

June 12, 2007

Mr. Jorge Luna-Camara  
Energy Information Administration  
Electric Power Division, EI-53  
Forrestal Building  
U.S. Department of Energy  
Washington, DC 20585

*sent via e-mail*

Dear Mr. Luna-Camara:

### **NERC Comments on EIA Forms**

In response to the EIA's request for comments pursuant to the Federal Register notice on April 4, 2007, page no. 16337, NERC submits the following comments:

#### **1. EIA-411, "Coordinated Bulk Power Supply Program Report"**

The new proposed Schedule 6 (Schedule 7 in the current Form 411) requires Regional Councils to submit transmission outage data to NERC and then NERC is to provide it to EIA. This data submittal is proposed to be mandatory for calendar year 2007 data and subsequent years.

1. Making Schedule 6 mandatory for 2007 calendar year data will impose a burden on many U.S. transmission owners (TOs) since TOs were not notified of the mandatory collection requirement *before* 2007. As a result, many TOs will have to manually construct the requested data from historic outage records. Therefore, we suggest that EIA make submissions of 2007 data voluntary as they have been in the past.
2. NERC has kept EIA apprised of its efforts to develop a comprehensive NERC Transmission Availability Data System (TADS) that will require *mandatory* submission to NERC of more comprehensive and useful transmission outage data than that which is proposed by EIA in Schedule 6. We will be implementing TADS in two phases:
  - a. Phase I, scheduled to be considered by the NERC Board of Trustees as discussed below, will require TOs to report automatic outage data beginning in calendar year 2008.
  - b. Phase II will add planned outage and manual unscheduled outage data in calendar year 2009. Phase II design has not yet begun, and its implementation will be subject to the NERC approval process.

A report describing TADS is attached. The TADS report was approved by NERC's Planning Committee on June 7, 2007. Approval of Phase I TADS by NERC's Board of Trustees is required and will be on the Board's agenda for consideration and approval at its October 2007 meeting. Funds for the implementation of TADS are currently in the 2008 NERC budget.

3. For submission of 2008 and 2009 calendar year data, we propose that EIA work with NERC to adopt NERC's mandatory outage reporting framework as the single outage framework for both NERC and EIA requirements. It is our understanding that this could be accomplished by administrative changes to Schedule 6 in order to align it with TADS or by replacing the data sought in Schedule 6 with TADS. These discussions could commence in the late fall of 2007, assuming TADS is approved for mandatory implementation by NERC's Board. Our discussions would include (i) our proposed phased implementation, (ii) an identification of EIA's administrative processes and timeline needed to accomplish NERC's objective of making TADS the sole source of transmission outage data for both NERC and EIA, and (iii) the resolution of confidential information concerns by both NERC and EIA.
4. Since TOs and NERC will incur start-up and training costs to implement TADS, complying with duplicative Schedule 6 reporting requirements will impose a burden on the industry.
5. By working together on this issue, NERC, the industry and EIA will benefit by the development of more comprehensive and useful TADS data and the elimination of duplicative reporting processes.

**2. EIA-860, "Annual Electric Generator Report"**

- a. Schedule 3 (Form and Instructions). For line 21 on the Form (and instruction 26 in the Instructions), we suggest that this additional question be asked with respect to Oil-Gas Fuel Switching:

- "Can the unit switch fuels while operating (i.e., without shutting down the unit)?"  Yes  No

This question would be inserted on the form at the location shown:

21	<b>Oil – Gas Fuel Switching</b>			
	a. Will the unit be able to switch between oil and natural gas?	<input type="checkbox"/> Yes <input type="checkbox"/> No	<input type="checkbox"/> Yes <input type="checkbox"/> No	<input type="checkbox"/> Yes <input type="checkbox"/> No
	If No, skip to line 23. If Yes:			
	• Expected net summer MW achievable running on natural gas:	_____ MW	_____ MW	_____ MW
• Expected net summer MW achievable running on fuel oil:	_____ MW	_____ MW	_____ MW	
• Expected Time Required to Switch this unit from using 100 percent natural gas to using 100 percent oil	<input type="checkbox"/> 0 to 6 hours <input type="checkbox"/> over 6 to 24 hours <input type="checkbox"/> over 24 to 72 hours <input type="checkbox"/> over 72 hours <input type="checkbox"/> unknown or uncertain	<input type="checkbox"/> 0 to 6 hours <input type="checkbox"/> over 6 to 24 hours <input type="checkbox"/> over 24 to 72 hours <input type="checkbox"/> over 72 hours. <input type="checkbox"/> unknown or uncertain	<input type="checkbox"/> 0 to 6 hours <input type="checkbox"/> over 6 to 24 hours <input type="checkbox"/> over 24 to 72 hours <input type="checkbox"/> over 72 hours <input type="checkbox"/> unknown or uncertain	
• Can the unit switch fuels while operating (i.e., without shutting down the unit)?	<input type="checkbox"/> Yes <input type="checkbox"/> No	<input type="checkbox"/> Yes <input type="checkbox"/> No	<input type="checkbox"/> Yes <input type="checkbox"/> No	

The Instructions would need to be modified accordingly.

**Background:** The ability for a generator to switch fuels while operating is an important characteristic from a reliability perspective. This information is important for analyzing the potential loss of gas transportation, whether such loss is due to a generator's use of interruptible transportation or due to the physical loss of gas pipeline capacity (*e.g.*, loss of capacity caused by the failure of one or more gas compression stations, a pipeline break, *etc.*).

- b. Schedule 4 (Form only). We suggest that the subtitle of the form be modified as follows: “**IDENTIFY OWNER(S)– OWNER(S) NAME AND CONTACT INFORMATION (d).**”

**Background:** The instructions should make it clear that the information requested is with respect to all owners.

### 3. EIA-861, “Annual Electric Power Industry Report”

- a. Schedule 6, Part A (Form and Instructions). In Part A, expand the “Load Management” to include time-based and incentive-based programs (as in Part C). Further, expansion of data collection for each of the specific demand response (DR) programs is needed as follows:

- Time-based
  1. direct load control
  2. interruptible programs
  3. demand bidding/buyback\*
  4. emergency demand response\*
  5. capacity market programs\*
- Incentive-based
  1. real-time pricing
  2. critical peak pricing\*
  3. variable peak pricing\*
  4. time-of-use rates\*

- b. Schedule 6, Part C. For each item above with an asterisk (“\*”), add the item's respective definition in the EIA glossary. These definitions may be obtained from the FERC<sup>1</sup>/DOE<sup>2</sup> responses to Section 1252 of the Energy Policy Act of 2005 (EPAAct 2005). Expand this section to include the number of customers for each program under both the time-based (for each individual item 1-5 above) and the incentive-based (for each individual item 1–4 above) programs.

**Background:** EPAAct 2005 Section 1252 directed that “FERC shall publish an annual report, by appropriate region, that assesses demand response.” The first annual

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<sup>1</sup> <http://www.ferc.gov/industries/electric/indus-act/demand-response.asp>

<sup>2</sup> [http://www.oe.energy.gov/DocumentsandMedia/congress\\_1252d.pdf](http://www.oe.energy.gov/DocumentsandMedia/congress_1252d.pdf)

reports have been completed by both DOE and FERC (*see* footnotes 1 and 2). Further, the EPAct 2005 encourages states to deploy DR programs.

NERC is, and will be, studying the influence of DR programs (both incentive- and time-based) on reliability. A critical part of this analysis is the determination of how much was actually deployed during the peak and the energy requirements displaced throughout the year. The aforementioned data will form the basis for DR effectiveness and availability analysis.

- c. EIA is currently seeking data from utilities and load serving entities. However, EIA also should obtain data with respect to DR participation. Towards this end, the Form 861 also should collect data from the ISO/RTOs and curtailment service providers related to DR activities.

**Background:** ISO/RTOs have extensive DR programs in place. Further, curtailment service providers help meet the resource needs through aggregation of DR. These two programs should be reported; however, EIA should ensure there is no double-counting of internal demand and energy.

- d. The method for reporting the amount of DR, customer count, and participation levels is unstated and should be specified.

**Background:** Inconsistent data reporting across entities will lead to unreliable and inaccurate assessments of DR participation and reliability. *See Schedule 6, 7A* — “Were these savings verified” is simply a yes/no question; not a “how” question.

- e. Respondents are asked to report how many MW and MWh equivalent DR the reporting entity has delivered. Each respondent should provide information on how actual performance during events is verified.

**Background:** There is no requirement to verify how resources actually performed during events. A metric similar to the Forced Outage Rate is not reported for DR, even though it is a key reliability metric. *See Schedule 6, Questions 5 and 7* — “Energy Effects (MWh)” and “Actual Peak Reduction (MW).”

- f. Current DR reporting is by customer type; however, such reporting also should include the nature of the DR resource.

**Background:** There is no distinction between DR resources that are dispatchable through direct load controls and those that can only be deployed through customer/end user intervention (non-dispatchable). The overall reliability and the rate of response can vary considerably between these two DR resources, and they should be reported separately. There also is no distinction between DR programs that are reliability-based programs (emergency load control), ancillary services programs, or economic programs. DR programs premised upon reliability objectives respond differently than economic programs. *See Schedule 6, Questions 3-7* — The only distinction is between customer type: Residential, Commercial, Industrial & Transportation.

Mr. Luna-Camara  
June 12, 2007  
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This concludes NERC's comments.

Respectively submitted,

A handwritten signature in black ink, appearing to read "D. R. N. S." with a stylized flourish at the end.

Attachment: TADSTF Final Report (in electronic format)