options that would minimize the filing burden.

<u>Proposed new EIA-930</u>

Please refer to the cover letter associated with this attachment for detailed comments on the proposed new form.

Attachment B –
EEI Summary of EIA's Proposed Changes to the Electric Power Survey Forms Effective 2014[1]

EIA-411 Coordinated Bulk Power Supply Program Report			
Survey Schedule	Proposed Survey Deletions	Proposed Survey Additions	EIA Explanation for Proposed Survey Change
Schedule 6, Part B, Characteristics of Projected Transmission Lines	Line No. 16 Conductor Size (MCM) Line No. 17 Conductor Material Type Line No. 18 Bundling Arrangement Line No. 21 Pole/Tower Type		Information was determined to have limited value that is outweighed by respondent burden
Schedule 7, Part A, Annual Data on Transmission Line Outages for AC Lines		Two additional line voltage classes added: Less than 100 kV and 100-199kV	Change will make the form consistent with the expansion of the Bulk Electric System definition requested by (FERC) and specific
Schedule 7, Part A, Annual Data on Transmission Line Outages for AC Lines		Disaggregating outages into three principal classifications: Number of Single Mode Outages, Number of Dependent Mode Outages, and Number of Common Mode Outages	No explanation provided
Schedule 8, Annual Data on Generating Unit Outages, Deratings and Performance Indexes		New schedule added to the EIA-411 that will collect data on generation unit outages, deratings and performance indexes by fuel type and capacity	EIA claims that the information from this new data collection will be extracted by NERC directly from its existing Generating Availability Data System (GADS) and that there will be no additional reporting burden on survey respondents
Schedule 9, Smart Grid Transmission System Devices and Applications		New schedule added to the EIA-411 that will collect information on smart grid technologies now being deployed to improve the	No explanation provided

1 This Attachment B together with the EEI's May 6, 2013 cover letter to Rebecca Peterson at EIA and separate Attachment A comprise EEI's comments on the EIA electric survey forms in response to EIA's request for comments at 78 Fed. Reg. 14521 (Mar. 6, 2013).

		reliability of the transmission system including phasor measurement units (PMUs) and dynamic capability rating systems (DCRSs)	

EIA-826 Monthly Electric Sales and Revenue with State Distribution Report			
Survey Schedule	Proposed Survey Deletions	Proposed Survey Additions	EIA Explanation for Proposed Survey Change
Schedule 3, Part A, Green Pricing	EIA proposes to remove the entire Schedule 3 on Green Pricing		Green pricing programs currently have a minimal presence in the retail power market and that this situation is not expected to change. Therefore, the value of the data collection is outweighed by the burden to the respondents.
Schedule 3, Part C Advanced Metering		Separate Advanced Metering Infrastructure (AMI) into two subgroups: AMI operated as Automated Meter Reading (AMR) and AMI operated as AMI	No explanation provided

EIA-860 Annual Electric Generator Report			
Survey Schedule	Proposed Survey Deletions	Proposed Survey Additions	EIA Explanation for Proposed Survey Change
Schedule 1, Identification		Collect the ownership type of the reporting entity	Information is frequently requested within DOE and by outside analysts.
Schedule 2, Power Plant Data, and Schedule 3, Part C, Generator Information	Reduce time horizon from plants and generators expected to begin commercial operations from 10 years to 5 years for all plants other than coal, nuclear and hydro plants. (Note: May potentially reduce reporting burden).		Change reflects the relatively short planning and construction horizon for the predominant types of power plants now being proposed in the U.S. such as combined cycle gas, wind, and solar generators.

EIA-860 Annual Electric Generator Report			
Survey Schedule	Proposed Survey Deletions	Proposed Survey Additions	EIA Explanation for Proposed Survey Change
Schedule 2, Power Plant Data		Collect the name of each plant's balancing authority instead of its regional transmission organization (RTO) or independent system operator (ISO). (Note: Only a change to an existing survey question).	Change reflects EIA's efforts to align its data collection with the actual operation of the electric power system
Schedule 2, Power Plant Data		Collect information on ash impoundments to include questions asking for information whether impoundments exist at a plant, the impoundment's statuses, and whether they are lined.	Increasing environmental concern at the federal and state levels.
Schedule 2, Power Plant Data	Stop collection of the datum associated with a plant's geographic coordinates		EIA has found that most respondents are unable to provide a correct answer to this question.
Schedule 2, Power Plant Data	Stop collection of plant geographic coordinates in minutes and seconds. Form will ask for coordinates only in modern digital format.		No explanation provided
Schedule 2, Power Plant Data		Collect information on whether a plant that has a primary purpose other than electricity generation for sale is net metered.	Information needed to improve the accuracy with which EIA can determine small renewable capacity, particularly solar.
Schedule 2, Power Plant Data		Collect information on whether a plant or any of the individual generating units at the plant is a blackstart unit. For those units identified as blackstart units, EIA will collect information on nameplate capacity.	Information would enhance the information on power system reliability made available by EIA to analysts and policy makers.

EIA-860 Annual Electric Generator Report			
Survey Schedule	Proposed Survey Deletions	Proposed Survey Additions	EIA Explanation for Proposed Survey Change
Schedule 3, Part A, Generator Information--Generators		Collect whether a combined-cycle unit can operate in simple-cycle mode by bypassing the heat recovery steam generator	Growing importance of operational flexibility due to the introduction of variable renewable technology and wider use of demand response programs.
Schedule 3, Part A, Generator Information--Generators	Delete questions on whether the generator is an electric utility, the date of a unit's sale, and whether the unit can deliver power to the transmission grid.		EIA has determined that these questions are either duplicative or provide information of limited value.
Schedule 3, Part B, Generator Information—Existing Generators		Collect information on whether an uprate or derate was completed during the reporting period.	Information particularly needed for nuclear units to confirm when an uprate became operational.
Schedule 3, Part B, Generator Information—Existing Generators		Collect data on nameplate power factor	Information will be used in verifying the reported nameplate and capacity factor of the unit.
Schedule 3, Part B, Generator Information—Existing Generators		Collect data on generator minimum load and minimum time required to reach full load from standby and shutdown. Questions are limited to units burning combustible fuels.	Questions added due to increased interest in the operational flexibility of the power system
Schedule 3, Part B, Generator Information—Existing Generators	Delete questions related to reactive power		NERC informed EIA that the need for this information no longer exists
Schedule 3, Part B, Generator Information—Existing Generators	Reduce the number of questions relating to fuel switching and multi-fuel operation from 13 questions to 8		Change is being made to reduce respondent burden by focusing on the fuel switching questions of greatest interest, which is essentially the issue of backup fuel for oil and gas-fired units.

EIA-860 Annual Electric Generator Report			
Survey Schedule	Proposed Survey Deletions	Proposed Survey Additions	EIA Explanation for Proposed Survey Change
Schedule 3, Part B, Generator Information—Existing Generators		Add new questions on the characteristics of wind turbines such as: --turbine manufacturer --designed average annual wind speed --wind quality class --average hub height	
Schedule 3, Part B, Generator Information—Existing Generators		Add new questions on the characteristics of solar energy systems such as: --identification of tracking --concentrating and collector technology --photovoltaic panel materials	
Schedule 3, Part B, Generator Information—Proposed Generators	Delete questions pertaining to reactive power, fuel switching, and multi-fuel operations at planned units		NERC informed EIA that the need for this information no longer exists
Schedule 5, Generator Cost Information	Delete all questions related to interconnection costs		No explanation provided
Schedule 5, Generator Cost Information	.	Add new questions on generator construction and financing costs. EIA will collect this information at the time of completion for most generating units. Long-lead coal and nuclear units will be required to provide annual estimates of the total cost for completing. NOTE: All of the data will be treated as sensitive and will be protected from disclosure	Cost estimates are considered critical elements in projections of power industry capital requirements and forecasts of new builds
Schedule 6, Boiler Information: Part A, Plant Configuration		Reorganize the manner in which data on environmental equipment are collected	To reflect the fact that a single pollution control technology can reduce emissions of more than one pollutant.

EIA-860 Annual Electric Generator Report			
Survey Schedule	Proposed Survey Deletions	Proposed Survey Additions	EIA Explanation for Proposed Survey Change
Schedule 6, Boiler Information: Part C, Boiler Information	Delete the question that collects boiler manufacturer		EIA cannot identify a need for this information
Schedule 6, Boiler Information: Part E, Nitrogen Oxide Emissions Controls		Collect information on the operating status, and installed cost of nitrogen oxide and mercury control systems	No explanation provided
Schedule 6, Boiler Information: Part F, Cooling System Information—Design Parameters		Add new question that collects the name of the cooling water discharge body if different than the intake body of water.	Information was requested as part of EIA's joint review with the U.S. Geological Survey (USGS)—an initiative recommended by the Government Accountability Office (GAO)
Schedule 6, Boiler Information: Part H, Flue Gas Desulfurization Unit Information	Delete question that collects the flue gas desulfurization unit manufacturer		Information no longer has value
Schedule 6, Boiler Information: Part I, Stack and Flue Information—Design Parameters	Delete the questions that collect geographic coordinate datum of stacks		EIA has found that most respondents are unable to provide a correct answer to this question.

EIA-861 Annual Electric Power Plant Report			
Survey Schedule	Proposed Survey Deletions	Proposed Survey Additions	EIA Explanation for Proposed Survey Change
EIA-861 Schedules that request information by state		Add a requirement to report by state and balancing authority combination. NOTE: In states that have more than one balancing authority, the respondent may have more than one schedule reported per state.	To align data collection with the actual operation of the power system

EIA-861 Annual Electric Power Plant Report			
Survey Schedule	Proposed Survey Deletions	Proposed Survey Additions	EIA Explanation for Proposed Survey Change
Schedule 2, Part C, Green Pricing	Remove the green pricing schedule		The limited presence of green pricing in the retail market does not justify the burden on respondents.
Schedule 2, Part D, Net Metering		Increase the capacity limit for reporting net metering installations from 2 MW's to unlimited	Will help identify the amount of net metering capacity by technology type and help in identifying all of the renewable capacity installed.
Schedule 4, Part A, Sales to Ultimate Customers		Add questions about Rate Decoupling	Rate decoupling programs have been common for retail sales of natural gas and now are being implemented for electricity sales.
Schedule 6, Part A, Energy Efficiency Programs		Change collection of Net Energy Savings to Gross Energy Savings (MWh)	An attempt to improve the collection of energy efficiency data
Schedule 6, Part A, Energy Efficiency Programs		Change collection of Annualized Incremental Effects and Actual Annual Effects to Incremental Annual Savings and Incremental Life Cycle Savings (Note: This is a question change but it will require time to report in this new format).	
Schedule 6, Part A, Energy Efficiency Programs		Replace Annual Costs with Reporting Year Incremental Costs and Incremental Life Cycle Costs	
Schedule 6, Part A, Energy Efficiency Programs	Reduce the number of cost components collected		No explanation provided
Schedule 6, Part A, Energy Efficiency Programs		Add the collection of the Weighed Average Life of a portfolio of Energy Efficiency programs and provide an automated spreadsheet to calculate this number based on program data entered into the spreadsheet	An attempt to improve the collection of energy efficiency data

EIA-861 Annual Electric Power Plant Report			
Survey Schedule	Proposed Survey Deletions	Proposed Survey Additions	EIA Explanation for Proposed Survey Change
Schedule 6, Part A, Energy Efficiency Programs	Remove questions about verification and reporting on another company's form		No explanation provided
Schedule 6, Part B, Demand Response Programs	Reduce the number of cost components collected		No explanation provided
Schedule 6, Part B, Demand Response Programs		Add the number of customers enrolled	No explanation provided
Schedule 6, Part C, Dynamic Pricing Programs		Add question on number of customers enrolled in dynamic pricing programs and the particular type of dynamic pricing programs	Increasing interest in dynamic pricing programs, particularly in combination with smart meters
Schedule 6, Part C, Advanced Metering and Customer Communications		Separate AMI into two subgroups: AMI operated as AMR and AMI operated as AMI	These statistics are of interest because of federal and state programs intended to encourage the use of smart meters and the possible value of smart meters in energy efficiency and demand response programs
Schedule 6, Part C, Advanced Metering and Customer Communications		Add data collection to include total number of meters, number of customers that receive certain types of communication from the service provider and frequency of the communication, and the number of customers participating in direct load control programs	These statistics are of interest because of federal and state programs intended to encourage the use of smart meters and the possible value of smart meters in energy efficiency and demand response programs
Schedule 6, Parts E and Part F, Distribution System Information and Reliability Information		Entirely new survey schedule added to include questions on distribution system automation and the reliability of the distribution system. Distribution system reliability questions include SAIDI, SAIFI, and percent of distribution system that is urban, suburban or rural. NOTE: Utilities that do not collect this information do not have to respond	Data is needed due to lack of a central repository of distribution system reliability statistics and because of requests for this information from Congress and state energy offices.

EIA-861 Annual Electric Power Industry Report (Short Form)			
Survey Schedule	Proposed Survey Deletions	Proposed Survey Additions	EIA Explanation for Proposed Survey Change
EIA-861S Schedules that request information by state		Add a requirement to report by state and balancing authority combination. NOTE: In states that have more than one balancing authority, the respondent may have more than one schedule reported per state.	To align data collection with the actual operation of the power system
Schedule 2, Part C, Green Pricing	Remove the green pricing schedule		The limited presence of green pricing in the retail market does not justify the burden on respondents.
Schedule 6, Part C, Dynamic Pricing Programs		Add a single Yes/No question asking if the respondent operates any time-based rate programs	Increasing interest in dynamic pricing programs, particularly in combination with smart meters
Schedule 6, Part D, Advanced Metering and Customer Communications		Separate AMI into two subgroups: AMI operated as AMR and AMI operated as AMI	No explanation provided

EIA-923 Power Plant Operations Report			
Survey Schedule	Proposed Survey Deletions	Proposed Survey Additions	EIA Explanation for Proposed Survey Change
Schedule 2, Cost and Quality of Fuel Purchases		Add questions on coal quality characteristics to include coal moisture and chloride content	These factors relate to the propensity of the coal to produce acid gases and assist in assessment of the quality of the various coal ranks
Schedule 2, Cost and Quality of Fuel Purchases		Add collection of the names of the pipeline systems connected to natural gas burning power plants	Information is needed to help reconcile natural gas sales information collected on other surveys and to get

			a more complete picture of natural gas disposition.
Schedule 3, Boiler and Generator Information for Steam-Electric Combustible	Simplification of form to combine two schedules dealing with generation and fuel consumption (Schedule 3 and Schedule 5)		To simplify form
Schedule 4, Fossil Fuel Stocks at the End of the Reporting Period		Questions to be added to clarify the relationship between stocks held off-site at coal terminals with the plants the terminals serve	To determine the relationship between coal stocks held offsite at coal terminals and the plants the terminals serve
Schedule 6, Nonutility Annual Source and Disposition of Electricity		Add “energy provided under tolling arrangements” to the Disposition of Electricity section	Changes are needed to distinguish power delivered under tolling agreements from the more generic category of “other out-going” power and to account for the increased number of tolling agreements between 2007 and 2012
Schedule 6, Nonutility Annual Source and Disposition of Electricity		Questions added to obtain identification of the nature of “other incoming” and “other out-going” electric energy	
Schedule 7, Annual Revenues from Retail Sales and/or Sales for Resale		Additional data collection to include data on retail sales by power plants that normally sell power at wholesale	Data are needed to complete the disposition of electricity by inclusion of retail sales by nonutility plants since they are not required to complete Form EIA-861
Schedule 8, Annual Environmental Information, Parts C, E and F		Schedules to be reconfigured to be equipment-oriented, rather than emission type oriented	Installed environmental controls can reduce more than one type of air emission

EIA-930 Balancing Authority Operations Report

A proposed new EIA survey form designed to collect hourly electric power operating data from Balancing Authorities in the contiguous U.S. and from selected electric utilities in Alaska and Hawaii.

EIA-930 will collect data including:

--Hourly demand
--Hourly next-day demand forecast

EIA-930 Balancing Authority Operations Report

--Hourly net generation
--Hourly actual interchange with each interconnected Balancing Authority

Respondents will be required to post hourly demand data at a web site address in a standard format within ten minutes of the end of the reporting hour. They will also post separately, the prior day's hourly demand, demand forecast, net generation, and actual interchange data in a standard format by 7:00 a.m. Eastern Time the next day.

EIA will treat these data as public but is soliciting comments on alternatives or supplements to the web posting requirement and the format for the posted data.

EIA does not believe that this information requested is business sensitive. However, they do note that a potential commercial issue is whether a specific utility is short on available generating capacity and may be willing to pay premium prices for electricity to meet load. The proposed survey data, including same-day posting of hourly demand, does not provide information about the availability of generating units. EIA claims that the next-day posting of operating data is after the relevant short-term wholesale power markets have closed.

In addition, because multiple power plants supply most Balancing Authorities, the generation data reported under the proposed survey will not reveal which specific generators are operating or a history of their operating trends. However, some individual generators and small utilities with little or no generation have chosen for commercial reasons to operate as Balancing Authorities. Most Balancing Authorities of this type are embedded within another Balancing Authority and have a single interconnection with that Balancing Authority.

While the proposed survey data does not provide information about the current availability of a single-generator Balancing Authority power plant, it does provide a history of the plant's hourly output. There is little value in collecting system level operating data from these Balancing Authorities. However, their information is needed by EIA to provide comprehensive operating statistics. EIA requests comments on how to exempt these Balancing Authorities or limit their reporting while maintaining the comprehensiveness of the survey.

EIA-63B Annual Photovoltaic Cell/Module Shipments Report

A proposed extension of a recent new EIA survey to track photovoltaic cell/module manufacturing, shipments, technology types, revenue and related information.

Companies required to file the EIA-63B include those companies involved in photovoltaic-related activities during the reporting year can be classified in any of the following categories: (1) manufacturer; (2) brand name manufacturer (private label owner); (3) subsidiary or business unit of overseas manufacturer; (4) U.S. registered publicly traded overseas manufacturer; (5) importer; and (6) exporter.

General Note Regarding Data Disclosure Limitation Rules Pertaining to Forms EIA-63B, 411, 826, 860 and 923:

EIA proposes to discontinue applying disclosure limitation rules that test aggregate statistics for the risk of disclosing identifiable information. EIA intends to add the following paragraph to the section on data confidentiality: ''Disclosure limitation procedures are not applied to the statistical data published from the survey information reported on this form. There may be some statistics that are based on data from fewer than three respondents, or that are dominated by data from one or two large respondents. In these cases, it may be possible for a knowledgeable person to closely estimate the information reported by a specific respondent."

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TO: Howard Gruenspecht, Acting Administrator
Stephen Harvey, Assistant Administrator for Energy Statistics
Stan Kaplan, Office Director
Carolyn Moses, Project Manager, 826 and 861 Surveys
U.S. Energy Information Agency

FROM: Hilary Forster, Patrick Wallace, and Nicolas Dahlberg
Evaluation and Research Team
Consortium for Energy Efficiency

SUBJECT: Suggestions for Modifications to Schedule 6 (Demand Side Management) of Form EIA-861 (2011) for 2013 Version of the Form

DATE: April 29, 2013

I am writing in response to the opportunity to comment on the proposed Form EIA-861, "Annual Electric Power Industry Report".

CEE is a consortium of energy efficiency program administrators from across the U.S. and Canada who work together on common approaches to advancing efficiency. CEE's members administer ratepayer-funded energy efficiency programs in United States and Canada.

The Evaluation and Research team at CEE conducts a voluntary annual survey of the ratepayer-funded demand side management (DSM) program industry to show the magnitude of the DSM program industry and to provide a timely sense of industry trends. Some of the information we collect from the larger DSM program administrators in the U.S. and Canada is very similar to what the U.S. Energy Information Administration (EIA) proposes to collect in Schedule 6 of Form 861. The data that CEE collects each year are meant to supplement, not replace, data collected by organizations such as the EIA.

These comments are provided by Hilary Forster, Patrick Wallace, and Nicolas Dahlberg of the Evaluation and Research team at CEE. Our comments are informed by the lessons we have personally learned over the years about the collection of these data, and do not necessarily represent the view of our members. We sincerely hope that you find these comments useful.

We have focused our review and comments on Schedule 6, Demand-Side Management Information. We have not attempted to review or comment on other Schedules of Form EIA-861, as we do not have expertise in the subject matter covered by these other Schedules.

The Evaluation and Research team largely agrees with the comments provided by The State and Local Energy Efficiency Action Network (SEE Action) Evaluation, Measurement, and Verification (EM&V) Working Group, so we will not provide specific comments on the topics covered in their recommendations. However, we would like to highlight our support for SEE Action's comments regarding the request that "EIA dedicate sufficient resources to ensure effective quality assurance, data verification, and more timely access to the results. As the role of energy efficiency as a utility system resource grows…it becomes more and more critical that data on this resource is accurate, consistent, and credible."

Comment 1

Collect information about natural gas efficiency programs that is similar to what is currently collected for electric efficiency programs.

Issue: Natural gas efficiency programs are growing, but information about those programs is not currently collected by EIA. This valuable information could be collected with very little additional burden on EIA or on responding organizations because many of the utilities that administer natural gas efficiency programs are dual-fuel companies and therefore already fill out Form 861 for their electric efficiency programs.

Recommendation: At least for dual-fuel utilities, use Form 861 or a similar form to collect information for natural gas efficiency programs that is similar to what is currently collected for electric efficiency programs.

Comment 2

Make separate UTILITY_IDs for utilities that operate in multiple states under the same name.

Issue: The "UTILITY_ID" serves as a unique identifier for each operating company in the Form 861. Therefore, the UTILITY_ID should not be duplicated in the data set. However, in cases where a utility operates in more than one state under the same name, the UTITILY_ID is duplicated. For example, Duke Energy Carolinas, LLC operates in both North and South Carolina. Therefore, the UTILITY_ID 5416 is duplicated because Duke Energy Carolinas, LLC submitted data for both their North Carolina and South Carolina operations.

Recommendation: Make separate UTILITY_IDs for utilities that operate in multiple states under the same name.

Thank you for providing the Evaluation and Research team with this opportunity to comment on the proposed EIA Form 861.

Sincerely,

Hilary Forster, Senior Program Manger
Evaluation, Research, and Behavior
Consortium for Energy Efficiency

UNITED STATES OF AMERICA
BEFORE THE
DEPARTMENT OF ENERGY

	)
Energy Information Administration Proposal to Create	)
Form EIA–930, ‘‘Balancing Authority Operations Report’’	)
	)

COMMENTS OF THE ISO/RTO COUNCIL

Pursuant to the Federal Register Notice (“Notice”)[1] issued by the Department of Energy, the ISO/RTO Council (“IRC”)[2] submits the following comments on the proposed new EIA reporting obligation that would be required pursuant to proposed Form EIA-930 - ‘‘Balancing Authority Operations Report.’’ The EIA proposal was published on March 6, 2013, and public comments were requested by May 6, 2013.

Form EIA–930 is a new survey that would require Balancing Authorities, such as the IRC members, to provide hourly electric power operating data, including:

- Hourly demand;
- Hourly next-day demand forecast;
- Hourly net generation;
- Hourly actual interchange with each interconnected Balancing Authority.

These comments will address the EIA’s tentative conclusions regarding the need for the data and, separately, the burden estimates associated with the provision of the data in the manner proposed in the rulemaking. The IRC also proposes changes to the proposed rule that will address the IRC’s concerns with each of these issues.

I. Issues Concerning the Stated Purpose for Collecting the Data

The IRC members are not opposed in principle to providing the relevant data, subject to reasonable parameters and timelines. However, EIA’s reporting proposal is premised on the interest of policymakers, legislators, industry researchers, among others, in electric systems operations and associated data. Given the stated purpose for the collection of the data, EIA has not explained why *near-real time reporting* of the information is necessary for the performance

[1] Notices, 78 Fed. Reg. 14521 (March 6, 2013).

[2] The IRC is comprised of the Alberta Electric System Operator, the California Independent System Operator Corporation, the Electric Reliability Council of Texas, Inc. the Independent Electricity System Operator, ISO New England, Inc., the Midcontinent Independent System Operator, Inc., the New York Independent System Operator, Inc., PJM Interconnection, L.L.C. and the Southwest Power Pool, Inc. The Alberta Electric System Operator and Independent Electricity System Operator are not subject to EIA reporting obligations and are not joining these comments.

of EIA's functions, and there is no evidence that EIA or any of the stated recipients of the proposed reports have failed to perform their functions to date due to an absence of this type of near real-time data. Stated another way, EIA has not provided a "business case" for the volumes of data and the timing of the posting requirements for the relevant reports that it proposes to collect except to state the agency wants to provide information to the public about the operation of the electric markets. For the reasons stated below, the requirements of the rule for near real-time transmittal of the data to EIA represent the most problematic part of the proposed form.

The Notice recognizes that this type of information is already publicly posted by RTOs and ISOs. Although EIA indicates that the purpose of the new requirement is to address an alleged need for a "central" source for hourly electric industry operating statistics, the IRC respects, but questions, the need for EIA to set up a separate reporting requirement given the availability of much of this data on the posted websites of the RTOs and ISOs.[3] Under these circumstances, the IRC believes that the incremental value of the proposed informational reporting is outweighed by the burdensome requirements associated with the near real-time reporting mandates (discussed in Section II below), as well as the potential liability attendant to the proposed reporting requirements.[4]

For these reasons, the IRC requests that EIA reconsider the imposition of the proposed reporting obligations. If the EIA nonetheless elects to pursue a proposed reporting obligation for the type of data at issue, it should better define the intended use and benefits of the data, and then seek industry input on the most appropriate and least burdensome means of obtaining the information. If EIA elects to move forward with this particular proposal, it should consider modifying the proposal as described in Section III of these comments.

II. Issues Concerning the Proposed Timing of Submission of the Data to EIA.

While the timeliness of making the requested data available is relevant, the near real-time submission requirements of the proposed rule are not necessary to achieve the potential benefits of any of EIA's stated purposes. Contrary to the discussion in the notice, meeting the requirement to "*post hourly demand data at a web address in a standard format within ten minutes of the need of the reported hour*" could require diversion of RTO/ISO staff resources and present issues associated with data quality. Moreover, there are arguably no benefits gained, because near real-time posting is not necessary to provide the asserted benefits of the provision of data.

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[3] Over two-thirds of the load in the nation is covered by RTOs and ISOs, such that a review of a very limited number of websites would provide an extensive review of electricity demand in over two-thirds of the nation.

[4] The RTOs/ISOs note that 15 USC Section 772 (i) may possibly subject Balancing Authorities to penalties associated with its provision of information to the EIA. Given that non-compliance may subject the reporting entities to penalties under this provision, the IRC questions the value of imposing such obligations where the intended value of the data would not be compromised by imposing more reasonable reporting timeframes. In addition, as discussed below, there are other potentially more efficient means of obtaining this data that utilize existing processes.

As EIA is aware, near real-time information is preliminary data, and, as the data represents an integration of metered data from thousands of buses and nodes across RTO/ISO systems, it is subject to review and revision to account for updated meter data or other technical issues.[5] Although RTOs and ISOs ultimately "scrub" the data and post accurate results, in terms of the reporting timeframe at issue in the proposal, Balancing Authorities perform no quality control on the data.[6] In fact, it is impractical to do so due to the volume and the proposed near-real time posting obligation.[7]

Accordingly, if EIA does not revisit the need for the proposal, or, at a minimum, the parameters and timeframes, the posted reports must state the data is not final and is subject to further review and correction, as necessary, by the reporting Balancing Authorities. Alternatively, as noted, EIA could revise the reporting timeframes. For example, the reports could be daily, monthly, quarterly or annually. This would reduce the burden and allow for the posting of final accurate data. Considering other, potentially more efficient means of obtaining the data outlined below is another possible option.

To address these matters, in accordance with the EIA's invitation for the submission of comments "on alternatives or supplements to the web posting requirement and the format for the posted data," the IRC proposes in Section III below alternative approaches that would, at least in part, address the IRC's concerns and mitigate the penalty risk.

III. Alternative Means of Obtaining the Data

The proposed near real-time reporting obligation appears to be related to information that is already available to regulators and government officials from NERC via its situational awareness project. Consistent with this potential overlap, the IRC believes a better alternative would be for EIA to coordinate with NERC to obtain and make available the relevant information. This alternative would provide procedural and administrative efficiency benefits, while also mitigating data quality issues, resource burdens and penalty risk to the entities that would otherwise be subject to these reporting obligations. The IRC understands there may be potential issues related to the terms of the relevant

[5] The IRC notes that this data should not be used to assess the state of the bulk power system as suggested in the announcement. In fact, the provision of this data should be accompanied by appropriate disclaimers, noting it is being provided for informational purposes only. For example, the posting should recognize that the data may be affected by computer or data issues within a given balancing authority, which could affect its accuracy and require that the information be updated.

[6] Balancing Authorities do review the relevant data for accuracy, but that review takes time, and completion of that process occurs well after the relevant operating day. The IRC notes that the data is consistent with the functions of the Balancing Authorities as relevant in the performance of its operational and other relevant activities pursuant to applicable rules. However, for the intended purposes, none of which implicate real-time or near-real time operational functions, the data is not considered final and would be subject to review and potential correction.

[7] Even assuming unlimited resources and that somehow the RTO/ISO was able to perform the quality review checks of the data prior to the proposed reporting timelines, such an expenditure of resources would still be imprudent, because the intended benefits outlined in the proposed rule can be achieved by more reasonable parameters and timelines.

information sharing agreements,[8] but given the potential efficiencies to be gained from obtaining the data via this existing information sharing relationship, it is worthwhile to review those matters to determine if they can be resolved so that process can be considered as an alternative to achieve EIA's goals with respect to this proposal.

Another alternative would be to use the ICCP data stream that flows from Balancing Authorities to Reliability Coordinators to NERC. This data could be integrated or averaged to give hourly values of a quality comparable to what a Balancing Authority could provide shortly after the hour. Either NERC or one of its vendors that processes real-time data could perform this task more efficiently than the nearly 100 Balancing Authorities could do individually.

If DOE elects not to pursue the above alternative approaches, but rather retains the approach that would impose reporting obligations on each Balancing Authority, the IRC recommends alternative reporting timeframes. The IRC believes the timeline for posting should be driven by the need relative to the intended use and benefits, which should be better defined. As noted above, daily, monthly, quarterly or annual timeframes are all potentially relevant. However, at a minimum, the reporting timeframe should be no more frequent than daily. Again, the need, use and benefits should be more specifically defined before imposing the timeframe, but daily obligations are at least arguably reasonable.[9] This should not undermine the intended value of providing this data for use by relevant entities.

IV. Miscellaneous Issues

Another potential issue EIA should be aware of is that sourcing the data solely from U.S. Balancing Authorities could lead to incorrect assumptions and conclusions regarding interchanges at the U.S. borders. Further, varying sign (+/-) conventions used by the Balancing Authorities could also impair public understanding.

The IRC also requests that the Final Rule contain explicit language that penalties under applicable statutes will not be triggered so long as there is a good faith attempt by the Balancing Authorities to meet the overall goals of timely posting of data consistent with the Final Rule.

V. IRC Responses to DOE Specific Questions

The IRC provides the following comments on the specific questions raised in the request for comments.

(a) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility;

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[8] For example, there may be confidentiality restrictions. However, if the data is already posted on ISO/RTO websites, with respect to that data at least, the applicable confidentiality requirements as they relate to this specific data set could be reviewed.

[9] The daily obligations would not be for the prompt day (*i.e.*, the day that the data was produced), as that obviously implicates the near-real time problem. They could be for the prior and subsequent day loads and forecasts, as relevant.

While some forecast and ex-post data would be useful, as discussed, it is not clear why near real-time data is needed. The stated purposes in the notice and all associated benefits can be achieved under more reasonable reporting timelines. Although it appears that the intended benefits for all relevant entities are related to after the fact analysis, the IRC notes that any use by any entity to take near real-time action would be problematic. For example, if DOE is intending this effort to be used to send signals to smart grid providers on the need to take action, this would be a significant concern. All operational actions, including the need to implement load management, should be managed by the Balancing Authority. Each balancing authority has specific rules governing how market participants can interact with their markets in real time and provide data as part of their overall market design for exactly this purpose. The market participants in each region already have access to the data necessary for their activities in each market and for their interactions with the relevant Balancing Authorities.

EIA's rule proposing data reporting form should not become a vehicle for additional regulation of data retrieval and posting, as the information dissemination requirements governing Balancing Authorities are already regulated by NERC, FERC and Texas PUC regulations, as relevant. Given the primacy of the relevant functional entities in operating their respective systems, EIA should ensure that any information provided pursuant to the proposed reporting requirements is denominated as for informational purposes only.

(b) the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

The IRC members submit that EIA's specific assessments of the resource impact associated with the EIA proposal are understated. The impact could well be greater than the estimate presented in the EIA notice given the timing requirements of the proposal, and may differ among organizations based on differences, for instance, between systems, existing resources and processes. For example, complying with the obligations imposed by the proposed rule would require the development of additional posting procedures to accommodate the duplicative EIA request. This would involve a non-trivial effort and resource impact, potentially delaying other projects currently scheduled by some Balancing Authorities.

(c) ways to enhance the quality, utility, and clarity of the information to be collected; and

As discussed above, near-real time data will not be final, and, therefore, will be subject to flaws that will be corrected via the relevant review processes, which are performed subsequent to the operating day - to put this in perspective, settlement processes typically take up to two months to review and resolve any data issues.

This issue can be mitigated by using the alternatives suggested in Section III of these comments, or some other alternative that provides for reasonable parameters and reporting timeframes that accommodate appropriate review and correction. For example, data that has gone through the NERC inadvertent accounting verification (end of the next business day) will be higher quality. Also, longer reporting timeframes will mitigate this potential problem. And as noted, consideration of such alternatives should not undermine the purposes and intended benefits underlying the proposal.

(d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology.

Please refer to the IRC's proposed alternatives in *Section III* in the General Comments section.

VI. Conclusion

The IRC questions the need for the form given the availability of this data to the public already. However, should the EIA insist on providing a function of "centralizing" the posting of this data, it should eliminate the ten-minute-after-the-hour reporting requirement and substitute a reporting requirement no more frequent than providing this data to EIA on a daily basis. The IRC also requests that the EIA revisit and reconsider the burden estimates and provide additional flexibility with respect to the reporting obligations given the intended uses of the data as outlined in the Notice.

The IRC respectfully requests that EIA give due consideration to these comments in reviewing the need for the proposed reporting obligation and, if EIA elects to move forward with the proposal, it should reconsider the proposed process in light of these comments.

Respectfully submitted,

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Date: May 6, 2013

The first set of changes to Form 860 we'd like to see concern a better understanding of technology choice and plant design at the unit level. The get at technology choice and market tracking, it would help to understand:

1. **Turbine Type** [respondents would only choose 1 for each unit]
    a. Francis
    b. Kaplan (Double Regulated)
    c. Kaplan (Single Regulated)
    d. Other Propeller Type
    e. Crossflow
    f. Pelton
    g. Turgo
    h. Other
2. **Turbine Manufacturer**
3. **Generator Manufacturer**

Note that for hydropower the generator and turbine are often (but not always) manufactured by different entities, so we'd ideally like to have a handle on both.

There are two technical parameters that drive unit design—hydraulic head (i.e. the elevation distance between reservoir surface and tailwater) and flow . Power = head*flow*efficiency. We'd like to understand from a technology choice and resource characterization standpoint what the technical parameters were for each unit in a plant, asking for:

4. **Design Hydraulic Head** [feet], and additionally:
    a. Minimum operating head
    b. Maximum operating head
5. **Design Flow/Hydraulic Capacity** [cubic feet per second], and additionally:
    a. Minimum hydraulic capacity
    b. Maximum hydraulic capacity

To help better characterize the distpatchabiltiy and flexibility, in addition to some of the changes already proposed form Form 860 (i.e. minimum generator loadings), it would help to have additional unit parameters as well, including:

6. **Whether the unit is equipped with Automatic Generation Control (AGC)** – asking this question for thermal units as well would provide DOE with the capability to look at the national capability for providing increasingly important (in the context of renewables integration) ancillary service products such as regulation and load following. Consider this outside of hydro too.
7. **Number of starts in a year**—this another easy to track variable that has real benefits outside of hydro as well. Tracking starts through time allows us to assess the impacts of changes in market structure and grid variability. Some thought needs to go into how "start" is defined but we would be happy to work with EIA on that if needed.

8. To that end, understanding **average generation during the hours in which the plant is synchronized to the grid** would provide a more insightful metric than just generation alone for all energy technologies

In addition to new unit design questions, there are a set of questions EIA is adding (Schedule 3 Part B 21 and 22) that hydropower units are not required to respond to currently:

9. **Hydro units should be required to report on Schedule 3 Part B questions 21 and 22**
10. **We would also suggest adding two new options to questions to 21 and 22 as a way of better characterizing the dispatchability of units**
    a. **0 to 1 minute**
    b. **1 to 5 minutes**

The fastest hydropower units should be able to be listed under these options, slower ones may live in the 30 minute range. This higher granularity would also be useful at a national scale for parameterizing the capabilities of hydro and thermal units in production cost models.

It would also be nice to understand the use of environmental equipment at the unit level, specifically:

11. **Aerating (oxygen injection) equipment**. There are two parameters it would help to have insight into:
    a. Whether the system is central or distributed
    b. Whether the system was installed with the unit or added later as a retrofit
12. **Annual number of hours aerating equipment was utilized in the past year**

Lastly at the unit level, we could also begin to better understand how ageing equipment is affecting hydropower availability through some questions similar to what was historically asked on FERC Form 1, but in our case we'd like:

13. **Forced outages (**hours in past year or reporting period)
14. **Unforced outages** (hours in past year or reporting period)

In addition to unit level information there are a number of things we'd like to know about the U.S. hydro fleet at the plant level. One of these is cost that will be recorded on Schedule 5, however we have one suggested change:

15. **Include hydropower in Schedule 5, Part A**. The long lead-time for hydropower development and large capital expense make cost escalation and financing concerns similar for hydropower as they are for nuclear and coal units.
16. In general, our experience working with capital cost data from FERC Form-1 data has not been ideal and we have a few suggestions to make sure capital costs are reported in a holistic, comparable manner:

a. To ensure consistency in the data collected, we need to highlight the importance of providing the respondents with a detailed description of what should be included under "total construction cost". It also needs to be specified that costs should always be in reporting year dollars, otherwise we will end up with incomparable, undocumented cost estimates

There may not be a clean, simple way to collect this data, but if possible there is one class of information we would like to try to find a way to collect systematically that may be a good candidate for inclusion on Form 860: storage metrics. Three variables would give us a good idea of capability and variability with respect to how dispatachable a hydropower plant really is:

1. **Annual maximum storage**—maximum volume of the power pool (either hours at design head/flow or directly as acre-feet)
2. **Annual average storage –** average annual volume of power pool
3. **Annual minimum storage –** lowest volume of the power pool from the reporting year

Comment [m1]: Important, move up.

Other useful information would be plant-level environmental mitigation measures:

4. **Downstream Fish Passage Strategies** (multiple may apply):
   a. Physical barriers (screens and barrier net)
   b. Behavioral Barriers (visual, auditory, electrical, and hydrodynamic stimuli)
   c. Structural Guidance Device (Angled bar/trash rack, Louver Array, surface collector)
   d. Surface Bypasses associated to intake trash racks
   e. Other methods (Trapping and Trucking, Pumping, spilling, barging, fish-friendly turbine)
5. **Upstream Fish Passage** (multiple may apply)
   a. Fish Ladders (pool-type fish passes, baffle fish passes)
   b. Fish Lifts
   c. Fish Pumps
   d. Collection and Transportation
   e. Nature-like Bypass Channel
   f. Other
6. **Water quality issues which require active monitoring and operational adjustments** (multiple may apply):
   a. Dissolved oxygen/Total dissolved gas levels
   b. Temperature
   c. Aquatic Species: Unit Shutdowns
   d. Aquatic Species: Spill

Comment [m2]: All interesting but lower priority. If you keep these, consider adding a catetory for environmental flow requirements – maybe that is where you put RoR, spillage or operational shutdown for fish, ramping rates for fish & wildlife habitat, etc.

The trickiest set of data, but potentially most rewarding is understanding the flexibility of hydropower plants under a combination of technological and competing water use constraints, in a perfect world we would like to know about:

7. **Ramp rate restrictions**
8. **Water release rule curves**
9. **Time-dependent storage capabilities**

From: Schmidt, Lisa L [mailto:LLSchmidt@integrysgroup.com]
Sent: Tuesday, March 26, 2013 3:55 PM
To: Peterson, Rebecca
Subject: Questions on Proposed Revisions

Rebecca,

I have a few questions for you before I can formulate my comments on the proposed EIA changes.

Please open the attached Schedule 8D from EIA-923.

1) Can you explain why you are asking for "unit of measurement" in cells I9 and I18 when cells E8 and E17 already provide the units?
2) Why does EIA ask for information "by month" in cell A7 and then "by Sysem ID" (TYPO) in cell A8? Virtually every other reporting agency asks for this information in reverse. "By System ID" at the top in cell A7 and all 12 months listed vertically on the same tab (for ease of data entry). Let's assume you have 1 unit. All of the information could be quickly entered and saved ONCE on the same tab. With your burdensome, slow format, you have to click…and wait…12 times for tabs to load and then 12 more times for each save. Multiply that by several system IDs and you have a very inefficient and time consuming process that easily uses up the 2.3 hour burden estimate provided in cell K1. So, I'm wondering why EIA asks for data in this difficult-to-enter format.

Please advise. Thank you.

Lisa L. Schmidt
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Providing support for Integrys Energy Group, Integrys Energy Services, Michigan Gas Utilities, Minnesota Energy Resources,
North Shore Gas, Peoples Gas, Upper Peninsula Power Company and Wisconsin Public Service.

Peterson, Rebecca

From: Draves, J.D. <Jdraves@HomerElectric.com>
Sent: Monday, May 13, 2013 9:01 PM
To: ERS2014
Subject: Homer Electric Association, Inc. Comments on Proposed Balancing Authority Operating Statistics

Homer Electric Association, Inc., (HEA), a member owned electric cooperative serving the majority of Alaska's Kenai Peninsula, submits the following comments regarding the proposed Form EIA-930.

(a) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall [sic] have practical utility

HEA at the present time is not a Balancing Authority (or control areas as they are referred to in Alaska). It receives its power through a wholesale power agreement with Chugach Electric Association, Inc. (CEA) and HEA's associated transmission system is operated by CEA as a part of this agreement. Other Railbelt utilities in the state, Matanuska Electric Association, Inc. (MEA) and the City of Seward are also not control areas. HEA does not view the collection of these data as practical or necessary for HEA given the utilities' operational duties being limited to the distribution function only. These data will be of little value to entities whose only function is the distribution aspect of the business. It will be of no usefulness to Alaska Electric Light and Power (AEL&P), the only non-Railbelt Alaskan utility identified in this proposal. AEL&P is an isolated system with no power sales outside its service territory.

Holding firm power supply commitments there is only a small spot market for sales for entrepreneurs looking to supply power to the Alaskan utilities. With HEA's load less than 90 MW at peak and less than 1,000 MW on the Railbelt system as a whole, this is not a market of size that independent power producers can expect to earn a sufficient return to justify an investment in generation of any significance.

The interest of other stakeholders listed in your notice is likely to be limited. Policymakers, legislators, industry researchers and the general public may have a use for it, but the limited need for hourly data in near real time does not justify the cost and effort required. Data could be recorded hourly and reported monthly or quarterly to serve their analytical needs concerning Alaska's control areas. Emergency Managers would find little value in data from the previous hour if a disaster or other emergency situation were to arise. If such an event were to occur that impacted the electrical grid it would likely affect electric load as well.

(b) The accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used

As an entity whose operational duties are currently distribution only, the burden of collecting and posting of the data would be challenging. HEA estimates we would need to spend significant sums to procure the necessary means to record and calculate hourly demand and net generation. Once the system is in place the ongoing burden for the system operator, whose priority is to ensure reliable operation of the distribution system, would require approximately two hours per week to ensure data collection and distribution are meeting the requirements. Additional time would be required for the generation of load forecasts. Utilizing system operators to perform such tasks will require additional management time since these tasks are not a part of the job description per HEA's collective bargaining agreement. Given the small size of the Alaskan utilities, costs that appear *de minimus* to a large utility in the Lower 48 are significant to Alaskan utilities.

HEA does not see the value in devoting additional resources and personnel to report near real-time data that are not currently collected and whose benefit is not readily apparent to EIA's target audience.

(c) Ways to enhance the quality, utility, and clarity of the information to be collected

Information enhancement would be easier if the purpose and public benefit of the data gathering was elucidated. Given the burden of requesting hourly data in near real-time from utilities across the country, the need should be for analyses that require essentially real time data for instantaneous decision making. If the data is for other purposes which can be satisfied by the utility archiving the hourly data and transmitting it less frequently such as monthly or quarterly, ,then that should be the standard. Additionally, more time before submittal would allow utilities to review and correct any errors in the data set.

(d) Ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology

Burden reduction will be significant if the data collection posting requirement is expanded beyond one hour. Preferably a monthly or quarterly requirement would allow for data review and improved accuracy while not compromising utility. The EIA should give consideration to the size of the utilities on which it is making these demands. To assume the burden for collecting and posting of data is the same for a 10 MW utility as for a 20,000 MW utility is unreasonable. The EIA may want to consider size in determining whether a utility with no interconnections should be required to collect and report these data as well.

For the reasons outlined above, HEA concludes that Form EIA-930 does not provide any value to HEA or any other organization in the state of Alaska. Implementation of this requirement will place an additional burden on HEA which is not a control area and therefore is deficient in the means to collect and post these data at the present time. This will require additional resources in terms of equipment as well as personnel that will have a far greater impact on a small organization such as HEA than the larger Balancing Authorities identified by the EIA in the Lower 48. HEA therefore requests an exemption from reporting Form EIA-930.

Sincerely,

J.D. Draves

Manager of Regulatory Affairs & Rate Design
Homer Electric Association, Inc.
jdraves@homerelectric.com

Environmental Energy Technologies Division

To: Rebecca Peterson, EIA

From: Joe Eto, Staff Scientist
Emily Fisher, Staff Research Associate
Kristina Hamachi LaCommare, Program Manager
Electricity Markets and Policy Group, Lawrence Berkeley National Lab

Subject: Comments on addition of distribution reliability questions to EIA-861

Date: May 3, 2013

Thank you for the opportunity to provide comments on the proposed Form EIA-861. We also appreciated the opportunity to provide input as the EIA-861 was being developed.

We strongly support EIA's proposal to collect data on distribution reliability in EIA-861 Schedule 6 Part F, Distribution System Reliability Information, for several reasons:

1. It is in the public interest
2. EIA is uniquely situated to collect this information in a meaningful way on a national basis
3. LBNL past research supports the need for and importance of this data collection

1. It is in the public interest

Utility-level system average interruption frequency index (SAIFI) and system average interruption duration index (SAIDI) are two well-known and widely used reliability metrics. These measures provide information on how customers experience the reliability of the electricity system.

The availability of these metrics, from all utilities in the country using the same methodology, is in the public interest because these data inform reliability activities of many groups. They are used by both utilities and State and Federal regulators to help assess, improve, and manage reliability. Additionally, these data can inform national decisions makers in development of policies, rules and regulations on reliability. In particular, these data would inform DOE and other R&D organizations on priorities for (and efficacy of) R&D on reliability technologies and practices.

Tracking these measures over time can provide insight into whether reliability (defined as customer service and interruptions) is improving or degrading, and whether and how that might be related to policies and actions taken with the goal of improving reliability. Given the substantial investments in infrastructure and programs, including smart grid investments, it is important for industry and government to know whether reliability is moving in a positive direction, or whether we should be pursuing a different set of policies and investments. Having a consistent, data set on reliability is crucial to providing this information. Current reliability data reporting does not provide a consistent data set. (Eto et al. 2012, pg 244)

2. EIA is uniquely situated to collect this information in a meaningful way on a national basis

EIA is the only organization with a mandate and the standing necessary to require the collection of reliability data on a national basis and make it publicly available. Currently no mandatory data collection effort exists. EIA's proposal will fill this gap by collecting meaningful reliability data calculated using a consistent methodology. EIA also has the ability to collect these data from all utilities in the country, thus creating a comprehensive national data set.

3. LBNL past research supports the need for and importance of this data collection

LBNL's past research directly supports the specific forms and approaches EIA has proposed to collect reliability information from electric utilities.

Our work over the past ten years has revealed a lack of consistently defined, publicly-available data on distribution reliability. (Eto et al. 2012, pp 243-244) Currently, utility and PUC practices vary considerably on definitions used to measure reliability performance, and whether these measures are publicly available. Power providers may be required to report reliability measures to their state regulators, and while some of these data may be publicly available many are not. In recent reports, we collected annual SAIDIs and SAIFIs from utilities and PUCs and were able to obtain data representing roughly half of the total electricity sales in the U.S. (Eto et al. 2012, pg 244-245; Eto and LaCommare 2008, pp 4, 10) In our work, we found that the data are not consistently measured and reported. Many factors defining which reliability events are included in SAIDI and SAIFI, such as the defined length of a sustained interruption and what constitutes a major event, vary among states and utilities. (Eto and LaCommare 2008, pg 8, 11-12, 17-19) This inconsistency makes it almost impossible to measure reliability across the country.

Industry trade organizations (EEI, APPA, NRECA) and industry professional organizations (IEEE) do not make these data publicly available, nor, with the exception of IEEE, do they enforce use of consistent definitions. (Eto et al. 2012, pg 244) IEEE does collect these data on a voluntary basis, but, because it is not required from all utilities, this does not represent a national census of all utility performance. (IEEE Distribution Reliability Working Group 2012) Moreover, the utilities providing information are not identified or associated with any information about them such as location or customer base characteristics. Existing national reliability data collection efforts by the Office of Electricity Delivery and Energy Reliability (OE), Department of Energy, and by the National Energy Reliability Corporation (NERC) are restricted to the reliability of the bulk power system, which accounts for less than 10% of the interruptions experiences by utility customers.

We support EIA's proposal to encourage utilities to report SAIDI and SAIFI values using the definitions and guidelines laid out in the IEEE Std 1366-2003 (and the most recent version, the 1366-2012), *IEEE Guide for Electric Power Distribution Reliability Indices*. (IEEE Power Engineering Society 2004, IEEE Power Engineering Society 2012) The IEEE Standard offers a consistent approach for defining and measuring reliability and has already been widely adopted by industry, so requesting that utilities follow the standard in providing this information should not create a new or undue burden. Obtaining SAIDI and SAIFI values that follow these guidelines will produce a data set that is consistently calculated and for which the calculations are known and have been vetted by an important industry group (IEEE). While there are differences between the Standards 1366-2003 and 1366-2012, none of the differences will affect the data being requested by EIA in the current proposed version of EIA-861.[1]

LBNL agrees that enabling utilities to report using definitions and practices other than those prescribed in IEEE Standard 1366-2003 or 1366-2012 is appropriate for the initial release of proposed revisions to EIA-861 only if additional requested information describing how reporting varies from this Standard is also included in the form. In the proposed EIA-861 these clarifying questions are included in Schedule 6 Part F, Section 2, lines 13 to 16. However, to promote consistency in the data set, LBNL recommends phasing-out this alternative reporting option in the next revision of Form EIA-861.

Again, thank you for this opportunity to comment.

References

Eto, Joseph H., Kristina Hamachi LaCommare, Peter Larsen, Annika Todd, and Emily Fisher, "Distribution-level electricity reliability: Temporal trends using statistical analysis." Energy Policy vol 49, pp 243-252, October 2012.

Eto, Joseph H., and Kristina Hamachi LaCommare, "Tracking the Reliability of the U.S. Electric Power System: An Assessment of Publicly Available Information Reported to State Public Utility Commissions." LBNL-1092E, October 2008.

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IEEE Power Engineering Society, *IEEE Std 1366-2012 (Revision of IEEE Std 1366-2003): IEEE Guide for Electric Power Distribution Reliability Indices*. New York: Institute of Electrical and Electronics Engineers, Inc., May 31, 2012.

IEEE Power Engineering Society, *IEEE Std 1366-2003: IEEE Guide for Electric Power Distribution Reliability Indices*. New York: Institute of Electrical and Electronics Engineers, Inc., May 14, 2004.

LaCommare, Kristina Hamachi, and Joseph H. Eto, "Cost of Power Interruptions to Electricity Consumers in the United States (U.S.)." LBNL-58164, February 2006.

LaCommare, Kristina Hamachi, and Joseph H. Eto, "Understanding the Cost of Power Interruptions to U.S. Electricity Consumers" LBNL-55718, September 2009.

[1] The difference between Std 1366-2003 and Std 1366-2012 include introduction of two new indices describing customers experiencing long interruption durations, CELID-s and CELID-t, a new section explaining investigation of catastrophic days, and clarification (but not modification) of some definitions.

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April 30, 2013

Ms. Rebecca Peterson
U.S Department of Energy,
U.S. Energy Information Administration,
Mail Stop EI-23, Forrestal Building,
1000 Independence Avenue SW.,
Washington, DC 20585

Re: Proposed changes to Energy Information Administration Forms EIA-63B, EIA-411, EIA-826, EIA-860, EIA-860M, EIA-861, EIA-861S, and EIA-923. Federal Register Vol. 78 No. 44, Wednesday March 6, 2013.

Dear Ms. Peterson:

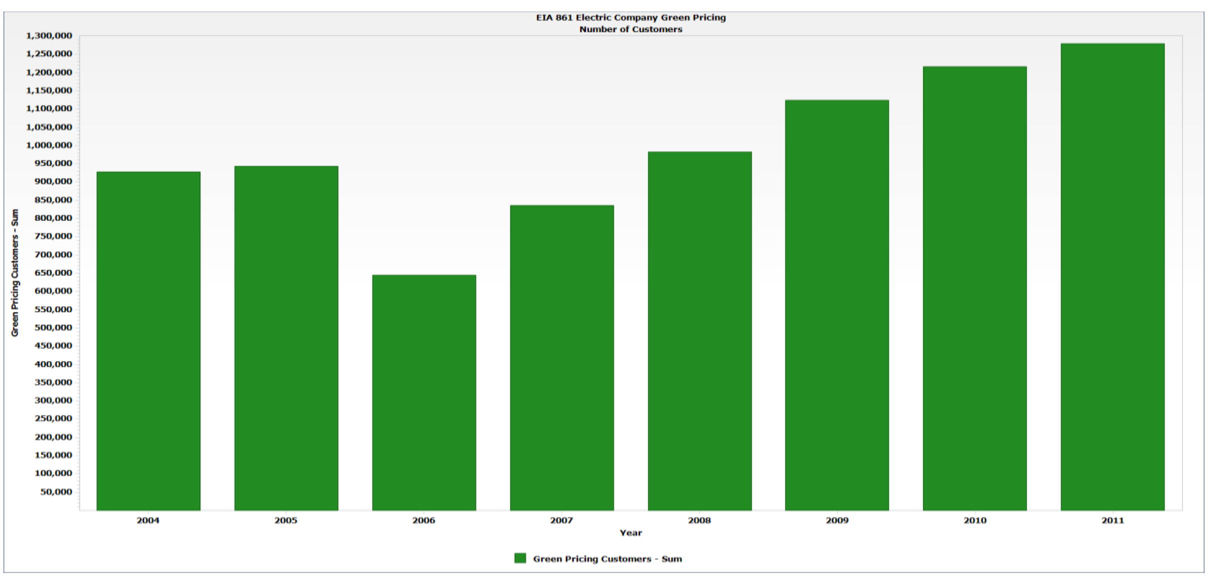
We appreciate the time and effort the Energy Information Administration spends collecting, maintaining and distributing industry wide data. The data found in EIA forms 923, 860, 860M, 861 and 826 is the industry standard and used by market analysts and participants to make important decisions that impact society on a daily basis.

We feel that industry transparency is extremely important and will always support the EIA's decision to add more. We support the EIA's decision to add detailed items like but not limited to Ownership Type, Balancing Authority, Generator Financing and Construction Costs, Operational Flexibility, Black Start Capability, Uprates and De-rates, Nameplate power factor, minimum load and minimum time to reach full load and Ash impoundment.

Renewable resources are more relevant than ever before. The year 2012 brought the United States 14,000 MW of new capacity from Wind and Solar resources alone. Congress recently passed legislation to extend the Wind and Solar Energy production and investment tax programs which will stimulate and produce more renewable capacity in 2013 and beyond. As a result we appreciate the fact that the EIA plans to add details like Wind turbine manufacturer, designed wind speed, hub height and photovoltaic panel material etc.

Eliminating accurate and timely information is our biggest concern. We would like the EIA to continue to collect data from facilities that expect to begin commercial operation within 10 years regardless of fuel type. We understand that Coal, Nuclear and Hydro facilities have longer planning and construction periods. We reluctantly accept the change from 10 years to 5 years for Coal, Nuclear and Hydro facilities exclusively.

We disagree with the EIA's proposed elimination of the Green Pricing schedule found in EIA forms 826, 861 and 861S. We disagree with the statement "Green Pricing programs have a minimal presence in the retail power market". It's our opinion that there is more interest in Green Pricing programs than ever before. Entire cities are embracing "Green" and the push to get these programs going with better incentives and marketing efforts is on the rise. The chart below shows the number of green pricing customers has increased annually by an average of 6.41% with an 11.34% increase from 2006 - 2011.



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We appreciate the EIA's effort to keep the industry transparent and the opportunity to comment on the proposed reduction.

Sincerely,
Jeff Chavez
Product manager
Ventyx an ABB company

NATIONAL RENEWABLE ENERGY LABORATORY

MEMO

Date: Wednesday, May 08, 2013

To: Rebecca Peterson, Energy Information Administration

From: Jenny Heeter, National Renewable Energy Laboratory

Subject: Comments on proposed changes to Form EIA-861 and Form EIA-826

Green pricing programs are a growing part of the renewable energy market in the United States, and are expected to continue to grow. In 2010, green pricing program sales grew by 5%, despite an economic downturn. Data from Form EIA-826 show that the largest green pricing programs grew between 1% and 9% in terms of sales between 2010 and 2011.[i]

NREL uses EIA data to track the green pricing market and finds this resource very valuable for its analysis. EIA data demonstrate the importance of the green pricing market, and provide a signal to utilities and industry that there is market demand for green power. As the only publically available data on green pricing, EIA-861 also provides market transparency and informs academic research.

NREL relies on the EIA-861 green pricing data to help round out our analysis of the green power market. Previous reports analyzing green pricing programs can be found at: http://apps3.eere.energy.gov/greenpower/resources/pub_chrono.shtml

Future green pricing program growth has been forecasted in Bird et al. 2011.[ii] Existing green power programs are expected to increase between 1.8 and 3.9 fold between 2008 and 2015, to between 9,000 thousand MWh and 19,200 thousand MWh. New green pricing programs could add an additional 629 thousand MWh to 1,600 thousand MWh by 2015.

If EIA were interested in consolidating or trimming green pricing-related questions, NREL suggests:

- Eliminating Line 1, Total Green Pricing Revenue, from Schedule 2, Part C, of Form EIA-861 (annual data).
- Eliminating all green pricing questions from Form EIA-826 (monthly data). While the monthly data provides a more current snapshot of the green pricing market, because it only contains a sample of utilities, it has not been as useful as Form EIA-826.

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[i] Heeter, J., Armstrong, P, and Bird, L. (2012). "Market Brief: Status of the Voluntary Renewable Energy Certificate Market (2011 Data)." NREL/TP-6A20-52925. http://www.nrel.gov/docs/fy12osti/56128.pdf
[ii] Bird, L., Sumner, J. and Kreycik, C. with Holt, E. (2010). "Voluntary Green Power Market Forecast through 2015." NREL/TP-6A2-48158. http://www.nrel.gov/docs/fy10osti/48158.pdf

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Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

BERKELEY LAB

Environmental Energy Technologies Division

To: Rebecca Peterson, EIA

From: Joe Eto, Staff Scientist
Emily Fisher, Staff Research Associate
Electricity Markets and Policy Group, Lawrence Berkeley National Lab

Subject: Comments on proposal to create EIA-930

Date: May 6, 2013

Thank you for the opportunity to provide comments on the newly proposed form EIA-930, Hourly and Daily Balancing Authority Operations Report. We are supportive of EIA's proposal to collect demand, generation and interchange information from balancing authorities. We believe this data collection would be in the public interest because it would inform industry, policy makers, and researchers working to make the operation and planning of electricity system more efficient, reliable and sustainable.

The availability of these data is in the public interest because it can provide insight into system operations and planning. Both of these issues are central to the industry, and are critical for policy makers to understand in order to make policy and regulation that promote an efficient, reliable and sustainable system. Having a common data set describing demand, generation and interchange is especially important given the electricity industry has moved away from centralized planning and operation. Additionally, the trend toward wider-area planning and operations, as illustrated by FERC Order 1000, the DOE Interconnection-wide Transmission Planning Grants, development of an energy imbalance market in parts of the western interconnection, and development of remotely-located renewables, would be served by consistent and national data collection.

In particular, as researchers and policy analysts, there are many types of questions we explore that could be informed by this kind of balancing authority data. Two such problems that would benefit from the new data collection proposed by EIA are (1) validating results from power system models and (2) identifying areas where the transmission system is heavily used or congested. Power system modeling is used extensively for transmission planning for capacity expansion and power flow modeling. Capacity expansion models explore what type of new generation might be built and where it may be located. Power flow modeling is used to determine what flows of electricity would result from different loads and generation. Models can be improved if their results are compared to actual data, such as that proposed in EIA-930. Identifying areas of heavy usage and congestion in the transmission system might be a factor in determining where new transmission lines or other technologies should be built. A common understanding by the industry of where high-usage is happening could be a strong foundation for wide-area transmission planning activities.

Currently the data EIA is proposing to collect are available and known to the balancing authorities, but are not gathered in a centralized way by one entity. By having information from all BAs, EIA would be in a position to analyze a variety of policy questions that are difficult to tackle now because of lack of data.

We would like to offer comments for improving the proposal, either now or in the future.

1. Eventually, we would hope these data would all become publicly available so the research community could use them to study the U.S. power grid and improve understanding of planning, operation and policies in an effort to make them more efficient, reliable and sustainable. In the current proposal, the respondents decide whether to make the data public.
2. Collecting information about available transfer capability between balancing authorities on an hourly basis would be a valuable extension of the proposed EIA-930. Transfer capabilities can change seasonally or because of expected or unexpected topological changes (e.g., a transmission line outage). Being able to compare actual interchange with potential interchange would be very useful in analyzing transmission system usage and congestion, as described above.

As it stands the EIA proposal is a valuable advancement in data collection for the industry, for researchers, and for the public.

ELECTRICITY
CONSUMERS
RESOURCE
COUNCIL

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John P. Hughes
Vice President – Technical Affairs

May 2, 2013

Ms. Rebecca Peterson
U.S. Department of Energy
U.S. Energy Information Administration
Forrestal Building
1000 Independence Avenue, S.W.
Washington, DC 20585

Submitted via email to ERS2014@eia.gov

Re: EIA Form Collection Extension with Changes, 78 Fed. Reg. 14521 (Mar. 6, 2013)

Dear Ms. Peterson:

The Electricity Consumers Resource Council ("ELCON") appreciates the opportunity to comment on the proposed information collection of the U.S. Energy Information Administration ("EIA") referenced above, and in particular on the "Annual Electric Generator Report," Form EIA-860, with proposed changes.

ELCON is the national association representing large industrial consumers of electricity. ELCON member companies produce a wide range of products from virtually every segment of the manufacturing community. ELCON members operate hundreds of major industrial facilities and are consumers of electricity throughout the United States. Many of ELCON's members also generate electricity on-site at their manufacturing facilities, such as via cogeneration, and therefore submit information under Form EIA-860.

ELCON's comments focus on the confidentiality of information collected and disseminated by EIA, which relates to the utility and burden of the proposed information collection.

ELCON's members consider certain information, especially related to financial aspects of their cogeneration and similar electricity generation facilities to be highly proprietary, as they relate to issues of the cost structure for the goods that they produce. Such information, if publicly disseminated, would give a marketplace advantage to the competitors of our members. These concerns may be even more important for industrial facilities than for public utilities or other electricity generators.

With respect to the proposed changes to Form EIA-860, ELCON has focused on the additions on cost-related issues, as that information is particularly sensitive. ELCON appreciates that the new questions on generator construction financing costs, along with the other “generator cost information” on Schedule 5, is designated as sensitive and is to be protected to the extent that it satisfies the criteria for exemption from public disclosure under the Freedom of Information Act. ELCON and its members believe that such protection is essential and that the final version of revised Form EIA-860 should retain and specify such protection.

However, the proposed revisions to Form EIA-860 also would add, at Schedule 6 Parts D and E, questions about the installed cost of nitrogen oxide control systems and mercury control systems. As this information is an aspect of the cost structure of an industrial facility with electricity generation, ELCON’s members also view it as proprietary and confidential. Accordingly, the new version of Form EIA-860 and the accompanying instructions should be revised to state that the cost related questions proposed to be added to Schedule 6 Parts D and E are subject to the same confidentiality protections as the cost-related information in Schedule 5.

Respectfully submitted,

John P. Hughes
Vice President - Technical Affairs

May 6, 2013

Ms. Rebecca Peterson
Energy Information Administration
Submitted by email: ERS2014@eia.gov

Dear Ms. Peterson:

This is to comment on the Energy Information Administration's (EIA) solicitation of comments on the proposed three-year reauthorization of forms EIA-63B, EIA-411, EIA-826, EIA-860, EIA-860M, EIA-861, EIA-861S, and EIA-923, and the creation of form EIA-930. These comments are in response to the notice published in Vol. 78, No. 44 of the *Federal Register* on March 6, 2013.

Omaha Public Power District (OPPD) is a customer-owned electric utility and political subdivision of the state of Nebraska. OPPD is currently a balancing authority and owns a transmission system and generation portfolio. OPPD serves approximately 350,000 retail customers located in 13 counties in eastern Nebraska. OPPD is a member of the American Public Power Association (APPA) and OPPD concerns on EIA's proposed revisions align with many of the items in the comments the APPA is planning to submit to this solicitation. In addition OPPD is submitting this letter to address a concern related to the new form, EIA-930.

OPPD is currently a balancing authority but will be passing our balancing authority functions to the Southwest Power Pool (SPP) on March 1, 2014. OPPD is a member of the SPP RTO. Upon SPP's implementation of an RTO-wide balancing area, OPPD will no longer be a balancing authority and no longer will have a net interchange with other balancing areas. Instead the SPP RTO region will have net interchange with its adjoining balancing areas. Since the EIA-930 is to begin for reporting year 2014, OPPD will be required to report hourly balancing area interchange for only a 2 month, interim, period.

OPPD requests the EIA consider granting a waiver to OPPD and the other current balancing authorities in the SPP RTO (OPPD is not speaking on behalf of those entities) and not require these balancing authorities to submit the data requested in the EIA-930 during the interim period discussed above. For OPPD there are set-up requirements for any new automated postings of meter-sourced data. Given that this set-up would only be needed on an interim basis of 2 months adds an extra context to this burden. Following this, EIA will begin receiving data from the SPP RTO consolidated balancing authority as of March 1, 2014. OPPD wonders how useful OPPD's January and February data, followed by a cessation of these specific data elements, would be in serving EIA and the industry.

OPPD appreciates the opportunity the EIA is providing to submit comments on the form revisions and the new Form EIA-930.

Sincerely,

Jon Iverson
Omaha Public Power District
Omaha, Nebraska

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

John N. Moura
Director, Reliability Assessment
NERC

May 6, 2013

Rebecca Peterson
Energy Information Administration

Dear Ms. Peterson,

NERC truly appreciates the opportunity to provide preliminary technical guidance and input for the 2014 development of Form EIA-411 "Coordinated Bulk Power Supply Program Report." As a way of background, NERC provides electric system and reliability data to the Energy Information Administration (EIA), and serves as the electric utility industry's point of contact with the U.S. Department of Energy (DOE), the EIA, and the Federal Energy Regulatory Commission (FERC) on electric system and reliability data reporting and coordination. NERC collects and processes electric system and reliability data to support EIA and FERC data publications and to help eliminate duplication and inefficiency in data reporting processes while improving overall data accuracy and consistency. NERC also serves as an electric industry point of contact for continuing review and comment on DOE's, EIA's, and FERC's various forms, instructions, and procedures for collecting electric system planning and operating data.

Coordinated activity between NERC, electric industry stakeholders, and the United States Energy Information Agency has a long-standing history of collaborative efforts—all of which are critical the continued success of each of our objectives.

NERC recognizes the importance of the many experts who contributed to this effort—in particular, the efforts of the Reliability Assessment Subcommittee and the Reliability Assessment Data Working Group (formerly the Data Coordination Working Group) representatives, NERC Senior Analyst Elliott Nethercutt, and Energy Information Agency staff Orhan Yildiz and Glenn McGrath. All involved have made enormous contributions which have ultimately improved the overall quality of the data to be gathered by the industry.

Preliminary suggestions for enhancements are provided by in the attached file package. Materials include a revised version of the form (Microsoft Excel format) and corresponding definitions and instructions (Microsoft Word format) used by NERC in collection data for the annual development of the Long-Term Reliability Assessment (LTRA). The data collected by NERC is used to populate a substantial portion of the Form EIA-411, as prescribed in an existing Memorandum of Understanding (MOU) between NERC, the eight Regional Entities, and EIA. Supplemental comments related to other requirements of Form EIA-411 have been provided in a separate word document as well. Questions regarding these comments should be directed to Elliott Nethercutt at NERC (elliott.nethercutt@nerc.net).

Additionally, NERC has also provided some comments to support the Form EIA-860. These comments are provided in the attachment as well.

As noted earlier, NERC's comments are preliminary. NERC continues to work with its stakeholders and refinements to some definitions may be needed. NERC will seek Planning Committee endorsement of these comments and looks forward to continued collaboration with EIA to finalize the 2014 Form EIA-411 and Form EIA-860.

Sincerely,

John N. Moura
Director, Reliability Assessment
North American Electric Reliability Corporation

CC: Mr. Stan Kaplan, Director, Office of Electricity, Renewables, and Uranium Statistics, EIA
Mr. Orhan Yildiz, Survey Manager, EIA
Mr. Elliott Nethercutt, Senior Technical Analyst, NERC
Mr. Thomas Burgess, Vice President and Director of Reliability Assessment and Performance Analysis, NERC

ERS2014@eia.gov

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RELIABILITY CORPORATION

EIA-411: Coordinated Bulk Power Supply Program Report

NERC Comments

Demand (Schedule 1A/1B)

- Suggest requiring an explanation for non-coincident instead of coincident peak. (A majority of the assessment areas submit coincident forecasts.)
- Net Internal Demand: removed "Load as a Capacity Resource." (By definition, this is a supply resource.)
- Total Internal Demand: Added "Values should also reflect adjustments for transmission line losses."

Demand Response (Schedule 3A/3B)

- Removed collection of Demand Response used for ancillary services (reserves, regulation, energy, etc.). (This is currently collected in DADS and does not contribute to the planning reserve margin calculations.)
- Removed breakdown of supply-side and load-modifying Demand Response by program; instead allow for each area to designate the amount of total Demand Response that is included for planning purposes as either load-modifying or supply-side. NERC is considering removing this option and designating all Demand Response as load-modifying.
- Added program totals for each category of demand response. This will allow for a more complete understanding of which programs are growing, compared to the amount of each program expected to be available during the peak.

Capacity Transfers (Schedule 3A/3B)

- Suggest collecting only two categories of transfers: Firm or Expected. Firm transfers will be counted toward the Anticipated Reserve Margin. Expected Transfers will be counted toward the Prospective Reserve Margin.
- Removed projected Non-Firm Transfers.
- Added Modeled Transfers as a subset of Firm.

Supply Categories (Schedule 3A/3B)

- Combined Scheduled Outages, derates, and Inoperable resources into a single category: Unavailable

Transmission (Schedule 6A, Schedule 7)

- Transmission voltage category 100-120 kV, 121-150 kV, and 151-199 kV combined to 100-199 kV. Apply BES threshold to included transmission (instead of 100 kV and above).

EIA-860: Annual Electric Generator Report

NERC Comments

41: What is the Maximum Net Summer Output Achievable (MW) When Running on Fuel Oil?

- Winter as well. This is especially needed as winter is when a fuel switch is likely to occur.

42a: How Much Time is Required to Switch This Unit From Using 100% Natural Gas to Using 100% Oil?

- Consider “0” as a separate category.

42b: How Much Time is Required to Switch This Unit From Using 100% Oil to Using 100% Natural Gas?

- Same comment as 42a.

SCHEDULE 3, PART C. GENERATOR INFORMATION – PROPOSED GENERATORS (COMPLETE ONE COLUMN FOR EACH GENERATOR, BY PLANT)

- I understand why the detailed information for proposed generator could be unknown at reporting time.

Additional Comments:

- Suggest adding NERC Assessment Areas for each unit to allow for easier comparison between NERC Reliability Assessment data.
- Dual Fuel Question:
    - Oil inventory—how many hours of burn?
    - Date of last testing
    - Suggest adding amount of time (hours) it takes for unit to switch from one fuel to another.
- Gas fuel and transportation questions:
    - Consider asking how many interstate pipelines that supply the unit are directly, laterally, or radially connected.
    - Does EIA have interest in collecting capacity backed by firm gas transportation contracts? Firm vs Non-Firm capacity (MW, MMBTU, Decatherms)?

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Assessment Data System

Definitions and Instructions

GENERAL INSTRUCTIONS
The fundamental test for determining the adequacy of the Bulk Power System (BPS) is to determine the amount resources and the certainty of these resources to be available to serve peak demand while maintaining sufficient margin to address operating events. This test requires the collection and aggregation of demand forecasts on a normalized basis. This is defined as a forecast that has been adjusted to reflect normal weather conditions, and is expected on a 50% probability basis – also known as a 50/50 forecast (i.e. there is a 50% probably that the actual peak realized will be either under or over the projected peak. This forecast can then be used to test against more extreme conditions. Load forecasts and resource availability projections will be provided for a10-year outlook, in addition to both summer and winter projections, provided for the current reporting year. All data is arranged on the basis of NERC Assessment Areas (a single Planning Coordinator, or group of Planning Coordinators as defined in the NERC functional model), collected by the eight NERC Regions and submitted to NERC.

LOAD FORECAST ASSUMPTIONS		
Code	**Options**	**Definition/Instruction**
A1.1	Coincident or Non-Coincident	Select how the load forecast and peak demand is reported; either on a coincident or non-coincident basis.
A1.2		For non-coincident forecasts, explain why coincident is not used.

NET ENERGY FOR LOAD (MONTHLY)			
Code	**Term**	**Period**	**Definition/Instruction**
A2.1	Net Energy For Load	Prior Year Actual	Net assessment area generation, plus energy received from other assessment areas, less energy delivered to other assessment areas through interchange. It includes assessment area losses but excludes energy required for storage at energy storage facilities.
A2.2		Current Reporting Year Actual (Jan-Mar)	
A2.3		Current Reporting Year Projection	
A2.4		Year 1	

NET ENERGY FOR LOAD (YEARLY)			
Code	**Term**	**Period**	**Definition/Instruction**
A2.5	Net Energy for Load	Year 2-10	Net assessment area generation, plus energy received from other assessment areas, less energy delivered to other assessment areas through interchange. It includes assessment area losses but excludes energy required for storage at energy storage facilities.

PEAK HOUR DEMAND (MONTHLY)			
Code	**Term**	**Period**	**Definition/Instruction**
A3.1	Peak Hour Demand	Prior Year Actual	The highest hourly integrated ("60-minute net integrated peak") Net Energy For Load within a reporting entity occurring within a given period. The integrated peak hour demand (MW) amount is derived by dividing Net Energy For Load (MWh) by 60 for a given hour. Enter the maximum load in megawatts during the specified reporting period. The value for the Prior Year, Current Year, and Year 1 (summer and winter) will populate Total Internal Demand values, based on data entered in those fields.
A3.2		Current Reporting Year Actual (Jan-Mar)	
A3.3		Current Reporting Year Projection	
A3.4		Year 1	

DEMAND		
Code	**Term**	**Definition/Instruction**
A4.1	Unrestricted Non-Coincident Peak Demand	Gross load of an assessment area, which includes New Conservation (Energy Efficiency) and Estimated Diversity; and excludes Additions for Non-member Loads and Stand-by Load Under Contract. This value is calculated automatically, based on data entered in other fields.
A4.1.1	Energy Efficiency	This Demand-Side Management category represents the amount of consumer load reduction at the time of peak for the assessment area, due to utility programs that reduce consumer load throughout the year. This also includes programs aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided and without any explicit consideration for the timing of program-induced savings. Examples include utility rebate and shared savings activities for the installation of energy efficient appliances, lighting and electrical machinery, and weatherization materials. Other examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, and heat recovery systems. The estimated impact of Energy Efficiency during the summer and winter peak should be provided for each year. The values submitted should include only Energy Efficiency that was embedded in the submitted load forecast, resulting in reduced Total Internal Demand projections.
A4.1.2	Estimated Diversity	Electric utility system load consists of many individual loads that vary depending on the time of day. Individual loads within the customer classes follow similar usage patterns, but these classes of service place different demands upon the facilities and the system grid. The service requirements of one electrical system can differ from another by time-of-day usage, facility usage, and/or demands placed upon the system grid. The values submitted should represent the difference between the peak and the sum of the peaks of the individual loads of the reporting entities (Load-Serving Entities, balancing area, zones, etc.).
A4.1.3	Additions for Non-member Loads	Load served by one or multiple non-registered Load-Serving Entities located in an assessment area. These values should equal the total adjustments to account for load of non-members, so that each Load-Serving Entity count its demand once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer Demand values.
A4.1.4	Stand-by Load Under Contract	Demand that is normally served by behind the meter generation, which has a contract to receive electric power from a utility if, the generator becomes unavailable. The summer and winter value for each year should represent the total amount of load (at time of assessment area peak) projected to be served through contracts with respective customer(s). This value should not be reported if projected Stand-By Load Under Contract is already integrated into the Total Internal Demand projections.
A4.1.5	Non-Controllable Demand Response	Demand response programs that are not controllable and non-dispatchable by the balancing authority (or authorities) within an assessment area, but are considered or otherwise integrated into the Total Internal Demand projections. Provide the values of the projected impacts of these programs during the summer and winter peaks for each year.
A4.2	Total Internal Demand	The sum of the metered (net) outputs of all generators within the system and the metered line flows into the assessment area, less the metered line flows out of the assessment area. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Total Internal Demand includes adjustments for indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, all non-dispatchable demand response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs) and some dispatchable demand response (such as Demand Bidding and Buy-Back). Adjustments for controllable demand response should not be incorporated in this value. Values should also reflect adjustments for transmission line losses. The value for the Prior Year, Current Year, and Year 1 (summer and winter) are populated by the highest monthly Peak Hour Demand values, based on data entered in those fields.
A4.3	Net Internal Demand	Equals the Total Internal Demand, reduced the total Dispatchable, Controllable Capacity Demand Response that is considered in planning studies as a load-modifying resource. The specific categories of load-modifying Demand Response include: • Direct Control Load Management • Contractually Interruptible (Curtailable) • Critical Peak Pricing (CPP) with Control

DEMAND RESPONSE			
Code	**Term 1**	**Term 2**	**Definition/Instruction**
A5.1	Total Demand Response		Aggregation of all (Supply-Side and Load-Modifying) Demand Response (5.3.1, 5.4.1, 5.5.1, 5.6.1) that is available to serve during the peak. This value is calculated automatically, based on data entered in other fields.
A5.1.1	Total Load-Modifying Demand Response		Enter the amount of Demand Response that is available to be available to serve during the peak. For planning purposes, these resources area treated as load-modifying by the assessment area.
A5.1.2	Total Supply-Side Demand Response		Enter the amount of Demand Response that is available to be available to serve during the peak. For planning purposes, these resources area treated similar to capacity (backed by firm reserves) by the assessment area.
A5.2	Direct Control Load Management (DCLM)	Program Total	Demand Response under the direct control of the system operator, with capability to control the electric supply to appliances or equipment operated by smaller (residential) customers. For Program Total (A5.2), values submitted should represent the total amount of program participation during the summer and winter peaks for all years. For Available (5.2.1), values submitted should represent the amount of demand that can be interrupted during the summer and winter peaks for all years.
A5.2.1		Available	
A5.3	Contractually Interruptible (Curtailable)	Program Total	Demand Response that, in accordance with contractual arrangements, can be interrupted by direct control of the system operator (remote tripping) or by action of the customer at the direct request of the system operator and in accordance with contractual provisions. Load that can be interrupted to fulfill planning or operating reserve requirements should be reported as Interruptible Demand. For Program Total (A5.3), values submitted should represent the total amount of program participation during the summer and winter peaks for all years. For Available (5.3.1), values submitted should represent the amount of demand that can be interrupted during the summer and winter peaks for all years.
A5.3.1		Available	
A5.4	Critical Peak-Pricing (CPP) with Control	Program Total	Demand Response that, in accordance with contractual arrangements, can be interrupted by direct control of the system operator (remote tripping), or by action of the customer by responding to high prices of energy triggered by system contingencies or high wholesale market prices. For Program Total (A5.4), values submitted should represent the total amount of program participation during the summer and winter peaks for all years. For Available (5.4.1), values submitted should represent the amount of demand that can be interrupted during the summer and winter peaks for all years.
A5.4.1		Available	
A5.5	Load as a Capacity Resource	Program Total	Demand Response that, in accordance with contractual arrangements, is committed to pre-specified load reductions when called upon by the system operator. This program is typically an aggregation of a variety of demand resources that must meet specific requirements associated with traditional generating units (e.g., frequency response, responsive to AGC). These resources are not limited to being dispatched during system contingencies and may be subject to economic dispatch from the system operator. These resources may also be used to meet resource adequacy obligations when determining planning reserve margins. The values submitted should represent the total amount of program participation during the summer and winter peaks for all years. For Program Total (A5.5), values submitted should represent the total amount of program participation during the summer and winter peaks for all years. For Available (5.5.1), values submitted should represent the amount of demand that can be interrupted during the summer and winter peaks for all years.
A5.5.1		Available	

CAPACITY TRANSFERS – IMPORTS			
Code	**Term 1**	**Term 2**	**Definition/Instruction**
A6.1	Prior Year Actual Imports		The amount of capacity (both firm and non-firm) imported into the assessment area during the summer and winter peaks for the prior year.
A6.2	Firm	Firm	The highest quality (priority) service offered to customer(s) under a filed rate schedule that anticipates no planned interruption. Values should reflect firm transfers for the assessment area summer and winter peaks of all years that have confirmed purchases from another area backed by signed firm contracts.
		Full-Responsibility	A firm contract for which the seller(s) is contractually obligated to deliver power and energy to the purchaser with the same degree of reliability as provided to the seller's own native load customers. The purchaser(s) and seller(s) must coordinate and agree on how transactions are reported under this heading. Values should reflect transfers for the summer and winter of all years that have confirmed purchases from another assessment area backed by signed, firm contracts.
		Externally Owned Capacity/Entitlement	A transfer in which owned capacity is physically located outside the assessment area footprint. Values should reflect externally owned capacity or capacity entitlements that will be available for the assessment area summer and winter peaks of all years.
		Modeled Transfers	Specific for Regions or assessment areas that model potential feasible transfers. Value should reflect the amount of energy that could be transferred, for the summer and winter seasons, with consideration for available generation and transfer capability.
A6.3	Expected		A firm contract has a reasonable expectation to be implemented. Values should reflect any potential transfers absent a firm contract, but with reasonable expectations for available purchase during the summer and winter peaks for all years.

CAPACITY TRANSFERS – EXPORTS			
Code	**Term 1**	**Term 2**	**Definition/Instruction**
A7.1	Prior Year Actual Exports		The amount of capacity (both firm and non-firm) exported out of the assessment area during the summer and winter peaks for the prior year.
A7.2	Firm	Firm	The highest quality (priority) service offered from the seller(s) under a filed rate schedule that anticipates no planned interruption. Values should reflect firm transfers for the assessment area summer and winter peaks of all years that have confirmed purchases by another area backed by signed firm contracts.
		Full-Responsibility	A firm contract for which the seller is contractually obligated to deliver power and energy from the purchaser with the same degree of reliability as provided to the seller's own native load customers. The purchaser(s) and seller(s) must coordinate and agree on how transactions are reported under this heading. Values should reflect transfers for the summer and winter of all years that have confirmed sales from the area to another assessment area backed by signed, firm contracts.
		Externally Owned Capacity/Entitlement	A transfer in which owned capacity is physically located outside the assessment area footprint. Values should reflect externally owned capacity or capacity entitlements that will be available for the assessment area summer and winter peaks of all years.
		Modeled Transfers	Specific for Regions or assessment areas that model potential feasible transfers. Value should reflect the amount of energy that could be transferred, for the summer and winter seasons, with consideration for available generation and transfer capability.
A7.3	Expected		A firm contract has a reasonable expectation to be implemented. Values should not include non-firm transfers, but instead reflect any potential transfers absent a firm contract, but with reasonable expectations for available sale during the summer and winter peaks for all years.

INDIVIDUAL UNITS			
Code	**Term 1**	**Term 2**	**Definition/Instruction**
B1	Status	Existing	An existing unit (included prior to initial upload)
		Future	A Future unit (see Future Capacity Categories)
		Cancelled	A unit that was once included as Future, but has been cancelled
		Retired	A unit that was once included as Existing (prior to initial upload) and has since been retired
		Inoperable	Aggregated amount of inoperable capacity expected to be unavailable to serve peak load. This value is calculated automatically, based on data entered in other fields.
B2	RADS Code		Assigned for existing units prior to initial upload. System will assign codes for all future units. RADS code cannot be changed or deleted.
B3	NERC GADS Code		Assigned for applicable existing units prior to initial upload.
B4	Region-Assessment Area		Assigned for existing units prior to initial upload. Future modifications to existing units will be executed by NERC Staff at the request of Regional staff.
B5	Plant Code		See EIA-860 definition. Required for applicable existing U.S. units prior to initial upload. EIA-860 will be used for verification.
B6	Unit Code/Identifier		Assigned for existing units prior to initial upload. EIA-860 will be used for verification of U.S. units.
B7	Other Unit Code		Optional; Regions with existing coding systems can leverage this field for comparison to internal record-keeping systems.
B8	Plant Name		See EIA-860 definition. Assigned for existing units prior to initial upload. Future modifications to existing units will be executed by NERC Staff at the request of Regional staff. Future units are modifiable.
B9	Prime Mover		See EIA-860 definition. Assigned for existing units prior to initial upload. EIA-860 will be used for verification of U.S. units. Future modifications to existing units will be executed by NERC Staff at the request of Regional staff.
B10	Energy Source – 1 (Predominant Energy Source)		See EIA-860 definition. Assigned for existing units prior to initial upload. EIA-860 will be used for verification of U.S. units. Future modifications to existing units will be executed by NERC Staff at the request of Regional staff.
B11	Energy Source – 2 (Second Most Predominant Energy Source)		See EIA-860 definition. Assigned for existing units prior to initial upload. EIA-860 will be used for verification of U.S. units. Future modifications to existing units will be executed by NERC Staff at the request of Regional staff.
B12	BES	Yes	Optional; designate unit as one that will be included in BES, or excluded from the BES.
		No	
B13	In-Service Date		Required for future units. Date when unit will become operational.
B14	Future Resource Tier		See Supply Categories section.
B15	Retirement Date		Enter a best-available date if the generator is expected to be retired within the next 10 years.
B16	Nameplate		See EIA-860 definition. Assigned for existing units prior to initial upload. EIA-860 will be used for verification of U.S. units. Future modifications to existing units will be executed by NERC Staff at the request of Regional staff.
B17	Installed		The nameplate capacity, plus any unit upgrades, minus any unit derates. Assigned for existing units prior to initial upload. Modifications to this field can be made on an annual basis with explanation.
B18	Summer Certain		The amount of capacity classified as Certain (see Supply Categories) to serve the summer peak.
B19	Winter Certain		The amount of capacity classified as Certain (see Supply Categories) to serve the winter peak.
B20	Comments		Provide comments as necessary or as required.

SUPPLY CATEGORIES		
Code	**Term**	**Definition/Instruction**
1	Certain	Capacity that have been confirmed available to operate and deliver power with firm transmission delivery during the peak for an assessment area. Includes capacity that meet one of the following conditions: • That has firm transmission, or considered a firm network resource. • Confirmed able to serve peak load without curtailment due to contractual obligations. • Eligible to bid into a market and unable to be sold elsewhere • That has been confirmed able to serve peak load without curtailment These values are calculated automatically, based on data entered in other fields. Modifications can be made to this field if changes are projected during the 10-year assessment period. Values submitted should represent the amount of Existing-Certain capacity available to serve the summer and winter peaks for all years.
2	Other	Capacity that may be available to operate and deliver power within the area during the peak, but may be curtailed or interrupted. Includes capacity that meet at least one of the following conditions: • With non-firm or other similar transmission arrangements • Considered an Energy-Only resource or non-firm resource that may be available to serve during peak load, but may be curtailed. Generating resources without firm transmission delivery, or that are designated as Energy-Only resources or have elected to be classified as such by the FERC interconnection process. These resources are not classified as Network Resources and may include capacity that may be recallable to another area. • Mothballed capacity that may return to serve the peak. The default value for Existing-Other capacity is zero for all 10 years. Modifications can be made to this field if changes are projected during the 10-year assessment period. Values submitted should represent the amount of Expected-Other capacity available to serve the summer and winter peaks for all years.
3	Unavailable	Capacity is confirmed unavailable to operate and deliver power within the area during the peak. Includes capacity: • That has been derated. • Due to a scheduled outage • Inoperable or mothballed
4	Installed	The nameplate capacity, plus any unit upgrades, minus any unit derates. Assigned for existing units prior to initial upload. Modifications to this field can be made on an annual basis with explanation. Assigned for existing units prior to initial upload. Modifications to existing units are modifiable, but will require an explanation.

FUTURE CAPACITY CATEGORIES				
Code	**Term**	**Definition/Instruction**		
B1 & B17	Future	Capacity resources in one of the following planning phases (tier) that are projected to be available to operate and deliver power within the area during the period of peak demand. To be included in a given tier, the resource must meet at least one of the requirements in each tier:		
		Tier	**Requirement**	**Certain**
		5	Construction complete, but not yet in commercial operation Construction has started Power purchase agreement (PPA) has been approved	100%
		4	Regulatory approvals received. Not under construction but site preparation could be underway Resource has been designated and approved by a market operator Resource has been included in an integrated resource plan under a regulatory environment that mandates resource adequacy requirements Signed Interconnection Service Agreement	100%
		3	Not under construction but site preparation could be underway Regulatory approvals, including those for inclusion in the rate base, have been requested Power purchase agreement (PPA) has been requested Under consideration for designation/approval as a resource by a market operator Included in an integrated resource plan as part of a preferred resource portfolio	50%
		2	Included in generator queue No approvals requested	10%
		1	Corporate announcement "Place-holder" capacity for use in modeling	0%

RESOURCE AND RESERVE MARGIN CATEGORIES		
Code	**Term**	**Definition/Instruction**
H1.1	Existing-Certain & Net Firm Transfers	This category includes the summation of: • Existing-Certain capacity • Net of Firm Capacity Transfers (Imports – Exports)
H1.2	Anticipated Resources	This category includes the summation of: • Existing-Certain Capacity • Net of Firm Capacity Transfers (Imports – Exports) • Future-Certain capacity (Tier 4 & 5) • Projected Supply-Side Demand Response
H1.3	Prospective Resources	This category includes the summation of: • Existing Certain Capacity • Net of Firm Capacity Transfers (Imports – Exports) • Future-Certain Capacity (Tier 4 & 5) • Projected Supply-Side Demand Response • Existing-Other Capacity • Net of Expected Capacity Transfers (Imports – Exports)
H1.4	Adjusted Potential Resources	This category includes the summation of: • Existing Certain Capacity • Net of Firm Capacity Transfers (Imports – Exports) • Future-Certain Capacity (Tier 4 & 5) • Projected Supply-Side Demand Response • Existing-Other Capacity • Net of Expected Capacity Transfers (Imports – Exports) • Future-Certain Capacity (Tier 1, 2, 3) with application of Certain Capacity reductions
H1.5	Total Potential Resources	This category includes the summation of: • Existing Certain Capacity • Net of Firm Capacity Transfers (Imports – Exports) • Future-Certain Capacity (Tier 4 & 5) • Projected Supply-Side Demand Response • Existing-Other Capacity • Net of Expected Capacity Transfers (Imports – Exports) • Future-Certain Capacity (Tier 1, 2, 3) without application of Certain Capacity reductions
H2.1	Existing-Certain & Net Firm Transactions Reserve Margin	This reserve margin is calculated by subtracting Net Internal Demand from the appropriate resource term. The result is then divided by Net Internal Demand.
H2.2	Anticipated Reserve Margin	
H2.3	Prospective Reserve Margin	
H2.4	Adjusted Potential Reserve Margin	
H2.5	Total Potential Reserve Margin	
A8.1	Area Target Reserve Margin (NERC Reference Margin Level)	A margin level or target (as a percentage) based on load, generation, demand-side resources, transmission characteristics, and/or regulatory requirements, as defined by the corresponding Regional Entity, State Public Utility Commission, Provincial authority, or other delegating body. In the absence of a defined margin level or target, NERC assigns 10% or 15% for predominately hydro or thermal systems, respectively. The margin level or target (either provided or assigned by NERC) is applied as the NERC Reference Margin Level for the respective assessment area.

EXISTING AND PROJECTED TRANSMISSION LINES – SUMMARY		
Code	**Category**	**Instructions**
F1-F7	Existing as of Q2 of the Reporting Year	NERC to report existing lines based on aggregations for each area, based on Transmission Owners (TO) from the Transmission Availability Data System (TADS)
	Under Construction as of Reporting Year	Automatically calculated.
	Planned - Completion expected during Reporting Year	Automatically calculated.
	Planned - Completed Year 1-5	Automatically calculated.
	Planned - Completed Year 6-10	Automatically calculated.
	Conceptual - Completed Year 1-5	Automatically calculated.
	Conceptual - Completed Year 6-10	Automatically calculated.
	Existing as of Q2 of the Reporting Year	Automatically calculated.

PROJECTED TRANSMISSION LINE ADDITIONS			
Code	**Term 1**	**Term 2**	**Definition/Instruction**
D1	RADS Transmission Project ID		No entry required. Project Identification Number to be assigned by NERC staff for tracking purposes.
D2	Region-Assessment Area		No entry required. Region-Assessment Area will be assigned by NERC.
D3	Region or Assessment Area Code		Region or Assessment Area can provide code used to track projects internally.
D4	Status	Under Construction	Construction of the line has begun
		Planned	All permits have been approved
			Design is complete
			Needed in order to meet a regulatory requirement
		Conceptual	Other projects that do not meet the requirements in the Planned category.
		Cancelled	A project that was included in prior year data, but has been cancelled.
		Completed	A project that was included in prior year data, but has been completed since the last reporting period.
D5	Type 1	New Standard Line	Project involves the construction of a new line.
		New Tie Line	Project involves the construction of a new tie line with a circuit connecting two balancing authorities or two separate systems.
		New Merchant Line	Project involves the construction of a new merchant line involving a third party that constructs and operates electric transmission lines through the franchise area of an unrelated utility.
		New Merchant/Tie Line	Project meets the requirements of a tie line and a merchant line.
		Line Cancellation	Select when the project has been cancelled.
D6	Type 2	Overhead	Select the predominant physical location of the line conductor.
		Underground	
		Submarine	
D7	Name (Project)		Enter the name associated with the project at the time of reporting.
D8	Origin		Enter the name of the beginning terminal point of the line.
D9	End Point		Enter the name of the ending terminal point of the line.
D10	Name 1(Company)		Enter the company that owns the majority of the project. If there are equal stakes in a project, use best judgment.
D11	EIA Code		Identify each organization by the six-character code assigned by EIA. Required for all projects within the U.S.
D12	Entity Type	Investor-Owned Utility	Identify the type of organization that best represents the majority line owner. If there is more than one organization, select the primary and list additional owners and the respective portion of ownership (as a percentage) in the comments section.
		Municipality	
		Cooperative	
		State-owned	
		Federally-owned	
		Other	
D13 & D14	Primary and Secondary Drivers	Reliability	Choose the two most significant drivers for each project.
		Economics / Congestion	
		Fossil-Fired /Nuclear Integration	
		Variable/Renewable Integration	
		Other	
D15	Line Length		Enter miles between beginning and ending terminal points of the line. Enter Circuit Miles as defined by TADS: One mile of either a set of AC three-phase conductors in an Overhead or Underground AC Circuit, or one pole of a DC Circuit. A one mile-long, AC Circuit tower line that carries two three-phase circuits (i.e., a double-circuit tower line) would equate to two Circuit Miles. A one mile-long, DC tower line that carries two DC poles would equate to two Circuit Miles. Also, a one mile-long, common-trenched, double-AC Circuit Underground duct bank that carries two three-phase circuits would equate to two Circuit Miles. For project upgrades, enter the net amount of additional circuit miles. For cancellations, enter zero (0).
D16	Type	AC	Alternating or Direct Current (AC/DC)
		DC	
D17	Operating (Voltage)	100-199	Select the voltage at which the line is operated at in kilovolts (kV).
		200-299	
		300-399	
		400-599	
		600+	

PROJECTED TRANSMISSION LINE ADDITIONS (CONTINUED)			
Code	**Term 1**	**Term 2**	**Definition/Instruction**
D18	Design (Voltage)		Enter the voltage at which the line was designed to operate in kilovolts (kV).
D19	BES	Yes	Optional; designate line as one that will be included in BES, or excluded from the BES.
		No	
D20	Conductor Size (MCM)		Enter the size of the line conductor in thousands of circular mils (MCM).
D21	Capacity Rating (MVA)		Enter the normal load-carrying capacity of the line in millions of volt-amperes (MVA).
D22	Pole/Tower Type	Wood	Identify the predominant pole/tower material for the line.
		Concrete	
		Steel	
		Combination	
		Composite Materials	
		Other	
		N/A	
D23	Conductor Material Type	Aluminum	Enter the line conductor material type. If the conductor type is not included in the drop-down list, please select "Other" and include the actual conductor material type in the comments section.
		Aluminum Conductor Composite Reinforced	
		Aluminum Conductor Steel Reinforced	
		Copper	
		Other	
D24 & D25	Circuits Per Structure Present & Ultimate	1	Indicate the number of three-phase circuits presently in-use as well as the number that will ultimately be in-use on the structure.
		2	
		3	
D26	Original (In-Service Date)		Enter the date the line was originally scheduled to be energized under the control of the system operator.
D27	Expected (In-Service Date)		Enter the revised date that the line is expected to be will be energized and under the control of the system operator. A date must be provided only for delayed projects. An explanation is required in the comments field.
D28	Comments		Provide comments as necessary or as required.

Peterson, Rebecca

From:	Paladino, Joseph (HQ) <Joseph.Paladino@hq.doe.gov>
Sent:	Monday, May 06, 2013 5:05 PM
To:	ERS2014
Cc:	Kenchington, Henry (SES) (HQ); Meyer, David (HQ); Lippert, Alice (HQ); Peterson, Rebecca
Subject:	Comments to EIA (with respect to March 6, 2013 Federal Register Notice)
Attachments:	specific comments to forms 861 and 411 25apr13 v2.docx

May 6, 2013

Ms. Rebecca Peterson
U.S. Department of Energy
U.S. Energy Information Administration
Forrestal Building
1000 Independence Avenue, SW.
Washington, DC 20585

Subject: Proposed Changes to Form EIA-861 and Form EIA-411

Dear Ms. Peterson:

We appreciate the opportunity to comment on the proposed revisions to Form EIA-861 and Form EIA-411. Attached are specific comments (using "track changes") and notes (in italics) pertaining to Parts C, D, E, and F of EIA-861 and Parts A, B and C of EIA-411.

We greatly support the efforts of the Energy Information Administration (EIA) to gather this additional information, as data on the extent of deployment of advanced metering infrastructure, dynamic pricing programs, automation within distribution systems, and synchrophasor technology is not readily available from primary sources. In addition, this office is responsible for submitting a biennial report to Congress, the Smart Grid Systems Report, which is meant to provide the status of smart grid deployment nationwide. The information you are proposing to collect will significantly aid our efforts in this endeavor and help us better determine the appropriate investments and policies concerning modernization of the electric grid.

If you have any questions or comments, please do not hesitate to contact me.

Respectfully,

Joe Paladino, on behalf of:

Henry Kenchington
Deputy Assistant Secretary
Smart Grid Investment Program
Office of Electricity Delivery and Energy Reliability U.S. Department of Energy
Henry.kenchington@hq.doe.gov

Comments offered by the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability (OE) on Proposed Updates to Form EIA-861 and Form EIA-411

OE has applied the "track changes" function to various parts of the proposed additions to these forms, specifically EIA-861 Schedule 6 Parts C, D, E, F and EIA-411 Schedule 9. In addition OE has provided separate notes in italics.

SCHEDULE 6. PART C. DYNAMIC PRICING PROGRAMS

OE's Note: It would be preferable to ask for the number of customers in each pricing program. We believe getting this detailed information would not put undue burden on respondents because they would need this information to arrive at a total number of customers enrolled in pricing programs. Knowing the number of customers in each specific program would provide greater insight into the extent of their application. In addition, we find the definitions of the pricing programs in the instructions that accompany this Part to be adequate, although we are suggesting minor revisions. We suggest that a longer-term initiative to standardize the definitions of pricing programs across federal data collection activities would be valuable. However, doing so would be beyond the scope of this EIA form, and would require coordination among EIA, DOE, FERC and possibly other stakeholders.

Instructions: Report the number of customers participating in dynamic programs, e.g. Time-of-Use Pricing, Real-Time Pricing, Variable Peak Pricing, Critical Peak Pricing programs.

	Residential	Commercial	Industrial	Transportation	Total
1. Number of Customers enrolled in dynamic pricing programs, by customer class					
INSTRUCTIONS: For each customer class, ~~mark~~ indicate the ~~types of~~ number of customers participating in the					

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dynamic pricing programs~~-~~ listed below~~in which the customers are participating~~.					
2. Time-of-Use Pricing	[ ]	[ ]	[ ]	[ ]	
3. Real Time Pricing	[ ]	[ ]	[ ]	[ ]	
4. Variable Peak Pricing	[ ]	[ ]	[ ]	[ ]	
5. Critical Peak Pricing	[ ]	[ ]	[ ]	[ ]	
6. Critical Peak Rebate	[ ]	[ ]	[ ]	[ ]	

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SCHEDULE 6. PART D. ADVANCED METERING AND CUSTOMER COMMUNICATIONS

OE's Note: We recommend streamlining the data request, as indicated below. In future surveys, it may be more valuable to understand how often customers are actually accessing their usage data than how often a utility or service provider makes the data available.

Only customers from schedule 4A and 4C need to be reported on this schedule. AMR- data transmitted one-way, from customer to utility. AMI- data can be transmitted in both directions, between the delivery entity and the customer.

	Residential	Commercial	Industrial	Transportation	Total
1. Number of AMR meters					
2. Number of AMI m~~M~~eters ~~operated as AMR~~					
~~3. Number of AMI mMeters operated as AMI~~					
2a. Number of AMI meters with home area network (HAN) gateway enabled.					
3~~4~~. Energy Served Through AMI meters ~~(operated as AMI)~~					
4~~5~~. Total Number of m~~M~~eters (All Types)					
5. Number of customers able to access daily energy usage through a webportal or other electronic means~~6. Number of~~					

~~Customers for whom service provider engages in non-billing electronic communication~~					
~~7. Frequency of non-billing electronic communication~~	~~[ ] hourly or more frequently~~ ~~[ ] between hourly and daily~~ ~~[ ] daily or less frequently~~	~~[ ] hourly or more frequently~~ ~~[ ] between hourly and daily~~ ~~[ ] daily or less frequently~~	~~[ ] hourly or more frequently~~ ~~[ ] between hourly and daily~~ ~~[ ] daily or less frequently~~	~~[ ] hourly or more frequently~~ ~~[ ] between hourly and daily~~ ~~[ ] daily or less frequently~~	
5~~8.~~6. Number of customers with direct load control					
~~9. Number of customers that can access their usage information at least daily~~					

SCHEDULE 6. PART E. DISTRIBUTION SYSTEM INFORMATION

OE's Note: We recommend removing lines 4a, 4b, and 4c because the type of customer served by distribution circuits with automation technology is not relevant to our data needs.

INSTRUCTIONS: For the purposes of this schedule, a distribution circuit is any circuit with a voltage of 34kV or below that emanate from a substation and that serves end use customers.

1. Total Number of Distribution Circuits	
2. Number of Distribution Circuits applying distribution automation technology ~~Using Any type of Automation~~	
2a. Do you employ automated feeder switching?~~have automated feeder switches?~~ YES/NO	[ ] Yes [ ] No
2b. Do you employ automated voltage and VAR control?~~have automated regulators and/or capacitors for the active management of voltage/VAR Control levels?~~ YES/NO	[ ] Yes [ ] No
2c. Do you perform diagnosis and notification of equipment condition with on-line monitoring~~have remote Equipment Condition Monitoring~~? YES/NO	[ ] Yes [ ] No
3. Load served by Distribution Circuits ~~with Automation~~applying automation technology (MWhs)	
4. Number of Customers Served by Distribution Circuits applying automation technology ~~with Automation~~	
~~4a. Number of Residential Customers Served by Distribution Circuits with Automation~~	

~~4b. Number of Commercial Customers Served by Distribution Circuits with Automation~~	
~~4c. Number of Industrial Customers Served by Distribution Circuits with Automation~~	
~~4d. Number of Transportation Customers Served by Distribution Circuits with Automation~~	

SCHEDULE 6. PART F. DISTRIBUTION SYSTEM RELIABILITY INFORMATION
SECTION 1: SAIDI and SAIFI in accordance with IEEE 1366-2003 standard

OE's Notes: We recommend moving line 13 in Section 1 to a separate Section (Section 3) to better distinguish between respondents' options.

If your entity calculates SAIDI and SAIFI and determines Major Event Days in accordance with the IEEE 1366-2003 or IEEE 1366-2012 standard complete Section 1.~~;,~~ I~~i~~f your entity calculates SAIDI and SAIFI via another method please complete Section 2. If your entity does not calculate SAIDI and SAIFI please check the box ~~on line 13~~in Section 3. For lines 1 to 6 complete all that you currently calculate.

1. SAIDI value (w/Major Event~~s~~ Days included)	
2. SAIDI value (w/o Major Event~~s~~ Days included)	
3. SAIDI value (w/o Major Event~~s~~ Days included) minus loss of supply	
4. SAIFI value (w/Major Event~~s~~ Days included)	
5. SAIFI value (w/o Major Event~~s~~ Days included)	
6. SAIFI value (w/o Major Event~~s~~ Days included) minus loss of supply	
7. Total number of customers used in these calculations	after first year prefill
8. Percent of your distribution system that is Urban (>150 customers per line mile)	after first year prefill
9. Percent of your distribution system that is Suburban (50 to 150 customers per line mile)	after first year prefill
10. Percent of your distribution system that is Rural (<50 customers per line mile)	after first year prefill
11. At what voltage do you distinguish the distribution system from the supply system?	after first year

	prefill
12. ~~Do you receive information about a customer outage in advance of a customer reporting it?~~Is information about customer outages recorded ~~manually or~~ automatically?	Yes [ ] No [ ] after first year prefill
13. We do not calculate SAIDI and SAIFI, by any method, and this data is not available	[ ]

SCHEDULE 6. PART F. DISTRIBUTION SYSTEM RELIABILITY INFORMATION
SECTION 2: SAIDI and SAIFI other methods

If your entity calculates SAIDI and SAIFI in accordance with the IEEE 1366-2003 or IEEE 1366-2012 standard complete Section 1. ~~-I~~If your entity calculates SAIDI and SAIFI via another method please complete Section 2. If your entity does not calculate SAIDI and SAIFI please check the box ~~on line 13~~in Section 3. For lines 1 to 6 complete all that you currently calculate.

1. SAIDI value (w/m~~M~~ajor e~~E~~vents included)	
2. SAIDI value (w/o m~~M~~ajor e~~E~~vents included)	
3. SAIDI value (w/o m~~M~~ajor e~~E~~vents included) minus loss of supply	
4. SAIFI value (w/m~~M~~ajor e~~E~~vents included)	
5. SAIFI value (w/o m~~M~~ajor e~~E~~vents included)	
6. SAIFI value (w/o m~~M~~ajor e~~E~~vents included) minus loss of supply	
7. Total number of customers used in these calculations	after first year prefill
8. Percent of your distribution system that is Urban (>150 customers per line mile)	after first year prefill
9. Percent of your distribution system that is Suburban (50 to 150 customers per line mile)	after first year prefill
10. Percent of your distribution system that is Rural (<50 customers per line mile)	after first year prefill
11. At what voltage do you distinguish the distribution system from the supply system?	after first year prefill
12. Is information about customer outages recorded ~~manually or~~ automatically?~~Do you receive information about a customer outage in advance of a customer reporting it?~~	Yes [ ] No [ ] after first year

	prefill
13. Do you include inactive accounts?	after first year prefill
14. Do you include non-customer meters i.e., street lighting?	after first year prefill
15. How do you define momentary interruptions? Less than 1 min, 5 min, other	after first year prefill
16. For lines 16a through 16e indicate what defines a major event ~~Which of the following do you consider major events?~~	~~after first year prefill~~
16a. Planned interruptions	Yes [ ] No [ ] after first year prefill
16b. Unplanned interruptions	Yes [ ] No [ ] after first year prefill
16c. Threshold value for loss of load	[value] after first year prefill
16d. Threshold value for number of customers interrupted	[value] after first year prefill
16e. Threshold value for interruption duration in minutes	[value] after first year prefill

Section 3:
We do not calculate SAIDI and SAIFI, by any method, and this data is not available [ ]

EIA-411
SCHEDULE 9. SMART GRID TRANSMISSION SYSTEM DEVICES AND APPLICATIONS

OE's Notes: We recommend rearranging the sections of this Schedule as follows:

SCHEDULE 9 PART A: Dynamic Capability Rating Systems
SCHEDULE 9 PART B: Phasor Measurement Units
SCHEDULE 9 PART C: Smart Grid PMU Applications

Additional edits are provided.

AC Circuit Voltage Class	100-299 kV	300-799 kV
SCHEDULE 9. PART A. SMART GRID TRANSMISSION SYSTEM DEVICES		
Phasor Measurement Units (PMUs)		
1. Number of non-networked PMUs		
2. Number of networked PMUs		
3. ~~Number of local Phasor Data Concentrators installed~~		
4. Number of substations with at least one networked PMU installed		
5. Number of total substations (report for high-side voltage)		
Dynamic Capability Rating Systems (DCRSs) – Move this before Part A, as new section		
6. ~~Number of dynamic capability rating systems used to determine real time ratings on transmission lines~~		
7. Number of transmission circuits utilizing a dynamic capability rating system		
8. Miles of AC transmission lines utilizing a dynamic capability rating system		

9. Number of station transformers utilizing a dynamic capability rating system		

SCHEDULE 9. PART B. SMART GRID PMU APPLICATIONS

A. Real-time Operations Applications	
1. Indicate whether PMUs are being used to support the following applications:	
1a. Wide-area situational awareness	[ ] Yes, [ ] No
1b. Frequency stability monitoring and trending	[ ] Yes, [ ] No
1c. Power oscillation monitoring	[ ] Yes, [ ] No
1d. Voltage monitoring and trending	[ ] Yes, [ ] No
1e. Alarming and setting system operating limits, event detection and	[ ] Yes, [ ] No
1f. Resource integration	[ ] Yes, [ ] No
1g. State estimation	[ ] Yes, [ ] No
1h. Dynamic line ratings and congestion management	[ ] Yes, [ ] No
1i. Outage restoration	[ ] Yes, [ ] No
1j. Operations planning	[ ] Yes, [ ] No
B. Planning and Off-line Applications	
2. Indicate whether PMUs are being used to support the following applications:	
2a. Baselining power system performance	[ ] Yes, [ ] No
2b. Event analysis	[ ] Yes, [ ] No
2c. Static system model calibration and validation	[ ] Yes, [ ] No
2d. Dynamic system model calibration and validation	[ ] Yes, [ ] No
2e. Power plant model validation	[ ] Yes, [ ] No
2f. Load characterization	[ ] Yes, [ ] No
2g. Special protection schemes and islanding	[ ] Yes, [ ] No
2h. Primary frequency (governing) response	[ ] Yes, [ ] No

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Instructions:
EIA-861. SCHEDULE 6. PART C. DYNAMIC PRICING PROGRAMS

1. **Dynamic pricing programs** (also known as time-based rate programs) are designed to modify patterns of electricity usage, including the timing and level of electricity demand. Report those customers that are enrolled in the program and are billed accordingly whether or not they are active participants. Note line 1 on this schedule is a sub set of Schedule 6 Part B line 5. For each state, balancing authority, and customer sector report the number of customers enrolled in any type of dynamic pricing program.
2. **Time of Use Prices (TOU)** is a program in which customers pay different prices at different times of the day. On-peak prices are higher and off-peak prices are lower than a "standard" rate. Price schedule is fixed and predefined, based on season, day of week, and time of day.
3. **Real Time Pricing (RTP)** is a program of rate and price structure in which the retail price for electricity typically fluctuates hourly or more often, to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.
4. **Variable Peak Pricing (VPP)** is a program in which a form of ~~Time-Of-Day (TOD)~~TOU pricing allows customers to purchase their generation supply at prices set on a daily basis with~~.~~ ~~Standard~~ varying on-peak and constant off-~~-~~peak ~~time-of-day~~ rates ~~are in effect throughout the month~~. Under the VPP program, the on-peak price for each weekday becomes available the previous day (typically late afternoon) and the customer ~~gets~~ is billed for actual consumption during the billing cycle at these prices.
5. **Critical Peak Pricing (CPP)** is a program in which rate and/or price structure is designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies, by imposing a pre-specified high rate or price for a limited number of days or hours. Very high "critical peak" prices are assessed for certain hours on event days (often limited to 10-15 per year). Prices can be 3-10 times as much during these few hours. Typically, CPP is combined with a TOU rate, but not always.
6. **Critical Peak Rebate (CPR)** is a program in which rate and/or price structure is designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies, by providing

a rebate to the customer on a limited number of days and for a limited number of hours, at the request of the energy provider. Under this structure the energy provider can call event days (often limited to 10-15 per year) and provide a rebate typically several times the average price for certain hours in the day. The rebate is based on the actual customer usage compared to its baseline to determine the amount of the demand reduction each hour.

7. On line 1, enter the number of customers participating in dynamic pricing programs, by customer class
8. On line 2, enter the number of customers ~~for each customer sector indicate if customers in this sector are~~ participating in Time-of-Use Pricing.
9. On line 3, enter the number of customers ~~for each customer sector indicate if customers in this sector are~~ participating in Real time Pricing.
10. On line 4, enter the number of customers f~~For each customer sector indicate if in this sector are~~ participating in Variable Peak Pricing
11. On line 5, enter the number of customers ~~for each customer sector indicate if customers in this sector are~~ participating in Critical Peak Pricing.
12. On line 6, enter the number of customers ~~for each customer sector indicate if customers in this sector are~~ participating in Critical Peak Rebate.

Instructions:

EIA-861. SCHEDULE 6: PART D. ADVANCED METERING AND CUSTOMER COMMUNICATIONS

1. **This schedule should only include customers from Schedule 4 Part A or Part C.**
2. **Standard (Electric) Meters** are electromechanical or solid state meters measuring aggregated kWh where data are manually retrieved over monthly billing cycles for billing purposes only. Standard meters may also include functions to measure time-of-use and/or demand with data manually retrieved over monthly billing cycles.
3. **Automated Meter Reading (AMR) meters:** Meters that collect data for billing purposes only and transmit this data **one way**, usually from the customer to the distribution utility. Aggregated monthly kWh data captured on these meters may be retrieved by a variety of methods including drive-by vans with short-distance remote reading capabilities and communication over a fixed network such as a cellular network. Enter the state and balancing authority and report the total number of AMR meters by sector.
4. **Advanced Metering Infrastructure (AMI) meters:** Meters that measure and record usage data at a minimum, in hourly intervals and provide usage data to energy companies and may also provide data electronically to consumers at least once daily. Data are used for billing and other purposes. Advanced meters include basic hourly interval meters and extend to real-time meters with built-in two-way communication capable of recording and transmitting instantaneous data.

~~5. **Installed AMI that is operated as AMR** should be reported separately from AMI operated as AMI.~~

~~6.~~5. **Energy Served through AMI** (MWh) should be entered in megawatt hours for customers served.

~~7. **Electronic Communication** – Communication that is delivered electronically in an automated fashion and that occurs in reoccurring time intervals. Utility or service provider may provide energy usage information, billing information, energy pricing, system conditions (e.g., "peak day"), or other similar information electronically to a customer. This information may or may not be in real-time (e.g., instantaneous system conditions or real-time prices) or be used for billing purposes.~~

~~8.~~6. **Direct Load Control:** A demand response activity by which the program sponsor remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, water heater) on short notice. Direct load control programs are primarily offered to residential or small commercial customers. Also known as direct control load management.

~~9.~~7. Enter the state and balancing authority and on line 1 enter the number of AMR meters, by customer class.

8. On line 2 enter the number of AMI meters ~~that are operated as AMR~~, by customer class.

~~10.~~9. On line 2a enter the number of AMI meters where the home area network (HAN) is enabled. In this case, a HAN consists of software and hardware components residing within an AMI meter that permits the meter to communicate with devices within a customer's premises.

~~11. On line 3 enter the number of AMI meters that are operated as AMI, by customer class.~~

~~12.~~10. On line ~~3~~4 enter the energy served (megawatt hours) through AMI meters ~~(operated as AMI)~~, by customer class.

11. On line ~~5~~4 enter the total number of meters (All Types), by customer class.

~~13.~~12. On line 5 enter the total number of customers who are able to access daily energy usage through a webportal or other electronic means, by customer class.

~~14. On line 6 enter the number of customers for whom the service provider engages in non-billing electronic communication, by customer class .~~

~~15. On line 7 indicate the frequency of non-billing electronic communication by marking one or more of the three options: "hourly or more frequent"; "between hourly and daily"; and "daily or less frequent", by customer class~~

~~16.~~12. On line ~~8~~6 enter the number of customers with direct load control, by customer class.

~~17. On line 9, enter the number of customers that can access their usage at least once daily.~~

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Instructions:
EIA-861. SCHEDULE 6: PART E. DISTRIBUTION SYSTEM INFORMATION

For purposes of this schedule, a distribution circuit is any circuit with a voltage of 34kV or below that emanate from a substation and that serves end use customers. Report in this schedule if you own distribution lines.

1. **Distribution automation** is a set of technologies providing sensing, communications, and control that enables an electric utility to remotely monitor and coordinate its distribution assets, and operate these assets in an optimal manner with or without manual intervention. ~~is any type of remote control, automated control or monitoring on lines that compose the distribution circuit or the substation or substation transformers connecting the distribution circuit to the transmission or sub-transmission system for purposes of improving operational efficiency or reliability.~~ Examples of distribution automation include ~~remote switches,~~ automated feeder switches, automated capacitors and voltage regulators ~~switching to enable voltage/VAR control~~, and equipment condition monitoring~~, and moving transformer taps~~.
2. **Automated feeder switching** is realized through automatic isolation and reconfiguration of faulted segments of distribution feeders via sensors, controls, switches, and communications systems. These devices can operate autonomously in response to local events or in response to signals from a central control system.~~es are circuit breakers that can be controlled remotely (i.e., without a truck roll) either by an operator, or by automatic response or intelligence without operator intervention or action.~~
3. **Automated Voltage & VAR Control** requires coordinated operation of reactive power sources (such as capacitors), voltage regulators and ~~: Automated voltage and VAR control requires coordinated operation of reactive power resources such as capacitor banks, voltage regulators,~~ transformer load-~~—~~tap changers~~, and distributed generators (DG)~~ with sensors, controls, and communications systems. These devices could operate autonomously in response to local events or in response to signals from a central control system to actively manage voltage levels within feeders.
4. **Diagnosis and notification of equipment ~~Automated Equipment~~ c~~C~~ondition is defined as on-line**

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monitoring **and analysis of equipment, its performance, and operating environment in order to** ~~refers to technologies that~~ monitor the status of equipment and remotely communicate that status to operators, allowing operators to make decisions regarding operations or maintenance. Examples of equipment monitoring are remote fault indicators and transformer monitors that check pressure, temperature, oil or fluid level, and or chemical constituents.

5. **Load served by distribution circuits with automation (MWh)** is the amount of energy delivered to customers traveling from the transmission system to the end-use customer through a distribution circuit (or distribution transformer or substation) that uses any form of automation during the reporting year.
6. **Number of customers served by distribution circuits with automation** are number of customers that are delivered energy that travels from the transmission system to the end-use customer through a distribution circuit (or distribution transformer or substation) that uses any form of automation.
7. On line 1 enter the Total Number of Distribution Circuits.
8. On line 2 enter the Total Number of Distribution Circuits ~~using~~ applying any type of distribution automation technology.
9. On line 2a enter "Y" or "N" for the question, do you ~~have~~ employ automated feeder switching~~es~~?
10. On line 2b enter "Y" or "N" for the question, do you employ ~~have~~ automated voltage~~/~~ and VAR control?
11. On line 2c enter "Y" or "N" for the question, do you perform diagnosis and notification of equipment condition with on-line monitoring~~have equipment monitoring~~?
12. On line 3 enter load served by Distribution Circuits ~~with~~ applying automation technology (MWhs).
13. On line 4 enter the total number of customers served by Distribution Circuits ~~with~~ applying automation technology.
    - 4a for Residential sector
    - 4b for Commercial sector
    - 4c for Industrial sector
    - 4d for Transportation sector

Instructions:
EIA-861. SCHEDULE 6: PART E. DISTRIBUTION SYSTEM RELIABILITY INFORMATION

If your entity calculates SAIDI and SAIFI and determines Major Events Days in accordance with the IEEE 1366-2003 or IEEE 1366-2012 standard, complete Section 1.~~;~~ I~~i~~f your entity calculates SAIDI and SAIFI via another method please complete Section 2. If your entity does not calculate SAIDI and SAIFI please check the "data not available" box located ~~on line 13~~in Section 3. For lines 1 through 6 complete all that you calculate.~~;~~ ~~f~~For example, if you only calculate SAIDI and SAIFI without Major Event Days~~s~~ included, then based on instructions for lines 2 and 4, complete lines 2 and 4 and then leave lines 1, 3, 5, and 6 blank.

Section 1: SAIDI and SAIFI in accordance with IEEE 1366-2003 or IEEE 1366-2012 standard, by state

1. The **system average interruption frequency index, or SAIFI**, indicates how often the average customer experiences a sustained interruption (of over 5 minutes) over a predefined period of time. In this schedule report annual SAIFI, or the SAIFI resulting from all interruptions in the reporting year. SAIFI is calculated as the sum over the year of total number of customers that experiences an interruption of more than 5 minutes, divided by the total number of customers.
2. SAIFI = [Sum of total number of customers interrupted over the year] / [Total number of customers served]
3. The **system average interruption duration index, or SAIDI**, indicates the total duration of interruption for the average customer over a predefined period of time. In this schedule report annual SAIDI, or the SAIDI resulting from all interruptions in the reporting year. SAIDI is calculated as the sum over the year of all customers interrupted for more than 5 minutes times the number of minutes they experienced an interruption, divided by total number of customers.
4. SAIDI = [Sum of customer minutes interrupted over the year] / [Total number of customers served]
5. On lines 1 through 6 report the values that you calculate.
    a. Report the Annual Distribution SAIDI with Major Event~~s~~ Days on line 1,
    b. Report the Annual Distribution SAIDI without Major Event Days~~s~~ on line 2
    c. Report the Annual Distribution SAIDI without Major Event~~s~~ Days excluding events where the

reliability event was not initiated from loss of supply (e.g., resulted from an event on the distribution system, not from the high-voltage system) on line 3.

d. Report the Annual Distribution SAIFI with Major Event Days~~s~~ on line 4,
e. Report the Annual Distribution SAIFI without Major Event Days~~s~~ on line 5,
f. Report the Annual Distribution SAIFI without Major Event Days~~s~~ excluding events where the reliability event was not initiated from loss of supply (e.g., resulted from an event on the distribution system, not from the high-voltage system) on line 6.

6. On line 7, enter the total number of customers used to calculate SAIDI and SAIFI, as reported on this schedule. A customer is defined as a metered electrical service point for which an active bill account is established at a specific location (e.g., premise). *(IEEE 1366-2003 pg 2)*

7. On lines 8 through 10 report the percent of your distribution system that is Urban Suburban, and Rural Distribution circuits can be classified as urban suburban and rural using the following criteria:
Urban: greater than 150 customers per circuit mile
Suburban: from 50 to 150 customers per circuit mile
Rural: less than 50 customers per circuit mile

Each circuit in a system can be classified as urban, suburban or rural. The count of each type of circuit is then divided by the total number of circuits to get a percent for each classification. The distribution circuit classifications as urban, suburban, and rural should add to one hundred percent, and fully describe the make-up of the utility.

Example[1]: A utility has the following circuits and circuit customer count:

	Circuit Length	Circuit

[1] (Example adapted from IEEE P1782 "Draft Trial-Use Guide for Collecting, Categorizing and Utilization of Information Related to Electric Power Distribution Interruption Events", pg 3)

	(mi)	Customers
Circuit A	7	100
Circuit B	31	2,000
Circuit C	10	1,500
Circuit D	12	500
Circuit E	17	3,000

To determine percentage of system that is urban, suburban, and rural, first determine the customer per circuit mile for each circuit by dividing the number of circuit customers by the corresponding circuit length.

Circuit A: 100 customers / 7 circuit miles = 14 customers per circuit mile
Circuit B: 2,000 customers / 31 circuit miles = 65 customers per circuit mile
Circuit C: 1,500 customers / 10 circuit miles = 150 customers per circuit mile
Circuit D: 500 customers / 12 circuit miles = 42 customers per circuit mile
Circuit E: 3,000 customers / 17 circuit miles = 179 customers per circuit mile

(Note: values rounded to the nearest whole number)

Then apply the criteria above to these values to determine the system designation for each circuit. For instance, Circuit A and Circuit D both have fewer than 50 customers per mile, so they are both classified as Rural. Circuit B has between 50 and 150, so it is Suburban. Circuit C is also Suburban, because it is exactly 150 customers per circuit mile. Circuit E has more than 150 customers per mile, so it is classified as Urban.

The System Designation percentages are then calculated as the number of circuits of a particular classification divided by the total number of circuits. In the example system,

Rural (Circuits A and D): 2 rural circuits / 5 total circuits = 40%
Suburban (Circuits B and C): 2 suburban circuits / 5 total circuits = 40%
Urban (Circuit E): 1 urban circuit / 5 total circuits = 20%

8. On line 11, indicate the voltage at which you distinguish the distribution system from the supply system
9. On line 12, indicate whether your utility records any information about customer outages automatically. For instance, if your utility has an outage management system that detects loss of load or customer outages, answer "yes", even if you also receive outage information manually via other methods. ~~receives information about a customer outage in advance of a customer reporting it.~~

Section 2 SAIDI and SAIFI calculations via other methods, calculated by state

1. On lines 1 through 6 reports the values that you calculate.
   a. Report the Annual Distribution SAIDI with m~~M~~ajor ~~Events~~ events on line 1,
   b. Report the Annual Distribution SAIDI without ~~M~~major ~~Events~~ events on line 2
   c. Report the Annual Distribution SAIDI without m~~M~~ajor ~~Events~~ events excluding events where the reliability event was not initiated from loss of supply (e.g., resulted from an event on the distribution system, not from the high-voltage system) on line 3.
   d. Report the Annual Distribution SAIFI with m~~M~~ajor ~~Events~~ events on line 4,
   e. Report the Annual Distribution SAIFI without ~~M~~major ~~Events~~ events on line 5,
   f. Report the Annual Distribution SAIFI without m~~M~~ajor ~~Events~~ events excluding events where the reliability event was not initiated from loss of supply (e.g., resulted from an event on the distribution system, not from the high-voltage system) on line 6.
2. On line 7, enter the total number of customers used to calculate SAIDI and SAIFI, as reported on this schedule.

3. On lines 8 through 10 report the percent of your distribution system that is Urban, Suburban and Rural.
4. On line 11 report the voltage that you use to distinguish the distribution system from the supply system.
5. On line 12 records any information about customer outages automatically. For instance, if your utility has an outage management system that detects loss of load or customer outages, answer "yes", even if you also receive outage information manually via other methods. ~~report whether or not you receive information concerning a customer outage in advance of a customer reporting it.~~
6. On lines 13 and 14, indicate whether your utility includes inactive accounts and/or non-customer meters in its definition of customer used to determine SAIDI and SAIFI.
7. On line 15, indicated how you're utility defines momentary outages. (Less than how many minutes) Outages can be classified as either momentary or sustained. Momentary outages are not included in determining SAIDI and SAIFI.
8. A major event ~~day (MED)~~ is ~~one~~ an event where the circumstances causing an interruption or reliability event are outside the reasonable scope of utility planning. Because of this, utilities often calculate reliability metrics with and without ~~MED~~major events. Utilities can use methods that can define ~~MEDs~~ major events differently. For instance, some state utility commissions allow or require other definitions of ~~MEDs~~major events.
9. On lines 16a to 16e indicate which of these factors are included in ~~MED~~ major event determination, and if they are indicate a value where appropriate. For instance, if your utility includes planned outages as a possible cause of ~~MED~~ major event interruptions, answer Yes on line 16a.

Instructions:
EIA-411. SCHEDULE 9: PARTS A and B.

Above we suggested an alternative ordering of these questions:

SCHEDULE 9 PART A: Dynamic Capability Rating Systems
SCHEDULE 9 PART B: Phasor Measurement Units
SCHEDULE 9 PART C: Smart Grid PMU Applications

We did not make changes to the instructions to mirror this suggested change in order.

SCHEDULE 9. PART A. SMART GRID TRANSMISSION SYSTEM DEVICES

A **phasor measurement unit** (PMU) is equipment that can monitor the precise grid **synchro phasor measurements** (magnitude and phase angle) of both voltage and current at high frequency (e.g., 30 times per second) and associated with an **accurate time-stamp**. PMUs are typically installed at substations or at power plants, at a variety of voltage levels. Depending on location and surrounding network configuration, a PMU can be used to monitor transmission lines, transformers and/or generators.

1. For **line 1,** enter the number of **non-networked PMUs** installed in your region. A non- networked PMU is a device that measures and stores phasor data at high frequency with a time-stamp, but these data are not transmitted automatically to any other device (e.g., control room equipment, phasor data concentrator). These data are available for later retrieval and analysis, for instance for event analysis after a reliability event.
2. For **line 2**, enter the number of **networked PMUs** installed in your region. A networked PMU measures and stores phasor data at high frequency with a time-stamp, and communicates these data at regular intervals (at least 30 samples per second) to remote locations. Typically the data are shared with a **Phasor Data Concentrator** (PDC), which then shares this information with other PMUs, operating or reliability organizations. These data are also stored in a data storage system. Communication between the PMU and

PDC, and then between the PDC and the users or storage system, is done via a private wide-area network or any other secure and reliable digital transport system. The data collected by a networked PMU can be used along with data collected by other networked PMUs in order to get a precise and comprehensive view of large areas of the grid.

~~3. For **line 3** enter the number of Phasor Data Concentrators in your region.~~

~~4.~~3. For **line 4** enter the total number of substations with at least one networked PMU installed. A substation is defined as any network node in the system where two or more transmission lines, or a transmission line and power plant, are connected directly or via step-up/step-down transformers.

~~5.~~4. For **line 5** enter the total number of **substations** in your region. If there is more than one voltage level in a substation, the substation should be listed under the voltage column that corresponds to the highest (or high-side) voltage.

Dynamic capability rating systems on *transmission circuits* continuously monitor ambient conditions, such as line tension, temperature or wind speed, and allow lines to be reliably loaded closer to their true operational capacity. Often this means they can carry electricity at higher levels than nominal limits; however, in some conditions, they can warn operators of situations where the capacity of the line is reduced. These systems include, but are not limited to, cable tension monitoring, line thermal or direct temperature monitoring, and thermal monitoring of conductor replicas. Equipment can be installed at substations or on transmission lines themselves, depending on the kinds of measurements being taken. Information collected by the monitors is transmitted back to the control center and made available to operators or integrated into energy management systems. If you have integrated equipment monitoring, such as Integrated Substation Condition Monitoring, that monitors transmission lines as well as other equipment, report it here.

~~6. For **line 6** enter the number of dynamic capability rating systems used to determine real time ratings on transmission lines.~~

~~7.~~5. For **line 7** enter the number of transmission circuits utilizing a dynamic capability rating system.

~~8.~~6. For **line 8** enter the miles of AC transmission lines utilizing a dynamic capability rating system.

~~9.~~7. For **line 9** enter the number of station transformers utilizing a dynamic capability rating system.

SCHEDULE 9. PART B. SMART GRID PMU APPLICATIONS

In this section respondents are asked to indicate whether the PMUs installed by entities in their regions are being used for either real-time operations applications, planning and off-line applications, by checking the appropriate box.

1. **Real-time operations applications** include, but are not limited to:
   - Wide-area situational awareness
   - Frequency stability monitoring and trending
   - Power oscillation monitoring
   - Voltage monitoring and trending
   - Alarming and setting system operating limits, event detection and avoidance
   - Resource integration
   - State estimation
   - Dynamic line ratings and congestion management
   - Outage restoration
   - Operations planning
2. **Planning and off-line applications** include, but are not limited to:
   - Baselining power system performance
   - Event analysis
   - Static system model calibration and validation
   - Dynamic system model calibration and validation
   - Power plant model validation
   - Load characterization

- Special protection schemes and islanding
- Primary frequency (governing) response

Applications can be at any stage of deployment within the control room, from research and development to full production.

Renewable Energy Markets Association

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Submitted via: ERS2014@eia.gov

May 6, 2013

Ms. Rebecca Peterson
U.S. Energy Information Administration
Mail Shop EI-23
Forrestal Building
1000 Independence Ave SW
Washington, DC 20585

RE: Comments of the Renewable Energy Markets Association on the Energy Information Administration's Agency Information Collection Extension

Dear Ms. Peterson:

The Renewable Energy Markets Association (REMA) is pleased to submit the following recommendations and comments in response to the Energy Information Administration's (EIA) call for improved industry data collection. REMA is a North American trade association dedicated to maintaining and growing strong markets for renewable energy. REMA represents the collective interests of both nonprofit and for-profit organizations that sell or promote renewable energy products through voluntary markets, including renewable electricity and renewable energy certificates, to individuals, companies, and institutions across North America.

REMA recommends that the *Green Pricing* question in both forms 826 and 861 be asked annually and voluntarily. The move from required monthly and annual reporting to an annual request will certainly achieve the EIA's goal of minimizing the burden upon respondents. Additionally, REMA requests that EIA maintain the presence of the *Green Power* question on Form 861. This continuity will also achieve an EIA goal of providing information that is of practical utility. Although the number of utilities participating in green power programs has not experienced significant growth over the past few years, continued data collection is vital to monitor and respond to new developments, if any. To adapt the business adage to the renewable energy markets, "one cannot manage what it cannot measure."

While REMA recommends an annual and voluntary approach to the EIA industry *Green Pricing* reporting, we also urge the EIA to expand its data coordination with related reporting entities. For example, the National Renewable Energy Laboratory's (NREL) annual reports on the voluntary and compliance renewable energy markets describe gross industry sales, generation figures, industry trends in green power marketing, and assess energy policy implications at the state and federal levels. These annual NREL reports, which draw upon the EIA Form 861 data, help inform the decisions of public and private renewable energy leaders alike in their shared pursuit of ever-increasing renewable energy use. NREL's analyses are meeting a critical need of the renewable energy markets, and an interruption of utility data could negatively impact its reporting. It is from this relationship that REMA recommends an open dialogue between NREL and EIA to share the most accurate industry data moving forward.

Again, we thank you for your consideration of our comments. For either questions or clarifications regarding REMA's submission, please contact me, Josh Lieberman, REMA General Manager, with the information below.

Sincerely,

Josh Lieberman
REMA General Manager
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E: jlieberman@ttcorp.com

McArdle, Paul

From: millickk@firstenergycorp.com
Sent: Tuesday, April 30, 2013 2:10 PM
To: ERS2014
Cc: mjfox@firstenergycorp.com; krpompeo@firstenergycorp.com; sdalton@firstenergycorp.com
Subject: FirstEnergy's comments on changes to EIA-923 ATTN: Rebecca Peterson

Hello Rebecca,

Here are my comments on the proposed changes to the EIA-923.

1. Use of Blended Coal Products (CBL) on Schedule 3A. FirstEnergy currently blends BIT and SUB coals for use at it plants. If we use the CBL code and an estimate for the % BIT and % SUB, are we still be required to accurately report the inventory values for BIT and SUB separately or can we report on inventory level by using the CBL code on Schedule 4?

2. Please see the screen print below for an example entry for Schedule 3A. The first lines illustrates a typical entry for a single boiler with multiple fuels to a single turbine generator, Is this correct? The second group shows two boilers supplying two turbine generators, in a common header arrangement, is this correct?

Boiler Generator or Group code (EIA use	Prime Mover Code	Boiler ID	Energy Source*	Quantity Consumed		Units	Average Heat Content (HHV)	Sulfur Content	Ash Content		Generator ID	Net Generation (MWh)	G	Gro Gene n (M
1	ST	1	BIT	10000		tons	24.000	2.55	10.2		1	50000		5
	ST	1	DFO	50		bbl	5.922							
	ST	1	NG	100		mcf	1.025							
2	ST	2	BIT	10000		tons	24.000	2.55	10.2		5	50000		5
	ST	2	DFO	50		bbl	5.922							
	ST	3	BIT	12000		tons	24.122	2.44	10.1		6	65000		7
	ST	3	DFO	55		bbl	5.922							

millickk:
I would prefer to enter Gross Generation in this column, and enter Net Generation in the next column

3. Please address the comment above concerning entry of Gross Generation then Net Generation.

4. The Megawatt hours from FirstEnergy's generators are listed Sales for Resale on Schedule 6, since we are part of the PJM ISO. As an employee of the competitive generation business I do not have access to the data needed to complete the table below, from Schedule 7. I believe that my access to this information would be in violation of FERC's Code of Conduct if I did have access to this information. I would strongly suggest that this information not be required as part of the EIA-923 data submittal.

Annual Retail Sales, Revenue, and Number of Customers - complete one grid for each State where customer(s) are located.				
STATE: ________	Residential	Commercial	Industrial	Transportation
Retail Sales (megawatthours)				
Revenue (in thousand dollars)				
Number of Customers				

Thank you,

Ken Millick

May 20, 2013

Ms. Rebecca Peterson
U.S. Department of Energy
U.S. Energy Information Administration
Forrestal Building
1000 Independence Avenue, S.W. Washington, DC 20585

Submitted via email to ERS2014@eia.gov

Re: Proposed Energy Information Administration Form 930 Balancing Authority Operations Report, 78 Fed. Reg. 14521 (Mar. 6, 2013)

Dear Ms. Peterson:

Chugach Electric Association, Inc. (Chugach) appreciates the opportunity to comment on this proposed new reporting requirement and the accommodation relaxing the May 6, 2013 comment deadline. Although Chugach is the largest of the electric power generation and transmission entities on the interconnected Alaska Railbelt electric power system, it is quite small by comparison with most generating and transmitting utilities in the contiguous lower 48 states (Lower 48). In 2012, Chugach had 462.6 MW of installed generation capacity, owned or leased 539 miles of transmission line and sold 2,606 GWh of energy, primarily to its member-owners. The Alaska Railbelt interconnected electric power system currently has three control areas—Chugach, Anchorage Municipal Light & Power (ML&P), and Golden Valley Electric Association, Inc. (GVEA) located in Fairbanks, Alaska. Chugach's generation and transmission control area covers most of the Kenai Peninsula (where Homer Electric Association, Inc. (HEA) is located), Anchorage (exclusive of ML&P's control area) and north to Teeland including the Matanuska/Sustina Valley areas (where Matanuska Electric Association, Inc. (MEA) is located). HEA and MEA may form their own control areas over the next two years after they are no longer primarily supplied with electric power by Chugach.

Summary

Chugach can understand the interest in agglomerating data already being separately collected for systems that are largely interconnected in the Lower 48 but would like to wait to see how that process works, what effort is required and what value it produces in the Lower 48 before considering whether to impose the same or similar information gathering burdens on Alaska Railbelt utilities. Chugach estimates that setting up a system for automatic disclosures for Chugach's system would require 5 to 10 days of initial work, several hours of follow-up monitoring/system revisions during each of the initial months and then approximately 40 hours per year of monitoring, maintenance and reporting. While this burden is not massive, it is significant for a company of Chugach's size. The Energy Information Administration (EIA) has not adequately articulated the potential uses and value of data gathered from Alaskan utilities through the Form 930 process either for Alaskans or for the nation. Chugach has not learned of and cannot conceive of any particular prospective use for the data produced that would return value commensurate with the monetary and opportunity cost of routinely gathering the data. For these reasons, Chugach recommends that the EIA wait to see how the new information gathering project works in the Lower 48 before considering gathering similar information from the Railbelt of Alaska.

Specific Comments

If, notwithstanding Chugach's contrary recommendation, the EIA moves forward with a Form 930 approach, Chugach has the following recommendations and comments directed to several of the specific provisions outlined in the notice published in the Federal Register.

Periodicity

Regardless of whether it may have value in the Lower 48, Chugach does not see value in requiring hourly information for its control area. Though hourly reports would be more burdensome it is perhaps more important to note that hourly reports are more likely to occasionally present inaccurate data. Requiring the reports 10 minutes after each hour is likely to contribute to inaccurate data as well.

Daily reporting may contain fewer errors than hourly reports but will be less reliable than monthly data. Because the utilities in the Railbelt do not have a need for the data organized in the way required by the proposed Form 930, utilities will naturally be disinclined to perform active quality control because it produces no value for Chugach's members. Because EIA has not articulated clear reasons or potential uses for the data it seeks Chugach cannot say for certain, but it may be that EIA's information needs can be met adequately through annual or monthly reporting.

The 7:00 a.m. Eastern Time deadline for daily reports would be extremely burdensome. Chugach recommends that EIA either pick a universal time that is convenient to all reporting time zones or make the deadline at a convenient local time such as noon, local time.

Day ahead and interchange data

Chugach already publishes its day ahead schedules to other Railbelt interconnected utilities. There are frequently deviations from these schedules. Information about the actual historical operation of the system – including interchange - is also available to utilities interconnected to the Railbelt system through access to SCADA data. Chugach does not see the value to be gained from Form 930 reports in these areas.

Penalties

The combination of extremely exacting and frequent reporting burdens proposed in the Form 930 reporting system make it highly likely that even utilities acting in good faith and expending appropriate efforts at compliance will nevertheless frequently fail to supply all of the information required on the strict deadlines with unfailing accuracy. It is extremely poor public policy to set up a reporting system where good faith compliance efforts are almost certain to expose reporting utilities to civil and criminal penalties. Even recognizing that the EIA would typically not use civil and criminal enforcement, this would vest far too much unfettered discretionary authority in the federal officials. Unless this issue is resolved, Chugach is adamantly opposed to the new Form 930 reporting proposal.

Conclusion

Because the Railbelt interconnected system is relatively simple by comparison to Lower 48 systems, at this time it is difficult to see that useful perspective, analytical opportunities or new insights would be gained from Form 930 reports. Chugach recommends waiting to decide whether to implement Form 930 data gathering in Alaska. This will allow Alaskan utilities and the EIA to watch and learn from any Form 930 data gathering that is implemented in the Lower 48 before considering whether and how gathering similar information from the Railbelt of Alaska might usefully integrate into that larger effort.

Sincerely,

CHUGACH ELECTRIC ASSOCIATION, INC.

Lee Thibert
Senior Vice President, Strategic Planning & Corporate Affairs

May 6, 2013

Ms. Rebecca Peterson
Energy Information Administration
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Forrestal Building
1000 Independence Avenue, SW
Washington D.C. 20585

RE: Comments on Energy Information Administration (EIA) Agency Information Collection Extension with Proposed Changes

Dear Ms. Peterson:

The National Mining Association (NMA) appreciates the opportunity to provide comments on EIA's electricity information collection 3-year extension and proposed changes (*Federal Register* Notice, March 6, 2013, Volume 78, No. 44, Page 14521).

NMA represents the interests of the nation's coal and non-fuel mineral producers; coal and mineral transporters; mining and mineral processing machinery and equipment manufacturers and suppliers; energy consulting firms and financial institutions that serve the mining industry. Its coal producing members and those members dependent on the coal industry use the data collected in the electricity surveys for market and trend analysis and for forecasting. The electric power sector represents more than 90 percent of coal's market. Complete, timely, reliable and publicly available data on electricity is important to the coal industry as well as the public and private sectors for sound business, energy and environmental policy decisions.

NMA is generally in favor of data transparency for EIA historical data unless the reporting requirements include economically sensitive data or its collection causes significant respondent burden. While we do favor transparency, we recognize that companies consider information pertaining to commodity price, CIF value or sales value and other information depending on survey sample size to be sensitive competitive information. We maintain that release of such information could be damaging and lead to under-reporting and could lead to reported data of limited value.

We appreciate EIA's efforts to include additional survey questions on plant and distribution system reliability, smart meter and smart grid information, plant construction costs, wind and solar plant characteristics, emissions control systems and ash pond conditions. We are in favor of fair and even collection and reporting/release of all primary energy and electricity sources. However, in an era of increasingly tight agency budgets, the additional burden hours and burden costs may eventually result in the elimination or curtailment of collection and reporting of some of EIA's core electricity and other vital energy information. The elimination of the *Annual Energy Review* report this year may be a recent example of this.

Regarding the various proposed survey question additions, we recommend electric survey forms include a series of options for users where applicable rather than free form answers. We also suggest further use of validity checks in the case of form EIA-923 (Schedule 2, Cost & Quality) to more accurately match the supplying mine to the fuel supplier name unless stated as brokered.

Again, we appreciate the opportunity to offer these comments.

Sincerely,
/s/ Leslie Coleman

Leslie Coleman
Assistant Vice President, Statistical Services
National Mining Association
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202-463-9780

Comments of the Northwest Balancing Authorities

May 6, 2013

Via E-mail to ERS2014@eia.gov

Ms. Rebecca Peterson
U. S. Energy Information Administration
U. S. Department of Energy

Re: Comments on Proposed Form EIA-930 "Balancing Authority Operations Report"

Avista Corporation ("Avista"), Portland General Electric Company ("PGE"), NorthWestern Energy, Puget Sound Energy ("PSE"), Seattle City Light, Chelan PUD, and Tacoma Power (collectively, "Northwest Balancing Authorities" or "Northwest BAs") appreciate the opportunity to make comments on the Energy Information Administration ("EIA") proposal to require that each Balancing Authority post its hourly demand, hourly next day demand forecast, hourly net generation, and hourly actual interchange to facilitate the understanding of real-time electric grid operations.

Background

Avista Corporation is an investor-owned utility engaged in, among other things, the business of generating, transmitting, and distributing electric power to wholesale and retail customers located primarily in Eastern Washington and Northern Idaho and transmitting power on behalf of third parties.

PGE is a public utility organized under the laws of Oregon, and is headquartered in Portland, Oregon. PGE provides electric services to residential, commercial, and industrial customers in the state of Oregon.

NorthWestern Corporation d/b/a NorthWestern Energy is an investor-owned utility and one of the largest providers of electricity and natural gas in the northwest quadrant of the United States, serving approximately 673,200 customers – 403,600 electric and 269,600 natural gas – in Montana, South Dakota and Nebraska. The company's headquarters are in Sioux Falls, S.D., with operational headquarters in Butte, Mt and Huron, S.D. The Company is listed on the New York Stock Exchange under the ticker symbol NWE.

Puget Sound Energy ("PSE") is a Washington corporation and wholly-owned subsidiary of Puget Energy, Inc., a holding company. PSE is an investor-owned public utility that provides retail electric and natural gas service in the state of Washington. PSE's retail and wholesale utility businesses include the generation, purchase, transmission, distribution and sale of electric energy, plus the purchase, transportation, storage, distribution and sale of natural gas.

Seattle City Light is a municipally owned electric utility that provides reliable, renewable and environmentally responsible power to nearly 1 million residents in Seattle, seven suburban cities and parts of unincorporated King County. The service territory is a dense, highly urban area with a large commercial load. About 92 percent of the utility's electricity comes from hydropower, and the utility has been carbon neutral since 2005. Seattle City Light is governed by elected Seattle officials and is primarily supported by customer revenues and surplus power sales.

Chelan PUD is a public utility district owned by its customers in Chelan County, Washington, and governed by a locally-elected Board of Commissioners. The utility owns and operates three hydroelectric projects and operates a balancing authority registered with the North American Electric Reliability Corporation (NERC) within the Western Electricity Coordinating Council (WECC). In addition to serving retail electric customers, Chelan PUD sells power into the wholesale electric market.

Tacoma Power is a consumer-owned utility, whose ratepayers are in the City of Tacoma and neighboring communities. Tacoma Power's mission is to provide our ratepayers with low cost power through optimization of our owned hydro system and participation in the wholesale market, while meeting regulatory requirements.

The Northwest BAs' Balancing Authority Areas ("BAAs") are located in the Northwest Power Pool, a region comprised of 19 individual BAAs that operate in a largely bilateral electric market. Market participants include independent power producers, consumer-owned utilities, investor-owned utilities, and a Federal Power Marketing Agency (Bonneville Power Administration).

EIA Proposal

The EIA has proposed new Form EIA-930 which is being evaluated, along with revisions to existing forms, under the Paperwork Reduction Act (PRA). The PRA requires the EIA to avoid unnecessary data collection, to minimize the burden of collecting data, and to handle confidential information with appropriate care. The PRA also requires data collections to be approved by the Office of Management and Budget (OMB) as meeting these requirements. The Northwest BAs encourage the EIA to revise its proposal to address our concerns and suggestions before submitting the proposal to OMB for review.

The EIA has proposed requiring Balancing Authorities (BAs) to post hourly operating data on a public website to "shed light on various operational dynamics important to integration of renewable energy sources and development of smart grid technologies and demand response."[1] The demand data is to be posted by 10 minutes after the operating hour and the forecast, generation, and interchange data is to be posted by 7:00 am Eastern Time the next day.

Balancing Authorities' Comments

Commercially Sensitive Data

A requirement to publicly post load and generation statistics creates significant confidentiality concerns because such information will reveal highly commercially sensitive data that could impact market prices. *Any party with access to the public website would have a picture of a Balancing Authority's proprietary short or long position, may be able to discern when plants are not operating, and may be able to derive generation dispatch costs*. In addition, the Balancing Authority's historical load and generation data would, over time, provide seasonal and annual historical trends that could be used in a commercially inappropriate manner in the electric markets.

For example, in the Northwest regional bilateral electric market, individual Balancing Authorities engage directly with other market participants. This is in contrast to RTO and ISO regions where the individual market participants are a subset of the broader RTO/ISO Balancing Authority or are BAs within an

[1] EIA Stakeholder Presentation, June 5, 2012, slide 16.

RTO/ISO market where they are able to engage in a more anonymous manner.[2] This is important because information considered sensitive for individual Balancing Authorities operating in a bilateral market would not necessarily be considered sensitive for BAs operating in an RTO or ISO market. When the data requested by EIA is provided by each BA individually, as it would be in the bilateral markets, the data could be misused by other market participants to garner unfair commercial advantage because of bilateral market dynamics. In other words, because of market clearing mechanisms in place within an ISO, reporting hourly load data would not negatively impact the ability of a BA located inside that ISO to achieve the lowest possible energy price. However, in a bilateral market, where purchasing and selling parties interact directly and not through a market clearing mechanism, public disclosure of near real-time system data would reveal highly sensitive commercially advantageous information, thus allowing the seller/buyer to benefit at the expense of another party. For these reasons the Northwest BAs object to making Balancing Authority hourly operating data public and encourage the EIA to solicit additional input from the industry, including Reliability Coordinators, to appropriately evaluate the proposal. The Edison Electric Institute (EEI) comments regarding public disclosure of the data EIA proposes to collect echo these concerns.

The Northwest BAs propose that collecting aggregate Regional Reliability Coordinator information instead of localized BA information would provide more abstract data and protect the BAs participating in bilateral markets while achieving EIA's ultimate goals. At a minimum, EIA should recognize the sensitive nature of this information and defer to existing confidentiality agreements.

Near Real-time Reporting Proposal

Reporting demand data within 10 minutes of the end of the reportable hour is not practical and may not report accurate data. Some data, such as dynamic schedules from remote generation facilities, must be updated from estimated values to actual values within 60 minutes after the end of the flow hour as outlined in the Western Electricity Coordinating Council ("WECC") Regional Business Practice for dynamic scheduling.[3] In addition, many Western transmission providers have posted business practices that allow changes to dynamic schedules up to the 168th hour past the hour of flow. A Balancing Authority's final load calculations may include such dynamic schedules. Therefore, a requirement to post within 10 minutes of the end of the reportable hour may not provide the best available data.

Duplicative Reporting

Load and forecast data provided on a monthly or daily basis is sufficient for the EIA to use in educating policymakers and the public in basic electric system operations. The load and forecast data is used by transmission providers to calculate their Available Transmission Capacity. Jurisdictional transmission service providers are already required by the Federal Energy Regulatory Commission ("FERC") to post their underlying load forecast assumptions and their actual peak load on their Open Access Same Time Information System ("OASIS") on a daily basis.[4] This data is available to a jurisdictional transmission provider's customer base and could be made available to the EIA. In addition, under FERC Order 771,

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[2] Requirements for certain RTO and/or ISOs to post near real-time data in many cases is based on regulatory or regional legislative requirements that may not reflect, or even have considered the commercial sensitivity of the data. EIA's assumption that the data are not commercially sensitive is overreaching. Quite the opposite can be true based on the market structure in which a BA participates.

[3] INT-008-WECC-RBP-1 "Dynamic Schedule e-Tagging Requirements", 6-14-2007

[4] *Preventing Undue Discrimination and Preference in Transmission Serv.*, 118 FERC ¶ 61,119, P 413 (2007) ("Order No. 890"), *order on reh'g*, 121 FERC ¶ 61,297 (2007) ("Order No. 890-A"), *order on reh'g*, 123 FERC 61,299 (2008) ("Order No. 890-B"), *order on reh'g*, 126 FERC ¶ 61,228 (2009) ("Order No. 890-C"); *order on reh'g*, 129 FERC ¶ 61,126 (2009) ("Order No. 890-D").

BAs are required to ensure that the FERC has access to electronic tags (e-Tags) used to schedule the transmission of electric power interchange transactions in wholesale markets. This data is available to the EIA and interested parties with the proper execution of a Non-Disclosure Agreement (NDA).

Several entities (Reliability Coordinators, the North American Electric Reliability Corporation ("NERC"), Public Service Commissions, and now the EIA) require similar data from BAs. To minimize both the burden and the impact to reporting BAs, the Northwest BAs suggest that the EIA employ the existing data to accomplish its objective. The Northwest BAs agree with EEI's comments that the type of data EIA proposes to collect would be far less burdensome to obtain from existing sources, if EIA needs the information, than for the EIA to create Form EIA-930.

Cost Considerations

EIA's proposed requirement to publically post operational data on an hourly basis would create an incremental cost for Balancing Authorities that are also Load Serving Entities. Therefore, retail end users would ultimately pay that incremental cost in their retail rates. Net energy for load (system demand) and the day-ahead demand forecasts as provided under FERC Order 890 to the WECC Regional Reliability Coordinator are sufficient to illustrate a Balancing Authority's load variability and regulating margin requirements and should be sufficient to accomplish EIA's goals without the need to publicly post additional commercially sensitive and confidential information. Access to the information via an appropriately executed Non-Disclosure Agreement with the Regional Reliability Coordinator would provide EIA with sufficient data granularity, ensure data consistency across all Balancing Authorities, and mitigate the cost burden that would be imposed on BAs by providing the data as requested in the Form EIA-930 survey.

Meeting the proposed data posting deadlines would involve automation of data transfer through a secure interface that would require storage, maintenance and management. The Northwest BAs are also concerned that a requirement to post hourly data would involve the purchase of particular products or tools to comply. Accordingly, there would likely be significant cost associated with compliance with EIA's proposal. Because neither the web address nor the standard format proposed is specified, the Northwest BAs cannot provide the EIA with an assessment of the burden to comply with the proposal. The EIA should expand upon and communicate the benefit and burden of its data collection proposal.

Conclusion

Requiring a Balancing Authority to post hourly operational data in near real-time inappropriately requires the public dissemination of commercially sensitive information (particularly in bi-lateral markets) that, under other reporting regimes, is protected information. The combination of both load and generation information at the Balancing Authority level, even if provided historically, is commercially sensitive information and is entirely proprietary. The understanding of basic electric system operations that the EIA seeks can be provided with existing, less-granular system operating data at the Balancing Authority level, subject to an appropriate Non-Disclosure Agreement. Such information is already provided to other agencies and, therefore, a new requirement to provide such information is duplicative, creates additional burden on the Balancing Authority to maintain and manage the data, and, ultimately, creates additional costs that must be borne by retail customers. The Northwest BAs urge the EIA not to post Balancing Authority hourly operating data on a public website and further request that the EIA not impose duplicative reporting requirements[5].

[5] Interfacing with an internet address to automatically transfer data raises concerns about cyber-security in general, and implementation of the appropriate protections to mitigate security risks also has an associated cost.

Respectfully submitted,

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Another concern is the risk of failure in an automated data transfer and the procedure to remedy such a failure. Additionally, Balancing Authority reliability risks may be subject to discovery by malicious actors through the public posting of hourly operating data.

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Peterson, Rebecca

From: mstatema@comcast.net
Sent: Friday, March 15, 2013 1:35 PM
To: ERS2014
Subject: EIA reporting changes.

Dear Rebecca
Received the notice of changes coming for the 860 and 923 reports and the to be aded 930 report. The changes seem to be bordering on making the reporting so detailed as to be onorous. Collecting detailed information might be helpful to EIA, but what burden does this place on the reporting company. Some of the detail would be difficult to even reconstruct or be able to respond correctly to. We want to cooperate to any reasonble extent possible, but it seems like the "reasonable" threshold may have been violated with these changes.
Marlin Statema

May 6, 2013

Ms. Rebecca Peterson
U.S. Department of Energy
U.S. Energy Information Administration
Mail Stop EI-23
Forrestal Building
1000 Independence Ave., SW
Washington, DC 20585

Submitted via e-mail to: ERS2014@eia.gov

Re: EIA Reporting Proposal

Dear Ms. Peterson:

On March 6, 2013, the Energy Information Administration ("EIA") requested comments on the proposed three-year reauthorization of forms EIA-63B, EIA-411, EIA-826, EIA-860, EIA-860M, EIA-861, EIA-861S, and EIA-923, and the creation of form EIA-930.[1]

This letter provides the comments of the National Rural Electric Cooperative Association ("NRECA") on the EIA's proposal. NRECA is the not-for-profit, national service organization representing 905 rural electric systems which provide central station electricity to more than 42 million consumer owners in 47 states. Of the approximately 905 rural electric systems, 65 are generation and transmission (G&T) cooperatives and 840 are distribution cooperatives.

Form EIA-63B: No comments

Form EIA-411: On Schedule 7, Part A, Annual Data on Transmission Line Outages for AC Lines, EIA is proposing on the transmission line sustained outage section of the form to have a new voltage category: below 199kV. The *Federal Register* notice states that this change will make the form consistent with the expansion of the Bulk Electric System ("BES") definition requested by FERC and specific recommendations from NERC. The new BES definition includes facilities at 100kV and above for reporting. Importantly, it also includes a process for identifying "exceptions" specifically for radial lines that make-up the preponderance of cooperative-owned lines above 100 kV. NRECA suggests that the EIA directly coordinate with NERC on this effort as has been done in the past to assure consistent reporting with the developing BES criteria and eliminate duplicative efforts to the extent possible in order to minimize this added burden to our members.

Form EIA-826: No comments

Form EIA-860: Schedule 5 seeks to add new questions on generator construction and financing costs. Generator construction costs are required for units greater than 25 MW of nameplate capacity that are in the planning, construction, or testing phase. This data request is redundant to the excellent job the

[1] Energy Information Administration, 78 Fed. Reg. No. 44 (proposed March 6, 2013) Page 14521.

EIA currently does at monitoring and projecting these costs today. Asking respondents to provide their cost projections, and regular revisions of their cost projections, creates a substantial data reporting burden that will provide little or no useful benefit. EIA should narrow its focus to collecting easily reported data that does not require estimates of future performance. In addition, Schedule 5 also requires respondents to report their financing costs associated with building a new power plant. This is an important competitive issue. The availability of this information can cause competitive harm to respondents. The EIA should abandon its plans to add new questions on construction and financing costs.

Form EIA-860M: No comments

Form EIA-861: Regarding Schedule 4, Part A, Sales to Ultimate Customers, Full Service, EIA is proposing to add questions about "rate decoupling." NRECA requests to see more on the questions in advance of incorporating these questions.

With respect to Schedule 6A, respondents are asked to estimate future savings and program costs resulting from energy efficiency programs. EIA should narrow its focus and only ask respondents to report actual data and not require estimates of future performance.

Regarding Schedule 6, Part C, Dynamic Pricing Programs, EIA proposes to enhance related questions. Five (5) different types of rates are requested. NRECA suggests that EIA simply ask if the electric utility offers such programs (Yes or No).

With respect to Schedule 6F, these additional proposed questions add to an already increased time burden for completing the Form-861. Moreover, the layout to Schedule 6F is confusing and is an indicator that reported information will not be useful, creating an extra burden with no apparent added benefit to the electric industry. NRECA believes reporting should be limited only to respondents that use IEEE Standard No. 1366.

EIA also proposes a requirement by entities using the Form-861 to report by state and balancing authority. We support this.

Form EIA-861S: EIA could achieve reductions in its data collection burden by eliminating the following schedules for those 1,100 utilities: Green Pricing, Net Metering, Demand-Side Management, Advanced Metering, Distributed and Dispersed Generation. We encourage the EIA to revise the EIA-861S so as to include the reporting of annual retail sales, revenues, and customers to Ultimate Customers (Bundled). This would be preferable to adding new areas of data collection and it would preserve a global reporting of annual sales, revenue and customer data that has been a hallmark of the EIA's uninterrupted data sources for decades.

The EIA also proposes a requirement by entities using the Form 861S to report by state and balancing authority. We agree.

Form EIA- 923: As a fundamental fairness issue, NRECA would propose that any information collected from one segment of the industry should be collected from all participants involved in that segment. Regarding EIA-923 Power Plant Operations Report, NRECA supports EIA's proposal to begin collecting data on retail sales made by power plants that normally sell wholesale. These retail sales go unaccounted for since independent power producers are not required to complete the EIA-861 where utilities report retail sales. This will close a reporting gap and provide a more complete and accurate portrayal of the disposition of electricity.

<u>Form EIA-930</u>: proposes to collect four new categories of information from Balancing Authorities ("BAs") on an hourly basis. Respondents will be requested to post hourly demand data at a web address in a standard format within ten minutes of the end of the reported hour. Respondents will also be requested to post demand, demand forecast, net generation and actual interchange data in a standard format by 7 am E.T. the next day. This data will be made available to the public. EIA states that the primary purpose of the proposed survey is specifically designed to minimize the burden on electric system operators. The EIA further states that the BAs already have in place the means for posting some of the data requested by the proposed survey.

In 2012, NRECA and other stakeholder trade associations commented extensively to the EIA on this proposal.[2] The detailed comments are attached for your review.

In summary, the comments suggest the EIA has not sufficiently explained the need for the volumes of data it proposes to collect. The North American Electric Reliability Corporation ("NERC") and the Federal Energy Regulatory Commission ("FERC") are responsible for ensuring reliable operation of the nation's electric transmission system and have the competitive and proprietary information they need to do that job without the EIA collecting the proposed new information. Moreover, both FERC and NERC have the data management systems in place to provide the appropriate protections to this data.

The proposed changes to the EIA-930 will result in a substantial data reporting burden on BAs which are responsible for ensuring electricity demand and supply remain in balance in real time. A requirement to compile and provide daily and hourly data to the EIA on a near real-time basis will involve additional costs in BA time, personnel, and other resources to the extent that it could potentially hamper the ability of BAs to perform their core real-time system operator tasks. Moreover, the reporting of this data in near real-time may seriously disadvantage utilities seeking to ensure adequate generation to meet their load at a reasonable price. This proposal may potentially facilitate the exercise of market power against smaller load-serving BAs. There is also significant concern that the data could contain critical infrastructure information that could potentially aid terrorists in targeting high volume intertie lines. For these reasons, NRECA encourages the EIA not to proceed with this proposal. If the proposed changes to the Form-930 are implemented, the EIA should explicitly identify its efforts to minimize the workload to BAs, the risks of loss of data confidentiality, market-power, and security concerns.

Sincerely,

Mike Ganley
Director, Strategic Analysis
NRECA

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[2] EIA Reporting Proposal: Balancing Authority Hourly Operating Information, American Public Power Association, Edison Electric Institute, Electric Power Supply Association, and the National Rural Electric Cooperative Association, September 14, 2012.

September 14, 2012

Stan Kaplan
Director, Office of Electricity, Renewables, and Uranium Statistics
William Booth
Senior Electricity Advisor
U.S. Energy Information Administration

U.S. Department of Energy
1000 Independence Ave., SW
Washington, DC 20585

Submitted via e-mail to: Stan.Kaplan@eia.gov, William.Booth@eia.gov, ERS2014@eia.gov

Re: EIA Reporting Proposal: Balancing Authority Hourly Operating Information

Dear Messrs. Kaplan and Booth:

The American Public Power Association ("APPA"),[1] Edison Electric Institute ("EEI"),[2] Electric Power Supply Association ("EPSA"),[3] and National Rural Electric Cooperative Association ("NRECA")[4] (jointly, "the Trade Associations")[5] are writing to provide the following input on the Energy Information Administration's ("EIA's") preliminary proposal to collect four new categories of information from Balancing Authorities ("BAs") on an hourly basis. We appreciate EIA's willingness to discuss the proposal with the Trade Associations recently and this further opportunity to provide input on the proposal.

[1] APPA is the national service organization representing the interests of over 2,000 not-for-profit, publicly owned electric utilities throughout the United States

[2] EEI is the association of the nation's shareholder-owned electric utilities, international affiliates, and industry associates world-wide. EEI's members represent approximately 70 percent of the U.S. electric power industry.

[3] EPSA is the national trade association representing competitive power suppliers, including generators and marketers. Competitive suppliers, which, collectively, account for 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally responsible facilities. EPSA seeks to bring the benefits of competition to all power customers. The comments contained in this filing represent the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.

[4] NRECA is the not-for-profit national service organization representing approximately 930 not-for-profit, member-owned rural electric cooperatives, including 66 generation and transmission cooperatives that supply wholesale power to their distribution cooperative owner-members.

[5] Trade Association members file the vast majority of the data collected by EIA in the agency's electric industry survey forms and bear the burden of providing that information. Thus, we have a direct interest in this matter.

Several member companies and staff of the Trade Associations participated in EIA's June 7 and July 26, 2012 WebEx briefings, during which EIA outlined its proposal to collect the following data on a daily basis or potentially (for demand data) even on an integrated, hourly basis from U.S. BAs in an hourly format: net generation, net energy for load (system demand), day-ahead forecasted demand, and actual interchange with all directly interconnected BAs.

Upon notification of the proposal, a number of the Trade Associations contacted their respective member companies, all of which either operate or participate in BAs, to determine potential concerns with the proposal. The Trade Associations also followed up with EIA staff to explore the potential need for this information and to convey concerns that the Trade Associations' members have been raising about the proposal.

The following is a summary of Trade Association members' concerns:

1. EIA has not explained the need or otherwise provided a "business case" for the volumes of data it proposes to collect except to say the agency wants to provide information to the public about the operation of the electric markets. Yet EIA staff concedes that no one has been asking for the information and that EIA does not need the information for direct regulatory or enforcement purposes. The North American Electric Reliability Corporation ("NERC") and the Federal Energy Regulatory Commission ("FERC") are responsible for ensuring reliable operation of the nation's electric transmission system and have the information they need to do that job without EIA collecting the proposed new information.

2. Furthermore, the Trade Associations have raised concerns about the substantial burden of providing this proposed information to EIA. This burden will fall in particular on BAs, which are responsible for ensuring that electricity demand and supply stay in tight balance every moment of the day. EIA staff has discounted the burden, saying the staff thinks much of the new information is already collected as part of "business as usual." But compiling and providing the information to EIA will involve additional costs in BA time, personnel, and other resources to verify, correct, and submit the data on a daily and/or hourly basis, thus hampering the ability of the BAs to perform their core real-time system operator tasks. The BAs simply should not face this added burden, absent good cause.

3. The Paperwork Reduction Act requires federal agencies to justify the need for the information they collect and to minimize the burden of collecting the information the agencies do need. 44 U.S.C. sec. 3506. Similarly, Executive Order 13563, issued by President Obama on January 18, 2011, requires agencies to "propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs" and to tailor agency regulations "to impose the least burden on society, consistent with obtaining regulatory objectives."

4. Yet as noted above, EIA in this case has not explained the need for the proposed new hourly data, so there is no clear benefit to EIA from collecting the information. The Trade Associations, representing nearly all of the respondents who provide information to

EIA on the agency's electric survey forms, have stated that the proposed new reporting requirement clearly would impose additional burdens upon their membership and BAs.

5. EIA is proposing to collect the new hourly data on a real-time or close to real-time basis. Until now, FERC has collected only one of the four proposed sets of hourly data, on the FERC Form 714, and has done so just once a year at a broader planning-area level rather than at the more discrete BA level. The prospect of providing real-time data at a BA level on a daily or even hourly basis raises commercial, security, and confidentiality concerns.

6. In particular, at a BA level, such real-time or near real-time posting of hourly demand, generation, forecast, and intertie information can provide details about the availability of specific generation that may seriously disadvantage utilities seeking to ensure adequate generation to meet their load at a reasonable price. In addition, this proposal may facilitate the potential exercise of market power against smaller load-serving BAs.

7. There also is a significant concern that the data could contain critical energy infrastructure information ("CEII") in certain situations or for certain Regions. For example, the proposed intertie information could help terrorists target high-volume intertie lines whose disruption could seriously harm the country's integrated electric system.

8. Furthermore, BAs do not necessarily have proprietary rights to disclose the data to EIA and may face concerns about having the proper consent to share the data and how the data will be protected, especially if it is to be posted publicly as (near) real-time data.

9. The distinction between providing the data on a lagged next-hour or next-day basis does not alleviate these confidentiality concerns. If EIA proceeds with its proposal, a minimum time lag of 4 – 6 months needs to be built into the process of providing the data, which should be collected no more frequently than once per quarter.

10. Public disclosure of these operating data files will do little to further public understanding of the country's electric system and how it works. In fact, all the concerns previously stated over confidentiality and critical energy infrastructure information are increased if the data are to be posted publicly. Real-time information could be misconstrued in public policy debates if data from a single point in time are mistakenly represented as a trend, for example.

For these reasons, the Trade Associations encourage EIA not to proceed with the proposal to collect the proposed new four sets of integrated, hourly data. At a minimum, EIA should identify clear reasons why the agency needs the data. Moreover, with submitting hourly or daily data streams compared to either a single annual submittal or four quarterly submittals, there could be a substantial burden on both industry and EIA as the data collection agency. If the EIA proposal is implemented, efforts to minimize the workload to BAs and to address the confidentiality, market-power, and security concerns we have raised herein need to be included in the implementation plan.

We appreciate the opportunity to provide comments on EIA's proposal to collect Balancing Authority Hourly Operating Information.

Sincerely,

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May 8, 2013

To: Rebecca Peterson
U.S. Energy Information Administration

From: Patricia A. Hoffman PH
Assistant Secretary
Office of Electricity Delivery and Energy Reliability

Subject: **Office of Electricity Delivery and Energy Reliability (OE) Comments on proposal to create EIA-930**

Thank you for the opportunity to provide comments on the proposed U.S. Energy Information Administration (EIA) forms to go into effect in 2014. In particular we would like to offer comments on the newly proposed EIA-930, Balancing Authority Operations Report.

We strongly support EIA's proposal to collect hourly information on actual transmission system utilization. We further encourage EIA to make the majority of these data publicly available, possibly on a different schedule than is proposed in the current EIA-930 instructions. Public reporting of these data would improve the effectiveness of our work in several areas, including the triennial National Electric Transmission Congestion Studies, Interconnection-wide Transmission Planning, and DOE-funded smart grid technology grants. We believe public reporting of these data can be accomplished without exposure of Critical Energy Infrastructure Information (CEII).

Preparation of National Electric Transmission Congestion Studies

The data that would be collected via the proposed EIA-930 form would provide important and much-needed input to DOE's triennial National Electric Transmission Congestion Study (Congestion Study), a report that is to identify major transmission constraints and congestion across much of the United States. These studies are required by EPAct 2005 (P.L. 109-58), and the law intends for them to provide much of the basis for possible decisions by the Secretary to designate specific geographic areas as National Interest Electric Transmission Corridors (National Corridors). Accurate, detailed information about transmission system utilization is essential to reaching factual findings about congestion.

To date, our ability to prepare these studies has been significantly hampered by the lack of public information on how the U.S. transmission system is actually used. Prior DOE Congestion Studies have been criticized for any reliance on data not in the public domain. A minimum requirement for developing well-founded future Congestion Studies is to have information publicly available on actual hourly flows between Balancing Authorities (BAs). Therefore, **we support EIA's draft EIA-930 that would collect this information, and recommend that EIA make these data publicly available.**

Further, because some Balancing Authorities have very large geographic footprints, information about transmission usage within Balancing Authorities would be valuable in producing future Congestion Studies. **We encourage EIA to consider collecting and making publicly available information on transmission utilization within Balancing Authority footprints in future surveys.**

<u>Frequency of making flow data publicly available</u>

While we require publicly available data on actual transmission utilization for the Congestion Studies, these data would not have to be available in near real-time or at frequent intervals. For our purposes it would be sufficient to have quarterly reporting of hourly flows, submitted one to two months following the close of a quarter. A time lag in making these data public would both allow time for data validation and reduce the likelihood of misuse of the data (e.g., disruption of real-time operations). Because of this, **we recommend EIA consider making these data publicly available quarterly, with a reasonable (one- to two-month) lag.**

<u>Data needed by OE are not CEII</u>

Our requirements for public information on transmission system utilization do not require public dissemination of Critical Energy Infrastructure Information (CEII). Actual flows between and among Balancing Authorities represent the aggregation of flows over many individual transmission assets. These aggregate flow values do not reveal potentially sensitive information about the utilization of specific physical transmission assets. Additionally, our recommendation to delay reporting months after the actual events substantially reduces the likely usefulness of the information for purposes of disrupting real-time operations.

We realize that certain Balancing Authorities have limited interconnection with other areas, for instance generation-only Balancing Authorities. Actual flows from these particular Balancing Authorities might be deemed commercially sensitive if placed in the public domain. These flows are not as important in assessing congestion, however, as are flows between and among Balancing Authorities with both generation and loads. Therefore, **we recommend EIA consider exempting generation-only Balancing Authorities from reporting on form EIA-930 in order to protect potentially sensitive information.**

Other OE activities that would benefit from Balancing Authority data

The Congestion Study is just one of the activities OE undertakes to improve the energy systems in the U.S. The effectiveness of other federally-funded activities we manage would be enhanced by the availability of public information on transmission system utilization, including the following:

- OE is managing $80M in American Recovery and Reinvestment Act (ARRA) funding to promote interconnection-wide transmission planning, and it will also continue its support for transmission planning at the regional and sub-regional levels. In the Western Interconnection, information on actual transmission system utilization is made publicly available today for selected paths. This information is relied on routinely to validate and calibrate the analysis models used to evaluate the impacts of planned transmission projects. OE believes that making such information available for all major paths would be beneficial. Similar information is not publicly available, however, for the Eastern Interconnection. Consistent information on transmission system utilization, collected and made publicly available by EIA, will significantly advance the validity, credibility, and public acceptance of regional transmission planning activities in both Interconnections.

- OE is also managing $4.5B in ARRA funding to install smart grid technologies to improve the operation of the nation's power system. Some of this funding is specifically directed to the deployment of advanced grid monitoring technologies that will enable more reliable operation as well as higher utilization of existing transmission systems. Consistent information on transmission system utilization, collected and made publicly available by EIA, will enable better measurement of the value of investments in grid reliability and efficiency.

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May 6, 2013

Ms. Rebecca Peterson
Energy Information Administration

Submitted by email: ERS2014@eia.gov

Dear Ms. Peterson:

Please accept these comments by the American Public Power Association (APPA) in response to the Energy Information Administration's (EIA) solicitation of comments on the proposed three-year reauthorization of forms EIA-63B, EIA-411, EIA-826, EIA-860, EIA-860M, EIA-861, EIA-861S, and EIA-923, and the creation of form EIA-930. Notice of the opportunity to comment was published in Vol. 78, No. 44 of the *Federal Register* on March 6, 2013.

APPA represents the interests of the nation's approximately 2,000 nonprofit, publicly owned electric utilities. APPA member systems file several of the forms listed in the *Federal Register* notice. Several larger public power systems must file the monthly EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions." All public power systems file sales and revenue information, either on form EIA-861, "Annual Electric Power Industry Report," or the short form, EIA-861S. Publicly owned utilities that operate generating capacity are required to supply information on EIA-860, "Annual Electric Generator Report," and EIA-923, "Power Plant Operations Report." Additionally, 36 public power systems serve as Balancing Authorities and would therefore have to complete the new form EIA-930, "Balancing Authority Operations Report."

APPA's comments are directed principally at those forms that most directly impact its members. As such, APPA does not address the changes to forms EIA-63B, EIA-411, EIA-826, or EIA-860M.

EIA-860

APPA supports most of the proposed changes to form EIA-860. These changes help to consolidate the form, dropping questions that are either not germane or provide little value in assessing the electric industry. For example, the elimination of questions regarding the plant's geographic coordinates removes an item many respondents don't know and which provided little utility to begin with. Collecting the name of the plant's balancing authority instead of its regional transmission organization (RTO) or independent system operator (ISO) is also a useful change. EIA has also proposed eliminating several other superfluous questions while tailoring the survey so that it focuses on plant operation issues of greater interest.

APPA recommends a slight change to the menu selection under "Entity Respondent" on Schedule 1 of the revised form. There are several types of municipally owned electric utilities, including political subdivisions of the states. Under the proposed revision, there is no option for political subdivision, but instead only “muni.” Since some political subdivisions would be uncertain which box to check, APPA recommends that the “muni” option be expanded to “muni, including political subdivision.”

On Schedule 5, respondents must provide generator cost information for recently completed units (except for small wind units). On Schedule 5A, operators of coal, nuclear, and petroleum coke units greater than 25 MW of nameplate capacity must also provide costs for units that are either in the planning, construction, or testing phase. As indicated in the instructions, this includes units that are in the process of receiving permits and regulatory approval, as well as nuclear units that have applied for a COL from the Nuclear Regulatory Commission. These units could be years away from being completed. Cost estimates for these units are likely to change dramatically, especially for units in the early stages of development. These estimates will not provide useful information to those attempting to gauge the true cost of power industry capital requirements and the costs of new capacity. Utilities may also have different methodologies for producing these estimates, thereby providing data of little comparative value. Therefore, EIA should only ask for financing and cost information for units that have come on-line in the data year.

Both Part A and B of Schedule 5 ask respondents to report financing costs, but EIA does not provide any guidance on what is included in financing costs. Do total financing costs include government grants, tax benefits, and other types of financing? As currently worded under the proposal, respondents would have to provide total construction costs exclusive of “financing and any government grants, tax benefits and other incentives.” Respondents then must furnish total financing costs, and so it is unclear whether those grants and other incentives must be included in that total. Furthermore, EIA has not explained the purpose of breaking up cost estimates into financing and other costs, nor has it shown what additional statistical value is gained by such a breakdown.

EIA-861

Many of the proposed changes to form EIA-861 will streamline the survey and produce data that are reflective of the trends within the electric industry; however, some of the new questions and schedules provide little statistical value and would unduly burden survey respondents.

APPA supports EIA’s decision to eliminate the Green Pricing Schedule as, at this time, not enough entities are engaged in green pricing to justify the burden of collecting this information. EIA should revisit this question when this form is being considered for re-approval in three years’ time.

APPA also supports the revisions to Schedules 6C and 6D related to dynamic pricing and advanced metering. These changes reflect the continued advance of these types of programs in the electric industry while providing needed clarity to the existing questions. At the same time, these questions are limited enough in scope so as not to overly burden respondents.

Many of the revisions to Schedules 6A and 6B related to energy efficiency and demand response programs would help make the forms slightly less complicated for respondents. The layout of each schedule and the division between types of programs and the types of costs provide clearer distinctions as to what is being asked.

Other changes to Schedule 6 are repetitive and/or contribute little overall value. EIA received a number of comments and suggestions from industry experts for form revisions, but this does not mean that those suggestions are appropriate questions for EIA to ask on this form. A number of these questions are too detailed for the purposes of collecting easy to understand, consistent data without placing an undue burden on respondents. In many instances, EIA failed to distinguish between necessary information that serves a useful public purpose and data that are highly unique to certain situations and which are more appropriate for consultants performing cost/benefit analyses for utility clients.

These revisions would also increase the overall time it takes to respond to the survey. The estimated time burden for completing the form is currently nine hours per respondent, and that is estimated to increase to 11.23 hours. This is a small but significant extra burden on utilities, and may under-estimate the actual added burden.

Some of this extra burden is due to complicated nature of some of the questions being asked. The sections on incremental life cycle savings (Schedule 6A, lines 3 and 4) and incremental life cycle costs (Schedule 6A, lines 7 and 8) ask users to estimate future savings and program costs due to energy efficiency programs. In other words, respondents are being asked to take data they may or may not already have and perform a calculation on it to arrive at a summary statistic. Instead of being asked to provide historic data such as total accumulated savings, survey participants must take an extra step and provide what amounts to modeling data that might be unique to the utility.

EIA has stated that these proposed changes are being made to improve the consistency of responses. Considering that utilities might have varying methodologies to determine life cycle savings and costs, these changes would only lead to even more inconsistent data as utilities provide information that is based on fundamentally different assumptions and calculations. As such, the resulting data would not be comparable, calling into question the analytical value of any studies based on the data.

Furthermore, EIA has not explained how these calculations demonstrate the reach of energy efficiency programs. The life cycle information does not convey program advances and industry savings. Meanwhile, the weighted average life calculation is touted as a “key metric to the economic comparison of energy efficiency activities and other options.” Such evaluations should be made by utilities and other implementers of energy efficiency programs who might have different ways of measuring value or benefits. EIA should narrow its focus to collecting easily reported data that does not require estimates of future performance.

EIA has also proposed adding two new schedules dealing with distribution system information and system reliability. These extra schedules and questions add to an already increased time burden for completing form EIA-861. This extra burden also comes with no added benefit to the electric industry as many of the questions on Schedules 6E and 6F offer no meaningful insight into system reliability.

Many municipally owned utilities do not employ computerized outage management systems nor calculate the traditional IEEE 1366 Indices. The effort to capture the data and implement a reliability management program to collect data on a limited number of outages would become a very costly and time consuming burden for these utilities. EIA should make very clear up front that utilities that do not collect the data and calculate SAIDI and SAIFI do not have to report on these schedules.

The layout of Schedule 6F causes further confusion. Respondents may select to complete either Section 1 of Schedule 6F if they calculate SAIDI and SAIFI in accordance with IEEE 1366-2003, or Section 2 if they calculate SAIDI and SAIFI via another method, *or* they merely check box 13 indicating that they don't calculate SAIDI and SAIFI at all. Although EIA is presumably attempting to assist utilities by offering them choices that best represent calculation methods that they are using (if any), this adds a layer of complexity to the form. The fact that EIA must offer this choice calls into question the benefit of asking respondents for this information since it is unlikely to be consistent across respondents.

A much more compressed version of Schedule 6F would alleviate the burden to respondents and produce more consistent data. EIA could consolidate Schedule 6F from two sections to one by asking at the outset if these statistics are calculated according to IEEE 1366 standards. The consolidated Schedule 6F could remove the most extraneous questions and include those that have the most public value. For instance, questions 1-2 and 3-4 about SAIDI and SAIFI values (with and without major events included), question 12 regarding advanced notification of outages, and question 15 (Schedule 6F2) on how momentary interruptions are defined would be appropriate for form EIA-861.

Schedule 6E collects Distribution System Information. While EIA has not provided a compelling reason to collect this information, APPA encourages EIA to ensure that the schedule is easy to fill out, the questions are simple, and the notice includes the statement that utilities that do not collect this information do not have to complete this schedule (in accordance with EIA's statement in the Federal Register Notice). In line with these parameters, APPA recommends that EIA eliminate questions 4A through 4D.

As EIA moves forward in considering these revisions to form EIA-861, it must keep the Paperwork Reduction Act (44 U.S.C. 3501) in mind. Two of the most important purposes of the act are:

> (1) minimize the paperwork burden for individuals, small businesses, educational and nonprofit institutions, Federal contractors, State, local and tribal governments, and other persons resulting from the collection of information by or for the Federal Government;
>
> (2) ensure the greatest possible public benefit from and maximize the utility of information created, collected, maintained, used, shared and disseminated by or for the Federal Government.

EIA must ensure that the additional information it is requesting is designed to help agencies avoid the burden of additional paperwork and directly provides a public benefit. By adopting APPA's recommendations on form EIA-861, EIA would maximize the insight it gains from information collected while minimizing additional burden imposed on small entities' already full work schedules.

As a general matter, EIA should clarify the definition of customer in its forms, particularly form EIA-861. Most utilities use billable meters as their baseline, but it would be helpful if EIA provided further guidance so as to avoid confusion. Along those same lines, utilities need further guidance on how to report transportation customers and whether or not to use the number of meters or the number of customers when reporting this figure.

EIA-861S

Many of the changes that apply to the form EIA-861S apply to form EIA-861, and therefore APPA re-iterates comments made above. Most of the small utilities that complete this form are unlikely to have very intricate smart meter programs, so simple yes-no questions for the Schedule 6 questions related to Net Metering and Demand-Side Management are all that are needed at this time.

APPA notes that the questions asked on Schedules 6C and 6D are similar in scope to the ones asked on the longer form EIA-861. These include questions about the number of customers served by dynamic pricing and advanced metering and other detailed questions about dynamic pricing programs. As stated above, very few of these entities have either AMR or AMI installations. Approximately 20 percent of utilities with fewer than 100,000 Megawatt-hours (MWh) in sales in 2011 had any customers with AMR, and only about 3 percent of these entities had any customers with AMI. With EIA cutting back or even eliminating certain forms due to budget constraints, it is incongruous to expand these surveys where it is likely that few respondents will have any meaningful information to report.

While Schedules 6C and 6D ask for sector-specific information, smaller utilities are no longer required to report sector-specific revenue, sales and customer information, and on Schedule 4A they are required to enter only **total** sales, revenue, and customers by state and Balancing Authority. It is inconsistent to ask for detailed information with regard to Advanced Metering while eliminating requirements to submit data that all of these entities must possess and do track. One of the purposes of this shorter form is to ease the reporting burden for small utilities, but these proposed schedules would add to the burden. Additionally, the lack of basic sector-specific information on sales and customers makes it much more difficult to perform any full-scale analysis with the Advanced Metering and Dynamic Pricing data procured from EIA-861S, as there would be no point of reference to perform comparative analysis. For instance, knowing the number of residential customers with AMI at a utility without knowing the total number of residential customers served by the same utility provides no basis to distinguish between pilot programs versus utility-wide deployment. EIA should therefore either expand Schedule 4A to include sector-specific information, or reduce the amount of information collected on Schedules 6C and 6D.

EIA-923

Most of the changes to form EIA-923 are fairly minor, yet these changes are generally helpful and eliminate information that is no longer relevant, while also consolidating the form and simplifying it for respondents. The question about electricity provided under tolling agreements provides a useful layer of information that more fully accounts for how entities procure electricity. The modified Schedule 8C streamlines elements that had previously been captured in Schedules 8C, 8E, and 8F. This appears to be a much more user-friendly format that should moderately reduce the reporting burden.

EIA-930

EIA has proposed the creation of a new survey of hourly electric power operating data from Balancing Authorities. This proposal would create an excessive time burden for Balancing Authorities and would make sensitive information publicly available in near real-time.

The proposal would direct Balancing Authorities to submit hourly demand data on a web portal within ten minutes of the end of the reporting hour, and post previous day hourly information daily by 7:00 a.m. the next day. Posting this data in real-time or near real-time creates serious confidentiality concerns, and a one-day lag in posting requirements does little to alleviate these concerns. It is also possible that posting this information could lead to the exercise of market power against small load serving Balancing Authorities. Additionally, this increases the likelihood of releasing data that contain critical energy infrastructure information in certain situations or regions. EIA states that the one-day lag in reporting will mitigate these concerns because it will prevent competitors from seeing if a utility is short on generating capacity. But market conditions may not change rapidly enough to make the previous day's data irrelevant, and so the lag isn't long enough to prevent some entities from taking commercial advantage of the most recent data. At a minimum, EIA should increase the lag between the reporting period and the time when this data will be posted.

Aside from these confidentiality issues, EIA has not indicated how this data is necessary to enhance public understanding of the electric system, or why it is necessary for the public to have access to this data in such a short timeframe. Reliability Coordinators have access to real-time data, as do entities and regulatory bodies that use the real-time data to monitor the electric system for market manipulation and other problems. EIA is an agency that was established to provide information to the public for analysis of the energy industry. It has not provided a business case for why it must have access to near real-time Balancing Authority hourly data to carry out its core agency mission.

EIA downplays the burden of data duplication, stating that respondents already collect this information or it is already known to them in the course of their normal business operations. While it is certainly true that these agencies most likely track this data in one way or the other, the extra time to then turn around and report this information still creates a burden that while perhaps comparatively small in each particular instance, cumulatively takes a toll. The Balancing

Authorities will need to verify, correct, and submit the data each hour and every day, thus distracting them from performing their core real-time system operator tasks.

Additionally, APPA questions the accuracy of the estimated reporting burden. EIA estimates the total annual number of total responses per year to be 39,055. EIA presumably arrives at this number by multiplying the number of Balancing Authorities (107) by 365 days. This implies one report per day. EIA does not seem to account for the number of hourly responses. Multiplying the number of balancing authorities by the number of days and the amount of hours in a day, the actual number of responses would be 937,320.

Similarly, EIA estimates the annual reporting hour burden to be 7,534 hours in the first year, and then 3,254 hours in the subsequent years. This amounts to ten minutes daily per each respondent in the first year, and five minutes daily thereafter. Once again, this estimate appears to assume a single daily response by each Balancing Authority, which does not account for the hourly reports that each of these entities would be required to file. Therefore the annual reporting burden would likely be significantly higher than what EIA estimates.

Conclusion

It is a difficult task to balance the need for more information while not creating an extra burden both to EIA staff and to the utility respondents who must complete these surveys. In many cases, EIA has struck just the right balance, revising the forms so that they provide useful information while not overly taxing the time of the survey respondents. To the extent that certain revisions would increase respondent burden with no concurrent increase in public benefit, APPA asks EIA to consider eliminating or consolidating those sections.

EIA should also consider the budgetary and workforce impact of some of these changes, both for those responding to the surveys as well as for the agency itself. EIA will have to devote already strained resources to ensuring the accuracy of reported information. Staff would have to monitor hourly reports from those submitting data on the EIA-930. Staff will also have to measure the accuracy of calculations being made on EIA-861. Though there is no doubt that EIA staff has the technical competency to perform this type of quality control, they should not be hindered from performing their core duties in the interests of checking data that is not essential to the public interest.

Thank you for the opportunity to comment. Should you have any questions concerning these comments, please do not hesitate to contact me. I may be reached at (202) 467-2969 or pzummo@publicpower.org.

Sincerely,

/s/ Paul Zummo

Paul Zummo
Research Analyst
American Public Power Association

Peterson, Rebecca

From: Garris, Pete <Garris@WAPA.GOV>
Sent: Monday, May 06, 2013 7:07 PM
To: ERS2014
Cc: Clark, Kim; Buck, Darren; Johnson, Steven; Linke, Lloyd; Moulton, Ron
Subject: Form EIA-930 form, ''Balancing Authority Operations Report

Rebecca

The EIA is creating an overlapping (redundent) reporting process. BAs already provide this information to the RC, FERC (FERC 714) and on their (BA's) OASIS. Much, if not all of the requested information could be obtained directly from the Regional Reliability Organization's Relibility Coordinator (RC).

Two comments:
1) the EIA should consider importing the data directly from the RC a much more efficient and "cleaner" process. This should eliminate the imposition of additional system requirements, process requirements, security requirements and possible vendor support for BAs.
2) reporting of hourly information within 10 minutes after the previous operating hour appears to be unecessary, how would information provided on this time line would be of use to the EIA? This comment refers only to the timing of the information not the requested data.

Thank you for the opportunity to provide comments.
Pete Garris

Peterson, Rebecca

From:	Robert Burns <burns.7@osu.edu>
Sent:	Monday, May 06, 2013 3:47 PM
To:	ERS2014
Cc:	Jan Beecher
Subject:	Comments in Response to OMB Review and Comment at 78 Fed Reg. 14521
Attachments:	pastedGraphic.pdf

We support the proposed changes to EIA-861 Schedule 6, Parts E and F that would add questions dealing with distribution system reliability and outage information that would be collected by a combination of state and balancing authority. This information is currently not collected in any consistent manner that allows comparative analysis. Yet, the information is necessary for effective Federal Energy Regulatory Commission and the state public utility regulatory commission oversight of transmission and distribution level reliability policy. The Federal Energy Regulatory Commission and the state public utility commissions need consistent data by a combination of state and load balancing authority so that they can determine what policies work and what actions to take on a consistent basis. In particular, the information is needed for regional transmission expansion planning at the regional transmission organization level as well as local distribution system upgrades by electric distribution cooperatives, municipal electrics, and state regulated local distribution companies. With such data, the Federal Energy Regulatory Commission and the individual state commissions can work together toward a systems approach to assuring electric reliability at a reasonable cost. Without consistent distribution outage data, rational and coordinated federal and state regulatory policies are not possible. Generally, see Robert Burns, *Regulatory Policies for Electricity Outages: A Systems Approach* (Columbus, OH, National Regulatory Research Institute, 07-07, August 2007) , especially figure 1 shown below.

Respectfully submitted,

Robert E. Burns, Esq.
Research Specialist
Center for Energy, Sustainability, & the Environment
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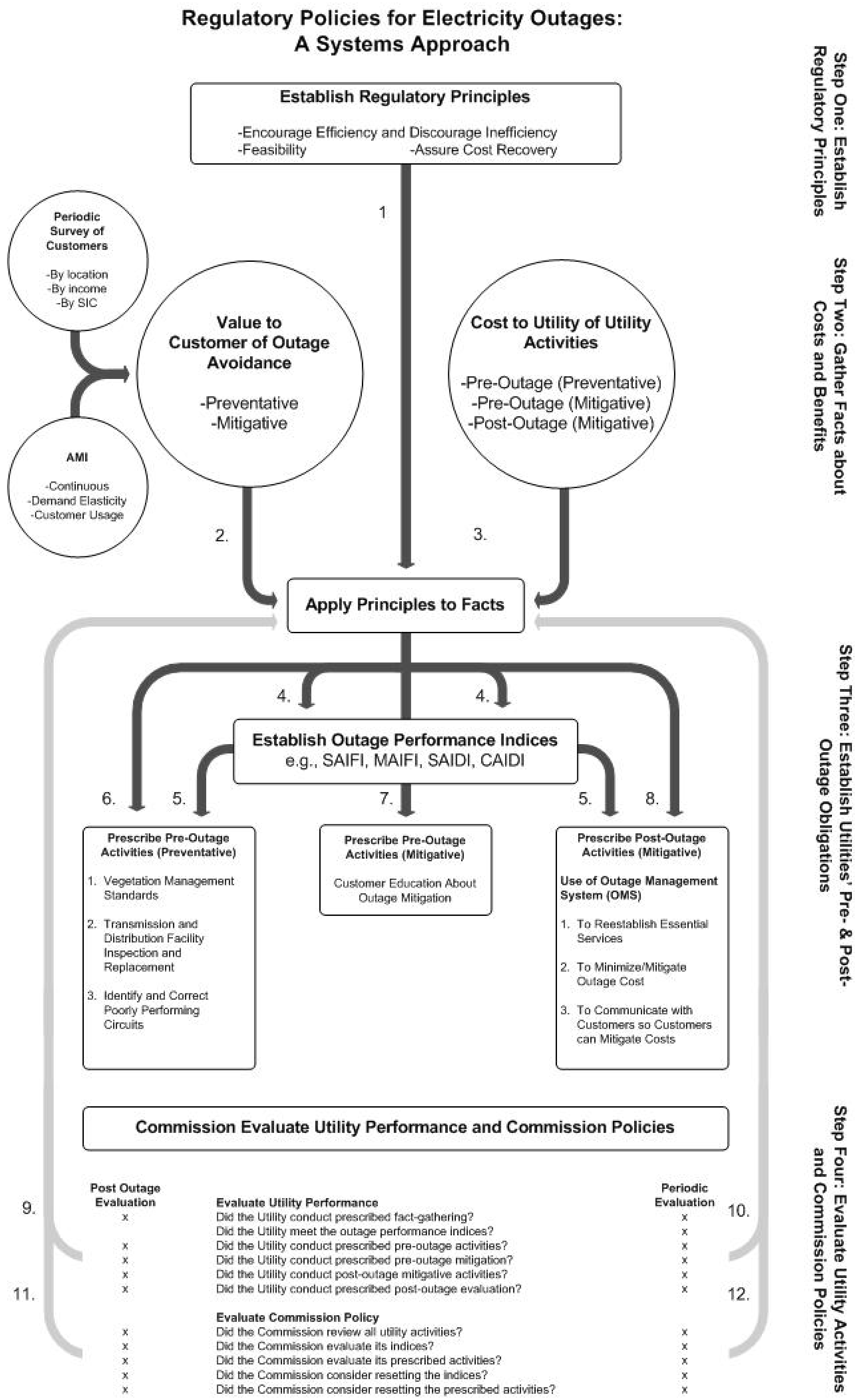

Fig. 1. Regulatory Policies for Electricity Outages: A Systems Approach

BEFORE THE ENERGY INFORMATION ADMINISTRATION

Agency Information Collection Extension with Changes	))	Proposed at 78 Fed. Reg. 14521

COMMENTS OF THE BONNEVILLE POWER ADMINISTRATION

The Bonneville Power Administration ("Bonneville") hereby submits the following comments on the proposal by the Energy Information Administration ("EIA") to modify its reporting requirements, specifically the proposed Form EIA-930, "Balancing Authority Operations Report".[1] Bonneville is a federal power marketing agency providing wholesale power and transmission services within the four state region of the Pacific Northwest and portions of neighboring states. Bonneville is also registered as a balancing authority with the North American Electric Reliability Corporation ("NERC"); consequently, Form EIA-930 directly affects Bonneville.

I. Introduction

EIA, in its proposal to create Form EIA-930, asked for comments on the necessity and burden of its proposed data collection; specifically, a) whether the proposed collection is necessary for EIA to properly perform its functions, including whether the information has practical utility; b) the accuracy of EIA's burden estimate; c) ways to enhance the quality, utility, and clarity of the collected information; and d) ways to minimize the burden of information collection on respondents.[2] Bonneville appreciates the opportunity to comment on these topics and submits the following for EIA's consideration.

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[1] Agency Information Collection Extension with Changes, 78 Fed. Reg. 14521 (proposed Mar. 6, 2013).
[2] *Id.*

II. Comments

A. The Proposed Collection is not Necessary for Proper Performance of EIA Functions, nor does it have Practical Utility for EIA

While the information EIA seeks is germane to its mission, EIA plans to collect the data in a manner that, given the functions EIA performs, is overly burdensome. EIA describes itself as "the statistical and analytical agency within the U.S. Department of Energy."[3] In this role, "EIA collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment."[4] Based on this description of its functions, EIA does not need real-time data; after-the-fact reporting is sufficient for analysis and policy development and less burdensome on reporting entities.

EIA's proposal requires balancing authorities to post data online for public viewing almost in conjunction with real-time, but EIA does not need the information in such a short timeframe to perform its functions. The collection proposal is not consistent with EIA's stated role as the agency that "collects, analyzes, and disseminates" energy information. This is particularly true of role of EIA's analytical role. Sound analysis requires adequate time to complete, which negates any value from receiving real-time data. Additionally, "sound policymaking, efficient markets, and public understanding of energy" do not require real-time data. They require concentrated study of a broad statistical base formed over time with large volumes of collected data.

Bonneville does not dispute that EIA can gain valuable insights by collecting and analyzing this information. But the burden of collecting the data in real-time (discussed below) outweighs any practical utility, to EIA or the public, of having the data in real-time.

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[3] EIA Mission and Overview, available at http://www.eia.gov/about/mission_overview.cfm.
[4] *Id.*

Additionally, the risk associated with transmitting real-time data outweigh any benefits EIA would gain.

B. The Burden Estimate is Inaccurate and Based on Incorrect Assumptions

There are several incorrect assumptions regarding the proposal's burden on responding balancing authorities. EIA has incorrectly determined the amount of time required to collect and submit the data, the ability of balancing authorities to automate the process, and that the submission is not duplicative.

EIA's hourly burden estimates are inaccurate, for both startup and ongoing reporting. The first-year estimate is 7,534 hours, which, after subtracting the estimated ongoing burden, leaves 4,280 hours to setup the reporting process.[5] This hourly requirement, on its face, would constitute a significant burden to any organization. If this value represents the total burden for all respondents, then the individual burden for each reporting entity becomes 40 hours. While 40 hours seems like a slight burden, Bonneville believes this value is inaccurate. It is overly optimistic to assume that an entirely new collection and reporting mechanism can be developed, tested, and implemented with only 40 hours of burden. EIA's estimate for ongoing reporting support is similarly incorrect. The ongoing burden estimate is 3,254 hours per year, which translates to roughly nine hours per day, assuming reporting would occur 365 days a year.[6] This level of cost and staff time to generate a single report would be very difficult to justify to ratepayers. If the estimated number of burden hours is the total for all respondents, then EIA's estimate becomes five minutes per day. This estimate, like the startup estimate, also appears non-burdensome but is inaccurate.

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[5] Agency Information Collection Extension with Changes, 78 Fed. Reg. at 14527.
[6] *Id.*

EIA estimates that there will be 39,055 total annual responses from 107 respondents.[7] This equates to 365 responses per respondent per year, or one response per day, but the reporting requirement involves submitting data after every hour. Presumably, the one response per day estimate comes from an assumption that the process will be automated. Data entry via web forms cannot be reliably automated, however, because HTTP (Hyper Text Transfer Protocol) is a stateless protocol. The automated, web form entry engines that Bonneville is aware of are generally custom-designed software. These applications are very sensitive to even minor updates to a web page and to HTTP communication failures. This software requires significant development time to trap common errors, and it has marginal reliability due to the application sensitivities mentioned earlier. Adding security protocols to protect sent data introduces even more complexity. Commercial products available to replace web form entry are largely focused on eliminating the need to request web pages.

Because of the difficulties associated with web form automation, reporting entities would need to input each entry manually, increasing the time required. Additionally, manual entry would require staff to be present for each entry. Regulatory reporting staff is currently available during regular business hours, but requirements for this report would require 7-day support. Bonneville's 7-day support staff consists of those critical to maintaining the electrical system, and those resources cannot be redirected to reporting responsibilities.

The requirement to utilize form EIA-930 also duplicates the efforts of current reporting requirements Bonneville has with its reliability coordinator. Bonneville submits the requested data to the reliability coordinator through the following automated transfers and web page accessible forms:

- 7-day load forecast, reported every eight hours to the reliability coordinator;

[7] *Id.*

- 3-day total interchange forecast, reported every eight hours to the reliability coordinator;
- Annual total interchange with each interconnected balancing authority, reported on Form FERC-714;
- 5-minute total generation by resource type, posted every five minutes on an external website;[8]
- 5-minute actual balancing authority load, posted every five minutes on an external website;[9]
- 5-minute actual total interchange, posted every five minutes on an external website.[10]

Bonneville suggests that EIA collect this data from the reliability coordinator to eliminate duplicative work and, as detailed below, to improve the quality and utility of the collection. Additionally, as described previously, EIA does not need near real-time data for statistical or analytical purposes, so the 8-hour reporting of this data to the reliability coordinator is adequate for performance of EIA's mission.

C. The Quality, Utility, and Clarity of the Information to be Collected can All be Enhanced if Reporting Entities do not have to Provide the Information so Close to Real-Time

Bonneville notes, as a preliminary matter, that the reliability coordinators already collect this data from balancing authorities—including smaller, generation-only balancing authorities—and they can most efficiently provide it to EIA in an aggregated and useful format. If EIA must collect the data from balancing authorities, those entities can increase the quality, utility, and clarity of the requested information if they are able to collect and transmit it on a less frequent

[8] BPA Balancing Authority Load and Total Wind, Hydro, Thermal Generation, and Net Interchange Near-Real-Time, available at http://transmission.bpa.gov/Business/Operations/Wind/baltwg3.aspx.
[9] *Id.*
[10] *Id.*

basis. By doing so, balancing authorities could more efficiently organize the requested hourly information. Rather than submitting the information as piecemeal data-points, balancing authorities would be able to collate it into meaningful blocks that would be more useful for statistical analysis. One bit of hourly information on demand, net generation, or net interchange is nearly useless for performing analysis or informing policymaking. These hourly data only become useful when they can be analyzed with data from other hours to examine trends, develop statistical models, or meet any other purpose for which anyone other than an electrical system operator would need the information. Since the hourly data is interdependent for analytical uses, it makes sense that the information would have more utility for EIA—while imposing less of a burden on responding balancing authorities—if it was provided on an aggregated basis.

The proposed collection would also be more useful, and more complete, if EIA collected data from all balancing authorities, including smaller, generation-only balancing authorities. EIA notes in its request for comments that information from these balancing authorities "is needed to provide comprehensive operating statistics."[11] EIA goes on to inquire "how to exempt these Balancing Authorities or limit their reporting while maintaining the comprehensiveness of the survey."[12] Generation-only balancing authorities must register as such with NERC, and they meet the same reliability requirements, including reporting to their respective reliability coordinators, as all other balancing authorities. If EIA's goal is to have a comprehensive survey of the power system operating statistics, then the query should include all parties that have an effect on the power system. An efficient way for EIA to accomplish its goal would be to collect the information from the reliability coordinators, who could create any necessary screens to

[11] Agency Information Collection Extension with Changes, 78 Fed. Reg. at 14527.
[12] *Id.*

protect generation-only balancing authorities. Alternatively, if EIA collects the information from balancing authorities, it should allow them to submit the data on a less-frequent basis.

D. The Collection Burden can be Reduced if Reporting Entities do not have to Provide the Information so Close to Real-Time and if the Process can be Automated Reliably

For the reasons outlined above, Bonneville believes the reliability coordinators can manage the data submission best. If EIA requires individual balancing authorities to submit the data, the burden will be smaller if the reporting frequency matches the timeline for reporting this data to the reliability coordinators. Employees who already organize the same or similar data for submission to other entities would be able to compile this information for EIA as part of their existing tasks, rather than as a new task. Again, Bonneville's concern is not with the collection of this data, but with the burdens created by the proposed submission format and timeline. Bonneville also recommends that a different mechanism be used for transmitting the data. As discussed above, web forms create issues with automation, human error in entering data, and increases time spent. Bonneville suggests EIA change the mechanism to an FTP (File Transfer Protocol) site, web service, e-mail, or other automatable protocol, as automation would decrease the reporting burden.

III. Conclusion

Because it is not necessary or practical for EIA to receive the proposed data so close to real-time, Bonneville recommends that EIA collect the data sought in Form EIA-930 on a less-frequent basis than immediately following the operating hour. EIA can accomplish this task best—and with the least burden on individual balancing authorities—by acquiring the data directly from the reliability coordinators. The reliability coordinators already collect this data from balancing authorities, including smaller, generation-only balancing authorities, and they can most efficiently provide it to EIA in an aggregated and useful format. Should EIA choose to collect this information directly from balancing authorities, it should adjust the reporting frequency to match the timeline for reporting to reliability coordinators. Additionally, EIA should revise the proposed reporting mechanism from a web form to a format more amenable to automation.

May 6, 2013.

Respectfully submitted,

/s/ Robert D. Davis, Jr.

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Peterson, Rebecca

From:	Reagan, Robert (Bob) R. <ReaganRR@ci.anchorage.ak.us>
Sent:	Monday, May 13, 2013 2:34 PM
To:	ERS2014
Cc:	Peterson, Rebecca; McArdle, Paul; Booth, William; Paul Jones (pjj@khe.com); Posey, James M. (MLP)
Subject:	ML&P Comments to EIA on Proposed Form 930

The Municipality of Anchorage d/b/a Municipal Light and Power (ML&P) submits the following comments regarding the Energy Information Administration's (EIA) proposed Form 930. Comment has also been solicited regarding the continuation of other forms, on which ML&P takes no position. ML&P's comments relate specifically to the application of Form 930 to utilities in Alaska, and should not be construed as a position on the value or burden of this form as applied to the rest of the country.

Comment has been invited on the following general topics:

(a) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall *[sic]* have practical utility;

(b) The accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

(c) Ways to enhance the quality, utility, and clarity of the information to be collected; and

(d) Ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology.

ML&P will comment on these issues in order.

(A) WHETHER THE PROPOSED COLLECTION OF INFORMATION IS NECESSARY FOR THE PROPER PERFORMANCE OF THE FUNCTIONS OF THE AGENCY, INCLUDING WHETHER THE INFORMATION SHALL *[SIC]* HAVE PRACTICAL UTILITY

ML&P is not sure exactly what the functions of the EIA are, and therefore cannot comment on whether the proposed collection of information in general is necessary for the proper performance of those functions. However, it appears that the proposed collection *from Alaska* is not only not necessary, it is applied in such a way that it will almost certainly not be useful. The information collected from Alaskan utilities will not be comparable to, and therefore will not be usable with (one hopes) the data collected from the rest of the United States.

For the contiguous 48 states, the survey appears to be designed to collect information from all Balancing Authorities, which would have the effect of reporting all of the demand and generation in those states with the apparent exception of one non-interconnected utility. In contrast, the proposed application to Alaska, would collect data from control areas (the equivalent in Alaska of Balancing Authorities in the lower 48), and from utilities that are not control areas (one of which is only 10MW!) and whose loads are included in the load of one of the control areas, and from one of Alaska's many electrically isolated utilities, chosen for no reason that is explained in the proposal. The question naturally arises, how does EIA intend to collate this data, and what meaning will users of the data be able to take from it? We also have to wonder how EIA will adjust its use of the data when existing control areas are absorbed into other control areas, or, as is more likely, respondents that are currently within an existing control area form their own control areas?

There is a reason that *ad hominem* legislation is frowned upon, and that reason applies equally to a situation like this. If EIA wishes to collect information from the individuals in a certain category (e.g. all entities that are responsible to match generation to load in a defined area), it should define the category and require response from all of the individuals that fall into that category, rather than trying to list individuals who may or may not fall into the relevant category. In this case, it seems that it would have been relatively easy to define by their attributes those entities from whom response should be required, and that is what EIA should have done.

Assuming that the issue of comparability is satisfactorily resolved, we must consider the more fundamental question of whether the collection of the information is necessary. The most troublesome aspect of the collection is not *what* information is collected, but *when* it is collected. The EIA has proposed that each of the utilities so honored be required to make 24 postings each day of hourly demand, each posting to be made within 10 minutes of the end of the hour, which could be as little as 3 minutes after the time when the respondent has the information available.

In describing its reasons for this requirement, EIA lists the following interested groups: other industry participants, policymakers, legislators, regulators, emergency and disaster response officials, entrepreneurs, economic analysts, industry researchers, and the public. ML&P finds it impossible to imagine that policymakers, legislators, regulators, economic analysts, industry researchers, or “the public” would have a legitimate need to know what the loads of these selected utilities were for the hour just past, so we are left with “other industry participants”, emergency and disaster response officials, and entrepreneurs as potential nearly-real-time users of the information. Of these, ML&P believes that “other industry participants” is a too vaguely conceived to merit any consideration. That leaves emergency and disaster response officials, and entrepreneurs.

With regard to emergency and disaster response officials, ML&P simply does not believe that load in the previous hour is useful information to anyone but the utility dealing with it in any disaster or emergency, particularly since the simple reporting of load imparts practically no information relating to the difficulty of meeting that load. ML&P believes that any disaster or emergency that actually affects the electrical grid will affect load *and/or capability* so significantly that load in the previous hour will be irrelevant. If that turns out not to be the case, there are only 6 utilities (currently 3 control areas) in the Railbelt, and one isolated utility in Juneau for which that information would have been made available through the EIA data collection program, and if the data ever becomes necessary, or even relevant, for a disaster or emergency response organization, it can easily be provided directly by the utilities. In discussion between the proposed Alaska respondents and EIA, ML&P does not recall that EIA was able to name a single emergency or disaster response organization that would make any use whatsoever of real-time load information in Alaska. If there were such an entity, the question would naturally arise, why would the real time information for AEL&P (the electrically isolated utility designated for this reporting requirement by EIA) be important enough to require AEL&P to respond, but the same information for other utilities of reasonably similar size not be important enough to require them to respond?

With regard to entrepreneurs, ML&P would remind the EIA that an electric power market of less than one gigawatt (the largest interconnection in Alaska, the Railbelt Interconnected System, is less than 1 GW) is going to have fewer entrepreneurial participants than a market of 100 GW or more. Because no market other than a spot market requires, or has any use for, load data in real time, the possibilities are still further restricted. ML&P does not believe that there are any entrepreneurs in Alaska that would make any use of real time data, and believes that EIA should wait until there is some evidence of a need for such data before requiring a subset of Alaska utilities to spend many thousands of dollars per year to make it publically available. If such a need ever does become apparent, EIA should put *some* thought into the question of which utilities should make the data available before imposing the burden on some of them.

(B) THE ACCURACY OF THE AGENCY'S ESTIMATE OF THE BURDEN OF THE PROPOSED COLLECTION OF INFORMATION, INCLUDING THE VALIDITY OF THE METHODOLOGY AND ASSUMPTIONS USED

The agency's estimate of the burden of the proposed collection of information *may* be acceptably accurate for the rest of the country, but it is wildly inaccurate for Alaska. Any reasonable estimate of the burden on persons or entities affected by a regulation must consider that burden in relation to the size or the economic power of the entity being burdened. EIA has apparently estimated the first year burden on the nation at 7,534 hours, which works out to 70 hours per respondent. For a respondent that controls thousands or tens of thousands of megawatts of load, and tens of thousands of gigawatt-hours of annual generation, that may not seem like much, but the average Alaska respondent would control about 150 MW of load and less than one thousand gigawatt-hours of annual generation. Whatever the burden is for the nation as a whole, it is **at least 40 times as high** compared to the size of the organization, for the respondents in Alaska, as explained in the following paragraph.

According to EIA Table 2.8 Retail Sales of Electricity to Ultimate Customers by End Use Sector, by State, 2011 and 2010, there were 3,749,846 GWH of sales to end users in 2011 for the nation. For Alaska, there were 6,320. If, as EIA seems to suggest in footnote 4 of the notice, the respondents in Alaska will account for about 75% of total end use in Alaska, the result for the respondents is about 4,740. EIA estimates first year burden at 7,534 (this comparison is the same for any estimate of total hours), hours for the 107 proposed respondents. If the Alaskan respondents could comply as efficiently as the rest of the respondents (which they will not be able to do because they do not currently post this information anywhere), the total burden for the 7 Alaska respondents would be 422 hours. For the nation, the burden per GWH would be 7,534/3,749,846 = 0.002 hours per GWH. For Alaska, the burden per GWH would be 422/4,740 = 0.089 hours per GWH. 0.89/0.002 = 44. (Burden per GWH in Alaska is 44 times as high as burden per GWH in the United States.) If the 17 Balancing Authorities of the Southwest Power Pool RTO merge, that ratio will increase to 52.

As mentioned in the paragraph above, this forty to one ratio would be valid only if the average burden per Alaskan respondent were equal to the average burden for all respondents. There is every reason to expect the burden to be higher for Alaskan respondents for two reasons: (1) the Alaskan respondents do not, in general, operate OASIS web sites, since even the largest market in Alaska, at less than 1 GW, is far too small to support any market that could be facilitated by such information, and (2) half of the proposed respondents are not control areas and therefore have no real need to even collect the required data.

The fact that no Alaskan utility is required to post data that could only come from SCADA in anything resembling real time means that Alaskan utilities do not need to post SCADA data to any outside accessible file transfer site. Considering the potential for mass destruction and casualties that could result from a cyber attack on utility SCADA systems, no utility should take lightly the prospect of connecting its SCADA to the internet in any way. ML&P estimates that its cost just for the hardware required to render such a connection acceptably secure would be more than $35,000. This cost alone is an order of magnitude larger than the 70 hours of labor that EIA estimates as the average first year cost for respondents in the nation as a whole, and presumably, ML&P would also have to devote at least the same 70 hours of programming labor into automating the EIA's new reporting requirement.

For utilities that are not control areas, and have no need to even develop the data that is being required, there would be all of the costs that the control areas would have to bear, plus all of the cost of compiling previously unneeded data.

For the reasons described in the two paragraphs above, the real comparison between the average burden for the nation as a whole and the burden imposed on the proposed Alaskan respondents would be much more dramatic than the forty to one ratio based only on size.

Finally, while ML&P is less concerned about the burden of a daily reporting requirement, as opposed to an hourly reporting requirement, the proposed requirement that the daily report be assembled between about 12:10 AM (when the required data would exist) and 3:00 AM (7:00 AM Eastern Time) each day is more than troubling. At the risk of appearing to harp on the size difference between the proposed Alaska respondents and the average respondent in the nation, ML&P suspects that the average balancing authority in the contiguous 48 states staffs its dispatch office with multiple dispatchers on a 24/7/52 basis. 150 megawatt utilities generally do not do that. ML&P, for example, has only one dispatcher on duty at night, and under some weekend and holiday conditions, and that dispatcher is responsible for both power and distribution. Adding a requirement to compile a report of the previous day's hourly demand, demand forecast, net generation, and net interchange (no interchange schedules?) between 12:10 AM and 3:00 AM each day, 365 days/year, could require costly revision of shift schedules, possibly including additional staff.

(C) WAYS TO ENHANCE THE QUALITY, UTILITY, AND CLARITY OF THE INFORMATION TO BE COLLECTED

EIA should start by determining exactly what it seeks to achieve with the collected information. ML&P is particularly confused by the proposal to solicit demand information both from control areas and from individual utilities operating within those control areas. ML&P would also like to know what the basis was for selecting the one respondent not in the Railbelt. ML&P would think that for the data to be useful there should be some organizing principle behind its selection and interpretation.

As mentioned above, ML&P believes that EIA should start by determining what purposes it seeks to serve by requiring this data from Alaskan utilities, and based on those purposes, determine what information should be reported, and define by their characteristics which Alaskan entities should respond.

(D) WAYS TO MINIMIZE THE BURDEN OF THE COLLECTION OF INFORMATION ON RESPONDENTS, INCLUDING THROUGH THE USE OF AUTOMATED COLLECTION TECHNIQUES OR OTHER FORMS OF INFORMATION TECHNOLOGY.

The most obvious way to reduce the burden on Alaska respondents of this data collection is to abandon the hourly posting requirement. ML&P believes that instead of being posted every hour, the same information could be posted daily, weekly, monthly, or even annually without seriously affecting the utility of the information. ML&P also believes that EIA should give some consideration to the size of the utilities on which it is making these demands. To ML&P, it seems particularly egregious that a 10 MW utility should face the same reporting requirements as a 20,000 MW utility. EIA should be mindful that the largest control area in the group named as respondents in Alaska is responsible for little more than 500 MW of combined load, but even that scale benefit is wasted by the requirement that three wholesale customers of that control area are also required to report hourly loads. It is possible that the largest two of the customers will form their own control areas, which may solve the problem of double counting inherent in the EIA's current proposal, but then the largest respondent will be responsible for only about 300 MW of load.

ML&P also believes that the requirement for a daily report of more extensive hourly data to be submitted by 3:00 AM the following morning should be abandoned. ML&P can see no justification for requiring this report to be submitted (by any respondent) before 7:00 AM local time.

CONCLUSION:

ML&P offers the following comments and recommendations:

(a) ML&P does not believe that a useful purpose will be served by requiring respondents in Alaska to post hourly demands within 10 minutes of the end of the hour. ML&P believes that the same information would be as useful if it were posted weekly or monthly.

(b) EIA's estimation of burden for Form 930 may be reasonable for the nation as a whole, but it vastly understates the burden on the proposed respondents in Alaska.

(c) Rather than naming respondents in Alaska, EIA should determine appropriate criteria defining which entities in Alaska must comply. ML&P would suggest that each control area in an interconnected system, and each electrically isolated system above a certain size should respond.

(d) Posting of hourly data for Alaska respondents should be weekly, or, preferably, monthly.

Robert R Reagan
Acting Manager, Regulatory Affairs
Anchorage Municipal Light & Power
1200 East First Ave.
Anchorage, AK 99501

(907) 263-5413 office
(907) 263-5888 fax

Comments on EIA-930 Balancing Authority Operations Report:

a) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency including whether the information shall have practical utility;

    We do not understand what function the agency needs this data to support. Requesting near real-time data within 10 minutes following the end of the reporting hour approaches real-time control of the electric system. Is this a function of DOE or is this a function for NERC and FERC? Without specific knowledge of what will be done with the data, it is difficult for us to determine whether the effort needed to collect the data and submit it to the agency is justified.

    Addressing the practicality of the data collection, entities are currently providing a goodly portion of this data to NERC in support of their situational awareness efforts. Rather than make an additional request of the Balancing Authorities, we would suggest that if DOE has a need for this type data that they obtain it from NERC. If this avenue is pursued, the issue of data sensitivity must be addressed. We feel that such data has an impact on the reliability of the Bulk Electric System (BES) as well as contains market sensitive information which could be used to the detriment of electric utilities. This data should not be made available to the general public.

b) the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

    We feel that the agency's estimate of the burden placed on each Balancing Authority is unrealistic and does not capture the true effort that will be required to respond appropriately. We do not know what went into the estimates that the agency has provided, but based on our experience with the effort that is required to collect new data or make changes to facilitate the collection of existing data in our control systems, we question whether the man-hours quoted by the agency for all 98 Balancing Authorities referenced are sufficient. While some of the data may be available, the timing of the submittal does not align with normal business hours. Requiring the data to be submitted by 0700 ET each morning, when traditional 8-5 staffing is not available, will require real-time operations personnel to support the effort. This could diminish their focus on real-time operation and could negatively impact the reliability of the BES. Additionally, once the formatting of the data is decided upon, a significant amount of effort will be needed to either manually submit the data on an hourly or daily basis as requested or manpower will be needed to develop automation techniques for data submittal.

c) ways to enhance the quality, utility and clarity of the information collected; and

Even if hourly data were available within 10 minutes after the end of the hour, the accuracy of that data is questionable at best. Typically this data is not considered final (accurate) until the following day to allow for any necessary adjustments. We again suffer because we don't fully understand how the agency is planning to use this data, but the accuracy of what has been proposed would lend any conclusions or results from studies to be questionable.

d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology.

We would encourage the agency to explore opportunities to take advantage of data that currently exists in other arenas such that the reporting burden could be totally eliminated for Balancing Authorities.

Other agency questions:

EIA requests comment on alternatives or supplements to the web posting requirement and the format for the posted data.

Again, we would suggest that the agency focus its efforts on utilizing the data that is currently available at NERC. It may be more efficient to address the requests by modifying existing reporting mechanisms rather than creating entirely new ones. We would further suggest that the agency move away from any reporting requests which could possibly impact real-time operations by delaying the turn-around time on any such requests.

EIA requests comments on how to exempt single generator Balancing Authorities or limit their reporting while maintaining the comprehensiveness of the survey.

As we have responded in other questions, we have concerns regarding the market sensitivity of this data. To exempt entities which may in turn use the data that is being submitted against those who are complying with the request is not comparable treatment of all the responsible entities. In this situation, if one Balancing Authority is required to submit the data, all should be required to submit the data.

List of commenters:

Lee Anderson	Lincoln Electric System
Mike Anderson	American Electric Power
Tim Brown	Grand River Dam Authority
Bob Flagle	Nebraska Public Power District
Sheldon Hunter	Sunflower Electric Power Corporation
Stephanie Johnson	Westar Energy
Bo Jones	Westar Energy
Tiffany Lake	Westar Energy
Dirk Ludwig	Nebraska Public Power District
Greg McAuley	Oklahoma Gas & Electric
Bill Nolte	Sunflower Electric Power Corporation
David Rhodes	Nebraska Public Power District
Robert Rhodes	Southwest Power Pool
Randy Root	Grand River Dam Authority
Bruce Samblanet	American Electric Power
Don Schmit	Nebraska Public Power District
Mike Stafford	Grand River Dam Authority
Carl Stelly	Southwest Power Pool
Joyce Summers	Grand River Dam Authority
Bryan Taggart	Westar Energy
Jessica Tucker	Kansas City Power & Light

LG&E / KU

May 6, 2013

Ms. Rebecca Peterson
U. S. Energy Information Administration
U. S. Department of Energy
Forrestal Building, Mail Stop EI-23
1000 Independence Avenue SW
Washington, DC 20585

Submitted by e-mail to ERS2014@eia.gov

Re: EIA electricity survey forms - "2014" triennial review – Comments requested at 78 Fed. Reg. 14521 (Mar. 6, 2013)

Dear Ms. Peterson:

Pursuant to the Energy Information Administration's ("EIA") invitation to provide written comments on the issues outlined in this Notice And Request For OMB Review And Comment issued on March 06, 2013 concerning creating the new Form EIA-930, "Balancing Authority Operations Report", Louisville Gas and Electric Company and Kentucky Utilities Company respectfully submit these comments.

Company Background

Louisville Gas and Electric Company and Kentucky Utilities Company (collectively, "LG&E and KU") are investor-owned public utilities supplying electricity and natural gas to customers primarily in Kentucky. LG&E and KU are fully owned subsidiaries of PPL Corporation. As owners and operators of interconnected electric generation, transmission and distribution facilities, LG&E and KU achieve economic benefits through operation as a single interconnected and centrally dispatched system and through coordinated planning, construction, operations and maintenance of their facilities. LG&E and KU are not members of a regional transmission organization ("RTO") or an independent system operator ("ISO"). LG&E and KU are registered with NERC as a Balancing Authority.

LG&E and KU Concerns with Proposed Form EIA-930

LG&E and KU welcome the opportunity to provide comments to the EIA Notice dealing with the creation of Form EIA-930. While LG&E and KU fully support the comments filed by

Edison Electric Institute, there are several issues with EIA's proposed form that LG&E and KU would highlight as areas of particular concern to LG&E and KU

First, because EIA's proposal may not allow time for posted data to be validated, the initially reported data may contain inaccuracies. It is not clear to LG&E and KU what liability may arise from the posting of data that upon subsequent verification is discovered to be incorrect. In addition, EIA does not address whether updates would be required after data is initially posted.

Second, much of the information proposed to be provided by utilities is already collected by other federal agencies. EIA's proposal appears to address only the timeliness with which this information is made publicly available, however, EIA has not explained why that timeliness is necessary. Collecting hourly demand data in order to post it within ten (10) minutes after the hour is not currently a uniform practice and thus the timeframes in which EIA expects the data to be made available add new and significant burdens to many utilities. Many utilities do not collect this data until well into the next operating hour. These utilities would have to invest significant resources to reconfigure existing data-collection systems. In addition, EIA does not address the consequences utilities would face for simply not being able to produce the data in the manner and within the timeframes proposed.

Third, EIA has provided little technical or commercial justification that would explain why provision of this information in the timeframes and formats proposed is necessary. EIA also fails to explain how the format EIA has proposed for providing the requested information has practical utility. EIA could get much of this information from those agencies which are already collecting it, and not impose additional costs upon utilities and ratepayers by requiring utilities to provide this information in the manner EIA proposes.

LG&E and KU believe EIA should first provide a sound basis as to why this data needs to be provided in the manner and within the timeframes proposed. A clearer articulation of what problems EIA is seeking to address would enable both EIA and industry to better determine the optimal way to provide needed data, whether that be directly from the Balancing Authorities or from other agencies to which the Balancing Authority has already submitted the data.

Respectfully submitted,

Robert Tallman, P.E.
Manager, Federal Regulation and Policy
LG&E and KU Energy, LLC
220 West Main Street
Louisville, KY 40202
Tel: 502-627-3414

Peterson, Rebecca

From:	Goza, Stuart L <slgoza@tva.gov>
Sent:	Monday, May 06, 2013 3:31 PM
To:	ERS2014
Subject:	TVA Comments regarding Form EIA-930
Attachments:	TVA Comments EIA-930 050613.docx

General Comments

TVA appreciates the opportunity to comment on the Form EIA-930 report, ‘‘Balancing Authority Operations Report’’. Because many DOE reporting obligations carry both civil and criminal sanctions for failure to provide data or for providing incorrect data, there must be an understanding that DOE is seeking hourly information within minutes of the time that it becomes available to the Balancing Authority (BA) in very raw form. There will be many cases during the day where the BA Operator will not be able to review the data appropriately before it is posted to the public website. Consequently, the data will not be of a high quality and will contain gaps and flaws.

TVA response to questions in the Federal Registry concerning EIA-930 Reporting:

(a) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility;

It is unclear what problem DOE is attempting to solve. As noted above, the data sought will be raw data that has not been adequately reviewed and trued up, thereby preventing any real comparisons between BAs. The gaps and flaws in the data will most likely raise additional DOE questions causing increased workload on the BA.

(b) The accuracy of the agency’s estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

TVA believes that DOE underestimated the burden associated with the data collection. Additionally, if there is an expectation that the data will be of high quality and readily available, DOE has significantly underestimated the workload. DOE estimates it will take approximately 75 man-hours per BA to set up and maintain this data stream. Because the data definition is not defined, most BAs will likely have to set up special processes to implement this requirement, TVA estimates that it will take 5-10 times that effort to set up the process and train operators on quality control actions.
The workload will vary significantly depending on the expectations regarding the quality of the data. If the data are acceptable “as-is,” and corrective actions can be taken on a “next business day” basis, the increased work load will not be as significant following implementation and initial orientation. If validated data are required, it will likely take another 300-1000 hours per BA annually to review the data before it is transmitted. This number range is based upon the size of the BA and the technology available. This estimate does not include troubleshooting time when there are problems with the data, time to respond to questions on data that is posted, etc.

c) Ways to enhance the quality, utility, and clarity of the information to be collected; and

Timing drives the quality of the data, with the quality decreasing with timing of receipt. Data provided 10 minutes after the hour will likely have inaccuracies. Data that has been through the NERC inadvertent accounting verification (end of the next business day) will be of higher quality. End of the month Settlements processes typically take up to close of business on the 15th of the next month to resolve remaining primary issues.

(d) Ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology.

The DOE suggested format is an unusual format. There should be a review of the suggested format with industry experts to enhance the collection process and accommodate DOE’s data needs. One suggested approach is to have a process where the EIA sweeps the data at specified times.

Stuart L. Goza, P.E.

General Comments

TVA appreciates the opportunity to comment on the Form EIA-930 report, ''Balancing Authority Operations Report''. Because many DOE reporting obligations carry both civil and criminal sanctions for failure to provide data or for providing incorrect data, there must be an understanding that DOE is seeking hourly information within minutes of the time that it becomes available to the Balancing Authority (BA) in very raw form. There will be many cases during the day where the BA Operator will not be able to review the data appropriately before it is posted to the public website. Consequently, the data will not be of a high quality and will contain gaps and flaws.

TVA response to questions in the Federal Registry concerning EIA-930 Reporting:

(a) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility;

It is unclear what problem DOE is attempting to solve. As noted above, the data sought will be raw data that has not been adequately reviewed and trued up, thereby preventing any real comparisons between BAs. The gaps and flaws in the data will most likely raise additional DOE questions causing increased workload on the BA.

(b) The accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

TVA believes that DOE underestimated the burden associated with the data collection. Additionally, if there is an expectation that the data will be of high quality and readily available, DOE has significantly underestimated the workload.

DOE estimates it will take approximately 75 man-hours per BA to set up and maintain this data stream. Because the data definition is not defined, most BAs will likely have to set up special processes to implement this requirement, TVA estimates that it will take 5-10 times that effort to set up the process and train operators on quality control actions.

The workload will vary significantly depending on the expectations regarding the quality of the data. If the data are acceptable "as-is," and corrective actions can be taken on a "next business day" basis, the increased work load will not be as significant following implementation and initial orientation. If validated data are required, it will likely take another 300-1000 hours per BA annually to review the data before it is transmitted. This number range is based upon the size of the BA and the technology available. This estimate does not include troubleshooting time when there are problems with the data, time to respond to questions on data that is posted, etc.

c) Ways to enhance the quality, utility, and clarity of the information to be collected; and

Timing drives the quality of the data, with the quality decreasing with timing of receipt. Data provided 10 minutes after the hour will likely have inaccuracies. Data that has been through the NERC inadvertent accounting verification (end of the next business day) will be of higher quality. End of the month Settlements processes typically take up to close of business on the 15th of the next month to resolve remaining primary issues.

(d) Ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology.

The DOE suggested format is an unusual format. There should be a review of the suggested format with industry experts to enhance the collection process and accommodate DOE's data needs. One suggested approach is to have a process where the EIA sweeps the data at specified times.

General Manager, Resource and Balancing Operations
(423) 751-8941

PowerSouth Energy Cooperative appreciates the opportunity to comment on the Form EIA-930 report, ''Balancing Authority Operations Report''. We have several concerns with the proposed data collection effort.

Some concerns PowerSouth has with the proposal are:

- The DOE is seeking hourly information within minutes of the time that it becomes available to the BA in very raw form. Many times, we will not have the data available by 10-minutes after an hour due to meter error, communication glitches, etc. Providing the data in such a way will lead to many errors and gaps with the data being provided.
- For a smaller sized BA such as PowerSouth, we are concerned by amount of work that will be needed to maintain the data with quality information and the potential sanctions. Most DOE reporting obligations carry both civil and criminal sanctions for failure to provide data or for providing incorrect data. We do not have the "back-office" personnel that larger BAs utilize to provide this type of data. With the current proposal, the responsibility of verifying and supplying the data will fall to the real-time System Operator whose job is to maintain the reliability of the Bulk Electric System and not be burdened by verifying and uploading data for the DOE.
- Making this data public, specifically load forecast data will expose market sensitive information. As a smaller sized BA, we are concerned that our next load forecast data could give a competitive advantage to others in the industry. We are concerned that if market participants can detect our next day load forecast if off, they could adjust energy pricing that would put us at a competitive disadvantage.

(a) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility;
This request appears to be a duplicate collection of data already received by other Federal Agencies. We suggest the DOE should investigate the possibility of using existing data received by other Federal Agencies.

(b) The accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

For PowerSouth's situation, we believe the agency grossly underestimated the burden associated with the data collection. The DOE estimates it will take roughly 75 man-hours per BA to set up and maintain this data stream. PowerSouth believes the effort to setup the process and train system operators, in our case, to verify and update the data required will take 10-15 times the man-hours above that being estimated by the agency. In our case, PowerSouth will have to set up special process to collect and provide the data. Being a smaller sized BA, the responsibility of verifying and updating the data will fall on the real-time system operator. One concern we have is the system operator will be removed performing their obligation of maintaining reliability of the Bulk Electric System in order to meet the data requirements proposed by the agency. Providing the requested data on a monthly basis by the 15th of the following month would be much more practical.

c) Ways to enhance the quality, utility, and clarity of the information to be collected; and

We believe collecting and providing the data on a monthly basis by the 15th of the following month will provide information that will be accurate and confirmed with neighboring BAs. This is the current timing method we use to checkout and true-up data with our neighbors.

(d) Ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology.

We would prefer the data to be uploaded to a secure DOE FTP site on a monthly basis where entities could deposit their data and the DOE would be able to retrieve and use the data as necessary for its purposes.

Peterson, Rebecca

From: Tony Braun <braun@braunlegal.com>
Sent: Monday, May 06, 2013 4:58 PM
To: ERS2014
Subject: Comments on Form EIA-930: Balancing Authority of Northern California

Ms. Rebecca Peterson
Energy Information Administration

Dear Ms. Peterson:

The Balancing Authority of Northern California (BANC) provides the following response to the Federal Register Notice issued on March 6, 2013, 78 FR 14521 (2013-03-06), seeking comments to the United States Department of Energy's Energy Information Administration (EIA), new Form EIA–930, ''Balancing Authority Operations Report." BANC supports the comments submitted by the American Public Power Association (APPA). BANC is greatly concerned that this new proposal will create an excessive time burden for Balancing Authorities and could make sensitive critical infrastructure and commercial information publicly available in near real-time.

The proposal would direct Balancing Authorities to submit hourly demand data on a web portal within ten minutes of the end of the reporting hour, and post previous day hourly information daily by 7:00 a.m. the next day. Posting this data in real-time or near real-time creates serious confidentiality concerns, and a one-day lag in posting requirements does little to alleviate these concerns. It is also possible that posting this information could lead to the exercise of market power by suppliers operating in wholesale markets, due to their ability to leverage demand and supply data to predict pricing and possible bidding behavior. EIA states that the one-day lag in reporting will mitigate these concerns because it will prevent competitors from seeing if a utility is short on generating capacity. But market conditions may not change rapidly enough to make the previous day's data irrelevant, and so the lag isn't long enough to prevent some entities from potentially gaining commercial advantage.

Aside from these confidentiality issues, EIA has not indicated how this data is necessary to enhance public understanding of the electric system, or why it is necessary for the public to have access to this data in such a short timeframe. Reliability Coordinators have access to real-time data to enable them to perform tasks critical to grid reliability. EIA is an agency that was established to provide information to the public for analysis of the energy industry. It has not provided a compelling case for why it must have access to near real-time Balancing Authority hourly data to carry out its core agency mission.

EIA downplays the burden of data duplication, stating that respondents already collect this information or it is already known to them in the course of their normal business operations. While it is certainly true that these agencies most likely track this data, Balancing Authorities will need to verify, correct, and submit the data each hour and every day, thus distracting them from performing core tasks of balancing loads and resources to ensure grid reliability. Additionally, APPA has raised valid questions about the accuracy of the estimated reporting burden. Hourly reporting burdens by all Balancing Authorities would appear to greatly exceed the total annual number of total responses of 39,055 per year.

In summary, BANC joins APPA concerns and opposition to the new Form EIA-930 as proposed, and is greatly concerned that the burdens of the proposed form EIA-930 will greatly exceed any benefits, and distract BANC's operators from performing tasks critical to system reliability.

Tony Braun

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U.S. Energy Information Administration
Independent Statistics & Analysis

FORM EIA-861

ANNUAL ELECTRIC POWER INDUSTRY REPORT

OMB No. 1905-0129
Approval Expires: 12/31/2016
Burden Hours: 11.23

Entity Name: ABC Company
Entity ID: 00000
Data Year: 2013

SCHEDULE 6. PART F. DISTRIBUTION SYSTEM RELIABILITY INFORMATION

State

SECTION 1: SAIDI and SAIFI in accordance with IEEE 1366-2003 standard

If your entity calculates SAIDI and SAIFI in accordance with IEEE 1366-2003 standard complete Section 1, if your entity calculates SAIDI and SAIFI via another method please complete Section 2. If your entity does not calculate SAIDI and SAIFI please check the box on line 13. For lines 1 to 6 complete all that you currently calculate.

1	SAIDI value (w/Major Events included)		Include or exclude pre-arranged interruptions?
2	SAIDI value (w/o Major Events included)		
3	SAIDI value (w/o Major Events included) minus loss of supply		Do you capture outage records for events that initiate outside your system (customer s
4	SAIFI value (w/Major Events included)		
5	SAIFI value (w/o Major Events included)		
6	SAIFI value (w/o Major Events included) minus loss of supply		
7	Total number of customers used in these calculations	after first year prefill	
8	Percent of your distribution system that is Urban (>150 customers per line mile)	after first year prefill	Point to calculation in P1782: use percentages weighted based upon the classification
9	Percent of your distribution system that is Suburban (50 to 150 customers per line mile)	after first year prefill	
10	Percent of your distribution system that is Rural (<50 customers per line mile)	after first year prefill	
11	At what voltage do you distinguish the distribution system from the supply system?	after first year prefill	
12	Do you receive information about a customer outage in advance of a customer reporting it?	after first year prefill	REWORD: The percent of customers automatically reported when they have lost power? e.g. SCADA, AMI, Etc.
13	We do not calculate SAIDI and SAIFI, by any method, and this data is not available	[ ]	

U.S. Energy Information Administration Independent Statistics & Analysis	FORM EIA-861 ANNUAL ELECTRIC POWER INDUSTRY REPORT	OMB No. 1905-0129 Approval Expires: 12/31/2016 Burden Hours: 11.23

Entity Name: ABC Company
Entity ID: 00000
Data Year: 2013

SCHEDULE 6. PART F. DISTRIBUTION SYSTEM RELIABILITY INFORMATION

State

SECTION 2: SAIDI and SAIFI other methods

If your entity calculates SAIDI and SAIFI in accordance with IEEE 1366-2003 standard complete Section 1, if your entity calculates SAIDI and SAIFI via another method please complete Section 2. If your entity does not calculate SAIDI and SAIFI please check the box on line 13, Section 1. For lines 1 to 6 complete all that you currently calculate.

1	SAIDI value (w/Major Events included)		
2	SAIDI value (w/o Major Events included)		
3	SAIDI value (w/o Major Events included) minus loss of supply		
4	SAIFI value (w/Major Events included)		
5	SAIFI value (w/o Major Events included)		
6	SAIFI value (w/o Major Events included) minus loss of supply		
7	Total number of customers used in these calculations	after first year prefill	
8	Percent of your distribution system that is Urban (>150 customers per line mile)	after first year prefill	
9	Percent of your distribution system that is Suburban (50 to 150 customers per line mile)	after first year prefill	
10	Percent of your distribution system that is Rural (<50 customers per line mile)	after first year prefill	
11	At what voltage do you distinguish the distribution system from the supply system?	after first year prefill	
12	Do you receive information about a customer outage in advance of a customer reporting it?	after first year prefill	REWORD: The percent of customers automatically reported when they have lost power? e.g. SCADA, AMI, Etc.
13	Do you include inactive accounts?	after first year prefill	
14	Do you include non-customer meters i.e., street lighting?	after first year prefill	
15	How do you define momentary interruptions? Less than 1 min, 5 min, other	after first year prefill	NOTE: IEEE 1366 Definition is 5 minutes or less…
16	Which of the following do you consider major events?	after first year prefill	REWORD: Which of the following are used in determining your major events?
16a	Planned interruptions	after first year prefill	
16b	Unplanned interruptions	after first year prefill	
16c	Threshold value for loss of load	after first year prefill	
16d	Threshold value for number of customers interrupted	after first year prefill	
16e	Threshold value for interruption duration in minutes	after first year prefill	

1 Total Number of Distribution Circuits

This one will require some amount of effort but not unreasonable. ~1 ManHr / Opco

2 Number of Distribution Circuits Using Any type of Automation

This one will require considerable effort. Much of information for the various types of equipment resides in files specific to the type of equipment & will require manual compilation. 40+ ManHr / Opco

2a Do you have automated switches? YES/NO [X] Yes [ ] No
2b Do you have voltage/VAR Control? YES/NO [X] Yes [ ] No
2c Do you have Equipment Monitoring? YES/NO [X] Yes [ ] No

3 Load served by Distribution Circuits with Automation (MWhs)

We do not directly measure or record energy delivered through most of our distribution circuits. This information is available through GIS based on information from SAP. 4 - 6 ManHr / Opco

4 Number of Customers Served by Distribution Circuits with Automation

This information is available through GIS based on information from SAP. ~4 - 5 ManHr / Opco for 4 through 4d

4a Number of Residential Customers Served by Distribution Circuits with Automation

If not available directly from GIS, Customer account numbers can be extracted from GIS for circuits identified in # 2 and then cross referenced to SAP. Residential Customers can be identified by Rate in SAP. - ManHr / Opco (Inc in #4)

4b Number of Commercial Customers Served by Distribution Circuits with Automation

Similar to the process described in 4a, non residential Customers can be identified by Rate type. However, there is no distinction to specifically identify Commercial Customers. - ManHr / Opco (Inc in #4)

4c Number of Industrial Customers Served by Distribution Circuits with Automation

Similar to the process described in 4a, non residential Customers can be identified by Rate type. However, there is no distinction to specifically identify Industrial Customers. - ManHr / Opco (Inc in #4)

4d Number of Transportation Customers Served by Distribution Circuits with Automation

Similar to the process described in 4a, non residential Customers can be identified by Rate type. However, there is no distinction to specifically identify Transportation Customers. - ManHr / Opco (Inc in #4)

From: Wade Schauer
Sent: Thursday, March 14, 2013 6:20 PM
To: ERS2014@eia.gov
Subject: Proposed EIA-930 survey/report

Hello Ms. Peterson,

Regarding the proposed EIA-930 survey
http://www.gpo.gov/fdsys/pkg/FR-2013-03-06/html/2013-05152.htm
http://www.eia.gov/survey/changes/electricity/
NEW Form EIA-930 and instructions

I would like to request that large Balancing Authorities, such as the Midwest ISO, which contain 20+ Local Balancing Authorities (LBAs), **be required to also submit Hourly Demand data for each of their LBAs**. Many/all of these LBAs were formerly balancing authorities that filed hourly demand data to FERC, but they were subsumed by MISO in Mid-2009 - https://www.midwestiso.org/Library/Repository/Tariff/Rate%20Schedules/Rate%20Schedule%2003%20-%20Amended%20BAA.pdf

Even more Balancing Authorities will disappear when Entergy and related balancing Authorities join the Midwest ISO next year and become LBAs - https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshop%20Materials/Southern%20Region%20Integration%20Workshop/20130315%20Southern%20Region%20Integration%20Workshop%20Presentation.pdf

So unless EIA/FERC expand the EIA-930 survey to include Local Balancing Authorities, the massive Midwest ISO footprint will be a relative black box in terms of any sort of geographic granularity of hourly demand data (far less than used to be available prior to 2009 when MISO took over BA duties), making meaningful 3rd-party power system analysis of the Midwest ISO footprint nearly impossible. I would also ask that MISO be required to report historical hourly demand for the LBAs in "arrears" back to Mid-2009 (when they stopped reporting data).

I'm singling out Midwest ISO in particular, but the Southwest Power Pool is also going to become a super-BA with many LBAs in the next few years, so they should be required to report hourly demand data for those member systems as well. Meanwhile, other ISOs like PJM, NYISO, and ISO New England voluntarily report historical hourly load data for many "zones" on their website, so there is currently no need to request they provide more data than they already do.

Thank you for your time.

Wade Schauer
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Wood Mackenzie
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M +1 (916) 690 5167
E wade.schauer@woodmac.com