EXHIBIT
OTP-48

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in North Dakota

Case No. PU-17-398
OAH File No. 20170622

Exhibit ___

Electricity Marginal Cost of Service Methods and Proposed Use for OTP's Rate Design in North Dakota

Rebuttal Testimony and Schedule of

Amparo Nieto

June 22, 2018

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ATTACHED SCHEDULES

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Amparo Nieto. My office is located at 101 Mission Street, San Francisco, California.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am Senior Vice President at Economists Incorporated (EI), a firm of consulting economists.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have over 20 years of experience providing advisory services and analyses on behalf of utilities, independent firms and energy regulatory commissions, in the context of energy regulatory policy and wholesale market designs. I have extensively advised on the development of marginal cost studies for use in the design of more efficient electricity and natural gas rates for utilities in North Dakota, South Dakota, Minnesota, California, Oregon, Arizona, Maine, New York, Manitoba, and other states, as well as provinces in Canada. As part of my work on rates, I have reviewed and developed more efficient utility electricity rate structures, recommended changes to demand response and interruptible rates, reviewed the impact of net metering rates and designed alternative compensation proposals for Distributed Energy Resources (DERs). In New York, I was involved in the initial stages of the Reforming the Energy Vision (REV) docket, as part of my work for an electric and gas utility, involving locational marginal cost studies. I have also advised energy regulatory commissions in Australia, Ireland, and Spain on methods to improve regulation of transmission and distribution, design of financial transmission rights, and reforms to wholesale market rules. I was a key member in the team advising and implementing energy auction designs in Pennsylvania and Spain, and have advised the ISO-NE and NYISO in various aspects of their wholesale capacity market rules.

I am currently the director of the "Utility of the Future Rates Group", a working group sponsored by EI and open to energy utilities across North America. The group meets twice a year to discuss ways to improve and innovate in utility pricing and marginal cost methods, and to more efficiently and cost-effectively accommodate new DERs in the utility's service territories. Additionally, I have conducted seminars on electricity marginal costing and rate design for rate managers and regulatory commission staff for over a decade. I have published energy papers and extensively participated as a panelist on industry and academic forums in the U.S. I hold a Masters' degree in Economic Analysis and Public Finance from the Madrid Institute for Fiscal Studies, and a B.A. in Economics from the University of Carlos III of Madrid. My curriculum vitae is set forth in Exhibit___(AN-1), Schedule 1. Prior to joining Economists Inc., I worked for 20 years at NERA Economic Consulting.

Q. WHAT IS YOUR EXPERIENCE WORKING WITH OTP AS IT PERTAINS TO THESE PROCEEDINGS?

A. I have supported Otter Tail Power Company (OTP) in the development of marginal cost estimates and rate design for the last decade. I prepared the 2018 Marginal Cost of Service Study (MCOSS) that was filed with the current Rate Case and was included as Exhibit___(DGP-1), Schedule 2 to the Direct Testimony of OTP witness Mr. David G. Prazak. In 2008, I was a lead consultant in the development of OTP's electricity MCOSS that was filed as part of OTP's 2008 North Dakota Rate Case (Case No. PU-08-862). I also prepared marginal cost studies for use in OTP's Minnesota and South Dakota jurisdictions.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of OTP.

Q. HAVE YOU PREVIOUSLY SPONSORED ANY TESTIMONY IS THIS PROCEEDING?

A. No.

Q. HAVE YOU TESTIFIED IN OTHER REGULATORY PROCEEDINGS?

A. Yes. I provided Rebuttal Testimony on behalf of OTP as part of its 2016 Minnesota Rate Case, providing a discussion of the benefits of establishing multi-part rate structures that follow the marginal costs structure. I also filed testimony before the New York Public Service Commission, the North Carolina Utilities Commission, and the Public Utilities Commission of Nevada in the context of electricity marginal cost studies, rate design and design of contracts with independent power producers. I have also provided expert testimony as part of the Salt River Project's price review process before its Board of Directors, with regard to its proposal to reform its net metering rates. Overseas, I have supported regulatory proceedings involving rate reforms in Ireland, as well as in Brazil, Africa and the Caribbean.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. OTP asked me to review the critique presented in the Direct Testimony of North Dakota Public Service Commission (the Commission) Advocacy Staff (Staff) consultant Dr. David Dismukes. As part of his testimony, Dr. Dismukes discusses OTP's MCOSS and its use in OTP's rate design proposal. The purpose of my testimony is to respond to Dr. Dismukes's Direct Testimony and in particular with regard to the robustness of OTP's MCOSS and its applications for residential rate design and intra-class cost allocation.

Q. HOW IS YOUR REBUTTAL TESTIMONY ORGANIZED?

A. My testimony is organized as follows.

- In Section II, I provide a summary of my Rebuttal Testimony.
- In Section III, I provide a high-level explanation of the role of marginal costs in utility ratemaking.
- In Section IV, I address the specific areas of criticism that Dr. Dismukes raises in his Direct Testimony with regard to OTP's MCOSS estimation methods. I highlight the areas where Dr. Dismukes has mischaracterized the nature of the calculations performed in the study and explain the appropriateness of OTP's marginal cost methods.

- In Section V, I address the objections of Dr. Dismukes to OTP's specific proposed use of MCOSS results for customer cost allocations and for the design of new North Dakota rates, and explain why OTP's rate changes are justified from the point of view of best industry practice on efficient ratemaking.
- In Section VI, I summarize my conclusions.

II. SUMMARY OF REBUTTAL TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. OTP has a long history of utilizing marginal costs to design rates. Its 2018 MCOSS was prepared using the same methods as were used to develop the MCOSS submitted in OTP's 2008 North Dakota Rate Case. Those methods are consistent with the development of MCOSSs for utility applications throughout the United States.

Dr. Dismukes focuses exclusively on OTP's calculation of marginal distribution and customer costs. He provides no analysis or assessment of marginal generation, transmission, distribution substation costs, or high-voltage distribution lines. His exclusive focus on the local distribution facilities and customer-related costs appears to be part of his overall advocacy for a rate design that incentivizes DERs. This goal, however, may not be efficiently achieved without ensuring that all customers see the time-varying marginal cost of using more or less electricity, through the volumetric charges.

Overall, OTP's proposed rate designs are a significant step closer to economically-efficient rates, which is consistent with ensuring that all customers contribute to OTP's cost of providing service on a non-discriminatory basis. OTP's rate designs also include elements of gradualism to moderate bill changes that might otherwise be considered a rate shock.

III. OTP'S MCOSS GOALS AND UTILITY APPLICATIONS

Q. WHAT IS MARGINAL COST?

A. Marginal cost is the cost of the additional resources needed to produce and/or deliver the next small increment of output (or the costs avoided when consumers reduce their demand by a small amount). It also represents the value of those resources in their next best alternative use, known as the opportunity cost. In perfectly competitive markets, the market-clearing price represents the marginal cost of the quantity sold. This price level is defined by the intersection of the total suppliers' marginal cost curve and the total market demand curve, where the demand curve reflects the customers' willingness to buy output at each price level. The market-clearing price represents both the value to the consumer of the additional unit of consumption, and the cost to the marginal supplier of producing the next unit.

Q. WHY IS IT IMPORTANT TO USE MARGINAL COSTS IN PRICING FROM A SOCIALLY EFFICIENCY STANDPOINT?

A. Pricing equal to marginal costs is economically-efficient, as it arrives at the efficient point of production/consumption that maximizes the sum of producer profits and consumer surplus (the value of the product net of the price paid). Producing output beyond that optimal level (using a price below marginal cost) is inefficient because the marginal cost of additional units of output would exceed the marginal benefit of that unit to society, thus, creating a loss to the producer that does not result in an increase in consumer surplus (or a social net deadweight loss). Producing below the optimal level by pricing above marginal cost would also create a social net cost. Thus, marginal cost-pricing leads to the least-cost result from a societal point of view.

Q. CAN THIS CONCEPT BE TRANSLATED TO ELECTRICITY UTILITY RATES?

A. Yes. Reflecting marginal costs in utility rates helps customers by expressly incorporating price signals of the incremental cost of providing electricity. As customers respond to these price signals, based on the value they gain from using electricity, their consumption patterns and levels will be more likely to align with a better utilization of the utility's infrastructure and resources. Customers' reaction to rates will slow down load growth in hours and or months when serving electricity needs has the highest opportunity cost to the utility. Marginal-cost based pricing thus has a direct and beneficial impact on determining the pace of expansion of the grid as well as in lowering the cost of generation. In short, it allows utilities to transact in the marketplace and to plan the system in a way that brings the highest value to their customers. Rates that signal marginal costs also maximize the ability to incent an efficient pattern of customers' adoption of DER technologies. The increasing adoption of behind the meter distributed generation resources, such as rooftop solar, in combination with net metering, has emphasized the problems that occur when marginal costs are ignored in rate design.

Q. SHOULD RATES USE A DIFFERENT PRICE SIGNAL, OTHER THAN MARGINAL COSTS, TO ACCOUNT FOR EXTERNALITIES?

A. In the presence of externalities, the product may provide other benefits (or cause negative effects), that do not affect exclusively the buyer of the particular output, but society at large. Since these other effects are not being internalized by the buyers, the social demand curve will diverge from the "private" demand curve of the product. A clear example of a negative externality is the consumption of electricity produced from sources that emit air pollutants. The socially optimal level of consumption is not observable at this point. However, retail rates are not the appropriate vehicle to correct for externalities. Governments generally adopt measures to address the externality (pollution) by making generators (at least partially) internalize these additional costs. Rates for electricity end use should then indirectly reflect the impact of the various correction mechanisms on the marginal costs of the supplier. In other words, the retail rate needs to continue reflect the marginal cost of meeting demand, given the cost structure of the suppliers and the demands of electricity customers, which already reflect the expected response to any prevailing environmental policies.

Q. PLEASE DEFINE THE REQUIRED CHARACTERISTICS OF A SUITABLE MCOSS.

A. A marginal cost study must answer the question: How do the utility's costs change when serving an additional kWh or kW at a particular hour or to provide connection service to an additional customer? The study needs to consider forward-looking marginal costs, over the period of years the rates are going to be in effect, and a forecast of demand conditions that drive those costs. There are several major concepts of marginal costs, namely linked to the timeframe that the analyst is considering. It is important to identify these and ensure that the right method is chosen for standard rate design purposes.

The short-run marginal costs (SRMC) is the cost of meeting an incremental unit of energy, or peak demand, using the existing resources, i.e., before adding any capacity that may be needed to reliably meet that demand. In the very short-run, if the utility has sufficient network capacity to meet the additional load, the system may only experience energy losses in bringing the power to the customer. If the load is exceeding capacity (e.g., circuit overload), severe voltage and instability problems may occur, potentially leading to involuntary load curtailment. The value of the foregone electricity to the customer for whom the service has been interrupted reflects the short-run marginal ("shortage") cost. This pure short-run marginal cost-scenario is not helpful to set utility rates because rates are set in advance of the tariff year, are fixed for a number of years, and do not change in real-time conditions. The MCOSS must also recognize that the utility will generally anticipate and plan well ahead of the capacity need since it is responsible to maintain a reliable service.

The second major concept in economics is the concept of long-run marginal cost (LRMC). The textbook definition of LRMC essentially assumes that all inputs can vary, the utility has an optimal amount of planning reserves to begin with, and, as demand grows, the utility will be able to re-optimize the system and undertake the optimal amount of investment (essentially, building the entire system "from scratch"). A pure textbook LRMC is not suitable for electricity rates. Utility MCOSS practitioners that claim to use LRMC are, in reality, just computing marginal costs assuming a long planning horizon of ten years or more. The use of LRMC is often justified from the point of view of securing a more stable "price signal" based on marginal costs. LRMC approaches are imperfect, however, because they do not allow rates to reflect the expected marginal cost to the utility of meeting demand increases during the period that rates will be in effect, thus they may fail to incent economically-efficient customer response.

A proper marginal cost approach will take into account the regional and system's actual and expected capacity conditions in the near term, and subsequently identify the investment and additional procurement needs triggered by the near-term forecasted load additions. This marginal cost approach is more suitable to estimate marginal distribution costs for rate design purposes, as it reflects the utility's near term incremental cost to respond to near-term demand growth. It provides a measure of the shortage-related marginal cost component associated with electricity usage in peak conditions.

Q. IN THE CONTEXT OF A VERTICALLY-INTEGRATED UTILITY, WHAT ARE THE VARIOUS ELEMENTS OF MARGINAL COSTS?

A. There are marginal generation, transmission, distribution, and customer costs. The need to reflect marginal costs in rates does not only pertain to the realm of passing-through marginal generation or marginal transmission costs in rates. It is also critical to look at marginal distribution costs and what components change with time of use and location and what components are customer-related verses demand-related. The proper calculation of marginal costs allows the rate analyst to have the tools to choose efficient rate structures, price signals to customers, which, in turn, can lead to more efficient consumption decisions, more efficient system expansion and ultimately improved social welfare. Even in the presence of market failures such as externalities or natural monopolies, utility rates should encourage customers to use electricity efficiently – according to marginal cost.

Q. HOW CAN UTILITY RATES BE STRUCTURED TO REFLECT MARGINAL COSTS AND STILL RECOVER THE AUTHORIZED REVENUE REQUIREMENT?

A. Transmission and distribution are natural monopolies, meaning they involve high fixed costs, and exhibit subadditivity of average costs (economies of scale). Recovering the fixed costs of utility monopoly service requires setting rates that, overall, produce higher revenues than marginal costs. The fixed costs of generation resources that the utility is authorized to recover may also be higher than the marginal generation cost at times of slow demand growth. In the context of monopoly businesses, electricity rates need to have a multi-part structure that preserves economically-efficient price signals for the various key components of the service, subject to ensuring full cost recovery. Rates can be designed to recover marginal costs plus any residual fixed costs needed to recover the revenue requirement, in a manner that minimizes the distortions in consumption decisions that result from pricing above or below marginal costs. This requires structuring rates as a two-part, or in some cases, a multi-part tariff that preserves price signals particularly for marginal use decisions, and that avoids uneconomic bypass of the system.

Q. WHAT OTHER REQUIREMENTS ARE IMPORTANT FOR PROPER UTILITY RATES IN ADDITION TO SENDING EFFICIENT MARGINAL-COST BASED PRICE SIGNALS?

A. The efficiency goal in utility rate designs needs to be balanced with equity, rate stability, customer acceptance, and price understandability goals. The concept of fairness in utility pricing and avoidance of rate shock sometimes requires departing from a pure marginal cost-based price structure, but even then, rates should aim to preserve the marginal cost signal in per-kWh charges as much as possible. In addition, marginal costs can inform the relative level of per-kWh price differentials by time of day and/or season, the appropriate price differential by voltage service, and ultimately the relative differences of the fixed charge across customer classes. When using a two-part rate, the fixed charge can be established to ensure that the utility recovers the prudent fixed costs of meeting demand and customer needs, while the output (electricity usage at various times of day) is priced at the total marginal unit cost that varies with level of usage. In the context of bundled electricity rates, an electricity marginal cost analysis seeks to estimate the impact on costs experienced by the utility from providing permanent customer access to the system and from accommodating changes in loads at different times of day and throughout the year.

Q. ARE THE OBJECTIONS OF DR. DISMUKES TO RELYING ON THE MCOSS FOR THE ALLOCATION OF CLASS REVENUE TARGET BETWEEN ENERGY AND FIXED CHARGES JUSTIFIED FROM A POINT OF VIEW OF ECONOMIC EFFICIENCY?

A. No. Dr. Dismukes is ignoring a wide body of academic and industry literature on the importance of using marginal costs when setting electricity price levels and rate structures. Beginning with economist Professor Alfred Kahn, who, in his influential book "The Economics of Regulation" (1970)[1] argued that attaining economic efficiency in the context of regulated utilities required ensuring that rate structures reflect marginal cost principles. Other authors, such as Turvey (1964, 1968, 2000),[2] or Brown and Sibley (1968)[3] were also influential in providing support to marginal cost pricing for electricity rates. Many other economists have supported the use of marginal cost estimates in the development of time of use and dynamic rates, including well-regarded economists Paul Joskow (2011).[4] OTP has put together a rate proposal for North Dakota that relies on well supported and sound economic principles by allowing price signals to get closer to marginal costs, while considering and moderating potential large effects on customers' bills.

Q. HOW SHOULD MARGINAL COSTS BE CONSIDERED IN SETTING EACH RATE CLASS'S REVENUE RESPONSIBILITY?

A. To avoid cross-subsidization, marginal costs should ideally be used as the starting point of the rate class[5] revenue target, i.e., making sure that no rate class pays below the marginal costs of serving them. Calculating this floor level of revenue by rate class must

[1] Kahn, Alfred E. 1970. *The Economics of Regulation: Principles and Institutions*, Volume 1. John Wiley & Sons.

[2] Turvey, Ralph. "Peak Load Pricing," Journal of Political Economy, January-February, 1968b. Turvey, Ralph. "Marginal Cost Pricing in Practice." Economica, Volume 31, Issue 124, November 1964, pp. 426-432. Turvey, Ralph. "What Are Marginal Costs and How to Estimate Them?" Centre for the Study of Regulated Industries. University of Bath, School of Management, March 2000.

[3] Brown, Stephen J. and David S. Sibley. The theory of public utility pricing. Cambridge University Press, 1986.

[4] Paul L. Joskow & Catherine D. Wolfram, 2012. "Dynamic Pricing of Electricity," American Economic Review, American Economic Association, vol. 102(3), pages 381-385, May.

[5] Mr. Prazak explains the difference between customer classes and rate classes in his Direct Testimony. *See* Prazak Direct, p. 7, n. 1.

recognize the marginal cost differences in serving different utility customer types, to limit inter or intra-class cross subsidies. To hit the overall authorized revenue requirement, and assuming that it is higher than total marginal cost revenues, each rate class revenue target will generally need to be increased above rate class' marginal costs. This exercise requires looking at the inverse price elasticity of demand of the rate class, as discussed by Ramsey (1927). Ramsey demonstrates that to maximize social welfare, those consumers with relatively more inelastic demands for the good will need to pay higher markups above marginal cost than other less price elastic consumer types. By setting mark-ups inversely proportional to price elasticity, the firm can recover all prudent on-going and sunk costs while minimizing the deviations from optimal consumption (usage that would occur if pricing strictly equal to marginal cost). In practice, many utilities use a variant of Ramsey pricing based on "equal percentage of marginal costs" (EPMC) methodology to allocate revenue requirement within classes. Under the EPMC method, each rate class is allocated a share of the revenue requirement based on its share of total class marginal cost revenues.

Q. DO YOU AGREE WITH DR. DISMUKES ASSESSMENT THAT THE MCOSS ARE GENERALLY TOO CONTROVERSIAL TO BE VALID FOR A UTILITY RATE CASE?

A. No. Utility-based MCOSS have been used for decades and accepted by the state commissions in rate proceedings of California, Nevada, Oregon, Arizona, New Hampshire, Illinois, New York, and other jurisdictions. In cases where the utility follows an embedded cost allocation study, rather than a marginal cost study to set class revenues, marginal costs can still be used to inform decisions on particular customer classes. States like Georgia use marginal costs for the design of special rates. Using marginal costs as a floor revenue level is common practice across the industry in developing Economic Development rates, to attract new high-load factor customers to the utility's service territory without imposing a burden on existing customers, or to develop retention rates. Marginal costs are also used to evaluate demand side programs and smart rates. In the last few years there has been a surge of marginal cost filings with state commissions since there is growing consensus among utilities as well as among regulators that marginal cost estimates are crucial to better inform customers of the cost impact and efficiency of their choices. There is also a generally accepted view that marginal cost-based rates produce more equitable and stable rates in the light of increasing amounts of DERs and particularly in the context of net metering. This is because when rate structures are based on marginal cost, the utility's revenues are more likely to track its total costs as electricity consumption changes, thereby reducing cross-subsidies between DER and non-DER owners.

IV. APPROPRIATENESS OF OTP'S MCOSS METHODS

Q. DO YOU AGREE WITH THE HIGH-LEVEL DESCRIPTION OF THE MCOSS METHODOLOGY PROVIDED BY DR. DISMUKES?

A. Yes. Dr. Dismukes's high-level summary of the MCOSS methods in pages 41-47 of his Direct Testimony is correct, with the exception that he mentions "In addition, the Company calculated economic carrying charges to capture elements of OTP's revenue requirement associated with marginal investment in certain categories of distribution plant."[6] In fact, the MCOSS applies an economic carrying charge (ECC) to annualize all categories of marginal distribution investment used in the study, as well as to meter and service drop. Otherwise, his description is aligned with the description provided in Mr. Prazak's Direct Testimony and my MCCSS supplemental report (Prazak Direct, Schedule 2).

I do not agree with how he characterizes these approaches later on in his Direct Testimony. For example, in page 50 of his testimony, Dr. Dismukes argues that the calculation of marginal distribution facilities costs, as well as other elements of the MCOSS are "simply an extrapolation of embedded costs." Dr. Dismukes has misinterpreted the approaches that the MCOSS used. There is no use of embedded distribution facilities costs in the study: the MCOSS estimates the cost that would require

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[6] Dismukes Direct, p. 47.

to connect a customer to the grid, using different types of customers within the class. The fact that the analysis was done in 2015 only recognizes that there was no need to modify the configuration of types of customer connections in the analysis because no change occurred since 2015.

Q. IS DR. DISMUKES' CHARACTERIZATION OF THE MCOSS METHODS CORRECT?

A. No, it is not. Dr. Dismukes has broadly characterized the MCOSS as being largely based on "historical average costs," which is not true. The MCOSS only relies on historical data where a forecast data is not available, such as in the case of operations and maintenance (O&M) expenses. He is also at times imprecise as to what he is referring to with the use of "average" costs. He uses this characterization to support his recommendation that the Commission should reject the MCOSS. This argument is biased and misleading. MCOSS needs to look at the average customer in the rate class, since rates are set for the entire customer base, not differentiated by customer type within the class. In general, Dr. Dismukes appears to justify in part his position against relying on OTP's MCOSS in this rate proceeding by way of pointing out at disagreements in the industry about MCOSS methods. In fact, the MCOSS approaches applied by utilities across the nation are not vastly different and they are becoming more homogeneous, particularly with regard to the distribution marginal costs.

Q. DOES DR. DISMUKES ADDRESS THE ENTIRETY OF THE MCOSS IN HIS TESTIMONY?

A. No. Dr. Dismukes focuses exclusively on distribution and customer marginal costs. He provides no analysis or assessment of marginal generation, transmission, or distribution substation costs.

Q. DID THE 2018 MCOSS USE THE SAME METHODOLOGY AS WAS USED IN OTP'S LAST NORTH DAKOTA RATE CASE?

A. Yes. OTP's 2009 MCOSS filed in Case No. PU-08-862 was prepared in the same way as the 2018 MCOSS. The Commission largely adopted OTP's proposed rate design in Case No. PU-08-862, which in turn reflected the 2009 MCOSS.

Q. PLEASE DESCRIBE HOW THE OTP MCOSS WAS PREPARED.

A. The MCOSS as filed by OTP is largely a forward-looking exercise. It is consistent with estimating incremental marginal costs of energy and capacity in the context of a vertically integrated utility, actively trading in MISO energy and capacity markets and using transmission under MISO open access transmission rates. It takes into account future distribution investments and distribution load growth, and the marginal costs of providing continued access to the grid and electricity service to existing and future customers. To summarize, OTP's MCOSS estimated:

- The forward-looking costs of energy (a forecast of MISO LMP) and capacity market prices (opportunity cost for OTP's generation capacity).
- A forecast of MISO transmission charges, a financial marginal cost to OTP.
- A forecast of distribution substation investment per kW of peak growth, based on expected capital expansion plan and a forecast of OTP's non-coincident load growth over the five-year 2018-2022 period.
- Expected going-forward marginal costs of customer connections for the typical customer in the rates class, based on cost of typical generic circuits.
- Expected marginal costs of meter and service drops and marginal customer service and account expenses.

The MCOSS recognizes that not all marginal costs are marginal with regard to energy usage, for example marginal customer cost and distribution facilities depend on number of customers and local design demand, respectively.

Q. WHAT ELEMENTS OF THE STUDY RELIED ON HISTORICAL INFORMATION?

A. The components of OTP's MCOSS that rely on historical information include the marginal distribution O&M expenses, the marginal customer service and informational expenses, and the marginal customer account expenses. Marginal customer account and service expenses represent the cost of adding and maintaining a new customer account. These costs were estimated taking as a starting point the account information for the last five years from FERC Form 1 data. They were allocated by OTP after conducting a survey of types of services provided to each rate class and relative weights, based on relative labor requirements and frequency of each activity by customer class. In addition, loading factors were projected based on historical information in order to develop an estimate of the how administration and general (A&G) expenses and general plant are expected to change with increments in O&M or plant.

Q. IS THE USE OF HISTORICAL O&M EXPENSES COMMON AMONG MCOSS?

A. Yes. Identifying marginal O&M per kW of demand, customer expenses per customer and A&G loading factors by using historical data is common practice in marginal cost analyses. Examples include studies by Pacificorp, Portland General Electric in Oregon, the three Investor Owned Utilities (IOUs) in California, Sacramento Municipal Utility District (SMUD), ConEdison, NYSEG and RG&E in New York and CMP in Maine. In order to project or develop a proxy, the MCOSS can either rely on the average costs in recent years, or develop a regression going back at least 15 years to have sufficient data to estimate a statistically significant correlation factor. By no means does this invalidate the estimated marginal O&M expenses or the marginal customer-related expenses. OTP's MCOSS produced reasonable estimates of the future expense per unit of plant or per customer by rate class over the period that the rates are expected to be in effect. In the case of OTP, the company did not anticipate a change in the way services were provided to customers by class, and therefore using the recent history on account levels as well as on weights was appropriate. In addition, customer expenses that were considered not-marginal were excluded from the calculation.

Q. DO YOU AGREE WITH DR. DISMUKES THAT THE MARGINAL O&M EXPENSES SHOULD HAVE BEEN LOWER?

A. No. Dr. Dismukes states that the MCOSS uses historical data as a proxy for future costs, in a manner "that is inconsistent and inappropriate" when estimating O&M expenses. It is unclear if he refers to the treatment of all O&M expenses, but he mentions meter O&M expense calculations as an example. Dr. Dismukes believes that the estimate should have been lower what the MCOSS estimated. In particular, he stated on p. 50 that:

> For instance, to estimate marginal O&M costs associated with meter and service-related customer costs, the Company simply estimates the average O&M expense per weighted customer for 2015 and 2016 and adjusts this estimate for inflation. However, it is important to note that the Company's O&M costs have declined in all but one year over the period from 2012-2016, so if the Company would have projected these costs based upon its reported trend, rather than using a historical average with a fixed inflation factor, these marginal O&M expenses would have most likely been lower.

I disagree with his conclusion as well as the description of the calculation.

Dr. Dismukes seems to ignore that the average meter expenses increased by 12 percent in 2014, before falling again in 2015. The MCOSS was conservative in extrapolating a trend because of this irregular change. In the end, the MCOSS did recognize the declining expense trend observed in four of the 5-years, but decided to only average of the last two years of data (2015 and 2016), as opposed to relying on the average over the last five years, which would have resulted in a larger O&M estimate. Ultimately, using a 5-year average would have had a very small impact on the resulting value, no more than 1 percent of the estimated annual residential meter expense of $8.25.

In addition, Dr. Dismukes description is not accurate. The MCOSS did not apply an inflation adjustment to the average meter expense, as he states. The inflation adjustment was applied *before* calculating the two-year average, to have everything in constant dollars.

Q. WHERE ELSE DOES DR. DISMUKES OBJECT TO THE USE OF HISTORICAL COSTS IN THE MCOSS?

A. Dr. Dismukes objects to the calculation of marginal customer accounts and marginal service and informational expenses because the MCOSS averaged different years for each.

Q. DO YOU AGREE WITH THIS CRITICISM?

A. No. The advantage of estimating marginal customer account expenses is that the approach is not constrained to measure the per-customer expenses in any given test year. The goal is to establish the best proxy for each type of expense. They need not to be based on the per-unit cost observed in the same years as customer service and informational expenses because the per-unit expense analysis simply shows different trends in those separate set of accounts. Customer account expenses are declining, overall and on a per customer basis, since 2013, thus the projection is based on an average of the two latest years in the study. In contrast, the marginal informational and service per-customer expense increased in 2015. Thus, using the average of the expense in the last three years acknowledges the lack of a clear declining trend. Choosing the same years would simply not have been justified from the point of view of obtaining the best possible proxy for a future per-customer expense. The breakdown of accounts allows the analyst to perform a disaggregated analysis.

Q. WHAT OTHER CRITICISMS DOES DR. DISMUKES MAKE ABOUT THE METHODS USED IN OTP'S MCOSS?

A. Dr. Dismukes states that the MCOSS does not provide "any considerable insights into the Company's true marginal cost of service.". He does not provide a clear definition of the "true marginal cost of service," or what is, in his view, the right marginal cost concept to apply when using marginal costs for utility ratemaking. He only mentions the issue of average costs in reference to the expenses calculation and the distribution facilities calculation.

Q. DO YOU AGREE THAT IT CAN BE PROBLEMATIC IN SOME INSTANCES USING AVERAGE EXPENSE INSTEAD OF MARGINAL EXPENSES?

A. It is unclear if Dr. Dismukes is referring to the fact that the MCOSS used an average of historical expenses or whether he is referring to the fact that the study computed marginal costs for the average customer in the rate class. I have already discussed above that is standard practice to rely at least partly on some historical data in calculating marginal expenses when a forecast has not been developed. I believe that his objection about considering the facility cost associated with the characteristics of the average customer is also invalid. The alternative would have been to only acknowledge a marginal cost expense when a new customer is added. This is clearly the wrong approach, since it would mean that only new customers impose a cost to the system.

When it comes to, for example, the marginal meter cost, a purely marginal cost-based price signal would reflect the on-going opportunity cost associated with continuing to provide meter service to the existing customer, not only the cost of new meters acquired for new customers over the expected rate period. Unless the customer pays for it up-front, the utility provides a meter and service drop to the connected customer at that customer premise in perpetuity. In fact, the annualized marginal meter cost represents the "rental value" of the meter that grows with inflation over its service life. In other words, the marginal meter cost associated with the existing customer is not zero just because the meter is fully depreciated. As long as the meter provides the same service as a new meter, there is a marginal cost because the company cannot use those facilities for another customer. This method has been adopted widely by utilities in the industry.

Q. DOES DR. DISMUKES PRESENT OTHER CRITICISMS OF THE CALCULATION OF DISTRIBUTION FACILITIES COSTS, OTHER THAN LOOKING AT HISTORICAL COSTS?

A. Dr. Dismukes seems again to object to the "averaging" of costs, in the sense that a dollar per kW of average design demand does not measure the cost of an added kW increment. The MCOSS does not estimate the facilities costs associated with connecting only the new customers that will be physically added to the system in the upcoming years, rather it estimates the cost that is incurred by OTP when connecting the most typical (average customer) in the class. Again, the utility is responsible to provide customer access in perpetuity, unless the site is permanently abandoned. Thus, OTP's MCOSS facilities cost approach needs to look at the current rental value of the average customer connection in the class.

Q. PLEASE EXPLAIN IN MORE DETAIL THE CALCULATION OF MARGINAL DISTRIBUTION FACILITIES COSTS IN OTP'S MCOSS.

A. The MCOSS provides the current installed cost and size of secondary transformer, primary lines, and/or secondary lines for different customer configurations in a rate class, net of up-front customer contributions. It then requires identifying design demand (or connected per-customer load) by customer segment within the class. OTP developed specific costs for generic circuits assuming the typical configurations for each rate class and using the same inventory stocks and prices that are used to price out actual jobs. The method looks at the marginal cost of providing the customer access to the distribution grid. There is an individual marginal cost that is distinct for each customer class, it is not an average cost across all connection facilities in the service area. The costs vary depending on type of area served, including customer density (urban, rural), and type of customer use (industrial versus primarily residential). Rural areas are less dense, thus other things equal, rural distribution facilities marginal costs as well as design demands tend to be larger than in urban areas. Single versus three-phase connections also have different costs. Marginal customer services also vary by customer type.

Q. WHY ARE THE DISTRIBUTION FACILITIES NOT RELATED TO CHANGES IN ON-GOING ENERGY USAGE?

A. The utility will invest in distribution facilities when a customer is initially connected to the grid, and again whenever the facilities are replaced at the end of their service life. At that point, the cost of the new transformer may have changed due to inflation, technological change, or if a different transformer size is required based on a significant change in customer site diversity or type of building in the premise and similar factors.

Aggressive and effective energy efficiency efforts by the connected customers might warrant a lower connected per-customer load, if a smaller transformer size at the time of replacement is enabled by such load reduction. In any case, distribution facilities are determined largely by what can be termed as "design demand." This concept of demand is different from the metered non-coincident "peak" demand that customers exhibit over time. The design demand that distribution planners use may inherently determine having extra capacity in the transformer in the near term to ensure it will accommodate all potential local customers' non-coincident demand in the area in the longer-term – not necessarily coincident with the substation peak – as new customers connect over the service life of the transformer. It is also distinctly different from the distribution system-peak demand at the upstream distribution voltage levels that is more diversifiable and shared. Because of this, marginal distribution facilities costs are more appropriately recovered based on a facility charge and not based on customer's monthly maximum metered demand. This facility charge will use as a billing determinant the customer's design demand or a contract demand.

Q. IS THIS FACILITIES APPROACH WIDELY USED IN MCOSS?

A. Yes. All of OTP's MCOSSs filed in North Dakota, South Dakota and Minnesota have used the facilities method. Further, the facilities method is a well-known and widely used methodology accepted by the regulatory commissions in California, Oregon and Nevada. It is sometimes called the "rental value" method as it is equivalent to reflecting the market value of "renting" the transformer capacity, or the opportunity cost for the utility to provide customer access to that customer versus to another potential customer with similar characteristics who would also want to receive electricity access. The implementation details may vary among utilities. The analysis may look at a review of actual connection jobs over five years, while others estimate the current installed cost for several generic circuits typical of the respective customer class. The latter is sometimes more appropriate than a sample review method if the sample is too narrowly set or if in recent years there has been too little customer growth or replacements. OTP essentially did the standard generic circuit method. Instead of recalculating the costs that had been developed in the 2015 MCOSS (filed as part of OTP's most recent Minnesota Rate Case), OTP used an inflation factor to convert the 2015 typical facility costs by rate class into 2018 dollars.

Q. DO YOU AGREE WITH DR. DISMUKES OBJECTION TO APPLYING AN INFLATION FACTOR TO 2015 MCOSS?

A. No. OTP's use of the 2015 marginal distribution facilities value reflects the fact that the mix of customers by feeder, the transformer size standards, and the size of the customers (average design demands) by rate class, all of which determine the marginal distribution facility cost for the average customer, have not changed in the last three years. There has also not been a change in the line extension policy. Thus, no changes have taken place that have skewed the type of facilities that OTP would normally install for the various connections, and there have been no material changes in cost, other than inflation.

Q. DID YOU PERFORM ANY ANALYSIS TO DETERMINE THE REASONABILITY OF THE ADJUSTMENT TO ARRIVE AT 2018 MARGINAL COSTS?

A. Yes. In order to test the reasonability of the inflation factor that was used in the MCOSS to escalate the facility costs to 2018 levels (3 percent annual), I reviewed the electric cost index (Handy Whitman) for the north-central region. The average inflation factor from 2015 to 2017 was 1.074. The study used 1.06, which is not far off. Hence, the MCOSS' approach should be within the expected range of the current cost of transformer.

Q. DR. DISMUKES STATES THAT BECAUSE CUSTOMERS DO NOT PAY MARGINAL COSTS, THE MCOSS SHOULD BE REJECTED IN THIS PROCEEDING. IS HIS ARGUMENT SUBSTANTIATED?

A. No. As I discussed earlier, pricing according to the "second-best" theory requires that customers pay as close as possible to marginal costs, with a mark-up that takes into account the need to recover fixed costs. A multi-part rate solves the problem of having class marginal costs that do not match the class' revenue target. Rates with prices that track the changes in marginal generation and transmission costs are already used in unbundled states, since they do a pass-through of the market and open access transmission-related costs.

Q. IS DR. DISMUKES'S REFERENCE TO THE NARUC ELECTRIC COST ALLOCATION MANUAL APPROPRIATE IN HIS COMMENTS ON THE MCOSS?

A. I disagree with Dr. Dismukes' reference to the NARUC Electric Cost Allocation Manual in support of his opposition to the MCOSS. Dr. Dismukes states that "The NARUC Electric Cost Allocation Manual notes that many marginal costing methodologies used by utilities are based upon information that is often more average in nature than it is marginal." OTP's MCOSS does not use average book costs. The only instances when the embedded expenses were used (i.e. those included in FERC accounts) are O&M expenses, customer expenses, and A&G expenses. Even then, the MCOSS excludes expenses that are considered non-marginal and it looks as how the expenses may change with load or plant. All other costs in the MCOSS are not embedded or accounting costs.

V. USE OF MCOSS FOR INTRA-CLASS REVENUE ALLOCATION AND PROPOSED RESIDENTIAL RATES

Q. DOES DR. DISMUKES AGREE WITH THE WAY THE MCOSS RESULTS ARE USED BY OTP IN ITS PROPOSED RATE DESIGNS?

A. No. Dr. Dismukes opines that the MCOSS results have been applied in a subjective manner by OTP for rate design purposes. I disagree with this characterization. OTP's proposed rate design is overall consistent with MCOSS results, albeit it includes some ex-post modifications to use some gradualism and to moderate fairness concerns in rate changes. In short, what Dr. Dismukes describes as "subjective" is really a gradualism exercise, in the interest of allowing customers to adapt to bill impacts. This is also explained by OTP in Mr. Prazak's Direct Testimony.

Q. DO YOU FIND THAT OTP RELIED ON SUBJECTIVE APPROACHES FOR RATE SETTING PURPOSES?

A. No. The only meaningful modification that OTP made to the MCOSS is with regard to the seasonal differentiation of the marginal generation capacity cost. The original MCOSS results indicated that almost the full annual marginal generation capacity cost will fall in the summer season. This is consistent with MISO resource adequacy rules, as they stand now, and the fact that summer is the season where MISO currently peaks as a region. The MCOSS determined that less than 1 percent of the probability of the region-wide peak falls in the winter, and so the summer MISO capacity transactions have the most value given the current rules. OTP decided to shift about 40 percent of the annual generation capacity cost to the winter season keeping in mind gradualism,[7] leaving 60 percent of the generation capacity marginal cost assigned to the summer. Again, this ad-hoc adjustment to the MCOSS was largely a rate design exercise by OTP, as opposed to a specific correction to marginal cost method. It seeks to moderate the fixed charge increase that would have likely resulted if the winter per-kWh charge had been set at the unmodified (lower) winter marginal cost.

Q. WHAT IS THE MAIN IMPACT OF THE MODIFICATION TO MARGINAL GENERATION CAPACITY COST BY SEASON?

A. As a result of the adjustment, OTP proposed winter per-kWh charge is higher than the underlying seasonal marginal costs. While this has a potential efficiency cost, since it signals higher opportunity cost to meeting demand in the winter, it can be seen as a phase in of the changes required in residential rates, smooth out on the basis of fairness and gradualism. OTP's rate design adjustments to mitigate rate impacts, while still making use of marginal cost results, are not uncommon. Often, utilities manage expected bill impacts by moderating rate differentials, either seasonally or by TOU periods. SCE and

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[7] The 2009 MCOSS, which was used in designing current rates, reflected the fact that at the time, OTP built its system to meet its peak, which occurs in the winter, not MISO's peak.

PG&E in California followed this approach in their Default TOU Rate applications.[8] OTP's rate design still sets usage charges closer to the underlying near-term marginal cost in each season as compared to the current rates. The proposed summer residential kWh charge is very close to the actual marginal summer cost, 7.86 cents/kWh. The proposed winter residential kWh charge is 2.79 cents above the winter marginal cost, 3.47 cents/kWh.

Q. PLEASE EXPLAIN HOW OTP USES THE MCCOSS TO ALLOCATE REVENUE WITHIN A GIVEN CUSTOMER CLASS.

A. OTP used MCOSS to apply EPMC for certain customer groups within the classes. Marginal cost revenues for a rate class were determined by multiplying the marginal cost times the rate class billing determinants. To avoid unacceptable bill impacts, OTP modified the EPMC shares of class revenue requirement as a first step toward a more efficient and equitable allocation of class revenue requirement among rates. Overall, OTP mostly relies on embedded cost allocations to set class revenue targets.

Q. DO YOU AGREE WITH OTP'S USE OF EPMC METHOD TO ALLOCATE INTRA-CLASS REVENUES TO INDIVIDUAL RATE SCHEDULES?

A. Yes. EPMC is generally used, in states where it is used, to set the starting point for class revenue targets (California, Nevada, Maine), where precise estimates of price elasticities are not known. By using EPMC in the rate classes, OTP is using the assumption that all rate groups have equal price elasticity. EPMC is however, rarely applied without any modifications to it that use other qualitative evidence of customer reaction to prices. For example, in California, the three IOUs predominantly use EPMC as the basis of cost allocation to customer groups, for all customer classes, except for FERC unbundled transmission rates. Class marginal costs are scaled to the total revenue requirement using EPMC but with modifications to moderate rate increases. Southern California Edison

[8] On April 14, 2017, SCE filed A.17-04-015, *Application for Approval of Its Proposal to Implement Residential Default Time-of-Use Rates.*

(SCE) caps EPMC-based allocations during the process of marginal cost revenue allocation to mitigate any effects of a rate shock that may be caused by changes in cost.

Q. IN YOUR OPINION, WHAT IS AN OPTIMAL RATE STRUCTURE FOR RESIDENTIAL CUSTOMERS AND WHAT COSTS SHOULD BE RECOVERED IN EACH RATE COMPONENT?

A. The optional rate structure would be a three-part rate that fully reflects the underlying structure of marginal costs. In particular, this rate would have the following rate components:

1. A monthly customer charge that recovers marginal customer-related costs (meter, service drop, customer-related expenses such as meter reading, billing, customer accounting, and customer information);
2. A monthly distribution facilities charge based on design non-coincident kW, that recovers the marginal costs of local distribution facilities (local primary, transformers, secondary lines);
3. Seasonal and TOD per-kWh charges[9] that recover time-differentiated generation, transmission and distribution substation/trunkline marginal costs.

The fixed charge may also include the marginal monthly distribution facilities costs (calculated on the basis of the average customers' design demand), if a facility charge is not separately included. Recovery of the marginal cost revenue shortfall would be included ideally in the fixed component of the rate, as I will discuss.

Q. WHAT IS THE BEST WAY TO RECOVER COSTS THAT ARE NOT STRICTLY MARGINAL FROM THE VARIOUS RATE COMPONENTS FROM AN EFFICIENCY STANDPOINT?

A. The theory of Ramsey, initially applied to determine fixed cost allocations can be extrapolated to rate components. It is generally intuitive for customers to realize that changes around the monthly bill throughout the year are triggered by the volumetric

[9] In some cases, a metered on-peak demand may be suitable to signal the higher peak costs.

charge. The least price-elastic components (the fixed charge) would receive the higher share of residual costs (or mark-up above the marginal costs if class marginal cost revenues are lower than the revenue target.) It is preferable to reconcile the marginal cost revenue gap in the fixed charges since it is the rate component less likely to affect marginal changes in usage decisions. The only caveat is that customer charges should not be increased to the point that makes a customer disconnect from the grid - it would be an uneconomic bypass. When raising the fixed charge to the required level is unacceptable, the next step is to raise the facilities charge, if there is one for the particular rate class. The last step is to mark up the energy or demand charges. Adding a significant amount of fixed costs – costs that do not vary with usage - to energy charges, distorts efficient usage patterns since those charges influence using more or less electricity in a given month.

Q. DO YOU AGREE WITH DR. DISMUKES STATEMENT THAT FIXED CHARGES DO NOT NEED TO STRICTLY EQUAL FIXED COSTS?

A. Ideally, those costs that do not vary with energy usage should be recovered in fixed charges so as not to distort the volumetric charges. Having said that, I agree that fixed charges do not always need to equal the "fixed" (sunk) costs of electricity service from an efficiency standpoint. Fixed costs, if we understand them as sunk costs, may sometimes be partially recovered in usage charges if necessary to keep volumetric (e.g., per-kWh) charges as close as possible to the underlying, near-term marginal costs. A clear example is when a region or system capacity is strained and requires capacity entry or new investments. In that case the near-term marginal costs will be higher than the costs of the utility's existing bilateral contracts or the variable cost of the utility's own generating plants. Thus, per-kWh charges that are set at near-term marginal cost may collect more than the direct variable cost, contributing to the partial recovery of sunk costs. When that occurs, lowering the fixed charge below the marginal customer and fixed local connection marginal costs is necessary to avoid recovering in excess of the class revenue target.

Q. IS OTP ENDORSING FIXED COST RECOVERY EXCLUSIVELY THROUGH THE FIXED CHARGE?

A. No, it is not. OTP is not endorsing that all the fixed costs from the class' revenue requirement are recovered in the fixed charge. OTP is considering effects on customer affordability. In addition, OTP class' marginal cost-based revenues are also lower than the class' revenue target. Thus, OTP's proposes using marginal customer-related costs as the floor level for the fixed charge.

Q. DO YOU AGREE WITH OTP'S METHOD FOR ALLOCATING THE CLASS COSTS BY RATE COMPONENT?

A. Yes. OTP's proposal to increase fixed charges up to the level of marginal customer-related costs is a definitive improvement with regard to the current rates. It is economically justified, for both efficiency and equity reasons, given the expected relatively low near-term marginal cost conditions (over the foreseeable five-year period). OTP proposed residential rates will effectively recover the marginal cost revenue shortfall from the volumetric (per-kWh) charge, and more so from the winter kWh charge, as opposed to the fixed charge. Overall, OTP has adhered to one of the most important principles in rate design, which is that rate *structures* consider the differences in the costs of providing service to different customer classes.

Q. DO YOU GENERALLY FIND THAT LOW INCOME CUSTOMERS ARE ALWAYS LOW-USAGE CUSTOMERS?

A. Not always. I think that it is important not to assume that low fixed charges guarantee a fair treatment to low-income customers; rather, impact of rate design on low-income customers needs to be considered on a case by case basis. For example, lifeline rates assume a direct correlation between low income and low usage, but studies in the U.S. and other countries have found that this assumption is often not correct.[10] It also does not

[10] See the evidence in Borenstein and Davis Borenstein, Severin and Lucas W. Davis. "The Efficiency and Equity of Two-Part Tariffs in U.S. Natural Gas Markets," The Journal of Law and Economics, vol. 55(1), pp. 75 – 128, 2012.

appear to be correct for OTP, as its usage information shows low-income customers use more energy, on average, than the residential class overall and non-low income residential customers.[11]

Q. DO YOU AGREE THAT OTP'S RATE PROPOSALS DISPROPORTIONALLY AFFECT THE MAJORITY OF LOW INCOME USERS?

A. No. I have reviewed Mr. Prazak's Direct Testimony and his description of the approach used to estimate fixed charges. As per this analysis, I believe that there is no indication that low income customers, on average, use less energy than the average customer in the class. Thus, higher volumetric charges would actually make electricity less affordable than if rates recovered more costs in the fixed charge.

Q. DO YOU BELIEVE THAT OTPS' PROPOSED INCREASED FIXED CHARGE LEADS TO RATE SHOCK?

A. No. I do not find the range of absolute monthly bill impacts associated with OTP's rate design to be a "rate shock", particularly for customers of an investor-owned utility. As a point of comparison, SCE in its 2017 filing of Default TOU rates, considered that increases of up to $150 or 15 percent was not rate shock for purposes of the expected transition towards default TOU rates. Customers with rate changes above these levels were then considered in the segment of "extreme non-benefiter." Rather than modifying the rates to avoid this rate shock, SCE plans to approach this by ensuring that extreme

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Originally issued as NBER Working Paper No. 16653, December 2010. (2012). Similar lack of correlation has been cited in rate cases involving the Commonwealth Edison Company of Illinois or Pacific Gas & Electric Company of California. See also Matthew Bennett, Dudley Cooke, and Catherine Waddams Price, "Left out in the Cold? The Impact of New Energy Tariffs on the Fuel Poor and Low-Income Households," (Center for Management under Regulation, University of Warwick: Coventry, UK, September 2000); and Meg Power, "A Profile of the Energy Usage and Energy Needs of Low-Income Americans," Report for the Association for Energy Affordability, (Economic Opportunity Research Institute, Washington, DC: March 28, 1999). See also Evan Brown, "Energy Performance Evaluation of New Homes in Arkansas," Report prepared for the Arkansas Energy Office, December, 1999".

[11] Prazak Direct, p. 15-18.

non-benefiters will receive extra communication in the form of phone calls from the utility to inform them, prepared and explain the default process.[12]

Q. HOW DIFFERENT WOULD THE RESIDENTIAL FIXED CHARGE HAVE BEEN IF USING A MORE STRICT APPLICATION OF MARGINAL COSTS BY RATE COMPONENT?

A. OTP's per-kWh charges include not only marginal costs that change with usage but also the marginal distribution facilities costs. A pure marginal cost rate design would dictate that the marginal distribution facilities costs is recovered through a separate per-kW of design demand facilities charge, or included in the fixed charge if the kW of design demand was sufficiently homogeneous among customers in the class, for administrative simplicity. If OTP had done the latter design, a rate where the facility cost is recovered in the fixed monthly charge and the per-kWh charges are set at the seasonal marginal cost, I estimated that the required addition to the residential fixed charge residential rate 9.01 would have been about $16.62 extra per month, totaling a monthly charge of $31.85 (assuming no price elasticity effects from the reduction in the winter charge). OTP's proposed charge is $15.23, which is 52 percent lower than the fixed charge that would have been needed in the alternative marginal cost-based rate design. It is expected that if customers responded to the lower winter charge by increasing their usage, the required increase in the fixed charge would be somewhat lower than these estimates.

Q. ARE THE OBJECTIONS OF DR. DISMUKES TO INCREASING RESIDENTIAL FIXED CHARGES JUSTIFIED?

A. No. Dr. Dismukes seems to be dismissing a wide body of academic and industry literature on the importance of using marginal cost-based price signals when setting electricity price levels and deciding the level of fixed charges relative to energy charges. Dr. Dismukes seems to focus on the impact on customer's monthly bills ignoring that low fixed charge would produce inter and intra-class cross-subsidies by including too much

[12] SCE's Advice Letter (AL 3500-E-A), March 15, 2017, in the context of CPUC's Decision D.15-07-001.

recovery in the per-kWh charge. In addition, high usage customers, which OTP data indicates includes many low-income customers, would actually be more negatively affected under Dr. Dismukes's approach.

Q. ARE THERE OTHER WAYS TO SUPPORT LOW INCOME USERS MORE EFFICIENTLY THAN THROUGH A LOWER FIXED CHARGE?

A. Yes. It is more efficient to provide a subsidy or bill protection mechanism to low income users, rather than resolving income distribution with prices that set low fixed charges for all customers in the class. Separate customer charge credits or direct payments can be provided, based on income eligibility to specific low-income customers, or through low income special programs outside of standard residential rates. For example, Oklahoma Gas & Electric provides a $10/month credit applied to the customer's bill to eligible low-income residential customers deemed qualified by the Oklahoma Department of Human Services. California has a specific low-income program (CARE)[13] program under which qualified low-income customers buy electricity at discounted tariffs, including a lower minimum bill than the standard rate. The loss in revenue is quantified recovered from all other customers. The United Kingdom provides direct "winter fuel payments" to vulnerable, low income customers to financially support their use of space heating, as well as other specific payments in severe winter weather conditions (the "Cold Weather payment") while keeping their rates intact.[14]

Q. HAVE OTHER INVESTOR OWNED UTILITIES SET RESIDENTIAL FIXED CHARGES ALONG THE SAME LEVELS AS OTP?

A. Yes, Figure 2 of Mr. Prazak's Direct Testimony indicates that all North Dakota IOUs have residential customer charges that are comparable to OTP's proposal. Nationwide, we find other examples of IOUs where monthly residential fixed charges are set higher than $15. Examples include: Central Hudson Gas and Electric ($24), RG&E ($22),

[13] California Alternate Rates for Energy (http://www.cpuc.ca.gov/PUC/energy/Low+Income/care.htm).

[14] https://www.gov.uk/cold-weather-payment.

NYSEG ($15.92), Madison Gas & Electric ($21.85), and ConEd ($15.76). Municipal utilities' residential rates tend to include customer charges comparable to those proposed by OTP. For example, Salt River Project's residential rate has a monthly fixed charge of $20. California municipal utility SMUD has a fixed charge of $20.30.

In addition to California utilities, others, including RG&E and NYSEG have used marginal cost studies to support an increase in fixed charges. Although they mainly rely on the results of an embedded cost study for class revenue allocation, they use MCOSS for rate design structures. The fixed charge includes the marginal cost associated with serving an additional customer added to the system and a portion (or all) of the local distribution costs (poles, wires, transformers) in the fixed charges.

Q. DO YOU BELIEVE THAT OTP'S PROPOSAL OF A HIGHER FIXED CHARGE MAY INEFFICIENTLY REDUCE CUSTOMERS' ENERGY CONSERVATION EFFORTS?

A. No. Best practice ratemaking aims to maintain or increase the incentives to use the system efficiently and to conserve when it is valuable to the system to do so. Energy conservation regardless of avoided cost has never been a goal per se of best practice ratemaking. Efficient price signals should, in fact, encourage higher electricity consumption outside of peak hours and outside of the peak months, where there is excess of generation capacity and unused network capacity. Even at peak hours, customers should not be discouraged to use more electricity if they would have been willing to pay the cost incurred by the utility to procure and deliver the additional electricity to them at peak hours. By pricing electricity usage at an artificially high per-kWh charge that exceeds the observable near-term marginal costs, customers may inefficiently adopt energy efficiency measures that lower their consumption even though the foregone value is lower than the avoided system cost. This conservation, if rates are not time of use, may also take place at times where the system is not constrained, such as in shoulder and off-peak hours. This is the outcome that any optimal pricing policy should avoid, because the "consumer surplus" is reduced, without a transfer to the producer, thus society welfare overall is lower. The fact that conservation at any cost is not consistent with public policy is also explained in Mr. Prazak's Direct Testimony.[15]

Q. WILL HIGHER FIXED CHARGES DECREASE INCENTIVES TO INVEST IN ENERGY EFFICIENCY ELECTRIC APPLIANCES?

A. Not necessarily. Customers will generally invest in energy efficiency if the present value of the investment in energy efficiency is lower than the present value of the benefits, including lower electricity bills. OTP's proposed residential energy charges are only 0.918 cents lower in the winter and 0.289 cents lower in the summer than the current rates. This small price differential should hardly be expected to significantly impact the net present value of any energy efficiency solution, much less to make it become negative. Finally, it is important to note that the proposed summer and winter charges are higher than the corresponding seasonal marginal cost as estimated in OTP's MCOSS, by about 2.09 cents and 2.15 cents respectively (after OTP's modification to capacity cost by season). They are also above the original seasonal marginal cost (0.33 cents in the summer and 2.78 cents in the winter). The proposed residential summer charge is also higher than the per-kWh marginal costs after accounting for OTP's adjustment of the generation capacity cost allocation by season. With a strictly applied marginal cost rate, the per-kWh winter charges would have been lower. Thus, OTP's proposed rates still provide customers with an incentive to conserve electricity that goes beyond what a purely marginal cost rate would dictate. In any case, targeted interruptible rates, dynamic rates such a critical peak pricing and load direct control do a better job at providing energy conservation incentives in standard rates.

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[15] Prazak Direct, p. 21-22.

VI. CONCLUSION

Q. WHAT IS YOUR FINAL CONCLUSION ON DR. DISMUKES' CRITIQUE OF OTP'S MCOSS?

A. OTP's MCOSS employs sound marginal cost estimation techniques from a utility rate design perspective. The MCOSS is consistent with the methods in prior MCOSS submitted in North Dakota. It relies on OTP's underlying planning and operational cost structure as a member of MISO, and with OTP's customer characteristics and connection policy going forward. I recommend that the Commission accept the Company's MCOSS.

Q. WHAT IS IN YOUR OPINION THE STRONGEST FEATURES OF OTP'S RATE STRATEGIES?

A. OTP's rate design is consistent with marginal costs, while also respecting the gradualism principle and moderated bill impacts. Overall, the proposed rates are a significant step closer to economically-efficient rates. OTP makes sure that the structure, the direction of the price increases by rate component and seasonality in the proposed rates are more aligned with the underlying marginal cost estimates than the current rates. By increasing fixed charges to at least marginal customer-related costs, the equity goal is also served, since cross-subsidies are less likely to occur. The Company's proposed rates are generally consistent with marginal cost principles. A pure marginal cost-base rate design would have resulted in even higher fixed charges, given the low marginal cost conditions expected in the region and in OTP's system. OTP's rate design recognizes that while a primary goal of rate design is to seek economic efficiency, there are also fairness considerations.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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Amparo Nieto is an energy economist with over twenty years of energy industry experience. She provides advice to utilities, independent system operators and energy regulatory commissions as they address complex regulatory challenges involving pricing, economic, and market design issues. Her consulting engagements involve entities and regulators in the US, Canada, Latin America, Europe, Oceania, and the Caribbean.

In the US, Ms. Nieto has directed an extensive number of energy regulatory projects involving major utilities in California, Nevada and Oregon, as well as utilities in NYISO, MISO, PJM, SPP and ERCOT. She has provided expert testimony before state public utility commissions on behalf of energy utilities on electricity and natural gas marginal cost analysis, electricity rate structures, reforms to tariffs for customers with distributed generation, evaluation of net metering and efficient power contract design. She has developed cost-benefit analysis of utility demand response programs, interruptible rates, and smart rates.

Ms. Nieto has authored expert reports on electricity sector restructuring policies and wholesale energy market design in Europe and Latin America. She has advised energy regulators and independent transmission operators in the US and Alberta on transmission planning, cost allocation, and planning reserve margin analysis. Ms. Nieto involved in the implementation of default service auctions on behalf of utilities in Illinois, Pennsylvania and Spain, as well as on the design of renewable resources in Mexico.

Ms. Nieto directs the Utility of the Future Rates Group (UFRG), a membership-based utility working group attended by senior executives from North American energy utilities. The group provides a forum for discussion of innovative rates, cost analyses and regulatory reforms to adapt to the expansion of distributed energy resources. For over ten years, she has conducted seminars on electricity marginal cost of service methods and best practice electricity ratemaking. These seminars were attended by energy utilities and state commissions from the US and overseas.

Ms. Nieto has published energy papers in The Electricity Journal and frequently speaks on energy regulatory topics at various industry forums.

Professional Experience

Economists Incorporated (San Francisco)

Senior Vice President — Dec 2017 – present

NERA Economic Consulting

Associate Director / Vice President (Los Angeles) 2000 – 2017

Consultant (Madrid, Spain) 1997 - 1999

Education

Master's Degree in Economics, Institute for Fiscal Studies, Madrid, Spain

Advanced microeconomics, macroeconomics, econometrics and micro-econometrics, public policy and optimal fiscal theory.

B.A., Economics (Honors), University of Carlos III, Madrid, Spain

Concentration on microeconomics, competition and industrial economics, financial analysis, econometrics.

Selected Consulting Assignments

Electricity Cost Studies, Rate Design, Pricing for Distributed Energy Resources

Various North American Electric Utilities, 2000 – present. Advised and testified on the development of electricity marginal cost studies, analysis of the value of new demand response rates, solar PV, customer contracts, design of time of use electricity tariffs, standby rates. Examples of utility clients include:

- Central Maine Power Company, Maine
- Rochester Gas and Electric, New York
- New York Service Electric and Gas, New York
- Sierra Pacific Power Company and Nevada Power d/a/a NV Energy, Nevada
- Sacramento Municipal Utility District (SMUD), California
- Los Angeles Department of Water and Power (LADWP), California
- Salt River Project (SRP), Arizona
- Con Edison, New York
- Otter Tail Power (OTP), Minnesota, North Dakota, South Dakota
- Xcel Energy, Minnesota
- Eversource Energy, New Hampshire
- MidAmerican Energy Company, Iowa
- Eugene Water and Electric Board, Oregon

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- o Iberdrola, Spain
- o NB Power, New Brunswick, Canada
- o Manitoba Hydro, Manitoba, Canada
- o BC Hydro, British Columbia, Canada
- o Newfoundland Labrador & Hydro, Newfoundland, Canada

Avangrid, New York. Advised in setting the basis and workplan to develop a locational distribution marginal cost study, to be used for a compensation of Distributed Energy Resources (DERs), as directed by the Commission VDER Order within the Reforming the Energy Vision (REV) proceeding.

Southern Company, US. Reviewed the company's proposed approach to undertake loss of load expectation analysis and recommended improvements. Provided guidance to develop capacity cost allocation factors for demand response programs and new customer evaluation.

NB Power, New Brunswick, Canada. Recommended approach to estimate the incremental costs to the utility when customers opt-out of smart metering, taking into account the pace of smart meter deployment plans. Provided rate design recommendations in the light of smart grid investments.

Abu Dhabi, UEA. Advised on the reform of distribution rates and suitable mechanism to undertake cost allocation based on marginal costs. Proposed revision to existing electricity cross-subsidies.

Electricity Regulatory Board (ERB), Kenya, Africa. Co-authored an Electricity Tariff Policy for ERB, aimed at improving the financial health of the sector and promoting the efficient expansion of electricity service. Developed financial models for calculation of utility revenue requirement and provided on-site training to the ERB staff. Designed the pricing terms of a new sample Power Purchase Agreement between the incumbent generator (KenGen) and the distribution utility (KPLC).

Barbados Federal Trade Commission, Barbados. Directed the team advising the Barbados energy regulatory commission during Barbados Power and Light (BP&L)'s rate application. Assessed the utility's estimated cost of capital and revenue requirement, the embedded and marginal electricity cost methods used by the utility to allocate costs to customer classes and time of use rate proposals.

Iberdrola, Spain. Member of the energy practice team advising a large Spanish electric utility regarding its regulatory strategy in preparation for the restructuring of the electricity sector in Spain as well as general advise in a broad range of regulatory issues involving retail access, stranded cost analysis and open access tariffs. Participated in industry working groups in charge of proposing detailed policy rules.

Wholesale Market Design, Competition Analysis

Analysis of utility mergers, various utilities, US. Review the competitive impact on electricity markets of a number of proposed utility mergers. Analyzed potential horizontal and vertical market power impacts.

Commission for Energy Regulatory of Ireland, Ireland: Member of the market design team for the all-island electricity market. Design of options for a Capacity Payment Mechanism on the island of Ireland that would be viable and sensible in the context of the Irish electricity market.

Independent System Operator (ISO) of New England, US. Advised the ISO-NE on revisions to ISO's Forward Capacity Market (FCM), with regard to the *Alternative Capacity Price Rule.*

Ministry of Energy, Argentina. Comprehensive review of the Argentine wholesale electricity market and their impact on competition. Recommended revisions to market rules.

PECO Energy Company, Pennsylvania, US. Manager of the Independent Evaluator team that administered the Default Service Supply auctions on behalf of PECO Energy Company. Prepared assessment report evaluating the competitiveness of the auction and results for the Commission's review.

Design and Monitoring of Energy and Capacity Auctions

First Energy, Philadelphia, US. Administered Default Service Supply solicitations via a descending-clock auction on behalf of Met-Ed and Penelec utilities in Pennsylvania. Authored the report evaluating the competitiveness of the auction and results for the Commission's review.

Ministry of Energy (SENER), Mexico: Advisor to SENER regarding the development of a procurement auction to procure multiple renewable technologies across a variety of time-frames.

Spanish National Energy Commission (CNE), Madrid, Spain. Administered the default service electricity supply ("CESUR") auctions on behalf of the large distribution companies in Spain and Portugal. Assessed the bidders' competitive behavior and prepared an assessment report. Advised the Commission during the discussions that led to major energy sector restructuring legislation.

Renewable Resources Integration and Incentive-Based Regulation

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UK Energy Networks Association, UK. Advisor to the Association on evaluating a potential reform of electricity distribution network planning standards to account for new developments, such as the emergence of smart grids and distributed resources.

Grid Australia, Sydney, Australia. Advisory services regarding Performance-Based Regulation (PBR) methods for electricity network.

Edison Electric Institute (EEI), US. Co-author of report "Making a Business of Energy Efficiency: Sustainable Business Models for Utilities". A report on incentive mechanisms to achieve utility goals for energy efficiency and demand response.

Iberdrola, California, US. Reviewed long-term forecasts of fuel costs, energy market conditions, and regulatory policy to assess the potential growth outlook for wind and solar generation resources in California over a 20-year horizon.

Regulatory Office for Network Industries (RONI), Slovakia. Directed the NERA team that assisted the Slovakian regulatory commission on the design of efficient support mechanisms for renewable energy sources and a reliable system of issuing guarantees of origin for RES. Trained the commission staff on best practice RES regulation.

Illinois Power Agency (IPA), US. Assessment of parameters and benchmark analysis for Solar Renewable Energy Credits (SRECs) in the context of the auction held by Ameren Illinois Company and Commonwealth Edison to procure RECs from solar distributed generation resources.

Southern California Edison, Los Angeles, California, US. Member of the team that advised the utility's Supply Group on improvements to the mechanism for contracting with renewable generation resources.

Various utilities, USA. Provided assessment of impact of solar distributed generation on the utility's avoided costs and net revenues. Recommended or evaluated revisions to tariff structures to avoid large cost shifting among customers and inequity concerns.

Transmission Planning and Cost Allocation

Australian Energy Market Commission, Australia. Critiqued the proposed revisions to the electricity market rules in Australia regarding firm transmission access and rights. Analyzed the suitability of Financial Transmission Rights, or their equivalent, for the Australian market. Conducted a survey of international transmission planning and cost-allocation methodologies in an earlier assignment.

TransGrid, Australia. Reviewed transmission planning and pricing policies, including arrangements to introduce competitive solicitations and non-wires alternatives in long-term transmission planning.

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Alberta Electric System Operator (AESO), Calgary, Alberta. Analyzed AESO's cost study and recommended revisions to improve transmission tariffs and cost allocation approach.

Commission for Energy Regulatory of Ireland, Ireland. Participated in the drafting of the all-island electricity market rules and recommended changes to the Transmission Use of System (TUoS) charges for the Republic of Ireland.

NYISO, New York, US. Provided recommendations to the New York Independent System Operator for a reform of their Black Start service compensation mechanism as part of the ISO Tariff.

SELECTED TESTIMONIES AND EXPERT REPORTS

"Otter Tail Power Company's Marginal Cost of Generation, Transmission and Distribution Service, Final Report." February 16, 2018. Report submitted to support OTP's 2018 South Dakota electricity rate case.

"Central Maine Power Company's Marginal Cost of Electricity Distribution Service, Final Report." October 30, 2017. Study report submitted in preparation of CMP's 2018 distribution rate case.

Expert Report: "A Review of Southern Company's Reserve Margin Methodology and Capacity Worth Factor Approach". Prepared for Southern Company, October 9, 2017.

Expert Report, SRP's Board of Directors: "Review of Salt River Project's Electricity Marginal Cost of Service Study and Proposed Rates for Net Metering Customers", August 2017.

Expert Report: "Review of Sacramento Municipal Utility District's Marginal Cost Study and Proposed Design of Residential Time of Use Rates". November 27, 2016.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony: "Marginal Costs, Revenue Reconciliation and Rate Design for Net Metering Customers", In the Matter of the Application of Sierra Pacific Power Company d/a/a NV Energy for Authority to Reform Rates for Electric Utility Service in 2016 General Rate Case. October 31, 2016

Before the Public Utilities Commission of the State of Minnesota, Rebuttal Testimony: "Fixed Charges, Marginal Cost Study and Rate Design Policy", In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota, September 12, 2016.

Salt River Project vs. Solar City, Law Suit, US. Deposition testimony regarding expert report and analysis of SRP's rate reform for solar customers. August 2016.

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Before the Public Utilities Commission of the State of Minnesota, Testimony: "Fixed Charges and Rate Design Policy", In the Matter of the Rate Application of Otter Tail Power Company in Minnesota, February 2016.

Before the Modesto Irrigation District Board of Directors, expert presentation: "Review of MID's Solar PV Cost-Shifting Analysis", California, April 2016.

Expert Report: "Assessment of Otter Tail Power Company's Interruptible Rate Portfolio and Development of Dynamic Rates", prepared for Otter Tail Power Co. November 2015.

Before the New York State Public Service Commission, Direct Testimony: "Rochester Gas & Electric Corporation Electricity and Natural Gas Marginal Cost of Service Studies", June 2015.

Before the New York State Public Service Commission, Direct Testimony: "New York State Electric and Gas Electricity and Natural Gas Marginal Cost of Service Studies", June 2015.

Before the Salt River Project Board of Directors, Testimony: "Review of SRP Proposed Residential Customer Generation Price Plan", February 2015.

Before the State of North Carolina Utilities Commission, Testimony: "Review of Alternative Application of the Peaker Method Proposed by EPCOR USA North Carolina LLC with respect to Computation of Avoided Energy and Capacity Costs", July 23, 2010.

Before the New Brunswick Board of Commissioners of Public Utilities, Testimony, with Wayne Olson: "The Role of DSM and Demand Response in Load Forecasting and Integrated Resource Planning", on behalf of the New Brunswick Public Intervener, November 9, 2006.

SELECTED PRESENTATIONS

"Estimating the Value of Distributed Energy Resources and Implications for Rates", presented at the California Municipal Utility Rates Group, May 2018.

"Marginal Cost Methods and Efficient Rate Design", presented at the Utility of the Future Rates Group, San Francisco, California, April 2018.

"Value-Based Tariff Model for Distributed Energy Resources: Principles and Framework Options". Presented at 30th Annual Western Conference (CRRI), Monterey, California, June 28, 2017.

"Regulatory Incentive Methods for Electricity Distributors: Emerging Trends", with Richard Druce. Presented at Rutgers University's 29th Annual Western Conference (CRRI), Monterey, California, June 23, 2016.

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"Renewable Microgrids: Getting the Pricing Right". Presented at the Marginal Cost Working Group (MCWG), Washington, D.C., May 5, 2016.

"Policy Options to Address Cross Subsidies from Self-Generation". Presented at the 12th Annual National Law Seminars International Conference on Electric Utility Ratemaking, Las Vegas, Nevada, March 14, 2016.

"Demand Charges and their Role in Net Energy Metering". Presented at the "Residential Demand Charges Symposium", EUCI, Calgary, Canada, December 1, 2015.

"Utility Regulation in the Era of Distributed Renewables: Is There a Need for a New Business Model?". Presented at Rutgers University's 28th Annual Western Conference (CRRI), Monterey, California, June 26, 2015.

"Solar Distributed Generation and Rate Restructuring". Presented at the California Municipal Rates Group (CMRG), Sacramento, California, May 18, 2015.

"Integrating Renewable Resources through Capacity Markets: The Case of California". Presented at Law Seminars International's Energy in California Conference, San Francisco, California, September 16, 2014.

"Rate Design Options to Deal with Solar Net Metering Concerns". Presented at the California Municipal Rates Group (CMRG), Sacramento, California, April 25, 2014.

"Capacity Markets Put to the Test: New Approaches to Meet Evolving Reliability Needs". Presented at Rutgers University's 27th Annual Western Conference (CRRI), Monterey, California, June 26, 2014.

"Connecting Wholesale and Retail Pricing: A Look at Required Policy and Market Design Decisions". Presented at the Harvard Electricity Policy Group (HEPG), Dana Point, California, March 7, 2013.

"Demand Response and its Role within Wholesale Energy and Capacity Markets". Presented at Rutgers University's 25th Annual Western Conference (CRRI), Monterey, California, June 2012.

"Achieving Efficient Demand Response through Dynamic Rates". Presented at Law Seminars International's Electric Ratemaking Conference, Las Vegas, Nevada, February 9, 2009.

"Critical Peak Pricing: A Marginal Cost Approach". Presented at the Marginal Cost Working Group (MCWG), Phoenix, Arizona, April 2008.

"Electricity Rate Structure Design: Sector Issues in Rate Design, Marginal and Embedded Cost Studies". Delivered at the University of PURC's World Bank International Training Program on Utility Regulation and Strategy, Florida, January 16, 2007.

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"Demand Bidding Programs in ISO/RTO Environments". Presented at the Marginal Cost Working Group (MCWG), Austin, Texas, October 12, 2006.

"Responding to EPAct 2005: Looking at Smart Meters for Electricity, Time-Based Rate Structures, and Net Metering". Sponsored by Edison Electric Institute, May 2006.

"Locational Generation Capacity Payments in New England". Presented at the Marginal Cost Working Group (MCWG), Albuquerque, New Mexico, April 27, 2005.

"Analysis of the International Experience with Performance Based Regulation". Presented at the Marginal Cost Working Group (MCWG), Nevada, April 3-5, 2000.

SELECTED ENERGY PUBLICATIONS

"Optimizing Prices for Small-Scale Distributed Generation Resources: A Review of Principles and Design Elements", *The Electricity Journal*, April 2016.

"Wholesale Energy Markets: Setting the Right Framework for Price Responsive Demand". *The Electricity Journal*, December 2012.

"The Role of Demand Response in the Efficiency of Electricity Wholesale Markets". *Papeles de Economía Española,* Madrid. Issue 134, December 2012.

"Locational Electricity Capacity Markets: Alternatives to Restore the Missing Signals". *The Electricity Journal*, Volume 20, March 2007.

"The Line in the Sand: The Shifting Boundary between Markets and Regulation in Network Industries." Co-author. NERA book, September 2007.

"Performance-Based Regulation of Electricity Transmission in the US: Goals and Necessary Reforms". NERA's Newsletter *Energy Regulation Insights*, Issue 28, March 2006.

"Analysis of the Electricity Sector in Spain". Utility Regulation in the EU. Privatisation International and Centre for the Study of Regulated Industries (CRI), *Utility Regulation 2000 Series*, Volume 1, June 2000.

LANGUAGES

English (fluent), Spanish (fluent)