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COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

APPLICATION OF

VIRGINIA ELECTRIC AND POWER COMPANY **CASE NO. PUE960036**

1995 Annual Informational Filing

COMMONWEALTH OF VIRGINIA

At the relation of the

STATE CORPORATION COMMISSION **CASE NO. PUE960296**

Ex Parte: Investigation of Electric Utility Industry Restructuring -- Virginia Electric and Power Company

Direct Testimony of Kathryn E. Iverson

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A My name is Kathryn E. Iverson; 5555 DTC Parkway, Suite B-2000; Englewood, Colorado 80111.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of public utility regulation and employed by the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants with corporate headquarters in St. Louis, Missouri.

1 Q **WOULD YOU PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND**
2 **EXPERIENCE?**
3 A I have a Bachelor of Science Degree in Agricultural Sciences and a Master of Science
4 Degree in Economics from Colorado State University. I have been a consultant in this
5 field since 1984, with experience in utility resource matters. More details are provided
6 in Appendix A to this testimony.
7
8 Q **ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS**
9 **PROCEEDING?**
10 A I am testifying on behalf of the Virginia Committee for Fair Utility Rates ("VCFUR"),
11 who are customers of Virginia Electric and Power Company ("Virginia Power," or
12 "Company").
13
14 Q **WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?**
15 A I will address the quantification of potential stranded costs as described in the
16 Company's Transition Cost Report ("TCR").
17
18 Q **PLEASE SUMMARIZE YOUR TESTIMONY.**
19 A The following is a summary of my conclusions and recommedations:
20 (1) Any estimation of stranded costs is premature at this time. Given that critical
21 parameters as to timing, customer choice and eligibility, market structure and
22 other essential characteristics of a competitive retail market are unknown at
23 this time, estimates of stranded cost should be regarded as highly speculative.
24
25 (2) Although all estimates are both premature and speculative at this time, the
26 Company's estimate of its stranded costs is particularly flawed and excessively
27 pessimistic. Virginia Power's hypothetical illustration of its stranded costs does
28 not reflect a rational illustration of the value of its generating assets in a
29 competitive marketplace.
30
31 (3) Beyond the problems inherent with any administrative determination of
32 stranded costs, the Company's estimate also suffers from these specific flaws:
33

- Many of the inputs rest on questionable support or support that is impossible to substantiate, particularly with respect to the price duration curves generated from the output from the MultiSym model.

- Virginia Power has made several premature assumptions with respect to timing, market structure and extent of impending competition.

- The capacity reservation values used in its modeling of economic valuation are significantly understated. The Company has inappropriately assumed the use of an economic carrying charge rather than a levelized carrying charge, and has significantly understated the fixed operation and maintenance costs for an advanced CT. These erroneous assumptions result in an understatement of the economic valuation of the Company's generation assets, causing the estimate of stranded costs to be overstated.

- The Company has included administrative and general expenses in its valuation modeling. These types of costs may be reasonably avoidable in a competitive marketplace, and so their recovery requires no special compensation as stranded costs.

- The Company's arbitrary decision to terminate its analysis in the year 2015 results in a significant understatement of stranded *benefits*.

- Possible mitigation of NUG contracts, as well as other relevant costs associated with generation assets, has not been incorporated into the model, thereby making the Company's estimate of stranded costs a worst-case scenario.

(4) Even though any estimate of stranded cost would be premature and speculative at this time, the Company's estimate is particularly sensitive to its chosen model assumptions. Virginia Power has not fully revealed the implications of the sensitivity of its model to changes in these assumptions. In order to determine the impact of the Company's estimate of stranded costs, my testimony includes modification of the model as to capacity reservation prices and the length of valuation beyond 2015. With just these changes to Virginia Power's model, the estimate of stranded net *benefits* soars as high as $2.7 billion for the Virginia jurisdiction.

Q HAVE YOU REVIEWED VIRGINIA POWER'S TESTIMONY ON THE ESTIMATION OF POTENTIAL STRANDED COSTS?

A Yes. I have reviewed the TCR, Exhibit No. RER- ___ (1), which summarizes the methodology the Company developed to assess the magnitude of its potential transition costs, along with its presentation of "illustrative transition costs based on a

given set of hypothetical assumptions."[1] The estimates of hypothetical transition cost exposure are based on a series of Company models that quantify the value of Virginia Power's existing portfolio of generation assets assuming that these same resources would operate in what the Company has characterized as a competitive generation market. The portfolio includes existing fossil, hydro and nuclear assets and NUG contracts. The economic value of these resources is then compared to their regulatory net book value to determine the potential exposure to transition costs. The Company proposes that an actual determination would be made when retail competition is authorized.[2]

Q WHAT ESTIMATE OF STRANDED COSTS DOES THE COMPANY PROVIDE IN ITS REPORT?

A Based on its analysis, the Company estimates total system-wide stranded costs of $3.2 billion. The vast majority ($3 billion) of these potential stranded costs relate to above-market NUG contracts. Fossil and hydro assets would provide *stranded benefits* of over $600 million that is, the assets are worth more in a competitive marketplace than the amount shown on the Company's books for those units. Nuclear assets would result in transition costs of $789 million, so that the subtotal of all generation would be an overall transition cost of $188 million.

Q HOW DO THE COMPANY'S INDIVIDUAL HYDRO AND FOSSIL GENERATING UNITS CONTRIBUTE TO THE $600 MILLION OF STRANDED BENEFITS?

A Exhibit ___ (KI-1), Schedule 1 details the Company's estimate of stranded benefits on a plant-by-plant basis. * * * * * **ALLEGED COMMERCIALLY SENSITIVE**

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[1]TCR, Page 1, Line 12.

[2]Testimony of Robert Rigsby, page 48.

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2 SENSITIVE INFORMATION DELETED * * * * * * * * ALLEGED COMMERCIALLY
3 SENSITIVE INFORMATION DELETED * * * *. Of all the fossil units, Clover Power
4 Station Units #1 and #2 have * * * * * * * ALLEGED COMMERCIALLY SENSITIVE
5 INFORMATION DELETED * * * * * *. North Branch is * * * ALLEGED
6 COMMERCIALLY SENSITIVE INFORMATION DELETED * * * * * and Bremo Power
7 Station Units #3 and #4 have a total of * * * * * *. In the case of Chesapeake Power
8 Station, Units #1 and #2 exhibit * * * * * * * * * * * ALLEGED COMMERCIALLY
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16 Bath County Pumped Storage shows * * * * * * while Cushaw has * * * * * * *
17 * * * *. The other hydro facilities * * * * * ALLEGED COMMERCIALLY SENSITIVE
18 INFORMATION DELETED * * * * *.[3]
19
20 Q YOU MENTIONED THAT * * * * * * * * HAS A SMALL NEGATIVE FREE CASH
21 FLOW. PLEASE DEFINE THE TERM FREE CASH FLOW.

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[3]Upon review of the Company's supporting workpapers, it appears the capacity-related revenues for the Roanoke Rapids Hydro Station units were inadvertently omitted. Although the model includes capacity prices and shows a maximum deliverable capacity of * * * * * * * *, the cells for capacity revenue are all $0. Correcting this oversight results in the total transition benefit of fossil and hydro increasing to $618 million, rather than $601 million.

1 A This term describes revenues less expenses (including taxes), with adjustments for
2 non-cash items such as depreciation and non-cash overhead. Capital expenditures
3 and increases in working capital also are removed from the estimate, so that free cash
4 flow provides the expected revenue free and clear of all expenses associated with
5 operating the resource. The stream of free cash flows is discounted and accumulated
6 to derive the asset value of the resource. *** * * * * * ALLEGED COMMERCIALLY**
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10
11 **Assumptions Used In Virginia Power's**
12 **Estimates of Stranded Costs**
13 Q **WHAT TYPES OF ASSUMPTIONS WERE MADE TO ARRIVE AT THE**
14 **HYPOTHETICAL SYSTEM STRANDED COST EXPOSURE OF $3.2 BILLION?**
15 A The stranded cost estimate is premised on models with assumptions as to: (1) future
16 market clearing prices for energy, (2) future capacity reservation prices, (3) the
17 expected operation of each Company generation unit, (4) the forecasted costs to
18 operate each generation unit, and (5) a specific time frame for analysis.
19
20 Q **HOW WERE ENERGY PRICES DEVELOPED?**
21 A Market clearing prices for energy were based on both utility and multi-regional data. A
22 computer model, known as MultiSym developed by Henwood Energy Services, Inc.,
23 was used to simulate the Virginia Power system and 22 neighboring interconnected
24 transmission areas including AEP to the west, PJM utilities to the north, and Florida
25 utilities, Southern Company and TVA to the south. The MultiSym model did not
26 generate electricity prices; instead, it generated the hourly marginal costs for each
27 modeled transmission area for the region for the years 1997 through 2005. Prices for

the period 2006 through 2012 were developed by escalating portions of the 2005 price duration curve by rates of 2.5% to 5.0%[4]. The post-2012 energy prices were escalated at 3.4% per year.[5] Virginia Power provided the following description of the results of MultiSym:

> Marginal costs can be interpreted as the prices at which the market clears in each area. These are therefore "spot" prices at which energy may be bought or sold in the simulated markets. The model does not explicitly forecast market prices ...[6]

In summary, MultiSym generated a distribution of hourly marginal costs over the year. These expected values of marginal costs then were converted to average energy prices and plotted as a function of cumulative hours (or probability) in the price duration curve. Energy prices then were separately verified by prices from a second model developed by IREMM, Inc.

Q WHAT IS A PRICE DURATION CURVE?

A Similar to a load duration curve, a price duration curve provides a summary of the average prices over the year. With hours (or cumulative probability) shown on the x-axis, and average price on the y-axis, a price duration curve provides the number of hours (or probability) that a price will be greater than y cents per kWh. For example, Exhibit ____ (KI-1), Schedule 2, is in the Company's price duration curve for 2003. It shows that, on average, market prices will be greater than $24 per MWh 100% of the time, but that prices will be greater than $30 per MWh only 52% of the time. For a

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[4]Virginia Power Response to Question No. 383 included in the Thirteenth Set of Interrogatories from the Office of the Attorney General.

[5]Virginia Power Response to Question No. 13 included in the Sixth Set of Interrogatories from VCFUR.

[6]Virginia Power Response to Question No. 68 included in the Third Set of Interrogatories from the Virginia Independent Power Producers.

smaller time of the year, say 10%, prices will be much higher: e.g., in 2003, prices will be greater than $51.40 per MWh only 10% of the time.

Q WHAT DATA IS REQUIRED TO CONSTRUCT A PRICE DURATION CURVE?

A Two items are necessary: marginal costs and expected hours (or probability). Referring to Page 2 of Exhibit ___ (KI-1), Schedule 2, marginal costs are first ranked in increasing order, along with their respective hours and probabilities of occurrence. As marginal costs increase, there is a corresponding decline in the cumulative probabilities of marginal cost exceeding a given amount. The decline in cumulative probability is shown in Column (4). Each marginal cost is weighted by its probability, and the weighted marginal costs are shown in Column (6). These expected values for marginal costs are summed [Column (7)] and then divided by the expected cumulative probability to derive the average price [Column (8)]. The average prices then are plotted as a function of cumulative probability, as shown on the graph on page 1 of Schedule 2.

Q HOW WERE THE PRICE DURATION CURVES USED TO QUANTIFY STRANDED COSTS?

A These annual price duration curves were used in two ways in the Company's modeling of stranded costs: (1) to estimate each unit's capacity factor, and (2) to estimate average energy revenue for each unit. First, these annual price duration curves were used to determine the expected annual capacity factors for each of the Company's generation resources as a function of each unit's annual variable operating cost.[7] For example, if a unit were forecasted to have a dispatch cost (or variable running cost) of

[7]There were certain exceptions to the use of price duration curves to determine expected annual capacity factors. Capacity factor was independently assigned to the nuclear generation (85%), to Bath County Pumped Storage (30%), and in situations where plants did not recover their variable costs, and so had 0% capacity factor.

$20 per MWh in 2003, and if the price duration curve for 2003 showed that marginal costs would exceed $20 per MWh 43.8% of the time in the year, then the unit's capacity factor would be set at 43.8%.

The second use of the price duration curve was to determine the weighted average price to be paid for energy generated by each unit. Again, using 2003 as an example, a unit with variable costs of $20 per MWh would receive prices that average $31.46 per MWh.

Q HOW WERE CAPACITY VALUES DERIVED?

A Capacity values incorporated in the Company's models are premised on the annual economic carrying charges for an advanced combustion turbine (CT), less an expected contribution to fixed costs from the value of its energy generation. An escalation of 3% per year was used to extrapolate prices past 2012.[8]

Q WHAT OTHER ASSUMPTIONS ARE RELEVANT TO THE COMPANY'S ESTIMATE OF TRANSITION COSTS?

A Assumptions as to expenses, such as fuel, operation and maintenance (O&M), administrative and general (A&G), overhead, depreciation, insurance and other taxes were also forecasted and either assigned or allocated to each generating unit. Finally, assumptions regarding the timing and extent of competition, length of analysis, and the applicable discount rate were made in order to develop the economic valuation of the assets.

[8]Virginia Power Response to Question No. 13 included in the Sixth Set of Interrogatories from VCFUR.

1 Q **WHAT DOES VIRGINIA POWER'S ESTIMATE OF TRANSITION COSTS**
2 **ILLUSTRATE?**
3 A The Company's modeling of its generation assets illustrates an administrative
4 approach to determining an estimate of value. By its very nature, an administrative
5 determination of stranded costs requires a wide range of assumptions as to the going
6 forward expenses to operate the units. More importantly, though, it requires an
7 administratively determined market price to be used in the revenue portion of the
8 model. Although the cash flow analysis described by the Company is generally
9 consistent with the way assets would be valued in a competitive market, there are,
10 nonetheless, serious flaws inherent in any administrative determination of future costs.
11 In fact, these types of forecasting follies for avoided costs led to the Company's
12 current estimates of massive stranded costs associated with the NUG contracts. As
13 Mr. Pollock testifies, administrative determinations of transition costs are necessarily
14 judgmental, and are critically dependent on expected levels of competitive market
15 prices for electricity and future operating costs of existing generation assets. Beyond
16 these obvious problems inherent with any administrative determination of stranded
17 costs, the Company's estimate also suffers from more specific flaws.
18
19 Q **WHAT FLAWS OR PROBLEMS DO YOU SEE WITH THE COMPANY'S**
20 **METHODOLOGY FOR ESTIMATING TRANSITION COSTS?**
21 A Many of the inputs to the Company's estimate rest on questionable support or support
22 that is impossible to substantiate, particularly with respect to the price duration curves
23 generated from the output from the MultiSym model. The Company's model also
24 suffers from flaws related to the following: (1) premature assumptions, (2) understated
25 capacity values, (3) inclusion of administration and overhead costs, (4) an arbitrary
26 cutoff date for the analysis as to the remaining lives of the generating units, and (5) an

assumption that no mitigation of NUG costs would occur. Making adjustments for only two of these flaws (capacity reservation prices and extending the valuation analysis) can raise the fossil and hydro stranded *benefit* to over $2 billion.

Marginal Costs As A Basis For Projecting Electricity Prices

Q **YOU HAVE TESTIFIED THAT THE MULTISYM MODEL WAS USED TO ESTABLISH MARGINAL COSTS, WHICH IN TURN WERE USED TO DETERMINE THE COMPANY'S PRICE DURATION CURVES. WHY HAS VIRGINIA POWER USED MARGINAL COSTS TO PROJECT FUTURE ELECTRICITY PRICES?**

A The general basis for using marginal costs stems from the assumption that under perfect competition, prices would be driven to marginal cost if there are many producers and consumers. That is, no one producer would be capable of influencing the market to cause the price to reach an artificially high level because alternative suppliers, seeing potential profit to be made, would enter the market, provide additional supply, and eventually push price toward marginal cost. There are several necessary conditions in order for price to equal marginal cost. There must be: (1) many buyers and sellers, (2) a standard (homogeneous) product, (3) perfect information, and (4) no barriers to entry in the marketplace.

Q **DO THESE MARGINAL COSTS INCLUDE ANY PROFIT, OR CONTRIBUTION FOR RECOVERY OF CAPITAL?**

A No. Whether one calls these marginal costs, "spot prices," "market clearing prices" or "incremental costs," the prices strictly reflect variable costs, such as fuel, operation and maintenance, wheeling, and losses. No profit is directly included in the spot price. Any contribution to fixed costs stems from the unit being dispatched at times when the spot price is greater than its variable operating costs.

1

2 Q **HAVE YOU BEEN ABLE TO REVIEW THOROUGHLY ALL THE INPUTS USED IN**
3 **THE MULTISYM MODEL USED TO GENERATE THESE MARGINAL COSTS?**
4 A No. The MultiSym model is a complex simulation model "black box." Although we
5 were not able to scrutinize the input to the model, we were able to analyze the results
6 of the model, that is, the price duration curves.
7
8 Q **WHAT HAVE YOU FOUND IN REVIEWING THE MARKET CLEARING PRICES**
9 **GENERATED BY MULTISYM?**
10 A The MultiSym model actually was used only for projecting market clearing prices for
11 the years 1997 through 2005. The results from the 2005 analysis were segregated by
12 probability and escalated at various rates to generate price duration curves for the
13 years 2006 through 2012. For years beyond 2012, prices were escalated at 3.4%.
14 Consequently, Virginia Power's direct use of MultiSym in its stranded cost estimate is
15 limited to energy prices in four years (2002 through 2005), with extrapolations for each
16 of the following years.
17 Exhibit ___ (KI-1), Schedule 3, graphically shows the trends associated with
18 four specific variable running (dispatch) costs: $17, $20, $25 and $30 per MWh.[9] For
19 the actual MultiSym model simulations in years 1997 through 2005, the average price
20 of energy actually *decreases* for most dispatch costs. For example, a unit with a low
21 dispatch cost of $17 per MWh would receive an average weighted price of $25 per
22 MWh in 1997, dropping over the years 1998 through 2003 and then increasing to a
23 level above $25 per MWh in years 2004 and 2005 for an overall annual increase of
24 0.9%. Units with dispatch costs of $20, $25 and $30 per MWh would all receive

[9]The term dispatch cost and variable running costs are used interchangeably. In the Company's model, variable running costs include expenses for fuel, variable O&M and SO_2 emissions.

1 *declining* energy prices of 1.2%, 1.4% and 1.9% respectively, even though their
2 dispatch costs were constant. The 2005 price duration curve served as the foundation
3 for all the remaining price duration curves used in the estimation of transition costs.
4
5 Q **DO THESE MARGINAL COSTS PROVIDE A REASONABLE FORECAST FOR**
6 **PRICES IN A COMPETITIVE MARKETPLACE?**
7 A That is simply unknown at this time. We do know that energy prices based strictly on
8 marginal costs require the acceptance of several critical assumptions as to market
9 structure, the universe of suppliers, and spot pricing inputs. First, a market price
10 based on spot prices assumes <u>all suppliers</u>, or over 1,100 regional generation units,
11 selling <u>all their output</u> into a single clearinghouse, and <u>all receiving</u> the same spot price
12 at any time based on the marginal unit on-line. Whether or not this type of market
13 structure (generally referred to as PoolCo) will develop for retail access is not known
14 today. Second, it assumes perfect competition, with no supplier exhibiting market
15 power, no barriers to entry for competitors to enter the market, full information and all
16 suppliers providing a homogenous product. Only under all these conditions would
17 competitive prices approach marginal costs at all times. Third, these spot prices are a
18 function of all the inputs into the MultiSym model, such as projections of load growth
19 and capacity expansion, fuel costs, wheeling charges, transmission constraints, etc.
20 Fuel forecasts alone used in the MultiSym represent costs of over 1,100 generating
21 resources owned by over 40 utilities and independent power producers. Any deviation
22 in initial fuel price levels, fuel price escalations, heat rates, variable O&M expenses, or
23 load forecasts presumably would alter the result from MultiSym.
24 Finally, the MultiSym model totally ignores the value or cost associated with
25 ancillary services. In a competitive environment, the value of this resource will be an
26 important consideration in the total price of delivered generation.

1

2 **Critical Assumptions as to Timing, Structure**
3 **And Extent of Competition Are Premature**

4 Q HOW DOES VIRGINIA POWER INCORPORATE CRITICAL ASSUMPTIONS AS TO
5 STRUCTURE AND TIMING OF COMPETITION IN ITS MODELS?

6 A Virginia Power has made several premature assumptions with respect to timing,
7 structure and extent of impending competition. The Company has selected one
8 specific date certain (1/1/2003) to model its estimate of transition costs. The choice of
9 this date influences the going-forward stream of revenues generated by its assets,
10 because any and all economic valuation in the Company's model is based on
11 competitive prices commencing in the year 2002. Delaying, or phasing in, retail
12 access has not been modeled by the Company.[10]

13 Second, as previously discussed, the Company has presumed a specific
14 market structure for competition that directly impacts the estimate of revenues for its
15 product. In its base case estimation, the net present value of energy-related revenues
16 comprises * * * * * **ALLEGED COMMERCIALLY SENSITIVE INFORMATION**
17 **DELETED** * * *, with capacity revenues at * * * * * * * and ash marketing at * * * * *
18 * * * * * * * *. All energy-related revenues are solely the result of market-clearing
19 marginal costs, or "spot prices." Under a PoolCo form of market structure, all buyers
20 and sellers must make transactions through a centralized clearinghouse. However,
21 the market structure that will develop with retail access is not known and measurable
22 today. Consequently, the Company's fundamental basis for over 80% of the assumed
23 revenues in its modeling hinges on this one highly uncertain assumption.

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[10]The results of the Company's model show estimated transition costs for years post 2003 (Virginia Power's Response to Question No. 121 included in the First Set of Interrogatories from the Staff). However, as explained later, all these estimates assume a cut-off date of 2015 for economic valuation.

1 Third, the Company's model is a "flash-cut" to competition whereby all
2 customers immediately switch to direct access, making this estimate of transition
3 costs the worst-case scenario. A more likely scenario would be that customers
4 moving to choice would proceed more slowly, without an instantaneous conversion of
5 each and every customer on day one of competition. Under this more likely scenario,
6 Virginia Power would continue to recover its fully allocated costs through traditional
7 bundled rates for provision of service to "full-requirements" customers. This would
8 reduce transition costs.
9
10 **Capacity Reservation Values Are**
11 **Understated in Company's Model**

12 Q **WHAT CAPACITY VALUES DOES THE COMPANY USE IN ITS MODELS?**
13 A In its base case scenario, Virginia Power uses capacity values of $24.48 per kW-year
14 in 2003, escalating at roughly 2% from 2003 through 2006, and at 3% thereafter. The
15 upper bound for capacity value is around 10% higher at $27.12 per kW-year in 2003,
16 also escalating at around 3%.
17
18 Q **ARE THESE REASONABLE ESTIMATES FOR THE VALUE OF CAPACITY IN**
19 **DETERMINING TRANSITION COSTS?**
20 A No, they are not. Through a combination of erroneous assumptions, the Company has
21 greatly understated capacity reservation values used in its modeling of transition costs.
22
23 Q **HOW HAS THE COMPANY UNDERSTATED CAPACITY VALUE?**
24 A First, the Company has inappropriately assumed the use of an *economic* carrying
25 charge rather than levelized carrying charge.
26

1 Q **WHAT IS A "CARRYING CHARGE"?**

2 A The total capacity cost for a CT must be adjusted by a carrying charge in order to put
3 the total costs on an annual basis. Virginia Power uses an economic carrying charge
4 for determining the annual cost of a CT. An economic carrying charge measures the
5 value of deferring CT capacity, or "delaying the installation of the facility by one year."[11]
6 It recognizes only a one-year deferral of capacity costs, and thus provides a short-
7 sighted value of capacity. The Company's myopic valuation of capacity reservation
8 prices does not reflect prices available under a long-term contract; it reflects only an
9 annual commitment.[12]
10
11 Q **WHY DOES THE COMPANY BELIEVE ITS METHOD OF USING AN ECONOMIC**
12 **CARRYING CHARGE IS APPROPRIATE?**
13 A Virginia Power bases its use of an economic carrying charge on the replacement cost
14 perspective:

15 > The appropriateness of this method derives from its replacement cost
16 > perspective; that is, it would appear reasonable that a buyer would not
17 > be willing to pay more for capacity in a given year than the cost that
18 > would be avoided by deferring the construction of the facility for that
19 > year.[13]
20
21 Q **DO YOU AGREE THAT "REPLACEMENT COST" IS THE CORRECT PERSPECTIVE**
22 **FOR VALUING CAPACITY IN A COMPETITIVE MARKET?**
23 A No. The replacement cost perspective assumes that a seller of capacity would only
24 recover the costs for its product several years out in the future. This wrongly assumes

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[11]Virginia Power Response to Question No. 34 included in the Sixth Set of Interrogatories from VCFUR.

[12]Virginia Power Response to Question No. 386 included in the Thirteenth Set of Interrogatories from the Office of the Attorney General.

[13]Virginia Power Response to Question No. 34 included in the Sixth Set of Interrogatories from VCFUR.

1 that future generators will be able to finance projects even though payments would be
2 significantly back-end loaded. For example, Exhibit ___ (KI-1), Schedule 4, provides a
3 simple hypothetical comparing a stream of payments under an economic carrying
4 charge stream of revenues versus the more traditional levelized approach. From the
5 seller's perspective, a payment stream based on an economic carrying charge would
6 provide insufficient dollars to pay off any principal whatsoever for 19 years -- that is,
7 the unpaid balance exceeds the original principal through year 19. A nominally
8 levelized revenue stream, on the other hand, consistently provides sufficient revenue
9 each year to pay off interest charges and make a contribution to reducing principal.
10 Virginia Power's assumption focuses on buyers unwilling to pay a price higher than the
11 amount associated with a one-year deferral. This ignores the other side of the
12 transaction -- sellers would be unwilling to sell at a price that delays recovery of their
13 costs for such a long period of time. Virginia Power's use of an economic carrying
14 charge understates the market value of capacity.
15
16 Q **BESIDES USING AN ECONOMIC CARRYING CHARGE, HAS THE COMPANY**
17 **UNDERSTATED THE MARKET VALUE OF CAPACITY IN ANOTHER WAY?**
18 A Yes. Virginia Power has significantly understated the fixed O&M costs for its assumed
19 advanced CT. The Company uses a fixed O&M cost of only $1.56 per kW-year in
20 1997 in the development of its all-in costs for a CT, with no substantiation or
21 supporting documentation. In contrast to the Company's estimated cost, the Energy
22 Information Administration estimates that annual fixed O&M for advanced combustion
23 turbines would be more in the neighborhood of $17.20 per kW,[14] more than ten times
24 the amount used in the Company's calculations. Thus, as a result of a combination of
25 errors, the Company has significantly understated the expected value of capacity.

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[14]"Assumption for the *Annual Energy Outlook 1997*," Energy Information Administration, December 1996, p. 58.

1

2 Q **IS THE COMPANY AWARE OF ANY RECENT LONG-TERM FIRM POWER**
3 **TRANSACTIONS THAT PROVIDE FOR CAPACITY AND ENERGY AT ITS**
4 **FORECASTED PRICES?**

5 A No. According to the Company's response, Virginia Power is not aware of any long-
6 term (i.e., greater than three years) transactions at prices comparable to the market
7 clearing prices and capacity reservation values shown in Figure 1 on Page 16 of the
8 TCR.[15] Again, this leads us to question the reasonableness of both the Company's
9 assumed energy and capacity values.

10

11 Q **HAVE YOU QUANTIFIED A MORE REASONABLE ALL-IN COST OF FUTURE**
12 **GENERATION CAPACITY ADDITIONS?**

13 A Yes. This is shown in Exhibit ___(KI-1), Schedule 5, Page 1, Column (5).

14

15 Q **HOW DOES THE ALL-IN COST OF NEW GENERATION CAPACITY COMPARE**
16 **WITH VIRGINIA POWER'S ESTIMATED MARKET PRICES?**

17 A The Company's projected market prices shown on Page 1 in Column (2) of this
18 Schedule are considerably below the all-in cost of new capacity that I have calculated.

19

20 Q **VIRGINIA POWER CLAIMS THAT "ENERGY AND CAPACITY PRICES INCREASE**
21 **TO LEVELS THAT SUPPORT THE CONSTRUCTION OF ADDITIONAL PEAKING**
22 **CAPACITY" DURING THE PERIOD FROM 2000 THROUGH 2005. DO YOU**
23 **AGREE?**

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[15]Virginia Power Response to Question No. 387 of the Thirteenth Set of Interrogatories from the Office of the Attorney General.

A No. The Company's energy prices and capacity reservation prices would not support construction of additional peaking capacity. In 2005, according to the Company's price duration curves, the average weighted price provides a contribution of only $12 per kW annually. This contribution, together with its forecasted base capacity reservation price of $2.12 per month, would provide only $38 per kW annually, an amount that would not cover the total all-in costs of $65 per kW in 2005.

Q HAVE YOU DEVELOPED AN ESTIMATE OF A MORE APPROPRIATE CAPACITY RESERVATION VALUE FOR USE IN ESTIMATING TRANSITION COSTS?

A Yes. Using construction costs of $300 per kW (in 1997 dollars), O&M costs based on the recent EIA information, and nominal levelization, a more realistic base net capacity cost would be around $50 per kW-year in the year 2002. This amount has been adjusted for the expected contribution to fixed costs from the value of its energy generation based on a 5% capacity factor. As shown in Column (6) of Schedule 5, the capacity margin provided through energy-related revenues averages close to $13 per kW-year for the years 2003 through 2006. Without this expected contribution to fixed costs, the capacity value would be higher by that amount.

The Company's Modeling Of Costs Should Not Include Continuing Levels of Administrative and General Overhead

Q WHAT TYPES OF COSTS ARE INCLUDED IN THE COMPANY'S PROJECTIONS FOR EACH GENERATING UNIT?

A In addition to typical on-going costs for fuel, planned outages, routine maintenance and operations, taxes, insurance, SO_2 emissions, etc., the Company has included general administrative costs and benefits. Only when market clearing prices rise to sufficient levels to cover these costs will these costs be recoverable in the competitive

1 marketplace. Although these expenses are not as large as say, fuel expenses, they
2 still impact the overall discounted free cash flow.
3 Q **ARE THESE TYPES OF COSTS RECOVERED BY UTILITIES THROUGH**
4 **TRADITIONAL REGULATION?**
5 A Yes, for the most part, they are. Under the present cost of service form of regulation,
6 a utility's costs drive rates. If a utility incurs increased costs, it can petition the
7 Commission for a rate increase. In a competitive environment, this would no longer be
8 the case; electricity prices would be market-determined. A utility's return will depend
9 much more on its ability to control costs successfully. If a supplier's costs are out of
10 line in a competitive environment, the supplier will find it necessary to control its costs
11 rather than seek additional revenues for relief. The Company's model escalates
12 administrative costs at 3.5% annually, and system benefits at 5%. A firm facing rising
13 costs and low prices for its output would search for any and all ways to reduce its
14 costs down to a level commensurate with the market.
15
16 Q **ARE A&G COSTS UNMITIGATABLE OR UNAVOIDABLE?**
17 A No. Some of these expenses are under the control of the resource operator, and thus
18 should not be accepted as unmitigatable or unavoidable. To the extent that average
19 energy prices in the competitive market are not sufficient to justify high levels of
20 administrative and general expenses, a competitive supplier would need to bring them
21 under control, or it would need to cease operations.
22
23 Q **IS IT APPROPRIATE TO INCLUDE A&G COSTS IN VALUING VIRGINIA POWER'S**
24 **GENERATION ASSETS?**
25 A No. As Mr. Pollock testifies, no special compensation is necessary or appropriate if a
26 utility has a reasonable opportunity either to mitigate or avoid a potentially strandable

1 cost, such as future administrative and general expenses. The inclusion of Virginia
2 Power's on-going levels of A&G costs in its asset valuation effectively lowers its free
3 cash flow, and correspondingly raises the level of stranded costs.
4
5 **Stranded Benefits are Greatly Understated As A**
6 **Result Of Arbitrarily Ending the Economic Valuation**

7 Q **FOR WHAT TIME PERIOD DID THE COMPANY EVALUATE ITS GENERATION**
8 **ASSETS?**
9 A In its models, Virginia Power determined the economic valuation of each generating
10 unit from 2002 through 2015. The NPV of discounted free cash flows at year end
11 2002 was compared to each unit's net book value as of 2002 to determine its
12 exposure to transition costs.
13
14 Q **WHY DID THE COMPANY CHOOSE THE YEAR 2015 AS THE ENDING POINT OF**
15 **ITS ANALYSIS?**
16 A According to the Company, 2015 is the year "... in which all of the Company's owned
17 and contracted generation resources in total are expected to clear the market." [16]
18
19 Q **IS THIS AN APPROPRIATE DATE TO END THE ANALYSIS?**
20 A No, it is not. The year 2015 marks only the beginning of the period in which the
21 Company's generating units will make a profit above market-clearing prices. By
22 artificially ending the analysis at 2015, Virginia Power has sent a strong signal to its
23 customers and the Commission that the Company is more concerned about the *costs*
24 competition will place on the utility, than the *benefits* it will receive through a
25 competitive marketplace. Once market clearing prices are sufficient to enable the

[16] TCR, Page 9, Line 1.

1 Company to sell its generation into the market for a profit, the Company will start to
2 benefit from competition. However, the transition cost analysis focuses only on the
3 initial years, when the Company's generation is relatively costly in comparison to the
4 market. It is as if Virginia Power proposes to ignore completely the reality that its
5 generating assets will be *operational*, as well as *profitable*, in the years after 2015.
6 The Company's proposal to ignore the later benefits of competition, while exclusively
7 focusing on near-term potential costs, should be rejected. The ability to earn returns
8 not capped under regulation is one of the upside benefits of retail competition for
9 current providers of generation services, like Virginia Power.
10

11 **The Company's Model Includes No Mitigation Of**
12 **Costs, Particularly Those Associated With NUG Contracts**

13 Q **THE COMPANY HAS INDICATED THAT NUG CONTRACTS COMPRISE OVER $3**
14 **BILLION OF ITS ESTIMATED STRANDED COSTS. HAS THE COMPANY FULLY**
15 **MITIGATED THE COSTS ASSOCIATED WITH THESE CONTRACTS?**
16 A The answer to this question is unknown at this time. It is my understanding that
17 Virginia Power is presently engaged in negotiations with its NUG suppliers to lessen
18 the impact of these contracts on future expenses. The outcome of these contract
19 negotiations is in doubt and is unlikely to be fully resolved by the conclusion of this
20 proceeding. It is my understanding that the $3 billion estimate of stranded NUG costs
21 does not include any forecast of mitigation that may result from these on-going
22 negotiations, making the Company's estimate of its stranded costs a worst-case
23 scenario.
24 Mitigation of costs associated with its owned generating assets also is
25 unknown at this time. Without a complete benchmarking of its generation, there is no
26 clear indication that any mitigation has been incorporated in the administratively
27 determined estimate of transition costs included in the Company's TCR.

1 As an example of mitigatable costs, Virginia Power has included in its estimate
2 of stranded costs $945,000 for the cost of land for a future generating station site
3 (Ahoskie).[17] The Company includes only revenues associated with sales of energy,
4 capacity and ash: no attempt has been made to place a value on land in its modeling
5 of asset valuation in a competitive marketplace. Thus, Virginia Power's modeling of
6 stranded costs effectively labels land costs as 100% potentially stranded. It is
7 reasonable to assume these strategically valuable generation sites would have a value
8 in the competitive market. As with future administrative and general expenses, the
9 utility has a reasonable opportunity to mitigate this cost (e.g., selling or leasing the
10 land), so consequently no special compensation for land costs is necessary.
11
12 **Estimated Change in Potential Stranded**
13 **Costs With More Appropriate Assumptions**
14 Q **HAVE YOU ASSESSED THE IMPACT ON THE COMPANY'S STRANDED COST**
15 **ESTIMATE OF USING ANY ALTERNATIVE ASSUMPTIONS?**
16 A Yes. In order to determine the impact of two key assumptions underlying the
17 Company's estimate of stranded costs, I have modified the Company's analysis to
18 include more reasonable capacity reservation prices and to extend the evaluation
19 beyond 2015. I adjusted these two elements of the Company's estimates of transition
20 costs to show just how sensitive the results of the analysis are to only these two
21 assumptions. I have not made any adjustment to the other assumptions, such as
22 energy price forecasts, administrative costs, or assumed mitigation levels, so this
23 should not be construed as an endorsement of, or an alternative to, the Company's
24 analysis.

[17]Virginia Power Response to Question No. 8 included in the Thirteenth Set of Interrogatories from the VCFUR.

Schedule 6 details the results of changing just these two assumptions under various scenarios. Page 1 shows the results of changing these two assumptions separately, by individual adjustments to the estimated transition costs, while page 2 shows the cumulative effects of these adjustments. The following explanation tracks each Column of this Schedule:

Column (1): This column displays the estimate of fossil, hydro, nuclear and NUG transition costs as calculated by Virginia Power in its TCR.[18]

Column (2): This column corrects for the omission of capacity revenues for Roanoke Rapids Hydro.

Column (3): This column incorporates the results of a more appropriate capacity reservation value.

Column (4): This column shows the results of extending the analysis beyond 2015 using the Company's capacity reservation prices.

Column (5): This column incorporates the revised capacity costs for the years 2016 through 2025.

Column (6): This column extends the analysis from 2025 to 2035, using the Company's capacity reservation prices.

Capacity (7): This column incorporates the revised capacity costs for the years 2026 through 2035.

The cumulative impacts of these individual adjustments are shown on Page 2 of Schedule 6. For example, extension of the analysis through the year 2035 together with revised capacity reservation prices results in a total net stranded *benefit* for the Virginia jurisdiction of over $2.7 billion.

Q WHAT CONCLUSIONS DO YOU DRAW BASED UPON YOUR EVALUATION AND ADJUSTMENTS TO VIRGINIA POWER'S ESTIMATE OF TRANSITION COSTS?

---

[18]The Company recently has detected an error in its estimate of transition costs for the Lakeridge facility (Virginia Power Response to Question No. 7 included in the Thirteenth Set of Interrogatories from VCFUR). This correction is not included in Schedule 6.

1 A As the Company has recognized, any estimate of stranded costs depends on the
2 assumptions used in the modeling. For example, the time period analyzed greatly
3 influences the estimate. The Company's decision to terminate its analysis at 2015
4 results in a significant overstatement of potential stranded costs. In addition, a more
5 appropriate level of capacity reservation prices also reduces the Company's estimated
6 stranded costs.

7 Although other important assumptions made by Virginia Power cannot be
8 quantified as readily in the modeling of transition costs, their importance to the overall
9 estimate should not be overlooked. Virginia Power's assumption as to a PoolCo-type
10 of market for the development of price duration curves and the flash-cut to competition
11 are also important contributors to any estimated transition costs developed with this
12 type of cash flow model. Should a different type of market structure eventually
13 emerge, or should customer choice be phased-in, estimates of potential stranded
14 costs based on the Company's models and assumptions would not be representative.
15 In any event, any estimate of stranded costs is premature and speculative at this time.
16
17 **Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**
18 A Yes, it does.
19
20 #414826

Qualifications of Kathryn E. Iverson

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Kathryn E. Iverson; 5555 DTC Parkway, Suite B-2000; Englewood, Colorado 80111.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation with Brubaker & Associates, Inc., regulatory and economic consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A In 1980 I received a Bachelors of Science Degree in Agricultural Sciences from Colorado State University, and in 1983, I received a Masters of Science Degree in Economics from Colorado State University.

In March of 1984, I accepted a position as Rate Analyst with the consulting firm Browne, Bortz and Coddington in Denver, Colorado. My duties included evaluation of proposed utility projects, benefit-cost analysis of resource decisions, cost of service studies and rate design, and analyses of transmission and substation equipment purchases.

In February 1986, I accepted a position with Applied Economics Group, where I was responsible for utility economic analysis including cogeneration projects, computer modeling of power requirements for an industrial pumping facility, and revenue impacts associated with various proposed utility tariffs. In January of 1989, I was promoted to the position of Vice President. In this position, I assumed the additional responsibilities of project leader on projects, including the analysis of alternative cost recovery methods,

1 pricing, rate design and DSM adjustment clauses, and representation of a group of
2 industrial customers on the Conservation and Least Cost Planning Advisory Committee
3 to Montana Power Company.

4 In March 1992, I accepted a position with ERG International Consultants, Inc., of
5 Golden, Colorado as Senior Utility Economist. While at ERG, I was responsible for the
6 cost-effectiveness analysis of demand-side programs for Western Area Power
7 Administration customers. I also assisted in the development of a reference manual on
8 the process of Integrated Resource Planning including integration of supply and demand
9 resource, public participation, implementation of the resource plan and elements of writing
10 a plan. I lectured and provided instructional materials on the key concept of life-cycle
11 costing seminars held to provide resource planners and utility decision-makers with a
12 background and basic understanding of the fundamental techniques of economic
13 analysis. My work also included the evaluation of a marginal cost of service study,
14 assessment of avoided cost rates, and computer modeling relating engineering simulation
15 models to weather-normalized loads of schools in California.

16 In November of 1994, I accepted a position with Drazen-Brubaker & Associates,
17 Inc. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most
18 of the former DBA principals and Staff. Since joining this firm, I have performed various
19 analyses of integrated resource plans, examination of cost of service studies and rate
20 design, as well as estimates of transition costs and restructuring plans.

21 Q **HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?**

22 A Yes. I have testified before the regulatory commissions in Colorado, Georgia, Michigan,
23 Montana, Texas and Wyoming.

VIRGINIA ELECTRIC AND POWER COMPANY

Summary of Company Estimates of Economic Value, Net Book Value and Transition Cost of Fossil/Hydro Units (Thousands of Dollars)

	Description	Asset Value In a Competitive Market (1)	Regulatory Net Book Value (2)	Transition Cost (3)	Adjusted to Revenue Requirements (4)
	FOSSIL PLANTS:				
1	Bremo Power Station				
2	Unit #3				
3	Unit #4				
4	Subtotal				
5	Chesapeake Power Station				
6	Unit #1				
7	Unit #2				
8	Unit #3				
9	Unit #4				
10	Chesapeake CT				
11	Kitty Hawk				
12	Gravel Neck				
13	Subtotal				
14	Chesterfield Power Station				
15	Unit #3				
16	Unit #4				
17	Unit #5				
18	Unit #6				
19	Unit #7				
20	Unit #8				
21	Subtotal				
22	Clover Power Station				
23	Unit #1				
24	Unit #2				
25	Subtotal				
26	North Branch Power Station				
27	Unit #1				
28	Subtotal				
29	Possum Point Station				
30	Unit #1				
31	Unit #2				
32	Unit #3				
33	Unit #4				
34	Unit #5				
35	Possum CT				
36	Darbytown				
37	Lowmoor				
38	Northern Neck				
39	Subtotal				

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VIRGINIA ELECTRIC AND POWER COMPANY

Summary of Company Estimates of Economic Value, Net Book Value and Transition Cost of Fossil/Hydro Units
(Thousands of Dollars)

	Description	Asset Value In a Competitive Market (1)	Regulatory Net Book Value (2)	Transition Cost (3)	Adjusted to Revenue Requirements (4)
	FOSSIL PLANTS (Cont'd):				
40	Mt. Storm Power Station				
41	Unit #1				
42	Unit #2				
43	Unit #3				
44	CT				
45	Subtotal				
46	Yorktown Power Station				
47	Unit #1				
48	Unit #2				
49	Unit #3				
50	Subtotal				
51	Total Fossil				
	HYDRO:				
52	Cushaw Hydro Station				
53	Units #1-5				
54	Gaston Hydro Station				
55	Unit #1				
56	Roanoke Rapids Hydro Station				
57	Unit #1				
58	Total Hydro				
59	PUMPED HYDRO:				
60	Bath County Pumped Storage				
61	Unit #1				
62	Unit #2				
63	Unit #3				
64	Unit #4				
65	Unit #5				
66	Unit #6				
67	Subtotal				
68	Total Hydro and Pumped Hydro				
69	Total Fossil and Hydro				
70	Plus: Innsbrook/Lakeridge (see note				
71	Plus: Future Use				
72	Total Fossil and Hydro				

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Column (1):

Column (2): ALLEGED COMMERCIALLY SENSITIVE INFORMATION DELETED **********

Column (3):

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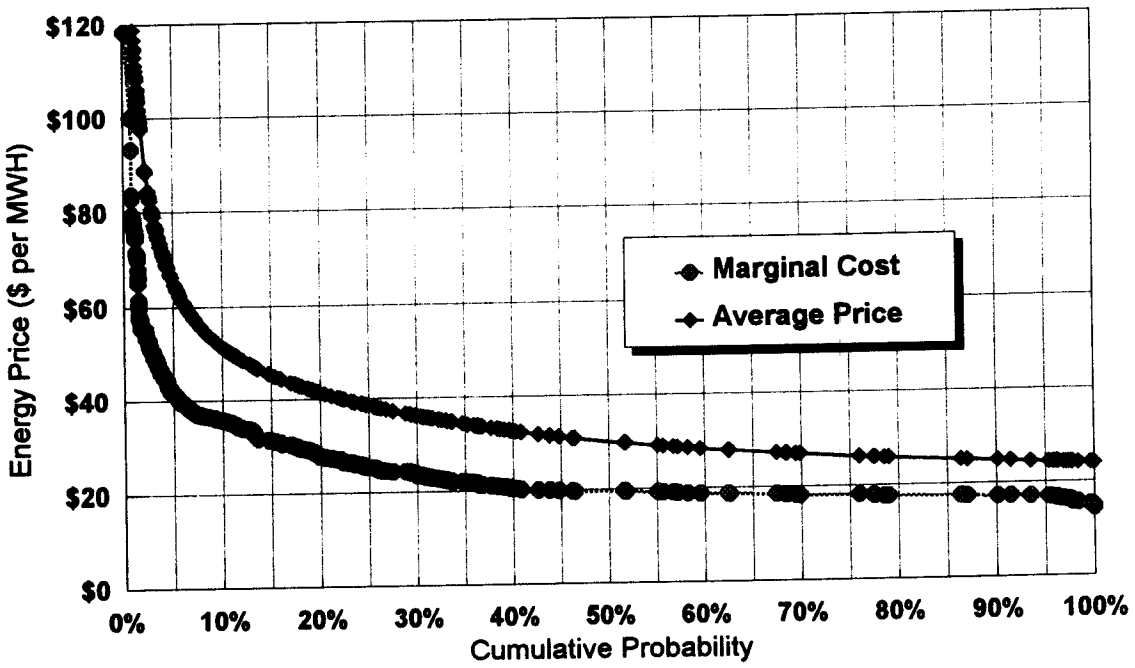
VIRGINIA ELECTRIC AND POWER COMPANY

Price Duration Curve Generated From
Results of MultiSym Model for the Year 2003



VIRGINIA ELECTRIC AND POWER COMPANY

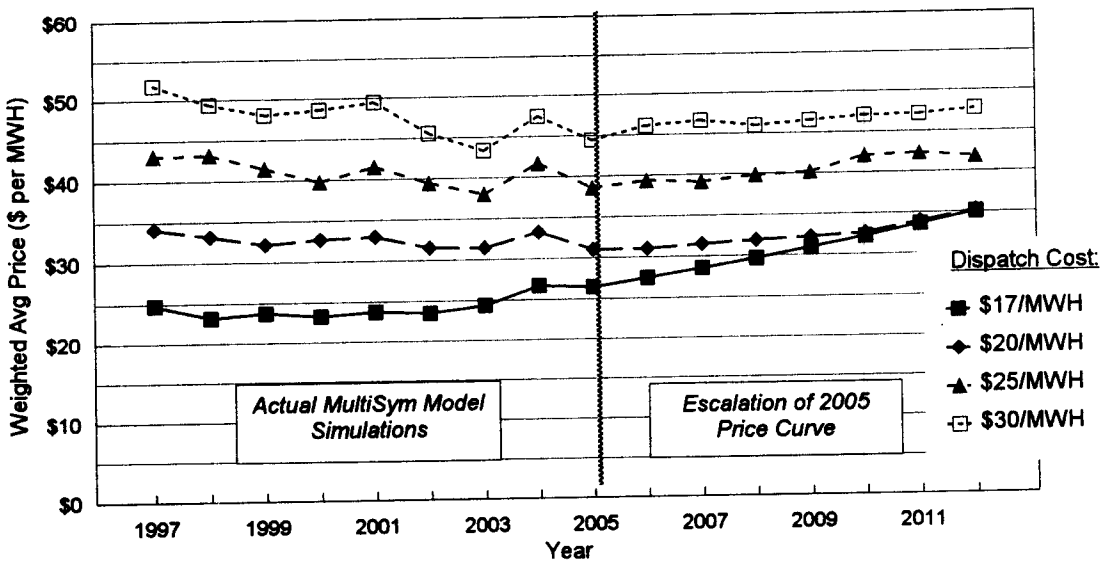
Price Duration Curve Generated From
Results of MultiSym Model for the Year 2003

Ln	Marginal Cost (1)	Hours (2)	Cumulative Hours (3)	Cumulative Probability (4)	Probability (5)	Expected Value (6)	Total Expected Value (7)	Average Price (8)
1	14.60	1	8,760	100.0000%	0.0114%	0.0017	24.00	24.00
2	14.70	2	8,759	99.9886%	0.0228%	0.0034	24.00	24.01
3	14.80	10	8,757	99.9658%	0.1142%	0.0169	24.00	24.01
4	15.20	25	8,747	99.8516%	0.2854%	0.0434	23.98	24.02
5	15.30	106	8,722	99.5662%	1.2100%	0.1851	23.94	24.04
6	15.70	55	8,616	98.3562%	0.6279%	0.0986	23.75	24.15
7	15.90	4	8,561	97.7283%	0.0457%	0.0073	23.66	24.21
8	16.00	1	8,557	97.6826%	0.0114%	0.0018	23.65	24.21
9	16.10	4	8,556	97.6712%	0.0457%	0.0074	23.65	24.21
10	16.20	3	8,552	97.6256%	0.0342%	0.0055	23.64	24.21
11	16.30	22	8,549	97.5913%	0.2511%	0.0409	23.63	24.22
12	16.40	21	8,527	97.3402%	0.2397%	0.0393	23.59	24.24
13	16.50	24	8,506	97.1005%	0.2740%	0.0452	23.55	24.26
14	16.60	47	8,482	96.8265%	0.5365%	0.0891	23.51	24.28
15	16.70	10	8,435	96.2900%	0.1142%	0.0191	23.42	24.32
			■		■	■		
153	31.30	2	1,292	14.7489%	0.0228%	0.0071	6.72	45.56
154	31.40	101	1,290	14.7260%	1.1530%	0.3620	6.71	45.58
155	31.60	2	1,189	13.5731%	0.0228%	0.0072	6.35	46.79
156	31.70	1	1,187	13.5502%	0.0114%	0.0036	6.34	46.81
157	31.90	3	1,186	13.5388%	0.0342%	0.0109	6.34	46.83
158	32.00	6	1,183	13.5046%	0.0685%	0.0219	6.33	46.87
159	32.30	17	1,177	13.4361%	0.1941%	0.0627	6.31	46.94
160	32.50	2	1,160	13.2420%	0.0228%	0.0074	6.24	47.16
161	32.60	4	1,158	13.2192%	0.0457%	0.0149	6.24	47.18
162	32.70	1	1,154	13.1735%	0.0114%	0.0037	6.22	47.23
163	33.10	4	1,153	13.1621%	0.0457%	0.0151	6.22	47.24
164	33.20	4	1,149	13.1164%	0.0457%	0.0152	6.20	47.29
165	33.30	1	1,145	13.0708%	0.0114%	0.0038	6.19	47.34
166	33.40	26	1,144	13.0594%	0.2968%	0.0991	6.18	47.35
167	33.50	1	1,118	12.7626%	0.0114%	0.0038	6.09	47.68
			■		■	■		
305	75.60	4	99	1.1301%	0.0457%	0.0345	1.30	114.99
306	76.20	5	95	1.0845%	0.0571%	0.0435	1.27	116.65
307	76.70	3	90	1.0274%	0.0342%	0.0263	1.22	118.90
308	76.90	1	87	0.9932%	0.0114%	0.0088	1.20	120.35
309	78.10	5	86	0.9817%	0.0571%	0.0446	1.19	120.86
310	78.20	5	81	0.9247%	0.0571%	0.0446	1.14	123.50
311	78.30	1	76	0.8676%	0.0114%	0.0089	1.10	126.47
312	79.10	5	75	0.8562%	0.0571%	0.0451	1.09	127.12
313	79.40	1	70	0.7991%	0.0114%	0.0091	1.04	130.55
314	82.90	1	69	0.7877%	0.0114%	0.0095	1.03	131.29
315	83.80	2	68	0.7763%	0.0228%	0.0191	1.02	132.00
316	93.30	3	66	0.7534%	0.0342%	0.0320	1.01	133.46
317	100.00	52	63	0.7192%	0.5936%	0.5936	0.97	135.37
318	118.50	2	11	0.1256%	0.0228%	0.0271	0.38	302.59
319	340.00	6	9	0.1027%	0.0685%	0.2329	0.35	343.50
320	350.50	3	3	0.0342%	0.0342%	0.1200	0.12	350.50
					Total:	24.0046		

Columns (1), (2), and (4):	Information from Virginia Power Response to Question No. 28 included in the Sixth Set of Interogatories from VCFUR.
Column (3):	Cumulative number of hours starting with highest marginal cost.
Column (5):	[Column (4) line n] - [Column (4) line n+1].
Column (6):	Column (1) * Column (5).
Column (7):	Summation of Column (6) for all marginal costs in lines n and higher. (Example: Line 15 is the sum of Column (6) for lines 15 through 320.)
Column (8):	Column (7) / Column (4).

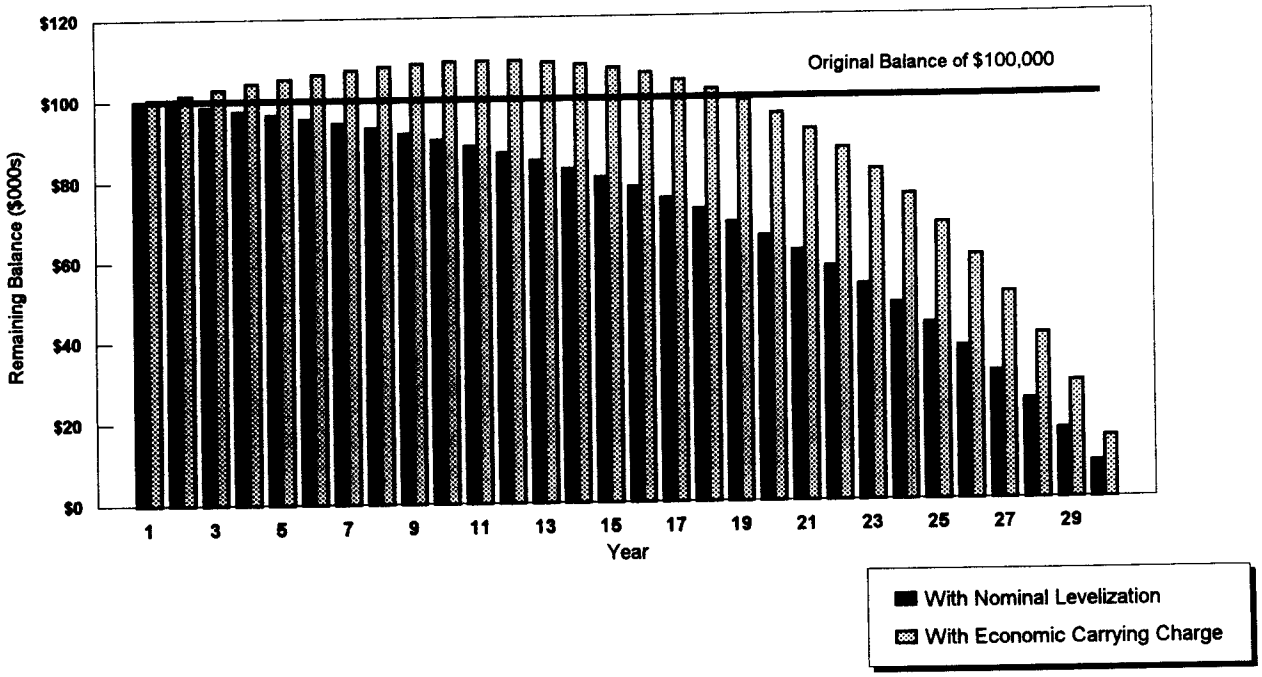
VIRGINIA ELECTRIC AND POWER COMPANY

Results of MultiSym Price Duration Curves 1997 - 2012
Average Prices Based on Various Dispatch Curves



VIRGINIA ELECTRIC AND POWER COMPANY

Example Comparing Nominally Levelized versus Economic Carrying Charge On Repayment of $100,000



VIRGINIA ELECTRIC AND POWER COMPANY

Example Comparing Nominally Levelized versus Economic Carrying Charge On Repayment of $100,000

	Payment Streams		Repayment with Nominally Levelized Stream			Repayment with Economic Carrying Charge		
Yr	Nominally Levelized (1)	Economic Carrying (2)	Remaining Balance (3)	Interest (4)	Principal Paid (5)	Remaining Balance (6)	Interest (7)	Principal Paid (8)
1	$9,561	$7,338	$100,000	$8,800	$761	$100,000	$8,800	($1,462)
2	$9,561	$7,544	$99,239	$8,733	$828	$101,462	$8,929	($1,385)
3	$9,561	$7,755	$98,410	$8,660	$901	$102,847	$9,051	($1,296)
4	$9,561	$7,972	$97,509	$8,581	$981	$104,142	$9,165	($1,193)
5	$9,561	$8,195	$96,528	$8,494	$1,067	$105,335	$9,269	($1,074)
6	$9,561	$8,425	$95,461	$8,401	$1,161	$106,409	$9,364	($939)
7	$9,561	$8,661	$94,300	$8,298	$1,263	$107,349	$9,447	($786)
8	$9,561	$8,903	$93,037	$8,187	$1,374	$108,135	$9,516	($613)
9	$9,561	$9,152	$91,663	$8,066	$1,495	$108,747	$9,570	($417)
10	$9,561	$9,409	$90,167	$7,935	$1,627	$109,165	$9,607	($198)
11	$9,561	$9,672	$88,541	$7,792	$1,770	$109,363	$9,624	$48
12	$9,561	$9,943	$86,771	$7,636	$1,926	$109,315	$9,620	$323
13	$9,561	$10,221	$84,845	$7,466	$2,095	$108,991	$9,591	$630
14	$9,561	$10,507	$82,750	$7,282	$2,279	$108,361	$9,536	$972
15	$9,561	$10,802	$80,471	$7,081	$2,480	$107,390	$9,450	$1,351
16	$9,561	$11,104	$77,991	$6,863	$2,698	$106,038	$9,331	$1,773
17	$9,561	$11,415	$75,292	$6,626	$2,936	$104,265	$9,175	$2,240
18	$9,561	$11,735	$72,357	$6,367	$3,194	$102,026	$8,978	$2,756
19	$9,561	$12,063	$69,162	$6,086	$3,475	$99,269	$8,736	$3,328
20	$9,561	$12,401	$65,687	$5,780	$3,781	$95,942	$8,443	$3,958
21	$9,561	$12,748	$61,906	$5,448	$4,114	$91,984	$8,095	$4,654
22	$9,561	$13,105	$57,792	$5,086	$4,476	$87,330	$7,685	$5,420
23	$9,561	$13,472	$53,317	$4,692	$4,870	$81,910	$7,208	$6,264
24	$9,561	$13,849	$48,447	$4,263	$5,298	$75,646	$6,657	$7,193
25	$9,561	$14,237	$43,149	$3,797	$5,764	$68,453	$6,024	$8,213
26	$9,561	$14,636	$37,385	$3,290	$6,272	$60,240	$5,301	$9,335
27	$9,561	$15,046	$31,113	$2,738	$6,824	$50,905	$4,480	$10,566
28	$9,561	$15,467	$24,289	$2,137	$7,424	$40,339	$3,550	$11,917
29	$9,561	$15,900	$16,865	$1,484	$8,077	$28,422	$2,501	$13,399
30	$9,561	$16,345	$8,788	$773	$8,788	$15,023	$1,322	$15,023
NPV	$100,000	$100,000						

Assumptions:

Inflation Rate: *2.80%* *Interest Rate:* *8.80%* *Initial Cost:* *$100,000*

Column (1): Levelized payment stream.
Column (2): Payment based on economic carrying charge, increasing at rate of inflation.
Column (3): Previous line of Column (3) - Previous line of Column (5).
Column (4): Column (3) * Interest Rate.
Column (5): Column (1) - Column (4).
Column (6): Previous line of Column (6) - Previous line of Column (8).
Column (7): Column (6) * Interest Rate.
Column (8): Column (2) - Column (7).

VIRGINIA ELECTRIC AND POWER COMPANY

Derivation of Capacity Reservation Value And Value of CT Energy Generation

Yr	Virginia Power's Total Capacity Cost ($/kW-mo)	Virginia Power's Total Capacity Cost ($/kW-yr)	Nominally Levelized	Fixed O&M	Total	Energy Credit	Net Capacity Value
			(All amounts shown as $ per kW-year)				
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1997	$1.91	$22.90	$34.82	$17.00	$51.82		
1998	$1.96	$23.55	$35.80	$17.48	$53.28		
1999	$2.02	$24.22	$36.80	$17.97	$54.77		
2000	$2.08	$24.91	$37.84	$18.47	$56.31		
2001	$2.14	$25.62	$38.90	$18.99	$57.89		
2002	$2.20	$26.36	$39.99	$19.53	$59.52	$9.61	$49.91
2003	$2.26	$27.11	$41.12	$20.08	$61.19	$8.55	$52.64
2004	$2.32	$27.89	$42.27	$20.64	$62.91	$18.79	$44.13
2005	$2.39	$28.69	$43.46	$21.22	$64.68	$12.21	$52.47
2006	$2.46	$29.51	$44.68	$21.82	$66.50	$12.93	$53.57
2007	$2.53	$30.36	$45.94	$22.43	$68.37	$13.69	$54.68
2008	$2.60	$31.23	$47.23	$23.06	$70.29	$14.50	$55.78
2009	$2.68	$32.12	$48.56	$23.71	$72.26	$15.36	$56.90
2010	$2.75	$33.04	$49.92	$24.37	$74.29	$16.30	$58.00
2011	$2.83	$33.99	$51.32	$25.06	$76.38	$17.51	$58.87
2012	$2.91	$34.96	$52.77	$25.76	$78.53	$18.82	$59.71

Assumptions:

Escalation: *2.81%* ***Discount Rate:*** *7.73%*

Column (1): For years 2003+, see TCR, page 16. For years prior to 2003, column (2) / 12.
Column (2): Virginia Power Response to Question No. 35 included in the Sixth Set of Interrogatories from VCFUR.
Column (3): Nominally levelized payment based on 1997 total cost; escalated for years 1998 forward. Escalation rates and discount rate from Virginia Power Response to Question No. 35 included in the Sixth Set of Interrogatories from VCFUR. Initial Cost of $300 per kW.
Column (4): "Assumptions for the Annual Energy Outlook 1997", EIA, December 1996, p. 58.
Column (5): Column (3) + Column (4).
Column (6): See Page 2 of this schedule.
Column (7): Column (5) - Column (6).

VIRGINIA ELECTRIC AND POWER COMPANY

Derivation of Capacity Reservation Value
And Value of CT Energy Generation

Yr	Dispatch Cost ($/MWH) (1)	Capacity Factor (2)	Average Price ($/MWH) (3)	Energy Credit ($/MWH) (4)	Total Credit ($ / kW) (5)
2002	$44.66	2.97%	$81.63	$36.97	$9.61
2003	$46.39	3.70%	$72.78	$26.39	$8.55
2004	$48.21	4.16%	$99.82	$51.61	$18.79
2005	$50.41	3.56%	$89.55	$39.14	$12.21
2006	$52.30	3.68%	$92.46	$40.16	$12.93
2007	$54.29	3.77%	$95.76	$41.47	$13.69
2008	$56.31	3.77%	$100.26	$43.95	$14.50
2009	$58.42	3.78%	$104.83	$46.41	$15.36
2010	$60.53	3.87%	$108.61	$48.08	$16.30
2011	$62.08	4.09%	$110.99	$48.91	$17.51
2012	$63.63	4.09%	$116.20	$52.57	$18.82
Average	$54.29	3.77%	$97.54	$43.24	$14.39

Column (1): Virginia Power Response to Question No. 35 included in the Sixth Set of Interrogatories from VCFUR.

Column (2): Based on the price duration curves for 2002 through 2012, the capacity factor which supports the dispatch cost. See also the spreadsheet file "fpc596r.xlw" provided in Virginia Power Response to Question No. 9 included in the Sixth Set of Interrogatories from VCFUR.

Column (3): Based on the price duration curves for 2002 through 2012, the average price corresponding to the dispatch cost and capacity factor. See also file referenced above.

Column (4): Colum (3) - Column (1).

Column (5): Column (4) * Column (2) * 8.76.

VIRGINIA ELECTRIC AND POWER COMPANY

Results of Changes to Virginia Power Assumptions In Estimating Transition Costs (Thousands of Dollars)

Ln	Description	As Filed By Company (1)	Adjustment For Correction to Roanoke Rapids* (2)	Individual Adjustments to Estimated Transition Costs: Revised Capacity Prices 2003 - 2015 (3)	Extending Analysis To 2025 (4)	Revised Capacity Costs 2016 - 2025 (5)	Extending Analysis To 2035 (6)	Revised Capacity Costs 2026 - 2035 (7)
1	Fossil Plants	($727,710)	$0	($1,361,681)	($1,439,553)	($518,377)	($1,070,060)	($330,866)
2	Hydro Plants	$108,679	($17,208)	($262,927)	($330,237)	($100,094)	($208,375)	($63,887)
3	Subtotal Fossil & Hydro	($619,030)	($17,208)	($1,624,608)	($1,769,790)	($618,471)	($1,278,435)	($394,752)
4	Plus: Other and Future Plant	$17,703	$0	$0	$0	$0	$0	$0
5	Total Fossil & Hydro	($601,328)	($17,208)	($1,624,608)	($1,769,790)	($618,471)	($1,278,435)	($394,752)
6	Nuclear	$787,291	$0	($416,413)	($195,316)	($42,828)	($0)	$0
7	Subtotal - Generation	$185,963	($17,208)	($2,041,021)	($1,965,106)	($661,299)	($1,278,435)	($394,752)
8	NUG Contracts	$3,015,199	$0	($487,273)	$186,803	($75,117)	$0	$0
9	Total System	$3,201,162	($17,208)	($2,528,294)	($1,778,303)	($736,416)	($1,278,435)	($394,752)
10	Virginia Jurisdiction	$2,464,984	($13,251)	($1,946,858)	($1,369,343)	($567,061)	($984,431)	($303,970)

* The correction to Roanoke Rapids is retained in columns 3 through 7.

VIRGINIA ELECTRIC AND POWER COMPANY

Results of Changes to Virginia Power Assumptions In Estimating Transition Costs (Thousands of Dollars)

Ln	Description	As Filed By Company (1)	Correction to Roanoke Rapids* (2)	Cumulative Adjustments to Estimated Transition Costs: Revised Capacity Prices 2003 - 2015 (3)	Extending Analysis To 2025 (4)	Revised Capacity Costs 2016 - 2025 (5)	Extending Analysis To 2035 (6)	Revised Capacity Costs 2026 - 2035 (7)
1	Fossil Plants	($727,710)	($727,710)	($2,089,391)	($3,528,944)	($4,047,321)	($5,117,381)	($5,448,247)
2	Hydro Plants	$108,679	$91,471	($171,456)	($501,693)	($601,787)	($810,162)	($874,049)
3	Subtotal Fossil & Hydro	($619,030)	($636,239)	($2,260,847)	($4,030,637)	($4,649,108)	($5,927,543)	($6,322,296)
4	Plus: Other and Future Plant	$17,703	$17,703	$17,703	$17,703	$17,703	$17,703	$17,703
5	Total Fossil & Hydro	($601,328)	($618,536)	($2,243,144)	($4,012,934)	($4,631,405)	($5,909,840)	($6,304,593)
6	Nuclear	$787,291	$787,291	$370,878	$175,562	$132,734	$132,734	$132,734
7	Subtotal - Generation	$185,963	$168,755	($1,872,266)	($3,837,372)	($4,498,671)	($5,777,106)	($6,171,859)
8	NUG Contracts	$3,015,199	$3,015,199	$2,527,926	$2,714,728	$2,639,611	$2,639,611	$2,639,611
9	Total System	$3,201,162	$3,183,954	$655,659	($1,122,644)	($1,859,060)	($3,137,495)	($3,532,248)
10	Virginia Jurisdiction	$2,464,984	$2,451,734	$504,876	($864,467)	($1,431,528)	($2,415,959)	($2,719,930)

* The correction to Roanoke Rapids is retained in columns 3 through 7.