

**Annual Electric Control and Planning Area
Report**
For the Year Ending December 31, 2003
FERC FORM NO. 714

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. Sandy J. Russell (202) 502-8376 or form714@ferc.gov.

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 which operates a control area. Part III is to be completed by each electric utility or group of electric utilities which 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.

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Annual Electric Control and Planning Area Report
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Part I - Schedule I. Identification and Certification

1. Respondent Identification:

Code: **19876** Name: **Virginia Electric and Power Company**

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

☒ Part I: Control Area (Complete Parts I, II and IV)

Control Area Name: **Virginia Electric and Power Company**

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

Planning Area Name: **Virginia Electric and Power Company**

3. Respondent Mailing Address:

William L. Thompson
Virginia Electric and Power Company
5000 Dominion Boulevard
Glen Allen, Virginia 23060-6711

4. Contact Person:

Name: **Carl J. Eng**
Title: **Manager – Power Supply Engineering**
E-mail address: **Carl_Eng@dom.com**
Telephone #: **(804) 273-3305** Ext. **n.a.**

5. Certifying Official:

Name: **William L. Thompson**
Title: **Director – Bulk Power Operations**

Signature:  Date: **May 28, 2004**

**Annual Electric Control and Planning Area Report
For the Year Ending December 31, 2003**

Utility Code: 19876
Utility Name: Virginia Electric and Power
Company

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 8.

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.	Virginia Electric and Power Company	Bellmeade	230	203
2.	Virginia Electric and Power Company	Bremo 3	71	72
3.	Virginia Electric and Power Company	Bremo 4	156	154
4.	Virginia Electric and Power Company	Chesapeake 1	111	112
5.	Virginia Electric and Power Company	Chesapeake 2	111	114
6.	Virginia Electric and Power Company	Chesapeake 3	156	149
7.	Virginia Electric and Power Company	Chesapeake 4	217	218
8.	Virginia Electric and Power Company	Chesterfield 3	100	98
9.	Virginia Electric and Power Company	Chesterfield 4	166	164
10.	Virginia Electric and Power Company	Chesterfield 5	310	296
11.	Virginia Electric and Power Company	Chesterfield 6	658	578
12.	Virginia Electric and Power Company	Chesterfield 7	197	186
13.	Virginia Electric and Power Company	Chesterfield 8	200	190
14.	Virginia Electric and Power Company	Clover 1	441	430

15.	Virginia Electric and Power Company	Clover 2	441	431
16.	Virginia Electric and Power Company	Hall Branch	63	63
17.	Virginia Electric and Power Company	Mount Storm 1	524	470
18.	Virginia Electric and Power Company	Mount Storm 2	524	504
19.	Virginia Electric and Power Company	Mount Storm 3	521	489
20.	Virginia Electric and Power Company	North Anna 1	925	922
21.	Virginia Electric and Power Company	North Anna 2	917	912
22.	Virginia Electric and Power Company	North Branch	74	74
23.	Virginia Electric and Power Company	Polyester	0	0
24.	Virginia Electric and Power Company	Possum Point 1	0	0
25.	Virginia Electric and Power Company	Possum Point 2	0	0
26.	Virginia Electric and Power Company	Possum Point 3	101	0
27.	Virginia Electric and Power Company	Possum Point 4	221	0
28.	Virginia Electric and Power Company	Possum Point 5	786	693
29.	Virginia Electric and Power Company	Possum Point 6	545	522
30.	Virginia Electric and Power Company	Southampton	63	45
31.	Virginia Electric and Power Company	Surry 1	810	810
32.	Virginia Electric and Power Company	Surry 2	815	811
33.	Virginia Electric and Power Company	Yorktown 1	159	149
34.	Virginia Electric and Power Company	Yorktown 2	167	161
35.	Virginia Electric and Power Company	Yorktown 3	818	703
36.	Virginia Electric and Power Company	Bath County Hydro *	1440	1503

37.	Virginia Electric and Power Company	Gaston Hydro	225	0
38.	Virginia Electric and Power Company	Roanoke Rapids Hydro	99	94
39.	Virginia Electric and Power Company	Cushaw Hydro	2	2
40.	Virginia Electric and Power Company	North Anna Hydro	1	0
41.	Virginia Electric and Power Company	Chesapeake CT	144	0
42.	Virginia Electric and Power Company	Darbytown CT	288	0
43.	Virginia Electric and Power Company	Gravel Neck CT	329	0
44.	Virginia Electric and Power Company	Ladysmith 1	145	0
45.	Virginia Electric and Power Company	Ladysmith 2	145	6
46.	Virginia Electric and Power Company	Remington CT	580	0
47.	Virginia Electric and Power Company	Kitty Hawk CT	44	0
48.	Virginia Electric and Power Company	Lowmoor CT	60	0
49.	Virginia Electric and Power Company	Mount Storm CT	12	0
50.	Virginia Electric and Power Company	Northern Neck CT	64	0
51.	Virginia Electric and Power Company	Possum Point CT	78	0
52.	Southeastern Power Administration	Kerr Dam	240	168
53.	Old Dominion Electric Cooperative	Louisa	459	298
54.	SEI Birchwood	Birchwood NUG	238	237
55.	James River Cogeneration	Cogentrix Hopewell NUG	93	80
56.	Cogentrix of Virginia Leasing Corp.	Lake Kingman NUG	115	102
57.	Ogden Martin Fairfax	OMF NUG	63	60
58.	Hopewell Cogeneration L.P.	HCF NUG	337	328

59.	Cogentrix - Rocky Mount	Edgecombe NUG	116	111
60.	Panda – Rosemary	Rosemary NUG	165	157
61.	Cogentrix of Richmond, Inc.	Spruance 1 NUG	116	112
62.	Cogentrix of Richmond, Inc.	Spruance 2 NUG	94	91
63.	Doswell, L.P.	Four Rivers 1 NUG	155	146
64.	Doswell, L.P.	Doswell NUG	605	589
65.	Commonwealth Atlantic, L.P.	Elizabeth River NUG	312	302
66.	Mecklenburg Cogen., L.P.	Buggs Island NUG	132	131
67.	Multitrade of Pittsylvania Co., L.P.	Hurt	80	40
68.	Westmoreland-Hadson Ptnrs.	Roanoke Valley 1	165	166
69.	Westmoreland-Hadson Ptnrs.	Roanoke Valley 2	44	44
70.	Gordonsville Energy, L. P.	South Anna 1	109	110
71.	Gordonsville Energy, L. P.	South Anna 2	109	109
72.	Non-Utility Power Producers	Various *	169	132
		Total	19,170	15,841

Annual Electric Control and Planning Area Report
For the Year Ending December 31, 2003Utility Code: 19876
Utility Name: Virginia Electric and Power Company**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, 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.

Line No. (a)	Month (b)	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)		Total Capability (g + h + i) (MW) (j)
		Available Capability (MW) (c)	Unavailable Capability Due to:			Total (c + d + e + f) (MW) (g)			
			Planned Outage and Derating (MW) (d)	Unplanned Outage and Derating (MW) (e)	Other Outage and Derating* (MW) (f)				
1.	Jan	19,600	-152	-2,998	0	16,450	0	0	16,450
2.	Feb	19,606	-607	-822	0	18,177	0	0	18,177
3.	Mar	19,606	-2,332	-1,914	0	15,360	0	0	15,360
4.	Apr	18,165	-4,602	-2,950	0	10,613	0	0	10,613
5.	May	18,165	-3,125	-1,536	0	13,504	0	0	13,504
6.	Jun	19,230	-202	-296	0	18,732	0	0	18,732
7.	Jul	19,170	-71	-394	0	18,705	0	0	18,705
8.	Aug	19,170	-108	-222	0	18,840	0	0	18,840
9.	Sep	19,170	-108	-962	0	18,100	0	0	18,100
10.	Oct	19,994	-2,353	-1,388	0	16,253	0	0	16,253
11.	Nov	20,064	-1,208	-2,123	0	16,733	0	0	16,733
12.	Dec	20,064	-1,801	-251	0	18,012	0	0	18,012

Annual Electric Control and Planning Area Report
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Utility Code: 19876
Utility Name: Virginia Electric and Power Company

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 11 and 12.

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)					Monthly Minimum Demand (MW) (k)
					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)	
1.	January	7,499,184	1,147,189	8,646,373	14,481	13	949	2,588	16,133	6,843
2.	February	6,621,606	899,941	7,521,547	14,528	6	815	817	14,536	7,657
3.	March	5,807,943	1,155,882	6,963,825	12,457	21	972	1,743	13,249	6,287
4.	April	5,030,115	1,220,673	6,250,788	9,821	21	929	2,530	11,443	6,041
5.	May	5,779,752	574,212	6,353,964	10,494	19	96	739	11,156	6,169
6.	June	6,850,715	473,157	7,323,872	16,425	19	1,077	642	16,009	6,187
7.	July	8,156,570	507,788	8,664,358	16,370	19	583	222	16,028	7,273
8.	August	8,411,580	315,817	8,727,397	16,594	19	828	564	16,349	7,209
9.	September	6,154,101	483,195	6,637,296	14,609	19	420	699	14,907	* 2,536
10.	October	5,272,649	1,090,585	6,363,234	9,978	4	562	1,424	10,844	6,280
11.	November	5,659,431	884,986	6,544,417	11,649	19	494	561	11,735	6,279
12.	December	7,465,557	563,904	8,029,461	14,163	19	690	110	13,602	7,052
	Total	78,709,203	9,317,329	88,026,532						

Annual Electric Control and Planning Area Report
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Utility Code: 19876
Utility Name: Virginia Electric and Power Company

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.	American Electric Power	Altavista - Leesville/Reusens	138
2.		Bearskin - Smith Mt.	138
3.		Banister - E Danville	138
4.		Bremo - Scottsville	138
5.		Cloverdale - Lexington	500
6.		Greenbrier/Hinton - Fudge Hollow	138
7.		Skimmer	115 - 69
8.	Carolina Power & Light	Battleboro - Rocky Mount	115
9.		Carson - Wake	500
10.		Edgecombe - Rocky Mount	230
11.		Greenville - Everetts	230
12.		Halifax - Person	230
13.		Hornertown - Rocky Mount	230

14.		Kerr Dam - Henderson	115
15.	Pennsylvania - New Jersey - Maryland Group	Dickerson - Pleasant View	230
16.		Doubs - Loudoun	500
17.		Doubs - Mt Storm	500
18.		Edinburg - Strasburg	138
19.		Meadow Brook - Mt Storm/Morrisville	500
20.		Mt. Storm – Pruntytown	500
21.		N. Shenandoah Transformer	138 - 115
22.		Possum Pt - Burches Hill	500

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Utility Code: 19876
Utility Name: Virginia Electric and Power Company

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. (a)	Name of Control Area (b)	Scheduled Interchange Between Control Areas (MWh)		Actual Interchange Between Adjacent Control Areas (MWh)	
		Received (c)	Delivered (d)	Received (e)	Delivered (f)
1.	American Electric Power	5,829,262	76,096	5,925,284	524,520
2.	Carolina Power & Light	4,753,026	370,233	5,102,237	1,648,923
3.	Pennsylvania – New Jersey – Maryland Group (PJM)	3,556,573	4,261,201	28,197,751	27,734,499
	Totals	14,138,861	4,707,530	39,225,272	29,907,942

**Annual Control Area and Electric System Report
For the Year Ending December 31, 2003**

Utility Code: 19876
Utility Name: Virginia Electric and Power Company

Part II - Schedule 6. Control Area System Lambda Data

Submit on a 3.5 inch diskette or CD 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, 2003. 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 megawatthour (mills per kilowatthour) 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.

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.

Description of Economic Dispatch

In the traditional sense the incremental cost of generation on an electric power system is thought of as a study program solution. Given this premise, the desired system load level is assumed and the various generators are evaluated for their incremental costs of output, reflected to the theoretical load center, by an Economic Dispatch program. Minimum overall cost for the electric power generation is determined by solving for the minimum incremental cost of power delivered to the load center from each generator. It can be shown that for all units not running at their highest (nor their lowest) output level we find the same incremental cost to the load center to be determined by the economic dispatch computation. This is the term commonly referred to as System Lambda.

In the practical world we are quite often not able to operate generators in an unrestricted manner. For example, a unit may not be able to reach its rated maximum output level due to wet coal or broken feeder mills. Within this restricted framework the real time economic dispatch programming seeks to find the lowest cost situation determined by calculating the incremental cost for all units able to be electronically controlled by the dispatch computer, within the real time megawatt limits of the generators. All generators with real-time control capability are considered by the economic dispatch program, which uses a fourth degree polynomial curve fit coefficients for each generator in order to model their costing. Specifically, we are using the first derivative of the Input/Output curve for each unit to evaluate that unit's incremental cost in the economic dispatch equation. The expression for the unit may be written as:

$$\text{IncrementalCost}_{\text{unit}} = [(B_{\text{unit}}) + (2 * C_{\text{unit}} * \text{NetMW}_{\text{unit}}) + (3 * D_{\text{unit}} * \text{NetMW}_{\text{unit}}^2)] * \text{FuelCost}_{\text{unit}} + \text{VariableO\&M}_{\text{unit}}$$

where B, C, and D are coefficients of the Input/Output curve.

Because we know that the minimum system cost is achieved when all units are at equal incremental costs, the real time computer system uses an inverted equation for each unit, solving instead for NetMW as a function of IncrementalCost. The iterative logic employed by the real time calculation is:

1. Pick a value for System Lambda.
2. For each unit from Unit 1 to Unit n, determine NetMW achieved at this value of System Lambda.
3. Sum the NetMW's from step 2.
4. Does this sum exactly meet the system load requirements?
5. If $\Sigma(\text{NetMW})$ is too high, lower the estimate of System Lambda and return to step 2. If $\Sigma(\text{NetMW})$ is too low, raise the estimate of System Lambda and return to step 2.

If $\Sigma(\text{NetMW})$ exactly meets system load requirements, you have determined the necessary NetMW for each unit to minimize total system costs, and the System Lambda used is the correct System Lambda.

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Utility Code: 19876
Utility Name: Virginia Electric and Power Company

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)	Winter (d)
1.	Old Dominion Electric Cooperative (ODEC)	1,449.57	1,595.11
2.	Central Virginia Electric Cooperative (CVEC)	56.94	100.96
3.	NC Electric Membership Corporation (NCEMC)	209.88	242.96
4.	Virginia Municipal Electric Association (VMEA)	200.43	198.40
5.	Craig-Botetourt Electric Cooperative (CBEC)	5.10	7.43
6.	Town of Enfield	6.99	5.45
7.	Town of Windsor	7.52	7.47
8.	Virginia Electric and Power Company	14,412.57	13,975.22
	Planning Area Totals	16,349.00	16,133.00

**Annual Electric Control and Planning Area Report
For the Year Ending December 31, 2003**

Utility Code: 19876
Utility Name: Virginia Electric and Power Company

**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 or CD 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, 2003. 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 megawatthours, for the next ten years.

The following Planning Area Forecast data is included on the enclosed diskette:

Year	Summer Peak	Winter Peak	Control Area Output
2004	17,580	15,593	90,619,876
2005	17,947	15,894	92,465,455
2006	18,314	16,170	94,489,388
2007	18,671	16,449	96,097,054
2008	18,872	16,574	97,421,593
2009	19,231	16,859	99,086,487
2010	19,579	17,138	100,978,937
2011	19,926	17,417	102,858,815
2012	20,280	17,688	105,058,156
2013	20,629	17,969	106,680,457

Annual Electric Control and Planning Area Report
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Utility Code: 19876
Utility Name: Virginia Electric and Power Company

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	36	d, e	Bath County Pumped Storage Hydro is jointly owned, 60% by Virginia Electric and Power Company (VAP), and 40% by Allegheny Power System (APS). Because APS' share is dynamically scheduled from VAP to APS, it is not included here in VAP's data.
6	72	d, e	These are base-loaded non-utility generators within the control area. The control area operator does not continuously monitor them; however, their input contributed to meeting our system energy and load requirements.
8	1-12	h	Includes Allegheny Power System's ownership share of Bath County generation as a 'sale' (see first note, above).
8	9	k	2,536 MW was the minimum load for September, 2003, due to Hurricane Isabel.
12			Virginia Electric and Power Company calculates lambda for units on control once per hour according to FERC requirements. This time series is made in the Eastern time zone. 2003 System Lambda data is provided on the enclosed diskette (Lambda2003.txt).
15			Virginia Electric and Power Company is in the Eastern time zone. Daylight Savings Time for 2003 was observed from April 6 to October 26. The enclosed diskette contains actual hourly demand for 2003 (HourlyDemand2003.txt). Also included is the forecast of summer and winter peak control area demand (MW), as well as forecasted control area output, for the next ten (10) years (10YearDemandForecast.txt).
			Also included on the enclosed diskette is an electronic copy of Virginia Electric and Power Company's 2003 FERC Form 714 Filing (FERC 714 - 2003 Filing.zip).