U.S. Department of Energy Energy Information Administration Form EIA-411 (2005)	*COORDINATED BULK POWER SUPPLY PROGRAM REPORT*	Form Approved OMB No. 1905-0129 Approval Expires

PURPOSE	~~The~~ Form EIA-411 ~~data provides the U.S. Department of Energy with a comprehensive source of~~ collects information about regional electricity supply and demand projections for a five-year advance period and information on the transmission system and supporting facilities. The data collected on this form are used by the U.S. Department of Energy to monitor the current status and trends of the electric power industry and to evaluate the future of the industry.
REQUIRED RESPONDENTS	Each of the Regional Councils of the North American Electric Reliability Council (NERC) is asked to submit Form EIA-411 data compiled from data furnished by utilities and other electricity suppliers within their Council areas to NERC. NERC is then compiles and coordinates these data and provides them to the Department of Energy, Energy Information Administration. ~~Although the Form EIA-411 is a voluntary filing, the generating capacity data collected on Schedule 3, “Generator Information,” is included under the mandatory Form EIA-860, “Annual Electric Generator Report.”~~
RESPONSE DUE DATE	Each Regional Council should submit the completed Form EIA-411 to the North American Electric Reliability Council by April ~~1~~30. After review, NERC should submit the completed Form EIA-411 to the EIA by ~~June 30~~July 15 of the year following the reporting year.
METHODS OF FILING RESPONSE	The North American Reliability Council (NERC) will oversee the methods of filing response of the data by of the Regional Councils. NERC then submits the compiled report to EIA. Submit the data via a secure file transfer process. Contact John Makens at John.Makens@eia.doe.gov for instructions. Maps and power flow cases can be transmitted electronically using a secure file transfer process. CD-ROM disks containing the data can also be mailed to EIA at the following address: John Makens, Survey Manager Energy Information Administration, Mail Stop EI-53 1000 Independence Avenue Washington, DC. 20585-0690 Retain a completed copy of this form for your files.
CONTACTS	***Data Questions:*** For questions about the data requested on Form EIA-411, contact: John Makens Telephone Number: (202) 287-1749 FAX Number: (202) 287-1960 Email: John.Makens@eia.doe.gov

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~~GENERAL INSTRUCTIONS~~

~~Each Regional Council should submit the completed Form EIA-411 to the North American Electric Reliability Council by April 1. After review, NERC should submit the completed Form EIA-411 to the EIA by June 30.~~

~~Complete the information at the top portion of the form with the name and telephone number of the two current contact persons.~~

1. ~~Include information from all Council members and significant interconnected nonmembers within the service territories of members that have responded to data requests.~~

2. ~~Submit revisions to data previously reported as soon as possible after the error or omission is discovered. Do not wait until the next reporting period's form is due to send resubmission(s). A photocopy of the original submission that clearly shows any changes to the data is acceptable. Draw a line through the incorrect data. Write the correct data above the incorrect data. The revised page will be treated as a replacement for the original page. FAX or mail one copy of the resubmission.~~

ITEM-BY-ITEM INSTRUCTIONS

Schedule 1. Historical and Projected Peak Demand and Energy

1. Enter annual and seasonal peak demands and net energy for load for designated years.

2. Schedule 1 is to be reported in total by each Regional Council for all utilities, groups of utilities, such as Council subregions, Independent System Operators, or Regional Transmission Operators, within athat Council ~~that plan their bulk electric systems on a coordinated basis may also report as a "reporting party." It is recognized that a Council may not be completely divided into reporting parties, but to the extent that reporting parties exist they should report.~~ The reported capacity should comprise the sum of all non-coincident peak loads for the various operating entities during the specified period.

Schedule 2. Capacity for Existing Generators in Reporting Year

1. Using the Form EIA-860 electronic database, identify every generator that is dedicated to supplying the regional load, including generators that may be physically located outside the regions boundaries. For each such generator, report the information requested on lines 6, 8, and 9. If a known regional generator cannot be located in the Form EIA-860 database, notify either the NERC or EIA.

2. For line 6, **GADS Generator ID**, report the unique identification code or number assigned to this generator for use by the NERC Generator Availability Database.

3. For line 7, **Net Capacity as Reported on Form EIA-860**, report the amount of the capacity that was reported to EIA on the Form EIA-860.

4. For line 8, **Inoperable Capacity**, enter all generating resources that are expected to be unavailable due to scheduled outage at the time of peak. This includes maintenance outages and planned outages. Also included are all generating resources that are out of service for reasons such as legal, regulatory, or environmental restrictions. This does not include derated portions of generating capacity.

5. For line 9, **Net Operable Capacity**, enter line 7 less line 8.

Schedule ~~2~~3. Historical and Projected Demand and Capacity
(NOTE: prior Schedule 3 was deleted entirely)

1. Schedule 3 is to be reported in total by each Regional Council for all utilities, groups of utilities, such as Council subregions, Independent System Operators, or Regional Transmission Operators, within that Council.

2. Enter demand and capacity for the summer (Part A) and winter (Part B) peak periods of the designated years for the NERC region. Peak demands reported should agree with the corresponding entries in Schedule 1, Part B.
~~3. Capacity data reported in Schedule 2 should be consistent with Schedule 3, Part D and Schedule 3, Part E. If the total capacity reported in Schedule 2 (lines 7, 8, or 9) differs from the simple summation of data in Schedule 3, Part D and Schedule 3, Part E, explain the reasons in a footnote on Schedule 8.~~

3. For hydroelectric capacity, explain in footnote on Schedule ~~8~~9, whether the projected years data are for an adverse water year, an average water year, or other.

4. The information in Schedule 3 is to be entered in megawatts (MW) for each peak period on the same basis as reported in Schedule 1.

5. For line 1**, Internal Demand**, the following instructions apply:

   Internal Demand is the sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. 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.

Internal Demand includes adjustments for utility indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates. Internal Demand should not include Stand-by Demand (line 2) and should not be reduced by Direct Control Load Management or Interruptible Demand, which are reported on Lines 4 and 5, respectively. ~~The Internal Demands of nonmember systems of the Council or Reporting Party should be included to the extent known.~~

~~State in a footnote on Schedule 8 whether or not Internal Demand includes Standby Demand.~~

6. For line 2, **Standby Demand**, enter the demand specified by contractual arrangement with a customer to provide power and energy to that customer as a secondary source or backup for an outage of the customer's primary source. Standby Demand is intended to be used infrequently by any one customer. ~~If Stand-by Demand is included in line 1, report "0" on line 2.~~ If there are no arrangements for Standby Demand, report "0" on line 2.

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 3~~2~~. Historical and Projected Demand and Capacity (Continued)

7. For line 3, **Total Internal Demand**, enter sum of lines 1 and 2. Data should be the same as reported in Schedule 1, Part B, Peak Hour Demand.

8. For line 4, **Direct Control Load Management**, enter the magnitude of customer demand that can be interrupted at the time of the Regional Council ~~or Reporting Party~~ seasonal peak by direct control of the System Operator by interrupting power supply to individual appliances or equipment on customer premises. This type of control usually reduces the demand of residential customers. Direct Control Load Management as reported here does not include Interruptible Demand (line 5).

9. For line 5, **Interruptible Demand**, enter the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Council's ~~or Reporting Party~~ seasonal peak by direct control of the System Operator or by action of the customer at the direct request of the System Operator. In some instances, the demand reduction may be effected by direct action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions. For example, demands that can be interrupted to fulfill planning or operating reserve requirements normally should be reported as Interruptible Demand. Interruptible Demand as reported here does not include Direct Control Load Management (line 4).

10. For line 6, **Net Internal Demand**, enter line 3, less line 4, less line 5 (Internal Demand, less Direct Control Load Management and Interruptible Demand).

11. For line 7, **~~Committed~~ Total Net Operable Capacity**, for the reporting year (only), enter the sum of the values reported on Schedule 3, Line 9, for all generators included by the reporting region. For all other years, report the region's current projection of net operable capacity that it will use in assessing its future needs. Include the capacity from any generator, regardless of physical location, if that capacity is dedicated to satisfying the needs of the reporting region. ~~enter the total of all existing capacity and all committed, planned capacity for the specified year. Existing capacity shall include all existing generators regardless of physical location. This includes generators with the codes of OP, SB and OS, as reported in Schedule 3, Part D. (The Net Capacity of parties that are not members of the Council or Reporting Party but are within the boundaries of the Council or Reporting Party should be included in the totals, to the extent known.) Committed, planned capacity shall include both capacity that is under construction and existing units that are to be retired and deactivated or reactivated during the specified year. This includes the following codes for Planned Generators, as reported in Schedule 3, Part B:~~

~~RT, TS, U, and V. Status Code M should be included in this line if the Council removes the unit from the capacity mix. Status Code RA should be included in this line if the Council intends to restore the unit to the capacity mix. Planned changes in capacity (if any) associated with Status Codes A, D, RP, and FC should be included on this line. Status Codes CO and IP should not appear on this line.~~

12. For line 7a, **Uncommitted Capacity**, enter the total amount of generating resources that are physically located in the Region, but are not dedicated to or contractually committed to serve load in the Region.

13. For line 7b1, **Reliability Derating Unit Specific Subtotal,** enter the total amount of reduction in the maximum capability of the units that can be specifically identified due to transmission constrains or the amount of generator capability that cannot be relied upon due to other issues, such as wind and hydro conditions.

14. For line 7b2, **Reliability Derating Group Subtotal**, enter the total amount of reduction in the maximum capability of the units that cannot be specifically identified (i.e., allocated or prorata derating) due to transmission constraints or the amount of generator capability that cannot be relied upon due to other issues, such as wind and hydro conditions.

15. For line 7c, **Other Generation**, enter the total amount of generation reported in the Form EIA-860 that is not included in Regional calculations of Planned Capacity Resources, e.g., behnd the meter, self-use, etc.

16. For line 7d, **Subtotal Committed Capacity**, subtract lines 7a, 7b1, 7b2, and 7c from line 7.

17. For Line ~~9~~8,**Generator Capacity, Less Than 1 Megawatt**, report the total of all grid-connected capacity less than 1 megawatt, regardless of physical location, that is dedicated to satisfying the needs of the reporting region. ~~Other **Capacity,** enter the amount of the capacity entered on Line 7, Committed Resources, that is comprised by other (non-distributed) generators 1 MW or greater.~~

18. For Line ~~10~~8a, **Distributed Generator Capacity**, **Less Than 1 Megawatt**, report the amount of the capacity reported on line 8 that is comprised by distributed generators, as defined in the glossary. ~~enter the amount of the capacity entered on Line 7, Committed Resources, that is comprised by distributed generators less than 1 MW~~.

~~19.~~ For Line 8b~~11~~, **Other Capacity**, **Less Than 1 Megawatt**, report the amount of the capacity reported on line 8 that is **not** comprised by distributed generators as defined in the glossary. (This should equal line 8, less line 8a.)~~enter the amount of the capacity entered on Line 7, Committed Resources, that is comprised by other (non-distributed) generators less than 1 MW.~~

20. For Line 9, **Total Net Generator Capacity**, report the sum of line 7d plus line 8.

21. For Line ~~8~~ 9a, **Distributed Generator Capacity, 1 Megawatt or Greater**, report the amount of the capacity reported on line 7 that is comprised by distributed generators, as defined in the glossary. This is broken out for informational purposes. ~~enter the amount of the capacity entered on Line 7, Committed Resources, that is comprised by distributed generators 1 MW or greater.~~

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 3 ~~2~~. Historical and Projected Demand and Capacity (Continued)

~~16. For line 12, **Uncommitted Resources**, enter all planned capacity that is not existing, not under construction, or is of unknown status. This would include status codes L, P, OT, and T for Planned Generators, as reported in Schedule 3, Part E. Status Codes A, CO, D, FC, IP, and RP should not appear in this line.~~

~~17. For line 13, **Total Capacity**, enter generating capacity regardless of physical location. If this item differs from the simple summation of data in Schedule 3, Part D and Schedule 3, Part E, explain in a footnote on Schedule 8. The Net Capacity of companies that are not members of the Council or Reporting Party but within the boundaries of the Council or Reporting Party should be included in the totals, to the extent known. This should be the sum of lines 7 and 12 on the form.~~

~~18. For line 14, **Inoperable Capacity**, enter all generating resources that are expected to be unavailable due to scheduled outage at the time of peak -- this includes maintenance outages and planned outages. Line 14 should also include all generating resources that are totally or partially out of service for reasons such as: environmental restrictions, legal or regulatory restrictions, extensive modifications or repair, or capacity specified as being in a mothballed state. Expected reduction in output due to hydro conditions can be addressed in either line 13 or 14 but it must be noted on which line this was accounted for.~~

~~19. For line 15, **Net Operable Capacity**, enter the amount of line 13 less line 14.~~

22. For line 10~~6~~, **Total Capacity Purchases/Transfers**, enter total of all capacity purchases from sources outside the boundaries of the Reporting Party as reported in Schedule 4 at the time of the purchaser's peak demand. If not equal to the total in Schedule 4, Parts A and B, explain in a footnote on Schedule ~~8~~9. Do not report ~~If the Reporting Party chooses to report~~ capacity physically located outside the ~~Reporting Party's~~ regions' boundaries ~~and reported in line 13,~~ as purchased capacity.~~, an appropriate adjustment should be reported in line 20~~ Such capacity should be accounted for on Schedule 2.

23. For line 10a, **Full Responsibility Purchases**, enter total of all purchases for which the seller 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). Each purchaser and seller must agree on which of their transactions are reported under this heading.

24. For line 11, **Total Capacity Sales/Transfers**, enter total of all capacity sales to purchasers outside the boundaries of the Reporting Party, as reported in Schedule 4 at the time of the seller's peak demand. If not equal to the total in Schedule 4, Parts C and D, explain in a footnote on Schedule ~~8~~9.

25. For line 11a, **Full Responsibility Sales**, enter total of all sales for which the seller 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). Each purchaser and seller must agree on which of their transactions are reported under this heading.

~~26. For line 20, Adjustment for Remotely Located (totally owned or shared) Generating Unit(s), enter the appropriate adjustment if transfers of capacity associated with remotely located, totally owned or jointly owned, generating units are included in the Capacity Purchases on Line 16 or the Capacity Sales on Line 18. For net transfer into a Reporting Party, this entry will be negative. The purpose of this adjustment is to eliminate "double counting" of capacity that may be duplicated in lines 13, 16, or 18.~~

26. For line 12, **Planned Capacity Resources**, enter the sum of lines 9 plus 10 minus 11.

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ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 4. Historical and Projected Capacity Purchases and Sales

1. Enter all projected capacity purchases and sales (in megawatts) that involve entities outside of the Council or Reporting Region. The totals should agree with the totals in Schedule 3, Line 10, **Total Capacity Purchases** and Line 11, **Total Capacity Sales**.

2. Some data may be non-coincident due to differences in the month of the seasonal peaks for the purchaser and seller. An example would be a transfer that changes magnitude from July to August. The transfer would be reported in July by the selling party whose peak occurs in July and reported in August by the purchasing party whose peak occurs in August.

3. Purchases from jointly owned shares of generators physically located outside the Regional Council ~~or Reporting Party~~, should not be reported as capacity in Schedule 4. These purchases should be accounted for in Schedule 3. ~~, should be included in Schedule 2, Line 16~~10~~, **Total Capacity Purchases**, or Line 18~~1~~, **Total Capacity Sales** and in Line 20, **Adjustment Transfers for Remotely Located Generating Unit(s)**.~~

4. For column (a), **Other Party, EIA Code**, enter the five character numeric code for that party. A list of the EIA company codes, by reporting party name, is available at the EIA website, http://www.eia.doe.gov/cneaf/electricity/page/gen_companies/codesp1.html. If the name of the reporting party is not on this list, please enter the name of the party on the form and a code will be assigned.

5. For columns (a2) and (a3), Plant ID and Unit ID, enter the EIA code for those unit specific purchases, sales, and transfers, if known.

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 5. Bulk Electric Transmission System Maps

1. Each Council is to submit a map(s) in electronic format, showing the existing bulk electric transmission system 230 kV and above, including ties to other Councils, and the bulk electric transmission system additions projected for a five-year period beginning with the year following the reporting year.

2. Only major geographic features and state boundaries, bulk electric facilities, and the names of major metropolitan areas need be shown. The map scale to be used is left to the discretion of the Region or Reporting Party, but should be such as to allow convenient use of the map. Show the voltage level of all bulk electric transmission lines. The year of installation of all projected system additions may be shown at the option of the Council or Reporting Party.

3. The map requirement may be satisfied by either:
   (a) A single map in electronic format showing the existing bulk electric transmission system as of January 1 of the reporting year and system additions for a five-year period beginning with the reporting year; or

   (b) Separate maps for a set of subregions that comprise the whole region.

4. For Line 1, enter the number of maps provided.

5. For Line 2, enter the requested map information in columns (a) through (d).

Schedule 6. Projected Transmission Line Additions

1. This Schedule must be completed by each Regional Council for all transmission line additions at 230 kV and above projected for the five-year period beginning with the year following the reporting year.

2. For line 1, **Terminal Location (From)**, enter the name of the beginning terminal point of the line.

3. For line 2, **Terminal Location (To)**, enter the name of the ending terminal point of the line.

4. For line 3, **Company Name**, enter the company name.

5. For line 4, **EIA Company Code**, identify each organization by the six-character code assigned by EIA.

6. For line 5, **Type of Organization**, identify the type of organization that best represents the line owner including the following types of utilities – Investor-owned (I), Municipality (M), Cooperative (C), State-owned (S), Federally-owned (F), or other (O).

7. For line 6, **Percent Ownership**, if the transmission line will be jointly-owned, enter the percentages owned by each individual respondent.

8. For line 7, **Line Length**, enter miles between beginning and ending terminal points of the line, regardless of the number of conductors or circuits carried.

9. For line 8, **Line Type**, select physical location of the line conductor – overhead (OH), underground (UG), or submarine (SM).

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 6. Projected Transmission Line Additions (Continued)

10. For line 9, **Voltage Type**, select voltage as alternating current (AC) or direct current (DC).

11. For line 10, **Voltage Operating**, enter the voltage at which the line is normally operated in kilovolts (kV).

12. For line 11, **Voltage Design**, enter the voltage at which the line was designed to operate in kilovolts (kV).

13. For line 12, **Conductor Size**, enter the size of the line conductor in thousands of circular mils (MCM).

14. For line 13, **Conductor Material Type**, enter the line conductor material type – aluminum, ACCR, ACSR, copper, or other.

15. For line 14, **Bundling Arrangement**, enter the bundling arrangement/configuration of the line conductors – single, double, triple, quadruple, or other.

16. For line 15, **Circuits per Structure Present,** enter the current number of three-phase circuits on the structures of the line.

17. For line 16, **Circuits per Structure Ultimate**, enter the ultimate number of three-phase circuits that the structures of the line are designed to accommodate.

ITEM-BY-ITEM INSTRUCTIONS Continued

18. For line 17, **Pole/Tower Type**, identify the predominant pole/tower material for the line – wood, concrete, steel, combination, composite material, or other. Also include the type of structure – single pole, H-frame structure, tower, underground, or other.

19. For line 18, **Capacity Rating**, enter the normal load-carrying capacity of the line in millions of volt-amperes (MVA).

20. For line 19, **Projected In-Service Date**, enter the projected date the line will be energized under the control of the system operator. Please provide a month and year (e.g. **12-2004**).

Schedule 7. Annual Data on Transmission Line Outages for EHV Lines, General Instructions for Part A and Part B

In general terms, an Outage is defined as the removal from service availability of a generation unit, transmission line, or other facility for either scheduled (planned) or unscheduled (unplanned) reasons. For this reporting purpose, individual outage duration should be reported following similar company standards and/or regional reliability guidelines. The outage durations reported on the Form EIA-411 represent the annual summation (in hours) of all these events for the reporting NERC region.

The duration of an outage is the amount of time that the transmission line was completely de-energized. For preferred reporting practices, do not start recording duration until the line is completely deenergized and stop recording duration when any portion of the line is reenergized. If practices differ, please footnote.

Outages that occur on inter-tie lines between utilities are to be reported only one by each reporting region.

Scheduled Outages

Information collected on scheduled outages is for the events where the duration was 1 hour or more in length. This includes line upgrades and the normal maintenance that is usually performed during non-peak load periods. Each time a line is removed from service, this is recorded as one scheduled outage (this includes accounting for periods where lines are returned to service on a periodic basis during the whole schedule work period).

Unscheduled Outages

The information requested on unscheduled events covers both outages due to preventable events and those that cannot be foreseen or prevented (such as severe weather). The unscheduled outage of any circuit continues until that circuit is restored to service. If company practices are different from this, please footnote.

- For any set of outages that have more than one cause, please report the initial cause (i.e., the cause that occurred first).
- For an outage of a circuit to be considered, the line(s) must be deenergized. If the line recloses and trips again within a minute of the initial outage, it is only considered one outage. The line would need to remain in service for longer than one minute between the breaker operations to be considered as two outages.
- ‘Failed tests’ are not considered additional outages. If the operator or dispatcher tries to energize a circuit that has a fault on it, and it immediately re-opens, this is considered a ‘failed test’ and is not an additional outage. However if the test ‘passed’ and the line remained in service for longer than one minute, any additional outages will be recorded as a new outage.

Schedule 7. Annual Data on Transmission Line Outages for EHV Lines, General Instructions for Part A and Part B (Continued)

- Removal of any transmission line (including radials) from service is considered as an outage. However, transmission lines that are removed for system stability (such as ‘voltage control’) should not be reported as an outage. These maybe reported separately as a footnote.
- When a tap off a transmission line is removed from service (scheduled or unscheduled outage) and the transmission line itself remains energized only the tap is considered out-of-service.

Schedule 7. Part A, Annual Data on Transmission Line Outages for EHV Lines, A.C. Lines, Specific Instructions

1. All transmission line outages involving Extra High Voltage (EHV) A.C. lines of 230 kV and above are to be aggregated by each Regional Council and reported on this schedule.
2. For line 1, if you are reporting an outage(s) of a voltage class that is not listed, identify the voltage class in column e.
3. For line 2, **Number of Scheduled Outages**, report the total number of scheduled outages that occurred in the reporting period for each voltage class.
4. For line 3, **Number of Circuits Involved**, report the total number of “circuit outages”, that occurred during the reporting period, for all scheduled outages. For example, if there was one outage and five circuits are involved, the respondent should report 5 circuit outages. Alternatively, if there was one outage with two circuits involved and subsequently there is another outage with four circuits involved, the respondent should report 6 circuit outages, for each voltage class.
5. For line 4, **Scheduled Circuit-Hours Out of Service**, report the total scheduled circuit-hours out of service for all of the scheduled outages for each voltage class during the year. This is the sum across all circuits of the number of hours each circuit

was out of service for scheduled reasons during the reporting period.

6. For line 5, **Number of Non-Momentary Unscheduled Outages,** report the number of non-momentary (lasting sixty seconds or longer) unscheduled outages that occurred during the reporting period for each voltage class.
7. For line 6, **Number of Circuits Involved**, report the total number of "circuit outages", that occurred during the reporting period, for all unscheduled outages, both momentary and non-momentary. For example, if there is one outage and five circuits are involved, the respondent should report 5 circuit outages. Alternatively, if there was one outage with two circuits involved and subsequently there was another outage with four circuits involved, the respondent should report 6 circuit outages, for each voltage class.
8. For line 7, **Unscheduled Circuit-Hours Out of Service**, report the unscheduled circuit-hours out of service for all of the unscheduled outages for each voltage class during the year. This is the sum across all circuits of the number of hours each circuit was out of service for unscheduled reasons during the reporting period.
9. For Line 8, **Weather**, includes all unscheduled outages caused by severe weather conditions (tornado, hurricane, lightning strikes, ice, high winds, etc.) that are the primary cause of the outage.
10. For Line 9, **Animals, Fire and Smoke, Human Accidents,** includes the events caused by actions where animal movement or nesting impacts electrical operations of equipment or facilities. Actions by humans (accidents or intention) that not employed or under contract by the utility in the responsible area that impact operations will be reported. Fire and conditions linked to this from whatever event that started the fire/smoke conditions need to be accounted for in this category.
11. For Line 10, **Vegetation**, includes outages initiated by vegetation in the proximity of transmission facilities. Reporting definition will be consistent with the NERC template and vegetation management criteria.

Schedule 7. Part A, Annual Data on Transmission Line Outages for EHV Lines, A.C. Lines, Specific Instructions (Continued)

12. For Line 11, **Operator Action**, includes any action traceable to employees and/or contactors for companies operating, maintaining, and/or providing assistance for actions that impacted any part of the operations of the Nation's power grids will be identified and reported in this category. Also, any failure or interpretation of standard industry practices and guidelines that cause an outage event will be reported in this category.
13. For Line 12, **Other or Unknown**, includes all other categories tracked by utility systems that are kept separate from the above groupings should be reported here. In addition, any unknown sources should also be reported in this category.
14. For line 10, **Number of Circuits with Outages**, sum lines 3 and 8.
15. For line 11, **Total Number of Outages Reported**, sum lines 2 and 7.

Schedule 7. Part B, Annual Data on Transmission Line Outages for EHV Lines, D.C. Lines, Specific Instructions

1. All transmission line outages involving Extra High Voltage (EHV) D.C. lines of ±100 kV and above are to be aggregated by each Regional Council and reported on this schedule.
2. For line 2, **Number of Scheduled Outages**, report the total number of scheduled outages that occurred in the year for each voltage class.
3. For line 3, **Number of Circuits Involved**, report the total number of "circuit outages", that occurred during the year, for all scheduled outages. For example, if there is one outage and five circuits are involved, the respondent should report 5 circuit outages. Alternatively, if there was one outage with two circuits involved and subsequently there

was another outage with four circuits involved, the respondent should report 6 circuit outages, for each voltage class.

4. For line 4, **Scheduled Circuit-Hours Out of Service**, report the total scheduled circuit-hours out of service for all of the scheduled outages for each voltage class during the year. This is the sum across all circuits of the number of hours each circuit was out of service for scheduled reasons during the year.
5. For line 5, **Number of Non-Momentary Unscheduled Outages,** report the number of non-momentary (lasting sixty seconds or longer) unscheduled outages that occurred during the year for each voltage class.
6. For line 6, **Number of Circuits Involved**, report the total number of "circuit outages", that occurred during the year, for all unscheduled outages, both momentary and non-momentary. For example, if there is one outage and five circuits are involved, the respondent should report 5 circuit outages. Alternatively, if there was one outage with two circuits involved and subsequently there was another outage with four circuits involved, the respondent should report 6 circuit outages, for each voltage class.
7. For line 7, **Unscheduled Circuit-Hours Out of Service**, report the unscheduled circuit-hours out of service for all of the unscheduled outages for each voltage class during the year. This is the sum across all circuits of the number of hours each circuit was out of service for unscheduled reasons during the year.
8. For Line 8, **Weather**, includes all unscheduled outages caused by severe weather conditions (tornado, hurricane, lightning strikes, ice, high winds, etc.) that are the primary cause of the outage.
9. For Line 9, **Animals, Fire and Smoke, Human Accidents,** includes the events caused by actions where animal movement or nesting impacts electrical operations of equipment or facilities. Actions by humans (accidents or intention) that not employed or under contract by the utility in the responsible area that impact operations will be reported. Fire and conditions linked to this from whatever event that started the fire/smoke conditions need to be accounted for in this category.

Schedule 7. Part B, Annual Data on Transmission Line Outages for EHV Lines, D.C. Lines, Specific Instructions (Continued)

10. For Line 10, **Vegetation**, includes outages initiated by vegetation in the proximity of transmission facilities. Reporting definition will be consistent with the NERC template and vegetation management criteria.
11. For Line 11, **Operator Action**, includes any action traceable to employees and/or contactors for companies operating, maintaining, and/or providing assistance for actions that impacted any part of the operations of the Nation's power grids will be identified and reported in this category. Also, any failure or interpretation of standard industry practices and guidelines that cause an outage event will be reported in this category.
12. For Line 12, **Other or Unknown**, includes all other categories tracked by utility systems that are kept separate from the above groupings should be reported here. In addition, any unknown sources should also be reported in this category.
13. For line 13, **Number of Circuits with Outages**, sum lines 3 and 8.
14. For line 14, Total Number of Outages Reported, sum lines 2 and 7.

Schedule ~~7~~8. Bulk Transmission Facility Power Flow Cases

1. Each Regional Council is to coordinate the collection of Schedule ~~7~~8 data on ~~collects~~ basic electrical data and power flow information on prospective new bulk transmission facilities of 230 kV and above (including lines, transformers, HVDC terminal facilities, phase shifters, and static VAR compensators) that have been approved for construction and are scheduled to be energized over the next two years.

2. If the prospective bulk transmission facilities are represented in the respondent's

current FERC Form 715 submission, please provide a copy of an annual peak load power flow case submitted which represents a period of at least two years into the future and complete Schedule ~~7~~8 (see Instructions 6 through 13).

3. If the facilities are not represented in the respondent's current FERC Form 715 submission, please submit a power flow case(s) representing the prospective facilities and complete Schedule ~~7~~8. The respondent may submit a single annual peak load power flow case that includes all prospective facilities to be energized in the next two years. Alternatively, the respondent may provide a copy of any annual peak load power flow case that includes the new facility for the year it is to be energized. If more than one facility is to be energized in a given year, it is acceptable to provide a single annual peak load power flow case that includes all the new facilities added in that year. The power flow shall be in the same format as used for the respondent's FERC Form 715 filing.

4. For each power flow case that is provided in response to Items 2 and 3 above, please identify on Schedule ~~7~~8 all prospective facilities that are not currently in service and the projected in-service date of those facilities. Complete one page for each new power flow case. In each case, identify only the new facility by type and list bus numbers and names that the new facility is connected with electrically.

5. The EIA expects that in nearly all cases the power flow format will be one of the following:

   - The Raw Data File format of the PTI (Power Technologies, Inc.) PSS/E power flow program;
   - The Card Deck Image format of the Philadelphia Electric power flow program;
   - The Card Deck format of the WSCC power flow program;
   - The Raw Data File format of the General Electric (formerly Electric Power Consultant, Inc. or EPC), or the PSLF power flow program; or
   - The IEEE Common Format for Exchange of Solved Power Flows.

   Respondents submitting their own cases must supply the input data to the solved base cases and associated ASCII output data on MS/PC DOS format (version 3.x or higher), high density (1.44 MB), compact disk in the format associated with the power flow program used by the respondents in the course of their transmission studies, as described above.

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule ~~7~~8. Bulk Transmission Facility Power Flow Cases Continued

6. For Line 1, enter the case name.
7. For Line 2, enter the year studied in this power flow case.
8. For Line 3, enter the case number assigned by respondent.
9. For Line 4, column a, enter the name of a prospective facility included on the power flow case.
10. For Line 4, column b, enter the type of facility, e.g. line, transformer, etc.
11. For Line 4, column c, enter the projected in-service date of the proposed facility. Please provide month and year (e.g. 12-2004).
12. For Line 4, column d and e, enter the number and name respectively of each bus to which the facility is connected. Use one line for each bus.
13. Repeat Instructions 9 through 12 for each prospective facility.

Schedule ~~8~~9. Footnotes

Identify each comment (footnote) by the appropriate schedule, part, line number, column identifier and page number. Use additional sheets, as required.

~~**Schedule 9. Authorization for Reporting**~~

~~Respondents have the option either to submit Schedule 3 to the EIA or to designate an agent or agents (e.g., regional electric reliability council, North American Electric Reliability Council (NERC), or other groups) to submit this information to the EIA on its behalf. Each respondent is encouraged to designate its regional electric reliability council(s) as its agent(s) to report to the EIA on the respondent's behalf. The designated agent(s) must specify the electric generating company for which it is submitting information. The respondent (the electric generating company) has the ultimate responsibility for submitting the Form EIA-860 data or any data not submitted on its behalf by its designated agent(s).~~

~~Respondents who designate an agent or agents to file on their behalf should return this completed schedule and a copy of the fully completed Form EIA-860 or the Form EIA-411, Schedule 3, to the EIA in the enclosed envelope or in an envelope using the mailing address above.~~

~~The completed schedule should include the name(s) of the designated agent(s), name(s) of contact person(s) at the designated agent(s), their corresponding telephone number(s), the name of the respondent (electric utility) official authorizing the agent(s) to file, the official's title, telephone number, signature, and the date the form is signed.~~

~~**GLOSSARY**~~

~~**Bundling Arrangement:** Identifies the conductor configuration for each phase of a transmission line, when more than one conductor per phase is used.~~

~~**Bus Name:** Unique name of a specific electrical connection point, as used by the respondent.~~

~~**Bus Number:** Unique number assigned to a specific electrical connection point by the respondent.~~

~~**Case Name:** Unique name assigned to the electronic data file that is used to track respondent's data filings.~~

~~**Circuits Per Structure, Present:** Current number of circuits on supporting structures of designated line.~~

~~**Circuits Per Structure, Ultimate:** Planned number of circuits on supporting structures of designated line.~~

~~**Combined Cycle:** An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.~~

~~**Combined Heat and Power (CHP) Plant:** A plant designed to produce both heat and electricity from a single heat source. *Note:* This term is being used in place of the term "cogenerator" that was used by EIA in the past. CHP better describes the facilities because some of the plants included do not produce heat and power in a sequential fashion and, as a result, do not meet the legal definition of cogeneration specified in the Public Utility Regulatory Policies Act (PURPA).~~

~~**Combined Heat and Power (CHP):** A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes. To receive status as a qualifying facility (QF) under the Public Utility Regulatory Policies Act (PURPA), the facility must produce electric energy and "another form of useful thermal energy through the sequential use of energy" and meet certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC). (See the code of Federal Regulations, Title 18, Part 292.)~~

~~**Committed Resources:** All existing capacity and all committed, planned capacity for the specified year. Existing capacity shall include all existing generators regardless of physical location. Committed, planned capacity shall include both capacity that is under construction and existing units that are to be retired and deactivated or reactivated during the specified year.~~

~~**Conductor:** Metal wires, cables, and bus-bar used for carrying electric current. Conductors may be solid or stranded, that is, built up by a assembly of smaller solid conductors.~~

~~**Conductor:** The portion of a transmission line that carries the electrical current.~~

~~**Conductor Material Type:** Identifies the type of material used to conduct electricity.~~

~~**Configuration Maps:** Geographic information containing transmission line, substation, and terminal information. It shows the normal operating voltages and includes information about other operational and political boundaries.~~

~~**Direct Control Load Management:** The magnitude of customer demand that can be interrupted at the time of the seasonal peak load by direct control of the system operator by interrupting power supply to individual appliances or equipment on customer premises. This type of control usually reduces the demand of residential customers.~~

~~**Distributed Generator:** Distributed generators (DGs) are grid-connected units that are typically located close to customer loads and are connected to the utility grid at distribution voltages (i.e. voltages less than 69 kV).~~

~~**EIA Company Code:** Unique identification number assigned by EIA to companies and entities~~

~~operating in the electric power industry.~~

~~**Electric Power:** The rate at which electric energy is transferred. Electric power is measured by capacity and is commonly expressed in megawatts (MW).~~

~~**GLOSSARY Continued**~~

~~**Electricity:** A form of energy characterized by the presence and motion of elementary charged particles generated by friction, induction, or chemical change.~~

~~**Electricity Generation:** The process of producing electric energy or the amount of electric energy produced by transforming other forms of energy, commonly expressed in kilowatthours (kWh) or megawatthours (MWh).~~

~~**Energy Source:** Any substance or natural phenomenon that can be consumed or transformed to supply heat or power. Examples include petroleum, coal, natural gas, nuclear, biomass, electricity, wind, sunlight, geothermal, water movement, and hydrogen in fuel cells.~~

~~**File Name:** The alpha-numeric name that identifies the electronic data file.~~

~~**Full Responsibility Purchases**: Total of all purchases for which the seller 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). Each purchaser and seller must agree on which of their transactions are reported under this heading.~~

~~**Full Responsibility Sales:** Total of all sales for which the seller 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). Each purchaser and seller must agree on which of their transactions are reported under this heading.~~

~~**Generator Nameplate Capacity (Installed):** The maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer. Installed generator nameplate capacity is commonly expressed in megawatts (MW) and is usually indicated on a nameplate physically attached to the generator.~~

~~**Gross Generation:** The total amount of electric energy produced by generating units and measured at the generating terminal in kilowatthours or megawatthours.~~

~~**Inoperable Capacity:** Generating capacity that is totally or partially out of service at the time of system peak load, either for scheduled outages (see GADS definition of "scheduled outages." These include both maintenance outages and planned outages.) or for reasons such as: environmental restrictions; extensive modifications or repair; or capacity specified as being in a mothballed state.~~

~~**Internal Demand:** Peak hour integrated megawatt demand is defined as the sum of the demands of all customers that a system serves, including the demands of the organization providing the electric service, plus the losses incidental to that service. Total Internal Demand is the sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demand of station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) is not included.~~

~~**Interruptible Demand:** The magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the NERC Council or Reporting Party seasonal peak by direct control of the System Operator or by action of the customer at the direct request of the System Operator. In some instances, the demand reduction may be effected by direct action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions. For example, demands that can be interrupted to fulfill planning or operating reserve requirements normally should be reported as Interruptible Demand. Interruptible Demand as reported here does not include Direct Control Load Management.~~

~~**Kilowatt (kW):** One thousand watts.~~

~~**Kilowatthour (kWh):** A measure of electricity defined as a unit of work or energy, measured as~~

~~1 kilowatt (1,000 watts) of power expended for 1 hour. One kWh is equivalent to 3,412 Btu.~~

~~**GLOSSARY Continued**~~

~~**Line Length:** Number of miles between beginning and ending terminal points of the line, regardless of conductors or circuits carried.~~

~~**Map Number:** The alpha-numeric identification for each map file, as assigned by the respondent.~~

~~**Map Software:** Identification of the computer software program (or system) that was used to develop the electronic data files and will be used to electronically import and interpret the data files.~~

~~**Maximum Generator Nameplate Capacity:** The maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer.~~

~~**Megawatt (MW):** One million watts of electricity.~~

~~**Megawatthour (MWh):** One thousand kilowatt-hours or 1 million watt-hours.~~

~~**Miles of Line by Voltage (Size):** Length of transmission lines by voltage for the electrical system.~~

~~**Net Capacity:** The maximum load that a generating unit, generating station, or other electrical apparatus can carry, exclusive of station use, under specified conditions for a given period of time without exceeding approved limits of temperature and stress.~~

~~**Net Energy:** The net electrical energy requirements of an electric system are defined as system net generation plus energy received from others, less energy delivered to others through interchange. It includes system losses but excludes energy required for storage at energy storage facilities.~~

~~**Net Generation:** The amount of gross generation less the electrical energy consumed at the generating station(s) for station service or auxiliaries. *Note:* Electricity required for pumping at pumped-storage plants is regarded as electricity for station service and is deducted from gross generation.~~

~~**Net Internal Demand:** Internal Demand less Direct Control Load Management and Interruptible Demand.~~

~~**Net Operable Capacity:** Total owned capacity less inoperable capacity.~~

~~**Net Summer Capacity:** The maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of May 1 through October 31). This output reflects a reduction in capacity due to electricity use for station service or auxiliaries.~~

~~**Net Winter Capacity:** The maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of peak winter demand (period of November 1 though April 30). This output reflects a reduction in capacity due to electricity use for station service or auxiliaries.~~

~~**Net Winter Capacity:** The steady hourly output, which generating equipment is expected to supply to system load exclusive of auxiliary power, as demonstrated by tests at the time of winter peak demand. The winter peak period begins on December 1 and extends through March 31.~~

~~**North American Industrial Classification System (NAICS):** A classification scheme, developed by the Office of Management and Budget to replace the Standard Industrial Classification (SIC) System, that categorizes establishments according to the types of production processes they primarily use.~~

~~**North American Industry Classification System (NAICS):** A set of codes that describes the~~

~~possible purposes of a facility.~~

~~**Ownership:** The entity or entities that own(s) the generator. The entity or entities that own(s) the transmission line. Ownership may be single, joint, or held by an entity other than the respondent.~~

~~**Peak Hour Demand:** The maximum load in megawatts during the specified year.~~

~~**Pole/Tower Type:** Identifies the type of transmission line supporting structure.~~

~~**GLOSSARY Continued**~~

~~**Prime Mover:** The engine, turbine, water wheel, or similar machine that drives an electric generator; or, for reporting purposes, a device that converts energy to electricity directly (e.g., photovoltaic solar and fuel cells).~~

~~**Projected In-service Date:** The projected date the line will be energized under the control of the system operator, including month and year.~~

~~**Qualifying Facility (QF):** A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act (PURPA). **Rated Capacity:** The maximum utilization level of transmission line, or other electrical device in millions of volt-amperes, or mega-volt amperes (MVA).~~

~~**Regulated Entity:** For the purpose of EIA's data collection efforts, entities that either provide electricity within a designated franchised service area and/or file forms listed in the Code of Federal Regulations, Title 18, part 141 are considered regulated entities. This includes investor-owned electric utilities that are subject to rate regulation, municipal utilities, federal and state power authorities, and rural electric cooperatives. Facilities that qualify as cogenerators or small power producers under the Public Utility Regulatory Power Act (PURPA) are not considered regulated entities.~~

~~**Renewable Resource:** An energy resource that is naturally replenishing but flow-limited. It is virtually inexhaustible in duration, but limited in the amount of energy that is available per unit of time. Renewable resources include: biomass, hydroelectric, geothermal, solar, and wind power.~~

~~**Size of Conductor:** Identifies either the diameter or the cross-sectional area of a transmission line conductor.~~

~~**Standby Demand:** The demand specified by contractual arrangement with a customer to provide power and energy to that customer as a secondary source or backup for an outage of the customer's primary source. Standby Demand is intended to be used infrequently by any one customer.~~

~~**Summer Peak Hour Demand:** The maximum load in megawatts during the period June through September.~~

~~**Terminal Location:** Identifies the physical location of one end of a transmission line segment.~~

~~**Tested Heat Rate:** The fuel consumed in British thermal units (Btu) necessary to generate one net kilowatthour of electric energy, reported based on primary energy source under full load conditions. Reported in Btu per kilowatthour.~~

~~**Total Internal Demand:** The sum of internal demand plus standby demand.~~

~~**Type of Facility:** A descriptive identification of what the facility does, highlighting the associated functional activity (e.g., transformer, transmission line, phase-shifter).~~

~~**Type of Line**: Identifies the physical location of the conductor (overhead, underground, or submarine).~~

~~**Type of Organization:** Identifies the type of organization that best represents the line owner including the following types of utilities – Investor-owned (I), Municipality (M), Cooperative (C),~~

	~~State-owned (S), Federally-owned (F), or other (O).~~ ~~**Uncommitted Resources:** All proposed generating capacity that is either not under construction or is of "unknown" status.~~
~~**GLOSSARY Continued**~~	~~**Unit Code:** Multi-generator code that identifies all generators that are operated with others as a single unit. Such generators should report a single heat rate.~~ ~~**Unregulated Entity:** For the purpose of EIA's data collection efforts, entities that do not have a designated franchised service area and that do not file forms listed in the Code of Federal Regulations, Title 18, part 141 are considered unregulated entities. This includes qualifying cogenerators, qualifying small power producers, and other generators that are not subject to rate regulation such as independent power producers.~~ ~~**Voltage, Designed:** Voltage at which a designated transmission facility was designed to operate.~~ ~~**Voltage, Operating:** Voltage at which a designated transmission facility currently operates.~~ ~~**Voltage Type:** With respect to transmission facilities, voltage type identifies whether the line is designed to operate at alternating current (a.c.) or direct current (d.c.) voltages.~~ ~~**Winter Peak Hour Demand:** The maximum load in megawatts during the period December through March.~~ ~~**Year of Study:** Identification of the projected years covered by a specified study.~~ ~~**Years Projected:** Identification of the specific time period for which the projection applies.~~
GLOSSARY	The glossary for this form is available online at the following URL: http://www.eia.doe.gov/cneaf/electricity/page/define.html
SANCTIONS	The timely submission of Form EIA-411 by those required to report is requested under Section 13(b) of the Federal Energy Administration Act of 1974 (FEAA) (Public Law 93-275), as amended. **Title 18 U.S.C. 1001 makes it a criminal offense for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction.**
REPORTING BURDEN	Public reporting burden for this collection of information is estimated to average 120 hours per regional response and 18 hours per utility response ~~15,720 hours or 1.572 1,280 hours per response,~~ including the time of reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. The burden includes not only the hours needed by the regional councils and NERC, but also for the members and regulated entities within that council. ~~This estimate excludes the hours needed to complete Schedule 3 of this form. Schedule 3 burden hours are accounted for in the burden associated with the mandatory Form EIA-860.~~ Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to the Energy Information Administration, Statistics and Methods Group, EI-70, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585-0670; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. A person is not required to respond to the collection of information unless the form displays a valid OMB number.

CONFIDENTIALITY	**The information contained on Schedule 5, Bulk Electric Transmission System Maps; and Schedule 8, Bulk Transmission Facility Power Flow Cases** will be kept confidential and not disclosed to the public to the extent that it satisfies the criteria for exemption under the Freedom of Information Act (FOIA), 5 U.S.C. §552, the DOE regulations, 10 C.F.R. §1004.11, implementing the FOIA, and the Trade Secrets Act, 18 U.S.C. §1905. The Energy Information Administration (EIA) will protect your information in accordance with its confidentiality and security policies and procedures. The Federal Energy Administration Act requires the EIA to provide company-specific data to other Federal agencies when requested for official use. The information reported on this form may also be made available, upon request, to another component of the Department of Energy (DOE); to any Committee of Congress, the General Accounting Office, or other Federal agencies authorized by law to receive such information. A court of competent jurisdiction may obtain this information in response to an order. The information may be used for any nonstatistical purposes such as administrative, regulatory, law enforcement, or adjudicatory purposes. Disclosure limitation procedures are applied to the statistical data published from EIA-411 confidential survey information to ensure that the risk of disclosure of identifiable information is very small. Any additional information reported on Form EIA-411 will not be treated as confidential and may be publicly released in identifiable form. In addition to the use of the information by EIA for statistical purposes, the information may be used for any nonstatistical purposes such as administrative, regulatory, law enforcement, or adjudicatory purposes.

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REPORT FOR: < respondent name > <respondent id>

REPORTING PERIOD: As of January 1, 2004

NOTICE: ~~Data reported on~~ The information contained on Schedule 5, Bulk Electric Transmission System Maps; and Schedule 8, Bulk Transmission Facility Power Flow Cases ~~Schedule 3, Part B, Latitude and Longitude and Schedule 3, Part D, Line 6 Tested Heat Rate, will be kept confidential.~~ All other data are not confidential. See instructions for reporting obligation, laws authorizing collection, purpose, confidentiality, and related information.

Title 18 U.S.C. 1001 makes it a criminal offense for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction.

SURVEY CONTACTS: Persons to contact with questions about this form.

Contact Person 1:		Title:
Telephone: ( )	FAX: ( )	E-mail:
Contact Person 2:		Title:
Telephone: ( )	FAX: ( )	E-mail:

Council		
Reporting Party		

SCHEDULE 1. PART A. HISTORICAL AND PROJECTED PEAK DEMAND AND ENERGY - MONTHLY

		YEAR					
		2004		2005		2006	
LINE NO.	MONTH	PEAK HOUR DEMAND (MEGAWATTS) (a)	NET ENERGY (1000s of MEGA-WATTHOURS) (b)	PEAK HOUR DEMAND (MEGAWATTS) (c)	NET ENERGY (1000s of MEGA-WATTHOURS) (d)	PEAK HOUR DEMAND (MEGAWATTS) (e)	NET ENERGY (1000s of MEGA-WATTHOURS) (f)
1	January						
2	February						
3	March						
4	April						
5	May						
6	June						
7	July						
8	August						
9	September						
10	October						
11	November						
12	December						

SCHEDULE 1. PART B. HISTORICAL AND PROJECTED PEAK DEMAND AND ENERGY - ANNUAL

LINE NO.		YEAR					
		2004	2005	2006	2007	2008	2009
1	Summer Peak Hour Demand, June - September (Megawatts)						
		2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
2	Winter Peak Hour Demand, December - March (Megawatts)						
		2004	2005	2006	2007	2008	2009
3	Net Annual Energy (1000s of Megawatthours)						

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SCHEDULE 2. CAPACITY FOR EXISTING GENERATORS IN REPORTING YEAR
(Complete One Column for Each Generator)

LINE NO		Generator (a)		Generator (b)		Generator (c)	
1	**EIA Plant Identification**	<pre-printed>		<pre-printed>		<pre-printed>	
2	**EIA Generator Identification**	<pre-printed>		<pre-printed>		<pre-printed>	
3	**Prime Mover Code**	<pre-printed>		<pre-printed>		<pre-printed>	
4	**Unit Code**	<pre-printed>		<pre-printed>		<pre-printed>	
5	**Ownership Code**	<pre-printed>		<pre-printed>		<pre-printed>	
6	**GADS Generator ID**						
		Summer	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**
7	**Net Capacity as reported on Form EIA-860 (MW)**	<pre-printed>	<pre-printed>	<pre-printed>	<pre-printed>	<pre-printed>	<pre-printed>
8	**Inoperable Capacity**						
9	**Net Operable Capacity (line 7 less line 8)**						

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SCHEDULE 3. PART A. HISTORICAL AND PROJECTED DEMAND AND CAPACITY - SUMMER

LINE NO.		YEAR					
		2004	2005	2006	2007	2008	2009
DEMAND (IN MEGAWATTS)							
1	Internal Demand						
2	Standby Demand						
3	Total Internal Demand (sum of lines 1 and 2)						
4	Direct Control Load Management						
5	Interruptible Demand						
6	Net Internal Demand (line 3, less line 4, less line 5)						
NET CAPACITY (IN MEGAWATTS)							
7	Total Net Operable Capacity (sum of Schedule 2, line 9 across all generators) col 1 only, out years projected						
7a	Uncommitted Capacity						
7b1	Reliability Derating Unit Specific Subtotal						
7b2	Reliability Derating Unit Specific Group Subtotal						
7c	Other Generation						
7d	Subtotal Committed Capacity (line 7 – 7a – a7b – 7c)						
8	Generator Capacity, less than 1 megawatt (8a +8b)						
8a	Distributed Generator Capacity, less than 1 megawatt						
8b	Other Capacity, less than 1 megawatt						
9	Total Net Generator Capacity (sum of line 7 and line 8)						
9b	Distributed Generator Capacity, 1 megawatt or greater						
PURCHASES AND SALES (IN MEGAWATTS)							
10	Total Capacity Purchases						
10a	Full Responsibility Purchases						
11	Total Capacity Sales						
11a	Full Responsibility Sales						
CAPACITY SUMMARY (IN MEGAWATTS)							
12	Planned Capacity Resources (sum of lines 9 plus 10 minus 11)						

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Council		
Reporting Party		

SCHEDULE 3. PART B. HISTORICAL AND PROJECTED DEMAND AND CAPACITY -- WINTER

LINE NO.		YEAR					
		2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
DEMAND (IN MEGAWATTS)							
1	Internal Demand						
2	Standby Demand						
3	Total Internal Demand (sum of lines 1 and 2)						
4	Direct Control Load Management						
5	Interruptible Demand						
6	Net Internal Demand (line 3, less line 4, less line 5)						
NET CAPACITY (IN MEGAWATTS)							
7	Total Net Operable Capacity (sum of Schedule 2, line 9 across all generators)						
7b1	Reliability Derating Unit Specific Subtotal						
7b2	Reliability Derating Unit Specific Group Subtotal						
7c	Other Generation						
7d	Subtotal Committed Capacity (line 7 – 7a – a7b – 7c)						
8	Generator Capacity, less than 1 megawatt (8a +8b)						
8a	Distributed Generator Capacity, less than 1 megawatt						
8b	Other Capacity, less than 1 megawatt						
9	Total Net Generator Capacity (sum of line 7 and line 8)						
9b	Distributed Generator Capacity, 1 megawatt or greater						
PURCHASES AND SALES (IN MEGAWATTS)							
10	Total Capacity Purchases						
10a	Full Responsibility Purchases						
11	Total Capacity Sales						
11a	Full Responsibility Sales						
CAPACITY SUMMARY (IN MEGAWATTS)							
12	Planned Capacity Resources (sum of lines 9 plus 10 minus 11)						

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REPORT FOR: < respondent name > <respondent id>

REPORTING PERIOD: As of January 1, 2004

Council	
Reporting Party	

SCHEDULE 4. PART A. HISTORICAL AND PROJECTED CAPACITY PURCHASES/INCOMING TRANSFERS (MEGAWATTS) - SUMMER

~~(If Necessary, Copy and Attach Additional Sheets)~~

		YEAR							
LINE NO.	**OTHER PARTY EIA CODE (a)**	**Plant ID**	**Unit ID**	**2004(b)**	**2005 (c)**	**2006 (d)**	**2007 (e)**	**2008 (f)**	**2009 (g)**
1									
2									
3									
4									
5									
6									
7									
8									
9									
10									
11	Total								

SCHEDULE 4. PART B. HISTORICAL AND PROJECTED CAPACITY PURCHASES/INCOMING TRANSFERS (MEGAWATTS) - WINTER

~~(If Necessary, Copy and Attach Additional Sheets)~~

		YEAR							
LINE NO.	**OTHER PARTY EIA CODE (a)**	**Plant ID**	**Unit ID**	**2004/2005 (b)**	**2005/2006 (c)**	**2006/2007 (d)**	**2007/2008 (e)**	**2008/2009 (f)**	**2009/2010 (g)**
12									
13									
14									
15									
16									
17									
18									
19									
20									
21									
22	Total								

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SCHEDULE 4. PART C. HISTORICAL AND PROJECTED CAPACITY SALES (MEGAWATTS) - SUMMER

~~(If Necessary, Copy and Attach Additional Sheets)~~

		YEAR							
LINE NO.	OTHER PARTY EIA CODE (a)	Plant ID	Unit ID	2004(b)	2005 (c)	2006 (d)	2007 (e)	2008 (f)	2009 (g)
1									
2									
3									
4									
5									
6									
7									
8									
9									
10									
11	Total								

SCHEDULE 4. PART D. HISTORICAL AND PROJECTED CAPACITY SALES (MEGAWATTS) - WINTER

~~(If Necessary, Copy and Attach Additional Sheets)~~

		YEAR							
LINE NO.	OTHER PARTY EIA CODE (a)	Plant ID	Unit ID	2004/2005 (b)	2005/2006 (c)	2006/2007 (d)	2007/2008 (e)	2008/2009 (f)	2009/2010 (g)
12									
13									
14									
15									
16									
17									
18									
19									
20									
21									
22	Total								

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SCHEDULE 5. BULK ELECTRIC TRANSMISSION SYSTEM MAPS

LINE NO.				
1	Specify the Number of Maps Provided:			
2	For each map provide file name, coverage, and map software:			
	MAP NUMBER (a)	FILE NAME (b)	YEARS PROJECTED (c)	MAP SOFTWARE (d)

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SCHEDULE 6. PROPOSED TRANSMISSION LINES

~~(If Necessary or Multiple Owners, Copy and Attach Additional Sheets)~~

LINE NO.		TRANSMISSION LINE (a)	TRANSMISSION LINE (b)	TRANSMISSION LINE (c)
TRANSMISSION LINE IDENTIFICATION				
1	Terminal Location (From)			
2	Terminal Location (To)			
TRANSMISSION LINE OWNERSHIP				
3	Company Name			
4	EIA Company Code			
5	Type of Organization			
6	Percent Ownership			
TRANSMISSION LINE DATA				
7	Line Length (miles)			
8	Line Type	[ ] OH [ ] UG [ ] SM	[ ] OH [ ] UG [ ] SM	[ ] OH [ ] UG [ ] SM
9	Voltage Type	[ ] AC [ ] DC	[ ] AC [ ] DC	[ ] AC [ ] DC
10	Voltage Operating (Kilovolts)			
11	Voltage Design (Kilovolts)			
12	Conductor Size (MCM)			
13	Conductor Material Type (Select codes from legend below)			
14	Bundling Arrangement (Select codes from legend below)			
15	Circuits per Structure Present			
16	Circuits per Structure Ultimate			
17	Pole/Tower Type (Select codes from legend below)	Pole Material: [ ] Pole Type: [ ]	Pole Material: [ ] Pole Type: [ ]	Pole Material: [ ] Pole Type: [ ]
18	Capacity Rating (Megavoltamperes)			
19	Projected In-Service Date (e.g., 12-2004)			

LEGEND

Line Type	Voltage Type	Conductor Material Type	Bundling Arrangement	Pole/Power Type: Pole Material	Pole/Power Type: Pole Type
OH=Overhead UG=Underground SM=Submarine	AC=Alternating Current DC=Direct Current	AL = Aluminum ACCR = Aluminum Composite Conductor Reinforced ACSR = Aluminum Core Steel Reinforced CU = Copper OT = Other	1 = Single 2 = Double 3 = Triple 4 = Quadruple OT = Other	W = Wood C = Concrete S = Steel B = Combination P = Composite O = Other	P = Single pole H = H-frame T = Tower U = Underground O = Other

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SCHEDULE 7. PART A, ANNUAL DATA ON TRANSMISSION LINE OUTAGES FOR EHV A.C. LINES
(Report following data for each applicable EHV Voltage Class)

LINE NO.						
1	Applicable A.C. Voltage Class	230 kV (a)	345 kV (b)	500 kV (c)	765 kV (d)	Other (specify) (e)
	Scheduled Outages for Specified Voltage Class					
2	Number of Scheduled Outages					
3	Number of Circuits Involved					
4	Scheduled Circuit-Hours Out of Service					
	Unscheduled Outages for Specified Voltage Class					
5	Number of Non-Momentary Unscheduled Outages					
6	Number of Circuits Involved					
7	Unscheduled Circuit-Hours Out of Service					
	Causal Categories for Unscheduled Outages of Specified Voltage Class (Percent)					
8	Weather					
9	Animals, Fire and Smoke, Human Accidents					
10	Vegetation					
11	Operator Action					
12	Other or Unknown					
	Total Outages for Specified Voltage Class					
13	Number of Circuits with Outages (sum of lines 3 and 6)					
14	Total Number of Outages Reported (sum of lines 2 and 5)					

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SCHEDULE 7. PART B, ANNUAL DATA ON TRANSMISSION LINE OUTAGES FOR EHV LINES D.C. LINES
(Report following data for each applicable EHV Voltage Class)

LINE NO.						
1	Applicable D.C. Voltage Class	± 100-199 kV (a)	± 200-299 kV (b)	± 300-399 kV (c)	± 400-499 kV (d)	± 500 kV or greater (e)
	Scheduled Outages for Specified Voltage Class					
2	Number of Scheduled Outages					
3	Number of Circuits Involved					
4	Scheduled Circuit-Hours Out of Service					
	Unscheduled Outages for Specified Voltage Class					
5	Number of Momentary Unscheduled Outages					
6	Number of Non-Momentary Unscheduled Outages					
7	Total Number of Unscheduled Outages (sum of lines 5 and 6)					
8	Number of Circuits Involved					
9	Unscheduled Circuit-Hours Out of Service					
	Total Outages for Specified Voltage Class					
10	Number of Circuits with Outages (sum of lines 3 and 8)					
11	Total Number of Outages Reported (sum of lines 2 and 7)					

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SCHEDULE ~~7~~8. BULK TRANSMISSION FACILITY POWER FLOW CASES

LINE NO.		
1	**Case Name:**	
2	**Year of Study:**	
3	**Case Number:**	

	PROSPECTIVE FACILITIES AND CONNECTIONS				
				CONNECTIONS	
4	NAME OF FACILITY (a)	TYPE OF FACILITY (b)	PROJECTED IN-SERVICE DATE (e.g., 12-2004) (c)	BUS NUMBER (d)	BUS NAME (e)

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SCHEDULE ~~8~~9. FOOTNOTES

~~**(If Necessary, Copy and Attach Additional Sheets)**~~

LINE NO.	SCHEDULE (a)	PART (b)	LINE NO. (c)	COLUMN (d)	PAGE (e)	COMMENT (f)
1						
2						
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~~**REPORT FOR:** < respondent name > <respondent id>~~

~~**REPORTING PERIOD:** As of January 1, 2004~~

~~**SCHEDULE 9. AUTHORIZATION FOR REPORTING**~~

~~The respondent authorizes the agent designated below to submit on its behalf, the Form EIA-411, Schedule 3 (Form EIA-860, *Annual Electric Generator Report),* to the U.S. Department of Energy. Respondents have the option either to submit this completed form to the EIA or to designate an agent or agents (e.g., regional electric reliability council, North American Electric Reliability Council (NERC), or other groups) to submit this information to the EIA on its behalf. Each respondent is encouraged to designate its regional electric reliability council(s) as its agent(s) to report to the EIA on the respondent's behalf. The designated agent(s) must specify the electric generator for which it is submitting information. The respondent (electric generator) has the ultimate responsibility for submitting all these data or any data not submitted on its behalf by its designated agent(s).~~

	~~**AUTHORIZED AGENT**~~	
~~**LINE NO.**~~		
~~**1**~~	~~**Agent Name**~~	
~~**2**~~	~~**Agent Contact Person**~~	
~~**3**~~	~~**Agent Address**~~	
~~**4**~~	~~**Agent Telephone**~~	
	~~**RESPONDENT AUTHORIZING OFFICIAL**~~	
~~**5**~~	~~**Respondent Authorizing Official Name**~~	
~~**6**~~	~~**Respondent Authorizing Official Title**~~	
~~**7**~~	~~**Respondent Authorizing Official Telephone**~~	
~~**8**~~	~~**Respondent Authorizing Official Signature**~~	
~~**9**~~	~~**Date**~~	