Form 714 - Annual Electric Balancing Authority Area and Planning Area Report Instructions

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I. General Information

A. Purpose

The FERC Form 714 (Form 714) collects information for the Federal Energy Regulatory Commission (FERC, Commission) from electric utility balancing authority and planning areas in the United States. The Form 714 is authorized by the Federal Power Act and is a regulatory support requirement as provided by 18 CFR § 141.51. The data will be used to obtain a broad picture of interconnected balancing authority area operations including comprehensive information of balancing authority area generation, actual and scheduled inter-balancing authority area power transfers, and load; and to prepare status reports on the electric utility industry including review of inter-balancing authority area bulk power trade information. Planning area data will be used to monitor forecasted demands by electric utility entities with fundamental demand responsibility, and to develop hourly demand characteristics.

B. Who Must Submit

The schedules in this report shall be completed as follows:

i. Each balancing authority area must file Parts I, II and IV.

These parts shall be completed by each electric utility that operates a balancing authority area and each group of electric utilities, which are bound together through pooling contracts, holding company operations or other contractual arrangements that operate a balancing authority area. In each balancing authority area there is generally one electric utility charged with operating the balancing authority area and its associated automatic generation balancing authority equipment. It is this utility that should complete Part I, II and IV. In some large power pools, the balancing authority area may be operated by an agency designated by the members, or by a holding company subsidiary. In these cases, these parts should be completed by the organization responsible for operating the balancing authority area. Electric utilities owning one or more generating plants located outside their balancing authority area, where the output is received and controlled by some other electric utility, should exclude such plants from consideration on Part II. The information pertaining to the excluded plant must be reported by the electric utility in whose area the plant is controlled.

ii. Each electric utility with its planning area annual peak demand greater than 200 megawatts (MW) must file Parts I, III and IV.

Respondents should be those electric utilities charged with carrying out the resource planning and demand forecasts for the planning area. A typical respondent is an electric utility that is the principal resource planning and forecasting entity with an obligation to serve the planning area demands. The respondent could be supplying full and partial requirements wholesale power to other electric utilities.

In many instances, the information to be reported in Form 714 will have been reported to the respondent's regional reliability council. However, only utilities subject to the reporting requirements may submit a Form 714. Entities that are neither balancing authority area operators nor planning area operators, but who are authorized by their members to compile Form 714 data on their behalf, are required to make the data available to their balancing authority area operators and planning area operators in order that those area operators may file the data with the Commission.

C. How to Submit

Submit this form electronically through the Form 714 Submission Software. Retain one copy of the report for your files. For any resubmissions, submit the filing using the Form 714 Submission Software.

D. When to Submit

Submit this form on or before June 1 of the year following the calendar reporting year. Note: A one-time extension was given to July 16, 2007, to file the 2006 calendar year report.

E. Sanctions and Confidentiality Statements

This report is mandatory under the Federal Power Act. Late filing or failure to file, keep records, or comply with these instructions may result in criminal fines, civil penalties, and other sanctions as provided by law. Data reported on the Form 714 are not confidential.

II. General Instructions

Conducting a valid survey requires that all respondents provide data using the same frame of reference. Therefore, we need your help. Please thoroughly familiarize yourself with all of the data requested on this form and their applicable definitions and instructions BEFORE you begin to provide any of the data.

Report in whole numbers (no decimal values); the only exception is reporting system lambda data in Part II – schedule 6 where 2 decimal places are required.

Use a minus sign when reporting negative numbers.

Furnish information for the balancing authority area or planning area as it existed at the end of the calendar year (December 31). If part of the system was acquired during the year, report for that part of the system for the entire year, obtaining the information from the previous owner. If part of the system was disposed of during the year, and the respondent was not operating that part of the system at the end of the year, do not report on that part of the system.

Some utilities, particularly municipal and other government-operated utilities, maintain records on other than a calendar year basis. Whenever this form requests annual data, please provide such data on a calendar year basis. If monthly data are requested, please provide such data for the month and year indicated, not for the corresponding month within the fiscal year.

III. Definitions

A. Actual Interchange

Metered electricity that flows from one balancing authority area to another.

B. Available Capability

The maximum load-carrying ability exclusive of station use and planned, unplanned or other outage or derating.

C. Coincident Peak Demand
Sum of two or more demands on individual systems that occur in the same demand interval.

D. Balancing Authority Area
The area operator that is responsible for matching generation and load, responsible for maintaining scheduled interchange with other balancing authority areas, and that is responsible for maintaining the frequency in real-time, of the electric power systems.

E. Demand
The rate at which electric energy is delivered to or by a system, part of a system, or piece of equipment, at a given instant or averaged over any designated period of time.

F. Dynamically-Scheduled Plant
An electric generating plant in another balancing authority area whose output matches a continuously adjusted schedule in real time effectively making the plant a part of the respondent's balancing authority area.

G. Electric System
The physically connected generation, transmission, distribution and auxiliary facilities that are operated as an integrated unit under single balancing authority, management, or operating supervision. For purposes of this report, electric system may consist of one or more electric utilities. An "electric utility" means a corporation, person, agency, authority, or other legal entity or instrumentality that owns and/or operates facilities within the United States for the generation, transmission, distribution, or sale of electric energy primarily for use by the public.

H. Firm Capability (Unit/System)
The commitment of generation service to a customer under a contractual agreement to which the parties to the service anticipate no planned interruption. The allocation of the utility's resources may be system wide, or only for a named unit; the time of availability is usually prescribed as well.

I. Firm Power (Sales/Purchases)
Electric power intended to meet the demand requirement of a utility's customers; there is no planned interruption of service with this type of sale/purchase. Utilities may sell/buy capacity for a limited duration and time to other utilities.

J. Full Requirements Customer
A wholesale customer without other generating resources whose electric energy supplier is the sole source of long-term firm power for the customer's service area. The terms and conditions of sale are equivalent to the supplier's obligations to its own retail service, if any.

K. Interchange
Electricity that flows from one balancing authority area to another.

L. Load
The amount of electrical power delivered or required at any specified point or points on a system. The requirement originates at the energy-consuming equipment of the customer.

M. Net Capability
The maximum load-carrying ability, exclusive of station use, under specified conditions for a given time interval independent of the characteristics of the demand. (Capability is determined by design characteristics, physical condition, adequacy of prime mover, energy supply, and operating limitations such as cooling and circulating water supply and temperature, headwater and tailwater elevations, and electrical use.)

N. Net Energy for Load (Generic)
This is the electric energy requirements of the system, which is defined as the system net generation plus energy received from others less energy delivered to others. It includes system losses but excludes energy required for the filling of reservoirs at pumped-storage plants.

O. Net Energy for Load (Balancing Authority Area)
The net generation plus actual interchange received minus actual interchange delivered within the boundaries of the balancing authority area.

P. Net Energy for Load (Planning Area)
The amount of energy required by the reported utility or group of utilities' retail customers in the system's service area plus the amount of energy supplied to full and partial requirements utilities (wholesale requirements customers) plus the amount of energy losses incurred in the transmission and distribution.

Q. Net Generation
Gross generation less plant use, measured at the high-voltage terminals of the station's step-up transformer. The energy required for pumping at pumped-storage plants is regarded as plant use and must be deducted from the gross generation. Generation from auxiliary and start-up generators should not be reported.

R. Other Outage and Derating
Refers to generators that are normally in an operating or stand-by status, but are unavailable for all reasons other than planned and unplanned outages, including transmission limitations at the generating plant, disruptions in fuel supplies of energy sources, environmental considerations etc.

S. Partial Requirements Customer

A wholesale customer with generating resources insufficient to carry all its demand and whose energy seller is a long-term firm power source supplemental to the customer's own generation or energy received from others. The terms and conditions of sale are similar to those for a full requirements customer.

T. Peak 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).

U. Planned Outage and Derating
Refers to generators that are normally in an operating or stand-by status, but are derated or unavailable due to routine service or planned maintenance.

V. Planning Area
The electric system wherein an electric utility is responsible for the forecasting of system demands and has the obligation to provide the resources to serve those demands.

W. Scheduled Interchange
Electricity scheduled to flow between balancing authority areas, usually the net of all sales, purchases, and wheeling transactions between those parties at a given time.

X. Unplanned Outage and Derating
Refers to generators that were derated or out-of-service for unplanned reasons, due to mechanical failures.

IV. Specific Instructions

A. Part I Schedule 1: Identification and Certification

i. Respondent Identification.
FERC utility code and name.

ii. Respondent Type.
Check the appropriate categories.

iii. Balancing Authority Area.
Enter/verify the name of the balancing authority area reporting. Use names as provided in the NERC Operating Manual, for example.

iv. Planning Area.
Enter/verify the name of the planning area reporting. If the planning area and balancing authority area are identical, then these names may be identical.

v. Respondent Address.
Enter the respondent’s address. Include an attention line, room number, building designation, etc. to facilitate the future handling and processing of this form.

vi. Contact person.
Enter/verify the name, title, E-mail address and telephone number of the individual to be contacted concerning the information provided on this form.

vii. Certifying official.
Enter/verify the name and title of the certifying official. The certifying official must date the form.

B. Part II: Balancing Authority Areas

i. Schedule 1. Generating Plants Included in Reporting Balancing Authority Area

This schedule identifies each power plant whose output is telemetered and monitored by the respondent (balancing authority area operator). This would include all generation, located within the respondent's balancing authority area, under automatic generation balancing authority either directly or indirectly through satellite balancing authority facilities, all dispatchable generation by the balancing authority area operator either directly or indirectly, and all other balancing authority area generation resources whose output is presumably significant enough to be continuously monitored for balancing authority area operations. Also, include any generation outside your balancing authority area which is dynamically scheduled. Do not list generation located outside your balancing authority area which you jointly own, but is not dynamically scheduled. Energy received from this generation should be reported as interchange.

The total output of such generation plus the net of transfers would then be the balancing authority area net load. Other generation within the balancing authority area not reported here and thus not included within the total reported output would then presumably be reflected in the demand as "negative demand."

Column b. List the name of each electric utility operating power plant within the respondent's balancing authority area whose output is telemetered and monitored by the respondent (balancing authority area operator) and outside the respondent's balancing authority area which is dynamically scheduled.

Column c. List for each electric utility identified in column b, the name of each such generating plant (or unit if units at a plant are dispatched separately) that is internal to your balancing authority area or dynamically scheduled as part of your balancing authority area. The monthly and annual output of these plants when summed in your balancing authority area should be identical to the monthly and annual net generation reported in Schedule 3, column c.

Column d. Enter the available capability at the time of the annual peak demand of each plant identified in column c. The available capability requested is at the time of balancing authority area annual peak demand for whatever fuel is then being used. This total should equal the value reported in Schedule 2, column c, "Available Capacity," for the month with the annual peak demand. Any differences must be explained in a footnote.

Column e. Enter the net demand on each plant at the time of the Balancing Authority Area's annual peak demand. The respondent should report by plant, the aggregate of the demands placed upon the generators located in the power plant identified in column c. If no generators in a plant were operating at the time of the annual peak demand, then report the integrated demand as zero (0) for that plant. If a non-operating plant was drawing power from the grid, report the amount as a negative number. Provide a total as a last line. This total should equal the value reported in Schedule 3, column f, "Output of Generating Plants," for the month with the annual peak demand. Any differences must be explained in a footnote.

ii. Schedule 2. Balancing Authority Area Monthly Capabilities at Time of Monthly Peak Demand
Schedule 2 collects the net generating capability available to the respondent to meet the balancing authority area demand and composition of internal and external resources available and on reserve. The capability data are requested at the time of the monthly hourly peak demands, where the peak demand is defined to be that 60-minute integrated time period when the net energy for load (NEL) as computed in Schedule 3, column (e), was the greatest. Available and unavailable capability are requested as well as available or unavailable unit or firm capability commitments.

Net capability is the steady hourly output which a generating unit is expected to supply to demand, exclusive of station use, under specified conditions, without exceeding limits of temperature and stress. Net capability should be based on average water conditions for thermal-electric plants and on average or median flow conditions for hydroelectric plants. Capability should be differentiated from nameplate rating which defines the output that the manufacturer guarantees the generator will produce under a defined set of conditions and remains fixed. Capability measures the amount of power that the generating unit can actually produce. This will likely be more or less than its rating due to atmospheric conditions, the characteristics of the fuel consumed, etc.

A generating unit may operate at reduced capability. In these cases, the respondent should split the capability between "available" (column c) and "unavailable" (columns d, e and f).

The capability data reported should reflect the respondent's best estimate of the capability that was available at that time given the then current operating conditions, not a fixed value based on extensive testing. If a generator was not operating at the time of the monthly peak demand, the respondent should estimate the capability that the generator would have been assigned if it had been operating. Further, if a portion of a generator's total estimated capability was unavailable due to a temporarily reduced rating, estimate the available and unavailable portions of the generator's capability as of the time of the monthly peak demand.

a. Column c. Report, in megawatts, by month, the aggregated available capability of those generators within the respondent's balancing authority area or dynamically scheduled as part of your balancing authority area as identified by plant in Schedule 1. Available capability refers to operating generators and those on stand-by that could have been made operational if needed. Available capability does not include generators in a test status, even if they were producing power at the time of the peak demand. Include any appropriate non-utility power producer capabilities.

b. Columns d, e, and f. Report, in megawatts, by month, the aggregated capability of those generators within the respondent's balancing authority area or dynamically scheduled as part of your balancing authority area as identified by plant in Schedule 1, but were unavailable to satisfy the demand at the time of the balancing authority area's peak demand. Report separately the capability that was unavailable for "planned or scheduled" reasons from that unavailable for "unplanned or forced outage" and "other" reasons. Derating of units also should be separated into planned maintenance conditions, unplanned events and other reasons.

1. Column d. Planned outage refers to generators that are normally in an operating or stand-by status, but were unavailable for service due to routine and planned maintenance. Planned derating refers to removal of a generator component for repairs which were scheduled well in advance and are of a predetermined duration. These represent capability that the balancing authority area did not expect to have available to satisfy its demand at the time of the monthly peak demand.

2. Column e. Unplanned outage refers to generators that were out-of-service for unplanned reasons, due to mechanical failures. Unplanned derating refers to an unplanned generator

component failure which required that the load on the unit be reduced.

3. Column f. Other outage refers to generators that were out-of-service for reasons other than planned or unplanned outages, including transmission limitation at the generating plant, disruptions in fuel supplies or energy sources, environmental considerations, etc. Other derating refers to other conditions which required that the load on the unit be reduced.

c. Column g. This column is the automatically calculated sum of Columns c, d, e, and f to arrive at the balancing authority area's internal total net generation capability.

d. Columns h and i.

1. Column h. If the respondent had capacity available that could be scheduled into its balancing authority area that could be traced to a particular generator operated within another balancing authority area or firm power commitment, and the respondent did not treat it as part of its balancing authority area's internal capability, then the capability from that generator or firm power commitment should be reported here. Generating capacity within the respondent's balancing authority area or firm power commitments to other balancing authority areas at the time of the respondents monthly peak demand are to be reported as a negative. If there are commitments into and out of the respondent's balancing authority area, provide a net figure. However, if that capacity or any portion of it was not available for any reason, then the corresponding capability should NOT be included in this column, rather it should be reported in column i.

2. Column i. This column reports the firm power capability not available to the respondent from sources external to the balancing authority area, at the time of the monthly peak demand based on NEL. Conversely, if the respondent sold firm capacity that was not taken because it was unavailable, and it was included as a part of the balancing authority area's internal capability, then the capability from that un-taken firm power sale should be reported here as a negative value.

e. Column j. This column is the automatically calculated respondent's total capability in megawatts, whether or not totally available, that is committed to

meet the monthly balancing authority area peak demand (the total of column g+h+i)

iii. Schedule 3. Balancing Authority Area Net Energy for Load and Peak Demand Sources by Month

This schedule covers all generation assigned to your balancing authority area, and actual interchange with other balancing authority areas, to determine the net energy for load in your balancing authority area.

a. Column c. Enter the monthly net generation, internal to the balancing authority area from those plants as identified in Schedule 1, including any external generation which is dynamically scheduled as part of your balancing authority area, less any generation in your balancing authority area dynamically scheduled as part of another balancing authority area. Indicate in a footnote if there are substantial amounts of internal generation whose output is not telemetered to the balancing authority area's control center and thus not included in net generation.

b. Column d. Enter the monthly net actual interchange received by members of your balancing authority area from suppliers (utilities or non-utility generators) in other balancing authority areas. The amounts should reflect actual interchange (see definition) rather than scheduled interchange. Receipts should not include the physical transfer into the balancing authority area of dynamically scheduled generation owned by utilities in the balancing authority area and deliveries should not include generation in your balancing authority area dynamically scheduled as part of other balancing authority areas. Total actual interchange should equal the difference between the totals for columns (e) and (f) on Schedule 5. Any difference must be explained in a footnote.

c. Column e. Automatically generated sum of columns c & d.

d. Column f. This column reports the megawatts of output for the generating plant's energy reported in column c. The value for the month of the annual peak should equal the total of all plant integrated net loads reported on Schedule 1, column (e). Any difference must be explained in a footnote.

e. Column g. If unit or firm purchase transactions were made from utilities external to the balancing authority area during the hour of the balancing authority area's monthly peak demand, then report the amount in megawatts.

f. Column h. If unit or firm sales transactions were

made to utilities external to the balancing authority area during the hour of the balancing authority area's monthly peak demand, then report the amount in megawatts.

g. Column i. Report the megawatts of net of non-firm transactions and inadvertent interchange with utilities external to the balancing authority area during the time of the balancing authority area's monthly peak demand. The amount will be positive for an in-flow and negative for an outflow.

h. Column j. Automatically generated respondent's monthly peak demand in megawatts which is defined to be that 60-minute integrated time period when the balancing authority area's NEL is the greatest.

i. Column k. Report, in megawatts, the respondent's monthly minimum demand based on net energy for load under normal operating conditions.

iv. Schedule 4 Instructions: Adjacent Balancing Authority Area Interconnections

a. Column b. Enter/verify the name of the adjacent interconnected balancing authority area. Use proper names to identify these balancing authority areas, as provided in the NERC Operating Manual, for example. Do not use the name of a transmission line owner if it is different from the balancing authority area name.

b. Column c. Enter/verify each individual line or bus name interconnecting each balancing authority area identified in Column b. Use common industry naming for lines, e.g., Bakerton - Bolivar No. 1 & 2, and naming for a bus, e.g. Potomac Bus. Note that the example line is a double circuit line.

c. Column d. Enter/verify the line or bus operating voltage.

v. Schedule 5 Instructions: Balancing Authority Area Scheduled and Actual Interchange

a. Column b. Enter/verify the names of all interconnected balancing authority areas and balancing authority areas with which interchanges were scheduled. Use balancing authority area names as provided in the NERC Operating Manual, for example. Do not list utilities or non-utilities which are not balancing authority areas. If these entities are located within the respondent's balancing authority area they should either be treated as generation, load or negative load.

b. Columns c and d. Enter in Column c the total annual

energy that was scheduled into the respondent's balancing authority area from the balancing authority area identified in column b, and, similarly for the annual energy that was scheduled to that balancing authority area in column d. Note: Scheduled interchange may occur with **non-adjacent** balancing authority areas.

c. Columns e and f. Enter in column e the actual metered electricity that flowed from the adjacent balancing authority area reported in column b into your balancing authority area. Enter in column f the actual metered electricity that flowed from your balancing authority area to the adjacent balancing authority area listed in column b. The difference between the totals should equal the total of column (d) on Schedule 3. Any difference must be explained in a footnote.

vi. Schedule 6 Instructions: Balancing Authority Area Hourly System Lambda

Enter in columns (c) to (z) the balancing authority area's system lambda, in dollars per megawatthour, calculated for each hour of the day starting with 1 a.m. on January 1. This schedule will have 365 records (or 366 for a leap year) with 24 hourly lambda values reported per day for each day of the year. The hourly lambda data calculations for each day is based on the respondent observing “standard time” for its respective time zone for the entire year even though it may have observed “daylight savings time” for part of the year. Respondents must denote in column (b) the actual time zone observed for each day (e.g., EST, EDT, CST, CDT, etc.).

a. Balancing Authority Area Hourly System Lambda. For balancing authority areas where demand following is primarily performed by thermal generating units, the system lambda is derived from the economic dispatch function associated with automatic generation control performed at the balancing authority area’s controlling utility or pool control center. Excluding transmission losses, the fuel cost ($/hr) for a set of on-line and loaded thermal generating units (steam and gas turbines) is minimum [(1)] when each unit is loaded and operating at the same incremental fuel cost ($/MWh) [(2)] with the sum of the unit loadings (MW) equal to the system demand plus the net of interchange with other balancing authority areas. This single incremental cost of energy is the system lambda. System lambdas are likely recalculated many times in one clock hour. However, the indicated system lambda occurring on each clock hour would be sufficient for reporting purposes.

Provide, as a footnote to the first lambda data cell in Part

II Schedule 6, an explanation describing the reason for the unavailability of system lambda information. The Commission expects that all Energy Management Systems, with proper instructions, can record the system lambda being used for economic dispatch of the balancing authority area's thermal units.

Respondents should be able to report system lambda, along with the other information reported on a balancing authority area basis that describe the operation of such areas from information that should be readily available. The Commission is not requesting Respondents to develop incremental or marginal cost (either short or long term) according to any formula. Nor is the Commission requesting "avoided cost rates" that electric utilities file with state commissions or otherwise make available for prospective qualified facilities.

b. Description of Economic Dispatch. Provide a detailed description of how the Respondent calculates system lambda. For those systems that do not use an economic dispatch algorithm and do not have a system lambda, provide in writing a detailed description of how balancing authority area resources are efficiently dispatched.

C. PART III: Planning Areas

i. Schedule 1. Electric Utilities that Compose the Planning Area

Part III respondents should be those electric utilities charged with carrying out the resource planning and demand forecasts for the electric system consisting of the electric utilities identified on this schedule. This should include all full requirements customers and any partial requirements customers which rely on their supplier to plan for incremental demand requirements.

a. Column b. Identify all the electric utilities, including the respondent that the respondent includes in its planning area.

b. Columns c and d. Based on the planning area's seasonal peak demands, enter in columns c and d the annual summer and winter coincident peak demands, respectively, for each utility identified in column b.

ii. Schedule 2. Planning Area Hourly Demand and Forecast Summer and Winter Peak Demands and Annual Net Energy for Load

a. Planning Area Hourly Demand. Respondents must submit hourly demand data.

Enter in columns (c) to (z) the planning area's actual hourly demand, in megawatts, for each hour of the day starting with 1 a.m. on January 1. This schedule will have 365 records (or 366 for a leap year) with 24 hourly demand values reported per day. The time basis of the hourly data for each day of the year will be based on “standard time” for the respondent’s respective time zone (even though it may have been observing “daylight savings time” for some days of the year). Respondents must denote in column (b) the actual time zone observed for each day (e.g., EST, EDT, CST, CDT, etc.).

b.Planning Area Forecast Summer and Winter Peak Demand. Provide the planning area's forecast summer and winter peak demand, in megawatts, and annual net energy for load, in megawatthours, for the next ten years.

D. Part IV. Footnotes.
Include a footnote for any data item by right-clicking on the cell, choosing Footnote from the drop-down list and typing your comment provided on the pop-up page.

Endnotes

[1] Some utilities may also include variable operation and maintenance costs that they consider "dispatchable." Therefore the costs to be minimized could include a variable O&M component as well as the fuel costs.

[2] Because unit heat rates and fuel costs vary, some units may not be able to operate at the same incremental fuel cost as the other units and, thus, those units may be loaded differently.