U.S. Energy Information Administration (Independent Statistics & Analysis)	**FORM EIA-411 INSTRUCTIONS** ***COORDINATED BULK POWER SUPPLY AND DEMAND PROGRAM REPORT***	**OMB No. 1905-0129** **Approval Expires: 03/31/2020** **Burden: 122 hours**

PURPOSE	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 U.S. Energy Information Administration (EIA) publications and 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.
REQUIRED RESPONDENTS	The Form EIA-411 is mandatory for those entities required to report. With the exceptions of Schedules 7 and 8 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 entities within their Region and provided to NERC. Data is aggregated by assessment area (defined as a planning coordinator or group of planning coordinators). NERC then compiles and coordinates these data and provides them to the U.S. Energy Information Administration. Schedule 7 data for each Regional Entity will be provided by NERC from its Transmission Availability Data System database. Schedule 8 data for each Regional Entity will be provided by NERC from its Generating Availability Data System database.
RESPONSE DUE DATE	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 EIA by July 15.
METHODS OF FILING RESPONSE	The North American Electric Reliability Corporation (NERC) will oversee the methods of filing the survey data collected from the Regional Entities on an assessment area basis. NERC then submits the compiled report to EIA. Maps and power flow cases should be transmitted electronically using a secure file transfer process. If necessary, CD-ROM disks containing the data can also be mailed via overnight delivery to EIA at the following address: Tim Shear U.S. Energy Information Administration, Mail Stop EI-23 1000 Independence Avenue, S.W. Washington, DC. 20585-0690 Please retain a completed copy of this form for your files.
CONTACTS	**Data Questions:** For questions about the data requested on Form EIA-411, contact the Survey Manager: Tim Shear Telephone Number: 202-586-0403 FAX Number: 202-287-1938 Email: Tim.Shear@eia.gov

GENERAL INSTRUCTIONS

1. All forecast and projections should represent a ten-year outlook.
2. For schedules which require annual data, the "**Actual**" column represents the year prior to the reporting year. For example, for data submitted during 2014, the "Actual" column should contain actual data for the prior year, or year 2013; the "Year 1" column should contain data for the "**Report Year**" (RY), in this example year 2014. The 2014 data would be considered projected, since the reporting year data would not be final at the time of survey submission.
3. FERC published a Final Rule on December 20, 2012, approving a new definition of the "Bulk Electric System" (BES) from Report Year 2016 forward report outage data for transmission elements that are part of the new BES definition.

ITEM-BY-ITEM INSTRUCTIONS

SCHEDULE 1: IDENTIFICATION

Survey Contact: Verify contact name, title, telephone number, fax number, and email address.

Supervisor of Contact Person for Survey: Verify the contact's supervisor's name, title, telephone number, fax number and email address.

Report For: Verify the NERC Regional Entity and reporting party, whether it is a Regional Entity or subregion.

SCHEDULE 2. HISTORICAL AND PROJECTED PEAK DEMAND AND ENERGY

GENERAL INSTRUCTIONS

The reported **peak demand** for each assessment area should be:

a. **Coincident**, treating all load serving entities within the assessment area (region/subregion) as a single system. For a given assessment area, the reported coincident peak demand will be for all the member entities in combination. If non-coincident, please explain why coincident is not used.
b. The highest hourly integrated ("60-minute net integrated peak") Net Energy For Load within a reporting entity occurring within a given period. The integrated peak hour demand (MW) amount is derived by dividing Net Energy For Load (MWh) by 60 for a given hour.

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 largest electric power requirement (based on Net Energy for Load) during a specific period of time, usually integrated over one clock hour and expressed in megawatts (MW). Actual peak hour demand should be provided on a coincident basis (the sum of two or more demands on individual systems that occur during the same demand interval).

The term "**Net Energy for Load**" is defined as:

- The amount of energy required by the reported utility or group of utilities' retail customers in the system's service area plus the amound of energy supplied to full and partial requirements utilities (wholesale requirements customers) plus the amount of energy losses incurred in the transmission and distribution.

The fundamental test for determining the adequacy of the power system is to determine whether resources exceed demand while allowing sufficient margin to address events (loss of generation for instance). This test requires that demand forecasts be provided and aggregated. While coincident demand determinations are preferable, this may not be feasible given the number of entities reporting and the time available to build hourly models. Therefore, it is possible that peak demand forecasts may not be aggregated at peak.

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.

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

1. For **lines 1-12**, Enter monthly peak demand and Net Energy for Load for designated months as defined above.

   Monthly peak demands should be reported based on Total Internal Demand (see definition on Schedule 3A and 3B, line 2.

SCHEDULE 2. PART B. HISTORICAL AND PROJECTED PEAK DEMAND AND ENERGY -- ANNUAL

All forecasts and projections should represent a **ten-year outlook**.

1. For line 1, enter Summer Peak Hour Demand for designated years as defined above.

   The summer peak demands will be the values entered on SCHEDULE 3, Part A, line 2 for the corresponding year.

2. For line 2, enter Winter Peak Hour Demand for designated years as defined above.

   The winter peak demands will be the values entered on SCHEDULE 3, Part B, line 2, for the corresponding year

3. For line 3, enter Net Energy for Load for designated years as defined above.

SCHEDULE 3. PART A. AND PART B. PROJECTED DEMAND, CAPACITY, TRANSACTIONS, AND RESERVE MARGINS

GENERAL INSTRUCTIONS

PART A should be filled out for the **summer seasonal peak**.

PART B should be filled out for the **winter seasonal peak**.

All forecasts and projections should represent a **ten-year outlook**.

Enter demand and capacity for the summer and winter 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.

Where capacity values are entered, values should accumulate through the ten-year projection period.

The example below would be correct for data submitted during 2014 -- the Report Year (RY). Following the table, in the Year 1 column “100 MW” was added; in Year 2 “0 MW” was added; in Year 3 “100 MW” was added; in Year 4 “100 MW” was added, and, in Year 5 “0 MW” was added. Hence, for the 2013 base-case, by Year 5 a capacity of 300 MW is planned to be added.

YEAR		Year 1 (RY 2017)	Year 2 (2018)	Year 3 (2019)	Year 4 (2020)	Year 5 (2021)
Actual or Planned Capacity (MW)		100	100	200	300	300

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).

For hydroelectric capacity, explain in SCHEDULE 10, COMMENTS whether the projected year's data are for an adverse water year, an average water year, or other.

1. For **line 1, Unrestricted Non-coincident Peak** Demand is the gross load of the assessment area, 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)**, provide the estimated impact of Energy Efficiency during the summer and winter peak for each year. The values submitted should include only Energy Efficiency that was embedded in the submitted load forecast, resulting in reduced Total Internal Demand projections.

     Note: This Demand-Side Management category represents the amount of consumer load reduction at the time of peak for the assessment area, due to utility programs that reduce consumer load throughout the year, also includes programs aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided and without any explicit consideration for the timing of program-induced savings. Examples include utility rebate and shared savings activities for the installation of energy efficient appliances, lighting and electrical machinery, and weatherization materials. Other examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, and heat recovery systems.

   - For **line 1b**, **Estimated Diversity** enter the difference between the assessment area peak and the sum of the peaks of the individual loads of reporting entities (Load-Serving Entities, balancing area, zones, etc.).

     Note: Electric utility system load consists of many individual loads that vary depending on the time of day. Individual loads within the customer classes follow similar usage patterns, but these classes of service place different demands upon the facilities and the system grid. The service requirements of one electrical system can differ from another by time-of-day usage, facility usage, and/or demands placed upon the system grid.

   - For **line 1c**, **Additions for Non-member Loads**, enter adjustments to account for load served by one or multiple non-registered Load-Serving Entities located in an assessment area. These values should equal the total adjustments to account for load of non-members, so that each Load-Serving Entity count its demand once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer Demand values.

   - For **line 1d**, **Stand-by Load Under Contract**, enter demand that is normally served by behind the meter generation, which has a contract to receive electric power from a utility if, the generator becomes unavailable. The summer and winter value for each year should represent the total amount of load (at time of assessment area peak) projected to be served through contracts with respective customer(s). This value should not be reported if projected Stand-By Load Under Contract is already integrated into the Total Internal Demand projections.

   - For **line 1e**, **Non-Controllable Demand Response**, enter the value of Demand Response programs that are not controllable and non-dispatchable by the balancing authority (or authorities) within an assessment area, but are considered or otherwise integrated into the Total Internal Demand projections.

2. 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) are not included. Internal Values should also reflect adjustments for transmission line losses. 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 **lines 2a-2d**, do not double count demand response for different Demand Response categories. All capacity should be counted once and only once and categorized as one for the four types of dispatchable and controllable Demand Response. Only report demand response here if the Region/subregion accounts for demand response as a load-reducing resource.

   - For **line 2a**, **Direct Control Load Management (DCLM)**, enter Demand Response under the direct control of the system operator, with capability to control the electric supply to appliances or equipment operated by smaller (residential) customers. Values submitted should represent the amount of demand that can be interrupted during the summer and winter peaks for all years. The value provided for the actual year should represent that amount of Direcrt Control Load Management realized during the peak.
   - For **line 2b**, **Interruptible Load**, enter Demand Response that, in accordance with contractual arrangements, can be interrupted by direct control of the system operator (remote tripping) or by action of the customer at the direct request of the system operator and in accordance with contractual provisions. Load that can be interrupted to fulfill planning or operating reserve requirements should be reported as Interruptible Demand. Values submitted should represent the amount of demand that can be interrupted during the summer and winter peaks for all years. The value provided for the actual year should represent that amount of Interruptible Load realized during the peak
   - For **line 2c**, **Critical Peak Pricing (CPP) with Control**, enter Demand Response that, in accordance with contractual arrangements, can be interrupted by direct control of the system operator (remote tripping), or by action of the customer by responding to high prices of energy triggered by system contingencies or high wholesale market prices. Values submitted should represent the amount of demand that can be interrupted during the summer and winter peaks for all years. The value provided for the actual year should represent that amount of Crititical Peak Pricing with Control realized during the peak
   - For **line 2d, Load as a Capacity Resource**, enter Demand Response that, in accordance with contractual arrangements, is committed to pre-specified load reductions when called upon by the system operator. This program is typically an aggregation of a variety of demand resources that must meet specific requirements associated with traditional generating units (e.g., frequency response, responsive to AGC). These resources are not limited to being dispatched during system contingencies and may be subject to economic dispatch from the system operator. These resources may also be used to meet resource adequacy obligations when determining planning reserve margins. The values submitted should represent the total amount of program participation during the summer and winter peaks for all

years. The value provided for the actual year should represent that amount of Load as a Capacity Resource realized during the peak

3. For **line 3**, **Net Internal Demand**, enter the Total Internal Demand (line 2), reduced by the total Dispatchable, Controllable Capacity Demand Response.
4. For **line 4**, **Total Demand Response**, enter the aggregate of Demand Response that is available to serve during the peak. (Line 2a + Line 2b + Line 2c + Line 2d).

Lines 5 through 20, Relating to Capacity: When determining categorization of supply resources, refer to the criteria listed within each supply category. Determine a supply resource's applicability to a category by assessing the criteria in each supply category in order of certainty (use logical progression). For example, first assess whether the resource falls into the Existing-Certain category. If the resource does not meet that criteria, assess the criteria of Existing-Other. If not, assess the criteria of Existing-Inoperable. If not, assess the criteria of Future-Planned. If not assess the criteria of Future-Other. If not, assess the criteria of Conceptual. A resource will qualify within a supply category if one or more of the listed criteria are true for that resource.

For supply definitions on this form, the criteria for each supply category is based on the “period of analysis”, which refers to the reported seasonal peak, not the full year.

5. **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 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 the summation of all Existing and Future Capacity Additions (Line 6 + Line 7a).
6. **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).
   - For **line 6a**, **Existing, Certain Capacity**, include capacity from existing generator units or portions of existing generator units that are physically located within the assessment area that meet at least one of the following requirements when examining the projected peak for the summer and winter of each year:
     i. Unit must have firm capability, a Power Purchase Agreement (PPA), and firm transmission.
     ii. Unit must be classified as a Designated Network Resource
     iii. Where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.

     When reporting Existing, Certain Capacity include the portion of capacity expected to be available during the summer and winter peak of each year.
   - For **line 6b**, **Existing, Other Capacity**, include capacity from existing generator units or portions of existing generator units that are physically located within the assessment area that do not qualify as Existing, Certain (line 6a) when examining the projected peak for the summer and winter peak of each year. Accordingly, these are the units or portions of units that may not be available to serve peak demand for each season/year.

- For **line 6c**, **Existing, Unavailable Capacity**, include existing capacity physically located within the assessment area that is projected to be unavailable to operate and deliver power within the area during the peak. Include:
  i. Inoperable or mothballed capacity
  ii. Derated capacity
  iii. Capacity on a scheduled outage
  iv. Transmission Limited Resources: The total amount of capacity that is transmission-limited with known physical deliverability limitations to serve load that the resource is obligated to serve.
  v. Capacity projected to be unavailable due to other reasons

7. For **line 7**, **Future Capacity Additions**, include the portion of future capacity resources that are projected to be available to operate and deliver power within the assessment area during the period of peak demand. The requirements of each tier will be determined in the LTRA instructions posted by NERC
   a) Line 7a, Tier 1 (Most certain):
   b) Line 7b, Tier 2
   c) Line 7c, Tier 3 (Least certain)

8. **Line 8**, **Anticipated Capacity**: This value is the summation of Existing, Certain Capacity (Line 6a) and Tier 1 Future Capacity Additions (Line 7a)

NOTES FOR CAPACITY TRANSFERS:

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 assessment area to the reporting Region or assessment area. Sales contracts refer to exported capacity that is transmitted from the reporting Region or assessment area to an outside Region or assessment area. 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, or 7).

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

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

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:

a. 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.

b. 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.

c. 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.

d. 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.

9. For **line 9**, **Capacity Transfers – Imports**, enter the sum of firm and expected import transfers.

- For **line 9a**, **Firm**, enter the amount of capacity purchases for which a firm contract has been signed. Firm contracts for import transfers are the highest quality (priority) service offered to customer(s) under a fixed rate schedule that anticipates no planned interruption. Values should reflect firm transfers for the assessment area summer and winter peaks of all years that have confirmed purchases from another area backed by signed firm contracts. These transactions include the following subcategories:

   i. **Full Responsibility Purchases** - Enter the total of all firm contracts for which the seller(s) is contractually obligated to deliver power and energy to the purchaser with the same degree of reliability as provided to the seller's own native load customers. The purchaser(s) and seller(s) must coordinate and agree on how transactions are reported under this heading. Values should reflect transfers for the summer and winter of all years that have confirmed purchases from another assessment area backed by signed, firm contracts. Values reported on this line represent a portion of Line 9a – Firm.

   ii. **Externally Owned Capacity/Entitlement –** Enter the amount of externally owned capacity transfer in which owned capacity is physically located outside the assessment area footprint. Values should reflect externally owned capacity or capacity entitlements that will be available for the assessment area summer and winter peaks of all years. Values reported on this line represent a portion of Line 9a – Firm.

   iii. **Modeled Transfers**, for regions or assessment areas that model potential feasible transfers, enter the amount of projected imported capacity transfers. Value should reflect the amount of energy that could be transferred, for the summer and winter seasons, with consideration for available generation and transfer capability.

- For **line 9b**, **Expected**, enter the amount of capacity for which a firm import transfer contract has not been executed, but has a reasonable expectation to be implemented. Values should reflect any potential transfers absent a firm contract, but with reasonable expectations for available purchase during the summer and winter peaks for all years. These transactions will be counted towards the Prospective Resources and Reserve Margin

10. For **line 10**, **Capacity Transfers – Exports**, enter the sum of firm and expected export transfers.

- For **line 10a**, **Firm**, enter the amount of capacity purchases for which a firm contract has been signed. Firm contracts for export transfers are the highest quality (priority) service offered from the seller(s) under a filed rate schedule that anticipates no planned interruption. Values should reflect firm transfers for the assessment area summer and winter peaks of all years that have confirmed purchases by another area backed by signed firm contracts. These transactions include the following subcategories:

i. **Full Responsibility Sales -** Enter the total of all firm contracts for which the seller(s) is contractually obligated to deliver power and energy to the purchaser with the same degree of reliability as provided to the seller's own native load customers. The purchaser(s) and seller(s) must coordinate and agree on how transactions are reported under this heading. Values should reflect transfers for the summer and winter of all years that have confirmed purchases from another assessment area backed by signed, firm contracts. Values reported on this line represent a portion of Line 10a – Firm.

ii. **Externally Owned Capacity/Entitlement –** Enter the amount of externally owned capacity transfer in which owned capacity is physically located outside the assessment area footprint. Values should reflect externally owned capacity or capacity entitlements that will be available for the assessment area summer and winter peaks of all years. Values reported on this line represent a portion of Line 10a – Firm.

iii. **Modeled Transfers**, for regions or assessment areas that model potential feasible transfers, enter the amount of projected exported capacity transfers. Value should reflect the amount of energy that could be transferred, for the summer and winter seasons, with consideration for available generation and transfer capability.

- For **line 10b**, **Expected**, enter the amount of capacity for which a firm export transfer contract has not been executed, but has a reasonable expectation to be implemented. Values should reflect any potential transfers absent a firm contract, but with reasonable expectations for available purchase during the summer and winter peaks for all years. These transactions will be counted towards the Prospective Resources and Reserve Margin.

NOTES FOR CAPACITY RESOURCES:

Lines 11-15 are calculations for capacity resources with varying degrees of certainty. They are calculated from capacity sources (generating supply) and transfers for future years, and will be used in margin calculations.

11. **Line 11**, **Existing Certain and Net Firm Transfers,** includes the summation of:
    - Existing-Certain capacity (line 6a)
    - Net of Firm Capacity Transfers (Imports – Exports) (line 9a - line 10a)
12. **Line 12**, **Anticipated Capacity Resources,** includes the summation of:
    - Existing Certain and Net Firm Transfers (line 11 above)
    - Future Capacity Resources, Tier 1 (line 7a above)
13. **Line 13**, **Prospective Capacity Resources,** includes the summation of:
    - Anticipated Capacity Resources (line 12 above)
    - Existing-Other Capacity (line 6b)
    - Net of Expected Capacity Transfers (Imports – Exports) (line 9b – line 10b)
    - Future Capacity Resources, Tier 2 weighted in accordance with the LTRA instructions posted by NERC (line 8b above * Weighting Factor).
14. **Line 14**, **Adjusted Potential Capacity Resources** includes the summation of:
    - Prospective Capacity Resources (line 13 above)

- Future Capacity Resources, Tier 3 weighted in accordance with the LTRA instructions posted by NERC (line 7b above * Weighting Factor).

15. For **line 15**, **Target Reserve Margin**, enter a value between 0 and 100 that represents the expected target reserve margin (%) set by the Region/Assessment Area. 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 MARGIN CALCULATIONS:

Reserve Margin and Capacity Margin calculations are computed by NERC and submitted on behalf of the Region or assessment area.

The reserve margin is calculated by subtracting Net Internal Demand from the appropriate capacity resource term. The resulting difference is then divided by Net Internal Demand. In calculating the capacity margin, the resulting difference divided by the appropriate capacity resource term.

16. For **line 16, Existing Certain and Net Firm Transactions**, take the difference between line 11 and line 3. Divide by line 3 for the reserve margin and divide by line 12 for the capacity margin.
17. For **line 17**, **Anticipated Capacity Resources**, take the difference between line 12 and line 3. Divide by line 3 for the reserve margin and divide by line 12 for the capacity margin.
18. For **line 18**, **Prospective Capacity Resources**, take the difference between line 13 and line 3. Divide by line 3 for the reserve margin and divide by line 13 for the capacity margin.
19. For **line 19**, **Adjusted Potential Resources**, take the difference between line 14 and line 3. Divide by line 3 for the reserve margin and divide by line 14 for the capacity margin.

SCHEDULE 4. BULK TRANSMISSION FACILITY POWER FLOW CASES

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.
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 4 (see Instructions 4 through 9).
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.
4. For each power flow case that is provided in response to Items 2 and 3 above, please identify on SCHEDULE 4 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. 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.
   - The Binary or Project File format of the PowerWorld simulator.

   If the software is either PTI PSS/E, GE PSLF, or PowerWorld Simulator, respondents should provide details on the options and parameters that vary from default and are necessary to ensure that the cases solve as-submitted.

   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.

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. **Line 4**, Prospective Facilities and Connections:
   - 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.
   - For **line 4, column b**, enter the projected in-service date of the proposed facility. Please provide month and year (e.g., 12-2017).
   - 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.

Note: Repeat Instruction 9 for each prospective facility.

SCHEDULE 5. BULK ELECTRIC TRANSMISSION SYSTEM MAPS

Each Regional Entity is to submit a map(s), in pdf format, showing the existing bulk electric transmission system, 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. 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.

The map requirement may be satisfied by either:

- 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
- Separate maps for a set of subregions that comprise the whole region.

1. For **line 1**, enter the number of maps provided.
2. For **line 2**, enter the requested map information in columns (a) through (c).

SCHEDULE 6. EXISTING AND PROJECTED TRANSMISSION CIRCUIT MILES AND CHARACTERISTICS OF PROJECTED TRANSMISSION ADDITIONS

SCHEDULE 6. PART A. EXISTING AND PROJECTED TRANSMISSION CIRCUIT MILES

For existing and projected transmission lines that are part of the NERC BES, report circuit miles for the specified voltage categories below. For the “Less than 100” range, reporting will start with Report Year 2016. Report transmission line circuit miles in WHOLE numbers.

Operative Voltage Range (kV)	**Voltage Type**	
Less than 100	AC	--
100-199	AC	--
100-299	--	DC
200-299	AC	--
300-399	AC	DC
400-599	AC	DC
600+	AC	DC

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

1. For **line 1**, report Existing transmission lines as of the last day in the prior reporting year. (For example, the 2014 Report Year, enter the amount of circuit miles existing as of 12/31/2013.)
2. For **line 2**, report Under Construction transmission lines as of the first day in the current reporting year. (For example, the 2017 Report Year, enter the amount of circuit miles under construction as of 1/1/2017.)
3. For **line 3**, report Planned transmission lines to be completed within the first 5 years starting the first day in the current reporting year.
4. For **line 4**, report Conceptual transmission lines to be completed within the first 5 years starting the first day in the current reporting year.
5. For **line 5**, report Planned transmission lines to be completed within the second 5 years starting the first day of the 6th projection year.
6. For **line 6**, report Conceptual transmission lines to be completed within the second 5 years starting the first day of the 6th projection year.
7. For **line 7**, report the sum of all Existing, Under Construction, and Planned transmission line circuit miles for the ten year projection period.

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

<u>SCHEDULE 6. PART B. CHARACTERISTICS OF PROJECTED TRANSMISSION LINE ADDITIONS</u>

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.

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.

1. For **line 1**, Project Name, enter the project name
2. 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)**
     i. Permits have been approved to proceed
     ii. Design is complete
     iii. Needed in order to meet a regulatory requirement
   - **Conceptual (any of the following)**
     i. A line projected in the transmission plan
     ii. A line that is required to meet a NERC TPL Standard or powerflow model and cannot be categorized as “Under Construction” or “Planned”
     iii. Projected transmission lines that are not “Under Construction” or “Planned”
3. For **line 3**, **Tie line**, specify whether this addition interconnects Balancing Authorities (YES/NO).
4. For **line 4a & 4b**, **Primary** and **Secondary Driver**, specify drivers from the following list:
   - Reliability
   - Variable/Renewable (identify by source or combination of sources)
   - Nuclear Integration
   - Fossil-Fired Integration (identify by source or combination of sources)
   - Hydro Integration
   - Economics / Congestion
   - Other (please specify in Schedule 10, Comments)
5. For **line 5**, **Terminal Location (From)**, enter the name,state and county of the beginning terminal point of the line.
6. For **line 6**, **Terminal Location (To)**, enter the name, state and county of the ending terminal point of the line.
7. For **line 7**, **Company Name**, enter the company name.
8. For **line 8**, **EIA Company Code**, identify each organization by the six-character code assigned by EIA.
9. 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).
10. For **line 10**, **Percent Ownership**, if the transmission line will be jointly-owned, enter the percentages owned by each transmission owner.

11. For **line 11**, Circuit **Line Length**, enter the number of circuit line miles between the beginning and ending terminal points of the line.
12. For **line 12**, **Line Type**, select physical location of the line conductor – overhead (OH), underground (UG), or submarine (SM).
13. For **line 13**, **Voltage Type**, select voltage as alternating current (AC) or direct current (DC).
14. For line 14, **Voltage Operating**, enter the voltage at which the line will be normally operated in kilovolts (kV).
15. For **line 15**, **Voltage Design**, enter the voltage at which the line is designed to operate in kilovolts (kV).
16. For **line 16**, **Circuits per Structure Present,** enter the current number of three-phase circuits on the structures of the line.
17. For **line 17**, **Circuits per Structure Ultimate**, enter the ultimate number of three-phase circuits that the structures of the line are designed to accommodate.
18. For **line 18**, **Capacity Rating**, enter the normal load-carrying capacity of the line in millions of volt-amperes (MVA).
19. For **line 19**, **Original In-Service Date**, enter the originally projected date the line was to be energized under the control of the system operator.
20. For **line 20**, **Expected In-Service Date**, enter the currently projected date the line will be energized under the control of the system operator.
21. For **line 21**, **Line Delayed**, enter "Y" if the line has been delayed and "N" if it has not.
22. For **line 22**, **Cause of Delay**, if the line has been delayed, enter the cause.

SCHEDULE 7. ANNUAL DATA ON TRANSMISSION LINE OUTAGES FOR EHV LINES

GENERAL INSTRUCTIONS FOR PARTS A, B, C, and D

FERC published a Final Rule on December 20, 2012, approving a new definition of the "Bulk Electric System" (BES).

From Report Year 2016 forward report outage data for transmission elements that are part of the new BES definition.

All data in section 7 are to be aggregated by each Regional Entity and reported on this schedule.

DEFINITIONS

Transmission line outages are defined below for purposes of reporting on this schedule and are intended to be consistent with the instructions and definitions in the NERC Transmission Availability Data System (TADS) Data Reporting Instruction Manual and TADS Definitions (Appendix 7 of the Instructions) at http://www.nerc.com/page.php?cid=4|62 An **Element** includes certain specified voltage classes of AC Circuits, DC Circuits, and Transformers. An **In-Service State** means an Element that is energized and connected at all its terminals to the system.

Outages that occur on intertie lines between regions are to be reported only once by one or the other of the reporting regions. Outages on lines that cross international borders must be reported.

Automatic Outages

An **Automatic Outage** is an outage which results from the automatic operation of a switching device, causing an Element to change from an In-Service State to a not In-Service State. A successful AC single-pole (phase) reclosing event is not an Automatic Outage. If practices are different from this, please note in SCHEDULE 10 Comments.

- A **Sustained Outage** is an Automatic Outage with an Outage Duration of a minute or greater.
- A **Momentary Outage** is an Automatic Outage with an Outage Duration of less than one (1) minute. Momentary outages should not be included.
- A **Single Mode Outage** is an Automatic Outage of a single Element which occurred independent of any other outages.
- A **Dependent Mode Outage** is an Automatic Outage of an Element which occurred as a result of an initiating outage, whether the initiating outage was an Elements outage or a non-Element outage.
- A **Common Mode Outage** is one of two or more Automatic Outages with the same Initiating Cause Code and where the outages are not consequences of each other and occur nearly simultaneously (i.e., within cycles or seconds of one another).

An **Event** is a transmission incident that results in the Automatic Outage (Sustained or Momentary) of one or more Elements.

Non-Automatic Outages

A **Non-Automatic Outage** is an outage which results from the manual operation (including supervisory control) of a switching device, causing an Element to change from an In-Service State to a not In-Service State. If practices are different from this, please note in SCHEDULE 10 Comments.

- An **Operational Outage** is a Non-Automatic Outage for the purpose of avoiding an emergency (i.e., risk to human life, damage to equipment, damage to property) or to maintain the system within operational limits and that cannot be deferred.
- A **Planned Outage** is a Non-Automatic Outage with advance notice for the purpose of maintenance, construction, inspection, testing, or planned activities by third parties that may be deferred. There is no requirement to report Non-Automatic, Planned Outages.

Automatic Outage Causes

- **Weather, excluding lightning,** covers all outages in which severe weather conditions (snow, extreme temperature, rain, tornado, hurricane, ice, high winds, etc.) are the primary cause of the outage, with the exception of lightning. This includes flying debris caused by wind.
- **Lightning**
- **Environmental,** includes environmental conditions such as earth movement (earthquake, subsidence, earth slide), flood, geomagnetic storm, or avalanche.
- **Foreign Interference,** includes objects such as aircraft, machinery, vehicles, kites, events where animal movement or nesting impacts electrical operations, flying debris not caused by wind, and falling conductors from one line into another.
- **Contamination,** covers outages caused by bird droppings, dust, corrosion, salt spray, industrial pollution, smog, or ash.
- **Fire,** includes outages caused by fire or smoke.
- **Vandalism, Terrorism, or Malicious Acts,** includes intentional activity such as gunshots, removed bolts, or bombs.
- **Failed AC Substation Equipment,** includes equipment inside the substation fence, but excludes protection system equipment.

- **Failed AC/DC Terminal Equipment,** includes equipment inside the terminal fence, including power-line carrier filters, AC filters, reactors and capacitors, transformers, DC valves, smoothing reactors, and DC filters. This excludes protection system equipment.
- **Failed Protection System Equipment,** includes any relay and/or control misoperations except those that are caused by incorrect relay or control settings that do not coordinate with other protective devices (these should be categorized as Human Error)
- **Failed AC Circuit Equipment,** includes overhead or underground equipment outside the substation fence.
- **Failed DC Circuit Equipment,** includes equipment outside the terminal fence.
- **Human Error,** covers any incorrect action traceable to employees and/or contractors for companies operating, maintaining, and/or providing assistance to the utility. This includes any human failure or interpretation of standard industry practices and guidelines that cause an outage.
- **Power System Condition,** include instability, overload trip, out-of-step, abnormal voltage, abnormal frequency, or unique system configurations.
- **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.
- **Unknown**, any unknown causes should be reported in this category.
- **Other**, includes outages for which the cause is known; however, the cause is not included in the above list.

<u>Non-Automatic, Operational Outage Causes</u>

- **Emergency,** includes outages taken to avoid risk to human life, damage to equipment, damage to property, or similar threatening consequences
- **System Voltage Limit Mitigation,** covers outages taken to maintain the voltage on the transmission system within desired levels (i.e., voltage control).
- **System Operating Limit Mitigation,** (excluding voltage limit mitigation) covers outages taken to keep the transmission system within System Operating Limits, including facility ratings, transient stability ratings, and voltage stability ratings covering MW, MVar, Amperes, Frequency, or Volts.
- **Other Operational Outage**, includes all other causes, including human error.

<u>SCHEDULE 7. PART A. ANNUAL DATA ON AC TRANSMISSION LINE OUTAGES</u>

For the appropriate outage type (Automatic; or Non-Automatic, Operational), enter the following:

1. **Number of Outages** (**lines 1 and 4**), report the total number of outages that occurred in the reporting period for each voltage class.

   For line 1, **automatic sustained outages**, also provide :

   - Line 1a, total number of Single Mode outages
   - Line 1b, total number of Dependent Mode outages
   - Line 1c, total number of Common Mode outages

2. **Number of Circuit-Hours Out of Service** (**lines 2 and 5**), report the total circuit-hours out of service for all of the outages for each voltage class during the year. This is the sum across all circuits of the number of hours each circuit was not in an In-Service State during the reporting period.
3. **Outage Cause** (**lines 3 and 6**), report the number of outages by the pertinent cause code, as listed above. For Automatic Outages, report the number of outages for both the

Initiating Cause and the **Sustained Cause**. For the Sustained Cause, use the Cause Code that describes the cause that contributed to the longest duration of the outage.

SCHEDULE 7. PART B. ANNUAL DATA ON DC TRANSMISSION LINE OUTAGES

For the appropriate outage type (Automatic; or Non-Automatic, Operational), enter the following:

1. **Number of Outages** (**lines 1 and 4**), report the total number of outages that occurred in the reporting period for each voltage class.
2. **Number of Circuit-Hours Out of Service** (**lines 2 and 5),** report the total circuit-hours out of service for all of the outages for each voltage class during the year. This is the sum across all circuits of the number of hours each circuit was not in an In-Service State during the reporting period.
3. **Outage Cause** (**lines 3 and 6**), report the number of outages by the pertinent cause code, as listed above. For Automatic outages, report the number of outages for both the **Initiating Cause** and the **Sustained Cause**. For the Sustained Cause, use the Cause Code that describes the cause that contributed to the longest duration of the outage.

SCHEDULE 7. PART C. ANNUAL DATA ON TRANSFORMER OUTAGES

For the appropriate outage type (Automatic; or Non-Automatic, Operational), enter the following:

1. **Number of Outages** (**lines 1 and 4**), report the total number of outages that occurred in the reporting period for each voltage class based on the high-side voltage of the transformer.
2. **Number of Transformer-Hours Out of Service** (**lines 2 and 5**), report the total transformer-hours out of service for all of the outages for each voltage class (by high-side voltage) during the year. This is the sum across all transformers of the number of hours each transformer was not in an In-Service State during the reporting period.
3. **Outage Cause** (**lines 3 and 6**), report the number of outages by the pertinent cause code, as listed above. For Automatic outages, report the number of outages for both the **Initiating Cause** and the **Sustained Cause**. For the Sustained Cause, use the Cause Code that describes the cause that contributed to the longest duration of the outage.

SCHEDULE 7. PART D. ELEMENT INVENTORY AND EVENT SUMMARY

The **Element** inventory data collected on Part D can be used to normalize the outage data collected on Parts A, B, and C. The Event summary data can be used to compare with outage totals collected on Parts A, B, and C.

Report in accordance with the applicable AC/DC circuit voltage class indicated.

1. For **line 1**, an AC Circuit is a set of overhead or underground three-phase conductors that are bound by AC substations. Radial circuits are AC Circuits.
   - For **line 1a**, enter the **Number of Overhead AC Circuits** in each voltage class.
   - For **line 1b**, enter the **Number of Underground AC Circuits** in each voltage class.
2. For **line 2**, an AC Circuit Mile is one mile of a set of three-phase AC conductors in an Overhead or Underground AC Circuit
   - For **line 2a**, enter the **Number of Overhead AC Circuit Miles** in each voltage class.
   - For **line 2b**, enter the **Number of Underground AC Circuit Miles** in each voltage class.
3. For **line 3**, enter the **Number of Multi-Circuit Structure Miles** in each voltage class. A Multi-Circuit Structure Mile is a one-mile linear distance of sequential structures carrying multiple Overhead AC Circuits. (Note: this definition is *not* the same as the industry term

"structure mile." A Transmission Owner's Multi-Circuit Structure Miles will generally be less than its structure miles since not all structures contain multiple circuits.)

4. For **line 4**, a DC circuit is one pole of an overhead or underground line which is bound by an AC/DC Terminal on each end.
   - For **line 4a**, enter the **Number of Overhead DC Circuits** in each voltage class.
   - For **line 4b**, enter the **Number of Underground DC Circuits** in each voltage class.
5. For **line 5**, a DC Circuit Mile is one mile of one pole of a DC Circuit.
   - For **line 5a**, enter the **Number of Overhead DC Circuit Miles** in each voltage class.
   - For **line 5b**, enter the **Number of Underground DC Circuit Miles** in each voltage class.
6. For **line 6**, enter the **number of transformers** in each voltage class. A Transformer is a bank of three single-phase transformers or a single three-phase transformer. A Transformer is bounded by its associated switching or interrupting devices.
   - For **line 6**, report in accordance with the applicable voltage class indicated based on the high-side voltage of the transformer.
7. For **line 7**, enter the total annual **number of events** associated with the outages reported on Schedules 7A, 7B, and 7C.

SCHEDULE 8. ANNUAL DATA ON GENERATING UNIT OUTAGES, DERATINGS AND PERFORMANCE INDEXES FOR CONVENTIONAL UNITS

Schedule 8 collects annual data on generating unit outages, deratings and performance indexes for **conventional generating units in active state**, available from the NERC Generating Availability Data System (GADS).

Generating unit outages, deratings, and required performance indexes are defined below for purposes of reporting on this schedule and are intended to be consistent with the instructions and definitions provided in the GADS *Data Reporting Instructions* manual, found at http://www.nerc.com/page.php?cid=4|43|45, Appendix F - Performance Indices and Equations.

All data in section 8 are to be aggregated by each Regional Entity and reported on this schedule.

Outages

A generating unit outage exists whenever a unit is not synchronized to the grid system and not in a Reserve Shutdown state.

Forced Outages

A Forced Outage (**FO**) is an unplanned, unscheduled outage that requires removal of a unit from the in-service state. There are three types of defined Forced Outages – immediate, delayed and postponed.

- **Immediate** Forced Outage (**U1**) is an outage that requires immediate removal of a unit from service, another Outage State, or a Reserve Shutdown state. This type of outage usually results from immediate mechanical/electrical/hydraulic control systems trips and operator-initiated trips in response to unit alarms.
- **Delayed** Forced Outage (**U2**) is an outage that does not require immediate removal of a unit from the in-service state but requires removal within six hours.

- **Postponed** Forced Outage (**U3**) is an outage that can be postponed beyond six hours but requires that a unit be removed from the in-service state before the end of the next weekend.

Planned and Maintenance Outages

- **Planned Outage** (**PO**) is an outage that is scheduled well in advance and is of a predetermined duration, lasts for several weeks, and occurs only once or twice a year.
- **Maintenance Outages** (**MO**) is an outage that can be deferred beyond the end of the next weekend, but requires that the unit be removed from service, another outage state, or Reserve Shutdown state before the next Planned Outage.
- **Planned Outage Extension (PE)** is an extension beyond the estimated completion date of a Planned Outage.
- **Maintenance Outage Extension (ME)** is an extension beyond the estimated completion date of a Maintenance Outage.

Outage Counts

- **Forced Outage Count** is the number of all forced outage incidents (U1, U2, U3), including Startup Failures (SF).
- **Maintenance Outage Count** is the number of all maintenance outage incidents (MO). Since Maintenance Extensions are part of the Maintenance Outages, they should not be included in this count.
- **Planned Outage Count** is the number of all planned outage incidents (PO). Since Planning Extensions are part of the Planning Outages, they should not be included in this count.

Outage Hours

- **Forced Outage Hours** (**FOH**) is the sum of all hours experienced during Forced Outages (U1, U2, U3) and **Startup Failures**.
- **Planned Outage Hours** (**POH**) is the sum of all hours experienced during Planned Outages (PO) and Planned Outage Extensions (PE) of any Planned Outages.
- **Maintenance Outage Hours** (**MOH**) is the sum of all hours experienced during Maintenance Outages (MO) and Maintenance Outage Extensions (ME) of any Maintenance Outages.

Deratings

A unit derating exists whenever a unit is limited to some power level less than the unit's **Net Maximum Capacity (NMC)**, defined below**.**

Seasonal Deratings

Seasonal Deratings are ambient-related deratings. GADS calculates Seasonal Deratings as the difference in Maximum Capacity and Dependable Capacity. **Net Maximum Capacity** (**NMC**) is the power level that the unit can sustain over a specified period of time when not restricted by ambient conditions or deratings, net of capacity (MW) utilized for that unit's station service or auxiliary load. **Net Dependable Capacity (NDC)** is the power level that the unit can sustain during a given period if there are no equipment, operating, or regulatory restrictions, net of capacity (MW) utilized for that unit's station service or auxiliary load.

Forced Deratings

There are three types of defined Forced Deratings – immediate, delayed and postponed.

- **Immediate** Forced Derating (**D1**) is a derating that requires an immediate reduction in capacity.
- **Delayed** Forced Derating (**D2**) is a derating that does not require an immediate reduction in capacity but requires a reduction within six hours.
- **Postponed** Forced Derating (**D3**) is a derating that can be postponed beyond six hours but requires a reduction in capacity before the end of the next weekend.

Planned and Maintenance Deratings

- **Planned Derating** (**PD**) is a derating that is scheduled well in advance and is of a predetermined duration.
- **Maintenance Derating** (**D4**) is a derating that can be deferred beyond the end of the next weekend but requires a reduction in capacity before the next Planned Outage.
- **Planned Derating Extension** (**DP**) is an extension of a Planned Derate (PD) beyond its estimated completion date.
- **Maintenance Derating Extension** (**DM**) is an extension of a maintenance derate (D4) beyond its estimated completion date.

Derating Counts

- **Forced Derating Count** (**FD**) is the number of all unique forced derating incidents (D1, D2, D3), including Startup Failures (SF).
- **Maintenance Derating Count** (**D4**) is the number of all maintenance derating incidents. Since Maintenance Derating Extensions (DM) are part of the Maintenance Deratings, they should not be included in this count.
- **Planned Derating Count** (**PD**) is the number of all planned derating incidents. Since Planned Derating Extensions (DP) are part of the Planned Deratings, they should not be included in this count.

Derated Hours

A derated unit operates below its potential power level. For GADS reporting purposes, derating hours are transformed into equivalent full outage hours, by weighing each derating with the size of capacity reduction in effect during the derated period of the unit.

- **Equivalent Seasonal Derating Hours** (**ESEDH**): Seasonal derating due to ambient conditions is a continuous state, affecting units throughout their available state. Therefore, ESEDH is the transformation of Available Hours multiplied by the MW size of power reduction (NMC-NDC) divided by the Net Maximum Capacity (NMC). Unit **Available Hours** (**AH**) are the in-service and reserve shutdown hours, plus additional hours for used for operations, such as pumping hours and synchronous condensing hours.
- **Equivalent Forced Derated Hours** (**EFDH)** is the duration of in-service and reserve shutdown forced (D1, D2, D3) deratings multiplied by the MW size of power reduction during derating, divided by the Net Maximum Capacity.
- **Equivalent Planned Derated Hours** (**EMDH**) is the duration of in-service and reserve shutdown planned deratings (PD), including associated **Planned Derating Extensions**

(**DP**), multiplied by the MW size of power reduction, during the derating, divided by the Net Maximum Capacity.

- **Equivalent Maintenance Derated Hours** (**EMDH**) is the duration of in-service and reserve shutdown maintenance deratings (D4), including associated **Maintenance Derating Extensions** (**DM**), multiplied by the MW size of power reduction, during derating, divided by the Net Maximum Capacity.

Generating Unit Performance Indexes

The explicit formulas of the performance indexes can be found in Appendix F - Performance Indices and Equations of the NERC Generating Availability Data System (GADS) Data Reporting Instructions manual.

- **Net Capacity Factor (NCF)** is the ratio of Net Actual Generation of the unit to maximum possible generation during period hours, calculated by multiplying the Period Hour (PH) with Net Maximum Capacity, expressed in percents.
- **Net Output Factor (NOF)** is the ratio of Net Actual Generation of the unit to maximum possible generation during service hours, calculated by multiplying the Service Hours (SH) with Net Maximum Capacity, expressed in percents.
- **Service Factor (SF)** is the ratio of Service Hours to Period Hours, expressed in percents.
- **Availability Factor (AF)** is the ratio of Available Hours to Period Hours, expressed in percents.
- **Unavailability Factor (UAF)** is the ratio of all unit outage hours (FOH+MOH+POH) to Period Hours, expressed in percents.
- **Unit Derating Factor (UDF)** is the ratio of equivalent unit derating hours (EFDH+EMDH+EPDH) to Period Hours, expressed in percents.
- **Equivalent Availability Factor (EAF)** is the ratio of Available Hours, adjusted for all unit derating hours (including seasonal derating hours) to Period Hours, expressed in percents.
- **Equivalent Forced Outage Rate (FOR)** is the ratio of Forced Outage Hours and Equivalent Forced Derating Hours to the sum of Forced Outage Hours, Service Hours, Pumping Hours and Synchronous Hours, expressed in percents.
- **Equivalent Maintenance Outage Rate (MOR)** is the ratio of Maintenance Outage Hours and Equivalent Maintenance Derating Hours to the sum of Forced Outage Hours, Service Hours, Pumping Hours and Synchronous Hours, expressed in percents.
- **Equivalent Planned Outage Rate (POR)** is the ratio of Planned Outage Hours and Equivalent Planned Derating Hours to the sum of Forced Outage Hours, Service Hours, Pumping Hours and Synchronous Hours, expressed in percents.
- **Forced Outage Rate Demand (FORd)** is the ratio of Forced Outage Hours during service demand time to the sum of Service Hours and Forced Outage Rate during service demand time, expressed in percents.
- **Equivalent Forced Outage Rate Demand (EFORd)** is the ratio of Forced Outage Hours and Equivalent Forced Derating Hours during service demand time to the sum of Service Hours and Forced Outage Rate during service demand time, expressed in percents. GADS calculates special factors to convert the Forced Outage Hours and Forced Derating Hours to their equivalent during service demand time.

SCHEDULE 8. PART A. ANNUAL DATA ON GENERATING UNIT OUTAGE HOURS AND COUNTS

1. For **line 1-8**, enter the respective outage counts and durations for Forced, Maintenance and Planned Outages, for the different generating unit types.

2. For **line 9**, enter the respective **total** outage counts and durations for Forced, Maintenance and Planned Outages, for all generating unit types.
3. For **lines 10-13**, enter the respective outage counts and durations for Forced, Maintenance and Planned Outages, for the different generating unit capacity categories.
4. For **line 14**, enter the respective **total** outage counts and durations for Forced, Maintenance and Planned Outages, for all generating unit capacity categories.
5. For **lines 15-18**, enter the respective outage counts and durations for Forced, Maintenance and Planned Outages, for coal units, by generating unit vintage – for units that entered commercial operations in or before 1972, and in or after 1973.
6. For **lines 19 and 20**, enter the respective outage counts and durations for Forced, Maintenance and Planned Outages, for combined cycle units, by generating unit vintage – for units that entered commercial operations in or before 2002, and in or after 2003.

SCHEDULE 8. PART B. ANNUAL DATA ON GENERATING UNIT DERATING HOURS AND COUNTS

1. For **line 1-8**, enter the respective derating counts and equivalent derated durations for Forced, Maintenance and Planned Outages, for the different generating unit types.
2. For **line 9**, enter the respective **total** derating counts and equivalent derated durations for Forced, Maintenance and Planned Outages, for all generating unit types.
3. For **lines 10-13**, enter the respective derating counts and equivalent derated durations for Forced, Maintenance and Planned Outages, for the different generating unit capacity categories.
4. For **line 14**, enter the respective **total** derating counts and equivalent derated durations for Forced, Maintenance and Planned Outages, for all generating unit capacity categories.
5. For **lines 15-18**, enter the respective derating counts and equivalent derated durations for Forced, Maintenance and Planned Outages, for coal units, by generating unit vintage – for units that entered commercial operations in or before 1972, and in or after 1973.
6. For **lines 19 and 20**, enter the respective derating counts and equivalent derated durations for Forced, Maintenance and Planned Outages, for combined cycle units, by generating unit vintage – for units that entered commercial operations in or before 2002, and in or after 2003.

SCHEDULE 8. PART C.1. AND C.2. ANNUAL DATA ON GENERATING UNIT PERFORMANCE INDEXES

1. For **line 1-8**, enter the respective index values for Net Capacity Factor, Net Output Factor, Service Factor, Availability Factor, Unavailability Factor, Unit Derating Factor, Equivalent Availability Factor, Equivalent Forced Outage Rate, Equivalent Maintenance Outage Rate, Equivalent Planned Outage Rate, Forced Outage Rate Demand, Equivalent Forced Outage Rate Demand, for the different generating unit types.
2. For **line 9**, enter the respective **total** index values for Net Capacity Factor, Net Output Factor, Service Factor, Availability Factor, Unavailability Factor, Unit Derating Factor, Equivalent Availability Factor, Equivalent Forced Outage Rate, Equivalent Maintenance Outage Rate, Equivalent Planned Outage Rate, Forced Outage Rate Demand, Equivalent Forced Outage Rate Demand, for all generating unit types.
3. For **lines 10-13**, enter the index values for Net Capacity Factor, Net Output Factor, Service Factor, Availability Factor, Unavailability Factor, Unit Derating Factor,

Equivalent Availability Factor, Equivalent Forced Outage Rate, Equivalent Maintenance Outage Rate, Equivalent Planned Outage Rate, Forced Outage Rate Demand, Equivalent Forced Outage Rate Demand, for the different generating unit capacity categories.

4. For **line 14**, enter the respective **total** index values for Net Capacity Factor, Net Output Factor, Service Factor, Availability Factor, Unavailability Factor, Unit Derating Factor, Equivalent Availability Factor, Equivalent Forced Outage Rate, Equivalent Maintenance Outage Rate, Equivalent Planned Outage Rate, Forced Outage Rate Demand, Equivalent Forced Outage Rate Demand, for all generating unit capacity categories.
5. For **lines 15-18**, enter the respective index values for Net Capacity Factor, Net Output Factor, Service Factor, Availability Factor, Unavailability Factor, Unit Derating Factor, Equivalent Availability Factor, Equivalent Forced Outage Rate, Equivalent Maintenance Outage Rate, Equivalent Planned Outage Rate, Forced Outage Rate Demand, Equivalent Forced Outage Rate Demand, for coal units, by generating unit vintage – for units that entered commercial operations in or before 1972, and in or after 1973.
6. For **lines 19 and 20**, enter the respective index values for Net Capacity Factor, Net Output Factor, Service Factor, Availability Factor, Unavailability Factor, Unit Derating Factor, Equivalent Availability Factor, Equivalent Forced Outage Rate, Equivalent Maintenance Outage Rate, Equivalent Planned Outage Rate, Forced Outage Rate Demand, Equivalent Forced Outage Rate Demand, for combined cycle units, by generating unit vintage – for units that entered commercial operations in or before 2002, and in or after 2003.

SCHEDULE 8. PART D. ANNUAL DATA ON GENERATING UNIT PRIMARY CAUSE OF ACTIVE STATE FORCED OUTAGES

In this section submit system/component failure cause codes for forced outages of conventional generating units in active state. The cause codes listed below are high level categories listed in Appendix B of the GADS Reporting Instructions.

For each generating unit type column, report counts for the listed cause codes. Cause code ranges are those provided in the GADS Reporting Instructions.

1. For **line 1** give the forced outage counts for the major generating unit components :

   1.a **Boiler** related components (cause code range 0010-1999)

   1.b **Reactor** related components for nuclear units

   1.c **Engine** related components for internal combustion units

   1.d **Steam turbine** related components for all units (cause code range 4000-4499)

   1.e **Generator** related components (cause code range 4500-4899)

2. For **line 2** give the forced outage counts for components of systems grouped under **Balance of Plant**:

   2.a **Water Systems** related components (cause code range 3110-3549)

   2.b **Electrical Systems** related components (cause code range 3600-3690)

   2.c **Power Station Switchyard** related components (cause code range 3700-3730)

   2.d **Auxiliary Systems** related components (cause code range 3800-3899)

   2.e **All Other Balance of Plant** components (cause code range 3950-3999)

3. For **line 3** give the forced outage counts for the components of **Pollution Control Equipment** (cause code range 8000-8845)

4. For **line 4** give the forced outage counts caused by factors external to the generating unit plant operations:

   4.a **Severe Weather** related factors (cause codes 9000, 9020, 9035, 9036)

   4.b **Other Catastrophes** not related to weather events (cause codes 9010, 9025, 9030, 9040)

   4.c **Economic factors** (cause code range 9130-9199, and cause code 0000)

   4.d **Fuel Quality** related factors (cause code range 9200-9291)

   4.e **Transmission System** related factors other than catastrophes (cause code 9300)

   4.f All **Other External** factors (cause code range 9300-9340)

5. For **line 5** give the forced outage counts not directly attributable to equipment failures and are caused by **Regulatory, Safety and Environmental** restrictions:

   5.a **Regulatory** factors (cause code range 9504-9590)

   5.b **Stack Emissions**, including exhaust emissions, restrictions (cause code range 9600-9656)

   5.c **Other Operating Environmental Limitations** (cause code range 9660-9690)

   5.d **Safety** related regulations and factors (cause codes 9700, 9720)

6. For **line 6** give the forced outage counts caused by factors related to **Personnel or Procedure** errors:

   6.a **Personnel Errors** (cause code range 9900-9920)

   6.b **Procedural Errors** (cause code range 9930-9950)

   6.c **Staff Shortage** (cause code 9960)

7. For **line 7** give the forced outage counts caused by **Performance** related factors (cause code range 9997-9999)

8. For **line 8** give the forced outage counts for units in active state that are not accounted for by the cause codes listed above, in lines 1 through 7.

9. For **line 9**, provide the **Total** outage counts for all causes in lines 1 through 8.

SCHEDULE 9. SMART GRID TRANSMISSION SYSTEM DEVICES AND APPLICATIONS

All data in section 9 are to be aggregated by each region / assessment area and reported on this schedule.

SCHEDULE 9. PART A. DYNAMIC CAPABILITY RATING SYSTEMS

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

1. For **line 1** enter the number of transmission circuits utilizing a dynamic capability rating system.
2. For **line 2** enter the miles of AC transmission lines utilizing a dynamic capability rating system.
3. For **line 3** enter the number of station transformers utilizing a dynamic capability rating system.

SCHEDULE 9. PART B. PHASOR MEASUREMENT UNITS

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

1. For **line 1,** enter the **number of non-networked PMUs** installed in your region. A non-networked PMU is a device that measures and stores phasor data at high frequency with a time-stamp, but these data are not transmitted automatically to any other device (e.g., control room equipment, phasor data concentrator). These data are available for later retrieval and analysis, for instance for event analysis after a reliability event.
2. For **line 2**, enter the **number of networked PMUs** installed in your region. A networked PMU measures and stores phasor data at high frequency with a time-stamp, and communicates these data at regular intervals (at least 30 samples per second) to remote locations. Typically the data are shared with a Phasor Data Concentrator (PDC), which then shares this information with other PMUs, operating or reliability organizations. These data are also stored in a data storage system. Communication between the PMU and PDC, and then between the PDC and the users or storage system, is done via a private wide-area network or any other secure and reliable digital transport system. The data collected by a networked PMU can be used along with data collected by other networked PMUs in order to get a precise and comprehensive view of large areas of the grid.
3. For **line 3** enter the total **number of substations with at least one networked PMU installed**. A substation is defined as any network node in the system where two or more transmission lines, or a transmission line and power plant, are connected directly or via step-up/step-down transformers.
4. For **line 4** enter the **total number of substations** in your region.

SCHEDULE 9. PART C. SMART GRID PMU APPLICATIONS

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

1. **Real-time operations applications** include, but are not limited to:

   - Wide-area situational awareness
   - Frequency stability monitoring and trending
   - Power oscillation monitoring
   - Voltage monitoring and trending
   - Alarming and setting system operating limits, event detection and avoidance
   - Resource integration
   - State estimation
   - Dynamic line ratings and congestion management

	• Outage restoration • Operations planning • Islanding detection, management, and restoration • Equipment problem detection 2. **Planning and off-line applications** include, but are not limited to: • Baselining power system performance • Event analysis • Static system model calibration and validation • Dynamic system model calibration and validation • Power plant model validation • Load characterization • Special protection schemes and islanding • Primary frequency (governing) response • Operator training Applications can be at any stage of deployment within the control room, from research and development to full production. **SCHEDULE 10. COMMENTS** 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.)
GLOSSARY	The glossary for this form is available online at the following URL: http://www.eia.gov/glossary/index.html For NERC definitions, see www.nerc.com, or this EIA copy at: http://www.eia.gov/cneaf/electricity/page/eia411/nerc_glossary_2009.pdf
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. 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.**
REPORTING BURDEN	The public reporting burden for this collection of information is estimated to be 122 hours per response for NERC Headquarters and the 8 Regional Reliability Entities, including the time of reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to the U.S. Energy Information Administration, Office of Survey Development and Statistical Integration, EI-21, 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.
DISCLOSURE OF INFORMATION	The following information reported on this survey will be protected 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 information associated with the "Survey Contact" and the "Supervisor of Contact Person for Survey" on SCHEDULE 1
- The information contained on SCHEDULE 4, Bulk Transmission Facility Power Flow Cases
- The information contained on SCHEDULE 5, Bulk Electric Transmission System Maps

All other information reported on Form EIA-411 is public information and may be publicly released in company identifiable form.

The Federal Energy Administration Act requires 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.

Data protection methods are not applied to the aggregate statistical data published from this survey. Some statistics may be based on data from fewer than three respondents, or that are dominated by data from one or two large respondents. In these cases, it may be possible for a knowledgeable person to closely estimate the information reported by a specific respondent.