Federal Energy Regulatory Commission
FERC Form No. 714 (2003)

Annual Electric Control and Planning Area Report

For the Year Ending December 31, 2003
FERC FORM NO. 714

Form Approved
OMB Numbers: 1902 - 0140
(Expires: 7-31-2000)

This report is mandatory under the Federal Power Act, and is a regulatory support requirement as provided by 18 C.F.R. § 141.51. Failure to comply may result in criminal fines, civil penalties and other sanctions as provided by law. Information reported on the FERC Form No. 714 is not considered confidential. Questions concerning this report will be answered by: Ms. Meesha M. Bond (202) 208-1414 or form714@ferc.fed.us.

This form consists of: Part I, Identification and Certification; Part II, comprising Schedules 1 through 6; Part III, comprising Schedules 1 and 2; and Part IV, Notes. All respondents are to complete Parts I and IV. Part II is to be completed by each electric utility or group of electric utilities that operates a control area. Part III is to be completed by each electric utility or group of electric utilities that constitute a planning area and has an annual peak demand that is greater than 200 MW. An electric utility is 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.

Public reporting burden for this collection of information is estimated to average 50 hours per response, including time for 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 Federal Energy Regulatory Commission, Office of the Chief Information Officer, CI-1, 888 First Street, N.E., Washington, DC 20426; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503. You shall not be penalized for failure to respond to this collection of information unless the collection of information displays a valid OMB control number.

List of Schedules

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Part I - Schedule I. Identification and Certification

1. Respondent Identification:

   Code: Name: New York Independent System Operator

2. Respondent Type: (Please check appropriate box and fill in name)

   [X] Part I: Control Area (Complete Parts I, II and IV)

   Control Area Name:

   [ ] Part II: Planning Area (Complete Parts I, III and IV)

   Planning Area Name:

3. Respondent Mailing Address:
   New York Independent System Operator
   290 Washington Avenue Extension
   Albany, NY 12203

4. Contact Person:

   Name: John C. Cutting
   Title: Senior Regulatory Affairs Analyst

   Telephone #: (518) 356-7521 Ext.

5. Certifying Official:

   Name: John Adams
   Title: Director, System and Resource Planning

   Signature: ________________ Date: _______

Return Completed Form to: **Federal Energy Regulatory Commission**
Form No. 714
Room 83-14
888 First Street, N.E.
Washington, DC 20426

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Please Type:
Utility Code
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Part II - Schedule 1. Generating Plants Included in Reporting Control Area
(Use continuation sheets if needed)

Under the name of its operating electric utility, list all generating plants (1) within the respondent's control area which are controlled, metered or for which the required information is otherwise available to control area operators and (2) dynamically scheduled plants or units outside the control area. Specifically identify dynamically scheduled plants. Report only plant totals with generators in an operating or standby status. Provide totals for columns (d) and (e) as a last line. The total in column (d) should equal the value in column (c) on Schedule 2 for the month of the annual peak demand. The total in column (e) should equal the value in column (f) on Schedule 3 for the month of the annual peak demand. Any differences must be explained in a note. For specific guidelines, please refer to the attached Schedule 1 Instructions on pages 14 and 15.

Line No. (a)	Electric Utility Name (b)	Plant Name (c)	Plant Available Capability at the Hour of the Annual Peak Demand Based on Net Energy for Load (MW) (d)	Integrated Net Load on the Plant at the Hour of the Annual Peak Demand Based on Net Energy for Load (MW) (e)
1.	Please see enclosed diskette for Part II Schedule I data.			See Part II Schedule 3 Column (f) for totals.
2.				
3.				
4.				
5.				
6.				
7.				
8.				
9.				
10.				
11.				
12.				
13.				
14.				
		TOTAL		

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Please Type:
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Part II - Schedule 2. Control Area Monthly Capabilities at Time of Monthly Peak Demand

The peak demand and other terms used in this schedule are defined in the attached instructions for Schedule 2, pages 15 through 18. Please first read the instructions, and then complete this Schedule. The value in column (c) for the month of the annual peak demand should equal the total in column (d) in Schedule 1. Any difference must be explained in a note.

		Net Capability at the Time of the Monthly Peak Demand, Based on Control Area Net Energy For Load (NEL)							
		Net Capability from Plants Reported on Schedule II					External to the Control Area Net Unit or Firm Capability (MW)		
			Unavailable Capability Due to:						
Line No. (a)	Month (b)	Available Capability (MW) (c)	Planned Outage and Derating (MW) (d)	Unplanned Outage and Derating (MW) (e)	Other Outage and Derating* (MW) (f)	Total (c + d + e + f) (MW) (g)	Available (MW) (h)	Not Available (MW) (i)	Total Capability (g + h + i) (MW) (j)
1.	Jan	37087	3578	669	0	32840	0	0	32840
2.	Feb	37087	4376	1350	0	31361	0	0	31361
3.	Mar	37087	4543	515	0	32029	0	0	32029
4.	Apr	37087	8014	336	0	28737	0	0	28737
5.	May	37087	1981	402	0	34704	0	0	34704
6.	Jun	37087	1691	2275	0	33121	0	0	33121
7.	Jul	37087	1298	24	0	35765	0	0	35765
8.	Aug	37087	2028	1166	0	33893	0	0	33893
9.	Sep	37087	2637	588	0	33862	0	0	33862
10.	Oct	37087	3561	539	0	32987	0	0	32987
11.	Nov	37087	5033	1764	0	30290	0	0	30290
12.	Dec	37087	3761	134	0	33192	0	0	33192

* Reductions in capability due to fuel supply problems, environmental restrictions, lack of transmission availability at a generating plant, etc.

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Please Type:
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Part II - Schedule 3. Control Area Net Energy for Load and Peak Demand Sources by Month

Enter the monthly "Net Energy for Load" which is the amount of energy that the control area requires internally including control area losses. The total in column (d) should equal the difference in the totals for columns (e) and (f) on Schedule 5. The value in column (f) for the month of the annual peak demand should equal the total in column (e) in Schedule 1. Any differences must be explained in a note. For detailed instructions and definitions, please refer to attached Schedule 3 Instructions on pages 19 and 20.

Line No. (a)	Month (b)	Control Area Net Generation (MWh) (c)	Net Actual Interchange (MWh) (d)	Net Energy for Load (MWh) (c + d) (e)	Control Area Load Sources at Time of Control Area Monthly Peak Demand, Based on Net Energy For Load (NEL): Output of Generating Plants (MW) (f)	Unit or Firm Purchases (MW) (g)	Unit or Firm Sales (MW) (h)	Net Non-Firm & Inadvertent (MW) (i)	Monthly Peak Demand (MW) (f+g-h+i) (j)	Monthly Minimum Demand (MW) (k)
1.	January	14,185,026	1.481,874	15,666,900	25,746	1514	2757	49	24454	13161
2.	February	12,594,314	1,281,704	13,870,018	24,407	1640	2582	75	23390	13711
3.	March	12,945,751	1,176,427	14,122,178	22,892	1815	1625	56	23026	12246
4.	April	11,778,282	1,445,738	13,224,020	22,774	488	2459	8	20795	11581
5.	May	11,851,215	1,400,876	13252091	20,897	1383	2418	-3	19865	11633
6.	June	12,959,906	1,436,184	14,396,090	32,609	1448	3688	36	30333	11727
7.	July	15,413,468	1,572,874	16,986,342	31,798	2056	4364	-38	29528	13926
8.	August	15,423,837	**	**	30,877	351	2372	1	28855	4977
9.	September	12,987,769	1,435,740	14,423,509	25,443	265	1986	-65	23784	12412
10.	October	12,316,170	1,009,048	13,325,218	22,372	668	1792	171	21077	12018
11.	November	12,066,282	1,359,440	13,425,722	22,363	311	1168	-141	21647	11894
12.	December	13,493,970	1,017,940	14,511,910	23,632	1065	1211	3	23483	12767
13.	Total	158,015,990								

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Please Type:
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Part II - Schedule 4. Adjacent Control Area Interconnections

Identify on this schedule: each adjacent control area with which the respondent control area is interconnected in column (b), all the interconnection line or bus names with the adjacent control area in column (c), and the line or bus voltage in column (d). See Schedule 4 Instructions on pages 20 and 21.

Line No. (a)	Name of Adjacent Control Area (b)	Control Area Interconnection Line or Bus Names (c)	Line or Bus Voltage (kV) (d)
1.	Hydro Quebec	Chateauqay - Massena Line 7040	765 kV
2.	ISO-NE	Rotterdam – Bear Swamp Line E205W	230 kV
3.	ISO-NE	Alps – Berkshire Line 393	345 kV
4.	ISO-NE	Whitehall – Blissville Line 7	115 kV
5.	ISO-NE	Hoosick - Bennington Line K6	115 kV
6.	ISO-NE	Plattsburgh – Grand Island Line PV20	115 kV
7.	ISO-NE	Pleasant Valley – Long Mountain Line 398	345 kV
8.	ISO-NE	Northport – Norwalk Harbor Line 1385	138 kV
9.	ISO-NE	Falls Village - Smithfield Line 690	69 kV
10.	Ontario IMO	Niagara - Beck Line PA301	345 kV

11.	Ontario IMO	Niagara - Beck Line PA302	345 kV
12.	Ontario IMO	Niagara - Beck Line PA27	230 kV
13.	Ontario IMO	Swan Road - Beck Line 104-1	115 kV
14.	Ontario IMO	Packard - Beck Line BP76	230 kV
	Ontario IMO	Harper – Beck 25 Hz Line 105	115 kV
	Ontario IMO	Harper – Beck 25 Hz Line 106	115 kV
	Ontario IMO	Moses – St. Lawrence Line L33P	230 kV
	Ontario IMO	Moses – St. Lawrence Line L34P	230 kV
	PJM	Ramapo – Branchburg Line 5018	500 kV
	PJM	West Nyack - Closter Line 751	69 kV
	PJM	North Waverly – East Sayre Line 956	115 kV
	PJM	Hillside – East Towanda Line 70	230 kV
	PJM	South Ripley – Erie South Line 69	230 kV
	PJM	Sugarloaf - Franklin Line D	115 kV
	PJM		

		Sugarloaf - Franklin Line J	115 kV
	PJM	Stolle Road – Homer City Line 37	345 kV
	PJM	Watercure – Homer City Line 30	345 kV
	PJM	Farragut - Hudson Line C3403	345 kV
	PJM	Farragut – Hudson Line B3402	345 kV
	PJM	Pearl River – Harings Corner Line 45	34.5 kV
	PJM	West Nyack – Harings Corner Line 701	69 kV
	PJM	Burns – Harings Corner Line 702	138 kV
	PJM	Goudey – Laurel Lake Line 952	115 kV
	PJM	Goethals - Linden Line A2253	230 kV
	PJM	Blue Hill – Montvale Line 43	69 kV
	PJM	Blue Hill – Montvale Line 44	69 kV
	PJM	Pearl River – Montvale Line 491	69 kV

	PJM	Hillburn – South Mahwah Line 65	69 kV
	PJM	South Mahwah – South Mahwah BK 258	345/138 kV
	PJM	Ramapo – South Mahwah Line 51	138 kV
	PJM	South Mahwah – Waldwick Line J3410	345 kV
	PJM	South Mahwah – Waldwick Line K3411	345 kV
	PJM	Falconer – Warren Line 171	115 kV

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Please Type:
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Part II - Schedule 5.
Control Area Scheduled and Actual Interchange

Identify on this schedule: each control area with which the respondent control area has actual or scheduled interchange of energy, in column (b); the total annual megawatthours (MWh) of the scheduled interchange that were received by the respondent control area through all interconnection points with each control area, in column (c); the MWh of scheduled interchange delivered to each control area, in column (d); the MWh of total annual actual interchange received and delivered within each **adjacent** control area, in columns (e) and (f). Provide totals for columns (c), (d), (e) and (f). The difference in the totals for columns (e) and (f) should equal the total in column (d) on Schedule 3. Any difference must be explained in a note. See Schedule 5 Instructions on page 21.

Line No.	Name of Control Area	Scheduled Interchange Between Control Areas (MWh)		Actual Interchange Between Adjacent Control Areas (MWh)	
		Received	Delivered	Received	Delivered
(a)	Eastern Time (b)	(c)	(d)	(e)	(f)
1.	IMO ONTARIO HYDRO	3,760,290	-210,473	946,038	-722,289
2.	PJM INTERCONNECTION	***	***	***	***
3.	ISO NEW ENGLAND	950,618	-966,943	977,667	-839,801
4.	HYDRO QUEBEC	1,831,664	-878,484		
5.					
6.					
7.					
8.					
9.					

10.	TOTAL				

Part II - Schedule 6. Control Area System Lambda Data

Submit on a 3.5 inch diskette formatted for the DOS operating system the following data file in ASCII format: the control area's system lambda for each hour of the year starting with 1 a.m., January 1, 1999. Identify clearly the time zone in which this time series is made. The file should have 8760 records (8784 for leap years). Each record is to contain the system lambda value at the clock hour in dollars per megawatt hour (mills per kilowatt hour) or an "NA" for those hours when system lambda was not calculated.

Control Area Hourly System Lambda. For control 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 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 control 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 note in Part IV, an explanation describing the reason for the unavailability of system lambda information and a definite plan for reporting the information with a target date. The Commission expects that all Energy Management Systems, with proper instructions, can record the system lambda being used for economic dispatch of the control area's thermal units.

Respondents should be able to report system lambda, along with the other information reported on a control 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, pursuant to PURPA 210, electric utilities file with state commissions or otherwise make available for prospective qualified facilities.

Description of Economic Dispatch. Also, provide in writing a detailed description of how 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 control area resources are efficiently dispatched.

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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.

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Please Type:
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Part III - Schedule 1. Electric Utilities That Compose the Planning Area
(Use continuation sheets if needed)

Enter the name of each entity, including the respondent, that forms the planning area for which this report is being prepared and their coincident summer and winter peak demands in megawatts. Please refer to Instructions on pages 23 and 24.

Line No. (a)	Electric Utility Name (b)	Electric Utility Coincident Peak Demand (MW) Summer (c)	Electric Utility Coincident Peak Demand (MW) Winter (d)
1.	Central Hudson Gas and Electric Corporation	1078	905
2.	Consolidated Edison Corporation of New York	11852	8497
3.	Long Island Power Authority	4794	3267
4.	New York Power Authority	474	658
5.	New York State Electric & Gas Corporation	2501	2571
6.	Niagara Mohawk Power Corporation	6127	5722
7.	Orange and Rockland Utilities Inc	995	665
8.	Rochester Gas & Electric Corporation	1485	1179
9.			
10.			
11.			

Part III - Schedule 2.
Planning Area Hourly Demand and Forecast Summer and Winter Peak Demand and Annual Net Energy for Load

PLANNING AREA HOURLY DEMAND

(1) Respondents must submit hourly demand data in electronic form to the Commission. Additionally, Respondents that participate in a national, regional or subregional process for consolidating and ensuring the consistency and accuracy of actual hourly and forecast demand information, may instead authorize the national, regional or subregional organization to release that information to the Commission, and to the public at the cost of reproduction, in an easily accessible electronic format, such as the EEI format.

(2) If the Respondent does not participate in the development of national, regional or subregional actual and forecast demand information, it must submit its own, equivalent, demand information directly to the Commission along with this report, as follows.

Respondents must submit on a 3.5 inch diskette formatted for the DOS operating system the following data file in ASCII format: the planning area's actual hourly demand, in megawatts, for each hour of the year starting with 1 a.m, January 1, 1999. Indicate the time zone and the period for which daylight savings time was used. The file should have 8760 records (8784 for leap years). For hours when this information is not available, enter "NA."

PLANNING AREA FORECAST SUMMER AND WINTER PEAK DEMAND

Provide on the diskette a file containing the planning area's forecast summer and winter peak demand, in megawatts, and annual net energy for load, in megawatt hours, for the next ten years.

2003 data for Part III Schedule 2 is included on the attached diskette.

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Part IV.
Notes

Indicate a note by placing an asterisk (*) next to the entry on Schedules 1 through 6 of Part II and Schedules 1 and 2 of Part III, and then provide the note below. For each note, enter the page number in Column (a), the line number in Column (b), the column letter in Column (c), and the Note in Column (d). Use more than one line if needed.

Page No. (a)	Line No. (b)	Column Letter (c)	Notes (d)
4	8	(d) & (e)	Due to August 14, 2003, blackout event, data has not yet been confirmed for August. A revised Form 714 will be filed when data analysis is complete.
6	2		Due to the August 14, 2003, blackout event, PJM data is still being verified. A revised Form 714 will be filed when data analysis is complete.
