STATE OF MARYLAND

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the Application of Delmarva	**)**	
Power & Light Company for Authority to	**)**	**Case No. 9093**
Revise Its Rates and Charges for Electric	**)**	
Service and for Certain Rate Design Changes	**)**	

DIRECT TESTIMONY OF

JONATHAN WALLACH

ON BEHALF OF

THE OFFICE OF PEOPLE'S COUNSEL

Resource Insight, Inc.

MARCH 7, 2007

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I. Introduction and Summary

Q: Please state your name, occupation, and business address.

A: I am Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Please summarize your professional education and experience.

A: I have worked as a consultant to the electric-power industry for more than two decades. From 1981 to 1986, I was a research associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a senior analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since September of 1990.

Over the last twenty-five years, I have advised clients on a wide range of economic, planning, and policy issues including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market valuation of generating assets and purchase contracts; power-procurement strategies; integrated resource planning; cost allocation and rate design; and energy-efficiency program design and planning.

My resume is attached as Exhibit JFW-1.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Office of People's Counsel.

Q: What is the purpose of your testimony?

A: On November 17, 2006, Delmarva Power & Light Company ("Delmarva"; "the Company") filed an application for an increase in its distribution rates, along with supporting testimony. This testimony addresses three aspects of the Company's filing: (1) the proposal to implement a Bill Stabilization Adjustment

("BSA") mechanism; (2) the Accounting Cost Of Service Study ("COSS"); and (3) the proposed residential rate design. These three elements are supported in the pre-filed testimony by Company witnesses Mark E. Browning, Paul M. Normand, Joseph F. Janocha,, and John Chamberlin.

The Company's filing is based on a test year that consists of six months of actual data and six months of projected data. On February 9, 2007, the Company amended portions of its filing to reflect a test year with twelve months of actual data. The Company did not update its Cost of Service Study or its tariff filing to reflect twelve months of actual data. Nor did Delmarva file any supplemental testimony supporting the portions of the filing it did amend. As such, my findings and recommendations with regard to cost allocation and rate design are preliminary in nature and subject to change once the Company files an amended COSS and any associated revisions to its proposed residential rate design.

People's Counsel is also sponsoring testimony by Mr. David Effron regarding revenue requirements and Mr. Charles King regarding rate of return.

Q: Please summarize your preliminary recommendations.

A: Based on my assessment of the Company's filing using a six-month actual, six-month projected test year, my preliminary recommendations are as follows:

- The Commission should approve the implementation of a Bill Stabilization Adjustment mechanism with two modifications, as described below in Section II. However, approval should be conditioned on the Company implementing a comprehensive, cost-effective portfolio of residential Demand Side Management ("DSM") programs, and on establishment of a program to monitor service quality and certain other changes in customer characteristics and economic conditions relevant to the BSA. In addition, as recommended by OPC witness Mr. King, the Company's authorized rate of return should be adjusted downward to reflect the significant reduction in risk to the Company from implementation of the BSA.

- The Company's proposal for a demand-elasticity adjustment as an alternative to the BSA should be rejected.
- The Commission should approve the Company's proposal for allocating to the residential class the revenue increase ultimately approved by the Commission. However, the Commission should reject the Company's Cost of Service Study as a reasonable basis for that allocation.
- The Company's proposal to increase the residential customer charge by 121% should be rejected. Instead, customer and energy charges should be increased in proportion to the overall revenue increase allocated to the residential class.
- The Company's proposed method for reducing the declining-block structure in winter rates should be rejected. While there is merit to the concept of reducing the difference between initial and trailing blocks, the proposed approach unreasonably reduces the summer-winter differential in energy charges for large residential customers.

II. Bill Stabilization Adjustment

Q: Please describe the Company' proposal for a BSA mechanism.

A: According to Dr. Browning, the Bill Stabilization Adjustment mechanism will decouple recovery of test-year revenues from actual sales during the rate effective period. The BSA is designed such that the Company collects only an amount of revenue per customer approved by the Commission for the test year. If actual revenue per customer is more or less than the approved test-year amount, the difference is credited or recovered from customers at a later time.

The BSA would be calculated quarterly and for each rate class separately as the difference between the class's actual and target revenues for the quarter. Subject to a 10% capping mechanism and revenue reconciliation, the calculated BSA would be applied to rates in the next quarter.

Q: What is the Company's rationale for the BSA?

A: The Company claims that the BSA would:

- Provide revenue stability for the Company, especially during periods of extreme weather.
- Reduce the Company's risk and cost of equity.
- Reduce the Company's disincentive to promote DSM.
- Provide an alternative to the demand elasticity adjustment proposed by the Company.
- Provide bill stability for customers, especially during periods of extreme weather.
- Correct for the "mismatch between the structure of costs and the structure of rates."[1]

Q: Are these arguments valid?

A: In part. The BSA would provide revenue stability for the Company, reduce the Company's risk and cost of capital, reduce the Company's financial disincentive to promote DSM (and its incentive to maximize sales), and eliminate the justification for the demand-elasticity adjustment. These effects will benefit ratepayers only if the reduced cost of capital is reflected in rates, the Company implements a significant DSM program, and the Commission rejects the demand-elasticity adjustment proposed in the Company's filing.

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[1] *Testimony of John Chamberlin*, Case No. 9093, November 17, 2006, p. 2.

With regard to the impact of the BSA on bill volatility, the Company overstates the extent to which the BSA would provide bill stability for individual customers. In addition, the Company's arguments regarding alignment of underlying costs and rate design are reasonable solely from the Company's narrow perspective of short-term revenue recovery, but are not valid in terms of long-term cost causation and price signals. Both of these issues are discussed below.

Q: Is the BSA a departure from traditional ratemaking for electric companies?

A: Yes. The BSA represents a significant departure from traditional cost-of-service regulation in that it guarantees that the Company will receive the level of revenues authorized by the Commission during the rate-setting process. As is clear from the Company's proposal in this case, the BSA provides a stable and guaranteed stream of revenue, without regard to the usual risk of declining revenues caused by weather, economic downturns or conservation measures undertaken by customers. According to Mr. King, the mitigation of business risk with a BSA warrants a significant reduction to the Company's return on equity.

Q: Does OPC agree with the Company's quantification of the effect of the BSA on the cost of equity?

A: No. Mr. King concludes that the Company's proposed reduction of 25 basis points is understated, and recommends a reduction in return on equity of 81 basis points.

Q: In what ways are the Company's claims regarding the effectiveness of the BSA in stabilizing customer bills overstated?

A: The BSA will likely provide greater stability in the average annual bills for the residential class. However, the BSA would not provide stability to individual customers' monthly bills. Distribution bills would still vary from month to month, and might well vary more with the BSA than without, as the over-collection (and high bills) in one quarter results in a refund (and hence lower-than-expected bills) in the next quarter. In addition, individual customer monthly bills would not be stabilized as much as total residential monthly revenues. For example, high bills in a cold winter (paid primarily by space-heating customers) would result in a BSA refund in the spring, with the refund spread more evenly among all residential customers.

Q: What are the limitations of the Company's claim regarding the mismatch between underlying costs and the rates intended to recover those costs ?

A: The Company's discussion of the BSA and the recovery of "fixed" costs is narrowly focused on the issue of short-term cost recovery, to the exclusion of consideration of issues of cost causation and appropriate price signals.

In terms of utility cost-recovery, most distribution costs are fixed in the short term. The revenue requirements associated with debt service and maintenance for a given set of lines and transformers in any year does not vary much with load or sales in that year.[2] Thus, recovery of distribution costs in volumetric charges results in revenue instability and financial risk. As I noted above, these are valid justifications for a BSA.

In terms of rate design, price signals, and cost causation, on the other hand, most distribution costs are not "fixed." Increased loading of existing lines, conduit, transformers, substations, and other distribution equipment reduces the lives of that equipment and requires the installation of more and larger

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[2]Higher loads, especially in the summer, are likely to result in failure of more transformers and underground lines, so current costs vary with current load to some extent. This is probably a small effect, compared to total distribution costs and the variation in distribution revenues with seasonal weather.

equipment. Higher loads may even require more poles and towers, to carry additional primary circuits, and higher poles and towers, to allow for higher distribution voltages. In general, energy charges better reflect the causation of these costs than fixed customer charges, and hence provide the better price signal.

Q: What do you recommend with regard to implementation of the BSA?

A: I recommend implementation of a modified version of the BSA. Specifically, the timing of BSA recovery should be corrected to better achieve the goals of bill stabilization and better matching of over-collections with refunds and under-collections with surcharges. In addition, the 10% cap on BSA recovery should be reduced to 5%, with Commission approval required for deferrals in excess of the 5% threshold.

Moreover, approval of the BSA, as modified, should be tied to implementation of a comprehensive, cost-effective portfolio of DSM programs; monitoring and reporting on service quality and changes in customer characteristics and economic conditions relevant to the BSA; and rejection of the Company's proposal for a demand-elasticity adjustment.

Q: How should the timing of BSA recovery be modified?

A: Under the Company's BSA proposal, one quarter's charge or credit is recovered in the succeeding quarter's adjustment—in particular, the weather-related fluctuation in loads that occurs largely in the summer and winter are recovered in fall and spring bills. The high bills in a cold winter would be paid primarily by space-heating customers, but would result in a BSA refund in the spring that flows predominantly to non-heating customers. This outcome – collection of excess revenues from one sub-class and refund to another – is inequitable and undermines the bill-stabilization goals of the BSA.

To avoid this problem, the quarterly adjustments can be lagged one year, so that excess revenues from a cold winter are refunded to customers the following winter, and excess revenues from a hot summer are refunded the following summer.

Q: How should the cap on BSA recovery be modified?

A: Under some circumstances (e.g., high generation prices, an economic slowdown), a 10% increase in distribution rates may be excessive. The Commission should direct the Company to seek Commission approval prior to instituting BSA recovery in excess of 5% of base distribution rates in any quarter.

Q: How should the BSA be tied to implementation of a comprehensive, cost-effective DSM portfolio?

A: Since a major benefit of the BSA is its effect in reducing utility resistance to energy efficiency, approval of the BSA should be conditioned on implementation of a comprehensive, aggressive DSM package. The Commission should require that the Company file program designs and implementation plans for a least-cost portfolio of DSM programs within 90 days of the start of the rate effective period. The Commission should also condition the continued operation of the BSA on the continued implementation of a comprehensive DSM portfolio.

Q: Why should approval of the BSA result in rejection of the Company's proposal for a demand-elasticity adjustment?

A: The Company proposes the demand-elasticity adjustment as an alternative to the BSA. If the Commission approves the Company's BSA proposal, this adjustment is unnecessary.

Q: What types of monitoring and reporting should be required in connection with the BSA?

A: I recommend three monitoring activities. By protecting Company revenues from falling sales, the BSA may allow the Company to stretch out the interval between distribution rate cases, creating a perverse incentive to increase earnings by skimping on service quality. The Commission should therefore require the Company to monitor and report to the Commission and OPC changes in service quality from the time of BSA implementation.

Second, the proposed BSA varies the target revenue for each class in proportion to the number of customers in the class. That mechanism is reasonable, so long as the size of new customers is not very different from the size of existing customers, and the number of large master-metered multi-family and commercial buildings converted to multiple small customers (increasing the customer number and hence the revenue target, but not distribution costs) is not significant. To ensure that these conditions apply, and to provide the opportunity to modify the BSA, the Company should be required to monitor the size of new customers in each class and the number of conversions from master-metered to multi-metered buildings, and to report to the Commission and OPC if conditions change significantly.

Third, the Company should monitor economic conditions. If an economic downturn were to reduce sales and revenues, the BSA would increase rates, exacerbating the effect on already stressed households, businesses and local governments. The Commission should be prepared to modify the BSA, either on its own or at the request of a party, if those conditions occur.

III. Cost Allocation

Q: What is the purpose of the cost-allocation process?

A: The cost allocation process assigns the Company's total Maryland-jurisdictional revenue requirement to the various customer and rate classes. The process is generally driven by some concept of fairness. It is a generally accepted principle that allocation based on cost causation results in an equitable sharing of costs.

Q: What are the results of Delmarva's Cost of Service Study?

A: The COSS indicates that for the 12 months ending September 30, 2006, the residential class, non-heating subclass and heating subclass were paying 99%, 114% and 86%, respectively, of the Company's average rate of return.[3]

Q: On which portions of the cost-allocation process do you have comments?

A: I have comments on the allocation of the proposed revenue increase (which is based in part on the Cost of Service Study), and on three aspects of the COSS itself. I will discuss each of these in turn.

A. Allocation of Revenue Increase

Q: How does the Company propose to use its COSS to allocate its requested rate increase among rate classes?

A: The Company proposes to equalize rates of return across classes. To do so, Delmarva calculates the change in each class's revenue requirement necessary to bring up the class's ROR to the requested ROR of 8.34%. Since the Company concludes that the residential class was earning very close to the Company

[3] *Prepared Direct Testimony of Paul Normand*, Case No. 9093, November 17, 2006, Schedule_PMN-6, page 1-1 and 1-2.

average in the test year, the proposed increase to the residential rate, 21%, is essentially equal to the Company's requested overall revenue increase.[4]

Q: Do you recommend any changes to the Company's proposal for allocating its overall revenue request to the residential class?

A: No. Increasing residential revenues by the same percentage allowed for the Company as a whole is reasonable for this proceeding. Consequently, any reduction in the Company's requested revenue increase should be applied evenly across rate classes.

However, the Company has not adequately supported its proposed allocation of the overall revenue increase. Specifically, the Cost of Service Study on which they are based appears to overstate the residential class's share of costs. If that is the case, then the residential class would probably be over-earning, and the rate change necessary to bring the class to the Company average rate of return, as indicated by the COSS, would be negative. The Commission should require the Company to correct its Cost of Service Study, to address the problems described in the following section of my testimony.

B. Evaluation of Delmarva's Cost of Service Study

Q: How does Delmarva allocate distribution plant?

A: According to Mr. Normand, the COSS allocates plant as follows:

- Primary distribution is assigned on the basis of the class peak demands non-coincident with the Company system peak ("NCP"), that is, the class's maximum load.

[4]*Testimony of Joseph F. Janocha*, Case No. 9093, November 17, 2006, Schedule JFJ-1, p. 1.

- Services are allocated on the sum of maximum customer demands (“MCD”), i.e., the sum of each customer’s individual annual maximum demand, whenever it occurs.
- Line transformers are assigned to small secondary customers based on a simple average of MCD and NCP, but to large customers based on MCD. Use of this allocator recognizes that small customers share transformers while each large customer requires its own transformer or set of transformers.
- Secondary lines (overhead and underground) are assigned to small secondary customers based on a simple average of MCD and NCP. Large general-service customers are not assigned any secondary lines, assuming that all large customers are directly served from the transformer.

Q: Do these allocators reasonably reflect cost causation?

A: No. I have identified a number of problems with the Company’s allocation decisions that are likely to overstate the allocation of costs to the residential class:

- The allocation of transformers based on a simple average of MCD and NCP may understate the diversity of load on these facilities.
- Delmarva’s allocation of services based on MCD (which assumes zero diversity in their loads) does not account for the sharing by many residential customers of a single service line to a multi-family building.
- The Company overstates the NCP of the residential class as a whole by calculating the class NCP as the sum of the NCPs for the heating and non-heating subclasses, rather than as the diversified NCP for the class in aggregate.

All of these problems arise as a result of the Company's apparent understatement of residential load diversity in its specification of residential allocators. By understating diversity, the Company likely overstates the residential-class contribution to distribution costs and thus over-allocates such costs to the residential class.

Q: How does load diversity affect the sizing of transmission and distribution ("T&D") plant?

A: The diversity of demand among a group of customers results in a group peak demand that is lower than the sum of customers' individual maximum demands. In other words, since customers reach their individual peak demands on different days and hours, their loads at the single hour when a distribution facility reaches its peak will be less than the sum of the individual customers' maximum demands. In general, utilities size T&D plant to meet the group peak, not the sum of customers' individual maximum demands.[5]

The load diversity on a given piece of distribution equipment, a transformer, or a length of line, depends upon the number and type of customers served by that equipment. The farther downstream the distribution equipment, the fewer the customers served, and the lower the load diversity.

Load diversity is frequently reported as a coincidence factor, the ratio of the peak of a group of customers to the sum of their maximum demands. In other words, the coincidence factor measures the percentage of the customers' maximum demand that occurs at the hour of the group peak.

[5] On pages 10-11 of Mr. Normand's testimony, the Company indicates that it sizes line transformers to meet the diversified load of the smaller customers "who are oftentimes served by one transformer for several customers." And in response to OPC Data Request No. 7, Question No. 4, Delmarva indicates that it sizes substations to meet diversified feeder loads. Copies of these and all other responses cited herein are attached.

Q: Do Delmarva's demand allocators reflect load diversity on distribution plant?

A: Yes. For example, at the primary level, Delmarva's analysis assumes a residential load coincidence factor of 44% when it assigns this plant based on the NCP factor. In other words, it assumes that the peak of a group of residential customers is 44% of the sum of their maximum annual demands. At the farthest end of the T&D system, at the service drop, Delmarva assumes no diversity of load (or a coincidence factor of 100%) when it allocates this plant according to the sum of individual customers' maximum demands. The diversity reflected in Delmarva's demand allocators is shown in the following table of coincidence factors:[6]

Allocator	Total Maryland	Resid	GS @ Secondary	GS @ Primary	Street Light
Class NCP	52%	44%	66%	88%	95%
50/50 NCP–MCD	76%	72%	73%	78%	88%
Class MCD	100%	100%	100%	100%	100%

Source: Schedule PMN-2, p. 18-1.

Q: Why does understating the load diversity overstate the residential class's share of costs?

A: There tends to be more load diversity on the distribution equipment serving small customers, because each piece of equipment typically can serve more small customers than large customers. For example, according to PEPCo's 1985 residential underground distribution guidelines, a 167 kVA transformer can serve 41 residential customers using gas heat and 3½ hp air conditioning, with a

[6] The 50/50 NCP-MCD coincidence factor is calculated as the simple average of the NCP and the MCD coincidence factors.

total non-coincident demand of 492 kVA.[7] But that same transformer could only serve a single commercial customer with a demand of around 167 kVA. There is no diversity in the large-customer load on the transformer, while the diversity of the residential loads reduces the peak on the transformer by 66% compared to the individual customer peaks. The greater the number of customers on a particular component, the greater the variation in loads and load shapes (that is, load diversity), the lower the contribution per customer to the group peak, and the lower the cost per customer.

Q: Has the Company provided any load diversity studies to support its specification of allocators?

A: No. While it recognizes that allocators should reflect load diversity on the distribution facilities, the Company relies on Mr. Normand's experience rather than an analysis of load diversity on the Delmarva system.[8]

The Company should undertake such an analysis in order to ensure that its allocators reasonably reflect the impact of load diversity on distribution costs.

1. Line Transformers

Q: What is the Company's rationale for using the 50/50 average of NCP and MCD to allocate transformers?

A: The Company's rationale is provided in response to OPC Data Request No. 6, Question No. 13:

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[7] *Underground Residential Distribution: Loading & Cable Parameters* (DR OPC-RD-1-36, Attachment A provided in Case No. 8466), Tables III and IX.

[8] Response to OPC Data Request No. 6, Question No. 13.

> The basis of the allocation factor for Line Transformers and Secondary plant costs was Mr. Normand's extensive experience in analyzing power systems for over 30 years. The allocation factor was based on the following:
>
> a) Line Transformers
>
> - Very large secondary customers generally will have their own transformer at their facility and are generally not adjacent to other large customers.
> - Smaller customers have much smaller loads and are oftentimes more clustered which provides for the aggregation of several customers per transformer which is typical (2–4 customers) based on Mr. Normand's experience.
>
> The use of a 50/50 weighting of class NCP and maximum demands is the only approach that recognizes this aggregation and properly allocates these costs. Either demand approach (NCP or maximum) would under allocate (NCP) or materially over allocate (maximum) to smaller customers such as residential. … The only proper use of maximum demands is in the allocation with respect to larger secondary customers.

Q: Is the 50/50 weighting the "only approach that recognizes this aggregation and properly allocates these costs"?

A: No. The weighting can be adjusted to reflect more accurately the load diversity on the distribution facilities

Q: Has Delmarva provided the data necessary to evaluate Mr. Normand's assumption of a 50/50 weighting, with its implied coincidence factor of 72%?

A: No. But in the absence of adequate information from the Company, I have prepared an illustrative calculation using Delmarva's overall average of customers per transformer and the PEPCo's estimates of residential load coincidence by number of houses and end use included in its 1985 underground distribution guidelines. This calculation illustrates how the 50/50 weighting may understate diversity on line transformers.

There were 59,926 transformers in Delmarva's Maryland jurisdiction as of year-end 2006 and 194,455secondary customers for the test year, for an average of 3.3 customers per transformer.[9] Assuming that no secondary transformers are attributable to the primary and streetlighting customers, and that the secondary general-service customers average one transformer per customer, the remaining transformers would each serve an average of about 4.8 customers.

Assuming four residential customers per transformer, PEPCo's 1985 underground distribution guidelines show less than 72% load coincidence for all but the largest electric air conditioning and-heating customers, even when all the customers on the transformer are assumed to have the same air conditioning or heating equipment. Based on Table III of PEPCo's guidelines, as indicated in the following table, a group of four houses each with 2½ hp air conditioning, for example, would have a coincidence factor of 64%:

	Air Conditioning (hp)								
	None	*1½*	*2*	*2½*	*3*	*3½*	*4*	*5*	*7½*
1 House	7	9	10	11	11	12	13	15	19
4 Houses diversified kVa	17	20	23	28	30	33	36	42	55
Coincidence Factor	61%	56%	58%	64%	68%	69%	69%	70%	72%

Likewise, as shown in the following table, based on Table IV of PEPCo's guidelines, a group of four houses each with 12.5 kW of electric heating, would have a coincidence factor of 66%:

	Electric Furnace (kW)							
	5	*7.5*	*10*	*12.5*	*15*	*20*	*25*	*30*
1 House	10	15	14	17	18	22	27	31
4 Houses diversified kVa	27	34	38	45	49	68	78	103
Coincidence Factor	68%	57%	68%	66%	68%	77%	72%	83%

[9] Response to OPC Data Request No. 7, Question No. 16 and Schedule PMN-5, page 3-1.

If diversity among different types of residential customers were also taken into account, the load coincidence factors would be even lower. A single transformer may serve some homes with electric heat that peak in the winter, and some with fossil heat that peak in the summer.

2. Sharing of Services

Q: Could taking into account the sharing of services in multi-family buildings have a significant effect on the services allocator for the residential class?

A: Yes. Where services are shared, the load on the equipment is less than the sum of individual customer's maximum demand. In other words, load diversity is greater than zero for these multi-family buildings and, in turn, greater than zero on average for the residential class as a whole.

Q: Have you estimated what the impact of shared services would be on the residential services allocator?

A: I am unable to estimate at this time the impact of shared services, since the Company has not provided data on load diversity required for such a calculation. In addition, Delmarva is unable to provide other necessary information, such as data on the mix of housing types and the number of customers per service in its Maryland jurisdiction.[10]

However, this impact may be significant, since a substantial portion of housing in Delmarva's service territory is multi-family. According to the 2000 Census of Housing, in the counties that Delmarva serves, 18.3% of the

[10] Responses to OPC Data Request No. 6, Question Nos. 11 and 12.

customers are in multi-family housing with 2 to 9 units, and 11.4% in multi-family housing with more than 9 units.[11]

Q: Would similar adjustments apply to other classes?

A: No. Other than multi-family residential customers on the residential rate, relatively few customers are likely to share services.[12]

3. Estimate of NCP

Q: How has Delmarva overstated the NCP of the residential class?

A: Delmarva determined the NCP of the residential class as the sum of the NCPs of the winter-peaking heating and summer-peaking non-heating subclasses, rather than as the NCP of the residential class as a whole. As a result, Delmarva's approach ignores the diversity of load between heating and non-heating customers. By dividing the residential rate class into two smaller, less heterogeneous subgroups, Delmarva's NCP residential allocator understates the load diversity of the residential class as a whole.

If Delmarva computed NCP for the entire residential class, the maximum diversified demand would probably occur in the summer, when the heating customers have load much lower than their winter peaks. If Delmarva had separated some other class into similar subgroups (e.g., heating versus non-heating, mid-day-peaking offices versus evening-peaking restaurants and entertainment), that other class's NCP would be similarly increased.

[11]The Census figures include housing in the Choptank service territory. Since Choptank is likely to serve fewer multi-family dwellings, the percentage of multi-family units in Delmarva's territory is probably understated.

[12]In some cases, small commercial customers in a strip mall or office building will share a service.

Q: How should the COSS be corrected for this problem?

A: Delmarva should use class maximum diversified peak for the residential class as a whole in the NCP allocator. However, Delmarva cannot provide this residential class allocator.[13]

Q: Have you estimated the effect of correcting this error?

A: Yes. Assuming the heating load has a summer load shape similar to the non-heating load, the contribution of each sub-class to the class NCP would be proportional to the sub-class sales in the peak summer month. For August 2005, heating sales were approximately 98% of non-heating sales.[14] Hence, I estimate the heating customers' contribution to total residential NCP as 98% of the non-heating customers' contribution to residential NCP. In other words, I estimate total residential NCP as 1.98 times non-heating NCP. That value is 10% lower than the NCP that Delmarva uses for the residential class.

Correcting this one error increases the residential relative return in Delmarva's cost-of-service study from 0.99 to 1.05. The relative return for the heating subclass rises from 0.86 to 1.05.

IV. Rate Design

Q: What are your concerns with regard to Delmarva's residential rate design proposals?

A: I have identified two issues with regard to Delmarva's proposed rate design for the residential class. First, the Company's proposal for a dramatic 121% increase in the monthly customer charge from $3.64 to $8.04 relies on a Cost of

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[13]Response to OPC Data Request No. 6, Question No. 7.

[14]Response to OPC Data Request No. 7, Question No. 5, Attachment.

Service Study that: (1) likely overstates the residential share of total distribution costs; and (2) counts load-related costs as a customer cost. Second, the Company's proposed method for reducing the declining-block structure in winter rates inappropriately reduces the summer-winter differential in energy charges for large residential customers.

Although not formally incorporated in its proposed rate design, I am also concerned by statements by Company witnesses that imply that load-related distribution costs should be shifted from the volumetric charge to the customer charge, since such costs are fixed in the short term. While such a shift might serve the Company's desire for revenue stability, it is antithetical to the goal of conservation, cost-based rate design, reduction of system costs, and non-disruptive impacts on customer bills. Moreover, if the Commission adopts a BSA, revenue stability should no longer be a matter of concern for the Company.

A. The Customer Charge Proposal

Q: What is Delmarva's proposal with regard to the residential customer charge?

A: The Company proposes to set the customer charge to half of the Customer Cost derived in the Cost of Service Study.[15]

Q: Should the results of the Cost of Service Study be the basis for the proposed increases to the R and R-TM customer charges?

A: No, for the following reasons:

[15] The proposed customer charge of $8.04 actually exceeds half of the full customer cost derived from the COSS, $13.86/month for non-heating customers and $15.24/month for heating customers. (Normand Testimony, page 17).

- As I discussed above in Section III, the Cost of Service Study suffers from a number of problems that likely overstate costs to the residential class.
- The customer charge includes costs that the Company itself allocates as load-related.
- The large increase disproportionately affects small customers' bills. Delmarva's approach would require that the smallest customers (with the least-expensive distribution equipment) pay the average of customer costs attributable to all sizes of residential customers. Using an average cost per customer does not take into account the effect of customer size on cost and results in the subsidy of large customers by small customers within the class.
- The large increase results in a disruptive change to small customers' bills. The Company itself recognizes that its proposals should temper intra-class shifts by limiting the proposed charge to half of the COSS-based customer-related costs.[16] However, a 121% increase is not a gradual change.

Q: Which costs typically classified as customer-related in cost of service studies should not be included in the calculation of the customer charge?

A: A number of customer-classified costs vary with the size of the customer (in revenues, sales, or demand), and therefore, should be recovered in part through the commodity charge. For example, the service drop for the average small residential customer is likely to be lower than for the average large customer. Large residential customers are likely to be single-family homes, each using a fairly long service drop. Small customers are more likely to share services in multi-family housing or townhouses, or perhaps in row houses with individual,

[16] Janocha Testimony, pp. 6-7.

but short, service lines. Other costs that are classified as customer-related will also vary with the customer's use. For example, uncollectible accounts and collection expense are likely to be larger for large customers than for small customers, since the large customers have larger bills to become uncollectible.

Q: Does Delmarva's Cost of Service Study recognize that customer size affects customer-classified costs?

A: Yes. In its COSS, the Company recognizes that some of the costs it calls "customer-related" are not equal for customers across classes, or among subclasses within a particular class. For example, Delmarva assigns 10% more in "customer costs" to the average heating customer (with an average 13.63 kW MCD) than to the average non-heating customer (with an average 9 kW MCD).

Q: What costs does the COSS classify as customer-related, but allocate on load?

A: The Cost of Service Study allocates service drops on class MCD, recognizing that the cost of services varies with customer loads. The Company also allocates half of Customer Service and Sales expenses to customer class based on class energy sales Yet, Delmarva includes all of these costs in its estimate of customer costs for rate-design purposes. Services, and associated costs, and half of Customer Service and Sales expenses constitute a significant portion of the plant cost that Delmarva includes in the customer charge.

Q: What do you recommend with regard to setting of the residential customer charge?

A: The Company's proposal to increase the customer charge based on the results of its Cost of Service Study should be denied. Instead, the Commission should direct the Company to increase customer and energy charges for the residential rate class in proportion to the overall revenue increase allocated to that class.

B. Seasonal Differentials

Q: How does the proposed approach for reducing the difference between initial and trailing winter blocks reduce the seasonal differential?

A: The Company proposes to reduce the declining-block structure by lowering the rate on the initial winter block and commensurately raising the rate for the tail block. This approach effectively reduces the difference between the summer rate and the average winter rate for large customers with average usage in excess of the initial block.

Q: Does the Company recognize that its proposed approach for reducing the declining-block structure will also reduce the summer-winter differential?

A: Yes. In response to OPC Data Request No. 7, Question No. 18, Delmarva states that:

> The Company believes that movement of the residential distribution energy charges to the cost basis provided in the cost of service study, which is not season sensitive, should be the ultimate goal of the residential rate design. This goal should be appropriately tempered with a level of gradualism so as to minimize intra class rate impacts to customers. As noted on page 9, line 3 to 15 in the testimony of Mr. Janocha, the Company is proposing to close the gap between the residential distribution energy initial and trailing blocks in the winter months. This is an initial step to removing the seasonal differentiation.

Q: Is the fact that the COSS is not "season sensitive" a valid argument for reducing the seasonal differential?

A: No. As I discussed in Section II, distribution costs are only considered fixed and evenly distributed throughout the year from a short-term utility accounting perspective. However, from the perspective of cost causation and rate design, such costs are driven by load and by the timing of peak loads during the year. Capacity limitations on the Delmarva distribution systems generally occur in the summer. Most of the large and expensive distribution elements—substations and feeders—experience their peak loads in the summer.

The Company's data indicate that 99% of its distribution feeders peak in the summer.[17] Nearly all of Delmarva's substations also peak in the summer.[18] Since summer capacity for feeders and substations is lower than winter capacity, distribution capacity is even more strongly driven by summer loads.[19] Hence, Delmarva's distribution rates should almost certainly be higher in summer than winter.

Q: Does seasonal rate design reflect generally accepted cost causation principles?

A: Yes. Charging more for summer usage and less for winter use may provide customers with more appropriate price signals than rates that are constant over the year. Shifting revenues onto the summer would increase customers' incentive to control summer loads that determine the need for distribution capacity.

In its *Electricity Utility Cost Allocation Manual* (1992, at 143–144), NARUC treats as non-controversial the concept of allocating distribution (and transmission) costs to seasons and time periods. Generally accepted cost-causation principles would *require* higher distribution costs in high-load seasons than in low-load seasons, where feasible.

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[17]Response to OPC Data Request No. 6, Question No. 38.

[18]Response to OPC Data Request No. 6, Question No. 39, Attachment.

[19]Delmarva acknowledges this seasonal capacity differential in response to OPC Data Request No. 7, Question No. 3.

Q: What about Delmarva's basic proposal to reduce the winter declining block structure?

A: This change is likely to be justified. It is possible that the very large monthly energy bills that reach into the second winter block represent usage that is heavily off-peak (thereby justifying a declining second block), but it is more likely that usage in the second block is mostly heating load on the coldest, highest-load, high-cost winter days.

Delmarva should examine its load data to determine whether elimination of the declining block structure is cost-justified, and, if so, how to modify seasonal charges that eliminates the declining block without reducing the summer-winter differential. In the meantime, Delmarva should apply the class revenue increase to all charges on a pro rata basis.

C. Rate Design and Cost Causation

Q: What statements by the Company give rise to your concern regarding the Company's theory of rate design?

A: The Company has made a number of statements that imply that load-related distribution costs should be shifted from volumetric charges to the customer charge, simply because such costs are fixed in the immediate term.

Specifically, in response to Staff Data Request No. 4, Question No.3(a), the Company states that "virtually all distribution costs are fixed in the short term." Dr. Chamberlin also asserts that "[e]lectric distribution costs are largely fixed, and change little in the short run as usage levels change."[20] Dr. Chamberlin then states that:

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[20]Chamberlin Testimony, p. 2.

> … In principle, rate structure changes that collect all of the fixed costs in a fixed charge would best meet the Bonbright standard for alignment of costs and rates. That approach would, however, significantly increase rates for small usage customers.[21]

These statements imply an approach to rate design – recovery of costs that vary with load through fixed customer charges – that is contrary to cost-causation principles.

Q: Does James C. Bonbright et al., *Principles of Public Utility Rates* support the recovery of load-related distribution costs in the customer charge?

A: No. In Case No. 9092, Dr. Chamberlin acknowledges that Bonbright does not support "the recovery of load-related distribution costs in the customer charge."[22] As I discuss in Section II, most distribution costs are not fixed (other than in the short-term sense), but instead are load-related.

Q: Does the Company recognize that the need for distribution capacity is driven by load?

A: Yes. In response to OPC Data Request No. 7, Question No. 1, the Company states that:

> … [T]he need for distribution plant capacity is affected by load. Each component on the electric system has a thermal rating which dictates the maximum amount of current that the component can handle safely. As new load is added to the electric system the amount of current passing through each component increases. When the thermal rating of any component is projected to be exceeded, that component must be relieved, either through system rearrangement to shift load to less used components through plant additions that increase capacity or provide new capacity that load can be transferred.

[21]Chamberlin Testimony, p. 7.

[22]Case No. 9092, Response to OPC Data Request No. 7, Question No. 26.

Q: Are volumetric charges the appropriate basis for recovering residential customers' contribution to load-related distribution costs?

A: Yes. Volumetric charges are appropriate, because energy use on the summer peak and the hours or days before and after the peaks, on periods of high load and high temperatures off the annual system peak, and during other periods of high load increases the catastrophic failure rate and reduces the service life of distribution equipment.

Variable energy charges are better at signaling load-related costs than a fixed customer charge that customers cannot avoid. Reducing variable charges will reduce customer control over bills, savings from DSM investments, and therefore incentives for customers to conserve.

Q: Does this conclude your testimony?

A: Yes, at this time.

Qualifications of

JONATHAN F. WALLACH

Resource Insight, Inc.
5 Water Street
Arlington, Massachusetts 02476

SUMMARY OF PROFESSIONAL EXPERIENCE

1990–Present **Vice President, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, regulation, and restructuring. Designs and assesses resource-planning strategies for regulated and competitive markets, including estimation of market prices and utility-plant stranded investment; negotiates restructuring strategies and implementation plans; assists in procurement of retail power supply.

1989–90 **Senior Analyst, Komanoff Energy Associates.** Conducted comprehensive cost-benefit assessments of electric-utility power-supply and demand-side conservation resources, economic and financial analyses of independent power facilities, and analyses of utility-system excess capacity and reliability. Provided expert testimony on statistical analysis of U.S. nuclear plant operating costs and performance. Co-wrote *The Power Analyst*, software developed under contract to the New York Energy Research and Development Authority for screening the economic and financial performance of non-utility power projects.

1987–88 **Independent Consultant.** Provided consulting services for Komanoff Energy Associates (New York, New York), Schlissel Engineering Associates (Belmont, Massachusetts), and Energy Systems Research Group (Boston, Massachusetts).

1981–86 **Research Associate, Energy Systems Research Group.** Performed analyses of electric utility power supply planning scenarios. Involved in analysis and design of electric and water utility conservation programs. Developed statistical analysis of U.S. nuclear plant operating costs and performance.

EDUCATION

BA, Political Science with honors and Phi Beta Kappa, University of California, Berkeley, 1980.

Massachusetts Institute of Technology, Cambridge, Massachusetts. Physics and Political Science, 1976–1979.

PUBLICATIONS

“The Future of Utility Resource planning: Delivering Energy Efficiency through Distributed Utilities” (with Paul Chernick), *International Association for Energy Economics Seventeenth Annual North American Conference* (460–469). Cleveland, Ohio: USAEE. 1996.

“The Price is Right: Restructuring Gain from Market Valuation of Utility Generating Assets” (with Paul Chernick), *International Association for Energy Economics Seventeenth Annual North American Conference* (345–352). Cleveland, Ohio: USAEE. 1996.

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“New Tools on the Block: Evaluating Non-Utility Supply Opportunities With *The Power Analyst*, (with John Plunkett), *Proceedings of the Fourth National Conference on Microcomputer Applications in Energy*, April 1990.

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“Best Practices in Market Monitoring: A Survey of Current ISO Activities and Recommendations for Effective Market Monitoring and Mitigation in Wholesale Electricity Markets” (with Paul Peterson, Bruce Biewald, Lucy Johnston, and Etienne Gonin). 2001. Prepared for the Maryland Office of People’s Counsel, Pennsylvania Office of Consumer Advocate, Delaware Division of the Public Advocate, New Jersey Division of the Ratepayer Advocate, Office of the People’s Counsel of the District of Columbia.

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"Response Comments of the City of New York on Vertical Market Power." 1998. Filed by the City of New York in PSC Case Nos. 96-E-0900, 96-E-0098, 96-E-0099, 96-E-0891, 96-E-0897, 96-E-0909, and 96-E-0898.

"Preliminary Comments of the City of New York on Con Edison's Generation Divestiture Plan and Petition." 1998. Filed by the City of New York in PSC Case No. 96-E-0897.

"Maryland Office of People's Counsel's Comments in Response to the Applicants' June 5, 1998 Letter." 1998. Filed by the Maryland Office of People's Counsel in PSC Docket No. EC97-46-000.

"Economic Feasibility Analysis and Preliminary Business Plan for a Pennsylvania Consumer's Energy Cooperative" (with John Plunkett et al.). 1997. 3 vols. Philadelphia, Penn.: Energy Coordinating Agency of Philadelphia.

"Good Money After Bad" (with Charles Komanoff and Rachel Brailove). 1997. White Plains, N.Y.: Pace University School of Law Center for Environmental Studies.

"Maryland Office of People's Counsel's Comments on Staff Restructuring Report: Case No. 8738." 1997. Filed by the Maryland Office of People's Counsel in PSC Case No. 8738.

"Protest and Request for Hearing of Maryland Office of People's Counsel." 1997. Filed by the Maryland Office of People's Counsel in PSC Docket Nos. EC97-46-000, ER97-4050-000, and ER97-4051-000.

"Restructuring the Electric Utilities of Maryland: Protecting and Advancing Consumer Interests" (with Paul Chernick, Susan Geller, John Plunkett, Roger Colton, Peter Bradford, Bruce Biewald, and David Wise). 1997. Baltimore, Maryland: Maryland Office of People's Counsel.

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"Comments on NOPSI and LP&L's Motion to Modify Certain DSM Programs." 1995. On behalf of the Alliance for Affordable Energy (New Orleans).

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“Demand-Management Programs: Targets and Strategies.” 1992. Vol. 1 of “Building Ontario Hydro’s Conservation Power Plant” (with John Plunkett, James Peters, and Blair Hamilton).

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“Comments of Public Interest Intervenors on the 1993–1994 Annual and Long-Range Demand-Side Management and Integrated Resource Plans of New York Electric Utilities” (with Ken Keating et al.) 1992.

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“Review of Rockland Electric Company’s 1992 DSM Plan and the Demand-Side Management Rules” (with Paul Chernick et al.). 1992.

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“Profitability Assessment of Packaged Cogeneration Systems in the New York City Area.” 1989. Principal investigator.

“Statistical Analysis of U.S. Nuclear Plant Capacity Factors, Operation and Maintenance Costs, and Capital Additions.” 1989.

“The Economics of Completing and Operating the Vogtle Generating Facility.” 1985. ESRG Study No. 85-51A.

“Generating Plant Operating Performance Standards Report No. 2: Review of Nuclear Plant Capacity Factor Performance and Projections for the Palo Verde Nuclear Generating Facility.” 1985. ESRG Study No. 85-22/2.

“Cost-Benefit Analysis of the Cancellation of Commonwealth Edison Company’s Braidwood Nuclear Generating Station.” 1984. ESRG Study No. 83-87.

“The Economics of Seabrook 1 from the Perspective of the Three Maine Co-owners.” 1984. ESRG Study No. 84-38.

“An Evaluation of the Testimony and Exhibit (RCB-2) of Dr. Robert C. Bushnell Concerning the Capital Cost of Fermi 2.” 1984. ESRG Study No. 84-30.

“Electric Rate Consequences of Cancellation of the Midland Nuclear Power Plant.” 1984. ESRG Study No. 83-81.

“Power Planning in Kentucky: Assessing Issues and Choices—Project Summary Report to the Public Service Commission.” 1984. ESRG Study No. 83-51.

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“Electricity and Gas Savings from Expanded Public Service Electric and Gas Company Conservation Programs.” 1983. ESRG Study No. 82-43/2.

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"Long Range Forecast of Sierra Pacific Power Company Electric Energy Requirements and Peak Demands, A Report to the Public Service Commission of Nevada." 1982. ESRG Study No. 81-42B.

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PRESENTATIONS

"Electricity Market Design: Incentives for Efficient Bidding, Opportunities for Gaming." NASUCA Northeast Market Seminar, Albany, N.Y., February 2001.

"Direct Access Implementation: The California Experience." Presentation to the Maryland Restructuring Technical Implementation Group on behalf of the Maryland Office of People's Counsel. June 1998.

"Reflecting Market Expectations in Estimates of Stranded Costs," speaker, and workshop moderator of "Effectively Valuing Assets and Calculating Stranded Costs." Conference sponsored by International Business Communications, Washington, D.C., June 1997.

EXPERT TESTIMONY

1989 **Mass. DPU** on behalf of the Massachusetts Executive Office of Energy Resources. Docket No. 89-100. Joint testimony with Paul Chernick relating to statistical analysis of U.S. nuclear-plant capacity factors, operation and maintenance costs, and capital additions; and to projections of capacity factor, O&M, and capital additions for the Pilgrim nuclear plant.

1994 **NY PSC** on behalf of the Pace Energy Project, Natural Resources Defense Council, and Citizen's Advisory Panel. Case No. 93-E-1123. Joint testimony with John Plunkett critiques proposed modifications to Long Island Lighting Company's DSM programs from the perspective of least-cost-planning principles.

1994 **Vt. PSB** on behalf of the Vermont Department of Public Service. Docket No. 5270-CV-1 and 5270-CV-3. Testimony and rebuttal testimony discusses rate and bill effects from DSM spending and sponsors load shapes for measure- and program-screening analyses.

1996 **New Orleans City Council** on behalf of the Alliance for Affordable Energy. Docket Nos. UD-92-2A, UD-92-2B, and UD-95-1. Rates, charges, and integrated resource planning for Louisiana Power & Lights and New Orleans Public Service, Inc.

1996 **New Orleans City Council** Docket Nos. UD-92-2A, UD-92-2B, and UD-95-1. Rates, charges, and integrated resource planning for Louisiana Power & Lights and New Orleans Public Service, Inc.; Alliance for Affordable Energy. April, 1996.

Prudence of utilities' IRP decisions; costs of utilities' failure to follow City Council directives; possible cost disallowances and penalties; survey of penalties for similar failures in other jurisdictions.

1998 **Massachusetts Department of Telecommunications and Energy** Docket No. 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Paul Chernick, January, 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

Massachusetts Department of Telecommunications and Energy Docket No. 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Paul Chernick, October, 1998. Joint surrebuttal with Paul Chernick, January, 1999.

Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

1999 **Maryland PSC** Case No. 8795, Delmarva Power & Light comprehensive restructuring agreement, Maryland Office of People's Counsel. July 1999.

Support of proposed comprehensive restructuring settlement agreement

Maryland PSC Case Nos. 8794 and 8808, Baltimore Gas & Electric Company comprehensive restructuring agreement, Maryland Office of People's Counsel. Initial Testimony July 1999; Reply Testimony August 1999; Surrebuttal Testimony August 1999.

Support of proposed comprehensive restructuring settlement agreement

Maryland PSC Case No. 8797, comprehensive restructuring agreement for Potomac Edison Company, Maryland Office of People's Counsel. October 1999.

Support of proposed comprehensive restructuring settlement agreement

Connecticut DPUC Docket No. 99-03-35, United Illuminating standard offer, Connecticut Office of Consumer Counsel. November 1999.

Reasonableness of proposed revisions to standard-offer-supply energy costs. Implications of revisions for other elements of proposed settlement.

2000 **U.S. FERC** Docket No. RT01-02-000, Order No. 2000 compliance filing, Joint Consumer Advocates intervenors. Affidavit, November 2000.

Evaluation of innovative rate proposal by PJM transmission owners.

2001 **Maryland PSC** Case No. 8852, Charges for electricity-supplier services for Potomac Electric Power Company, Maryland Office of People's Counsel. March 2001.

Reasonableness of proposed fees for electricity-supplier services.

Maryland PSC Case No. 8890, Merger of Potomac Electric Power Company and Delmarva Power and Light Company, Maryland Office of People's Counsel. September 2001; surrebuttal, October 2001. In support of settlement: Supplemental, December 2001; rejoinder, January 2002.

Costs and benefits to ratepayers. Assessment of public interest.

Maryland PSC Case No. 8796, Potomac Electric Power Company stranded costs and rates, Maryland Office of People's Counsel. December 2001; surrebuttal, February 2002.

Allocation of benefits from sale of generation assets and power-purchase contracts.

2002 **Maryland PSC** Case No. 8908, Maryland electric utilities' standard offer and supply procurement, Maryland Office of People's Counsel. Direct, November 2002; Rebuttal December 2002.

Benefits of proposed settlement to ratepayers. Standard-offer service. Procurement of supply.

2003 **Maryland PSC** Case No. 8980, adequacy of capacity in restructured electricity markets; Maryland Office of People's Counsel. Direct, December 2003; Reply December 2003.

Purpose of capacity-adequacy requirements. PJM capacity rules and practices. Implications of various restructuring proposals for system reliability.

2004 **Maryland PSC** Case No. 8995, Potomac Electric Power Company recovery of generation-related uncollectibles; Maryland Office of People's Counsel. Direct, March 2004; Supplemental March 2004, Surrebuttal April 2004.

Calculation and allocation of costs. Effect on administrative charge pursuant to settlement.

Maryland PSC Case No. 8994, Delmarva Power & Light recovery of generation-related uncollectibles; Maryland Office of People's Counsel. Direct, March 2004; Supplemental April 2004.

Calculation and allocation of costs. Effect on administrative charge pursuant to settlement.

Maryland PSC Case No. 8985, Southern Maryland Electric Coop standard-offer service; Maryland Office of People's Counsel. Direct, July 2004.

Reasonableness and risks of resource-procurement plan.

2005 **FERC** Docket No. ER05-428-000, revisions to ICAP demand curves; City of New York. Statement, March 2005.

Net-revenue offset to cost of new capacity. Winter-summer adjustment factor. Market power and in-City ICAP price trends.

FERC Docket No. PL05-7-000, capacity markets in PJM; Maryland Office of People's Counsel. Statement, June 2005.

Inefficiencies and risks associated with use of administratively determined demand curve. Incompatibility of four-year procurement plan with Maryland standard-offer service.

FERC Dockets Nos. ER05-1410-000 & EL05-148-000, proposed market-clearing mechanism for capacity markets in PJM; Coalition of Consumers for Reliability, Affidavit October 2005, Supplemental Affidavit October 2006.

Inefficiencies and risks associated with use of administratively determined demand curve. Effect of proposed reliability-pricing model on capacity costs.

2006 **MD PSC** Case No. 9052, Baltimore Gas & Electric rates and market-transition plan; Maryland Office of People's Counsel, February 2006.

Transition to market-based residential rates. Price volatility, bill complexity, and cost-deferral mechanisms.

MD PSC Case No. 9056, default service for commercial and industrial customers; Maryland Office of People's Counsel, April 2006.

Assessment of proposals to modify default service for commercial and industrial customers.

MD PSC Case No. 9054, merger of Constellation Energy Group and FPL Group; Maryland Office of People's Counsel, June 2006.

Assessment of effects and risks of proposed merger on ratepayers.

Illinois Commerce Commission Docket No. 06-0411, Commonwealth Edison Company residential rate plan; Citizens Utility Board, Cook County State's Attorney's Office, and City of Chicago, Direct July 2006, Reply August 2006.

Transition to market-based rates. Securitization of power costs. Rate of return on deferred assets.

MD PSC Case No. 9064, default service for residential and small commercial customers ; Maryland Office of People's Counsel, Rebuttal Testimony, September 2006.

Procurement of standard-offer power. Structure and format of bidding. Risk and cost recovery.

FERC Dockets Nos. ER05-1410-000 & EL05-148-000, proposed market-clearing mechanism for capacity markets in PJM; Maryland Office of the People's Counsel, Supplemental Affidavit October 2006.

Distorting effects of proposed reliability-pricing model on clearing prices. Economically efficient alternative treatment.

MD PSC Case No. 9063, optimal structure of electric industry; Maryland Office of People's Counsel, Direct Testimony, October 2006; Rebuttal November 2006; surrebuttal November 2006.

Procurement of standard-offer power. Risk and gas-price volatility, and their effect on prices and market performance. Alternative procurement strategies.

ATTACHMENT 1

1. Response to OPC Data Request No. 7, Question No. 4.
2. Response to OPC Data Request No. 6, Question No. 13.
3. Response to OPC Data Request No. 7, Question No. 16.
4. Response to OPC Data Request No. 6, Question No. 11.
5. Response to OPC Data Request No. 6, Question No. 12.
6. Response to OPC Data Request No. 6, Question No. 7.
7. Response to OPC Data Request No. 7, Question No. 5.
8. Response to OPC Data Request No. 7, Question No. 18.
9. Response to OPC Data Request No. 6, Question No. 38.
10. Response to OPC Data Request No. 6, Question No. 39.
11. Response to OPC Data Request No. 7, Question No. 3.
12. Response to OPC Data Request No. 7, Question No. 26 in Case No. 9092.
13. Response to OPC Data Request No. 7, Question No. 1.

Case No. 9093
Application of the Delmarva Power & Light Company
OPC Data Request Set No. 7

7-4 Q. Please provide the load diversity assumptions used for planning and designing distribution facility additions.

A. Planning for feeders is based on peak feeder load measured at the substation. Total feeder load is diversified to the transformer peak. Total transformer load is diversified to the substation peak. Total substation load is diversified to the transmission system peak.

Sponsor: Dr. Mark E. Browning

**Case No. 9093
Application of the Delmarva Power & Light Company
OPC Data Request Set No. 6**

6-13 Q. Please provide the basis for the 50/50 weighting of class NCP and customer maximum demands used in the allocation of:

a) Line Transformers

b) Secondary plant costs

c) Include analyses, studies of load diversity, workpapers and spreadsheets relied upon

A. The basis of the allocation factor for Line Transformers and Secondary plant costs was Mr. Normand's extensive experience in analyzing power systems for over 30 years. The allocation factor was based on the following:

a) Line Transformers

- Very large secondary customers generally will have their own transformer at their facility and are generally not adjacent to other large customers.
- Smaller customers have much smaller loads and are oftentimes more clustered which provides for the aggregation of several customers per transformer which is typical (2 – 4 customers) based on Mr. Normand's experience.
- The use of a 50/50 weighting of class NCP and maximum demands is the only approach that recognizes this aggregation and properly allocates these costs. Either demand approach (NCP or maximum) would under allocate (NCP) or materially over allocate (maximum) to smaller customers such as residential. The magnitudes of these demands by customer class are clearly shown on page 18-2 of Mr. Normand's Schedule PMN-6.
The only proper use of maximum demands is in the allocation with respect to larger secondary customers.

b) Secondary Plant

These facilities are used by secondary customers to provide power from the line transformer to the customer's service entrance. The approach for allocation of these costs is similar and consistent with Line Transformers as previously discussed with the only exception being larger secondary customers who were not assigned any of these costs.

c) There are no separate analyses other than Mr. Normand's experience in analyzing power systems.

Sponsor: Paul M. Normand

Case No. 9093
Application of the Delmarva Power & Light Company
OPC Data Request Set No. 7

7-16 Q. Please provide the number of secondary transformers in the Maryland jurisdiction in the period 12 months ending September 30, 2006.

A. The number of secondary transformers in the Delmarva Maryland jurisdiction is 59,926 as of December 31, 2006. This information is not available at September 30, 2006.

Sponsor: W. Michael VonSteuben

Case No. 9093
Application of the Delmarva Power & Light Company
OPC Data Request Set No. 6

6-11 Q. For non-heating and heating residential customers, separately, please provide the average number of customers per service.

A. This information is not readily available.

Sponsor: Joseph F. Janocha

**Case No. 9093
Application of the Delmarva Power & Light Company
OPC Data Request Set No. 6**

6-12 Q. Please provide an estimate of the percentage of non-heating and heating residential customers that live in multifamily dwellings.

A. This information is not readily available.

Sponsor: Joseph F. Janocha

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6-7 Q. Please provide the non-coincident peak of the residential class as a whole, treating heating and non-heating customers as a single group.

A. This calculation has not been developed.

Sponsor: Dr. Mark E. Browning

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7-5 Q. Please provide the average use per residential customer by month for Rates R and RTOU-ND as a whole and for the residential heating and non-heating subclasses separately.

A. Refer to the attached provided electronically.

Sponsor: Joseph F. Janocha

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7-18 Q. Please indicate whether the Company believes that seasonal differentiation of the residential energy charges should be retained in residential rate design.

a) Provide the basis for this response, including supporting studies.

b) If so, provide the Company's best estimate of the appropriate differential and include the basis of this estimate (studies and workpapers relied upon).

A. The Company believes that movement of the residential distribution energy charges to the cost basis provided in the cost of service study, which is not season sensitive, should be the ultimate goal of the residential rate design. This goal should be appropriately tempered with a level of gradualism so as to minimize intra class rate impacts to customers. As noted on page 9, line 3 to 15 in the testimony of Mr. Janocha, the Company is proposing to close the gap between the residential distribution energy initial and trailing blocks in the winter months. This is an initial step to removing the seasonal differentiation.

Sponsor: Joseph F. Janocha

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6-38 Q. Please specify the percentage of feeders that peak in the summer and the percentage that peak in the winter.

A. Approximately 99% of Delmarva's distribution feeders peak in the summer and 1% peak in the winter. This information is based on the Delmarva system.

Sponsor: Dr. Mark E. Browning

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6-39 Q. Please provide the summer and winter peaks on Delmarva's substations.

A. Refer to the attachment provided electronically which includes a list of Delmarva system substations.

Sponsor: Dr. Mark E. Browning

Distribution Substation Load				
			Transformer Load (MVA)	
			Winter	**Summer**
Substation Name	**Transformer Number**	**Voltage Level (kV)**	**2005-2006**	**2006**
Carrcroft	T2	34.23	12.0	20.6
Darley	T1	12.38	12.3	21.7
Darley	T2	34.23	18.1	33.9
Darley	T3	12.38	9.0	15.4
Faulk Road	T01	12.38	2.7	5.9
Faulk Road	T02	12.38	12.7	15.7
Naamans	T1	12.38	12.8	12.8
Naamans	T2	12.38	4.5	4.4
Point Breeze	T01	12.38	7.9	13.2
Point Breeze	T02	12.38	6.0	15.3
Silverside	T1	12.38	11.9	21.4
Silverside	T2	12.38	5.7	11.1
Silverside	T3	34.23	23.1	33.7
Talleyville	T01	12.38	4.2	7.7
Talleyville	T02	12.38	7.2	7.5
Talleyville	T3	12.38	10.5	24.6
Brandywine	T4	12.38	27.2	28.0
Brandywine	T5	12.38	31.7	36.5
Chestnut Run	T02	12.38	2.7	4.4
Chestnut Run	T03	12.38	5.8	11.6
Christiana	T1	12.38	18.6	25.3
Christiana	T2	12.38	20.6	24.6
Christiana	T3	12.38	26.2	29.3
Edgemoor	T1	12.38	18.6	22.2
Edgemoor	T2	12.38	20.7	22.8
Edgemoor	T6	12.38	8.2	8.4
Fifth Street	T0	12.38	3.5	4.7
North Wilmington	T01	12.38	Data Not Available	Data Not Available
North Wilmington	T05	12.38	Data Not Available	Data Not Available
North Wilmington	T06	12.38	Data Not Available	Data Not Available
North Wilmington	T08	12.38	Data Not Available	Data Not Available
North Wilmington	T03	12.38	Data Not Available	Data Not Available
Rogers Road	T01	12.38	Data Not Available	Data Not Available
Rogers Road	T03	12.38	Data Not Available	Data Not Available
Rogers Road	T04	12.38	Data Not Available	Data Not Available
Rogers Road	T06	12.38	Data Not Available	Data Not Available
Silverbrook	T2	34.23	27.0	39.3
Silverbrook	T3	34.23	7.9	9.8
Tenth Street	T01	4.3	Data Not Available	Data Not Available
Tenth Street	T02	4.3	Data Not Available	Data Not Available
West Wilmington	T1	12.38	27.8	32.4
West Wilmington	T2	12.38	28.8	36.8
Center Meet.	T01	4.3	Data Not Available	Data Not Available

Chapel Street	T01	12.38	5.1	3.5
Chapel Street	T2	34.23	12.1	13.1
Hockessin	T03	12.38	10.2	Data Not Available
Hockessin	T5	12.38	Data Not Available	3.7
Hockessin	T4	12.38	21.9	17.8
Mermaid	T021	12.38	11.7	8.7
Mermaid	T022	12.38	Data Not Available	Data Not Available
Mermaid	T1	12.38	18.2	24.4
Milford Crossroad	T01	12.38	9.0	12.6
Milford Crossroad	T02	12.38	12.8	14.3
Milltown	T01	12.38	4.6	9.1
Milltown	T02	12.38	7.3	7.2
Milltown	T3	12.38	12.7	19.2
Montchanin	T02	12.38	Data Not Available	Data Not Available
Montchanin	T03	12.38	Data Not Available	Data Not Available
Old Kennett	T01	4.3	Data Not Available	Data Not Available
Basin Road	T1	12.38	Data Not Available	17.4
Basin Road	T2	12.38	7.0	9.9
Bear	T1	12.38	25.3	25.9
Bear	T2	12.38	27.2	32.0
Bear	T3	34.23	Data Not Available	3.4
Brookside	T01	12.38	10.8	15.7
Brookside	T02	12.38	1.3	3.2
Churchmans	T3	12.38	20.4	30.2
Churchmans	T4	12.38	7.7	13.2
Hares Corner	T1	12.38	23.9	20.1
Hares Corner	T2	12.38	Data Not Available	10.6
Harmony	T1	34.23	29.0	36.9
Harmony	T2	12.38	23.4	30.7
Harmony	T3	34.23	20.8	21.3
Harmony	T4	12.38	21.5	19.5
Kiamensi	T2	34.23	11.9	17.8
Little Falls	T01	12.38	11.1	6.1
New Castle	T1	12.38	16.6	17.9
New Castle	T2	12.38	11.3	11.9
New Castle	T3	12.38	11.2	23.4
West	T1	12.38	19.3	23.8
West	T2	34.23	0.1	0.1
West	T3	12.38	24.1	44.3
West	T5	34.23	14.2	18.1
Delaware City	T4	14	Data Not Available	Data Not Available
Glasgow	T4	12.38	6.9	11.3
Glasgow	T2	34.23	31.2	38.9
Keeney thirty-four	T2	34.23	25.1	32.9
Keeney twelve	T2	12.38	12.7	20.1
Lums Pond	T1	25.67	13.7	16.1
Lums Pond	T2	25.67	23.8	27.1
Red Lion	T1	25.67	11.0	10.0
Reybold	T1	12.38	7.1	11.1
Reybold	T2	12.38	14.9	17.4

Sunset Lake	T1	12.38	14.0	16.4
Sunset Lake	T3	12.38	19.7	24.2
Sunset Lake	T2	25.67	Data Not Available	Data Not Available
Cedar Creek	T1	25.67	13.6	14.9
Mt. Pleasant	T1	25.67	21.5	37.5
Townsend	T1	25.67	13.0	19.6
Darlington	T01	4.3	Data Not Available	1.4
Dublin	T01	4.3	Data Not Available	1.8
Dublin	T02	4.3	Data Not Available	0.8
Gallion	T01	4.3	Data Not Available	1.7
Gallion	T02	4.3	Data Not Available	0.9
Harford	T03	4.3	Data Not Available	1.2
Harford	T02	4.3	Data Not Available	0.9
Macton	T03	4.3	Data Not Available	3.4
Macton	T02	4.3	Data Not Available	1.1
Susquehanna	T10	34.23	20.4	25.9
Whiteford	T01	4.3	Data Not Available	1.6
Andora	T01	4.3	Data Not Available	2.7
Appleton	T01	4.3	Data Not Available	2.6
Appleton	T03	4.3	Data Not Available	1.4
Bohemia	T01	4.3	Data Not Available	1.2
Bohemia	T02	4.3	Data Not Available	1.2
Calvert	T01	4.3	Data Not Available	1.8
Cathers	T01	4.3	Data Not Available	1.5
Cathers	T02	4.3	Data Not Available	2.0
Cayots	T01	4.3	Data Not Available	2.2
Cayots	T02	4.3	Data Not Available	0.5
Cecil	T3	34.23	66.6	77.9
Cecil	T2	34.23	11.8	26.0
Cecil Four kV	T01	4.3	Data Not Available	2.5
Cecil Four kV	T02	4.3	Data Not Available	Data Not Available
Charles	T03	4.3	Data Not Available	1.6
Charles	T02	4.3	Data Not Available	0.7
Chesapeake City	T01	4.3	Data Not Available	1.6
Colora	T1	34.23	49.0	58.7
Colora	T2	34.23	33.2	32.6
Cowlane	T01	4.3	Data Not Available	1.0
Elkneck	T01	4.3	Data Not Available	0.4
Elkton	T01	4.3	Data Not Available	2.2
Elkton	T02	4.3	Data Not Available	1.9
Elkton	T04	4.3	Data Not Available	1.4
Foundry	T01	4.3	Data Not Available	1.7
Gilpin	T01	4.3	Data Not Available	3.1
Glen	T01	4.3	Data Not Available	0.6
Glen	T02	4.3	Data Not Available	Data Not Available
Greenbank	T01	4.3	Data Not Available	1.2
Hances	T01	4.3	Data Not Available	1.5
Harris	T01	4.3	Data Not Available	0.8
Irishtown	T01	4.3	Data Not Available	1.5
Kilby	T02	4.3	Data Not Available	0.5

Leslie	T01	4.3	Data Not Available	1.5
Liberty Grove	T01	4.3	Data Not Available	0.5
Liberty Grove	T02	4.3	Data Not Available	1.8
Mechanics	T01	4.3	Data Not Available	2.5
Middle	T01	4.3	Data Not Available	2.9
Nesbitt	T01	4.3	Data Not Available	1.9
Normira	T01	4.3	Data Not Available	2.4
North East	T01	4.3	Data Not Available	2.5
Ostego	T01	4.3	Data Not Available	1.9
Perch	T02	4.3	Data Not Available	1.6
Perryville	T01	4.3	Data Not Available	1.0
Porters Bridge	T01	4.3	Data Not Available	1.4
Prince	T01	4.3	Data Not Available	0.9
Rising Sun	T01	4.3	Data Not Available	1.6
Rising Sun	T01	4.3	Data Not Available	3.0
Stoltzfus	T01	4.3	Data Not Available	Data Not Available
Theodore	T01	4.3	Data Not Available	1.3
Triumph	T01	4.3	Data Not Available	1.8
Walnut	T01	4.3	Data Not Available	1.4
Woodlawn	T01	4.3	Data Not Available	1.5
Chestertown	T1	25.67	21.0	21.0
Chestertown	T2	25.67	17.0	17.2
Church	T3	25.67	5.0	5.8
Church	T4	25.67	9.5	10.9
Lynch	T1	25.67	Data Not Available	Data Not Available
Lynch	T2	25.67	Data Not Available	Data Not Available
Massey	T1	25.67	7.4	6.9
McCleans	T01	12.38	Data Not Available	2.8
N. Chestertown	T01	25.67	Data Not Available	Data Not Available
Rock Hall	T01	4.3	Data Not Available	0.7
Rock Hall	T02	4.3	Data Not Available	0.7
Centreville	T1	12.38	9.0	8.3
Centreville	T2	12.38	14.2	12.5
Church Hill	T1	12.38	Data Not Available	3.1
Grasonville	T1	25.67	9.0	12.7
Grasonville	T2	25.67	21.1	16.5
Hillsboro	T1	25.67	Data Not Available	11.1
Steele	T3	25.67	32.1	33.1
Stevensville	T1	25.67	17.1	13.7
Stevensville	T2	25.67	37.4	26.0
Wye Mills	T2	25.67	12.5	15.1
Cheswold	T02	12.38	2.1	3.1
Cheswold	T3	25.67	10.1	15.0
Clayton	T1	25.67	11.0	16.6
Clayton	T2	25.67	13.0	1.8
Clayton	T03	4.3	Data Not Available	27.0
Felton	T1	25.67	18.9	29.9
Greenwood	T1	4.3	Data Not Available	3.7
Harrington	T1	25.67	0.9	8.7
Harrington	T2	25.67	11.3	13.4

Harrington Fairgrounds	T01	4.3	Data Not Available	0.8
Harrington Fairgrounds	T02	4.3	Data Not Available	Data Not Available
Kent	T1	25.67	3.9	4.9
Kent	T2	25.67	16.1	20.4
Milford	T1	25.67	5.2	5.8
Milford	T2	25.67	13.4	17.2
Wyoming	T01	12.38	Data Not Available	3.0
Wyoming	T02	12.38	Data Not Available	Data Not Available
Bozman	T1	25.67	Data Not Available	Data Not Available
Easton	T2	25.67	6.2	5.5
Grace Street	T1	12.38	Data Not Available	Data Not Available
Grace Street	T2	12.38	Data Not Available	Data Not Available
Trappe Sub	T3	12.38	Data Not Available	15.6
Cambridge	T3	12.38	15.0	16.9
Cambridge	T4	12.38	9.7	12.0
East New Market	T1	12.38	Data Not Available	5.3
Jacktown	T1	12.38	Data Not Available	8.1
Preston	T1	12.38	Data Not Available	3.6
Todd	T3	12.38	4.1	4.3
Todd	T1	25.67	16.2	19.4
Todd	T2	25.67	15.4	18.0
Vienna	T1	12.38	Data Not Available	Data Not Available
West Cambridge	T1	12.38	18.0	18.4
Bridgeville	T1	12.38	Data Not Available	4.3
Bridgeville	T2	12.38	Data Not Available	Data Not Available
Frankford	T1	25.67	Data Not Available	Data Not Available
Harbeson	T1	25.67	7.2	7.9
Harbeson	T2	25.67	4.6	5.5
Laurel	T1	12.38	14.9	15.8
Laurel	T2	12.38	8.5	9.1
Millsboro	T1	25.67	14.2	14.1
Millsboro	T2	25.67	17.8	22.5
North Seaford	T2	12.38	7.3	8.1
North Seaford	T3	12.38	7.3	7.7
Sussex	T1	12.38	18.0	21.7
Sussex	T2	12.38	8.0	8.4
Bethany	T1	12.38	21.7	21.3
Bethany	T2	12.38	17.8	20.2
Cedar Neck	T1	12.38	20.3	33.2
Five Points	T1	12.38	22.0	16.3
Five Points	T2	12.38	10.0	13.0
Midway	T1	12.38	Data Not Available	Data Not Available
Rehoboth	T1	12.38	26.3	37.3
Rehoboth	T2	12.38	19.4	22.7
Chesapeake	T01	25.67	Data Not Available	Data Not Available
Chesapeake	T02	25.67	Data Not Available	Data Not Available
Fruitland	T1	25.67	11.2	11.7
Fruitland	T2	25.67	26.6	29.4
Hebron	T1	12.38	Data Not Available	Data Not Available
Hebron	T2	12.38	Data Not Available	Data Not Available

Hudson	T01	4.3	Data Not Available	Data Not Available
Hudson	T02	4.3	Data Not Available	Data Not Available
Mt. Hermon	T1	25.67	33.8	32.8
Mt. Hermon	T2	25.67	42.1	40.4
N. Salisbury	T1	25.67	24.6	27.8
N. Salisbury	T2	25.67	20.9	27.8
Nelson	T2	12.38	6.8	9.5
Nelson	T3	12.38	10.2	11.9
Pemberton	T1	25.67	28.5	28.8
Riverside	T01	4.3	Data Not Available	Data Not Available
Sharptown	T1	12.38	Data Not Available	Data Not Available
Tyaskin	T01	12.38	Data Not Available	Data Not Available
Waverly	T01	4.3	Data Not Available	Data Not Available
Ches-Ply	T01	4.3	Data Not Available	1.2
Crisfield	T1	12.38	Data Not Available	9.1
Crisfield	T3	25.67	3.7	3.6
Kenney	T1	25.67	Data Not Available	5.2
Kenney	T2	25.67	Data Not Available	4.4
Kings Creek	T1	25.67	Data Not Available	10.7
Kings Creek	T2	25.67	18.6	17.5
Pocomoke	T1	12.38	7.6	8.8
Pocomoke	T2	12.38	Data Not Available	Data Not Available
Stockton	T1	4.3	Data Not Available	Data Not Available
138th Street	T1	12.38	21.8	25.5
138th Street	T2	12.38	17.3	25.9
Culver	T1	25.67	Data Not Available	19.1
Maridel	T1	12.38	8.3	11.2
Maridel	T2	12.38	12.3	17.7
Ocean City	T1	12.38	4.9	12.9
Ocean City	T2	12.38	7.9	13.9
Ocean Bay	T1	12.38	11.8	18.6
Ocean Bay	T2	12.38	18.0	20.3
Worcester	T1	25.67	9.5	4.0
Worcester	T2	25.67	14.1	20.4
Bayview	T1	25.67	12.3	11.3
Chincoteague	T1	12.38	8.7	11.7
Chincoteague	T2	12.38	6.0	4.3
Kellam	T1	25.67	9.4	10.0
Kellam	T2	25.67	8.2	9.1
Oak Hall	T1	25.67	10.1	15.1
Oak Hall	T2	25.67	Data Not Available	Data Not Available
Tasley	T1	25.67	3.5	3.5
Tasley	T4	25.67	Data Not Available	Data Not Available
Wallops	T1	12.38	4.1	7.6
Wattsville	T1	12.38	5.6	7.2
Wattsville	T2	12.38	9.3	8.6

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7-3 Q. Please indicate whether the load-carrying capability of distribution facilities varies with the season.

a. Provide the basis for this response.

A. Yes, load-carrying capability of distribution facilities does vary with the season. For planning and operating purposes, equipment that is affected by ambient temperature has a summer rating and a winter rating. The winter rating is usually higher than the summer rating. For equipment affected by ambient temperature, the equipment rating is most often based on a thermal rating. The thermal rating is determined by how hot a component can get before damage begins to occur. Lower ambient temperature allows for more cooling of the equipment, effectively allowing the equipment to carry more current, and thus, raising the load-carrying capacity.

Sponsor: Dr. Mark E. Browning

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MARYLAND CASE NO. 9092
OFFICE OF PEOPLE'S COUNSEL DATA REQUEST NO. 7

26. Q. REGARDING THE HIS TESTIMONY ON PAGE 10, PLEASE INDICATE WHETHER DR. CHAMBERLIN BELIEVES THAT JAMES C, BONBRIGHT ET AL., *PRINCIPLES OF PUBLIC UTILITY RATES* SUPPORTS THE RECOVERY OF LOAD-RELATED DISTRIBUTION COSTS IN THE CUSTOMER CHARGE.

A. IF SO, PROVIDE A CITE.

A. No, Dr. Chamberlin does not believe that James C, Bonbright Et Al, *Principles of Public Utility Rates* supports the recovery of load-related distribution costs in the customer charge.

Sponsor: Dr. Browning

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7-1 Q. Please indicate whether the need for distribution plant capacity is affected by load.

a. Provide the basis for this response.

A. Yes, the need for distribution plant capacity is affected by load. Each component on the electric system has a thermal rating which dictates the maximum amount of current that the component can handle safely. As new load is added to the electric system, the amount of current passing through each component increases. When the thermal rating of any component is projected to be exceeded, that component must be relieved either through system rearrangement to shift load to less used components, through plant additions that increase capacity, or through new capacity to which that load can be transferred.

Sponsor: Dr. Mark E. Browning