

U.S. Department of Energy Energy Information Administration Form EIA-411 (2011)	COORDINATED BULK POWER SUPPLY AND DEMAND PROGRAM REPORT	Form Approved OMB No. 1905-0129 Approval Expires: 12/31/2013
PURPOSE	<p>Form EIA-411 collects information about regional electricity supply and demand projections for a ten-year advance period and information on the transmission system and supporting facilities. The data collected on this form appear in the Energy Information Administration (EIA) publication, <i>Electric Power Annual</i>. They are also 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.</p>	
REQUIRED RESPONDENTS	<p>The Form EIA-411 is mandatory for those entities required to report. The information used in Schedule 7 will come from the Transmission Availability Data Base of the North American Electric Reliability Corporation (NERC). The form is to be completed by each of the Regional Entities of NERC. Each Regional Entity compiles the responses from data furnished by utilities and other members within their Region and provided to NERC. Where subregions exist, a subregional submittal is required. NERC then compiles and coordinates these data and provides them to the Energy Information Administration.</p>	
RESPONSE DUE DATE	<p>Annual data, following the end of the calendar year, are due to the North American Electric Reliability Corporation by June 1st. After review, NERC will submit the completed Form EIA-411 to the EIA by July 15.</p>	
METHODS OF FILING RESPONSE	<p>The North American Reliability Corporation (NERC) will oversee the methods of filing response of the data by the Regional Entities. NERC then submits the compiled report to EIA.</p> <p>Submit the data via a secure file transfer process. Contact Marie Rinkoski Spangler at Marie.Rinkoski-Spangler@eia.doe.gov for instructions.</p> <p>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:</p> <p style="text-align: center;">Marie Rinkoski Spangler, Survey Manager Energy Information Administration, Mail Stop EI-53 1000 Independence Avenue, S.W. Washington, DC. 20585-0690</p> <p>Please retain a completed copy of this form for your files.</p>	
CONTACTS	<p>Data Questions: For questions about the data requested on Form EIA-411, contact the Survey Manager:</p> <p style="text-align: center;">Marie Rinkoski Spangler Telephone Number: (202) 586-2446 FAX Number: (202) 287-1934 Email: marie.rinkoski-spangler@eia.doe.gov</p>	

GENERAL INSTRUCTIONS

ITEM-BY-ITEM INSTRUCTIONS

SCHEDULE 1: IDENTIFICATION

1. **Survey Contact:** Verify contact name, title, telephone number, fax number, and e-mail address.
 2. **Supervisor of Contact Person for Survey:** Verify the contact's supervisor's name, title, telephone number, fax number and e-mail address.
 3. **Report For:** Verify the NERC Regional Entity and reporting party, whether it be Regional Entity or subregion.
- If any of the above information is incorrect, revise the incorrect entry and provide the correct information. Provide any missing information.

SCHEDULE 2, Part A and B: HISTORICAL AND PROJECTED PEAK DEMAND AND ENERGY

GENERAL INSTRUCTIONS

1. The reported peak demand for a Region or subregion should be non-coincident, comprised of the sum of all peak demands for the various operating entities within a NERC Region or subregion during the specified period. For Regions or subregions that provide coincident peak demands, submit justification for providing a coincident value.

The term peak is defined as:

- **Summer Peak Hour Demand:** The maximum load in megawatts during the period June through September. The summer peak period begins on June 1 and extends through September 30.
- **Winter Peak Hour Demand:** The maximum load in megawatts during the period December through February. The winter peak period begins on December 1 and extends through the end-of-February.
- **Peak Hour Demand:** The maximum load in megawatts during the specified reporting period.

The term Net Energy for Load is defined as:

- Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to other Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.

2. The fundamental test for determining the adequacy of the power system is to determine whether resources exceed demand while allowing sufficient margin to address operating events (loss of generation for instance). This test requires that demand forecasts be provided and aggregated. While coincident demand determinations are preferable, this is not feasible given the number of entities reporting and the time available to build hourly models. Therefore, peak demand forecasts will need to be aggregated at peak. In some cases this can be done on a monthly interval during the peak season.

3. When providing a demand forecast to EIA the fundamental approach is to provide a normalized forecast. This is defined as a forecast which has been adjusted to reflect normal weather, and is expected on a 50% probability basis, (i.e., a peak demand forecast level that has a 50% probability of being under or over achieved by the actual peak). This is also known as the 50/50 forecast. This forecast can then be used to test against more extreme conditions.

PART A: Enter monthly peak demand and Net Energy for Load for designated months as defined above.

PART B: Enter seasonal peak demand and Net Energy for Load for designated years as defined above.

SCHEDULE 3, PART A and B: HISTORICAL AND PROJECTED DEMAND, CAPACITY, TRANSACTIONS, AND RESERVE MARGINS

GENERAL INSTRUCTIONS

1. PART A should be filled out for the summer seasonal peak. PART B should be filled out for the winter seasonal peak.
2. Enter demand and capacity for the summer (PART A) and winter (PART B) peak periods of the designated years for the NERC Region or subregion. Peak demands reported should agree with the corresponding entries in SCHEDULE 2, Part B.
3. Where capacity values are entered, values should accumulate through the ten year projection period. For example, following the table below, in 2011 "0" was added; in 2012 "100" was added; in 2013 "0" was added; in 2014 "100" was added; in 2015 "100" was added. For the 2011 base-case, by 2015 "300" is planned to be added.

YEAR	2011	2012	2013	2014	2015
Planned Capacity	0	100	100	200	300

4. For demand and capacity values, all numbers should be entered as MW in positive values – no negatives, up to one decimal place. (All subtractions will be shown on the respective line found in the form).
5. For hydroelectric capacity, explain in SCHEDULE 9, COMMENTS whether the projected year's data are for an adverse water year, an average water year, or other.
6. For line 1, **Unrestricted Non-coincident Peak Demand** is the gross load of the region/sub-region, which includes New Conservation (Energy Efficiency) and Estimated Diversity; and excludes Additions for Non-member Loads and Stand-by Load Under Contract, as defined below.
 - For line 1a, **New Conservation (Energy Efficiency)**, enter the estimated impact of incremental passive energy efficiency programs. The increment represents the increase above the embedded amount from the base year. These impacts should be associated with programs to increase energy efficiency beyond its natural or normal growth.
 - For line 1b, **Estimated Diversity**, enter the difference between the region's/subregion's peak and the sum of the peaks of the reporting entities (LSEs, balancing area, zones, etc.).
 - For line 1c, **Additions for Non-member Loads**, enter adjustments to account for load of non-members, in accordance with the NERC standard MOD-16 that "data submittal requirements shall stipulate 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."
 - For line 1d, **Stand-by Load Under Contract**, enter the expected demand at time of system peak required to provide power and energy (under a contract with a customer as a secondary source or backup for an outage of the customer's primary source). Do not report the total (sum) of all contracted stand-by load. Additionally, do not separately report expected contract standby demand if it is already included in the forecasted peak data previously provided.
6. For line 2, **Total Internal Demand**, enter 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)

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are not included. 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. These values should equal those as reported in SCHEDULE 2, Part B, Seasonal Peak Hour Demand for the corresponding years.

- For line 2a, **Direct Control Load Management (Direct Load Control)**, enter the magnitude of customer demand that can be interrupted at the time of the seasonal peak load by direct control of a single operator by interrupting power supply to individual appliances or equipment on customer premises. This type of control usually reduces the demand of residential or small commercial customers. Direct Control Load Management (Direct Load Control) as reported here does not include Interruptible Demand (line 2b).
- For line 2b, **Contractually Interruptible Demand (Curtailable)**, enter the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Region or subregion's 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. Contractually Interruptible Demand as reported here does not include Direct Control Load Management (line 2a).
- For line 2c, **Critical Peak Pricing (CPP) with Control**, enter the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Entity's seasonal peak by direct control of the System Operator or by action of the customer by responding to high prices of energy triggered by system contingencies or high wholesale market prices.
- For line 2d, **Load as a Capacity Resource**, enter the magnitude of customer demand that, in accordance with contractual arrangements, is committed to pre-specified load reductions when called upon by a balancing authority. These resources are not limited to being dispatched during system contingencies and may be subject to economic dispatch from balancing authorities. Additionally, this capacity may be used to meet resource adequacy obligations when determining planning reserve margins.

7. For line 3, **Net Internal Demand**, enter line 2, less line 2a, less line 2b, less 2c, less 2d (Total Internal Demand, less Direct Control Load Management, Interruptible Demand, Critical Peak Pricing (CPP) with Control, and Load as a Capacity Resources).
8. For line 4a, **Demand Response used for Reserves - Spinning**, enter demand-side resources, which displace generation deployed as operating reserves that are synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an electric grid event. Penalties are assessed for non-performance.
9. For line 4b, **Demand Response used for Reserves – Non-Spinning**, enter demand-side resources, which displace generation deployed as operating reserves that are not connected to the system but capable of serving demand within a specified time. Penalties are assessed for non-performance.
10. For line 4c, **Demand Response used for Regulation**, enter demand-side resources responsive to Automatic Generation Control (AGC) to provide normal regulating margin.
11. For line 4d, **Demand Response used for Energy, Voluntary - Emergency**, enter demand-side resources, which curtail voluntarily when offered the opportunity to do so for compensation. Demand-side resources, which curtail during system and/or local capacity constraints.
12. For line 5, **Total Internal Capacity**, is the internal capacity for the reporting area. (Defined as seasonal rated capability during peak period - where full availability of primary fuel, wind, and

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<p>water is assumed.) The reported value should include capacity of all generators physically located and interconnected in the reporting area or planned to be physically located and interconnected in the reporting area, including the full capacity of those generators wholly or partially owned by (or with entitlement rights held by) entities outside of the reporting area. Additionally, where load is considered a capacity resource, this capacity is also included. This value is automatically calculated by the summations of all Existing and Future Capacity Additions (Line 6 + Line 7).</p> <p>13. For Line 6 – Existing Capacity is the sum of all existing generation connected to the electric system for the purpose of supplying electric load during the seasonal peak. Existing capacity does not include generation serving customers behind the meter. This value is automatically calculated by the summations of all Existing Capacity (Line 6a + Line 6b + Line 6c).</p> <p>14. For line 6a, Existing, Certain Capacity, included in this category are generation resources available to operate and deliver power within or into the region during the period of analysis in the assessment. Resources included in this category may be reported as a portion of the full capability of the resource, plant, or unit. This category includes, but is not limited to the following:</p> <ol style="list-style-type: none"> 1. Contracted (or firm) or other similar resource confirmed able to serve load during the period of analysis in the assessment. 2. Where organized markets exist, designated market resource that is eligible to bid into a market or has been designated as a firm network resource. 3. Network Resource, as that term is used in the Federal Energy Regulatory Commission (FERC) <i>pro forma</i> or other regulatory approved tariffs. 4. Energy-only resources confirmed able to serve load during the period of analysis in the assessment and will not be curtailed 5. Capacity resources that can not be sold elsewhere 6. Other resources not included in the above categories that have been confirmed able to serve load and not to be curtailed during the period of analysis in the assessment <p>For Actual Year data, do not derate this value by unplanned or “forced” outages. Unplanned outages are to be reported on line 6c1.</p> <ul style="list-style-type: none"> • For line 6a1, Wind Expected On-Peak, enter the amount of existing wind capacity that is expected to be available on seasonal peak. • For line 6a2, Solar Expected On-Peak, enter the amount of existing solar capacity that is expected to be available on seasonal peak. • For line 6a3, Hydro Expected On-Peak, enter the amount of existing hydro capacity that is expected to be available on seasonal peak. • For line 6a4, Biomass Expected On-Peak, enter the amount of existing biomass capacity that is expected to be available on seasonal peak. • For line 6a5, Load as a Capacity Resource Expected On-Peak (Load Management Programs), enter the magnitude of customer demand that, in accordance with contractual arrangements, is committed to pre-specified load reductions when called upon by a balancing authority. These resources are not limited to being dispatched during system contingencies and may be subject to economic dispatch from wholesale balancing authorities. Additionally, this capacity may be used to meet resource adequacy obligations when determining planning reserve margins. Values reported on this line are treated as a capacity resource and are held to the same expectations as an Existing, Certain resource. Only the expected on-peak seasonal capacity is reported on this line. <p>15. For line 6b, Existing, Other Capacity, included in this category are generation resources that may be available to operate and deliver power within or into the region during the period of analysis in the assessment, but may be curtailed or interrupted at any time for various reasons. This category also includes portions of intermittent generation not included in 6a, Existing, Certain. This category includes, but is not limited to the following:</p> <ol style="list-style-type: none"> 1. A resource with non-firm or other similar transmission arrangements 2. Energy-only resources that have been confirmed able to serve load for any reason during the Reporting Period, but may be curtailed for any reason. 3. Mothballed generation (that may be returned to service during the Reporting Period) 4. Portions of variable generation not counted in the Existing, Certain category (e.g. 		

wind, solar, etc.) that may not be available or de-rated during the Reporting Period.

5. Hydro generation not counted as Existing, Certain or de-rated.

6. Generation resources constrained for other reasons.

For Actual Year data, do not derate this value by unplanned or "forced" outages. Unplanned outages are to be reported on line 6c2.

- For line 6b1, **Wind Derated On-Peak**, enter the amount of existing wind capacity that is expected to be unavailable on seasonal peak.
- For line 6b2, **Solar Derated On-Peak**, enter the amount of existing solar capacity that is expected to be unavailable on seasonal peak.
- For line 6b3, **Hydro Derated On-Peak**, enter the amount of existing hydro capacity that is expected to be unavailable on seasonal peak.
- For line 6b4, **Biomass Derated On-Peak**, enter the amount of existing biomass capacity that is expected to be unavailable on seasonal peak.
- For line 6a5, **Load as a Capacity Resource Derated On-Peak (Load Management Programs)**, enter the amount of Load as a Capacity Resource that is expected to be unavailable on seasonal peak.
- For line 6b6, **Energy Only**, enter the amount of generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the area but may be recallable to another area.
- For line 6b7, **Scheduled Outage - Maintenance**, enter the amount capacity reduction due to a generator outage that is scheduled well in advance and is of a predetermined duration.
- For line 6b8, **Transmission-Limited Resources**, enter the amount of transmission-limited generation resources that have known physical deliverability limitations to serve load within the region.

16. For line 6c, **Existing, Inoperable Capacity**, included in this category are generation resources that are out-of-service and cannot be brought back into service to serve load during the period of analysis in the assessment. However, this category can include inoperable resources that could return to service at some point in the future. This value may vary for future seasons and can be reported as zero (0). This includes ALL existing generation within a Region or subregion not included in line 6a, Existing, Certain. or line 6b, Existing, Other, but is not limited to, the following:

1. Mothballed generation (that can not be returned to service for the period of the assessment)
2. Other existing but out-of-service generation (that can not be returned to service for the period of the assessment)
3. This category does not include behind-the-meter generation or non-connected emergency generators.
4. This category does not include partially dismantled units that are not forecasted to return to service

For Actual Year values, unplanned or "forced" outage capacity is to be considered as Existing, Inoperable Capacity. Report these values on lines 6c1 and 6c2.

- For line 6c1, Existing, Certain Capacity Forced Outage on Peak, enter the unplanned or "forced" outage of generators in MW, which were out-of-service due to **any** failures at the absolute peak.
- For line 6c2, Existing, Other Capacity Forced Outage on Peak, enter the unplanned or "forced" outage of generators in MW, which were out-of-service due to **any** failures at the absolute peak.

17. For line 7, **Future Capacity Additions**, included in this category are generation resources the reporting entity has a reasonable expectation of coming online during the period of the assessment. As such, to qualify in either of the Future categories, the resource must have achieved one or more of these milestones:

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	<ol style="list-style-type: none"> 1. Construction has started 2. Regulatory permits (e.g. Site Permit, Construction Permit, Environmental Permit) being approved 3. Regulatory approval has been received to be in the rate base 4. Approved power purchase agreement 5. Approved and/or designated as a resource by a market operator <p>18. For line 7a, Future, Planned, included in this category are generation resources anticipated to be available to operate and deliver power within or into the region during the period of analysis in the assessment. This category includes, but is not limited to, the following:</p> <ol style="list-style-type: none"> 1. Contracted (or firm) or other similar resource 2. Where organized markets exist, designated market resource that is eligible to bid into a market or has been designated as a firm network resource. 3. Network Resource, as that term is used in FERC's pro forma or other regulatory approved tariffs. 4. Energy-only resources confirmed able to serve load during the Reporting Period and will not be curtailed. 5. Where applicable, included in an integrated resource plan under a regulatory framework that mandates resource adequacy requirements and an obligation to serve. <p>For this value, only enter the Net Expected On-Peak Value. Do not include derates.</p> <ul style="list-style-type: none"> • For line 7a1, Wind Expected On-Peak, enter the amount planned wind capacity that is expected to be available on seasonal peak. • For line 7a2, Solar Expected On-Peak, enter the amount planned solar capacity that is expected to be available on seasonal peak. • For line 7a3, Hydro Expected On-Peak, enter the amount planned hydro capacity that is expected to be available on seasonal peak. • For line 7a4, Biomass Expected On-Peak, enter the amount planned biomass capacity that is expected to be available on seasonal peak. <p>19. For line 7b, Future, Other, included in this category are generation resources that do not qualify as Future, Planned and are not included in the Conceptual category. This category includes, but is not limited to, generation resources during the period of analysis in the assessment that may:</p> <ol style="list-style-type: none"> 1. Be curtailed or interrupted at any time for any reason 2. Energy-only resources that may be able to serve load during the Reporting Period 3. Variable generation not counted in the Future, Planned category or may not be available or is de-rated during the Reporting Period 4. Hydro generation not counted in the Future, Planned category or de-rated. <p>Resources included in this category may be adjusted using a confidence factor to reflect uncertainties associated with siting, project development or queue position. The confidence factor for Future, Other resources should be entered on line 16a and only adjusts the expected on-peak values and not the derated values.</p> <ul style="list-style-type: none"> • For line 7b1, Wind Expected On-Peak, enter the amount planned wind capacity that is expected to be available on seasonal peak. • For line 7b2, Wind Derate On-Peak, enter the amount proposed wind capacity that is expected to be unavailable on seasonal peak. • For line 7b3, Solar Expected On-Peak, enter the amount planned solar capacity that is expected to be available on seasonal peak. • For line 7b4, Solar Derate On-Peak, enter the amount proposed solar capacity that is expected to be unavailable on seasonal peak. • For line 7b5, Hydro Expected On-Peak, enter the amount planned hydro capacity that is expected to be available on seasonal peak. • For line 7b6, Hydro Derate On-Peak, enter the amount proposed hydro capacity 	

that is expected to be unavailable on seasonal peak.

- For line 7b7, **Biomass Expected On-Peak**, enter the amount planned biomass capacity that is expected to be available on seasonal peak.
- For line 7b8, **Biomass Derate On-Peak**, enter the amount proposed biomass capacity that is expected to be unavailable on seasonal peak.
- For line 7b9, **Energy Only**, enter the amount of generating resources that are designated as energy-only resources or have elected to be classified as energy only resources and may include generating capacity that can be delivered within the area but may be recallable to another area.

20. For line 8, **Conceptual**, included in this category are generation resources that are not in a prior listed category, but have been identified and/or announced on a resource planning basis through one or more of the following sources:

1. Corporate announcement
2. Entered into or is in the early stages of an approval process
3. Is in a generator interconnection (or other) queue for study
4. "Placeholder" generation for use in modeling.

For this value, only enter the Net Expected On-Peak Value. Do not include derates or energy only.

Resources included in this category may be adjusted using a confidence factor to reflect uncertainties associated with siting, project development or queue position. The confidence factor for Conceptual resources should be entered on line 16c and only adjusts the expected on-peak values and not the derated values.

- For line 8a1, **Wind Expected On-Peak**, enter the amount planned wind capacity that is expected to be available on seasonal peak.
- For line 8a2, **Wind Derate On-Peak**, enter the amount proposed wind capacity that is expected to be unavailable on seasonal peak.
- For line 8a3, **Solar Expected On-Peak**, enter the amount planned solar capacity that is expected to be available on seasonal peak.
- For line 8a4, **Solar Derate On-Peak**, enter the amount proposed solar capacity that is expected to be unavailable on seasonal peak.
- For line 8a5, **Hydro Expected On-Peak**, enter the amount planned hydro capacity that is expected to be available on seasonal peak.
- For line 8a6, **Hydro Derate On-Peak**, enter the amount proposed hydro capacity that is expected to be unavailable on seasonal peak.
- For line 8a7, **Biomass Expected On-Peak**, enter the amount planned biomass capacity that is expected to be available on seasonal peak.
- For line 8a8, **Biomass Derate On-Peak**, enter the amount proposed biomass capacity that is expected to be unavailable on seasonal peak.
- For line 8a9, **Energy-Only**, enter the amount of generating resources that are designated as energy-only resources or have elected to be classified as energy only resources and may include generating capacity that can be delivered within the area but may be recallable to another area.

21. For line 9, **Deliverable Internal Capacity**, this value is automatically calculated by the summations of Existing, Certain and Future. Planned Capacity Additions (Line 6a + Line 7a)

NOTES FOR TRANSACTIONS:

Contracts for capacity are defined as an agreement between two or more parties for the Purchase (Import) and Sale (Export) of generating capacity. Purchase contracts refer to imported capacity that is transmitted from an outside Region or subregion to the reporting Region or subregion. Sales contracts refer to exported capacity that is transmitted from the reporting Region or subregion to an outside Region or subregion. For example, if a generating resource subject to a contract is located in one region and sold to another region, the region in which the resource is located reports the capacity of the resource and reports the sale of such capacity that is being sold

to the outside region. The importing region reports such capacity as an import, and **does not** report the capacity as a supply resource (in line 6, 7, or 8).

TRANSMISSION CAPACITY MUST BE AVAILABLE FOR ALL REPORTED IMPORT AND EXPORT TRANSACTIONS.

DO NOT INCLUDE TRANSMISSION SYSTEM LOSSES WHEN REPORTING IMPORTS AND EXPORTS TRANSACTIONS.

The following examples are provided to show how unit-specific transactions are handled between two or more reporting Regions or subregions for Imports and Exports:

1. Unit physically located in Area A that is fully owned by a company in Area B and not connected to the Area A network but instead has a direct and adequate transmission connect to the Area A.

Solution: Show the unit completely in Area B with no transfers. All derating accounted for in Region or Province B.

2. Unit physically located in Area A that is half owned by a company in Area B.

Solution: Show the unit completely in Area A with an export to Area B of half of the capacity. Area B would show an import of half of the capacity from Area A, as long as Area A & B can demonstrate adequate transmission capacity. Unit derating accounted for in Area A and export reduced by half of the derated amount.

3. Unit physically located in Area A that is fully owned by a company in Area B.

Solution: Show the unit completely in Area A with an export to Area B of the full amount. Area B would show an import of the full amount of capacity from Area A, as long as Area A & B can demonstrate adequate transmission capacity. Unit derating should be accounted for in Area A and the import and export reduced by derated amounts in both Areas.

4. Unit physically located in Area A that is fully owned by a company in Area C and “wheeled” through Area B.

Solution: Show the unit completely in Area A with an export to Area C of the full amount. Area B does not report either import or export. Area C would show an import of the full amount of capacity from Area A, as long as Areas A, B, and C can demonstrate adequate transmission capacity.

22. For line 10, **Capacity Transactions – Imports**, the sum of lines 10a through 10d.

23. For line 10a, **Firm**, enter the amount of capacity purchases for which a firm contract has been signed. These transactions will be associated with Existing Certain Capacity.

- For line 10a1, **Full Responsibility Purchases** - Enter the 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. Values reported on this line represent a portion of Line 10a – Firm.
- For line 10a2, **Owned Capacity/Entitlement Located Outside the Region/subregion** – Enter the amount of externally owned capacity or capacity entitlements that will move from an outside Region or subregion to the reporting Region or subregion. Values reported on this line represent a portion of Line 10a – Firm.

24. For line 10b, **Non-firm**, enter the amount of capacity purchases for which a non-firm contract has been signed. This value should only be entered for the previous year actual data.

25. For line 10c, **Expected**, enter the amount of capacity for which a contract has not been

executed, but in negotiation, projected, or other. These transactions will be associated with Planned Capacity Additions.

- For line 10c1, **Full Responsibility Purchases** - Enter the 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. Values reported on this line represent a portion of Line 10c – Expected.
- For line 10c2, **Owned Capacity/Entitlement Located Outside the Region/subregion** - Enter the amount of externally owned capacity or capacity entitlements that will move from an outside Region or subregion to the reporting Region or subregion. Values reported on this line represent a portion of Line 10c – Expected.

26. For line 10d, **Provisional**, enter the amount of capacity for which the transaction(s) is under study, but negotiations have not begun.

27. For line 11, **Capacity Transactions – Exports**, the sum of lines 11a through 11d.

28. For line 11a, **Firm**, enter the amount of capacity purchases for which a firm contract has been signed. These transactions will be associated with Existing Certain Capacity.

- For line 11a1, **Full Responsibility Sales** - Enter the 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. Values reported on this line represent a portion of Line 11a – Firm.
- For line 11a2, **Owned Capacity/Entitlement Located Outside the Region/subregion** - Enter the amount of externally owned capacity or capacity entitlements that will move from an outside Region or subregion to the reporting Region or subregion. Values reported on this line represent a portion of Line 11a – Firm.

29. For line 11b, **Non-firm**, enter the amount of capacity purchases for which a non-firm contract has been signed. This value should only be entered for the previous year actual data.

30. For line 11c, **Expected**, enter the amount of capacity for which a contract has not been executed, but in negotiation, projected, or other. These transactions will be associated with Planned Capacity Additions.

- For line 11c1, **Full Responsibility Sales** - Enter the 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. Values reported on this line represent a portion of Line 11c – Expected.
- For line 11c2, **Owned Capacity/Entitlement Located Outside the Region/subregion** - Enter the amount of externally owned capacity or capacity entitlements that will move from an outside Region or subregion to the reporting Region or subregion. Values reported on this line represent a portion of Line 11c – Expected.

31. For line 11d, **Provisional**, enter the amount of capacity for which the transaction(s) is under study, but negotiations have not begun.

NOTES FOR MARGIN CALCULATIONS:

Lines 12-15a are calculated automatically and represent the amount of capacity (generating supply and transactions) that will be counted towards margin calculations.

32. For line 12, **Existing, Certain and Net Firm Transactions** is calculated by the summation of Existing, Certain Capacity and the net of Firm Transactions

33. For line 13, **Deliverable Capacity Resources** is calculated by the summation of Deliverable

Internal Capacity, the net of Firm and Expected Transactions.

34. For line 14, **Prospective Capacity Resources** is calculated by the summation of Deliverable Capacity Resources, Existing, Other Capacity, and the adjusted Future, Other Capacity (For this calculation, Future, Other resources are adjusted using the confidence factor reported on line 16a. This amount is automatically calculated in line 16b). All derates and outages are subtracted from this calculation.
35. For line 15, **Potential Capacity Resources** is calculated by the summation of Deliverable Capacity Resources, Existing, Other Capacity, Future, Other Capacity, Conceptual Capacity, and the net of Provisional Transactions. All derates and outages are subtracted from this calculation.
36. For line 15a, **Adjusted Potential Capacity Resources** is calculated by the summation of Prospective Capacity Resources, the adjusted Conceptual Capacity (For this calculation, Conceptual Resources are adjusted using the confidence factor reported on line 16c. This amount is automatically calculated in line 16d.) and the net of Provisional Transaction. All derates and outages are subtracted from this calculation.
37. For line 16a, **Confidence of Future, Other Resources** (line 7b), using reasonable judgment, enter a value between 0 and 100 that corresponds to the weight of emphasis placed on Future, Other additions for the given year. This factor only adjusts the expected on peak values.
38. For line 16b, **Net Future, Other Resources After Confidence Percentage Is Applied**, line 7b times line 16a.
39. For line 16c, **Confidence of Conceptual Resources** (line 8), using reasonable judgment, enter a value between 0 and 100 that corresponds to the weight of emphasis placed on Conceptual additions for the given year. This factor only adjusts the expected on peak values.
40. For line 16d, **Net Conceptual Resources After Confidence Percentage Is Applied**, line 8 times line 16c.
41. For line 17, **Target Reserve Margin**, enter a value between 0 and 100 that represents the expected target margin (%) for the Region/subregion. If no value is entered, a reference margin level will be applied and it is assumed this value will remain constant throughout the reporting period.

NOTES FOR RESERVE MARGINS:

Margin calculations are computed by NERC and submitted on behalf of the Region or subregion.

42. For line 18, **Existing Certain and Net Firm Transactions**, (line 12 minus line 3) divided by line 32.
43. For line 19, **Deliverable Capacity Resources**, (line 13 minus line 3) divided by line 3.
44. For line 20, **Prospective Capacity Resources**, (line 14 minus line 3) divided by line 3.
45. For line 21, **Total Potential Resources**, (line 15 minus line 3) divided by line 3.
46. For line 22, **Adjusted Potential Resources**, (line 15a minus line 3) divided by line 3.

SCHEDULE 5. BULK ELECTRIC TRANSMISSION SYSTEM MAPS

1. Each Regional Entity is to submit a map(s), in electronic format, showing the existing bulk electric transmission system 100 kV and above, including ties to all other Regional Entities, and the bulk electric transmission system additions projected for a ten-year period beginning with the year following the reporting year. The submission of Computer-Aided Design and/or Computer-Aided Design and Drafting (CAD/CADD) file types is also allowed.
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 Regional Entity 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 Regional Entity 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 ten-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 PART A & B: EXISTING TRANSMISSION CIRCUIT MILES AND PROJECTED TRANSMISSION ADDITIONS

PART A: Existing and Projected Transmission Circuit Miles

1. For the following lines, report transmission lines in WHOLE number circuit miles for the specified voltages:

Operative Voltage Range(kV)	Voltage Type	
100-120	AC	--
121-150	AC	--
151-199	AC	--
100-299	--	DC
200-299	AC	--
300-399	AC	DC
400-599	AC	DC
600+	AC	DC

2. All transmission lines must be classified into one of the following categories:
 - **Existing**
 - Energized line available for transmitting power
 - **Under Construction**
 - Construction of the line has begun
 - **Planned (any of the following)**
 - Permits have been approved to proceed
 - Design is complete
 - Needed in order to meet a regulatory requirement
 - **Conceptual (any of the following)**
 - A line projected in the transmission plan
 - A line that is required to meet a NERC TPL Standard or powerflow model and cannot be categorized as "Under Construction" or "Planned"
 - Projected transmission lines that are not "Under Construction" or "Planned"
3. For line 1, report Existing transmission lines as of the last day in the prior reporting year. (For example, the 2011 Report Year, enter the amount of circuit miles existing as of 12/31/2010.)
4. For line 2, report Under Construction transmission lines as of the first day in the current reporting year. (For example, the 2011 Report Year, enter the amount of circuit miles existing as of 1/1/2011.)
5. For line 3, report Planned transmission lines to be completed within the first 5 years starting the first day in the current reporting year.
6. For line 4, report Conceptual transmission lines to be completed within the first 5 years starting the first day in the current reporting year.
7. For line 5, report Planned transmission lines to be completed within the second 5 years starting the first day of the 5th projection year.
8. For line 6, report Conceptual transmission lines to be completed within the second 5 years starting the first day of the 5th projection year.

9. For line 7, report the sum of all Existing, Under Construction, and Planned transmission line circuit miles for the ten year projection period.
10. For line 8, report the sum of all Existing, Under Construction, Planned, and Conceptual transmission line circuit miles for the ten year projection period.

PART B: Projected Transmission Line Additions

1. This SCHEDULE must be completed by each Regional Entity for all transmission line additions at 100 kV and above projected for the ten-year period beginning with the first day of the current reporting year.
2. For transmission classified as Conceptual, the assumptions used during the transmission planning process and in the planning models are to be reported in this schedule.
3. For line 1, Project Name, enter the project name
4. For line 2, Project Status, enter the level of certainty defined by the following criteria:

- **Under Construction**
 - Construction of the line has begun
- **Planned (any of the following)**
 - Permits have been approved to proceed
 - Design is complete
 - Needed in order to meet a regulatory requirement
- **Conceptual (any of the following)**
 - A line projected in the transmission plan
 - A line that is required to meet a NERC TPL Standard or powerflow model and cannot be categorized as "Under Construction" or "Planned"
 - Projected transmission lines that are not "Under Construction" or "Planned"

5. For line 3, **TIE line**, specify whether this addition interconnects Regional Balancing Authorities or sub-regions within a Balancing Authority (YES/NO).

6. For line 4a & 4b, **Primary Driver**, specify one or two of the principal drivers from the following list:

- Reliability
- Generation integration
 - Variable/Renewable
 - Nuclear
 - Fossil-Fired
 - Hydro
- Economics or Congestion
- Other

Note that the specified primary drivers, lines 4a and 4b, are not weighted by importance.

7. For line 5, **Terminal Location (From)**, enter the name of the beginning terminal point of the line.
8. For line 6, **Terminal Location (To)**, enter the name of the ending terminal point of the line.
9. For line 7, **Company Name**, enter the company name.
10. For line 8, **EIA Company Code**, identify each organization by the six-character code assigned by EIA.
11. For line 9, **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).
12. For line 10, **Percent Ownership**, if the transmission line will be jointly-owned, enter the percentages owned by each individual respondent.
13. For line 11, **Circuit Line Length**, enter the number of circuit line miles between the beginning and ending terminal points of the line.
14. For line 12, **Line Type**, select physical location of the line conductor – overhead (OH), underground (UG), or submarine (SM).

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<ol style="list-style-type: none"> 15. For line 13, Voltage Type, select voltage as alternating current (AC) or direct current (DC). 16. For line 14, Voltage Operating, enter the voltage at which the line is normally operated in kilovolts (kV). 17. For line 15, Voltage Design, enter the voltage at which the line was designed to operate in kilovolts (kV). 18. For line 16, Conductor Size, enter the size of the line conductor in thousands of circular mils (MCM). 19. For line 17, Conductor Material Type, enter the line conductor material type – aluminum, ACCR, ACSR, copper, or other. 20. For line 18, Bundling Arrangement, enter the bundling arrangement/configuration of the line conductors – single, double, triple, quadruple, or other. 21. For line 19, Circuits per Structure Present, enter the current number of three-phase circuits on the structures of the line. 22. For line 20, Circuits per Structure Ultimate, enter the ultimate number of three-phase circuits that the structures of the line are designed to accommodate. 23. For line 21, 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. 24. For line 22, Capacity Rating, enter the normal load-carrying capacity of the line in millions of volt-amperes (MVA). 25. For line 23, Projected In-Service Month, enter the projected month the line will be energized under the control of the system operator. 26. For line 24, Projected In-Service Year, enter the projected year the line will be energized under the control of the system operator. 		
<p style="text-align: center;">SCHEDULE 7. ANNUAL DATA ON TRANSMISSION LINE OUTAGES FOR EHV LINES, GENERAL INSTRUCTIONS FOR PART A AND PART B</p>		
<p>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.</p>		
<p>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 de-energized and stop recording duration when the entire line is reenergized. If practices differ, please SCHEDULE 9, COMMENTS.</p>		
<p>Outages that occur on intertie lines between regions are to be reported only once by one or the other of the reporting regions.</p>		
<p><u>Scheduled Outages</u></p>		
<p>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 a previously scheduled work period).</p>		
<p><u>Unscheduled Outages</u></p>		
<p>The information requested on unscheduled outages covers all events in which a line is automatically removed from service by system protection or must be removed from service due to unforeseen circumstances. The unscheduled outage of any circuit continues until that circuit is restored to service. If company practices are different from this, please note in SCHEDULE 9</p>		

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<p>COMMENTS.</p> <ul style="list-style-type: none"> • 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. • 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 may be 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. <p style="text-align: center;">SCHEDULE 7. PART A. ANNUAL DATA ON TRANSMISSION LINE OUTAGES FOR EHV LINES, AC LINES, SPECIFIC INSTRUCTIONS</p> <ol style="list-style-type: none"> 1. All transmission line outages involving Extra High Voltage (EHV) AC lines of 230 kV and above are to be aggregated by each Regional Entity 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 five 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 six 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 60 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 five 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 six 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) who are 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.
12. For line 11, **Operator Action**, includes any action traceable to employees and/or contractors 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, **Equipment Failure**, includes failure of any line or terminal equipment.
14. Line 13, **Unknown**, any unknown sources should be reported in this category.
15. Line 14, **Other**, includes all other causes (computed automatically to be the difference between 100 percent and the sum of lines 8 through 13).

**SCHEDULE 7. PART B. ANNUAL DATA ON TRANSMISSION LINE
OUTAGES FOR EHV LINES, DC LINES, SPECIFIC INSTRUCTIONS**

1. All transmission line outages involving Extra High Voltage (EHV) DC lines of ± 100 kV and above are to be aggregated by each Regional Entity 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 five 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 six 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 60 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 five 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 six 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.

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	<p>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.</p> <p>11. For Line 11, Operator Action, includes any action traceable to employees and/or contractors 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.</p> <p>12. For line 12, Equipment Failure, includes failure of any line or terminal equipment.</p> <p>13. For line 13, Unknown, any unknown sources should be reported in this category.</p> <p>14. For line 14, Other, includes all other causes (computed automatically to be the difference between 100 percent and the sum of lines 8 through 13).</p> <p style="text-align: center;">SCHEDULE 8. BULK TRANSMISSION FACILITY POWER FLOW CASES</p> <p>1. Each Regional Entity is to coordinate the collection of data on basic electrical data and power flow information on prospective new bulk transmission facilities of 100 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.</p> <p>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 (see Instructions 6 through 13).</p> <p>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. 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.</p> <p>4. For each power flow case that is provided in response to Items 2 and 3 above, please identify on SCHEDULE 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.</p> <p>5. The EIA expects that in nearly all cases the power flow format will be one of the following:</p> <ul style="list-style-type: none"> • 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. <p>Respondents submitting their own cases must supply the input data to the solved base cases and associated ACSII output data on 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.</p> <p>6. For Line 1, enter the case name.</p> <p>7. For Line 2, enter the year studied in this power flow case.</p> <p>8. For Line 3, enter the case number assigned by respondent.</p> <p>9. For Line 4, column a, enter the name and type (e.g. line transformer, etc.) of a prospective facility included on the power flow case.</p> <p>10. For Line 4, column b, enter the projected in-service date of the proposed facility. Please</p>	

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	<p>provide month and year (e.g., 12-2004).</p> <p>11. For Line 4, column c and d, enter the number and name respectively of each bus to which the facility is connected. Use one line for each bus.</p> <p>12. Repeat Instructions 9 through 12 for each prospective facility.</p> <p style="text-align: center;">SCHEDULE 9. COMMENTS</p> <p>Identify each comment by the appropriate schedule, part, line number, column identifier and page number. Use additional sheets, as required. (Any comment referencing sensitive information will be considered sensitive.)</p>	
GLOSSARY	<p>The glossary for this form is available online at the following URL: http://www.eia.doe.gov/glossary/index.html</p>	
SANCTIONS	<p>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. Failure to respond may result in a penalty of not more than \$2,750 per day for each civil violation, or a fine of not more than \$5,000 per day for each criminal violation. The government may bring a civil action to prohibit reporting violations, which may result in a temporary restraining order or a preliminary or permanent injunction without bond. In such civil action, the court may also issue mandatory injunctions commanding any person to comply with these reporting requirements. 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.</p>	
REPORTING BURDEN	<p>Public reporting burden for this collection of information is estimated to be 12,960 hours or 960 hours per reporting entity 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 Entities and NERC, but also for the members within each council. 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.</p>	
PROVISIONS REGARDING THE CONFIDENTIALITY OF INFORMATION	<p>The information reported on Form EIA-411 will be treated as non-sensitive and may be publicly released in identifiable form, except as noted below.</p> <p>The information contained on SCHEDULE 5, Bulk Electric Transmission System Maps, and SCHEDULE 8, Bulk Transmission Facility Power Flow Cases, will be treated as sensitive and protected 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.</p> <p>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 Government Accountability 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.</p> <p>Disclosure limitation procedures are applied to the sensitive statistical data published from SCHEDULES 5 and 8, EIA-411 survey information to ensure that the risk of disclosure of identifiable information is very small.</p>	

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NOTICE: This report is **mandatory** under the Federal Energy Administration Act of 1974 (Public Law 93-275) for all parts but Schedule 7. Failure to comply may result in criminal fines, civil penalties and other sanctions as provided by law. For further information concerning sanctions and data protections see the provision on sanctions and the provision concerning the confidentiality of information in the instructions. **Title 18 USC 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.**

SCHEDULE 1. IDENTIFICATION

Survey Contact

First Name: _____ Last Name: _____

Title: _____

Telephone (include extension): _____ Fax: _____

E-mail: _____

Supervisor of Contact Person for Survey

First Name: _____ Last Name: _____

Title: _____

Telephone (include extension): _____ Fax: _____

E-mail: _____

Report For

Regional Entity: _____

Reporting Party (Regional Entity or subregion): _____

For questions about the data requested on Form EIA-411, contact the Survey Manager:

Marie Rinkoski Spangler
Telephone Number: (202) 586-2446
FAX Number: (202) 287-1934
E-mail: marie.rinkoski-spangler@eia.doe.gov

Regional Entity: _____

Reporting Party: _____

SCHEDULE 2. PART A. HISTORICAL AND PROJECTED PEAK DEMAND AND ENERGY - MONTHLY

Peak Demand Reported	Non-Coincident _____		Coincident _____				
If coincident, please explain why not non-coincident							
YEAR							
		2011 (Prior Year)	2012 (Report Year)		2013 (Next Year)		
LINE NO.	MONTH	PEAK HOUR DEMAND (MEGAWATTS) (a)	NET ENERGY (THOUSANDS OF MEGA-WATTHOURS) (b)	PEAK HOUR DEMAND (MEGAWATTS) (a)	NET ENERGY (THOUSANDS OF MEGA-WATTHOURS) (b)	PEAK HOUR DEMAND (MEGAWATTS) (a)	NET ENERGY (THOUSANDS OF MEGA-WATTHOURS) (b)
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 2. PART B. HISTORICAL AND PROJECTED PEAK DEMAND AND ENERGY - ANNUAL

		YEAR										
		Previous Year Actual	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
1	Summer Peak Hour Demand, June - September (Megawatts)											
2	Winter Peak Hour Demand, December - March (Megawatts)											
3	Net Annual Energy											

Regional Entity: _____

Reporting Party: _____

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

LINE NO.		YEAR					
		2008	2009	2010	2011	2012	2013
DEMAND (IN MEGAWATTS)							
1	Unrestricted Non-coincident Peak Demand						
1a	New Conservation						
1b	Estimated Diversity						
1c	Additions for non-member load						
1d	Stand-by Load Under Contract						
2	Total Internal Demand						
2a	Direct Control Load Management						
2b	Contractually Interruptible						
2c	Critical Peak Pricing with Control						
2d	Load as a Capacity Resource						
3	Net Internal Demand						
4a	Demand Response Used for Reserves - Spinning						
4b	Demand Response Used for Reserves – Non-Spinning						
4c	Demand Response used for Regulation						
4d	Demand Response used for Energy, Voluntary – Emergency						
CAPACITY (IN MEGAWATTS)							
5	TOTAL INTERNAL CAPACITY (sum of 6 and 7)						
6	EXISTING CAPACITY						
6a	Existing, Certain						
6a1	Wind Expected On-peak						
6a2	Solar Expected On-peak						
6a3	Hydro Expected On-peak						
6a4	Biomass Expected On-peak						
6a5	Load as a Capacity Resource Expected On-peak						

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Regional Entity: _____							
Reporting Party: _____							
SCHEDULE 3. PART A. HISTORICAL AND PROJECTED DEMAND AND CAPACITY - SUMMER							
LINE		YEAR					
NO.		2008	2009	2010	2011	2012	2013
DEMAND (IN MEGAWATTS)							
6b	Existing, Other						
6b1	Wind Derate On-peak						
6b2	Solar Derate On-peak						
6b3	Hydro Derate On-peak						
6b4	Biomass Derate On-peak						
6b5	Load as a Capacity Resource Derate On-peak						
6b6	Energy Only						
6b7	Scheduled Outage – Maintenance						
6b8	Transmission-Limited Resources						
6c	Existing, Inoperable						
7	FUTURE CAPACITY ADDITIONS						
7a	Future, Planned						
7a1	Wind Expected On-peak						
7a2	Solar Expected On-peak						
7a3	Hydro Expected On-peak						
7a4	Biomass Expected On-peak						
7b	Future, Other						
7b1	Wind Expected On-peak						
7b2	Wind Derate On-peak						
7b3	Solar Expected On-peak						
7b4	Solar Derate On-peak						
7b5	Hydro Expected On-peak						
7b6	Hydro Derate On-peak						
7b7	Biomass Expected On-peak						
7b8	Biomass Derate On-peak						
7b9	Energy Only						
8	CONCEPTUAL CAPACITY						
8a	Conceptual						
8a1	Wind Expected On-peak						
8a2	Wind Derate On-peak						
8a3	Solar Expected On-peak						
8a4	Solar Derate On-peak						
8a5	Hydro Expected On-peak						
8a6	Hydro Derate On-peak						
8a7	Biomass Expected On-peak						
8a8	Biomass Derate On-peak						
8a9	Energy Only						
9	DELIVERABLE INTERNAL CAPACITY						

Regional Entity: _____
Reporting Party: _____

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

LINE		YEAR					
NO.		2008	2009	2010	2011	2012	2013
CAPACITY (IN MEGAWATTS)							
10	CAPACITY TRANSACTIONS - IMPORTS						
10a	Firm						
10a1	Full-Responsibility Purchases						
10a2	Owned Capacity/Entitlement Located Outside the Region/subregion						
10b	Non-Firm						
10c	Expected						
10c1	Full-Responsibility Purchases						
10c2	Owned Capacity/Entitlement Located Outside the Region/subregion						
10d	Provisional – transactions under study, but negotiations have not begun.						
11	CAPACITY TRANSACTIONS - EXPORTS						
11a	Firm						
11a1	Full-Responsibility Purchases						
11a2	Owned Capacity/Entitlement Located Outside the Region/subregion						
11b	Non-Firm						
11c	Expected						
11c1	Full-Responsibility Purchases						
11c2	Owned Capacity/Entitlement Located Outside the Region/subregion						
11d	Provisional – transactions under study, but negotiations have not begun.						

Council: _____
Reporting Party: _____

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

LINE NO.		YEAR					
		2008	2009	2010	2011	2012	2013
CAPACITY - Continued (IN MEGAWATTS)							
12	EXISTING, CERTAIN & NET FIRM TRANSACTIONS						
13	DELIVERABLE CAPACITY RESOURCES						
14	PROSPECTIVE CAPACITY RESOURCES						
15	TOTAL POTENTIAL CAPACITY RESOURCES						
15a	ADJUSTED POTENTIAL CAPACITY RESOURCES						
16a	Confidence of Future, Other (7b)						
16b	Net Future, Other Resources						
16c	Confidence of Conceptual (8)						
16d	Net Conceptual Resources						
17C	Region/subregion Target Capacity Margin						
17R	Region/subregion Target Reserve Margin						
Margins							
18C	Existing Certain and Net Firm Transactions						
19C	Deliverable Capacity Resources						
20C	Prospective Capacity Resources						
21C	Total Potential Resources						
22C	Adjusted Potential Resources						
18R	Existing Certain and Net Firm Transactions						
19R	Deliverable Capacity Resources						
20R	Prospective Capacity Resources						
21R	Total Potential Resources						
22R	Adjusted Potential Resources						
23	Other Capacity < 1 MW						
24	Distributed Generator Capacity >= 1 MW						
25	EIA-860 Capacity Total						

Regional Entity: _____

Reporting Party: _____

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

LINE NO.		YEAR					
		2008	2009	2010	2011	2012	2013
DEMAND (IN MEGAWATTS)							
1	Unrestricted Non-coincident Peak Demand						
1a	New Conservation						
1b	Estimated Diversity						
1c	Additions for non-member load						
1d	Stand-by Load Under Contract						
2	Total Internal Demand						
2a	Direct Control Load Management						
2b	Contractually Interruptible						
2c	Critical Peak Pricing with Control						
2d	Load as a Capacity Resource						
3	Net Internal Demand						
4a	Demand Response Used for Reserves - Spinning						
4b	Demand Response Used for Reserves – Non-Spinning						
4c	Demand Response used for Regulation						
4d	Demand Response used for Energy, Voluntary – Emergency						
CAPACITY (IN MEGAWATTS)							
5	TOTAL INTERNAL CAPACITY (sum of 6 and 7)						
6	EXISTING CAPACITY						
6a	Existing, Certain						
6a1	Wind Expected On-peak						
6a2	Solar Expected On-peak						
6a3	Hydro Expected On-peak						
6a4	Biomass Expected On-peak						
6a5	Load as a Capacity Resource Expected On-peak						

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Regional Entity: _____							
Reporting Party: _____							
SCHEDULE 3. PART B. HISTORICAL AND PROJECTED DEMAND AND CAPACITY - WINTER							
LINE		YEAR					
NO.		2008	2009	2010	2011	2012	2013
DEMAND (IN MEGAWATTS)							
6b	Existing, Other						
6b1	Wind Derate On-peak						
6b2	Solar Derate On-peak						
6b3	Hydro Derate On-peak						
6b4	Biomass Derate On-peak						
6b5	Load as a Capacity Resource Derate On-peak						
6b6	Energy Only						
6b7	Scheduled Outage – Maintenance						
6b8	Transmission-Limited Resources						
6c	Existing, Inoperable						
7	FUTURE CAPACITY ADDITIONS						
7a	Future, Planned						
7a1	Wind Expected On-peak						
7a2	Solar Expected On-peak						
7a3	Hydro Expected On-peak						
7a4	Biomass Expected On-peak						
7b	Future, Other						
7b1	Wind Expected On-peak						
7b2	Wind Derate On-peak						
7b3	Solar Expected On-peak						
7b4	Solar Derate On-peak						
7b5	Hydro Expected On-peak						
7b6	Hydro Derate On-peak						
7b7	Biomass Expected On-peak						
7b8	Biomass Derate On-peak						
7b9	Energy Only						
8	CONCEPTUAL CAPACITY						
8a	Conceptual						
8a1	Wind Expected On-peak						
8a2	Wind Derate On-peak						
8a3	Solar Expected On-peak						
8a4	Solar Derate On-peak						
8a5	Hydro Expected On-peak						
8a6	Hydro Derate On-peak						
8a7	Biomass Expected On-peak						
8a8	Biomass Derate On-peak						
8a9	Energy Only						
9	DELIVERABLE INTERNAL CAPACITY						

Regional Entity: _____
Reporting Party: _____

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

LINE		YEAR					
NO.		2008	2009	2010	2011	2012	2013
CAPACITY (IN MEGAWATTS)							
10	CAPACITY TRANSACTIONS - IMPORTS						
10a	Firm						
10a1	Full-Responsibility Purchases						
10a2	Owned Capacity/Entitlement Located Outside the Region/subregion						
10b	Non-Firm						
10c	Expected						
10c1	Full-Responsibility Purchases						
10c2	Owned Capacity/Entitlement Located Outside the Region/subregion						
10d	Provisional – transactions under study, but negotiations have not begun.						
11	CAPACITY TRANSACTIONS - EXPORTS						
11a	Firm						
11a1	Full-Responsibility Purchases						
11a2	Owned Capacity/Entitlement Located Outside the Region/subregion						
11b	Non-Firm						
11c	Expected						
11c1	Full-Responsibility Purchases						
11c2	Owned Capacity/Entitlement Located Outside the Region/subregion						
11d	Provisional – transactions under study, but negotiations have not begun.						

Regional Entity: _____
Reporting Party: _____

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

LINE		YEAR					
NO.		2008	2009	2010	2011	2012	2013
CAPACITY - Continued (IN MEGAWATTS)							
12	EXISTING, CERTAIN & NET FIRM TRANSACTIONS						
13	DELIVERABLE CAPACITY RESOURCES						
14	PROSPECTIVE CAPACITY RESOURCES						
15	TOTAL POTENTIAL CAPACITY RESOURCES						
15a	ADJUSTED POTENTIAL CAPACITY RESOURCES						
16a	Confidence of Future, Other (7b)						
16b	Net Future, Other Resources						
16c	Confidence of Conceptual (8)						
16d	Net Conceptual Resources						
17C	Region/subregion Target Capacity Margin						
17R	Region/subregion Target Reserve Margin						
Margins							
18C	Existing Certain and Net Firm Transactions						
19C	Deliverable Capacity Resources						
20C	Prospective Capacity Resources						
21C	Total Potential Resources						
22C	Adjusted Potential Resources						
18R	Existing Certain and Net Firm Transactions						
19R	Deliverable Capacity Resources						
20R	Prospective Capacity Resources						
21R	Total Potential Resources						
22R	Adjusted Potential Resources						
23	Other Capacity < 1 MW						
24	Distributed Generator Capacity >= 1 MW						
25	EIA-860 Capacity Total						

SCHEDULE 4 - RESERVED

Regional Entity: _____
Reporting Party: _____

SCHEDULE 6. PROJECTED TRANSMISSION LINES

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
9	Voltage Type	[] 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 Material: []
		Pole Type: []	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	
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	Pole Material W = Wood C = Concrete S = Steel B = Combination P = Composite O = Other	Pole Type P = Single pole H = H-frame T = Tower U = Underground O = Other

Regional Entity: _____

Reporting Party: _____

SCHEDULE 7. PART A, ANNUAL DATA ON TRANSMISSION LINE OUTAGES FOR EHV AC LINES

(Report following data for each applicable EHV Voltage Class)

LINE NO.						
1	Applicable AC 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	Equipment Failure					
13	Unknown					
14	Other					

Regional Entity: _____

Reporting Party: _____

SCHEDULE 7. PART B, ANNUAL DATA ON TRANSMISSION LINE OUTAGES FOR EHV DC LINES

(Report following data for each applicable EHV Voltage Class)

LINE NO.					
1	Applicable DC Voltage Class	± 100-299 kV (a)	± 300-399 kV (b)	± 400-499 kV (c)	± 500 kV or greater (d)
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	Equipment Failure				
13	Unknown				
14	Other				

Regional Entity: _____

Reporting Party: _____

SCHEDULE 9. COMMENTS

LINE NO.	SCHEDULE (a)	PART (b)	LINE NO. (c)	COLUMN (d)	PAGE (e)	COMMENT (f)
1						
2						
3						
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