SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH)

IURC CAUSE NO. 44910

REBUTTAL TESTIMONY
OF
RUSSELL A. FEINGOLD
VICE PRESIDENT
BLACK & VEATCH MANAGEMENT CONSULTING, LLC

ON

TRANSMISSION, DISTRIBUTION, AND STORAGE SYSTEM IMPROVEMENT CHARGE ("TDSIC") RATE DESIGN

SPONSORING PETITIONER'S EXHIBIT NO. 14,
ATTACHMENT RAF-R1

REBUTTAL TESTIMONY OF RUSSELL A. FEINGOLD

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Russell A. Feingold. My business address is 2525 Lindenwood Drive, Wexford, Pennsylvania, 15090-7914.

Q. By whom and in what capacity are you employed?

A. I am employed by Black & Veatch Management Consulting, LLC ("Black & Veatch") as a Vice President and I lead its Rates & Regulatory Services Practice.

Q. Are you the same Russell A. Feingold who provided direct testimony in this Cause?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. My rebuttal testimony will address certain issues within the direct testimony of Citizens Action Coalition of Indiana, Inc. ("CAC") and Valley Watch (collectively, "Joint Intervenors") witness Karl R. Rabago[1] regarding Vectren South's Transmission, Distribution, and Storage Improvement Charge ("TDSIC") rate design proposal, as well as the rate design supported by the Stipulation and Settlement Agreement ("the Settlement") entered into between Vectren South, the Indiana Office of Utility Consumer Counselor, and the Vectren Industrial Group (collectively, the "Settling Parties"). My comments throughout my rebuttal testimony will address, both separately and collectively, the merits of and principles supporting both the Company's rate design proposal as well as the Settlement rate design.

Q. Are you sponsoring any attachments with your rebuttal testimony?

A. Yes. I am sponsoring Attachment RAF-R1.

Q. Do the Settling Parties in this proceeding agree, as a general matter, on the

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[1] Exhibit JI No. 1.

rate design principles and concepts regarding the use of fixed monthly charges for electric utilities?

A. No. As I note from my review of the settlement testimony of OUCC Witness Rutter, the OUCC has reserved the right to address rate design issues related to the use of fixed monthly charges in future utility proceedings before the Commission. The rebuttal testimony I present in this Cause represents Vectren South's response to a Joint Intervenor witness and it includes arguments that Vectren South believes to be valid and appropriate, but that should not be interpreted as a policy position held by any of the Settling Parties other than Vectren South.

Q. Have you reviewed the direct testimony and attachments of Mr. Rabago?

A. Yes. I have conducted a thorough review of his direct testimony and attachments and have a number of serious concerns with his specific findings and recommendations related to Vectren South's rate design proposal for its residential class.

II. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Can you briefly summarize your findings and recommendations related to the Joint Intervenors' presentation?

A. Yes. Based on my review of the direct testimony and attachments presented by witness Rabago concerning the Company's rate design proposal for its residential class, I have reached the following conclusions and make the following recommendations:

- The numerous criticisms made by Mr. Rabago of the Company's rate design proposal for its residential class are factually incorrect, misleading, or misplaced relative to the underlying economic concepts and utility ratemaking methods supporting the structure of the Company's rate design proposals.
- Mr. Rabago's rate design recommendation to recover the entirety of Vectren South's TDSIC costs through a volumetric (per kWh) charge, rather than recovering a portion of those costs through a fixed monthly charge, for the

Company's residential customers will create economically inefficient electricity prices and send distorted price signals to customers, who will react inappropriately with energy-related investments based purely on a flawed theory of cost avoidance, thus putting the burden on the Company's rate design to erroneously support customer payback of their investments.

- This Commission should approve the Settlement rate design because it achieves a reasonable balance between cost causation principles and the impact of its rate design method on customers' electric bills. Under these methods, the Company will avoid creating even greater cross-subsidies among customers within a particular rate schedule during the 7-year TDSIC Plan period.
- Finally, the Settlement rate design reduces, or at the very least avoids increasing, intra-class subsidies and will help establish the necessary ratemaking foundation to evaluate a wider variety alternative rate design approaches that will recognize the changing landscape of the electric utility industry and assist its customers in making economically rational decisions on the energy choices available to them.

I will demonstrate the validity of these points in detail when I respond to the specific criticisms raised by the Joint Intervenors concerning the Company's rate design proposal for its residential class.

Q. In his Summary of Findings at page 6 of his direct testimony, Mr. Rabago provides a list of alleged deficiencies in the Company's rate design proposals presented in its petition, and in the proposed settlement, including, "electric service rates for residential customers that are economically inefficient, unjustly discriminatory, and unreasonable, and that will impair customer choice and the economics of energy efficiency and distributed generation." Do you agree with Mr. Rabago's summary of findings on the Company's rate design proposals?

A. Absolutely not. In my opinion, Mr. Rabago fails to provide the necessary evidentiary support for the rate design deficiencies he claims exist in the Company's rate design proposals. Not a single one of these claims has any logical foundation as I summarize below and discuss in more detail later in my rebuttal testimony. The rates proposed by the Company are more economically efficient than if the rates were designed to recover TDSIC costs only from the volumetric energy charge, as proposed by Mr. Rabago, which would further increase volumetric rates above short run marginal costs ("SRMC"). As such, the rate design proposal of witness Rabago results in rates that are more economically inefficient than the rates proposed by the Company because his proposal will greatly increase the Company's volumetric energy charges.

For Mr. Rabago to characterize the Company's rate design proposal as being inefficient is to effectively self-condemn his own rate design proposal. Since the Company's proposed rates gradually move towards cost, they cannot be characterized as unjustly discriminatory unless the existing approved rates are also unjustly discriminatory. Witness Rabago is effectively also condemning the Company's current rates as being unjustly discriminatory since the Company's proposal results in prices that are closer to cost-based rates than its current rates, and despite the fact that the Commission has approved the Company's current rates. For the same reason that the rates are not unjustly discriminatory, they cannot be characterized as being unreasonable since the Company's longer-term goal is to achieve cost-based rates in a series of gradual steps over time, as described in Vectren South's direct testimony.

It is not possible for the Company's proposed rates to impair customer choice since nothing about the rates changes the costs of electric production. In fact, customer choice is promoted by cost-based delivery rates. With respect to energy efficiency, the mere fact that kWh charges increase under the Company's proposal means that energy efficiency is worth more than at current rates. However, the level of the kWh charges under the Company's rate design proposal are less than they would have been (and closer to SRMC) than under the Joint Intervenors' rate design proposal sponsored by witness Rabago. The same argument that applies to energy efficiency applies to DG. That is, the price signal for electricity exceeds the avoided cost, with the result that any investment in DG results in an artificial subsidy for DG.

Q. As a threshold matter, is the Company's rate design proposal for its residential class reflective of widely accepted ratemaking principles and rate design concepts in the utility industry?

A. Yes. The Company's continued use of a two-part rate design for its mass market customers[2] and the recovery of fixed costs through the fixed monthly charges contained in those rate schedules are fully consistent with, and supportive of, the most fundamental economic principles and ratemaking concepts that serve as a basic foundation for utility pricing. In contrast, Mr. Rabago's rate design proposal for the Company's residential class belies 100 years of ratemaking history in the utility industry by ignoring: (1) the recognition that a material portion of an electric utility's fixed distribution costs are customer-related in nature; (2) the universal acceptance of the matching of a utility's embedded costs with rates; and (3) the recognition that SRMC should serve as the appropriate guideline for the setting of a utility's volumetric energy or kWh charges.

III. <u>THE DETERMINATION OF JUST AND REASONABLE UTILITY RATES</u>

Q. At page 5 of his direct testimony, Witness Rabago makes the claim that the rates proposed by the Company are not just and reasonable. Please comment on this claim.

A. Aside from the fact that witness Rabago does not offer any relevant proof for reaching this conclusion, there are a number of errors in his claim. First, the basis for just and reasonable utility rates is cost causation. The U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) has defined the cost causation principle as follows: "[I]t has been traditionally required that all approved *rates reflect to some degree the costs actually caused by the customer who must pay them.*"[3] (Emphasis

[2] For Vectren South, the phrase "mass market customers" refers to its residential and small general service customers.

[3] K N Energy, Inc. v. FERC, 968 F.2d 1295, 1300 (D.C. Cir. 1992) (K N Energy).

added.) The U.S. Court of Appeals for the Seventh Circuit (Seventh Circuit) recently quoted and elaborated on that definition by stating: "All approved rates must reflect to some degree the *costs actually caused by the customer who must pay them."* Not surprisingly, we evaluate compliance with this intuitively apparent and reasonable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party. To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed."[4] (Emphasis added.)

The capital investments included in the Company's TDISC related revenue requirements serve to replace aging infrastructure and all customers benefit directly from the improved reliability of the electric system. A portion of those costs as well as a portion of the costs of the assets being replaced are customer-related in nature, but are not being fully recovered from customers who cause those costs. The reason is that an electric utility's existing two-part rate cannot match costs and revenues when the fixed monthly charge does not recover the full customer costs, much less the demand component of distribution and transmission costs, because customers' load factors vary as significantly as they do in the Vectren South's residential class, as I described in my direct testimony.

Q. If cost based rates are just and reasonable as found in the court decisions above and in the recent Appeals Court decisions in Indiana related to the Indianapolis Power & Light ("IPL")[5] and Northern Indiana Public Service Company ("NIPSCO")[6] cases that affirmed the Commission's decisions that

[4] Illinois Commerce Comm'n v. FERC, 576 F.3d 470, 476 (7th Cir. 2009) (Illinois Commerce Commission) (citing K N Energy, 968 F.2d at 1300; Transmission Access Policy Study Group v. FERC, 225 F.3d 667, 708 (D.C. Cir. 2000); Pacific Gas & Elec. Co. v. FERC, 373 F.3d 1315, 1320-21 (D.C. Cir. 2004); Midwest ISO Transmission Owners v. FERC, 373 F.3d 1361, 1368 (D.C. Cir. 2004) (Midwest ISO Transmission Owners); Alcoa Inc. v. FERC, 564 F.3d 1342 (D.C. Cir. 2009); Sithe/Independence Power Partners, L.P. v. FERC, 285 F.3d 1, 4-5 (D.C. Cir. 2002) (Sithe); 16 U.S.C. 824d).

[5] Cause No. 44576 (3/16/16) and Indiana Court of Appeals Decision 93A02-1604-EX-804 (4/5/17).

[6] Cause No. 44688 (7/18/16) and Indiana Court of Appeals Decision 93A02-1608-EX-1854 (4/19/17).

found those utilities' rates to be just and reasonable, is it a condition of just and reasonable rates to consider a variety of social concerns as claimed by witness Rabago in establishing just and reasonable rates?[7]

A. No. The argument being made by witness Rabago is essentially that one can deviate from just and reasonable rates to solve a host of issues that he mentions in his direct testimony such as low-use and low-income customer impacts, energy efficiency investments and Distributed Generation ("DG") investments. His argument falls apart because cost-based rates provide the most meaningful rationale for rate design satisfying the objectives cited by James Bonbright – (1) the revenue-requirement, production-motivation or financial-need objective (capital attraction); (2) the optimum-use, demand control, or consumer-rationing objective (consumer rationing); and (3) the compensatory income transfer function or fair-cost-apportionment objective (fairness to ratepayers).[8]

One obvious problem with Mr. Rabago's stated desire to protect low income customers by recovering all TDSIC costs in the Company's kWh charges is the unavoidable consequences of this rate design on high use, low income customers who must now subsidize not only other low income customers but also vacant premises, high income/low use customers, and separately metered barns and other outside structures. Rational public policy requires that rates be cost- based and social issues be resolved outside of the rate design process. With all of the price distortions that would be created by witness Rabago in his rate design proposal, the most obvious example is found in the market for residential DG. Low and moderate income households generally speaking cannot afford DG. It is larger use and wealthier customers who make those investments and it is low and moderate income customers who must pay the difference between the actual avoided costs and the full rate benefit received in the form of revenue decoupling charges, lost fixed cost adjustment riders, or future base rates. The significance of the Joint Intervenors' position and related rate design proposal to further deviate from cost of service has

[7] For example, see JI Exhibit No. 1, page 11 and pages 40-43.

[8] James C. Bonbright, Albert L. Danielson, David R. Kamerschen, Principles of Public Utility Rates, Public Utility Reports, Inc, 1988, page 385.

negative implications for the very customers who witness Rabago seeks to protect. His proposal to deviate from cost-based rates to accommodate social concerns should be rejected by the Commission.

Q. Witness Rabago contends at page 19 of his direct testimony that, "The problem with witness Feingold's testimony about rate design is that there is no such principle of just and reasonable rates." Do you agree with Mr. Rabago's contention?

A. No. The simple fact is that my discussion on the basis for just and reasonable rates is completely consistent with each of Bonbright's three primary criteria of rate design discussed above. Capital attraction is enhanced by improving the utility's opportunity to earn its allowed rate of return authorized by the regulator. Consumer rationing is enhanced by moving the price of electricity toward the optimal SRMC price. Finally, fairness to customers result when utility rates are based on cost causation principles and the revenues from those rates match the costs approved in the utility's total revenue requirement. The Company's rate design proposal satisfies all of these rate design criteria.

IV. USE OF A TWO-PART RATE DESIGN FOR THE PRICING OF ELECTRICITY TO A UTILITY'S MASS MARKET CUSTOMERS

Q. Witness Rabago asserts at page 10 of his direct testimony that volumetric-based recovery of fixed costs is the optimal basis for recovery of demand-related distribution fixed costs. Please comment on his assertion.

A. Mr. Rabago's assertion is incorrect and has no basis in fact. Volumetric rates cannot track demand-related distribution costs unless the particular class is perfectly homogeneous. With the range of actual load factors observed for the Company's residential customers, adoption of a volumetric rate for recovery of these costs would result in large cross-subsidies between customers for the demand component of distribution costs, just as it would for the customer cost component. Taken together, volumetric recovery of such costs is not only suboptimal, but would be extremely regressive if Mr. Rabago's rate design proposal is adopted relative to either the Company's proposed rates, the Settlement rate design, or the Company's current rates.

Q. Please comment on Mr. Rabago's statement made at page 9 of his direct testimony that, "Precisely because of the concerns that I cover in this testimony, utilities and regulators throughout the country have typically allocated a large proportion of fixed costs to volumetric rate elements for residential and small commercial customers."

A. This view is nothing more than an example of Mr. Rabago attempting to rewrite history. The real reason for this outcome is found in the history of the electric utility industry's cost structure. This ratemaking compromise universally adopted was that it was too costly to have three-part rates (i.e., a fixed monthly charge, a volumetric energy charge and a fixed demand charge). The ability to meter a customer's demand was simply not economic. The compromise was to use a fixed monthly charge and a kWh charge to recover the fixed costs included in the utility's revenue requirement. This method produced reasonable results initially and continued to be reasonable as long as the particular rate class using the two-part rate structure was relatively homogeneous. As the residential class, in particular, became less homogeneous over time, the rates were no longer just and reasonable and multiple rates were used for the residential class (e.g., use of multiple rate blocks, sub-classes). As the bifurcation of traditional and engaged customers evolved, it became necessary to change this long-standing rate design because it was no longer just and reasonable and could not properly match costs and revenues for customers in the utility's typical residential class.

This evolving process of change in the Company's view will take some time so it chose to begin the ratemaking evolution in this proceeding. As evidenced by the Settlement, the parties agreed to temper that evolution by capping the amount of distribution-related costs recovered in the fixed TDSIC charge. How the final evolution will be implemented has not yet been determined with the exception that the Company's fixed monthly charge is proposed to be cost-based to include the relevant distribution-related costs in the determination of the appropriate rate levels.

Q. Witness Rabago claims at page 17 of his direct testimony that I disagree with Mr. Albertson on the use of fixed charges. Is that statement correct?

A. No. In fact, witness Rabago appears to misquote Mr. Albertson's statement in order to make it appear as though we disagree on this issue. Mr. Rabago specifically states, "Witness Albertson says that variation in customer usage levels makes average fixed monthly charges inappropriate. Witness Feingold asserts that residential customers are becoming less homogenous, and that this supports average fixed monthly charges for distribution fixed costs." There is no disagreement between us unless you conveniently omit the fact that the variation in usage levels in Mr. Albertson's direct testimony relates specifically to larger, demand metered customers who are billed on three-part rates while my statement refers to residential customers who have no demand meters and are billed under two-part rates. There is absolutely no disagreement between Mr. Albertson and me on this issue, and certainly no disagreement between the evidentiary support provided for the Company rate design proposals and the underlying economic principles and ratemaking concepts of utility ratemaking.

Q. Can you cite any other examples where Mr. Rabago apparently chose to misquote your direct testimony to help support his arguments?

A. Yes. At page 18 of his direct testimony, Mr. Rabago states that, "Even after citing this broad range in cost causation, witness Feingold incongruously asserts that a *single average fixed charge* is the appropriate rate design." (Emphasis added) In fact, my direct testimony at page 14, lines 19-22, actually states that the increases in the Company's TDSIC fixed costs need to be collected "through *fixed components* of the rate structure." (Emphasis added). It is important to note the difference between the singular tense used by witness Rabago and my use of the word "components." Again, it appears to me that Mr. Rabago has conveniently chosen to misquote my direct testimony to provide him with an opportunity to raise an unwarranted criticism of the Company's rate design proposal.

V. PROMOTING ECONOMIC EFFICIENCY THROUGH RATE DESIGN

Q. Witness Rabago states on page 11 of his direct testimony that, "I am not aware of any evidence or analysis, and see none in this record, that increasing fixed customer charges improves system-wide economic efficiency or the efficiency of customer decisions." Please comment on Mr. Rabago's statement.

A. Mr. Rabago is apparently unaware of significant literature supporting this concept. For example, Ronald Coase in the seminal work entitled, "The Marginal Cost Controversy" explains in great detail both the economic efficiency for the economy and the efficiency of customer decisions. Coase recommends a two-part rate consisting of a volumetric charge based on marginal cost and a fixed charge that recovers the remainder of the total cost.[9]

In a more modern article written by one of the authors cited by witness Rabago in his direct testimony and by the Company in its response to CAC Request No. 5.15, Severin Borenstein in his article, "The Economics of Fixed Cost Recovery by Utilities" makes it clear that setting the volumetric price at short-run marginal cost and recovering the fixed costs (and in particular the fixed customer related costs) in a fixed charge results in efficient electricity prices.[10] In addition to that discussion, he notes that the condition requiring such pricing is related to both the transmission and distribution of electricity.[11]

Another example of this concept related specifically to electric distribution utilities is found in a recent report by the Massachusetts Institute of Technology ("MIT") where the authors state, "Allocating network costs primarily on the basis of volumetric

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[9] "The Marginal Cost Controversy", by R. H. Coase, Economica, New Series, Vol. 13, No. 51. (Aug., 1946), p. 173

[10] "The Economics of Fixed Cost Recovery by Utilities", Severin Borenstein, July 2016, http://ei.haas.berkeley.edu, and as revised in Electricity Journal, Volume 29, Issue 7, August/September 2016.

[11] P. 5

energy consumption presents inefficiencies in distribution systems evolving to incorporate a growing number of DER and a growing list of new stakeholders. These inefficiencies include: few price signals to incentivize optimal network utilization; cross-subsidization among network users; and business model arbitrage of rate structures."[12] In that same article, the authors also comment that, "While DG serves as the primary example in this discussion, it is worth noting that the drawbacks of purely volumetric network charges are apparent not only with distributed generation, but with demand response and energy efficiency as well." These are just a few samples of the literature that discusses the efficacy and efficiency of the Company's rate design proposal as it relates to the creation of proper price signals through rate design.

Q. At page 12 of his direct testimony, witness Rabago states that, "volumetric energy rates are the best rate design option for sending price signals for both energy and demand cost causation on a going-forward basis." Is that statement correct?

A. No. Volumetric two-part rates cannot result in just and reasonable cost recovery unless the class is nearly perfectly homogeneous. Even then, if the monthly customer charge is not compensatory, volumetric recovery of fixed costs cannot send proper price signals as discussed above, and as confirmed by the academic literature on distribution utility pricing. This claim has been disproven throughout the years, beginning as early as 1900. Further, as the Company's residential class becomes less homogeneous; it becomes impossible for Mr. Rabago's claim to be true.

Q. If we take Mr. Rabago's self-proclaimed theory of price signals and rate design to an extreme, what type of rate design would maximize the economic price signal to a utility's customers?

A. Using Mr. Rabago's concept, a 100% volumetric rate design would send the

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[12] "A Framework for Redesigning Distribution Network Use of System Charges Under High Penetration of Distributed Energy Resources: New Principles for New Problems", Ignacio Pérez-Arriaga and Ashwini Bharatkumar October 2014 CEEPR WP 2014-006, A Joint Center of the Department of Economics, MIT Energy Initiative and MIT Sloan School of Management, p. 6

strongest price signal to a utility's customers. However, such a rate design is extremely regressive in nature. It would create exactly the wrong price signal to send to customers since it would promote inefficient energy investment decisions by customers that would waste valuable resources and greatly overstate the costs that could be avoided by the utility. Keeping volumetric prices at or near SRMC is justified by well-accepted economic principles.

Q. At page 40 of his direct testimony, witness Rabago states that, "increases in fixed customer charges create powerful price signals against investment in energy efficiency." Does that statement apply in this case?

A. No. The Company's current rates are already above SRMC and the energy charge is increasing under the Settlement rate design for the TDSIC, in any event. In no way does the increase in the resulting kWh charge signal that the reward for energy efficiency is lower. It actually increases on an absolute basis under the Company's rate design proposal – just not as much as if the TDSIC costs were recovered solely from the kWh charge portion of the rates as recommended by the Joint Intervenors.

Q. At page 41 of his direct testimony, witness Rabago provides a number of "adverse impacts" he claims demonstrates that the Company's rate design proposal cannot promote energy efficiency and DG. Please comment on the validity of his reasoning.

A. First, Mr. Rabago claims that the Company's proposed increase in fixed charges means that the incentive to either invest in efficiency and the payback associated with energy savings are reduced. This statement is simply false. Increases in the kWh charges still occur under the Company's rate design proposal so the incentive to the customer increases and the payback period is shortened.

Second, Mr. Rabago claims that the overall bill impacts from the Company's rate design proposal will send a price signal, in comparison to its current rates, that means higher consumption will yield bill savings by spreading fixed charges across more units of usage. However, higher usage does not yield any bill savings as both the fixed monthly charge and the kWh charge are increasing. The price signal to customers will increase based on either the level of the marginal price or the total bill increasing. Mr. Rabago's suggested outcome is likewise false.

Third, Mr. Rabago claims that the Company's proposal to "lock demand-related fixed costs into a per-customer charge" means that residential customers have no financial incentive under proposed default rates to reduce their demand. There is no proposal made by the Company to lock demand-related distribution costs into the fixed monthly charge. The portion of demand costs in the Company's existing rates for distribution, transmission and production are not impacted by its rate design proposal in this proceeding. At the same time, it is acknowledged that under the Company's existing two-part rate, there is no direct incentive for customers to manage their demands. However, this incentive for delivery demand requires a separate demand charge based on either the customer's connected load or maximum demand, and no party has proposed that type of rate structure in this proceeding.

VI. <u>COST CAUSATION AND THE RECOVERY OF SUNK COSTS IN A UTILITY'S RATES</u>

Q. At page 16 of his direct testimony, Mr. Rabago claims that the Company believes that the "only function of rates is to account for sunk fixed costs, and that rates have no role in sending price signals relating to future, marginal costs of service. How do you respond to this claim?

A. Mr. Rabago's claim is misplaced and very shortsighted recognizing that a utility such as Vectren South has its rates set by the Commission based on embedded costs, which is a historically-based approach. Under the concept of embedded costs, any capital costs that are prudently incurred by the utility each year become sunk costs that eventually will be reflected in the utility's rate base and revenue requirement. Yet, Mr. Rabago's approach would rely upon a type of long-run incremental cost ("LRIC") concept that is forward-looking in nature to set utility rates. The problem this creates is that you cannot set a utility's rates using LRIC principles while at the same time establishing its total revenue requirement based on embedded costs. It creates a fundamental mismatch between costs and rates which violates the "matching principle" of costs and rates which is a cornerstone of utility ratemaking.

Q. Please describe this "matching principle" in greater detail.

A. An essential element of sound ratemaking is the principle of matching costs and revenues (or rates). Under this "matching principle", the utility's customers are charged with the costs of producing the service they receive. Without this principle, current customers would not be paying for the costs they cause the utility to incur.

It is also important to note that the failure to match costs and revenues does not meet policy goals such as rate efficiency and the creation of appropriate price signals. Absent tools to mitigate cost mismatches between the test year and the rate year, both investors and customers are impacted negatively. The ultimate result from a continued mismatch of costs and revenues is either higher bills for customers in the near-term when revenues exceed costs, or higher bills for customers in the long-run when revenues are less than costs. The first result is obvious because when a utility over earns, it is the customer who has paid more than necessary. The second result is less obvious, but nevertheless is a real outcome. Higher bills result over time as the utility's cost of capital rises and as the utility "chases" revenues through more frequent and administratively costly rate cases.

Failure to match costs and revenues may also have the effect of signaling customers to use more utility service because bills are lower than the actual cost to provide the service. To the extent that better price signals provide customers with the proper information to make better energy choices, the economy is more efficient. The second outcome of matching costs and revenues is the lower long-run cost of service for all classes of customers through lower financing costs for the utility.

Q. At page 16 of his direct testimony, Mr. Rabago contends that the Company's rate design proposal is "inefficient and anti-competitive" because it will "force customers to pay for costs that they offset through self-investment in

efficiency and other distributed energy resources." Under this scenario, could the Company be impacted by these types of future customer actions?

A. Yes. These customer actions could cause the Company to experience a significant reduction in revenues (caused by the much higher volumetric charges recommended by the Joint Intervenors) even though its distribution-related costs would remain the same since they are fixed. Mr. Rabago's clear interest in providing rate relief to customers who can reduce their electricity usage is evident from this situation. However, the fact that the Company's revenue requirement and rates are based on historical costs must be considered to properly align rates with the underlying costs that support the utility services utilized by customers on an ongoing basis, even for those customers who invest in DG or pursue energy efficiency activities.

Q. At page 15 of his direct testimony, Mr. Rabago states that recovering fixed costs in fixed charges is "a nonsense approach not supported by any rate making authority." Can you please comment on his claim?

A. Yes. As I have discussed above in great detail, this conclusion of fixed charge recovery of fixed costs is very logical and is fully supported by numerous utility ratemaking authorities. For example, one of my colleagues at Black & Veatch, Dr. H. Edwin Overcast who has been a rate practitioner for over 40 years, recently published a white paper entitled, "Smart Rates for Smart Utilities" that I have attached as <u>Petitioner's Exhibit No. 14</u>, Attachment RAF-R1. That paper provides a full discussion of the rationale and calculation of an appropriate customer charge based on cost causation. It also relies on his deep experience related to planning, designing and operating the utility that is necessary to an understanding of rate design.

VII. THE NATURE OF THE COMPANY'S DISTRIBUTION-RELATED TDSIC COSTS AND THEIR RECOVERY THROUGH FIXED MONTHLY CHARGES

Q. Does witness Rabago support the proposed increase in the Company's fixed monthly charge for residential customers by any statements made in his direct testimony?

A. Yes. It is ironic given the multiple pages of arguments made by Mr. Rabago in his direct testimony opposing the increase in the Company's fixed monthly charge for residential customers that he would make a statement such as the one at page 9 of his direct testimony, "The notable exception to this approach are the customer costs related directly to connecting a customer to the grid, as these costs do vary with the number of customers served." This statement is fundamental to the cost basis of utility rates. Apparently, Mr. Rabago has either forgotten or was not aware of the Company's obligation to connect new customers to its distribution system.

In the Company's Electric Tariff - General Terms and Conditions, Section 19 – Facilities Extensions and Modifications, it defines the customer connection it provides as consisting of "facilities including wires, poles, transformers and other equipment necessary to provide the service." The other equipment to connect the customer (service line and meter) is included in a separate provision. The Company incurs at least the cost of the minimum size of each of these service components to connect a new customer to its distribution system. Consistent with Mr. Rabago's definition of customer costs presented above, this is the minimum cost of the customer connection that the Company's fixed monthly charge proposal will include from distribution plant accounts that reflect these components. Of course, there are other fixed distribution-related TDSIC costs that the Company originally proposed to include in its fixed monthly charges and (for larger customers) demand charges. Here, under the Settlement, the Company has agreed to a cap on the fixed charge for distribution-related costs, placing approximately half of its TDSIC distribution costs in a fixed charge.

Q. Does Mr. Rabago consistently misinterpret or mischaracterize a utility's cost of

customer connections?

A, Yes. Whenever Mr. Rabago discusses the concept, he chooses to ignore the components of the process related to the Company's obligation to connect new customers (i.e., every customer was once a new customer, and over time the connection must be replaced for the utility's existing customers). Those components are consistent with the Company's definition of a customer connection and that the number of customers is a primary cause of the costs of distribution facilities.

Q. Does witness Rabago indicate in another part of his direct testimony that he may use a different method for defining the concept of customer costs?

A. Yes. Mr. Rabago makes reference to the so called "basic customer method" at page 9 of his direct testimony. I characterize the concept in this way because the method is not recognized in the NARUC Electric Utility Cost Allocation Manual. It is also not discussed in any seminal works on utility cost of service. Most importantly, it is an empirically flawed method designed to limit customer costs to only the cost of the meter and service line and some of the costs of a utility's customer service function. Since there is no formal literature in the public domain describing the details of this method, simply based on the informal description of the method I have seen used by some others in the utility industry, it is sufficient to conclude that the proponents of this method ignore cost causation in proposing the method which effectively shifts other customer-related costs from residential to industrial and other larger customers.

Q. Is that the only instance where witness Rabago misstates Company testimony in order to create a strawman to attack Company evidence?

A. No. At page 18 witness Rabago states that I say "miles of installed conductors do not change with the number of kWh that a customer uses, and therefore would argue that recovery of conductor investments should be through a fixed customer charge." This is not my testimony. My testimony speaks for itself in that I merely point out that fixed costs cannot be recovered volumetrically because volume is not the cause of the costs. I did not distinguish at this point between the demand and the customer components of distribution costs. Thus the whole discussion that follows in witness

Rabago's testimony including his statement about "my willful ignorance" is completely fabricated and does not exist in my testimony.

Q. At page 21 of his direct testimony, Mr. Rabago states that, "The Company offers no evidence to support the leap of logic that distribution costs should be collected as a customer cost, i.e. a cost that varies primarily and directly with the number of customers." Please comment on that statement.

A. The statement mischaracterizes the Company's proposal. Distribution costs are caused by both customers and demand. The Company's proposal is to move toward the rate recovery of the customer-related portion of distribution costs in the monthly customer charge. Failure to recover customer costs in customer charges requires other customers to subsidize the fixed customer component not covered in customer charges. The proposal is just and reasonable.

Q. Do the Company's distribution-related TDSIC costs include customer-related costs that should be recovered in a fixed monthly charge?

A. Yes. Based on my review of the Company's proposed TDSIC investments, the nature of the facilities indicate that a large number of the plant categories are recognized in the utility industry to include a material customer cost component. These plant categories include; Poles, Towers and Fixtures (FERC Account No. 364), Overhead Conductors and Devices (FERC Account No. 365), Underground Conduit (FERC Account No. 366), Underground Conductors and Devices (FERC Account No. 367) and Line Transformers (FERC Account No. 368).

Q. Please indicate why you believe the costs of these types of electric utility facilities are recognized by the utility industry as having a customer cost component.

A. For example, Dr. James Suelflow writes in his treatise, Public Utility Accounting: Theory and Practice published by the Institute of Public Utilities at Michigan State University, "... distribution transformers and primary and secondary lines including conductors and devices (account 365 "Distribution Plant") and poles and towers (account 364 "Distribution"), all contain capacity and customer costs."[13] Dr. Suelflow recognizes that costs are more closely related to customers the closer one approaches the ultimate customer. In other words, assets that are in closer proximity to the load served reflect less diversity and the classification of the costs associated with those assets should recognize this point.

Public utility regulatory accounting, including the NARUC Electric Utility Cost Allocation Manual ("NARUC Manual") supports the classification of distribution plant between customer and demand. In fact, the NARUC Manual does not even mention the basic customer method (which is a method discussed by Mr. Rabago at page 9 of his direct testimony) as an alternative for classifying and allocating distribution plant. There is no question that the NARUC Manual states that the distribution plant costs in Accounts 364-368 have both a demand and a customer component. The NARUC Manual states "When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, *the utility must classify distribution plant data separately into demand- and customer-related costs.*"[14] (Emphasis added.)

This is not a new concept. In 1963 Constantine Bary published his treatise Operational Economics of Electrical Utilities. This rigorous study of utility costs and how loads cause those costs provides a summary chart of cost causation. This chart shows that a portion of the distribution plant beginning with primary lines is customer related. In the parlance of uniform system of accounts this is accounts 364-368. I should note that support for both the minimum system concept and for customer charges to reflect these costs is not new or novel. Writing in 1900 Henry L. Doherty formulated a three part rate consisting of a customer charge, demand charge and energy charge.[15] In the original paper "Equitable, Uniform and Competitive Rates" Doherty defined the minimum costs associated with "readiness to serve" and

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[13] Public Utility Accounting: Theory and Practice, James E. Suelflow, The Institute of Public Utilities at Michigan State University, 1974, p.241

[14] Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, February 1991, p.95

[15] See for example Bonbright 1988 Edition p. 401 for reference to Dohery.

specifically included not only the components of the basic customer costs but the costs of poles, lines and conductors with 50% classified to the customer component and 50% to the demand component. His analysis also included overhead loaders in the cost per customer.[16]

Writing in 1956, Russel Caywood describes customer costs as "Varies with the number of customers served and includes investment charges and expenses relative to a *portion of the general distribution system,* service drop or other local connection facilities, metering equipment, meter reading, billing and accounting."[17] Further, H. E. Eisenmenger has written an extensive analysis of electric utility costs in 1919 and includes in the customer cost component the minimum size of poles and conductors. He states "Up to a certain size of consumer this investment will be practically constant per consumer and above that size we can regard it as composed of two parts: A constant part (cost of average length of service connection, if constructed with minimum size of poles and minimum thickness of service wires: also cost of minimum size of meter, etc.) and another part proportional to the maximum demand of the consumer."[18]

Q. What do you conclude from these utility industry citations?

A. The above citations demonstrate that the recognition of customer-related costs is neither new nor novel. Its pedigree has been established for over 100 years by a variety of disciplines and industry participants including engineers, entrepreneur utility owners, rate experts and others.

It is only through the use of fixed charges to recover fixed costs that the matching

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[16] A reprint of the 1900 article may be found in The Development of Scientific Rates for Electricity Supply, Printed for Private Circulation Only by The Edison Illuminating Company of Detroit, 1915, pp.53-78 (Available from GOOGLE Books)

[17] Electric Utility Rate Economics, Russell E. Caywood, Sixth Printing, 1972, Sponsored and Distributed by Electrical World and Russell E, Caywood, p. 26

[18] "Central-Station Rates in Theory and Practice, Seventh Article—The Consumer Cost, What It Includes and How It Varies—Determining the Numerical Values of the Three Elements of Cost—Analytical Valuation of Costs", Electrical Review, Volume 75, No. 8, 1919, p. 304 (Available from GOOGLE Books)

principle of rates is satisfied. This principle is important since it is required to provide a reasonable opportunity to earn the allowed return and is required for reasonable rates that reflect the cost of service principle. This is the practical side of rates for groups that are not perfectly homogeneous. It is well established that the residential class has grown less homogeneous over the last 100 years—a trend that has accelerated in recent years—increasing the practical requirement that just and reasonable rates recover fixed customer costs in the fixed customer charge. In the past, when residential customers had more homogenous usage, the distinction was less important, and volumetric charges could be used to recover fixed costs, because with similar usage those costs would end up being paid relatively uniformly by the customers. That is no longer the case.

Q. At page 26 of his direct testimony, Mr. Rabago quotes Bonbright's definition of customer costs and through some process concludes that Bonbright supports his rate design proposal. Is that a correct reading of the entirety of Professor Bonbright's comments on customer costs?

A. No. In Principles of Public Utility Rates, Professor Bonbright notes that the use of a two-part rate structure is based on the assumption that one part of the total cost of a utility's business is a function of the output or energy of the system, whereas another part is a function of plant capacity and hence of all costs related to this capacity. Professor Bonbright goes on to point out, however, that "this two-fold distinction overlooks the fact that *a material part of the operation and capital costs of a utility business is more directly and closely related to the number of customers* than to energy consumption on the one hand or maximum kilowatt demand on the other hand."[19] (Emphasis added).

In addition, in his section dealing with the criteria of a sound rate structure, Professor Bonbright states that, "customer costs incurred to serve a customer are invariant with respect to consumption. They are the costs incurred to serve a customer even if the customer does not use the service at all. The most obvious examples of these

[19] Principles of Public Utility Rates, Second Edition, James C. Bonbright, Albert L. Danielson, David R. Kamerschen, Public Utility Reports, Inc., 1988, page 401.

customer costs are the expenses associated with local connection facilities, metering equipment and meter reading, billing and accounting, *and a portion of the distribution system.*"[20] (Emphasis added) Finally, Professor Bonbright states that, "in actual practice the vast majority of utilities utilized some form of minimum system to classify costs, which is in line with FERC accounts."[21]

Q. Do any other recognized authorities in the utility regulatory field respond to Mr. Rabago's contention that it is improper to characterize a portion of a utility's distribution system on a customer basis?

A. Yes. In his widely utilized text, The Regulation of Public Utilities,[22] Dr. Charles F. Phillips, Jr. states that, "customer costs vary with the number of customers. These costs include a portion of the distribution system, local connection facilities, metering equipment, billing and accounting. Customer costs, moreover, are independent of consumption."[23]

Similar to the concepts accepted in the electric utility industry, In Gas Rate Fundamentals,[24] published by the American Gas Association (AGA), it is stated that customer-related costs are primarily distribution and customer accounting costs. In conjunction with its discussion of various utility cost components, it is further stated that, "the closer a plant item (e.g., a meter and service line) is located to a customer, the more that particular item is related to the specific requirements of that customer. Thus, the customer component of distribution costs reflects the theoretical distribution system that would be needed to serve customers at nominal or minimum load conditions."[25] Additionally, in discussing the various functions and cost causative components attributable to the operations of a gas distribution utility, it is stated that for distribution costs, the prime cost causation component is one that is

[20] Ibid, page 401.

[21] Ibid, page 492.

[22] The Regulation of Public Utilities, Charles F. Phillips, Jr., Public Utility Reports, 1984.

[23] Ibid, page 406.

[24] Gas Rate Fundamentals, Fourth Edition, American Gas Association, 1987.

[25] Ibid, page 136.

customer-related.

While these utility costing concepts are presented within the context of a gas utility's distribution system, they are reasonably applicable to an electric utility such as Vectren South and should be considered as additional support for its rate design proposal.

VIII. CONCLUSION

Q. Does this conclude your prepared rebuttal testimony?

A. Yes, it does.

VERIFICATION

I, Russell A. Feingold, Vice President of Black & Veatch Management Consulting LLC, under penalty of perjury, affirm that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Black & Veatch Management Consulting, LLC
By:

Russell A. Feingold
Vice President

Dated: June 12, 2017

SMART RATES FOR SMART UTILITIES

Creating a New Customer Paradigm with Enhanced Pricing of Utility Services

H. Edwin Overcast

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Building a world of difference.®

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Introduction

The U.S. electric utility industry is in the midst of rapid technological change and a transformation of the customer service paradigm. Much of the debate surrounding the changing industry centers on the implementation of more sustainable practices, such as energy efficiency and distributed energy resources, and compliance with more stringent environmental regulations. Notably, the debates continue to focus on technological and operational solutions. However, developing a 21st century rate design, or Smart Rates, can help facilitate solutions to today's industry challenges and provide customers with better price signals to assess competitive service offerings.

Smart Rates recognize that utilities provide a variety of services to customers and that the costs of these services are not always caused by the amount of energy the customer consumes. From a rate design perspective, Smart Rates fully unbundle[1] each component of utility costs and bill those components on the appropriate customer billing determinants consistent with the concept of cost causation. The unbundling of costs changes virtually all of the current rate traditions because it no longer rolls all utility costs into a single kilowatt-hour (kWh) charge or single kilowatt (kW) charge as if those costs are caused only by the single measure of customer energy consumption. Cost unbundling is critical for accommodating competition from on-site generation and allowing customers to choose which services they need from the utility.

This paper sets forth the theory and practice of 21st century rate designs through full rate unbundling of utility services and provides a framework for "Smart Rates" that enable customers to purchase – and pay an equitable and supportable price for – the services they want and need, regardless of their energy consumption levels. Through the use of Smart Rates, a utility can send customers a proper price signal associated with each service and improve the efficiency of all its services to customers.

Many aspects of the electric utility industry have changed dramatically since its founding, yet rate structures have significantly lagged these advancements. In order to best represent today's electric services and meet the needs of today's electric consumers, modern rate designs are essential. Smart Rates enable customers to use electricity and electric services more efficiently and provide utilities with revenue stability that enable the offering of more responsive services to accommodate customers' specific demands.

[1] Rate unbundling in this context is simply pricing each utility provided service separately so that customers pay only for the services they use, rather than paying a single charge that includes all services and assumes that all customers within a class have homogenous service requirements.

The Challenge with Current Utility Rate Designs

Current utility rate designs have their foundation in rates developed in the 19th century. The most common rates in use today are based on the watt-hour meter and consist of a fixed customer charge and some form of volumetric charge per kWh. As a practical matter, the choice of rate designs for various customer classes has depended specifically on the cost of metering relative to the total cost of service to the customer. For larger customers, most utilities use one of the following rate forms, both developed in the 19th century, or a combination of the two forms:

- **Hopkinson Demand Rate:** The most common method of pricing electricity for customers served with demand meters, such as large industrial customers. The Hopkinson Demand Rate consists of an energy charge for total kWh consumption in addition to a demand charge based on the facility's maximum energy use during any short time period (quarter-hour, half-hour or one-hour) in the month.
- **Wright Hours Use of Demand:** This rate form is also used for demand metered customers and bills those customers using kWh charges for different levels of hours use of demand. The Wright Hours Use of Demand consists of a customer charge and kWh charge blocks based on the number of hours that the customer's maximum monthly demand is used. Hours use is calculated by dividing the monthly kWhs by the measured maximum demand. The price of energy declines as the hours use increases recognizing both the customer's increased load factor and the increasing use of off-peak energy.

Even today, not all electric service applications are metered and the rate design used for such services are the same flat rate service used by the industry when it first started delivering electric power to customers in the 1880s.

Unless the rate design reflects cost causation for the services provided, customers who elect to buy particular service components will not pay for all the services they consume. This creates market instabilities as the result of cross-subsidies embedded in the utility's rates. Such cross-subsidies cannot withstand today's market pressures and will result in skewed prices and service levels for all market participants.

UNDERSTANDING COST DRIVERS

As noted, modern regulatory requirements for demand-side management (DSM) and energy efficiency, as well as customer demands for distributed generation (DG), do not align with current utility rate structures. The reason for this is that current rate structures incorrectly assume that energy, or measured kWh use, causes the utility to incur nearly all costs except for the costs that are reflected in a modest customer charge. For larger customers, the use of both a demand component and an energy component assume that a single measure of kW demand coupled with a unit kWh charge cause all of the fixed costs of utility service. In reality, utility services and the costs associated with each are caused by fixed and variable cost drivers. Both the fixed and variable cost drivers differ for different cost components and for different seasonal and diurnal periods.

Fixed costs do not change with energy use but can vary as a result of other cost drivers, such as customers or demand. Because these costs are fixed, they do not change with any hourly pattern of energy use, even though some time interval is used to measure demand (e.g., highest 15, 30 or 60 minutes). *Appendix A* provides a brief description of the determination of demand for billing capacity-related costs to customers. Examples of utility fixed costs include:

- The investment in the fleet of plants generating electric power.
- The integrated transmission network investment that moves power from generators to the distribution system.
- The distribution system that provides power to homes and businesses.

Variable costs, on the other hand, can vary by season of the year, time of use, and/or environmental conditions such as forced outages or partial unit deratings that change the marginal source of energy for a particular time period. Examples of variable costs include:

- Fuel and fuel handling costs.
- Purchased power.
- Volumetric charges from regional transmission organizations (RTOs) or independent system operators (ISOs).
- Chemical costs.
- Energy-related operations and maintenance costs.
- Other environmental costs.

A Utility's Cost Causative Factors

Whether fixed or variable, costs are generally caused by one or a combination of three general factors:

- **Customer:** In general, if a cost varies as a result of customer count, then this is a customer-caused cost and can include customer service expenses (e.g., billing and meter reading), and facilities or assets located on the customer premise, such as the meter and service line, and even portions of the distribution system that serve to connect customers to the grid.

- **Energy:** These are the costs that vary directly with the number of kWhs produced, with the cost of fuel being the largest component.

- **Demand**: Demand related costs are those costs caused by the largest load in kW imposed on various parts of the utility's transmission or distribution systems.

  NOTE: *The demand factor that causes costs differs for different types of cost elements. For example, some form of coincident demand is the cause of both utility production and transmission costs. This peak hour or other measure of demand drives the required capacity along with a level of reserves and it is this measure of demand that should be the basis for the charges to recover that unbundled cost.*

Understanding the nature of different utility costs, the types of costs, and what causes costs to be incurred enables utilities to use specific pricing mechanisms that align with cost factors (Table 1).

Table 1 - Unbundled Costs by Type and Causal Factors

COST FUNCTION	COST TYPE	CAUSAL FACTOR(S)	PRICING
Generation Plant	Fixed	Demand	kW Charge
Transmission Plant	Fixed	Demand	kW Charge
Distribution Plant	Fixed	Demand, Customers	kW Charge and Customer Charge
General Plant	Fixed	Demand, Customers	kW Charge and Customer Charge
Generation O&M	Fixed, Variable	Demand, Energy	kW Charge and kWh Charge
Transmission O&M	Fixed	Demand	kW Charge
Distribution O&M	Fixed	Demand, Customers	kW Charge and Customer Charge
Administrative & General costs	Fixed	Demand, Customers	kW Charge and Customer Charge

This table shows the appropriate type of charge to recover the categorized costs in order to match cost causation with pricing without a detailed specification of the particular charge.

UNDERSTANDING UTILITY SERVICES

Unbundling of rates requires an understanding of all services a utility provides, and the cost drivers for each service. Most stakeholders generally understand that a utility provides safe and reliable electric service to its customers. However, most characterize this service as simply providing the energy product, which is one reason why the kWh-based rate structure continues to prevail today. In reality, utilities provide numerous services, including:

- Generation service
- Transmission and distribution services
- Customer service
- A variety of services that provide safe and reliable operation of the electric system as well as the facilities that use the electricity behind the meter, such as voltage regulation, in-rush current for starting electric motors and other ancillary services.

Each of the listed major functions of the utility can provide multiple specific services for a variety of customers. Furthermore, each service also includes a quality of service component, generally defined as firm or non-firm. Firm quality means that the utility provides service continuously without interruption except those related to unavoidable system outages (e.g. outages caused by severe weather). Non-firm quality means that the customer has agreed with the utility to permit its service to be interrupted at times the utility chooses. Table 2 demonstrates the multiple services provided under the generation functional umbrella, and how those services have different patterns of cost based on the quality of service.

Table 2. Potential generation services

SERVICE	QUALITY
Full Requirements	Firm
Full Requirements	Non-Firm
Partial Requirements- Supplemental	Firm/ Non-Firm
Partial Requirements- Supplemental Baseload	Firm/ Non-Firm
Partial Requirements- Supplemental Peaking	Firm/ Non-Firm
Partial Requirements- Standby/Backup	Firm/ Non-Firm
Partial Requirements- Maintenance Service	Firm/ Non-Firm
Partial Requirements- Scheduled Maintenance Service	Firm/ Non-Firm
Partial Requirements- Unscheduled Maintenance Service	Firm/ Non-Firm
System Related Services- Black Start, Area Protection, Frequency, Transmission Support	Firm

As Table 2 illustrates, there are many potential services (the list is not intended to be comprehensive) provided by the generation assets. Each service has different cost characteristics as well as quality differences. The result is that rates for unbundled generation may differ based on the type of service required. A similar set of requirements relate to transmission and even to some distribution services, although the closer the service is to the customer the less costs and quality of service provided vary. For example, if the provision of energy is non-firm, that service does not change the cost of the distribution facilities for serving the customer because the utility must still be able to meet the customer's maximum requirements when there is no interruption of service.

MODERN CHALLENGES TO TRADITIONAL RATES

Net Metering Policies

The fallacy of applying 19th century rate structures to the types of 21st century electric utility services required by customers is made clear by the economic effects of DSM programs, and the growing adoption of DG assets (e.g., rooftop solar) among customers who seek the economic benefit net metering policies provide. While these customers are using less energy, and some may even be net-producers of energy, they are still using utility services. However, because current rate structures assume that the level of kWh consumed by the customer causes the utility's costs; discontinuities in billing and cost recovery among customers are created. According to the Edison Electric Institute (EEI):

While net metering policies vary by state, customers with rooftop solar or other distributed generation systems usually are credited at the full retail electricity rate for any electricity they sell to electric companies via the grid. The full retail electricity rate includes, not only the cost of power but also all of the fixed costs ... that makes the electric grid safe, reliable, and able to accommodate solar panels or other distributed generation systems. Through the credit, net-metered customers effectively are avoiding paying these costs for the grid.[2]

Net metering is the practice of allowing on-site generation to reduce the kWh portion of the residential customer's bill (netting generation against load) on a unit kWh generated basis. Recognizing that under a utility's traditional rate design the kWh charge for these customers recovers most of the fixed costs and the variable costs of energy on an average basis, the compensation for the customer's level of self-generation essentially assumes that all of the costs not recovered under net metering can be saved by the utility. That is simply not the case.

Consider, for example, the utility that peaks after sunset in every month of the year. Solar PV makes zero contribution to reducing the fixed costs for that utility. Importantly, the only cost savings are the avoided energy costs - and that would not even be valued at the utility's highest energy cost hours. In this case, net metering forces all non-solar PV customers to bear the costs of production, transmission and distribution capacity costs that are caused by the solar PV customer. While this is an extreme case to illustrate this deficiency in net metering, there are many utilities where the peak loads occur when solar PV is not generating its maximum output. This means that the avoided costs of the utility will not be as large as the credit provided under net metering, and that a cross subsidy will be created which allows solar PV customers to avoid paying for the fixed costs they cause the utility to incur.

Demand-Side Management Issues

With respect to DSM, issues similar to those under net metering arise when DSM programs save energy, but not capacity. A simple example illustrates this point:

A recreational facility owner invests in skylights to save energy during the day. The skylight salesman calculated his expected savings by dividing the total utility bill by the monthly kWh and providing a unit kWh savings. However, the facility was billed on a commercial rate that included a demand charge. Needless to say, the savings did not materialize because the facility's peak demand occurred at night due to its heavy lighting load. The skylights created no demand savings - only daytime energy savings. Based on the actual savings, the skylights were not economic and the owner made a poor decision to invest his limited capital on an inefficient solution to reduce energy-related costs.

By unbundling rates, the utility recovers all of its costs from each customer regardless of the amount of energy (kWh) used by the customer, or when the energy was used. Such a pricing structure will create rates that fairly portray the value of the service in the market and will eliminate the inherent

[2] "Straight Talk About Net Metering." Edison Electric Institute (http://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/Straight%20Talk%20About%20Net%20Metering.pdf). September 2013.

intra-class cost subsidies in current utility rates, creating benefits for all segments of the energy industry.

21st Century Rate Design

A 21st century rate design fully unbundles each component of cost and bills those components to customers based on the appropriate billing determinants (customer, kW, kWh) consistent with cost causation. The unbundling of costs and the implementation of modern rate designs appropriately change virtually all of the current rate traditions perpetuated over the years. Different rate components are billed separately and each customer will only pay for the services they use. This section focuses on the components of an unbundled rate design.

Unbundled rates consist of the basic customer, demand and energy charges. Under full unbundling, these basic rate components are translated into:

- Customer charge
- Production demand charge
- Transmission demand charge
- Distribution demand charge
  - Distribution substation service
  - Distribution primary service
  - Secondary distribution demand
- Energy charge
  - Energy service at transmission voltage
  - Energy service at substation delivery
  - Energy service at primary delivery with and without transformation
  - Energy service at secondary voltage.

Obviously, not every utility will require all of these distinct charges based on their existing service arrangements and the customers' available service options. Further, there may well be subcomponents of various costs associated with services such as back-up, standby, maintenance and supplemental power as each relate to generation, transmission, distribution and energy services. In some markets, unbundled services, such as meter reading and billing, may not be provided by the utility. In that case, the customer charge component needs to reflect the exclusion of the costs of these services.

A customer's rates may also differ based on geographic segments of the utility's system because costs may differ at different load nodes (this consideration is particularly important for systems with wide geographic reach that include different load nodes and/or climatic considerations.)

UNBUNDLED RATE COMPONENTS

Derivation of the Customer Charge

The derivation of a fully unbundled rate design begins with the customer cost component. While customer costs will always be a subject of debate among a utility's stakeholders, the logic supporting this concept is quite simple: If a cost varies based on customer count, then the cost is customer-related. This includes a utility's customer service functions and its assets located on the customer premise.

Another element of customer costs are those portions of the utility's minimum distribution system required to serve even the smallest customer. Minimum distribution system requirements include transformers, secondary conductors, poles and/or underground facilities.

To derive its fixed customer charge, a utility uses a detailed cost of service study that unbundles costs into various components. These unbundled costs form the basis for setting the rates for each component of service. For example, if the cost of service study calculates the customer component to be $300 per year, that amount would be the basis for a $25 per month customer charge. The annual cost derived from the utility's cost of service study would include the annualized cost to support the investment in a meter, service line, transformers, secondary conductors and poles, Operation & Maintenance (O&M) expenses related to the customer's plant, general plant, and any other assets required to provide the service, and customer service expenses (e.g., billing, meter reading, customer accounts and collections).

Derivation of the Production Demand Charge

Not all electric utilities will have production demand charges. This discussion focuses on the need for such charges for a vertically integrated utility. In that case, the production demand charge includes the fixed costs of generation and the transmission lines and related facilities that interconnect the utility's generation to its bulk transmission system. Ideally, these costs would be collected through two separate demand charges. This is the preferred rate structure because the typical electric utility experiences distinct differences between the marginal costs of production for serving peak loads compared to the costs for serving loads occurring other than during the peak period (i.e., base load production). At the same time, with the expected increase in the penetration of distributed energy resources (DER) on utility systems, this rate structure will properly value the benefits of DER to the customer based on the times when such self-generation actually is operating.

In general terms, the first demand charge (known as the Production Peak Demand Charge) recognizes the capacity costs associated with the utility's peak demand period, while the second demand charge recognizes the higher capacity costs of base load units that provide substantially lower energy costs. These costs are recovered based on the maximum demand in the peak demand period subject to a one hundred percent ratchet.

The carrying cost of the utility's least-cost production resource (nominally a gas turbine) and the associated transmission costs would be collected as a demand charge based on a demand measure during the highest load hours, where load is defined as: *The sum of customer load, forced outage load, scheduled outage load and generator deratings.*

This demand charge reflects the unbundled costs of required capacity with a level of reserves. The result is that certain charges may be incurred by the customer based on specific time periods that may differ from on-peak hours for energy, in general, and may differ for generation and transmission. For example, if the reserve requirements are calculated by an RTO or ISO based on a specific set of critical hours, those critical hours may be appropriate for determining the billable production demand associated with peaking facilities. If these hours are very short periods, such as the maximum demand hour in the summer months of June, July and August, it is not feasible to know in advance when those peak hours may occur and the peak hours used to measure the hours when the demand charge is applied may change from year-to-year and month-to-month.

It is important to note that deriving the Production Peak Demand Charge based on a short demand period runs the risk of shifting load out of that period. In addition, this also creates risk for increasing load after the peak demand period, causing the peak to occur in different hours because shifting load out of a short period may reduce natural diversity. It is critical that the shifting peak concept be fully assessed because there is a possibility that the loss of natural diversity in loads may cause other capacity-related costs to increase - such as for the utility's distribution and transmission facilities.

By establishing a longer fixed period for deriving the Production Peak Demand Charge, the shifting demand peak creates no issue for creating a new production demand peak outside of the demand hours. This is done by taking advantage of the natural diversity that occurs between loads.

It is also critical to understand that the need for capacity is based on more than just the customer load on the utility's system. Simply, the total maximum load on the system is the sum of customer loads, scheduled outage loads, unscheduled outage loads and unit derating loads. The latter two components change for every time interval just like customer loads. In some cases, the seasonal derating is known in advance based on the generation technology or a condition such as lower water flows that occur naturally.

Other factors may also derate the capacity of a unit without forcing the unit out of service (e.g., tube leaks). Since these types of occurrences reduce available capacity, they must be treated as load for purposes of determining the peak hours that matter for cost causation purposes. It has been said that if load factor on the generation system increases beyond a certain point, it will be necessary to build reserves just to schedule maintenance activities. Thus, it is important to understand the full demand on generation resources for purposes of establishing the demand period for production. Shifting load to off-peak periods does not always result in the full expected savings and could with some technologies create a new peak period in the former off-peak hours.

The second demand charge (known as the Production Base Load Demand Charge) is designed to recover that portion of the utility's revenue requirement associated with production not recovered through the Production Peak Demand Charge. The value of this charge may be zero in some circumstances. Where there are additional costs, the Production Base Load Demand Charge will be based on the highest monthly demand outside the peak demand period, without any ratchet provision. Thus, customers who benefit from lower cost energy will contribute to the additional capacity costs that produce those savings.

In the alternative, where utilities operate in restructured markets, the Production Peak Demand Charge of RTO or ISO participants could be based on the capacity responsibility determined by the operational control entity. This charge would be subject to a 100 percent ratchet on an annual basis. The remainder of the capacity costs not covered by the Production Peak Demand Charge would be recovered in a second demand charge applicable to the highest monthly load occurring in the month, without a ratchet.

Derivation of the Transmission Demand Charge

For transmission, the analysis of peak loads need not be the same as for generation. On integrated utility systems, native load may be only one component of the peak load. Understanding how the system is loaded on an hourly basis is a necessary element for the determination of transmission system peak periods. It is possible that the demand allocation for the generation function will differ from the allocation that is appropriate for the transmission function. This is particularly true where transmission for others across the utility system results in higher loading at times other than the native load system peak.

Transmission system loading on integrated utility systems is not solely a function of customer load on the system because of congestion management and centralized dispatch. For example, if load flows across the individual utility system because of lower cost generation, a transmission system may be fully loaded many more hours than retail customers' own load alone would indicate. Determination of the expected loading may also change because of events unrelated to the transmission facility owner, such as unit forced outages, changes in relative fuel costs, must-run generation and other factors that alter grid dispatch. The result of these factors is to change the allocation and cost responsibility for transmission in a way that impacts the appropriate demand period determination. To do this, it is important to understand the components of the transmission system and the cost drivers for each:

- **Generation laterals**: costs driven by connecting generation to the system and should be included in the generation/production demand costs.
- **Load laterals:** Costs driven by the loads on the lateral and may differ from the system or the transmission peak. Costs for load laterals are recovered through the distribution facilities demand charge.
- **Bulk transmission system**: Costs driven by loading of the bulk system and are recovered based on the load characteristics of the system. Options include:
  - Maximum load occurs in each month of the year: The demand charge is based on the peak period demand within every month and is the basis for the transmission demand charge.
  - Maximum load occurs in summer: If system is loaded only during four summer months, then the costs would be based on demand that occurs during the peak demand time period, even though the charges are billed over all 12 months. In essence, the non-seasonal demand would be equal to the average of the four critical peak demand periods.

Derivation of the Distribution Demand Charge

Distribution demand costs are driven by the customer peak load whenever it occurs. These costs are not identifiable on a time-of-use basis and the individual customer's maximum demand or contract demand (the maximum obligation of the utility to provide the local distribution service) is the appropriate demand measure to use to recover such costs. Any distribution costs not recovered in the customer cost category and the portion of transmission costs for load laterals are recovered in the distribution demand charge. The distribution demand charge would include a 100 percent demand ratchet based on either the customer's contract or actual demand.

As a general rule, the distribution system components peak at times that may not be coincident with the generation or transmission peak load. In planning and designing the distribution system, an important design element is natural load diversity that occurs based on the electricity use of the premise (businesses and residences have differing time patterns of load).

Certain activities, such as storage may alter the natural diversity of loads. For example, controlling electric water heaters by shutting them off for extended peak periods results in much higher coincident peak demands on delivery facilities because the natural load diversity is disrupted by the added control. The result is both higher distribution costs and higher peak demands for customers subject to control. Based on experience with time-of-use rates, there is potential for a similar impact on the distribution peaks and the cost of delivery service.

The recovery of distribution-related costs based on maximum demand whenever it occurs is fundamental to cost-based rates.

The three components of the distribution demand charge are recognized in the cost allocation process and relate to substation costs, primary facilities and secondary facilities not recovered in the customer charge. Conceptually, in a modern electric system all secondary costs should be customer-related. The allocation process recognizes that diversity increases as the load is measured further from the customer's individual load. To the extent that loads are homogeneous, a single distribution demand charge would be adequate. If there is little homogeneity, then the costs may need to be broken out separately but billed under the same 100 percent ratchet provision.

The customer and ratcheted demand charges would be based on an annual cost payable in 12 equal amounts. These annual charges would be premise-based so that a new customer occupying the premise would have his bills initially based on the premise's measures of demand. In addition, if a customer has service turned off at the premise and subsequently turns service back on, the customer would be responsible for the payment of fixed charges for the period where service was not taken as part of the cost of establishing service. Non-ratcheted demand charges would be based on the actual monthly use of demand.

Derivation of the Energy Charge

The final component of the unbundled rate design is the energy charge. The energy charge recovers all of the variable costs associated with the production or purchase of power. Further, the energy charge is not part of the utility's base rate. Rather, it is reflected in a full tracking fuel clause that recovers not only fuel and purchased power, but also variable production costs, environmental costs (e.g., scrubber chemicals), variable charges from the RTO or ISO, and any other costs that change with the consumption of energy.

The energy charge is subject to regular adjustments, like a fuel clause, and includes a deferral account that matches these costs dollar for dollar. The energy charges under this charge are differentiated based on cost causation by season, by time of use, by voltage level of service and, where applicable, by critical periods above and beyond the time of use periods. The adjustments to this charge are always seasonal-based adjustments in the sense that over or under recoveries of cost in a season are subsequently recovered in that season.

Energy charges may not require the inclusion of all of the cost components described above. For example, some utilities may not have distinct seasons. Others may have diurnal cost differences that are so small that there is no reason to separately bill for those differences. Some utilities with little diurnal difference may instead have critical peak periods when, for a few hours per month or for a few hours per season, they may experience costs far in excess of typical average or marginal cost levels. For example, the average cost might be approximate $35 per MWh for 97 percent of the time, but could easily exceed $100 per MWh in the remaining hours. In this case, the ability to provide proper price signals to customers would be important as would rate provisions designed to match costs and revenues under the critical peak period.

ILLUSTRATIVE RATE STRUCTURES

Using the concept of fully unbundled rates means that a utility's traditional rate class definitions are no longer as important. Cost-based rates enable the use of a less homogeneous class of customers, (e.g., there is no need to have one or more residential classes of service). There will no longer be a need for separate rate classes for certain end-uses, such as churches or schools, to reflect their different load characteristics compared to those of other general service customers. The ability to recover costs based on individual load characteristics then allows for rates based on other relevant conditions of service that have specific cost implications, such as voltage level of service or transformer or substation ownership.

Thinking about the factors that impact cost must begin with the customer component of costs including meter and service investment. This classification should also recognize that voltage level of service is of particular importance. In that context, it is possible to define a Small General Service Secondary Voltage Class. This class would consist of all customers who have essentially the same types of meter installations and service lines (e.g., residential, residential space heating, small commercial, small commercial all electric, etc.). Differences in other characteristics of utility service, such as demand coincidence factors and individual maximum demands, would not matter since the costs that are caused by these demand measures are already unbundled. The important point is to derive each component of the rate structure to reflect the actual cost of service.

Other classes would include General Service Primary Voltage, General Service Primary Voltage Transformer Ownership, Large General Service Substation, Large General Service Transmission, Non-Firm Service Rates and Back-Up and Standby Service Rates. These rates would reflect the different costs associated with each service and, as appropriate, seasonal, time of use and critical peak pricing-type considerations based on service level requirements and associated costs.

Customers who require unique service arrangements would have those costs recovered in a separate monthly fixed charge for directly-assigned facilities. For example, an industrial customer may take service at the substation, but require one or more dedicated lines to connect the substation to its facility. In that instance, the dedicated lines would be a directly-assigned cost and recovered under a separate charge unrelated to the customer's actual load.

To illustrate these concepts, the following tables outline the rate forms for General Service Secondary Voltage Class and General Service Primary Voltage Class customers.

Rates for the General Service Secondary Voltage Class assume the following operating conditions:

- All customers have the same meter costs and the average cost of secondary service lines consistent with the applicable line extension policy (customer's requiring a greater level of service investment make an appropriate contribution for the excess investment).
- Customer costs include a minimum system component for local distribution facilities at the secondary level.
- All primary related costs are included in the distribution demand charge.
- The utility is strongly summer-peaking for the 4 months, June through September.
- Partial requirements customers take service under this rate and the applicable back-up and standby service rate.
- Customers who require unique service arrangements either make a contribution in aid of construction for excess facilities or they pay a separate fixed charge.

Table 3 - Rate structure for General Service Secondary Voltage Class customers (i.e., residential)

RATE STRUCTURE (Billed amount)	TYPE OF CHARGE	DESCRIPTION OF CHARGE
Customer Charge $300.00/year or $25.00/month	Fixed	Charges that support the customer service functions of a utility (e.g., billing, meter reading, distribution connection)
Distribution Demand Charge $3.00/kilowatt of billed demand	Fixed	Charges resulting from the demand-related portions of the distribution system. This charge can be based on the greater of the current month's maximum demand, or the maximum demand occurring in any of the preceding 11 months.
Transmission Demand Charge $12.00/kilowatt year or $1.00/month	Fixed	This charge is for services provided by the bulk transmission system. It should be based on the rolling average of the maximum on-peak demand for the system
Production Demand Charge $96.00/kilowatt year or $8.00/month	Fixed	Includes the fixed costs of generation and the infrastructure that connects generation to the bulk transmission system.
Energy Charge Charges would vary based on time of use, such as $0.058/kWh for summer on-peak and $0.038/kWh for winter off-peak	Variable	Recovers all of the variable costs associated with the production or purchase of power, most notably fuel and environmental costs.

Charges based on a hypothetical vertically integrated electric utility providing a bundled service.

The rate components of a General Service Primary Voltage Class are outlined below assuming the following operating conditions:

- All customers have the same meter costs and the average cost of secondary service lines consistent with the applicable line extension policy (customer's requiring a greater level of service investment make an appropriate contribution for the excess investment).
- Customer costs include a minimum system component for local distribution facilities at the primary level.

- Remaining primary related costs are included in the distribution demand charge.
- The utility is strongly summer-peaking for the 4 months, June through September.
- Partial requirements customers take service under this rate and the applicable back-up and standby service rate.
- Customers who require unique service arrangements either make a contribution in aid of construction for excess facilities or they pay a separate fixed charge.

Table 4 - Rate structure for General Service Primary Voltage Class

RATE STRUCTURE (Billed amount)	TYPE OF CHARGE	DESCRIPTION OF CHARGE
Annual Customer Charge $600.00/year or $50.00/month	Fixed	Charges that support the customer service functions of a utility (e.g., billing, meter reading, distribution connection)
Primary Distribution Facilities Demand Charge $24.00/year or $2.00/kilowatt of billed demand	Fixed	Charge based on the greater of the current month's maximum demand or the maximum demand occurring in any of the preceding 11 months payable in monthly installments.
Transmission System Demand Charge $11.75/kW-year or $0.98/month	Fixed	Charge based on the rolling average of the maximum on-peak demand occurring in the hours of 12 noon through 9 pm weekdays in the months of June through September payable in twelve monthly installments
Production Peak Demand Charge $94.00/kW-year or $7.84/month	Fixed	Charge based on the rolling average of the maximum peak demand occurring during the hours of 12 noon through 9 pm weekdays in the months of June through September payable in twelve monthly installments.
Production Base Load Demand Charge $6.86/kW per month	Fixed	Charge based on the actual maximum demand occurring monthly regardless of the time the demand occurred.
Energy Charges Variable	Variable	The energy charges hereunder shall be determined from time to time to recover the total variable costs associated with the production, purchase and delivery of energy to the Company's transmission system including any volumetric charges imposed under an RTO/ISO Tariff. The summer season is defined as the months of June through September. The charges effective for the twelve months commencing June 1, 2014 are as follows: • Summer On-Peak (Hours 10 AM to 11 PM weekdays excluding holidays) $0.568 per kWh • Summer Off-Peak (All other hours in the season) $0.0441 per kWh • Winter On-Peak (Hours 6 AM to 10 AM and 5 PM to 9 PM weekdays excluding holidays) $0.0451 per kWh • Winter Off-Peak (All other hours in the season) $0.0372 per kWh

As these two rate structures illustrate, many of the unit charges for primary customers are lower because generation and transmission capacity related costs reflect lower primary voltage losses. For primary distribution costs, the lower charge represents the exclusion of secondary facilities from the cost of service at the distribution level. The lower energy-related charges are also the result of lower losses. The higher customer charge reflects higher metering and service costs, including using primary minimum system costs for service at this level. This general pattern will be repeated for each additional rate schedule with charges declining as the result of fewer facilities and lower losses. In addition, charges such as the residual generation costs or transmission costs will differ based on class load characteristics.

ROLE OF ADVANCED TECHNOLOGIES

Perhaps the primary reason rate structures have not changed significantly during the past century was due to a lack of technology to measure and appropriately charge for a variety of utility services. Until recently, utilities did not possess the technology and capability for measuring and recording data for each of its individual cost drivers.

Today's smart meters and advanced metering infrastructure (AMI) enable utilities to measure more than monthly kWh consumption. The technologies and back office software programs enable utilities to produce dynamic pricing information for customers and measure, record, bill and credit based on the usage levels of each service. Examples of additional services advanced technologies can track include:

- Time differentiated energy costs including critical peak prices;
- Demands by time of use and by maximum demand regardless of time; and
- Power factor measurement.

Smart meters permit a wider variety and type of price signals that can remove rate subsidies and send better, more cost-effective price signals to customers. With smart meters, each different rate component may be billed separately, enabling customers to pay for only the services they use.

OTHER CONSIDERATIONS

In addition to the various unbundled charges described above, it will be important to overlay seasonal and diurnal cost characteristics, critical peak pricing and time-of-use pricing, load control credits and other yet to be developed programs that reduce loads and create cost savings that would not be reflected in rates. Thus, we would expect to see energy prices that vary by season and by time of day based on time periods defined by cost differences, where appropriate. It will be important to develop seasonal and diurnal periods based on the underlying marginal costs recognizing that for some utilities those periods may vary in different parts of their systems. This would be the case where a portion of the utility delivery system is served off an electrically isolated load node of the transmission system. Where the system receives service from isolated facilities, the cost of these facilities and service should be borne only by the customers using these services. If the system is fully integrated, the costs of different nodes should be averaged across those nodes.

It is also important to remember that because unbundled rates eliminate intra-class subsidies that are included in many of today's traditional rate structures, certain policy goals could no longer be viably reflected as part of the rate. As such, programs such as low income bill assistance would need to be addressed indirectly through fixed bill credits funded by a separate rate component.

Ultimately these unbundled rates will be designed to recover the utility's class-related revenue requirements. The resulting price signals will be significantly more efficient from an economic perspective resulting in less resource waste and more economically efficient power systems. A key element of the successful implementation of unbundled rates will be to educate customers on how the rates reflect the underlying costs of particular utility services and how the customer can manage electricity use to reduce those costs. Overall, such rates are expected to generate efficiency gains for both customers and the utility.

The benefits of unbundled Smart Rates will accrue to every stakeholder group even though some members will pay more for the services they buy and others will pay less. Customers who pay more benefit from receiving the correct price signal and understand the benefits of alternative choices related to DSM and DG investments. For the utility, unbundled rates will not change the utility's revenue requirement in total, but will impact the stability of revenues favorably and will cause the utility to be more proactive in its marketing of unbundled services to customers. It will likely take substantial effort on the part of the utility to educate stakeholders of these benefits in a rising cost environment. It is the Smart Rates that will allow customers to use electricity more efficiently and allow the utility to recover its costs from customers who cause those costs to be incurred. While the utility will be economically indifferent as rate designs change, it will also benefit from better price signals as consumers adapt to the cost causative factors that form the basis for unbundled rates. Changing rate design will also impact customers who have made investments based on the economic signals of the 19th Century rates and some of those investments will no longer be cost effective. The issue of customer stranded costs will be a difficult element of the transition, but is inevitable because of technological advances in metering and in utility operations.

The end result of unbundled rates will be a more cost effective and better integrated utility system to the benefit of economic growth and new investments that enhance the efficiency of the utility grid. This new customer paradigm is a prerequisite for improving the safety and reliability of the utility system.

Appendix A

As electric rates become unbundled, it is important to understand the concept of demand billing. The concept of demand billing is one of measuring the maximum capacity of the electric utility's system used in any particular period of measurement. Load varies from moment to moment based on the actual use of electric appliances including motor loads such as compressors in HVAC systems or refrigerators and freezers. Lighting load varies even from minute to minute as lights are turned on and off. Some loads run continuously while other loads operate infrequently. The net result is that any particular customer can have a different load shape on a daily basis.

Figure A-1 Daily Residential Hourly Load Shape

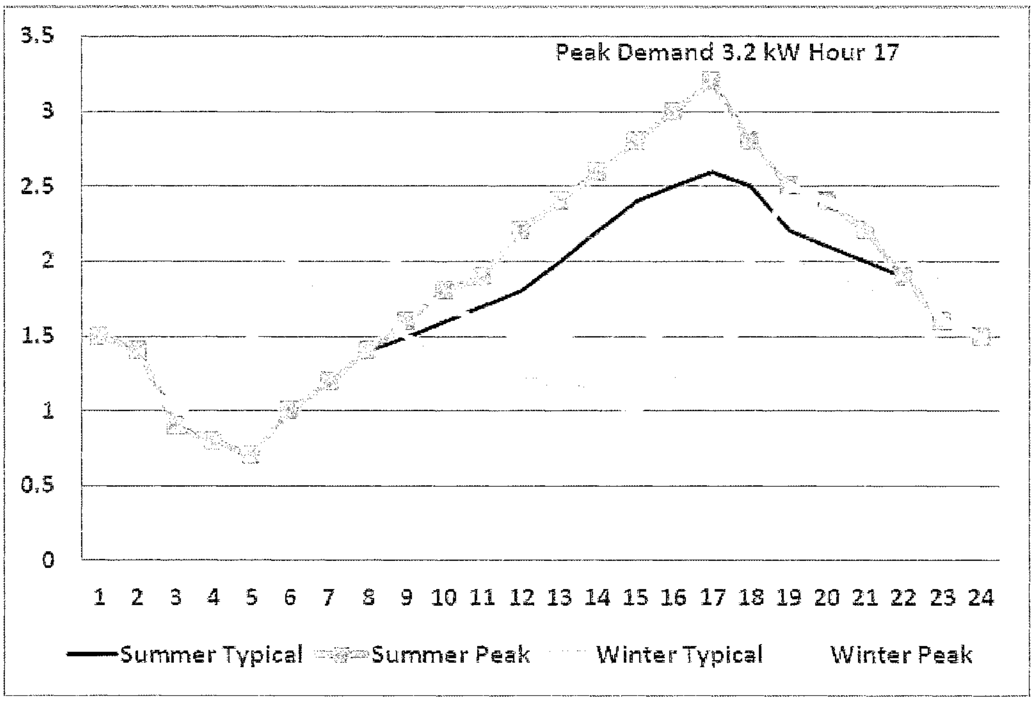

Figure A-1 shows a typical day summer and winter load shape and the peak day for both seasons. The peak hour demand for this customer occurs in the summer and is 3.2 kW. This is the customer's non-coincident peak demand based on an hourly measure. Hourly demand averages the kWh usage over the underlying measurement interval. For example, this demand may be average over four-15 minute intervals as illustrated in Figure A-2.

Figure A-2 Summer Peak Hour kW per Interval

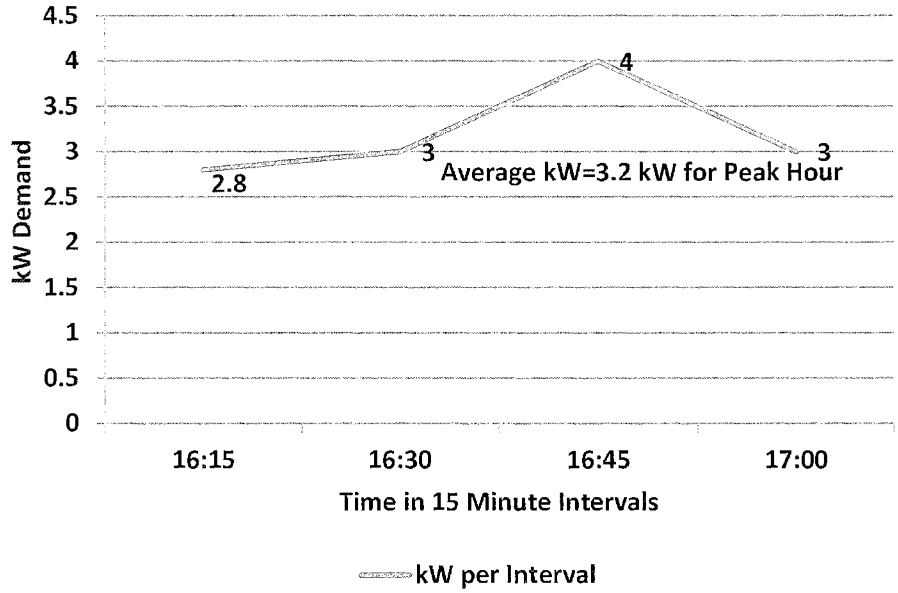

Figure A-2 illustrates the averaging of four-15 minute intervals to derive the customer's maximum demand. Maximum demand is also measured using shorter intervals. Table A-1 provides the demand in kW for each of the three possible measurement intervals.

INTERVAL	kW DEMAND
15 Minutes	4 kW
30 Minutes	3.5 kW
60 Minutes	3.2 kW

Since the kW measure of capacity required to meet the customer's load is the maximum demand on the utility system, the 15-minute interval is more representative of the required capacity for the utility's local distribution facilities. In any event, the choice of the measurement interval has little impact on customers' bills except for customers with highly variable loads. The reason for this is the costs are fixed and the higher measure of demand results in a lower unit charge for the customer.

As discussed earlier, there are many different billing demands that are relevant for cost recovery purposes. The same method of calculation is used in each instance although the hour or hours of measurement may differ. That is, some measures of demand might be defined as occurring within a specific range of hours. For example, the demand may be defined as occurring between the hours of 1 p.m. and -4 p.m. Since our data is reported on an hour-ended basis, the peak demand would be measured as the maximum demand occurring during the hours of 14 through 16 above. In that case, the demand would be 3 kW occurring at hour 16.