

**TESTIMONY OF CHARLES A. STADELMEIER
FOR
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
VIRGINIA STATE CORPORATION COMMISSION
CASE NO. PUE _____**

1 Q. Please state your name, business address and position of employment.

2 A. My name is Charles A. Stadelmeier and my business address is One James River Plaza,
3 Richmond, Virginia. I am Supervisor - Regulatory Compliance for Virginia Electric and
4 Power Company (the "Company"). In my current position, I am responsible for the estimation
5 of production costs for the Company's native load customers. A statement of my background
6 and qualifications is attached to this testimony as Appendix A.

7

8 Q. Please describe your testimony and the issues that will be addressed.

9 A. My testimony reviews the Company's fuel expense methodology and provides schedules of
10 actual energy and expenses for the prior fuel factor period, February 2000 through September
11 2000, and projected energy and expenses from October 2000 through December 2001. I also
12 review the unit operating and net power transaction assumptions for the proposed fuel factor
13 period, and the current status of cogeneration, small power production and other non-Company
14 generation.

15 My testimony also presents the actual fuel expenses incurred by the Company during
16 the period February 1, 2000 through September 30, 2000. I will also discuss the status of the
17 fuel recovery balances as of September 30, 2000.

1

2 Q. During the course of your testimony, will you introduce an exhibit?

3 A. Yes. Company Exhibit No. ____, CAS, Schedules 1-12, was prepared under my direction and
4 is accurate to the best of my knowledge.

5

6 Q. How does the Company's nuclear unit performance compare to industry averages?

7 A. The 1999 nuclear system capacity factor of 95.2% far exceeded the 1999 industry average of
8 operational nuclear units, 86.27 %, reported by the Utility Data Institute (UDI). This excess
9 over the industry average of 8.93 percentage points equates to approximately 2.7 million
10 additional megawatt-hours of nuclear generation for the period.

11 In addition, the UDI rated North Anna and Surry among the lowest-cost producers of
12 power in 1999. North Anna ranked second among the lowest-cost producers of nuclear-
13 generated electricity of the 58 stations that provided data to be included in the Institute's
14 ranking and Surry ranked ninth. For the 1997-1999 three year average nuclear production costs
15 ranking, North Anna was ranked as the lowest-cost producer for the period and Surry was
16 ranked fourth.

17

18 Q. Focusing on the prior period, February 2000 through September 2000, how did the nuclear
19 units perform?

20 A. The nuclear units operated at a combined capacity factor of 94.5% for the period. Surry Units
21 1 and 2 established a combined capacity factor of 95.6%. Surry Unit 1 had an actual capacity
22 factor of 89.0% for this period, while Surry Unit 2 achieved an actual capacity factor of

1 100.0%. The actual capacity factor of North Anna Unit 1 was 85.8% and the North Anna Unit
2 2 capacity factor was 100.0%. North Anna Units 1 and 2 achieved a combined capacity factor
3 of 93.6%.

4
5 Q. How did the Company's fossil units perform in 1999?

6 A. The fossil units continued their record of excellent performance in 1999. The 1999 fossil steam
7 system heat rate was 9,808 BTU/kWh, which represents the twelfth year these units have
8 sustained a heat rate below 10,000 BTU per kWh. The Company's coal units performed well,
9 with an average heat rate of 9,920 BTU/kWh. This represents the fourteenth consecutive year
10 the units ran below 10,000 BTU/kWh. The Company's coal-fired units' equivalent availability
11 was 82.1% in 1999. This was the sixteenth year the equivalent availability of the units
12 exceeded 80%.

13
14 Q. How has the fossil steam system performed over the period February 2000 through September
15 2000?

16 A. The coal units achieved an equivalent availability of 87.57%. The actual heat rate for these
17 units was 9,910 BTU/kWh. The individual unit performance statistics are shown on Schedules
18 1 and 2.

19
20 Q. What was the actual mix of energy sources for the prior period?

21 A. For the period of February 2000 through September 2000, 34.6% of system energy was
22 supplied by nuclear generation (excluding Old Dominion Electric Cooperative's undivided

1 11.6% interest in North Anna 1 and 2), 43.1% by coal-fired generation, 3.0% by heavy oil-
2 fired and refinery gas generation, 3.0% by combined cycle and combustion turbine generation,
3 and 16.6% by net power transactions. Hydro, pumped storage generation net of pumping
4 energy, and other generation accounted for less than 1% of system energy.

5
6 Q. How did actual energy compare to projected energy for this period?

7 A. Schedule 3 shows a comparison of actual and estimated system energy and fuel expenses.
8 Total actual system energy was 539,000 MWh less than projected for the period. Nuclear
9 generation was 983,200 MWh greater than projected. Actual coal generation was 871,800
10 MWh lower than projected for the period. Heavy oil and refinery gas generation was 112,700
11 MWh greater than projected. Combustion turbine generation was 346,900 MWh less than
12 projected and combined cycle generation was 3,400 MWh less than projected. Actual net
13 power transactions were 412,800 MWh less than estimated for the period.

14 The February 2000 through September 2000 estimates were based on the Company's
15 1999 filing (PUE990717) that became effective February 1, 2000.

16
17 Q. Mr. Stadelmeier, please comment on the Company's under-recovery of its fuel expenses
18 through September 2000.

19 A. The primary cause of this under-recovery is attributable to two major components. First, actual
20 fuel prices were greater than projected. Company witnesses Eckroade and Barker address this
21 in detail in their testimonies. Second, actual off-system sales were less than projected in the
22 previous fuel factor filing. The previous fuel factor case included a projection of \$34.3 million

1 system margin offsetting projected fuel expense. The actual system margin incurred by the
2 Company during the current fuel year as of September 30, 2000 is approximately \$400,000.

3
4 Q. Briefly describe the Company-developed fuel expense forecast methodology used for
5 projecting system fuel expenses.

6 A. Projected system fuel expenses are calculated through a planning process which matches
7 projected generating capability with expected demand. This process has four phases. First,
8 the projection of system load for native load customers is prepared by Finance and Business
9 Services. This forecast provides expected monthly peak demands and expected monthly area
10 output and sales. The second phase is the projection of generating unit operating information
11 which is prepared by the Nuclear and Fossil and Hydro Business Units. This information
12 includes detailed input data on the operating parameters of the existing units. The Capacity
13 Acquisition Department provides detailed data on capacity available to the Company from
14 non-utility generators. Third, the Fossil and Hydro Fuel Analysis group prepares the fuel price
15 projections. Finally, the Regulatory Compliance Department assembles the data from these
16 sources and performs a probabilistic simulation of system operation for the study period using
17 the PROMOD production costing model. The unit commitment and economic dispatch logic
18 used in the simulation take into account the expected peak loads, energy requirements, unit
19 outage schedules, forced outage rates, unit operating parameters, fuel prices, and the net power
20 transactions. In addition, off-system purchases and sales were modeled in this simulation and
21 the PROMOD dispatch logic reflected the effects of these transactions. The results from this
22 simulation are used to calculate system fuel expenses and are ultimately transmitted to the

1 Rates Department which uses these values to develop the fuel factor.

2 PROMOD is an accepted “state-of-the-art” production costing model leased by the
3 Company from New Energy Associates which the Company uses to develop projections of
4 fuel expenses. The input data used in the PROMOD analysis for this case was based on
5 information available in time to prepare the filing, and reflects historical, as well as expected
6 operation of the Company's system.

7

8 Q. Are there any major changes to the Company’s assumptions in this filing?

9 A. Yes. Effective January 1, 2001 the maximum dependable capacity ratings of the four nuclear
10 units will be revised and this revision has been included in the model evaluation. Also, the
11 Company recently received approval to construct two new combustion turbine units in
12 Caroline County, Virginia. These units, expected to come on line in the summer of 2001 and
13 add 298 MW of dependable summer capacity to our system, were included in the model
14 evaluations. Finally, the Company's Wholesale Power Group sales and purchases have been
15 modeled as a single area system. This market information was developed by ICF Kaiser
16 Consulting.

17

18 Q. How has the Company treated the sale of a portion of the Henrico Lateral Pipeline to the City
19 of Richmond?

20 A. The Company has removed the expenses associated with that portion of the Pipeline sold to
21 the City of Richmond.

22

- 1 Q. Has the Company changed the way the off-system sales margins were calculated for inclusion
2 in projected fuel expense?
- 3 A. Yes. First, the Company calculated the off-system sales margin consistent with the calculation
4 presented in the 1999 fuel factor filing. The results of this calculation were similar to the
5 margin that was calculated in last year's fuel factor filing, i.e., approximately \$35 million.
6 Given the Company's actual system margin of \$400,000 for the current fuel year through
7 September 30, 2000, a calculated margin of approximately \$35 million for the fuel year 2001
8 is unrealistic to be included as an offset to fuel expenses. The Company's Wholesale Power
9 Group has estimated the appropriate level of system margin to be \$28 million, of which \$14
10 million will offset system fuel expense for the twelve months ended December 2001.
11
- 12 Q. What is the Company's current projection for sources of system energy and expenses for
13 October 2000 through December 2000?
- 14 A. Schedule 4 shows estimated energy and expenses for the October 2000 through December
15 2000 period. The "Net Power Transaction" expense column includes the offsetting "sales for
16 resale" fuel revenue and one-half of the margin on off-system sales projected during this
17 period. Schedule 5 shows forced outage rates, equivalent availability factors and capacity
18 factors for the same three-month period and Schedule 6 shows the maintenance outages which
19 have been modeled for the Company's generating units.
20
- 21 Q. What are the Company's system energy and fuel expense projections for January 2001 through
22 December 2001?

1 A. The energy projections are shown on Schedule 7, page 1, with the associated system fuel
2 expenses shown on page 2 of this schedule. Again, the “Net Power Transaction” expense
3 column includes the offsetting “sales for resale” fuel revenue and one-half of the margin on
4 off-system sales projected during this period. This one-half margin amount equals \$14 million
5 on a system basis for the twelve months ending December 2001. Also, the Virginia Coal Tax
6 Credit has been incorporated into the proposed coal expenses as indicated in Mr. Eckroade's
7 testimony.

8
9 Q. What kilowatt-hour sales forecast was used by the Company to develop the 2000-2001
10 estimates for the proposed fuel factor?

11 A. The Company’s most recent load forecast, as prepared by Finance and Business Services, was
12 used to develop the current fuel factor projections. This forecast is based on economic
13 assumptions provided by the Regional Forecasting Associates (RFA), an economic consulting
14 firm. RFA provides forecasts of Virginia-specific economic variables based on their national
15 economic data. The load and energy forecast excludes customers served under special
16 contracts. Schedule 8 shows the sales forecast for both the system and the Virginia jurisdiction.

17
18 Q. What are the unit operating assumptions used in the Company's projections for the January
19 2001 through December 2001 period?

20 A. Schedule 9 shows the forced outage rates, equivalent availability factors and capacity factors
21 for the projected period and Schedule 10 shows the PROMOD maintenance outages modeled
22 for the Company's generating units.

1 For the period ending December 2001, North Anna 1 and 2 and Surry 1 and 2 are
2 projected to operate at 87.6%, 87.6%, 87.6 % and 96.9 % capacity factors, respectively. The
3 four major coal-fired units - Chesterfield 6, and Mt. Storm 1, 2, and 3, are projected to operate
4 at 89.9%, 67.2%, 67.1% and 78.4% equivalent availabilities, respectively. Clover Units 1 and
5 2, two 441 MW coal-fired units which are jointly-owned with Old Dominion Electric
6 Cooperative (ODEC), are projected to operate at an 89.5% and an 88.2% capacity factor,
7 respectively.

8
9 Q. What operating assumptions has the Company made for its nuclear units in developing the fuel
10 expense projections for the period of January 2001 through December 2001 contained in this
11 case?

12 A. The Company based the nuclear run-time capacity factor assumption on a five-year average
13 based on historical nuclear unit operation through 1999, resulting in a 96.9% run-time capacity
14 factor for all four nuclear units. The units are assumed to be refueled on eighteen-month
15 cycles. North Anna Units 1 and 2 are both scheduled for 35-day refueling outages in 2001.
16 Surry Unit 1 is also scheduled for a 35-day refueling outage in 2001.

17
18 Q. What are the Company's net power transaction assumptions which have been included in the
19 projections of system fuel expenses?

20 A. The Company's contracts with non-utility generators are expected to generate 11,937 GWh
21 during the period January 2001 through December 2001. The summer capability of these
22 projects is expected to be 3,256 MW throughout this period.

1

2 Q. What are the actual fuel expenses incurred by the Company during the prior period of February
3 2000 through September 2000?

4 A. Schedule 11 of my exhibit presents the actual fuel expenses incurred by the Company during
5 the period of February 2000 through September 2000. Column 1 of the schedule reflects actual
6 system booked fuel expenses, by month, for the period and Column 2 shows the actual system
7 fuel expenses adjusted to reflect the Virginia jurisdictional approved fuel factor methodology.

8

9 Q. Please describe the adjustments which cause the amounts in Schedule 11, Column 2 to differ
10 from those in Column 1.

11 A. These adjustments are necessary to reflect differences between financial accounting and
12 ratemaking accounting as prescribed by this Commission in Case Nos. PUE790010 and
13 PUE840006 and various other Commission orders as referenced below.

14 **Fossil/Steam**

15 Expenses in Column 2 exclude handling and analysis costs and demurrage costs.

16 **Nuclear**

17 a. Expenses in Column 2 exclude costs related to allowance for funds used during
18 construction accrued on and after September 1, 1981 pursuant to this Commission's Order in
19 Case No. PUE810025.

20 b. Expenses in Column 1 include interim storage costs based on a system accrual;
21 however, for the Virginia jurisdiction, the Company will continue to recover the costs on an
22 incurred basis. Therefore, Column 2 includes only the expenses that have been paid.

1 **Combustion Turbines**

2 Expenses in Column 2 exclude handling and analysis costs and demurrage costs.

3 **Purchased Power**

4 Expenses in Column 1 include only the energy portion of purchased power costs.

5 Revenues from off-system sales are recorded in Account 447 on the Company's books
6 pursuant to FERC Order No. 529. For purposes of calculating the Virginia Jurisdictional fuel
7 factor the appropriate energy revenues from these sales have been credited to the energy
8 amounts. This is consistent with the accounting for off-system sales in fuel cases approved by
9 this Commission prior to FERC Order No. 529. Column 2 reflects these credits.

10
11 Q. How were system fuel expenses on Schedule 11, Column 2 allocated to the Virginia
12 jurisdiction as shown on Schedule 12, Page 1, Column 1?

13 A. The fuel expenses were allocated on a kilowatt-hour sales basis using the North Anna/Non-
14 North Anna allocation methodology previously approved by this Commission in Case No.
15 PUE850001.

16
17 Q. Please discuss the contents of Schedule 12.

18 A. Schedule 12 contains the actual Virginia jurisdictional fuel cost recovery experienced during
19 the February 1, 2000 through September 30, 2000 period. It consists of actual data for the
20 current period and prior period Virginia jurisdictional fuel expense recovery. Current period
21 refers to the recovery position of fuel expenses incurred from February 1, 2000 through
22 September 30, 2000. Prior period refers to the recovery position as of September 30, 2000 of

1 previously unrecovered fuel expenses that have not been recovered as of September 30, 2000.
2 On Page 1, the actual current period recovery experience of Virginia jurisdictional fuel
3 expenses have been calculated and show an under-recovery of \$49,899,952 as of September
4 30, 2000. As shown on Page 2, the actual prior period under-recovery balance is \$20,323,828
5 at September 30, 2000.

6 Page 3 of Schedule 12 presents the summary of the Company's jurisdictional fuel cost
7 recovery position, which at September 30, 2000 was a net under-recovery of \$70,223,780.

8

9 Q. Does this conclude your testimony?

10 A. Yes, it does.

BACKGROUND AND QUALIFICATIONS

FOR

CHARLES A. STADELMEIER

I graduated from Virginia Polytechnic Institute and State University in 1974 with a Bachelor of Science Degree in Accounting. In 1978, I received a Master of Business Administration Degree from Virginia Commonwealth University. I was employed by the Company in 1975 as an assistant accountant. My career with the Company includes positions in Corporate Accounting, Taxes, and Regulatory Accounting. On February 1, 2000 I assumed by current position as Supervisor - Regulatory Compliance.

I have previous presented testimony before the Virginia State Corporation Commission and the North Carolina Utilities Commission.