BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Northern States Power Company - Wisconsin for Authority to Adjust Electric and Natural Gas Rates	) Docket No. 4220-UR-117

DIRECT TESTIMONY OF JONATHAN WALLACH
ON BEHALF OF THE CITIZENS UTILITY BOARD OF WISCONSIN
October 11, 2011

I. Introduction and Summary

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

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

Q: Please summarize your professional experience.

A: I have worked as a consultant to the electric-power industry since 1981. 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 past thirty 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; risk assessment and management; integrated resource planning; cost allocation and rate design; and energy-efficiency program design and planning.

My resume is attached as Exhibit 2.3 (JFW-1).

Q: Have you testified previously in utility regulatory proceedings?

A: Yes. I have sponsored expert testimony in more than 45 federal, provincial, or state proceedings in the U.S. and Canada. Exhibit 2.3 (JFW-1) includes a detailed list of my previous testimony.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Citizens Utility Board (CUB).

Q: What is the purpose of your testimony?

A: On June 1, 2011, Northern States Power Company of Wisconsin (NSP or "the Company") filed an application to increase electric rates by 3.8% in order to recover an expected revenue deficiency of $21.9 million in the 2012 test year. On June 17, 2011, the Company revised its application to request a rate increase of 5.1% in order to recover an expected deficiency of $29.2 million. Based on the results of an embedded customer class cost of service study (CCOSS), the Company proposes to increase average rates for the residential class by 5.7%. In addition, the Company proposes to increase the residential customer charge from $8/month to $9.25/month, or by about 16%.

This testimony addresses three aspects of the Company's filing: (1) the recommended allocator for production capacity costs; (2) the proposed separation of distribution costs into customer-related and demand-related components; and (3) the proposed increase in the residential customer charge. These three elements are discussed in the pre-filed direct testimony by Company witnesses Gerald W. Marx and Donald R. Dahl.

Q: Please summarize your findings and conclusions.

A: The Company lacks a reasonable basis for its proposal to increase residential rates by 5.7%. The Company has not provided any documentation to support its decision to discontinue using the production capacity allocator it supported in its prior rate case in Docket No. 4220-UR-116. Nor has NSP offered any explanation for its current support for the two production capacity allocators that form the basis for the proposed 5.7% rate increase.

Contrary to the Company's undocumented claims, I find that the cost allocations resulting from the production capacity allocator supported by the Company in Docket No. 4220-UR-116 fall within a reasonable range. In contrast, the production capacity allocators supported by NSP in this proceeding appear to overstate the appropriate allocation of production capacity costs to the residential class.

In addition, the Company's CCOSS appears to overstate the appropriate allocation of distribution plant costs to the residential class. The CCOSS classifies distribution costs as customer-related or demand-related based on a minimum system analysis. Minimum system methods are generally unreliable and tend to misclassify demand-related costs as customer-related costs. As a result, cost allocations based on minimum system classifications overstate the appropriate allocation of distribution costs to residential customers.

The impact of this overstatement on the residential revenue increase may be substantial. Using the cost classifications from the minimum system analysis, the Company finds that the residential revenue increase ranges from 4.0% to 6.0%, depending on the production capacity allocator used in the CCOSS. In contrast, if all distribution plant costs other than costs for services are classified as demand-related, as is the practice in other jurisdictions, the residential revenue increase ranges from 0.2% to 2.1%, depending on the production capacity allocator.

Finally, the Company lacks a reasonable basis for its proposal to increase the residential customer charge. The proposed increase would disproportionately and inequitably increase bills for the Company's smallest residential customers, and exacerbate the subsidization of larger residential customers' costs by these lower-usage customers. Moreover, recovering cost increases through the customer charge will dampen price signals to consumers for reducing energy usage.

Q: What do you recommend with regard to the proposed increase to residential revenues?

A: The Commission should reject the Company's proposed 5.7% increase to residential revenues. Using appropriate allocators for production capacity and distribution costs, the CCOSS model would support a residential increase in the range of 2%-3%, or about half of the 5.1% system average increase requested by the Company. If residential revenues were increased by 2.5%, then revenues from the medium and large rate classes would have to increase by about 7.5% in order to achieve the 5.1% overall increase requested by the Company.

If the Commission seeks to moderate rate impacts for all customer classes, an alternative approach would be to allocate the revenue increase ultimately approved by the Commission in this proceeding according to the following guidelines:

- Increase revenues for the medium and large rate classes by the system average percentage plus one percentage point.

- Increase revenues for lighting customers by the system average percentage.[1]
- Increase revenues for the residential and small general service classes by the remainder of the allowed total revenue increase after allocations to the medium, large, and lighting classes.

Under these guidelines, if for example the Commission were to approve the Company's request for a 5.1% revenue increase, then class revenues would be increased as follows:

Table 1: Guidelines for Revenue Allocation if the Commission Approves the Company's Entire Proposed Revenue Increase

	Present Revenues ($000)	Revenue Increase ($000)	Revenue Increase (%)
Residential	215,788	8,632	4.0%
Small General Service	44,784	1,791	4.0%
Lighting	5,434	277	5.1%
Medium Use	88,210	5,381	6.1%
Large Use	214,801	13,103	6.1%
Total Retail	569,017	29,184	5.1%

Q: What do you recommend with regard to the Company's proposal to increase the residential customer charge?

A: As it did in Docket No. 4220-UR-116, the Commission should reject the Company's proposal to increase the residential customer charge and once again find that it is reasonable to maintain the residential customer charge at its current level of $8.00 per month. If any increase to residential revenues is allowed by the Commission, it should be recovered solely through the energy charge.

[1] This is the same allocation as proposed by the Company.

II. Production Capacity Allocator

Q: Please describe the Company's requested rate increase.

A: The Company is requesting that electric rates be increased on average by 5.1% in order to recover an expected revenue deficiency of $29.2 million in the 2012 test year. Of the total $29.2 million requested revenue increase, NSP proposes to allocate $12.3 million to residential customers.[2] This amount represents a 5.7% increase over residential revenues under current rates.

Q: What is the basis for the proposed residential allocation of the revenue increase?

A: According to Mr. Dahl, the proposed residential allocation was derived using as "guidelines" two runs of the Company's cost of service model that differed solely with respect to the allocator for production capacity costs. One run allocated production capacity costs on the basis of each customer class's contribution to the average of the twelve monthly system coincident peaks ("12CP"). The other run used an allocator that was derived by blending the 12CP demand allocator and an energy allocator based on each class's contribution to system energy requirements. Specifically, this second run allocated 57.3% of production capacity costs using the 12CP demand allocator and the remaining 42.7% of production capacity costs using the energy allocator.[3]

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[2] Exhibit No. 1.12 (DRD-3), Schedule No. 3 (PSC REF #:149565).

[3] Allocating all costs on the basis of contribution to 12CP implies that, from a generation planning perspective, production capacity costs are incurred solely for the purposes of meeting system reliability requirements, i.e., that all production capacity costs are classified as "demand-related." On the other hand, allocating all costs on the basis of contribution to system energy requirements implies that production capacity costs are incurred solely for meeting energy requirements, i.e., that all costs are classified as "energy-related." The 57.3% demand / 42.7%

Of the $29.2 million requested increase, the CCOSS based on the 12CP demand allocator allocates $13.0 million to the residential class, representing a 6.0% increase over current revenues. In contrast, the CCOSS based on the 57.3% demand / 42.7% energy blended allocator allocates $11.1 million to residential customers, for an increase of 5.2%. The proposed residential allocation of $12.3 million is slightly greater than the average of the allocations from these two CCOSS runs, and is comparable to the residential allocation that would result from using a 84.8% demand / 15.2% energy allocator.

Q: Why did Mr. Dahl use these two CCOSS allocations as "guidelines"?

A: Mr. Dahl states that he used these two allocations as guidelines because Mr. Marx "indicated that a range between the 12CP method CCOSS and the blended energy capacity CCOSS provided an appropriate range."[4]

Q: What is the basis for Mr. Marx's assertion that these two allocators provide an "appropriate range" of revenue allocations to the residential class?

A: Mr. Marx does not explain why the Company is supporting these two allocators as the "appropriate range."

Instead, in his direct testimony, Mr. Marx presents the percentage revenue increases for each customer class resulting from the CCOSS for six different production capacity cost allocators:

1. Class contribution to single system peak ("1CP").
2. Class contribution to average of four summer monthly peaks ("4CP").
3. 12CP.

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energy allocator therefore implies that 57.3% of costs are incurred to meet reliability, with the remainder incurred to meet energy requirements.

[4] *Direct Testimony of Donald R. Dahl*, PSCW Docket No. 4220-UR-117, June 17, 2001, pp. D1.191-D1.192 (PSC REF #:149562).

4. 57.3% demand / 42.7% energy.

5. 38.4% demand / 61.6% energy.

6. 0.0% demand / 100% energy.

These six production capacity allocators yield a wide range of allocations of the requested revenue increase to the residential class:[5]

Table 2: Residential Revenue Increase Under Varying Production Capacity Allocators

	Production Capacity Allocator	Residential Increase	System Increase
1	1CP	6.0%	5.1%
2	4CP	4.6%	5.1%
3	12CP	6.0%	5.1%
4	57.3% / 42.7%	5.2%	5.1%
5	38.4% / 61.6%	4.8%	5.1%
6	0.0% / 100%	4.0%	5.1%

According to Mr. Marx, the Company supported the 38.4% demand / 61.6% energy blended allocator in the previous rate case in Docket No. 4220-UR-116.[6] However, based on a subsequent review of "various production cost allocation methods used by other utilities and … the guidelines of the National Association of Utility Regulatory Commissioners (NARUC)," the Company now believes that this blended allocator "assigns too much cost responsibility to

[5] With the exception of the residential increase for the 4CP allocator, all data is from Table 1 (p. D1.154) of *Direct Testimony of Gerald W. Marx*, PSCW Docket No. 4220-UR-117, June 17, 2011 (PSC REF #:149561). In an e-mail to CUB dated September 22, 2011, the Company indicated that it had revised the result shown in Table 1 for the residential increase under the 4CP allocator from 4.3% to 4.6%.

[6] This allocator was also found to be "not unreasonable" by PSC Staff in that proceeding. See *Direct Testimony of James B. Petersen*, PSCW Docket No. 4220-UR-116, October 21, 2009, p. D9.62 (PSC REF #: 122011).

energy-using customers."[7] Instead, the Company now believes that the 57.3% demand / 42.7% energy allocator "assigns a more balanced cost responsibility between energy-using and demand-causing customers."[8]

While Mr. Marx offers an explanation for the Company's shift away from relying solely on the 38.4% demand / 61.6% energy allocator, he provides no rationale for the Company's current support for the range bounded by the 12CP allocator (i.e., 100% demand / 0% energy blend) and the 57.3% demand / 42.7% energy allocator.

To the contrary, Mr. Marx appears to argue against reliance on the 12CP allocator, noting that "employing a production capacity cost allocator based upon a blend of demand and energy usage is more appropriate than exclusively using either demand or energy."[9] In fact, Mr. Marx appears to argue in support of the range bounded by the 57.3% demand / 42.7% energy and 38.4% demand / 61.6% energy allocators, noting with regard to the CCOSS results associated with these two allocators that:

> Neither [of these two results] is "correct" or "incorrect." Rather each represents a point estimate along a continuum of reasonable alternatives.... Ultimately, the point chosen along the continuum is a matter of judgment.[10]

[7] *Direct Testimony of Gerald W. Marx*, PSCW Docket No. 4220-UR-117, June 17, 2011, p. D1.156 (PSC REF #: 149561).

[8] *Id.*

[9] *Id.*, pp. D1.156-D1.157.

[10] *Id.*, p. D1.155.

Q: What led the Company to conclude from its review of allocation methods that the 38.4% demand / 61.6% energy allocator "assigns too much cost responsibility to energy-using customers?"

A: Mr. Marx does not describe how the Company's review led to this conclusion. Nor is the Company is able to provide any documentation of the basis for this conclusion.[11]

Q: Have you assessed whether a 38.4% demand/ 61.6% energy allocator is reasonable?

A: Although I did not undertake a comprehensive assessment, I used a simplified version of the Equivalent Peaker method to classify the Company's production capacity costs as either demand- or energy-related. This analysis indicates that at least 70% of production capacity costs would appropriately be classified as energy-related, suggesting that, contrary to the Company's conclusion, the 38.4% demand / 61.6% energy allocator does not over-allocate production capacity costs to "energy-using customers."

Q: Please describe your classification of production capacity costs using the Equivalent Peaker method.

A: The Equivalent Peaker method for classifying production capacity costs reflects investment decision-making under typical generation expansion planning practices. The Equivalent Peaker method classifies fixed costs (i.e., capital and fixed O&M costs) for a peaking unit as demand-related, since peaking units would be the least-cost option for meeting an increase in peak demand and planning reserve requirements. The Equivalent Peaker method likewise classifies fixed costs for a baseload or intermediate unit *in excess of peaking*

[11] See the Company's response to 2-CUB/RFP-3(b) attached as Exhibit 2.4 (JFW-2).

fixed costs (so-called "capitalized energy" costs) as energy-related, since these incremental fixed costs are incurred to minimize the total cost of meeting an increase in energy requirements.

In order to provide an indication of the reasonableness of the 38.4% demand / 61.6% energy allocator, I applied the Equivalent Peaker method in two different ways. Under the first approach, I estimate the demand- and energy-related portions of the Company's production capacity costs using gross capital and fixed O&M costs as reported in the Company's 2010 FERC Form 1. In this case, I calculated: (1) the average fixed cost per kW-yr for the Company's combustion turbines; and (2) the average fixed cost per kW-yr for the Company's entire generation portfolio.[12] The ratio of (1) to (2) gives the percentage of the Company's production capacity costs that are demand-related under this version of the Equivalent Peaker method.[13]

Using this approach, I estimate that 20% of the Company's production capacity costs are demand-related and about 80% are energy-related.

Under the second approach, I estimate the averaged fixed cost per kW-year for the Company's combustion turbines and for the entire generation portfolio based on U.S. Energy Information Administration (EIA) assumptions for the capital and fixed O&M costs for new generic combustion-turbine, combined-cycle, coal, and nuclear resources. In this case, I estimated demand-related costs

[12] Specifically, I calculated the average fixed cost per kW-year for combustion turbines by summing gross capital costs as of 2010 for all combustion turbines, applying an assumed 10% fixed-charge rate, adding 2010 fixed O&M costs for all combustion turbines, and then dividing by the total capacity of the combustion turbines. I calculated the average fixed cost per kW-year for the entire portfolio in the same fashion.

[13] This is a simplified application of the Equivalent Peaker method, since it does not adjust gross capital cost values to account for the timing of the capital expenditures recorded in this cumulative account.

for the total generation portfolio as the product of: (1) the total kW capacity of the Company's generation portfolio; and (2) the EIA estimate of the fixed cost per kW-yr for generic combustion-turbine plant. I then calculated the production capacity cost for each of the resources in the Company's portfolio as the product of: (1) the kW capacity for that resource; and (2) the EIA estimate of the fixed cost per kW-yr for that resource type (e.g., nuclear). I then derived total production capacity costs for the Company's generation portfolio by summing the estimated production capacity costs for each resource in the portfolio. Finally, I estimated the percentage of the Company's production capacity costs that are demand-related by dividing demand-related costs for the portfolio by the total production capacity costs for the entire portfolio.

Using this approach, I estimate that 30% of the Company's production capacity costs are demand-related and about 70% are energy-related.

Q: How much of the requested revenue increase would be allocated to residential customers using a 30% demand / 70% energy allocator?

A: Of the $29.2 million requested increase, the CCOSS based on a 30% demand / 70% energy blended allocator allocates about $10.0 million to the residential class, representing a 4.6% increase over current revenues. Thus, the residential increase with a 30% demand / 70% energy blended allocator is about $2.3 million, or about 19%, less than the 5.7% increase proposed by the Company.

Q: What are your conclusions with respect to the appropriate allocator for production capacity costs?

A: The Company lacks a reasonable basis for its decision to abandon use of the 38.4% demand / 61.6% energy allocator and instead to rely on the 12CP and 57.3% demand / 42.7% energy allocators to allocate the requested revenue increase. The Company has not offered any support for its conclusion that the

38.4% / 61.6% allocator "assigns too much cost responsibility to energy-using customers." In fact, application of the Equivalent Peaker method to classify production capacity costs indicates that cost allocations based on the 38.4% / 61.6% allocator fall within a reasonable range. Moreover, as the Company acknowledges, it would be inappropriate to allocate 100% of production capacity costs on demand, as would be the case if the 12CP allocator were used. As such, using the range of CCOSS results with the 12CP and 57.3% demand / 42.7% energy allocators overstates the cost responsibility for residential customers and therefore assigns too large a share of the requested revenue increase to the residential class.

I agree with Mr. Marx when he states that the CCOSS results associated with the 57.3% demand / 42.7% energy and the 38.4% demand / 61.6% energy allocators represent a "continuum of reasonable alternatives." The Company should therefore allocate any revenue increases based on the range of CCOSS results associated with these two blended allocators.

III. Classification of Distribution Costs

Q: How does the Company allocate distribution plant costs to customer classes?

A: The Company first classifies distribution plant costs (FERC Accounts 364 through 369) as either demand-related or customer-related based on a minimum system analysis.[14] The Company then allocates demand-related costs based on

[14] All distribution substation costs are considered to be demand-related, while all meter costs are considered to be customer-related.

class non-coincident peaks and customer-related costs based on number of customers.[15]

Q: How is the cost of the minimum distribution system generally derived?

A: The most common methods used are: (1) the minimum-size method; or (2) the zero-intercept method.

A minimum-size analysis attempts to calculate the cost of a utility's installed units (transformers, poles, conductor-feet, etc.), assuming that each of those units are the minimum size for that type of equipment that would ever be used on the system. This type of analysis attempts to estimate the cost to install the same number of units (poles, conductor-feet, transformers) as are currently on the system, assuming that each of those units are the smallest size currently used on the distribution system.

The zero-intercept method attempts to estimate a functional relationship between equipment cost and equipment size based on the current system, and then to extrapolate that cost function to estimate the cost of equipment that carries zero load (e.g., 0-kVA transformers), the smallest units legally allowed (e.g., 25-foot poles), or the smallest units physically feasible (e.g., the thinnest conductors that will support their own weight in overhead spans). The goal of this procedure is to estimate the cost of equipment required to connect existing customers, even if they had virtually no load.

Under either approach, the minimum-system cost is deemed to be customer-related, with the remaining cost classified as demand-related.

[15] Customer-related line-transformer costs are allocated using a weighted customer allocator.

Q: Which approach does the Company use to classify distribution costs?

A: According to the 1992 report on the Company's minimum system study, the Company used the minimum-size method to classify poles (FERC Account 364) and line transformers (Account 368) and used the zero-intercept method to classify overhead conductors (Account 365), underground conduit (Account 366), underground conductors (Account 367), and services (Account 369).[16]

Q: Do minimum system approaches generally produce reasonable classifications of costs?

A: No. As James Bonbright, Albert Danielson, and David Kamerschen explain in their *Principles of Public Utility Rates*, these approaches are fundamentally flawed because minimum-system costs, however estimated, are neither properly classified as wholly customer-related nor demand-related.[17] Instead, Bonbright, Danielson, and Kamerschen argue that such costs are inherently "unallocable":

> But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs …, while it is also denied a place among the customer costs …, to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs…. But fully-distributed cost analysts dare not avail themselves of this solution, since they are prisoners of their own assumption that "the sum of the parts is equal to the whole." They are therefore under impelling pressure to fudge their cost apportionments by

[16] Gerald W. Marx, "Minimal System Analysis", Northern States Power Company (Wisconsin), June 1, 1992. Provided in response to Commission filing requirement 25G (PSC REF #:149586).

[17] In other words, these costs are not driven primarily by either changes in the number of customers or by changes in customer demand, but instead may depend on such factors as customer density or terrain.

> using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories.[18]

Residential customers are especially burdened when a high percentage of these unallocable costs are inappropriately dumped into the customer-cost bin.

In addition, the minimum-size and zero-intercept methods suffer from specific problems that tend to produce unreasonable results. In a 1981 article, George Sterzinger identified a flaw in the minimum-size approach that could result in over-allocation of costs to the residential class.[19] The problem arises because the minimum-size method typically defines the minimum system to include equipment that would carry a large portion of the average customer's load. For example, assume that the minimum-size line transformer is large enough to cover the average load of residential customers. In this case, only those costs incurred for the minimum-size transformers are appropriately attributable to, and appropriately allocated to, the residential class. However, the minimum-size method would not only allocate these minimum-size transformer costs to the residential class as customer-related costs, but would also inappropriately allocate a portion of the remaining costs for larger-sized transformers to residential customers as demand-related costs, even though the costs for these larger transformers were not incurred to serve residential load.

The zero-intercept method avoids the over-allocation problem associated with the minimum-size approach. However, the zero-intercept method suffers from its own shortcomings. This approach may produce classifications that are not statistically reliable or robust. Moreover, at a conceptual level, the zero-

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[18] Bonbright, James C., Albert L. Danielsen, and David R. Kamerschen, *Principles of Public Utility Rates*, Arlington, VA: Public Utilities Reports, 1988., p. 492.

[19] George J. Sterzinger, "The Customer Charge and Problems of Double Allocation of Costs", *Public Utilities Fortnightly*, July 2, 1981.

intercept method is so abstract that its application may not yield realistic results. For example, it may not be appropriate to extrapolate from the current system to estimate the cost of a system that provides zero load. A system designed to connect customers but provide zero load would likely look very different from the existing system. For example, a zero-capacity electric system would not use the overlapping primary and secondary systems and line transformers that the real system uses. Without the need for high voltages to carry power, poles could be shorter and cross-arms would be unnecessary; with no transformers and cross-arms, and lighter conductors, poles could be thinner as well. The labor and equipment costs of setting those short, light poles would be much lower than the costs of real utility poles of any size. It is therefore unlikely that a cost estimate based on an extrapolation from the current system would reasonably reflect the cost of an actual zero-load system.

Q: Is there a reasonable alternative to the minimum system method for classifying distribution plant costs?

A: Yes. A reasonable and reasonably straightforward alternative approach, and one that has been used in other jurisdictions, would be to classify services as customer-related and all other distribution plant costs as demand-related.

Q: Have you estimated the impact on revenue allocations if the Company were to classify distribution costs in this fashion?

A: Yes. I modified the inputs in the CCOSS model relating to distribution plant classifications in order to simulate the classification of all costs in FERC Accounts 364 through 368 as demand-related and of all costs in FERC Account 369 as customer-related.[20] As indicated in the following table, this alternative

[20] In discovery, I asked the Company to confirm that I was correctly modifying the CCOSS inputs to simulate these classifications of distribution costs. In its response to 6-CUB/Inter-1 (PSC

classification approach dramatically reduces the revenue increase allocated to the residential class compared to the Company's requested allocation based on the minimum system approach.

Table 3: Residential Revenue Increase With Minimum System and Alternative Classifications of Distribution Costs

	Production Capacity Allocator	Residential Increase	
		Minimum System	Alternative Classification
1	1CP	6.0%	2.1%
2	4CP	4.6%	0.8%
3	12CP	6.0%	2.2%
4	57.3% / 42.7%	5.2%	1.3%
5	38.4% / 61.6%	4.8%	0.9%
6	0.0% / 100%	4.0%	0.2%

Q: What do you conclude with regard to the Company's classification of distribution costs?

A: The Company's minimum system analysis misclassifies demand-related costs as customer-related. This misclassification leads to an over-allocation of distribution plant costs to the residential class and thus to an over-allocation of the requested revenue increase to the residential customers.

REF #:154221), the Company stated as follows: "Upon cursory review, it appears these input changes would produce the results intended by the questioner. However, to be certain, the Company would need to rerun the COSS model, which is beyond the scope of the Company's obligations in responding to an interrogatory, and is therefore objectionable…."

IV. Residential Customer Charge

Q: What is the Company's proposal with respect to the customer charge for residential rates?

A: According to Mr. Dahl, the Company proposes to increase the residential customer charge from $8.00 per month to $9.25 per month, or by about 16%.

Q: What is the basis for the Company's proposed increase?

A: Mr. Dahl offers a number of arguments in support of the Company's proposal:

- The proposed customer charge will be about 64% of the "full cost of service level of $14.50" derived in the CCOSS.
- The proposed customer charge will represent about 10% of the average bill, comparable to the percentage level in 2000.
- The proposed increase "maintains a moderate and equitable bill impact for large-usage customers."

Q: Should estimates of customer costs in the CCOSS be relied on to determine the level of the residential customer charge?

A: No. While it may be reasonable to classify certain costs as customer-related for the purposes of allocating such costs among customer classes in the CCOSS, it is not appropriate to recover all such costs allocated to the residential class through a fixed customer charge. A number of customer-classified distribution costs – such as services or uncollectible accounts and collection expense – are likely to vary with the size of the customer (in revenues, sales, or demand). If such costs were recovered through a fixed customer charge, then the smallest residential customers (with the least-expensive distribution equipment) would be required to pay the average of customer costs attributable to all sizes of residential customers. In other words, if all customers pay the same customer charge regardless of size, then small customers will subsidize larger customers' distribution costs.

Q: What is the relevance of the fact that the customer charge represented 10% of the average bill in 2000?

A: As far as I am aware, that particular percentage at that particular time has no bearing on whether and to what extent the customer charge should be increased today. While a 10% contribution from the customer charge may have been appropriate in 2000, a smaller percentage may be appropriate today if, for example, the bulk of the system cost increases since 2000 have been demand- or energy-related (such as investment in production or transmission plant or addition of emissions controls on existing plant).

Q: Do you agree that the proposed increase to the residential customer charge "maintains a moderate and equitable bill impact for large-usage customers?"

A: No. In fact, Mr. Dahl's analysis of bill impacts shows otherwise. According to Mr. Dahl's analysis of the proposed residential rate design with the increased customer charge, bills for the *smallest* RG-1 customers increase on average by 7.8%, or about two percentage points more than for the average RG-1 customer. Mr. Dahl also estimates bill impacts from an alternative rate design that maintains the current customer charge and recovers the revenue increase through the energy charge. In this case, bills for the *largest* RG-1 customers increase on average by 6.1%, or only 0.4 percentage points more than average. In other words, the harm to the smallest residential customers from an increase in the customer charge is greater than the harm to the largest residential customers from a corresponding increase in the energy charge.

Not only is an increase in the energy charge more equitable than an increase in the customer charge, it also provides more opportunity for reducing the bill impact of a rate increase than an increase in the customer charge. Residential customers, particularly larger-usage customers, can offset the impact of energy-charge increases by investing in energy-efficiency measures that reduce energy consumption. No such opportunities exist for reducing the bill impact from an increase in the customer charge.

Q: What do you recommend with regard to the Company's proposal to increase the residential customer charge?

A: The Company's proposal to increase the residential customer charge would disproportionately and inequitably harm smaller customers. The Commission should therefore reject the Company's proposal to increase the residential customer charge. Any increase to residential revenues allowed by the Commission should be recovered solely through the energy charge.

Q: Does this complete your direct testimony?

A: Yes.